Byron Energy Ltd

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MST Access

A research platform of MST Financial

8 December 2023

This is a revised version of the note published 5 December 2023

Strategic focus on USA paying off.

NEED TO KNOW

- Byron is growing a successful USA Gulf of Mexico (GoM) oil & gas business by applying deep experience and high-tech exploration to known fields. It is undervalued on reserve and DCF measures.
- Production costs are low, cash flows are robust and the balance sheet is strong. Recent drilling success provides growth and informs future drilling activity.
- Positive macro with high oil prices, supportive USA Government and stable and attractive fiscal regime.

Byron applies cutting edge technology and deep experience to acreage that hosted previous production, with success delivering strong growth in production to the current ~2000 bopd of oil and 5 mmcfd of gas (net to Byron) and material revenue and cash generation, from a nil base in 2017.

There is a large inventory of prospects for future drilling. Recent drilling success at SM58 steps-up production over the outlook, and upgrades targets for the next phase of development, funded by a conservative balance sheet, and operating cashflow. Byron is undervalued on absolute cash-flow measures, and peer group reserves-based valuations.

The USA is receptive to the oil and gas industry with entrenched fiscal and operational rules, providing confidence that Byron can commercialise successful drilling results rapidly and in a cost-efficient manner.

Investment case

Inventory of undeveloped reserves and resources provide exploration targets over the outlook. The geological risk is low and development times are short. Cash and cashflow, conservative balance sheet and potential to forward-sell oil provides funding for growth.

The USA oil sector is a supportive investment location. The legal and regulatory regime is entrenched, product pricing is transparent in a deep-market and geology is well known from thousands of wells. These factors attenuate commercial and financial risk.

Byron is undervalued compared to absolute DCF of proven reserves, and peers based on reserves and profit measures. We forecast EV/EBITDAX of 1.7X in FY2024, 1.4X in FY2025, and EV per boe of US$3.6/boe for 19MMboe of 2P.

Valuation: A$0.49

Our Valuation is a SoP of 2P production in the GoM, and risked upside from exploitation of 3P reserves and prospective resources.

Risks

Cashflows are determined by USA energy prices which are volatile. Operationally, production wells may not perform as expected with downside to reserves and future production. Exploration wells may fail to discover oil or gas with negative consequences. Up-front well costs are high and increases financial risk if drilling results are negative. Access to growth capital is at risk from societal backlash on fossil fuel production.

Equities Research Australia

Energy

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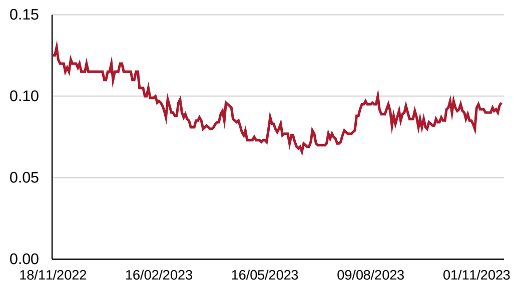
Byron Energy is a USA oil and gas exploration and production company focused in the shallow waters of the Gulf of Mexico.
https:www.Byronenergy.com

Valuation	**A$0.49**
Current price	**A$0.115**
Market cap	**A$124M**
Net Cash	**US$3.4M (Sept 30 2023)**

Upcoming Catalysts and News flow

Period	
4Q CY23	Initial production from G4 & G6 wells.
1Q CY24	Increased production and revenue
CY CY24	Additional SI-58 wells (G7, G8)

Share Price (A$)

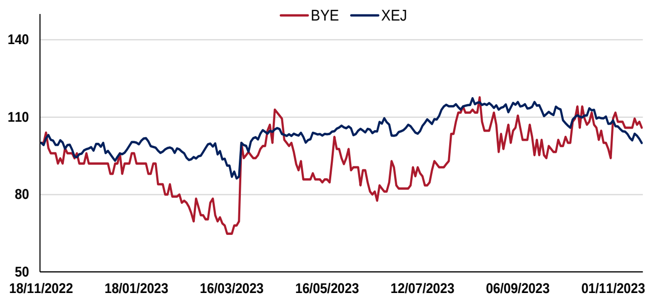


Source: FactSet, MST Access

Figure 1: Financial summary. Figures all in US$ unless otherwise stated. Financial year end: June 30

Market Data	Y/E Jun 30		Lo	Hi
Share price	A$/sh	0.105		
52 week range	A$/sh		0.12	0.22
Shares on issue	M	1081		
Options	M	2.00		
Market Cap	A$M	114		
Net Cash	A$M	5.6		
Enterprise Value	A$M	108		
A$/US$ conversion	cents	0.63		
EV / boe -2P	US$/boe	3.59		

Chart



Valuation multiples	2022A	2023A	2024E	2025E	2026E
EPS (US cents)	0.02	0.02	0.02	0.03	0.04
PE	3.4	3.3	3.5	2.6	1.8
DPS (US cents)	0	0	0	0	0
Yield-%	0	0	0	0	0
EBITDAX/sh (US cents)	0.04	0.04	0.04	0.05	0.06
P/FCF	2.0	1.9	1.8	1.5	1.2
EV/EBITDAX	1.9	1.8	1.7	1.4	1.1
Revenue/boe (US$/boe)	72.5	77.6	67.4	69.0	75.9
EBITDAX/Sales-%	61%	60%	58%	61%	64%
Net cash (Debt)	-7	-1	-11	-7	23
ND/(ND+E)	NM	NM	7%	4%	-11%
Realised prices	**2022A**	**2023A**	**2024E**	**2025E**	**2026E**
Gas-US$/mmBtu	5.41	4.52	2.74	2.95	3.04
Oil-US$/bbl	83.37	76.47	75.46	75.03	77.28
A$/US$ rate	0.7	0.67	0.63	0.63	0.63
Production (Net)	**2022A**	**2023A**	**2024E**	**2025E**	**2026E**
Gas- Bcf	2.30	1.61	2.19	2.32	2.00
Liquids (MMbbl)	0.52	0.58	0.66	0.77	0.91
MMboe	0.9	0.8	1.0	1.2	1.2
% liquids	57%	68%	65%	67%	73%

Net Reserves (MMboe)	1P	2P	3P	Prosp.
Oil- MMbbls	8.5	13.8	18.6	18.4
Gas- Bcf	23.2	31.0	36.4	208.2
Total	12.4	18.9	24.7	53.0
% oil	72%	73%	75%	35%

SoP Valuation	Unrisked	RF	Risked
Production	US$M		US$M
Oil & gas production 2P	336	100%	336
3P upside	71	25%	18
Prospective reserources			
SM-71	50	15%	7
SM-58	203	15%	30
SM-69	7	15%	1
GI 63/72	1		1
Corp costs	-60		-60
Total E&P assets	606		333
Cash	17		17
Debt / Provisions	-13		-13
Total Equity value	**610**		**337**
Per share- US$	**0.56**		**0.31**
Per share- AUD	**0.89**		**0.49**

Income (US$)	2022A	2023A	2024E	2025E	2026E
Gas Revenue (NRI)	11.6	8.0	6.2	6.8	6.
Oil Revenue (NRI	40.6	44.4	50.0	57.8	70.
Total sales NRI	53.1	53.0	56.2	64.6	76.
Sales Revenue (W.I)	65.2	65.4	69.3	79.8	94.
Opex	7.5	9.1	10.8	10.8	10.
Royalties	11.6	11.9	13.2	15.2	18.
G&A	6.4	5.1	5.0	5.0	5.
EBITDAX	**39.6**	**39.3**	**40.4**	**48.8**	**60.**
Exploration exp.	3.1	3.1	0.0	0.0	0.
Depreciation	12.1	11.9	16.5	18.5	19.
EBIT u/l	24.5	24.3	23.9	30.3	40.
Finance charges	2.3	1.6	3.6	2.9	1.
Tax	0.0	0.0	0.0	0.0	0.
NPAT-underlying	**22.2**	**22.7**	**20.3**	**27.4**	**39.**
Significant items	0.0	-1.7	0.0	0.0	0.
Reported NPAT	22.2	21.0	20.3	27.4	39.
Share count EOP (M)	1040	1081	1081	1081	108
Cash flow (US$M)	**2022A**	**2023A**	**2024E**	**2025E**	**2026E**
Receipts	60.7	69.0	69.3	79.8	94.
Payments	-21.7	-27.2	-29.0	-31.0	-33.
Payments for E&A	0.0	0.0	-1.0	-1.0	-1.
Interest & other	-2.4	-1.3	-3.6	-2.9	-1.
Net cash from ops.	36.6	40.6	35.7	44.9	58.
Exp & Devb capex	-25.5	-34.0	-45.2	-40.7	-28.
Acquistions / other	0.0	0.0	0.0	0.0	0.
Net investing	-25.5	-34.0	-45.2	-40.7	-28.
Equity issuance	0.0	0.0	0.0	0.0	0.
Debt Issue	-1.1	-16.4	17.5	-5.0	-5.
Divs / other	0.0	0.0	0.0	0.0	0.
Net cash Finaning	-1.1	-16.4	17.5	-5.0	-5.
Increase in cash	9.9	-9.8	8.0	-0.8	23.
Cash at EOP	14.1	4.2	12.2	11.4	35.
Balance sheet (US$M)	**2022A**	**2023A**	**2024E**	**2025E**	**2026E**
Cash	14	4	12	11	3
Rcvbls / Inventory	10	7	12	14	1
P, P & E	3	2	2	2	
Exploration & eval	122	128	158	181	19
other	3	4	1	1	
Total Assets	**151**	**144**	**184**	**208**	**24**
Patables	17	4	4	-1	-
Debt	21	6	23	18	1
Other	7	7	8	10	1
Total liabilities	46	16	35	27	1
Share-holder funds	106	128	149	181	22

Source: MST Access

Investment summary: Success in the US GoM

- Operator of low cost oil and gas fields in shallow waters in the USA Gulf of Mexico (GoM).
- Portfolio of low geological risk drilling targets near to existing production facilities.
- Exploration leases with significant resource potential for future drilling.
- Proven strong financial and operational track record in converting drilling to revenue.
- The USA GoM is geologically understood, has a vibrant services sector, is fiscally stable and with supportive regulatory agencies.

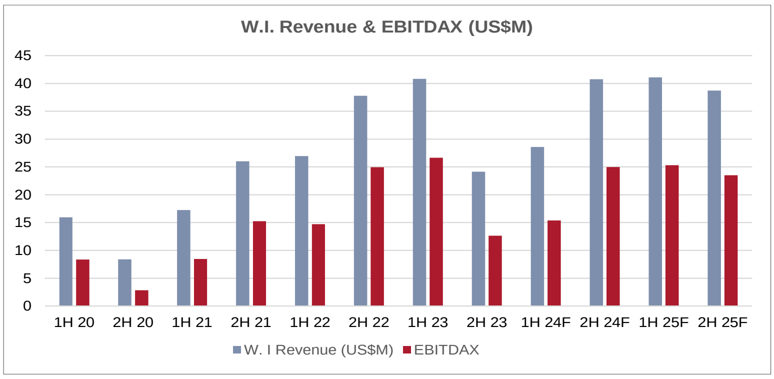
Byron listed on the ASX in March 2013 and is focused on oil and gas exploration and production in shallow waters in the USA Gulf of Mexico (GoM) offshore where the executive team have considerable experience, and where costs, logistics and capital markets are supportive of small companies in general.

Byron's strategy is to couple its in-house capability from decades of working in the GoM, with proprietary tools and the latest cutting-edge technologies to acreage that has been previously explored or produced. Byron has been very successful since drilling its first well in 2017 and initial production in 2018. Following on has been low-cost facilities development, growth in production from drilling at SM-58, and growth in revenue and reserves. Figures 2 & 3.

Byrons's cash operating costs are low, averaging ~US$ 7/boe over the previous 5 years. Reserves are biased to gas but revenue is dominated by higher value oil resulting in high cash margins, with average EBITDAX/ revenue of 58% since FY2018 to June 2023, on a net revenue interest (NRI) basis.

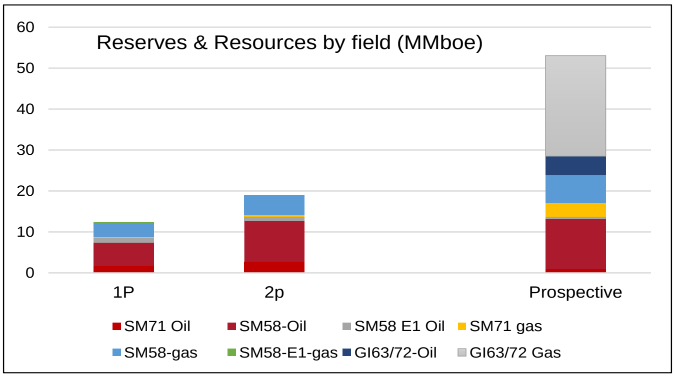
Over the outlook, Byron plans to apply its in-house expertise to the portfolio of undrilled prospects where chances of success are high, in addition to exploiting the existing production assets. In FY 2024, we forecast growth in production, revenue and cashflow from the G4 and G6 wells drilled on lease SM58 in 3Q CY2023. The SM58 lease has significant 2P reserves and multiple drilling targets. We anticipate more drilling at SM58 in cy 2024.

Figure 2: Revenue & EBITDA growth (US$M)



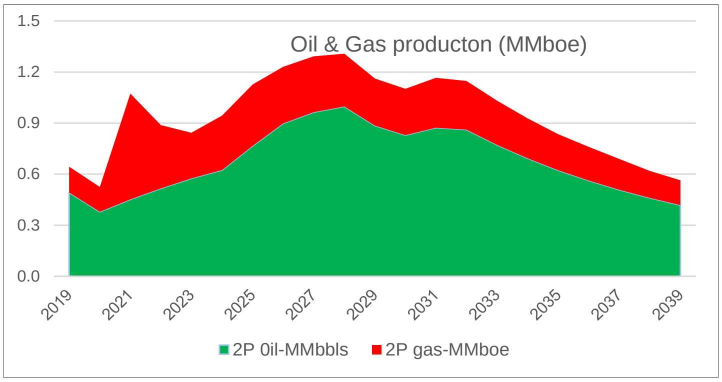
Source: MST Access forecasts, and Byron historical reports. Revenue is on a working interest basis.

Figure- 3: Oil and Reserves and Resources (MMboe, net)



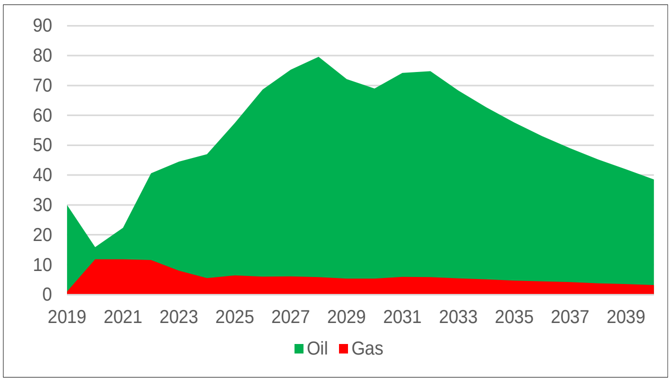
Source: MST Access, and Byron historical reports. Figures are net of Federal royalties

Figure 4: Production history & outlook (MMBoe, net basis)



Source: MST Access forecasts

Figure 5: Oil and gas revenue forecasts (NRI, US$ M)



Source: MST Access forecasts

Strategic enablers

- Byron majority own's and operates its permits and field facilities, which allows it to control allocation of capital and prioritisation of drilling opportunities.
- Highly experienced US-based technical and commercial team to manage all aspects of exploration and direction with a collective ~150 years of operational experience in the GoM
- Executives & board owning ~18% of the company, and along with other shareholders have supported the company through its formative phases.
- The USA regulatory frameworks are well established. Community and governmental support for oil and gas activities in general appears to be strong.
- The GoM has extensive oil and gas production infrastructure with spare capacity, enabling access to end-customers for small producers. Cycle time from exploration to production is very fast relative to Australia.

Investment attributes

- Substantial reserve and resource portfolio which if commercialised will materially increase value.
- Low-cost production insulates the company from low oil prices. Field production costs over the past five years average ~US$7/boe.
- Conservative approach to borrowing to fund growth, with oil pre-sales, and internal cashflow and hedging to lock-in cash-flow for reinvestment.
- 2P reserves are 19 MMboe, with 73% from oil resulting in a high-value product mix. Field margins averaged 58% over the past 5 years, at the "working interest" level, after Federal royalties.
- Incremental 3P reserves of 5.7 MMboe in salt dome leases where development costs can benefit from utilisation of existing platform and pipeline infrastructure.
- Prospective resources of 53 MMboe provides a portfolio of opportunities for future drilling.

Valuation and catalysts

Byron is undervalued relative to a DCF, and relative to peers in terms of EV-per-barrel of reserves. These are examined in more detail in the valuation section.

- SoP DCF of 2P reserves, plus risked upside for 3P and prospects of A$0.49/share
- EV/EBITDAX of 1.7X in FY 2024 and 1.4x in FY 2025 are low.
- EV-per-boe of US$3.59/ boe for 2P reserves on a net interest basis, after federal royalties.

Outlook and catalysts

- Excellent results from SM-58 G4 and G6 wells boost production and cashflows from year end 2023, confirms the geology and de-risks nearby targets.
- Drilling plans for 2024 are to be determined but will likely target other prospects within reach of the SM-58 Platform, in addition to work-over activity on a number of production wells.

Risks

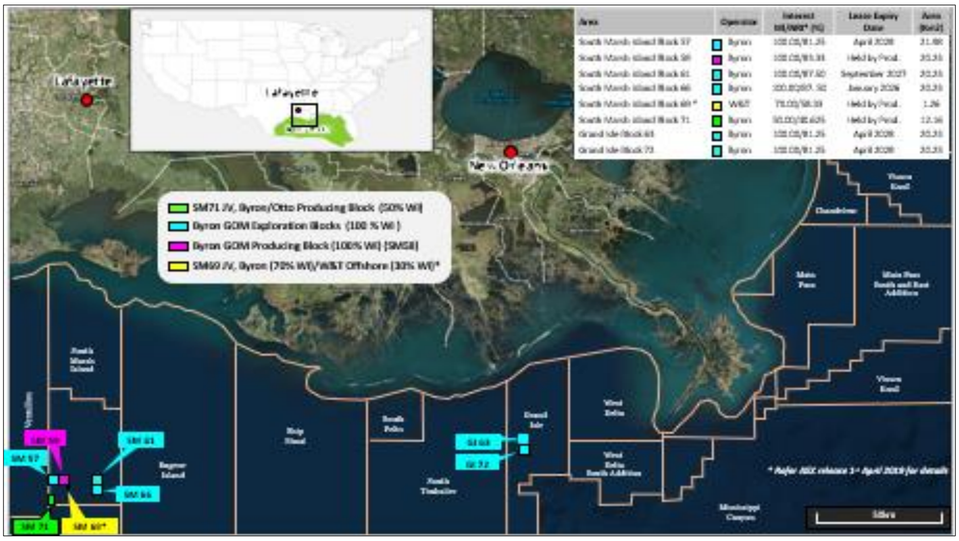
- Capex for individual wells to drill and connect is high at ~US$10-15M, so negative well results impact finances and value.
- Oil and gas prices are volatile, and Byron is a price-taker in the USA energy market. Current oil hedges mitigate price risk in the short term.
- Production from Byron's fields declines rapidly in the absence of ongoing drilling and work-over activity to maintain output. New wells, or re-completion of old wells is a recurring activity needed to offset natural field depletion. This activity is subject to future management decisions.
- Reserves are subject to geological uncertainty.

Production anchors value and funds growth

Byron specialises in acquiring, exploring and developing leases in shallow waters offshore of the USA Gulf of Mexico (GoM). Byron's executive team has deep experience and a successful track record in this area. Byron's strategy is to redevelop acquired leases by applying the latest technologies and proprietary knowledge. This has been very successful. From a nil base in 2017, Byron has generated substantial production, revenue and cashflows, and Byron plans to continue this strategy over the outlook.

Byron's GoM acreage is shown in Figure 6. The company has interests in three production platforms, eleven production wells, and capacity to accommodate production from new wells. Over the forecast period, Byron plans to drill more wells on an expanded asset base. License awards in CY2023 at Grand Isle, increases the asset and provides an opportunity for Byron to apply its E&P model to a new region.

Figure- 6: Byron GoM leases as at August 2023



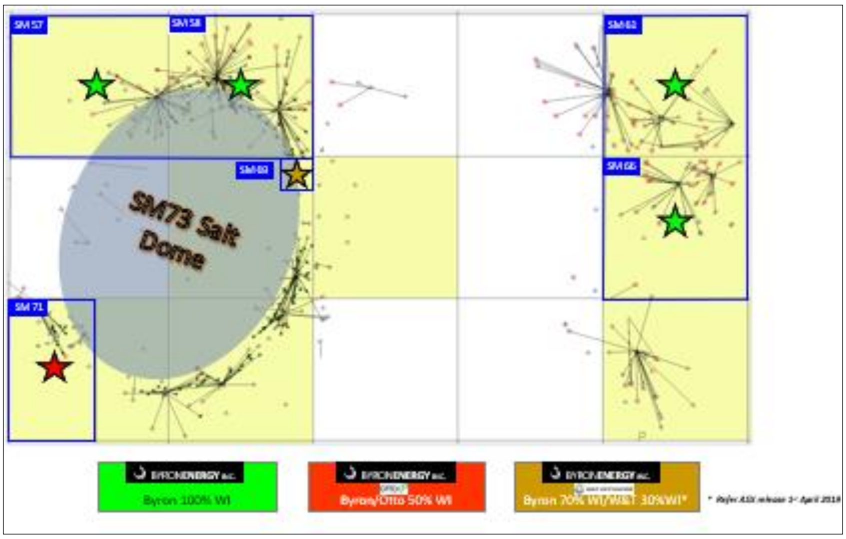
Source: Byron Energy 2023 Annual Report

Success in re-working salt dome oil and gas targets

Byron's core asset is acreage with reserves and production on the South Marsh island 73 salt dome. (SM73). Refer to figure 7. This area has been exploited since the 1960's, yielding 125 MMbbls of oil and 390 Bcf of gas to date. In general, the geology is well defined.

The SM73 field is covered by several smaller leases covering 81 square miles, overlying a large piercement salt dome. Numerous SM73 fields produce from multiple sandstone reservoirs at various depths abutting the salt, and figure 7 shows the pattern of many wells drilled over decades searching for oil and gas in these targets.

Figure- 7: Leases around the SM73 Salt dome.



Source: Byron Energy

How can a small company prosper is such an intensively worked region ?

Byron is exploiting an area where there has been previous exploration and production activity by other companies since the 1960's. The early pioneers were super-major companies but over the decades as the region matured and became less material to larger companies, smaller companies have entered to exploit what remains and that characterises the industry in the near-shore GoM at this time.

From the historical activities the geology is understood, there is collective industry knowledge, and usually there is pre-existing production and processing infrastructure.

Two critical factors have enabled Byron's success.

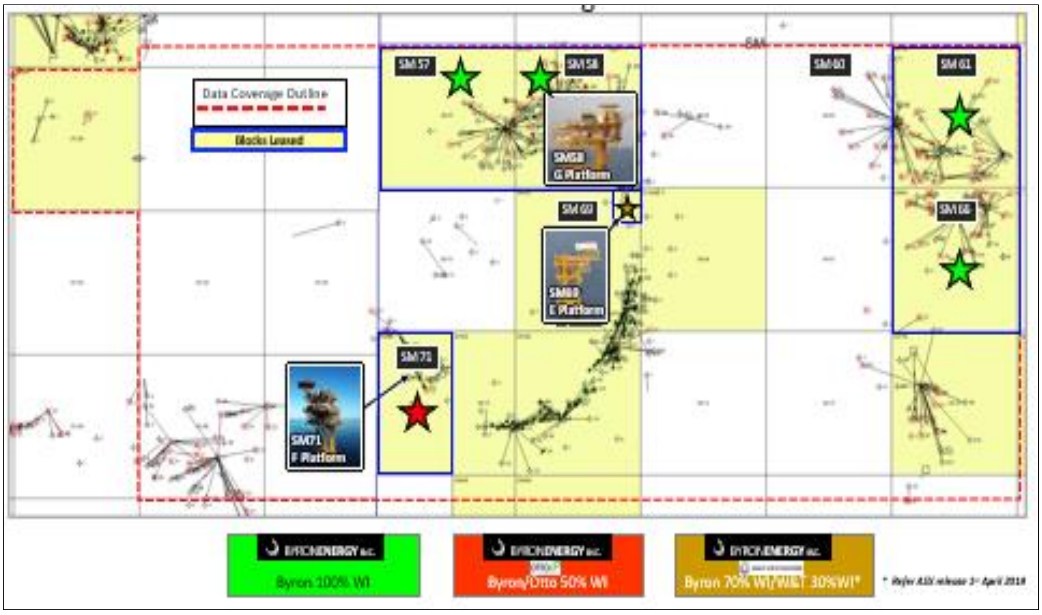
The first is oil and gas prices. Decades of generally low oil (and gas) prices after 1985 curtailed activity and major companies vacated the shallow GoM and re-focused on the US onshore such as today's Permian Basin, or into deeper waters and new frontiers in pursuit of larger discoveries.

The second is technology. Seismic processing and drilling technologies have provided new tools for E&P companies. Specifically for Byron, sophisticated seismic data analysis has been used to identify drilling targets.

In 2018 and 2019, Byron undertook "high effort" seismic re-processing, of 445 Km2 of data, using the latest proprietary techniques licenced from Western Geophysical, a world leader in geophysical data acquisition.

Byron is applying many cutting-edge tools to define drilling targets, principally RTM. "Reverse Time Migration" (RTM) is a relatively new method of processing raw seismic data to better image subsurface reservoirs. Commonly these images show bright spots which if confirmed by drilling, validate the model and result in higher success rates on similar images. Byron has applied RTM to the entire SM73 salt dome as shown in figure 8 and this results in a portfolio of targets which can then be assessed for size and ranked economically. This has proved successful for Byron at SM71 from discovery on 2017 and more recently at SM58.

Figure- 8: Byron Energy GoM South March Island lease and RTM data coverage area



Source: Byron Energy

Reserves and resources.

Reserves underpin production, revenues and cashflows. Leads and prospects provide future drilling and growth opportunities. Byron's proven (1P), proven + probable (2P) and proven +probable+possible (3P) reserves are shown figures 9 & 10.

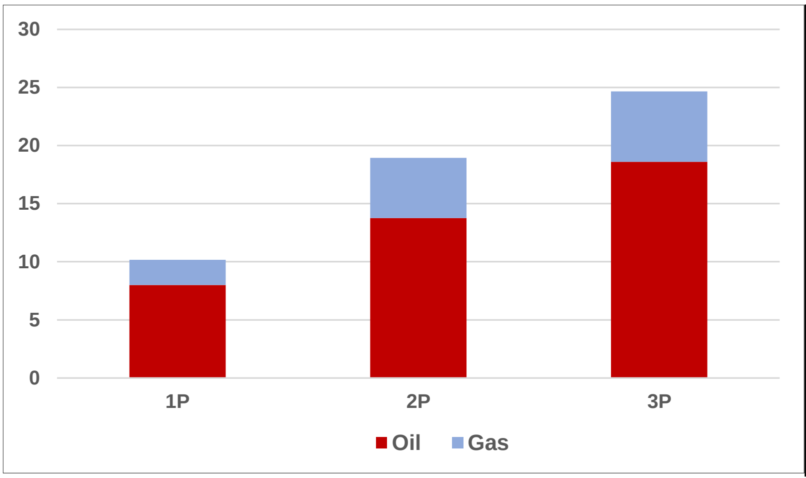
- Reserves and resources are reported on a "net" basis. Net reserves are Byron's working interest, less the volume sold for federal royalties. In the SM73 leases, the royalty varies between 19% and 12.5%. This is an important differentiation in comparing Byron to companies with assets in Australia where reserves are based on working interest and royalties are accounted for in the financial statements below the EBITDA line.

- The oil / gas split is 73 % oil / 23 % gas, at the 2P level. As oil prices are far greater than gas, the revenue and value mix is biased in favour of oil.
- By field, SM58 accounts for 84% of Byron's total 2P. Byron's drilling & development activities are focused on exploiting the undeveloped proven and probable reserves in this block.
- Of the 2P, 28% is developed and in production, with the rest behind pipe, or not accessible with existing wells. To access the 2P, additional wells, recompletions and work-overs will be required in the future. Our forecasts assume 2P production, and the estimates of associated capex.

Reserves below have been independently assessed by Collarini and Associates as of June 30, 2023.

The prospective resource is more than 4x larger than the proven reserves, which provides significant upside if geological modelling and seismic data justify drilling. This is concentrated in recently acquired leases in the Grand Isle region south of Louisiana, in GI72 and GI63. Prospective resource estimates are Byron Energy estimates.

Figure 9: 2P oil and gas reserves by type



Source: Byron Energy 2023 Reserves report

Figure 10: Reserves & Resources at 30 June, 2023

	1P	2P	3P	Pros
Oil SMI-71	1.6	2.7		1.0
Oil SMI-58	5.8	9.9		12.2
Oil SMI-69	1.1	1.1		0.5
Oil- GI-63 &72				4.6
Total Oil- MMbbls	8.5	13.8	18.6	18.4
Gas SMI-71	1.1	2.2		19.9
Gas SMI-58	20.8	27.6		40.4
Gas SMI-69	1.2	1.2		0.5
Gas- GI-63&72				147.4
Total Gas- Bcf	23.2	31.0	36.4	208.2
Total MMBOE	**12.4**	**18.9**	**24.7**	**53.1**

Source: Byron Energy 2023 Reserves report

Production assets: SM71, 58 and 69

These blocks are the core of Byron's current developed and undeveloped reserves, and production. Key statistics are:

- Three wholly or partially owned platforms (SM71, SM58, SM69) and eleven production wells.
- 1P reserves of 12.4 MMboe, 2P of 18.9 MMboe and 3P of 24.7 MMMboe.
- FY 2023 sales revenue of US$53M on a net revenue interest basis. (US$65M on "working interest" basis, which is revenue before allocation of Federal royalty)
- Production growth in CY2024 from G4 & G6 wells at SM58.

SM71 was Byron's first production commencing in April 2018 and has been a major success having generated cumulative revenue of US$128M to September 30, 2023. There are 2 wells in production, and 2 are shut-in and require work-over to bring back on-line. Over the outlook Byron plans to manage production via ongoing work-over, and side-tracks to exploit un-tapped oil, and up dip oil in attics not accessed by the current completions.

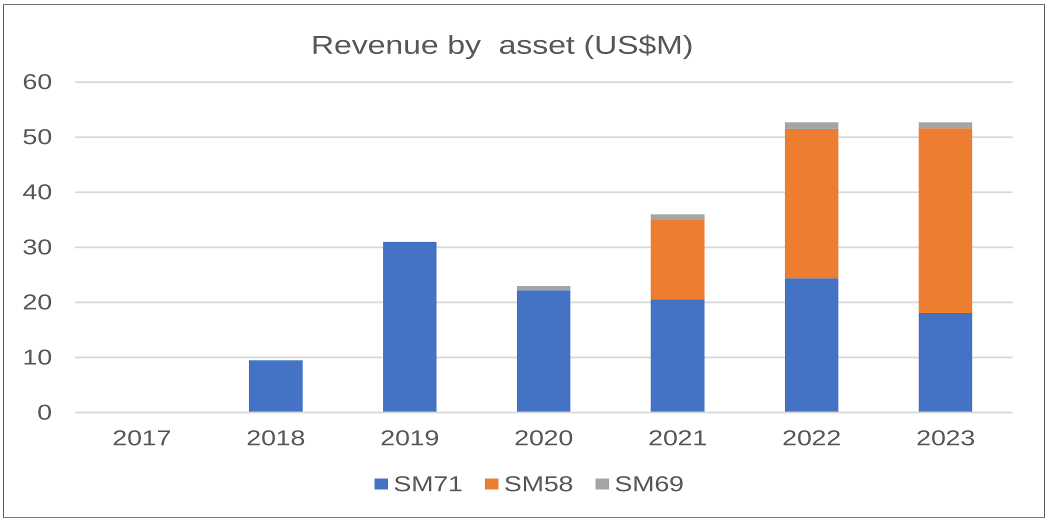
The SM58-G platform is more recent with first production in October 2020. It has 6 wells in production (G1,2,3,4, 5, 6). SM58 is a much larger field than SM71 in terms of reserves and resources and is likely to be a focus of activity over the next few years.

In the September quarter 2023, two wells on SM58, the G4 and G6 were drilled, discovering oil and gas, and were completed for production. The G4 well was brought into production in October and G6 well in November. Combined production from these two wells at the time of this report is 950 bopd (gross) for oil and 2.5 Mmmcfd of gas (gross). On November 28, Byron provided detail as to these, and all other well performances. Refer to ASX release dated 28 November 2023.

The success of these wells justifies the drilling of other targets around the SM58 platform in CY2024. Byron's guidance as to CY2024 activity is documented in following sections of this report. Our forecasts assume additional drilling and work-over in 2024.

Figure 11 shows revenue contribution at the asset level and shows the increasing materiality of SM58.

Figure 11: Revenue history by asset (US$M, YT June 30)



Source: Byron Energy Annual Reports

SM71: A foundation field and now a cash-cow.

- Ownership is Byron Energy 50%, Otto Energy (ASX: OEL) 50%
- SMI-71 was Byron's first GoM discovery, in 2017. Success confirmed the strategy, development was cost effective and revenues and cashflow delivered a foundation for growth.
- This is a mature asset and the upside is not as great as newer assets, nevertheless this is a low cost and highly cash generative source of funds to grow the broader business.
- At 30 June 2023, remaining net recoverable reserves are 1.627 MMbbls of oil and 1.15 Bcf of gas 1P. Proved + probable reserves are 2.7MMbbls of oil and 2.24 Bcf of gas.

Summary chronology

- Acquired in the Federal Offshore Continental lease sale in 2012 for US$166,000.
- Drilled the F1 discovery well in April 2016, followed by F2 in December 2017.
- A refurbished well-head platform was acquired and installed 2H CY 2017.
- Production commenced March 2018 from the F1 & F2 wells, with F3 connected in April 2018.
- F4 well drilled in 2019 and commenced production March 2020. The F5 well was drilled in 2020 but not completed due to low oil prices at the time. It is a candidate for future recompletion.

The SM71 lease is approximately 160 miles south of the Louisiana coastline, in 40m of water. The lease is one of several covering a very large salt dome, and sedimentary reservoirs abutting this impermeable barrier are common in the US GoM. Key statistics are shown in Figure 12.

The SM71 field is not a "green field" discovery. It has ownership and production history dating from 1962 with 27 wells in total drilled by Shell, Tenneco, Transco and Apache for historical production of 3.9MMbbls and 10 Bcf. Importantly, no wells had been drilled since 1999 and the last owner, Apache Energy, surrendered the block in 2010.

The discovery well F1 was drilled in 2017 and discovered oil and gas in several high-quality reservoirs thus validating the geological model and paving the way for drilling additional, successful wells F2, F3 and F4. There are currently two wells in production, F1 and F3, producing from different reservoir horizons. Characteristically, these wells produce light sweet crude from multiple high-quality sandstone reservoirs accompanies by minor volumes of associated gas.

On November 28, 2023, Byron advised that its net share of oil and gas production was 386 bopd and 0.5mmcfd respectively.

Figure 12: Key statistics

SM71 Project Summary	
Working interest holders	BYE 50% (Operator), Otto Energy 50%
Water Depth	~40 meters
Previous SMI production	3.9 MMbbls / 10 Bcf (1995-2010)
Acquired	OCS lease sale June 2012 for US$166,620
BYE interest	W.I 50%, N.R.I 40.625%
BYE discovery well	F1, April 2016
Development	F Platform installed October 2017
Production drilling	F2, F3, March -April 2018. F4 March 20
Gross production (March 2018-Sept 2023)	4.8 MMbbls / 5.4 Bcf
Cum. Net revenue (March 2018-June 2023)	US$123M
Approx. gross capex to Dec 2022	~US$45
Gross remaining 2P @ 30 June 2023	6.8 MMbbls / 5.0 Bcf
Net remaining 2P @ 30 June 2023	2.7 MMbbls/ 2.2 B Bcf
Platform capacity	5000 bpd

Source: Byron Energy

Figure 13: SM71 platform, key infrastructure with ullage

Source: Byron Energy

Robust economics.

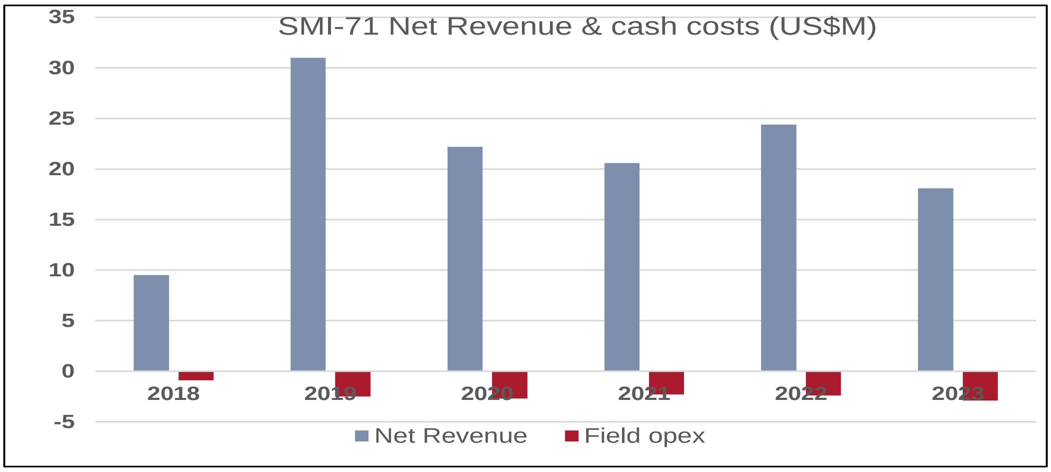
The economic model is typical of that for any offshore project, with capex front loaded for facilities, in this an offshore platform, producing wells and tie-in to oil and gas gathering systems. Byron kept these costs down by acquiring a pre-owned platform, re-refurbishing, and installing in the field for ~$20M (100%).

This field is Byron's first operated project and is a low-cost development with drilling and development activity staged over time as a function of capital availability. The platform allows for cost-effective ongoing work-over and maintenance over using jack-up rigs. Operating costs are very low. Excluding royalties and transportation tolls, the only field cash costs are for the onshore support base, insurance, maintenance, consumables and workovers. These are generally fixed and in the order of US$2.5-3M p.a, net to Byron.

Oil and gas is sold ex-platform. Oil realises up to a US$3/bbl premium to WTI, and gas approximately US$0.36/mmbtu less than the Henry Hub marker, after tolls and quality differentials.

Cash margins are very high. Figure 14. Cumulative net revenue after tolls and royalties is US$123M up to 30 June, 2023 which is an excellent pay-back of ~$45M of cumulative net capex including all drilling.

Figure 14: Summary financial history for SMI-71: a cash cow



Source: Byron Energy Annual Reports

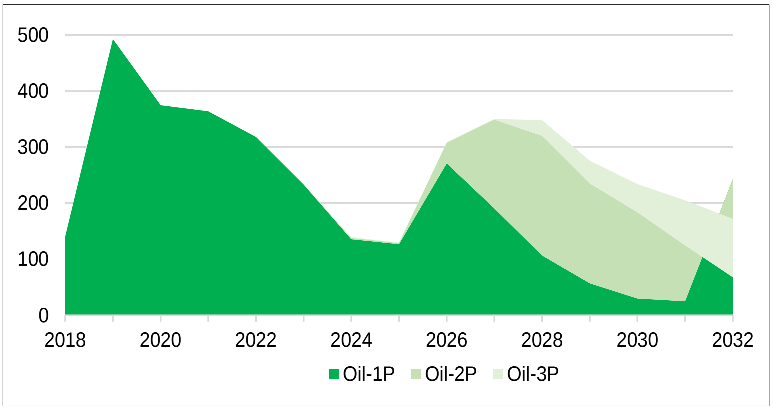
Future activity: Workovers and recompletions to recover known reserves.

SM71 reservoirs contain multiple sands with individual oil, gas and water contacts. The development wells are engineered for maximum initial production but over time production pressure in these wells will decline and water and gas levels will change and impinge on oil rates. Maintaining oil output will require future work-over activity to shut-off water zones and open fresh oil or gas zones, which may be behind casing or in attics.

At this time, the best performing well is the F1 well, and is a candidate for future recompletion to recover additional oil and gas, but the timing and likelihood is uncertain and requires joint venture alignment.

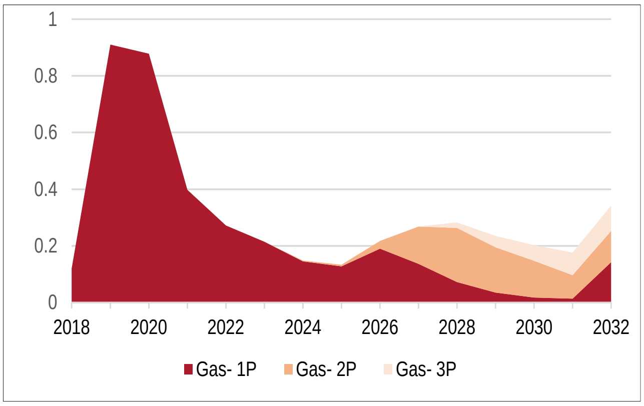
Our valuation and production forecasts assume future activity and expenditure in the order of ~US$20-25M (net) to 2040 to fully capture the 2P reserve beyond 2025 with this activity taking place in ~2025 or 2026. However, the timing and likelihood is not certain and is a function of oil prices, development costs, and economic importance relative to other opportunities in the Byron portfolio, and joint venture agreement.

Figure 15: SM71 Oil production forecast -'000 bbls p.a.



Source: MST

Figure 16: SM71 Gas production forecast – Bcf p.a.



Source: MST

SM58. The growth engine over the outlook

- Byron is the sole owner and operator, with 100% working interest and 83.3% net revenue interest.
- Byron's most productive asset at this time, with current production ~1600 bopd and 4.55mmcfd (net)
- Drilling results in late 2023 were successful and underpin revenue growth over the outlook.
- Large 2P reserve of 9.5 MMbbl of oil and 25 Bcf of gas offer multiple drilling targets.

- Success to date reinforces Byron's strategic approach, and recent wells de-risk other prospects.

The success at SM71 in applying RTM techniques are pivotal to the excellent drilling outcomes in the SM58 block, which is on the northern side of the SM73 salt dome. CY2023 drilling results have been excellent and there are numerous targets identified for future drilling, to convert the large 2P and 3P reserves to production.

Summary chronology

- Acquired in January 2019 for US$4.25M. The transaction included a 53% working interest. in the SM69 platform, and the producing E1 well in the adjacent block, operated by W&T Offshore Inc.
- Drilled the G-1 well in Sept 2019, and discovered 301 feet of pay.
- Installed the "G" platform in in July 2020, enabling first production from G1 in September 2020.
- Drilled G2, G3, G5 wells during FY2021 & FY2022, with production from G2 in FY2021 and the G3 and G5 wells in FY 2022.
- In September 2023, the G4 and G6 wells were successful and are now in production.

The SM58 block is part of the South Marsh Island Block 73 field, located 220km offshore southwest of New Orleans, in approximately 37m of water. Since first production in 1963, 36 MMbbls of oil and 273 Bcf of gas have been produced by previous operators.

Block 58 was acquired from Fieldwood Energy Inc in 2019. For Byron this is a "newer" project, compared to SM71, but leverages the in-house skills honed from success at SM71.

Prospects in the SM58 lease are larger and economically more important to Byron because it has a 100% working interest, and we anticipate this asset is likely to be the focus of growth and investment over the outlook period.

There are a number of seismically defined prospects in a geological setting analogous to the geology at SM71, with multiple sandstone reservoirs abutting the salt intrusion. To date, six of these prospects have been drilled, the G1, G2, G3, G5, G4 and G6 wells, and all have been commercial discoveries. These wells all produce through the Byron-owned "G platform".

Some of the prospects are in adjacent acreage SMI 69, where there is a pre-existing processing platform "E". Platform "E" and the producing SM58E1 well, is operated by W&*T Offshore Inc, and Byron has a 53% W.I. Under a farm-in and surface facilities management agreement, Byron drilled the E2 well. Byron W.I in this well is 70%, and 58.3% NRI. This well is located on the SM 69 platform, with all produced oil and gas piped to Byron's G platform in SM58 for processing and sales.

By reserves, SM58 is larger than SM71, and maximisation production and value will require several wells over a number of years, with the rate and pace of drilling activity likely to be guided by operational performance. The platform has significant oil and gas production capacity, with fluid handling rates up to 16,000 barrel per day of fluids, comprising 8,000 bpd of oil and 8,000 barrel per day of water.

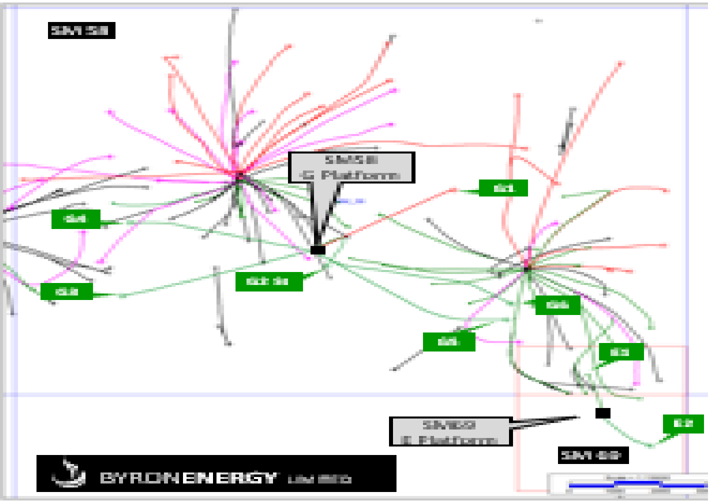
In summary the SM58 lease is shaping up to be an excellent asset and is likely to be an area prioritised for additional drilling.

Figure 17: Key statistics

SMI-58 Project Summary	
Working interest / NRI	BYE 100% (Operator). NRI 83.33
Water Depth	~37 meters
Previous production	36 MMbbls / 265 Bcf
Acquired	Jan 2019, US$4.25M from Fleetwood Energy
BYE discovery well	G1, Sept 2019
Development	G Platform installed July 2020
Production drilling	G1, 2,3,5,4 &6 and E2
Gross production (July 2020- June 2023)	0.7 MMbbls / 9.2 Bcf
Cum. Net revenue (July 2020-June 2023)	US$76M
Initial capex, BYE share	US$27
Net remaining reserves (June 30,2023)	9.2 MMbbls/ 27 Bcf
Platform capacity	8000 bopd / 80 MMcfd gas

Source: Byron Energy, updated after 2023 Annual report

Figure 18: Well locations to G platform

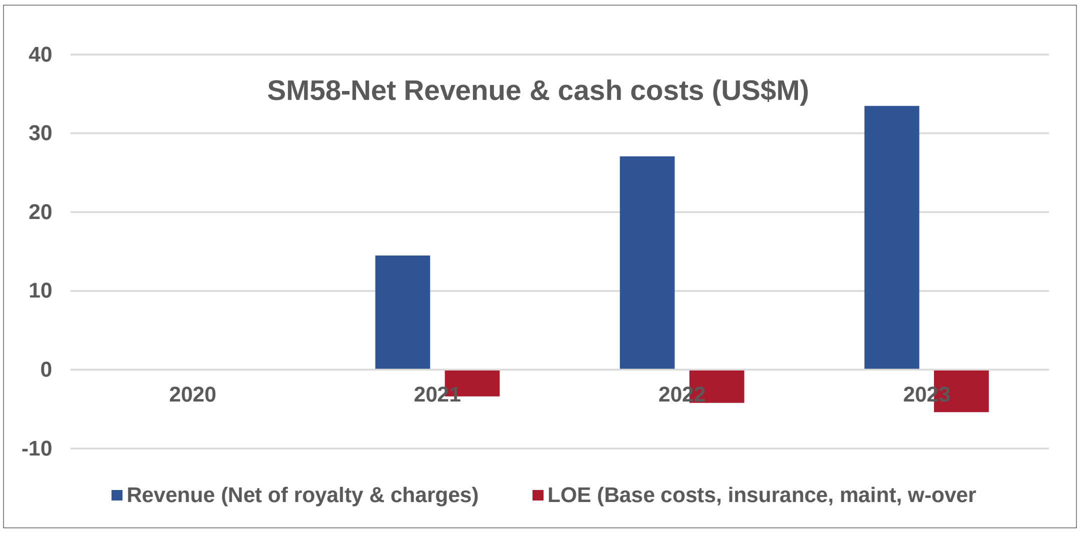


Source: Byron Energy

SM58 economics.

Cumulative revenue after royalties and transport costs to 30 June 2023 total US$77M, including the 'E2" well from an initial capital investment of US$27M, after only two years of production. The upfront capex includes the refurbished "G" platform. These are excellent economics.

Figure 19: Summary financial history for SM-58.



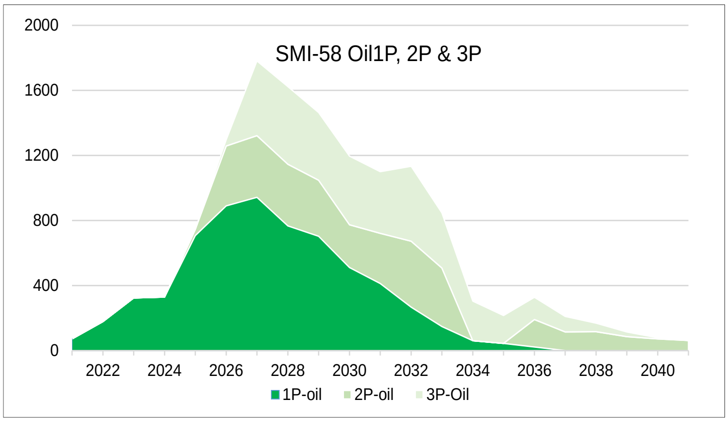
Source: Byron Energy Annual Reports

Development activities

The 2P, 3P and prospective resources in SM-58 are large and offer future drilling opportunities. Completion and connection of the successful G4 and G6 wells will boost production from CY 2023. Production data will inform overall understanding of the extent of the reservoirs and offset targets.

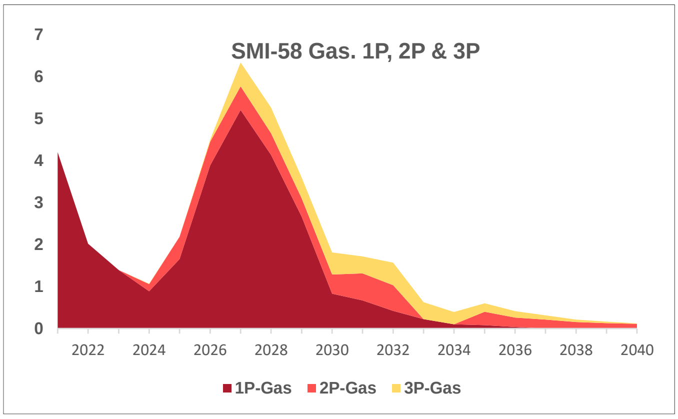
In CY2024, we anticipate more wells on surrounding seismically defined drilling targets, which are upgraded in terms of chances of success by the wells drilled to date. Byron's guidance for upcoming work is (1) a well down-dip at G1 to intersect an interpreted oil zone (2) recompletion of the G2 and G5 wells to access oil behind pipe (3) and zone change recompletions on wells G3 and G6.

Figure 20:SMI-8 forecast oil production (NRI, bopd)



Source: MST Access

Figure 21:SM-58 forecast gas production



Source: MST Access

SMI69 platform and E1/E2 wells

- Smaller production asset, but important infrastructure.

Byron owns a 53% working interest and 44.2% net revenue interest in the joint area reservoirs from the surface to 7490 TVD located in the S1/2 and SE1/4 of the SM58 block, and a 53% W.I. in the SM69 platform, operated by W&T Offshore Inc.

This complex arrangement allows for the surface operation of the jointly owned SM58 E1 well, and operation of Byron's SM69-E2 well, which is owned 70% by Byron and is located on the SM69 platform but is piped back to the SM-58 platform for sales.

By reserves and production, the E2 well continues to be a meaningful contributor to Byron and paid out in a short 15months, and the SM69 Satellite platform is another important piece of infrastructure that Byron has majority interest in on the broader SM73 salt dome which offers Byron additional opportunity for diversification and growth.

Figure 22: Key statistics: SMI 69

SMI-69 & SMI-58E1 Project Summary	
Working interest holders	BYE and W&T Offshore
Water Depth	38 meters (125 feet)
Previous SM58 production	36 MMbbls & 265 Bcf
Acquired (SM-69E Platform and SM58E1 w ell)	From Fleew od for US$4.85M in Jan 2019.
Farm-in Agreement	With W&T Offshore to drill SM69 E2 w ell in SM69
BYE interest SM 69 E2 w ell	W.I. 70%/ NRI 58.33 %
BYE interest in SM69E platfrom & E1 w ell	W.I. 50%/ NRI 44.17 %
BYE discovery w ell	E2. w ell, Sept 2021
Production	E2 w ell: Oct 2021
Approx. gross capex E2	US$18M
Cum net revenue to BYE to 30/6/2023	US$28M
Net 2P @ 30 June 2023 (E1,E2 & future E3)	1.1 MMbbls oil / 1.2 Bcf gas

Source: MST Access, from Byron reports

Figure 23: SM-69 Platform

Source: Byron Energy

Exploration acreage awards in 2023 stock portfolio for future drilling

On 17 March 2023, Byron advised it had been awarded three new leases in "Offshore Continental Shelf" Lease Sale 259, as follows:

- Grand Isle blocks 63 and 72, for a high bid of US$147,525 each.
- South Marsh Island Area block 57 (SM57) for a high bid of US$147,525.

Byron's working interest in these blocks is 100%, and net revenue interest 81.25%. Tenure is 5 years.

A detailed history and exploration strategy can be found in Byron's ASX report dated 19 April 2023. In summary, these blocks are consistent with Byron's exploration strategy of applying modern advanced seismic techniques in acreage that hosted historical production and are now considered as prospective with the application of modern methods, in a higher oil price environment.

Grand Isle 63 and 72

The Grand Isle blocks are an additional salt dome project area and were evaluated using Reverse Time Migration (RTM) 3D seismic data. These blocks are located 84 miles south of New Orleans in ~120 feet of water. Historical production from the field totals 0.9 MMbbls of oil and 11 Bcf of gas, but currently there are no active production wells.

Byron's RTM modelling has identified several prospects which are up-dip from previous production or are in newly identified fault compartments. Collarini's estimate of prospective resources in GI-63 and GI-72 is 4.6 MMbbls of oil and 147 Bcf of gas, net to Byron. These blocks are located125 km east of Byron's existing platforms at South Marsh Island and development in the event of success would require Byron to install new production facilities and negotiate access to nearby pipelines.

Compared to Byron's current reserves, the prospective resource base in Grand Isle blocks is very large and provides a major growth opportunity in the event of exploration success.

South Marsh Island exploration & evaluation areas 57, 61, and 66

BYR holds 100% W.I in SM-57, SM-61 and SM-66. Acquisition of these blocks were part of a seismic re-processing project which Byron undertook with Western Geophysical to identify drilling prospects. Byron's tenure ranges from December 2025 to April 2028. All these blocks are in the SM-73 area where Byron and others have extensive existing production infrastructure.

Financial history & forecasts

As an established production company, there is financial history to calibrate our forecasts, and this reduces forecasting uncertainty.

Key drivers of P&L, and cashflow

Global oil prices and USA domestic gas prices a key driver of revenue, profit and valuation. We outline in the valuation section, our assumptions for oil prices going forward, but in broad terms, Byron is a “price taker” selling all it can produce into a very large USA energy market. In many parts of the world discovered resources may be stranded due to lack of infrastructure, but that is not the case in the USA GoM where Byron has installed its own and infrastructure and executed deals with third parties to access end consumers.

Byron discloses working interests (WI) and net revenue interest (NRI) production and revenue in all its reserves, production and financial reports with the difference between WI and NRI figures due to federal royalties which are typically in the range of 17-20% of reserves, production & revenue.

Cash operating costs are low and averaged ~US$7/boe since 2018 to June 2023. This measure will rise or fall as production levels fluctuate due to the predominantly fixed cost nature of production. These cash costs are commonly referred to as “lease operating expenses” (LOE) in the USA and include the costs of staffing offshore platforms, local taxes, operational logistics, consumables, routine maintenance and third-party tolls. These costs are typically fixed for each platform or field. In FY2023, field cash costs totalled US$8.5M. Oher costs for general & admin, hedging and other activities at the corporate level are in the order of $5m p.a.

Figure 24:Summary financial history and outlook forecasts

US$M- Year to June 30	2018	2019	2020	2021	2022	2023	2024E	2025E	2026E
Net production (MMboe)	0.16	0.60	0.54	1.22	0.90	0.84	1.03	1.16	1.24
Sales Revenue N.R.I.	9.5	31.3	21	34	53	53	56	65	77
Sales Revenue W.I.	11.7	38.6	26.2	43	64.7	64.9	69.3	79.8	94.5
Total income (US$M)	12.0	38.6	26.2	43.6	65.2	65.4	69.3	79.8	94.5
Royalties	2.2	7.2	4.8	7.4	11.6	11.9	13.2	15.2	18.0
Cash costs	5.7	11.9	8.7	12.5	13.9	14.2	15.8	15.8	15.7
EBITDAX	**4.1**	**19.5**	**12.7**	**23.7**	**41.6**	**39.3**	**39.3**	**39.3**	**39.3**
DDA & Impairments	1.8	13.0	5.8	14.4	17.1	15.1	15.4	9.0	-1.6
EBIT	2.3	6.5	7.0	9.3	24.5	24.3	23.9	30.3	40.9
Interest & Taxes	1.1	0.5	1.8	3.5	2.3	1.6	3.6	2.9	1.8
Core profit	1.2	6.0	5.2	5.9	22.2	22.7	20.3	27.4	39.1
Cash from operations	2.6	23.2	13.7	21.4	36.6	40.6	35.7	44.9	58.0
Investing cashflow	-24.1	-19.6	-54.3	-35.1	-25.5	-34.0	-45.2	-40.7	-28.4
Financing cashflows	20.4	1.0	50.6	1.1	-1.1	-16.4	17.5	-5.0	-5.9
Net assets	28.5	36.7	74.1	81.2	105.5	128.4	148.9	181.3	225.4
Cash	2.3	6.8	16.6	4.1	14.1	4.2	12.2	11.4	35.1
Debt	6.5	5.8	19.9	21.9	21.0	5.6	23.1	18.1	12.2

Source: Byron Energy Annual Reports, MST Access forecasts.

Financing strategy & hedging

- Conservative approach to use of debt, with history or development borrowings being paid back from cashflow before undertaking new projects.

- SM58 G4 and G6 development capex approximates US$31M, and was funded from cash and oil-presales, and is now generating cashflow.

- Cash at bank US$16.9M, while oil revenue prepayments and borrowings totalled US$13.4M as at Sept 30, 2023.

Byron’s drilling and development expenditures run ahead of revenue, which is typical of companies in growth mode. To finance development, Byron historically used a mix of debt, equity issuance, and forward sale of oil. Debt levels peaked in 2021, at a period of low commodity prices and expenditure on the SMI-58 platform and wells, and this was paid out in 2022 along with oil hedges taken out years earlier. As a result, Byron was in a very strong position in early 2022 to fund a step-up in production, which is now evident. Going forward, cash-flow from operations will become a key enable of growth funding.

The SM58 G4 and G6 wells were discoveries justifying completion for production, at a combined total cost in the order of US$31M. To fund this, in August 2023 Byron secured a pre-payment loan of up to US$22M, provided by Byron’s oil purchaser. On 15 September 2023 Byron drew-down US$10M for SM-58 completion activities and has access to an additional US$12M for completion activities.

Oil hedging is integral to under-writing finance and Byron have hedged future production to lock-in payment of operating costs and development capex.

At 30 September 2023, Byron had hedged approximately 475 bopd (on a working interest basis) of oil over 24 months, at an average composite price of US$74.80/bbl. This volume approximates 20% of Byron's current working interest oil production. This hedge expires in August 2025. In the event that Byron choose to drawdown a further US$10M from the available facility, then it will be required to hedge another ~200 bopd over 2 years. The hedge prices and volumes are included in our forecast revenue estimates.

Price realisation and oil & gas marketing

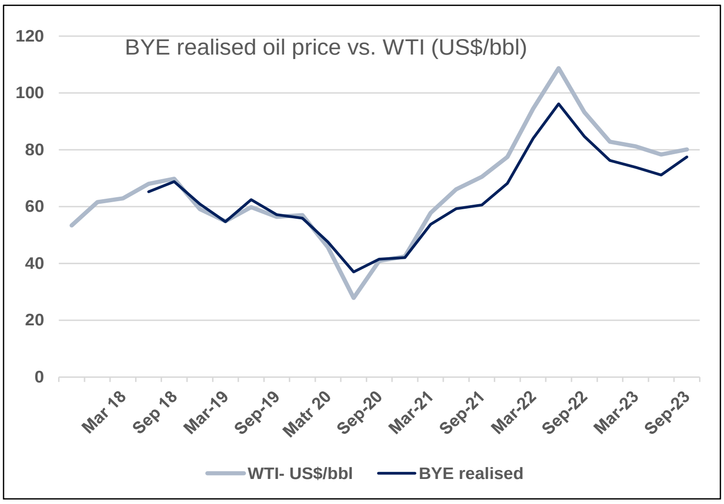
Monetisation of production in the USA is straightforward due to well-defined fiscal terms, deep product markets and extensive mid-stream infrastructure enabling access to the vast USA gas distribution and refining network. Byron sells to mid-stream infrastructure companies and pays tariffs for gas or oil transportation to price hubs, such as Henry Hub for natural gas.

- For oil, Byron sells crude benchmarked to Louisiana Light Sweet (LLS) crude oil which is priced at a premium of US$3-5/bbl over WTI. Oil transportation costs are <US$6/bbl.
- For gas, Byron realises prices related to the Henry Hub marker, adjusted for differentials for quality, transportation, & shrinkage. On average over the past 5 years, Byron has realised an ex-field price of US$0.36/MMBtu discount relative to Henry Hub. Our assumption going forward is a fixed US$0.36cMMBtu.

Figures 25 and 26 show Byron realised oil and gas prices relative to oil and gas benchmark prices.

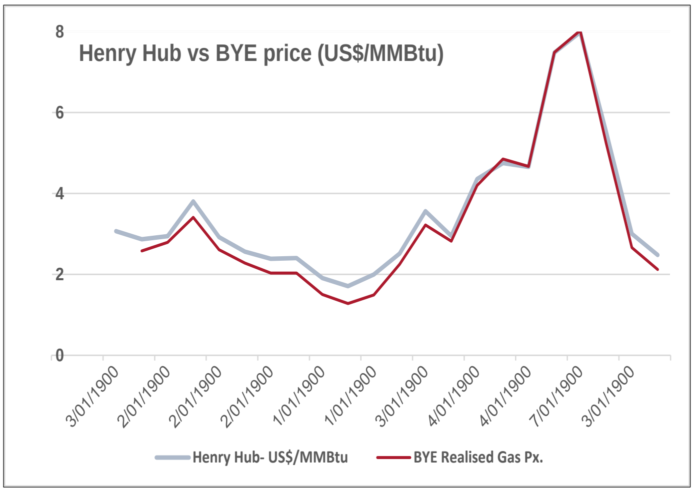
Risk management of commodity exposure is via oil hedging, which Byron has utilised from time to time, specifically to ensure revenues during periods of capital expenditure, or if required by financiers. Importantly, unlike many parts of the world, Byron does not have to negotiate fiscal terms with a host Government or engage in bi-lateral agreements for gas sales.

Figure 25: Byron oil prioes vs WTI



Source: Byron and MST access

Figure 26: Byron gas prices vs. Henry Hub market



Source: Byron and MST Access

Capital structure

- Uncomplicated capital structure with negligible options or performance shares

There are 1081M ordinary shares on issue, and 2M performance options. There has been minimal increase in share count since 2020.

Board and management have 18% of the company.

There are no substantial institutional or corporate shareholders.

Valuation: A$0.49

Our valuation is a sum-of-parts derived from estimated cashflows from production of 2P oil and gas reserves, plus static values for non-producing acreage. Refer to figure 27.

Our key assumptions are as follows:

- Benchmark WTI prices of US$80/bbl in CY2024 and escalated at 2%p.a. beginning in January 2025.
- Benchmark Henry Hub gas prices of US$3.30/mmBtu in CY 2024, and then escalated at 2% p.a, after 2024 and with Byron realising a US$0.36/mmBtu discount at the point-of-sale ex-field.
- Base case production model which delivers 2P reserves to 2040 of 18.9 MMboe.
- 3P reserves are valued at ~$3/boe which is materially lower that than 2P per boe value due to uncertainties in recovering this volume and the costs required. We apply a 25%- risk for geological and commercial uncertainty.
- Cashflows are discounted from Q1 2024 at an after tax WACC of 10% p.a.
- 2023 acreage at Grand Isle is valued at acquisition cost.
- Cash of US$16.9M, and bank debt and other liabilities of US$13.4M as of September 30, 2023.
- US$ valuation is converted to AS$ using a spot rate of AU$ 63c.

Figure 27: Sum-of-parts valuation

Asset Value (US$M)	Unrisked	R.F	Risked	Oil	Gas	BOE	US$/boe
	US$M	%	US$M	MMbbls	Bcf	MMboe	
Production							
Oil & gas production 2P	336	100%	336	13.77	31.0	18.94	17.75
3P upside	71	25%	18	4.81	5.4	5.71	3.12
Prospective resources & acreage							
SM-71	50	15%	7	1.0	19.9	4.29	1.73
SM-58	203	15%	30	12.2	40.4	18.93	1.61
SM-69	7	15%	1	0.5	0.5	0.64	1.54
GI 63&72	1		1	4.6	147.0	29.13	0.03
Corporate costs capitalised	-60		-60				
Total E&P assets	607		334				
Cash	17	Sep-30	17				
Debt & other obligations	-13	Sep-30	-13				
Total equity value	611		337				
Shares on issue	1081		1081				
Perf rights & options	2		2				
Per share- US$	**0.56**		**0.31**				
Exchange rate	**0.63**		**0.63**				
Per share- A$	**0.90**		**0.49**				

Source: MST Access.

Valuation Methodology: Cash-flow DCF plus risked resource upside

We forecast future cashflow for each production asset (SM71, 58 and 69) to 2040, with the production envelope capturing 2P reserves, on a net entitlement basis. We adopt the 2P figure because (1) it is statistically the most likely outcome with a 50% or greater probability and (2) for consistency with consensus valuation for ASX listed companies which are commonly valued on 2P reserves.

Capture of the 2P reserves at all fields will require ongoing field management and drilling of additional wells over future years. We make assumptions regarding the timing, and capital cost of future development.

We value incremental possible (or "3P") reserves and prospective resources using a dollar-per-boe. This is less deterministic than a DCF measure, but reasonable given the numerous uncertainties and judgement required to develop a cash-flow model.

Byron documents very large prospective resources in recently acquired leases at Grand Isle, of ~147 Bcf of gas. Applying a per-mcf figure to this would generate a large figure, but the acquisition cost for leases that were bought from the State at public auction for $0.3M is a reality check.

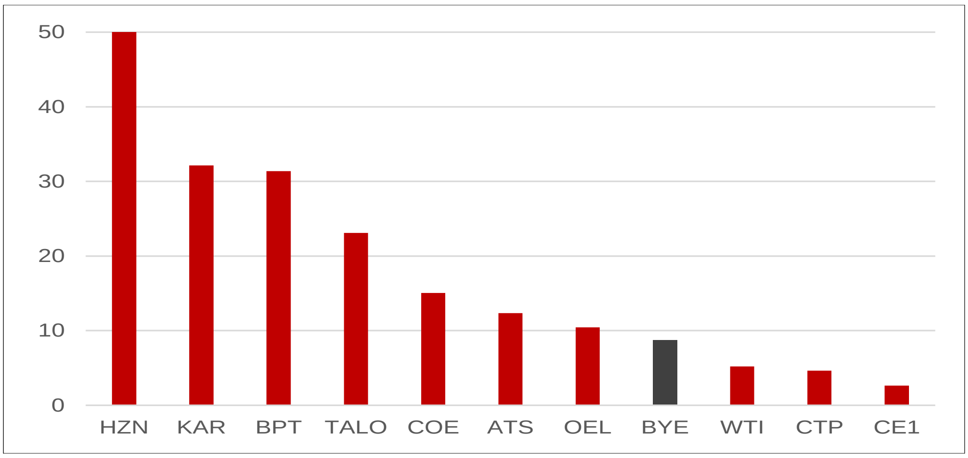
Peer Group and secondary valuation measures

We refer to other market valuation measures which are common usage in the finance industry, specifically resource estimates such as enterprise value per boe of reserves (EV/boe).

We show in figure 28 the EV/boe, for proven (1P) reserves for ASX-listed small to medium sized producers, and USA GoM participants of similar size, namely Talos Energy (TALO) and W&T Offshore Inc. (WTI). USA companies which would be peer companies statutorily report 1P reserves but not 2P, which constrains our data set of comparable companies to those which report a 1P reserve.

We show the 1P EV/boe measure for purposes of consistency. An additional nuance is the USA based companies report reserves which are net of Federal royalties, in contrast to Australia where Federal royalties such as Petroleum Resource Rent Tax (PRRT) is excluded. The figure for Byron is A$8.70/boe which is toward the low end of the peer group. In this data set, no adjustments are made for product mix (gas vs oil), jurisdictional fiscal terms and taxes, or any other factors that might impact the value of barrel of oil or gas in production.

Figure 28: EV/ boe for 1P reserves in A$/bbl



Source: MST Access.

Sensitivity analysis: Oil prices and reserves

Oil prices and oil reserves are key drivers of profit and value l relative to oil revenue, gas price variation as not overly material. Nevertheless, US gas prices are in a multi-year trough and gas prices risks are to the upside. Figure 29 shows our per share value for a range of WTI oil price scenarios. In calculating oil price scenarios, we make no assumptions regarding management actions to mitigate costs when oil prices are low, or to increase investment when oil prices are high.

Figure 29: Valuation sensitivity to WTI Oil price

WTI-USD/bbl	40	50	60	70	80	90	100
AUD cents per Share	0.14	0.23	0.32	0.41	0.49	0.59	0.68

Source: MST Access.

Oil and gas reserves are another critical variable in determining value. Our base case valuation assumes recovery of 2P oil and gas until 2040, and including estimates of capex required. Actual recoveries could be higher or lower. Figure 30 shows our per share value in A$ cents for percentage changes in reserves, all other factors assumed equal. In calculating reserves and production scenarios, no assumptions are made regarding management responses to better or worse production and reserve outcomes.

Figure 30: Valuation sensitivity to percentage change in 2P oil and gas reserves

2P Rserves (+/- %)	-20	-10	0	10	20
AUD cents per Share	0.37	0.44	0.49	0.52	0.59

Source: MST Access.

Risk factors

Key risks

- Byron is a fossil fuel producer, and these companies are under pressure from climate activists. So far, these risks are less onerous in the USA compared to other parts of the world, but the risk of doing business is increasing.
- Commodity prices and markets. Byron is a price taker for its oil and gas products and these prices are volatile and driven by global factors.
- Inflation. Costs for exploration and development are increasing in general.
- Sovereign risk in the USA is low but could change at any time.
- Geology. Exploration and appraisal drilling even in well-known areas like the GoM, is risky and not all wells will succeed.
- Operational. Key operational risks are accidental oil spills, or accidents the injure people of damage facilities.
- Production and reserves. Fields my decline faster than expected, and future drilling to recover 2P reserves may not succeed and lead to downside risks to future production and reserves.
- Key management personal (KMP's). Byron has a small team of highly experienced KMP's and the departure of key personnel could reduce the value of the company's intellectual property and reduce its ability to operate.
- Access to capital. Byron has historically financed its activities with equity, oil pre-payments and at time, modest amounts of corporate and related part debt, however debt funding is becoming harder to source and there is risk that Byron cannot raise funds for ongoing development, or that funding costs become onerous.

Board and executive team

Although an ASX listed company with an Australian -based Board, Byron has an USA based executive team with a collective 150 years of relevant experience in the areas of focus, specifically shallow water of the US Gulf of Mexico. Directors and KMP's have been working for Byron since its formative days, and the company's success is attributable to their collective effort and experience.

Collectively, Board members, senior executives and staff own ~18% of issued capital.

Key personnel are:

Douglas G. Battersby. Non-Executive Chair, appointed 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 Ltd, which was acquired by Santos Ltd in November 2011, and SAPEX Ltd, which was acquired by Linc Energy in October 2008), and two private oil and gas companies Darcy Energy Ltd which was sold to Daiwa Corporation in 2005, and Byron Energy where he was Executive Chair until May 2013 when Byron merged with Trojan Energy Ltd to create Byron Energy Ltd. Between 1990 and 1999, Doug was Technical Director at Petsec Energy, and ASX-listed operator in the shallow waters of the GoM with production reaching 100 MMcfd of gas and 10,000 bpd of oil in 1997.

Doug holds a M.Sc degree in Petroleum Geology and Geochemistry from Melbourne University.

Maynard V. Smith, Executive Director and Chief Executive Office, appointed March 2013

Maynard is a geophysicist with approximately 50 years' experience in the oil and gas industry with technical and managerial experience with particular focus in the US GoM.

Maynard co-founded Darcy Energy Ltd, which was acquired by Daiwa in 2005, and Byron Energy where he has been Chief Executive following its merger with Trojan to create Byron Energy Ltd, in 2013. Prior to that, Maynard was Chief Operating Officer at Petsec Energy (1989-2000). In the late 1970's and early 1980's Maynard held senior exploration positions with Tenneco Oil Company, based in Bakersfield, California.

Maynard holds a B.Sc degree in Geophysics from the California State University at San Diego, CA, USA

Prent H. Kallenberger, Executive Director and Chief Operating Officer, appointed March 2013

Prent is a geoscientist with over 40 years' experience in the oil and gas industry with extensive exploration and development experience in the US GoM, having generated prospects which have led to the drilling of over 125 wells in the GoM and in California. He was Vice President of Exploration with Byron Energy Ltd until its merger with Trojan Energy in 2013, to create Byron Energy Ltd.

Between 2000 and 2006t, Prent was Vice president of Exploration with Petsec Energy Inc, where he was responsible for a team of seven people and generated prospects leading to the drilling of ten successful wells from twelve in shallow waters in the GoM. These wells produced 3s Bcf og as and 1.5 MMbbls of oil. Between 1992 and 1998, Prent was Geophysical Manager with Petsec Energy.

Prent holds a B.Sc degree in Geology from the Boise State University, and M.Sc degree in Geophysics from the Colorado School of Mines.

Charles.J Sands, Non-executive Director appointed March 2013

Charles was a non-executive Director of Byron Energy (Australia) Pty Ltd until March 2013 when it merged with Trojan Energy to create Byron Energy Ltd. Previously, Charles was also a direct of Darcy Energy Ltd.

Charles has over 40 years of broad based business experience in the USA and is President of A.Santini Storage Company of new Jersey, enabling him to advise on the general business operating environment and practices in the USA. Charles is a member of the Audit and Risk Management Committee.

Charles holds a B.Sc degree from Monmouth University, New Jersey.

Paul A. Young, non-executive Director appointed March 2013.

Paul has been in the merchant banking industry for more than 35 years. His extensive experience in the provision of corporate advice to a wide range of Australian and International listed and unlisted companies includes restructuring, capital raisings, initial public offerings and mergers and acquisitions.

Paul is an Honours Graduate in Economics from the 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 chairs the Audit and Risk management Committee.

William R. Sack, Non-executive Director appointed March 2014.

Bill is an explorationist with more than 35 years' experience in the US GoM region in technical and executive roles. Bills qualifications comprise a BSc. In earth Science and 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 BSc in Earth Science/Physices from St.Cloud State University Minnesota, a MSc degree in geology from Michigan State University and a Master of Business Administration from Tulane University, Louissiana.

Nick Filipovic, Chief Financial Officer and Company Secretary.

Nick is a qualified accountant with over 40 years' experience in the financial services and natural resources industries, including oil and gas. He has held a range of senior financial, commercial and investment management positions with AXA Asia Pacific Holdings, National Mutual, Costain Australia Limited and CRA Limited (now Rio Tinto). He was the Chief Financial Officer and

Company Secretary of Byron Energy (Australia) Pty Ltd from 2008 until 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited.

Appendix 1: US Natural Gas & Oil Prices

Oil prices

Byron sells oil into a very deep USA domestic energy market, which is import dependent and where prices are determined by global factors. Byron's crude oil refining characteristics are a "light oil" and prices are closely aligned to Louisiana Light Sweet (LLS) which in turn is related to global benchmarks such as brent oil. As is evident from figure 31, global oil prices are volatile and determined by a combination of supply and demand, OPEC policies, and geopolitical events.

Apart from specific hedging policies, Byron is a "price-taker". Our price assumption is for global oil price of US$80/bbl in real terms, although consensus estimates vary widely from $70/bbl to >US$100/bbl. OPEC, and EIA monthly oil reports are widely referenced by market forecasters and both predict a tightening oil market from 2024.The key risk longer term is the rate of transition of renewables with impact on fossil fuel demand in general.

USA gas prices

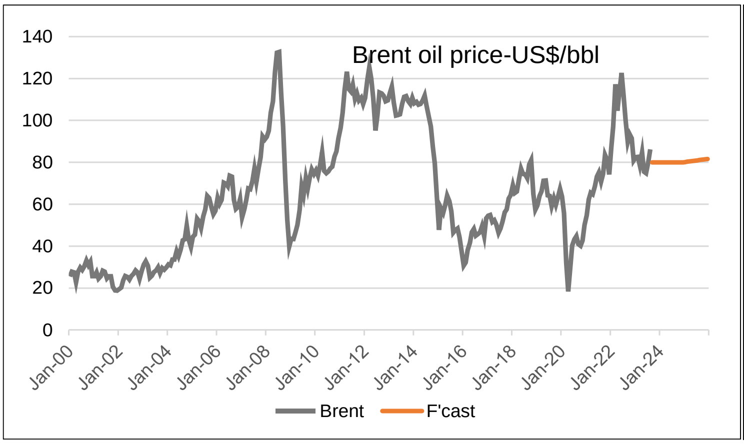
Gas prices in many regions are set by local supply and demand forces because gas is not cheap or easy to distribute compared to oil. In the USA, most production is priced off the Henry Hub market, which is the domestic clearing house for all USA production, plus or minus differentials for gas quality, and transportation charges.

The HH is very volatile in the short term, primarily driven by weather events in the USA, and domestic production and storage levels. Longer term, there isn't an observable secular trend, but a cycle that reflects extended periods of under and over investment. Extended periods of low gas prices drive down drilling and development activity which inevitably leads to contraction in supply, followed by periods of higher prices to incentivise drilling.

In addition, gas is frequently a by-product of oil production and there is more value in oil. When oil prices are low, oil production falls and so too does by-product gas. Exploration purely to sell gas is rare, because the costs or finding and producing gas are similar to oil yet the selling price for gas relative to oil is very low. In recent years, abundant and lowly priced gas has proved very stimulative for gas-intense manufacturing and power generation, and a boom in LNG exports to higher priced regions such as Asia and Europe, however US gas prices and forward strip remain at adds with higher prices for oil and gas around the world.

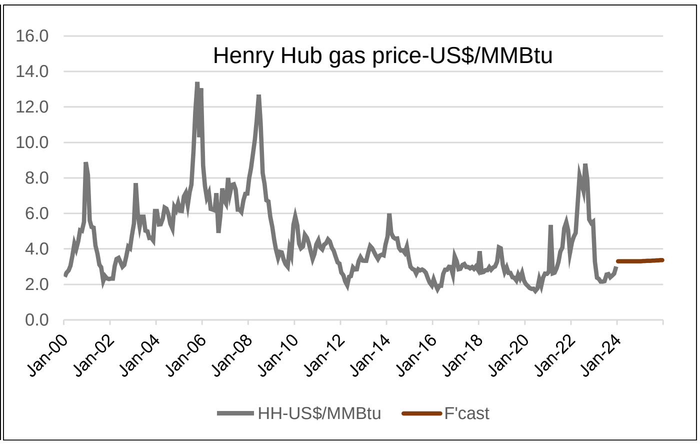
Our Forward price is US$3.30/MMBtu, which is in line with the forward price strip. Figure 32.

Figure 31: Brent oil price-US$/bbl (Past & forecast)



Source: Historical data from USA EIA, forecasts are MST

Figure 32: US Henry Hub Gas price (Past & forecast)



Source: Historical data for USA Energy Information Agency. Forecast's are MST.

Appendix 2

Byron Energy leases, as of September 30, 2023

Figure 33: Byron leases in th US GoM

Property	Operator	W.I.(%)	NRI (%)	Lease expiry	Area(Km2)
SMI-71	BYE	50	40.625	Production	12.2
SMI-57	BYE	100	81.25	Apr-28	22
SMI-61	BYE	100	87.5	Sep-27	20.2
SMI-58	BYE	100	83.3	Production	20.2
SMI-69 E2 (*)	BYE	70	58.3	Production	20.2
SMI-66	BYE	100	87.5	Dec-25	20.2
GI-63	BYE	100	81.25	Apr-28	20.2
GI-72	BYE	100	81.25	Apr-28	20.3

Source: From Byron 2023 Annual Report

(*) Byron has a 53% WI and $$.17% NRI in SM69E platform and SM58E1 well operated by W&T Offshore

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