Annual Report

FY25

Amplitude energy

We are proud to explore, develop and produce domestic gas for Australians to deliver shareholder value, support energy security and contribute to the wealth of our nation.

Proudly part of Australia's energy future.

Amplitude Energy Limited | ABN 93 096 170 295
The terms "the Company" and "Amplitude Energy" are used in this Annual Report to refer to Amplitude Energy Limited and/or its subsidiaries. The terms "2025", "FY25" and the "2025 financial year" refer to the 12 months ended 30 June 2025 unless otherwise stated. References to 2024, FY24 or 2026, FY26 refer to the 12 months ending 30 June of that year. References to information and events that occurred after 30 June 2025 are current as at 1 September 2025 unless otherwise stated. This Annual Report uses terms and abbreviations relevant to the company, its accounts and the petroleum industry. Information on abbreviations and terms, rounding and reserves and resources reporting is provided at the back of this report.

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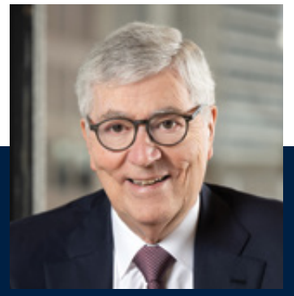
Acknowledgements
Amplitude Energy recognises and acknowledges First Nations Peoples as the Traditional Owners and Custodians of the lands where we operate. We pay respect to the Elders past and present of the world's oldest living culture.

Chairman's Foreword



John Conde AO
Chairman

"Operating in the tight Southeast Australian gas market, higher and more reliable production performance allowed the Company to generate record revenue and, with reduced production costs, greater margins. This translated into record earnings and cash flows."

Summary

Your Company produced excellent operational and financial results over the 2025 financial year, while preparing for a highly desirable growth opportunity over the next few years.

Operating in the tight Southeast Australian gas market, higher and more reliable production performance allowed the Company to generate record revenue and, with reduced production costs, greater margins. This translated into record earnings and cash flows.

On behalf of the Board and I am sure all shareholders, I express my appreciation to our Managing Director and CEO Jane Norman and the broader leadership team. In just a little over two years, Jane and the management team have turned the operations of our Company around. This has involved taking an innovative approach to solving problems, a mindset of continuous improvement and a commitment to the Company's long term strategy.

A highlight of FY25 was the material improvement in Orbost Gas Processing Plant (OGPP) operations. There were new production records set regularly over the year and an increase in production overall of more than twenty five per cent. Many shareholders will recall that the OGPP's historical production issues, particularly under third-party operatorship, frustratingly constrained our Company. To finish the financial year with the OGPP operating at its nameplate production rate of 68 TJ/day in June was a great reward for the effort that our engineering and operational teams expended to improve plant operations. We also acknowledge the leadership of our Chief Operating Officer Chad Wilson. Maximising production at the OGPP remains a priority for FY26 as we ponder further increases in the plant's performance.

Over FY25 our Company made very satisfactory progress with the East Coast Supply Project (ECSP), which maximises use of our existing infrastructure and produces attractive returns along with an accelerated development pathway. O.G. Energy was introduced as a new joint venture partner into our Otway Basin assets, allowing us to pursue our preferred three-well ECSP programme. The ECSP has the potential to be one of the largest sources of new gas supply for the Southeast Australian gas market from as early as 2028. With an aligned partner secured, funding in place and approvals in hand, the drilling phase of this much-needed project will begin soon.

For a Company of our size, partnerships are extremely important to make major projects a reality. O.G. Energy is aligned with our strategy to bring local gas to the domestic market as quickly as possible, starting with the ECSP. We look forward to working with them to make it happen in the target timeframe.

Maximising production from our assets and bringing new supply into the market via the ECSP will maximise shareholder returns - and demonstrate clearly our purpose of being proudly part of Australia's energy future.

In summary, I thank all Amplitude Energy staff for their focus, their hard work and their untiring persistence.

Importance of new gas supply

It is encouraging to see recognised the importance of gas to our economy and our way of life. Millions of Australians rely on affordable natural gas every day in their homes and for their jobs. Gas is essential in the production of everyday products like bricks and glass and for a reliable electricity supply. Without new local gas supplies, Southeast Australian consumers will be forced to rely on higher-cost and higher-emissions gas diverted from Queensland or imported as LNG. Our Company is one of few able to help address looming gas shortages in Southeastern Australia with cost competitive, local supply.

Gas is also an essential part of the "firming" of renewable energy. Reliable electricity supply is an essential service and the nation needs more than just additional solar, wind and batteries to keep commerce, industry and homes functioning when the sun isn't shining and the wind isn't blowing.

The criticality of these issues seems finally to be gaining recognition; gas will be an essential element of any solution.

Board renewal

In August this year, we were delighted to welcome Ian Davies to the Board as a Non-Executive Director. Ian brings exceptional leadership credentials and a nationally-recognised track record in delivering complex energy projects that drive economic value, support energy security and are consistent with Government policy. In his former executive roles, Ian was instrumental in attracting investment into East Coast energy infrastructure to support stable domestic gas supply.

As announced previously I will retire from the Board at this year's Annual General Meeting (AGM) on 6 November 2025, when my current term expires. Subject to shareholders approving Ian's appointment to the Board at the AGM, he will be appointed Chairman.

We also welcomed Gillian Larkins to the Board. Gillian is recognised for her strategic oversight, stakeholder engagement and ability to drive transformation, evidenced by her leadership in implementing significant operational improvements and governance frameworks through her executive career. It is intended that, upon election at the Company's AGM, Gillian be appointed Chair of the Amplitude Energy Audit Committee.

I thank Elizabeth 'Betsy' Donaghey warmly for her seven years of service to the Board. Betsy's understanding and insights into energy markets were valuable additions to Board discussions. She was a significant contributor to strategy development and demonstrated always a strong commitment to safety and caring for our people.

I acknowledge also Giselle Collins who left the Board in April 2025. Giselle served with dedication for almost four years, including in recent times as Chair of the Amplitude Energy Audit Committee.

The transition of Board leadership follows eighteen months of change. With our recent director appointments, and those of Gary Gray AO and Frank Tudor late last year, the Board has been refreshed and is enthusiastic about the Company making a significant contribution to Australia's energy market. Following my departure at the AGM, only one director on your Board will have served for longer than three years.

Final word

It has been an honour and a pleasure to have served as your Chairman these past twelve years. The Company has been on an incredible journey, including ownership and operational changes at the OGPP, major decommissioning projects, and prospectively a major growth project in the Otway Basin.

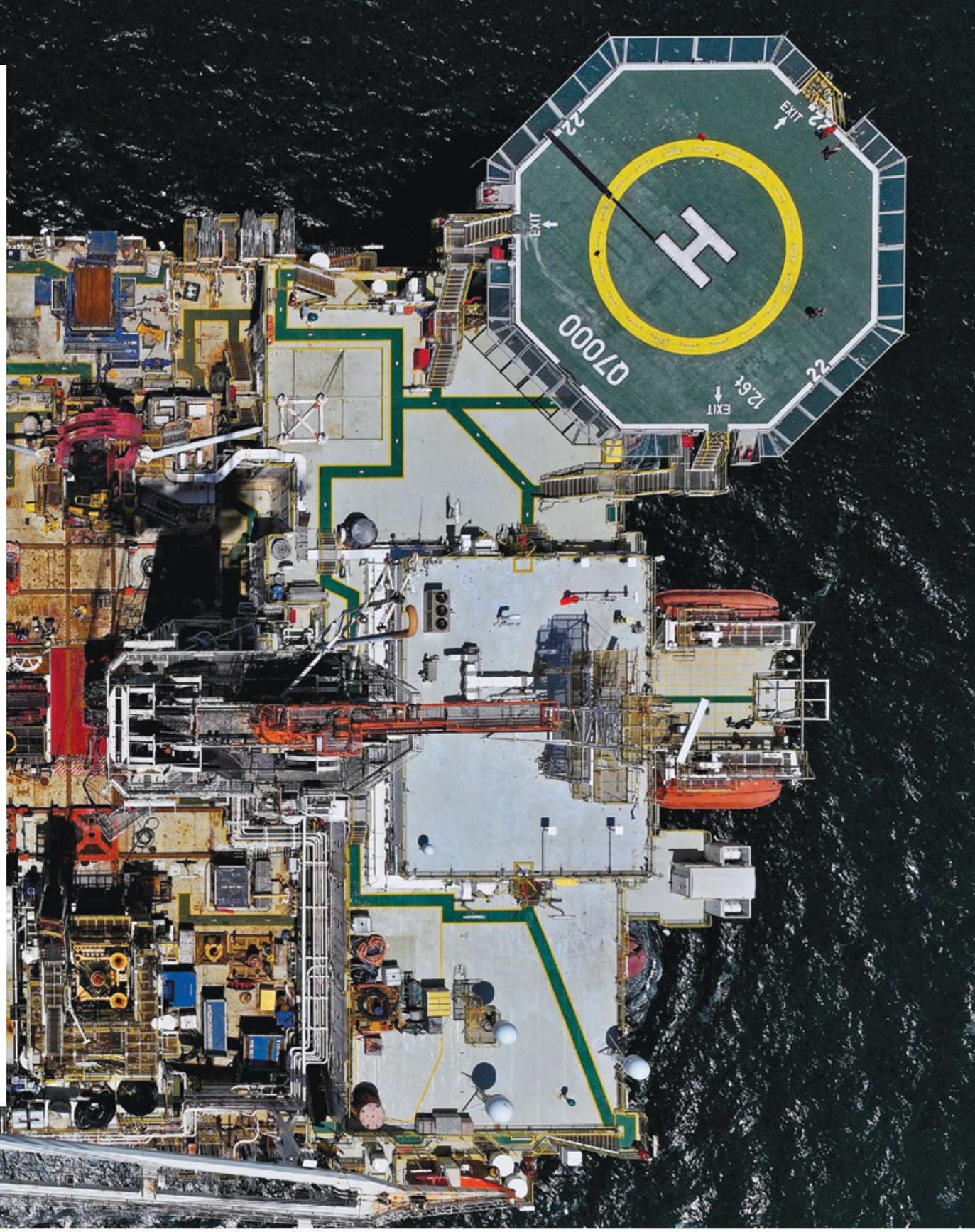
Through my tenure I have lived the Company's successes and endured its challenges. With Amplitude Energy now on a strong footing to pursue its growth strategy, the time is right for me to retire. During my time the Company has gone from being a non-operating, minority owner of primarily oil assets in the Cooper Basin to one of the key gas producers in the East Coast domestic market, with the ability to grow production and assist in providing energy security for Australian consumers.

It was not many years ago that the Company identified the domestic gas opportunity on the East Coast and decided to move away from a focus on oil production. This strategic shift has been highly successful. Now, under the leadership of Jane Norman, we are delivering on that strong market opportunity by growing production, unlocking the value of our assets and laying the foundation for the next phase of growth.

On behalf of the Board, but also personally, I express my appreciation to shareholders for their loyalty and look forward to that loyalty being rewarded in FY26. I thank shareholders for the many discussions, suggestions and support provided to me over the last twelve years.

I leave Amplitude Energy with a twinge of sadness but remain excited about its potential and I will remain a keen observer of, and rejoice in, the Company's future successes.

John Conde AO
Chairman



Managing Director's Report

Financial year 2025 was another record year for Amplitude Energy and positioned the company for transformational growth. When I started as Managing Director and Chief Executive Officer just over two years ago in March 2023, the business faced significant hurdles: production instability at Orbost Gas Processing Plant (OGPP), a significant decommissioning project in the Basker, Manta, Gummy fields in Gippsland Basin, and lack of alignment in the Otway Basin with our joint venture partner regarding the asset's future growth opportunity.

I'm pleased to report that our business has overcome these challenges, laying a strong foundation as we embark on the largest growth project in the company's history, and one of the largest new gas supply projects progressing in Eastern Australia, the East Coast Supply Project (ECSP). We are delivering against our announced strategy of maximising production through our existing infrastructure and unlocking the latent potential within the business, whilst living by our Purpose and Values, to be proudly part of Australia's Energy future, and to Think Differently, Deliver Together and Act Responsibly.

We continued to build on our track record of performance over FY25:

Record high production of 73.0 terajoules equivalent per day (TJe/d), a 17.5% increase compared to FY24

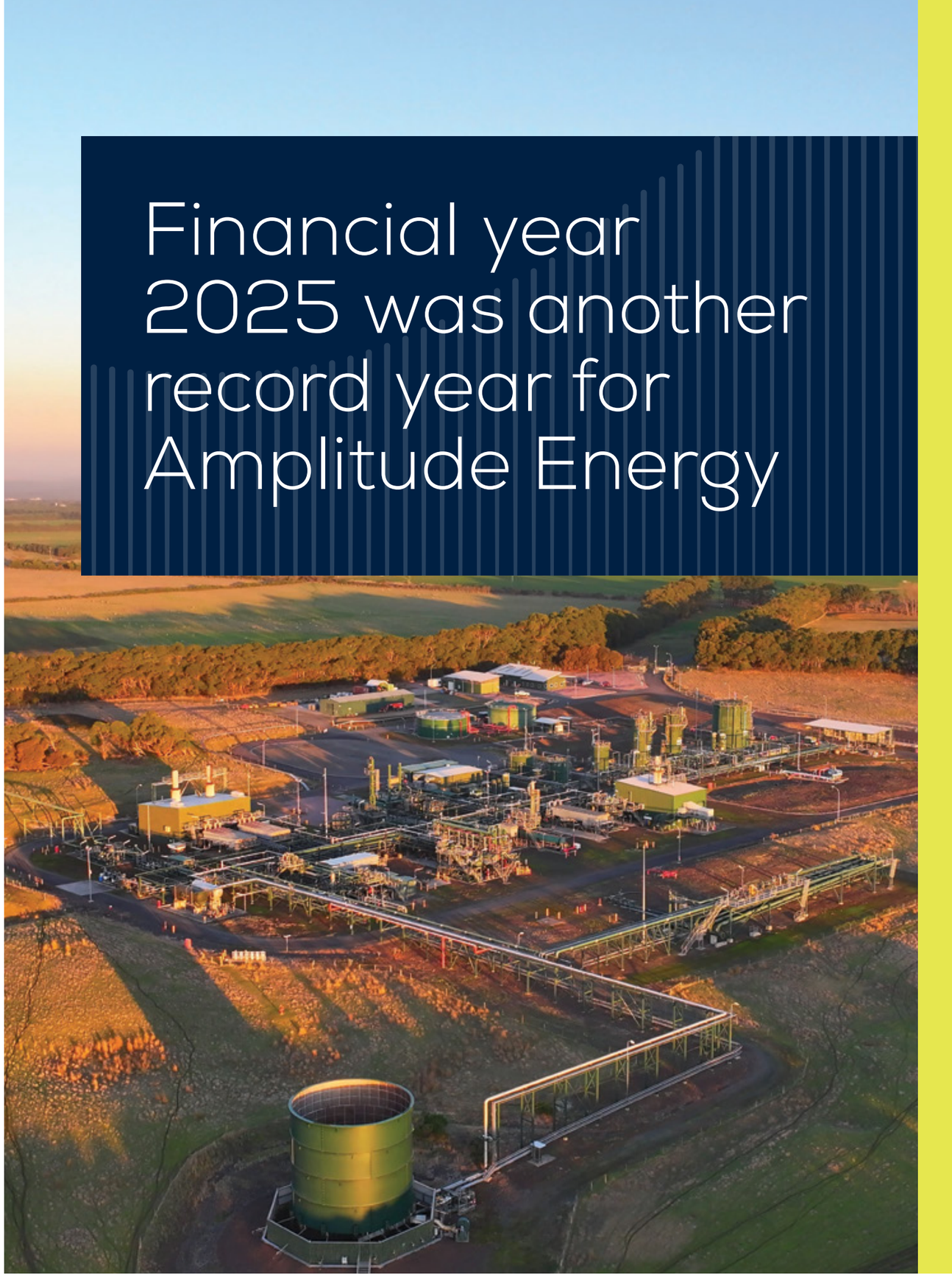
Record low unit production costs of $2.33/GJ produced, a further 10% decrease from FY24

Record high underlying EBITDAX of $173.9 million, representing a margin of 65%, which is approaching industry-leading levels

Over the last year, key stakeholders such as the Federal and State governments, and local communities, have recognised the critical role of gas in Australia's energy future. Gas remains central to Australia's way of life and is correctly being seen as a fuel that is essential to meeting Australia's energy security and energy transition objectives. The Eastern Australian gas market continues to be structurally short of gas from as early as 2028 in outlooks prepared by the Australian Energy Market Operator and Australian Competition and Consumer Commission. This reinforces the urgent need for timely development of new gas supply in existing basins, into market-connected infrastructure, such as our resource positions in the offshore Otway and Gippsland Basins. As more weather-dependent renewables are integrated into the electricity network and coal-fired generation units run past their design lives, we see gas-fired power generation as providing fast-start, responsive firming generation to maintain electricity grid stability and security across Eastern Australia.

There is now a better understanding that industrial manufacturers that produce everyday goods, such as steel and bricks for construction, fertiliser for our agriculture industry and plastics and glass for food and beverage packaging, do not have commercially viable alternatives to gas. Keeping these manufacturers in Australia and maintaining our supply chain security requires access to reliable, affordable natural gas.

In Victoria, which is the largest demand centre for domestic gas and where we operate our gas plants, public policy to transition homes away from gas has been wound back, now allowing residential users to have the choice to continue using natural gas for heating and cooking. This is a win for consumers and we commend the Victorian Government for listening to public feedback. In Victoria, using natural gas in a home is four times less carbon intensive, and less than half the cost on a unit basis, compared to using electricity from the grid.



FY25 In Review

Health, safety and environment

We continue to maintain our strong health and safety record, with no lost time injuries over the last 18 months and our total recordable injury frequency rate (TRIFR) reducing to 3.36, well below the industry benchmark of 5.16[1]. We also had no reportable[2] or notifiable[3] environmental incidents through FY25. This is a particularly good outcome for a year where we had planned maintenance shutdowns at both the Athena Gas Plant (AGP) and OGPP, where there was a large volume of high-risk work completed. We proudly accepted the 2025 Safety Project Excellence Award from Australian Energy Producers (AEP), our industry body, recognising our strong safety culture and performance. We had one recordable injury, where a contractor slipped and cut his hand following the OGPP shutdown. This has led us to review glove wearing procedures across our two sites as part of our ambition to continuously improve our health, safety and environmental performance, to ensure that all our people go home safely from work.

We continue to maintain our Climate Active certification as a carbon neutral organisation[4] and have made considerable progress against our emissions reduction targets published in FY24. In FY25, our company-level flaring is 59% lower than FY23, compared to our target of achieving a 40% reduction by FY30. This has been driven by the improved production stability and performance at OGPP, minimising the number of outages and flaring events. On our Scope-2 target, to integrate renewable electricity to support Amplitude Energy operations, we have now signed a power purchase agreement for a behind-the-meter solar PV project at AGP. This should reduce the electricity we need to purchase from the Victorian grid, which remains the most carbon intensive in Australia. In the past year, we have also progressed physical emissions reductions across our operated assets, with opportunities that reduce our emissions by more than 5,000 tonnes per annum of carbon dioxide equivalent in execution. This also has a real cost benefit, reducing the number of credits required to maintain our carbon neutral certification[4].

We delivered strongly against the four key business priorities set at the start of FY25:

Group production run rate >70 TJe/d by end of FY25

We comfortably exceeded our production target, with FY25 average group production of 73 TJe/d. In June 2025, when OGPP averaged its nameplate of 68 TJ/d for the first time in its history, our group production run-rate exceeded 77 TJe/d. This was the result of strong production performance across both OGPP and AGP, with reliability loss of less than 1% across both plants in FY25. We are proud of the turnaround our Operations and Engineering teams have delivered at OGPP and pleased that this improvement project has unlocked more gas for the domestic market.

Progress 3-well ECSP drilling program, targeting backfill for AGP from 2028

As announced in March 2025, O.G. Energy has acquired our previous partner, Mitsui E&P Australia's 50% stake in the Otway Basin JV, including 50% in our Annie discovery and Nestor prospect. With alignment now established for the ECSP, we have locked in our 3-well drilling program and the project remains on track to bring gas online from as early as 2028. O.G. Energy is repaying approximately $28m in back costs to Amplitude Energy, in the form of a carry in FY26. In the last quarter of FY25, we entered front-end engineering design (FEED) for the development phase of the project, in preparation for connecting the wells as soon as possible, if they are successful.

The improved external environment for our industry delivered smooth approval processes for ECSP drilling activities and the completion of O.G. Energy's entry into our Otway Basin JV, enabling us to move forward with our project plan, on budget and on schedule.

Increase realised gas prices

The stronger market environment for domestic natural gas has delivered higher average realised gas prices of around $10/GJ, a 12% increase compared to FY24. This was driven partially by new short-term contracts that we signed on the basis of stronger production performance at OGPP and also higher realised prices in our spot sales, where we now have the capability to sell into both the Victorian and Sydney markets.

Drive further continuous improvement and efficiencies

Amplitude Energy's successful transformation program in FY24 was succeeded by our FY25 continuous improvement program, targeting cost reductions, value and system improvements. We have delivered over 70 initiatives, with over half of these added in FY25. This program delivered around $20 million in cashflow improvements across the business in FY25, with further cost reduction opportunities of over $5 million p.a. expected to be delivered during FY26.

FY26 focus areas

As we embark on FY26, we see shareholder value being driven by continuing to increase gas production into a tight market and pursuing our transformational growth opportunity, the ECSP. Specifically, our priorities for the year are:

1. Achieving a final investment decision on the ECSP: drilling Elanora / Isabella, completing subsea and plant FEED, securing Gas Sales Agreements at market competitive prices and receiving the required regulatory approvals;
2. Maximising production: increasing the capacity of the OGPP to an instantaneous rate of 70+ TJe/day by the end of FY26 and maintaining reliability loss of <1% across AGP and OGPP; and
3. Growing margins by reducing production costs, streamlining systems and processes and increasing average realised gas prices.

Concluding remarks

We continue to believe that gas is more than just a transition fuel - it will be essential to support Australia's climate commitments and integration of renewable energy in the future. Australian manufacturers, businesses and homes continue to need access to reliable, low emissions and affordable gas. Domestic gas from existing basins, leveraging existing infrastructure, is the lowest cost, lowest emission supply to meet this demand. Without gas, Australia cannot ensure energy or supply chain security, or meet its climate objectives during the energy transition.

Our ECSP project has the potential to increase group production to more than 110 TJ/d, double group revenue compared to FY25 levels, grow group reserves and resources by more than 60% and potentially extend the life of AGP by over a decade[5].

Amplitude Energy is uniquely positioned to supply affordable, reliable and low emissions gas to Southeast Australia, and through this deliver long-term, sustainable value to all shareholders, stakeholders, customers and the communities in which we live and work.

Amplitude Energy is proudly part of Australia's energy future.

Thank you to our investors, the Board, the Executive team, our staff and contractors, lenders, customers and suppliers for supporting our journey and success. I look forward to further progress in financial year 2026.

Jane Norman
Managing Director and Chief Executive Officer

[1] NOPSEMA industry rolling 12-month TRIFR for 30 June 2025

[2] As defined by the Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009

[3] As defined by the Victorian Environment Protection Act 2017

[4] Amplitude Energy has been certified by Climate Active as a carbon neutral organisation for its Scope 1, Scope 2 and what Amplitude Energy defines as its relevant Scope 3 emissions (see FY25 Sustainability Report for details) for FY20-24

[5] Conversion of resources require development in subsequent campaign/s

Proudly Part of Australia's Energy Future

Think Differently

We innovate by keeping it simple while raising the bar. Nothing stops us from continually learning how to do things better and we move with pace.

Act Responsibly

We know how to act responsibly and why it is important to work safely, keep our promises and act ethically with integrity in everything we do.

Deliver Together

Our clarity of purpose, can-do mindset and respect for each other means that anything is possible, and we are accountable to deliver our part.

Our Business

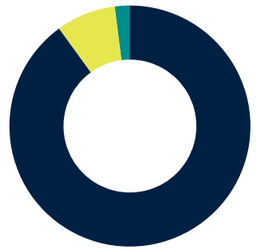
Amplitude Energy is an Australian company providing energy exclusively for the domestic market.

Our headquarters are in Adelaide, with regional offices in Perth and Melbourne. We operate two gas processing facilities in regional Victoria which produce gas from offshore fields in the Otway and Gippsland basins. The Company also holds an extensive portfolio of exploration and development prospects in those basins, including undeveloped discovered resources such as the Annie and Manta gas fields, in close proximity to its existing infrastructure.

We have various non-operated interests in the South Australian Cooper Basin and in the onshore Otway basin in regional South Australia and Victoria.

Production Chart (TJ/d)

- Gippsland Basin
- Otway Basin
- Cooper Basin



2P Proved & Probable reserves at 30 June 2025:
31.1 MMboe (190.6 PJe)[1]

- Gippsland Basin: 28.1 MMboe
- Otway Basin: 2.5 MMboe
- Cooper Basin: 0.6 MMboe

2C Contingent Resources at 30 June 2025:
48.2 MMboe[1]

- Gippsland Basin: 37.4 MMboe
- Otway Basin: 10.5 MMboe
- Cooper Basin: 0.3 MMboe

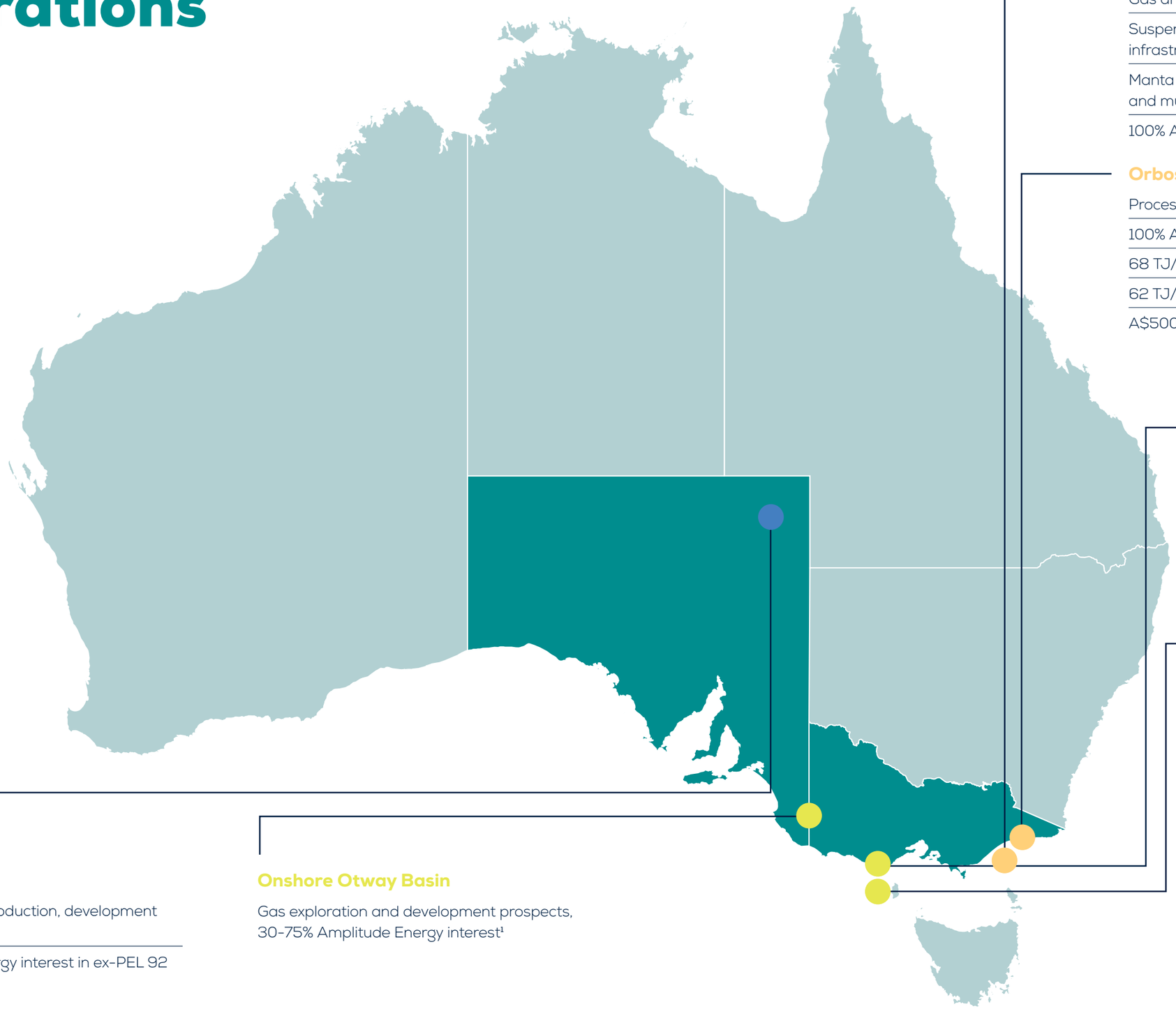
[1]Refer to conversion factors described on page 23

Other key statistics at 30 June 2025

Market cap	Net debt	Issued shares	Employee headcount[2]
$556.8 million	$243.0 million	2,651.4 million	136 staff

[2]Full- and part-time permanent employees and casual employees

Our Operations



Offshore Gippsland Basin

Gas and gas liquids production from the Sole field

Suspended Patricia Baleen gas field and associated infrastructure

Manta and Gummy gas and gas liquids resource and multiple gas exploration prospects

100% Amplitude Energy interest

Orbost Gas Processing Plant

Processing hub for offshore Gippsland Basin gas

100% Amplitude Energy interest

68 TJ/day capacity

62 TJ/day average production FY25

A$500-550mm estimated replacement value

Athena Gas Plant

Processing hub for Otway Basin gas

50% Amplitude Energy interest

150 TJ/day capacity

9.4 TJ/day average production FY25

A$450-500mm estimated replacement value

Offshore Otway Basin

Gas and gas liquids production from the Casino, Henry and Netherby fields

Annie gas discovery and multiple exploration prospects

Preparing for the East Coast Supply Project

50% Amplitude Energy interest in CHN

10% Amplitude Energy interest in VIC/L21 (Minerva)

Cooper Basin

Western Flank oil production, development and exploration

25% Amplitude Energy interest in ex-PEL 92

Onshore Otway Basin

Gas exploration and development prospects, 30-75% Amplitude Energy interest[1]

[1]Including certain interests in process of being divested

Our Social and Environmental Commitment

Health, safety & environment

Zero fatalities and **zero lost time injuries**

No reportable[2] or notifiable[3] environmental incidents during the period

Industry recognition for safety excellence during the Basker, Manta, Gummy decommissioning campaign

Ahead of industry benchmark TRIFR[1]

Over **18 months** without a lost time injury

Gender diversity

50% female representation on the Executive Leadership Team[6]

33% female representation on the Board of Directors[6]

100% Scope-1, Scope-2 and relevant Scope-3 emissions offset[4]

Maintained Climate Active Carbon Neutral Organisation certification[5]

Local content

>$110 million in purchases from SA and Victorian-based suppliers

>300 suppliers in SA & Victoria

Proudly part of the **Australian Made Campaign**

[1]NOPSEMA industry rolling 12-month TRIFR for FY25

[2]As defined by Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009

[3]As defined by the Victorian Environment Protection Act 2017

[4]Organisational carbon emissions voluntarily offset according to Climate Active's scheme for FY24. These consist of Scope-1 (direct), Scope-2 (purchased electricity) and what Amplitude Energy has defined as its relevant Scope-3 emissions (embedded energy and business travel). Downstream Customer Scope-3 transportation and combustion emissions are not included. More information regarding Scope definition is available in the Amplitude Energy 2025 Sustainability Report

[5]Amplitude Energy has been certified by Climate Active as a Carbon Neutral organisation for its Scope 1, Scope 2 and what Amplitude Energy defines as its relevant Scope 3 emissions (e.g. embedded energy and business travel) for FY20-24. It is in the process of seeking FY25 certification. See the 2025 Sustainability Report for further information

[6]As at 30 June 2025

Key Results

Financial

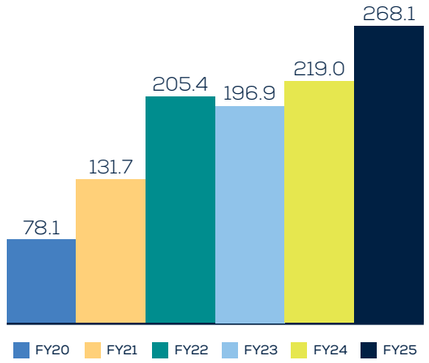
Record production, up 17.1% to 73.0 TJe/d (26.6 PJe for the year)

Record revenue, up 22.4% to $268.1 million

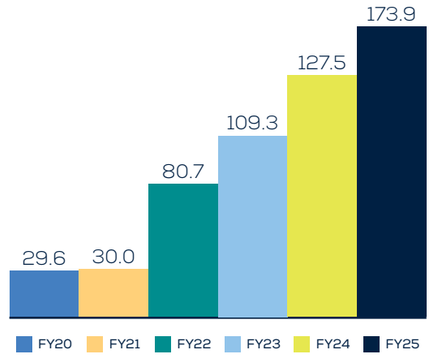
Record underlying EBITDAX, up 36.4% to $173.9 million

Record adjusted[1] cash from operations, up 39.8% to $160.5 million

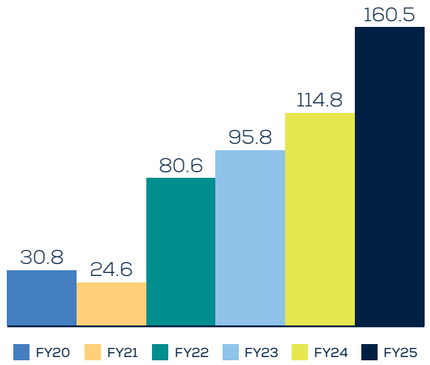
Sales revenue ($ million)



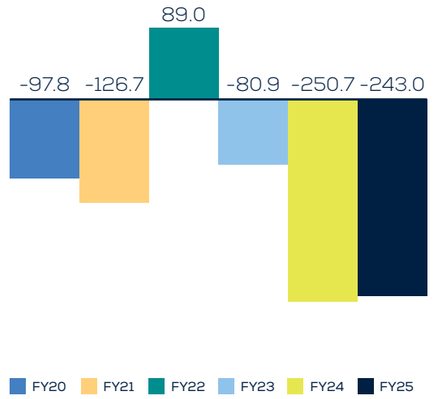
Underlying EBITDAX ($ million)



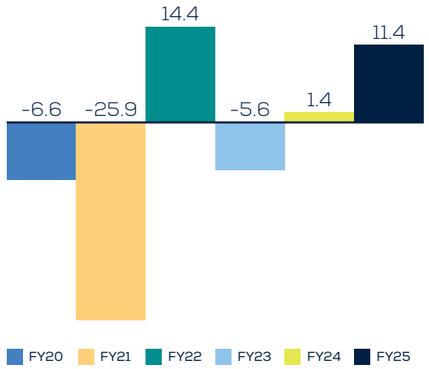
Underlying cash from operations[1] ($ million)



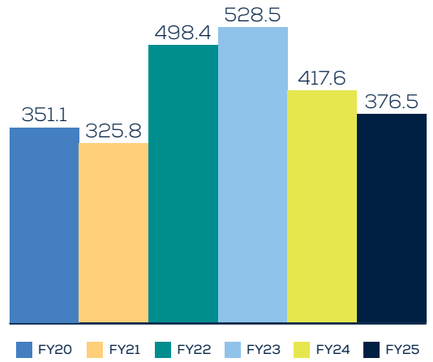
Net (debt)/cash ($ million)



Underlying net profit ($ million)



Total equity ($ million)



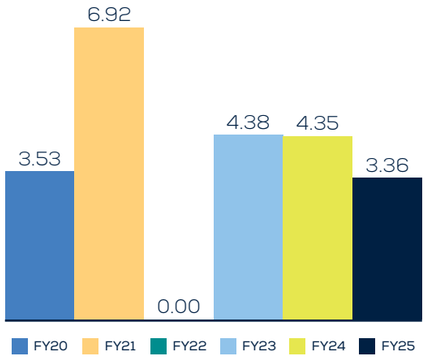
[1]Operating Cash Flow excluding restoration spend and other non-recurring and non-underlying items

Operations & Reserves

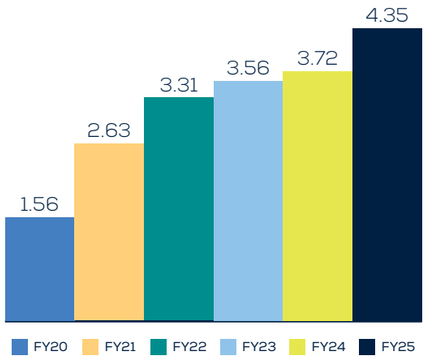
Fifth consecutive year of record production

Excellent safety performance

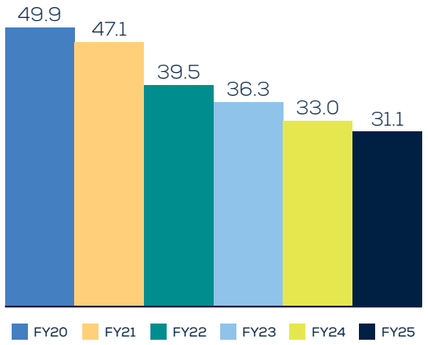
Safety (total recordable injury frequency rate)



Production (MMboe)

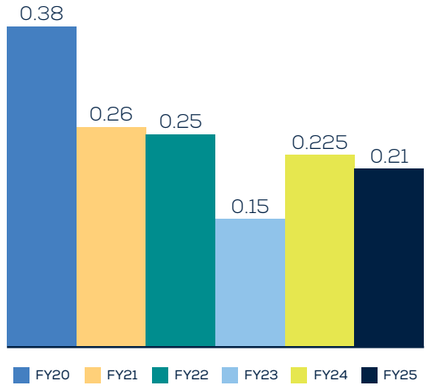


Proved and Probable Reserves
(MMboe)

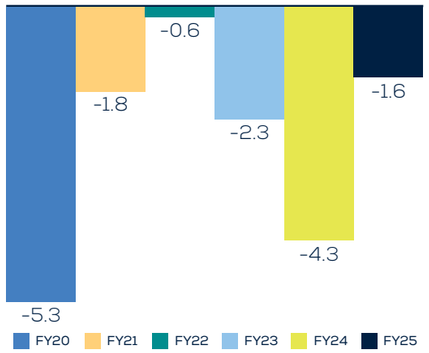


Equity

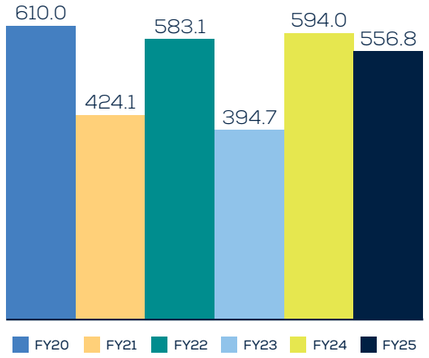
Share price (dollars per share at 30 June)



Basic earnings per share
(cents per share at 30 June)



Market capitalisation ($million at 30 June)



Gas & Oil Revenue

Gas	FY25	FY24	FY23
Total sales volume (PJ)	25.8	22.5	21.4
Average realised price ($/GJ)	9.91	8.83	8.59
Total revenue ($million)	256.6	198.5	184.0
2P Reserves (PJ)	187.0	196.1	217.2

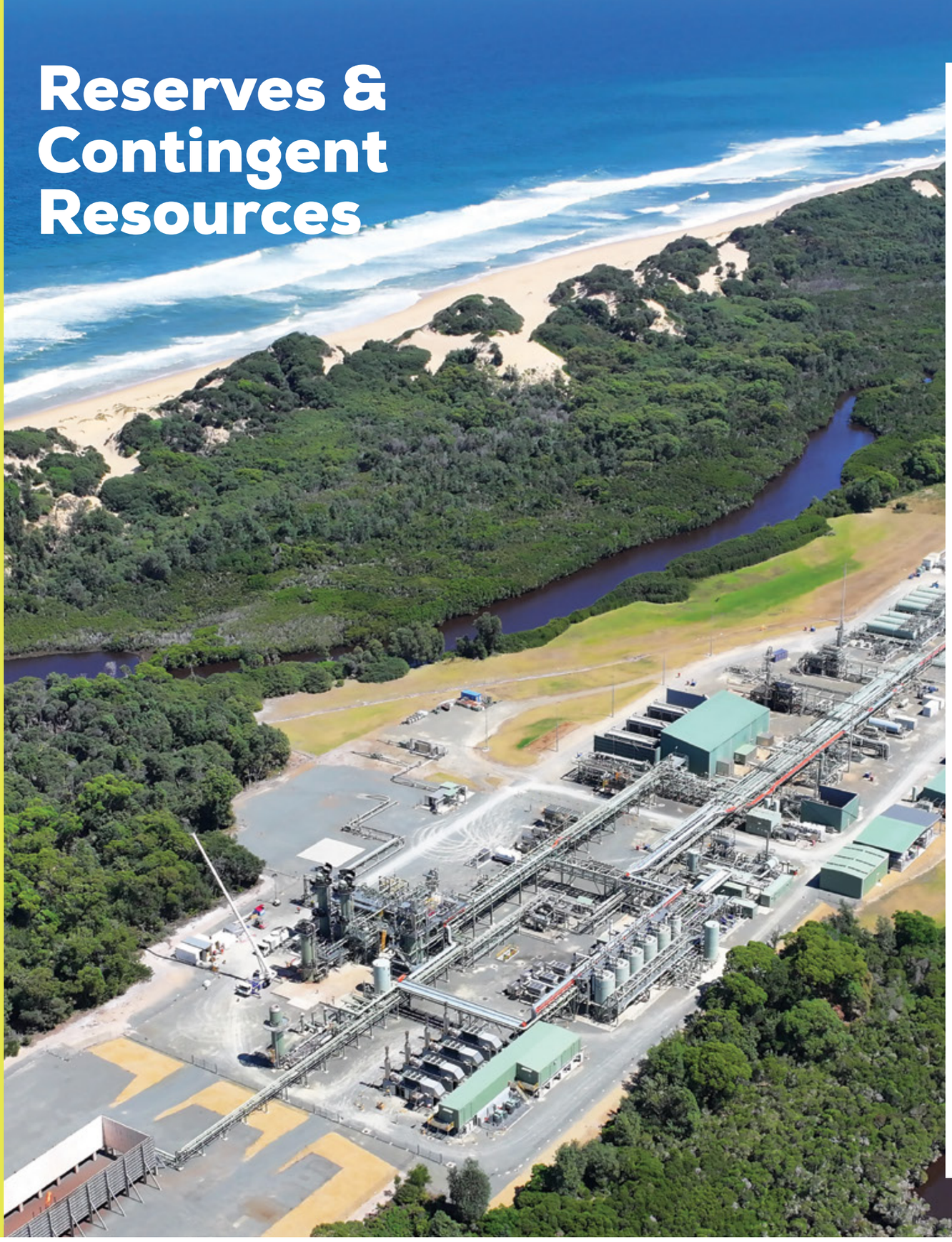
Oil and condensate	FY25	FY24	FY23
Total sales volume (kbbl)	100.8	146.8	91.5
Average realised price ($/bbl)	123.40	138.97	136.59
Total revenue ($million)	11.5	20.5	13.0
2P Reserves (MMbbl)	0.6	0.9	0.8

Capital Expenditure

By activity ($million)	FY25	FY24	FY23
Exploration & appraisal	44.7	14.6	23.9
Development	19.4	9.3	17.3
Total	**64.1**	**23.9**	**41.2**

By basin ($million)	FY25	FY24	FY23
Gippsland Basin	8.8	6.5	18.3
Otway Basin	46.3	10.6	17.8
Cooper Basin	2.3	6.0	4.2
Other	6.7	0.8	0.9
Total	**64.1**	**23.9**	**41.2**

Reserves & Contingent Resources



Reserves

Amplitude Energy's 2P gas and oil Reserves at 30 June 2025 are assessed to be 31.1 MMboe (190.6 PJe)[1].

[1]Refer to conversion factors described on page 23

Production of 4.4 MMboe in FY25

Upward revisions of 3.7 MMboe (1P) and 2.7 MMboe (2P) in the offshore Gippsland Basin through updated subsurface modelling and history matching to the Sole gas field's performance

Upward revisions of 0.1 MMboe (in both 1P and 2P) in the offshore Otway Basin through lower Athena inlet pressures and reduced fuel-flare-vent observations and assumptions

Downward revisions of 0.1 MMboe (1P) and 0.2 MMboe (2P) in the onshore Cooper Basin through production performance at Parsons and Callawonga and field economic limits

Reserves at 30 June 2025[1]

Category	Unit	1P Proved			2P Proved and Probable			3P Proved, Probable and Possible		
		Dev.	Undev.	Total	Dev.	Undev.	Total	Dev.	Undev.	Total
Sales gas	**PJ**	125.4	0.0	125.4	187.0	0.0	187.0	242.4	0.0	242.4
Oil + cond.	**MMbbl**	0.1	0.1	0.2	0.4	0.1	0.6	0.7	0.2	1.0
Total [2]	**MMboe**	20.6	0.1	20.7	31.0	0.1	31.1	40.4	0.2	40.6

[1]As announced to the ASX on 19 August 2025

[2]Reserves exclude Amplitude Energy's share of future fuel usage. Totals may not reflect arithmetic addition due to rounding. The Reserves information displayed should be read in conjunction with the information in the Notes on calculation of Reserves and Contingent Resources provided in this document. "Dev." refers to developed Reserves and "Undev." refers to undeveloped Reserves

Year-on-year movement in Reserves

2P Category	Unit	Proved and Probable 2P Reserves			
		Cooper	Otway	Gippsland	Total
Reserves at 30 June 2024 [1]	**MMboe**	0.9	3.0	29.1	**33.0**
FY25 Production [2]	**MMboe**	-0.1	-0.6	-3.7	-4.4
Revisions/Acquisitions	**MMboe**	-0.2	0.1	2.7	2.6
Reserves at 30 June 2025 [3]	**MMboe**	0.6	2.5	28.1	**31.1**

1P Category	Unit	Proved 1P Reserves			
		Cooper	Otway	Gippsland	Total
Reserves at 30 June 2024 [1]	**MMboe**	0.4	2.3	18.7	**21.4**
FY25 Production [2]	**MMboe**	-0.1	-0.6	-3.7	-4.4
Revisions/Acquisitions	**MMboe**	-0.1	0.1	3.7	3.7
Reserves at 30 June 2025 [3]	**MMboe**	0.2	1.8	18.7	**20.7**

[1]As announced to the ASX on 23 August 2024

[2]Production from 1 July 2024 to 30 June 2025

[3]As announced to the ASX on 19 August 2025. Totals may not reflect arithmetic addition due to rounding

Contingent Resources

Amplitude Energy's 2C Contingent Resources at 30 June 2025 are 48.2 MMboe[1]. No material changes have occurred to the Contingent Resources since 30 June 2024.

[1]Refer to conversion factors described on page 23

Contingent Resources at 30 June 2025[1]

	1C			2C			3C		
Category	**Gas**	**Oil/Cond**	**Total**	**Gas**	**Oil/Cond**	**Total**	**Gas**	**Oil/Cond**	**Total**
Basin	**PJ**	**MMbbl**	**MMboe**	**PJ**	**MMbbl**	**MMboe**	**PJ**	**MMbbl**	**MMboe**
Gippsland	100.9	2.5	19.0	198.9	4.9	37.4	365.0	9.7	69.3
Otway	43.6	0.0	7.2	63.8	0.1	10.5	82.9	0.1	13.7
Cooper	0.0	0.2	0.2	0.0	0.3	0.3	0.0	0.6	0.6
Total[1]	**144.6**	**2.8**	**26.4**	**262.7**	**5.3**	**48.2**	**447.8**	**10.4**	**83.6**

[1]As announced to the ASX on 19 August 2025. Totals may not reflect arithmetic addition due to rounding. The Contingent Resources information displayed should be read in conjunction with the information in the Notes on calculation of Reserves and Contingent Resources provided in this document. "Oil/Cond" refers to oil + condensate resources

Year-on-year movement in Contingent Resources

Category	Unit	1C	2C	3C
Contingent Resources at 30 June 2024[1]	MMboe	26.4	48.4	83.7
Revisions	MMboe	0.0	-0.1	-0.1
Contingent Resources at 30 June 2025[2]	MMboe	26.4	48.2	83.6

[1]As announced to the ASX on 23 August 2024

[2]As announced to the ASX on 19 August 2025. Totals may not reflect arithmetic addition due to rounding. The method of aggregation is by arithmetic sum by category. As a result, the 1C estimate may be conservative and the 3C estimate may be optimistic due to the effects of arithmetic summation

Notes on calculation of Reserves and Contingent Resources

Amplitude Energy prepares its petroleum Reserves and Contingent Resources in accordance with the definitions and guidelines in the Society of Petroleum Engineers (SPE) 2018 Petroleum Resources Management System (PRMS).

The estimates of petroleum Reserves and Contingent Resources contained in this Reserves statement are as at 30 June 2025. The Company is not aware of any new information or data that materially affects the estimates of reserves and contingent resources, and the material assumptions and technical parameters underpinning the estimates continue to apply and have not materially changed.

Amplitude Energy Reserves and Contingent Resources are estimated in line with the Amplitude Energy Reserves and Resources Protocol. All assets with booked Reserves are internally reviewed each year. An independent technical expert review was completed on all Reserves in 2025, with these reviews conducted at least once every three years.

Unless otherwise stated, all references to Reserves and Contingent Resource quantities in this document are net to Amplitude Energy.

Amplitude Energy has completed its own estimation of Reserves and Contingent Resources for its operated Otway and Gippsland Basin assets. Elsewhere, Reserves and Contingent Resource estimations are based on assessment and independent views of information provided by the permit operators (Beach Energy Limited for PEL 92).

Reference points for Amplitude Energy's petroleum Reserves and Contingent Resources and production are defined points where normal operations cease, and petroleum products are measured under defined conditions prior to custody transfer. Fuel, flare and vent consumed prior to the reference point is excluded.

Petroleum Reserves and Contingent Resources are prepared using deterministic, with support from probabilistic, methods. The Reserves and Contingent Resources estimate methodologies incorporate a range of uncertainty relating to each of the key reservoir input parameters to predict the likely range of outcomes.

Project and field totals are aggregated by arithmetic summation by category. Aggregated 1P and 1C estimates may be conservative and aggregated 3P and 3C estimates may be optimistic due to the effects of arithmetic summation.

Totals may not exactly reflect arithmetic addition due to rounding.

The conversion factor of 1 PJ = 0.163417 MMboe has been used to convert from sales gas (PJ) to oil equivalent (MMboe). Condensate and crude oil are converted at 1bbl = 1 boe. The conversion factor 1 MMbbls = 6.11932 PJe has been used to convert oil (MMbbls) and condensate (MMbbls) to gas equivalent (PJe).

Reserves

Under the SPE PRMS 2018, "Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions".

The Otway Basin totals comprise the arithmetically aggregated project fields (Casino, Henry and Netherby). The Cooper Basin totals comprise the arithmetically aggregated PEL 92 fields. The Gippsland Basin totals comprise Sole Reserves only.

Contingent Resources

Under the SPE PRMS 2018, "Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies".

The Contingent Resources assessment includes resources in the Gippsland, Otway and Cooper Basins.

Qualified petroleum Reserves and resources evaluator statement

The information contained in this report regarding Amplitude Energy's Reserves and Contingent Resources is based on, and fairly represents, information and supporting documentation reviewed, prepared by, or under the supervision of, Mr James Clark who is a full-time employee of Amplitude Energy Limited holding the position of Manager, Exploration & Subsurface. Mr Clark holds a Bachelor of Arts (Hons), A Doctorate in Geology, is a member of the American Association of Petroleum Geologists and the Society of Petroleum Engineers, and is qualified in accordance with ASX listing rule 5.41. Mr Clark has consented to the inclusion of this information in the form and context in which it appears and has approved the Reserves and Contingent Resources statement as a whole.

Review of Operations

Safety

Detailed information regarding Amplitude Energy's safety performance is provided in the 2025 Sustainability Report.

The 2025 Sustainability Report was published at the time of this Annual Report and can be viewed and downloaded from the Company's website.

Safety metrics

	FY25	FY24	FY23
Hours worked	297,854	689,398	228,482
Lost-time injuries (LTI)	0	1	0
Total recordable injury frequency rate (TRIFR)[1]	3.36	4.35	4.38
Industry TRIFR[2]	5.16	5.86	5.68

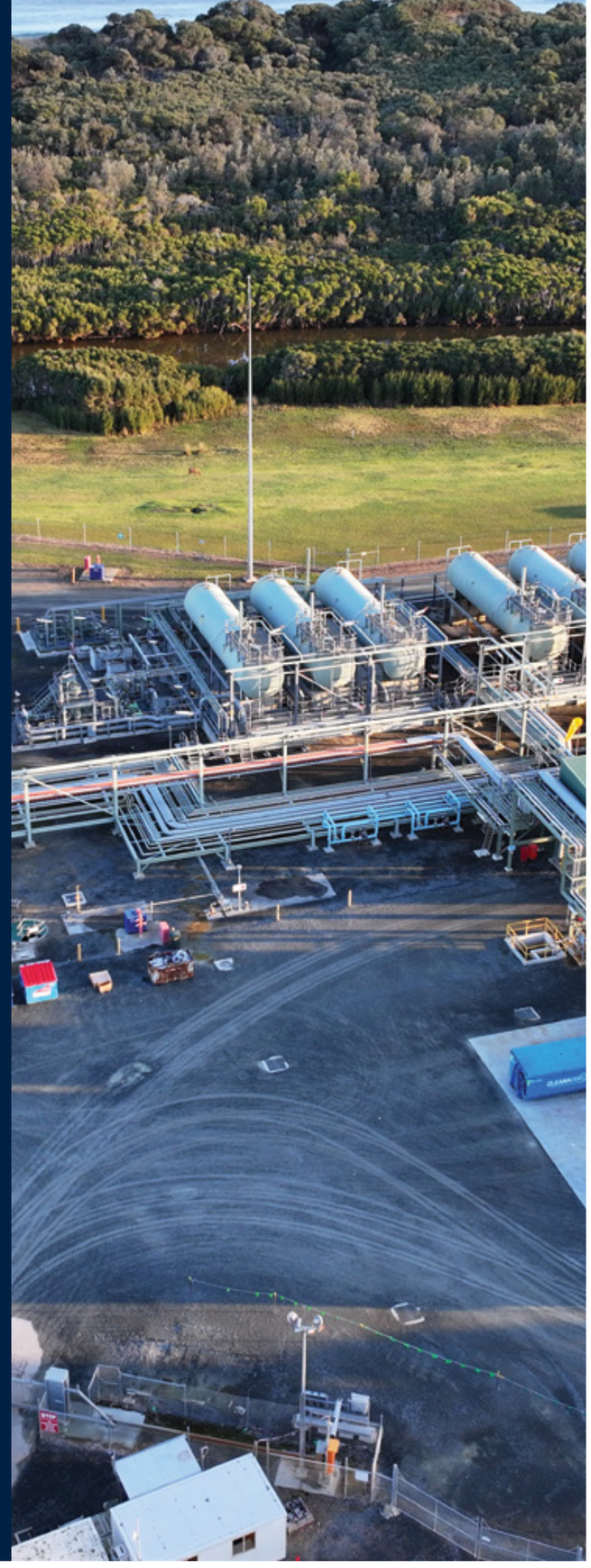
[1]TRIFR is recordable injuries (medical treatment injuries + restricted work case + lost time injuries + fatalities) per million hours worked. Calculated on a rolling 12-month basis

[2]Industry TRIFR is the NOPSEMA benchmark for offshore Australian operations; data is updated every 3 months; published at www.nopsema.gov.au

Production

Amplitude Energy achieved record annual gas and oil production of 26.6 PJe in FY25, mainly due to increasing gas production from the Sole field in the Gippsland Basin.

	FY25			FY24		
	Gas (PJ)	**Oil & Cond. (kbbl)**	**Total (PJe)**	**Gas (PJ)**	**Oil & Cond. (kbbl)**	**Total (PJe)**
Gippsland Basin	22.6	-	22.6	18.1	-	18.1
Otway Basin	3.4	3.6	3.4	3.8	3.6	3.8
Cooper Basin	-	91.4	0.6	-	127.4	0.8
Total	**26.0**	**95.0**	**26.6**	**21.9**	**131.0**	**22.7**



Gippsland Basin

Amplitude Energy is the operator and 100% interest holder for all its Gippsland Basin interests. As at 30 June 2025, these interests comprised:

VIC/L32, which contains the Sole gas field;

VIC/RL13, VIC/RL14 and VIC/RL15, which contain the Basker, Manta and Gummy (BMG) gas and liquids field (these retention leases also hold legacy infrastructure associated with the BMG oil project);

VIC/RL16, which contains the shut-in Patricia-Baleen gas field and infrastructure which connects to the OGPP; and

exploration permits VIC/P72, VIC/P75 and VIC/P80

Orbost Gas Processing Plant

OGPP delivered an average gas processing rate of 62.0 TJ/d during FY25 (FY24: 49.5 TJ/d).

Multiple production records for Sole/OGPP production were set during FY25 including a record 30-day average at nameplate capacity of 68.0 TJ/d and 90-day average of 67.1 TJ/d.

Production rates significantly increased in FY25 compared to prior years as a result of sulphur processing and reliability improvements at OGPP. The improvements stemmed from a combination of physical modifications undertaken at the OGPP over FY24 and FY25 as a part of the methodical execution of the OGPP Improvement Project, as well as a greater focus on plant reliability and process efficiency.

Physical modifications included trials of different forms of absorber packing material to assess impacts on plant performance and reliability. Stainless steel packing material was installed in both absorber units in H2 FY25 which resulted in reduced foaming and fouling in the units, significantly increasing the time between absorber cleans.

As a result, record runtime between cleans was achieved for both absorber units by end FY25, being seven weeks for the first unit and 14 weeks for the second. The number of absorber cleans undertaken during FY25 was reduced to 21, compared to 46 cleans undertaken in FY24.

The average duration of absorber cleans was significantly reduced, driven by process improvements and avoiding the need for confined space entry. In January 2025 the shortest-ever absorber clean was completed in six hours (compared to the FY24 average duration of 32 hours), with peak gas rates restored in less than 20 hours (compared to FY24 average of 49 hours).

Combined with improved plant production when operating with a single absorber, faster cleans allowed the OGPP to operate at higher daily rates during absorber cleans and eliminated the need for spot gas purchases during the financial year.

A liquid H2S scavenger chemical injector was installed and commissioned at the OGPP in February 2025, resulting in improved sulphur removal outcomes and increasing redundancy in the overall sulphur removal system.

A planned OGPP maintenance shutdown was conducted in March 2025 with the full planned scope of works completed in seven days. The scope of work included installation of a chemical clean-in-place system in both absorbers and further modifications to the internal configuration of the absorbers. Production at the OGPP was steadily ramped up following the shutdown and operated at a record quarterly average rate of 67.1 TJ/d for the June Quarter.

Strong performance of the absorbers following the shutdown, together with redundancy provided by H2S scavenger injection, allowed the Company to defer the next replacement of media in the polisher unit to the second half of CY2025.

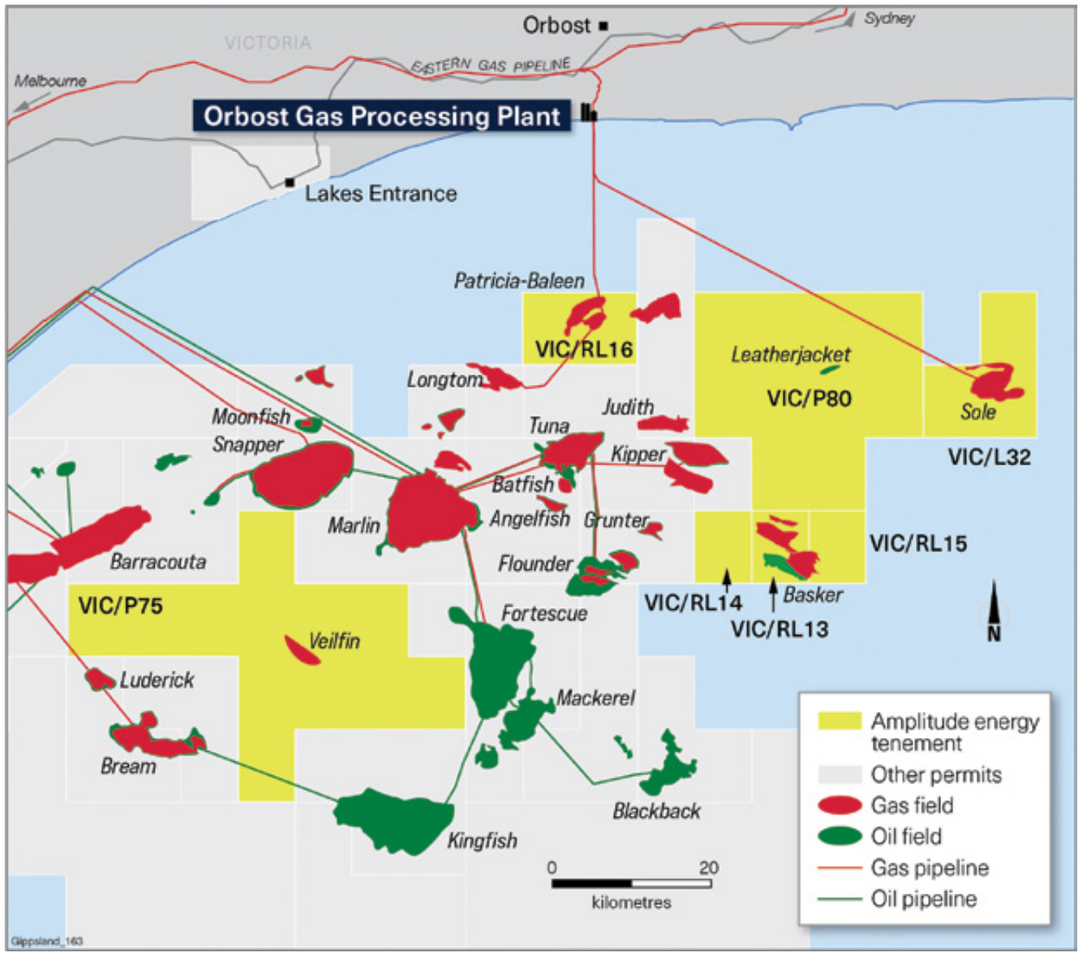
OGPP achieved a reliability loss rate of only 0.6% for FY25, well ahead of the Company's target for reliability loss of <2% by end FY26.

Patricia Baleen commercialisation opportunity

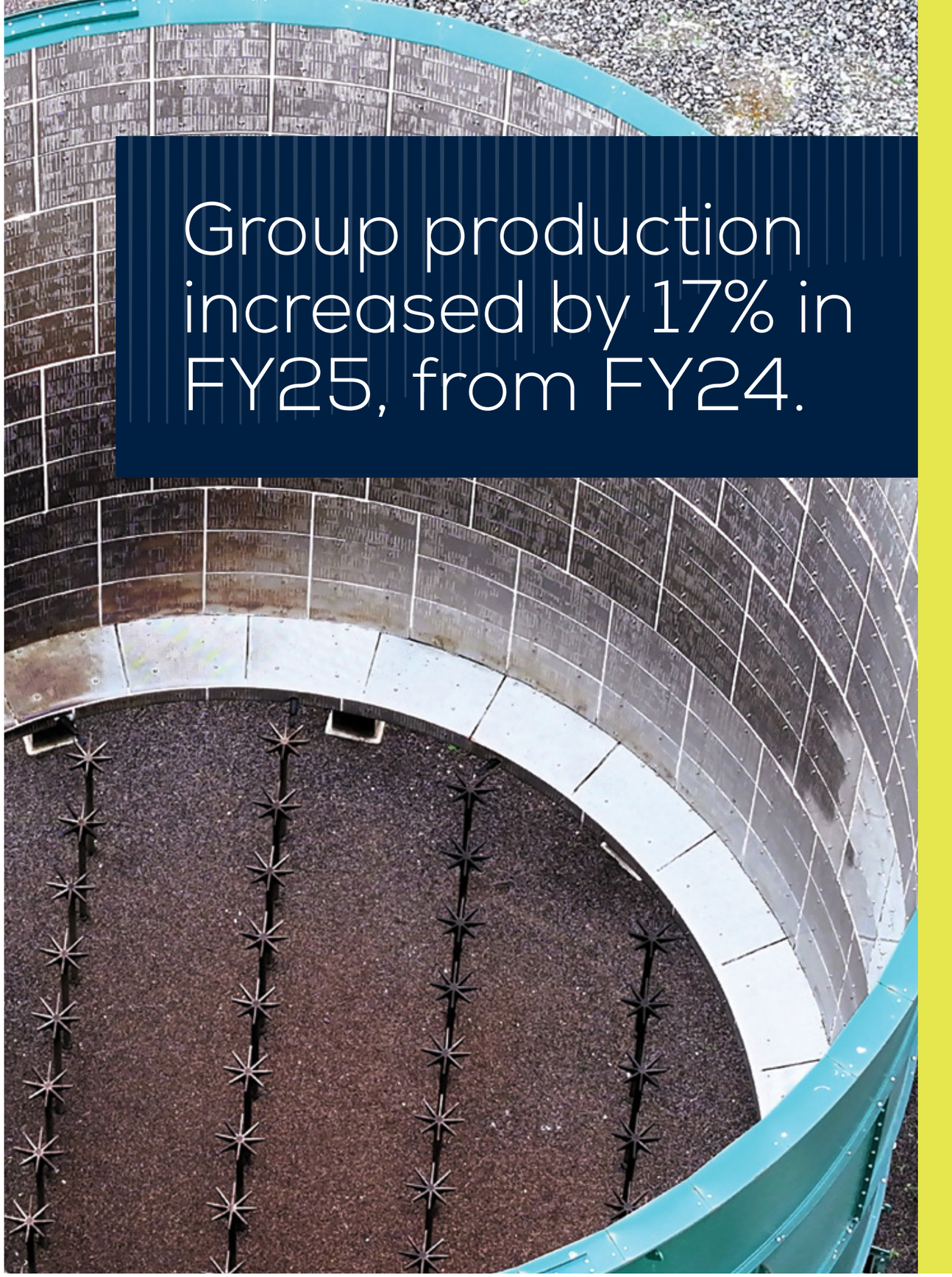
Amplitude Energy continued to assess the potential to commercialise the shut-in Patricia Baleen field in VIC/RL16 as a production or gas storage asset. The project has entered the Select phase, ahead of a decision to enter FEED.

During 2H FY25, Amplitude Energy completed an umbilical and subsea controls repair study and progressed engineering and early cost estimates for umbilical repair options.

Amplitude Energy has commenced engagement with NOPTA regarding a Production Licence for Patricia Baleen.



Gippsland Basin



Group production increased by 17% in FY25, from FY24.

Otway Basin (Offshore)

The Company's interests in the offshore Otway Basin as at 30 June 2025 comprised:

a 50% interest in and operatorship of production licences VIC/L24 and VIC/L30 containing the producing Casino, Henry and Netherby ("CHN") gas fields, with the remaining 50% interest held by Mitsui E&P Australia and its associated entities ("MEPAU")[1];

a 50% interest in and operatorship of production licences VIC/L33 and VIC/L34 containing part of the Black Watch and Martha gas fields, with the remaining 50% interest in these production licences held by MEPAU[1];

a 100% interest[2] in and operatorship of exploration permit VIC/P44 containing the undeveloped Annie gas discovery;

a 100% interest[2] in and operatorship of exploration permit VIC/P76;

a 50% interest in and operatorship of AGP (onshore Victoria), which is jointly owned with MEPAU[1] and processes gas from the Casino, Henry and Netherby gas fields; and

a 10% non-operated interest in production licence VIC/L22, which holds the shut-in Minerva gas field, with Woodside Energy the operator and 90% interest holder.

Athena Gas Plant (AGP)

In the Otway Basin, CHN gas production during FY25 was 9.4 TJ/d or 3.4 PJ (net to Amplitude Energy's 50% share), which is 10% lower than FY24, primarily due to natural decline in the CHN fields.

The reliability of the AGP has significantly improved compared to previous years, with 0.1% reliability loss as a proportion of asset capacity in FY25, compared to 2.4% in FY24.

Regular cycling of the CHN wells was impacted between November 2024 and February 2025 by a failure in the CHN electro-hydraulic umbilical cable, resulting in a temporary increase in the rate of field decline over that period.

Repairs to the CHN electro-hydraulic umbilical cable in February 2025 re-established communication to Casino 5, Henry 2 and Netherby 1 wells, allowing cycling of these wells to resume. The Company is assessing options to re-establish communication to the Casino 4 well.

The planned AGP maintenance shutdown was conducted in early March with the full planned scope of works completed in less than six days without injuries or significant incidents.

East Coast Supply Project (ECSP)

In March 2025 the Company entered into a number of commercial agreements with subsidiaries of O.G. Energy regarding the development of the East Coast Supply Project on a 50/50 basis.

The agreements contain terms of O.G. Energy's participation in the ECSP, including that it will participate in 50% of point-forward project costs from the date of signing, and reimburse Amplitude Energy for 50% of all historical ECSP project costs spent[3]. The agreements also align each party's interests in Amplitude Energy's Offshore Otway Basin assets at 50% each.

Contemporaneously, subsidiaries of O.G. Energy and MEPAU, executed a sale and purchase agreement for O.G. Energy's acquisition of MEPAU's existing interests in the Otway Basin joint ventures, including the Athena Gas Plant. A summary of the transactions that Amplitude Energy is a party to, including the conditions of the relevant agreements, is detailed in the ASX release titled 'Execution of Otway Basin Joint Venture Agreements' on 24 March 2025. This transaction completed on 31 July 2025.

The respective Boards of Amplitude Energy and O.G. Energy approved the three-well ECSP drilling programme and determined that the Elanora exploration well, with sidetrack to Isabella, will be the first to be drilled in the upcoming campaign. Amplitude Energy exercised its options for its second and third well drilling slots within the Transocean Equinox rig consortium, with those two slots targeting the Juliet prospect followed by the Annie discovery.

On 24 March 2025 Amplitude Energy also released additional project details regarding the ECSP, including preliminary indicative cost estimates for the two phases of the project, being a well drilling and completions phase, followed by a development phase encompassing subsea tie-ins and modifications at the Athena Gas Plant.

The Transocean Equinox drilling rig arrived in the Offshore Otway Basin in April and is expected to commence drilling the first well of its campaign for Amplitude Energy in late calendar year 2025, or early 2026.

[1]Held by MEPAU as at 30 June 2025, with completion of the sale of its interest to O.G. Energy occurring on 31 July 2025
[2]After the reporting period the VIC/P76 Farm-in completed, which gave rise to the transfer of a 50% interest in VIC/P76 to O.G. Energy
[3]Payment of back costs is in the form of a carry from completion. The reimbursement amounts to approximately A$27.8 million

Detailed planning and engineering for the ECSP continued, with multiple contracts awarded during the quarter to progress with drilling for the three well programme. Key long-lead items, including subsea trees, are in the delivery stages in readiness for the drilling windows.

The Company's Athena Supply Project environment plan (EP), which covers the drilling of Elanora, Isabella and Juliet, was accepted, allowing the commencement of the Equinox's rig activities for the Otway Basin Joint Venture (JV). In early July 2025, the Company also received approval of its Offshore Project Proposal (OPP) for the ECSP, which includes the development drilling of the Annie contingent resource, meaning that both primary approvals required for the drilling stage of the project have been received.

Planning for the development phase of the ECSP is progressing, with front-end engineering and design (FEED) having commenced in Q1 FY26, and tenders for the subsea tie-in scopes to be issued in H1 FY26.

Amplitude Energy commenced a marketing campaign with potential gas customers regarding foundation contracts for the ECSP on behalf of the Offshore Otway Basin joint venture partners in Q4 FY25.

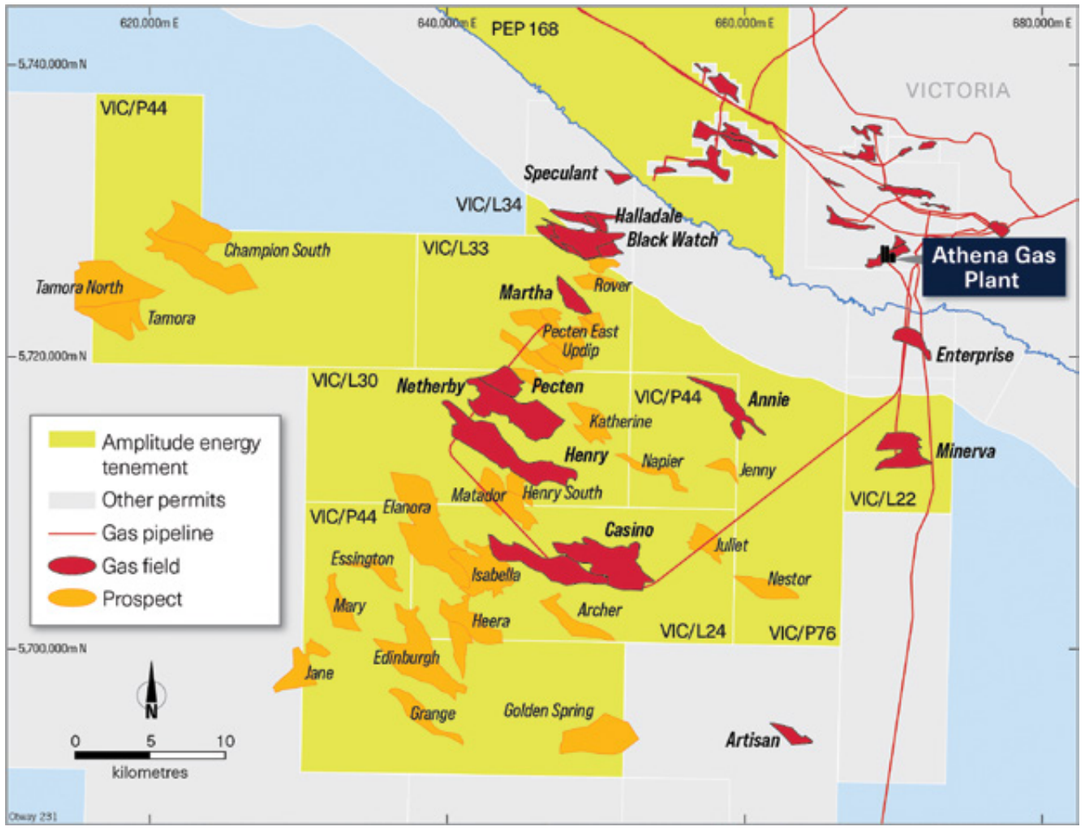
Subject to exploration success, Amplitude Energy and O.G. Energy intend to proceed to a final investment decision to undertake the development phase of the project in H1 CY2026.

Amplitude Energy expects to fund ECSP capital expenditure from existing cash on hand, underlying organic cash generation over 2025-2028 and the Company's existing bank debt facility.

The ECSP is targeting to backfill the Athena Gas Plant with up to 90 TJ/day of gross gas supply as early as 2028, subject to receipt of regulatory approvals.

Minerva decommissioning

Woodside Energy, the Operator of VIC/L22 (Amplitude Energy share 10%), completed the decommissioning of wells in the Minerva gas field in H2 FY25 utilising the Transocean Equinox rig. The Operator had earlier commenced the removal of the subsea facilities in the field (pipeline, umbilical cables, etc.) but has deferred the completion of this work.



Otway Basin (Onshore)

The Company's interests in the onshore Otway Basin as at 30 June 2025 comprised:

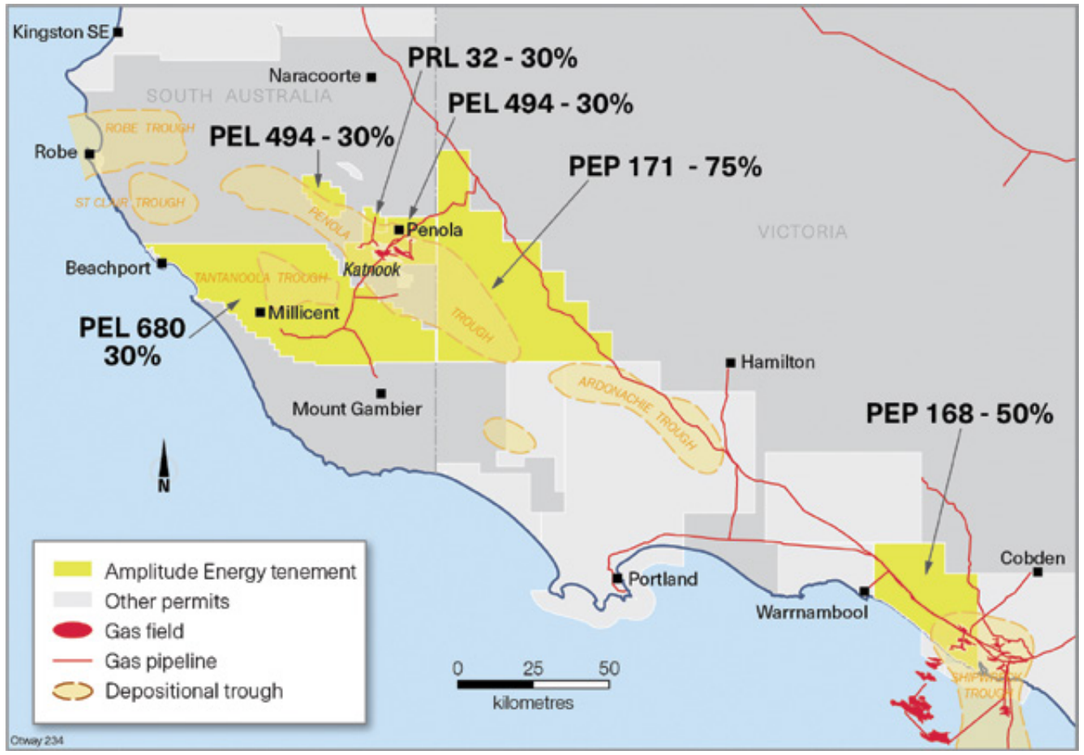
a 30% interest[1] in PEL 494, PRL 32 and PEL 680 in South Australia, with the remaining interests held by the operator, Beach Energy;

a 50% interest in PEP 168 in Victoria, with the remaining interest held by the operator, Beach Energy; and

a 75% interest in PEP 171 in Victoria, with the remainder held by operator Vintage Energy Limited[1].

Exploration activity

Amplitude Energy and its joint venture partners continue to progress the technical evaluation of onshore exploration and development opportunities.



Onshore Otway Basin

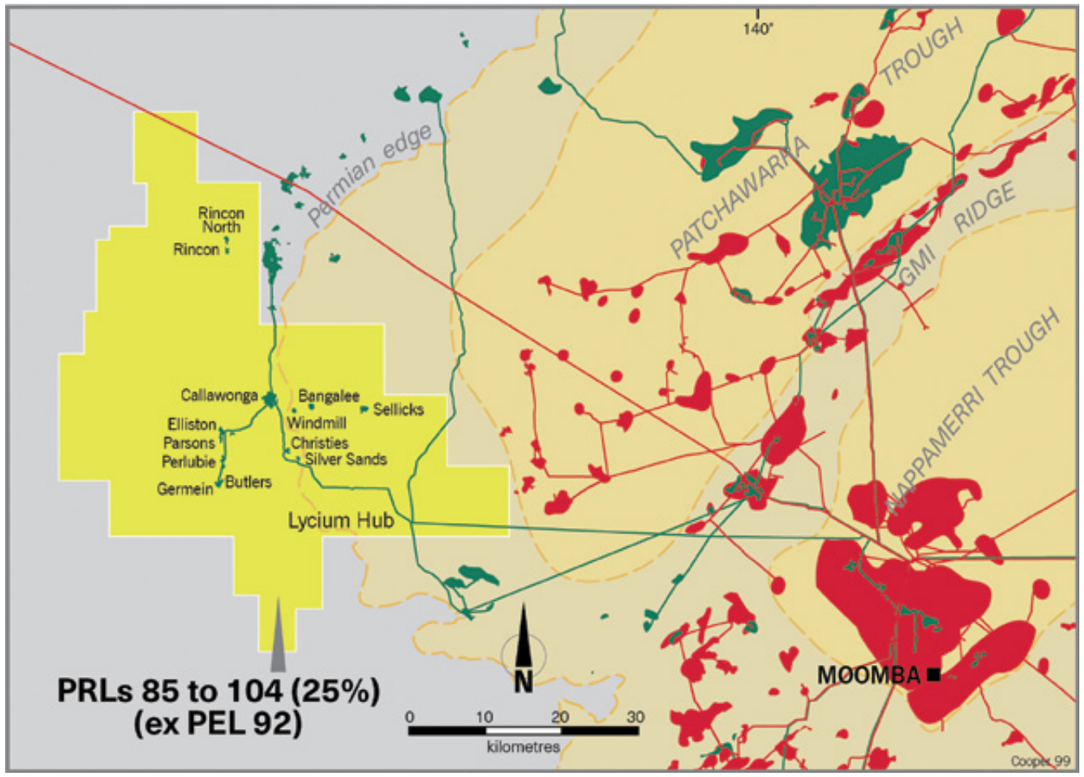
Cooper Basin

The Company's interests in the Cooper Basin as at 30 June 2025 comprised a 25% interest in PRLs 85-104 (formerly PEL 92), with the remaining interests held by the operator, Beach Energy.

Exploration and development activity

Planning is underway for a three well development campaign at Callawonga. The timing of this campaign was deferred from mid-CY2025 as initially planned to later in FY26 due to flooding in the Cooper Basin.

The Company and its joint venture partner are also refreshing the prospect portfolio ready for the next phase of exploration.



Cooper Basin

[1]Amplitude Energy has entered into agreements to transfer its interests in PEL 494 and PEP 171 to Beach Energy, and to exit exploration permit PEL 680

Truck being loaded with elemental sulphur for delivery from OGPP

Continuous Improvement Programme

A key focus area for the Company over FY25 was to extract further value from its operations through a programme focused on continuous improvement and efficiencies. Building on the success of the FY24 transformation programme, the continuous improvement programme focussed on delivering value and cashflow improvements through cost and emissions reductions, improved productivity and margin maximisation.

Over 70 separate initiatives across the business were being worked on in FY25, with half realising value. The remaining initiatives are still in delivery and will continue to be worked on in FY26.

In aggregate, the continuous improvement programme realised around $20 million in cashflow improvements in FY25, with the completion of remaining initiatives expected to realise benefits into FY26 and beyond.

Around 70% of the value realised in FY25 came from new OGPP operational improvements, primarily associated with absorber cleaning and polisher treatment improvements. These have driven near-term value through increased sales volumes, reduced contractor costs and reduced consumables costs.

Gas marketing and trading initiatives to maximise the Company's realised gas prices contributed 15% of the value realised in the continuous improvement programme over FY25.

The Company's focus on cost control remained, including initiatives to reduce waste disposal costs, optimise maintenance spend and manage pipeline-related costs.

The continuous improvement focus will continue into FY26.

Orbost sulphur sales

Amplitude Energy has been working to commercialise the sulphur by-product from OGPP. This involved completing a six-month trial with the Gippsland Agriculture Group in East Gippsland, demonstrating the effectiveness of Amplitude Energy's sulphur as a soil amendment additive for agricultural applications, and engaging with EPA Victoria on the opportunity for beneficial use.

At the end of FY25, Amplitude Energy commenced delivering elemental sulphur as a product to Devco Australia Holdings ("Devco").

Devco manufactures a range of sulphur-based products for the agricultural and industrial markets across Australia, importing elemental sulphur fertiliser products into Australia and New Zealand. It handles 12,000 to 15,000 tonnes of sulphur per year. The sulphur from OGPP is anticipated to be used in its existing form as fertiliser within the East Gippsland region.

Debt facility increase and extension

In December 2024 the Company executed documentation to amend its existing debt facilities with a group of domestic and international banks.

The amendments result in an $80 million increase in the initial facility limit of the reserves based loan (RBL) to $480 million and an extension in the maturity of the facility by two years, to 30 September 2029, which is expected to be post the commencement of production from the ECSP. Amplitude Energy's existing $20 million working capital facility has been retained, with the maturity also extended to 30 September 2029.

The interest rates and margins on both facilities are unchanged from existing levels.

The increase in the facility limit and maturity extension will maximise Amplitude Energy's liquidity and funding flexibility over the medium term, particularly during the ECSP exploration and development phase. The facilities have also been structured to enable the potential introduction of other forms of finance for the ECSP.

We continued to build on our track record of performance over FY25.

Portfolio

Amplitude Energy Exploration & Production Tenements (at 30 June 2025)

Gippsland Basin

State	Tenement	Interest	Location	Area (km²)	Operator	Activity
Victoria	VIC/P72	100%	Offshore	271	Amplitude Energy	Exploration
	VIC/P75	100%	Offshore	808	Amplitude Energy	Exploration
	VIC/P80	100%	Offshore	676	Amplitude Energy	Exploration
	VIC/RL13 (Basker-Manta-Gummy)	100%	Offshore	67	Amplitude Energy	Retention
	VIC/RL14	100%	Offshore	67	Amplitude Energy	Retention
	VIC/RL15	100%	Offshore	67	Amplitude Energy	Retention
	VIC/RL16	100%	Offshore	135	Amplitude Energy	Retention
	VIC/L32	100%	Offshore	203	Amplitude Energy	Production

Otway Basin

State	Tenement	Interest	Location	Area (km²)	Operator	Activity
South Australia	PEL 494[1]	30%	Onshore	1,277	Beach Energy	Exploration
	PEL 680[1]	30%	Onshore	1,929	Beach Energy	Exploration
	PRL 32	30%	Onshore	37	Beach Energy	Retention
Victoria	PEP 168	50%	Onshore	795	Beach Energy	Exploration
	PEP 171[1]	75%	Onshore	1,974	Vintage Energy	Exploration
	VIC/P44[2]	100%	Offshore	603	Amplitude Energy	Exploration
	VIC/P76[2]	100%	Offshore	162	Amplitude Energy	Exploration
	VIC/L22 (Minerva)	10%	Offshore	58	Woodside Energy	Production
	VIC/L24 (Casino)	50%	Offshore	201	Amplitude Energy	Production
	VIC/L30 (Henry & Netherby)	50%	Offshore	201	Amplitude Energy	Production
	VIC/L33	50%	Offshore	128	Amplitude Energy	Production
	VIC/L34	50%	Offshore	6	Amplitude Energy	Production

[1]Amplitude Energy has entered into agreements to transfer its interests in PEL 494 and PEP 171 to Beach Energy, and to exit exploration permit PEL 680

[2]Pending completion of the sale of a 50% interest to O.G. Energy

Cooper Basin

State	Tenement	Interest	Location	Area (km²)	Operator	Activity
South Australia	PPL 204 (Sellicks)	25%	Onshore	2.0	Beach Energy	Production
	PPL 205 (Christies-Silver Sands)	25%	Onshore	4.3	Beach Energy	Production
	PPL 220 (Callawonga)	25%	Onshore	5.5	Beach Energy	Production
	PPL 224 (Parsons)	25%	Onshore	1.8	Beach Energy	Production
	PPL 245 (Butlers)	25%	Onshore	2.1	Beach Energy	Production
	PPL 246 (Germein)	25%	Onshore	0.1	Beach Energy	Production
	PPL 247 (Perlubie)	25%	Onshore	1.5	Beach Energy	Production
	PPL 248 (Rincon)	25%	Onshore	2.0	Beach Energy	Production
	PPL 249 (Ellison)	25%	Onshore	0.8	Beach Energy	Production
	PPL 250 (Windmill)	25%	Onshore	0.6	Beach Energy	Production
	PRL 85-104[1] (formerly PEL 92)	25%	Onshore	1,899.3	Beach Energy	Exploration

[1]Includes associated PPLs

Directors

Mr John C. Conde AO

B.Sc., B.E (Hons), MBA

Chairman
Independent Non-Executive Director

Appointed 25 Feb 2013
Retires on 6 Nov 2025

Experience and expertise
Mr Conde has extensive experience in business and commerce and in chairing high profile business, arts and sporting organisations.

Previous positions include non-executive director of BHP Billiton (ASX:BHP), Chairman of Bupa Australia, Chairman of Pacific Power (the Electricity Commission of NSW), Chairman of the Sydney Symphony Orchestra, director of AFC Asian Cup, Chairman of Events NSW, President of the National Heart Foundation, Chairman of the Pymble Ladies' College Council, director of Dexus Property Group (ASX:DXS) and Deputy Chairman of Whitehaven Coal Limited (ASX:WHC).

Current and other directorships in the last 3 years
Mr Conde is Chairman of The McGrath Foundation (since 2013 and director since 2012) and Chairman of Dexus Wholesale Property Fund (DWPF) (since 2020).

Mr Conde is a former President of the Commonwealth Remuneration Tribunal (2003 – 2023).

Special responsibilities
Mr Conde is Chairman of the Board of Directors. Effective 19 August 2021 he is also the Chairman of the Governance & Nomination Committee.

Ms Jane L. Norman

B.Sc., B.Eng. (Hons)
PGDip, GAICD

Managing Director and CEO

Appointed
20 March 2023

Experience and expertise
Jane has worked and studied in Australia and the UK and brings 30 years of industry experience in the energy markets. She began her career with Shell International Exploration & Production as a Process Engineer in operations and then as a Commercial Advisor in The Hague, Aberdeen and London. Subsequently, in London, Jane held corporate finance and equity capital markets roles with Cazenove & Co (now JP Morgan Cazenove) and Goldman Sachs.

Jane returned to Australia to join Santos where she held senior commercial, corporate strategy and Executive Committee roles. She led major strategic initiatives at Santos and played a key role in Santos' growth strategy, in particular the merger with Oil Search.

During her time at Santos Jane helped drive the transformation of company performance, helping to establish the growth strategy focused on cash generation and shareholder returns and, more recently, the company's energy transition strategy. Jane holds a Bachelor of Science (Pure Mathematics and Chemistry) and Bachelor of Chemical Engineering (Hons) from the University of Sydney and a Graduate Diploma in Management and Economics of Natural Gas (Distinction) from the University of Oxford. Jane is a Graduate of the Australian Institute of Company Directors.

Current and other directorships in the last 3 years
Ms Norman is a director of the wholly owned subsidiaries of Amplitude Energy Limited and is on the Board of the Australian Energy Producers (since 2023).

Special responsibilities
Ms Norman is Managing Director and CEO. She is responsible for the day-to-day leadership of Amplitude Energy, and is the leader of the Executive Leadership Team.

Mr Timothy G. Bednall

LLB (Hons)

Independent Non-Executive Director

Appointed
31 March 2020

Experience and expertise
Mr Bednall is a highly experienced and respected corporate lawyer and law firm manager. He is a partner of King & Wood Mallesons (KWM), where he specialises in mergers and acquisitions, capital markets and corporate governance, representing public company and government clients. Mr Bednall has advised clients in the oil and gas and energy sectors throughout his career.

Mr Bednall was the Chairman of the Australian partnership of KWM from January 2010 to December 2012, during which time the merger of King & Wood and Mallesons Stephen Jaques was negotiated and implemented. He was also Managing Partner of M&A and Tax for KWM Australia from 2013 to 2014, and Managing Partner of KWM Europe and Middle East from 2016 to 2017. He was General Counsel of Southcorp Limited (which became the core of Treasury Wine Estates Limited) from 2000 to 2001.

Current and other directorships in the last 3 years
Mr Bednall is a board member of the National Portrait Gallery Foundation (since 2018) and a non-executive director of Perpetual Equity Investment Company Limited since May 2025.

Mr Bednall was formerly a non-executive director for Pooling Limited (2017 – 2025).

Special responsibilities
Effective 19 August 2021 Mr Bednall is a member of the Audit Committee, and the Governance & Nomination Committee, and effective 7 November 2024 Mr Bednall is the Chairman of the People & Remuneration Committee.

Directors cont.

Mr Frank Tudor

BEng (Mech), PGDipEng (Chem), DipEc, MBA, AMP, GAICD, FIEAust

Independent Non-Executive Director

Appointed 1 October 2024

Experience and expertise
Mr Tudor brings 40 years of domestic and international experience in the oil, and gas and electricity industry. Frank has a deep understanding of organisational governance and demonstrated ability to manage political, public, stakeholder and media engagement processes.

Mr Tudor's previous experience includes Managing Director roles at Jemena and Horizon Power, General Manager at Woodside Energy, and various roles at BP. He is member of the Australia-China Council (ACC) and has performed extensive committee roles as Chairman and Vice Chairman of Chamber of Commerce, Energy and Resources Forum and National Chairman of the Australia China Business Council (ACBC).

Current and other directorships in the last 3 years
Mr Tudor has formerly held roles as National Chair of Energy Networks Australia (2022 – 2023), Chairman of Zinfra (2018 – 2023), member and Deputy Chairman of ActewAGL (2018 – 2023) and National Chair of the Energy Charter (2021 – 2022).

Special responsibilities
Effective 7 November 2024 Mr Tudor is a member of the People & Remuneration Committee and the Risk & Sustainability Committee. Effective 15 April 2025 Mr Tudor is acting Chairman of the Audit Committee.

Mr Gary Gray AO

B.Ec., GAICD

Independent Non-Executive Director

Appointed 1 October 2024

Experience and expertise
Mr Gray has a strong public policy, and political background. Gary is a former Executive Director of the WA Institute of Medical Research. Gary brings considerable industry and commercial experience through private sector positions.

Mr Gray's previous experience includes Australia's Ambassador to Ireland, director of the Australian Submarine Corporation, director of the Perth Astronomical Observatory, director of Corporate Affairs at Woodside Energy, General Manager of External Affairs at Mineral Resources Ltd, and as a Trustee of Australia's largest charity; Telethon.

Gary served as Federal Parliamentary Member for Brand, as Federal Minister for Resources, Energy, Small Business and Tourism, and separately as Federal Minister for the Public Service and Federal Integrity Agencies.

Current and other directorships in the last 3 years
Mr Gray is a member of the Independent Parliamentary Expenses Authority (since 2016) and non-executive director of Civmec Limited (ASX:CVL) since 2024. Effective from 1 August 2025 Mr Gray is Acting Chairman of the Risk & Sustainability Committee.

Special responsibilities
Effective 7 November 2024 Mr Gray is a member of the People & Remuneration Committee, the Governance & Nomination Committee and the Risk & Sustainability Committee.

Mr Ian Davies

BBus, FCA

Independent Non-Executive Director

Appointed 1 August 2025

Experience and expertise
As former Managing Director and CEO of Senex Energy Limited and former Chair of Australian Energy Producers (AEP) Board, Mr Davies is a highly distinguished and experienced industry leader.

In his time at Senex Energy, Mr Davies was instrumental in attracting investment into the Australian east coast energy market to support domestic gas supply and has been a leading voice for national energy policy and market reforms. Under Mr Davies' leadership, Senex Energy was transformed from a micro-cap explorer into a leading east coast energy producer, including through a $1 billion expansion in Queensland's Surat basin which created over 900 regional jobs, secured long-term gas supply for major Australian manufacturers and retailers and supplying approximately 15% of the domestic gas market.

Mr Davies' previous experience includes Chief Financial Officer of Queensland Gas Company Limited (QGC) and leading the LNG joint venture transaction with BG Group to develop the Gladstone QCLNG Project, and subsequent acquisition of QGC by BG Group. Mr Davies held several senior positions with BG Group following acquisition, and his prior experience includes investment banking with Barclays Capital in London and corporate tax advisory with PwC.

Current and other directorships in the last 3 years
Mr Davies is a non-executive director of G50 Corp Limited (ASX:G50) since 2024 and a former non-executive director of Australian Energy Producers (2017 to 2025).

Special responsibilities
Effective 1 August 2025 Mr Davies is a member of the Audit Committee, People & Remuneration Committee, Governance & Nomination Committee and the Risk & Sustainability Committee.

Ms Gillian L. Larkins

BCom, GDip (Acctg/Fin), MBA, (FCA, GAICD)

Independent Non-Executive Director

Appointed 1 September 2025

Experience and expertise
Ms Larkins has over 30 years' combined experience as a non-executive director and in financial executive roles. Her previous public company executive roles included Chief Financial Officer (CFO) of ASX Limited, where she managed finance, investor relations and ESG functions, as well as CFO of Perpetual Limited, Westpac Institutional Bank and Citi (Aus & NZ).

Current and other directorships in the last 3 years
Ms Larkins presently acts as Non-Executive Chair and Chair of the Audit & Risk Committee at Bennelong Funds Management Limited and Non-Executive Director at Wal Mart de México, S.A.B. de C.V (WALMEX.MX).

Special responsibilities
Ms Larkins was appointed Non-Executive Director effective 1 September 2025 and it is intended that, upon election at the Company's AGM, she be appointed Chair of the Amplitude Energy Audit Committee.

Directors cont.

Ms Elizabeth A. Donaghey

B.Sc., M.Sc.

Independent Non-Executive Director

Appointed 25 June 2018

Retired 19 August 2025

Experience and expertise
Ms Donaghey brings over 30 years' experience in the energy sector including technical, commercial and executive roles in EnergyAustralia, Woodside Energy and BHP Petroleum.

Ms Donaghey's experience includes non-executive director roles at Imdex Ltd (an ASX-listed provider of drilling fluids and downhole instrumentation), St Barbara Ltd (a gold explorer and producer), and the Australian Renewable Energy Agency. She has performed extensive committee roles in these appointments, serving on audit and compliance, risk and audit, technical and regulatory, remuneration and health and safety committees.

Current and other directorships in the last 3 years
Ms Donaghey is currently a non-executive director of the Australian Energy Market Operator (AEMO) (since 2017) and a non-executive director of Ampol Limited (ASX: ALD) (since 2021).

Special responsibilities
Prior to her retirement, Ms Donaghey was the Chairman of the Risk & Sustainability Committee and was a member of the People & Remuneration Committee and the Audit Committee.

Ms Giselle M. Collins

B. Ec, CA, GAICD

Independent Non-Executive Director

Appointed 19 Aug 2021

Retired 15 April 2025

Experience and expertise
Ms Collins has broad executive and director experience across finance, treasury and property disciplines.

Ms Collins' executive positions included General Manager Property, Treasury and Tourism of NRMA, Chief Executive Officer, Property and General Manager Finance with the Hannan Group, and Senior Manager, Audit Services with KPMG Switzerland. Ms Collins is a former non-executive director and Chairman of the following companies: Generation Life (2018 – 2021), Aon Superannuation (2016 – 2017), The Travelodge Hotel Group (2009 – 2013) and The Heart Research Institute Limited (2003 – 2011).

Current and other directorships in the last 3 years
Ms Collins is Chairman of Hotel Property Investments (ASX:HPI) since 2022, director since 2017. Ms Collins is also a non-executive director of Generation Development Group (ASX:GDG) since 2018 and Chairman of the responsibility entity for AMP Limited's managed investment schemes since 2021.

Ms Collins is a former Chairman for Indigenous Business Australia in the Darwin Hotel Pty Limited and Peak Rare Earths Limited (ASX:PEK) (2021 – 2023). Ms Collins is a former non-executive director of Pacific Smiles Limited from 2023 to 2024 (Chairman from August 2024 to December 2024).

Special responsibilities
Prior to her retirement, Ms Collins was the Chairman of the Audit Committee and was a member of the Risk & Sustainability Committee and the Governance and Nomination Committee.

Mr Jeffrey W. Schneider

B.Com

Independent Non-Executive Director

Appointed 12 Oct 2011

Retired 7 Nov 2024

Experience and expertise
Mr Schneider has over 30 years of experience in senior management roles in the oil and gas industry, including 24 years with Woodside Energy. He has extensive corporate governance and board experience as both a non-executive director and chairman in resources companies.

Current and other directorships in the last 3 years
Mr Schneider does not currently hold any other directorships.

Special responsibilities
Prior to his retirement, Mr Schneider was the Chairman of the People & Remuneration Committee and was a member of the Audit Committee.

Executive Leadership

Ms Jane L. Norman

B.Sc., B.Eng. (Hons) PGDip, GAICD

Managing Director and CEO

Ms Norman's biography is shown in the Director's section of the report.

Mr Eddy Glavas

B. Acc., FCPA, MBA

Chief Commercial Officer,

Acting Chief Financial Officer

Mr Glavas joined Amplitude Energy in August 2014 and has more than 25 years of experience in business development, finance, commercial, portfolio management and strategy, including 22 years in the oil and gas sector. Prior to joining Amplitude Energy, he was employed by Santos as Manager Corporate Development with responsibility for managing multidisciplinary teams tasked with mergers, acquisitions, partnerships and divestitures.

Prior roles within Santos included: Finance Manager WA and NT, where Mr Glavas was a member of the leadership team that managed a large asset portfolio; corporate roles in strategy and planning; and operational, commercial and finance roles for Santos' Cooper Basin assets.

Mr Chad Wilson

B.Sc. Chem. Eng. (Distinction), B.Sc. Zoology (Chemistry), PEng, MIEAust, CPEng, NER

Chief Operating Officer

Mr Wilson joined Amplitude Energy in October 2023 and has over two decades of experience in project development, production operations and business transformation.

He embarked on his professional journey as a Process Engineer at a prominent Canadian mining firm. He later joined Talisman Energy, where he held various roles in engineering, development, and, finally, an operational management role comprising five operating areas, six sweet gas plants and one of Alberta's major sour gas processing plants.

Subsequently, he joined Santos in Australia, where Chad was appointed Chief Production Engineer and later Vice President of Cooper Basin. He was instrumental in the transformation of the Cooper Basin asset through 2015-16, ensuring the asset was sustainably profitable in the low oil price environment. After heading up development and operations of the Cooper Basin for a further 4 years, he became Vice President, Energy Solutions, where he oversaw the development of the Moomba Carbon Capture and Storage Project and emissions reduction strategy and execution across Santos's portfolio. Chad has a proven track record of enhancing safety, production, and profitability through applying lean systems thinking.

He holds a Bachelor of Science in Chemical Engineering and a Bachelor of Science in Zoology/Chemistry from the University of Alberta, Canada.

Mr Nathan Childs

B. Chem. Eng. (Hons)

Chief Corporate Services Officer

Mr Childs has over 25 years of experience in the gas and oil industry, having held line, technical, engineering and executive management roles.

Before joining Amplitude Energy in October 2019 as Head of Engineering and Planning, he was Santos's Vice President of Production Mid stream. He worked through several roles at Santos across plant and process operations; engineering; production optimisation; asset management; commercial business development; integrity, and reliability.

While working for Santos, Nathan made several strategic changes, including lowering operating costs, improving asset performance, increasing production, delivering $50 million of transformation initiatives to improve free cash flow and implementing Operations Discipline.

Nathan began his career with Rio Tinto in research and technology development. He later worked at ExxonMobil's refining and supply business after graduating with first-class honours from Adelaide University with a Bachelor of Engineering–Chemical.

Executive Leadership cont.

Ms Ying Luo

B. Eng. (Hons), B.Sc. (Hons), MBA, Grad Cert.

Chief Advisor & General Manager Strategy

Ms Luo has almost 15 years of experience working in the energy sector in onshore gas, LNG and hydrogen.

She began her career as a Graduate Mechanical Engineer with Santos. She progressed through several roles over the following decade including Production Engineer, and Operations Engineer where she implemented solutions to design and operability issues identified during the commissioning and start-up of the GLNG Project upstream wells and facilities.

Ying also worked in the Corporate Strategy and Planning team, providing oil, LNG and domestic gas market analysis, supporting the development of Santos' 10-year strategic plan. Her last four years with Santos were as the Project and Strategy Lead for the Energy Solutions division. Ying developed, implemented, and maintained the Energy Solutions strategy and led a portfolio of emissions reduction, renewable integration and hydrogen projects. Most recently she worked as the Senior Adviser, Hydrogen Development for the Australian Gas Infrastructure Group where she led the development of Australia's largest renewable hydrogen production and blending project in Albury-Wodonga, Victoria.

Ying has a Bachelor of Mechanical Engineering with First Class Honours; Bachelor of Science (Mathematics, Computer Science) with First Class Honours; Graduate Certificate in Energy and Resources Policy and Practice and an MBA. She was awarded the Sir John Monash Scholarship for Excellence at Monash University and the Exceptional Young Women in Resources from the South Australian Chamber of Mines and Energy.

Ms Nicole Ortigosa

BA, LLB (Hons), Grad Dip Legal Practice

Company Secretary & General Counsel

Ms Ortigosa has over 15 years' experience as a corporate and commercial lawyer, specialising in the energy and resources sector. Prior to joining Amplitude Energy she worked for top tier law firms across Australia, including Clifford Chance and Minter Ellison. Nicole's experience covers all legal, corporate, and commercial aspects of the business, including joint ventures, gas sales, infrastructure, environment, regulatory, procurement, mergers and acquisitions, corporate governance and compliance.

Nicole started at Amplitude Energy in 2017 and prior to becoming General Counsel & Company Secretary was the Legal Manager. Amongst other matters, she has advised the company on the development of the Sole gas field, the acquisition of the Athena Gas Plant and associated infrastructure and the acquisition of the Orbost Gas Processing Plant and associated onshore and offshore pipeline infrastructure.

She holds a Bachelor of Laws with Honours from the University of Adelaide, and a Graduate Diploma in Legal Practice from the Law Society of South Australia.

Mr Daniel Young

B. Com (Hons), MBA (Hons), CA, CFA

Chief Financial Officer

Ceased as Executive KMP on 26 May 2025

Mr Young joined Amplitude Energy in May 2022. Mr Young is an energy professional with over 28 years of experience in Australia, Asia and Europe. He joined Amplitude Energy from Jadestone Energy plc where he held the role of Chief Financial Officer for over five years. He also held the role of Executive Director with Jadestone. Daniel played a key role in the management team, charged with the funding, growth and development of Jadestone. The compound annual share price growth rate averaged 25% over this period.

Prior to Jadestone, Mr Young was Head of APAC Consulting for Wood Mackenzie and earlier worked in J.P. Morgan's energy investment banking coverage/ mergers & acquisitions group, in Europe and in Asia. During this time, he worked on a number of noteworthy transactions in the energy sector.

After completing his undergraduate studies, Daniel joined Deloitte where he qualified as a Chartered Accountant. Daniel holds a Bachelor of Commerce with Firsts in Accounting and Finance from the University of Western Australia and an MBA with Honours from the University of Chicago Booth School of Business. He is also a CFA® charterholder.

Mr Young ceased as an Executive KMP on 26 May 2025 and left Amplitude Energy on 18 July 2025.

Key Performance Indicators

		FY21	FY22	FY23	FY24	FY25
Operational						
Production	PJe	16.1	20.3	21.8	22.7	26.6
Total Recordable Injury Frequency Rate (TRIFR)[1]		6.92	0.00	4.38	4.35	3.36
2P Proved and Probable Reserves	MMboe	47.1	39.5	36.3	33.0	31.1
Wells drilled	#	1	2	2	4	-
Exploration wells spudded	#	-	2	-	4	-
1P Reserves replacement ratio[2]	%	17%	-65%	24%	-1%	84%
Financial						
Realised gas price	$/GJ	6.86	8.29	8.59	8.83	9.91
Sales revenue	$ million	131.7	205.4	196.9	219.0	268.1
Underlying EBITDAX	$ million	30.0	80.7	109.3	127.5	173.9
Net profit / (loss) before tax	$ million	-33.5	-22.7	-104.7	-125.1	-24.3
Underlying profit / (loss) after tax	$ million	-25.9	14.4	-5.6	1.4	11.4
Cash and cash equivalents	$ million	91.3	247.0	77.1	14.3	62.2
Underlying cash from operations	$ million	24.6	80.6	95.8	114.8	160.5
Working capital	$ million	30.3	190.3	-121.8	-52.9	43.8
Accumulated losses	$ million	-166.0	-177.5	-214.3	-328.4	-369.8
Franking credits	$ million	42.9	42.9	42.9	42.9	42.9
Total Equity	$ million	325.8	498.4	528.5	417.6	376.5
Earnings per share	cents	-1.8	-0.6	-2.3	-4.3	-1.6
Total shareholder return	%	-30.7%	-5.8%	-38.8%	+50.0%	-6.7%
Capital as at 30 June 2025						
Share price	$	0.260	0.245	0.15	0.225	0.21
Issued shares	million	1,631.0	2,379.8	2,631.5	2,640.0	2,651.4
Market capitalisation	$ million	424.1	583.1	394.7	594.0	556.8
Enterprise value[3]	$ million	550.8	494.1	475.6	844.7	799.8

[1]Total recordable injury frequency rate (TRIFR)

[2]The annual reserve replacement ratio is calculated based on the net 1P reserve additions for the year divided by annual production

[3]Sum of market capitalisation and net debt/(cash) as at 30 June of the relevant financial year

Amplitude energy

Financial Report

30 June 2025

Amplitude Energy Limited
ABN 93 096 170 295
Report ending 30 June 2025
Corresponding period 30 June 2024

Higher and more reliable production performance allowed the Company to generate record revenue and greater margins.

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Operations

Amplitude Energy Limited and its controlled entities ("Amplitude Energy", or the "Company", or the "Group") generate revenue from the production of gas and condensate in the Otway and Gippsland Basins, and from the production of oil in the Cooper Basin.

As at 30 June 2025, the Company's operations and interests included:

- offshore gas and gas liquids production in the Gippsland Basin, Victoria, from the Sole gas field;
- offshore gas and gas liquids production in the Otway Basin, Victoria, from the Casino, Henry and Netherby ("CHN") gas fields;
- onshore oil production in the western flank of the Cooper Basin, South Australia;
- the Orbost Gas Processing Plant ("OGPP") onshore Gippsland Basin, Victoria;
- the Athena Gas Plant ("AGP") onshore Otway Basin, Victoria;
- the Annie gas discovery and exploration prospects in the offshore Otway Basin, which the Company is seeking to develop as part of its East Coast Supply Project ("ECSP");
- the shut-in Patricia Baleen gas field, which the Company is assessing the potential to restart as a production or gas storage asset, and infrastructure connecting it to the OGPP;
- the undeveloped Manta and Gummy gas and liquids fields, and exploration prospects such as the Wobbegong field, in the Gippsland Basin;
- the Dombey gas discovery in the onshore Otway Basin; and
- other exploration prospects in the onshore and offshore Otway, offshore Gippsland and Cooper Basins.

The Company is the operator of all its offshore activities, as well as the OGPP and AGP, and non-operator of all its onshore activities.

Workforce
At 30 June 2025, the Company had 133.0 full time equivalent ("FTE") employees and 13.4 FTE contractors, compared with 126.1 FTE employees and 13.4 FTE contractors at 30 June 2024.

Changes to employee numbers in FY25 are primarily related to improved staffing to support operations and upcoming projects, including the East Coast Supply Project (ECSP).

Contractors are engaged via third parties in South Australia, Western Australia and Victoria, and as at 30 June 2025, all contractors engaged by Amplitude Energy were contracted via third party providers.

Health, Safety and Environment
For the twelve months to 30 June 2025 the Group recorded zero fatalities, zero lost time injuries, zero medical treatment injuries and one restricted work case.

The restricted work case occurred at OGPP in March 2025, where a contractor suffered a hand injury requiring restricted work duties to be assigned.

The total recordable injury frequency rate ("TRIFR") was 3.36 per million hours worked in the 12 months to 30 June 2025, well below the industry benchmark of 5.16[1], and a reduction from 4.35 in the previous 12 months.

Amplitude Energy received notable industry recognition at the annual Australian Energy Producers (AEP) conference as winner of the 2024 Safety Excellence Award for the Basker, Manta, Gummy (BMG) wells decommissioning campaign.

There were no reportable[2] or notifiable[3] environmental incidents during the period.

Sustainability
A mixture of Australian Carbon Credit Units and Verified Carbon Units were retired at the end of H1 FY25 and H2 FY25 to offset the Company's estimated FY25 scope 1, scope 2 and relevant scope 3 emissions. Carbon credit retirements in H2 FY25 were based on an estimate of emissions and will be trued-up once FY25 emissions data is finalised.

Scope 3 emissions are all indirect emissions - not included in Scope 2 - that occur in the supply chain. In other words, emissions that are linked to the Company's operations and products. The GHG Protocol splits Scope 3 emissions into 15 categories. Categories 1-8 are described by Amplitude Energy as relevant Scope 3 emissions and categories 9-15 as downstream Scope 3 emissions.

Relevant Scope 3 emissions are emissions embedded in significant infrastructure such as the concrete and steel that we construct our wells, pipelines and gas processing plants from, together with smaller categories such as business travel. We include these within our organisational boundary. These emissions are fully offset as part of Amplitude Energy's Climate Active Carbon Neutral certification. By fully offsetting all Scope 1, Scope 2 and relevant Scope 3 emissions, when gas leaves Amplitude Energy's organisational boundary, all emissions upstream of that point have been offset. In the past, we have referred to these as "controllable", others may use the term "upstream" Scope 3 emissions.

Downstream Scope 3 emissions are outside the Company's organisational boundary and outside the direct control of Amplitude Energy. The largest contributors to downstream Scope 3 emissions arise from the final utilization of our gas by our customers and by end users to generate electricity, for industrial and residential heating or for cooking. A significant fraction also arises from downstream fugitive emissions from pipelines owned and operated by others. This category can generally be summarised as the Scope 1 emissions of our customers. These customer and end user emissions are not offset as part of our Climate Active Carbon Neutral certification. These emissions account for 99% of Scope 3 emissions.

[1] NOPSEMA industry rolling 12-month TRIFR for 30 June 2025
[2] As defined by Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009
[3] As defined by the Victorian Environment Protection Act 2017

Reserves and Contingent Resources
Proved and Probable Reserves (2P) at 30 June 2025 are assessed to be 31.1 MMboe, compared with 33.0 MMboe at 30 June 2024.

Changes to 2P Reserves for FY25 include production of -4.4 MMboe and 2P Reserves revisions of +2.6 MMboe. Contingent Resources (2C) at 30 June 2025 are assessed to be 48.2 MMboe, compared with 48.4 MMboe at 30 June 2024.

More consistent performance from OGPP throughout FY25 provided high quality production data that showed the Sole field in the Gippsland Basin is performing ahead of the Company's previous expectations. Reservoir modelling, including history matching of the Sole field subsurface models to the production data, provided increased confidence in the model forecasts. The results of this work supported upwards revisions to the previously-disclosed FY24 Expected Ultimate Recoverable (EUR) volumes at the 1P and 2P levels and a slight downwards revision in EUR at the 3P level.

Details of Reserves and Contingent Resources and the movement from the previous year are available in the ASX announcement titled 'Reserves and Contingent Resources at 30 June 2025', released on 19 August 2025.

	Proved and Probable Reserves (2P)			Contingent Resources (2C)		
As at 30 June 2025[1]	**Gas PJ**	**Oil & condensate MMbbl**	**Total MMboe**	**Gas PJ**	**Oil & condensate MMbbl**	**Total MMboe**
Gippsland Basin	172.1	0.0	28.1	198.9	4.9	37.4
Otway Basin	14.9	0.0	2.5	63.8	0.1	10.5
Cooper Basin	0.0	0.6	0.6	0.0	0.3	0.3
Total Amplitude Energy	**187.0**	**0.6**	**31.1**	**262.7**	**5.3**	**48.2**

[1] As announced on 19 August 2025. Totals may not reflect arithmetic addition due to rounding. The method of aggregation is by arithmetic sum by category.

Production[4]
Group gas and oil production for FY25 was 26.6 PJ-equivalent ("PJe"), or 73.0 TJ-equivalent per day, 17.1% higher than the prior year. This represented the upper end of the Company's FY25 production guidance of 69 – 73 TJ-equivalent per day, which was increased twice over FY25.

Total gas production of 26.0 PJ, or 71.4 TJ/d, was 18.7% higher than the prior year. In the Gippsland Basin, increased Sole production and improved OGPP performance resulted in a 24.9% increase in gas production to 22.6 PJ, or 62.0 TJ/d. In the Otway Basin, gas production declined by 10.2% to 3.4 PJ, or 9.4 TJ/d (both net to Amplitude Energy's 50% share), primarily due to natural field decline at CHN.

Oil and condensate production was 91.4 kbbl, or 250 bbl/d (net to Amplitude Energy's 25% share), 28.3% lower than the prior year due to natural field decline and the impacts of flooding in the Cooper Basin.

Production by product and basin is summarised in the following tables.

Production by product		**FY25**	**FY24**	**Change**
Sales gas	PJ	26.0	21.9	18.7%
Oil and condensate	Kbbl	95.0	131.0	(27.5%)
Total production	**PJe**	**26.6**	**22.7**	**17.1%**

Production by basin		**FY25**	**FY24**	**Change**
Gippsland Basin				
Sole: sales gas	PJ	22.6	18.1	24.9%
Otway Basin				
Casino Henry: sales gas	PJ	3.4	3.8	(10.2%)
Casino Henry: condensate	kbbl	3.6	3.6	(0.9%)
Cooper Basin				
Oil	kbbl	91.4	127.4	(28.3%)
Total production	**PJe**	**26.6**	**22.7**	**17.1%**

[4] Totals may not reflect arithmetic addition due to rounding

Orbost Gas Processing Plant
OGPP delivered an average gas processing rate of 62.0 TJ/d during FY25 (FY24: 49.5 TJ/d).

Multiple production records for Sole/OGPP production were set during FY25 including a record 30-day average at nameplate capacity of 68.0 TJ/d and 90-day average of 67.1 TJ/d.

Production rates significantly increased in FY25 compared to prior years as a result of sulphur processing and reliability improvements at OGPP. The improvements stemmed from a combination of physical modifications undertaken at the OGPP over FY24 and FY25 as a part of the methodical execution of the OGPP Improvement Project, as well as a greater focus on plant reliability and process efficiency.

Physical modifications included trials of different forms of absorber packing material to assess impacts on plant performance and reliability. Stainless steel packing material was installed in both absorber units in H2 FY25 which resulted in reduced foaming and fouling in the units, significantly increasing the time between absorber cleans.

As a result, record runtime between cleans was achieved for both absorber units by end FY25, being 7 weeks for the first unit and 14 weeks for the second. The number of absorber cleans undertaken during FY25 was reduced to 21, compared to 46 cleans undertaken in FY24.

The average duration of absorber cleans was significantly reduced, driven by process improvements and avoiding the need for confined space entry. In January 2025 the shortest-ever absorber clean was completed in 6 hours (compared to the FY24 average duration of 32 hours), with peak gas rates restored in less than 20 hours (compared to FY24 average of 49 hours).

Combined with improved plant production when operating with a single absorber, faster cleans allowed the OGPP to operate at higher daily rates during absorber cleans and eliminated the need for spot gas purchases during the financial year.

A liquid H_2S scavenger chemical injector was installed and commissioned at the OGPP in February 2025, resulting in improved sulphur removal outcomes and increasing redundancy in the overall sulphur removal system.

A planned OGPP maintenance shutdown was conducted in March 2025 with the full planned scope of works completed in seven days. The scope of work included installation of a chemical clean-in-place system in both absorbers and further modifications to the internal configuration of the absorbers. Production at the OGPP was steadily ramped up following the shutdown and operated at a record quarterly average rate of 67.1 TJ/d for the June Quarter.

Strong performance of the absorbers following the shutdown, together with redundancy provided by H_2S scavenger injection, allowed the Company to defer the next replacement of media in the polisher unit to the second half of CY2025.
OGPP achieved reliability loss of only 0.6% for FY25, well ahead of the Company's target for reliability loss of <2% by end FY26.

Athena Gas Plant
In the Otway Basin, CHN gas production during FY25 was 9.4 TJ/d or 3.4 PJ (net to Amplitude Energy's 50% share), which is 10% lower than FY24, primarily due to natural decline in the CHN fields.

The reliability of the AGP has significantly improved compared to previous years, with 0.1% reliability loss as a proportion of asset capacity in FY25, compared to 2.4% in FY24.

Regular cycling of the CHN wells was impacted between November 2024 and February 2025 by a failure in the CHN electro-hydraulic umbilical cable, resulting in a temporary increase in the rate of field decline over that period.

Repairs to the CHN electro-hydraulic umbilical cable in February 2025 re-established communication to Casino 5, Henry 2 and Netherby 1 wells, allowing cycling of these wells to resume. The Company is assessing options to re-establish communication to the Casino 4 well.

The planned AGP maintenance shutdown was conducted in early March with the full planned scope of works completed in less than 6 days without injuries or significant incidents.

Commercial

Contracting initiatives
Amplitude Energy commenced a marketing campaign with potential gas customers regarding foundation contracts for the ECSP on behalf of the Offshore Otway Basin joint venture partners in Q4 FY25.

Strong OGPP production in FY25 allowed Amplitude Energy to consider additional short-term gas sales agreements with the objective of maximising overall realised gas prices and balancing exposure to spot gas prices. Consistent with this, in the FY25 June Quarter Amplitude Energy contracted supply of 0.7 PJs over the remainder of CY2025 at a price consistent with current short-term market prices[5].

Trading opportunities
Increases in OGPP production, which provided greater volume and consistency of gas available for spot sales, allowed Amplitude Energy to explore trading opportunities to optimise the pricing of its spot gas sales.

[5] As an indication of current market conditions, please see the ACCC Gas Inquiry Report, Interim update on east coast gas market, December 2024, Page 26, Chart 2.7

Development, Exploration and Decommissioning

Gippsland Basin
Amplitude Energy is the operator and 100% interest holder for all its Gippsland Basin interests. As at 30 June 2025, these interests comprised:

a) VIC/L32, which contains the Sole gas field;
b) VIC/RL13, VIC/RL14 and VIC/RL15, which contain the Basker, Manta and Gummy (BMG) gas and liquids fields (these retention leases also hold legacy infrastructure associated with the BMG oil project);
c) VIC/RL16, which contains the shut-in Patricia Baleen gas field and infrastructure which connects to the OGPP; and
d) exploration permits VIC/P72, VIC/P75 and VIC/P80.

Patricia Baleen commercialisation opportunity
Amplitude Energy continued to assess the potential to commercialise the shut-in Patricia Baleen field in VIC/RL16 as a production or gas storage asset. The project has entered the Select phase ahead of a decision to enter FEED.

During 2H FY25, Amplitude Energy completed an umbilical and subsea controls repair study and progressed engineering and early cost estimates for umbilical repair options. Amplitude Energy has commenced engagement with NOPTA regarding a Production Licence for Patricia Baleen.

Otway Basin (Offshore)
The Company's interests in the offshore Otway Basin as at 30 June 2025 comprised:

a) a 50% interest in and operatorship of production licences VIC/L24 and VIC/L30 containing the producing Casino, Henry and Netherby gas fields, with the remaining 50% interest held by Mitsui E&P Australia and its associated entities ("MEPAU")[6];
b) a 50% interest in and operatorship of production licences VIC/L33 and VIC/L34 containing part of the Black Watch and Martha gas fields, with the remaining 50% interest in these production licences held by MEPAU[6];
c) a 100% interest[7] in and operatorship of exploration permit VIC/P44 containing the undeveloped Annie gas discovery;
d) a 100% interest[7] in and operatorship of exploration permit VIC/P76;
e) a 50% interest in and operatorship of AGP (onshore Victoria), which is jointly owned with MEPAU[6] and processes gas from the Casino, Henry and Netherby gas fields; and
f) a 10% non-operated interest in production licence VIC/L22, which holds the shut-in Minerva gas field, with Woodside Energy the operator and 90% interest holder.

East Coast Supply Project
In March 2025 the Company entered into a number of commercial agreements with subsidiaries of O.G. Energy regarding the development of the East Coast Supply Project on a 50/50 basis.

The agreements contain terms of O.G. Energy's participation in the ECSP, including that it will participate in 50% of point-forward project costs from the date of signing, and reimburse Amplitude Energy for 50% of all historical ECSP project costs spent[8]. The agreements also align each party's interests in Amplitude Energy's Offshore Otway Basin assets at 50% each.

Contemporaneously, subsidiaries of O.G. Energy and MEPAU, executed a sale and purchase agreement for O.G. Energy's acquisition of MEPAU's existing interests in the Otway Basin joint ventures, including the Athena Gas Plant. A summary of the transactions that Amplitude Energy is a party to, including the conditions of the relevant agreements, is detailed in the ASX release titled 'Execution of Otway Basin Joint Venture Agreements' on 24 March 2025. This transaction completed on 31 July 2025.

The respective Boards of Amplitude Energy and O.G. Energy approved the three-well ECSP drilling programme and determined that the Elanora exploration well, with sidetrack to Isabella, will be the first to be drilled in the upcoming campaign. Amplitude Energy exercised its options for its second and third well drilling slots within the Transocean Equinox rig consortium, with those two slots targeting the Juliet prospect followed by the Annie discovery.

On 24 March 2025 Amplitude Energy also released additional project details regarding the ECSP, including preliminary indicative cost estimates for the two phases of the project, being a well drilling and completions phase, followed by a development phase encompassing subsea tie-ins and modifications at the Athena Gas Plant.

The Transocean Equinox drilling rig arrived in the Offshore Otway Basin in April and is expected to commence drilling the first well of its campaign for Amplitude Energy in late calendar year 2025. Detailed planning and engineering for the ECSP continued, with multiple contracts awarded during the quarter to progress with drilling for the three well programme. Key long-lead items, including subsea trees, are in the delivery stages in readiness for the drilling windows.

The Company's Athena Supply Project environment plan (EP), which covers the drilling of Elanora, Isabella and Juliet, was also accepted, allowing the commencement of the Equinox's rig activities for the Otway Basin Joint Venture (JV). In early July 2025, the Company also received approval of its Offshore Project Proposal (OPP) for the ECSP, which includes the development drilling of the Annie contingent resource, meaning that both primary approvals required for the drilling stage of the project have been received.

Planning for the development phase of the ECSP is also progressing, with front-end engineering and design (FEED) having commenced in Q1 FY26, and tenders for the subsea tie-in scopes to be issued in H1 FY26.

Subject to exploration success, Amplitude Energy and O.G. Energy intend to proceed to a final investment decision to undertake the development phase of the project in H1 CY2026.

Amplitude Energy expects to fund ECSP capital expenditure from existing cash on hand, underlying organic cash generation over 2025-2028 and the Company's existing bank debt facility.
The ECSP is targeting to backfill the Athena Gas Plant with up to 90 TJ/day of gross gas supply as early as 2028, subject to receipt of regulatory approvals.

[6] Held by MEPAU as at 30 June 2025, with completion of the sale of its interest to O.G. Energy occurring on 31 July 2025
[7] Pending completion of the sale of a 50% interest to O.G. Energy

[8] Payment of back costs is in the form of a carry from completion. The reimbursement amounts to approximately A$27.8 million.

Minerva decommissioning
Woodside Energy, the Operator of VIC/L22 (Amplitude Energy share 10%), completed the decommissioning of wells in the Minerva gas field in H2 FY25 utilising the Transocean Equinox rig. The Operator had earlier commenced the removal of the subsea facilities in the field (pipeline, umbilical cables, etc.) but has deferred the completion of this work.

Otway Basin (Onshore)
The Company's interests in the onshore Otway Basin as at 30 June 2025 comprised:

a) a 30% interest in PEL 494, PRL 32 and PEL 680 in South Australia, with the remaining interests held by the operator, Beach Energy Limited;
b) a 50% interest in PEP 168 in Victoria, with the remaining interest held by the operator, Beach Energy Limited; and
c) a 75% interest in PEP 171 in Victoria, with the remainder held by operator Vintage Energy Limited.

Exploration
Amplitude Energy and its joint venture partners continue to progress the technical evaluation of onshore exploration and development opportunities.

Cooper Basin
The Company's interests in the Cooper Basin as at 30 June 2025 comprised a 25% interest in PRLs 85-104 (formerly PEL 92), with the remaining interests held by the operator, Beach Energy Limited.

Exploration and development
Planning is underway for a 3 well development campaign at Callawonga. The timing of this campaign was deferred from mid-CY2025 as initially planned to later in FY26 due to flooding in the Cooper Basin.

The company and its joint venture partner are also refreshing the prospect portfolio ready for the next phase of exploration.

Continuous Improvement Programme

A key focus area for the Company over FY25 was to extract further value from its operations through a programme focused on continuous improvement and efficiencies. Building on the success of the FY24 transformation programme, the continuous improvement programme focussed on delivering value and cashflow improvements through cost and emissions reductions, improved productivity and margin maximisation.

Over 70 separate initiatives across the business were being worked on in FY25, with half realising value. The remaining initiatives are still in delivery and will continue to be worked on in FY26.

In aggregate, the continuous improvement programme realised around $20 million in cashflow improvements in FY25, with the completion of remaining initiatives expected to realise benefits into FY26 and beyond.

Around 70% of the realised value in FY25 came from new OGPP operational improvements, primarily associated with absorber cleaning and polisher treatment improvements. These have driven near-term value through increased sales volumes, reduced contractor costs and reduced consumables costs.

Gas marketing and trading initiatives to maximise the Company's realised gas prices contributed 15% of the value realised in the continuous improvement programme over FY25. The continuous improvement focus will continue into FY26.

Other Activities

Orbost sulphur sales
As previously announced, Amplitude Energy has been working to commercialise the sulphur by-product from OGPP. This involved completing a 6-month trial with the Gippsland Agriculture Group in East Gippsland, demonstrating the effectiveness of Amplitude Energy's sulphur as a soil amendment additive for agricultural applications, and engaging with EPA Victoria on the opportunity for beneficial use.

As at 30 June 2025, Amplitude Energy is now delivering elemental sulphur as product to Devco Australia Holdings ("Devco"). Devco manufactures a range of sulphur-based products for the agricultural and industrial markets across Australia, importing elemental sulphur fertiliser products into Australia and New Zealand. It handles 12,000 to 15,000 tonnes of sulphur per year. The sulphur from OGPP is anticipated to be used in its existing form as fertiliser within the East Gippsland region.

Debt facility increase and extension
In December 2024 the Company executed documentation to amend its existing debt facilities with a group of domestic and international banks.

The amendments result in an $80 million increase in the initial facility limit of the reserves based loan (RBL) to $480 million and an extension in the maturity of the facility by two years, to 30 September 2029, which is expected to be post the commencement of production from the ECSP. Amplitude Energy's existing $20 million working capital facility has been retained, with the maturity also extended to 30 September 2029. The interest rates and margins on both facilities are unchanged from existing levels.

The increase in the facility limit and maturity extension will maximise Amplitude Energy's liquidity and funding flexibility over the medium term, particularly during the ECSP exploration and development phase. The facilities have also been structured to enable the potential introduction of other forms of finance for the ECSP.

Pertamina proceedings
Amplitude Energy continues to pursue its claim in the Victorian Supreme Court ("Court") against PT Pertamina Hulu Energi ("Pertamina") for Pertamina's 10% share of the BMG decommissioning costs.

Pertamina, via its Australian subsidiary (now deregistered), participated in the BMG oil project during its production life. Amplitude Energy's claim against Pertamina arises from the withdrawal and decommissioning provisions of the Joint Operating and Production Agreement, and a parent company guarantee given by Pertamina.

The parties attended mediation in Melbourne in May 2025. The mediation process remains on foot. A directions hearing is scheduled for 22 August 2025, where the Court will make orders for the next stage of the legal proceedings.

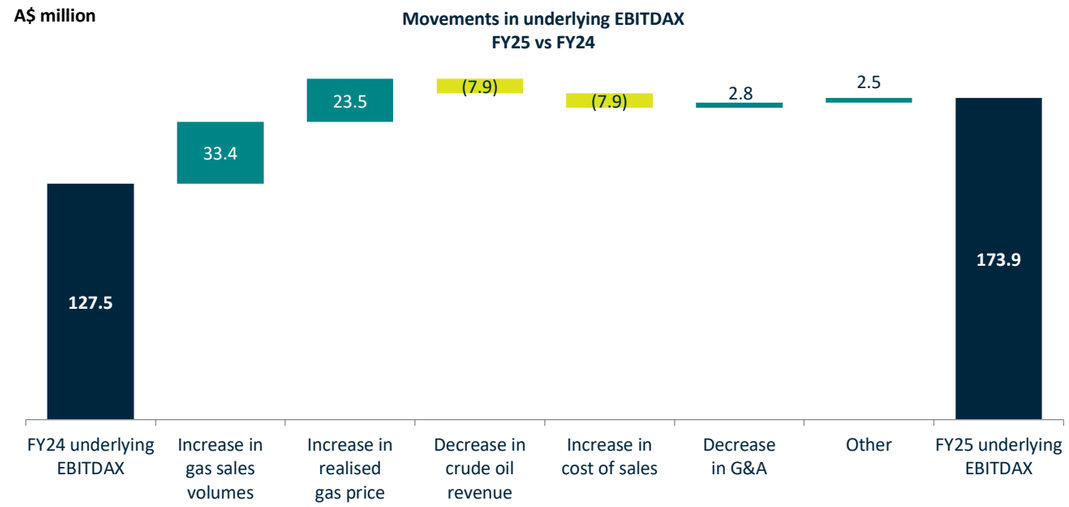
Financial Performance

All numbers in tables in the Operating and Financial Review have been rounded and are expressed in Australian dollars, except where noted otherwise. Some total figures may differ insignificantly from totals obtained from the arithmetic addition of the rounded numbers presented.

In order to provide a more meaningful comparison of operating results between periods, the calculation of underlying EBITDAX and of underlying net profit/(loss) after tax includes adjustments for items which are considered unrelated to the Company's underlying operating performance.

Underlying EBITDAX and underlying net profit/(loss) after tax are not defined measures under International Financial Reporting Standards and are not audited. For that reason, reconciliations of underlying EBITDAX and of underlying net profit/(loss) after tax are included at the end of this review.

Amplitude Energy recorded FY25 underlying EBITDAX of A$173.9 million, 36.4% higher than FY24. There are several drivers behind the change, which is summarised in the following chart.



The principal factors which contributed to the movement in underlying EBITDAX between the periods included:

- an increase of A$33.4 million due to increased gas volumes compared to the previous year (25.8 PJ in FY25, versus 22.5 PJ in FY24);
- an increase of A$23.5 million due to increased realised gas prices across the portfolio (A$9.91/GJ in FY25, versus A$8.83/GJ in FY24) as a result of increased GSA pricing and the average realised spot price;
- a decrease of A$7.9 million in oil sales revenue driven by lower sales volumes (97.1 kbbls in FY25 versus 143.2 kbbls in FY24);
- an increase of A$7.9 million in cost of sales in FY25, in part due to general visual inspections on the CHN pipeline and increased costs of waste disposal;
- a decrease of A$2.8 million in G&A linked to savings realised from the continuous improvement programme; and
- other items were lower by A$2.5 million

Underlying profit after tax (exclusive of the items noted below) was A$11.4 million, compared with A$1.4 million in FY24. Factors driving the change, in addition to those listed above for underlying EBITDAX, included:

- a decrease of A$7.8 million in accretion expense, in part due to the reduction in restoration provisions following the completion of the BMG wells decommissioning;
- a decrease of A$3.4 million in exploration and evaluation expense;
- an increase of A$14.7 million in amortisation and depreciation of gas and oil assets and property, plant and equipment, due to higher production;
- an increase of A$10.7 million in net interest expense; and
- an increase of A$22.2 million in tax expense.

The Company's statutory loss after tax was A$41.3 million, which compares with a loss after tax of A$114.1 million recorded in FY24. The FY25 statutory loss included a number of significant items considered to fall outside underlying operating performance, which affected the result by a total of A$52.7 million.

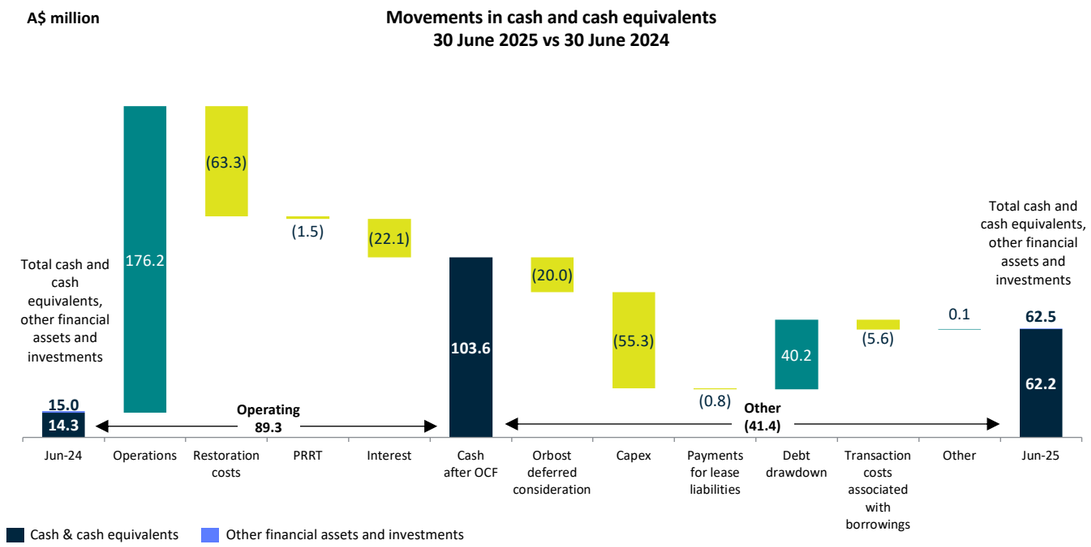
These items comprise:

- a non-cash impairment expense of A$27.4 million in relation to four of the Group's exploration licences;
- non-cash restoration expense of A$11.0 million resulting from a reassessment of the Minerva Field, BMG and Patricia-Baleen decommissioning provisions;
- asset write-offs relating to the Orbost third absorber, CHN umbilical and other minor items of A$5.4 million;
- business restructuring and transformation costs of A$2.6 million;
- movement in the previously derecognised deferred tax asset in respect of the Sole gas field decommissioning of A$18.6 million[9];
- other expense of A$2.3 million in respect of the National Oil & Gas Australia Pty Ltd Commonwealth Government levy; and
- tax impact of the above items of A$14.6 million.

Financial performance		FY25	FY24	Change	%
Production volume	PJe	26.6	22.7	3.9	17.1%
Sales volume[1]	PJe	26.5	23.4	3.1	13.3%
Revenue	A$ million	268.1	219.0	49.1	22.4%
Gross profit	A$ million	80.1	51.7	28.4	54.5%
Underlying EBITDAX[2]	A$ million	173.9	127.5	46.4	36.4%
Operating cash flow	A$ million	89.3	(99.8)	189.1	N/M
Underlying profit/(loss) before tax	A$ million	24.5	(7.7)	32.2	N/M
Underlying profit after tax	A$ million	11.4	1.4	10.0	N/M
Reported loss after tax	A$ million	(41.3)	(114.1)	72.8	63.8%
Cash, other financial assets and investments	A$ million	62.5	15.0	47.5	N/M

[1] FY25 sales volumes were lower due to timing of liftings. On a comparative basis, FY24 sales volumes were higher than production volumes due to third-party product purchases
[2] Earnings before interest, tax, depreciation, amortisation, restoration, exploration and evaluation expense and impairment

Cash and cash equivalents increased by A$47.9 million over the period, as summarised in the chart below.



[9] Based on the current 2P profile of the business, and before the additional production assumed from the ECSP and/or other future developments, taxable profits may not be generated at the time that Sole decommissioning is undertaken, hence there may be no taxable profits to be offset by the deduction for decommissioning costs.

Net operating cash inflows were A$89.3 million in FY25 versus net operating cash outflows of A$99.8 million in FY24. The main line items for operating cashflow comprised:

- cash generated from operations of A$176.2 million (FY24: A$121.2 million). The major drivers of the increase are explained above in relation to underlying EBITDAX, while noting that changes in working capital are captured in cash from operations whereas EBITDAX is reported on an accruals basis;
- restoration costs of A$63.3 million (FY24: A$207.7 million), relating to Minerva wells decommissioning and close out of invoices from the FY24 wells decommissioning activity at BMG;
- petroleum resource rent tax (PRRT) payments of A$1.5 million (FY24: A$0.2 million refund), impacted by lower deductible expenditure in the first quarter of FY25; and
- net interest paid of A$22.1 million (FY24: A$13.5 million).

Excluding restoration spend and other non-recurring and non-underlying items, operating cash flow is A$160.5 million (FY24: A$114.8 million).

Financing, investing and other net cash outflows for the period were A$41.4 million (FY24: A$37.0 million net cash inflows) and primarily included:

- OGPP deferred acquisition payment of A$20.0 million (FY24 deferred acquisition payment of: A$40.0 million);
- capex spend of A$55.3 million, mainly in relation to ECSP (FY24: A$26.5 million);
- repayment of lease liability of A$0.8 million (FY24: A$1.5 million);
- debt drawdown of A$40.2 million (FY24: 107.0 million);
- costs associated with borrowings, including the amendment and extension of the RBL, of A$5.6 million; and
- other including foreign exchange revaluation of A$0.1 million (FY24: A$2.1 million).

Financial Position

Financial Position		30 June 2025	30 June 2024	Change	%
Total assets	A$ million	1,175.7	1,223.2	(47.5)	(3.9%)
Total liabilities	A$ million	799.2	805.5	(6.3)	(0.8%)
Total equity	A$ million	376.5	417.6	(41.1)	(9.8%)
Net debt[1]	A$ million	(243.0)	(250.7)	7.7	(3.1%)

[1] Net debt equals drawn debt less cash and cash equivalents. Drawn debt at June 2025 was A$305.2 million (FY24: A$ 265.0 million). Total debt per the statement of financial position is A$291.8 million (FY24: A$253.1 million), which includes A$13.4 million (FY24: A$11.9 million) of prepaid financing costs.

Total Assets
Total assets decreased by A$47.5 million from A$1,223.2million at 30 June 2024 to A$1,175.7 million at 30 June 2025.

At 30 June 2025, the Company held cash and cash equivalents of A$62.2 million and investments of A$0.3 million.

Gas and oil assets increased by A$9.6 million from A$475.2 million to A$484.8 million, mainly due to revisions to restoration cost estimates, offset by amortisation driven by production during the period. Property, plant and equipment decreased by A$117.7 million from A$346.3 million at 30 June 2024 to A$228.6 million at 30 June 2025, mainly due to revisions to restoration cost estimates and depreciation. Exploration and evaluation assets increased by A$16.5 million from A$193.8 million to A$210.3 million, due to the activity on ECSP.

Total Liabilities
Total liabilities decreased by A$6.3 million from A$805.5 million at 30 June 2024 to A$799.2 million at 30 June 2025.

Provisions decreased by A$21.1 million from A$466.6 million to A$445.6 million, primarily driven by the completion of BMG decommissioning in FY24 and the impact of updated gross cost estimates of certain other provisions.

Total Equity
Total equity decreased by A$41.1 million from A$417.6 million to A$376.5 million. In comparing equity at 30 June 2025 to 30 June 2024, the key movements were:

- higher contributed equity of A$1.8 million due to vesting of performance rights during the period;
- lower reserves of A$1.6 million due to fair value movements in derivatives designated in a hedge relationship, share-based payments issued during the period offset by the transfer to issued capital for the vested rights; and
- higher accumulated losses of A$41.3 million due to the statutory loss for the period.

Strategy and Outlook

Amplitude Energy remains focused on playing a crucial role in Australia's energy future, by building on its core business of producing domestic gas for Australian customers. Our strategy aligns with the Australian Government's Future Gas Strategy, which underscores the importance of gas in ensuring energy security, reliability and affordability, and supports the broader energy transition.

At Amplitude Energy, we are committed to delivering Australian gas to Australian consumers, including industrial manufacturers and major energy generators and retailers. Our strategy leverages our existing offshore and onshore infrastructure across Victoria, where the industry and community have coexisted for decades. This includes backfilling our facilities by developing new supply from existing basins that are close to market and opening our infrastructure for third-party access to maximise utilisation.

As the way gas is used evolves in the future, the shape of gas demand will change. We are investigating gas storage and peak gas demand opportunities to deliver gas to our customers when they need it. Being able to supply gas during peak demand periods, particularly when flexible gas-powered generation is called upon, will enable us to capture additional value and margin. Gas storage could be provided through existing commercial arrangements that allow us to use 'line pack' in transmission pipelines, or using depleted reservoirs, such as our Patricia Baleen field.

Having delivered strongly against our FY25 business priorities of increasing production and organic cash generation, our FY26 business priority is to pursue growth on schedule and on budget while maintaining our strong base business. Specifically, this includes:

1. Achieving a final investment decision on the ECSP: drilling Elanora / Isabella, completing subsea and plant FEED, securing Gas Sales Agreements at market competitive prices and receiving regulatory approvals;
2. Maximising production: increasing the capacity of the OGPP to an instantaneous rate of 70+ TJe/day by the end of FY26 and maintaining reliability loss of <1% across AGP and OGPP; and
3. Growing margins by reducing production costs, streamlining systems and processes and increasing average realised gas prices.

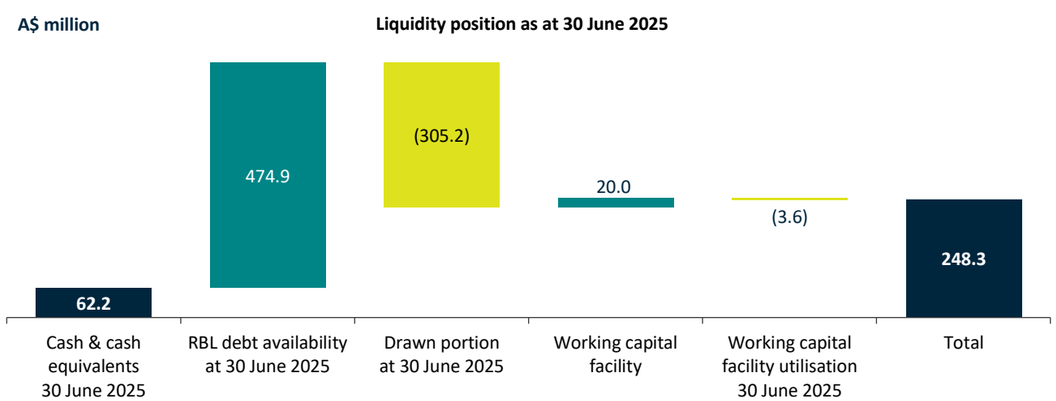
Funding and Capital Management

At 30 June 2025, the Company had cash reserves of A$62.2 million and drawn debt of A$305.2 million.

The Company has a reserves-based loan facility with a group of eight banks, with a facility commitment level of A$480 million (excluding an additional accordion facility of up to A$25.0 million) and debt availability of A$474.9 million as at 30 June 2025, to be used for general corporate purposes.

The Company has additional liquidity of A$20.0 million through a working capital facility to be used for general business purposes, of which around A$3.6 million has been utilised in respect of bank guarantees as at 30 June 2025.

The Company's liquidity position as at 30 June 2025 is illustrated in the following chart:



Further information is detailed in the basis of preparation and accounting policies section of the Financial Statements. The Company continues to assess accretive funding options as it pursues growth opportunities.

Risk Management

The Company has an established risk management protocol that is applied at all organisational levels, and serves to identify and manage risk within the Company's risk appetite.

The Company's management system is regularly reviewed and revised to provide effective management of operational and business risks. The Executive Leadership Team (ELT) revises risk assessments and reviews risk management actions for corporate level risks to ensure each risk is being reviewed at least twice a year.

The non-financial internal audit program supports the risk management program by reviewing the effectiveness of key risk controls and advising on improvements.

Corporate risk activities and internal audit outcomes are reported to and discussed with the Risk & Sustainability Committee of the Board. This Committee oversees the risk and non-financial audit programs and provides guidance.

Risk	Description
Production performance	The OGPP contributed over 80% of Amplitude Energy group production in FY25. The plant has historically encountered sulphur removal and general reliability issues and until recent months has produced below its nameplate production capacity of 68 TJ/day. Amplitude Energy has successfully implemented a number of operational improvements at the plant minimising the risk of sulphur deposition and fouling in the absorbers, as well as general reliability improvements, which resulted in increased OGPP production rates in FY25. There remains risk that OGPP performance does not meet Amplitude Energy's expectations in the future, or that the production improvements delivered in FY25 are not sustained. Should OGPP production fall from FY25 levels of 62 TJ/day on average, Group revenue and operating cashflows will, all else held equal, likely decrease, which may impact Amplitude Energy's strategic planning. Conversely, should OGPP improvements continue to increase production towards its nameplate capacity, Group revenue and operating cashflows will, all else held equal, likely increase from FY25 levels. The Athena Gas Plant or AGP, formerly named the Minerva Gas Plant, was built by BHP in 2009, and was repurposed and renamed the Athena Gas Plant by Amplitude Energy in 2020. Characterised as a mature asset, there are inherent risks associated with aging equipment nearing end of life. Sales gas and raw gas compression reliability, aging fixed equipment, and end of life control systems for the offshore wells present ongoing production, revenue, and operating cashflow risks. Amplitude Energy has developed, and is progressing, strategies and actions to mitigate and minimise these risks. Amplitude Energy operates with a comprehensive range of operating and risk management plans and an enterprise-wide integrated management system to ensure safe and sustainable operations. To the extent that it is reasonable and possible to do so, Amplitude Energy mitigates the risk of financial loss associated with operating events through insurance.
Major Capital Project Risk – ECSP	Amplitude Energy is progressing the East Coast Supply Project (ECSP), a three-well program targeting an exploration well at Elanora—including a side-track to Isabella—and one at Juliet, alongside the development of the Annie discovery. Subject to successful drilling outcomes, the company plans to proceed with the development of Isabella and Juliet alongside Annie. The project faces risks typical of the oil and gas industry, which may lead to increased costs, extended timelines, or lower than expected returns. These risks may include, but are not limited to, price fluctuations, demand changes, currency variations, geotechnical factors, drilling and production outcomes, development progress, operating results, engineering estimates, reserve estimates, environmental risks, physical risks, regulatory developments, cost projections, relevant regulatory approvals (both State and Commonwealth), and timing delays beyond the reasonable control of Amplitude Energy. Amplitude Energy is conscious of the risk of activism from some parts of the community and certain other stakeholders, aimed at delaying new natural gas projects, such as Amplitude Energy's East Coast Supply Project (ECSP). Amplitude Energy's project opportunities are in existing basins, leveraging existing infrastructure, helping to minimise the environmental footprint. The Australian Government's Future Gas Strategy, released in May 2024, highlights the principle of the need for new sources of gas supply, such as the ECSP, to meet demand during the economy-wide transition. Amplitude Energy manages these risks through the Company's project management systems that integrate technical, and engineering requirements aimed at mitigating project execution risks, including a comprehensive approach to the management of health, safety and environmental risk. All major development investment decisions are subjected to assurance reviews which include external experts and contractors where appropriate. Progress and performance of this project is actively monitored by the ELT and the Board.

JV partnership alignment	Joint venture (JV) ownership and operation of assets is common in the gas and oil exploration and production industry. Joint ventures are structured to achieve a common goal to develop and operate an asset and are also used by individual JVPs to mitigate exploration and development risks including sharing of costs. Amplitude Energy is building on its common purpose with O.G. Energy to develop and operate ECSP so as to minimise misalignment in the future. The joint operating agreement (JOA) that covers the Company's JV in the offshore Otway contains sole risk and voting provisions in scenarios where JV parties have different or misaligned objectives. In FY25 Amplitude Energy's existing JV partner in its Offshore Otway Basin assets, MEPAU, entered into agreements to sell its interests to O.G. Energy. This transaction completed on 31 July 2025. The JOA facilitates this change of ownership, and Amplitude Energy is working closely with O.G. Energy to minimise the risk of JV misalignment in the future with its co-investment in the ECSP.
East coast gas market failure	Amplitude Energy recognises the evolving risks in the east coast gas market, including the potential for major supply disruptions in a tightly balanced market with declining upstream production. To manage these risks, the company maintains rigorous operational standards across its facilities to minimise the likelihood of unplanned outages and is in a position to respond to directions from the Australian Energy Market Operator (AEMO).
Changes to restoration obligations/ provisions	Amplitude Energy has certain restoration obligations with respect to its exploration and development licences, including subsea wells, production facilities and related infrastructure. These liabilities are derived from legislative and regulatory requirements, which are subject to change. Amplitude Energy's balance sheet incorporates estimates for such decommissioning activity, with those estimates included within provisions. Amplitude Energy conducts a review of restoration provisions on a semi-annual basis. This includes a review of the assumptions included in the estimation, such as changes to the legislative and/or regulatory requirements for decommissioning, future remaining reserves estimates, timing and costs and resultant production from the commercialisation of contingent resources, current prevailing market rates and costs to undertake decommissioning activity, future inflation rates, and appropriate discount rates. Gas and oil reserves and estimates of contingent resources are expressions of judgement based on knowledge, experience and industry practice. Estimates may change significantly, or become uncertain, when new information becomes available and/or there are material changes to circumstances which result in a change to plans. This may have a positive or negative effect on estimated restoration provisions. Changes to the estimate of restoration provisions are recognised in line with accounting standards. Restoration provisions are informed estimates, but there can be no assurance that the future actual costs associated with decommissioning will not exceed the long-term provision quantum recognised to cover this activity.
Positive cash generation and access to capital	Amplitude Energy undertakes significant capital expenditure to fund exploration, appraisal, development and restoration requirements. While Amplitude Energy generates positive operating cashflow to reinvest into the business, it may also seek, from time to time, to access third-party capital to accelerate organic and/or inorganic growth options. Organic operating cashflow generation is dependent upon many variables, such as production rates including uptime, prevailing spot prices for uncontracted gas and global oil price benchmarks, operating costs, general and administration costs, taxation and foreign exchange rates. Spot gas prices are subject to fluctuations and are affected by numerous factors beyond the control of Amplitude Energy. Amplitude Energy monitors and analyses its markets and seeks to reduce price risk where reasonable and practical. Gas price risk is assessed within the context of the Company's ongoing modelling of the Southeast Australian energy market and through its gas contracting strategy, which prioritises long-term agreements and appropriate indexation and price review clauses. There can be no assurance that sufficient organic operating cashflow generation and/or access to incremental third-party capital will be available on acceptable terms, or at all. Lower organic operating cashflow generation and/or limitations on access to adequate incremental third-party capital could have a material adverse effect on the business, including the ability to commercialise discoveries and expand the Company's operations, long-term results from operations, financial conditions and prospects, and compliance with covenants under the existing bank facility. If Amplitude Energy accesses further funding under the existing debt facility, Amplitude Energy's debt levels will increase. Consequently, there is a risk that Amplitude Energy may be more exposed to risks associated with gearing and leverage.

	Failure to comply with the covenants of the debt facility could limit financial flexibility. It may enable the bank group to accelerate repayment of the Company's debt obligations. Lower organic operating cashflows, whether as a result of a decline in commodity prices or otherwise, may also give rise to changes in the assumptions incorporated into the estimation of fair market values used to test the carrying value of Amplitude Energy's assets.
Market intervention and legislative changes	Amplitude Energy operates in a regulated environment and takes all reasonable steps to ensure that it complies with the law. Federal or State Government intervention, legislative, policy or guideline changes can impact Amplitude Energy's operations and market value. Changes, and uncertainty with respect to future legislative changes, can prolong compliance, delay approvals and escalate costs, impacting the company's financial position or expected financial returns. Amplitude Energy engages with Federal and State governments and regulators on a regular basis to maintain open channels of communication.
Climate change & energy transition	Amplitude Energy recognises its activities may be impacted by climate change and the energy transition. Risks are identified and managed in two broad categories: physical climate change risks relating to acute and chronic direct impacts on the Company's operations, and energy transition risks arising from the move to a lower carbon energy system. As highlighted in the Australian Government's Future Gas Strategy, released in May 2024, Australia will need natural gas through to 2050 and beyond, even in net-zero scenarios and new sources of gas supply are needed to meet demand during the economy-wide transition. Amplitude Energy is a 100% domestic gas producer and proud to play our part in Australia's energy future. A comprehensive range of risks and opportunities associated with climate change is incorporated into company policy, strategy and risk management processes. Amplitude Energy also identifies and executes opportunities to reduce physical emissions from its operated assets, including opportunities to reduce flaring and fuel gas consumption, which also make more gas available to market. Since 2020, Amplitude Energy has voluntarily offset its Scope 1 (direct), Scope 2 (purchased electricity) and relevant Scope 3 emissions[10] (e.g. embedded energy and business travel), with certified Australian and international carbon credits. Amplitude Energy is also investigating opportunities to invest in carbon credit origination projects, both in Australia and overseas. Investing in carbon credit origination projects aims to reduce the cost to access credible carbon credits for our voluntary offset scheme. Our proactive approach to emissions reduction and voluntary offsets may also help to mitigate risks associated with climate activism or the risk of reduced support from key stakeholders. The Company's domestic gas assets and business are expected to be resilient to the threat of demand loss from climate change. AEMO scenarios, including their central Step Change scenario, indicate that although gas demand may reduce slightly in Amplitude Energy's target markets of Southeast Australia, gas supply is declining faster than demand, creating a significant opportunity for additional domestic gas supply. This underpins Amplitude Energy's long-term strategy to grow its business and to increase market share. Gas is expected to play a significant role through the energy transition in two key areas. First, as a source for heating and industrial use by Australian manufacturers, where limited cost effective or practical alternatives are available, and second, to provide firming of variable renewable power generation as the electricity network continues to decarbonise. The Company's strategy continues to focus on conventional gas production into the Southeast Australian market. The Company measures and publicly reports its emissions and emissions offsets. These results, together with detail on climate change impacts, direct emissions reduction initiatives and its energy transition strategy, are described in Amplitude Energy's annual Sustainability Report.
Health safety and environment	The nature of Amplitude Energy's operations pose inherent risks to the health and safety of employees and contractors as well as posing a range of environmental risks. A major safety or environmental incident could jeopardise Amplitude Energy's licence to operate, leading to delays, disruption and a potential interruption of the company's activities. Amplitude Energy has a comprehensive approach to the management of health, safety and environmental risks. The company's management systems integrate technical and engineering requirements with management and mitigation of personal health and safety risks, process safety risks and environmental risks.

[10] Amplitude Energy has been certified by Climate Active as a carbon neutral organisation for its Scope 1, Scope 2 and what Amplitude Energy defines as it's relevant Scope 3 emissions for FY20-24. Amplitude Energy is in the process of seeking FY25 certification. See page 50 for Scope 3 definition.

Cyber security

Amplitude Energy's operations are, and will continue to be, reliant on various computer systems, data repositories and interfaces with networks and other systems. Failures or breaches of these systems (including by way of virus and hacking attacks) have the potential to negatively impact Amplitude Energy's operations.

Amplitude Energy has barriers, continuity plans and risk management systems in place, however there are inherent limits to such plans and systems. Further, Amplitude Energy has no control over the cyber security plans and systems of third parties which may interface with Amplitude Energy's operations, or upon whose services Amplitude Energy's operations are reliant.

Access to skills and capabilities

Amplitude Energy relies on the ability to attract and retain people with the right skills, behaviours and capability to deliver both its base business and its growth opportunities. It also relies on skills and expertise provided through industry service providers for both onshore and offshore operations.

Failure to access such capability and services may constrain the achievement of business objectives. Amplitude Energy has established employment conditions, practices, incentives and a workplace culture designed to attract and retain the skills and experience needed to deliver business objectives. The Company seeks to engage a diverse group of resources and promote inclusion within its 'one team' culture. Metrics are in place to monitor employee engagement and enablement, and these are regularly reviewed by the ELT and the Board.

The company has well-established relationships with service providers regionally, domestically and globally. Amplitude Energy collaborates with industry colleagues to partner in offshore campaigns, for example, as a means to share access to skills and experience. This includes the engagement of international providers with access to a global workforce. The company also has access to well-known and highly skilled contract personnel engaged to meet the various project requirements.

Reconciliations for net loss to underlying net loss and underlying EBITDAX

Reconciliation To Underlying EBITDAX[1]		FY25	FY24	Change	%
Underlying profit after tax	**A$ million**	11.4	1.4	10.0	N/M
Add back:					
Net finance costs	A$ million	25.7	15.0	10.7	71.3%
Accretion expense	A$ million	9.9	17.7	(7.8)	(44.1%)
Tax expense/(benefit)	A$ million	17.1	(11.0)	28.1	N/M
Tax adjustments to generate underlying profit	A$ million	(4.0)	1.9	(5.9)	N/M
Depreciation	A$ million	48.3	40.1	8.2	20.4%
Amortisation	A$ million	65.2	58.7	6.5	11.1%
Exploration and evaluation expense	A$ million	0.3	3.7	(3.4)	N/M
Underlying EBITDAX	**A$ million**	**173.9**	**127.5**	**46.4**	**36.4%**

Reconciliation to Underlying Profit		FY25	FY24	Change	%
Net loss after income tax	**A$ million**	(41.3)	(114.1)	72.8	63.8%
Adjusted for:					
OGPP acquisition and integration costs	A$ million	-	0.1	(0.1)	N/M
Hedging costs	A$ million	-	1.5	(1.5)	N/M
Business restructuring and transformation	A$ million	2.6	3.4	(0.8)	(23.5%)
Asset write-off	A$ million	5.4	-	5.4	N/M
Restoration expense and associated costs	A$ million	11.0	110.3	(99.3)	N/M
NOGA levy	A$ million	2.3	1.8	0.5	27.8%
Impairment	A$ million	27.4	0.3	27.1	N/M
Derecognition of income tax deferred tax asset	A$ million	18.6	33.3	(14.7)	(44.1%)
Tax impact of underlying adjustments	A$ million	(14.6)	(35.2)	20.6	58.5%
Underlying profit after tax	**A$ million**	**11.4**	**1.4**	**10.0**	N/M

[1] Earnings before interest, tax, depreciation, amortisation, restoration, exploration and evaluation expense and impairment.

We are delivering against our announced strategy of maximising production through our existing infrastructure

Directors' statutory report

For the year ended 30 June 2025

The Directors present their report together with the Consolidated Financial Report of the Group, being Amplitude Energy Limited (the "parent entity" or "Amplitude Energy" or "Company") and its controlled entities, for the financial year ended 30 June 2025, and the Independent Auditor's Report thereon.

1. Directors

The Directors of the parent entity at any time during or since the end of the financial year are:

Mr John C. Conde AO B.Sc. B.E(Hons), MBA Chairman Independent Non-Executive Director *Appointed 25 February 2013* *Retires on 6 November 2025*	**Experience and expertise** Mr Conde has extensive experience in business and commerce and in chairing high profile business, arts and sporting organisations. Previous positions include non-executive director of BHP Billiton (ASX:BHP), Chairman of Bupa Australia, Chairman of Pacific Power (the Electricity Commission of NSW), Chairman of the Sydney Symphony Orchestra, director of AFC Asian Cup, Chairman of Events NSW, President of the National Heart Foundation, Chairman of the Pymble Ladies' College Council, director of Dexus Property Group (ASX:DXS) and Deputy Chairman of Whitehaven Coal Limited (ASX:WHC). **Current and other directorships in the last 3 years** Mr Conde is Chairman of The McGrath Foundation (since 2013 and director since 2012) and Chairman of Dexus Wholesale Property Fund (DWPF) (since 2020). Mr Conde is the immediate past President of the Commonwealth Remuneration Tribunal (1998 – 2023). **Special responsibilities** Mr Conde is Chairman of the Board of Directors. Effective 19 August 2021 he is also the Chairman of the Governance & Nomination Committee.
Ms Jane L. Norman B.Sc.,B.Eng.(Hons) PGDip GAICD Managing Director and CEO *Appointed 20 March 2023*	**Experience and expertise** Jane has worked and studied in Australia and the UK and brings 30 years of industry experience in the energy markets. She began her career with Shell International Exploration & Production as a Process Engineer in operations and then as a Commercial Advisor in The Hague, Aberdeen and London. Subsequently, in London, Jane held corporate finance and equity capital markets roles with Cazenove & Co (now JP Morgan Cazenove) and Goldman Sachs. Jane returned to Australia to join Santos where she held senior commercial, corporate strategy and Executive Committee roles. She led major strategic initiatives at Santos and played a key role in Santos' growth strategy, in particular the merger with Oil Search. During her time at Santos Jane helped drive the transformation of company performance, helping to establish the growth strategy focused on cash generation and shareholder returns and, more recently, the company's energy transition strategy. Jane holds a Bachelor of Science (Pure Mathematics and Chemistry) and Bachelor of Chemical Engineering (Hons) from the University of Sydney and a Graduate Diploma in Management and Economics of Natural Gas (Distinction) from the University of Oxford. Jane is a Graduate of the Australian Institute of Company Directors. **Current and other directorships in the last 3 years** Ms Norman is a director of the wholly owned subsidiaries of Amplitude Energy Limited and is on the Board of the Australian Energy Producers (since 2023). **Special responsibilities** Ms Norman is Managing Director and CEO. She is responsible for the day-to-day leadership of Amplitude Energy, and is the leader of the Executive Leadership Team.

Mr Timothy G. Bednall
LLB (Hons)
Independent Non-Executive Director
Appointed 31 March 2020

Experience and expertise
Mr Bednall is a highly experienced and respected corporate lawyer and law firm manager. He is a partner of King & Wood Mallesons (KWM), where he specialises in mergers and acquisitions, capital markets and corporate governance, representing public company and government clients. Mr Bednall has advised clients in the oil and gas and energy sectors throughout his career.

Mr Bednall was the Chairman of the Australian partnership of KWM from January 2010 to December 2012, during which time the merger of King & Wood and Mallesons Stephen Jaques was negotiated and implemented. He was also Managing Partner of M&A and Tax for KWM Australia from 2013 to 2014, and Managing Partner of KWM Europe and Middle East from 2016 to 2017. He was General Counsel of Southcorp Limited (which became the core of Treasury Wine Estates Limited) from 2000 to 2001.

Current and other directorships in the last 3 years
Mr Bednall is a board member of the National Portrait Gallery Foundation (since 2018) and a non-executive director of Perpetual Equity Investment Company Limited since May 2025.

Mr Bednall was formerly a non-executive director for Pooling Limited (2017 – 2025).

Special responsibilities
Effective 19 August 2021 Mr Bednall is a member of the Audit Committee, and the Governance & Nomination Committee, and effective 7 November 2024 Mr Bednall is the Chairman of the People & Remuneration Committee.

Mr Frank Tudor
B.Eng (Mech), PGDipEng (Chem), DipEc, MBA, AMP, GAICD, FIEAust
Independent Non-Executive Director
Appointed 1 October 2024

Experience and expertise
Mr Tudor brings 40 years of domestic and international experience in the oil, and gas and electricity industry. Frank has a deep understanding of organisational governance and demonstrated ability to manage political, public, stakeholder and media engagement processes.

Mr Tudor's previous experience includes Managing Director roles at Jemena and Horizon Power, General Manager at Woodside Energy, and various roles at BP. He is member of the Australia-China Council (ACC) and has performed extensive committee roles as Chairman and Vice Chairman of Chamber of Commerce, Energy and Resources Forum and National Chairman of the Australia China Business Council (ACBC).

Current and other directorships in the last 3 years
Mr Tudor has formerly held roles as National Chair of Energy Networks Australia (2022 – 2023), Chairman of Zinfra (2018 – 2023), member and Deputy Chairman of ActewAGL (2018 – 2023) and National Chair of the Energy Charter (2021 – 2022).

Special responsibilities
Effective 7 November 2024 Mr Tudor is a member of the People & Remuneration Committee and the Risk & Sustainability Committee. Effective 15 April 2025 Mr Tudor is acting Chairman of the Audit Committee.

Mr Gary Gray AO
B.Ec, GAICD
Independent Non-Executive Director
Appointed 1 October 2024

Experience and expertise
Mr Gray has a strong public policy and political background. Gary is a former Executive Director of the WA Institute of Medical Research. Gary brings considerable industry and commercial experience through private sector positions.

Mr Gray's previous experience includes Australia's Ambassador to Ireland, director of the Australian Submarine Corporation, director of the Perth Astronomical Observatory, director of Corporate Affairs at Woodside Energy, General Manager of External Affairs at Mineral Resources Ltd, and as a Trustee of Australia's largest charity; Telethon.

Gary served as Minister for Resources, Energy, Small Business and Tourism, Minister for the Public Service and Federal Integrity Agencies, Gary served as Federal Parliamentary Member for Brand.

Current and other directorships in the last 3 years
Mr Gray is a member of the Independent Parliamentary Expenses Authority (since 2016) and non-executive director of Civmec Limited (ASX:CVL) since 2024.

Special responsibilities
Effective 7 November 2024 Mr Gray is a member of the People & Remuneration Committee, the Governance & Nomination Committee and the Risk & Sustainability Committee.

Mr Ian Davies
BBus, FCA
Independent Non-Executive Director
Appointed 1 August 2025

Experience and expertise
As former Managing Director and CEO of Senex Energy Limited and former Chair of Australian Energy Producers (AEP) Board, Mr Davies is a highly distinguished and experienced industry leader.

In his time at Senex Energy, Mr Davies was instrumental in attracting investment into the Australian east coast energy market to support domestic gas supply and has been a leading voice for national energy policy and market reforms. Under Mr Davies' leadership, Senex Energy was transformed from a micro-cap explorer into a leading east coast energy producer, including through a $1 billion expansion in Queensland's Surat basin which created over 900 regional jobs, secured long-term gas supply for major Australian manufacturers and retailers and supplying approximately 15% of the domestic gas market.

Mr Davies' previous experience includes Chief Financial Officer of Queensland Gas Company Limited (QGC) and leading the LNG joint venture transaction with BG Group to develop the Gladstone QCLNG Project, and subsequent acquisition of QGC by BG Group. Mr Davies held several senior positions with BG Group following acquisition, and his prior experience includes investment banking with Barclays Capital in London and corporate tax advisory with PwC.

Current and other directorships in the last 3 years
Mr Davies is a non-executive director of G50 Corp Limited (ASX:G50) since 2024 and a former non-executive director of Australian Energy Producers (2017 – 2025).

Ms Elizabeth A. Donaghey
B.Sc., M.Sc.
Independent Non-Executive Director
Appointed 25 June 2018

Retires effective 19 August 2025

Experience and expertise
Ms Donaghey brought over 30 years' experience in the energy sector including technical, commercial and executive roles in EnergyAustralia, Woodside Energy and BHP Petroleum.

Ms Donaghey's experience includes non-executive director roles at Imdex Ltd (an ASX-listed provider of drilling fluids and downhole instrumentation), St Barbara Ltd (a gold explorer and producer), and the Australian Renewable Energy Agency. She has performed extensive committee roles in these appointments, serving on audit and compliance, risk and audit, technical and regulatory, remuneration and health and safety committees.

Current and other directorships in the last 3 years
Ms Donaghey is currently a non-executive director of the Australian Energy Market Operator (AEMO) (since 2017) and a non-executive director of Ampol Limited (ASX: ALD) (since 2021).

Special responsibilities
Prior to her retirement, Ms Donaghey was Chairman of the Risk & Sustainability Committee and a member of the People & Remuneration Committee and the Audit Committee.

Ms Giselle M. Collins
B. Ec, CA
GAICD
Independent Non-Executive Director
Appointed 19 August 2021

Retired 15 April 2025

Experience and expertise
Ms Collins has broad executive and director experience across finance, treasury and property disciplines.

Ms Collins' executive positions included General Manager Property, Treasury and Tourism of NRMA, Chief Executive Officer, Property and General Manager Finance with the Hannan Group, and Senior Manager, Audit Services with KPMG Switzerland. Ms Collins is a former non-executive director and Chairman of the following companies: Generation Life (2018 – 2021), Aon Superannuation (2016 – 2017), The Travelodge Hotel Group (2009 – 2013) and The Heart Research Institute Limited (2003 – 2011).

Current and other directorships in the last 3 years
Ms Collins is Chairman of Hotel Property Investments (ASX:HPI) since 2022, director since 2017. Ms Collins is also a non-executive director of Generation Development Group (ASX:GDG) since 2018 and Chairman of the responsibility entity for AMP Limited's managed investment schemes since 2021.

Ms Collins is a former Chairman for Indigenous Business Australia in the Darwin Hotel Pty Limited and Peak Rare Earths Limited (ASX:PEK) (2021 – 2023). Ms Collins is a former non-executive director of Pacific Smiles Limited from 2023 to 2024 (Chairman from August 2024 to December 2024)

Special responsibilities
Prior to her retirement, Ms Collins was the Chairman of the Audit Committee and was a member of the Risk & Sustainability Committee and the Governance and Nomination Committee.

Mr Jeffrey W. Schneider
B.Com
Independent Non-Executive Director
Appointed 12 October 2011

Retired 7 November 2024

Experience and expertise
Mr Schneider has over 30 years of experience in senior management roles in the oil and gas industry, including 24 years with Woodside Energy. He has extensive corporate governance and board experience as both a non-executive director and chairman in resources companies.

Current and other directorships in the last 3 years
Mr Schneider does not currently hold any other directorships.

Special responsibilities
Prior to his retirement, Mr Schneider was the Chairman of the People & Remuneration Committee and was a member of the Audit Committee.

2. Company secretary

Ms Nicole Ortigosa B.A., LLB (Hons), Grad Dip Legal Practice was appointed to the position of Company Secretary and General Counsel effective from 21 April 2023.

Nicole has over 16 years experience as a corporate and commercial lawyer, specialising in the energy and resources sector. Prior to joining Amplitude Energy she worked for top tier law firms across Australia, including Clifford Chance and Minter Ellison. Nicole's experience covers all legal, corporate, and commercial aspects of the business, including joint ventures, gas sales, infrastructure, environment, regulatory, procurement, mergers and acquisitions, corporate governance and compliance.

Nicole started at Amplitude Energy in 2017 and prior to becoming General Counsel & Company Secretary was the Legal Manager. Amongst other matters, she has advised the company on the development of the Sole gas field, the acquisition of AGP and associated infrastructure and the acquisition of OGPP and associated onshore and offshore pipeline infrastructure.

She holds a Bachelor of Laws with Honours from the University of Adelaide and a Graduate Diploma in Legal Practice from the Law Society of South Australia.

3. Directors' meetings

The number of Directors' meetings (including meetings of committees of Directors) and number of meetings attended by each of the Directors during the period in which they were members of the board and each respective committee during the financial year were:

Director	Board Meetings		Audit Committee Meetings		Risk & Sustainability Committee Meetings		People & Remuneration Committee Meetings		Governance & Nomination Committee Meetings	
	A	B	A	B	A	B	A	B	A	B
Mr J. Conde AO	7	7	-	-	-	-	2	2	1	1
Ms J. Norman	7	7	-	-	-	-	-	-	-	-
Mr T. Bednall	7	7	3	3	2	2	5	5	1	1
Ms E. Donaghey	7	7	1	1	4	4	5	5	1	1
Mr G. Gray AO*	5	5	-	-	-	-	3	3	-	-
Mr F. Tudor*	5	5	1	1	3	3	3	3	-	-
Mr J. Schneider**	4	4	2	2	-	-	2	2	-	-
Ms G. Collins***	5	5	3	3	3	3	-	-	-	-

* Mr Gray and Mr Tudor were both appointed as Non-executive Directors effective 1 October 2024.
**Mr Schneider retired effective 7 November 2024.
*** Ms Collins retired effective 15 April 2025.

A = Number of meetings attended.

B = Number of meetings held during the time the Director held office, or was a member of the Committee, during the year.

4. Remuneration report (audited)

Information about the remuneration of the Company's key management personnel for the financial year ended 30 June 2025 is set out in the Remuneration Report. The Remuneration Report forms part of the Directors' Report. It has been prepared in accordance with section 300A of the Corporations Act 2001 and has been audited as required by that Act.

Remuneration Report Introduction from the Chair of the People & Remuneration Committee

Dear fellow Shareholder

The 2025 financial year (FY25) marked a period of substantial progress for Amplitude Energy, highlighted by enhancements in the performance and reliability at the Orbost Gas Processing Plant (OGPP), aligning a new joint venture partner in the offshore Otway Basin and Athena Gas Plant (AGP) and commitment to our three-well East Coast Supply Project (ECSP). These achievements, coupled with progress on strategic initiatives, have positioned the company for future growth.

Under the leadership of Managing Director & Chief Executive Officer Jane Norman, who commenced her role in March 2023, the refreshed Executive Leadership Team (ELT) has been instrumental in driving these achievements.

This Remuneration Report outlines the remuneration outcomes for Key Management Personnel (KMP) in FY25, reflecting the company's performance and adherence to our remuneration framework and guiding principles. We will seek shareholders' support for this report at the 2025 Annual General Meeting.

Remuneration report context: 2025 financial year

The Company's performance in the 12 months to 30 June 2025 is reported in the Operating and Financial Review of the Financial Report. This performance and how it compared with the specific targets of the Company Scorecard provide the context of the remuneration outcomes outlined in the Remuneration Report.

In FY25, Amplitude Energy maintained excellent health and safety standards, with only one restricted work case, no fatalities, no lost time or medical treatment injuries and no recordable environmental incidents. Stretch financial targets, including production expenses, net G&A and SIB capex, were all achieved. OGPP exceeded ambitious production targets and AGP fell just short of its target due to the declining upstream fields and Casino-4 being offline since November 2024 due to loss of communications to the offshore well.

The Projects & Growth dimension of our scorecard was primarily focused on making substantial progress on our transformational growth project, ECSP. With the Company and subsidiaries of O.G. Energy entering into a binding interim joint venture agreement (IJVA) from March 2025 regarding the development of the ECSP, we have committed to the preferred three-well drilling program for ECSP, including purchasing long-lead items to enable us to complete and connect the wells on a successful discovery.

The Company Scorecard for FY25 achieved a result of 88.7%, as detailed in section 4.6.2. Consequently, a short-term incentive plan (STIP) payment was awarded, reflecting this outcome. Individual performance-based STIP awards were also granted to Executive KMP and staff. Details of these outcomes are provided in section 4.6.3.

Remuneration developments

In FY25, accountabilities were consolidated, reducing the number of Executive KMP roles to four: Managing Director & CEO, Chief Financial Officer, Chief Operating Officer and Chief Commercial Officer. Other executive roles shown in this report continue to be part of the Amplitude Energy Executive Leadership Team (ELT).

A review of our remuneration framework led to changes in the STIP and LTIP for Executive KMP and the broader ELT, as described in section 4.4.2. These adjustments aim to strengthen the link between shareholder experience and executive remuneration outcomes.

The Board introduced a Minimum Shareholding Requirement Policy effective 1 July 2025. This policy supports long-term shareholder alignment by requiring directors to build and maintain a meaningful shareholding in the Company. Further detail is provided at section 4.9.3 of the Remuneration Report.

Remuneration outcomes

Fixed annual remuneration (FAR): In FY25 general increases were applied to the FAR for Executive KMP and the broader ELT, consistent with the wider business, effective from 1 July 2024. These adjustments were made in recognition of no general increases for Executive KMP or the broader ELT in FY24, other than increases to recognise increase role scopes (Dan Young, Chief Financial Officer and Nathan Childs, Chief Corporate Services Officer).

FAR increases were applied in line with market benchmarking and sought to strike a balance of motivating and retaining key personnel in a high cost of living environment, whilst maintaining focus on our ongoing cost management imperatives.

Statutory increases to the superannuation rate have been passed on to all employees. The next general review of base salaries will occur on 1 October 2025.

Short-term incentive plan (STIP): FY25 STIP outcomes for Executive KMP, detailed in section 4.6.3, reflect the Company Scorecard result and individual performance achievements.

A deferred equity component has been introduced to the STIP for the ELT in FY25. Partial deferral of STIP outcomes provides further alignment of the Company's executive remuneration framework with shareholders, as well as providing a retention benefit.

For the Managing Director & CEO and Chief Operating Officer, part of the existing STIP opportunity that would previously have been provided in cash is now provided in equity (performance rights) with a 12-month deferral. Other ELT members have had

their maximum STIP opportunity increased to better align with competitive benchmarks, with the additional amount allocated as performance rights. Details are provided in section 4.4.4.

Shareholder approval will be sought at the 2025 Annual General Meeting (AGM) for any eligible grant of performance rights to the Managing Director & CEO under the FY25 STIP.

Long-term incentive plan (LTIP): the LTIP includes two equally weighted measures: relative total shareholder return (RTSR) and absolute total shareholder return (ATSR). Grants now consist wholly of performance rights. Awards under the previous structure were provided half in performance rights and half in share appreciation rights. This new structure was applied to the December 2023 LTIP offer to the ELT. Shareholders approved the Managing Director & CEO LTIP grants pursuant to this revised structure at the 2023 AGM.

The 2021 Performance Rights were tested in December 2024 following the conclusion of the three-year performance period. The Amplitude Energy RTSR over the performance period (as compared to applicable peer group companies) was determined to be equal to the 50th percentile. As a result, 30% of the 2021 Performance Rights vested (2,508,675 out of 8,362,264 LTIP rights granted) however no SARs vested. This was the first vesting since December 2020, following improved company performance.

LTIP grants from December 2022 will be tested in December 2025. LTIP continues to depend on strong business performance for any vesting.

Directors' fees: non-executive director fee remuneration was last increased on 1 July 2019. Effective 1 July 2024, the Board resolved that the Company would pay the increase to the superannuation rate (from 11% to 11.5%) but that there would be no other increase in directors' fees. A consistent approach will be taken to these fees from 1 July 2025, whereby non-executive director fees will remain unchanged, but for the superannuation rate increase (from 11.5% to 12%) which will be passed on. This is reflected in the Board Fees shown in 4.9.1.

The level of energy and commitment to succeed in the Company continues to be very strong, buoyed by progress this year.

The Board recognises the gains made in FY25 and is very appreciative of the efforts of all staff in this regard. Under Jane Norman's leadership we are confident we will continue to unlock the company's potential as we embark on the next phase of growth, and we look forward to FY26.

Yours sincerely

Mr Tim Bednall
Chair of the People & Remuneration Committee

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4.1 Introduction

This Remuneration Report (Report) details the approach to remuneration frameworks, outcomes and performance for Amplitude Energy. The Remuneration Report forms part of the Directors' Report and provides shareholders with an understanding of the remuneration principles and practices in place for Key Management Personnel (KMP) for the reporting period.

4.2 Key Management Personnel covered in this Report

In this Report, KMP are the people who have the authority and responsibility for planning, directing and controlling the activities of the Group, either directly or indirectly. They are:

- the Non-Executive Directors;
- the Managing Director and Chief Executive Officer; and
- selected executives on the Executive Leadership Team.

The Managing Director and Chief Executive Officer and selected executives on the Executive Leadership Team are referred to in this Report as "Executive KMP". The following table sets out the KMP of the Group during the reporting period and the period they were KMP:

Name	Position	Period as KMP
Non-Executive Directors		
John Conde AO	Chairman	Full Year
Timothy Bednall	Non-Executive Director	Full Year
Giselle Collins	Non-Executive Director	Part Year[1]
Elizabeth Donaghey	Non-Executive Director	Full Year
Jeffrey Schneider	Non-Executive Director	Part Year[2]
Frank Tudor	Non-Executive Director	Part Year[3]
Gary Gray AO	Non-Executive Director	Part Year[4]
Executive KMP		
Jane Norman	Managing Director & Chief Executive Officer	Full Year
Chad Wilson	Chief Operating Officer	Full Year
Eddy Glavas	Chief Commercial Officer	Full Year
Dan Young	Chief Financial Officer	Part Year[5]

[1] Giselle Collins retired from the Board effective 15 April 2025.
[2] Jeffrey Schneider retired from the Board effective 7 November 2024.
[3] Frank Tudor commenced on the Board effective 1 October 2024.
[4] Gary Gray AO commenced on the Board effective 1 October 2024.
[5] Dan Young ceased as Executive KMP on 26 May 2025. Dan ceased employment with Amplitude Energy on 18 July 2025.

4.3 Remuneration governance

4.3.1 Philosophy and objectives

The Company is committed to a remuneration philosophy that aligns with its business strategy and encourages superior performance and shareholder returns. Amplitude Energy's approach towards remuneration is aimed at ensuring that an appropriate balance is achieved between:

- Health, safety and environmental performance.
- Maximising sustainable growth in shareholder returns.
- Operational and strategic requirements.
- Providing attractive and appropriate remuneration packages.
- Maintaining a respectful relationship with all stakeholders.

The primary objectives of the Company's remuneration policy are to:

- Attract, retain and motivate high calibre employees;
- Ensure that remuneration is fair and competitive with both peers and competitor employers;
- Provide significant incentive to deliver superior performance (when compared to peers), against Amplitude Energy's strategy and key business goals without rewarding conduct that is contrary to the Amplitude Energy values or risk appetite;
- Ensure remuneration is delivered in a way which aligns outcomes with the shareholder experience;
- Achieve the most effective returns (employee productivity), for total employee spend; and
- Ensure remuneration transparency and credibility for all employees and in particular for Executive KMP.

Amplitude Energy's policy is to pay fixed annual remuneration (FAR) at the median level, compared to resource industry benchmark data and supplement this with "at risk" remuneration to bring total remuneration within the upper quartile when outstanding performance is achieved.

4.3.2 People & Remuneration Committee

The People & Remuneration Committee (which, as at 30 June 2025, was comprised of four non-executive directors, all of whom are independent) makes recommendations to the Board about remuneration strategies and policies for the executive KMP and considers matters related to organisational structure and operating model, company culture and values, diversity, succession for senior executives, and executive development and talent management. The ultimate responsibility for, and power to make company decisions with respect to these matters, remains with the full Board.

On an annual basis, the People & Remuneration Committee makes recommendations to the Board about the form of payment and incentives to Executive KMP, and the amount. This is done with reference to Company performance and individual performance of the Executive KMP, relevant employment market conditions, current industry practices and independent remuneration benchmark reports.

4.3.3 External remuneration advisers

The People & Remuneration Committee may consider advice from external advisors who are engaged by and report directly to the Committee. Such advice will typically cover Non-Executive Director fees, Executive KMP remuneration and advice in relation to equity plans.

The *Corporations Act 2001* requires companies to disclose specific details regarding the use of remuneration consultants. The mandatory disclosure requirements only apply to those advisors who provide a "remuneration recommendation" as defined in the *Corporations Act 2001*. The Committee did not receive any remuneration recommendations during the FY25 reporting period.

4.4 Nature & structure of Executive KMP remuneration

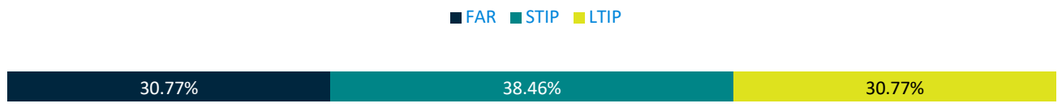
Executive KMP remuneration during the reporting period consisted of a mix of:

- Fixed annual remuneration – being cash salary and superannuation (FAR).
- Short-term incentive plan (STIP) participation.
- Benefits such as car parking.
- Long-term incentive plan (LTIP) participation.

It is the Company's policy that performance-based (or at-risk) pay forms a significant portion of the Executive KMPs' total remuneration. The Company aims to achieve an appropriate balance between rewarding operational performance (through the STIP reward) and rewarding long-term sustainable performance (through the LTIP).

The Company's current remuneration profile for Executive KMP (at maximum performance) is as follows:

Managing Director & CEO



The above split of fixed and at risk pay reflects the ongoing remuneration for the Managing Director & CEO.

Chief Operating Officer

Other Executive KMP

4.4.1 Remuneration strategy and framework - linking reward to performance

The remuneration strategy sets the remuneration framework and drives the design and application of remuneration for the Company, including Executive KMP.

The remuneration strategy:

- Encourages a strong focus on financial and operational performance and motivates Executive KMP to deliver sustainable business results and growth, over the short and long term.
- Attracts, motivates and retains appropriately qualified and experienced talent.
- Aligns executive and shareholder interests, through well designed performance incentives and equity linked plans.

The Board believes that remuneration should include a fixed component and at-risk or performance-related components, including both short-term and long-term incentives.

This remuneration framework is shown in the table following, including how performance outcomes will impact remuneration outcomes for Executive KMP. The Board will continue to review the remuneration framework to ensure it continues to align with the Company's strategic objectives and ensure shareholder alignment.

4.4.2 Remuneration strategy and framework – overview

This current remuneration framework overview includes changes made to the STIP and LTIP during FY25. The FY24 introduction of deferred equity (performance rights) as part of STIP is effective from FY25 (performance year which commenced on 1 July 2024). Details of the STIP and LTIP that operated in FY25 are shown in 4.4.4 and 4.4.5 respectively.

	Performance Conditions	Remuneration Strategy/Performance Link
Fixed Annual Remuneration (FAR) **Salary and other benefits (including statutory superannuation)**	**Key Considerations** ▪ Scope of individual's role. ▪ Individual's level of knowledge, skills and expertise. ▪ Individual performance. ▪ Market benchmarking.	FAR is set at a competitive market level to attract, retain and motivate the talent needed to deliver the Company's strategy and achieve financial and operational targets. For executives new to their role, the aim is to set FAR at a modest level relative to peers, with the intent to progressively increase as they gain experience and deliver strong performance. This links fixed remuneration to individual performance. The Company benchmarks executive FAR annually, using independent market data, including participation in the National Rewards Group Remuneration survey and other industry remuneration reports covering comparable roles from peer companies.
Short-Term Incentive Plan (STIP) **Annual incentive opportunity, delivered in cash and equity, based on Company and individual performance**	**Company Performance** There are four key dimensions for which company performance is measured: ▪ Health, Safety, Environment, Sustainability and People & Culture. ▪ Production. ▪ Financial. ▪ Projects and Growth. The targets that were established for FY25 and the achievement level against these targets are outlined in 4.6.2 of this report. **Individual performance KPIs** Individual performance measures are agreed each year. The measures include key business objectives, while also being role-specific, i.e. related to individual and team specific responsibilities.	STIP performance conditions are designed to support the financial, operational and strategic direction of the Company and are clearly defined and measurable. The achievement of these conditions will in turn create shareholder value. A large proportion of outcomes is subject to the operational and financial targets of the Company or business unit, depending on the role of the executive, to ensure clear line of sight to outcomes that will create shareholder value. Strategy and project targets ensure that continued focus on future opportunities is maintained. Non-financial targets are aligned to core values (including safety and sustainability) and key strategic and growth objectives. Threshold, Target, and Stretch targets for each measure are set by the Board to ensure that a challenging performance-based incentive is provided. The Board has discretion to adjust STIP outcomes up or down to ensure appropriate company and individual outcomes are aligned with the shareholder experience and Amplitude Energy values.
Long-Term Incentive Plan (LTIP) **Three-year incentive opportunity delivered through performance rights.**	LTIP can reward executives subject to performance hurdles being met, with the allocation of performance rights. **Performance Measures** There are two equally weighted performance measures: ▪ Relative total shareholder return (RTSR), where performance requires a sustained superior share price performance of the Company compared to a peer group of companies. The peer group companies are ASX-listed companies in the oil and gas sector, with a range of market capitalisation. ▪ Absolute total shareholder return (ATSR). This measures the compound average growth rate (CAGR) over a three-year period.	Allocation of performance rights encourages executives to 'behave like shareholders' from the grant date. The performance rights are restricted and subject to risk of forfeiture at the end of the three-year performance period. The Company believes that encouraging its employees to become shareholders is the best way of aligning employee interests with those of the Company's shareholders. The LTIP can also act as a retention incentive for key talent (due to the three-year vesting period). RTSR and ATSR measures are designed to encourage executives to focus on the key performance drivers which underpin sustainable growth in shareholder value. The performance conditions are designed to ensure vesting can only occur where shareholders have enjoyed superior share price performance in relative (against peers) and absolute terms.
Total remuneration: The combination of these elements is designed to attract, retain and motivate appropriately qualified and experienced individuals, encourage a strong focus on performance, support the delivery of outstanding returns to shareholders, and align executive and shareholder interests through share ownership.		

4.4.3 Fixed annual remuneration (FAR)

FAR includes base salary (paid in cash) and statutory superannuation. Executives are paid FAR which is competitive in the markets in which the Company operates and is consistent with the responsibilities, accountabilities and complexities of the respective roles.

The Company benchmarks FAR for its Executive KMP against resource industry market surveys (and, in particular, oil and gas companies) which are published annually. Additionally, the pay levels of Executive KMP positions in the Company may be benchmarked against national market executive remuneration surveys. It is the Company's policy to position itself at the median level of the market when benchmarking FAR.

4.4.4 Short-term incentive plan (STIP) - overview

The STIP is an annual incentive opportunity delivered in cash and performance rights (equity) based on a mix of Company and individual performance. The individual measures are a mixture of business unit and employee-specific goals. The key features of the STIP for FY25 were as follows:

STIP FY25 Plan Features	Details
What is the purpose of the STIP?	Motivate and reward individuals for their contribution to the annual performance of the Company.
How does the STIP align with the interests of Amplitude Energy's shareholders?	The STIP is aligned to shareholder interests by encouraging individuals to achieve operational and business milestones in a balanced and sustainable manner whilst growing assets and total company value.
What is the vehicle of the STIP award?	The STIP award in FY25 is delivered in the form of a cash payment, payable in October following the performance year, and a deferred component provided in performance rights vesting 12 months after the initial grant date, provided the service condition of current employment is met. Performance rights are subject to forfeiture under certain conditions of the EIP rules. The FY25 STIP resulted in an eligible grant of performance rights (equity) for the MD & CEO, the allocation of which will be presented at the 2025 AGM for the approval of shareholders, consistent with good governance (and ASX requirements as awards may be satisfied by the issue of new shares or shares acquired on market).
What is the maximum award opportunity (% of FAR)?	**Managing Director & CEO** **Maximum STIP (% of FAR) — FY25** **Cash** — 105% **Deferred Equity** — 20% **Maximum STIP** — 125% **Chief Operating Officer** **Maximum STIP (% of FAR) — FY25** **Cash** — 60% **Deferred Equity** — 10% **Maximum STIP** — 70% **Other Executive KMP** **Maximum STIP (% of FAR) — FY25** **Cash** — 50% **Deferred Equity** — 10% **Maximum STIP** — 60%
What is the performance period?	The Company's STIP operates over a 12-month performance period from 1 July to 30 June. Each year, the Board reviews and approves the performance criteria for the year ahead by approving a Company scorecard and individual performance contracts which are agreed with each Executive KMP.

How are the performance measures determined and what are their relative weightings?	The measurement of Company performance is based on the achievement of KPIs set out in the Company scorecard. See section 4.6.2 for the Company scorecard measures used for FY25. The KPIs focus on the core elements the Board believes are needed to successfully deliver the Company strategy and maximise growth in company value. For each KPI in the scorecard, a base or Threshold performance level is established as well as a Target and Stretch goal (Stretch being the maximum). Personal performance measures are agreed between each Executive KMP and Amplitude Energy each year. The relative weighting of Company scorecard and individual performance is as follows: **KMP** — **Company Scorecard** — **Individual Performance** **Managing Director & CEO** — 75% — 25% **Other Executive KMP** — 70% — 30% Performance measures are challenging, and maximum award opportunities are only achieved by outstanding performance. 50% of the maximum award opportunity will be awarded if the Company meets the Target level performance. 0% STIP will be awarded for performance achievement below the Threshold level. 0% STIP will be awarded if during any measurement period the Company sustains a fatality or major environmental incident. Irrespective of the scorecard outcome, payment of any STIP is entirely at the discretion of the Board.

4.4.5 Long-term incentive plan (LTIP) - overview

The key features of the grants made in the 2025 financial year (granted December 2024) are set out in the following table:

FY25 LTIP plan features	Details
What is the purpose of the LTIP?	The Company believes that encouraging its employees, including Executive KMP, to become shareholders is the best way of aligning their interests with those of the Company's shareholders. Having an LTIP is also intended to be a retention incentive, with a vesting period of three years before securities under the plan are available to employees.
How is the LTIP aligned to shareholder interests?	Employees benefit from the LTIP when there is sustained superior share price performance, in absolute terms and/or relative to a defined peer group. This dual performance requirement ensures that the LTIP rewards performance that is meaningful in the broader market context, thereby aligning with the interests of shareholders.
What is the vehicle of the LTIP?	LTIP grants during the reporting period were entirely in the form of performance rights. A performance right is a right to acquire one fully paid share in the Company, provided specified performance hurdles are met.
What is the maximum annual LTIP grant (% of Fixed Remuneration)?	**KMP** — **% of FAR** **Managing Director & CEO** — 100% **Other Executive KMP** — 70%
What is the LTIP performance period?	The performance period is three years.
What are the performance measures?	There are two equally weighted performance measures: ▪ Relative total shareholder return (RTSR) (50%). Performance requires a sustained superior share price performance of the Company compared to a peer group of companies. The peer group companies are ASX-listed companies in the oil and gas sector, with a range of market capitalisation. ▪ Absolute total shareholder return (ATSR) (50%). ATSR is calculated as the compound average growth rate (CAGR) of the Company's share price over a 3-year period and is expressed as a percentage.

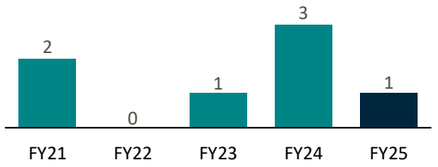
FY25 LTIP plan features	Details
	RTSR and ATSR are common long-term incentive measures across ASX-listed companies. Relative measures ensure that maximum incentives are only achieved if Amplitude Energy's performance is above the median performance of its peers and therefore supports competitive returns against other comparable organisations. Absolute measurement rewards share price growth over a 3-year period.
Which companies make up the RTSR peer group?	The RTSR is measured as a percentile ranking compared to the following comparator group of listed entities: Beach Energy (BPT), Carnarvon Energy (CVN), Comet Ridge (COI), Beetaloo Energy Australia (BTL), Horizon Oil (HZN), Melbana Energy (MAY), Pancontinental Energy (PCL), Strike Energy (STX) and Tamboran Resources (TBN).
What is the vesting schedule?	**RTSR (tranche 1) 50% of performance rights** The vesting criteria for performance rights (PRs) is based on the Company's RTSR performance, with the percentage of PRs which vest at the end of the performance period determined by the Company's RTSR percentile ranking as assessed against the peer group of companies. Subject to the plan rules, the number of incentives which are achieved and will vest at the end of the performance period as a result of the Tranche 1 PRs will be the number which corresponds to the Company's RTSR as set out below: **RTSR percentile ranking** — **Percentage of tranche 1 performance rights to vest** **Below 50th percentile** — No performance rights **At 50th percentile** — 50% of performance rights **Between 50th percentile and 75th percentile** — 50% of performance rights plus 2% for each additional percentile **At or above 75th percentile** — 100% of performance rights **ATSR (tranche 2) 50% of performance rights** Subject to the plan rules, the number of PRs which are achieved and will vest at the end of the performance period as a result of the tranche 2 PRs will be the number which corresponds to the CAGR as set out below: **3-year CAGR** — **Percentage of tranche 2 performance rights to vest** **Less than 10%** — No performance rights **At 10%** — 50% of performance rights **Between 10% and 20%** — 50% of performance rights plus 5% for each additional percentile **20% or above** — 100% of performance rights The vesting schedule reflects the Board's requirement that performance measures are challenging, and maximum award opportunities are only achieved by outstanding performance.
What happens on cessation of employment?	Generally, if an employee ceases employment prior to the vesting date (e.g., resigning their employment), they will forfeit all awards. In the case of "qualifying leavers" as defined (examples of which include redundancy, retirement or incapacity), awards may be retained, unless the Board determines otherwise. The Board also has the discretion to determine that some or all awards may be retained upon cessation of employment.
What happens if there is a change of control?	In the event of a change of control, unless the Board determines otherwise, pro-rata vesting will occur on the basis of the proportion of the relevant performance period that has elapsed.
Who can participate in the LTIP?	Eligibility is generally restricted to Executive KMP and members of the ELT.
Will the Company make any changes to the LTIP for the grant to be made in the 2026 financial year (FY26)?	As indicated earlier in this Remuneration Report, a review of the remuneration structure was undertaken in FY25. The Board is satisfied that the revised LTIP aligns executive and shareholder interests through the equity linked plan. No further changes are envisaged to the LTIP grant to be made in FY26.

4.5 Amplitude Energy's five-year performance and link to remuneration

The following graphs illustrate the Company's five-year performance, which link to the remuneration strategy and framework:

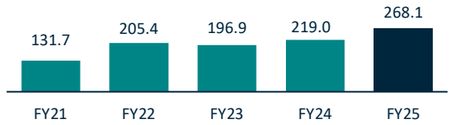
Safety – Number of consequence level 2&3 incidents (recordable injuries)(per year)

Links directly to Company STIP reward outcome as a HSE, Sustainability and People & Culture KPI.



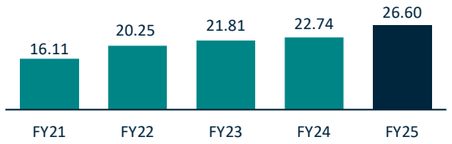
Sales revenue ($ million)

Links indirectly to Company STIP reward outcome as Production and Financial KPIs.



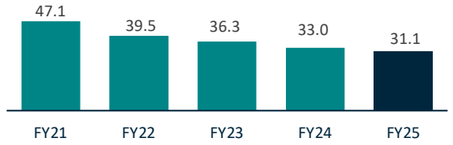
Annual production (PJe)

Links directly to Company STIP reward outcomes as a Production KPI.



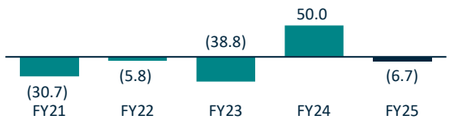
Proved & probable natural gas & oil reserves (MMboe)

Links indirectly to Company STIP reward outcome as a Projects & Growth KPI.



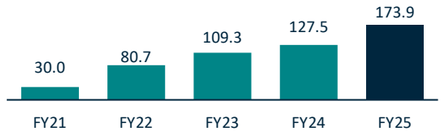
Financial – total shareholder return (%)

Links directly to Company LTIP reward outcome by increasing shareholder value.



Financial – underlying EBITDAX ($ million)

Links indirectly to Company STIP reward outcome as a Financial KPI.



In FY25, and in the past 5 years, dividends were not paid by the Company to its shareholders, nor was there a return of capital to shareholders.

4.6 2025 Executive KMP performance and remuneration outcomes

4.6.1 Fixed annual remuneration outcome

Increases to the statutory superannuation contribution, effective 1 July 2025, have been applied to all employees including the Executive KMP.

The Board determined that a benchmarked increase to FAR would be applied effective 1 October 2025.

4.6.2 STIP Performance Outcomes – Company Results

Performance measure (FY25 weighting)	Performance measure outcome	Result Threshold Target Stretch
HSE, sustainability, people & culture (20%) Result: 16.3/20.0	▪ No health & safety incidents > level 2 (OGPP hand laceration) ▪ No environmental incidents > level 1 (recordable incidents) ▪ Organisational emissions < 105 ktCO2e ▪ Voluntarily surrendered credible carbon credits to meet 100% Scope 1, Scope 2 and relevant Scope 3 emissions[11] ▪ Projects to deliver >3.9 ktCO2e p.a. in execution ▪ Clear position descriptions, KPIs and individual development plans in place for all staff ▪ Diversity strategy actions and metrics met (>30% female representation across company) ▪ Employee survey action plan in place and all FY25 actions delivered ▪ Voluntary employee turnover rate below industry benchmark	
Production (25%) Result: 21.7/25.0	▪ Sole/OGPP production of 62.0 TJ/d ▪ CHN/AGP production of 9.45 TJe/d ▪ PEL 92 production of 250.5 bbl/d	
Financial (25%) Result: 23.8/25.0	▪ Production expenses of $66.9 million ▪ Net G&A of $11.7 million ▪ SIB capex below stretch ▪ Realised contract price of $8.98/GJ, new winter gas contract signed for Sole/OGPP at market competitive pricing, incremental M&T activities adding +$1 mm revenue ▪ Underlying cash generation above stretch	
Projects & growth (30%) Result: 27.0/30.0	▪ Aligned JV partner, committed to three-well drilling program ▪ Project capex below stretch ▪ Net debt of $243.0 million ▪ RBL funding extended to 2029 ▪ All primary approvals – Athena Supply (drilling) EP and ECSP OPP – approved by NOPSEMA	
FY25 performance		**88.7 / 100**

[11] See page 50 for Scope 3 definition

4.6.3 STIP performance outcomes – individual results

When the Company scorecard result and individual performance outcomes were combined, the Board determined the FY25 STIP outcomes for the Executive KMP as follows:

Executive KMP	KMP Short-Term Incentive (STIP) for the year ended 30 June 2025					
	STIP - % of FAR at Target	STIP - % of FAR at Maximum	Cash STIP $	Deferred STIP[2] $	% earned of maximum STIP opportunity	% forfeited of maximum STIP opportunity
Jane Norman	62.5%	125%	781,781	148,911	89%	11%
Chad Wilson	35.0%	70%	325,041	54,174	90%	10%
Eddy Glavas	30.0%	60%	212,567	42,513	89%	11%
Dan Young[1]	30.0%	60%	250,578	50,116	89%	11%

[1] Dan Young ceased as Executive KMP on 26 May 2025. STIP represents payment for the full financial year. Dan ceased employment with Amplitude Energy on 18 July 2025.
[2] The value for deferred STIP (DSTIP) is the full entitlement the KMP achieved as part of the 2025 financial year. DSTIP is awarded for the performance achieved in a certain financial year and is earnt over a period of two years. This value will not align with the data in section 4.8.2 as this shows just FY25.

Managing Director & CEO individual performance

Jane Norman, the Managing Director and CEO, received a FY25 STIP payment of $930,692 gross. The calculation of this payment was as follows:

Jane Norman	Maximum eligibility % FAR	Maximum eligibility $	FY25 Result %	FY25 Cash STIP $	Deferred STIP $	FY25 STIP Gross Payment $
Company Scorecard (75%)	93.75%	781,875	88.7	582,559	110,964	693,523
Individual performance (25%) *	31.25%	260,625	91.0	199,222	37,947	237,169
Total	125%	1,042,500		781,781	148,911	930,692

* The Managing Director & CEO's Individual performance was assessed by the Board as follows:

Performance measure (FY25 weighting)	Performance measure outcome	Result (Threshold / Target / Maximum)
Drive continuous improvement in HSE. Create 'one team' and drive performance culture. **Weighting: 10%**	▪ Strong safety culture and performance, external recognition of safety performance through AEP Safety award received in May 2025. ▪ High functioning and cohesive ELT, driving organisational performance and lifting the bar. Excellent collaborative culture in ELT, strong sense of 'owning the problem' and challenging each other. ▪ Cohesive and constructive relationship with Board. ▪ Female participation >30% with increase in number of senior females. ▪ Positive Duty training undertaken across leadership team in preparation for broader regulation of psycho-social hazards in the workplace.	
Deliver improved production, additional margin and reduced costs to maximise free cash flow and accelerate debt repayment. **Weighting: 30%**	▪ 25% increase in production rates at OGPP. ▪ >$20m in value improvements achieved, including cost reductions, volume increase and margin expansion. ▪ All economic emission reduction initiatives have been implemented. 2030 Flaring target met in FY25, with ongoing monitoring intended in FY26. ▪ Certified carbon credit secured below Budget cost expectations. ▪ Elemental sulphur now sold as a product with first shipment to Devco on 30 June 2025. ▪ Achieved strong margin expansion through new contracts, increased spot gas exposure and trading into Sydney spot market.	
Progress of the East Coast Supply Project and Patricia Baleen storage / restart. **Weighting: 40%**	▪ O.G. Energy on board as new JV partner in ECSP, aligned with our ambition for growth. ▪ RBL extended to strengthen funding capacity for ECSP. ▪ three-well ECSP drilling program approved by the Board including long-lead orders for development phase. ▪ Joint marketing with O.G. Energy agreed, with discussions with potential customers underway. ▪ Strong relationship with regulators supporting timely approvals being delivered. ▪ Progressing restart of Patricia Baleen.	
Build investor relationships and deliver clear messaging to the market and other stakeholders to maintain confidence in the future of AEL. Enhance shareholder returns including share price performance year on year, M&A activity and other activities to generate positive returns. **Weighting: 20%**	▪ Ongoing focus on non-holder roadshow meetings to attract new shareholders. ▪ New investors brought on register, with better distribution amongst top shareholders. ▪ Board endorsed Energy Transition Strategy published in FY24 Sustainability Report. ▪ AGP behind-the-meter solar project supported by O.G. Energy, which will lower Scope 2 emissions and support delivery of our Scope 2 emissions target. Investigations ongoing into biogas opportunities. ▪ Strong sell-side analyst support for AEL on continued delivery and operational performance. ▪ M&A activity included farm-down of Nestor and Annie to O.G. Energy to ensure alignment across Otway growth portfolio. ▪ Robust company defence strategy in place.	
FY25 performance		**91 / 100**

Other Executive Key Management Personnel Individual Performance

STIP for other Executive KMP has a 70% weighting on the company scorecard and 30% individual performance weighting. Commentary on individual performance and FY25 STIP outcomes follow:

Chad Wilson **Chief Operating Officer**		**Eddy Glavas** **Chief Commercial Officer**	
▪ Record production and improved reliability delivered at OGPP, supporting company reputation and growth. ▪ Stronger operational discipline and governance embedded across Operations and Engineering. ▪ Strengthened site teams with greater focus on maintenance planning and inventory control. ▪ Oversight of ECSP Project delivery, building JV partner confidence and improving project cost and schedule management. ▪ Advanced Continuous Improvement initiatives, delivering repeatable cost reductions and production gains. ▪ Effectively drove performance culture and maintained team focus.		▪ Appointed Acting Chief Financial Officer from 26 May 2025, assuming additional finance leadership responsibilities. ▪ Led successful transaction to secure new JV Partner for the Otway Basin, securing three-well program, reimbursement of back costs, and JV Partner funding—positioning AEL for growth. ▪ Built and maintained strong JV and commercial relationships, including improving gas sales margin by re-marking Otway Basin gas, optimising Sole gas sales and implementing tactical spot trading. ▪ Effectively allocated commercial resources and maintained strategic cost discipline. ▪ Leveraged industry networks to identify growth and value creation opportunities.	
Company performance	**88.7%**	Company performance	**88.7%**
Individual performance	**92.5%**	Individual performance	**89.5%**
FY25 STIP as % of maximum	**90%**	FY25 STIP as % of maximum	**89%**

Former Executive Key Management Personnel Individual Performance

Dan Young ceased as Executive KMP on 26 May 2025 and his STIP outcome is based solely on Company performance of 88.7%. No individual performance assessment applied and he has achieved 88.7% of his maximum available STIP.

4.6.4 LTIP Outcome

LTIP grants issued in December 2021 and tested in December 2024 (during FY25) had a relative percentile ranking of equal to the 50th percentile and therefore 30% of performance rights vested, resulting in 2,508,675 shares being issued.

LTIP grants issued in December 2022 (to be tested in December 2025) involve grants of performance rights (50%) and share appreciation rights (50%) while December 2023 (to be tested in December 2026) involve grants of only performance rights (100%). These grants will be tested against their respective peer groups and absolute TSR. Vesting will rely on RTSR and ATSR as previously disclosed.

Details, including performance hurdles, of the LTIP grants issued in December 2024 (to be tested in December 2027) are included under 4.4.5 Long-term incentive plan (LTIP) – overview.

4.7 Executive KMP employment contracts

Each Executive KMP has an ongoing employment contract. All Executive KMP have termination benefits that are within the allowed limits under the *Corporations Act 2001*. Contracts include the treatment of entitlements on termination in the event of resignation, with notice or for cause.

Key terms for each Executive KMP are set out below:

Executive KMP	Notice by Amplitude Energy	Notice by Executive KMP	Indemnity Agreement	Treatment on Termination by Amplitude Energy
Jane Norman	6 months	6 months	Company provides indemnity agreement, Directors and Officers indemnity insurance and access to Company records.	Where the Managing Director is not employed for the full period of notice, a payment in lieu may be made. A payment in lieu of notice is based on fixed remuneration (base salary and superannuation). Upon termination, superannuation is not paid on accrued annual leave or long service leave. Unused personal leave is not paid out and is forfeited.
Other Executive KMP	6 months	3 months	Company provides indemnity agreement, Directors and Officers indemnity insurance and access to Company records.	Where an Executive KMP is not employed for the full period of notice, a payment in lieu may be made. Upon termination, superannuation is not paid on accrued annual leave or long service leave. Unused personal leave is not paid out and is forfeited.

Under the rules of the STIP and the EIP, if an Executive KMP ceases employment prior to the vesting date of an incentive award (STIP and LTIP) (e.g., resigning their employment), they will forfeit all awards.

In the case of "qualifying leavers" as defined (examples of which include redundancy, retirement or incapacity), awards may be retained, unless the Board determines otherwise. The Board also has a discretion to determine that some or all awards that would otherwise be forfeited may be retained upon cessation of employment subject to applicable laws.

4.8 2025 Remuneration outcomes for Executive KMP

4.8.1 Remuneration realised by Executive KMP in FY25 and FY24

The Company believes that providing details of the remuneration actually realised by current Executive KMP is useful to shareholders. It provides clear and transparent disclosure of remuneration provided by the Company as opposed to statutory accounting values which show the value at the time awards are granted rather than actual remuneration realised by individuals. See table in section 4.8.2.

The table set out below shows amounts paid, and the value of any equity awards which vested (valued at the vesting date), during the reporting period. It serves to answer the question: what was actually paid as compensation including salary, STIP and LTIP realised in the financial year and any other awards.

This information is a non-IFRS measure and is in addition to and different from the disclosures required by the *Corporations Act 2001* and Accounting Standards in the rest of the Remuneration Report including the tables in sections 4.8.2 and 4.9.2.

The total benefits delivered during the reporting period and set out in the table below comprise the following elements:

- FAR is base salary and superannuation (statutory and salary sacrifice).
- STIP cash payment made in October each year. The STIP payments shown here correspond to the combined company scorecard and individual performance outcomes from the prior financial year. Currently, STIP awards are assessed and finalised in August and paid in October, in arrears, for the previous financial year. As a result, the amounts shown in the 2025 row, relate to STIP payments in respect of FY24. These amounts were assessed and approved by the Board in August 2024 and disclosed in section 4.6.3 of the remuneration report for the year ended 30 June 2024. The STIP payments shown here align to the financial year when they were actually paid, while the table in section 4.8.2 aligns STIP payments to the financial year to which they relate.

Executive KMP	Financial year	FAR $	STIP $	LTIP $	Other $	Total $
Jane Norman	**2025**	**834,000**	**642,438**	**-**	**7,752**	**1,484,190**
	2024	802,105	57,144	-	407,684	1,266,933
Chad Wilson	**2025**	**603,000**	**180,606**	**-**	**598,262**	**1,381,868**
	2024	403,602	-	-	290,212	693,814
Eddy Glavas	**2025**	**470,000**	**141,716**	**37,657**	**6,762**	**656,135**
	2024	450,106	45,360	-	6,741	502,207
Dan Young [1]	**2025**	**520,741**	**178,072**	**45,872**	**6,762**	**751,447**
	2024	555,000	72,128	-	6,741	633,869

[1]Dan Young ceased as Executive KMP on 26 May 2025. 2025 payments are for the full year. Dan ceased employment with Amplitude Energy on 18 July 2025.

4.8.2 Table of Executive KMP Statutory Remuneration Disclosure for FY25 and FY24

The following table provides IFRS aligned disclosures on KMP remuneration required by the Corporations Act 2001 and Accounting Standards. By contrast with the table in section 4.8.1, which discloses amounts paid in respect of Executive KMP and the cash value of equity awards which vested during the reporting period, the disclosures provided in the following table present the KMP remuneration costs incurred and accrued during the reporting period. Amounts included as STIP and LTIP in section 4.8.1 represent realised benefits to Executive KMP during the reporting period, whilst the amounts shown in the table below as STIP and LTIP represent benefits incurred during the reporting period (LTIP grants are subject to vesting conditions described in section 4.4.5).

Benefits												
			Short-term		Long-term	Post-employment	Share based remuneration		Termination Payments[5]			Total
		Base salary	STIP[1]	Other short-term benefits[2]	Long service leave	Superannuation[3]	LTIP[4]	DSTIP	Base salary[6]	Severance	Share based remun.[7]	
Executive KMP	**FY**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
Jane Norman	**2025**	**804,068**	**823,091**	**7,752**	**-**	**29,932**	**296,302**	**78,390**	**-**	**-**	**-**	**2,039,535**
	2024	774,707	642,438	407,684	-	27,398	114,038	-	-	-	-	1,966,265
Chad Wilson	**2025**	**573,068**	**342,216**	**598,262**	**-**	**29,932**	**134,668**	**28,518**	**-**	**-**	**-**	**1,706,664**
	2024	383,053	180,606	290,212	-	20,549	46,178	-	-	-	-	920,598
Eddy Glavas	**2025**	**440,068**	**223,799**	**6,762**	**15,646**	**29,932**	**210,338**	**22,380**	**-**	**-**	**-**	**948,925**
	2024	422,708	141,716	6,741	11,090	27,399	236,144	-	-	-	-	845,798
Former Executive KMP												
Andrew Thomas[8]	**2025**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**		**-**	**-**
	2024	469,708	154,277	6,741	12,323	27,399	260,984	-	133,943	379,379	309,992	1,754,746
Dan Young[9]	**2025**	**490,809**	**241,833**	**6,762**	**39,538**	**29,932**	**229,221**	**24,184**	**191,503**	**133,767**	**395,749**	**1,783,298**
	2024	527,601	178,072	6,741	-	27,399	238,676	-	-	-	-	978,489
Totals	**2025**	**2,308,013**	**1,630,939**	**619,538**	**55,184**	**119,728**	**870,529**	**153,472**	**191,503**	**133,767**	**395,749**	**6,478,422**
	2024	2,577,777	1,297,109	718,119	23,413	130,144	896,020	-	133,943	379,379	309,992	6,465,896

[1] Refer to 4.6.3 for STIP amount earned in FY24 which will be paid in FY25.

[2] Other short-term benefits include fringe benefits, car parking, sign on bonuses, relocation and other benefits. Other short-term benefits such as short-term compensated absences, short-term cash profit-sharing and other bonuses are not applicable to Executive KMP in FY25.

[3] Superannuation is the only applicable post-employment benefit i.e., no pension or similar benefits for Executive KMP. Superannuation includes the amounts required to be contributed by the Company and does not include amounts salary sacrificed.

[4] In accordance with the requirements of the Accounting Standards, remuneration includes a proportion of the value of the equity-linked compensation determined as at the grant date of PRs and progressively expensed over the vesting period. The amount allocated as remuneration is not relative to or indicative of the actual benefit, if any, that may ultimately be realised should the equity instruments vest. The value of the PRs was determined in accordance with AASB 2 Share-based Payments and is discussed in Section 4.8.3 below and in more detail in Note 27 of the Notes to the Financial Statements.

[5] Base salary, severance, LTIP and DSTIP post 30 June 2025 are termination benefits and have been accounted for as such.

[6] Includes base salary, other short-term benefits and superannuation.

[7] Relate to LTIP awards made in December 2022, 2023 and 2024 which have not yet been fully expensed as the three-year testing period has not finished. These are non-cash expenses for LTIP and DSTIP grants that have not yet vested. These rights remain on foot for qualifying leavers and vesting of these grants remain contingent on the performance hurdles noted in section 4.4.5.

[8] Andrew Thomas ceased as an Executive KMP effective 30 June 2024 but entitlements reflect the full period until his leaving date on 30 September 2024.

[9] Dan Young ceased as an Executive KMP effective 26 May 2025 but entitlements reflect the full period until his cessation date on 18 July 2025.

4.8.3 Performance rights accounting for the reporting period

The value of the performance rights (PRs) issued under the EIP is recognised as share based payments in the Company's statement of comprehensive income and amortised over the vesting period. The performance period for the PRs granted under the EIP commenced on 11 December 2024.

PRs are granted for no consideration and employees receive no cash benefit at the time of receiving the rights.

The cash benefit, if any, will be received by the employee following the sale of the resultant shares, but this can only be achieved after the rights have vested and the shares are issued. Further, the rights can only vest when the relative total shareholder return (RTSR) and absolute total shareholder return (ATSR) thresholds described in section 4.4.5 have been achieved.

PRs granted under the EIP were valued by an independent consultant applying a Monte Carlo simulation model to determine the probability of achievement of the RTSR and ATSR against performance conditions.

The value of PRs shown in the tables below are the accounting fair values for grants in the reporting period:

Performance rights (equity incentive plan)				
	No. of rights granted during period	**Fair value of rights at grant date ($)**	**No. of rights vested during period**	**% of all rights vested from first award to 30 June 2025**
Directors				
Jane Norman	4,362,128	518,439	-	0%
Executive KMP				
Chad Wilson	2,207,739	285,461	-	0%
Eddy Glavas	1,720,792	222,498	203,550	14%
Former Executive KMP				
Dan Young [1]	2,068,611	267,471	247,956	4%

[1] Dan Young ceased as Executive KMP on 26 May 2025. Dan ceased employment with Amplitude Energy on 18 July 2025.

The estimated fair value of the rights granted to the Managing Director and CEO is $0.12 per right based on a share price on grant date of $0.165. The estimated fair value of the rights granted to Executive KMP is $0.13 based on a share price at grant date of $0.18[12]. These grants relate to performance rights awarded during the period. The performance period for these rights commenced on 11 December 2024 and will end on 11 December 2027.

4.8.4 Movement in incentive rights

The movement during the reporting period in the number of PRs granted but not exercisable over ordinary shares in Amplitude Energy held, directly, indirectly or beneficially, by each executive KMP, including their related parties, is as follows:

Performance rights (equity incentive plan)	Held at 1 July 2024	Granted	Lapsed	Vested & exercised	Held at 30 June 2025
Directors					
Jane Norman	8,378,307	4,362,128	-	-	12,740,435
Executive KMP					
Chad Wilson	3,392,657	2,207,739	-	-	5,600,396
Eddy Glavas	3,938,560	1,720,792	474,950	203,550	4,980,852
Former Executive KMP					
Dan Young[1]	4,621,036	2,068,611	578,565	247,956	5,863,126

[1] Dan Young ceased as Executive KMP on 26 May 2025. Dan ceased employment with Amplitude Energy on 18 July 2025.

[12] The grant date of the Managing Director and CEO's rights are linked to shareholder approval and hence grant date is the date of the AGM whilst for other Executive KMP grant date is linked to the date the rights were officially granted.

From previous LTIP grants (those granted in December 2022), SARs represent the right to receive a quantity of shares based on an amount equal to the difference in share price at grant date and test date. The movement during the reporting period in the number of SARs granted but not exercisable over ordinary shares in Amplitude Energy held, directly, indirectly or beneficially, by each Executive KMP, including their related parties, is as follows:

Share appreciation rights (equity incentive plan)	Held at 1 July 2024	Granted	Lapsed	Vested & exercised	Held at 30 June 2025
Directors					
Jane Norman	-	-	-	-	-
Executive KMP					
Chad Wilson	-	-	-	-	-
Eddy Glavas	3,802,455	-	2,134,369	-	1,668,086
Former Executive KMP					
Dan Young [1]	4,542,590	-	2,600,000	-	1,942,590

[1] Dan Young ceased as Executive KMP on 26 May 2025. Vesting of the balance held at 30 June 2025 remains subject to meeting market conditions of the award.

4.8.5 Directors and executives' movement in shares

The movement during the reporting period in the number of ordinary shares in Amplitude Energy held, directly, indirectly or beneficially, by each KMP, including their related parties, is as follows:

Ordinary shares	Held at 1 July 2024	Purchases	Received on vesting of PRs & SARs	Sales	Held at 30 June 2025
Directors					
John Conde AO	1,904,254	-	-	-	1,904,254
Jane Norman	-	-	-	-	-
Timothy Bednall	320,499	385,000	-	260,000	445,499
Elizabeth Donaghey	1,179,000	-	-	-	1,179,000
Jeffrey Schneider[1]	2,423,232	-	-	-	2,423,232
Giselle Collins[2]	160,000	-	-	-	160,000
Frank Tudor	-	634,147	-	-	634,147
Gary Gray AO[3]	465,000	122,000	-	-	587,000
Executive KMP					
Chad Wilson	-	-	-	-	-
Eddy Glavas	1,501,945	-	203,550	-	1,705,495
Former Executive KMP					
Dan Young [4]	-	-	247,956	-	247,956

[1] Jeffrey Schneider retired from the Board effective 7 November 2024.
[2] Giselle Collins retired from the Board effective 15 April 2025.
[3] Gary Gray AO was appointed as a non-executive director effective from 1 October 2024. The shares shown as "Held at 1 July 2024" are those held on that date of appointment.
[4] Dan Young ceased as Executive KMP on 26 May 2025.

Options

No options were issued (or forfeited) during the year.

4.9 Nature of Non-Executive Director remuneration

Non-Executive Directors are remunerated solely by way of fees and statutory superannuation. Their remuneration is reviewed annually to ensure that the fees reflect their responsibilities and the demands placed on them. Non-executive directors do not receive any performance-related remuneration.

4.9.1 Non-Executive Director fee structure

The maximum aggregate remuneration pool for non-executive directors, as approved by shareholders at the Company's 2018 AGM, is $1.25 million. The non-executive directors' fee structure for the reporting period (FY25) was as follows:

Role	Board Fee	Audit Committee	Risk & Sustainability Committee	People & Remuneration Committee	Governance & Nomination Committee
Chairman*	$241,081	$20,090	$20,090	$20,090	$0
Member	$115,518	$10,045	$10,045	$10,045	$10,045

Effective from 1 July 2025 (FY26), the Board resolved to adjust the fee structure only to reflect the increase to the statutory superannuation rate from 11.50% to 12%. The table below shows this adjustment to take effect 1 July 2025.

Role	Board Fee	Audit Committee	Risk & Sustainability Committee	People & Remuneration Committee	Governance & Nomination Committee
Chairman*	$242,162	$20,180	$20,180	$20,180	$0
Member	$116,036	$10,090	$10,090	$10,090	$10,090

*Where the Chairman of the Board is a member of a committee, they will not receive any additional committee fees.

Remuneration paid to the non-executive directors for the reporting period and for the previous reporting period is shown in the table in Section 4.9.2.

The Company has entered into written letters of appointment with its non-executive directors. The term of the appointment of a non-executive director is determined in accordance with the Company's Constitution and is subject to the provisions of the Constitution dealing with retirement, re-election and removal of non-executive directors. The Constitution provides that all non-executive directors of the Company are subject to re-election by shareholders by rotation every three years. The Company has entered into indemnity, insurance and access agreements with each of the non-executive directors under which the Company will, on the terms set out in the agreement, provide an indemnity, maintain an appropriate level of Directors' and Officers' indemnity insurance and provide access to Company records.

4.9.2 Table of non-executive KMP remuneration for 2025 and 2024 financial years

Current Non-Executive Directors (NED)[1]		Benefits						
		Short-term			Long-term	Post-employ-ment	Share based remuneration	
		Fees	STIP[2]	Other short-term benefits	Long service leave	Super-annuation[3]	LTIP	Total
		$	$	$	$	$	$	$
John Conde AO	**2025**	**216,216**	**-**	**-**	**-**	**24,865**	**-**	**241,081**
	2024	215,233	-	-	-	23,676	-	238,909
Tim Bednall	**2025**	**139,640**	**-**	**-**	**-**	**16,058**	**-**	**155,698**
	2024	136,043	-	-	-	14,965	-	151,008
Elizabeth Donaghey	**2025**	**139,640**	**-**	**-**	**-**	**16,058**	**-**	**155,698**
	2024	136,043	-	-	-	14,965	-	151,008
Frank Tudor[4]	**2025**	**95,292**	**-**	**-**	**-**	**10,959**	**-**	**106,251**
	2024	-	-	-	-	-	-	-
Gary Gray AO[5]	**2025**	**95,292**	**-**	**-**	**-**	**10,959**	**-**	**106,251**
	2024	-	-	-	-	-	-	-
Jeffrey Schneider[6]	**2025**	**54,429**	**-**	**-**	**-**	**6,259**	**-**	**60,688**
	2024	130,037	-	-	-	14,304	-	144,341
Giselle Collins[7]	**2025**	**116,366**	**-**	**-**	**-**	**13,382**	**-**	**129,748**
	2024	133,081	-	-	-	14,639	-	147,720
Vicky Binns[8]	**2025**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	2024	47,221	-	-	-	5,194	-	52,415
Totals	**2025**	**856,875**	**-**	**-**	**-**	**98,540**	**-**	**955,415**
	2024	797,658	-	-	-	87,743	-	885,401

[1] Non-executive directors do not participate in the LTIP.
[2] Non-executive directors are not eligible for STIP payments.
[3] Superannuation includes the amounts required to be contributed by the Company and does not include amounts salary sacrificed.
[4] Frank Tudor joined the Board effective 1 October 2024.
[5] Gary Gray AO joined the Board effective 1 October 2024.
[6] Jeffrey Schneider retired from the Board effective 7 November 2024.
[7] Giselle Collins retired from the Board effective 15 April 2025.
[8] Vicky Binns retired from the Board effective 9 November 2023.

4.9.3 Minimum Shareholding Requirement Policy

The Board has approved a Non-Executive Director Minimum Shareholding Requirement Policy. Effective 1 July 2025, this policy requires each Non-Executive Director to acquire and, thereafter, retain shares in the Company equivalent in value to a minimum of approximately one times the annual non-executive director base fee (excluding superannuation). This policy is designed to further align the interests of non-executive directors with those of shareholders and reflects contemporary governance expectations. The requirement is to be satisfied within three years from the date of appointment.

End of remuneration report.

5. Principal activities

Amplitude Energy is an upstream gas and oil exploration and production company who recognises the important role of clean, reliable and affordable energy in support of decarbonisation. Amplitude Energy's primary purpose is to secure, find, develop, produce and sell hydrocarbons. These activities are undertaken either solely or via unincorporated joint ventures. There was no significant change in the nature of these activities during the year.

6. Operating and financial review

Information on the operations and financial position of Amplitude Energy and its business strategy and prospects is set out in the Operating and Financial Review.

7. Dividends

The Directors do not recommend the payment of a dividend and no amount has been paid or declared by way of dividends since the end of the previous financial year, or to the date of this report.

8. Environmental regulation

The Company is a party to various exploration, development and production licences or permits. In most cases, the licence or permit terms specify the environmental regulations applicable to gas and oil operations in the respective jurisdiction. The Group aims to ensure that it complies with the identified regulatory requirements in each jurisdiction in which it operates. There have been no significant known breaches of the environmental obligations of the Group's licences or permits.

9. Likely developments

Other than disclosed elsewhere in the Financial Report (including the Operating and Financial Review under the heading "Outlook"), further information about likely developments in the operations of the Group and the expected results of those operations in future financial years has not been included in this report because disclosure of the information would likely result in unreasonable prejudice to the consolidated entity.

10. Directors' interests

The relevant interest of each Director in ordinary shares and options over shares issued by the parent entity as notified by the Directors to the Australian Stock Exchange in accordance with S205G(1) of the Corporations Act 2001, at the date of this report is as follows:

	Ordinary Shares	Performance Rights	Share Appreciation Rights
Mr J. Conde AO	1,904,254	Nil	Nil
Ms J. Norman	Nil	12,740,435	Nil
Mr T. Bednall	445,499	Nil	Nil
Ms E. Donaghey	1,179,000	Nil	Nil
Mr F. Tudor	634,147	Nil	Nil
Mr G. Gray AO	587,000	Nil	Nil
Mr I. Davies	243,100	Nil	Nil

11. Share options and rights

At the date of this report, there are no unissued ordinary shares of the parent entity under option. At the date of this report, there are 71,336,943 outstanding PRs and 17,452,898 SARs under the EIP approved by shareholders at the 2022 AGM.

During the financial year 11,369,795 shares were issued as a result of PRs exercised. At the date of this report, no PRs have vested and been exercised subsequent to 30 June 2025.

12. Events after financial reporting date

Refer to Note 30 of the Notes to the Financial Statements.

13. Proceedings on behalf of the company

No person has applied to the Court under section 237 of the Corporations Act 2001 for leave to bring proceedings on behalf of the Company, or to intervene in any proceedings to which the Company is a party for the purpose of taking responsibility on behalf of the Company for all or part of the proceedings.

14. Indemnification and insurance of directors and officers

14.1 Indemnification

The parent entity has agreed to indemnify the current Directors and Officers, and past Directors and Officers, of the parent entity and its subsidiaries, where applicable, against all liabilities (subject to certain limited exclusions) to persons (other than the parent entity and its subsidiaries) which arise out of the performance of their normal duties as a Director or Officer, unless the liability relates to conduct involving a lack of good faith. The parent entity has agreed to indemnify the Directors and Officers against all costs and expenses (other than certain excluded legal costs) incurred in defending an action that falls within the scope of the indemnity and any resulting payments.

14.2 Insurance premiums

During the financial year, the parent entity has paid insurance premiums in respect of Directors' and Officers' liability and legal insurance contracts for current and former Directors and Officers of the parent entity. The insurance contracts relate to costs and expenses incurred by the relevant Directors and Officers in defending proceedings, whether civil or criminal and whatever their outcome and other liabilities that may arise from their position, with exceptions including conduct involving a wilful breach of duty or improper use of information or position to gain a personal advantage. The insurance contracts outlined above do not contain details of premiums paid in respect of individual Directors or Officers of the parent entity.

15. Indemnification of auditors

To the extent permitted by law, the Company has agreed to indemnify its auditors, Ernst & Young, as part of the terms of its audit engagement agreement against claims by third parties arising from the audit (for an unspecified amount) except in the case where the claim arises because of Ernst & Young's negligent, wrongful or wilful acts or omissions. No payment has been made to indemnify Ernst & Young during or since the financial year.

16. Auditor's independence declaration

The auditor's independence declaration is set out on page 146 and forms part of the Directors' report for the financial year ended 30 June 2025.

17. Non-audit services

The amounts paid and payable to the auditor of the Group, Ernst & Young and its related practices for non-audit services provided during the year was $333,250 (2024: $62,000). The directors are satisfied that the provision of non-audit services is compatible with the general standard of independence for auditors imposed by the Corporations Act 2001. The nature and scope of each type of non-audit service provided means that auditor independence was not compromised.

18. Rounding

The Group is of a kind referred to in ASIC Corporations (Rounding in Financial/Directors' Reports) Instrument 2016/191 dated 24 March 2016 and in accordance with that Legislative Instrument, amounts in the financial report have been rounded to the nearest thousand dollars, unless otherwise stated.

This report is made in accordance with a resolution of the Directors.

Mr John C. Conde AO
Chairman
Dated at Adelaide 19 August 2025

Ms Jane L. Norman
Managing Director & CEO

Consolidated statement of comprehensive income

For the year ended 30 June 2025

	Notes	2025 $'000	2024 $'000
Revenue from gas and oil sales	2	**268,061**	219,047
Cost of sales	2	**(187,996)**	(167,321)
Gross profit		**80,065**	51,726
Other income	2	**4**	3,355
Other expenses	2	**(68,696)**	(147,440)
Finance income	18	**2,058**	3,484
Finance costs	18	**(37,688)**	(36,219)
Loss before tax		**(24,257)**	(125,094)
Income tax expense	3	**(11,603)**	(915)
Petroleum resource rent tax (expense)/benefit	3	**(5,471)**	11,900
Total tax (expense)/benefit		**(17,074)**	10,985
Loss after tax for the period attributable to shareholders		**(41,331)**	(114,109)
Other comprehensive income/(expenditure)			
Items that will be reclassified subsequently to profit or loss			
Fair value movements on interest rate derivatives accounted for in a hedge relationship		**(412)**	-
Fair value movements on exchange rate derivatives accounted for in a hedge relationship		**(4,248)**	-
Income tax effect on fair value movement on derivative financial instrument		**757**	-
Items that will not be reclassified subsequently to profit or loss			
Net loss on equity instruments recorded at fair value through other comprehensive income		**(424)**	(412)
Other comprehensive expenditure for the period net of tax	19	**(4,327)**	(412)
Total comprehensive loss for the period attributable to shareholders		**(45,658)**	(114,521)
		Cents	Cents
Basic loss per share	4	**(1.6)**	(4.3)
Diluted loss per share	4	**(1.6)**	(4.3)

The above Consolidated Statement of Comprehensive Income should be read in conjunction with the accompanying notes.

Consolidated statement of financial position

As at 30 June 2025

	Notes	2025 $'000	2024 $'000
Assets			
Current Assets			
Cash and cash equivalents	5	**62,188**	14,332
Trade and other receivables	6	**35,385**	35,209
Prepayments	7	**7,832**	6,064
Inventory	8	**6,222**	2,044
Other financial assets	20	**281**	-
Total Current Assets		**111,908**	57,649
Non-current assets			
Other financial assets	20	**1,233**	718
Contract asset	2	**1,855**	2,069
Property, plant and equipment	10	**228,568**	346,320
Intangible assets	11	**1,303**	466
Right-of-use assets	16	**5,351**	1,380
Exploration and evaluation assets	12	**210,341**	193,805
Gas and oil assets	13	**484,776**	475,152
Deferred tax asset	3	**72,972**	83,818
Deferred petroleum resource rent tax asset	3	**57,375**	61,809
Total Non-Current Assets		**1,063,774**	1,165,537
Total Assets		**1,175,682**	1,223,186
Liabilities			
Current Liabilities			
Trade and other payables	9	**39,811**	76,773
Provisions	15	**26,098**	32,920
Lease liabilities	16	**476**	847
Other financial liabilities	20	**1,736**	-
Total Current Liabilities		**68,121**	110,540
Non-current liabilities			
Provisions	15	**419,486**	433,720
Lease liabilities	16	**7,840**	927
Interest bearing loans and borrowings	17	**291,804**	253,147
Other financial liabilities	20	**5,065**	2,830
Deferred petroleum resource rent tax liability	3	**6,850**	4,376
Total Non-Current Liabilities		**731,045**	695,000
Total Liabilities		**799,166**	805,540
Net Assets		**376,516**	417,646
Equity			
Contributed equity	19	**720,645**	718,881
Reserves	19	**25,622**	27,185
Accumulated losses		**(369,751)**	(328,420)
Total Equity		**376,516**	417,646

The above Consolidated Statement of Financial Position should be read in conjunction with the accompanying notes.

Consolidated statement of changes in equity

For the year ended 30 June 2025

	Notes	Issued Capital $'000	Reserves $'000	Accumulated Losses $'000	Total Equity $'000
Balance at 1 July 2024		**718,881**	**27,185**	**(328,420)**	**417,646**
Loss for the period		-	-	**(41,331)**	**(41,331)**
Other comprehensive expenditure		-	**(4,327)**	-	**(4,327)**
Total comprehensive loss for the period		-	**(4,327)**	**(41,331)**	**(45,658)**
Transactions with owners in their capacity as owners:					
Share based payments	19	-	**4,528**	-	**4,528**
Transferred to issued capital	19	**1,764**	**(1,764)**	-	-
Balance as at 30 June 2025		**720,645**	**25,622**	**(369,751)**	**376,516**
Balance at 1 July 2023 (restated)		716,726	26,071	(214,311)	528,486
Loss for the period		-	-	(114,109)	(114,109)
Other comprehensive expenditure		-	(412)	-	(412)
Total comprehensive loss for the period		-	(412)	(114,109)	(114,521)
Transactions with owners in their capacity as owners:					
Share based payments	19	-	3,681	-	3,681
Transferred to issued capital	19	2,155	(2,155)	-	-
Balance as at 30 June 2024		718,881	27,185	(328,420)	417,646

The above Consolidated Statement of Changes in Equity should be read in conjunction with the accompanying notes.

Consolidated statement of cash flows

For the year ended 30 June 2025

	Notes	2025 $'000	2024 $'000
Cash flows from operating activities			
Receipts from customers		**270,814**	214,079
Payments to suppliers and employees		**(94,646)**	(92,844)
Payments for restoration		**(63,263)**	(207,723)
Petroleum resource rent tax (paid)/refund		**(1,451)**	195
Interest received		**1,924**	3,603
Interest paid		**(24,072)**	(17,073)
Net cash from/(used in) operating activities	5	**89,306**	(99,763)
Cash flows from investing activities			
Payments for property, plant and equipment		**(29,657)**	(46,846)
Payments for intangibles		**(1,538)**	(34)
Payments for exploration and evaluation		**(39,953)**	(15,045)
Payments for gas and oil assets		**(4,125)**	(4,555)
Net cash flows used in investing activities		**(75,273)**	(66,480)
Cash flows from financing activities			
Repayment of principal portion of lease liabilities		**(766)**	(1,457)
Proceeds from borrowings	5	**40,163**	107,000
Transaction costs associated with borrowings	5	**(5,648)**	-
Net cash flow from financing activities		**33,749**	105,543
Net increase/(decrease) in cash held		**47,782**	(60,700)
Net foreign exchange differences		**74**	(2,102)
Cash and cash equivalents at 1 July		**14,332**	77,134
Cash and cash equivalents at 30 June	5	**62,188**	14,332

The above Consolidated Statement of Cash Flows should be read in conjunction with the accompanying notes.

Amplitude energy

Notes to the Consolidated Financial Statements

Notes to the consolidated financial statements

For the year ended 30 June 2025

Corporate information

The consolidated financial report of Amplitude Energy Limited and its controlled entities ("Amplitude Energy", "the Group", or "the Company"), for the year ended 30 June 2025, was authorised for issue on 19 August 2025 in accordance with a resolution of the Directors.

Amplitude Energy Limited is a for profit company limited by shares, incorporated and domiciled in Australia, and whose shares are publicly traded on the Australian Securities Exchange.

The nature of the operations and principal activities of the Group are described in the Directors' Statutory Report and Note 1.

Basis of preparation

The financial report is a general-purpose financial report, which has been prepared in accordance with the requirements of the Corporations Act 2001, Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board ("AASB") and International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board.

The financial report has also been prepared on a historical cost basis, except for equity instruments measured at fair value through other comprehensive income and other items as set out in the notes indicated as measured at fair value through profit and loss.

The financial report is presented in Australian dollars. Under the option available to the Group under ASIC Corporations (Rounding in Financial/Directors' Reports) Instrument 2016/191, all values are rounded to the nearest thousand dollars ($'000), unless otherwise stated. Australian dollars is the functional currency of Amplitude Energy Limited and all of its subsidiaries. Transactions in foreign currencies are initially recorded in the functional currency of the transacting entity at the exchange rates ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies at the reporting date are translated at the rates of exchange prevailing at that date. Exchange differences in the consolidated financial statements are taken to the income statement.

East Coast Supply Project

On 24 March 2025, the Group announced it had entered into a binding joint venture agreement ("IJVA") with subsidiaries of O.G. Energy regarding the development of the East Coast Supply Project ("ECSP") on a 50/50 basis. The IJVA established an unincorporated joint venture between subsidiaries of Amplitude Energy and O.G Energy to progress the ECSP in the interim period between the signing of the IJVA and completion of the O.G. Energy's acquisition of Mitsui E&P Australia's interest in the Otway Basin joint ventures ("Otway Sale Transaction"). The IJVA contains agreed terms of O.G. Energy's participation in the ECSP, including that it will participate in 50% of point-forward project costs from the 1 March 2025, and reimburse Amplitude Energy for 50% of all historical ECSP project costs spent. The reimbursement is structured in the form of a cost carry on ECSP expenditure, and accounted for as a farm-in arrangement, commencing from the completion of the Otway Sale Transaction on 31 July 2025. These costs, totalling $27.8 million, will be repaid by O.G. Energy by fully funding future project costs until historical costs have been recovered. As part of this transaction, an agreement between Amplitude Energy and O.G. Energy's relevant subsidiaries has also been executed to align each party's interest in the VIC/P44 title (containing the Annie gas discovery).

VIC/P76 farm-in

On 24 March 2025, the Group announced it had entered into a farm-in agreement with O.G. Energy whereby O.G. Energy agreed to contribute $0.5 million in exchange for a 50% interest in VIC/P76. Upon completion of the Otway Sale Transaction, the transaction will be accounted for as a farm-in arrangement, and the consideration received of $0.5 million will be recognised as a reduction in costs previously capitalised in the VIC/P76 exploration and evaluation assets. After completion, the Group will account for the joint arrangement as a joint operation and recognise their share of assets and liabilities.

Funding overview

The Group holds cash balances of $62.2 million and has drawn debt of $305.2 million as at the end of the reporting period with a further $169.7 million committed, available and undrawn as at 30 June 2025, under a senior secured reserve based loan facility with an expected maturity date of September 2029. The Company also has a further $16.4 million available under the Company's working capital facility. All debt covenants have been complied with to the date of this report.

Going concern basis

The consolidated financial statements have been prepared on the basis that the Group is a going concern, which contemplates continuity of normal operations and the realisation of assets and settlement of liabilities in the ordinary course of business. The directors have formed the view that there are reasonable grounds to believe that the Group will continue as a going concern.

Basis of consolidation

The consolidated financial statements are those of the consolidated entity, comprising Amplitude Energy Limited ("the parent entity") and its controlled entities ("Amplitude Energy" or "the Group").

The financial statements of subsidiaries are prepared for the same reporting period as the parent entity, using consistent accounting policies. All inter-company balances and transactions, income and expenses and profit and losses arising from intra-group transactions, have been eliminated in full. Subsidiaries are consolidated from the date on which the Group gains control of the subsidiary and cease to be consolidated from the date on which the Group ceases to control the subsidiary.

Significant accounting judgements, estimates and assumptions

In the process of applying the Group's accounting policies, management is required to make judgements, estimates and assumptions that affect the reported amounts in the financial statements. Judgements, estimates and assumptions which are material to specific notes of the financial statements are below:

Note 3	Income tax	Note 15	Provisions
Note 13	Gas and oil assets	Note 22	Interests in joint arrangements
Note 14	Impairment	Note 27	Share based payments

Judgements, estimates and assumptions which are material to the overall financial statements are below:

Significant accounting judgements, estimates and assumptions

Determination of recoverable hydrocarbons
Estimates of recoverable hydrocarbons impact the asset impairment assessment, depreciation and amortisation rates and decommissioning and restoration provisions.

Estimates of recoverable hydrocarbons are evaluated and reported by qualified petroleum reserves and resources evaluators in accordance with the ASX Listing Rules and definitions and guidelines in the Society of Petroleum Engineers (SPE) 2018 Petroleum Resources Management System (PRMS).

Recoverable hydrocarbon estimates may change, from time to time, if any of the forecast assumptions are revised.

Climate change
In preparing the financial report, management has considered the impact of climate change and current climate-related legislation.

The focus of the Company's strategy on conventional gas production, located close to market in Southeast Australia, is conducive to the supply of lower emissions intensity gas. The Company measures and reports its emissions and emissions offsets to maintain its carbon neutral[13] position as certified by Climate Active, a partnership between the Australian Government and Australian businesses to drive voluntary climate action, whilst also seeking to reduce its gross emissions. These results are published annually in the Company's Sustainability Report and are aligned with the Financial Stability Board's Task Force on Climate-Related Financial Disclosures recommendations on climate-related financial disclosures.

The Company continues to monitor climate-related policy and its impact on the financial report. The current impacts of climate change include estimates of a range of economic and climate-related scenarios. This includes market supply and demand profiles, carbon emissions profiles, legal impacts and technological impacts. These are factored into discount rates, commodity price forecasts, and demand and supply profiles, all of which are impacted by the global demand profile of the economy as a whole. The estimates and forecasts used by the Company are in accordance with current climate-related legislation and policy.

The impact of climate change is considered in the significant judgements and key estimates in a number of areas in the Company's financial report including:

- asset carrying values (exploration and evaluation assets, gas and oil assets) through determination of valuations considered for impairment – refer note 14;
- restoration obligations, including the timing of such activities – refer note 15; and
- deferred taxes, primarily related to asset carrying values and restoration obligations – refer note 3.

The Group continues to monitor climate-related policy and its impact on the Financial Report.

New accounting standards and interpretations

New standards, interpretations and amendments thereof, adopted by the Group

The Group has adopted all the new and revised Standards and Interpretations issued by the Australian Accounting Standards Board (the AASB) that are relevant to their operations and effective for the 2025 financial year.

Accounting standards, amendments and interpretations applicable on 1 July 2024 have had no material impact on the Group's financial statements.

Accounting standards and interpretations issued but not yet effective

The accounting standards and interpretations that have recently been issued or amended but are not yet effective and have not been adopted by the Group for the annual reporting period ending 30 June 2025, are outlined below:

[13] Amplitude Energy has been certified by Climate Active as a carbon neutral organisation for its Scope 1, Scope 2 and what Amplitude Energy defines as it's relevant Scope 3 emissions. See page 50 for Scope 3 definition.

AASB 2024-2 Amendments to AASB 7 and AASB 9 – Classification and Measurement of Financial Instruments

Description	The amendments clarify the following: • That a financial liability is derecognised on the 'settlement day', being when the related obligation is discharged, cancelled, expires or the liability otherwise qualifies for derecognition • How to assess the contractual cash flow characteristics of financial assets that include environmental, social and governance (ESG)-linked features • The treatment of non-recourse assets and contractually linked instruments • Requirements for additional disclosures for financial assets and liabilities with contractual terms that reference a contingent event (including those that are ESG-linked), and equity instruments classified at fair value through other comprehensive income
Impact on Consolidated Financial Statements	The impact of this accounting standard amendment on the Group is yet to be determined.
Application date of the standard	1 January 2026

AASB 18 – Presentation and Disclosure in Financial Statements

Description	AASB 18 replaces AASB 101 Presentation of Financial Statements and introduces significant changes to the presentation and disclosure requirements of financial statements. Key changes include the introduction of defined subtotals in the statement of profit or loss, mandatory disclosure of management-defined performance measures (MPMs), and enhanced requirements for the aggregation and disaggregation of information to improve transparency and comparability.
Impact on Consolidated Financial Statements	The impact of this accounting standard amendment on the Group is yet to be determined.
Application date of the standard	1 January 2027

Australian sustainability reporting standards

The AASB issued the final Australian Sustainability Reporting Standards (ASRS) in September 2024, following the Royal Assent of the climate-related financial disclosures legislation *Treasury Laws Amendment (Financial Market Infrastructure and Other Measures) Act 2024*. The Act mandates relevant entities to disclose their climate-related plans, financial risks and opportunities, in accordance with ASRS made by the AASB.

The first ASRS were also issued in September 2024 by the AASB and comprise:

- ASRS 1 General Requirements for Disclosure of Climate-related Financial Information
- ASRS 2 Climate-related Financial Disclosures

The Group has performed a gap assessment from current reporting to the requirements of the new standards noted above to ensure appropriate disclosures are made for the period commencing 1 July 2025.

Notes to the financial statements

The notes include information which is required to understand the financial statements and is material and relevant to the operations, financial position and performance of the Group. They include applicable accounting policies applied and significant judgements, estimates and assumptions made. Specific accounting policies are disclosed in the respective notes to the financial statements. The notes are organised into the following sections:

Group performance	Provides additional information regarding financial statement lines that are most relevant to explaining the Group's operating performance during the period.
Working capital	Provides additional information regarding financial statement lines that are most relevant to explaining the working capital assets used to contribute to generating the Group's operating performance during the period.
Capital employed	Provides additional information regarding financial statement lines that are most relevant to explaining the capital investments made that contribute to the ability for the Group to generate its operating result during the period and liabilities incurred as a result.
Funding and risk management	Provides additional information regarding financial statement lines that are most relevant to explaining the Group's funding sources. This section also provides information relating to the Group's exposure to various financial risks, its impact on the financial position and performance of the Group and how these risks are managed.
Group structure	Summarises how the group structure affects the financial position and performance of the Group as a whole.
Other information	Includes other information that is disclosed to comply with relevant accounting standards and other pronouncements, but is not directly related to the individual line items in the financial statements.

Group performance

1. Segment reporting

Identification of reportable segments and types of activities

The Group has identified its reportable segments to be Southeast Australia, Cooper Basin (both based on the nature and geographic location of its assets) and Corporate and Other. This forms the basis of internal Group reporting to the CEO & Managing Director who is the chief operating decision maker for the purpose of assessing performance and allocating resources between each segment. Revenue and expenses are allocated by way of their natural expense and income category. Other prospective opportunities are also considered from time to time and, if they are secured, will then be attributed to the segment where they are located, or a new segment will be established.

The following are reportable segments:

Southeast Australia
The Southeast Australia segment primarily consists of the operated Sole producing gas assets and the OGPP, the operated Casino Henry Netherby producing gas assets and the operated Athena Gas Plant. Revenue is derived from the sale of gas and condensate to six contracted customers and via spot sales. The segment also includes exploration and evaluation and care and maintenance activities ongoing in the Gippsland and Otway basins.

Cooper Basin
This segment comprises production and sale of crude oil in the Group's permits within the Cooper Basin, along with exploration and evaluation of additional oil targets. Revenue is derived from the sale of crude oil to Santos Limited and Beach Energy (Operations) Limited, the two participants in the South Australia Cooper Basin joint venture.

Corporate and Other
The Corporate residual component includes the revenue and costs associated with the running of the business and includes items which are not directly allocable to the other segments.

Accounting policies and inter-segment transactions

The accounting policies used by the Group in reporting segments internally is the same as those contained in the financial statements.

	Southeast Australia $'000	Cooper Basin $'000	Corporate and Other $'000	Consolidated $'000
30 June 2025				
Revenue from gas and oil sales to external customers	**256,074**	**11,987**	**-**	**268,061**
Total revenue	**256,074**	**11,987**	**-**	**268,061**
Production expenses (excluding depreciation and amortisation)	**(72,486)**	**(5,545)**	**-**	**(78,031)**
Segment result before interest, tax, depreciation, amortisation and restoration, exploration and evaluation expense and impairment	**216,005**	**6,408**	**(60,063)**	**162,350**
Restoration expense	**(9,848)**	**-**	**-**	**(9,848)**
Depreciation and amortisation	**(107,695)**	**(2,451)**	**(3,291)**	**(113,437)**
Exploration and evaluation expense	**(304)**	**-**	**-**	**(304)**
Impairment	**(27,388)**	**-**	**-**	**(27,388)**
Net finance costs	**(9,652)**	**(78)**	**(25,900)**	**(35,630)**
Profit/(loss) before tax	**61,118**	**3,879**	**(89,254)**	**(24,257)**
Income tax expense	**-**	**-**	**(11,603)**	**(11,603)**
Petroleum resource rent tax expense	**(5,471)**	**-**	**-**	**(5,471)**
Net profit/(loss) after tax	**55,647**	**3,879**	**(100,857)**	**(41,331)**
Segment assets	**389,163**	**36,111**	**750,408**	**1,175,682**
Segment liabilities	**478,510**	**4,602**	**316,054**	**799,166**
Additions of non-current assets[1]				
Exploration and evaluation assets	**43,288**	**940**	**-**	**44,228**
Gas and oil assets	**73,422**	**1,180**	**-**	**74,602**
Property, plant and equipment	**(71,913)**	**-**	**5,110**	**(66,803)**
Intangibles	**-**	**-**	**1,595**	**1,595**
Total additions of non-current assets	**44,797**	**2,120**	**6,705**	**53,622**

[1]Additions include the movement in the restoration assets

1. Segment reporting continued

	Southeast Australia $'000	Cooper Basin $'000	Corporate and Other $'000	Consolidated $'000
30 June 2024				
Revenue from gas and oil sales to external customers	199,142	19,905	-	219,047
Total revenue	199,142	19,905	-	219,047
Production expenses (excluding depreciation and amortisation)	(62,448)	(8,616)	-	(71,064)
Segment result before interest, tax, depreciation, amortisation and restoration, exploration and evaluation expense and impairment	102,049	11,300	(16,198)	97,151
Restoration expense	(86,790)	-	-	(86,790)
Depreciation and amortisation	(92,837)	(3,601)	(2,361)	(98,799)
Exploration and evaluation expense	(1,605)	(2,047)	-	(3,652)
Impairment	(269)	-	-	(269)
Net finance costs	(17,407)	(248)	(15,080)	(32,735)
Profit/(loss) before tax	(96,859)	5,404	(33,639)	(125,094)
Income tax expense	-	-	(915)	(915)
Petroleum resource rent tax benefit	11,900	-	-	11,900
Net profit/(loss) after tax	(84,959)	5,404	(34,554)	(114,109)
Segment assets	467,825	32,263	723,098	1,223,186
Segment liabilities	707,559	4,634	93,347	805,540
Additions of non-current assets[1]				
Exploration and evaluation assets	11,318	3,002	-	14,320
Gas and oil assets	(6,508)	2,869	-	(3,639)
Property, plant and equipment	4,379	-	354	4,733
Intangibles	-	-	482	482
Total additions of non-current assets	9,189	5,871	836	15,896

[1]Additions include the movement in the restoration assets

In 2025, contracted revenue from three customers amounted to $51.8 million, $45.5 million and $17.3 million respectively in the Southeast Australia segment. In 2024, contracted revenue from three customers amounted to $79.0 million, $42.5 million and $21.7 million respectively in the Southeast Australia segment.

2. Revenues and expenses

Revenues

Revenue from gas and oil sales

	Notes	2025 $'000	2024 $'000
Revenue from contracts with customers			
Gas revenue from contracts with customers		**256,074**	199,154
Oil revenue from contracts with customers		**11,987**	19,893
Total revenue from contracts with customers		**268,061**	219,047
Other income			
Lease adjustment		**-**	2,614
Other income		**4**	741
Total other income		**4**	3,355

Contract assets related to contracts with customers

The Group has recognised the following assets related to contracts with customers.

Opening balance	**2,069**	2,323
Unwind of contract asset	**(214)**	(254)
Closing balance	**1,855**	2,069

Expenses

Cost of sales

Production expenses	**(67,779)**	(59,212)
Royalties	**(998)**	(1,558)
Third-party product purchases, transport and trading costs	**(10,130)**	(9,389)
Amortisation of gas and oil assets	**(64,468)**	(58,214)
Depreciation of property, plant and equipment	**(45,496)**	(38,043)
Inventory movement	**875**	(905)
Total cost of sales	**(187,996)**	(167,321)

	Notes		
Other expenses			
Selling expense		**(1,139)**	(1,100)
General administration		**(11,661)**	(14,472)
Depreciation of property, plant and equipment		**(1,992)**	(745)
Amortisation of intangibles		**(701)**	(534)
Depreciation of right-of-use assets		**(780)**	(1,263)
Care and maintenance		**(2,230)**	(8,102)
Restoration expense		**(9,848)**	(86,790)
Exploration and evaluation expense	12	**(304)**	(3,652)
Impairment expense	14	**(27,388)**	(269)
Expected credit losses of trade and other receivables		**(1,150)**	(23,546)
Other (including new ventures)		**(11,503)**	(6,967)
Total other expenses		**(68,696)**	(147,440)

Employee benefits expense included in general administration	2025 $'000	2024 $'000
Director and employee benefits	**(43,098)**	(37,246)
Share based payments	**(4,528)**	(3,681)
Superannuation expense	**(3,227)**	(2,823)
Total employee benefits expense (gross)	**(50,853)**	(43,750)

2. Revenues and expenses continued

Accounting policy

Revenue from contracts with customers

Revenue from contracts with customers is recognised at the point in time when control of the natural gas, liquids or crude oil is transferred to the customer, at an amount that reflects the consideration to which the Group expects to be entitled in exchange for those goods. This is generally when the product is transferred to the delivery point specified in the individual customer contract. The Group's performance obligations are considered to relate only to the sale of the natural gas, liquids or crude oil, with each GJ of natural gas or barrel of liquids or crude oil considered to be a separate performance obligation under the contractual arrangements in place.

The Group has concluded that it is the principal in all of its revenue arrangements since it controls the goods before transferring them to the customer. Under the terms of the relevant joint operating arrangements, the Group is entitled to its participating share in the natural gas, liquids or crude oil, based on the Group's entitlement interest. Revenue from contracts with customers is recognised based on the actual volumes sold to customers.

The Group's sales of natural gas are predominantly based on contracted prices, while crude oil and liquids transactions are priced based on crude oil market prices, adjusted for a quality differential.

Contract assets

A contract asset is recognised for gas contracts that have variable selling prices, which are allocated proportionately to all the performance obligations over the life of the contract. Contract assets unwind as "revenue from contracts with customers" with reference to the performance obligation over the life of the contract.

3. Income tax

	2025 $'000	2024 $'000
Consolidated Statement of Comprehensive Income		
Current income tax		
Current year	-	-
	-	-
Deferred income tax		
Origination and reversal of temporary differences	**(9,218)**	(66,835)
(Utilisation)/recognition of tax losses	**(2,385)**	65,920
	(11,603)	(915)
Income tax expense	**(11,603)**	(915)
Current petroleum resource rent tax		
Current year	**1,437**	155
	1,437	155
Deferred petroleum resource rent tax		
Origination and reversal of temporary differences	**(6,908)**	11,745
	(6,908)	11,745
Petroleum resource rent tax (expense)/benefit	**(5,471)**	11,900
Total tax (expense)/benefit	**(17,074)**	10,985
Reconciliation between tax expense and pre-tax net profit		
Accounting loss before tax from continuing operations	**(24,257)**	(125,094)
Income tax based on the domestic corporation tax rate of 30% (2024: 30%)	**7,277**	37,528
(Increase)/decrease in income tax expense due to:		
Non-deductible expenditure	**(1,951)**	(1,478)
Recognition of royalty related income tax benefits/(expense)	**1,206**	(3,512)
Movement in deferred tax assets not recognised	**(18,576)**	-
Derecognition of deferred tax asset	**-**	(33,285)
Other	**441**	(168)
Income tax expense	**(11,603)**	(915)
Petroleum resource rent tax (expense)/benefit	**(5,471)**	11,900
Total tax (expense)/benefit	**(17,074)**	10,985

Tax consolidation

Amplitude Energy Limited and its 100% owned Australian resident subsidiaries are consolidated for Australian income tax purposes, with Amplitude Energy Limited being the head entity of the tax consolidated group. Members of the Group entered into a tax sharing arrangement in order to allocate income tax expense to the wholly-owned subsidiaries. In addition, the agreement provides for the allocation of income tax liabilities between the entities based on the separate taxpayer within a group approach, should the head entity default on its tax payment obligations.

Members of the tax consolidated group have entered into a tax funding agreement. The tax funding agreement requires members of the tax consolidated group to make contributions to the head company for tax liabilities and deferred tax balances arising from transactions occurring after the implementation of tax consolidation. Contributions are payable following the payment of the liabilities by Amplitude Energy Limited. The assets and liabilities arising under the tax funding agreement are recognised as inter-company assets and liabilities with a consequential adjustment to income tax expense or benefit. In addition, the agreement provides for the allocation of income tax liabilities between the entities should the head entity default on its tax payment obligations or upon leaving the Group. The current and deferred tax amounts are measured in a systematic manner that is consistent with the broad principles in AASB 112 *Income Taxes*.

Unrecognised temporary differences

At 30 June 2025, the Group has a $51.9 million unrecognised deferred tax asset in respect of the Sole gas field decommissioning (2024: $33.3 million).

3. Income tax continued

Franking tax credits

At 30 June 2025 the parent entity had franking tax credits of $42.9 million (2024: $42.9 million). The fully franked dividend equivalent is $142.9 million (2024: $142.9 million).

Petroleum resource rent tax

Amplitude Energy Limited has recognised a deferred tax asset for PRRT of $57.4 million (2024: $61.8 million) and a deferred tax liability for PRRT of $6.9 million (2024: $4.4 million).

Income tax losses

(a) Revenue Losses

A deferred tax asset has been recognised for the year ended 30 June 2025 of $157.3 million (2024: $161.6 million).

(b) Capital Losses

Amplitude Energy has not recognised a deferred tax asset for Australian income tax capital losses of $15.5 million (2024: $15.5 million) on the basis that it is not probable that the carried forward capital losses will be utilised against future assessable capital profits.

	Consolidated Statement of Financial Position		Consolidated Statement of Comprehensive Income	
	2025 $'000	2024 $'000	**2025 $'000**	2024 $'000
Deferred corporate income tax				
Deferred income tax at 30 June relates to:				
Deferred tax liabilities				
Trade and other receivables	**-**	21	**(21)**	(36)
Gas and oil assets	**102,575**	90,321	**12,254**	(7,452)
Exploration and evaluation	**48,638**	53,069	**(4,431)**	4,429
Property, plant and equipment	**12,604**	36,845	**(24,241)**	4,405
Other	**18,372**	18,083	**289**	1,614
	182,189	198,339	**(16,150)**	2,960
Deferred tax assets				
Leases	**2,495**	532	**1,963**	(2,663)
Provisions	**92,720**	117,252	**(24,532)**	(61,038)
Tax losses	**157,301**	161,577	**(4,276)**	65,372
Other	**2,645**	2,796	**(151)**	374
	255,161	282,157	**(26,996)**	2,045
Deferred tax expense			**(10,846)**	(915)
Deferred tax asset from corporate tax	**72,972**	83,818		
Deferred tax from PRRT				
Deferred PRRT at 30 June relates to:				
Deferred tax liabilities				
Gas and oil assets	**6,850**	4,376	**2,474**	(3,103)
Deferred tax liability from PRRT	**6,850**	4,376		
Deferred tax assets				
Gas and oil assets	**57,375**	61,809	**(4,434)**	8,642
Deferred tax asset from PRRT	**57,375**	61,809		
Total PRRT deferred tax (expense)/benefit			**(6,908)**	11,745

3. Income tax continued

Accounting policy

Current tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities, based on tax rates and tax laws that are enacted, or substantively enacted, by the reporting date.

Deferred tax is recognised on all temporary differences, except for:

- when deferred tax arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss and does not give rise to equal taxable and deductible temporary differences; and
- the taxable temporary difference is associated with investments in subsidiaries, associates or interests in joint ventures, and the timing of the reversal of the temporary difference can be controlled and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred income tax assets are recognised for all deductible temporary differences, carry-forward of unused tax assets and unused tax losses, to the extent that it is probable that future taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilised.

The carrying amount of deferred income tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilised. Unrecognised deferred income tax assets are reassessed at each reporting date and are recognised to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

Deferred income tax assets and liabilities are measured at the tax rates that were expected to apply to the year when the asset is realised or the liability is settled, based on tax rates and tax laws that have been enacted or substantively enacted by the reporting date.

Income taxes relating to items recognised directly in equity are recognised in equity and not in profit or loss.

Deferred tax assets and deferred tax liabilities are offset only if a legally enforceable right exists to offset current tax assets against current tax liabilities and the deferred tax asset and liabilities relate to the same taxable entity and the same taxation authority.

Petroleum Resource Rent Tax

For PRRT purposes, the impact of future augmentation on expenditure is included in the determination of future taxable profits when assessing the extent to which a deferred tax asset can be recognised in the statement of financial position. Deferred tax assets are reduced to the extent that it is no longer probable that the related tax benefit will be realised.

Goods and Services Taxes ("GST")

Revenues, expenses and assets are recognised net of the amount of GST. Receivables and payables are stated inclusive of the amount of GST receivable or payable. The net amount of GST recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the Consolidated Statement of Financial Position. Commitments and contingencies are disclosed net of the amount of GST recoverable from, or payable to, the taxation authority.

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

Significant accounting judgements, estimates and assumptions

The Group has a Tax Risk Management Framework which outlines how the direct and indirect tax obligations of Amplitude Energy Limited are met from an operational, governance and tax risk management perspective.

Management judgements are made in relation to the types of arrangements considered to be a tax on income, including PRRT, in contrast to an operating cost.

Judgement is also made in assessing whether deferred tax assets and certain deferred tax liabilities are recognised on the Consolidated Statement of Financial Position. Deferred tax assets, including those arising from un-recouped tax losses, capital losses, and temporary differences arising from the PRRT legislation, are recognised only where it is considered more probable they will be recovered, which is dependent on the generation of sufficient future taxable profits. Future taxable profits are estimated by using Board approved internal budgets and forecasts.

Judgements are also required about the application of income tax legislation. These judgements and assumptions are subject to risk and uncertainty, hence there is a possibility changes in circumstances will alter expectation, which may impact the amount of deferred tax assets and deferred tax liabilities recognised on the Consolidated Statement of Financial Position and the amount of other tax losses and temporary differences not yet recognised.

In such circumstances, some or all of the carrying amounts of recognised deferred tax assets and liabilities may require adjustment, resulting in a corresponding credit or charge to the Consolidated Statement of Comprehensive Income.

Notes to the consolidated financial statements
For the year ended 30 June 2025

4. Earnings per share

The following reflects the net loss and share data used in the calculations of earnings per share:

	2025 $'000	2024 $'000
Net loss after tax attributable to shareholders	**(41,331)**	(114,109)

	2025 Thousands	2024 Thousands
Weighted average number of ordinary shares used in calculating basic earnings per share	**2,646,035**	2,636,076
Dilutive performance rights and share appreciation rights[1]	**-**	-
Weighted average number of ordinary shares used in calculating dilutive earnings per share	**2,646,035**	2,636,076
Basic loss per share for the period (cents per share)	**(1.6)**	(4.3)
Diluted loss per share for the period (cents per share)	**(1.6)**	(4.3)

[1] The weighted average number of potentially dilutive shares at 30 June 2025 is 69.1 million (2024: 47.3 million)

At 30 June 2025 there exist performance rights and share appreciation rights that if vested, would result in the issue of additional ordinary shares over the next three years. In the current period, these potential ordinary shares are considered antidilutive as their conversion to ordinary shares would reduce the loss per share. Accordingly, they have been excluded from the dilutive earnings per share calculation. There have been no other transactions involving ordinary shares, or potential ordinary shares, between the reporting date and the date of completion of these financial statements.

Accounting policy

Basic earnings per share are calculated as net profit attributable to shareholders divided by the weighted average number of ordinary shares. Diluted earnings per share is calculated as net profit attributable to shareholders divided by the weighted average number of ordinary shares and dilutive potential ordinary shares.

Working capital

5. Cash and cash equivalents and term deposits

	2025 $'000	2024 $'000
Current Assets		
Cash at bank and in hand	**62,188**	14,332
Cash and cash equivalents	**62,188**	14,332

Reconciliation of net profit to net cash flows from operating activities

	2025 $'000	2024 $'000
Net loss after tax	**(41,331)**	(114,109)
Add/(deduct) non-cash items:		
Amortisation of gas and oil assets	**64,468**	58,214
Depreciation of property, plant and equipment	**47,488**	38,788
Amortisation of intangibles	**701**	534
Depreciation of right-of-use assets	**780**	1,263
Impairment expense	**27,388**	269
Exploration and evaluation expense	**304**	3,652
Restoration expense	**9,848**	86,790
Share based payments	**4,528**	3,681
Finance costs	**14,044**	19,174
Foreign exchange (gain)/loss	**(74)**	2,102
Other non-cash movements	**1,856**	23,408
Net cash from operating activities before changes in assets or liabilities	**130,000**	123,766
Add/(deduct) changes in operating assets or liabilities:		
Decrease/(Increase) in trade and other receivables	**(2,020)**	(29,707)
(Increase)/decrease in inventories	**(4,178)**	138
Increase in prepayments	**(1,804)**	(305)
Decrease/(Increase) in net deferred tax asset	**18,511**	(10,830)
Increase/(Decrease) in trade and other payables	**(9,032)**	29,778
Decrease in provisions	**(42,171)**	(212,603)
Net cash from operating activities	**89,306**	(99,763)

Reconciliation of liabilities arising from financing activities

	Borrowings		Lease Liabilities	
	2025 $'000	2024 $'000	2025 $'000	2024 $'000
Balance at beginning of period	**253,147**	143,956	**1,774**	10,649
Financing cash flows[1]	**34,515**	107,000	**(766)**	(1,457)
Other	**4,142**	2,191	**7,308**	(7,418)
Balance at end of period	**291,804**	253,147	**8,316**	1,774

[1] Financing cash flows consist of: for borrowings, the net amount of proceeds from borrowings and transaction costs associated with borrowings, and for lease liabilities, repayment of lease liabilities in the statement of cash flows.

Accounting policy

Cash and cash equivalents in the Consolidated Statement of Financial Position and the Statement of Cash Flows comprise cash at bank.

6. Trade and other receivables

	2025 $'000	2024 $'000
Current Assets		
Trade and other receivables	**11,106**	13,243
Accrued revenue	**24,074**	21,895
Interest receivable	**205**	71
	35,385	35,209

Expected credit losses in respect of trade and other receivables is set out in Note 20.

Accounting policy

Trade receivables are non-interest bearing and generally have an average of 31 day terms. Trade receivables are initially recognised at the transaction price as defined by AASB 15 *Revenue from Contracts with Customers* and subsequently carried at amortised cost less any allowances for expected credit loss. An allowance for expected credit loss is recognised using the simplified approach which permits the use of the lifetime expected loss provision for all trade receivables. Bad debts are written off when identified.

7. Prepayments

	2025 $'000	2024 $'000
Insurance	**3,265**	3,752
Prepaid cash calls to joint arrangements	**1,108**	1,747
Other prepayments	**3,459**	565
	7,832	6,064

8. Inventory

	2025 $'000	2024 $'000
Petroleum products	**1,301**	426
Spares and parts	**4,921**	1,618
	6,222	2,044

All inventory items are carried at cost in the current and previous financial years.

Accounting policy

Inventories are carried at the lower of their cost or net realisable value. Inventories held by the Group are in respect of unsold oil and condensate, and spares and parts involved in gas processing operations. Items held as insurance or capital spares are treated as part of property, plant and equipment.

9. Trade and other payables

	2025 $'000	2024 $'000
Current		
Trade payables	**16,880**	29,531
Accruals (capital and operating expenditure)	**22,931**	27,242
Deferred consideration[1]	**-**	20,000
	39,811	76,773

[1] Deferred consideration represents the fixed payments due 12 and 24 months after the 28 July 2022 financial close of the OGPP acquisition. The Group records deferred consideration at the present value of consideration payments.

Accounting policy

Trade payables are non-interest bearing and carried at amortised cost. The amounts represent liabilities for goods and services provided during the financial year, but not yet settled at the balance sheet date. Accruals represent unbilled goods or services.

Capital employed

10. Property, plant and equipment

	Production assets		Corporate assets		Total	
	2025 $'000	2024 $'000	**2025 $'000**	2024 $'000	**2025 $'000**	2024 $'000
Reconciliation of carrying amounts at beginning and end of period:						
Carrying amount at beginning of period	**343,718**	377,382	**2,602**	2,993	**346,320**	380,375
Additions	**8,009**	5,607	**5,110**	354	**13,119**	5,961
Write-off	**(3,461)**	-	**-**	-	**(3,461)**	-
Restoration	**(79,922)**	(1,228)	**-**	-	**(79,922)**	(1,228)
Depreciation	**(45,496)**	(38,043)	**(1,992)**	(745)	**(47,488)**	(38,788)
Carrying amount at end of period	**222,848**	343,718	**5,720**	2,602	**228,568**	346,320
Cost	**348,624**	423,996	**9,259**	8,468	**357,883**	432,464
Accumulated depreciation	**(125,776)**	(80,278)	**(3,539)**	(5,866)	**(129,315)**	(86,144)
Carrying amount at end of period	**222,848**	343,718	**5,720**	2,602	**228,568**	346,320

Accounting policy

Property, plant and equipment comprises office and IT equipment, leasehold improvements, the OGPP and the Athena Gas Plant, and are stated at historical cost less accumulated depreciation and any accumulated impairment losses (refer to Note 14 for a description of the Company's impairment policy). Historical cost includes expenditure that is directly attributable to the acquisition of the items. Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. Repairs and maintenance are recognised in the Consolidated Statement of Comprehensive Income, as incurred.

Depreciation on corporate assets is calculated at between 7.5% and 37.5% per annum using the straight line method over the respective asset's estimated useful live. Production assets are depreciated on a units of production basis. The assets' residual values and useful lives are reviewed and adjusted, if appropriate, at each reporting date.

An item of property, plant and equipment is derecognised upon disposal, or when no further future economic benefits are expected from its use. Any gains or losses arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the net carrying amount of the asset) is included in the Consolidated Statement of Comprehensive Income.

11. Intangible assets

	2025 $'000	2024 $'000
Reconciliation of carrying amounts at beginning and end of period:		
Carrying amount at beginning of period	**466**	967
Additions	**1,595**	482
Disposals	**(57)**	(449)
Amortisation	**(701)**	(534)
Carrying amount at end of period	**1,303**	466
Cost	**6,717**	4,427
Accumulated amortisation	**(5,414)**	(3,961)
Carrying amount at end of period	**1,303**	466

Accounting policy

Intangible assets comprise software and carbon credits, and are stated at historical cost less accumulated amortisation and any accumulated impairment losses where applicable. Historical cost includes expenditure that is directly attributable to the acquisition of the items. Intangible assets are determined to have a finite useful life and are amortised over their useful lives and tested for impairment whenever there is an indicator of impairment. Amortisation on intangibles is calculated at 20% per annum using the straight line method. The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each reporting date.

12. Exploration and evaluation assets

	Notes	**2025 $'000**	2024 $'000
Reconciliation of carrying amounts at beginning and end of period			
Carrying amount at beginning of period		**193,805**	184,569
Additions		**44,340**	14,545
Restoration		**(112)**	(225)
Impairment	14	**(27,388)**	(269)
Exploration and evaluation expense		**(304)**	(3,652)
Transfer to gas and oil assets		**-**	(1,163)
Carrying amount at end of period[1]		**210,341**	193,805

[1] Recoverability is dependent on the successful development and commercial exploration or sale of the respective areas of interest.

Accounting policy

Exploration and evaluation expenditure include costs incurred in the search for hydrocarbon resources and determining the commercial viability in each identifiable area of interest. Exploration and evaluation expenditure is accounted for in accordance with the successful efforts method and is capitalised to the extent that:

i. the rights to tenure of the areas of interest are current and the Group controls the area of interest in which the expenditure has been incurred; and
ii. such costs are expected to be recouped through successful development and exploration of the area of interest, or alternatively by its sale; or
iii. exploration and evaluation activities in the area of interest have not at the reporting date:
   a. reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves; and
   b. active and significant operations in, or in relation to, the area of interest are continuing.

An area of interest refers to an individual geological area where the potential presence of a natural gas or an oil field is considered favourable or has been proven to exist and, in most cases, comprises an individual prospective gas or oil field.

Exploration and evaluation expenditure which does not satisfy these criteria is written off. Specifically, costs carried forward in respect of an area of interest that is abandoned, or costs relating directly to the drilling of an unsuccessful well, are written off in the year in which the decision to abandon is made, or the results of drilling are concluded. The success or otherwise of a well is determined by reference to the drilling objectives for that well. For successful wells, the well costs remain capitalised on the Consolidated Statement of Financial Position as long as sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. Any appraisal costs relating to determining commercial feasibility are also capitalised as exploration and evaluation assets. A regular review is undertaken of each area of interest to determine the appropriateness of continuing to carry forward costs in relation to that area of interest.

Where facts and circumstances suggest that the carrying amount exceeds the recoverable amount, or where one of the specific factors set out in i-iii above are no longer met, the Group will test for impairment in accordance with the impairment policy stated in Note 14.

Where an ownership interest in an exploration and evaluation asset is exchanged for another, the transaction is recognised by reference to the carrying value of the original interest. Any cash consideration paid, including transaction costs, is accounted for as an acquisition of exploration and evaluation assets. Any cash consideration received, net of transaction costs, is treated as a recoupment of costs previously capitalised with any excess accounted for as a gain on disposal of non-current assets. Where a discovered gas or oil field enters the development phase, the accumulated exploration and evaluation expenditure is tested for impairment and then transferred to gas and oil assets.

13. Gas and oil assets

	Notes	2025 $'000	2024 $'000
Reconciliation of carrying amounts at beginning and end of period:			
Carrying amount at beginning of period		**475,152**	535,842
Additions		**4,661**	2,932
Restoration		**69,941**	(6,571)
Transferred from exploration and evaluation		**-**	1,163
Amortisation		**(64,468)**	(58,214)
Write-off		**(510)**	-
Carrying amount at end of period		**484,776**	475,152
Cost		**911,514**	837,422
Accumulated amortisation & impairment		**(426,738)**	(362,270)
Carrying amount at end of period		**484,776**	475,152

Accounting policy

Gas and oil assets are carried at cost including construction, installation of infrastructure such as roads, pipelines or umbilicals, and the cost of development of wells.

Any restoration assets arising as a result of recognition of a restoration provision are also included in the carrying amount of gas and oil assets. Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. All other repairs and maintenance are charged to the Consolidated Statement of Comprehensive Income as incurred.

Gas and oil assets are amortised on a units-of-production basis, using the latest approved estimate of reserves and future development cost estimates. Amortisation is charged only once production has commenced. No amortisation is charged on areas under development where production has not commenced. Gas and oil assets are subject to impairment testing, refer to Note 14.

Significant accounting judgements, estimates and assumptions

Estimation of gas and oil asset expenditure

Capitalised gas and oil assets for the construction of major projects or ongoing well construction activities include accruals in relation to the value of work done. These remain estimates until the contractual arrangement is finalised, including any rebates, credits and variations as part of the standard contractual process.

Amortisation of gas and oil assets

The amortisation of gas and oil assets is impacted by management's estimates of reserves and future development costs. Refer to the significant accounting judgements, estimates and assumptions section on page 98 in relation to reserves. Future development cost estimates are costs necessary to develop an assets' undeveloped 2P reserves. These costs are subject to changes in technology, regulation and other external factors.

Significant accounting judgements, estimates and assumptions are also made in relation to the impairment of gas and oil assets and recognition of restoration assets, refer to Note 14 and Note 15 respectively.

14. Impairment

	2025 $'000	2024 $'000
Exploration and evaluation assets	**27,388**	269
Total impairment recognised	**27,388**	269

The impairment losses recognised in the 2025 financial year relate to four of the Group's exploration licences being fully impaired in accordance with AASB 6 *Exploration for and Evaluation of Mineral Resources* (refer also to Note 12). Two licenses in the Onshore Otway Basin (PEL 494 and PEP 171) and two licenses in the Gippsland Basin (VIC/P72 and VIC/P75) have been fully impaired as the decision had been made to exit the licenses. There have been no commercial discoveries in these areas.

During the year, the Group's gas and oil assets and property, plant and equipment were assessed for impairment indicators in accordance with AASB 136 *Impairment of Assets*. There were no impairment indicators present, therefore no impairment was recognised.

In the previous financial year, impairment was recognised in relation to one of the Group's exploration licences being fully impaired in accordance with AASB 6 *Exploration for and Evaluation of Mineral Resources*.

Accounting policy

The carrying values of non-current assets, including, property, plant and equipment, capitalised exploration and evaluation assets, and gas and oil assets, are assessed for indicators of impairment at each reporting date (every six months). Where indicators of impairment are present, an impairment test is performed.

An impairment loss is recognised for the amount by which the asset or CGU's carrying amount exceeds its recoverable amount. The recoverable amount of a non-current asset or CGU is the higher of value in use ("VIU") and fair value less cost of disposal ("FVLCD"). For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows. In assessing VIU, the estimated future cash flows are discounted to their present value using a pre-tax rate that reflects the risks specific to the asset. Where the recoverable amount is based on FVLCD, a discounted cash flow model is also used and the inputs are consistent with level 3 on the fair value hierarchy. The estimated future cash flows are prepared on a real (no estimates for future inflation) basis and discounted to their present value using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the asset that would be taken into account by an independent market participant.

Significant accounting judgements, estimates and assumptions

Impairment of exploration and evaluation assets

The future recoverability of capitalised exploration and evaluation expenditure is dependent on a number of factors, including whether the Group decides to exploit the related lease itself or, if not, whether it successfully recovers the related exploration and evaluation asset through sale.

Management is required to make certain estimates and assumptions in applying this policy. Factors which could impact the future recoverability include the level of gas and oil resources, future technological changes which could impact the cost of extraction, future legal changes (including changes to environmental restoration obligations) and changes to commodity prices. These estimates and assumptions may change as new information becomes available. To the extent that capitalised exploration and evaluation expenditure is determined not to be recoverable in the future, this will reduce profits and net assets in the period in which this determination is made.

In addition, exploration and evaluation expenditure is capitalised if activities in the area of interest have not yet reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable gas and oil reserves or resources. To the extent that it is determined in the future that this capitalised expenditure should be written off, this will reduce profits and net assets in the period in which this determination is made.

Impairment of exploration and evaluation assets and gas and oil assets

The Group reviews the carrying amount of gas and oil assets at each reporting date (every six months), starting with an analysis of any indicators of impairment. Where relevant this may involve the preparation of trigger test modelling, for certain CGUs, to determine if any indicators of impairment are present. Where indicators of impairment are present, the Group will test whether the CGU's recoverable amount exceeds its carrying amount, with reference to formal impairment models where discounted cash flow models are used to assess the recoverable amount. Relevant items of working capital and property, plant and equipment are allocated to CGUs when testing for impairment.

The estimated expected cash flows used in the discounted cash flow model are based on management's best estimate of the future production of reserves and sales volumes, commodity prices, foreign exchange rates, development expenditure in order to access the reserves, and operating expenditure. Estimates of future commodity prices are based on the Group's best estimate of future market prices with reference to external brokers, market data and futures prices. Future commodity prices are reviewed at least annually. Where volumes are contracted, future prices are based on the contracted price.

15. Provisions

	2025 $'000	2024 $'000
Current Liabilities		
Employee benefits	**3,898**	4,265
Restoration provisions	**22,200**	28,655
	26,098	32,920
Non-Current Liabilities		
Employee benefits	**1,218**	1,207
Restoration provisions	**418,268**	432,513
	419,486	433,720

	2025 $'000	2024 $'000
Movement in carrying amount of the current restoration provision:		
Carrying amount at beginning of period	**28,655**	161,551
Restoration expenditure incurred[1]	**(30,292)**	(212,764)
Changes in provisions[2]	**17,997**	55,710
Transferred from non-current provisions	**5,840**	24,158
Carrying amount at end of period	**22,200**	28,655
Movement in carrying amount of the non-current restoration provision:		
Carrying amount at beginning of period	**432,513**	416,746
Changes in provisions[2]	**(18,242)**	23,055
Transferred to current provisions	**(5,840)**	(24,158)
Increase through accretion	**9,837**	16,870
Carrying amount at end of period	**418,268**	432,513

[1] Majority of the expenditure incurred in FY25 relates to the Minerva decommissioning programme (FY24: BMG decommissioning programme).

[2] Changes in provisions arise from a combination of changes to estimates of the cost to undertake restoration activities, changes to the estimated time periods during which restoration activity is forecast to occur, changes to assumed future rates of inflation to forecast future expected costs and changes to assumed discount rates to discount future expected costs to derive the present value included here within the restoration provision. Changes to estimates of the costs to undertake restoration activities arise from changes to the assumed scope of activity based on current planning for decommissioning and remediation work, changes in the regulatory requirements and also arise from the current cost environment which, in some cases, have led to an increase to service costs.

The discount rate used in the calculation of the provisions as at 30 June 2025 ranged from 3.43% to 4.19% (2024: 4.10% to 4.31%) reflecting a risk-free rate that aligns to the timing of restoration obligations. The movement in the risk-free rate reflects the change in Australian and US government bond rates since the last assessment. Inflation rate assumptions applied in the calculation of the provision as at 30 June 2025 ranged from 2.0% to 2.85% (2024: 2.0% to 3.15%).

Amplitude Energy continues to pursue its claim in the Victorian Supreme Court ("Court") against PT Pertamina Hulu Energi ("Pertamina") for Pertamina's 10% share of the BMG decommissioning costs.

Pertamina, via its Australian subsidiary (now deregistered), participated in the BMG oil project during its production life. Amplitude Energy's claim against Pertamina arises from the withdrawal and decommissioning provisions of the Joint Operating and Production Agreement, and a parent company guarantee given by Pertamina.

The parties attended mediation in Melbourne in May 2025. The mediation process remains on foot. A directions hearing is scheduled for 22 August 2025, where the Court will make orders for the next stage of the legal proceedings.

Accounting policy

Provisions are recognised when the Group has a legal or constructive obligation, as a result of past transactions or other past events, and it is probable that a future sacrifice of economic benefits will be required and that a reliable estimate can be made of the amount of the obligation.

Employee benefits
Liabilities for wages and salaries, including non-monetary benefits and annual leave are recognised in respect of employees' services up to the reporting date and are measured at the amount expected to be paid when the liabilities are settled. Expenses for non-accumulating sick leave are recognised when the leave is taken and are measured at the rates paid or payable.

The provision for long service leave is recognised and measured as the present value of expected future payments to be made, in respect of services provided by employees up to the reporting date, using the projected unit credit method. Consideration is given to expected future wage and salary levels, years of experience of departed employees, and periods of service.

15. Provisions continued

Expected future payments are discounted using market yields at the reporting date based on high quality corporate bonds with terms of maturity and currencies that match, as closely as possible, the estimated future cash outflows.

Employees' accumulated long service leave is ascribed to individual employees at the rates payable as and when they become entitled to long service leave.

A provision for bonus is recognised and measured based upon the current wage and salary level and forms part of the employee short-term incentive plan. The basis for the bonus relating to Key Management Personnel is set out in the Remuneration Report.

Restoration
The Group records a restoration provision for the present value of its share of the estimated cost to restore its sites. The nature of restoration activities includes the obligations relating to the reclamation, waste site closure, plant closure, production facility removal and other costs associated with the restoration of the site. Risks associated with climate change are factored into forecast timing of restoration activities and will continue to be monitored.

A restoration provision is recognised upon commencement of construction and then reviewed every six months at each reporting date. When the liability is recorded, the carrying amount of the production or exploration asset is increased by the same amount and is depreciated over the remaining producing life of the asset. The movement is recorded as a restoration expense when there is no asset recorded. Over time, the liability is increased for the change in the present value based on a risk-free discount rate and the discount unwind is recorded as an accretion charge within finance costs.

Any changes in the estimate of the provision for restoration arising from changes in the gross cost estimate or changes in the discount rate of the restoration provision are recorded by adjusting the provision and the carrying amount of the production, gas and oil or exploration asset, to the extent that it is appropriate to recognise an asset under accounting standards, and then depreciated over the remaining producing life of the asset. Where it is not appropriate to recognise an asset, changes will immediately be recorded through profit or loss. Any change in assumptions is applied prospectively. These estimated costs are based on current technology available, State, Federal and international legislation, and industry practice.

Significant accounting judgements, estimates and assumptions

Provisions for restoration costs
Decommissioning and restoration costs are a normal consequence of gas and oil extraction and the majority of this expenditure is incurred at the end of a field's life, many years in the future. In determining an appropriate level of provision, assumptions are made as to the expected future costs to be incurred, the timing of these expected future costs (largely dependent on the life of the field), and the estimated future level of inflation.

The ultimate cost of decommissioning and restoration is uncertain and these costs can vary in response to many factors. These factors include the extent of restoration required due to changes to the relevant legal or regulatory requirements, the emergence of new restoration techniques or experience at other fields, and prevailing service costs.

The expected timing of expenditure can also change, for example in response to changes in gas and oil reserves or to production rates.

Provisions for restoration costs are based on the Company's best estimates based on the information available at the time. Changes to any of the estimates could result in significant changes to the amount of the provision recognised, which would in turn impact future financial results.

The Group's restoration provision includes the following costs:

- for onshore projects, provision has been made for the demolition and removal of all onshore production facilities, removal of contaminated soil, and revegetation of the affected area;
- for offshore assets, provision has been made for the removal of subsea trees and manifolds and removal of flowlines and umbilicals to a certain distance from shore and at a certain depth of water. This includes an assumption that all offshore materials that are constructed using plastics are to be fully removed; and
- offshore pipelines that are constructed from steel and concrete are assumed to remain in-situ, where it can be demonstrated that this will result in a net environmental benefit compared to full removal and where regulatory approval is anticipated to be obtained. Offshore pipelines that are constructed from steel and concrete have previously been accepted by the Australian regulator to be decommissioned in-situ, where it has been demonstrated that this will result in a net environmental benefit, compared to full removal.

15. **Provisions** continued

No assumption is made regarding the potential residual value for the onshore production facilities, nor regarding the potential to repurpose any of the onshore and offshore infrastructure and wells (e.g. potential to convert to gas storage and processing, or for carbon capture and storage).

The Group estimates the future decommissioning and restoration costs at different phases in an asset's lifecycle, which in many instances occurs many years into the future. The provisions reflect the Group's best estimate based on current knowledge and information, however further planning and technical analysis of the restoration activities for individual assets will be performed near the end of field life and/or when detailed decommissioning plans are required to be submitted to the relevant regulatory authorities.

Actual decommissioning and restoration costs can materially differ from the current estimate as a result of changes in regulations and their application, service costs, site conditions, timing of restoration and changes in removal technology. These uncertainties may result in decommissioning and restoration costs differing from amounts included in the provision recognised as at 30 June 2025.

In the event that the removal of all pipelines was required, the Group estimates the additional cost would lead to an increase to the provision of approximately $35-85 million. The Group's provision in respect of the Sole Gas Project is based on estimated cessation of production of the fields and timing of decommissioning activities is linked to NOPSEMA's restoration guidance. It is intended that existing infrastructure at Sole will be utilised in a future Manta development. This has not been factored into the provision calculations and would therefore extend the timing of these decommissioning activities.

16. Leases

The group as a lessee

The Group has lease contracts for properties with remaining lease terms of 4-10 years and fixed monthly payments. The Group also has certain leases with lease terms of 12 months or less and low value leases.

Right-of-use assets

	2025 $'000	2024 $'000
Reconciliation of carrying amounts at beginning and end of period:		
Carrying amount at beginning of period	**1,380**	7,448
Addition	**4,920**	-
Reset[1]	**(169)**	(4,805)
Depreciation	**(780)**	(1,263)
Carrying amount at end of period	**5,351**	1,380
Cost	**5,967**	7,101
Accumulated depreciation	**(616)**	(5,721)
Carrying amount at end of period	**5,351**	1,380

[1] Adjustment due to change in lease term of the corporate offices

Lease liabilities

	2025 $'000	2024 $'000
Reconciliation of carrying amounts at beginning and end of period:		
Carrying amount at beginning of period	**1,774**	10,649
Addition	**7,478**	-
Reset[1]	**(170)**	(7,418)
Accretion of interest	**286**	523
Payments	**(1,052)**	(1,980)
Carrying amount at end of period	**8,316**	1,774

[1] Adjustment due to change in lease term of the corporate offices

Current	**476**	847
Non-Current	**7,840**	927

16. **Leases** continued

Short-term and low-value lease asset exemptions

For the year ending 30 June 2025, the following expense has been recognised in the Statement of Comprehensive Income for lease arrangements that have been classified as short-term leases or low-value assets.

	2025 $'000	2024 $'000
Short-term leases[1]	**635**	41,441
Leases for low-value assets	**169**	28
Total expense recognised	**804**	41,469

[1] Short-term leases in FY24 relate to the BMG decommissioning activity.

The Group had total cash outflows for leases of $1.9 million (2024: $43.5 million), inclusive of short-term leases and leases for low-value assets.

Accounting policy

The Group recognises right-of-use assets, and corresponding lease liabilities, at the commencement date of the lease (the date the underlying asset is available for use).

Right-of-use assets are initially measured at a value equal to the respective lease liability, adjusted for any initial direct costs incurred, and lease payments made at or before the commencement date, less any lease incentives received. Subsequently, right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. Property right-of-use assets are depreciated on a straight-line basis over the shorter of estimated useful life and the respective lease term. Right-of-use assets are also allocated to CGUs when testing for impairment (refer to Note 14). Lease liabilities are excluded from the carrying amount of a CGU.

At the commencement date of the lease, the Group recognises lease liabilities measured as the present value of lease payments to be made over the lease term. In calculating the present value of lease payments, the Group uses the incremental borrowing rate at the lease commencement date, if the interest rate implicit in the lease is not readily determinable. Subsequent to initial measurement, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. The carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the fixed lease payments, or a change in the assessment to purchase the underlying asset.

The Group applies the short-term lease recognition exemption to its short-term leases (those leases that have a lease term of 12 months or less, from the commencement date, and do not contain a purchase option). It also applies the lease of low-value assets recognition exemption to leases of office equipment that are considered of low value (below $10,000). Lease payments on short-term leases and leases of low-value assets are recognised as an expense on a straight-line basis over the lease term.

Funding and risk management

17. Interest bearing loans and borrowings

	2025 $'000	2024 $'000
Non-current bank debt[1]	**291,804**	253,147

[1] Net of capitalised transaction costs of $13.4 million (2024: $11.9 million).

In December 2024, Amplitude Energy executed documentation to amend its existing debt facilities with a group of domestic and international banks. The Group now has a $480.0 million senior secured reserve-based lending facility, secured across a portfolio of producing assets, and a senior secured $20.0 million working capital facility. It is expected that the facility will be utilised to part fund the planned ECSP growth project in the Otway Basin. The facility is subject to covenants and Amplitude Energy is in compliance with all covenants at 30 June 2025. A summary of the Group's secured facilities is included below.

Facility	Senior secured reserve based lending facility	Working capital facility
Currency	Australian dollars	Australian dollars
Limit	$480.0 million[1] (2024: $400.0 million)	$20.0 million (2024: $20.0 million)
Utilised amount	$305.2 million (2024: $265.0 million)	$3.6 million[4] (2024: $7.4 million)
Accounting balance	$291.8 million (2024: $253.1 million)	Nil (2024: Nil)
Effective interest rate[2]	8.25% floating	Nil
Maturity[3]	30 September 2029[3]	30 September 2029

[1] As at 30 June 2025, of the $480.0 million limit, the maximum debt availability is $474.9 million. Of this, $169.7 million remains available.
[2] Includes unwind of capitalised transaction costs
[3] Based on the facility reduction schedule, the reserves profile of the borrowing base assets and the facility maturity date.
[4] As at 30 June 2025, no cash amounts have been drawn, $3.6 million has been utilised by way of bank guarantees.

Accounting policy

Borrowings are recognised initially at fair value net of directly attributable transaction costs. Subsequent to initial recognition, borrowings are stated at amortised cost, with any difference between cost and redemption value being recognised in profit or loss over the period of the borrowings on an effective interest basis. Transaction costs are capitalised initially and included in the effective interest rate calculation and unwound over the expected term of the facility.

Borrowings are classified as current liabilities unless the Group has a right to defer the settlement of the liability for at least 12 months after the end of the reporting period. Interest expense is recognised as interest accrues, using the effective interest rate and if not paid at balance date, is reflected in the balance sheet as a payable.

18. Net finance costs

	2025 $'000	2024 $'000
Finance Income		
Interest income	**2,058**	3,484
Finance Costs		
Unwind discount on liabilities	**(9,902)**	(17,721)
Finance costs associated with lease liabilities	**(286)**	(523)
Interest expense	**(27,500)**	(17,975)
Total finance costs	**(37,688)**	(36,219)
Net finance costs	**(35,630)**	(32,735)

Accounting policy

Interest earned is recognised in the Consolidated Statement of Comprehensive Income as finance income and is recognised as interest accrues, using the effective interest rate. This is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset. Interest expense is capitalised to the cost of a qualifying asset during the development phase.

19. Contributed equity and reserves

For the purposes of Group capital management, capital includes issued capital and all other equity reserves attributable to the equity holders of the parent entity.

The primary objective of the Group's capital management strategy is to maintain an appropriate capital profile to support its business activities and to maximise shareholder value.

At 30 June 2025, the Group has utilised $305.2 million of its reserves based lending facility.

The Group manages its capital structure and makes adjustments in light of economic conditions and within the requirements of financial covenants. To maintain or adjust the capital structure, the Group may adjust its dividend policy, return capital to shareholders, issue new shares or draw on debt. No changes were made in the objectives, policies or processes during the current and prior period.

Share capital

	2025 $'000	2024 $'000
Ordinary shares issued and fully paid	**720,645**	718,881

	2025		2024	
	Thousands	**$'000**	Thousands	$'000
Movement in ordinary shares on issue				
At 1 July	**2,640,037**	**718,881**	2,631,530	716,726
Issuance of shares for performance rights	**11,370**	**1,764**	8,507	2,155
At 30 June	**2,651,407**	**720,645**	2,640,037	718,881

Accounting policy

Issued and paid up capital is recognised as the fair value of the consideration received by the Group. The shares issued do not have a par value and there is no limit on the authorised share capital of the Group. Fully paid ordinary shares carry one vote per share, which entitles the holder to participate in the proceeds on winding up of the Company in proportion to the number of, and amounts paid on, the shares held.

Any transaction costs arising on the issue of ordinary shares that would not have been incurred had ordinary shares not been issued, are recognised directly in equity as a reduction of the share proceeds received.

19. Contributed equity and reserves continued

Reserves

	Consol. Reserve $'000	Share based payment reserve $'000	Option premium reserve $'000	Equity instruments reserve $'000	Cash flow hedge reserve $'000	Total $'000
Consolidated						
At 30 June 2023	(541)	25,811	25	776	-	26,071
Other comprehensive expenditure	-	-	-	(412)	-	(412)
Transferred to issued capital	-	(2,155)	-	-	-	(2,155)
Share-based payments	-	3,681	-	-	-	3,681
At 30 June 2024	**(541)**	**27,337**	**25**	**364**	**-**	**27,185**
Other comprehensive expenditure	**-**	-	**-**	**(424)**	**(3,903)**	**(4,327)**
Transferred to issued capital	**-**	**(1,764)**	**-**	**-**	**-**	**(1,764)**
Share-based payments	**-**	**4,528**	**-**	**-**	**-**	**4,528**
At 30 June 2025	**(541)**	**30,101**	**25**	**(60)**	**(3,903)**	**25,622**

Nature and purpose of reserves

Consolidation reserve
This reserve comprises the premium paid on acquisition of minority shareholdings in a controlled entity.

Share based payment reserve
This reserve is used to record the value of equity benefits provided to employees, contractors and executive directors as part of their remuneration.

Option premium reserve
This reserve is used to accumulate amounts received from the issue of options. The reserve can be used to pay dividends or issue bonus shares.

Equity instruments reserve
This reserve is used to capture the fair value movement in the value of equity instruments designated at fair value through Other Comprehensive Income. Items in this reserve are never recycled through profit or loss.

Cash flow hedge reserve
This reserve is used to capture the effective portion of the mark to market movement of instruments designated in a hedge relationship.

20. Financial risk management

The Group's principal financial instruments comprise cash and short-term deposits (Note 5), receivables (Note 6), payables (Note 9), borrowings (Note 17) and other financial assets and liabilities as disclosed in the table below.

	2025 $'000	2024 $'000
Other financial assets – Current		
Derivative financial instruments designated in a hedge relationship	**281**	-
Other financial assets – Non-Current		
Equity instruments	**295**	718
Derivative financial instruments designated in a hedge relationship	**938**	-
	1,233	718
Other financial liabilities – Current		
Derivative financial instruments designated in a hedge relationship	**1,736**	-
Other financial liabilities – Non-Current		
Success fee financial liability	**3,059**	2,830
Derivative financial instruments designated in a hedge relationship	**2,006**	-
	5,065	2,830
Movement in carrying amount of the success fee financial liability:		
Carrying amount at 1 July	**2,830**	2,853
Accretion of success fee liability	**65**	114
Fair value adjustment	**164**	(137)
Carrying amount at 30 June	**3,059**	2,830

Fair value hierarchy
Fair value is the price that would be received to sell an asset, or the price that would be paid to transfer a liability, in an orderly transaction between market participants at the measurement date. All financial instruments for which fair value is recognised, or disclosed, are categorised within the fair value hierarchy, described as follows, and based on the lowest level input that is significant to the fair value measurement as a whole:

Level 1
Quoted market prices in an active market (that are unadjusted) for identical assets or liabilities

Level 2
Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable

Level 3
Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable

For financial instruments that are recognised at fair value on a recurring basis, the Group determines whether transfers have occurred between levels in the hierarchy by re-assessing categorisation (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period. Set out below are the carrying amounts and fair values of financial instruments held by the Group:

		Carrying amount		**Fair value**	
	Level	**2025 $'000**	2024 $'000	**2025 $'000**	2024 $'000
Financial assets					
Trade and other receivables	**2**	**35,385**	35,209	**35,385**	35,209
Equity instruments	**1**	**295**	718	**295**	718
Derivative financial instruments designated in a hedge relationship	**2**	**1,219**	-	**1,219**	-
Financial liabilities					
Trade and other payables	**2**	**39,811**	76,773	**39,811**	76,773
Success fee financial liability	**3**	**3,059**	2,830	**3,059**	2,830
Derivative financial instruments designated in a hedge relationship	**2**	**3,742**	-	**3,742**	-
Interest bearing loans and borrowings	**2**	**291,804**	253,147	**295,745**	264,847

20. Financial risk management
continued

The following summarises the significant methods and assumptions used in estimating the fair values of financial instruments.

Equity instruments

Equity instruments are not held for trading, and are measured at fair value through other comprehensive income based on an irrevocable election made at inception on an instrument basis.

They are initially recognised at fair value plus any directly attributable transaction costs. After initial recognition, investments are remeasured to fair value, determined by reference to their quoted market price on a prescribed equity stock exchange at the reporting date. Hence they are a Level 1 fair value measurement.

Changes in the fair value of equity investments are recognised as a separate component of equity and not recycled to profit and loss at any stage. Any dividends received are reflected in profit or loss.

Success fee financial liability

The success fee liability is the fair value of the Group's liability to pay a $5.0 million success fee upon the commencement of commercial production of hydrocarbons on the Group's VIC/RL 13-15 assets, which includes the Manta gas field, acquired on 7 May 2014.

The significant unobservable level 3 valuation inputs for the success fee financial liability include: a probability of 33% that no payment is made and a probability of 67% the payment is made in 2032. The discount rate used in the calculation of the liability as at 30 June 2025 equalled 3.43% (30 June 2024: 4.31%), reflecting a risk-free rate that aligns to the timing of payment. The financial liability is measured at fair value through profit and loss and valued using a discounted cash flow model. The value is sensitive to changes in discount rate and probability of payment. Significant changes in any of the key unobservable inputs would result in significantly higher or lower fair value measurement.

Derivative financial instruments designated in hedge relationship

The derivative financial instruments relate to the Group's hedging activities to hedge against cash flow risks from movements in interest rates and exchange rates, for which hedge accounting has been applied. The derivative financial instruments are measured at fair value through other comprehensive income and the fair value is obtained from third party valuation reports. The use of derivative financial instruments is subject to a set of policies, procedures and limits approved by the Board of Directors. The Group does not trade in derivative financial instruments for speculative purposes.

Risk management

The Group manages its exposure to key financial risks in accordance with its risk management policy, with the objective to ensure that the financial risks inherent in gas and oil production and exploration activities are identified and then managed, or kept as low as reasonably practicable. The Group has a separate Risk & Sustainability Committee.

The main financial risks that arise in the normal course of business for the Group's financial instruments are foreign currency risk, commodity price risk, share price risk, credit risk, liquidity risk and interest rate risk. The Group uses different methods to measure and manage different types of risks to which it is exposed. These include monitoring exposure to foreign exchange risk and assessments of market forecasts for interest rates, foreign exchange rates and commodity prices. Liquidity risk is monitored through the development of future rolling cash flow forecasts.

The Board's policy is that no speculative trading in financial instruments be undertaken. The primary responsibility for the identification and control of financial risks rests with the Managing Director and the Chief Financial Officer, under the authority of the Board. The Board is apprised of these and other risks at Board meetings and agrees any policies that may be implemented to manage any of the risks identified below.

Market Risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises four types of risk: foreign currency risk, commodity price risk, interest rate risk and share price risk. Financial instruments affected by market risk include deposits, trade receivables, equity accounted investments, trade payables, accrued liabilities and borrowings.

The sensitivity analyses in the following sections relate to the position as at 30 June 2025 and 30 June 2024. The sensitivity analyses are intended to illustrate the sensitivity to changes in market variables on the Group's financial instruments and show the impact on profit or loss and shareholders' equity, where applicable.

When calculating the sensitivity analyses, it is assumed that the sensitivity of the relevant profit before tax item and/or equity, is the effect of the assumed changes in respective market risks, with all other variables held constant.

20. Financial risk management
continued

The Group has transactional currency exposure arising from oil sales which are denominated in United States dollars, whilst the great majority of costs are denominated in Australian dollars, with some costs incurred in United States dollars and Great British pounds. Transaction exposures, where possible, are netted off across the Group, to reduce volatility and provide a natural hedge.

a) Foreign currency risk

The Group may from time to time have cash denominated in United States ("US") dollars.

At 30 June 2025, the Group has hedged a portion of its USD exposure during the drilling phase of ECSP (refer to note 21). The Group also manages the purchase of foreign currency to meet expenditure requirements, which cannot be netted off against US dollar receivables.

The financial instruments which are denominated in US dollars are as follows:

	2025 **$'000**	2024 $'000
Financial assets		
Cash	**3,906**	171
Trade and other receivables	**-**	2,274

b) Commodity price risk

Commodity price risk arises from the sale of oil denominated in US dollars. From time to time, the Group may use oil price options to manage some of its oil price exposures.

The Group is exposed to changes in Southeast Australian gas spot prices, with respect to gas production in excess of contracted volumes. Spot gas trades at year end were executed with reference to the prevailing intraday price marker, i.e., at known settlement prices on the day.

c) Interest rate risk

The Group has borrowings of $305.2 million at 30 June 2025 (2024: $265.0 million). Interest on borrowings is at variable rates (refer to Note 17). The Group has hedged a portion of its exposure to rising BBSY-linked interest rates under the Reserve-Based Lending (RBL) facility (refer to note 21).

Any fluctuation of the interest rate either up or down will have only a limited impact on the principal amount of the cash on term deposit at the banks. The Group does not invest in financial instruments that are traded on any secondary market.

d) Share price risk

Share price risk arises from the movement of share prices on a prescribed stock exchange. The Group has equity instruments measured at fair value through Other Comprehensive Income the fair value of which fluctuates, due to movements in the share price.

The following table summarises the sensitivity of financial instruments held at the year end, to the market risks above, with all other variables held constant.

	2025 **$'000**	2024 $'000
Foreign currency risk	**Impact on after tax profit**	
If the Australian dollar were 10% higher at the balance date	**(355)**	(222)
If the Australian dollar were 10% lower at the balance date	**434**	272
Interest rate risk		
If the interest rates were 100 basis points higher at the balance date	**(2,898)**	(2,650)
If the interest rates were 100 basis points lower at the balance date	**2,768**	2,650
Share price risk	**Impact on reserve**	
If the share price were 10% higher at the balance date	**29**	72
If the share price were 10% lower at the balance date	**(29)**	(72)

20. Financial risk management continued

Credit risk

Credit risk arises from the financial assets of the Group, which comprise cash and cash equivalents and trade and other receivables including hedge settlement receivables, escrow proceeds receivable (disclosed as other financial assets), and certain prepayments. The Group's exposure to credit risk arises from potential default of the counterparty, with a maximum exposure equal to the carrying amount of these instruments.

The Group trades only with recognised creditworthy third parties and has a concentration of credit risk with trade receivables due from a small number of entities which have traded with the Group since 2003. Trade receivables are settled on a 31 day average term. The Group has some exposure to credit loss from other receivables and an amount of $29.8 million calculated on lifetime expected credit loss has been recognised in respect of credit-impaired joint venture related receivables.

Cash and cash equivalents are held at two financial institutions that each have a Standard & Poor's credit rating of AA- (stable).

Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet its financial obligations as they fall due. The liquidity position of the Group is managed to ensure sufficient liquid funds are available to meet all financial commitments in a timely and cost-effective manner. The Managing Director and Chief Financial Officer review the liquidity position on a regular basis, including cash flow forecasts, to determine the forecast liquidity position and maintain appropriate liquidity levels.

The table below summarises the maturity profile of the Group's financial liabilities based on contractual undiscounted payments:

	Less than 3 months $'000	3 to 12 months $'000	1 to 5 years $'000	Greater than 5 years $'000	Total $'000
At 30 June 2025					
Trade and other payables	**39,811**	**-**	**-**	**-**	**39,811**
Lease liabilities	**309**	**932**	**4,996**	**5,365**	**11,602**
Interest bearing loans and borrowings	**6,293**	**18,879**	**375,594**	**-**	**400,766**
Success fee financial liability	**-**	**-**	**-**	**5,000**	**5,000**
	46,413	**19,811**	**380,590**	**10,365**	**457,179**
At 30 June 2024					
Trade and other payables	76,773	-	-	-	76,773
Lease liabilities	367	554	1,021	32	1,974
Interest bearing loans and borrowings	5,131	15,394	308,470	-	328,995
Success fee financial liability	-	-	-	5,000	5,000
	82,271	15,948	309,491	5,032	412,742

21. Hedge accounting

During the period, the following hedging activities were undertaken:

Cash flow hedges – interest rate collars

The Group uses zero cost interest rate collars to manage its exposure to fluctuations in interest rates. The collars are designated as a cash flow hedge instrument to hedge forecast interest payments in respect of the Group's reserve base lending facility. The collars are measured at fair value through other comprehensive income.

	2025	2024
Interest rate collars (cash flow hedges)		
Carrying amount ($'000)	**(412)**	-
Notional amount ($'000)	**100,000**	-
Maturity date	**FY 2028**	-
Hedge ratio	**1:1**	-
Average hedging rate – Cap/Floor	**4.5%/2.94%**	-

The terms of the interest rate collars match the terms of the expected highly probable forecast interest payments.

The cash flow hedges of the expected future interest payments were assessed to be highly effective, and a net unrealised loss of $0.4 million and an income tax impact of $0.1 million has been included in OCI. No reclassifications have been made to the profit and loss statement in the current period.

Cash flow hedges – foreign exchange contracts

Through foreign exchange forward and options contracts, the Group hedged the US dollar to Australian dollar exchange rate for a portion of the US dollar denominated capital expenditure expected to be incurred for the East Coast Supply Project.

	2025	2024
FX forwards and options (cash flow hedges)		
Carrying amount ($'000)	**(2,111)**	-
Notional amount (US$'000)	**85,300**	-
Maturity date	**FY 2026-27**	-
Hedge ratio	**1:1**	-
Weighted average hedge rate	**0.63**	-

The terms of the FX forwards and options match the terms of the expected highly probable forecast US$ payments.

The cash flow hedges of the expected future US$ payments were assessed to be highly effective and a net unrealised loss of $4.2 million and a tax expense of $1.3 million relating to the hedging instrument are included in OCI. No reclassifications have been made to the profit and loss statement in the current period.

Group structure

22. Interests in joint arrangements

The Group has the following interests in joint arrangements involved in the exploration and/or production of gas and oil in Australia:

		Ownership Interest	
		2025	2024
Joint Arrangements in Australia in which Amplitude Energy Limited is the operator/manager			
VIC/L24 & 30	Gas exploration and production	**50%**	50%
VIC/P44	Gas exploration	**100%**[1]	50%
Athena Processing Plant	Gas processing services	**50%**	50%
ECSP IJVA	Gas exploration	**50%**[2]	-
Joint Arrangements in Australia in which Amplitude Energy Limited is not the operator/manager			
PEL 494	Gas and oil exploration	**30%**	30%
PEP 168	Gas and oil exploration	**50%**	50%
PEP 171	Gas and oil exploration	**75%**	75%
PRL 32	Gas and oil exploration	**30%**	30%
PEL 680	Gas and oil exploration	**30%**	30%
PRL 85-104[3] (Formerly PEL 92)	Oil and gas exploration and production	**25%**	25%

[1] The Group's interest in the VIC/P44 joint arrangement increased to 100% during the period on Mitsui E&P's exit of the permit. Subsequently, this joint arrangement is part of the transaction with O.G. Energy and the Group interest will decrease back to 50% on completion.
[2] On 24 March 2025, the Group announced it had entered into a binding joint venture agreement ("IJVA") with subsidiaries of O.G. Energy regarding the development of the East Coast Supply Project ("ECSP") on a 50/50 basis. The IJVA established an unincorporated joint venture between subsidiaries of Amplitude Energy and O.G. Energy to progress the ECSP in the interim period between the signing of the IJVA and completion of the O.G. Energy's acquisition of Mitsui E&P Australia's interest in the Otway Basin joint ventures ("Otway Sale Transaction").
[3] Includes associated PPLs.

Accounting policy

The Group has interests in arrangements that are controlled jointly. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control. A joint arrangement is either a joint operation or a joint venture. The Group has several joint arrangements which are classified as joint operations. A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement.

In relation to its interests in joint operations, the Group recognises its share of:

- Assets, including its share of any assets held jointly
- Liabilities, including its share of any liabilities incurred jointly
- Revenue from the sale of its share of the output arising from the joint operation
- Expenses, including its share of any expenses incurred jointly

Significant accounting judgements, estimates and assumptions

Joint arrangements
Judgement is required to determine when the Group has joint control over an arrangement, which requires an assessment of the relevant activities and when the decisions in relation to those activities require unanimous consent. The Group has determined that the relevant activities for its joint arrangements are those relating to the operating and capital decisions of the arrangement, such as approval of the capital expenditure program for each year and appointing, remunerating and terminating the key management personnel or service providers of the joint arrangement. Where joint control does not exist, the relationship is not accounted for as a joint arrangement. The considerations made in determining joint control are similar to those necessary to determine control over subsidiaries.

Judgement is also required to classify a joint arrangement. Classifying the arrangement requires the Group to assess their rights and obligations arising from the arrangement. Specifically, the Group considers:

- the structure of the joint arrangement – whether it is structured through a separate vehicle; and
- when the arrangement is structured through a separate vehicle, the rights and obligations arising from the legal form of the separate vehicle, the terms of the contractual arrangement, and other facts and circumstances (when relevant).

This assessment often requires significant judgement. A different conclusion on joint control, and also whether the arrangement is a joint operation or a joint venture, may materially impact the accounting.

23. Investments in controlled entities

(a) Deed of Cross Guarantee
Pursuant to ASIC Corporations (Wholly-owned Companies) Instrument 2016/785 dated 29 September 2016, relief has been granted to certain controlled entities of Amplitude Energy Limited from the Corporations Act 2001 for preparation, audit and lodgement of financial reports, and directors' reports. As a condition of the Class Order, Amplitude Energy Limited, and the controlled entities subject to the Class Order, entered into a Deed of Cross Guarantee.

The effect of the deed is that Amplitude Energy Limited has guaranteed to pay any deficiency in the event of the winding up of any member of the Closed Group, and each member of the Closed Group has given a guarantee to pay any deficiency, in the event that Amplitude Energy Limited or any other member of the Closed Group is wound up.

(b) Schedule of controlled entities
The Group's consolidated financial statements include the financial statements of Amplitude Energy Limited and the subsidiaries listed in the following table.

			Ownership Interest	
Name	**Country of incorporation**	**Note**	**2025**	2024
Somerton Energy Limited	Australia	(a)	**100%**	100%
Essential Petroleum Exploration Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (Australia) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (PBF) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (PB Pipelines) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (CH) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (TC) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (MF) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (MGP) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (IC) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (HC) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (EA) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (Sole) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (VO) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (Marketing) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (BMG) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (CB) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (Finance) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (AGP) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (CS) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (MS) Pty Ltd	Australia	(a)	**100%**	100%
Amplitude Energy (ECSP) Pty Ltd	Australia	(a)(b)	**100%**	-

The parties that comprise the Closed Group are denoted by (a) and parties that have been added to the Closed Group in 2025 are denoted by (b).

Accounting policy

Business combinations are accounted for using the acquisition method. The consideration for an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any non-controlling interest in the acquiree. For each business combination, the Group elects whether it measures the non-controlling interest in the acquiree at fair value, or at the proportionate share of the acquiree's identifiable net assets. Acquisition costs incurred are expensed and included in administrative expenses.

When the Group acquires a business, it assesses the financial assets and liabilities acquired for appropriate classification and designation per AASB 9 *Financial Instruments* (AASB 9), in accordance with the contractual terms, economic circumstances and pertinent conditions, as at the acquisition date. If the business combination is achieved in stages, the acquisition date fair value of the acquirers previously held equity interest in the acquiree is remeasured to fair value at the acquisition date, through profit or loss.

Any contingent consideration to be transferred by the acquirer will be recognised at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration that is deemed to be an asset or liability will be recognised in accordance with AASB 9 and measured at fair value, through profit and loss. If the contingent consideration is classified as equity, it will not be remeasured. Subsequent settlement is accounted for within equity. In instances where the contingent consideration does not fall within the scope of AASB 9, it is measured in accordance with the appropriate AASB.

An asset or group of assets that do not meet the definition of a business are accounted for as asset acquisitions. Under this method, assets are initially recognised at cost based on their relative fair value at the date of acquisition. Under this method transaction costs are capitalised to the asset and not expensed.

24. Parent entity information

Information relating to the parent entity, Amplitude Energy Limited	2025 $'000	2024 $'000
Current Assets	**215,603**	126,135
Total Assets	**343,271**	460,395
Current Liabilities	**37,537**	57,694
Total Liabilities	**101,652**	118,601
Issued capital	**720,645**	718,881
Accumulated loss	**(509,152)**	(404,449)
Option premium reserve	**25**	25
Share based payment reserve	**30,101**	27,337
Total shareholders' equity	**241,619**	341,794
Loss of the parent entity	**(104,703)**	(150,385)
Total comprehensive loss of the parent entity	**(104,703)**	(150,385)

Notes to the consolidated financial statements
For the year ended 30 June 2025

Other information

25. Commitments for expenditure

The Group has the following commitments for exploration expenditure for which no liabilities have been recorded in the financial statements as the goods or services have not been received.

	2025 $'000	2024 $'000
Due within 1 year	**3,653**	32,403
Due within 1-5 years	**30,225**	33,878
	33,878	66,281

From time to time through the ordinary course of business, Amplitude Energy enters into contractual arrangements that may give rise to negotiated outcomes.

Amplitude Energy has executed a number of material contracts to the value of $103.2 million at 30 June 2025 (2024: $44.6 million) relating to the East Coast Supply Project. The minimum payment under these contracts at 30 June 2025 is $88.0 million (2024: $23.5 million) for which no liabilities have been recorded.

As at 30 June 2025 the parent entity has bank guarantees for $3.6 million (2024: $7.4 million), see also Note 17. These guarantees are in relation to credit support for gas trading and guarantees on office leases.

26. Contingent liabilities

Contingent liabilities may arise in the ordinary course of business through commercial disputes or claims, including contractual or third-party claims. Contingent liabilities are possible obligations whose existence will only be confirmed by the occurrence or non-occurrence of uncertain future events. The Group does not have any material contingent liabilities at reporting date as it is not probable that a future sacrifice of economic benefits will be required, or the amount of the obligation cannot be measured with sufficient reliability.

27. Share based payments

2022 EIP

The Company's amended EIP was approved by shareholders at the 2022 AGM. The EIP applies only to Executive KMPs and a small number of senior staff. Performance rights were issued for no consideration under the EIP under two tranches:

- Tranche 1 – relative total shareholder return (RTSR)
- Tranche 2 – absolute total shareholder return (ATSR).

No share appreciation rights were issued in the financial year.

Issued rights vest as shares in the parent entity, subject to performance hurdles being met.

A performance right is the right to acquire one fully paid share in the Company, provided a specified hurdle is met. Share appreciation rights are rights to acquire shares in the Company to the value of the difference in the Company share price between the grant date and vesting date. Testing of the performance rights and historical share appreciation rights occur at the end of the three-year performance period.

The vesting of tranche 1 performance rights is based on a comparison of the Company's RTSR percentile ranking against the RTSR of a peer group of nine other companies. Subject to the plan rules, the number of tranche 1 performance rights that will vest at the end of the performance period is as follows:

- Below 50th percentile – no tranche 1 performance rights will vest
- At 50th percentile – 50% of tranche 1 performance rights will vest
- Between 50th and 75th percentile – 50% of tranche 1 performance rights plus 2% for each additional percentile
- 75th percentile or greater – 100% of tranche 1 performance rights will vest

The vesting of tranche 2 performance rights takes account only of the Company's ATSR, calculated as the compound average growth rate (CAGR) of the Company's share price over a three-year period. Subject to the plan rules, the number of tranche 2 performance rights that will vest at the end of the performance period is as follows:

- Less than 10% CAGR – no tranche 2 performance right will vest
- At 10% CAGR – 50% of tranche 2 performance rights will vest
- Between 10% and 20% CAGR – 50% of tranche 2 performance rights will vest, plus 5% for each additional percentile
- 20% or above – 100% of tranche 2 performance rights will vest

2019 EIP

The vesting of EIP performance rights in FY25 relates to rights granted in December 2021 and is determined from the absolute total shareholder return of Amplitude Energy's share price ranked against the absolute total shareholder returns of 12 peer companies listed on the Australian Securities Exchange. If Amplitude Energy is ranked lower than the 50th percentile, no rights will vest. If Amplitude Energy is ranked in the 50th percentile, 30% of the eligible rights will vest. If Amplitude Energy is ranked greater than the 50th percentile, but less than the 90th percentile, the amount of eligible rights vested will be based on a pro rata calculation. If Amplitude Energy is ranked in the 90th percentile or higher, 100% of the eligible rights will vest. Share appreciation rights issued in previous financial years remain on foot and subject to testing.

27. Share based payments continued

Performance rights are also granted as part of deferred awards under the short-term incentive plan ("STIP"). Testing of these rights will occur at the end of a 12-month performance period. Rights granted will vest if the employee remains employed by the Company at the end of the performance period.

There are no participating rights or entitlements inherent in the rights and holders will not be entitled to participate in new issues of capital offered to shareholders during the period of the rights. All rights are settled by physical delivery of shares.

Information with respect to the number of performance rights and share appreciation rights granted to employees is as follows:

Date Granted	Number of share appreciation rights (SARs) granted	Number of performance rights granted	Average share price at commencement date of grant	Average contractual life of rights at grant date in years	Remaining life of rights in years
9 December 2022	**20,636,373**	**7,608,195**	**$0.195**	**3**	**0.5**
23 November 2023	**1,084,611**	**407,814**	**$0.105**	**3**	**0.5**
23 November 2023	**-**	**9,547,387**	**$0.105**	**3**	**1.4**
11 December 2023	**-**	**29,249,252**	**$0.100**	**3**	**1.5**
7 November 2024	**-**	**4,362,128**	**$0.165**	**3**	**2.4**
26 November 2024	**-**	**11,352,557**	**$0.180**	**3**	**2.4**
11 December 2024	**-**	**10,358,427**	**$0.190**	**1**	**0.5**

The number of performance rights and share appreciation rights held by employees are as follows:

	Number of Share Appreciation Rights		Number of Performance Rights[1]	
	2025	2024	**2025**	2024
Balance at beginning of year	**43,758,208**	60,807,624	**62,738,389**	28,694,792
- granted	**-**	1,084,611	**26,073,112**	48,436,318
- vested	**-**	-	**(11,369,795)**	(8,506,969)
- expired and not exercised	**(26,305,310)**	(16,796,442)	**(5,853,589)**	(5,460,544)
- forfeited	**-**	(1,337,585)	**(251,174)**	(425,208)
Balance at end of year	**17,452,898**	43,758,208	**71,336,943**	62,738,389
Achieved at end of year	**-**	-	**-**	-

[1] The Performance Rights, which vested in 2024, are Deferred STIP that applies to staff generally and Performance Rights issued under the EIP for Executive KMP.

The fair value of services received in return for the performance rights granted are measured by reference to the fair value of performance rights granted. The estimate of the fair value of the services received is measured based on the Black-Scholes methodology and a Monte-Carlo simulation model that allows for the incorporation of market-based performance hurdles that must be met before the shares vest to the holder.

Fair value assumptions on LTIP grants	**9 December 2022**	**11 December 2023**	**7 November 2024**	**26 November 2024**
Fair value of share appreciation rights at measurement date	6.4 cents	N/A	N/A	N/A
Fair value of performance rights at measurement date	13.4 cents	7.0 cents	11.9 cents	12.9 cents
Share price	19.5 cents	10.0 cents	16.5 cents	18.0 cents
Risk free interest rate	3.02%	3.80%	4.13%	3.99%
Expected volatility	52%	53%	60%	60%
Dividend yield	0%	0%	0%	0%

27. Share based payments continued

Accounting policy

The Group provides benefits to employees of the Group in the form of share-based payment transactions, whereby employees render services in exchange for rights over shares ("equity-settled transactions").

The cost of these equity-settled transactions with employees is measured by reference to the fair value at the date at which they are granted and are recorded as an expense, with a corresponding increase in reserves, on a straight-line basis over the vesting period of the related instrument.

The fair value is determined using the Black-Scholes methodology and a Monte-Carlo simulation model that takes into account the exercise price, the vesting period, the vesting and performance criteria, the non-tradable nature of the performance right or share appreciation right, the share price at grant date, the expected volatility of the price of the underlying share, the expected dividend yield and the risk-free interest rate for the term of the vesting period.

There are no non-market vesting conditions (e.g., profitability, or sales growth targets), and as such the estimation of the fair value of the performance rights and share appreciation rights granted is based solely on the results of the Black-Scholes based Monte-Carlo simulation model.

The volatility assumption is based on the actual volatility of Amplitude Energy's daily closing share price over the three-year period to the valuation date.

The cost of equity-settled transactions is recognised, together with a corresponding increase in equity, over the period in which the performance and/or service conditions are fulfilled, ending on the date on which the relevant employees become fully entitled to the award (the vesting period).

The cumulative expense recognised for equity-settled transactions at each reporting date until vesting date reflects:

- the extent to which the vesting period has expired; and
- the Group's best estimate of the number of equity instruments that will ultimately vest.

No adjustment is made for the likelihood of market performance conditions being met as the effect of these conditions is included in the determination of fair value at grant date. The Consolidated Statement of Comprehensive Income charge or credit, for a period, represents the movement in cumulative expense recognised as at the beginning and end of that period.

No expense is recognised for awards that do not ultimately vest, except for awards where vesting is only conditional upon a market condition.

If the terms of an equity-settled award are modified, as a minimum an expense is recognised as if the terms had not been modified. In addition, an expense is recognised for any modification that increases the total fair value of the share-based payment arrangement, or is otherwise beneficial to the employees as measured at the date of modification.

If an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation, and any expense not yet recognised for the award is recognised immediately. However, if a new award is substituted for the cancelled award and designated as a replacement award on the date that it is granted, the cancelled and new award are treated as if they were a modification of the original award, as described in the previous paragraph.

The dilutive effect, if any, of outstanding performance rights and share appreciation rights is reflected as additional share dilution in the computation of diluted earnings per share.

Significant accounting judgements, estimates and assumptions

The Group measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date at which they are granted. The fair value is determined by an external valuation expert using the calculation criteria.

28. Related party disclosures

The Group has a related party relationship with its joint arrangements (Note 22), its subsidiaries (Note 23), and its key management personnel (disclosure below).

The key management personnel's remuneration included in General Administration (see Note 2) is as follows:

	2025 $	2024 $
Short-term benefits	**5,415,365**	5,390,663
Other long-term benefits	**55,184**	23,413
Post-employment benefits	**218,268**	217,887
Performance rights and share appreciation rights	**1,024,001**	896,020
Termination benefits	**721,018**	823,314
	7,433,836	7,351,297

29. Remuneration of auditors

	2025 $	2024 $
The auditor of Amplitude Energy Limited is Ernst & Young		
Audit services		
Amounts received or due and receivable by Ernst & Young Australia for:		
Audit of statutory report of Amplitude Energy Limited	**369,200**	463,800
	369,200	463,800
Other services		
Other assurance services	**101,250**	-
Taxation and other services	**232,000**	62,000
	333,250	62,000
Total fees to Ernst & Young	**702,450**	525,800

30. Events after the reporting period

On 15 July 2025 Amplitude Energy entered into an agreement with Beach Energy Limited to transfer interests held by Amplitude Energy's wholly owned subsidiary, Somerton Energy Pty Ltd, in certain Onshore Otway Basin exploration permits, including Amplitude Energy's 75% interest in PEP 171 and 30% interest in PEP 494. This agreement remains subject to certain conditions, including regulatory approvals. During the June quarter Amplitude Energy agreed to separate terms with Beach Energy Limited for Amplitude Energy's exit from the PEL 680 exploration permit, which is also subject to regulatory approvals. The exit of these interests allows the Company to focus on its growth priorities in the Offshore Otway and Gippsland Basins.

On 31 July 2025, the subsidiaries of O.G. Energy completed the acquisition of Mitsui E&P Australia's interests in the Offshore Otway Basin (the "Otway Sale Transaction"). Completion of the Otway Sale Transaction triggers the commencement of O.G. Energy reimbursing Amplitude Energy for 50% of all historical East Coast Supply Project (ECSP) costs spent up to March 2025. On 7 August 2025, following completion of the Otway Sale Transaction, the VIC/P76 farm-in transaction completed.

Consolidated entity disclosure statement

As at 30 June 2025

Entity name	Entity type	Body corporate country of incorporation	Body corporate % of share capital held	Country of tax residence
Amplitude Energy Limited	Body corporate	Australia	100%	Australia
Somerton Energy Limited	Body corporate	Australia	100%	Australia
Essential Petroleum Exploration Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (Australia) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (PBF) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (PB Pipelines) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (CH) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (TC) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (MF) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (MGP) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (IC) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (HC) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (EA) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (Sole) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (VO) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (Marketing) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (BMG) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (CB) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (Finance) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (AGP) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (CS) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (MS) Pty Ltd	Body corporate	Australia	100%	Australia
Amplitude Energy (ECSP) Pty Ltd	Body corporate	Australia	100%	Australia

Directors' declaration

In accordance with a resolution of the Directors of Amplitude Energy Limited, I state that:

In the opinion of the Directors:

(a) the financial statements and notes of the consolidated entity 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 2025 and of its performance for the year ended on that date; and

(ii) complying with Australian Accounting Standards and the Corporations Regulations 2001;

(b) the financial statements and notes also comply with International Financial Reporting Standards as disclosed in the Basis of Preparation;

(c) the consolidated entity disclosure statement required by section 295(3A) of the Corporations Act is true and correct; and

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

This declaration has been made after receiving the declarations required to be made to the Directors in accordance with section 295A of the Corporations Act 2001 for the financial year ended 30 June 2025.

In the opinion of the Directors, as at the date of this declaration, there are reasonable grounds to believe that the members of the closed group identified in Note 22 will be able to meet any obligations or liabilities to which they are, or may become subject, by virtue of the Deed of Cross Guarantee between the Company and those members of the Closed Group pursuant to ASIC Corporations (Wholly-owned Companies) Instrument 2016/785.

Signed in accordance with a resolution of the Directors.

Mr John C. Conde AO
Chairman

Ms Jane L. Norman
Managing Director and CEO

19 August 2025

Amplitude energy

Independent auditor's report to the members of Amplitude Energy Limited

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Ernst & Young
121 King William Street
Adelaide SA 5000 Australia
GPO Box 1271 Adelaide SA 5001

Tel: +61 8 8417 1600
Fax: +61 8 8417 1775
ey.com/au

Independent auditor's report to the members of Amplitude Energy Limited

Report on the audit of the financial report

Opinion

We have audited the financial report of Amplitude Energy Limited (the Company) and its subsidiaries (collectively the Group), which comprises the consolidated statement of financial position as at 30 June 2025, the consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the year then ended, notes to the financial statements, including material accounting policy 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:

a. Giving a true and fair view of the consolidated financial position of the Group as at 30 June 2025 and of its consolidated financial performance for the year ended on that date; and

b. Complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

Basis for opinion

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

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

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial report of the current year. These matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, but we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the financial report* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the financial report. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying financial report.

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1. Carrying value of gas and oil assets and exploration and evaluation assets

Why significant	How our audit addressed the key audit matter
At 30 June 2025, the Group's Gas and Oil assets and Exploration and Evaluation assets are valued at $484.8 million and $210.3 million respectively. At year-end, the Group identified an indicator of impairment in respect of four Exploration and Evaluation assets, for which an impairment charge of $27.4m was recognised, as disclosed in Note 14. In accordance with the requirements of Australian Accounting Standards, the Group is required to assess in respect each reporting period, whether there is any indication that an asset may be impaired, or conversely whether reversal of a previously recognised impairment may be required. If any impairment indicators exist, an entity shall estimate the recoverable amount of the asset or cash generating unit ('CGU'). The assessments for indicators of impairment and reversals of impairment are judgmental and include assessing a range of external and internal factors, including the determination of preliminary recoverable amounts for CGUs where relevant. Where impairment indicators are identified throughout the period, forecasting cash flows for the purpose of determining the recoverable amount of a CGU, including a preliminary recoverable amount, involves accounting estimates and judgements and is affected by expected future performance and market conditions. Key forecast assumptions, such as discount rates, foreign exchange rates, commodity prices and recoverable hydrocarbon reserves used in the Group's impairment assessment are disclosed in Note 14. We considered the impairment trigger assessment of the Group's CGUs and its exploration and evaluation assets throughout the period, and the related disclosures in the financial report, to be a key audit matter.	*Assessing indicators of impairment* In assessing whether indicators of impairment or reversal of impairment existed throughout the period, we evaluated whether there had been significant changes to the external or internal factors considered by the Group. The indicators included specific matters related to the Group, CGUs, and industry as well as broader market-based indicators. In the process of assessing for triggers of impairment the Group prepared preliminary recoverable amounts, we assessed the composition of the forecast cash flows and the reasonableness of key inputs used to formulate the trigger assessment valuations. Depending on the CGU, these audit procedures included: ► Reconciling future production profiles to the latest hydrocarbon reserves and resources estimates (discussed further below), current sanctioned development budgets, long-term asset plans and historical operations. ► Independently developing a reasonable range of forecast gas and oil prices, based upon external data. We compared this range to the Group's forecast gas and oil price assumptions to evaluate whether the Group's assumptions were reasonable. In developing our ranges, we obtained a variety of third-party forecasts, peer information and market data, which contemplate forecast gas and oil demand in a decarbonising global economy. ► Evaluating discount rates used by the Group for impairment tests, which contemplate costs of capital considerations in light of a decarbonising global economy. ► Evaluating the reasonableness of inflation rates, foreign exchange rates and carbon costs used by the Group for impairment tests. ► Understanding the operational performance of the CGUs relative to plan, comparing future operating and development expenditure within the impairment assessments to current sanctioned budgets, historical expenditures and long-term asset plans, and ensuring the Group's judgements were within our expectations based upon other information obtained throughout the audit. ► Assessing the key drivers of changes to calculated recoverable amounts and ensuring the reasonableness of those drivers' assumptions. ► Testing the mathematical accuracy of the Group's discounted cash flow models and their compliance with the requirements of the Australian Accounting Standards.

	Future production profiles A key input to impairment trigger assessments is the Group's production forecast, which is closely related to the Group's hydrocarbon reserves and resource estimates and development plans. Our audit procedures over the work of the Group's internal and external experts included: ► Assessing the processes and relevant controls associated with estimating reserves and resources. ► Reading reports provided by internal and external experts and assessing their scopes of work and findings. ► Assessing the qualifications, competence and objectivity of the Group's internal and external experts involved in the estimation process. ► Assessing whether key economic assumptions used in the estimation of reserves and resources volumes were consistent with those used by the Group in the impairment testing of gas and oil assets, where applicable. ► Understanding the reasons for reserve changes or the absence of reserves changes, for consistency with other information that we obtained throughout the audit. *Impact of Climate-Related Risks* In undertaking our impairment audit procedures, we incorporated consideration of climate change-related risks by: ► Performing independent sensitivity analysis of recoverable amounts across a range of key inputs which have been formulated to incorporate uncertainty risk associated with climate change, such as the inclusion of premiums in discount rates and alternative price forecasts which contemplate varied climate change-related assumptions and scenarios. ► Assessing the recoverable amount for the appropriate inclusion of carbon costs. ► Assessing the overall results of our audit procedures carried out over restoration and rehabilitation obligations and their impact on impairment risk (refer to the 'Accounting for Restoration Obligations' Key Audit Matter below). ► Inquiring of management and reading the Group's communication and publicly stated climate commitments regarding sustainability and climate-related risks where relevant and their impact on financial reporting. *Exploration and Evaluation Assets* For exploration and evaluation assets, we assessed whether any impairment indicators, as set out in AASB 6: *Exploration for and Evaluation of Mineral Resources*, were present, Our audit procedures included:

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Why significant	How our audit addressed the key audit matter
	► Assessing whether the Group's right to explore was current, which included obtaining supporting documentation such as licenses, permits and agreements. ► Assessing the Group's intention to carry out significant ongoing exploration and evaluation activities in the relevant areas of interest and enquiring of senior management as to their intentions and the strategy of the Group as it relates to particular areas of interest. ► Assessing whether exploration and evaluation data, commercial, technical, climate-related or other information existed to indicate that the carrying value of capitalised exploration and evaluation assets was unlikely to be recovered through successful evaluation and development or sale. We assessed the adequacy and appropriateness on the disclosures included in the Notes to the financial report.

2. Accounting for Restoration obligations

Why significant	How our audit addressed the key audit matter
At 30 June 2025, the Group has recognised provisions for restoration obligations relating to onshore and offshore assets of $440.5 million. As disclosed in Note 15, the calculation of restoration provisions is conducted by specialist engineers and requires significant judgements, assumptions and estimates to be made by the Group regarding removal date, compliance with environmental legislation and regulations, the extent of restoration activities required, the engineering methodology for estimating costs, future removal technologies in determining the removal costs and liability-specific discount rates to determine the present value of these cash flows. The judgements and estimates are based upon conditions existing at 30 June 2025, including key assumptions related to certain items remaining in-situ. Australian regulatory approval for these items remaining in-situ will only be sought towards the end of the respective asset's field life and accordingly, at 30 June 2025, there is uncertainty whether the Australian regulator will approve plans for these items to be decommissioned in-situ. Changes to these significant judgements, assumptions and estimates can lead to changes in the restoration provisions. Accordingly, the restoration provision calculation and the related disclosures in the financial report are a key audit matter.	We assessed the restoration obligation provisions prepared by the Group, evaluating the assumptions and methodologies used and the estimates made. Our audit procedures included the following: ► Evaluating the Group's process for identifying its legal and regulatory obligations for restoration and decommissioning and testing the completeness of operating locations. ► Understanding and documenting the controls over the Group's internal methodology for determining and approving gross cost estimates used to calculate the Group's restoration provisions. ► In conjunction with our environmental specialists, assessing the reasonableness and completeness of restoration cost estimates based on the relevant current legal and regulatory requirements. ► Assessing the qualifications, competence and objectivity of the Group's internal and external experts engaged to carry out the gross restoration cost estimations as a basis for our reliance on the output of their work. ► Comparing current year cost estimates to those of the prior year and obtained explanations from management and both internal and external experts for observed changes.

Why significant	How our audit addressed the key audit matter
	► Comparing the timing of the future cash outflows against the anticipated end-of-field lives, cross-checking that these dates were consistent with the Group's reserve estimates, impairment calculations and regulatory notices. ► Evaluating the appropriateness of the discount rates, inflation rates and foreign exchange rates used to calculate the present value of each of the provisions. ► Testing the mathematical accuracy of the restoration provision calculations. *Impact of Climate-Related Risks* In undertaking our restoration procedures, we incorporated consideration of climate change-related risks by: ► Understanding the regulatory framework in which each project operates to ensure compliance with the regulatory requirements of the various jurisdictions as they relate to restoration obligations. ► Evaluating the assumptions associated with the form and extent of abandonment activities, including conformity with regulation and industry practice, and the nature of the items expected to be left in-situ in abandonment activities. ► Reading litigation registers, correspondence with solicitors and regulators to confirm the completeness of liabilities recognised. ► Obtained an understanding of the estimated dates for the commencement of restoration and rehabilitation activities and the possible impacts of physical risks of climate change on the Group's provisions. We assessed the adequacy and appropriateness of the disclosures included in the Notes to the financial report.

Information other than the financial report and auditor's report thereon

The directors are responsible for the other information. The other information comprises the information included in the Company's 30 June 2025 annual report other than the financial report and our auditor's report thereon. We obtained the directors' report and Operating Financial Review that are to be included in the annual report, prior to the date of this auditor's report, and we expect to obtain the remaining sections of the annual report after the date of this auditor's report.

Our opinion on the financial report does not cover the other information and we do not and will not express any form of assurance conclusion thereon, with the exception of the Remuneration Report and our related assurance opinion.

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 on the other information obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the directors for the financial report

The directors of the Company are responsible for the preparation of:

- The financial report (other than the consolidated entity disclosure statement) that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001*; and
- The consolidated entity disclosure statement that is true and correct in accordance with the *Corporations Act 2001;* and

for such internal control as the directors determine is necessary to enable the preparation of:

- The financial report (other than the consolidated entity disclosure statement) that gives a true and fair view and is free from material misstatement, whether due to fraud or error; and
- The consolidated entity disclosure statement that is true and correct and is free of misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters relating 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 judgment 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 units 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.

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

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

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

Report on the audit of the Remuneration Report

Opinion on the Remuneration Report

We have audited the Remuneration Report included in pages 69 to 89 of the directors' report for the year ended 30 June 2025.

In our opinion, the Remuneration Report of Amplitude Energy Limited for the year ended 30 June 2025, complies with section 300A of the *Corporations Act 2001*.

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Responsibilities

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

Ernst & Young

Darryn Hall
Partner
Adelaide
19 August 2025

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At Amplitude we have 50% female representation on the Executive Leadership Team.

Amplitude energy

Auditor's Independence Declaration

to the directors of Amplitude Energy Limited

EY
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Ernst & Young
121 King William Street
Adelaide SA 5000 Australia
GPO Box 1271 Adelaide SA 5001

Tel: +61 8 8417 1600
Fax: +61 8 8417 1775
ey.com/au

Auditor's independence declaration to the directors of Amplitude Energy Limited

As lead auditor for the audit of the financial report of Amplitude Energy Limited for the financial year ended 30 June 2025, I declare to the best of my knowledge and belief, there have been:

a. No contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the audit;

b. No contraventions of any applicable code of professional conduct in relation to the audit; and

c. No non-audit services provided that contravene any applicable code of professional conduct in relation to the audit.

This declaration is in respect of Amplitude Energy Limited and the entities it controlled during the financial year.

Ernst & Young

Darryn Hall
Partner
19 August 2025

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Securities Exchange and Shareholder Information

As at 1 September 2025

Listing

The company's shares are quoted on the Australian Securities Exchange under the code of "AEL".

Number of Shareholders

There were 7,328 shareholders as at 1 September 2025. All issued shares carry voting rights. On a show of hands every member at a meeting of shareholders shall have one vote and upon a poll each share shall have one vote.

Distribution of Shareholdings

Range	Total holders	Shares	% of Total Shares
1-1,000	958	235,776	0.01
1,001 - 5,000	1,928	5,548,280	0.21
5,001 - 10,000	1,138	9,216,777	0.35
10,001 - 100,000	2,565	94,718,176	3.57
>100,001	739	2,541,689,015	95.86
Total	7,328	2,651,408,024	100.00

Unmarketable Parcels

At 1 September 2025 there were 1,631 shareholders, representing 1,322,845 shares, holding less than a marketable parcel of 2,041 shares in the company.

Unquoted Options on Issue

Nil

Unquoted Performance Rights

Number of Holders of Performance Rights	Total Rights
108	71,336,943 Performance Rights
8	17,452,898 Share Appreciation Rights

Twenty Largest Shareholders

Rank	Shareholder Name	Shares	%
1	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED	712,126,490	26.86
2	CITICORP NOMINEES PTY LIMITED	593,399,681	22.38
3	J P MORGAN NOMINEES AUSTRALIA PTY LIMITED	455,257,244	17.17
4	WASHINGTON H SOUL PATTINSON AND COMPANY LIMITED	100,335,389	3.78
5	MCCUSKER HOLDINGS PTY LTD	65,000,000	2.45
6	UBS NOMINEES PTY LTD	63,572,668	2.40
7	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED <NT-COMNWLTH SUPER CORP A/C>	52,800,079	1.99
8	QUOTIDIAN NO 2 PTY LTD	25,644,883	0.97
9	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED - A/C 2	19,714,343	0.74
10	BNP PARIBAS NOMINEES PTY LTD <AGENCY LENDING A/C>	15,774,919	0.59
11	BNP PARIBAS NOMS PTY LTD	15,552,400	0.59
12	NATIONAL NOMINEES LIMITED	14,871,756	0.56
13	BNP PARIBAS NOMS PTY LTD <GLOBAL MARKETS>	12,667,755	0.48
14	CERTANE CT PTY LTD <ARGONAUT NATURAL RES FUND>	10,803,918	0.41
15	MR SIMON HANNES + MRS MIGNON CATHERINE BOOTH <SGH SUPER FUND A/C>	9,895,323	0.37
16	INVIA CUSTODIAN PTY LIMITED <DAVID PETER MAXWELL A/C>	9,349,573	0.35
17	WANNA QUICKIE PTY LTD	8,909,607	0.34
18	BOND STREET CUSTODIANS LIMITED <LAMAN - D05019 A/C>	8,777,699	0.33
19	SARACENI'S PTY LTD	8,000,000	0.30
20	INVIA CUSTODIAN PTY LIMITED <LEWXAM SUPER FUND A/C>	7,175,387	0.27
Total Top 20 Holders		2,209,629,114	83.34
Total Remaining Holders Balance		441,778,910	16.66

Substantial Shareholders

The following were substantial holders in the company as at 1 September 2025, as disclosed in substantial holding notices given to the Company as required by section 671B of the Corporations Act.

Name of entity	Number of securities in which substantial shareholder has a relevant interest as at date of last notice	Voting power as at date of last notice
Challenger Limited	192,448,580	7.26%
Greencape Capital Pty Ltd	192,448,580	7.26%
Retail Employees Superannuation Pty Limited as trustee for the Retail Employees Superannuation Trust	187,880,025	7.08%
Yarra Capital Management and its associated entities	185,615,005	7.00%
L1 Capital Pty Limited	181,667,300	6.85%
Mitsubishi UFJ Financial Group, Inc.	162,407,586	6.13%
First Sentier Group Limited	162,407,586	6.13%
Pinnacle Investment Management Group Limited	132,580,489	5.00%

Enquiries and share registry address

Shareholders with enquiries about their shareholdings should contact the Company's share registry, Computershare Investor Services Pty Ltd, via the contact details in the Corporate Directory of this Annual Report.

Online Shareholder information

Shareholders can obtain information about their holdings or view their account instructions online, as well as download forms to update their holder details. For identification and security purposes, you will need to know your Holder Identification Number (HIN/SRN), Surname/Company Name and Post/Country Code to access. This service is accessible via the Computershare website.

Change of address

Shareholders who have changed their address should advise Computershare in writing or online via the Computershare website. Written notification can be mailed or faxed to Computershare and must include both old and new addresses and the security holder reference number (SRN) of the holding. Change of address forms are available for download from the Computershare website. Shareholders who have broker sponsored holdings should contact their broker to update these details.

Annual Report mailing list

Shareholders who wish to vary their annual report mailing arrangements should advise Computershare online via the Computershare website. Electronic versions of the report are available to all via the Company's website. Annual Reports will be mailed to all shareholders who have elected to be placed on the mailing list for this document.

Forms for download

All forms relating to amendment of holding details and holder instructions to the Company are available for download from the Computershare website.

Investor information

Information about the Company is available from a number of sources:

Website
www.amplitudeenergy.com.au

E-news
Shareholders can nominate to receive Company information electronically. This service is hosted by Computershare and can be accessed via Computershare's website.

Publications
The Annual Report is the major printed source of Company information. Other publications include the Sustainability Report, half-yearly and quarterly reports, company press releases and investor presentations. All publications can be obtained either through the Company's website or by contacting the Company.

Telephone or email enquiry
Tom Fraczek,
Investor Relations & Treasurer
+61 439 555 165,
tom.fraczek@amplitudeenergy.com.au

This Annual Report has been prepared to provide Shareholders with an overview of Amplitude Energy Limited's performance for the 2025 financial year and its outlook. The Annual Report is mailed to shareholders who elect to receive a copy and is available free of charge on request (see Shareholder Information printed in this Annual Report). This Annual Report and other information about the company can be accessed via the Company's website at www.amplitudeenergy.com.au

Annual General Meeting

Date of meeting
Thursday, 6 November 2025

Time of meeting
10:30 am (Australian Central Daylight Time)

Place of meeting
Ground Floor Auditorium
55 Currie Street, Adelaide SA 5000

The Notice of Meeting has been mailed to Shareholders. Additional copies can be obtained from the Company's registered office or downloaded from our website at www.amplitudeenergy.com.au

Abbreviations and terms

This Report uses terms and abbreviations relevant to the Group, its accounts and the petroleum industry.

The terms "the Company" and "Amplitude Energy" and "the Group" are used in the report to refer to Amplitude Energy Limited and/or its subsidiaries. The terms "2025", or "2025 financial year" refer to the 12 months ended 30 June 2025 unless otherwise stated. References to "2024", or other years refer to the 12 months ended 30 June of that year.

$: Australian dollars unless specified otherwise

AASB: Australian Accounting Standards Board
ACCC: Australia Competition and Consumer Commission
AEMO: Australian Energy Market Operator
AGP: Athena gas plant
ANREO: accelerated, non-renounceable entitlement offer
ATSR: absolute total shareholder return
ASRS: Australian sustainability reporting standards
bbls: barrels of oil
bbls/d: barrels of oil per day
BMG: Basker, Manta, Gummy
CAGR: compound average growth rate
CHN: Casino, Henry, and Netherby
CGU: cash generating unit
DWGM: declared wholesale gas market
EBITDAX: earnings before interest, tax, depreciation, amortisation, restoration, exploration and evaluation expense and impairment
ECSP: East Coast Supply Project
EIP: equity incentive plan
ELT: Executive Leadership Team
EP: environment plan
ESG: environmental, social, and governance
FAR: fixed annual remuneration
FEED: front-end engineering and design
FTE: full time equivalent
FVLCD: fair value less cost of disposal
GJ: gigajoule
GSA: gas sales agreement
GST: goods and services taxes
HSE: health, safety and environment
HSEC: health, safety, environment and community
IFRS: International Financial Reporting Standards
JV: joint venture
JOA: joint operating agreement
kbbl: thousand barrels of oil
KMP: key management personnel
LNG: liquified natural gas
LTI: lost time injury
LTIP: long-term incentive plan
MEPAU: Mitsui E&P Australia and its associated entities
MMbbl: million barrels of oil
MMboe: million barrels of oil equivalent
OGPP: Orbost gas processing plant
OPP: offshore project proposal
Pertamina: PT Pertamina Hulu Energi
PJ: petajoules
PJe: petajoules-equivalent
PRRT: Petroleum resource rent tax
PRs: performance rights
RTSR: relative total shareholder return
STIP: short-term incentive plan
STTM: short-term trading market
TJ: terajoules
TJ/d: terajoules per day
TRIFR: total recordable injury frequency rate
US: United States
VIU: value in use
2P: best estimate of reserves. The sum of proved plus probable reserves
2C: best estimate of contingent resources

Corporate directory

Directors
John C Conde AO, Chairman
Jane L Norman, Managing Director
Timothy G Bednall
Elizabeth A Donaghey
Gary Gray AO
Frank A Tudor
Ian Davies

Company secretary
Nicole Ortigosa

Registered office and business address
Level 11, 55 Currie Street
Adelaide, South Australia 5000
Telephone: +618 8100 4900
Facsimile: +618 8100 4997
Email: customerservice@amplitudeenergy.com.au
Website: www.amplitudeenergy.com.au

Auditors
Ernst & Young
121 King William Street
Adelaide, South Australia 5000

Share registry
Computershare Investor Services Pty Limited
Level 5, 115 Grenfell Street
Adelaide, South Australia 5000
Website: investorcentre.com/au
Telephone:
Australia 1300 556 161
International +61 3 9415 4000
Facsimile +61 3 9473 2500

Head Office
Level 11, 55 Currie Street
Adelaide, South Australia 5000
Phone: +61 8 8100 4900
www.amplitudeenergy.com.au