QUARTERLY REPORT

For the three months ended 31 March 2025

PROUDLY PART OF AUSTRALIA'S ENERGY FUTURE

Highlights

15 April 2025

- **East Coast Supply Project (ECSP) JV alignment reached:** with O.G. Energy, allowing the 3-well drilling programme to proceed on a 50/50 basis, with O.G. Energy to fund its 50% share of all past and future costs[1]
- **Quarterly production:** of 67.8 TJe/d or 6.10 PJe for Q3 FY25, 7% lower on a daily average basis than the prior quarter, primarily due to planned maintenance shutdowns at both the OGPP and AGP
- **OGPP improvements continue:** including a new 30-day average production record of 67.5 TJ/d and no third party gas purchases made in the quarter. Use of H_2S scavenger injection, chemical clean-in-place and new absorber internal configuration are expected to yield additional future production improvements
- **Record average realised gas price:** of $10.19/GJ for Q3 FY25 (+2% on Q2 FY25) and $9.85/GJ FY25 YTD (+13% vs. prior corresponding period), supported by annual inflation-indexation of gas contract prices and continued spot sales into the Sydney and Victorian markets
- **Net debt reduced:** to $248.8 million (-2% on Q2 FY25), despite increased ECSP spend during the quarter (at 100%), general visual inspection activity in the Otway and shutdowns at both plants

Comments from Managing Director and CEO, Jane Norman

"We are excited to welcome O.G. Energy as our new, aligned joint venture partner in the Otway Basin and confirm our preferred 3-well drilling programme for the East Coast Supply Project. We expect the ECSP to be transformational for Amplitude Energy, significantly increasing the company's scale, margins and earnings. With the project now progressing at pace, we are closely managing our contracting strategy, hedging risks and sharing services with other rig consortium members wherever feasible to reduce project costs and risks. We are encouraged by the strong customer interest shown in securing gas supply from the ECSP, with those customers recognising the limited supply alternatives available and the high costs and infrastructure constraints of importing gas from Queensland or via LNG."

"We are pleased with the performance of our plants following their planned maintenance shutdowns and progress against our FY25 financial targets. Our increased exposure to spot gas sales, and relatively strong spot gas pricing in the Sydney and Victorian markets over the summer period, resulted in improved realised gas prices and operational cash flows."

Key performance metrics[2]

$ million unless indicated	Mar Q3 FY24	Dec Q2 FY25	**Mar Q3 FY25**	*Qtr on Qtr change*	FY24 YTD	**FY25 YTD**	*Change*
Production (PJe)	5.74	6.67	**6.10**	*(9%)*	16.93	**19.62**	*16%*
Sales volume (PJe)	5.77	6.61	**6.04**	(9%)	17.42	**19.46**	12%
Average gas price ($/GJ)[3]	9.24	9.98	**10.19**	2%	8.71	**9.85**	13%
Sales revenue	55.9	67.9	**63.4**	(7%)	161.8	**197.1**	22%
Cash and cash equivalents	53.3	51.0	**56.4**	11%	53.3	**56.4**	6%
Net debt	164.7	254.2	**248.8**	(2%)	164.7	**248.8**	51%

[1] Payment of historical costs, subject to completion of the Otway Sale Transaction, is in the form of a carry from completion
[2] Quarterly and FY25 YTD figures are unaudited and subject to production allocation reconciliations
[3] Average realised gas price across both Gippsland and Otway basins, including spot sales

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Production

Quarterly gas and oil production averaged 67.8 TJe/d, or 6.10 PJe for the quarter, 7% lower on a daily average basis than the prior quarter, primarily due to the planned maintenance shutdowns at both Orbost Gas Plant and Athena Gas Plant in March 2025.

Production by product	Mar Q3 FY24	Dec Q2 FY25	**Mar Q3 FY25**	*Qtr on Qtr change*	FY24 YTD	**FY25 YTD**	*Change*
Sales gas (PJ)	5.54	6.51	**5.96**	*(8%)*	16.30	**19.15**	*17%*
Oil & condensate (kbbl)	32.76	26.76	**23.56**	*(12%)*	103.12	**77.27**	*(25%)*
Total production (PJe)	5.74	6.67	**6.10**	*(9%)*	16.93	**19.62**	*16%*
Total production (MMboe)	0.94	1.09	**1.00**	*(9%)*	2.77	**3.21**	*16%*

Gippsland Basin (Sole)[4]

Sole gas production processed through the OGPP averaged 57.8 TJ/d, or 5.20 PJ for the quarter, 5% lower on a daily average basis than the prior quarter of 60.7 TJ/d. Excluding the planned maintenance shutdown, OGPP production averaged 62.7 TJ/d, or 3% higher than the prior quarter. Apart from a minor compressor trip in March, the plant achieved no reliability loss during the quarter.

A liquid H_2S scavenger chemical injector was installed and commissioned at the OGPP in February, resulting in improved sulphur removal outcomes and increasing redundancy in the overall sulphur removal system. With the support of H_2S scavenger injection, the OGPP achieved a new record 30-day average production rate of 67.5 TJ/d in mid-March.

The planned OGPP maintenance shutdown was conducted in late March with the full planned scope of works completed in seven days without injuries or significant incidents. The scope of work included installation of chemical clean-in-place hardware 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 has since operated at, or near, nameplate capacity.

Strong performance of the absorbers following the shutdown, together with redundancy provided by H_2S scavenger injection, has allowed the Company to defer the next replacement of media in the polisher unit to May 2025.

Otway Basin (Casino, Henry and Netherby or CHN)[5]

CHN gas production processed through the Athena Gas Plant averaged 8.4 TJ/d, or 0.76 PJ for the quarter (both net to Amplitude Energy's 50% share), 16% lower than the prior quarter of 10.0 TJ/d. Excluding the planned maintenance shutdown, AGP production averaged 8.9 TJ/d net to Amplitude Energy's 50% share.

Repairs to the CHN electro-hydraulic umbilical cable in late February re-established communication to Casino 5, Henry 2 and Netherby 1, allowing cycling of those 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.

Cooper Basin[6]

Oil production in the Cooper Basin averaged 253 bbls/d (net to Amplitude Energy's 25% share), 10% lower than the prior quarter of 280 bbls/d, due primarily to natural field decline.

Production by basin	Mar Q3 FY24	Dec Q2 FY25	**Mar Q3 FY25**	*Qtr on Qtr change*	FY24 YTD	**FY25 YTD**	*Change*
Gippsland Basin (Sole)							
Sales gas (PJ)	4.73	5.58	**5.20**	*(7%)*	13.46	**16.52**	*23%*

[4] Amplitude Energy 100% and operator
[5] Amplitude Energy 50% and operator
[6] Amplitude Energy 25%, Beach Energy 75% and operator

Otway Basin (CHN)							
Sales gas (PJ)	0.80	0.92	**0.76**	*(18%)*	2.84	**2.63**	*(7%)*
Condensate (kbbl) [7]	0.77	0.97	**0.83**	*(15%)*	2.70	**2.77**	*3%*
Cooper Basin							
Oil (kbbl)[8]	31.99	25.79	**22.74**	*(12%)*	100.42	**74.50**	*(26%)*
Total production (PJe)	5.74	6.67	**6.10**	*(9%)*	16.93	**19.62**	*16%*
Total production (MMboe)	0.94	1.09	**1.00**	*(9%)*	2.77	**3.21**	*16%*

Exploration and development

East Coast Supply Project (Offshore Otway Basin)

As announced on 24 March 2024, 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 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 date of signing, and reimburse Amplitude Energy for 50% of all historical ECSP project costs spent[9]. 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 Mitsui E&P Australia ("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[10]. 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.

The respective boards of Amplitude Energy and O.G. Energy have 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 intends to exercise its options for the second and third well drilling slots, with the Transocean Equinox rig consortium in due course, with those two slots targeting the Juliet prospect followed by the Annie discovery.

On 24 March the Company 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 development and modifications at the Athena Gas Plant.

The Transocean Equinox drilling rig arrived in the Offshore Otway Basin earlier this month 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 continues, with multiple contracts awarded during the quarter to progress with drilling for the three well programme. Subsea tie-in planning is also progressing, with FEED entry for the ECSP development phase expected shortly.

Amplitude Energy's ECSP capital expenditure is expected to be funded from a range of sources including existing cash on hand, underlying organic cash generation over 2025-2028 and the Company's existing bank debt facility. The Company is also considering other potential forms of debt financing to reduce the overall cost of financing the ECSP.

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

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[7] CHN condensate production data is preliminary for the current quarter, awaiting March reconciled data.
[8] Cooper Basin production data is preliminary for the current quarter, awaiting March reconciled data.
[9] Payment of back costs, subject to completion of the Otway Sale Transaction, is in the form of a carry from completion. As at 31 January 2025, the reimbursement amounts to approximately A$25 million.
[10] No assurances can yet be given as to timing of completion, or whether approvals will ultimately be granted. In the event that the transaction does not complete, Amplitude Energy and O.G. Energy will seek alternative ownership structures to facilitate O.G. Energy's 50% participation in the ECSP

Subject to exploration success, the Company and O.G. Energy intend to proceed to a final investment decision to undertake the development phase of the project in 2026. Amplitude Energy is currently in discussions with potential gas customers regarding foundation contracts for the ECSP.

Patricia Baleen gas storage opportunity (Gippsland Basin)

Amplitude Energy continued to assess the potential to commercialise the shut in Patricia Baleen field in VIC/RL16 (Amplitude Energy 100%) as a gas storage or production asset. During the quarter Amplitude Energy completed engineering and early cost estimates for umbilical repair options and commenced a pipeline re-lifing study.

Financial

Sales volume and revenue

Total Q3 FY25 gas and liquids volumes sold averaged 67.1 TJe/day (6.04 PJe total for the quarter), 7% lower on a daily average basis than the previous quarter of 71.9 TJe/day (6.61PJe total), primarily due to the planned plant shutdowns.

Surplus Gippsland gas production, relative to Sole term contracts, resulted in quarterly spot gas sales of 1,756 TJ, 9% lower than the previous quarter of 1,928 TJ.

Increases in the Company's contracted gas prices due to annual inflation indexation and relatively strong spot gas prices in the Sydney and Victorian markets over the summer period resulted in higher average realised prices for the quarter overall. The Company achieved an average realised gas price of $10.19/GJ in Q3 FY25, 2% higher than the $9.98/GJ achieved in Q2 FY25, and 10% higher than the $9.24/GJ achieved in the previous FY24 corresponding quarter.

PEL 92 volumes sold were 21,878 bbls (Q2 FY25: 25,174 bbls), at an average oil price realisation of A$132.83/bbl (Q2 FY25: A$123.48/bbl).

Total liquids revenue, including condensate, was $3.2 million in the quarter (Q2 FY25 $3.5 million). Crude oil inventory at 31 Mar 2025 was 11,391 bbls (31 December 2024: 8,388 bbls).

		Mar Q3 FY24	Dec Q2 FY25	**Mar Q3 FY25**	*Qtr on Qtr change*	FY24 YTD	**FY25 YTD**	*Change*
Sales volume								
Gas	PJ	5.61	6.45	**5.90**	(9%)	16.69	**18.99**	14%
Oil	kbbl	26.03	25.17	**21.88**	(13%)	116.38	**73.92**	(36%)
Condensate	kbbl	0.77	0.97	**0.73**	(25%)	2.70	**2.67**	(1%)
Total sales volume	PJe	5.77	6.61	**6.04**	(9%)	17.42	**19.46**	12%
Sales revenue ($ million)								
Gas[11]		51.8	64.4	**60.2**	(7%)	145.4	**187.0**	29%
Oil & condensate		4.1	3.5	**3.2**	(9%)	16.4	**10.1**	(39%)
Total sales revenue		55.9	67.9	**63.4**	(7%)	161.8	**197.1**	22%
Average realised prices								
Gas	$/GJ	9.24	9.98	**10.19**	2%	8.71	**9.85**	13%
Oil & condensate	$/boe	144.66	133.44	**132.83**	5%	135.68	**127.96**	(6%)

The tables below summarise gas sales and sources.

[11] Includes sale of third-party gas purchases

Sole GSA sales and sources		Dec Q2 FY25	Mar Q3 FY25		Dec Q2 FY25	Mar Q3 FY25
Sole GSA sales	PJ	3.6	3.4	TJ/d (average)	**39.1**	37.7
Sole spot sales[12]	PJ	1.9	1.8	TJ/d (average)	**21.0**	19.5
Comprising:						
OGPP processing	PJ	5.5	5.2	TJ/d (average)	**60.1**	57.2
Third-party gas purchases[13]	PJ	0.0	0.0	TJ/d (average)	**0.0**	0.0

CHN GSA sales and sources		Dec Q2 FY25	Mar Q3 FY25		Dec Q2 FY25	Mar Q3 FY25
CHN GSA sales	PJ	0.9	0.8	TJ/d (average)	10.0	8.4

Capital expenditure

Q3 FY25 incurred capital expenditure was $28.3 million, the majority of which was growth capital, spent on progressing the ECSP.

$ million	Mar Q3 FY24	Dec Q2 FY25	Mar Q3 FY25	*Qtr on Qtr change*	FY24 YTD	FY25 YTD	*Change*
Exploration and appraisal	0.7	7.3	**23.4**	221%	5.1	**39.9**	682%
Development	2.4	3.6	**4.9**	36%	5.7	**12.3**	116%
Total capital expenditure	3.1	10.9	**28.3**	160%	10.8	**52.2**	383%

By basin, $ million	Q3 FY25			FY25 YTD		
	Exploration	Development	**Total**	Exploration	Development	**Total**
Otway Basin	22.9	2.5	**25.4**	38.4	3.7	**42.1**
Gippsland Basin	0.3	1.4	**1.7**	0.8	5.8	**6.5**
Cooper Basin	0.2	0.2	**0.4**	0.8	1.0	**1.8**
Other	-	0.8	**0.8**	-	1.8	**1.8**
Total capital expenditure	23.4	4.9	**28.3**	39.9	12.3	**52.2**

Liquidity

As at 31 March 2025, Amplitude Energy had cash reserves of $56.4 million (Q2 FY25: $51.0 million), with drawn debt at $305.2 million (Q2 FY25: $305.2 million), as summarised below.

$ million	Mar Q3 FY24	Dec Q2 FY25	Mar Q3 FY25	*Qtr on Qtr change*	FY24 YTD	FY25 YTD	*Change*
Cash and cash equivalents	53.3	51.0	**56.4**	11%	53.3	**56.4**	6%
Drawn debt	218.0	305.2	**305.2**	0%	218.0	**305.2**	40%
Net debt	164.7	254.2	**248.8**	(2%)	164.7	**248.8**	51%

[12] Sole spot sales were 1,756 TJ in Q3 FY25 (Q2 FY25: 1,928 TJ). Sole spot sales also includes as-available sales to Alinta under the Bairnsdale Power Station Agreement.
[13] Third party purchases were 0 TJ in Q3 FY25 (Q2 FY25: 3 TJ).

Cash generation during the quarter was impacted by $22.9 million of ECSP costs incurred (at 100%), $5.1 million of costs incurred with the general visual pipeline inspection programme in the Otway, and approximately $4.2 million of costs incurred related to the two planned plant maintenance shutdowns.

Commercial, corporate and subsequent events

Minerva decommissioning

On 31 March, the Company announced that it expects an increase to its share of Minerva restoration costs, following an update of the programme from the Minerva operator, Woodside Energy Limited (the "Operator"). The Operator informed Amplitude Energy that it expects a significant increase in the timeframe and cost of the decommissioning programme's execution, logistics and weather allowances. The Operator's total estimate for the cost of the programme has resulted in a more than 100% increase versus the budget put forward by the Operator in November 2024.

The Minerva budget increase will result in an additional pre-tax restoration expense of approximately A$24 million in Amplitude Energy's FY25 Consolidated Statement of Comprehensive Income, with the cash costs to be spread across FY25 and FY26 based on the current schedule of activity.

Amplitude Energy holds a 10% non-operating interest in the Minerva field, with the Operator holding the remaining 90%. The Company's 10% Minerva working interest is a legacy, minority asset position which was acquired as part of Amplitude Energy's acquisition of multiple assets from Santos in 2017, including its current producing interests in the Otway and Gippsland Basins.

The Operator expects to have completed decommissioning of the subsea facilities (pipeline and associated infrastructure) by the end of May 2025 with well abandonment work expected to be completed by August 2025.

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.

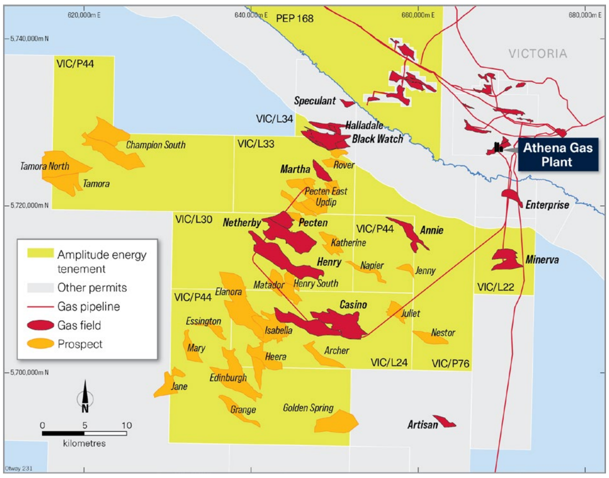
Pertamina, via its Australian subsidiary (now deregistered), participated in the BMG oil project during its production life. Amplitude Energy's claim against Pertamina arises from the withdrawal and abandonment provisions of the Joint Operating and Production Agreement, and a parent company guarantee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

The Court has ordered the parties to attend mediation, which is scheduled for May 2025.

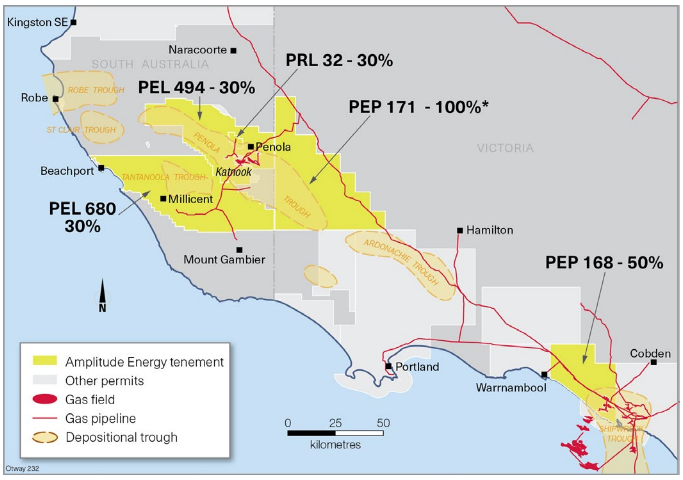
Amplitude Energy tenements

Please refer to Amplitude Energy's 2024 Annual Report for further information regarding tenement interests.

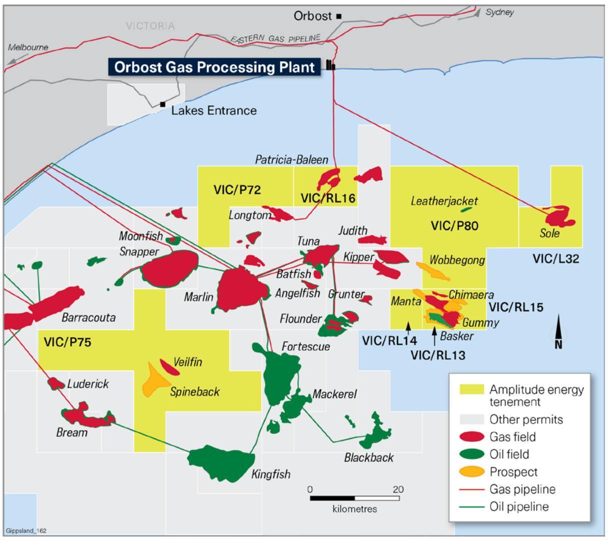
Offshore Otway Basin:



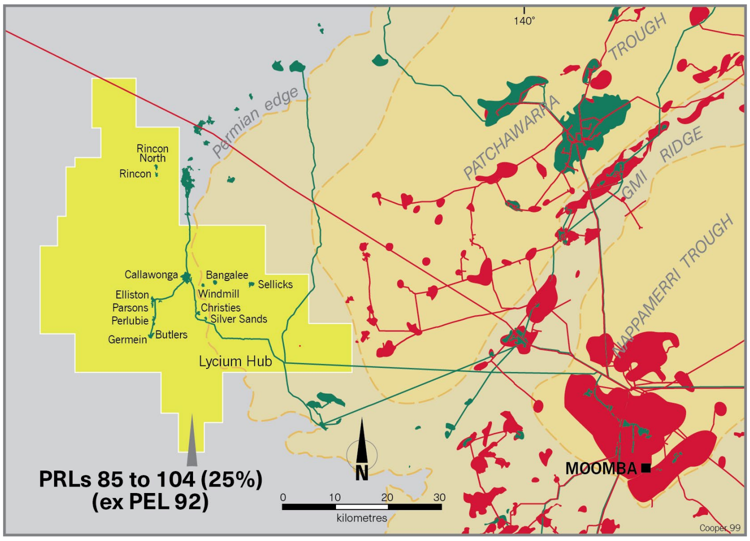
Onshore Otway Basin:



Gippsland Basin:



Cooper Basin



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Terms, abbreviations and conversion factors

Terms and abbreviations

$	Australian dollars
AGP	Athena Gas Plant
bbls	Barrels
BMG	Basker, Manta and Gummy fields
CHN	Casino, Henry and Netherby fields
Amplitude Energy or **the Company**	Amplitude Energy Limited ABN 93 096 170 295
ECSP	East Coast Supply Project
GJ	Gigajoules
GSA	Gas Sales Agreement
kbbl	Thousand barrels
MMboe	Million barrels of oil equivalent
OGPP	Orbost Gas Processing Plant
PEL	Petroleum Exploration Licence
PJ	Petajoules
PJe	Petajoules-equivalent
TJ	Terajoules of gas
TJe	Terajoules-equivalent
TJ/d	Terajoules of gas per day

Conversion factors

Gas	1 PJ	= 0.163 MMboe
Oil	1 bbl	= 1 boe
	1 MMboe	= 6.11932 PJe
Condensate	1 bbl	= 1 boe

Disclaimer

This report contains forward looking statements, including statements of current intention, statements of opinion and expectations regarding Amplitude Energy's present and future operations, possible future events and future financial prospects. These statements are subject to risks associated with the oil and gas industry. Amplitude Energy believes the expectations reflected in these statements are reasonable. However, a range of variables or changes in underlying assumptions may affect these statements and may cause actual results to differ. These variables or changes include but are not limited to price, demand, currency, geotechnical factors, drilling and production results, development progress, operating results, engineering estimates, reserve estimates, environmental risks, physical risks, regulatory developments, cost estimates and relevant regulatory approvals (State and Commonwealth).

Amplitude Energy makes no representation and gives no assurance or guarantee as to the likelihood of fulfilment of any forward-looking statement or any outcomes expressed or implied in any forward-looking statements, or discussion of future financial prospects, whether as a result of new information or future events. Forward-looking statements do not constitute guidance. Except as required by applicable law or the ASX Listing Rules, Amplitude Energy disclaims any obligation or undertaking to publicly update any forward-looking statements, or discussion of future financial prospects, whether as a result of new information or of future events.

The ECSP is also subject to project and corporate risks associated with the oil and gas industry. Amplitude Energy believes the expectations reflected in the ECSP are reasonable. However, a range of variables or changes in underlying assumptions may affect these statements and may cause actual results to differ. These variables or changes include but are not limited to price, demand, currency, geotechnical factors, drilling and production results, development progress, operating results, engineering, engineering estimates, reserve estimates, environmental risks, physical risks, regulatory developments, cost estimates, relevant regulatory approvals (State and Commonwealth) and timing delays beyond the reasonable control of Amplitude Energy.

Numbers and percentages in this report have been rounded. As a result, some figures may differ insignificantly due to rounding and totals reported may differ insignificantly from arithmetic addition of the rounded numbers.

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