FY25 half year results

25 February 2025

Disclaimer

This document contains summary information about Amplitude Energy and its activities as at the date of this document and should not be considered to be comprehensive or to comprise all the information which a shareholder or potential investor in Amplitude Energy may require in order to determine whether to deal in Amplitude Energy shares. The information is a general summary only and does not purport to be complete. It should be read in conjunction with Amplitude Energy's periodic reports and other continuous disclosure announcements released to the Australian Securities Exchange, which are available at www.asx.com.au.

This document contains forward looking statements. These statements are subject to risks associated with the oil and gas industry. Amplitude Energy believes the expectations reflected in these statements are reasonable. 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, approvals and cost estimates.

Amplitude Energy makes no representation, assurance or guarantee as to the accuracy or likelihood of fulfilment of any forward-looking statement or any outcomes expressed or implied in any forward-looking statement. 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 following are non-IFRS measures: EBITDAX (earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment); EBITDA (earnings before interest, tax, depreciation, depletion and impairment); EBIT (earnings before interest and tax); underlying profit; and free cash flow (operating cash flows less investing cash flows net of acquisitions and disposals and major growth capex less lease liability payments). Amplitude Energy presents these measures to provide an understanding of Amplitude Energy's performance. They are not audited but are from financial statements reviewed by Amplitude Energy's auditor. Underlying profit excludes the impacts of asset acquisitions and disposals, impairments, hedging, and items that fluctuate between periods.

Numbers 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.

The estimates of petroleum reserves and contingent resources contained in this presentation are at 30 June 2024. Amplitude Energy prepares its petroleum reserves and contingent resources estimates in accordance with the 2018 Petroleum Resources Management System (PRMS) sponsored by the Society of Petroleum Engineers (SPE). The reserves and resources information in this presentation is based on, and fairly represents, information and supporting documentation prepared by, or under the supervision of James Clark, who is a full time employee of Amplitude Energy and is a member of the SPE. He meets the requirements of a QPRRE and is qualified in accordance with ASX Listing Rule 5.41. 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)

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

Approved and authorised for release by Jane Norman, Managing Director and CEO, Amplitude Energy Limited, Level 8, 70 Franklin Street, Adelaide 5000.

Key Contacts

Investor enquiries: Tom Fraczek, Investor Relations & Treasury Manager. +61 439 555 165 | **Media enquiries:** Bindi Gove, Head of External Affairs. +61 406 644 913

#1

H1 FY25 in review

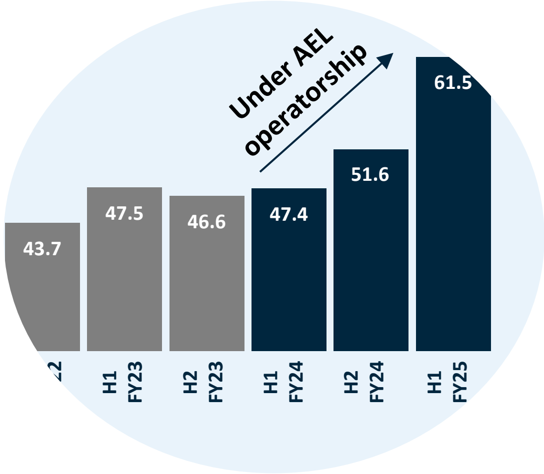
Unlocking Amplitude's value

Amplitude has moved past historical challenges and is now focused on growing supply into the tight East Coast domestic gas market

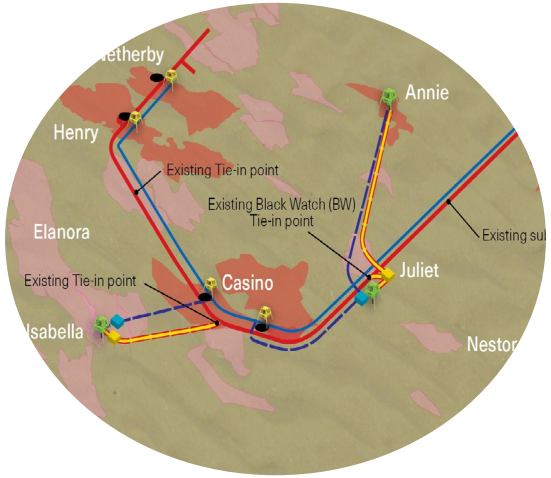
H1 FY25 highlights

Major decommissioning spend complete

OGPP improvement & margin growth



Progressing Otway growth



Strategic focus areas

Maximising underlying cash flow and deleveraging

Maximising margins via increasing exposure to higher gas prices and lower production unit costs

Developing new products and services, including gas storage and supporting GPG firming for renewables

Filling existing infrastructure and bringing brownfield growth in Otway to market

Health, safety, environment and community performance

Results ahead of industry benchmarks through disciplined operations

Safety

- Excellent safety performance
- Ahead of industry benchmark TRIFR[1]
- No Tier 1 or Tier 2 process safety events
- Over a year without a lost time injury

Environment

- No reportable[2] or notifiable[3] environmental incidents during the period
- Certified by Climate Active as a carbon neutral organisation since FY20[4]

Community

- Proactive engagement with stakeholders in the areas where we operate

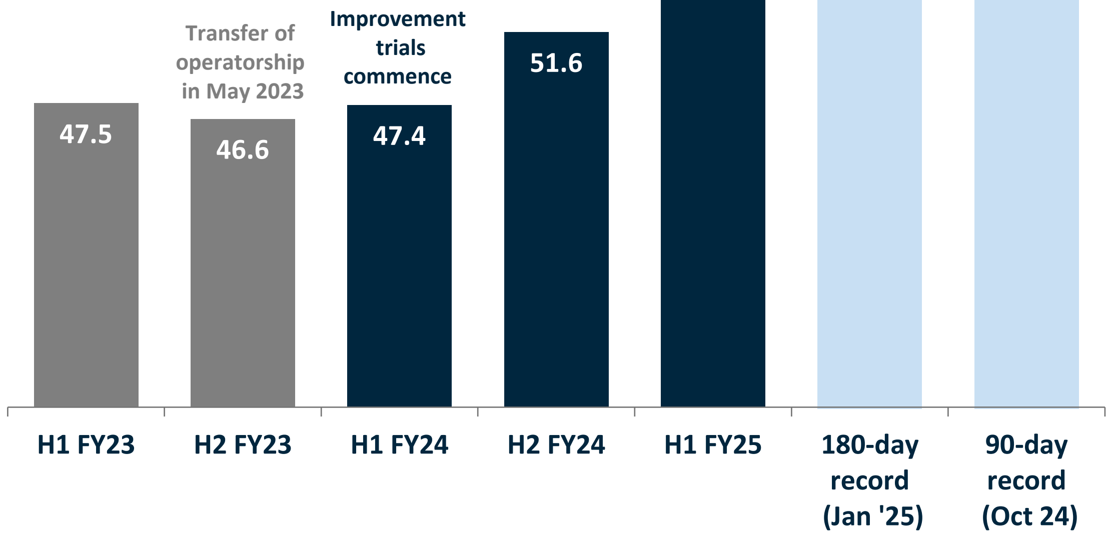
	H1 FY24	H1 FY25
Hours worked	216,782	**129,058**
Recordable injuries	1	**0**
Total recordable injury frequency rate (TRIFR)	5.86	**3.34**
Industry TRIFR[1]	5.09	**6.17**
Reportable environmental incidents	0	**0**

[1] NOPSEMA industry rolling 12-month TRIFR for 31 December 2023 and 30 December 2024 | [2] As defined by 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 for FY20-23. Amplitude Energy is in the process of seeking FY24 certification. Refer to page 21 of the Amplitude Energy 2024 Sustainability Report for scope definitions.

Orbost performance improvement

New production records set at Orbost with further improvements targeted for H2 FY25

Orbost Gas Processing Plant (OGPP) average processing rate, TJ/d

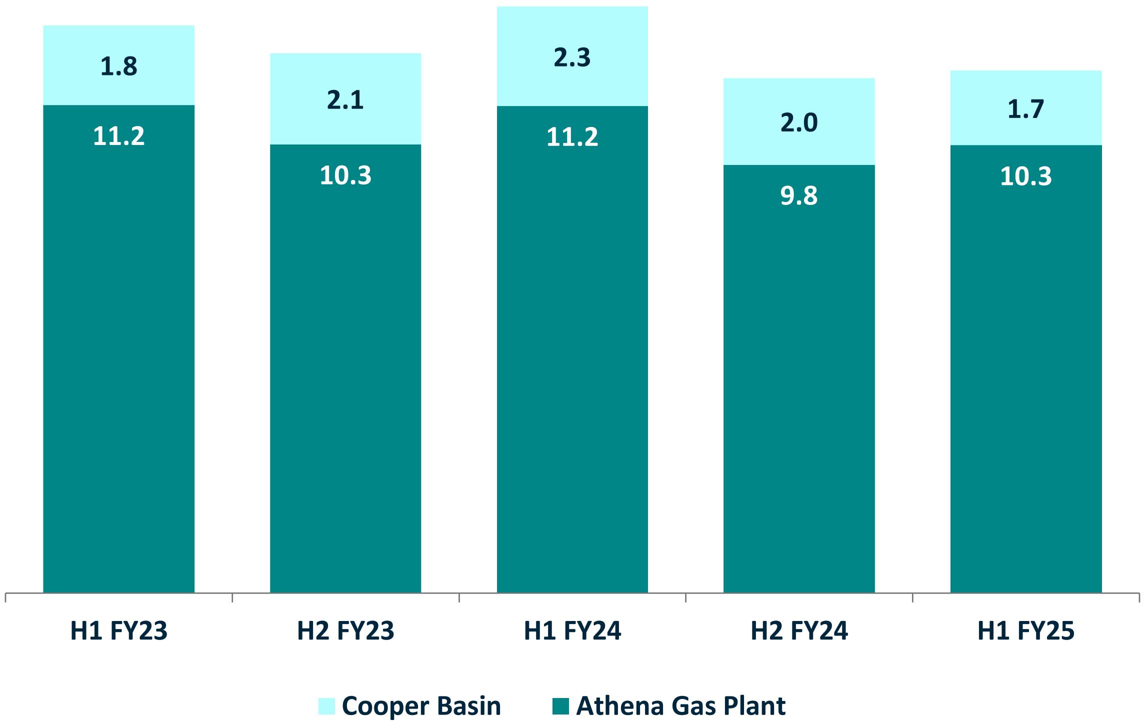


- Production improvement in H1 FY25 driven by
  - Innovative engineering solutions to historical sulphur processing issues
  - Greater focus on plant reliability and process efficiency
- New production records set during H1 FY25
  - >66 TJ daily rate achieved for over half of H1 FY25
  - Nameplate production (68 TJ/d) achieved for weeks at a time
- Further initiatives to improve OGPP production in H2 FY25
  - Chemical clean-in-place operational on absorber units
  - Installation of alternative polisher media to extend run-life beyond 5-6 months
  - Operational trials from the results of data analytics work
  - Debottlenecking the plant to achieve instantaneous rates above nameplate capacity

Stable performance at Athena & Cooper Basin

Targeting group production run-rate of >70 TJe/d by end-FY25

AGP average processing rate & Cooper Basin production, TJe/d[1]



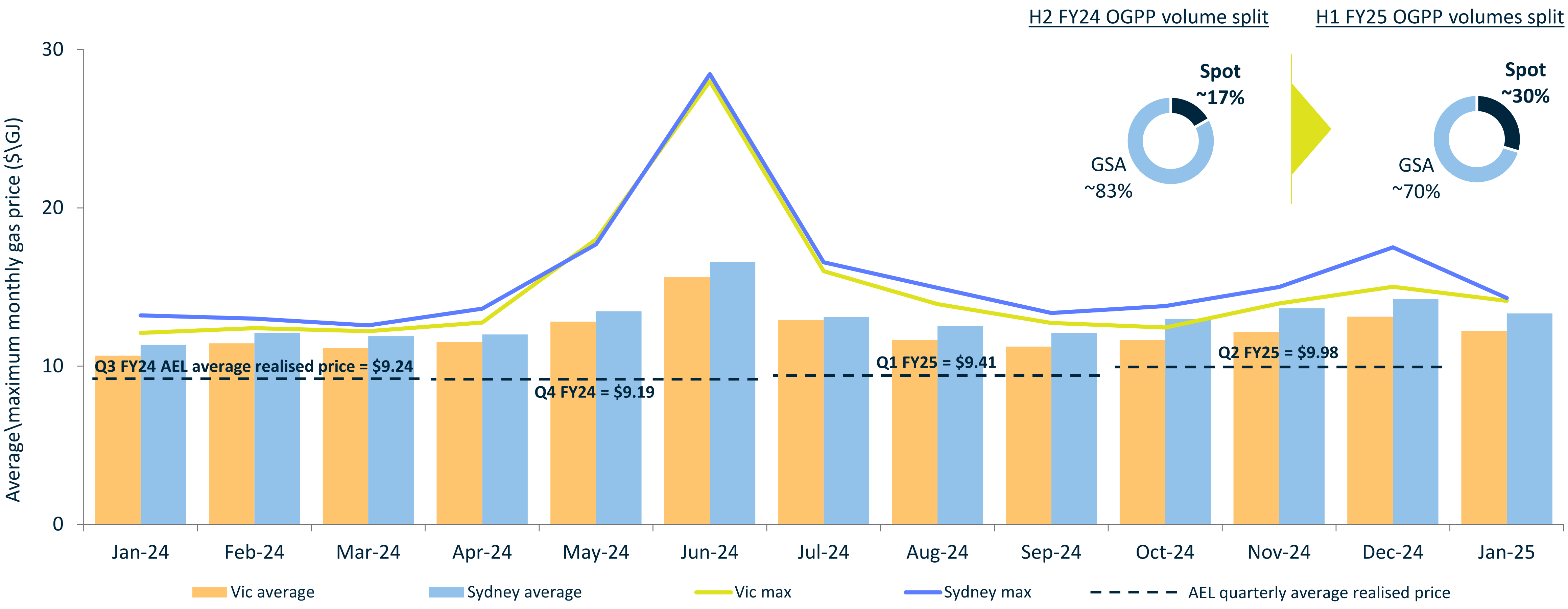
- Steady AGP production
  - Natural field decline offset by excellent plant reliability performance over the half
  - Production since November 2024 slightly reduced due to loss of CHN umbilical communications. Umbilical communication was recently re-established[2], allowing regular well-cycling operations to recommence
- Cooper Basin
  - Natural decline of existing fields
  - Planning underway for a new development campaign at Callawonga
  - Remains a source of high margin, US$-denominated cash flow

[1] All figures shown net to Amplitude Energy | [2] Communications re-established to the Casino 5, Henry 2 and Netherby 1 wells

Gas trading & marketing opportunities

Amplitude is generating additional value for its gas sales due to improved production performance and gas market tightness

Spot market gas prices[1] and AEL realised gas prices since Jan 2024, A$/GJ



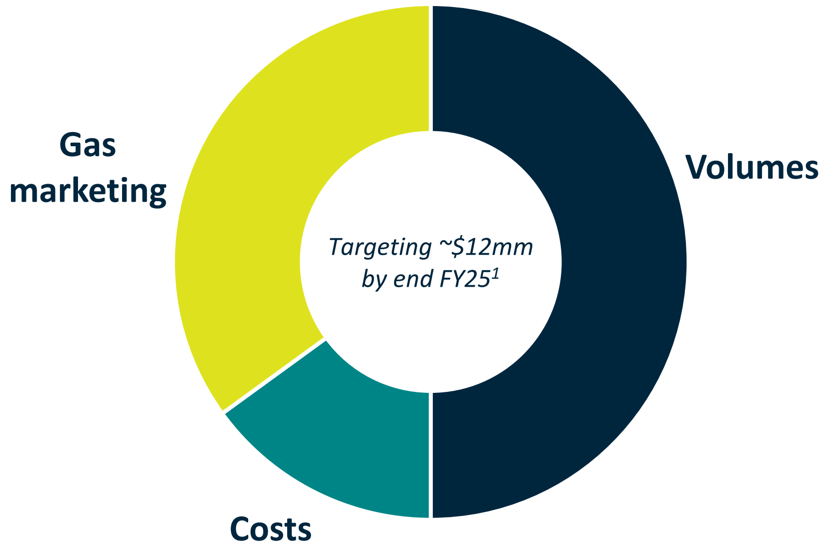
[1] AEMO, Victorian DWGM and Sydney STTM Prices. DWGM average prices across all intervals. STTM prices shown on an ex post basis.

Continuous improvement programme

On track to realise around $12mm in cashflow improvements by the end of FY25[1]

FY25 success - year-to-date and full year targets

- ✓ 59 initiatives company-wide, over half newly added in FY25
- ✓ Emphasis on expenses continues, but broadened to production and margin maximisation
- ✓ Initiatives delivering emissions reductions by end of FY25



FY25 targets & example focus areas

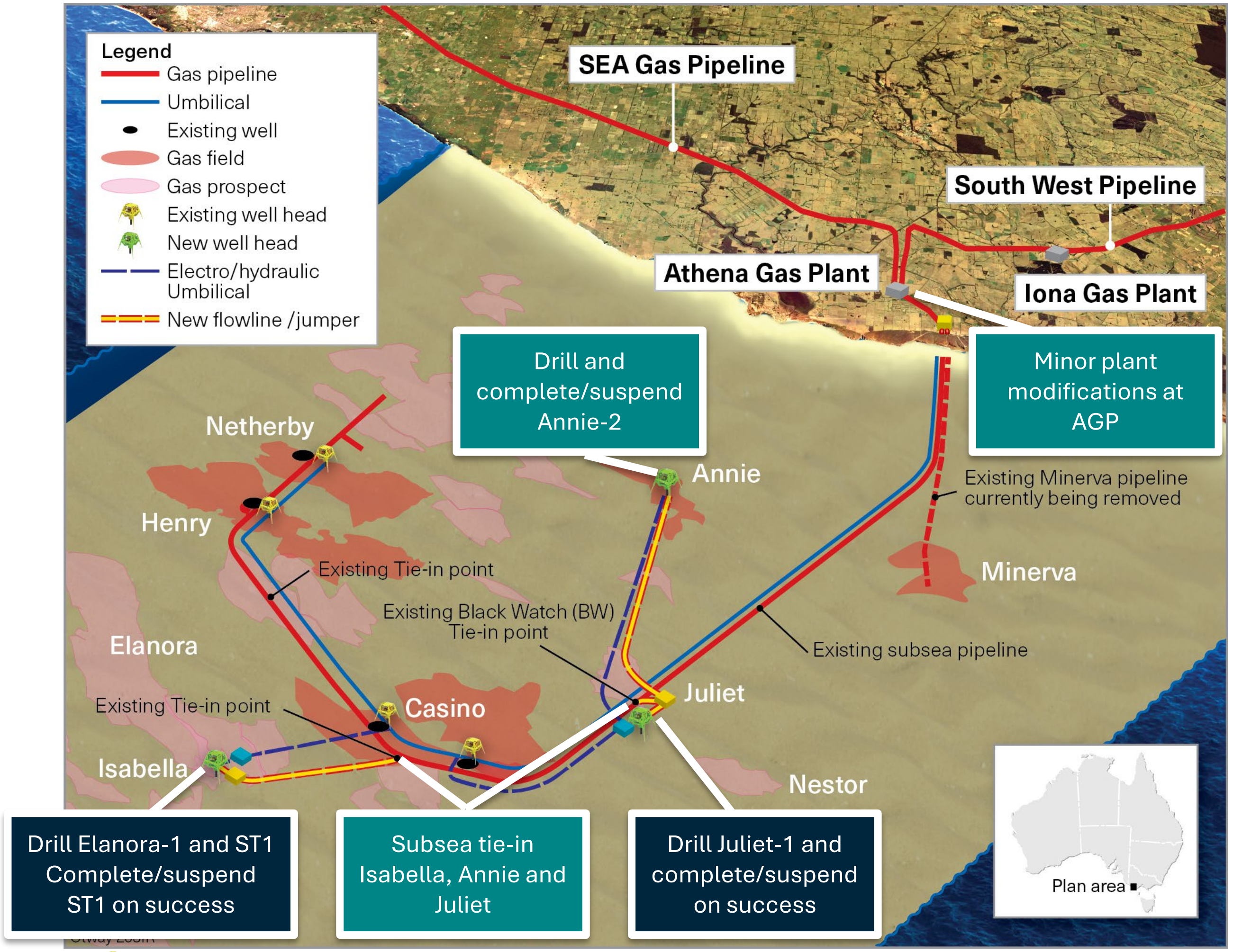
Targets	▪ Complete outstanding actions from FY24 program ▪ Accelerate production, maintain cost discipline, increase margin
Volumes	▪ LEAN absorber cleans (phase 2) ▪ Polisher performance ▪ Other initiatives across both plants
Costs	▪ Further reduction in the OGPP absorber clean times ▪ Reduced contractor costs & further plant optimisation
Gas marketing	▪ Price premiums through increasing sales volumes to the Sydney and Victorian spot markets ▪ Margin improvement from reduced pipeline transport costs utilising day ahead auction

[1] Cashflow improvements expected to be realised in FY25 . This includes permanent benefits (from operational efficiencies, and revenue improvements) and temporal benefits (e.g., production acceleration)

East coast supply project (ECSP) targeting first gas in 2028

Unlocking gas resources in established basins to backfill existing infrastructure

Otway Basin



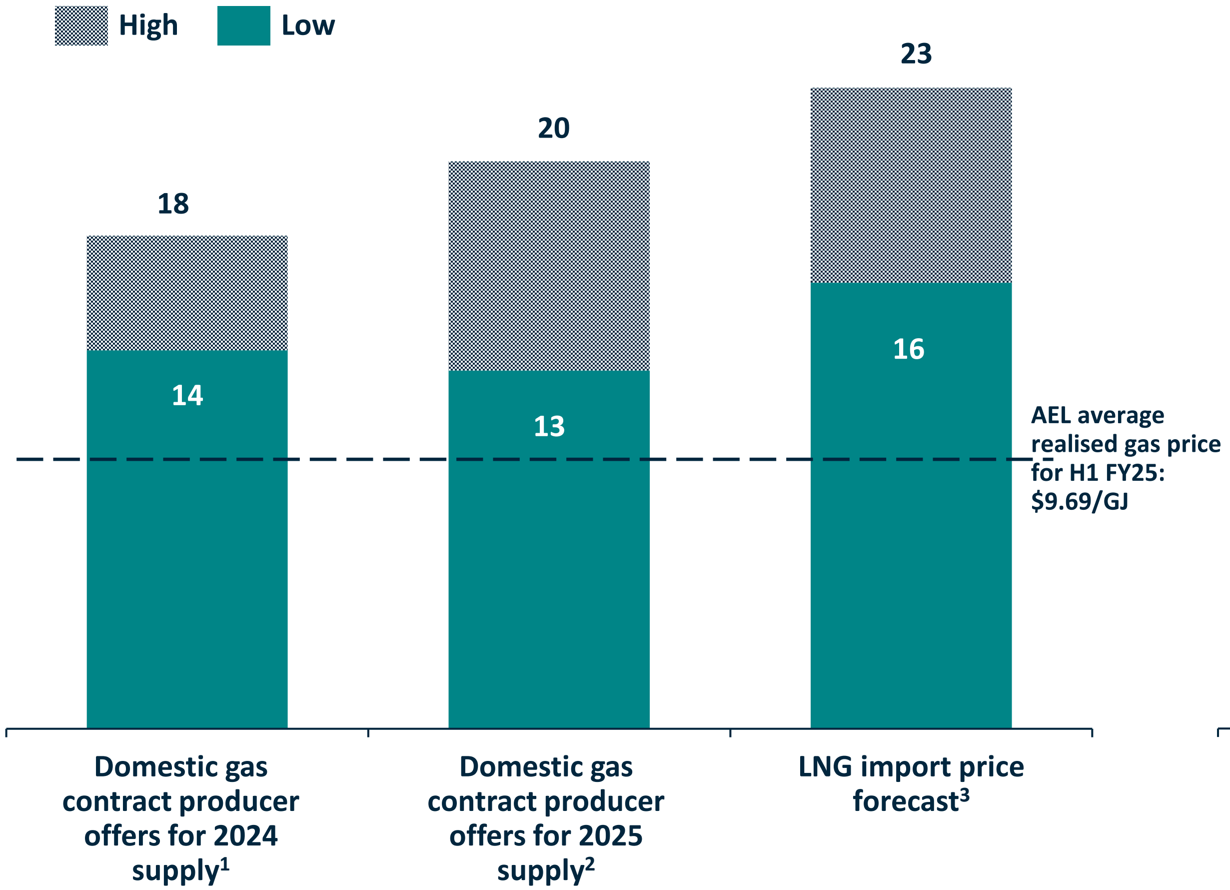
- Negotiating terms with O.G. Energy for its participation in the preferred three well ECSP programme on a 50% basis
- Amplitude's firm rig slot on track for late CY2025
  - Multiple optional slots, allowing 2nd & 3rd wells to be drilled in CY2026
- Targeting to backfill the Athena Gas Plant with up to ~90 TJ/day gross production, with first gas targeted for 2028
- Developing 65 PJ[1] gross 2C (32.4 PJ AEL net) through one well (Annie-2)
- Wells at Elanora, with sidetrack to Isabella, and Juliet, targeting 358 Bcf[2] (179 Bcf AEL net) of gross mean unrisked prospective resource potential
  - 98% probability of gas at one of Elanora, Isabella or Juliet
- Attractive economics with low ongoing cash costs
- Strong customer offtake and funding support

Indicative only, not guidance. Projects are not yet sanctioned. This forward-looking statement is subject to the qualifications on page 2 of this presentation | [1] Annie 2C resource on net AEL share is 32.4 PJ and is included on a gross basis as part of the Otway Basin 2C number in the FY23 Reserves and Contingent Resources ASX release on the 25 August 2023 | [2] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and net share of each prospect, were announced to ASX on 9 February 2022

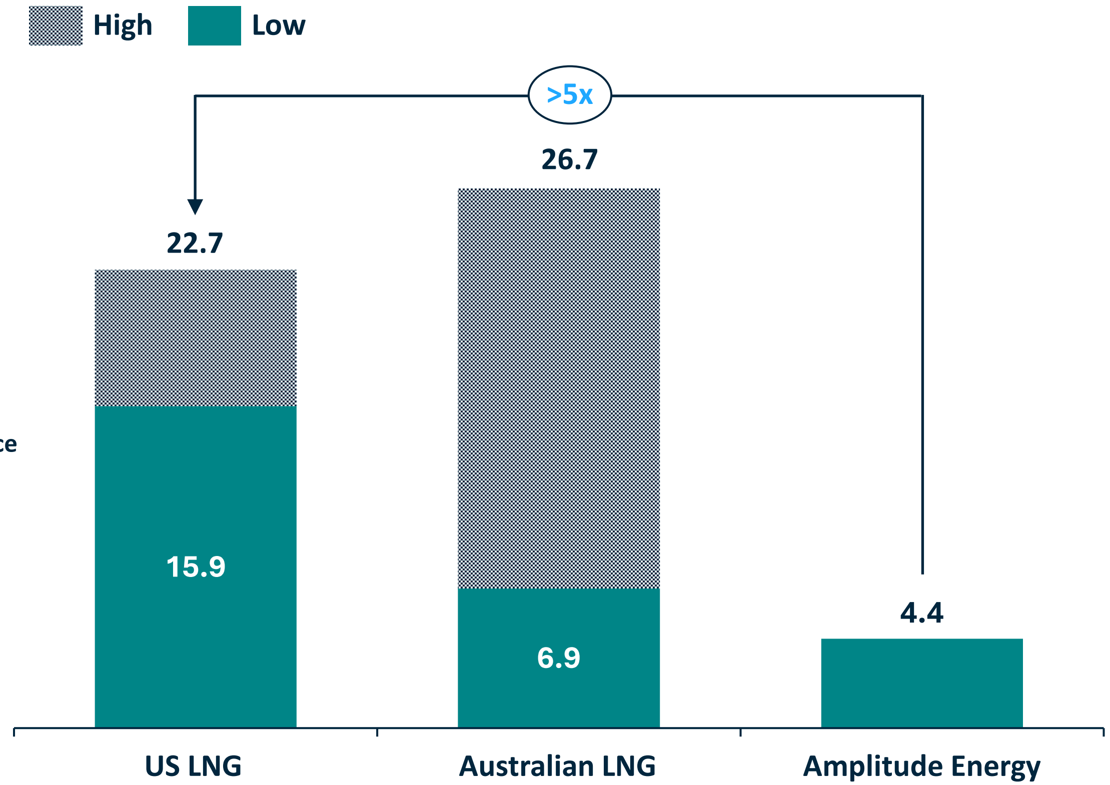
Domestic gas is the cheapest & lowest emissions option

LNG imports to Victoria would be more expensive and ~2-6x more emissions intensive than Amplitude Energy's domestic gas

East Coast contracted gas prices, A$/GJ



Emissions intensity of producing LNG vs. domestic gas, $kgCO_2$-e/GJ[4]

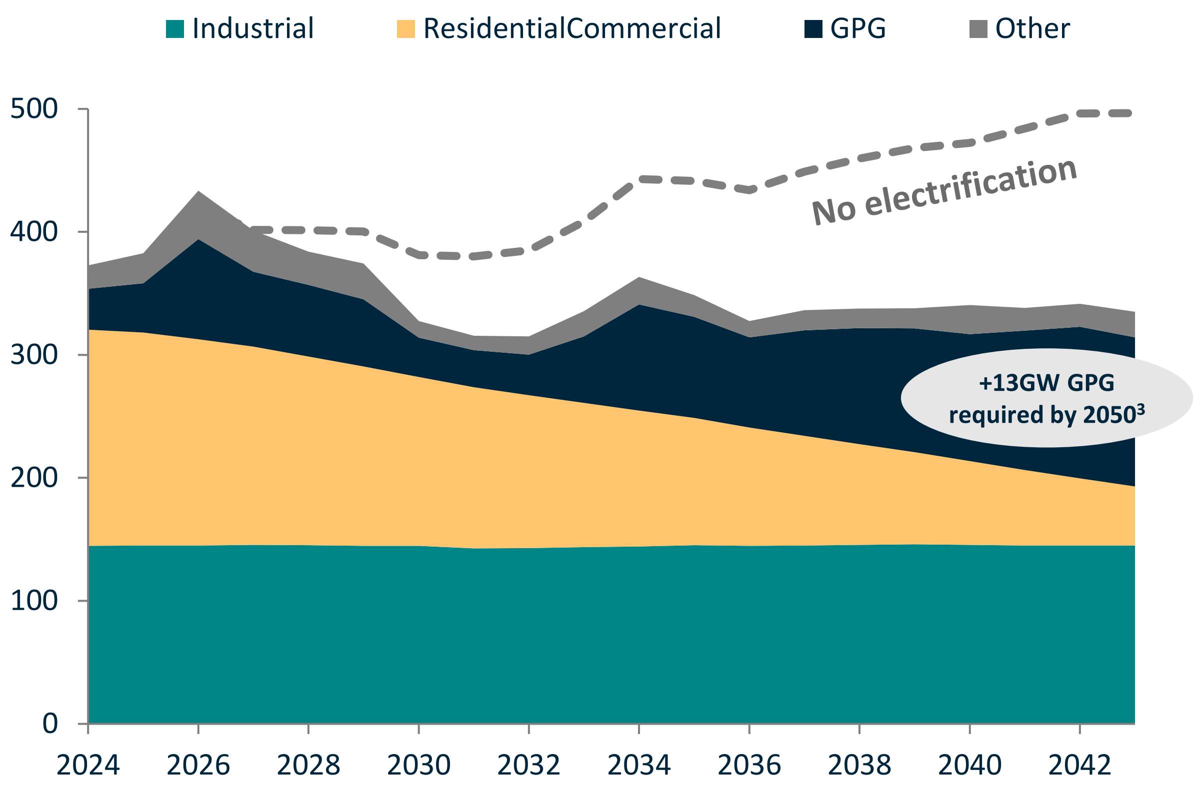


[1]ACCC Gas Inquiry Report, December 2023, Page 87, Chart 4.8 | [2]ACCC Gas Inquiry Report, December 2024, Page 26, Chart 2.7 | [3]EnergyQuest, East Coast Gas Outlook 2024, column indicates the "low" and "high" estimates for LNG imports from Port Kembla Energy Terminal into Sydney in 2026| [4] Greenhouse gas emissions from the liquified natural gas industry in Australia, https://agit.org.au/wp-content/uploads/2023/05/Greenhouse-gas-emissions-from-LNG-CSIRO-final.pdf. LNG ranges exclude shipping and regasification. Regasification typically adds less than 2 $kgCO_2e$/GJ. Amplitude Energy data calculated from FY24 published data for Scope 1 and 2.

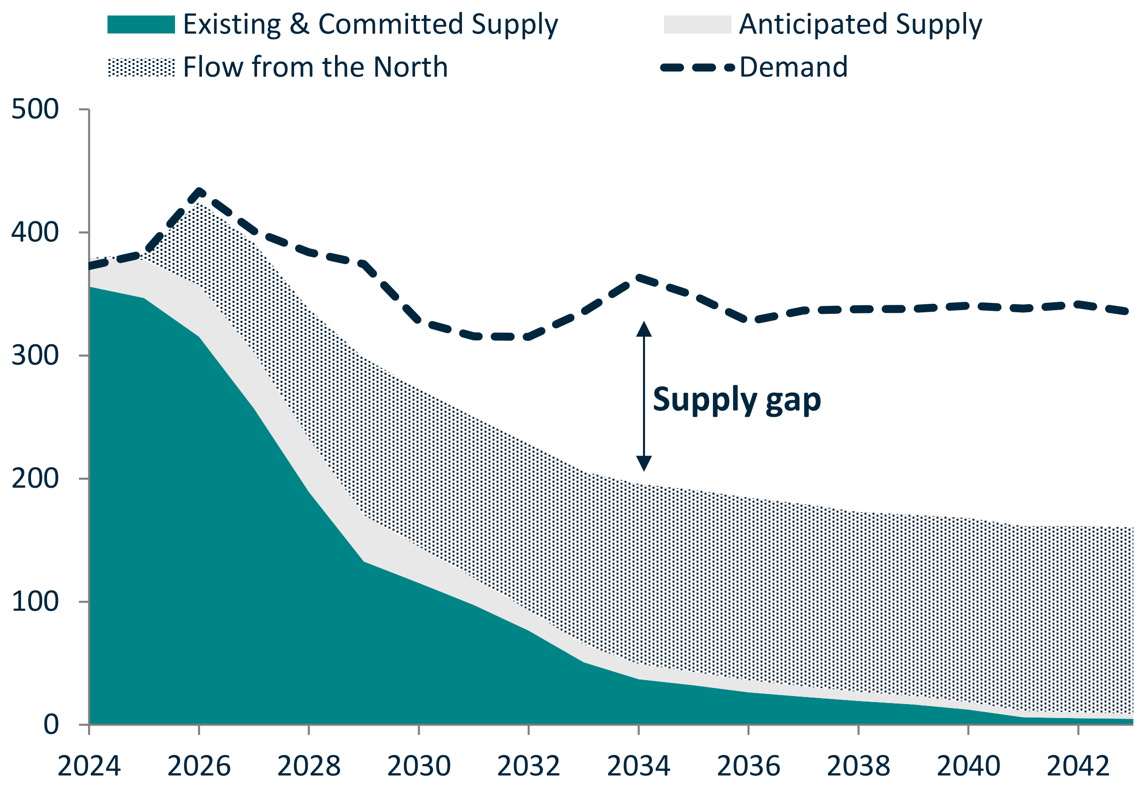
Urgent demand for new domestic gas supply

Risk of supply shortfalls during peak winter demand periods from 2025, and larger seasonal shortfalls from 2026 onwards

Southern States AEMO domestic demand forecast, PJ p.a.[1]



Southern States AEMO supply forecast, PJ p.a.[2]



[1] AEMO 2024 Gas Statement of Opportunities, Step Change 2° Celsius scenario, National Electricity and Gas Forecasting Portal. Southern States include Victoria, NSW, SA and Tasmania. Other includes losses and energy efficiency
[2] AEMO 2024 Gas Statement of Opportunities, Figure 41 | [3] AEMO, 2024 Integrated System Plan

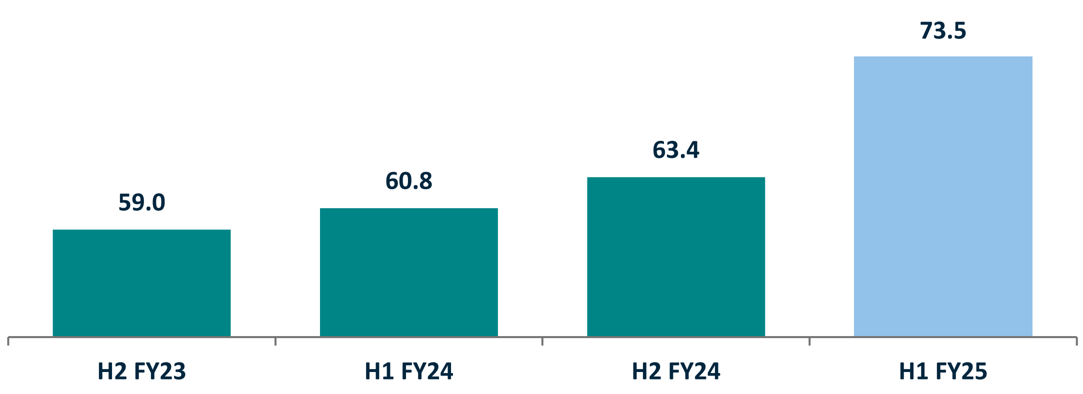
#2

H1 FY25 financial highlights

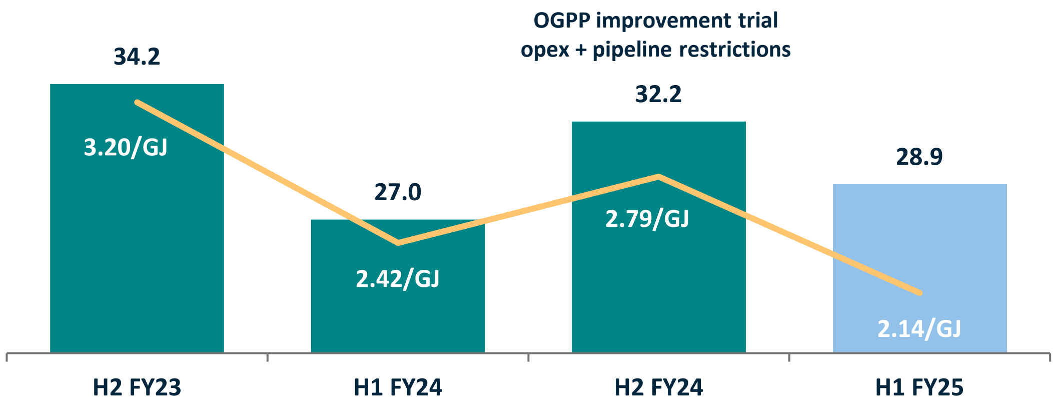
Building a track record of performance

Delivering production growth and cost reductions to drive earnings and cash generation

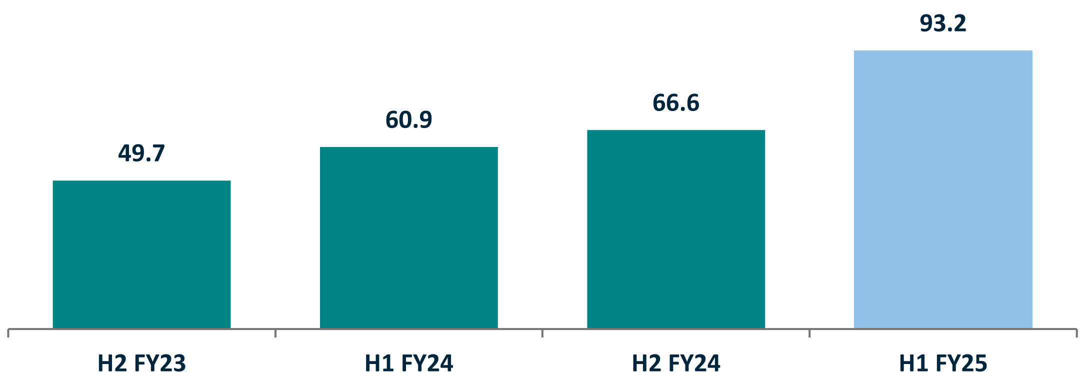
Production, TJe/d



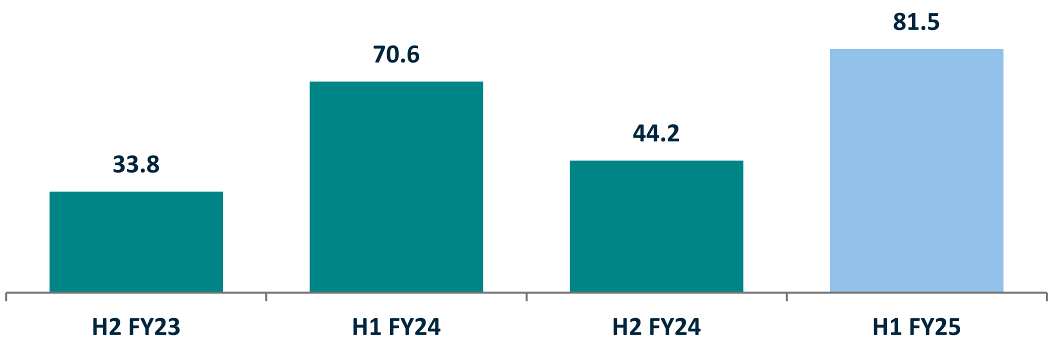
Production expenses, $mm \ $ per GJ produced



Underlying EBITDAX, $mm



Adjusted cash from operations[1], $mm



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

Record production & financial metrics

Higher production growth and gas price realisations driving earnings and cash generation

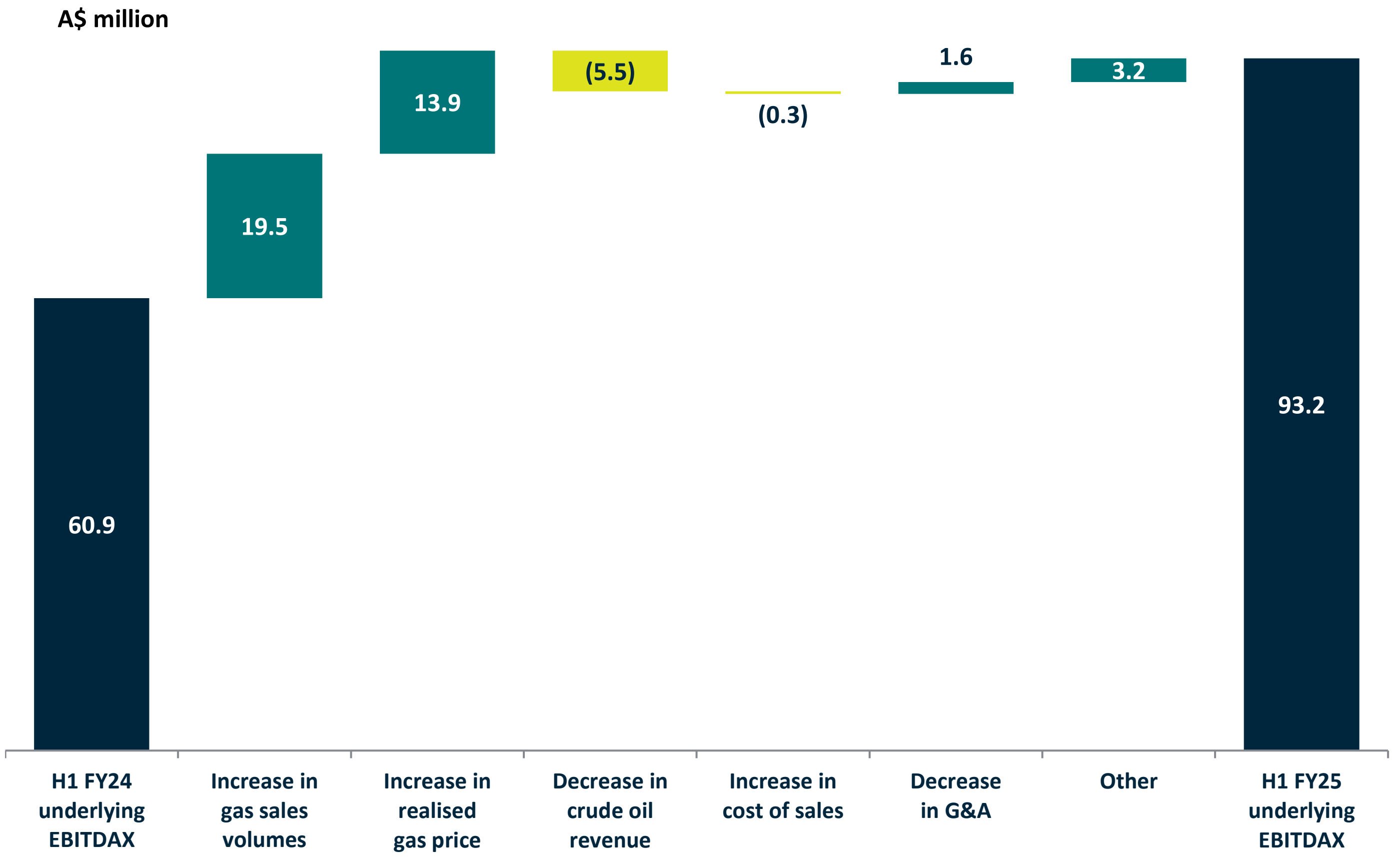
$mm unless indicated	H1 FY24	H1 FY25	Change
Production, TJe/d	60.8	**73.5**	▲ 21%
Sales revenue	105.9	**133.7**	▲ 26%
Average realised gas price ($/GJ)	8.44	**9.69**	▲ 15%
Production expenses[1]	27.0	**28.9**	▲ 7%
u-EBITDAX	60.9	**93.2**	▲ 53%
Underlying profit/(loss) after tax	5.4	**8.5**	▲ 58%
Operating cash flow	21.1	**45.4**	▲ 115%
Adjusted cash from operations[2]	70.6	**81.5**	▲ 15%
Capital expenditure incurred	7.6	**23.9**	N/M
Restoration payments	44.4	**32.9**	▼ 26%
	30 June 24	**31 Dec 24**	
Cash and cash equivalents	14.3	**51.0**	
Drawn debt	265.0	**305.2**	
(Net debt)/cash	(250.7)	**(254.1)**	

- Record production due to improved OGPP performance
  - Tracking above guidance, ahead of plant shutdowns in March
- Record revenue due to higher sales volumes and higher realised gas prices
- Production expenses run-rate in-line with guidance
  - Lower OGPP sulphur phase plant costs
  - Increased costs to resolve Sole pipeline restrictions in Q1 FY25
  - Higher waste disposal costs associated with increased production
- Unit costs ↓ 12% to $2.14/GJe (H1 FY24: $2.42/GJe)
- Record u-EBITDAX due to margin expansion and operational leverage
- Record adjusted cash from operations[2]
- Restoration payments mainly reflect the final BMG wells decommissioning payments made in Q1 FY25
- Capex primarily directed to ECSP long-leads
- Net debt peaked in Q1 FY25
  - Ongoing focus on deleveraging

[1] Production expenses comprise labour, materials, overheads, insurance, license costs, JV management and carbon offset costs, but excludes third-party product purchases, transport and trading costs, royalties, pipeline general visual inspection (GVI) costs and non-cash depreciation and amortisation | [2] Excluding restoration spend and other non-recurring and non-underlying items

Record u-EBITDAX - bridge from H1 FY24

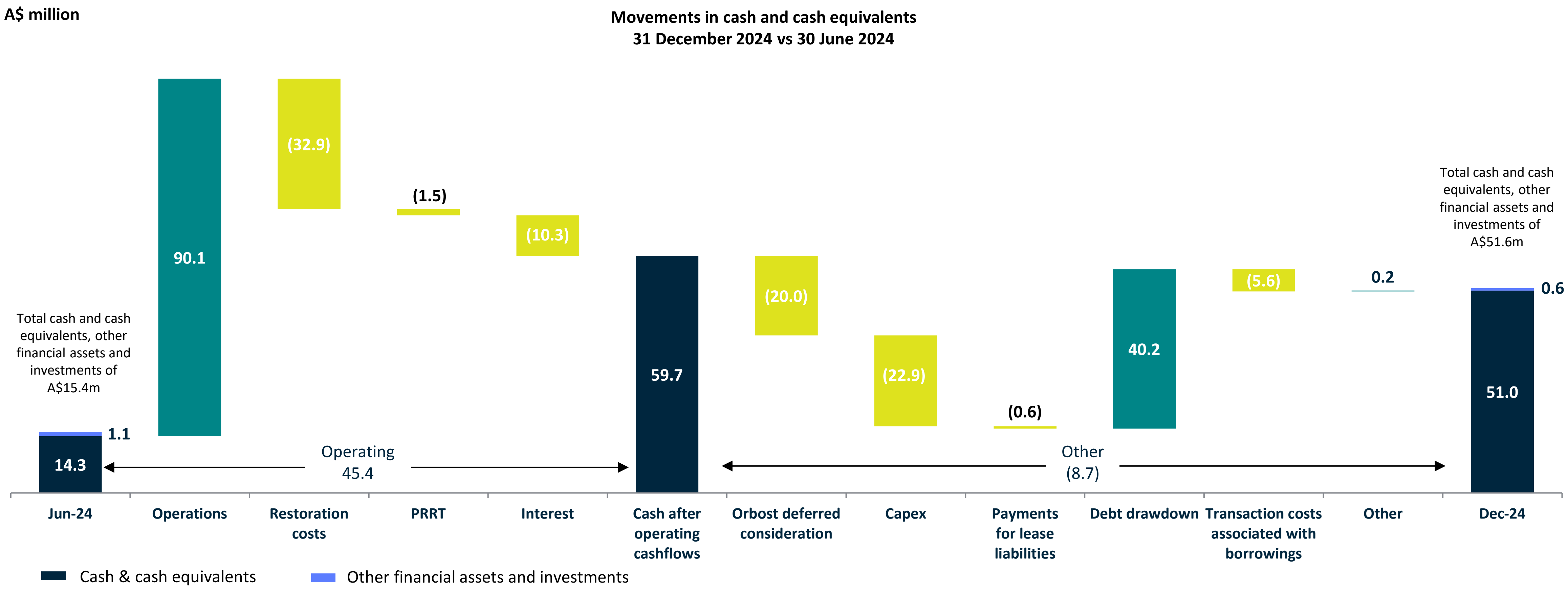
Record underlying earnings driven by greater gas sales volume and prices



- Increased sales volumes and average realised gas prices
- Reduced crude oil liftings
- Slightly increased cost of sales, with reduced sulphur phase costs and third-party product purchases offsetting increases in other production expenses and trading/pipeline transport costs
- Reduced G&A linked to savings realised from the transformation programme
- Result demonstrates strong operating leverage of assets and margin expansion

Group cash—six monthly bridge from June to December 2024

Strong operating cash flows allowing reduction in net debt, following one-off payments in Q1 FY25



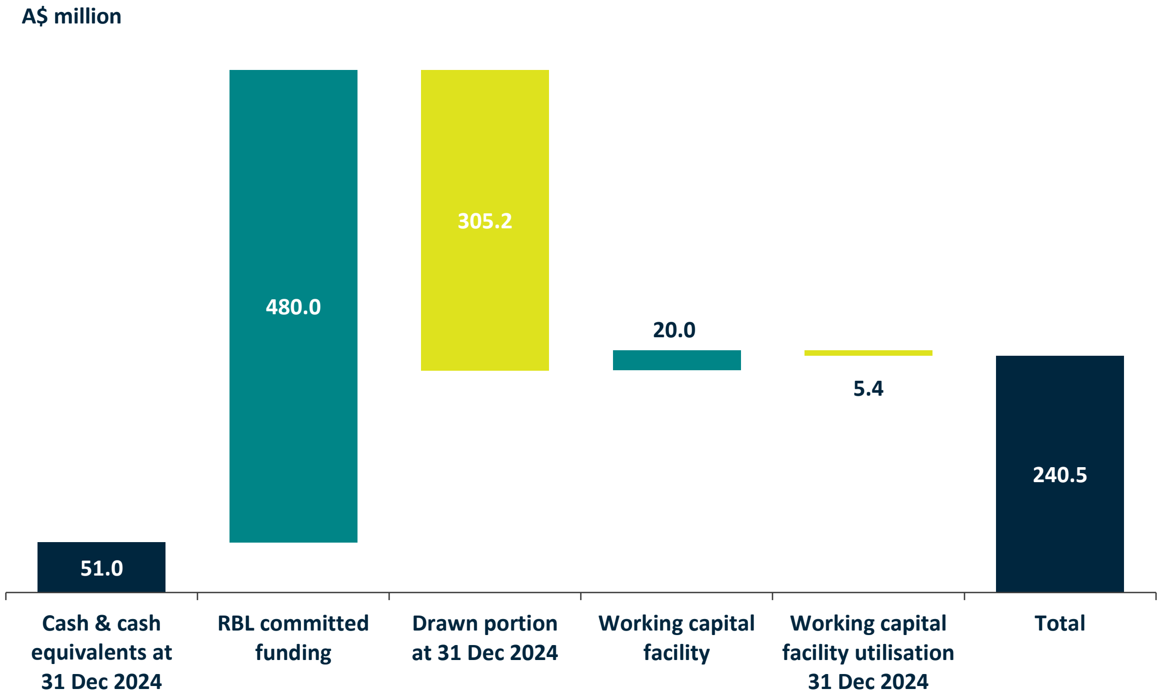
Significant capacity within debt facilities

Amplitude recently increased and extended its secured reserve-based loan (RBL) facility to maximise its financing flexibility and liquidity as the company enters its next leg of growth

Bank facilities overview

- Senior, secured RBL increased and extended in December 2024
  - Newly increased facility limit of $480mm
  - Current borrowing base above this level
  - Maturity extended to September 2029
  - Fully committed and available
  - Strong lending group
- RBL currently drawn to $305m, with cash on balance sheet of $51m (net debt $254m)
- $20mm working capital facility
- Facility limit reduces according to a pre-agreed schedule, from $480mm in Sep 2026 to $216mm at maturity
  - Reduction schedule is sculpted to reflect the borrowing base, expected cash flows and ECSP capex in coming years

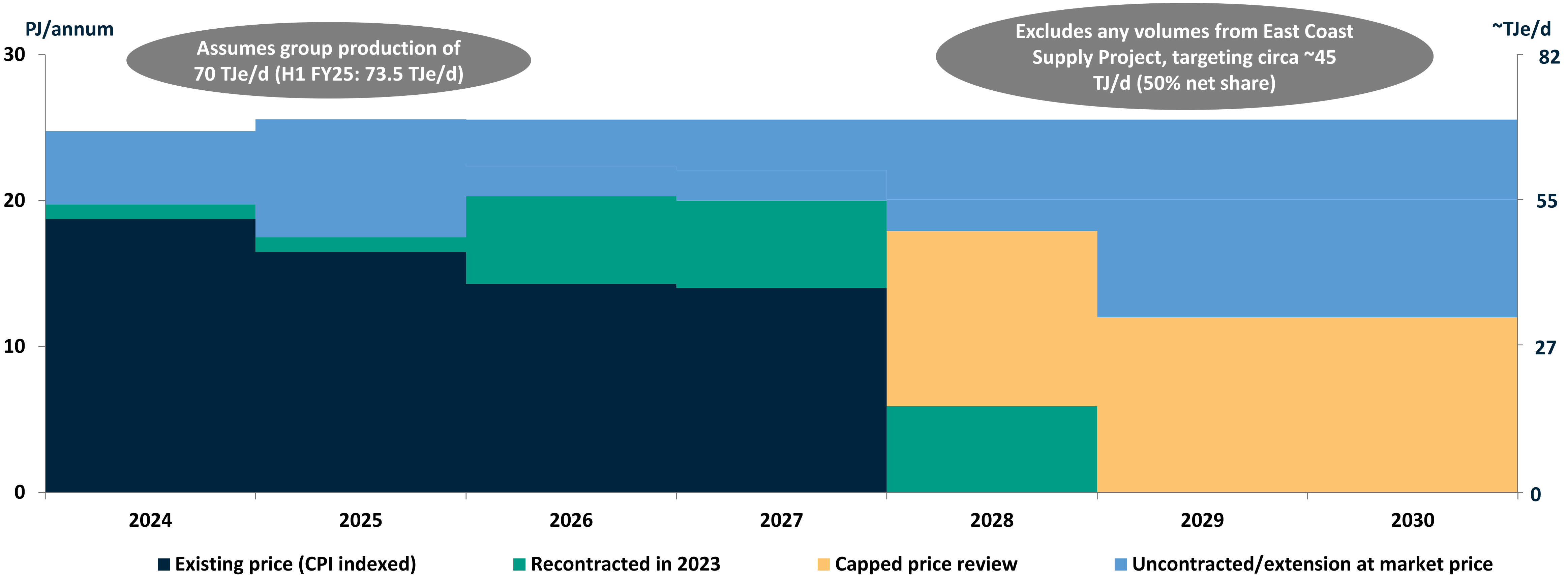
Liquidity overview



Increasing exposure to spot and current market prices

Indicative uncontracted volumes assuming group average production of 70 TJe/day (equity gas) from CY2025 onwards

Gas contract stack, existing reserves only[1]



[1] Net to Amplitude Energy's equity share, the annual contract quantity volumes shown are indicative only and assume group production of 70 TJday from 1 January 2025 (actual spot sales for CY2024 shown). This forward-looking statement is subject to the qualifications on slide 2 of this presentation. There can be no guarantee that this production level will be achieved, notwithstanding recent improved average rates at OGPP. The annual contract quantity volumes shown are for illustrative purposes only and do not constitute production guidance.

#3
H2 FY25 outlook

FY25 focus areas

Shareholder returns to be driven by increasing production into a tight market, operational leverage and de-risking growth

- Targeting group production run-rate of >70 TJe/d by end-FY25
- Progress the preferred drilling program to deliver the East Coast Supply Project and backfill AGP from 2028
- Increase realised gas prices through increased exposure to spot and peaking gas product opportunities
- Drive further cost and emissions reductions through continuous improvement and efficiencies

Positive outlook

Amplitude Energy has numerous value catalysts over the near and medium-term

Catalysts in FY25

- Next stage of OGPP improvement initiatives
- Higher average realised gas prices through CPI indexation and increased spot sales
- Increased margins through operational leverage
- Increased cash flow generation and deleveraging

Project catalysts through 2025 and beyond

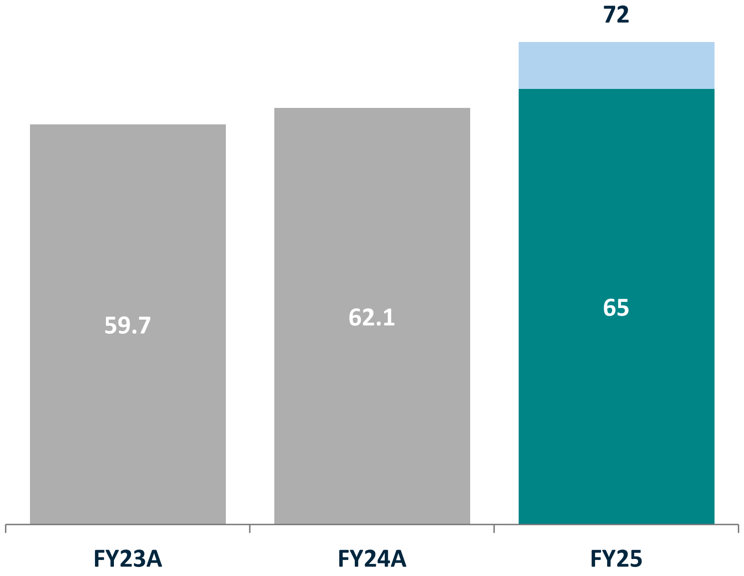
- Confirmation of ECSP drilling programme details in H2 FY25
- First ECSP well drilled ~late CY25
- 2nd & 3rd wells drilled in CY26

#4
Appendix

FY25 guidance

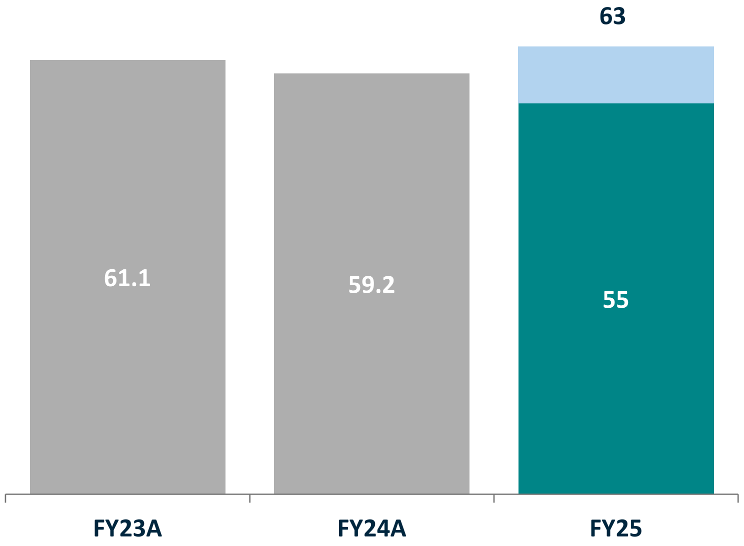
Focus on higher gas production driving cost efficiencies, cash generation and deleveraging, ahead of ECSP

FY25 production: Upgraded to 65 – 72 TJe/day



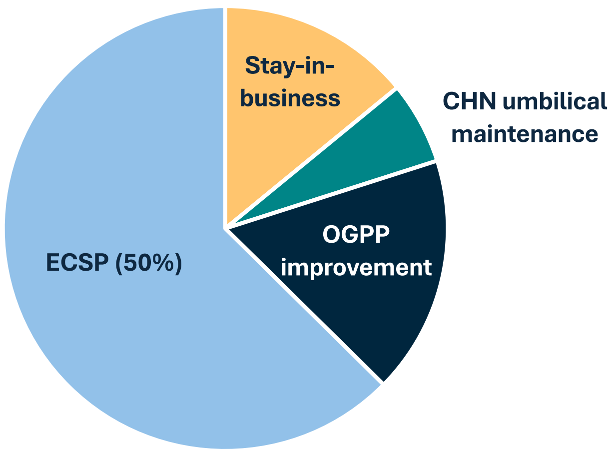
- Recently upgraded due to continued improvement at OGPP
  - Guidance reflects a range of outcomes at OGPP
- Natural decline at CHN fields and PEL 92

FY25 production expenses: $55 – 63mm[1]



- Reflects cost-out/transformation programme
  - Partly offset by general cost inflation and costs of increased production
- Excludes ~$12mm for abnormal general visual integrity inspection (GVI) of Sole and CHN offshore pipelines in FY25
  - Once-in-five-years plus type activity

FY25 capex: $50 – 60mm[2]



- Long-lead items for ECSP (at 50%)
  - Up to an additional $20mm if ECSP long-lead items are sole-risked
- Excludes abandonment expenditure
  - Minerva decommissioning expected to take place late FY25 and/or early FY26

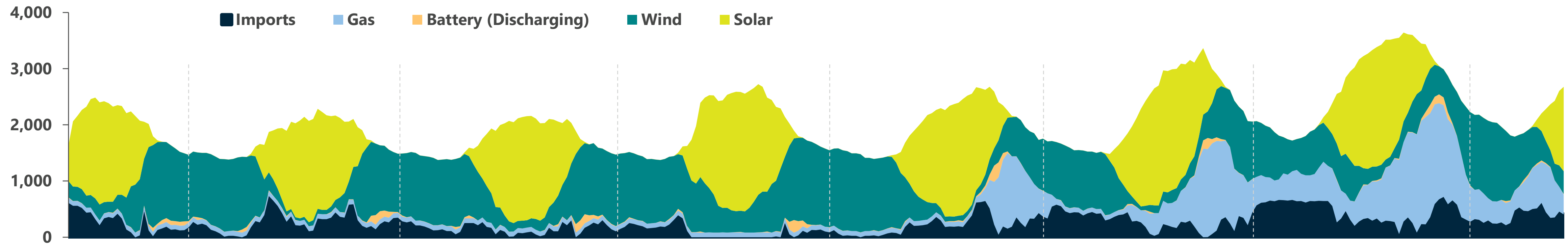
[1] Excludes GVI expenses as described above | [2] Assumes 50% partner in three well ECSP drilling programme. Excludes decommissioning costs.

Gas plays a critical role in the future electricity market

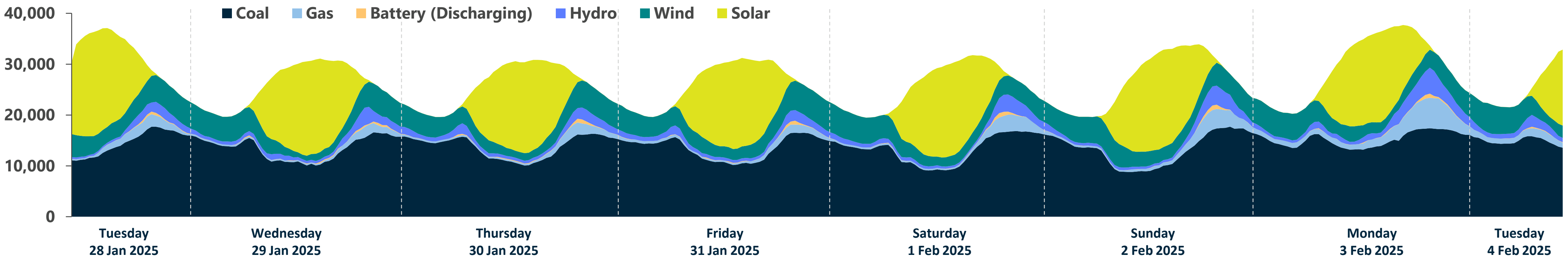
"Without GPG, the electricity grid would be unable to cope with peak electricity demand."

Future Gas Strategy, Department of Infrastructure, Science and Resources, May 2024

South Australian electricity supply by type (~71% renewables annually), MW[1]



National electricity[2] supply by type (~39% renewables annually), MW[1]

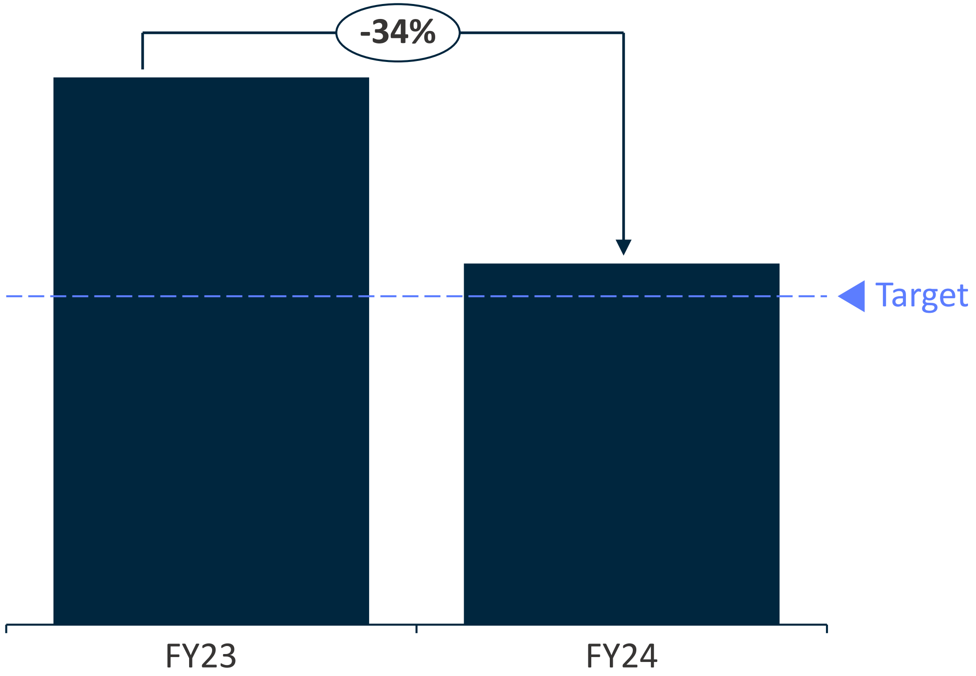


[1] Data sourced from www.opennem.org.au | [2] Electricity refers to the National Electricity Market (NEM), incorporating all Australian states and territories excluding Western Australia and the Northern Territory

Strong progress on emissions reduction targets

Delivered significant flaring reduction and progressing behind-the-meter solar PV opportunity

Scope 1: Reduce flaring by 40% by FY30 from FY23 on an equity basis



Scope 2: Integrate renewable electricity to support Amplitude Energy operations

- ✓ Negotiating power purchase agreement (PPA) for behind-the-meter solar PV at AGP

Scope 1: Direct emissions from company-owned and controlled resources
Scope 2: Indirect emissions released due to the generation of purchased energy from a utility provider
Scope 3: All indirect emissions not included in Scope 2 – primarily downstream emissions from the combustion of our products

Otway exploration opportunities

High quality, low risk prospects in amplitude-supported play

Otway Basin, Top Waarre Formation Prospective Resource Summary[1]

Prospect	Permit	AEL equity (%)	Low (P90)		Best (P50)		Mean		High (P10)		Pg[4]
			Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]	
Elanora	VIC/L24	50	56.1	28.1	131.5	65.8	160.9	80.5	307.0	153.5	67%
Isabella	VIC/L24	50	56.0	28.0	124.1	62.1	148.6	74.3	276.4	138.2	70%
Heera	VIC/L24	50	35.2	17.6	75.1	37.6	86.1	43.1	153.1	76.6	63%
Pecten East	VIC/L33	50	48.6	24.3	72.9	36.5	76.3	38.2	109.2	54.6	73%
Nestor	VIC/P76	100	38.9	38.9	60.9	60.9	64.2	64.2	94.3	94.3	81%
Juliet	VIC/L24	50	30.1	15.1	46.4	23.2	48.8	24.4	71.0	35.5	84%
Total (Bcf)[5]			**264.9**	**151.9**	**510.9**	**285.9**	**584.9**	**324.6**	**1,011.0**	**552.7**	

[1] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and net share of each prospect, were announced to ASX on 9 February 2022 | [2] Gross Prospective Resource is 100% of the unrisked volume estimated to be recoverable from any prospect. The estimated quantities of petroleum that may be potentially recovered by the application of future development project(s) relate to undiscovered accumulations | [3] Net Prospective Resource is the unrisked volume estimated to be recoverable from any discovery attributable to the Amplitude Energy joint venture interest | [4] Pg is chance (or probability) of encountering a measurable volume of mobile hydrocarbons | [5] Total is the arithmetic summation of prospective resource estimates. The total may not reflect arithmetic addition due to rounding. Arithmetic addition of independent probabilistic resource estimates will underestimate the Low estimate and overestimate the High estimate

Gippsland exploration opportunities

Prolific basin adjacent to existing infrastructure

Prospective Resource Estimates for Gummy Deep, Manta Deep, Chimaera East and Wobbegong Prospects, offshore Gippsland Basin[1]

Prospect	Permit	AEL equity (%)	Low (P90)		Best (P50)		Mean		High (P10)		Pg[4]
			Bcf[2]	MMbbl[3]	Bcf[2]	MMbbl[3]	Bcf[2]	MMbbl[3]	Bcf[2]	MMbbl[3]	
Gummy Deep	VIC/RL13	100	98	1.7	289	7.2	401	9.9	855	26.5	33%
Manta Deep	VIC/RL13	100	74	1.3	265	6.6	414	10.3	941	29.1	18%
Chimaera East	VIC/RL15	100	74	1.3	193	4.8	250	6.2	503	15.6	23%
Wobbegong	VIC/P80	100	71	0.7	185	2.5	242	3.2	494	8.9	29%
Total Gas (Bcf) & Condensate (MMbbl) [5]			**317**	**4.9**	**932**	**21.1**	**1,307**	**29.6**	**2,793**	**80.1**	

[1] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and net share of each prospect, were announced to ASX on 15 May 2023 (Gummy Deep), 13 April 2022 (Wobbegong) and for Manta Deep and Chimaera East prospects on 4 May 2016 | [2] Gas: Non-associated gas at reservoir conditions | [3] Condensate: Condensate from gas reservoirs | [4] Pg is chance (or probability) of encountering a measurable volume of mobile hydrocarbons | [5] Totals may not reflect arithmetic addition due to rounding. The method of aggregation of the targets in each prospect is by arithmetic sum by category. As a result, the Low (P90) Prospective resource may be a very conservative estimate and aggregated High (P10) Prospective resource may be a very optimistic estimate 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 2024. 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.

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.

Throughout this announcement, 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, is qualified in accordance with ASX listing rule 5.41, and has consented to the inclusion of this information in the form and context in which it appears.

Reconciliations

Underlying adjustments include restoration and business restructuring/transformation costs

$mm	H1 FY24	**H1 FY25**
Underlying net profit / (loss) after tax	**5.4**	**8.5**
Adjusted for:		
Net finance costs	6.8	13.8
Accretion expense	8.7	4.9
Tax expense / (benefit)	(4.3)	8.1
Depreciation	19.7	24.0
Amortisation	28.9	33.5
Exploration and evaluation expense	2.4	-
Tax impact of adjustments	(6.7)	0.4
Total underlying adjustments after tax	**55.5**	**84.7**
Underlying EBITDAX	**60.9**	**93.2**

$mm	H1 FY24	**H1 FY25**
Statutory net profit / (loss) after tax	(90.8)	**7.6**
Adjusted for:		
NOGA levy	0.8	**1.0**
Restoration (income)/expense and associated costs	83.6	**(2.9)**
OGPP acquisition and integration costs	0.3	**-**
Business restructuring and transformation	3.3	**3.2**
Hedging costs	1.5	**-**
Derecognition of deferred income tax asset	33.5	**-**
Tax impact of adjustments	(26.8)	**(0.4)**
Total significant items after tax	**96.2**	**0.9**
Underlying net profit / (loss) after tax	**5.4**	**8.5**

Abbreviations

$	Australian dollars
Amplitude Energy or Company	Amplitude Energy Limited ABN 93 096 170 295
AGP	Athena Gas Plant
ASX	Australian Securities Exchange
bbl	Barrels
Bcf	Billion cubic feet of gas
boe	Barrel of oil equivalent
CHN	Casino, Henry and Netherby fields
GJ	Gigajoule
JV	Joint venture
mm	Millions
mmbbl	Million barrels
MMboe	Million barrels of oil equivalent
N/M	Not meaningful
OGPP	Orbost Gas Processing Plant
PEL	Petroleum Exploration Licence
PJ	Petajoules
PJe	Petajoules-equivalent
TJ	Terajoules
TJe/d	Terajoules-equivalent per day
TJ/d	Terajoules per day