Amplitude energy

FY25 full year results

19 August 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, cost estimates, relevant regulatory approvals (State and Commonwealth) and timing delays beyond the reasonable control of Amplitude Energy.

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. 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. See further Risk Management section (pages 60-63) of Amplitude Energy's FY24 Annual Report.

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 cashflow (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.

References to "$mm" mean millions of Australian dollars, unless stated otherwise. Conversions of US dollar denominated figures into Australian dollars has been made where applicable.

The estimates of petroleum reserves, prospective and contingent resources contained in this presentation are at 30 June 2025. Amplitude Energy prepares its petroleum reserves, prospective 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, 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. 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 11, 55 Currie 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

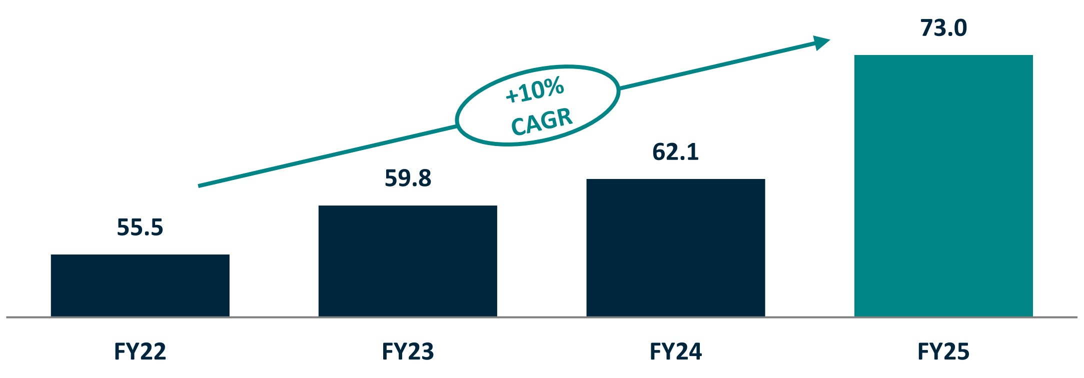
FY25 business priorities delivered

Priority	Outcome
Group production run-rate of >70 TJe/d by end-FY25	▪ June 2025 group production run-rate >77 TJe/d ▪ FY25 total group production 73 TJe/d
Progress 3 well ECSP drilling program, targeting backfill for AGP from 2028	▪ JV alignment established; 3 well drilling programme locked in and on-track ▪ Development phase FEED entered
Increase realised gas prices	▪ Average realised gas prices ~$10/GJ, +12% on FY24
Drive further continuous improvement and efficiencies	▪ Further unit cost reductions ▪ Sulphur sales commenced

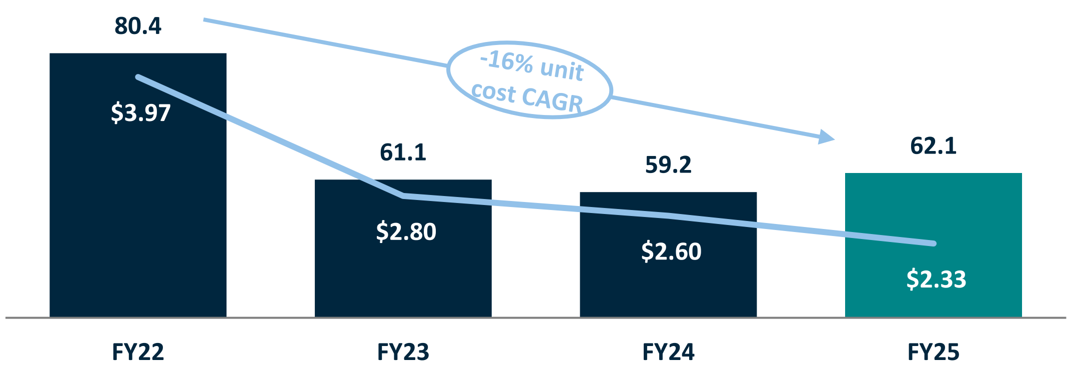
Building a track record of performance

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

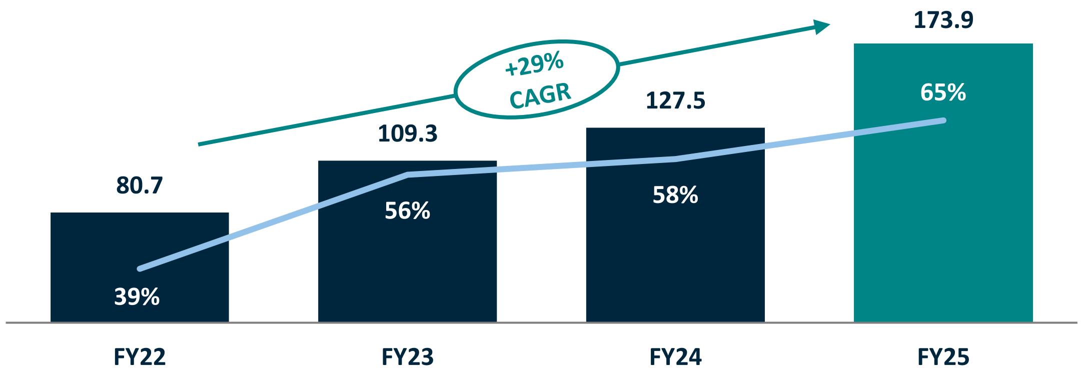
Production, TJe/d



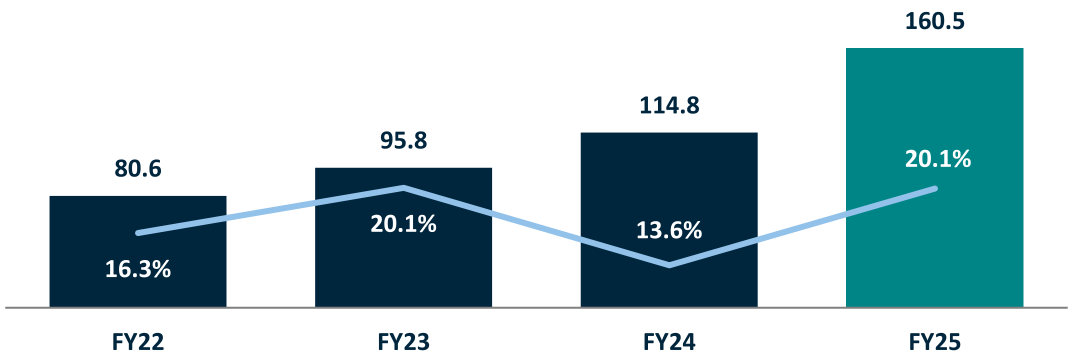
Production expenses[1], $m \ $ per GJ produced



Underlying EBITDAX, $m \ margin, %



Adjusted cash from operations, $mm[2] \ Adjusted cash flow yield (%)[3]



[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] Operating cashflows excluding restoration spend and other non-recurring and non-underlying items. | [3] Adjusted cash from operations divided by Enterprise Value as at 30 June of the relevant financial year

#1

FY25 in review

Health, safety, environment and community performance

Results ahead of industry benchmarks through disciplined operations

Safety

- Excellent safety performance
- Ahead of industry benchmark TRIFR[1]
- Over 18 months without a lost time injury
- Industry recognition for safety excellence during BMG decommissioning campaign

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

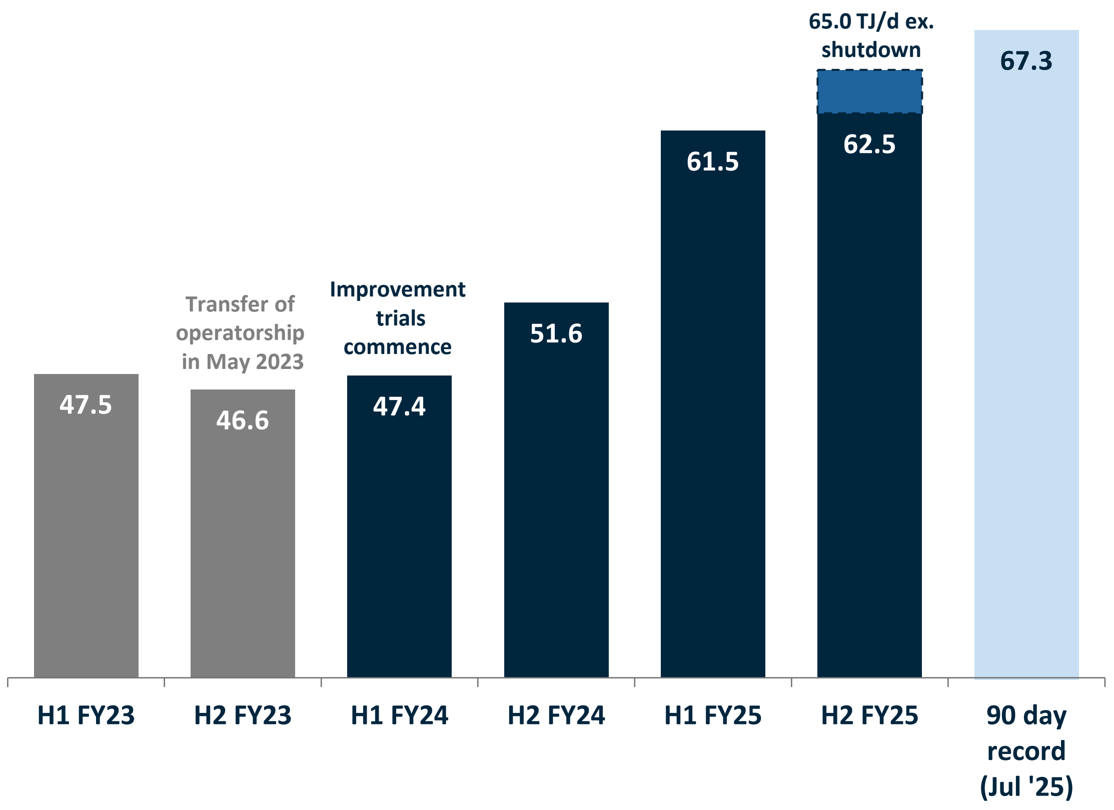
	FY24	FY25
Hours worked	689,398	**297,854**
Lost time injuries (LTI)	1	**0**
Recordable injuries	1	**1**
Total recordable injury frequency rate (TRIFR)	4.35	**3.36**
Industry TRIFR[1]	5.86	**5.16**
Reportable environmental incidents	0	**0**

[1] NOPSEMA industry rolling 12-month TRIFR for 30 June 2024 and 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 | [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 FY20-24. Amplitude Energy is in the process of seeking FY25 certification. Refer to page 21 of the Amplitude Energy 2024 Sustainability Report for scope definitions.

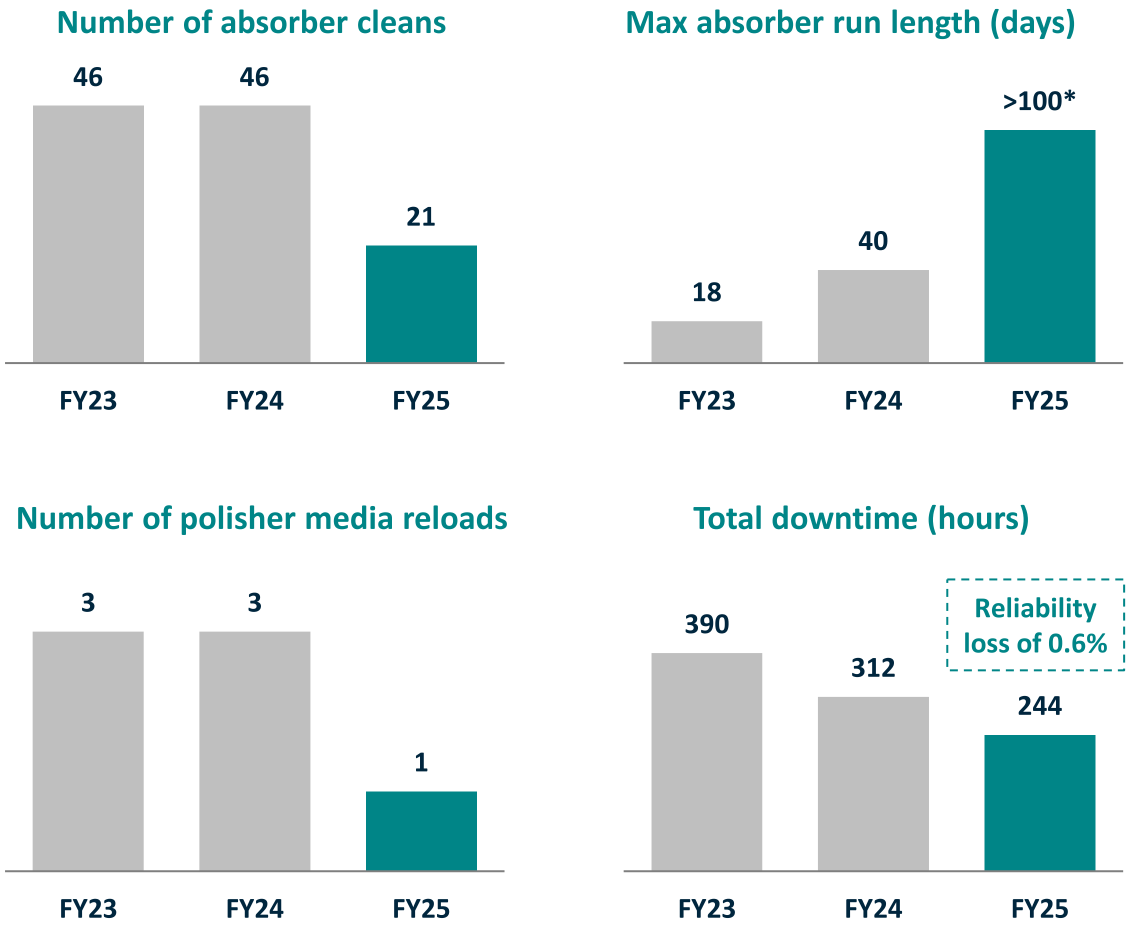
Orbost performance improved to nameplate

New production records set at Orbost Gas Processing Plant (OGPP), with improved sulphur removal performance and reliability loss <1%

OGPP average processing rate, TJ/d



Select OGPP operational KPIs

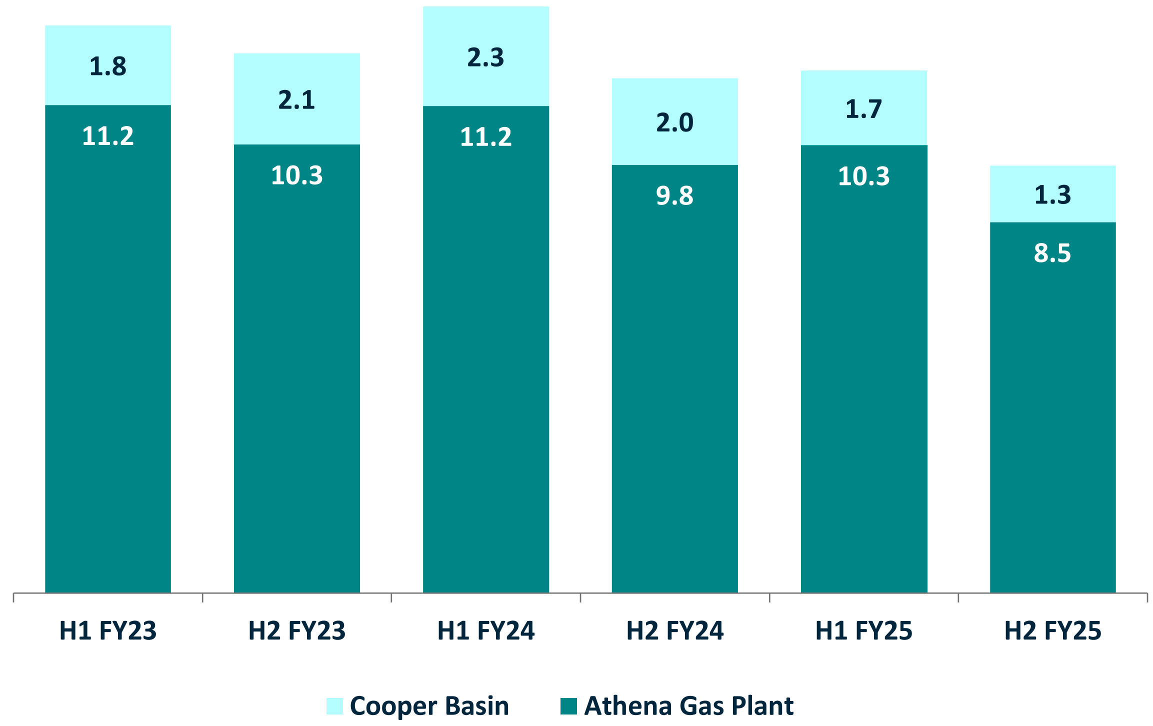


*100 days as at end FY25 – no absorber cleans undertaken in FY26 to date

Athena & Cooper Basin

Production impacted by short-term issues in H2 FY25

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



- Athena Gas Plant
  - Excellent plant reliability performance over FY25
  - Planned maintenance shutdown in March 2025 completed
  - Regular well cycling restored in February 2025
  - Assessing options to bring Casino-4 well back online to slow decline
  - Steady production over Q4 FY25 of 8.7 TJ/d
  - FEED work on re-lifing for East Coast Supply Project
- Cooper Basin
  - Natural decline of existing fields
  - Recent operations impacted by flooding in the Cooper Basin
  - Intention to pursue development campaign at Callawonga when conditions allow
  - Remains a source of high margin, US$-denominated cash flow

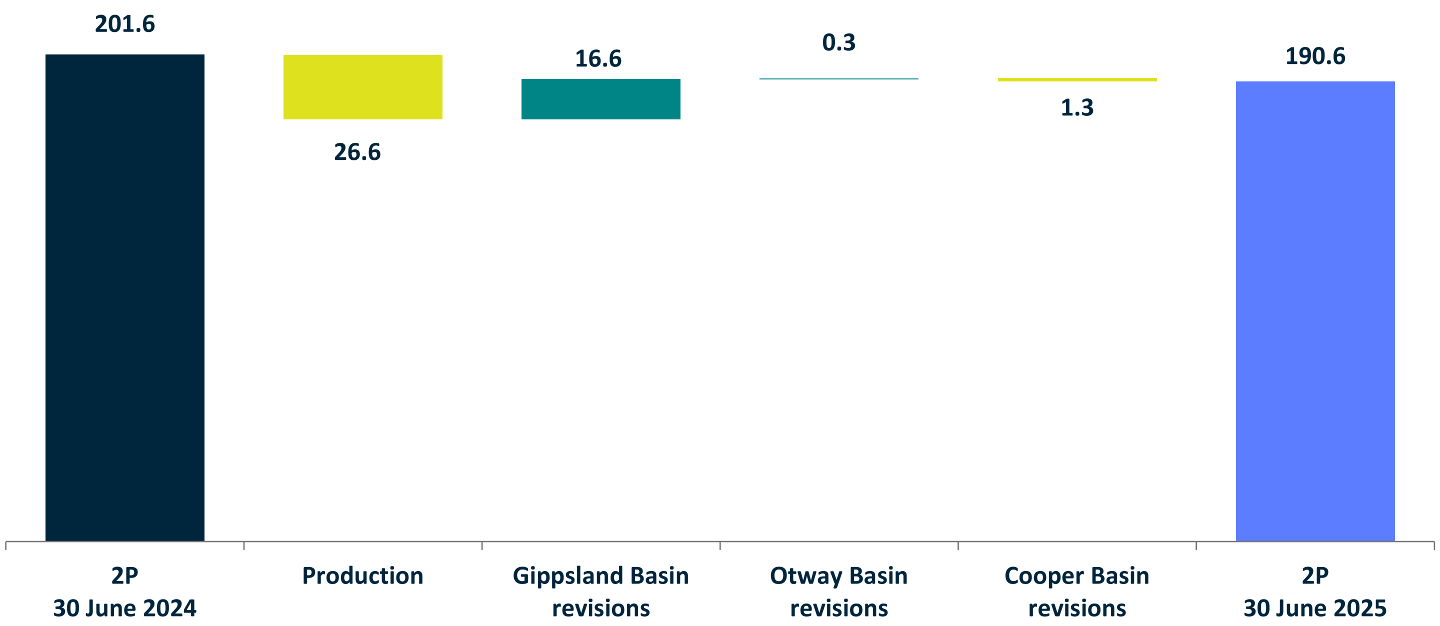
[1] All figures shown net to Amplitude Energy

Reserves & Resources at 30 June 2025[1]

Sole performing ahead of previous expectations, with 100% 1P reserves replacement and material 2P increase

- Annual movement in 2P Reserves
  - FY25 production
  - Material upwards revision to Sole through updated history matching of the gas field subsurface model
  - Minor other revisions
- 1P reserves replacement ratio of 100% at Sole and 84% at group level
- 2C Contingent Resource of 48.2 MMboe (FY24: 48.4 MMboe)

Change in 2P Reserves from 30 June 2024, PJe



MMboe	33.0	(4.4)	+2.7	+0.1	(0.2)	31.1

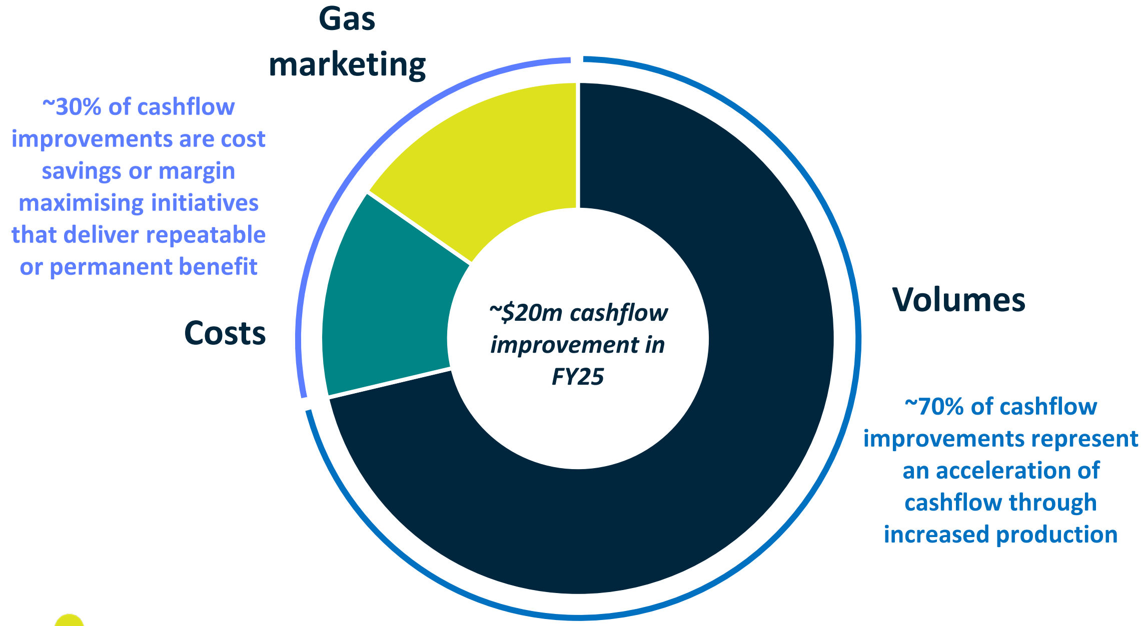
[1] As announced on 19 August 2025. Totals may not reflect arithmetic addition due to rounding. The method of aggregation is by arithmetic sum by category.

Continuous improvement programme

~$20m of cashflow improvement realised in FY25, with further improvement & cost reduction expected in FY26

FY25 success

- ✓ 70 initiatives completed or in delivery, over half newly added in FY25
- ✓ Emphasis on expenses continues, highlighted by $2.8m reduction in G&A in FY25, but broadened to production and margin maximisation
- ✓ Initiatives delivering sustainable emissions reductions



FY26 targets & example focus areas

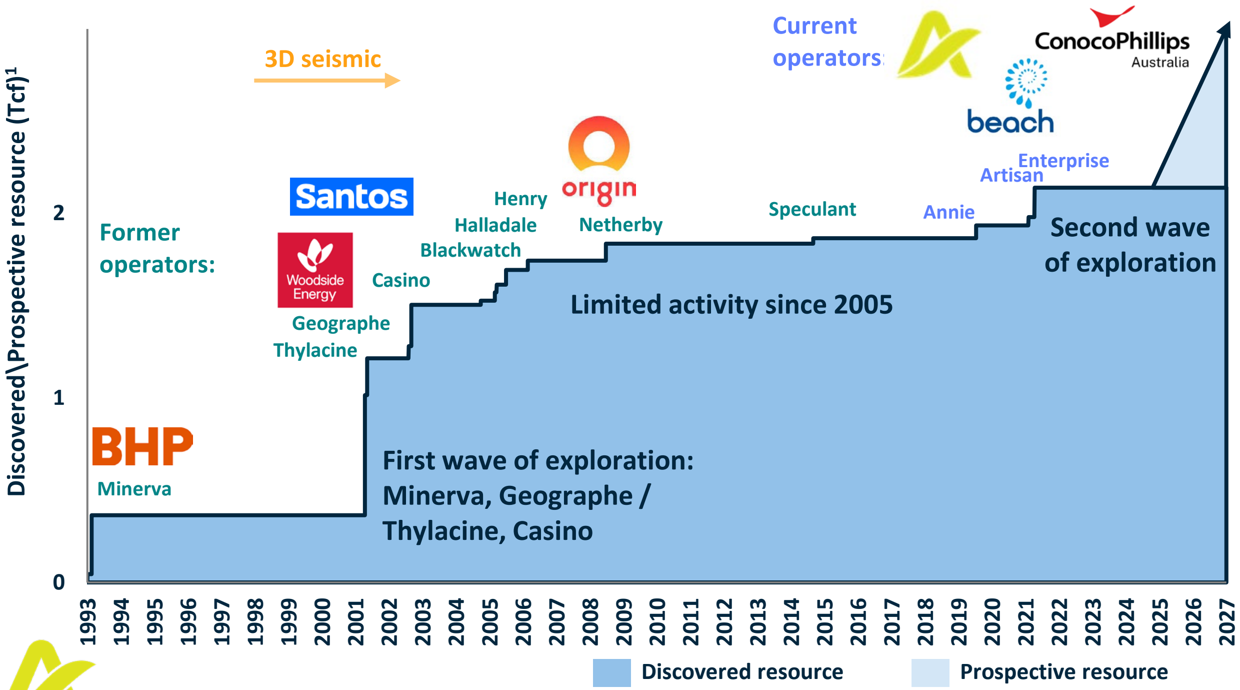
Targets	▪ Complete outstanding actions from FY25 program ▪ Accelerate production, maintain cost discipline, increase margins
Volumes	▪ Maintain FY25 production and reliability performance improvements at both plants ▪ Increase OGPP nameplate capacity
Costs	▪ ~$5m+ cost reduction opportunity in FY26, including: – Optimisation of Sole pipeline costs – Reduced waste disposal costs – Optimising maintenance spend
Gas marketing	▪ Maximising flexibility to direct spot sales into the highest-price markets on any given day ▪ Shaping spot sale volumes based on market conditions ▪ Additional short & long-term contracting opportunities

Investment in Otway Basin growth

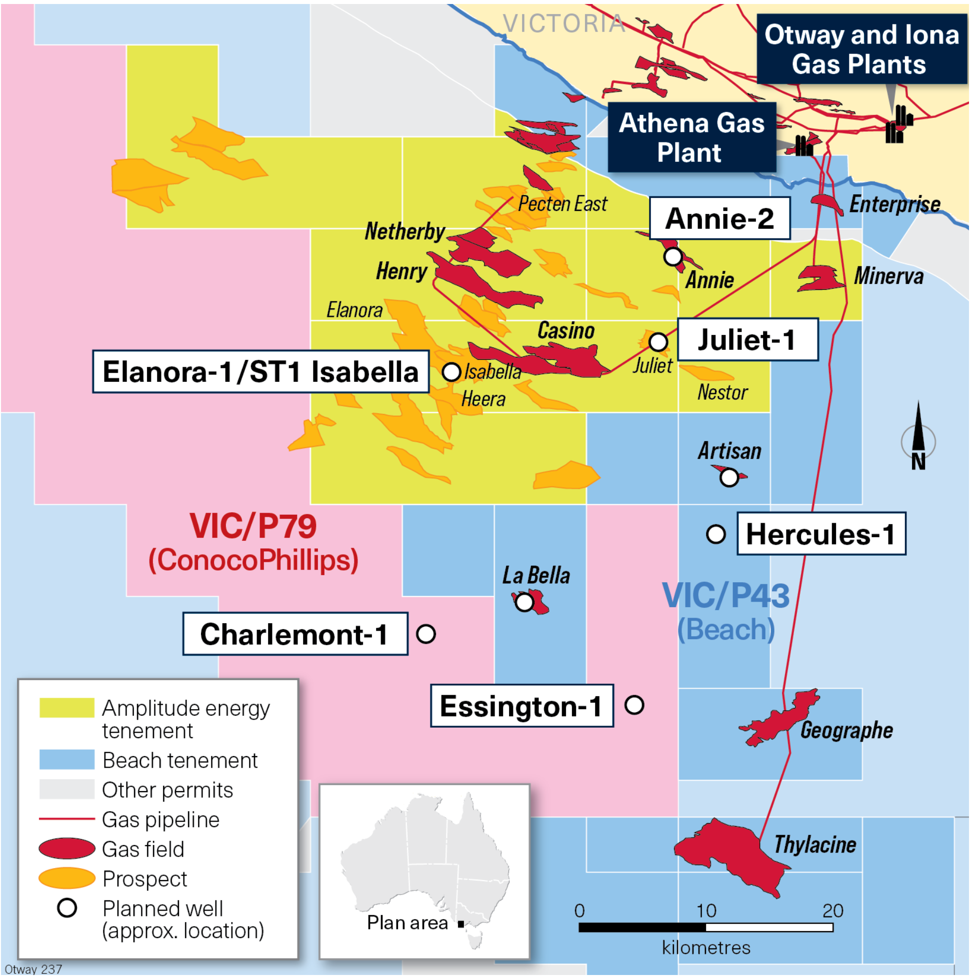
A number of operators have identified the Otway Basin as a strategic gas supply source for Australia's domestic market

Strategic, yet underexplored, gas supply basin for the tight domestic market

- Basin reinvigorated with upcoming Transocean Equinox exploration campaign
  - Rig consortium drilling 5 firm exploration wells, targeting >800Bcf[2] prospective resource, with up to a further 5 optional wells
  - Highly-prospective, yet underexplored acreage
- Committed growth investment of ~$1.5bn+
- Improved seismic data and previous drilling results support high Pg rates



Offshore Otway Basin, all operators



Additional Beach Energy and ConocoPhillips-operated acreage exists further south of this map

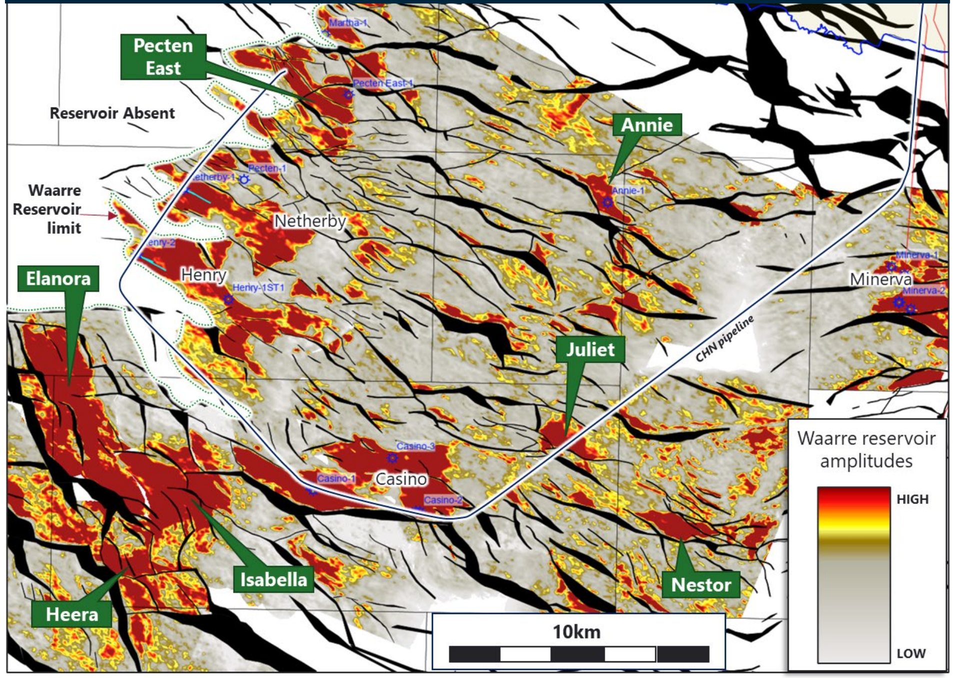
[1]Cumulative EUR volume. Source AEL internal estimates + IHS database. | [2]Aggregate gross mean unrisked prospective resource across two Amplitude Energy operated wells (refer page 20 of this presentation), Hercules well operated by Beach Energy (refer page 18 of Beach Energy's FY25 Half Year Results presentation on 6 February 2025) and two ConocoPhillips operated wells (refer page 12 of 3D Energi's July Investor Presentation on 4 July 2025).

Exploration success rates in the Offshore Otway Basin are world class

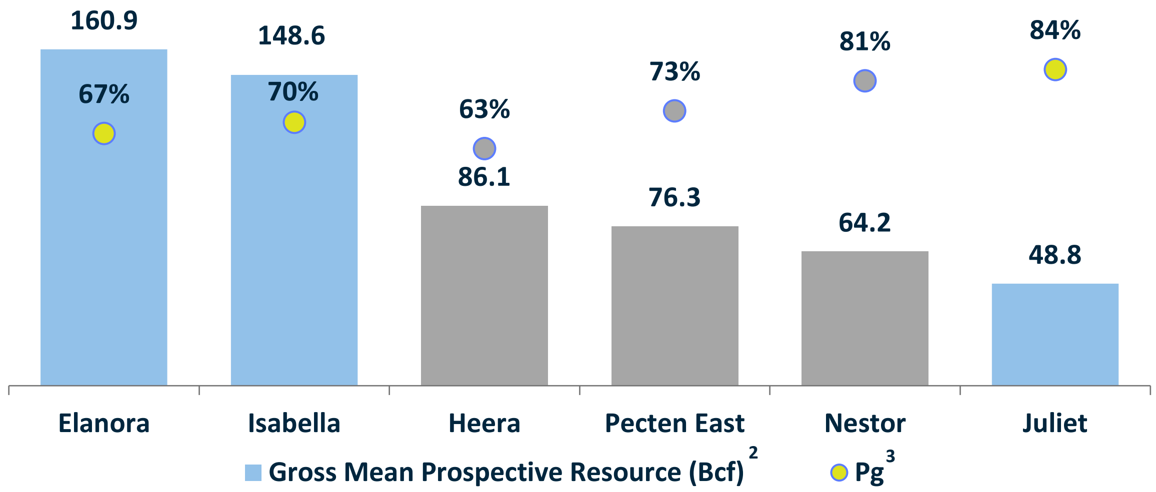
94% success rate for seismic amplitude-supported prospects in Otway Basin licences

- ECSP prospects identified using modern seismic interpretation techniques on the same 3D dataset as the CHN fields
- Gas properties expected to be similar to CHN analogues
- ECSP prospects are within existing production licences and are akin to low-risk field-extension drilling projects

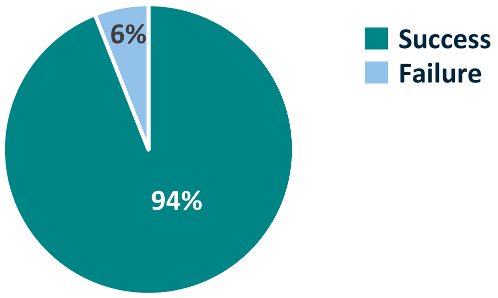
Waarre Formation seismic amplitude map - AEL Offshore Otway fields



Otway Basin, top Waarre Formation prospective resource highlights[1]



All seismic amplitude-supported targets drilled, Offshore Otway Basin



16 successful of 17 wells drilled[4]

[1] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and AEL's 50% net share of each prospect, were announced to ASX on 9 February 2022. Refer also to page 40 | [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] Pg is chance (or probability) of encountering a measurable volume of mobile hydrocarbons. | [4] Incorporates exploration wells drilled in Offshore Otway Basin by Amplitude Energy and other operators.

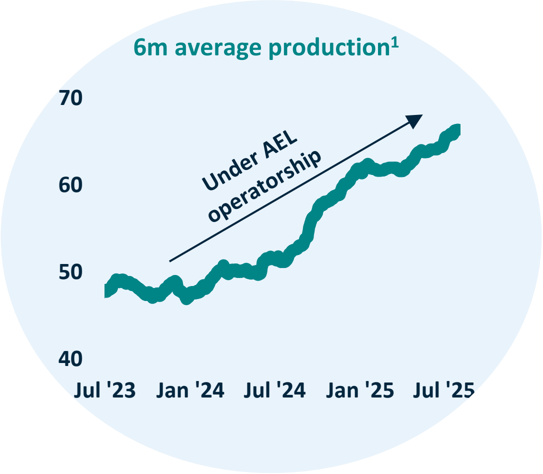
Unlocking the latent potential of our existing assets

Maximising value by utilising our existing installed infrastructure

Backfilling Athena via ECSP

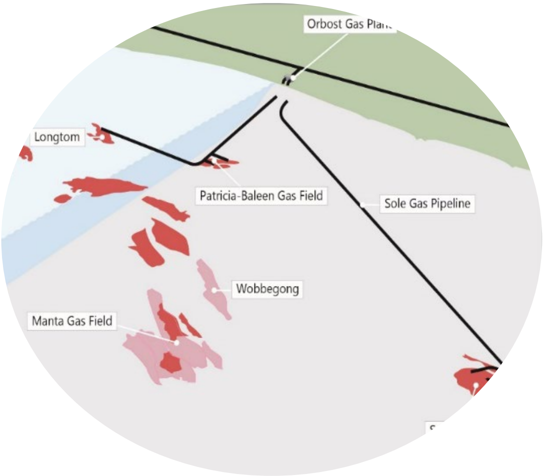
- Replacement value of Athena >$500m
- ECSP targets 90 TJ/d plateau production; up to 150 TJ/d installed production capacity
- Peak gas supply and third-party processing opportunities

Increasing OGPP production



- Increased OGPP production maximises cash generation and margins
- Increased exposure to spot gas pricing

Progressing Patricia Baleen options



- PB restart project entered Select phase, ahead of any FEED decision
- Assessing potential as a future production or gas storage asset
- MoU with SGH to participate in the Select phase in Q1FY26 to assess Longtom gas processing options

[1]Average excludes planned shutdowns

#2
FY25 financial highlights

Record production & financial metrics

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

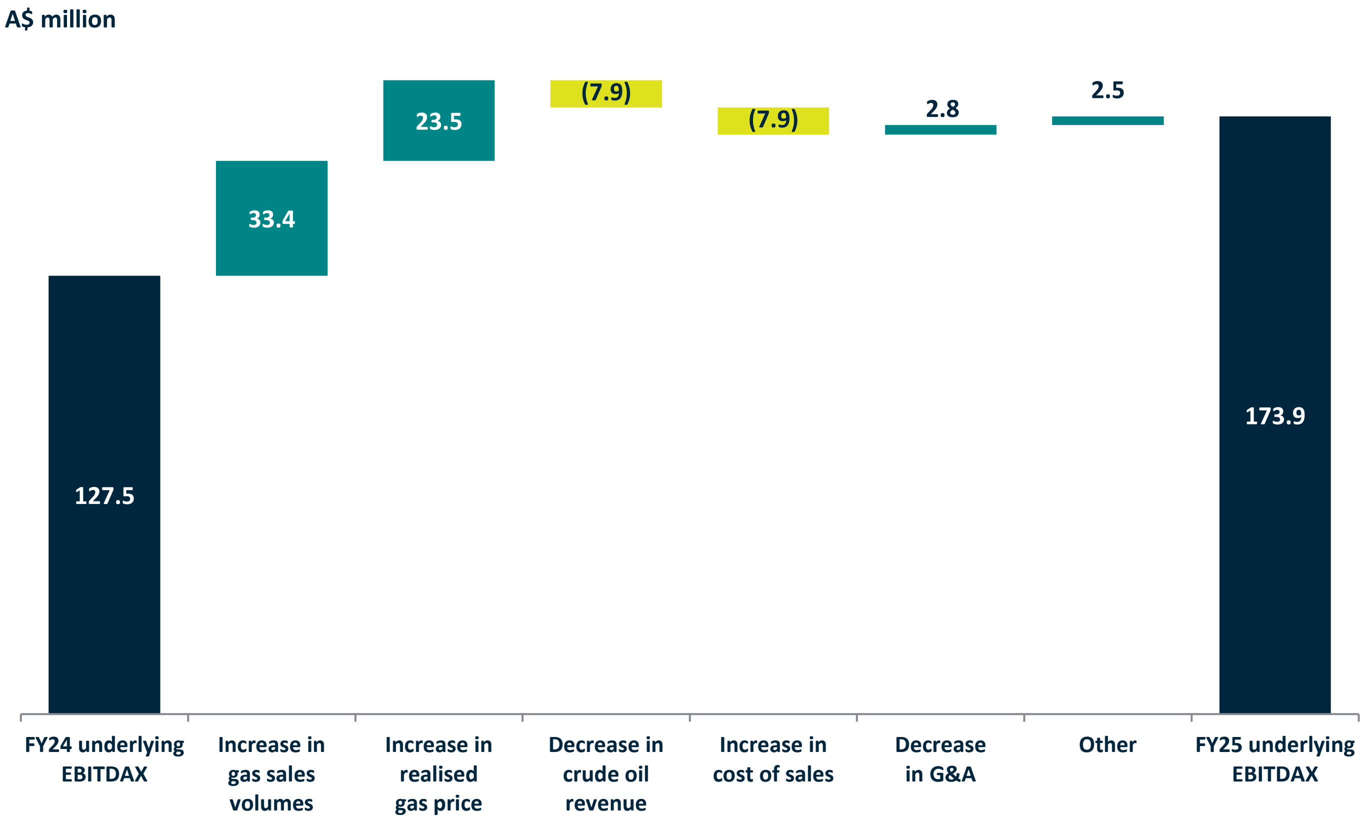
$m unless indicated	FY24	**FY25**	Change
Production, TJe/d	62.1	**73.0**	▲ 17%
Sales revenue	219.0	**268.1**	▲ 22%
Average realised gas price ($/GJ)	8.83	**9.91**	▲ 12%
Production expenses[1]	59.2	**62.1**	▲ 5%
u-EBITDAX	127.5	**173.9**	▲ 36%
Underlying profit/(loss) after tax	1.4	**11.4**	N/M
Operating cash flow	(99.8)	**89.3**	N/M
Adjusted cash from operations[2]	114.8	**160.5**	▲ 40%
Capital expenditure incurred	23.9	**64.1**	▲ 168%
Restoration payments	207.7	**63.3**	▼ 70%
	30 June 24	**30 June 25**	
Cash and cash equivalents	14.3	**62.2**	▲ 335%
Drawn debt	265.0	**305.2**	▲ 15%
Net debt/(cash)	250.7	**243.0**	▼ 3%

- Record production driven by OGPP turnaround
  - Top end of the twice-increased guidance range
- Record revenue due to higher sales volumes and higher realised gas prices
- Production expenses in-line with guidance
  - Reduced OGPP plant costs relating to sulphur removal
  - Higher total costs driven by increased production, largely associated with the Sole pipeline and waste disposal
  - Unit costs ↓ 10.5% to $2.33/GJe (FY24: $2.60/GJe)
- Record u-EBITDAX due to margin expansion and operational leverage
  - 65% u-EBITDAX margin, well above global E&P average
- Record adjusted cash from operations of $160.5m[2]
- Capex primarily focused on ECSP long-leads, prior to O.G. Energy's entry into Otway Basin JV (back costs to be reimbursed via cost carry in FY26)
- Restoration payments mainly reflect the final BMG wells payments made in Q1 FY25 and Woodside's Minerva programme (AEL 10%)
- Net debt down >$35m since its peak in Q1 FY25
  - Ongoing focus on deleveraging prior to ECSP drilling

[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 FY24

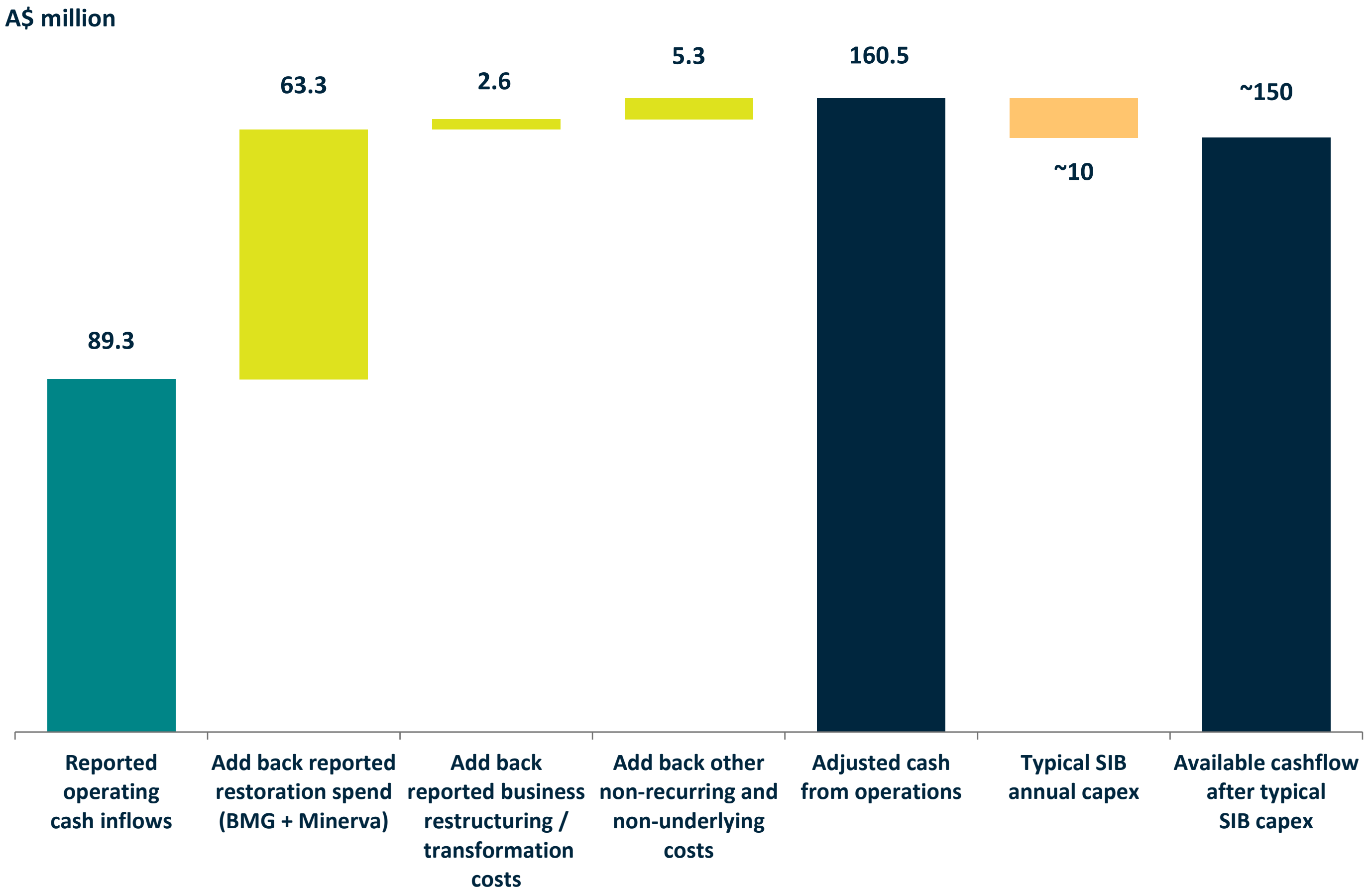
Record underlying earnings driven by greater gas sales volumes, higher realised prices and ongoing cost reductions



- Increased sales volumes and average realised gas prices
- Reduced crude oil production from Cooper Basin due to flooding and natural decline
- Increased cost of sales due to higher pipeline-related costs, greater waste disposal from higher production and general visual inspections on the CHN pipeline
- G&A reduced by $2.8m to $11.7m
- Result demonstrates strong operating leverage of assets and margin expansion

AEL is generating strong underlying organic cashflow

FY25 financial results demonstrate AEL's ability to generate >A$150m of annual underlying organic cashflow, with a largely fixed cost base supporting stronger cash generation and margin expansion at higher production rates



- Indicative only, and not guidance
- Strong rise in FY25 operating cash flow due to production and realised gas price increases
- Operating cash flow should continue to improve as further OGPP production increases occur
  - Recent OGPP production rates tracking well ahead of FY25 average (62.0 TJ/d inc. shutdown)
- Potential for further margin expansion into FY26 & FY27
  - Improving average gas price realisations
  - Ongoing work to reduce cost base/efficiency improvements
- Few one-off cash cost items in FY26:
  - General visual inspections for Sole and Patricia Baleen offshore pipelines, as per guidance[2]
  - Residual Minerva wells decommissioning payments

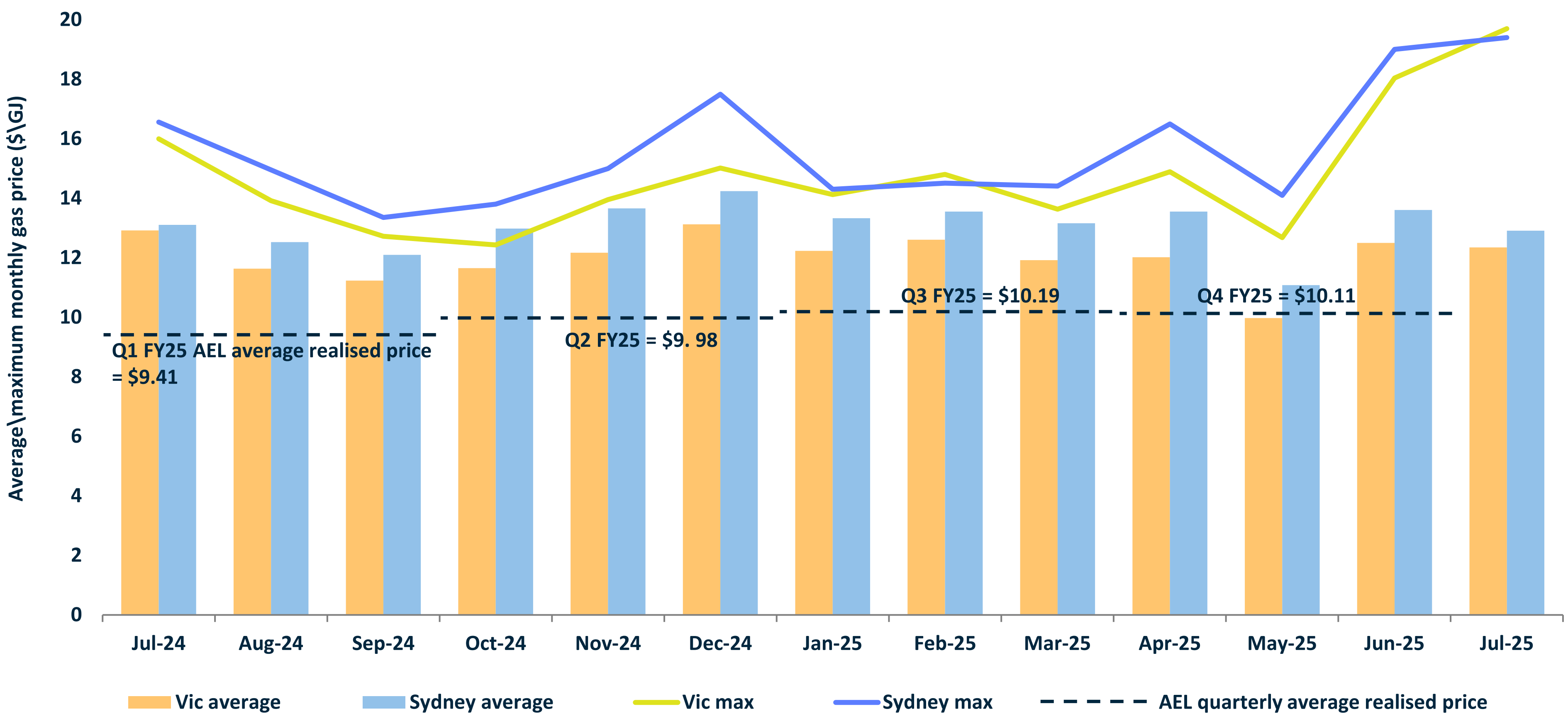
[1] Reported net cash from operations and restoration spend are sourced directly from the FY25 Consolidated Statement of Cash Flows (page 46 of AEL's FY25 Financial Report). The add back of business restructuring/ transformation costs and other non-recurring and non-underlying costs is sourced from the reconciliation to underlying loss (page 16 of AEL's FY25 Financial Report).

[2] Refer page 23

Gas trading & marketing opportunities

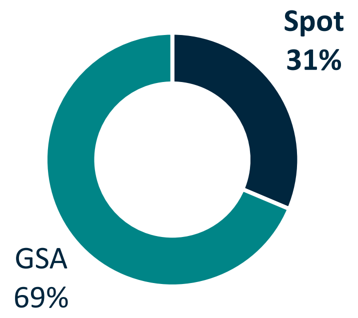
Spot sales increased to 31% of total gas sales in FY25 vs. 15% in FY24

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



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

FY25 gas sales mix



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

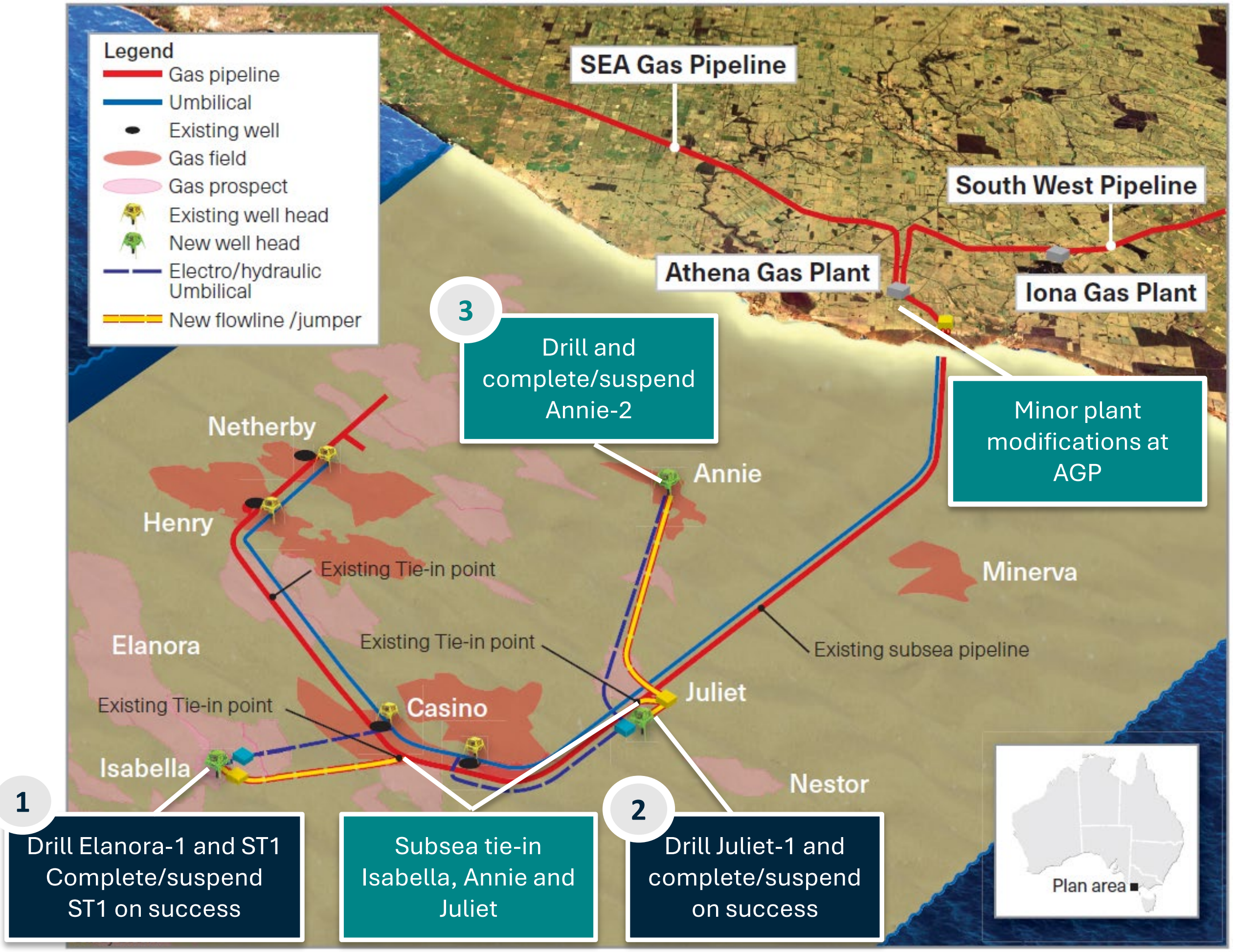
#3

East Coast Supply Project

ECSP: Brownfield project on track to supply the market in 2028

Unlocking supply from the Offshore Otway Basin through highly-prospective gas fields and use of existing infrastructure

Otway Basin



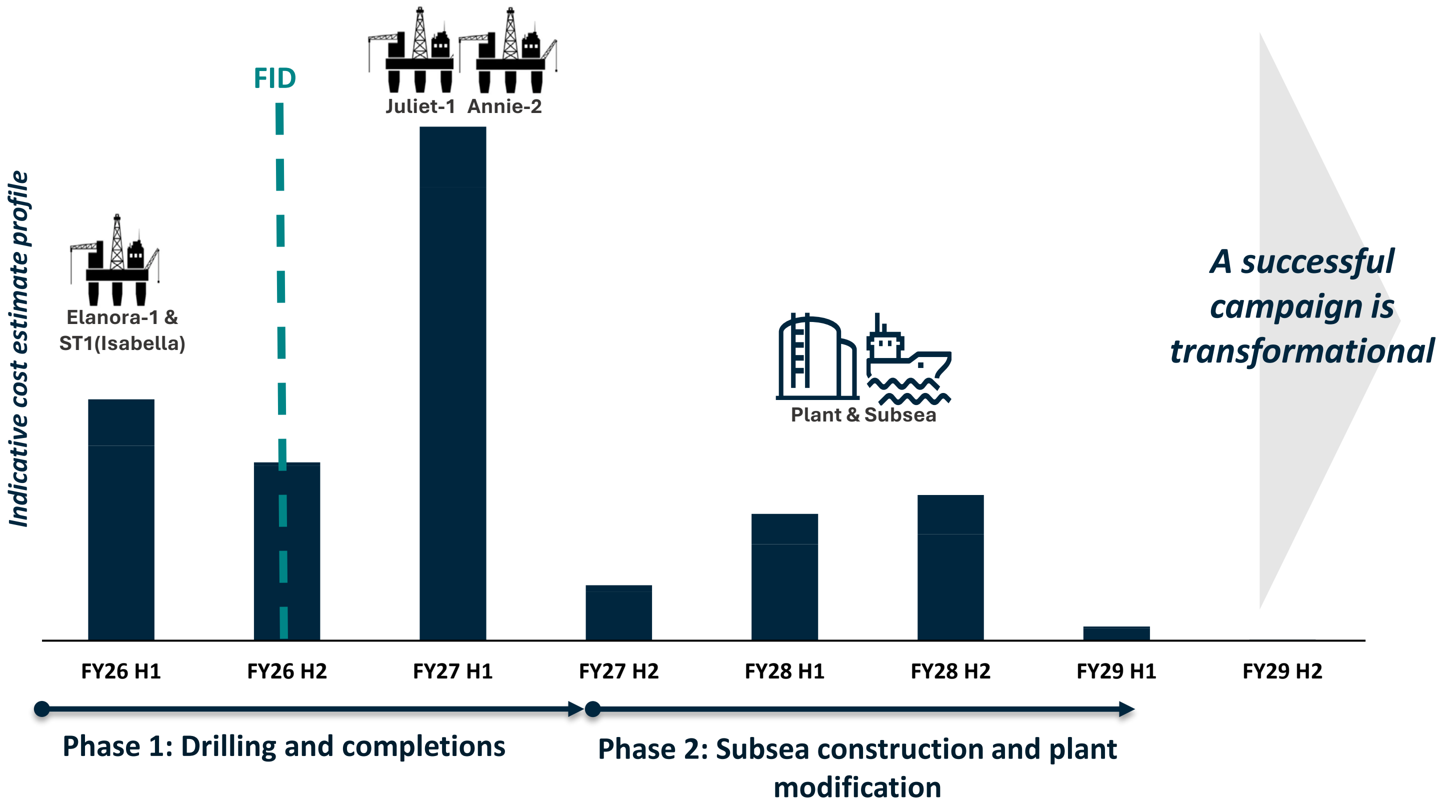
Low-risk 3-well exploration & development program

- Prioritising backfill for the Athena Gas Plant of up to ~90 TJ/day gross production (capacity 150 TJ/day), with first gas targeted in CY2028
- Targeting 2P + 2C equivalent to >10 years reliable production at Athena[1]
- 1st exploration well at Elanora, with sidetrack to Isabella, and 2nd exploration well at Juliet
  - Targeting 358 Bcf[2] (179 Bcf net to AEL) of gross mean unrisked prospective resource across Elanora, Isabella and Juliet
  - 98% probability of gas discovery
- 3rd well at Annie-2, intending to develop 65 PJ[3] gross 2C (32.4 PJ net to AEL)
- Current expectation for 1st well to spud in December
  - 2nd & 3rd wells likely to be drilled mid-CY2026
- Attractive project economics upon successful development
  - Project comfortably exceeds internal investment hurdle rates[4]
- Strong interest from gas customers in long-term GSAs
- O.G. Energy acquisition of Otway assets completed; $28m cost carry activated

Indicative only, not guidance. This forward-looking statement is subject to the qualifications on page 2 of this presentation. | [1] Conversion of resources require development in subsequent campaign/s. | [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 and are shown on page 40 of this presentation. This total reflects arithmetic summation of independent probabilistic resource estimates. 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. | [3] 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 FY25 Reserves and Contingent Resources ASX release on the 19 August 2025. | [4] Based on AEL internal mid-case assumptions.

ECSP is a phased near-field tie-in campaign

Appropriate levels of activity allowance and contingency are embedded in cost estimates rapidly de-risking as phases are completed



Capex estimates remain consistent as announced in March 2025 and include activity time allowances and contingency

From the first year of plateau production, ECSP has the potential[1] to:

- Increase Group production to 36PJe per annum
- Grow Group revenue to c.$500MM
- Grow Group free cash flow to > $300MM
- Completely deleverage the business
- Increase Group reserves & resources by > 60%
- Extend the life of the Athena Gas Plant by a decade
- Provide significant margin expansion and value accretion to AEL's portfolio

[1] Indicative only based on success – not guidance

#4

FY26 outlook

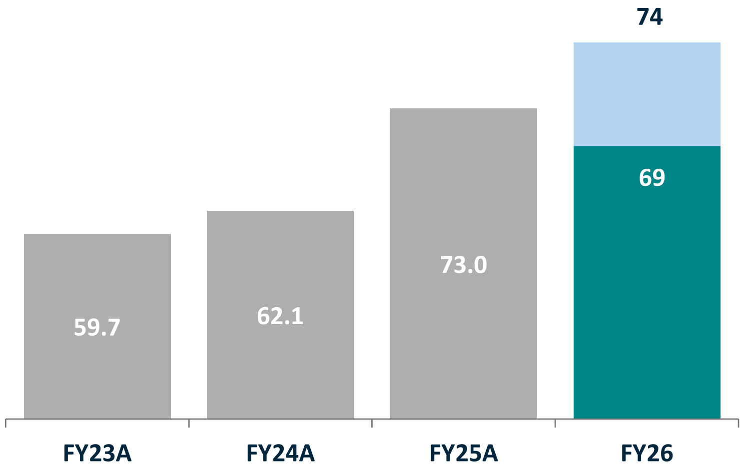
FY26 guidance

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

FY26 production: 69 – 74 TJe/day

Annual PJ-equivalent

21.8	22.7	26.6	25.2 – 27.0

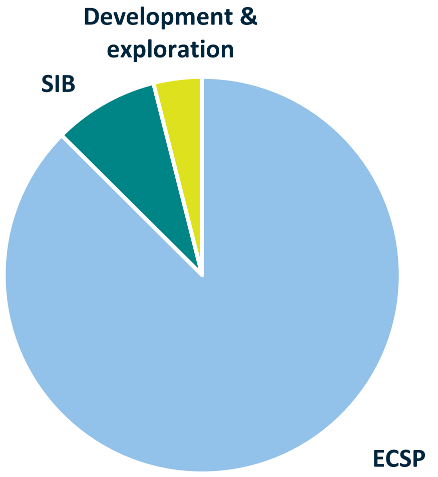


- Reflects confidence that recent OGPP production rates will be sustained
  - Guidance does not assume increases in nameplate capacity through debottlenecking
  - Range reflects different scenarios for absorber runtime, clean times and plant uptime
  - No planned maintenance shutdown in FY26
- Natural decline at CHN fields and PEL 92

FY26 production expenses: $54 – 60mm[1]

- Reflects achieved & expected production cost savings, primarily at OGPP
  - Partly offset by general cost inflation
  - Implied production unit cost $2.00 - 2.38/GJ
- Other cash expenses & costs of sales of $24 – 28m[1,2]
- Excludes ~$16m for general visual inspection (GVI) of Sole and Patricia Baleen pipelines in FY26
  - Irregular activity (required once per ~5 years)
  - Supports Patricia Baleen field re-life

FY26 capex: $125 – 150mm[3]



- ECSP capex includes Elanora/Isabella drilling and development phase long-lead orders & FEED costs
  - Reflects AEL's 50% share and ~$28m cost carry by O.G. Energy
  - Guidance to be updated upon development FID
- Excludes decommissioning expenditure
  - Residual Minerva infrastructure removal may take place post FY26

[1] Excludes pipeline GVI expenses | [2] Excludes selling & transport costs associated with accessing Sydney spot gas market. | [3] Excludes decommissioning costs.

FY26 focus areas

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

Progress the ECSP on schedule and budget to achieve FID	▪ Elanora / Isabella drilling ▪ Development FEED ▪ Foundation GSAs
Maximise asset utilisation	▪ Increase OGPP capacity to >70 TJ/d instantaneous rate by end of FY26 ▪ Reliability loss of <1% across AGP & OGPP ▪ Progress Patricia Baleen restart
Increase average realised gas prices	▪ Marketing & trading initiatives, including recontracting ▪ Progress opportunities to link our products to power generation
Reduce production costs, streamline systems & processes	▪ Reduce OGPP production cost to <$2/GJ ▪ Further organisational improvement initiatives

#4

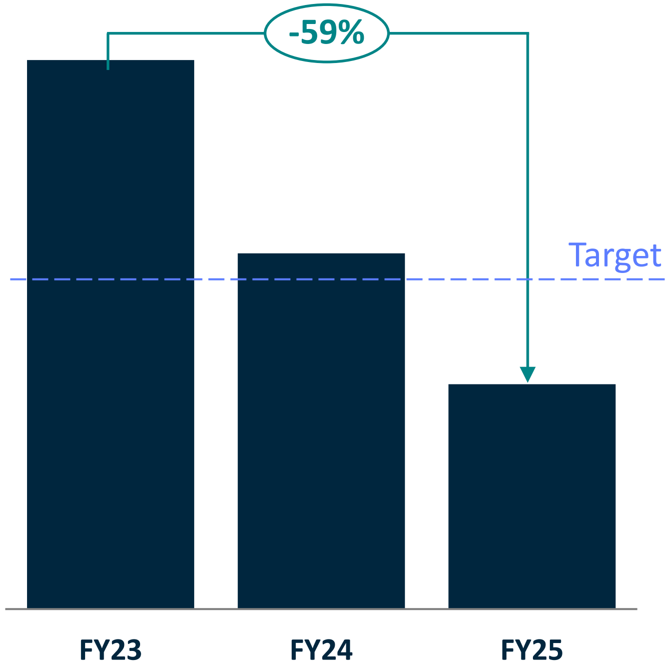
Appendix A

Strong progress on sustainability targets

Delivery against our priorities

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

✓ 59% reduction achieved in FY25



Scope 2: Integrate renewable electricity to support Amplitude Energy operations

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

Athena Gas Plant

Maintain carbon-neutral status

✓ Carbon neutral status maintained[1]

✓ Reduced waste & costs from sulphur beneficial use project

Truck being loaded with elemental sulphur for delivery from OGPP

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
[1] 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 FY20-24. Amplitude Energy is in the process of seeking FY25 certification.

Abbreviations

$	Australian dollars
Amplitude Energy or the 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
EBITDAX	Earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment
ECSP	East Coast Supply Project
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
SIB	Stay in business
TJ	Terajoules
TJe/d	Terajoules-equivalent per day
TJ/d	Terajoules per day
u-EBITDAX	Underlying EBITDAX

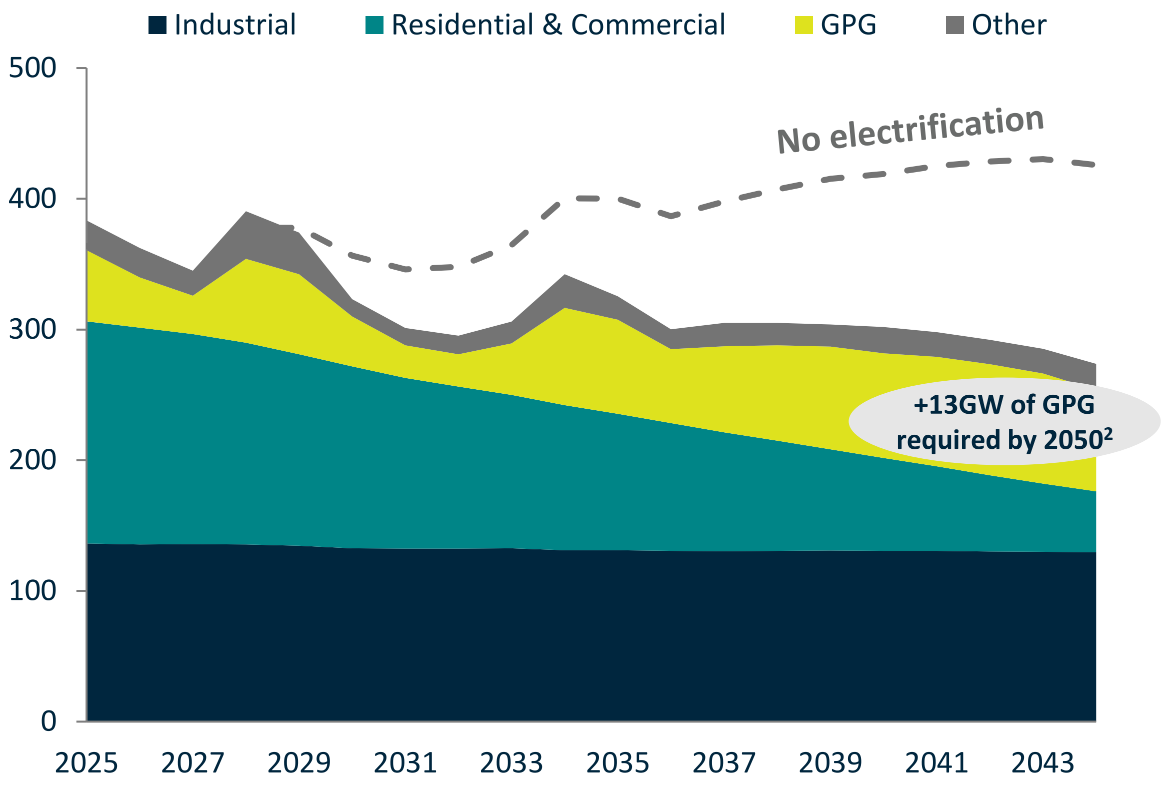
#4

Appendix B: East Coast Domestic Gas Market

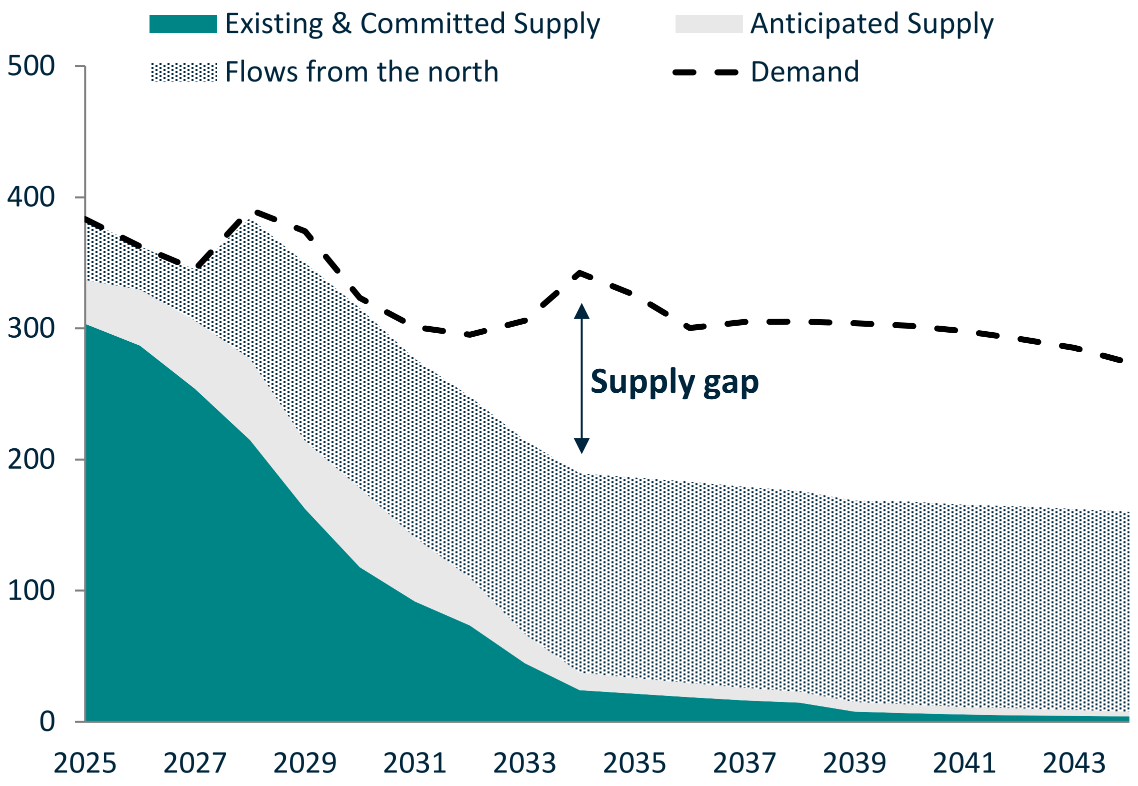
Urgent demand for new domestic gas supply

Federal agencies highlight risks of supply shortfalls during peak demand periods from 2026 and an ongoing supply gap from 2028[1]

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



Southern States AEMO supply forecast, PJ p.a.[3]

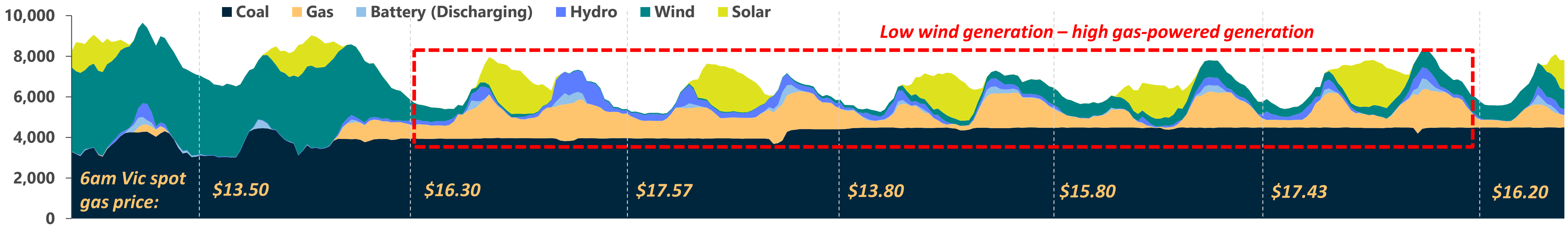


[1] ACCC Gas Inquiry 2017-2030, Interim update on east coast gas market, June 2025
[2] AEMO 2025 Gas Statement of Opportunities, Step Change scenario, National Electricity and Gas Forecasting Portal. Southern States include Victoria, NSW, SA and Tasmania. Other includes losses and energy efficiency.
[3] AEMO 2025 Gas Statement of Opportunities, Figure 41

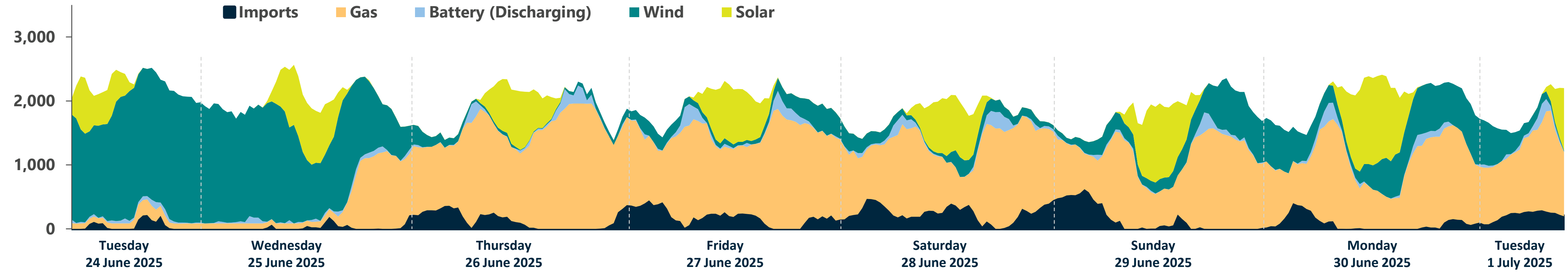
Increasing role of gas in the electricity market

Gas is already proving its critical role in firming the national electricity grid; its role will become more important as coal retires.

Victorian electricity supply by type (average ~40% renewables over FY25), MW[1]



South Australian electricity supply by type (average ~70% renewables over FY25), MW[1]

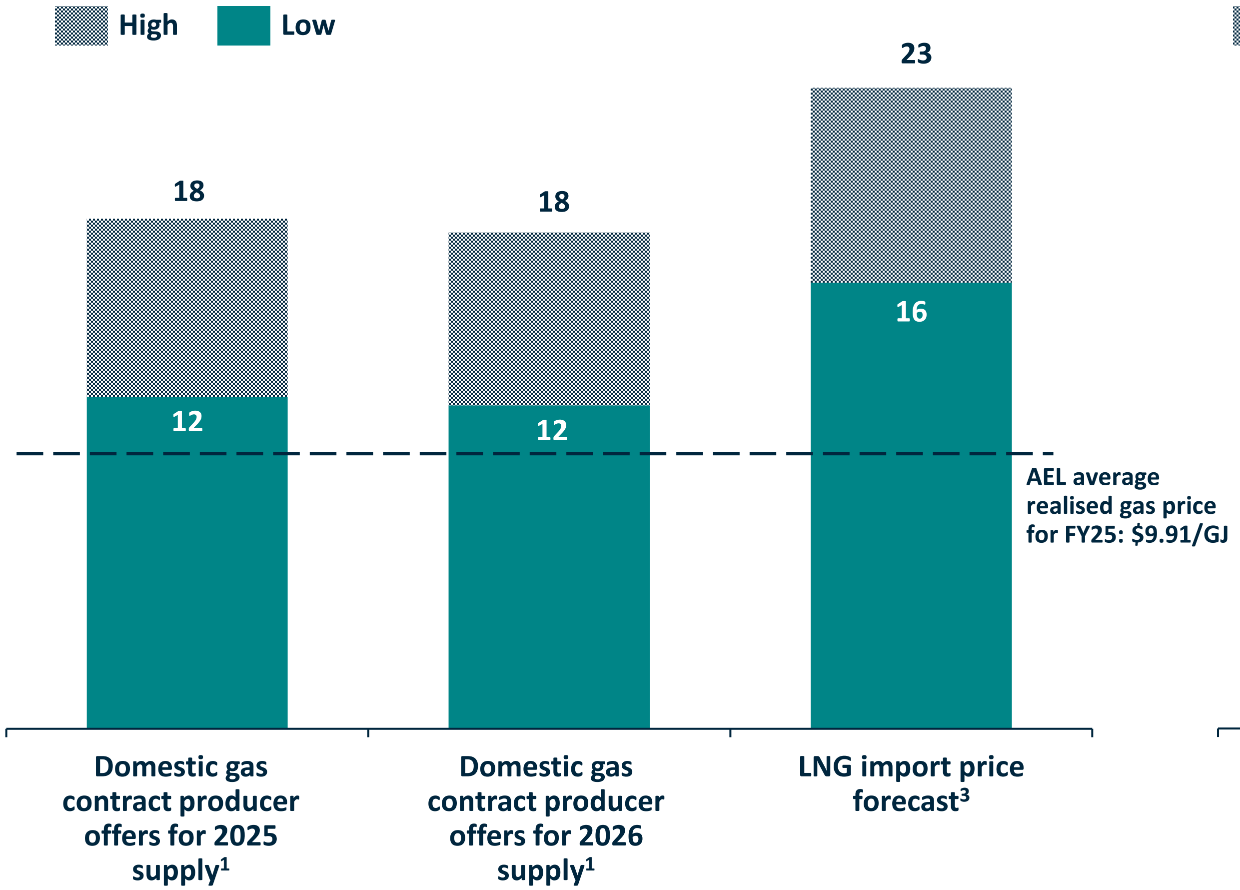


[1] Data sourced from www.opennem.org.au. Excludes exports | [2] Electricity refers to the National Electricity Market (NEM), incorporating all Australian states and territories excluding Western Australia and the Northern Territory

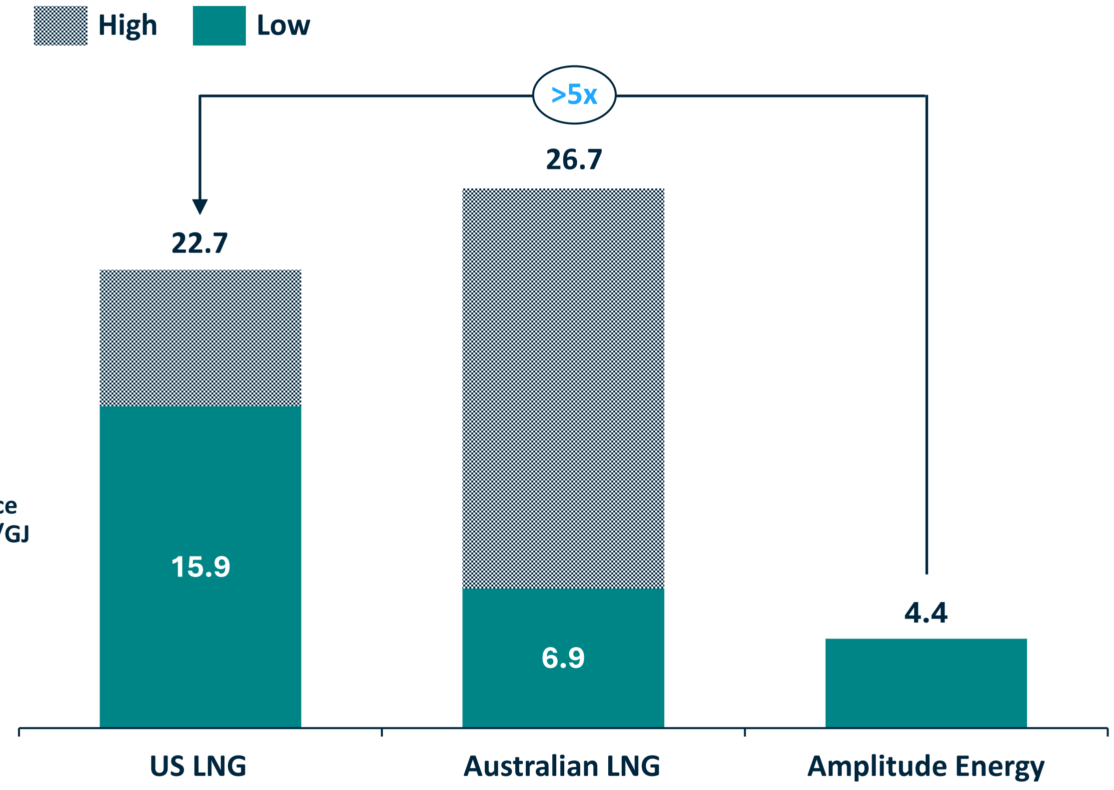
Domestic gas is the cheapest & lowest emissions option

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

Australian Southern States contracted gas prices, A$/GJ



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



[1]ACCC Gas Inquiry, June 2025 Interim Report, Page 41, Chart 2.12. Ranges reflect GSAs executed for Southern States supply only. | [2]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.

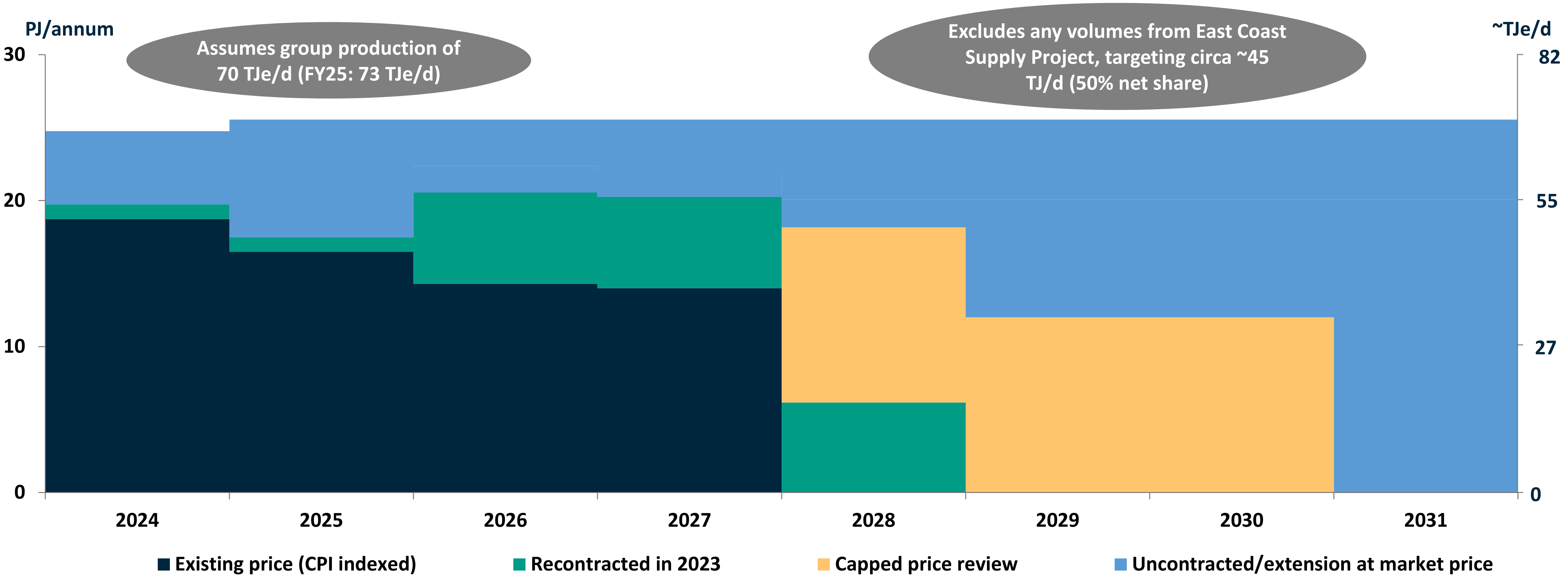
#4

Appendix C: Additional Financial Information

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 TJe/day from 1 January 2025 (actual spot sales for CY2024 shown). This forward-looking statement is subject to the qualifications on page 2 of this presentation. There can be no guarantee that this production level will be achieved, notwithstanding FY25 average group production rates above 70 TJe/day. The annual contract quantity volumes shown are for illustrative purposes only and do not constitute production guidance.

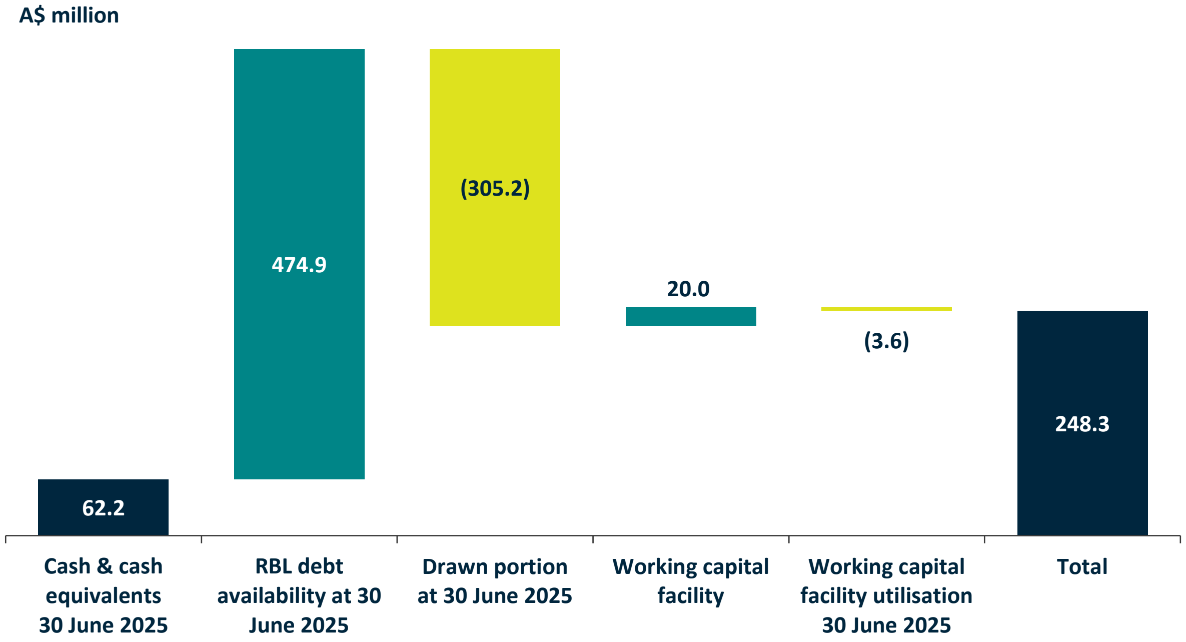
Significant capacity within debt facilities

Reserve-based loan (RBL) provides financing flexibility and liquidity as the company enters its next leg of growth

Bank facilities overview

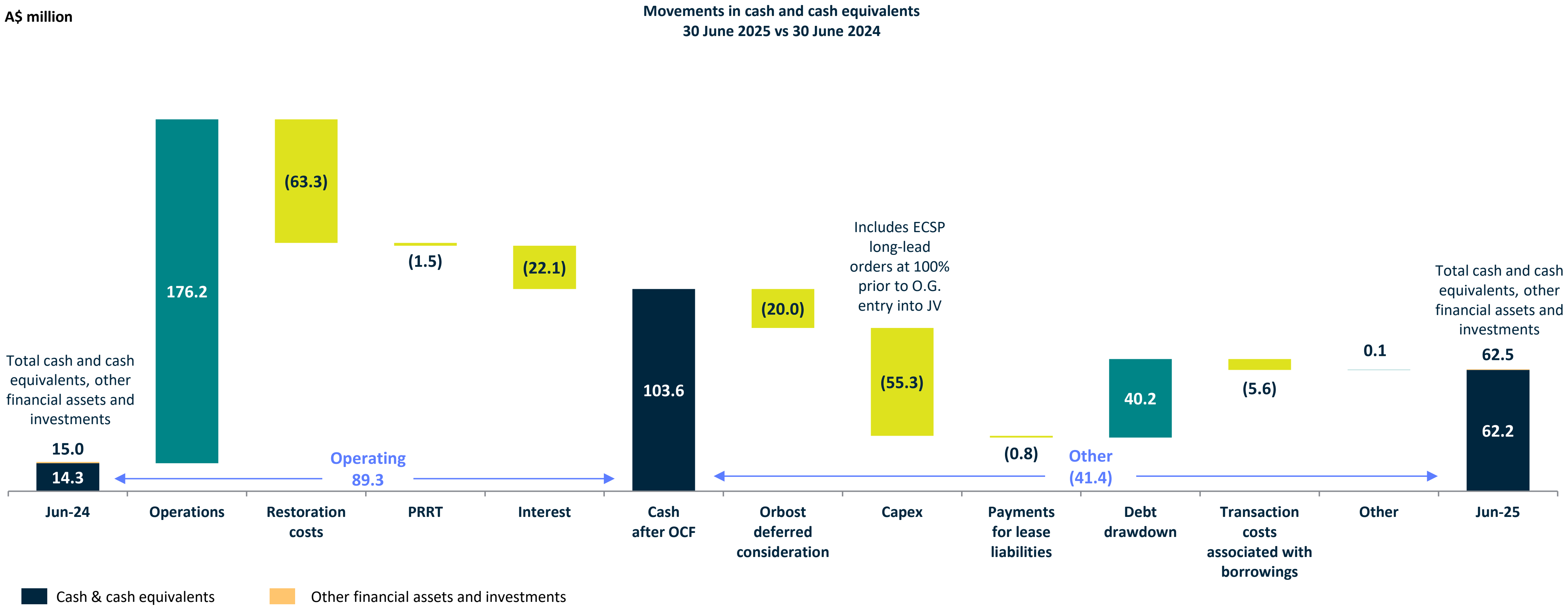
- Senior, secured RBL increased and extended in December 2024
  - Facility limit of $480mm, $475m available as at 30 June
  - Maturity extended to September 2029
  - Strong lending group
  - Interest rate on drawn portion BBSY + 3.25%
- Intention to further maximise debt available by optimising RBL parameters
  - Includes potentially incorporating Offshore Otway discoveries in the ECSP into the RBL borrowing base
- RBL currently drawn to $305m, with cash on balance sheet of $62m (net debt $243m)
- $20m working capital facility

Liquidity overview



Group cash— bridge from June 2024 to June 2025

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



Illustrative Group net debt trajectory to first gas (indicative only, not guidance)

Based on preliminary indicative ECSP cost estimates (three well success case) & illustrative underlying organic cashflow generation

- Indicative only and does not constitute net debt guidance or cashflow guidance
- Assumes three well success case
- Range of illustrative net debt outcomes based on AEL cashflow and ECSP capex scenarios
  - ECSP spend based on phase 1 cost estimate range and phase 2 preliminary cost indication range
  - Cashflow generation based on average OGPP production of 65 TJ/day and range of spot gas prices
    - Flat $12/GJ in low cashflow scenario
    - $15.10-18.85/GJ (non-peak/peak) in high cashflow scenario
- Reflects commencement of O.G. Energy's carry of ECSP costs in H1 FY26
- Illustrative peak net debt in H1 FY27

[1] Illustrative range of Group leverage assumes an average realised OGPP production rate of 65 TJ/day over the period (after shutdowns and assumed planned and unplanned downtime). The high end of the net debt shaded range reflects a low cashflow scenario and the high ends of the ECSP phase 1 drilling cost estimate and phase 2 preliminary cost indication. The low end of the net debt shaded range reflects a high cashflow scenario and the low ends of the ECSP phase 1 drilling cost estimate and phase 2 preliminary cost indication. The low cashflow scenario assumes a flat spot gas price of $12/GJ over the period while the high cash flow scenario assumes A$15.10-18.85/GJ (non-peak/peak spot gas prices) over the period. This forward-looking statement is subject to the qualifications on page 2 of this presentation and does not represent net debt guidance (or cashflow guidance). AEL believes these assumptions are reasonable. However, these assumptions are subject to change due to various factors and may cause actual results to differ from those presented in the indicative trajectory above. Except as required by applicable law or the ASX Listing Rules, AEL may not update any assumptions, whether because of new information or future events.

Reconciliations

Reconciliation To Underlying EBITDAX

$mm	FY24	FY25
Underlying net profit after tax	**1.4**	**11.4**
Adjusted for:		
Net finance costs	15.0	25.7
Accretion expense	17.7	9.9
Tax expense / (benefit)	(11.0)	17.1
Depreciation	40.1	48.3
Amortisation	58.7	65.2
Exploration and evaluation expense	3.7	0.3
Tax adjustments to generate underlying profit	1.9	(4.0)
Total underlying adjustments after tax	**126.1**	**162.5**
Underlying EBITDAX	**127.5**	**173.9**

Reconciliation To Underlying Profit

$mm	FY24	FY25
Statutory net loss after income tax	(114.1)	**(41.3)**
Adjusted for:		
OGPP acquisition and integration costs	0.1	-
Hedging costs	1.5	-
Business restructuring and transformation	3.4	2.6
Asset write-off	-	5.4
Restoration expense and associated costs	110.3	11.0
NOGA levy	1.8	2.3
Impairment	0.3	27.4
Derecognition of deferred income tax asset	33.3	18.6
Tax impact of adjustments	(35.2)	(14.6)
Total significant items after tax	**115.5**	**52.7**
Underlying profit after tax	**1.4**	**11.4**

Decommissioning provisions & impairment summary

The vast majority of decommissioning provisions relate to work expected beyond 5 years from today

Major items for next 5 years (<17% of the total decommissioning provision)

- Minerva (10% interest)
  - Remaining subsea pipeline & equipment removal
  - Remaining work may take place post FY26
- Onshore Otway (30% interest)
  - Onshore wells to be decommissioned around FY28
  - Transfer of AEL interests expected to reduce decommissioning risks
- BMG Phase II (90% interest[1])
  - Subsea equipment removal
  - Planned to occur following ECSP[2]

Beyond next five years (>83% of the total decommissioning provision)

- Patricia Baleen wells
  - Accounting rules do not permit consideration of potential storage repurposing[3]
- CHN & Sole wells
- Athena & Orbost gas plants
  - Accounting rules do not permit consideration of potential repurposing[3]
- Sundry

Further development in each of the Otway and Gippsland is likely to extend out the estimated timing of abandonment activity in both basins

Non-cash impairment related to Onshore Otway Basin

- $27m non-cash impairment of carrying value of AEL's interests in the Onshore Otway Basin, and certain Gippsland Basin interests
- Reflects exit and transfer of certain permits[4] to Beach Energy and AEL's prioritisation of development of the Offshore Otway / ECSP assets

[1] 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. | [2] Amplitude Energy intends to undertake the BMG subsea equipment removal with a support vessel at the end of activity for the East Coast Supply Project, allowing cost savings and synergies to be achieved on the vessel contract | [3] Accounting rules require project sanction before provision is updated | [4] 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.

#4

Appendix D: Reserves and Resources Information

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	50	38.9	19.5	60.9	30.5	64.2	32.1	94.3	47.2	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

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.

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.