Amplitude energy



Investor presentation

NOVEMBER 2026

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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.

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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 65-69) of Amplitude Energy's FY26 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 2026. 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)

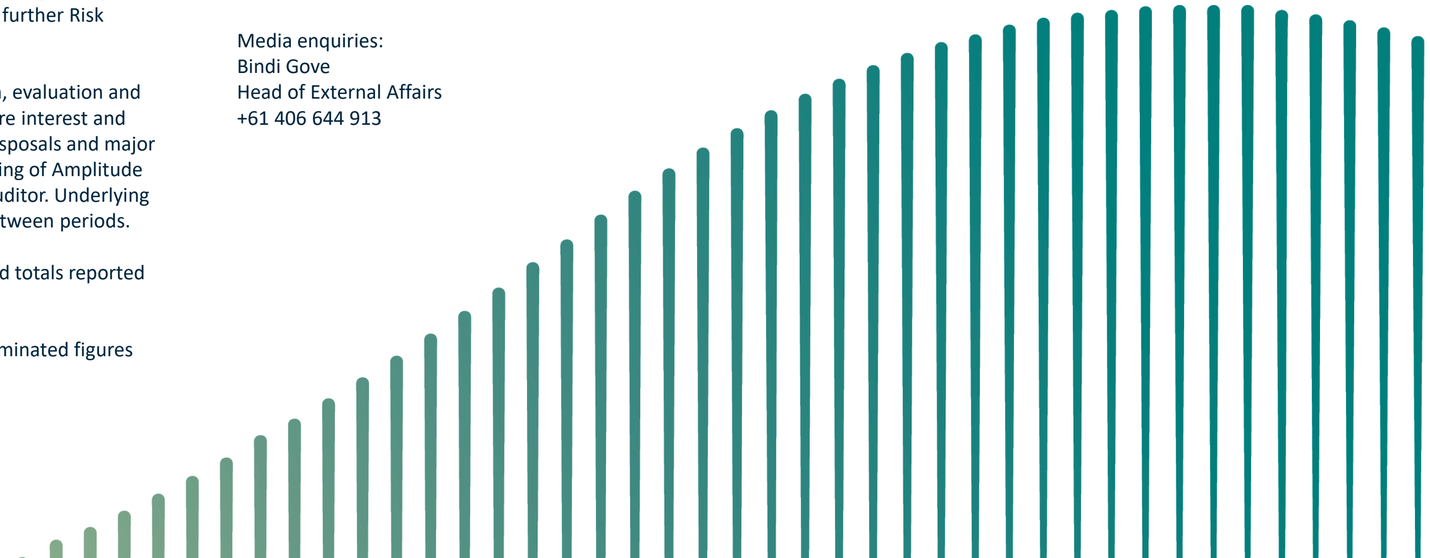
For Prospective Resources the estimated quantities of petroleum that may be potentially recovered by the application of future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration, appraisal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

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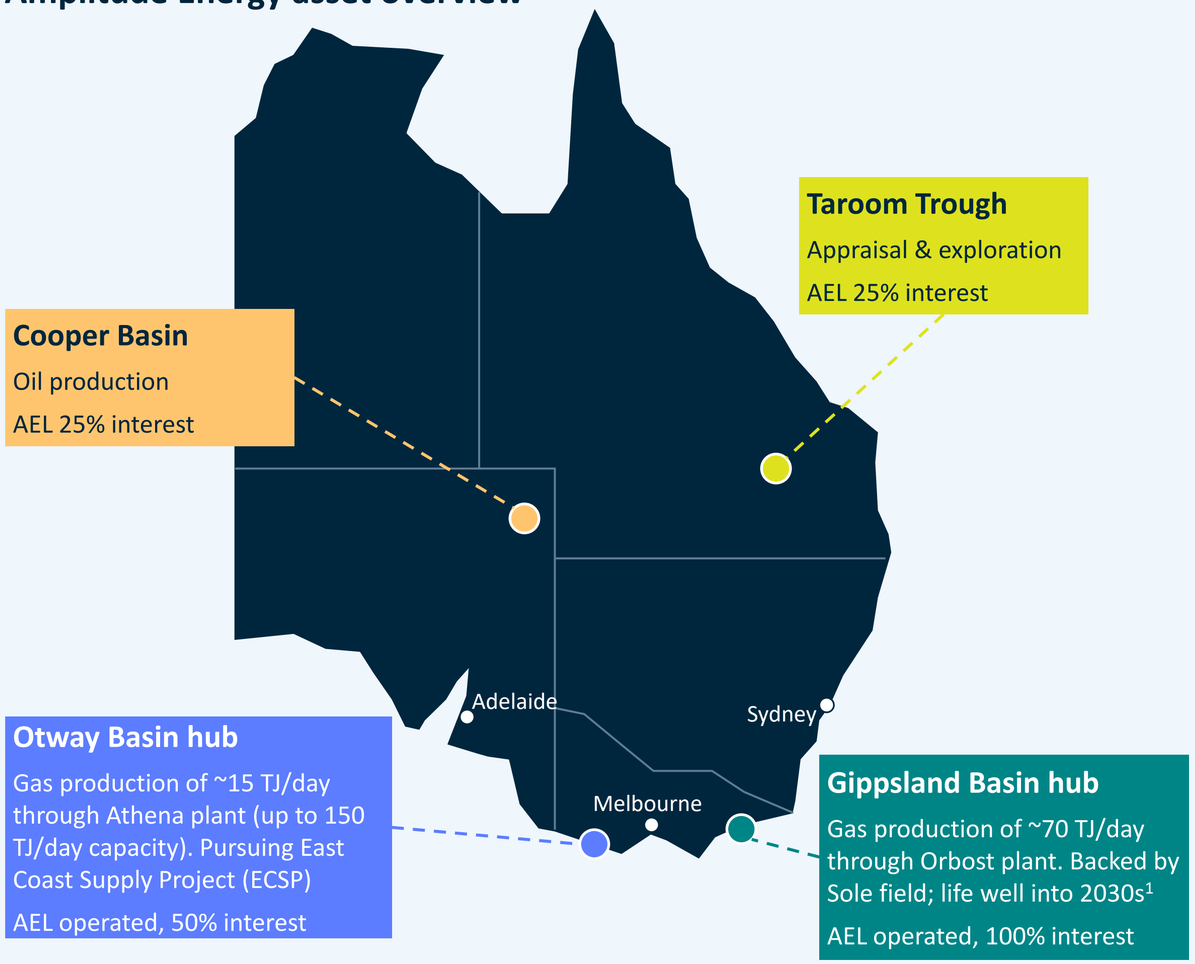


#1
About Amplitude Energy

Amplitude Energy overview

Production and near-term development, deliver strong and growing cash flows

Amplitude Energy asset overview

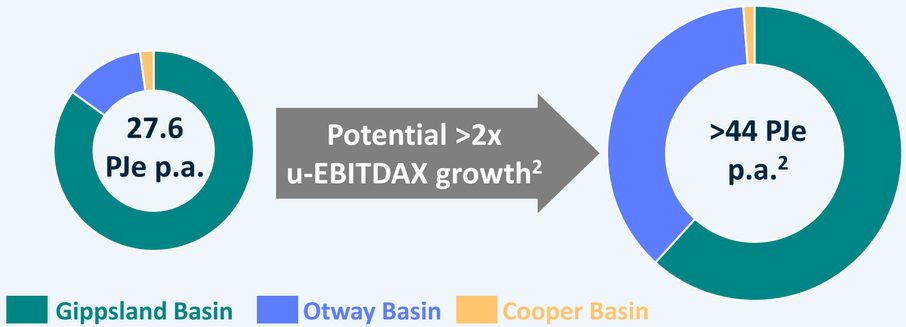


Amplitude Energy Investment Proposition

- Increasing market share in structurally tight domestic gas market
- Strategic infrastructure position, located close to customers
- Strong existing cash flow generation from producing assets
- High value growth and optionality in established basins
- Experienced management team with proven track-record

FY26 group net production

Target from mid-2028

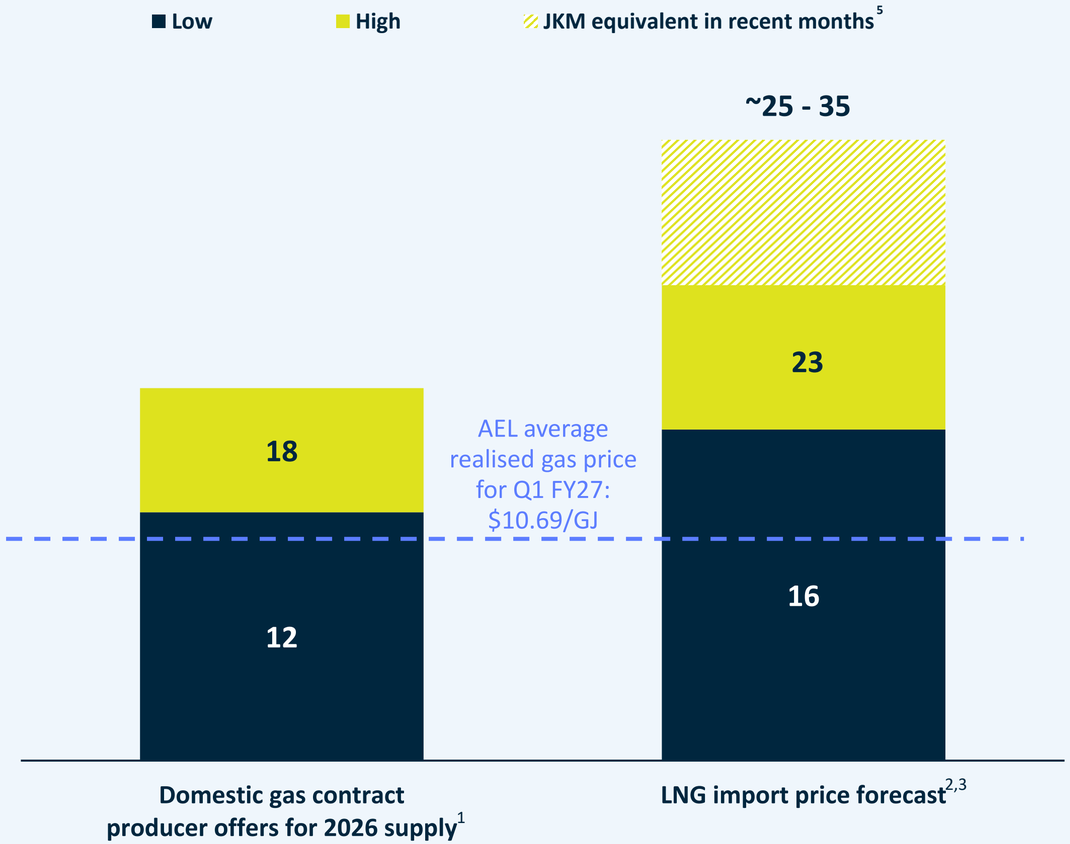


[1] Based on assessed Sole 2P reserves as at 30 June 2026. | [2] Illustrative, and does not constitute guidance. Assumes ECSP achieves target plateau production rates in mid-2028, which is indicative, based on ECSP production from the Annie, Juliet and Artisan fields, and is subject to a number of variables including field resources, resource composition and field pressures. Other assumptions are based on AEL internal model mid case. u-EBITDAX is defined as underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment.

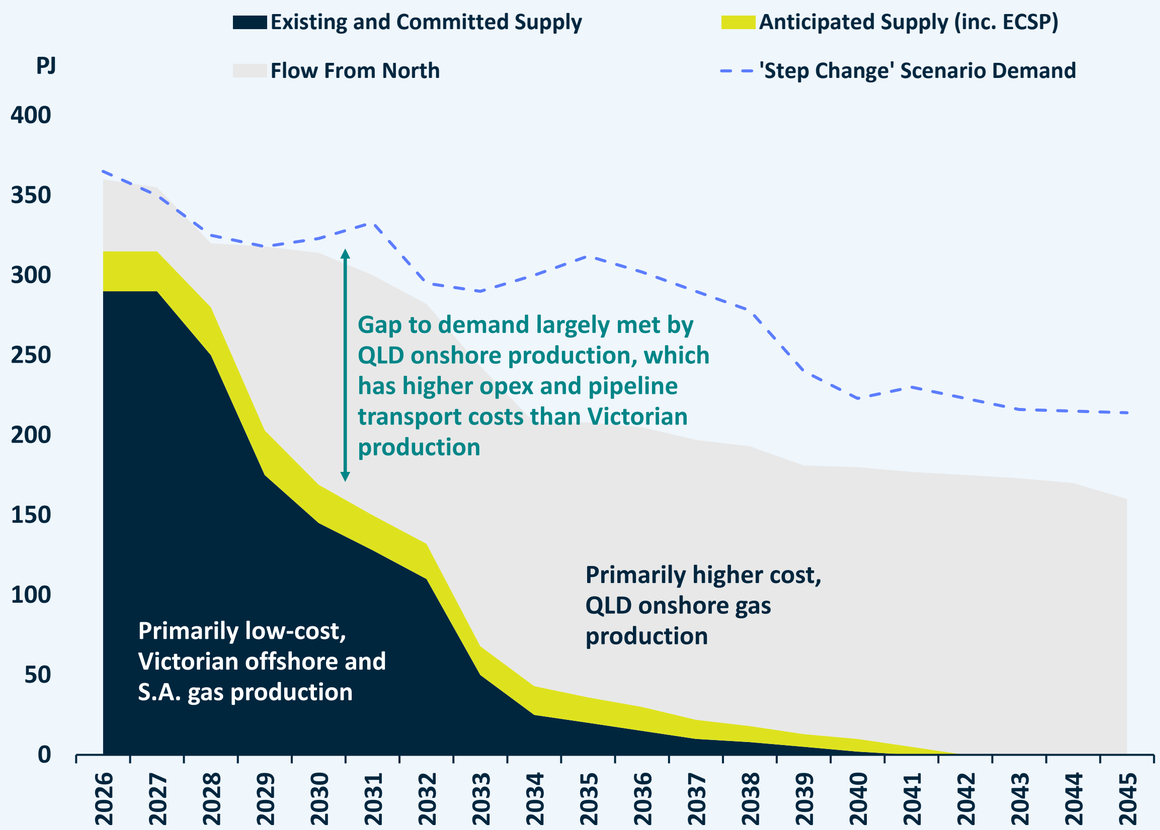
Leveraged to the tight east coast gas market

Amplitude Energy is an existing, low-cost operator, growing production into the increasingly tight east coast domestic gas market

Australian Southern States contracted gas prices, A$/GJ



Australian Southern States supply and demand balance[4], PJ



[1] ACCC Gas Inquiry Report, December 2025, Page 28, Chart 2.8 | [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 |
[3] Platts, LNG Japan / Korea DES Spot Cargo converted from US$/MMBtu to equivalent A$/GJ. | [4] AEMO, 2026 Gas Statement of Opportunities. | [5] Japan/Korea Marker (Asian benchmark reference price for LNG spot sales)

Strategy to deliver transformational growth

Increased production through existing infrastructure extracts additional value from each gas molecule

Delivered → **in progress** → **2028 & beyond**

Fix the base

>50%

Orbost plant production growth since FY23

- **Orbost turnaround:** now producing >70 TJ/day, from less than 50 TJ/day in FY23
- **>25% reduction in group unit costs** since FY23
- Major decommissioning liabilities cleared
- **Strong regulator, government & community relationships**
- Refocused business on **production, cash generation and returns**

Near term brownfield growth

>100%

potential u-EBITDAX growth to FY29[1]

- **Production growth** target of **around 60%+ in FY29,** mainly via East Coast Supply Project **(ECSP)**[1]
- **High return** Patricia Baleen restart project progressing through FEED
- Utilising plant turn-up & pipeline storage opportunities to **maximise the value of gas sold**

Longer term growth opportunities

Targeting high-return growth

- Operated Otway & Gippsland Basins remain **core and highly cash-generative** assets
- Taroom Trough entry represents **significant resource potential & product diversification**
- Opportunity to utilise equity gas or toll third-party resources through existing infrastructure

[1] Illustrative, and does not constitute guidance. Comparisons use FY26 as the base year (FY26 u-EBITDAX $191.8 million and group production of 75.5 TJ/day) and assume ECSP achieves target plateau production rates in mid-2028, which is indicative, based on ECSP production from the Annie, Juliet and Artisan fields, and is subject to a number of variables including field resources, resource composition and field pressures. Other assumptions are based on AEL internal model mid case. u-EBITDAX is defined as underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment.

Experienced management team delivering the strategy

Amplitude Energy's management team has led a successful turnaround of the business

Executive Leadership Team



Jane Norman
Managing Director & Chief Executive Officer



Chad Wilson
Chief Operating Officer



Ian Bucknell
Chief Financial Officer



Eddy Glavas
Chief Commercial Officer



Nathan Childs
Chief Corporate Services Officer



Ying Luo
Chief Advisor & GM Strategy



Nicole Ortigosa
Company Secretary & General Counsel

>50% Orbost production growth and >25% reduction in group unit production costs since FY23

Progressed brownfield growth projects

ECSP now ~18 months from first production

Refocused the business on maximising production and returns

Built strong regulator, government & community relationships

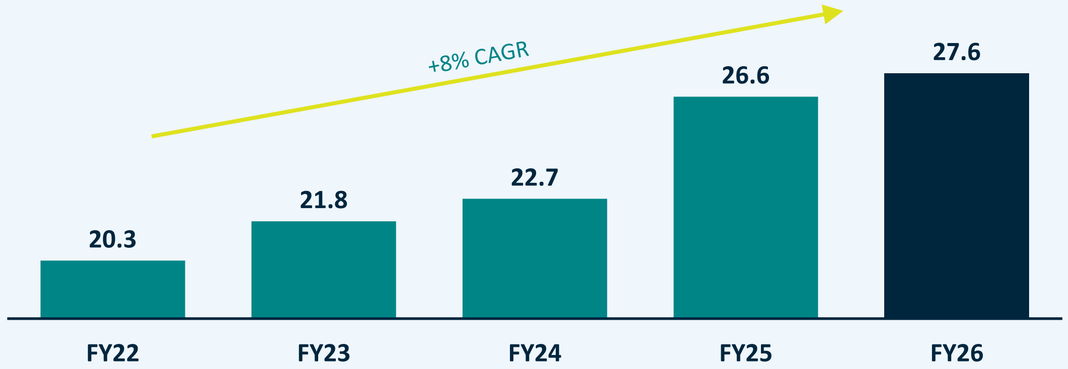
Decommissioning risks mitigated

#2
Strong base business

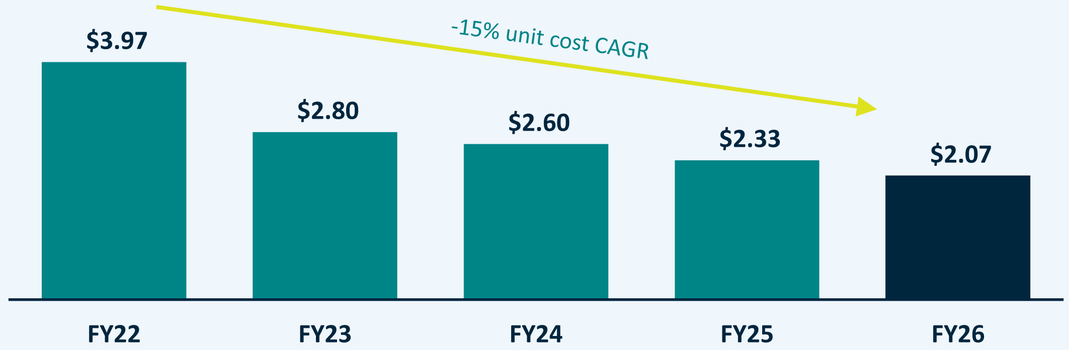
Proven performance & cash generation, prior to transformational growth

Increased production and operational leverage has generated substantial margin expansion

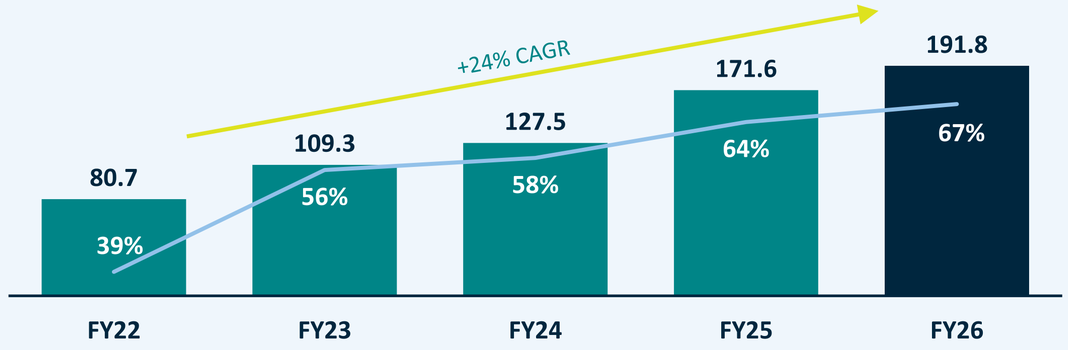
Production, PJe



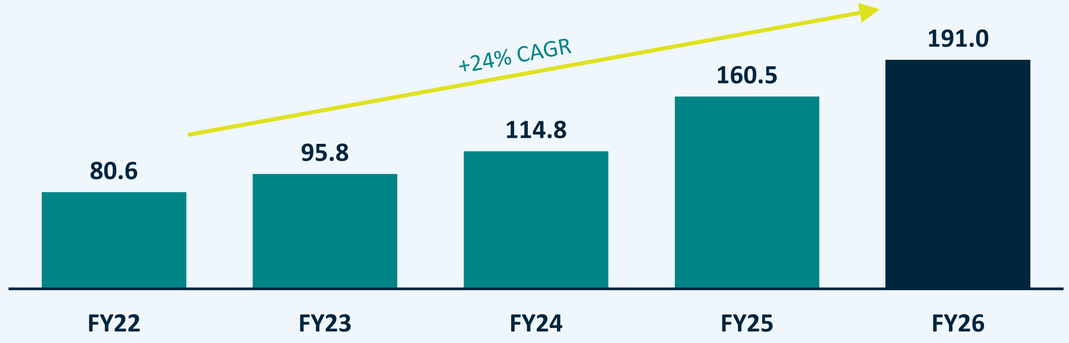
Production expenses[1], $ per GJ produced



Underlying EBITDAX[2], $mm \ margin, %



Adjusted cash from operations, $mm[3]

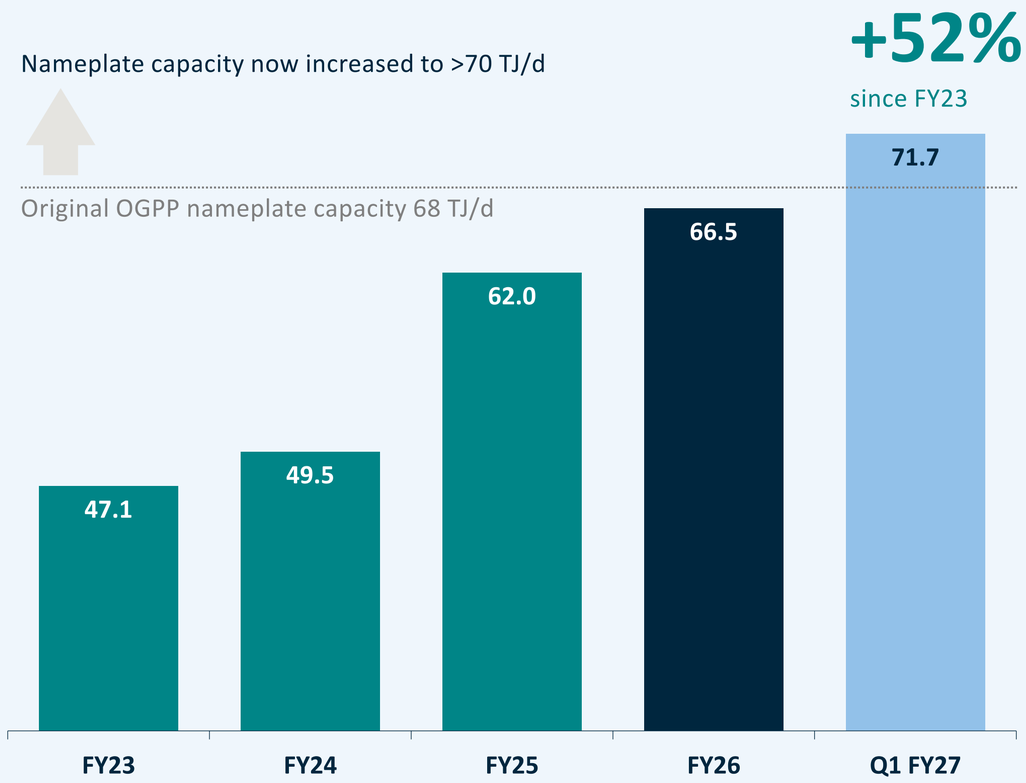


[1] Production expenses comprise labour, materials, overheads, insurance, license costs, JV management and carbon offset costs, but excludes third-party product purchases, transport and trading costs, royalties, pipeline general visual inspection (GVI) costs and non-cash depreciation and amortisation | [2] Underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment. In FY26, the Company is no longer adjusting for the NOGA levy in its underlying results due to it being a recurring expense. | [3] Operating cashflows excluding restoration spend and other non-recurring and non-underlying items

Orbost production continues to increase

New records set at Orbost Gas Processing Plant (OGPP), with sustained production above previous nameplate capacity

OGPP average daily production rate, TJ/day

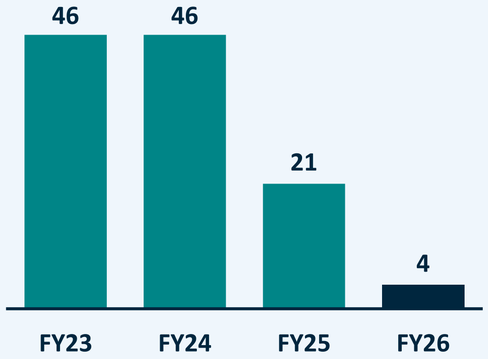


PJ	17.2	18.1	22.6	24.3

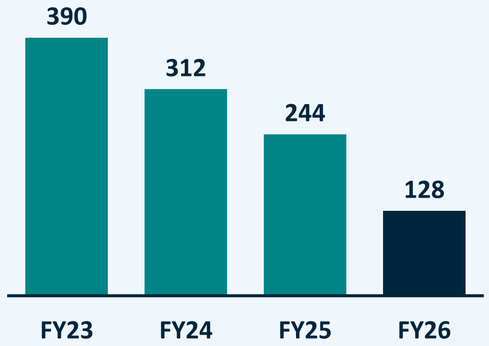
[1] Includes planned and unplanned downtime

Select OGPP operational KPIs

Number of absorber cleans



Production downtime (hours)[1]



OGPP sulphur removal system no longer a constraint on production

Focus now on plant debottlenecking and further reliability improvements

- Record daily production rate of 74.7 TJ achieved in July

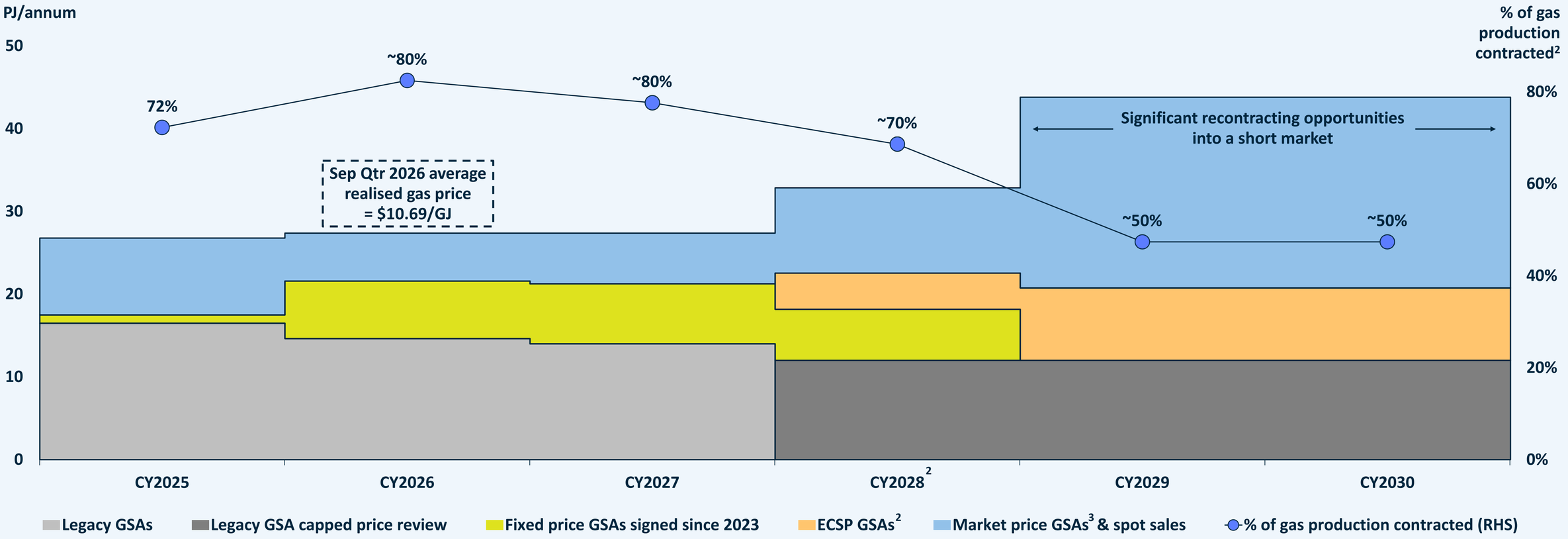
Sole reservoir performance remains strong

- Additional 2C resource booking in FY26, with future reserves reviews to be undertaken to assess further upside

Exposure to higher gas contract prices

Amplitude Energy has a strong revenue base supported by fixed-price, CPI-indexed gas sales contracts with major energy retailers

Gas sales agreement (GSA) contract stack per calendar year, including ECSP[1]

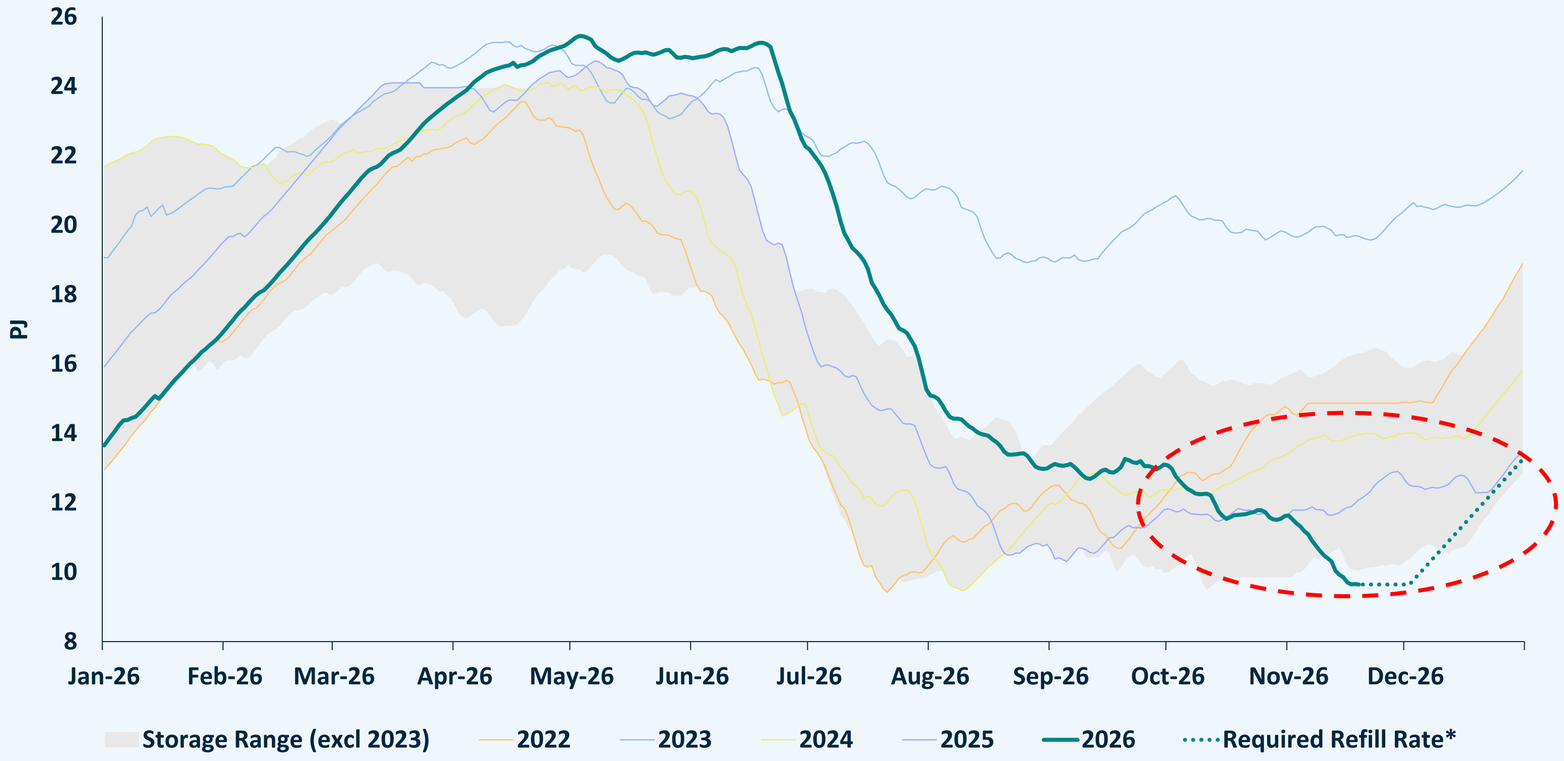


[1] Net to Amplitude Energy's equity share, the annual contract quantity volumes shown are indicative only and assume group gas sales volume of 75 TJe/day over CY2026-2027 (actual group sales volume of 73.4 TJe/d shown for CY2025), 90 TJe/d for CY2028 and 120 TJe/d from CY2029. This assumes a partial-year contribution of ECSP production in CY2028 and does not include a production contribution from Nestor. This forward-looking statement is subject to the qualifications on page 2 of this presentation. There can be no guarantee that these production levels will be achieved. The annual contract quantity volumes shown are for illustrative purposes only and do not constitute production guidance. | [2] ECSP gas sales agreements remain subject to certain conditions being met or waived. Graphic displayed assumes ECSP contracts commence in CY2028 for 50% of annual contracted quantities. One of the ECSP contacts is linked to oil prices while all other contracts displayed have a fixed price with annual CPI indexation. Contracted proportion includes multi-year long-term contracts as well as short-term contracts with tenors equal to, or less than, one year. | [3] Short term contracts linked to prevailing market prices.

Spot gas prices supported by low storage levels

Spot gas prices have traded above $12/GJ in recent weeks with market demand & supply tightly balanced

Iona Underground Gas Storage Balance (PJ)[1]



Iona storage has been **depleting** since October 2026, **unusually late** into the calendar year

- Storage now **historically low** for this time of year

Coal plant **availability** has **reduced** vs. earlier in 2026, **increasing** recent calls on **gas power generation**

Planned and unplanned **Longford outages** have had **significant impact** on available gas **supply**

Declining upstream QLD gas production is incentivising greater gas **flows north** from the southern states

Iona required to inject >120 TJ/day from early December to refill capacity **by April 2027**

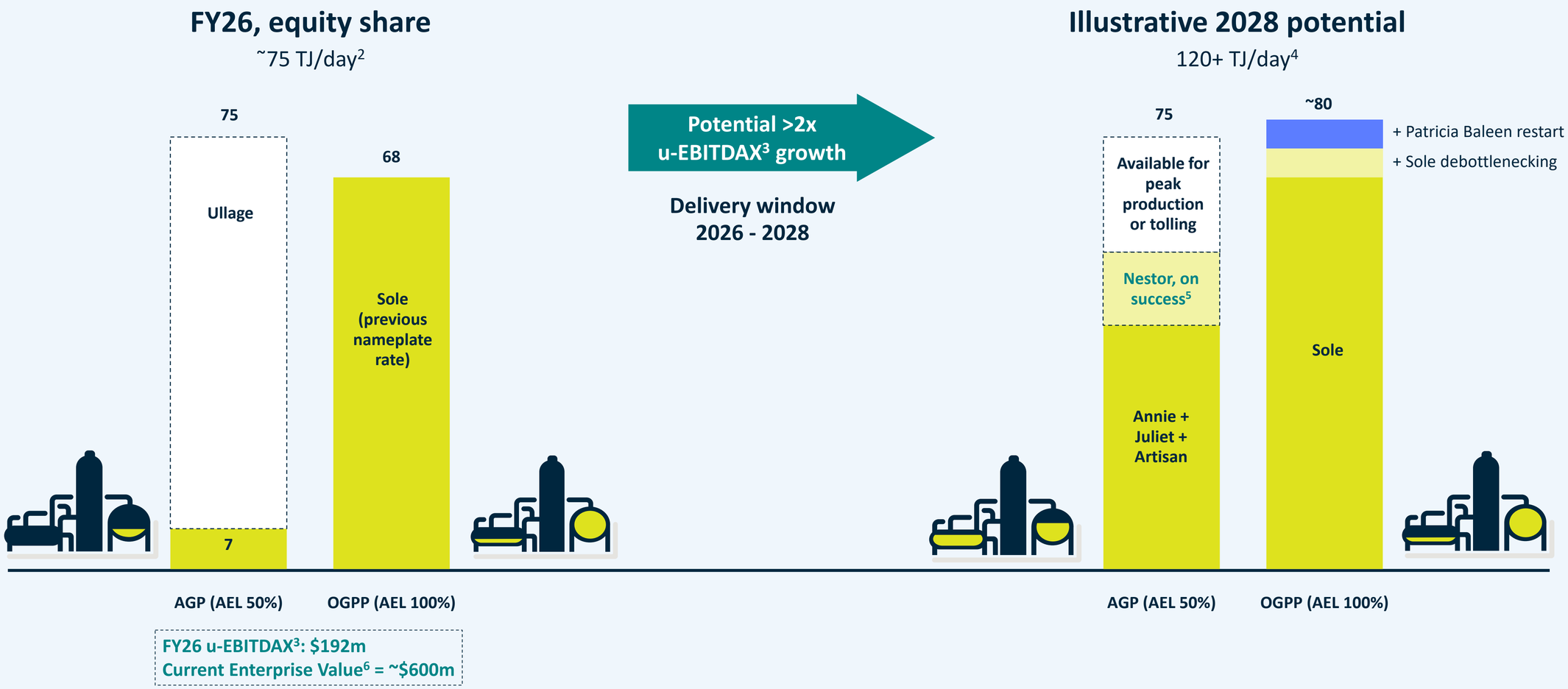
- **Highest required refill rate** in recent years
- Substantial incremental demand over summer

[1] Source: AEMO. The Iona Underground Gas Storage facility is not owned or operated by Amplitude Energy; however storage levels, injections and withdrawal rates influence gas prices in the markets in which Amplitude Energy operates. *Average net injection rate required to return Iona Underground Gas Storage facility to 24.4 PJ by 1 April 2027 from early December 2026 (with Iona maintenance shut down being undertaken in late November).

#3
Near term brownfield growth

Transformative near-term brownfield growth

Backfilling existing infrastructure can deliver growth in equity production of around 60%+ by 2028[1]



[1] Illustrative, increase by end 2028 is relative to group production of 75.5 TJ/day in FY26. Targeted production through the Athena Gas Plant (AGP) in 2028 is indicative, based on ECSP production from the Annie, Juliet and Artisan fields, and is subject to a number of variables including field resources, resource composition and field pressures. | [2] FY26. >80% of gas sales, on average, made under existing contracts. | [3] Underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment. Assumes ECSP production achieved in mid-2028 and AEL model mid case outcomes. | [4] Post ECSP production, first gas expected in 2028. | [5] Nestor production assumes a commercial discovery from exploration drilling. | [6] Based on basic market capitalisation as at 26 October of $570 + net debt as at 30 Sep of $31m

ECSP on track, targeting first gas in 2028[1]

Annie, Juliet and Artisan deliver strong project economics with potentially more exploration upside still to come

Brownfield project underpinned by **Annie, Juliet & Artisan** discovered resources, targeting plateau production of **90 TJ/day gross for at least four years from CY2028**

Further potential resource upside from **Nestor** exploration well in coming weeks[1] and Annie & Juliet **reserves assessments**

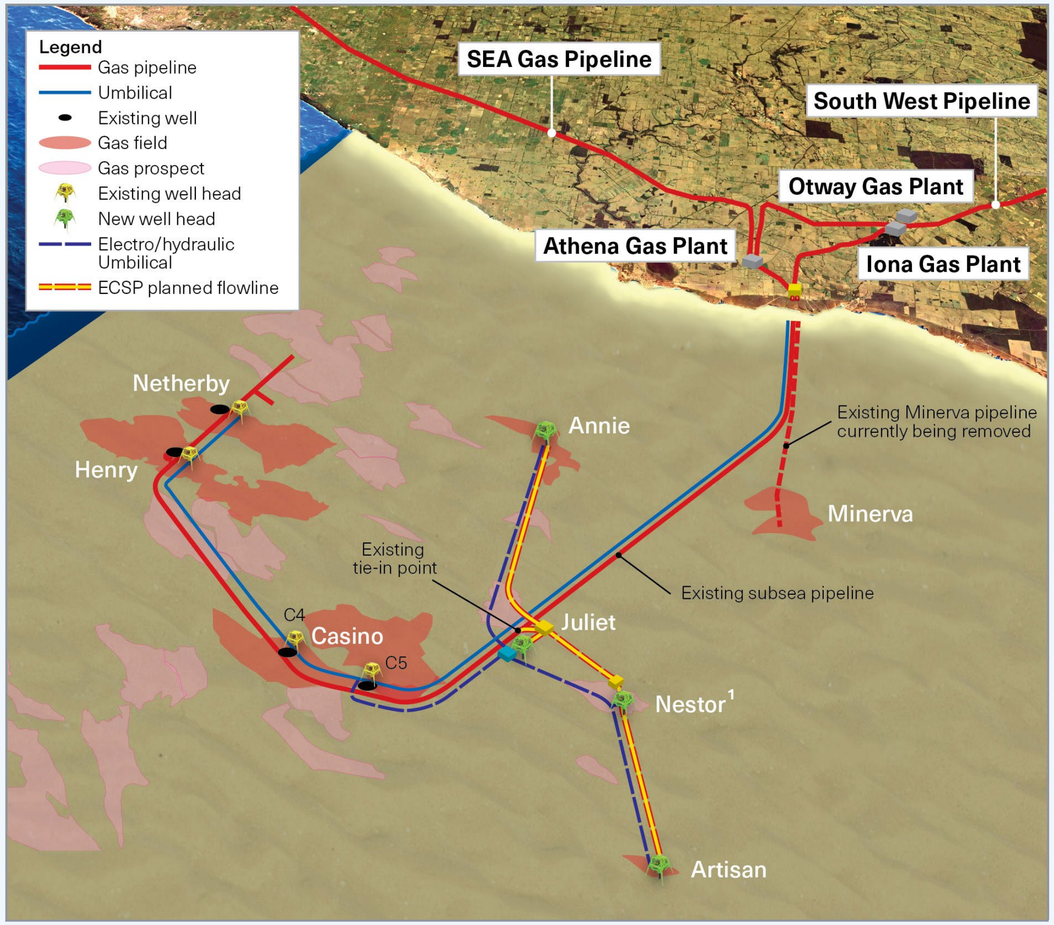
Strong support from market with **foundation offtake contracts secured** with EnergyAustralia and AGL[2]

Project is **fully funded**, with strong JV alignment

Project development phase **FID recently taken;** majority of costs relate to **fixed-cost items or fixed-rate contracts**, mitigating risks

Returns expected to comfortably exceed internal investment hurdle rates[3]

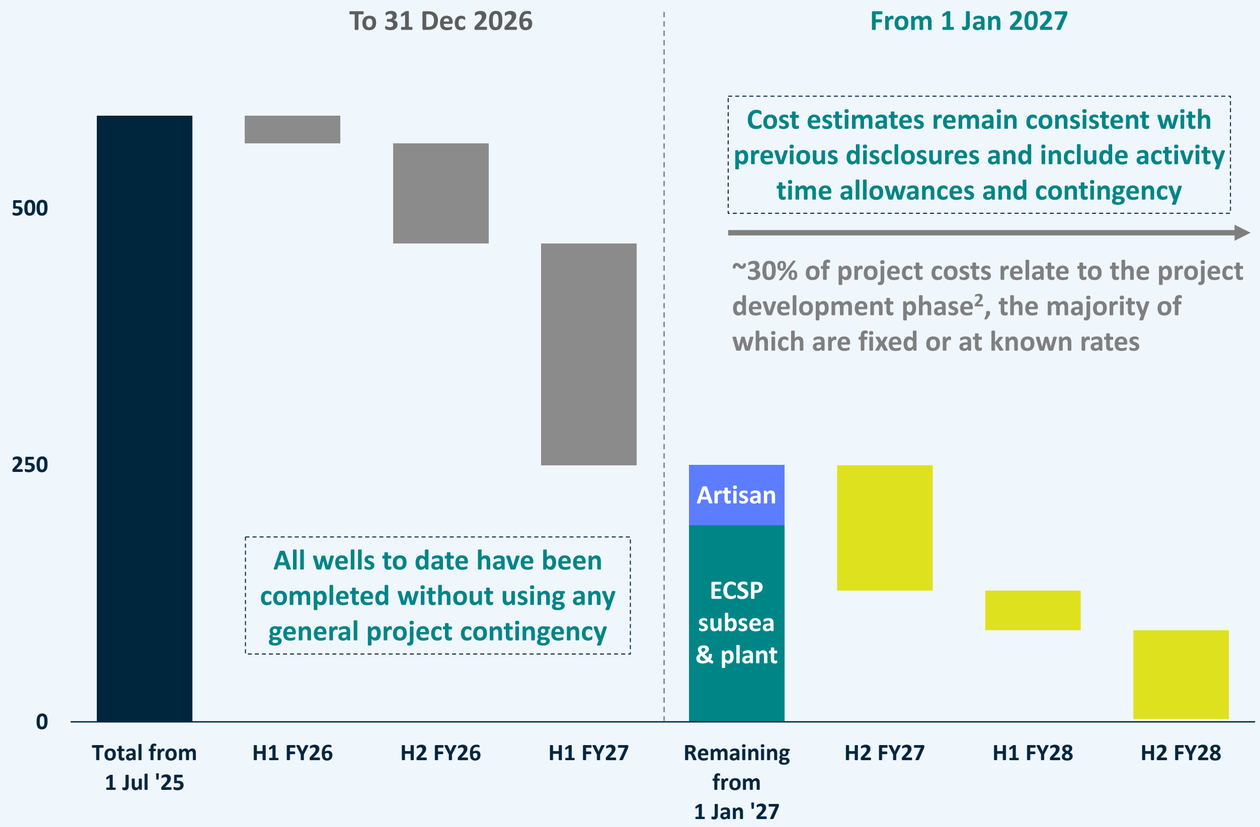
[1] Nestor is a prospective exploration target. | [2] Contracts are conditional on a minimum level of reserve bookings and field deliverability from the ECSP drilling phase, and FID for the ECSP development phase. | [3] Based on AEL internal model mid-case assumptions.



Remaining ECSP spend de-risked

Carefully managed phasing of spend and associated risks

Remaining ECSP spend (illustrative profile, net to AEL)[1], A$m



Drilling & well completions performance to date ahead of budget

ECSP drilling phase expected to complete before end CY2026

Remaining project development phase costs de-risked:

- Around half comprised of long lead equipment orders
- Remainder reflects fixed-rate & fixed cost contracted project development work scheduled for early CY2028

Risks to capex from end CY2026 substantially mitigated

Appropriate contingency included in cost estimates

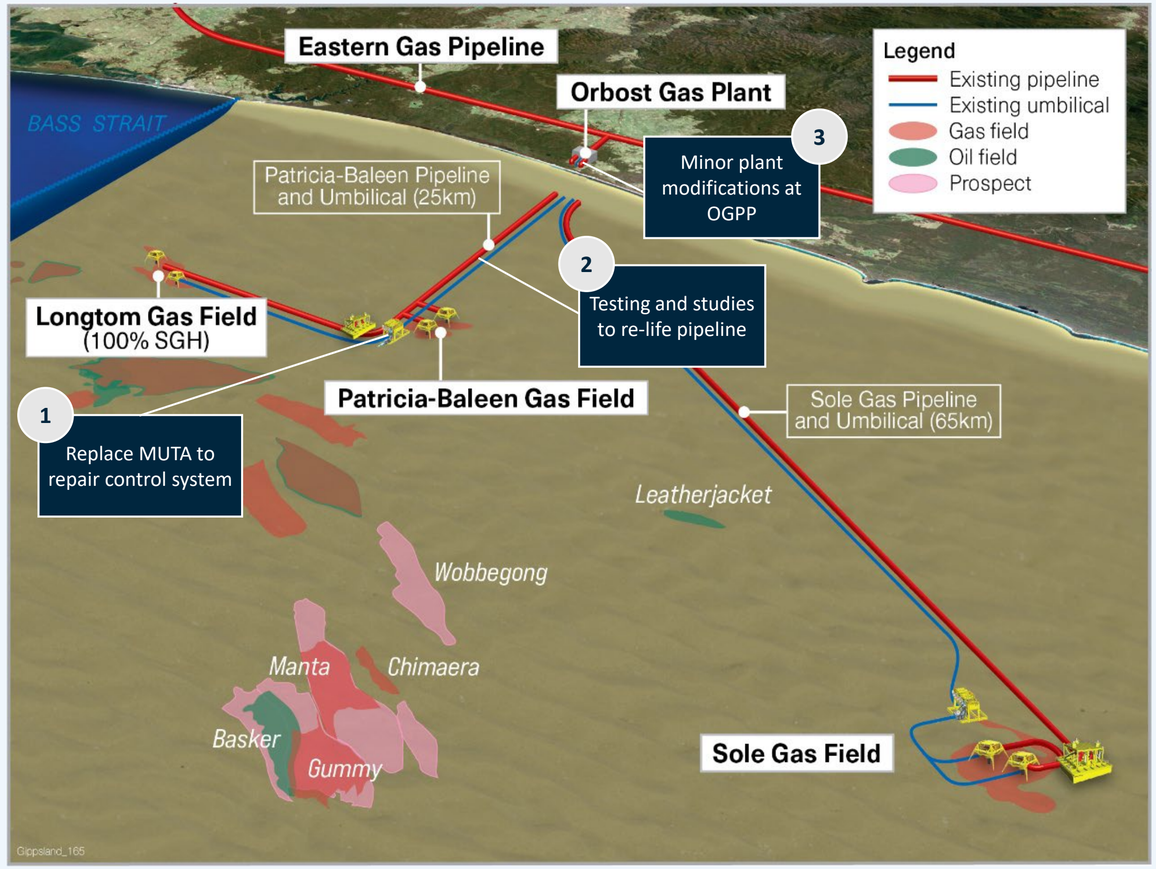
ECSP capex spread over ~3 years, largely funded through underlying cash generation from the base business

[1] Illustrative profile only, assuming exploration success at Nestor. Figures are in 2026 dollar, 50% net to AEL terms. Assumes Artisan transaction completion in H2 FY27, with the associated payment of AEL's share of upfront consideration. These cost estimates include reasonable time allowances and project contingencies, however are subject to various execution risks, including variables outside of Amplitude Energy's control. These forward-looking statements are subject to the qualifications on page 2 of this presentation. | [2] Excludes upfront consideration for the Artisan field acquisition of a fixed $58.3 million.

Progressing Patricia Baleen restart in Gippsland Basin

The Patricia Baleen restart project is a unique, low-cost opportunity to unlock supply flexibility for the east coast market while adding value to Amplitude Energy's existing portfolio

Gippsland Basin infrastructure overview



[1] Indicative rate range tested as part of the Select Phase studies. To be confirmed during FEED studies.

Wholly-owned **existing resource**, **already connected** to OGPP

Low cost, high return restart potential targeting an **incremental** **~3-10 TJ/day** through OGPP[1]

Project **maximises value** from existing **Sole/OGPP** infrastructure

Maintains critical infrastructure and optionality to **enable future gas discoveries, field developments** and **third-party processing** opportunities

Production licence application submitted and **SELECT Phase complete**; progressing **FEED in CY2026**, targeting FID in CY2027

SGH participated in SELECT phase to assess Longtom gas processing options

#4
Longer term growth opportunities

Taroom Trough entry

Land release in a highly prospective onshore oil & gas region in Queensland, close to available infrastructure

Block PLR2026-1-7 is a Permian “tight gas” exploration play, **analogous to similar unconventional plays in North America**

Large volumes of proven gas and oil in place within Taroom Trough, with ability to commercialise earlier than other greenfield basins

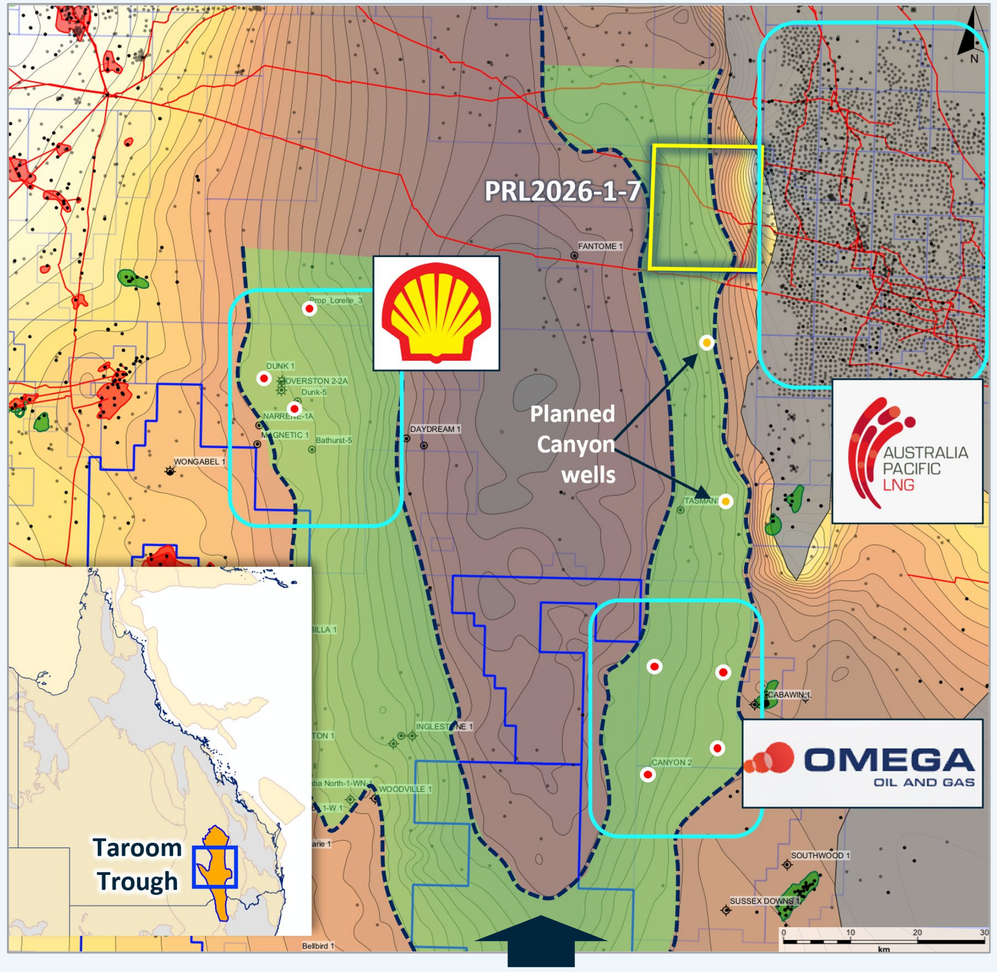
PLR2026-1-7 is **along trend** from **Shell (Dunk)** and **Omega (Canyon)** wells at similar depths; further Canyon wells to be drilled in 2026

Potential CSG upside; APLNG has hundreds of producing coal-bed methane wells immediately adjacent

Close to **existing infrastructure and services**, with multiple pipeline export options available and nearby

Joint venture approach allows potential for **Tcf-scale resource** additions at **low cost initial commitment** (AEL 25% share)[1]

[1] Joint venture comprises subsidiaries of Amplitude Energy (25%), Beetaloo Energy (25%), Eastern States Energy (25%) and Xstate Resources (25% and operator)

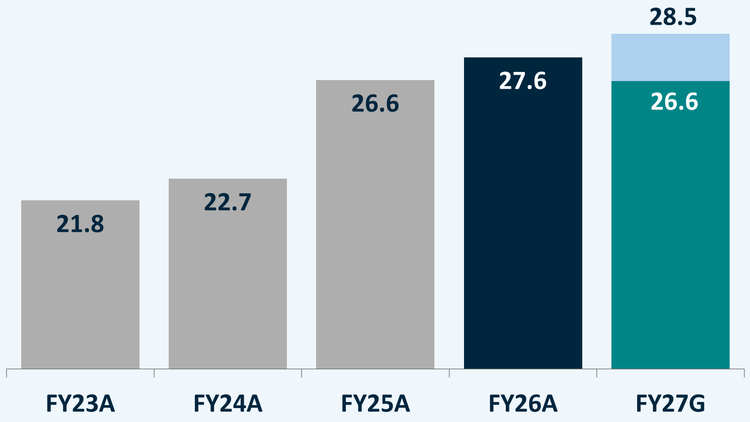


#5
Outlook

FY27 guidance on track

Focus on higher gas production, cost efficiencies and cash generation while ECSP drilling is undertaken

FY27 production: 26.6 – 28.5 PJe



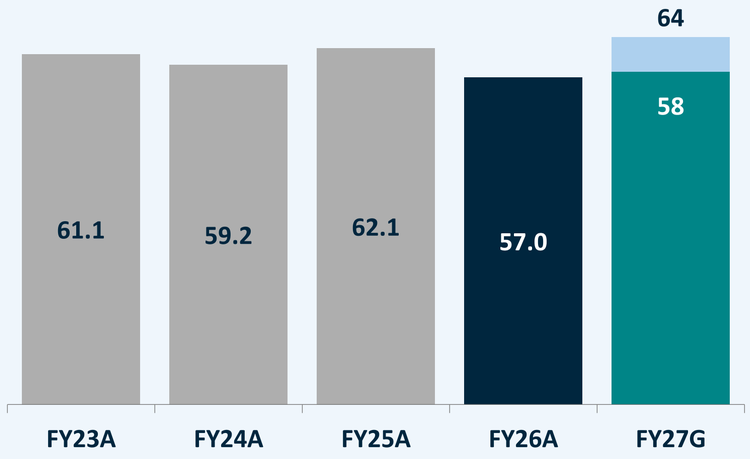
Range of outcomes largely based on recent OGPP production, incorporating ability to produce at >70 TJ/d

- Includes planned maintenance shutdown at OGPP in H2 FY27

Guidance includes allowances for other planned and unplanned downtime at both plants

Natural decline at legacy Otway & Cooper Basin assets

FY27 production expenses: $58 – 64m[3]



Underlying production expenses of $58 – 64m

- Implied group production unit cost $2.04 – 2.40/GJ

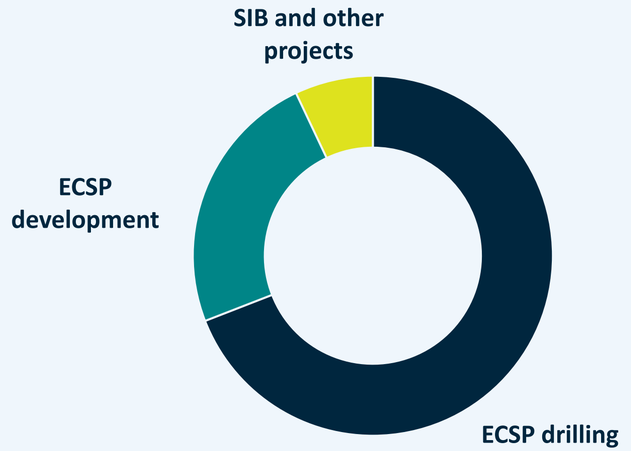
Other cash expenses & costs of sales of $27 – 31 m[1]

- Now incorporates all selling & transport costs[2]

Non-regular items expected to impact FY27 opex include:

- ERP replacement project costs of ~$6-7m, and
- Patricia Baleen well inspection costs of ~$5m

FY27 capex: $320 – 390m[3]



FY27 ECSP capex includes Juliet, Annie and now Nestor drilling, plus long-lead development phase costs

- Reflects AEL's 50% share

Does not include Artisan upfront consideration ($58m to AEL)

Excludes decommissioning expenditure

[1] Excludes ERP replacement project and pipeline inspection costs. | [2] Including costs associated with accessing Sydney spot gas market. | [3] Excludes decommissioning costs and capitalised interest. Capex guidance was updated on 30 September 2026 to incorporate the sanction of the Nestor well.

FY27 focus areas

Progress ECSP

- Complete drilling on budget and schedule
- Executing project development, maintaining CY2028 first gas target
- Selectively target additional contract sales

Maximise asset utilisation

- Optimise Orbost production, including at >70 TJ/day when market conditions are favourable
- Reliability loss of <1% across the Athena and Orbost gas plants
- Progress Patricia Baleen restart

Grow margins

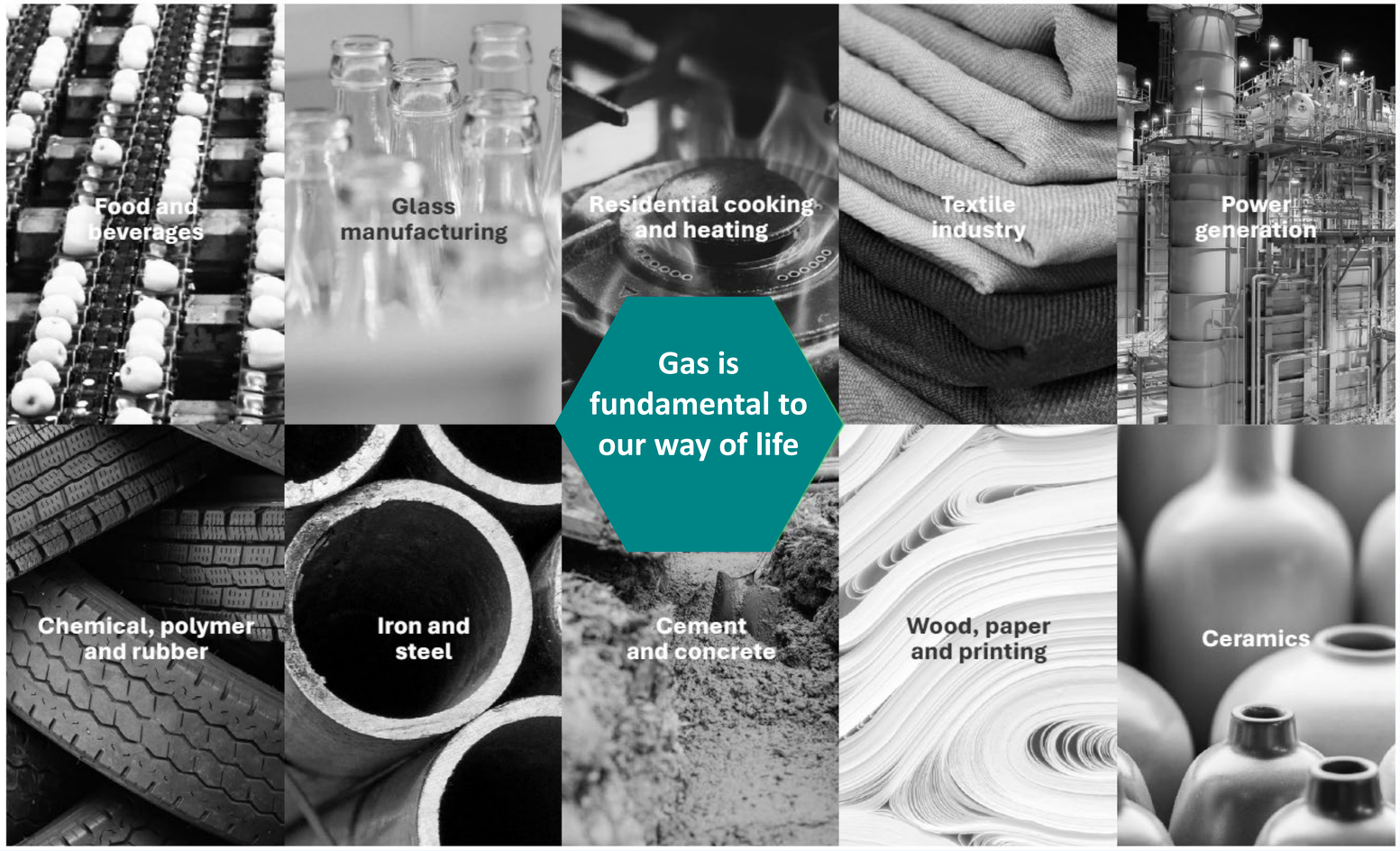
- Increase realised gas prices through marketing & trading initiatives
- Further reductions in production costs
- Organisational improvement through streamlining systems and processes

Appendix
Additional materials

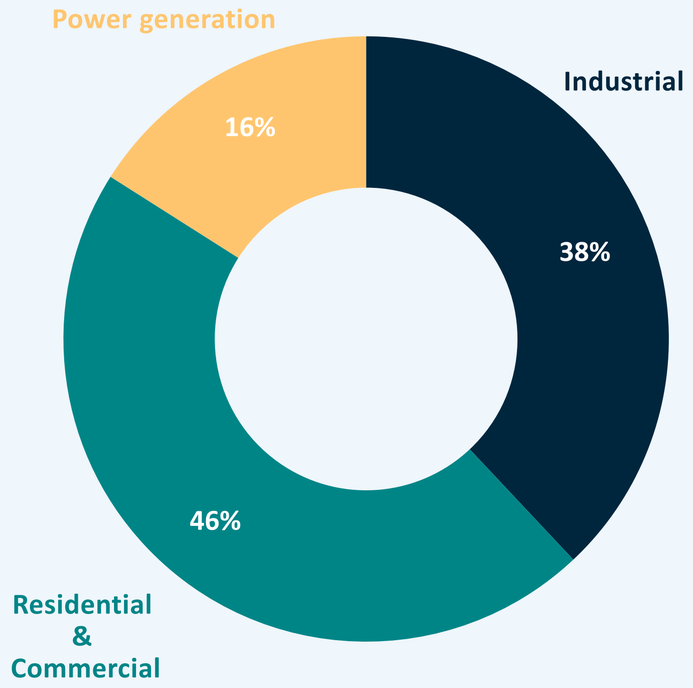
Gas meets 25% of Australia's energy demand[1]

"We cannot turn off Australia's gas without significant adverse impacts on Australians and our region."

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



Gas demand in Southern States[2], 2025



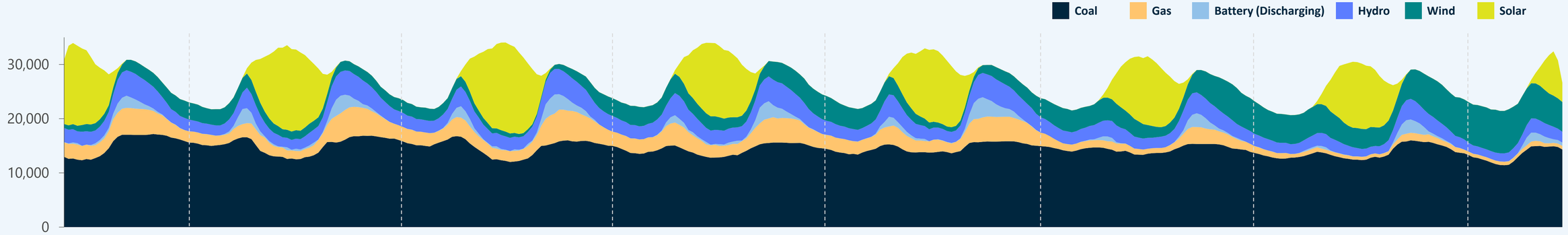
Total = 350.2 PJ

[1] Australian Energy Update, August 2026, 2024-25, Table A| [2]AEMO, 2026 Gas Statement of Opportunities, National Electricity and Gas Forecasting Portal. Step Change scenario (2˚C scenario), Southern States include Victoria, South Australia, NSW, and Tasmania.

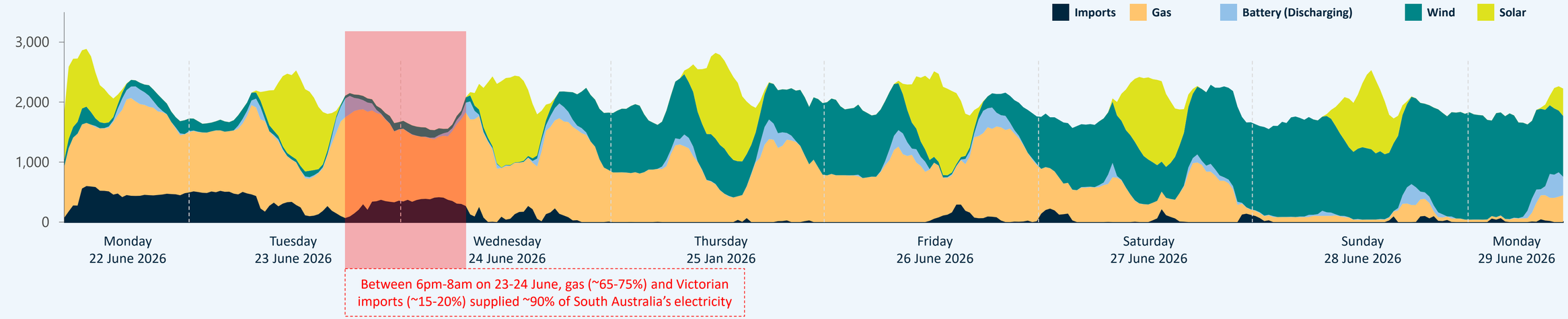
Increasing role of gas in the electricity market[1]

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

NEM electricity supply[2] by type (average ~45% renewables in CY2025), MW



South Australian electricity supply[2] by type (average ~70% renewables in CY2025), MW

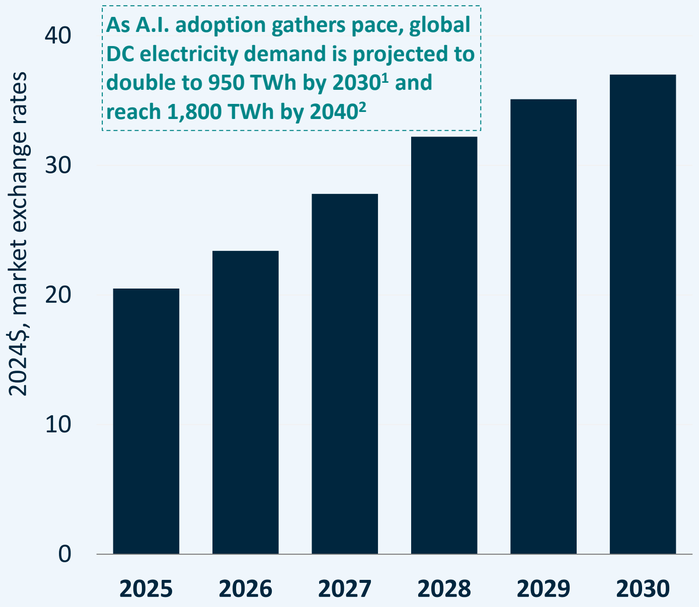


Data sourced from www.opennem.org.au. Excludes exports. | [1] As described in the most recent AEMO 2026 Integrated System Plan. | [2] Refers to reported electricity supply in the National Electricity Market (NEM), incorporating all Australian states and territories excluding Western Australia and the Northern Territory

Drivers of future gas demand

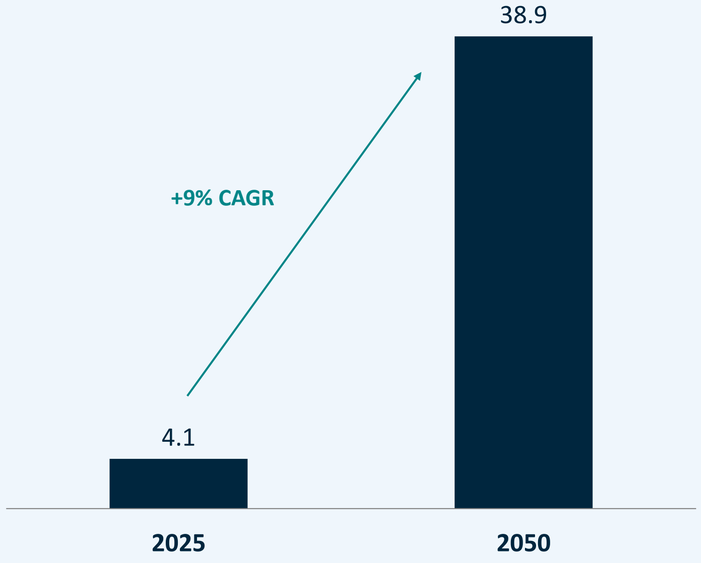
Global gas demand growth is being driven by electrification, data centre (DC) roll-outs and coal-to-gas switching

Forecast global DC power investment, US$bn[1]



DC operators are being driven to conventional, dispatchable sources of power like gas[1] due to its availability & reliability

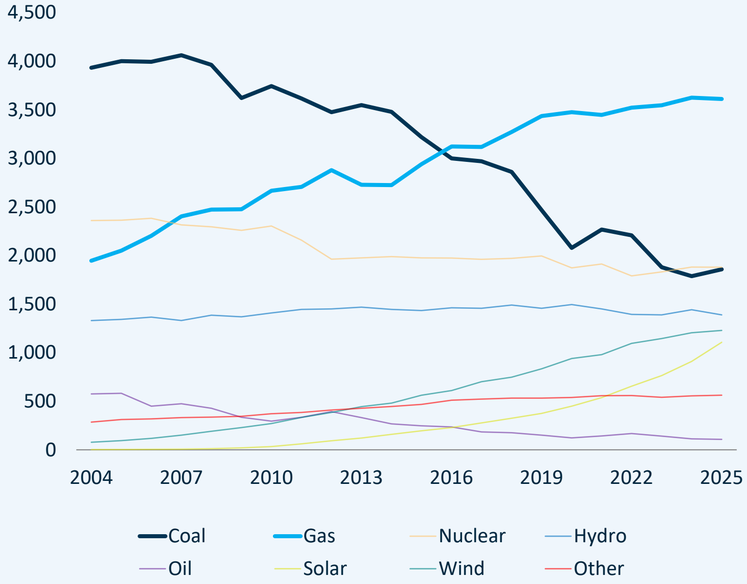
Forecast Australian DC electricity demand, TWh[3]



DCs driving renewed electricity demand growth in Australia at the same time as coal plants retire

More gas generation capacity, as well as renewables and battery storage, required to meet this demand

OECD Electricity production by fuel, Twh[4]



Coal to gas switching an established global trend, stretching back decades

Gas powered generation is the only alternative to coal that is currently available at scale in Australia for long-duration, dispatchable electricity

[1] International Energy Agency, *World Energy Investment 2025, 10th Edition* | [2] Rystad Energy | [3] Source: AEMO, 2026 Integrated System Plan. |
[4] Source: Energy Institute's Statistical Review of World Energy, 2026. Emphasis added to the coal and gas series on the chart displayed.

Gas policy and the investment the east coast needs

A successful Domestic Gas Reservation would incentivise more domestic gas supply into the Southern states

The Australian Government says new gas supply is needed…

FUTURE GAS STRATEGY, 2024[1]

What government has said

Gas needed through to 2050 and beyond

even in net-zero scenarios

New sources of supply are needed

to meet demand during the transition

Develop existing discoveries faster

in established gas-producing regions

…policy must give companies the confidence to deliver it

Amplitude Energy well placed for domestic gas reservation policy

Low-cost, conventional **gas assets in Victoria**, Australia's key demand center

Low transport costs to bring gas to market, with strategic infrastructure **located around exiting resources & customers**

Fixed-price, take-or-pay gas sales contracts comprise the **majority of revenue**

Strong cash flow generation from **assets already in production**

Strong social license to operate and support from local communities

Increasing exposure to export-linked pricing; once ECSP is online, around **15%** of revenue is expected to come from liquids or oil-linked prices (vs. 5% today)

1. Australian Government, Future Gas Strategy (DISR, May 2024): gas needed at lower levels through to 2050 and beyond, even in net zero scenarios; new sources of supply needed; action to encourage more timely development of existing discoveries.

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

- Facility limit of $480mm
- September 2029 maturity
- Supportive group of eight domestic and international banks
- Interest rate on drawn portion BBSY + 3.25%

Intention to maximise future debt availability by optimising RBL parameters

- Includes potentially incorporating Offshore Otway discoveries in the ECSP into the RBL borrowing base

RBL currently drawn to $175m, with cash on balance sheet of $138m (net debt $38m)

Additional $20m working capital facility

Liquidity overview as at 30 September 2026



Decommissioning provisions summary

Limited decommissioning exposure in production today and where work is expected beyond 5 years

Major items for next 5 years (~16% of the total restoration provision)

Minerva subsea infrastructure (10% interest)

Remaining subsea pipeline & equipment removal

BMG subsea infrastructure (90% interest[1])

Subsea equipment removal

Planned to occur following ECSP[2]

Restoration provisions are reviewed, assessed and audited annually

Amplitude Energy also conducts an independent cost estimate for offshore and onshore decommissioning every 3 years (last conducted FY25)

Beyond next five years (~84% of the total decommissioning provision)

Patricia Baleen wells

Accounting rules do not permit consideration of potential restart or repurposing at this stage[3]

CHN[4] & Sole wells

Athena & Orbost gas plants

Accounting rules do not permit consideration of potential repurposing[3]

Other

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

[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] Casino, Henry and Netherby.

Abbreviations

$	Australian dollars
Amplitude Energy or AEL 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
ECSP	East Coast Supply Project
FEED	Front End Engineering Design
G&A	General administration expenses
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
u-EBITDAX	Underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment