Amplitude energy

FY26 full year results

18 AUGUST 2026

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Disclaimer

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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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Executive summary

Amplitude Energy’s strategy to maximise asset utilisation is on track

- **Record FY26 operational and financial metrics, with strong start to Gippsland Basin production in FY27**
- **Increase in contracted sales, plus gas marketing & trading value add, provided resilient revenue base and higher realised prices**
- **ECSP de-risked through Artisan acquisition; FID on project development phase expected in the near term**
- **Juliet exploration drilling imminent, followed by Annie development**
- **Strong customer support for ECSP supply; consistent with the domestic market’s need for low-cost production from Southern Australia**

FY26 highlights

Record production and financial metrics

27.6 PJe

GROUP PRODUCTION

NEW RECORD

75.5 TJe/DAY

+3%

$285.8m

SALES REVENUE

NEW RECORD

+7%

$10.36/GJ

AVERAGE REALISED GAS PRICE

NEW RECORD

+5%

$191.8m

UNDERLYING EBITDAX[1]

NEW RECORD

67% MARGIN

+12%

$191.0m

ADJUSTED CASH FROM OPERATIONS[2]

NEW RECORD

+19%

ECSP progress

JULIET DRILLING IMMINENT

ARTISAN & ANNIE UNDERPIN PROJECT ECONOMICS

TARGETING FID IN Q1 FY27

[1] Underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment | [2] Operating cashflows excluding restoration spend and other non-recurring and non-underlying items

#1

FY26 in review

Health, safety, environment and community performance

Results ahead of industry benchmarks through disciplined operations

Health & Safety

Safety performance well ahead of industry benchmarks[1]

Over 2.5 years without a lost time injury

External recognition for safety excellence during BMG decommissioning campaign

Environment

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

On track to achieve target to reduce operational flaring by 40%[4] by FY30

AGP solar PV power project underway

100% of Scope-1 and Scope-2 emissions offset[5]

Community

Proactive engagement with stakeholders in the areas where we operate

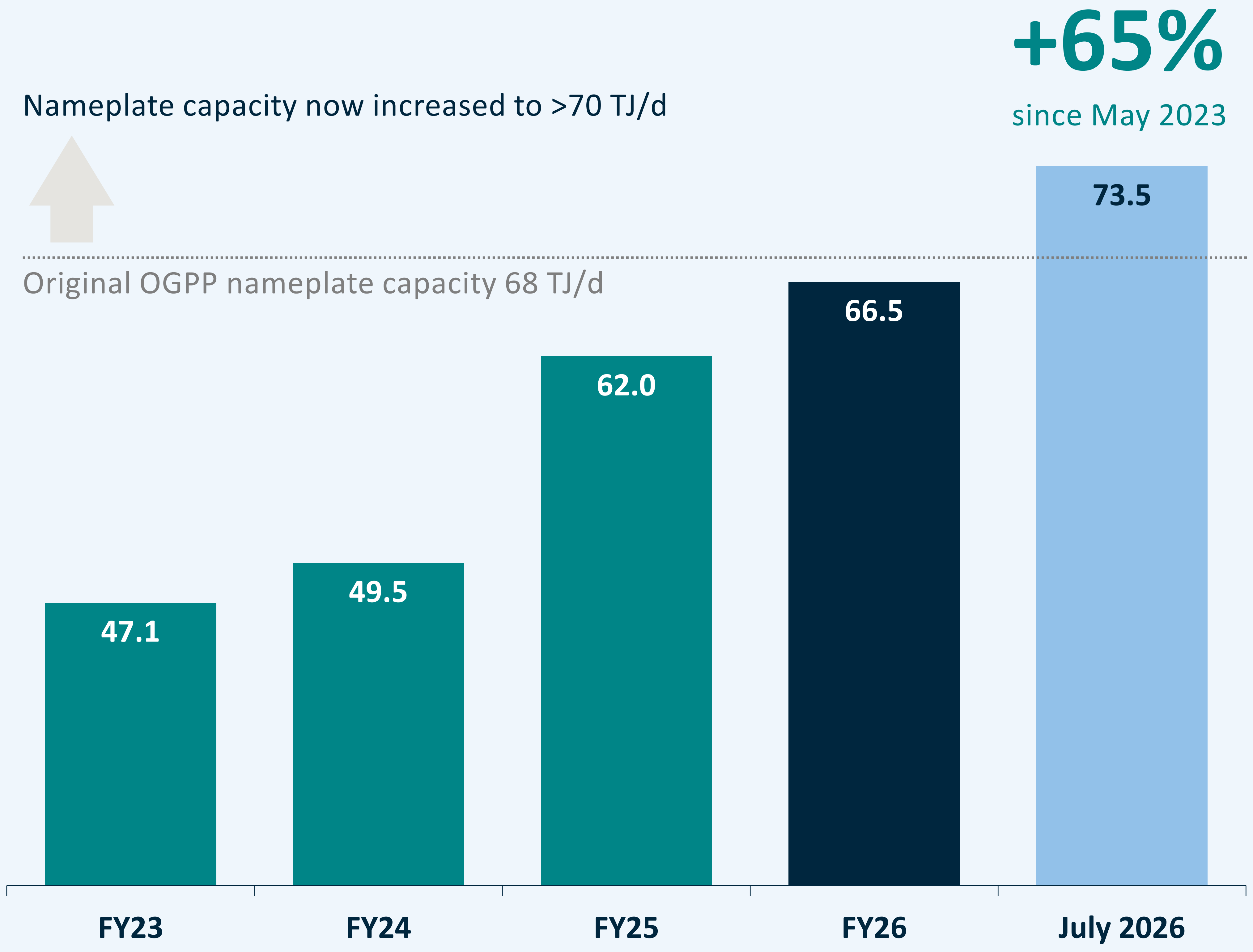
	FY25	FY26
Hours worked	297,854	**506,436**
Lost time injuries (LTI)	0	**0**
Recordable injuries	1	**1**
Total recordable injury frequency rate (TRIFR[6])	3.36	**1.97**
Industry TRIFR[6]	5.86	**6.00**
Reportable environmental incidents	0	**0**

[1] Based on NOPSEMA industry rolling 12-month TRIFR for 30 June 2026.| [2] As defined by Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2023. | [3] As defined by the Victorian Environment Protection Act 2017. | [4] On an equity basis, using FY23 flaring baseline. Target applies to base-business operations, excluding any one-off project related flaring. | [5] Verified Carbon Units were retired at the end of H1 FY26 and H2 FY26 to voluntarily offset the Company's estimated FY26 Scope 1 and Scope 2 emissions. Scope 3 emissions are not offset. More information regarding Scope definitions is available on pages 92-93 of Amplitude Energy's FY26 Annual Report. | [6] TRIFR is recordable injuries (medical treatment injuries + restricted work case + lost time injuries + fatalities) per million hours worked. Calculated on a rolling 12-month basis. Industry TRIFR displayed is the NOPSEMA benchmark for offshore Australian operations; data is updated every 3 months; published at www.nopsema.gov.au

Orbost production continues to increase

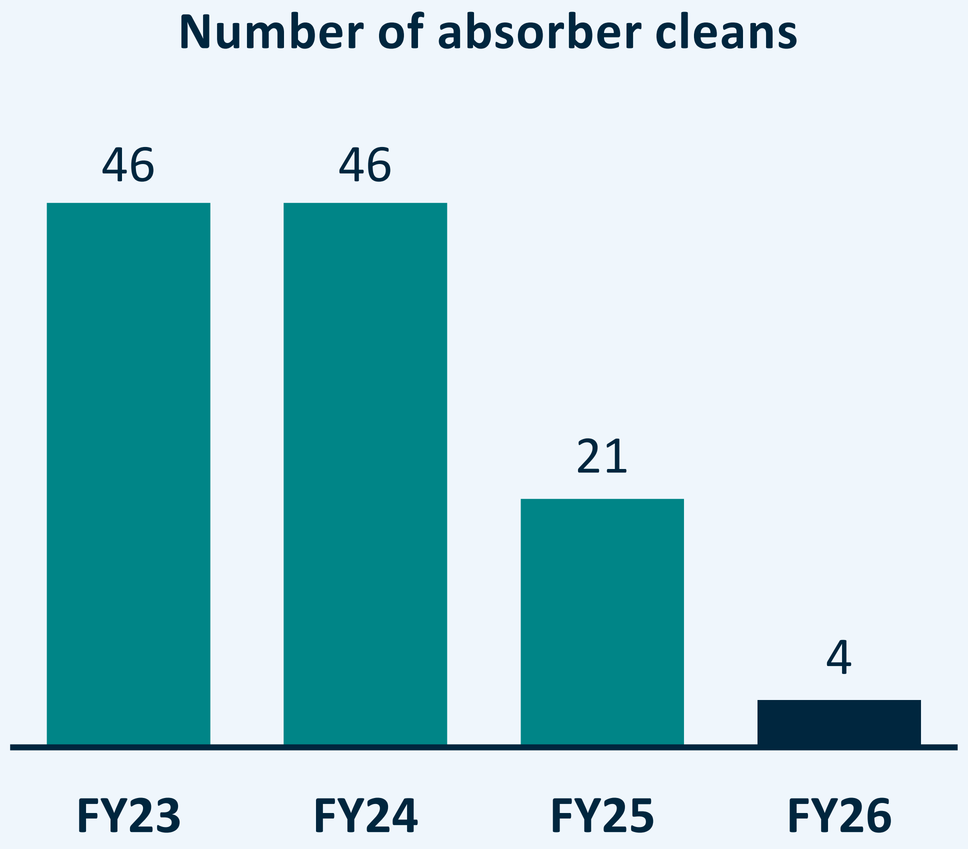
New records set at Orbost Gas Processing Plant (OGPP), with sustained production above previous nameplate capacity

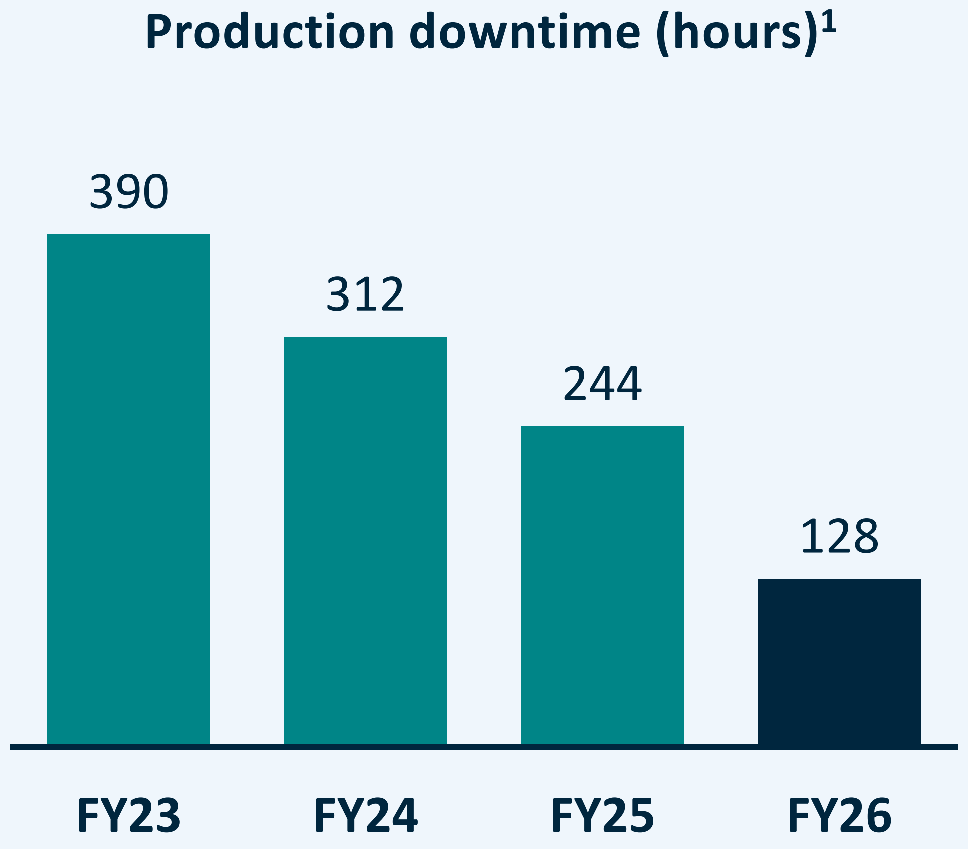
OGPP average daily production rate, TJ/day



PJe	17.2	18.1	22.6	24.3

Select OGPP operational KPIs





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

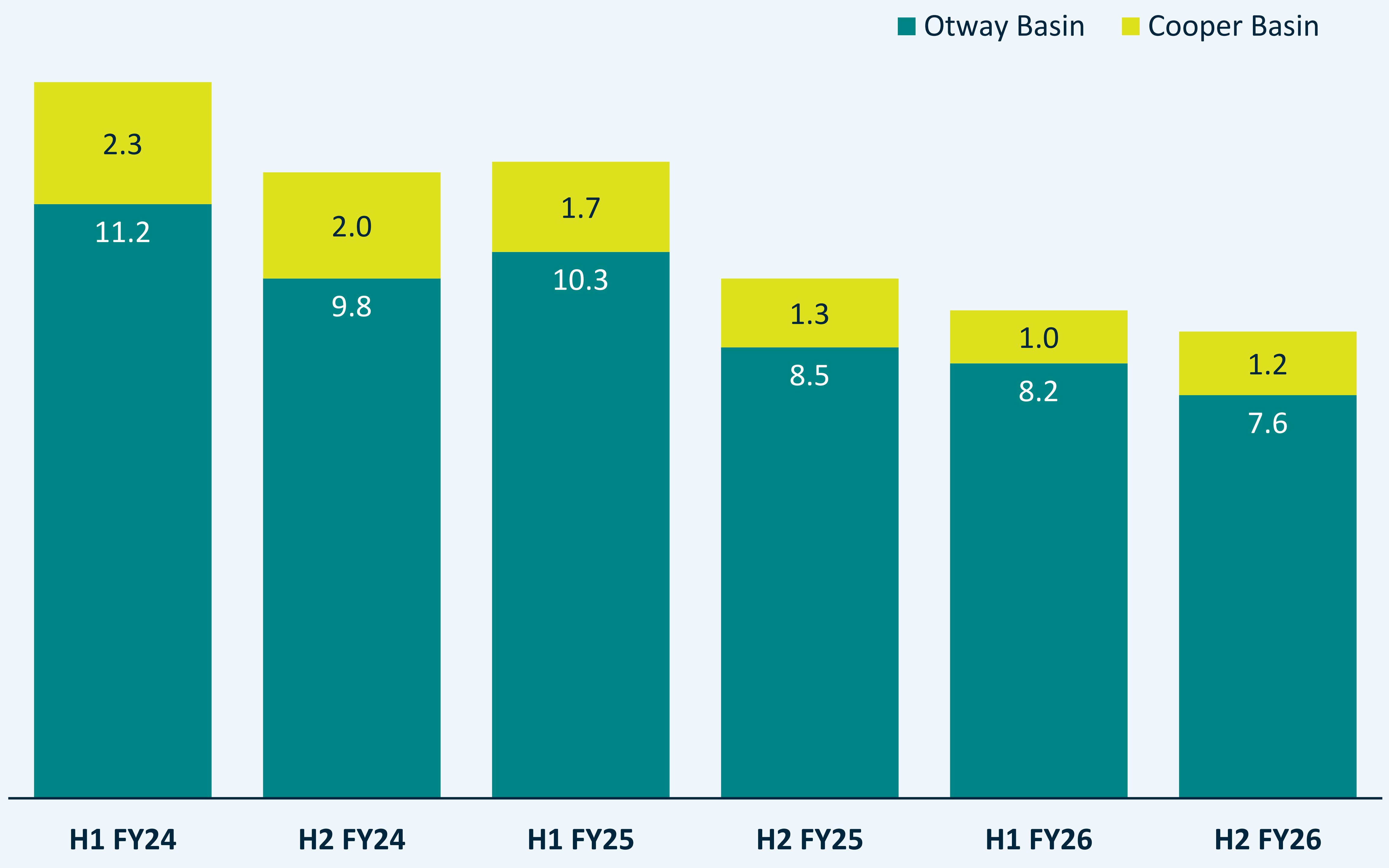
- Additional 2C resource booking in FY26, with future reserves reviews to be undertaken to assess further upside

[1] Includes planned and unplanned downtime

Otway & Cooper Basins

Otway Basin natural decline partially offset by return of Casino-4 well in H2 FY26

Otway & Cooper Basin net production, TJe/d[1]



PJe	**2.5**	**2.1**	**2.2**	**1.8**	**1.7**	**1.6**

[1] All figures shown net to Amplitude Energy. | [2] Casino, Henry and Netherby fields in the offshore Otway Basin

Otway Basin \ Athena Gas Plant (AGP)

Excellent AGP reliability performance over FY26

Casino-4 well brought back into production in H2 FY26, improving CHN[2] well-cycling and reducing near-term natural decline rate

AGP producing at over 17 TJ/day gross (>8.5 TJ/day net to AEL) on average post April shutdown

FEED complete on AGP re-lifing for East Coast Supply Project

Cooper Basin

Increased production from successful 3-well development campaign at Callawonga

Existing production recovered post H1 FY26 flooding impacts

Assessing prospect portfolio ahead of next phase of development

Reserves & Resources at 30 June 2026[1]

Sole reservoir continues to perform strongly

Annual movement in 2P Reserves explained by FY26 production

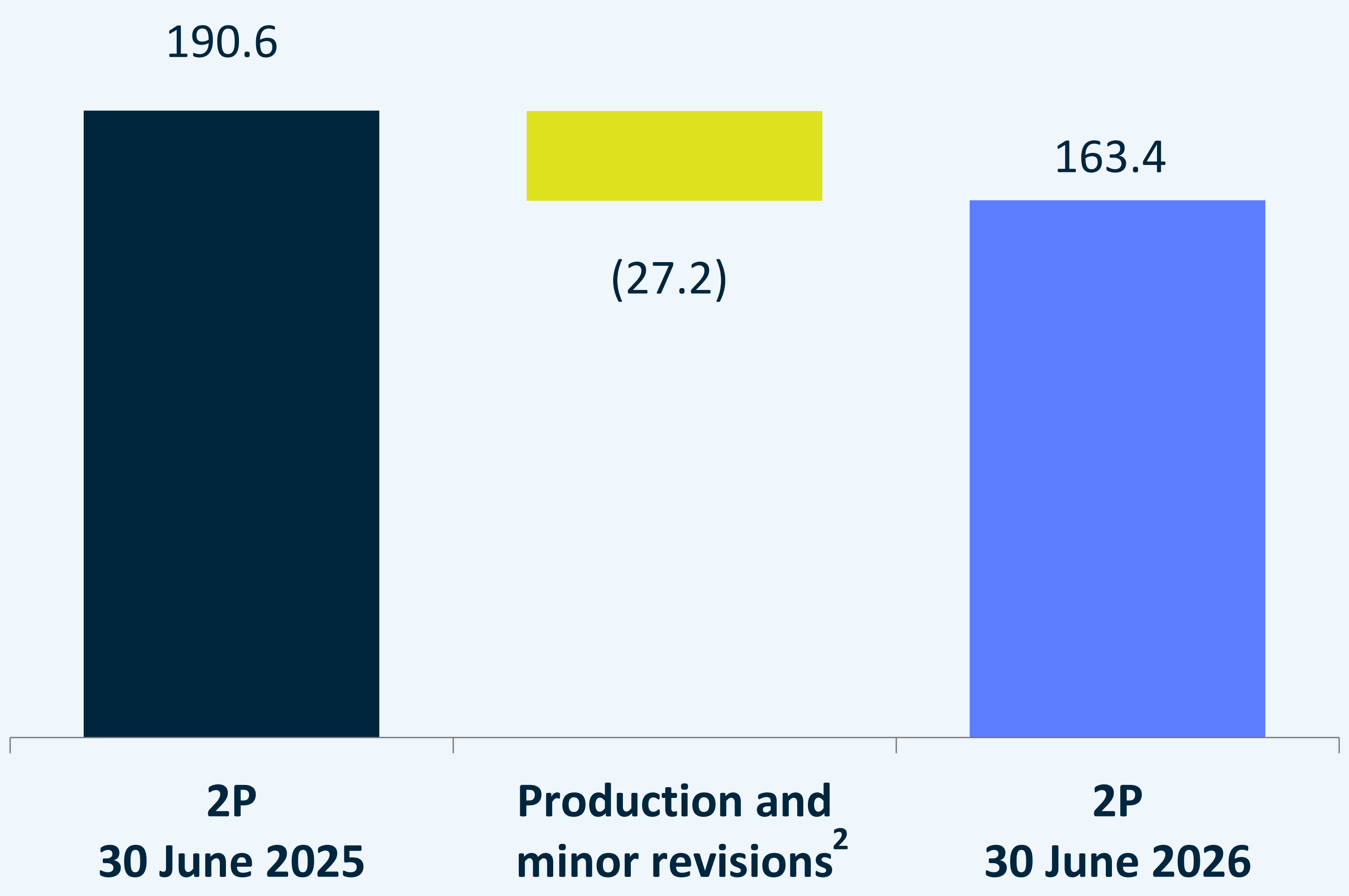
- No material reserves revisions[2]

Upward net revision to total 2C Contingent Resources

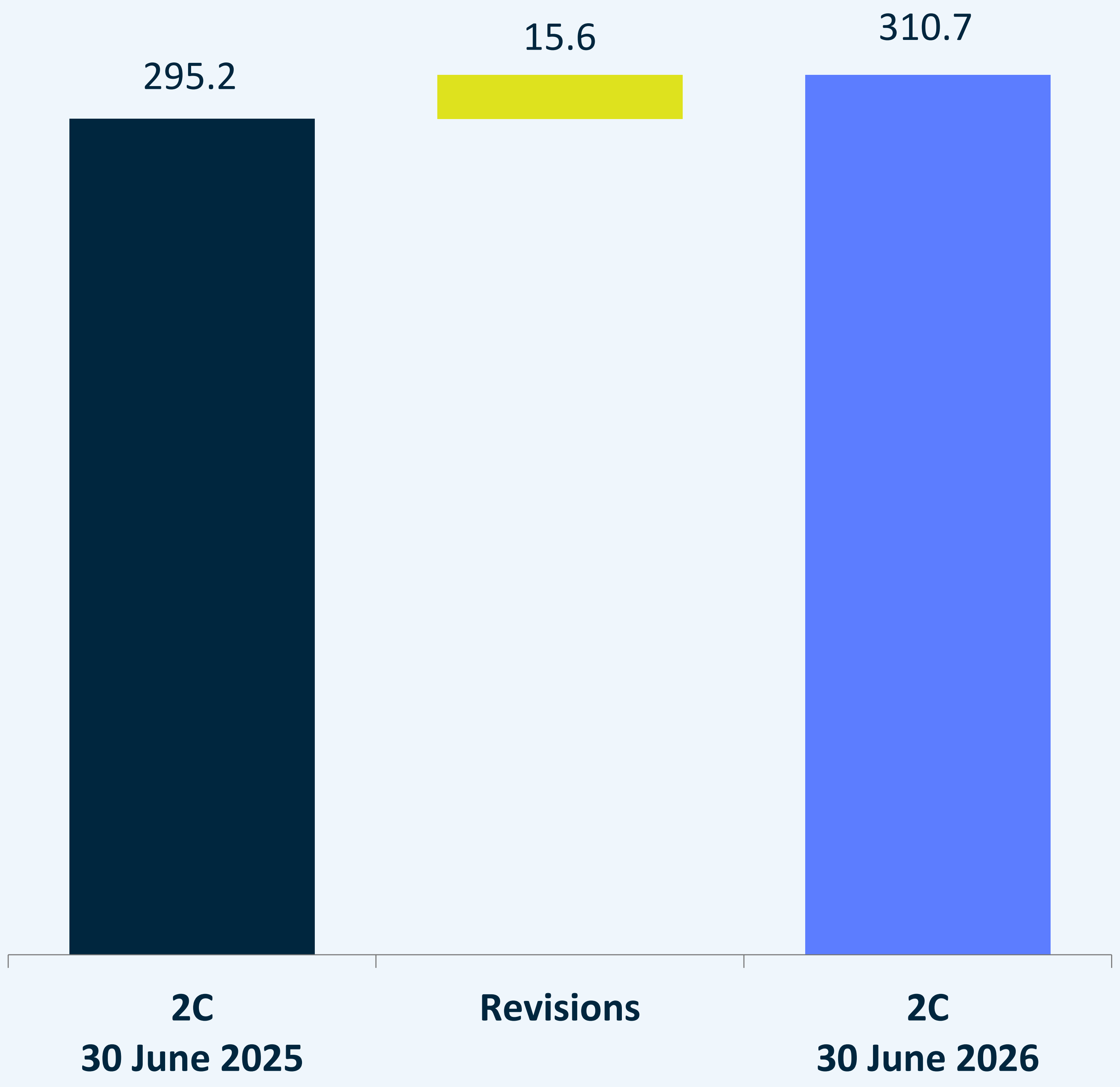
- Reflects additional Contingent Resource potential at Sole
- Small uplift at Patricia Baleen
- Partly offset by Otway Basin permit relinquishments

Total 2C of 50.8 MMboe (FY25: 48.2 MMboe)

Change in 2P Reserves FY25-26, PJe



Change in 2C Resources FY25-26, PJe



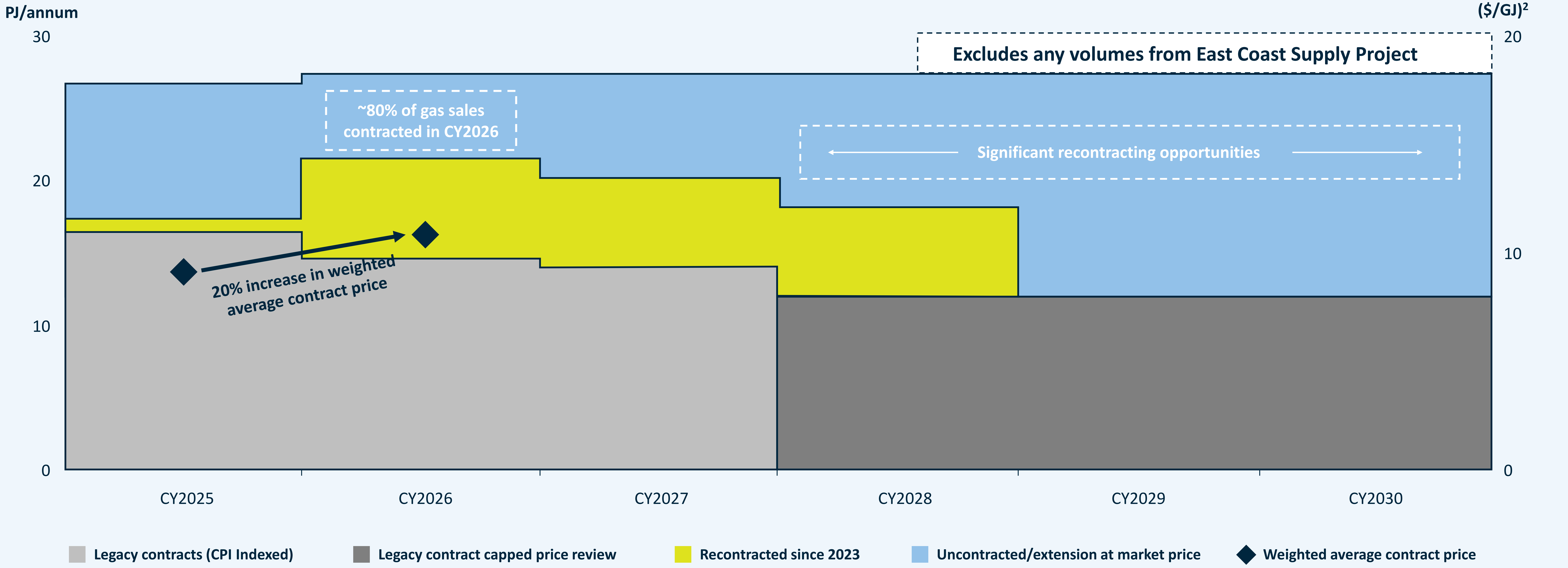
MMboe	**31.1**	**(4.4)**	**26.7**	**48.2**	**+2.5**	**50.8**

[1] As announced on 18 August 2026. Totals may not reflect arithmetic addition due to rounding. The method of aggregation is by arithmetic sum by category. Does not include the Artisan asset as acquisition completion is yet to occur. | [2] Revisions total <0.1 MMboe.

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 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 sales volume of 75 TJe/day from 1 January 2026 (actual group sales volume of 73.4 TJe/d shown for CY2025). 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. Existing reserves are on a 2P basis. | [2] Amplitude Energy weighed average contract price for the calendar year shown.

Continuous improvement programme

A further $13.4m of annualised cashflow improvement realised in FY26, with further cost improvement focus into FY27

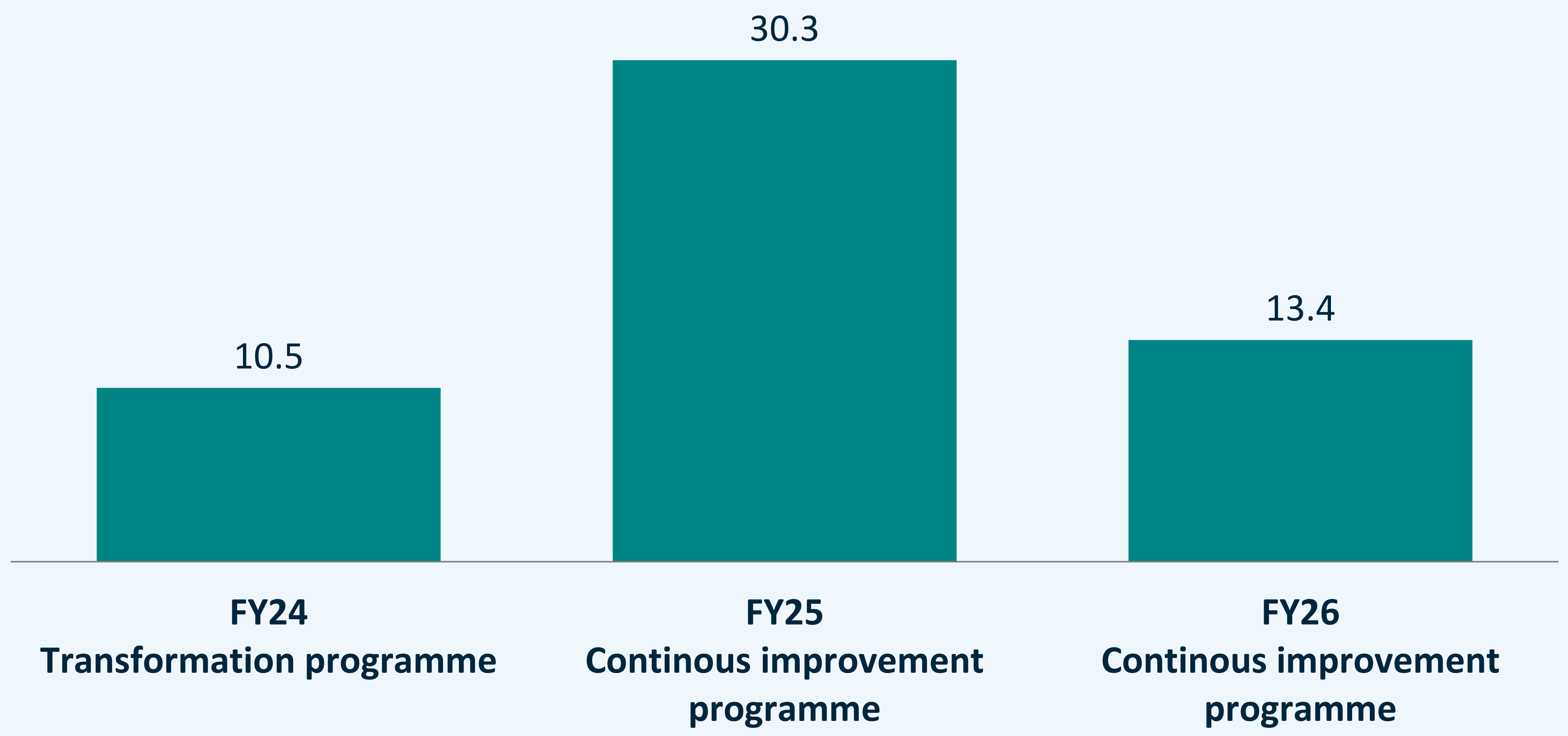
FY26 success

✓ 70 initiatives completed or in delivery in FY26

✓ Cost savings and value improvements related to sulphur treatment/disposal, reduced contractor and consumables costs, and night shift optimisation

✓ Initiatives also delivering sustainable emissions reductions

>$50m in annualised[1] cash flow improvement since FY24



[1] Cash flow improvement shown as the annualised total of all initiatives completed in each relevant year shown. >$50m in annualised cash flow improvement is relative to FY23.

FY27 targets & example focus areas

Targets	▪ Accelerate production, where economic to do so ▪ Maintain cost discipline ▪ Increase sales margins
Volumes	▪ Optimise OGPP production at its new higher capacity levels ▪ Further improve OGPP reliability performance ▪ Maintain stable, reliable operations at AGP
Costs	▪ Cost reduction opportunity in FY27 includes: – Streamlining internal systems with ERP replacement to support future efficiencies – Reduction in corporate expenses – Optimising maintenance and waste management
Gas marketing	▪ Shaping spot sale volumes based on market conditions ▪ Prioritising spot sales to the highest-price markets on any given day ▪ Additional short & long-term contracting opportunities

Transformative growth through backfilling existing infrastructure

Pursuing brownfield growth projects with the potential to more than double earnings by FY29[1]

Otway Basin \ Athena Gas Plant (AGP)

Backfilling AGP

- ECSP brings in new fields to backfill the Athena Gas Plant
- Up to 150 TJ/day installed processing capacity
- Peak gas supply and third-party processing opportunities

Gippsland Basin

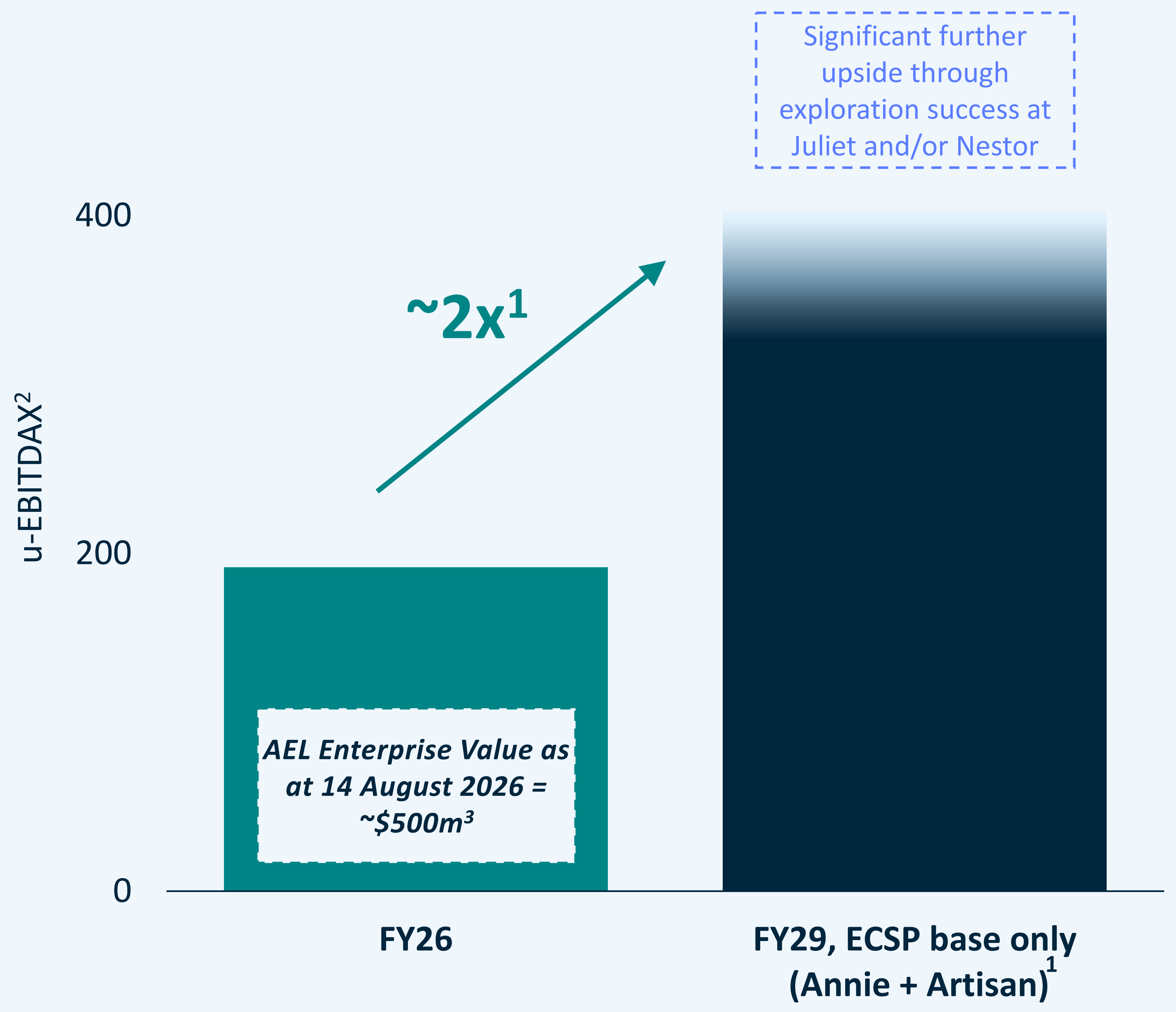
Increasing OGPP production

- Debottlenecking production capacity; now >70 TJ/day
- Reducing unit costs, maximising margins and cash flows
- Sole reservoir continues to perform well

Progressing Patricia Baleen restart

- Targeting FEED entry in CY2026 for PB restart project
- Highly economic restart of existing field and infrastructure
- Focused on lowest-cost option to restart production

Amplitude Energy Illustrative Group Earnings Potential

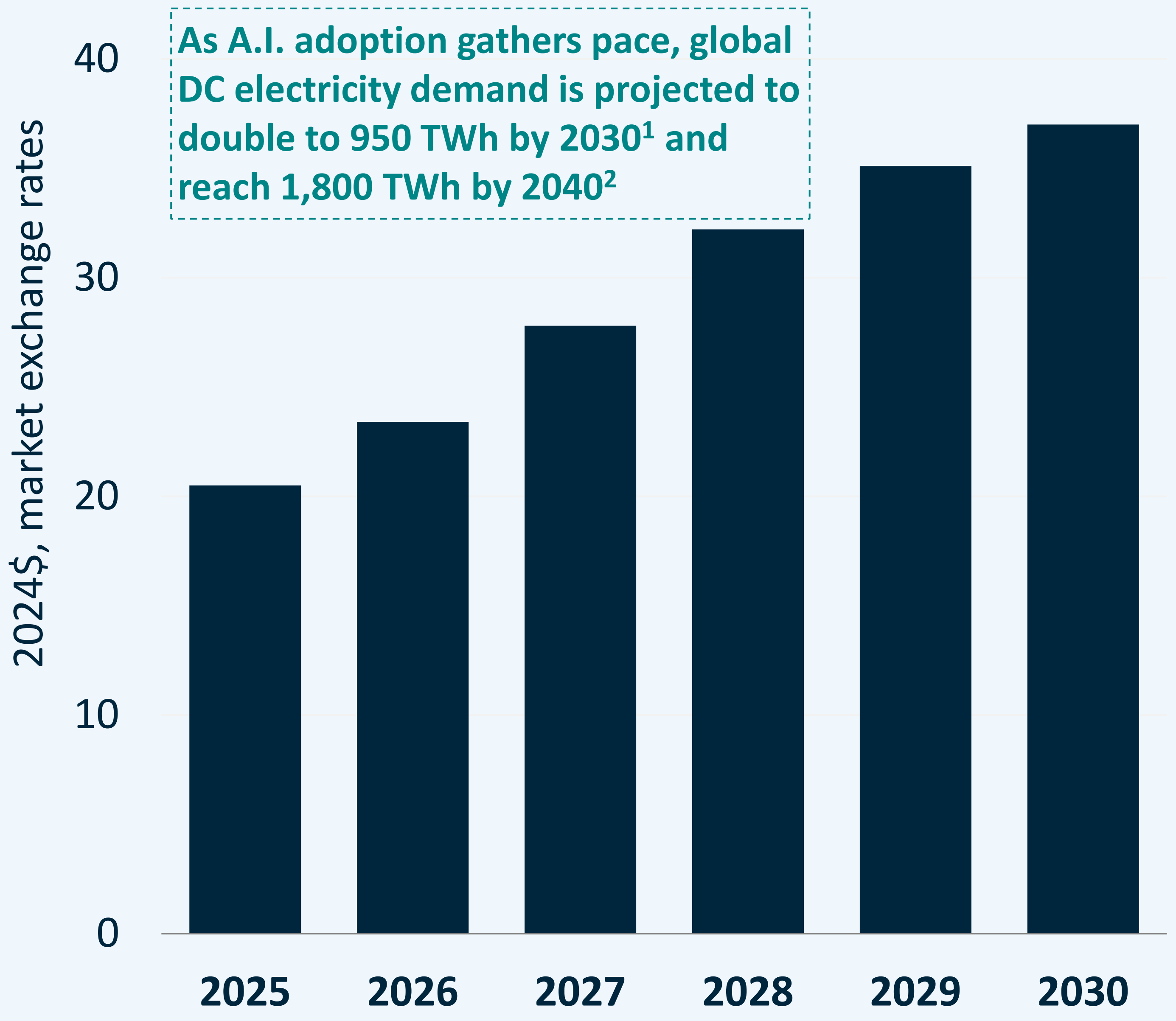


[1] Illustrative, and does not constitute guidance. Assumes ECSP production achieved in mid-2028, which is indicative and subject to a number of variables including exploration success, Final Investment Decision, field resources, resource composition and field pressures. Other assumptions based on AEL internal model mid case. | [2] Underlying earnings before interest, tax, depreciation, depletion, exploration, evaluation and impairment. Illustrative, and does not constitute guidance. In FY26 the Company is no longer adjusting for the NOGA levy in its underlying results due to it being a recurring expense. | [3] Based on basic market capitalisation as at 14 August of $458.8m + reported net debt as at 31 March of $37.6m

Drivers of future gas demand

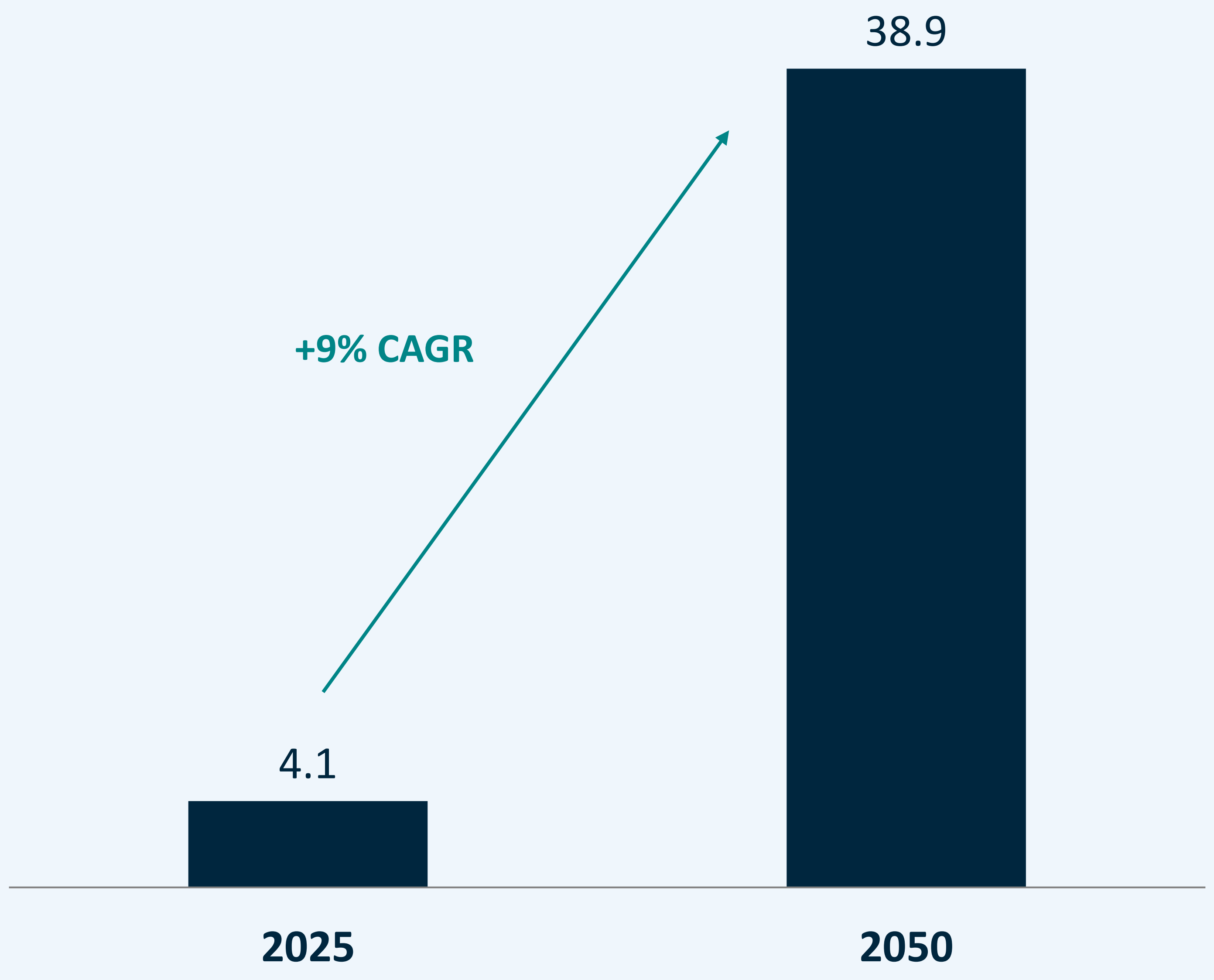
Global gas demand growth is being driven by electrification, data centre (DC) roll-outs and coal-to-gas switching

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

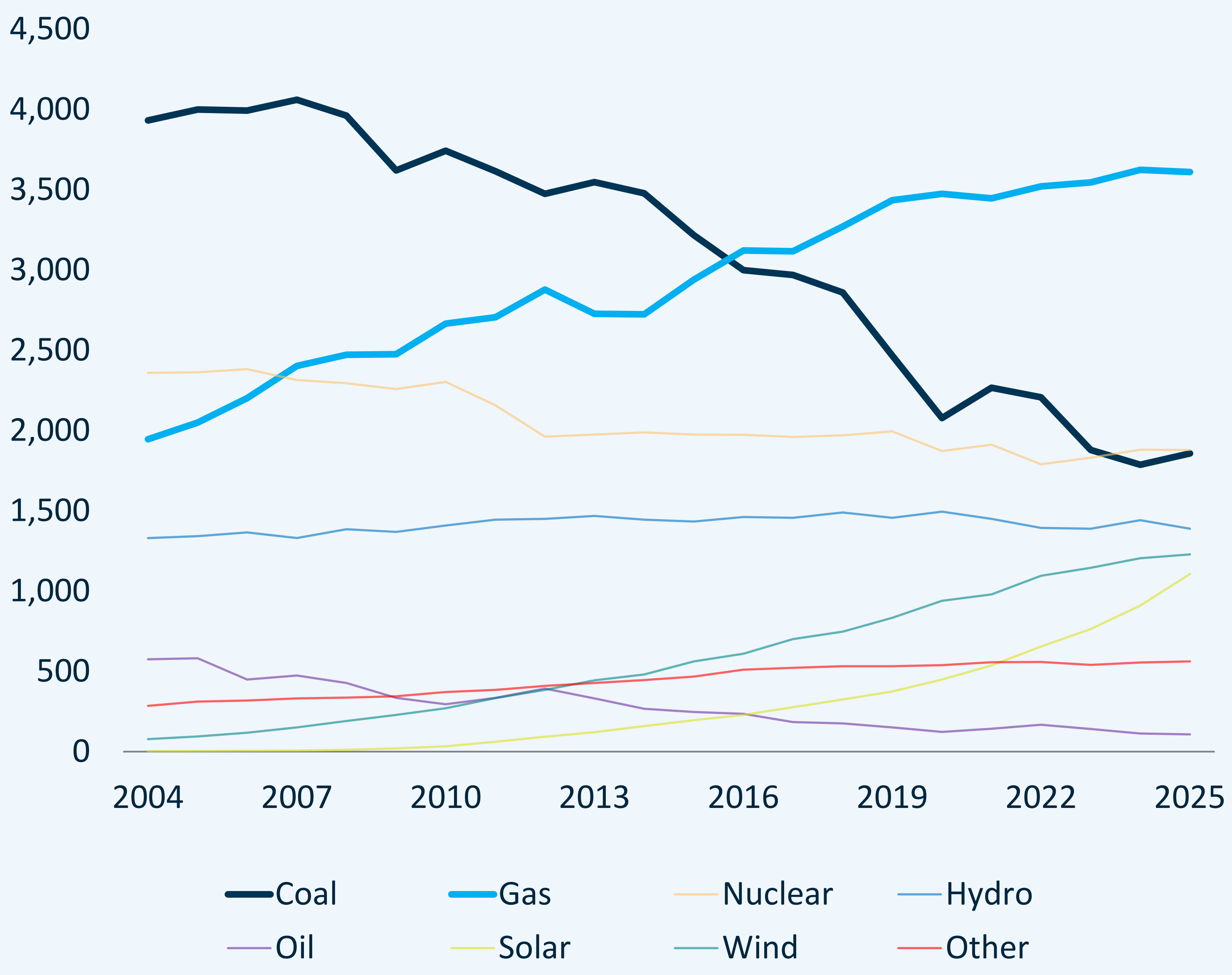
Forecast Australian DC electricity demand, TWh[3]



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.

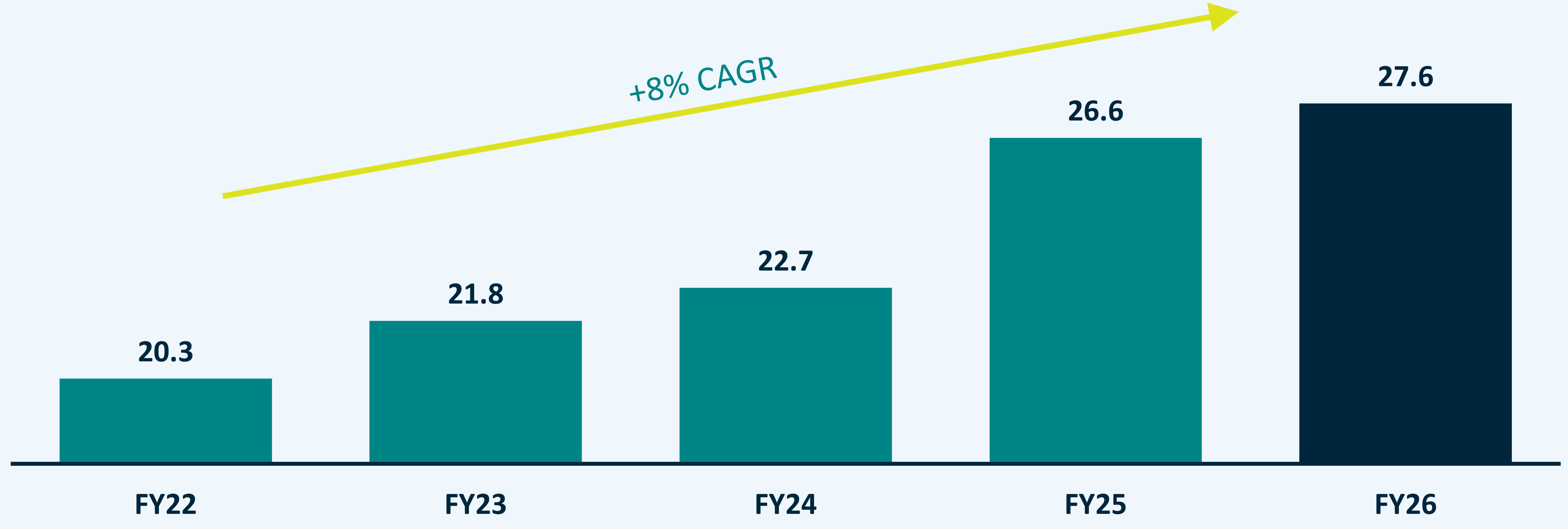
#2

FY26 financial highlights

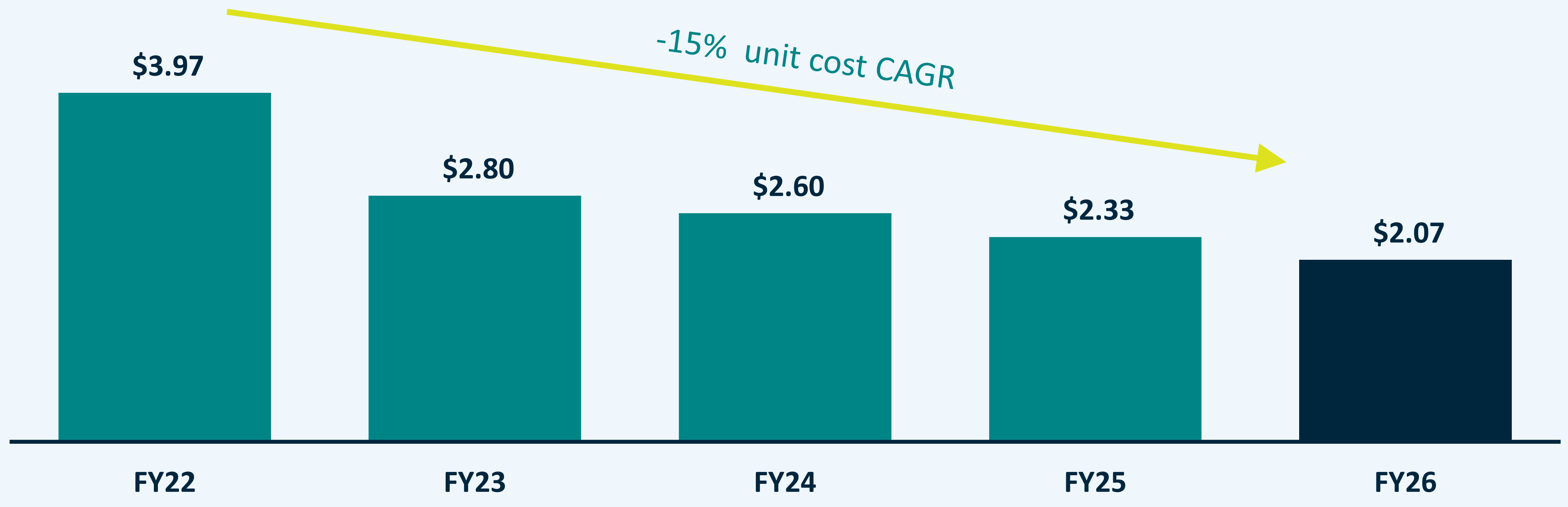
Proven performance & cash generation, prior to transformational growth

Increased production and operational leverage has generated substantial margin expansion

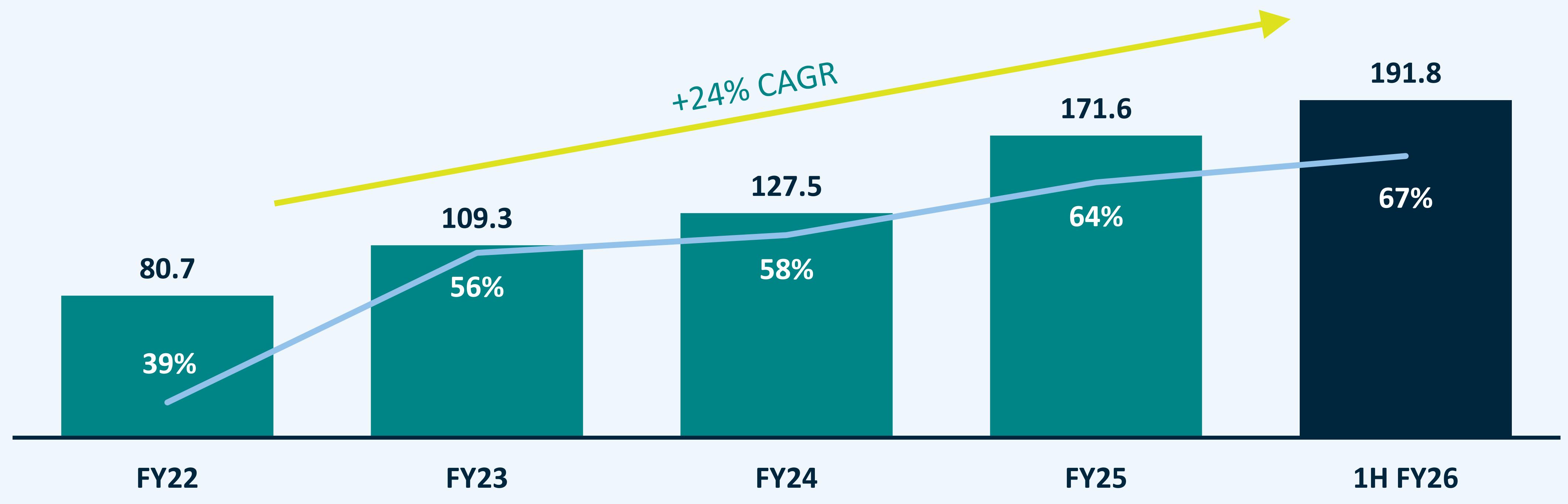
Production, PJe



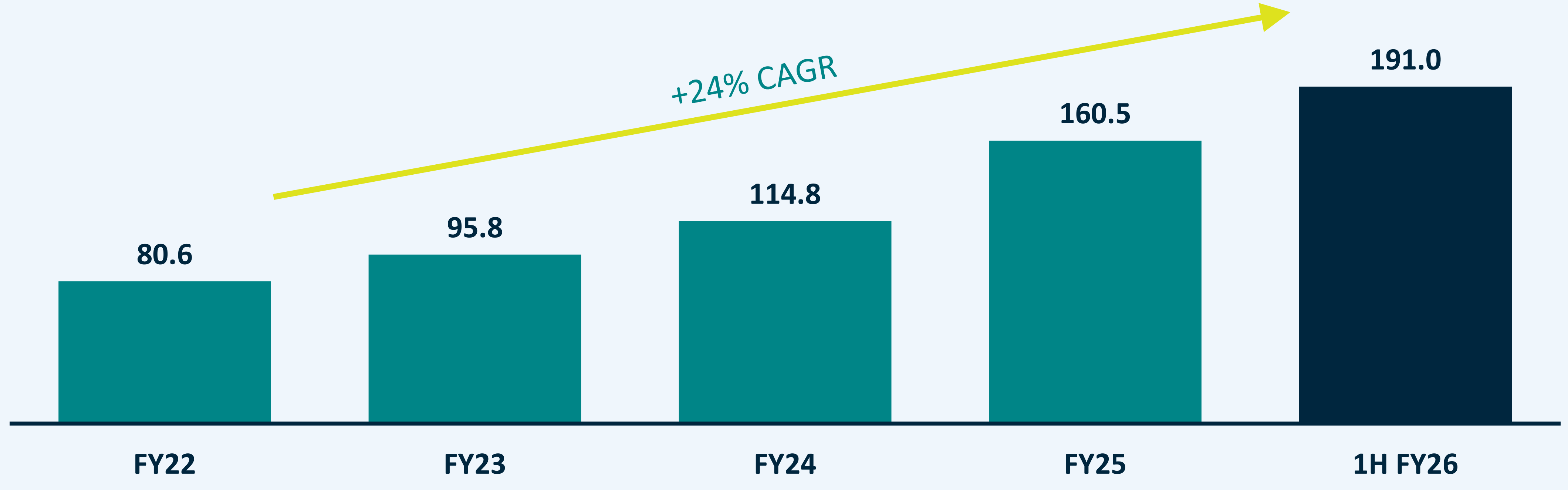
Production expenses[1], $ per GJ produced



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

Record production & financial metrics

Higher production and gas prices, combined with lower production expenses, are driving earnings, margin growth and cash generation

$m unless indicated	FY25	FY26	Change
Production (PJe)	26.6	**27.6**	▲ 3%
Sales revenue	268.1	**285.8**	▲ 7%
Average realised gas price ($/GJ)	9.91	**10.36**	▲ 5%
Production expenses[1]	62.1	**57.0**	▼ 8%
u-EBITDAX	171.6	**191.8**	▲ 12%
Underlying profit after tax	9.1	**45.0**	N/M
Reported loss after tax	(41.3)	**(27.2)**	N/M
Operating cash flow	89.3	**180.3**	▲ 102%
Adjusted cash from operations[2]	160.5	**191.0**	▲ 19%
Capital expenditure incurred	64.1	**118.6**	▲ 85%
Restoration payments	63.3	**10.5**	▼ 83%
	30 June 25	**30 June 26**	
Cash and cash equivalents	62.2	**137.5**	▲ 121%
Drawn debt	305.2	**175.2**	▼ 43%
Net debt/(cash)	243.0	**37.6**	▼ 85%

Record production driven by OGPP/Sole

- Towards top end of increased guidance range (26.6 – 28.1 PJe)

Record revenue due to higher sales volumes and higher realised gas prices

Production expenses and other opex in line with guidance

- Further reductions in OGPP plant costs, now well below $2/GJ
- Unit production costs ↓ 11% to $2.07/GJe (FY25: $2.33/GJe) on a group basis

Record u-EBITDAX due to margin expansion and operational leverage

- 67% u-EBITDAX margin, well above global E&P average

Record operating and adjusted cash flows

Capex below guidance range, with ECSP costs below FY26 expectations

- Capex incurred over FY26 primarily relates to ECSP drilling and long-lead items

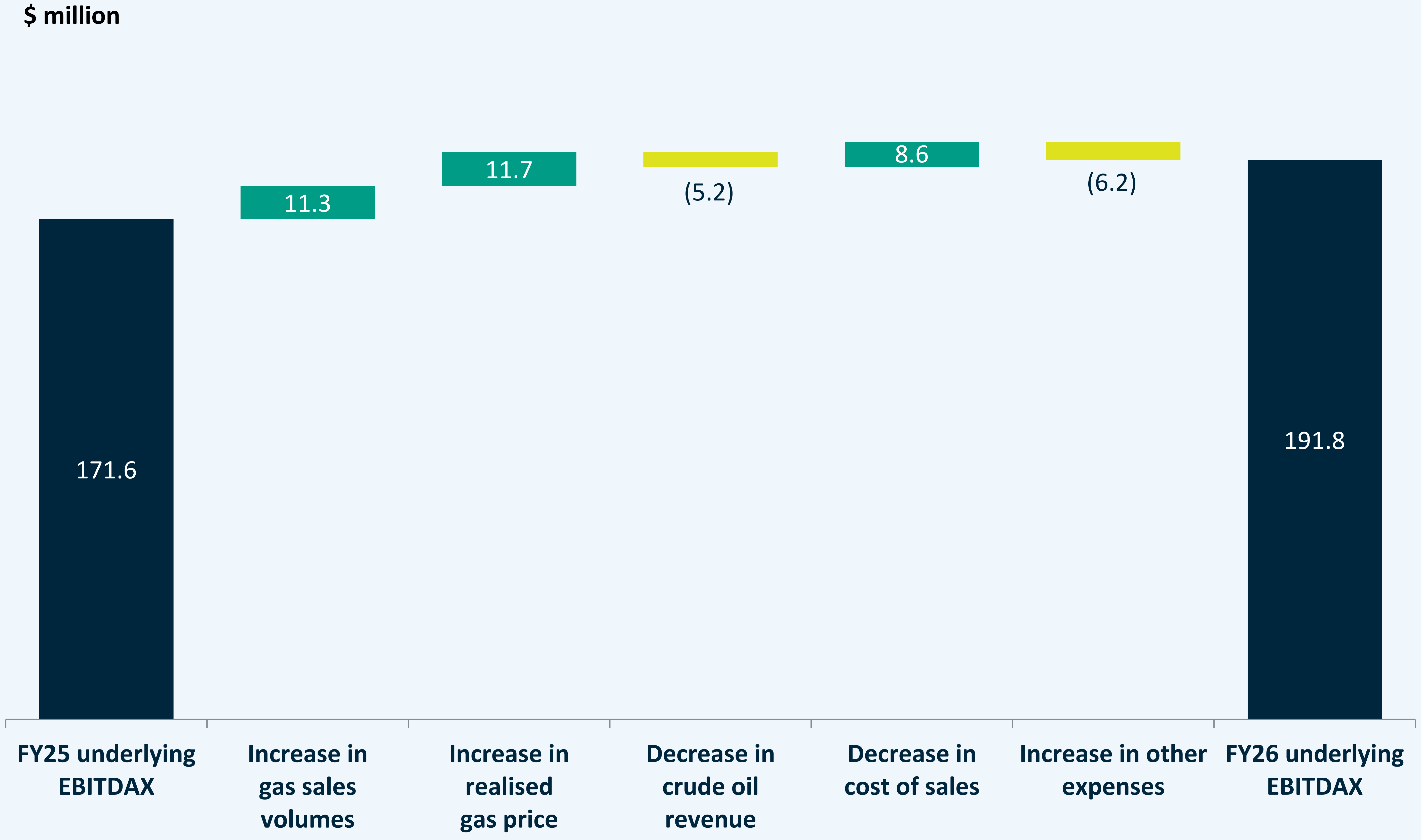
Net debt down >$200m since its peak in FY25

- Strong cash flows offset ECSP capex in H2 FY26

[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 FY25

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

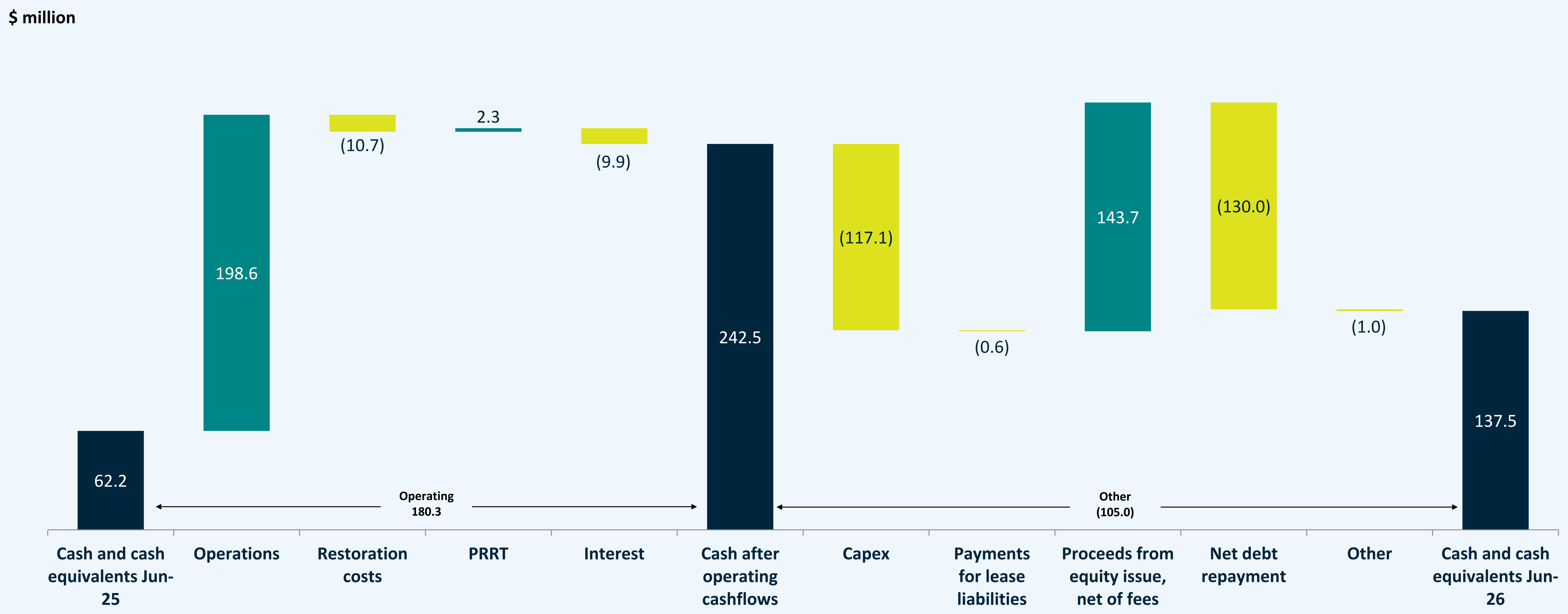
Decreased cost of sales through improved plant reliability, operating efficiencies and reduced maintenance requirements at OGPP

Higher care and maintenance costs associated with the pipeline visual inspection program, partially offset by a reduction in corporate G&A

Result demonstrates strong operating leverage of assets and margin expansion

Group cash - bridge from FY25 to FY26

Strong operating cash flows, more than covering capex over FY26

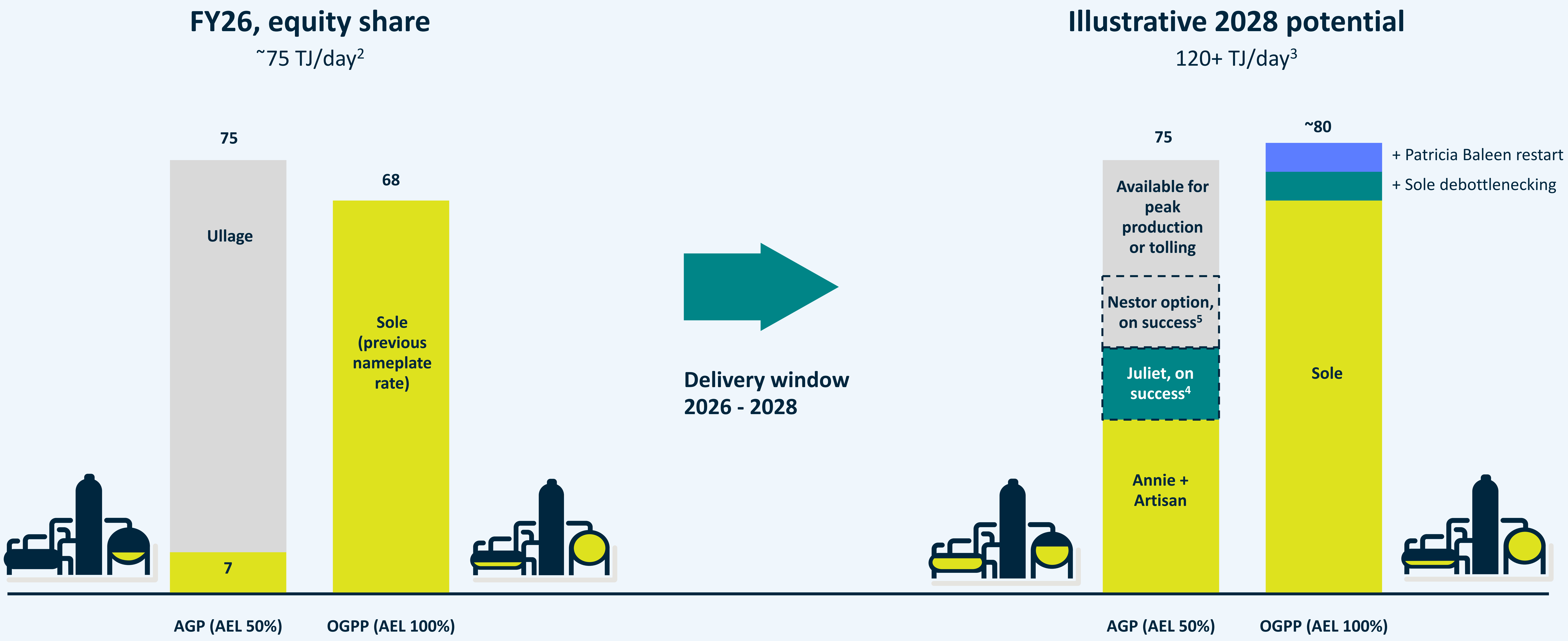


#3

Growth projects

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 H1 FY26. Targeted production through the AGP in 2028 is indicative, based on ECSP production from the Annie and Artisan fields and the Juliet exploration target, and is subject to a number of variables including exploration success, Final Investment Decision, field resources, resource composition and field pressures. | [2] FY26. >80% of gas sales, on average, made under existing contracts.| [3] Post ECSP production, first gas expected in 2028. | [4] Juliet production assumes commercial discovery from exploration drilling. | [5] Exercise of the option to drill the Nestor exploration well is subject to joint venture and board approvals. Nestor production assumes a commercial discovery from exploration drilling.

ECSP on track for first gas in 2028[1]

Annie + Artisan deliver strong project economics with exploration upside still to come

Project economics underpinned by **Annie + Artisan**[1] discovered resources

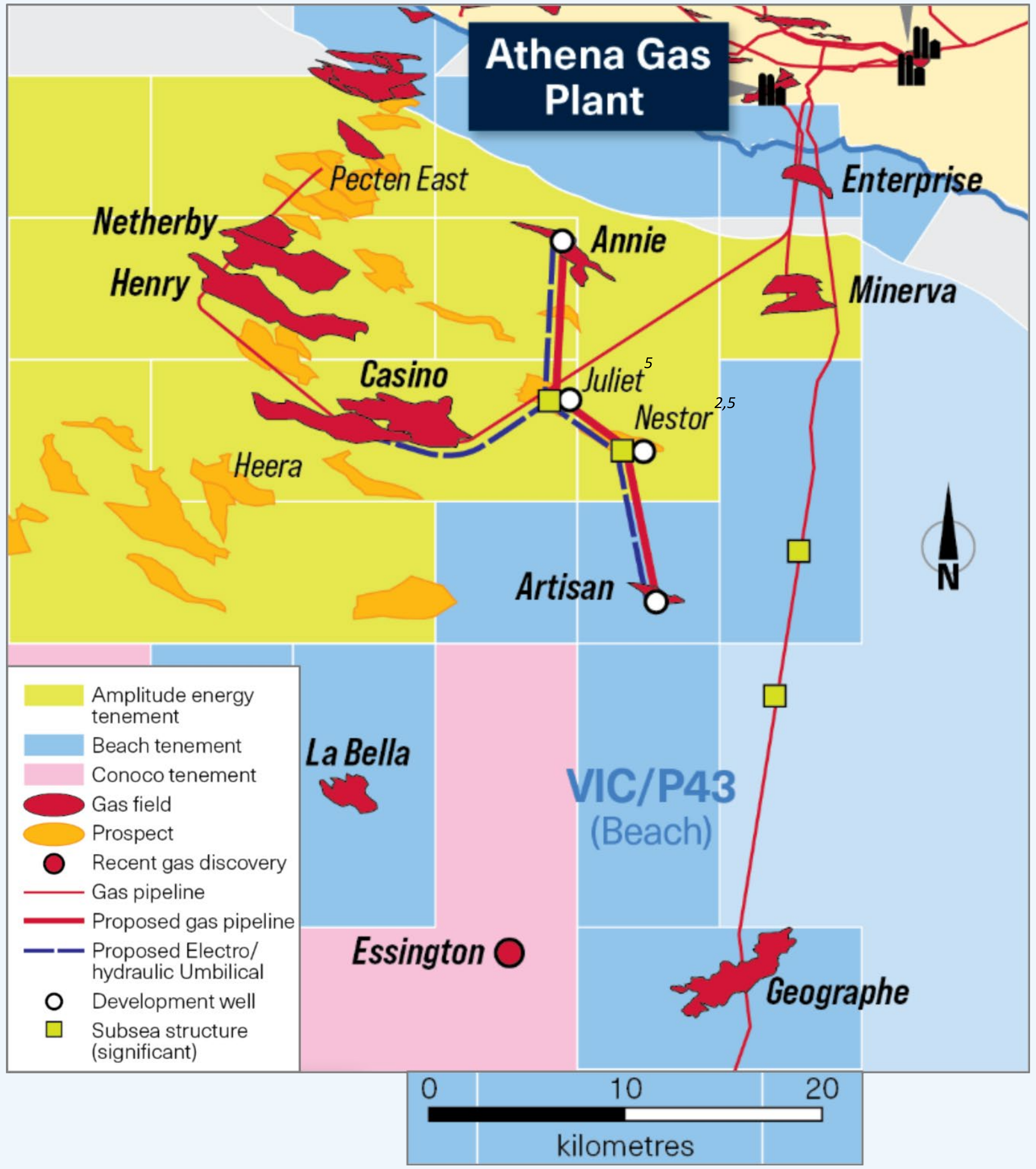
Potential upside from the **Juliet** well, and optional **Nestor** well later in 2026[2], to further improve project economics

Strong support from market with **foundation offtake contracts secured with** EnergyAustralia and AGL[3]

Project is **fully funded**, with strong JV alignment[1]

Vast majority of **project contracts locked-in** and project engineering complete

Returns expected to comfortably exceed internal investment hurdle rates[4]



[1] No final investment decision has been taken in relation to development of the ECSP or the Artisan field as a result of this announcement. | [2] Nestor well is subject to joint venture and board approvals. | [3] 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. | [4] Based on AEL internal model mid-case assumptions. | [5] Juliet and Nestor are prospective exploration targets.

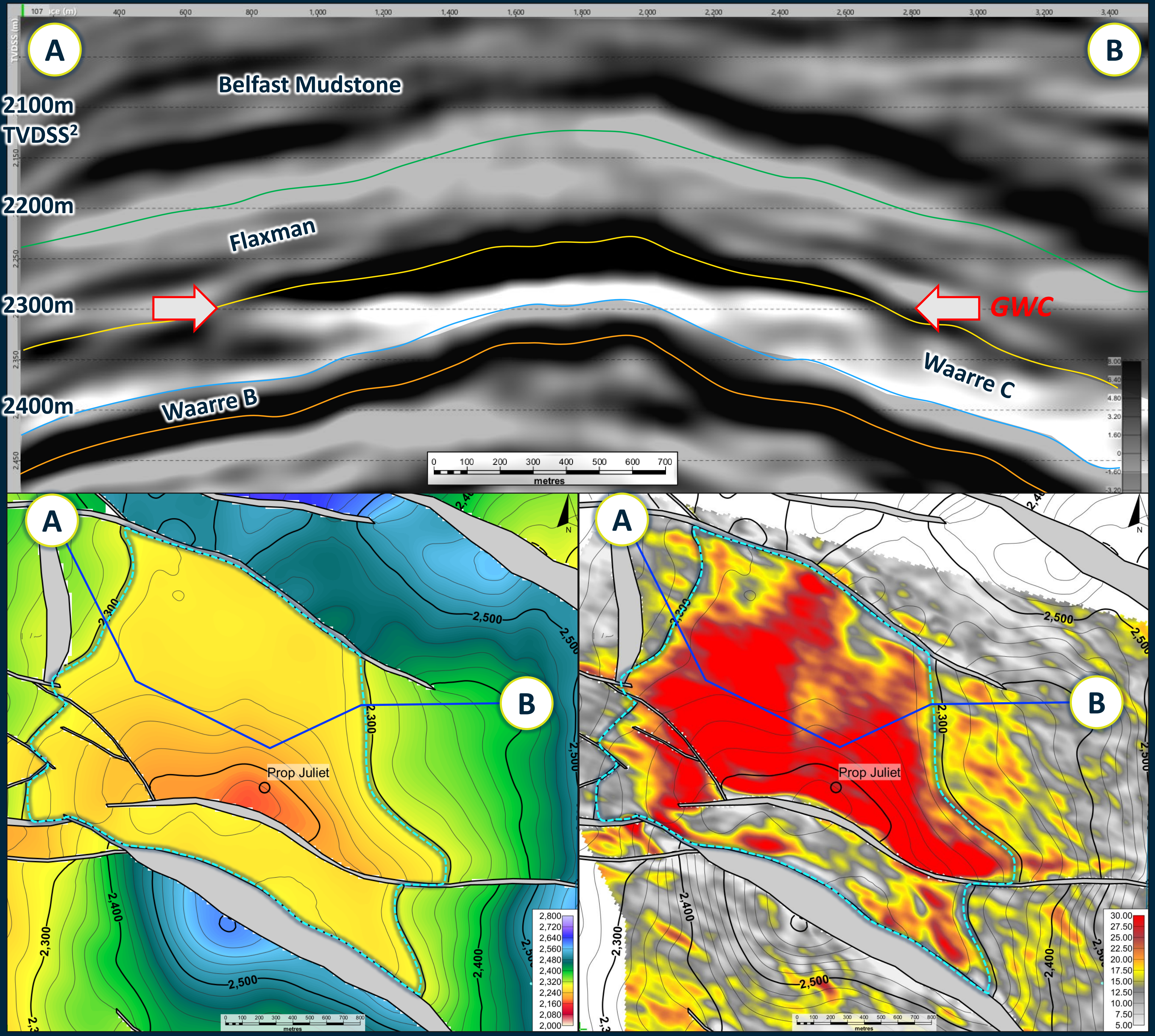
Juliet exploration drilling imminent

Geophysical elements support Juliet's prospectivity (84% Pg[1])

Strong geophysical response	Conformable amplitude shut-off at top Waarre C reservoir Clear flat spot at 2,300m TVDSS, implying gas-water contact (GWC)
Structure	Simple structure imaged on good quality 3D-seismic
Reservoir	Proven excellent reservoir quality in all nearby wells Seismic flat spot indicative of high net sand thickness
Seal	Confirmed thick Skull Creek/Belfast Mudstone sealing interval
Charge	Surrounded by adjacent gas discoveries

Prospective Resource Summary (Bcf)[2]				
Basis	P90	P50	Mean	P10
Gross 100%	30.1	46.4	48.8	71.0
Net 50%	15.1	23.2	24.4	35.5

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.

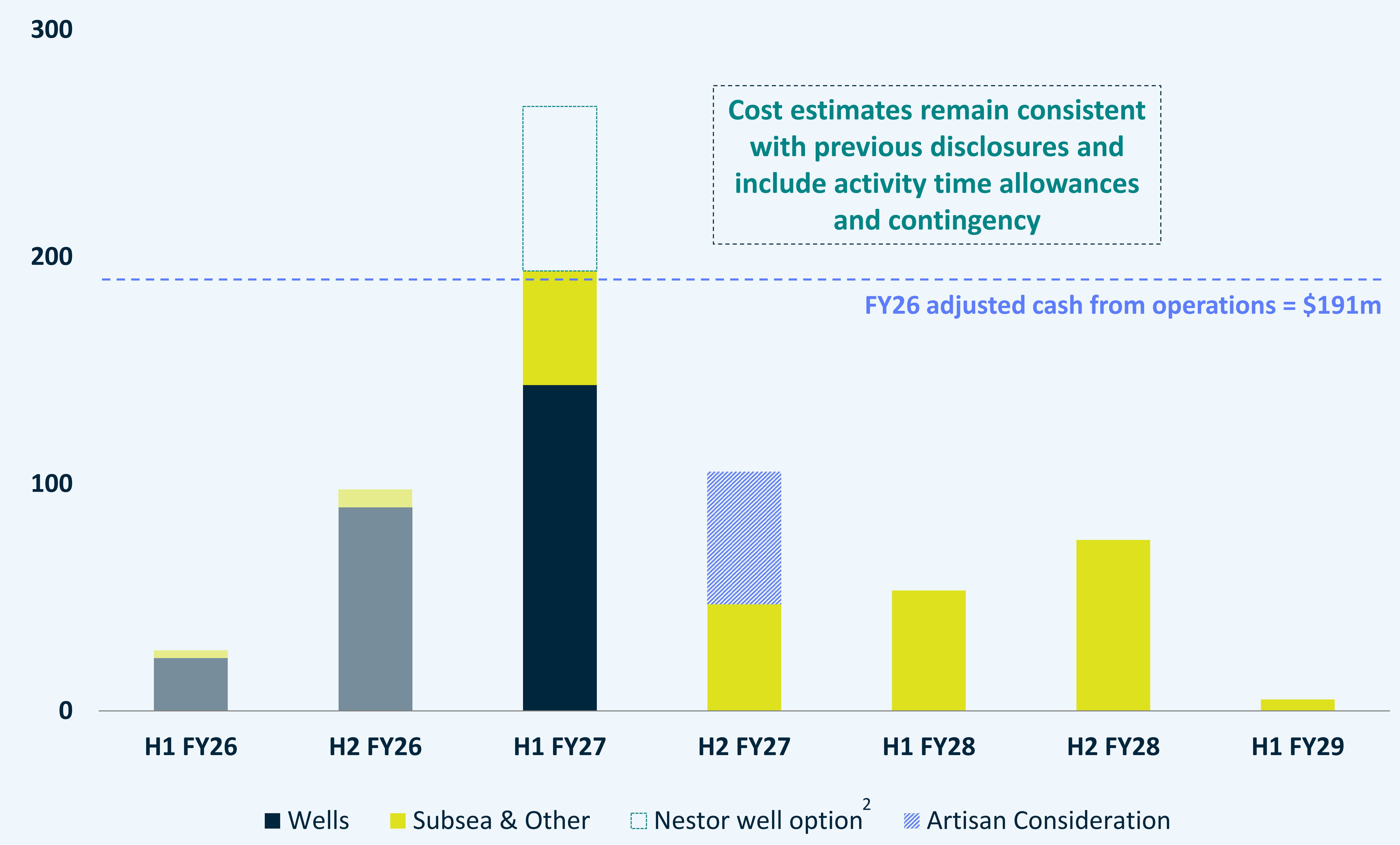


[1] Pg is chance (or probability) of encountering a measurable volume of mobile hydrocarbons. | [2] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and AEL's 50% net share of each prospect, were announced to ASX on 9 February 2022. Net figures are reported according to AEL's economic interest and net of contractual royalties

ECSP spend profile

Carefully managed phasing of spend and associated risks

Illustrative ECSP spend profile (net to AEL)[1], $m



Drilling & well completions comprise ~70% of ECSP capex over FY27

ECSP drilling phase will complete before end CY2026

Subsea and other development costs will be known at project FID, expected in coming weeks

- Around half comprised of long lead equipment orders
- Remainder reflects project development work scheduled for late CY2027 / early CY2028

Risks to capex from end CY2026 substantially mitigated

Appropriate contingency included in cost estimates

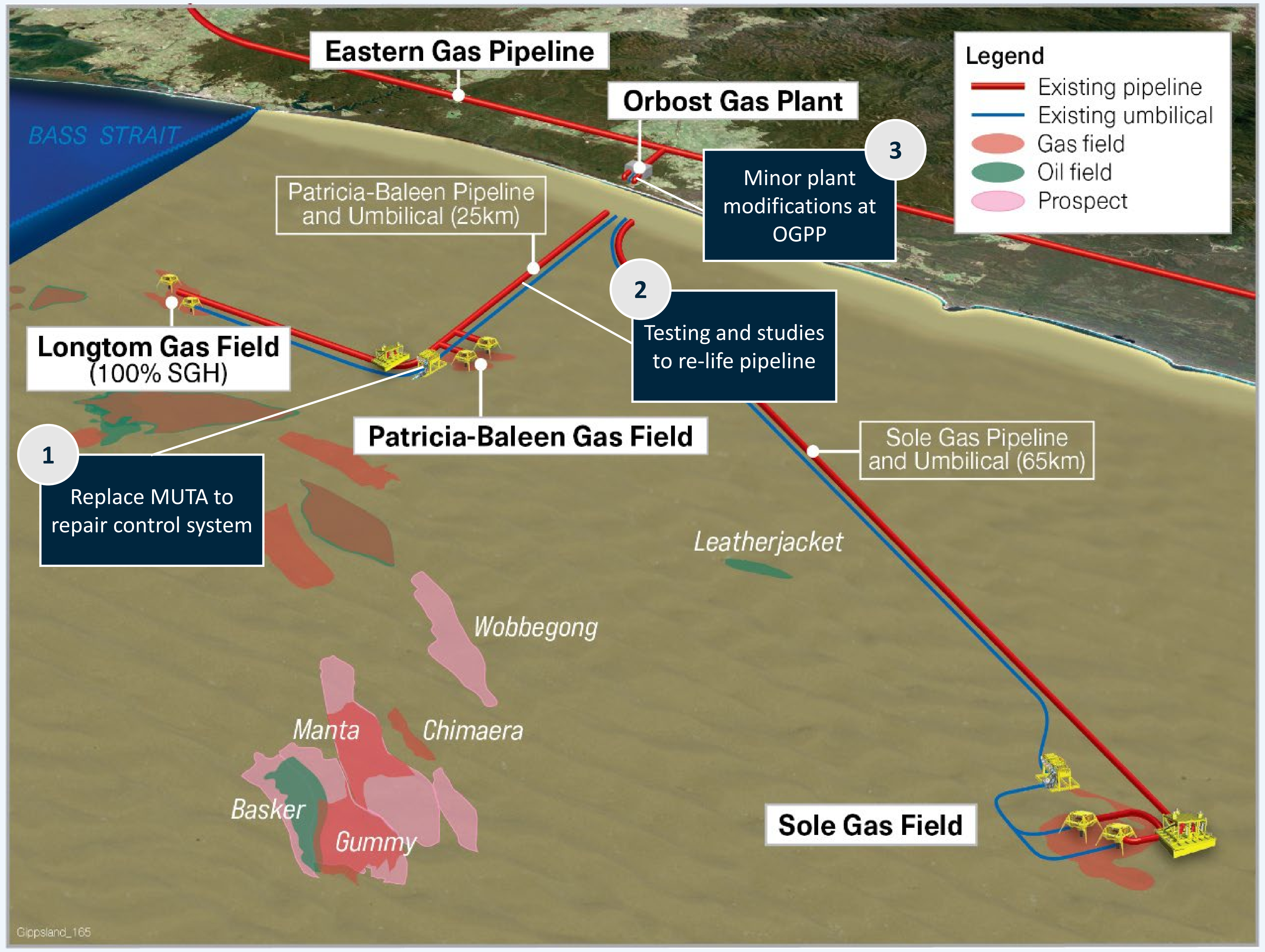
ECSP capex spread over ~3 years, largely funded through underlying cash generation from the base business

[1] Illustrative profile only, assuming exploration success at Juliet and 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. No final investment decision has yet been taken in relation to development of the ECSP or the Artisan field as a result of this announcement. | [2] Nestor well is subject to joint venture and board approvals

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

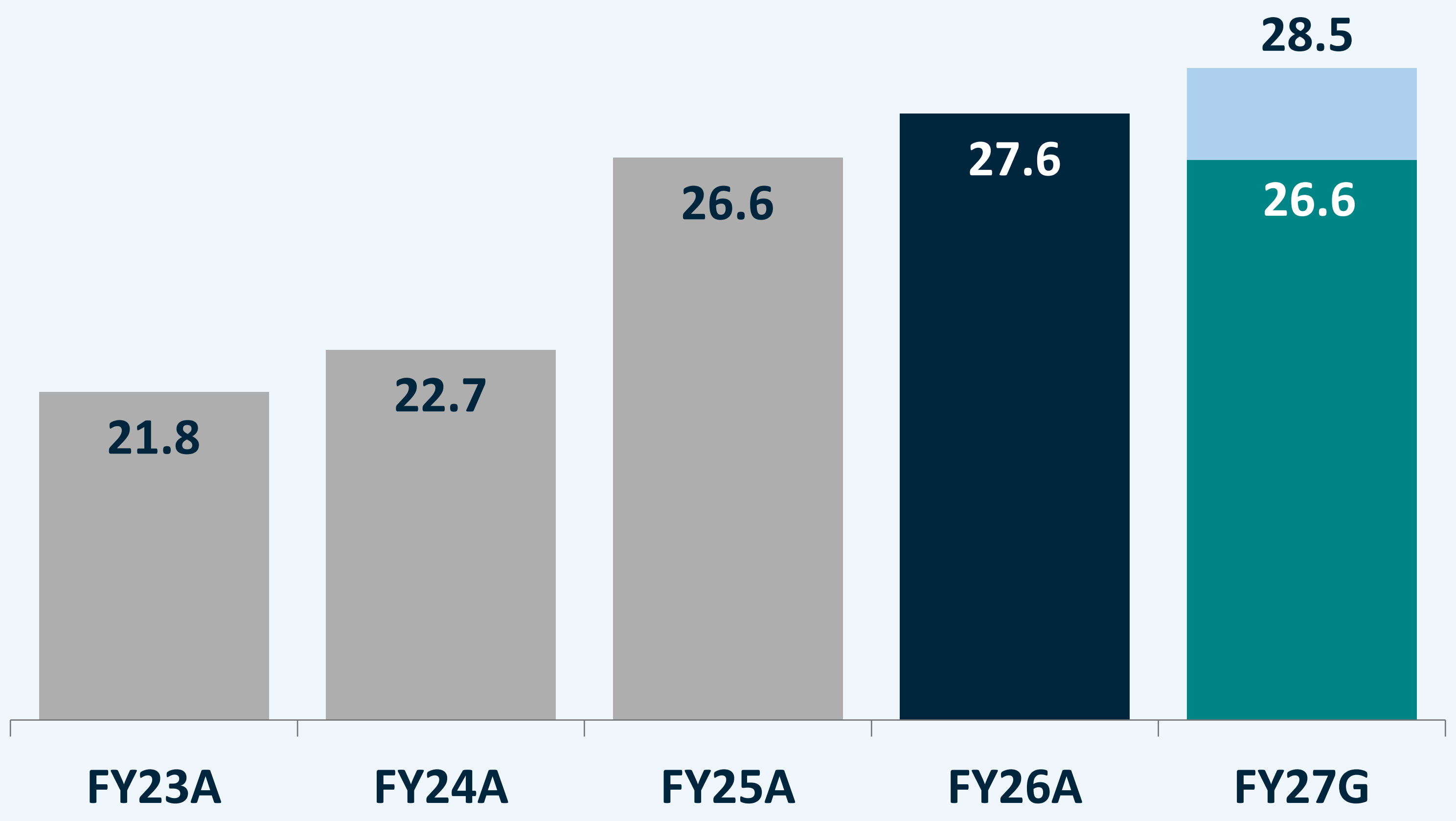
#4

FY27 outlook

FY27 guidance

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

FY27 production: 26.6 – 28.5 PJe



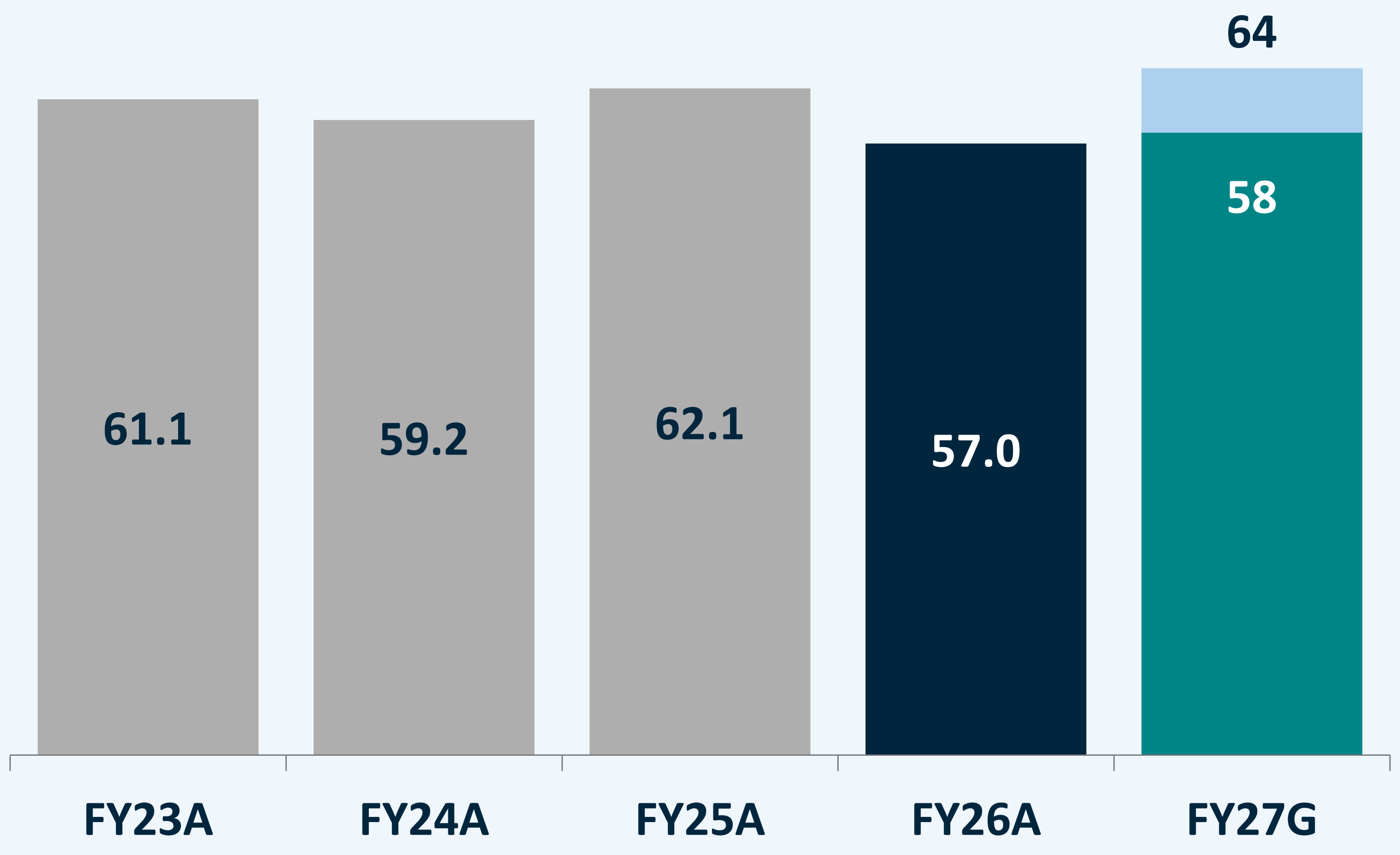
Range of outcomes largely based on recent OGPP production, incorporating ability to produce at >70 TJ/d

- Includes planned maintenance shutdown at OGPP in H2 FY27

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

Natural decline at CHN fields and PEL 92

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



Underlying production expenses of $58 – 64m

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

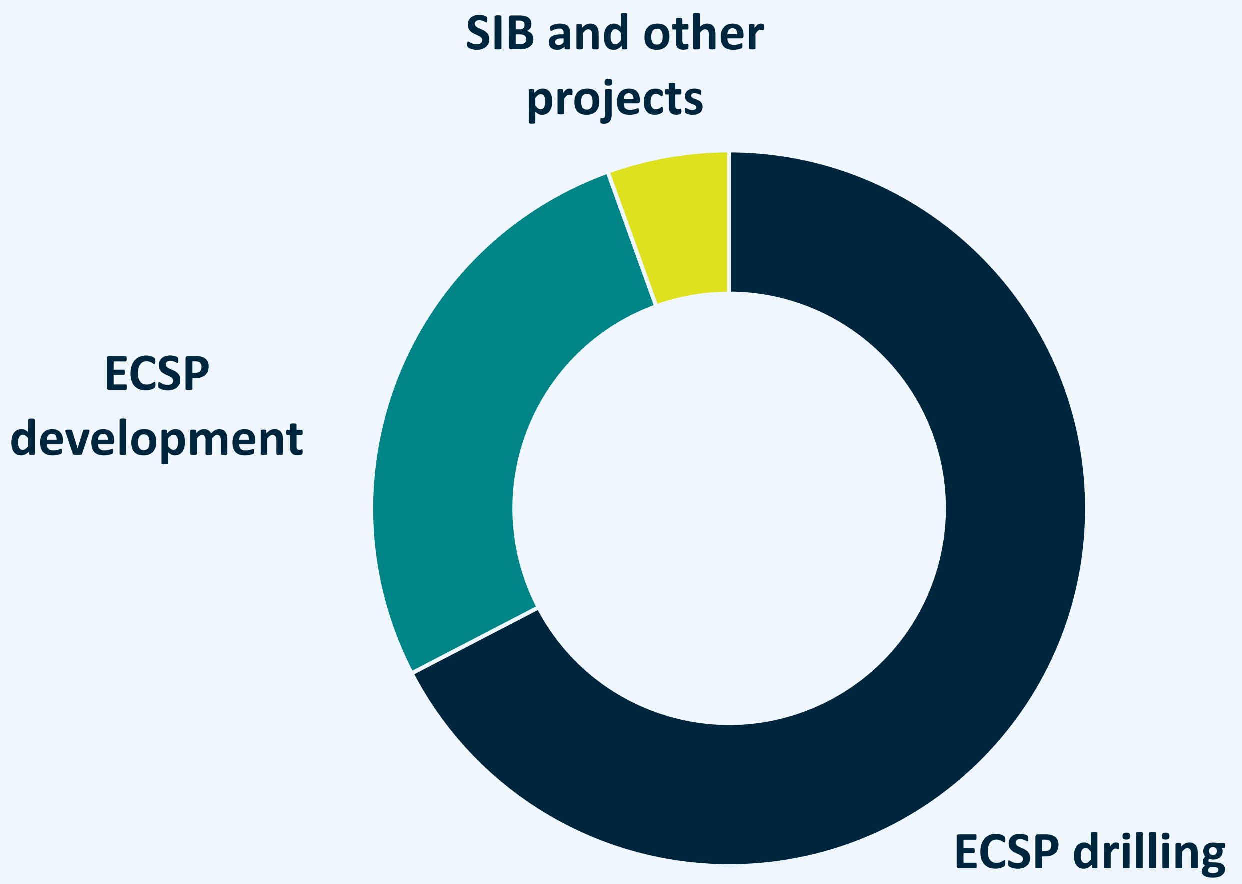
Other cash expenses & costs of sales of $27 – 31 m[1]

- 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: $250 – 310m[3]



FY27 ECSP capex includes Juliet & Annie drilling and long-lead development phase costs, assuming FID in H1 FY27

- Reflects AEL's 50% share

Does not include uncommitted costs relating to Nestor drilling[4] or 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. | [4] Uncommitted drilling cost estimate $60 – 75 million (AEL 50% share).

FY27 focus areas

Progress ECSP

- Complete drilling safely, on time and budget
- FID for the development phase of the project
- Maintain project timeline for first gas in CY2028

Maximise asset utilisation

- Optimise OGPP production, including at >70 TJ/day when market conditions are favourable
- Reliability loss of <1% across AGP & OGPP
- Progress Patricia Baleen restart

Grow margins

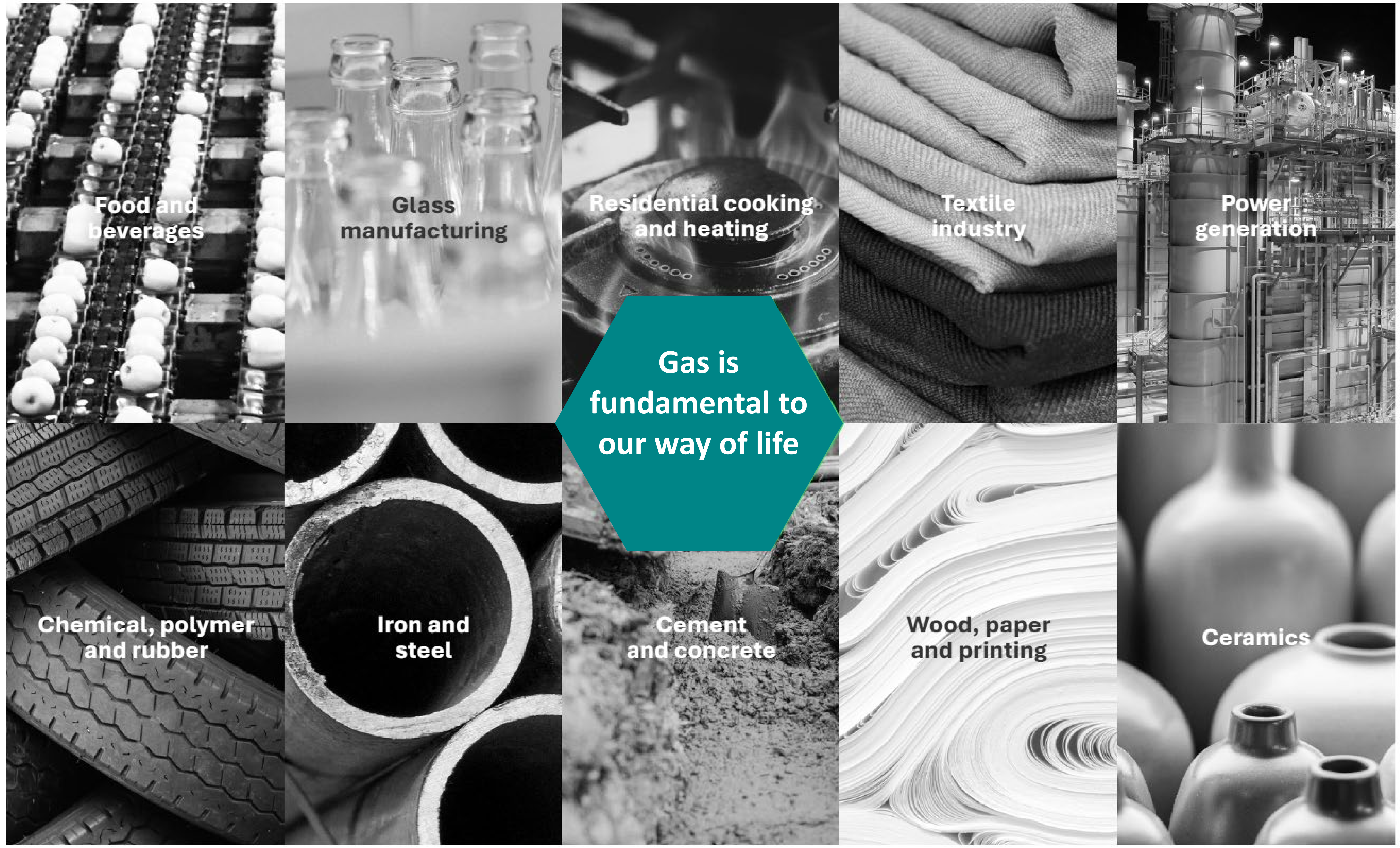
- Increase realised gas prices through marketing & trading initiatives
- Further reductions in production costs
- Organisational improvement through streamlining systems and processes

Appendix A
Additional materials

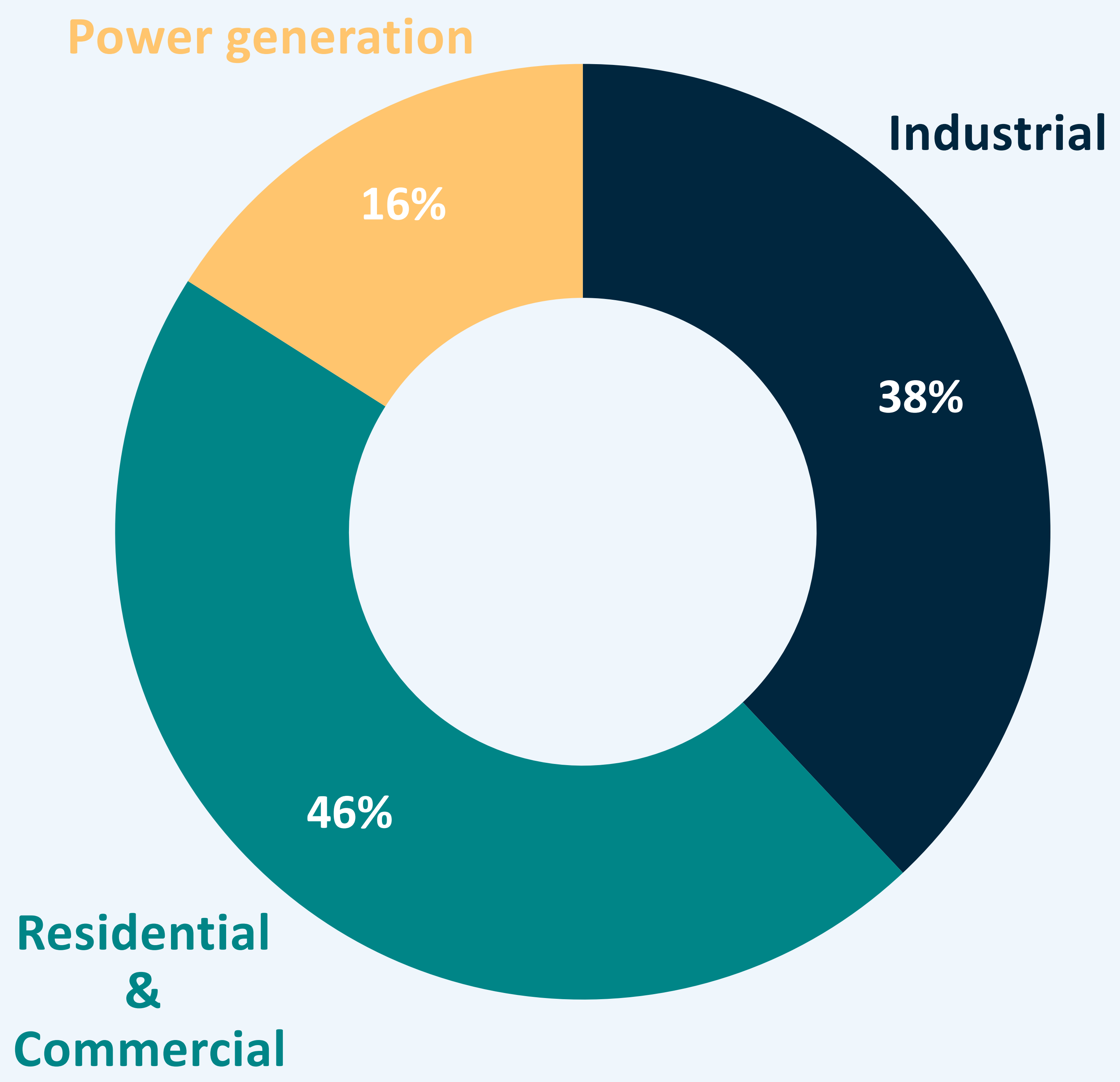
Gas meets 25% of Australia's energy demand[1]

"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



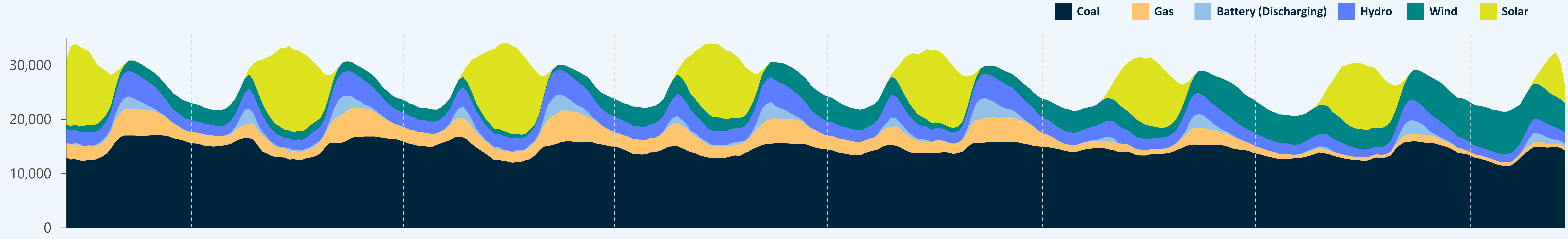
Total = 350.2 PJ

[1] Australian Energy Update, August 2025, 2023-24, 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.

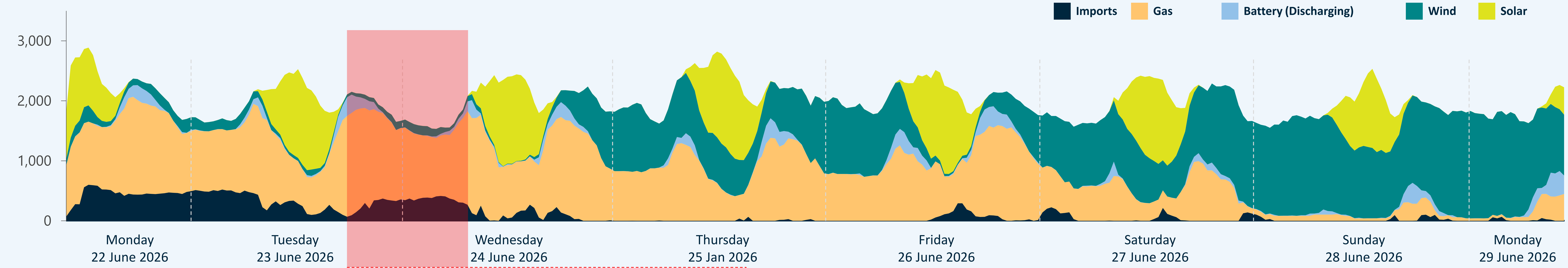
Increasing role of gas in the electricity market[1]

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



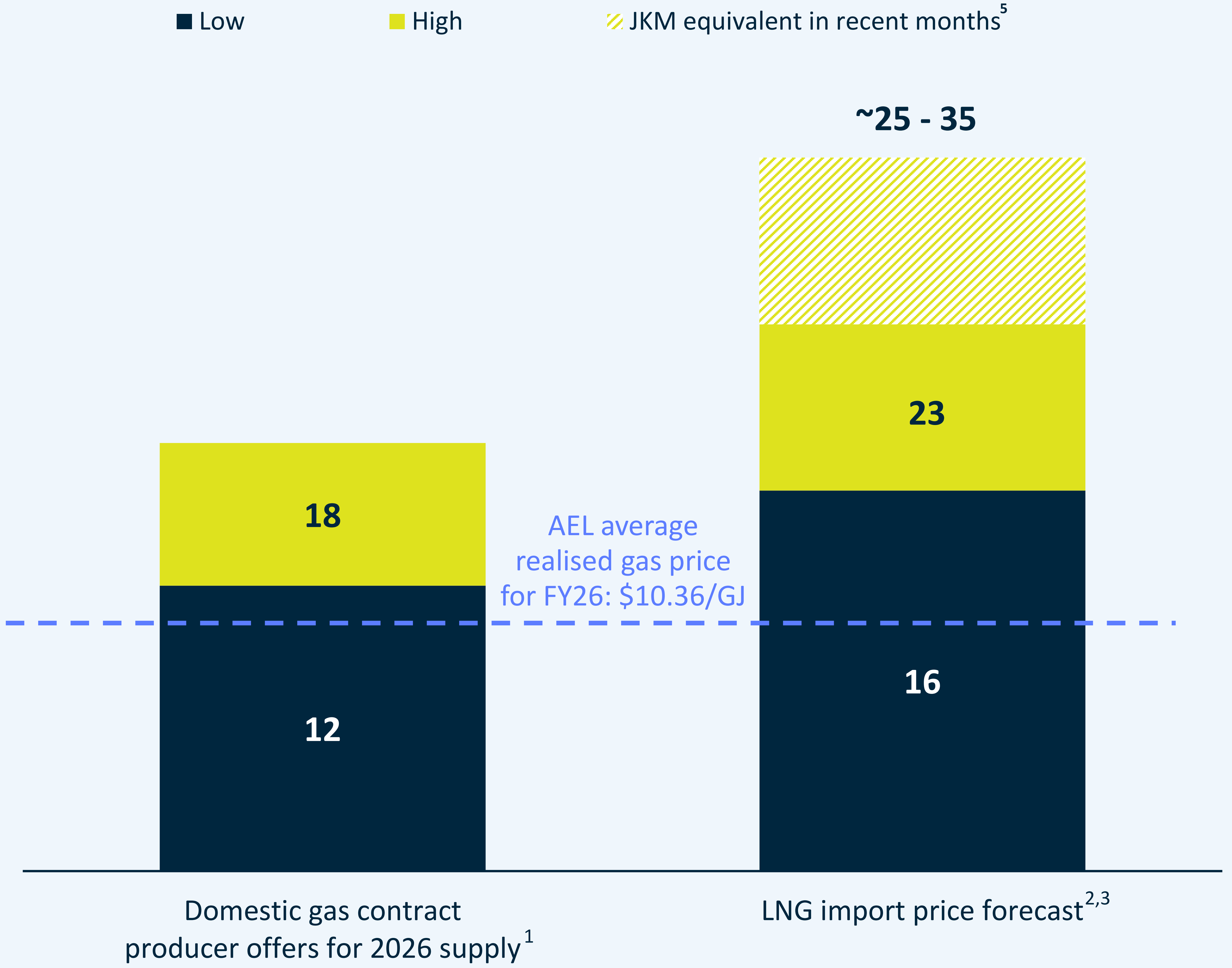
Between 6pm-8am on 23-24 June, gas (~65-75%) and Victorian imports (~15-20%) supplied ~90% of South Australia's electricity

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

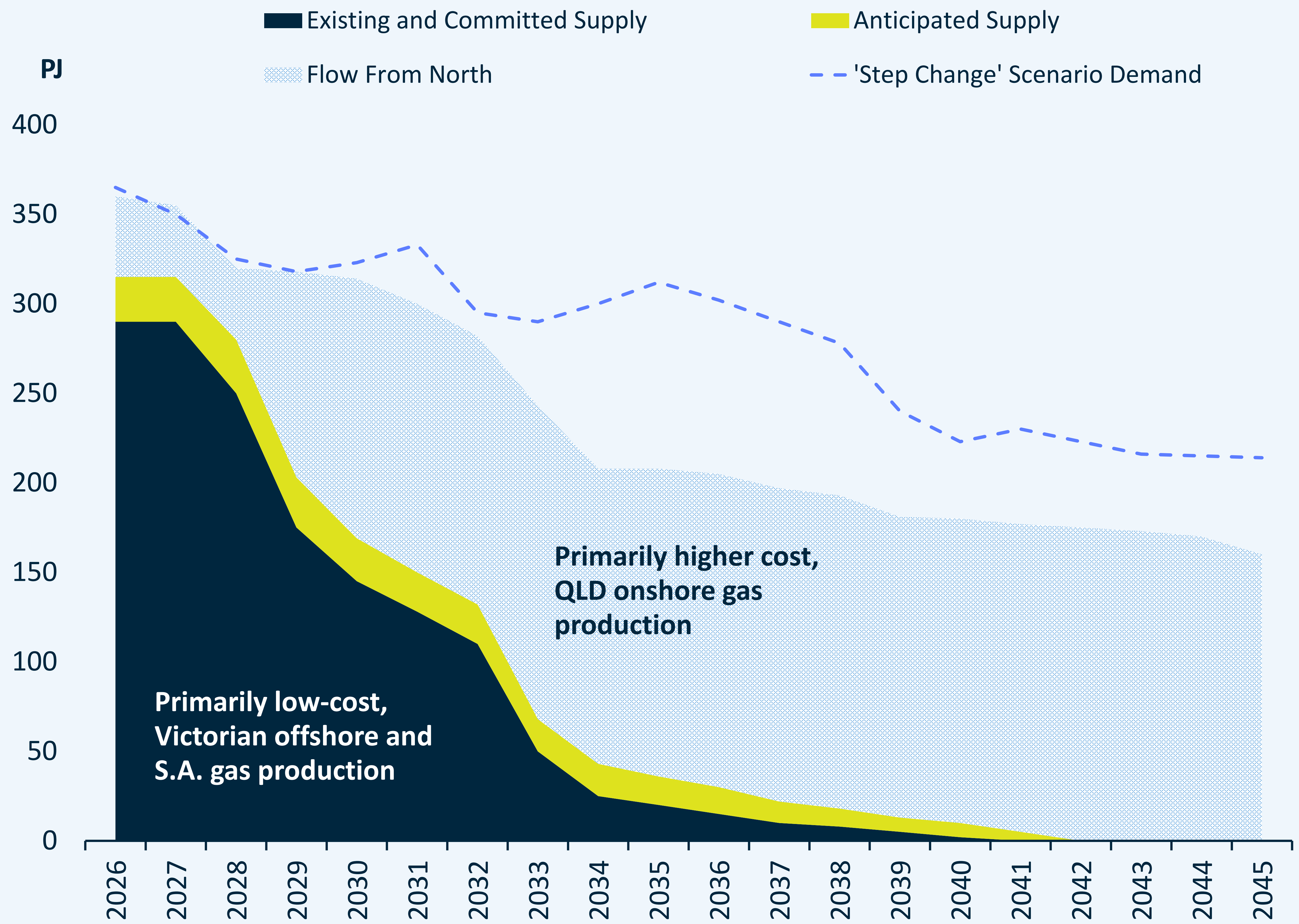
New gas supply in southeastern states required to meet local demand

Domestic gas is the cheapest and lowest emissions option to meet local demand

Australian Southern States contracted gas prices, A$/GJ



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

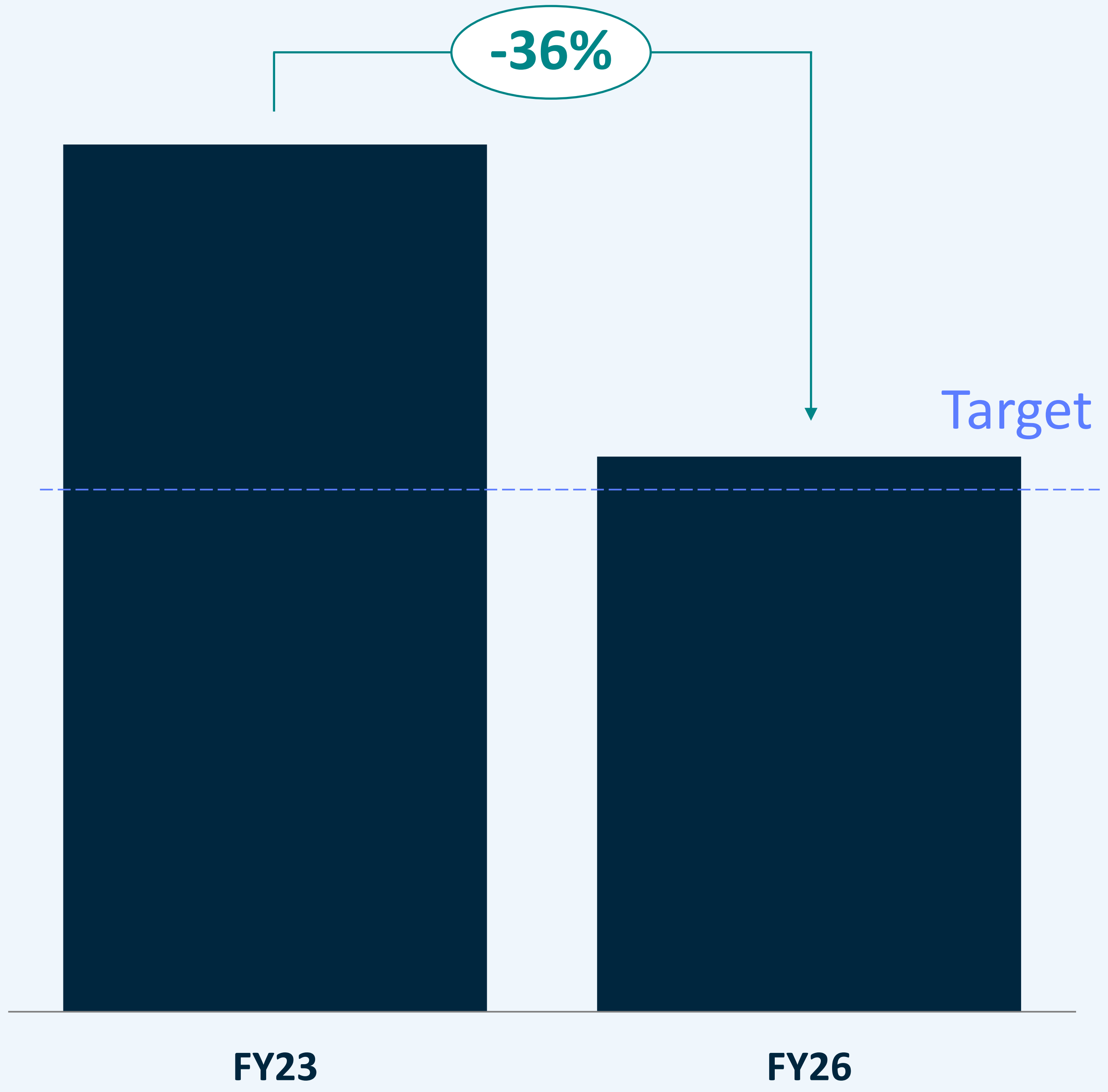


[1] ACCC Gas Inquiry Report, December 2025, Page 28, Chart 2.8 | [2] EnergyQuest, East Coast Gas Outlook 2024, column indicates the “low” and “high” estimates for LNG imports from Port Kembla Energy Terminal into Sydney in 2026 | [3] Platts, LNG Japan / Korea DES Spot Cargo converted from US$/MMBtu to equivalent A$/GJ. | [4] AEMO, 2026 Gas Statement of Opportunities. | [5] Japan/Korea Marker (Asian benchmark reference price for LNG spot sales)

Strong progress on sustainability metrics

Scope 1: Reduce greenhouse gas emissions from flaring by 40% by FY30 from FY23 baseline

- ✓ 36% reduction achieved in FY26



Scope 2: Integrate renewable energy to support AEL operations by FY30 from FY23 baseline[1]

- ✓ Installing behind-the-meter solar PV at AGP
- ✓ In FEED on solar + battery project at OGPP

Athena Gas Plant

Other sustainability metrics

- ✓ FY26 Scope 1 and Scope 2 emissions offset[2]
- ✓ 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] This target concerns integrating renewable energy at each site, which will meet a portion of onsite energy requirements. | [2] Verified Carbon Units were retired at the end of H1 FY26 and H2 FY26 to voluntarily offset the Company's estimated FY26 Scope 1 and Scope 2 emissions. Scope 3 emissions are not offset. More information regarding Scope definitions is available on pages 92-93 of the Company's FY26 Annual Report.

Otway Basin prospective resource targets

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]	
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]			152.8	76.5	255.3	127.8	275.4	137.8	427.6	213.9	

Note: Effective date: 30 June 2026, unless otherwise specified. AEL is not aware of any new information or data that materially affects the information included in the prior market announcement, and all material assumptions and technical parameters underpinning the estimates continue to apply and have not materially changed. The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both a 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 recoverable hydrocarbons.

[1] Prepared in accordance with SPE-PRMS. Reserves and resources information has been prepared by, or under the supervision of, a Qualified Petroleum Reserves and Resources Evaluator (as identified in the Important Notice) and is included with the evaluator's consent. Units: gas volumes in Bcf or PJ. Conversion: 1PJ = 0.163417 MMboe (as disclosed in the important notice). The Low (P90), Mid (P5 0), Mean and High (P10) prospective resource estimates, and net share of each prospect, were announced to ASX on 9 February 2022. Prospective resource estimates were prepared using the probabilistic method. | [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. Prospective resources are reported net of contractual royalties and of volumes lifted on behalf of royalty owners.| [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. Note: The aggregate low estimate may be a very conservative estimate and the aggregate high estimate may be a very optimistic estimate due to the portfolio effects of arithmetic summation

Appendix B

Additional financial information

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%

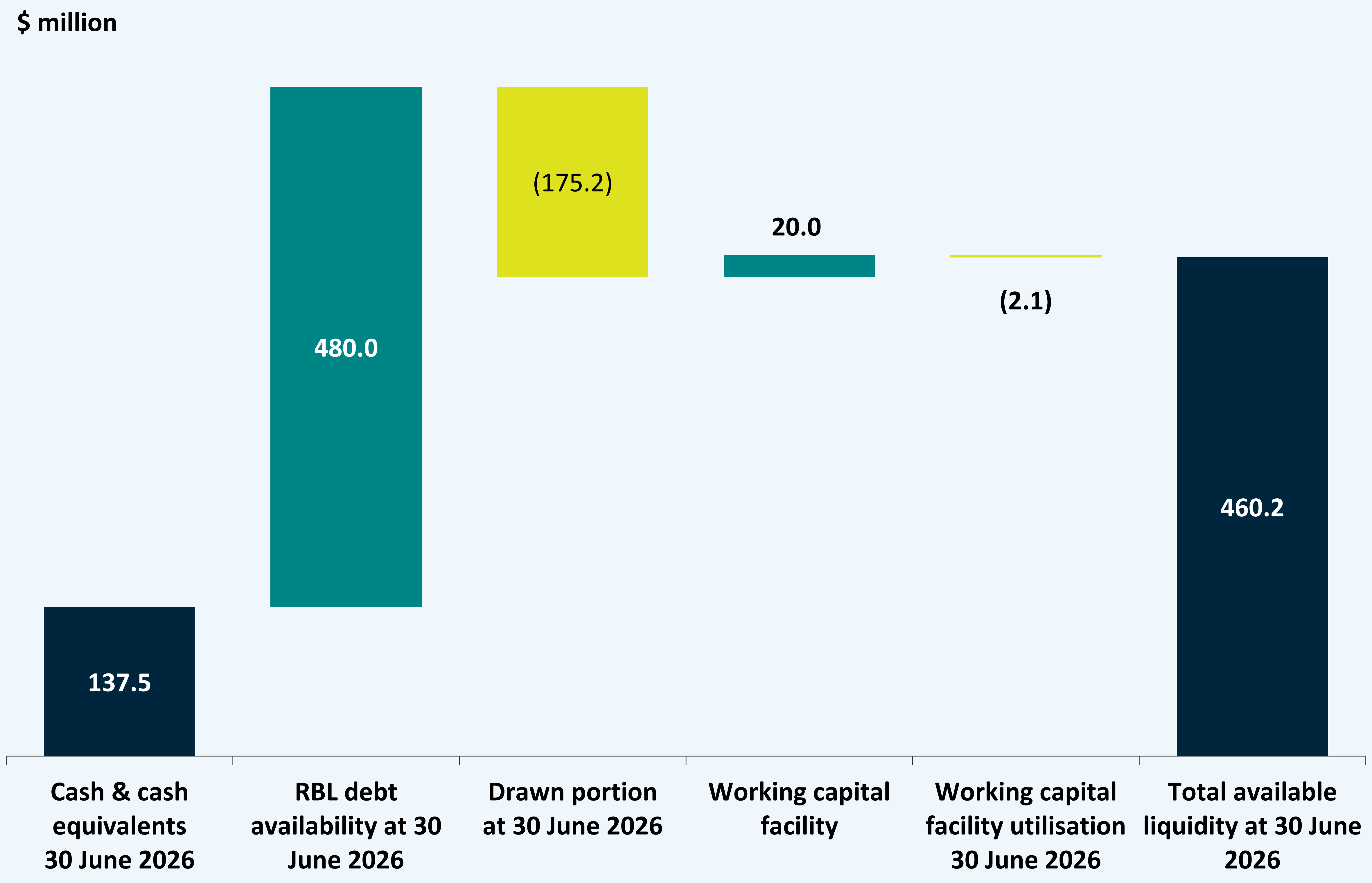
Intention to maximise future debt availability by optimising RBL parameters

- 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 June 2026



Reconciliations

Reconciliation To Underlying EBITDAX

$mm	FY25	**FY26**
Underlying net profit after tax[1]	**9.1**	**45.0**
Adjusted for:		
Net finance costs	25.7	**16.2**
Accretion expense	9.9	**17.7**
Tax expense / (benefit)	17.1	**(25.5)**
Depreciation	48.3	**32.7**
Amortisation	65.2	**72.7**
Exploration and evaluation expense	0.3	-
Tax adjustments to generate underlying profit	(4.0)	**33.0**
Total underlying adjustments after tax	**162.5**	**146.8**
Underlying EBITDAX[1]	**171.6**	**191.8**

Reconciliation To Underlying Profit

$mm	FY25	**FY26**
Statutory net profit/(loss) after income tax	**(41.3)**	**(27.2)**
Adjusted for:		
Exploration and evaluation expense	-	106.3
Business restructuring and transformation	2.6	-
Asset write-off	5.4	-
Restoration expense and associated costs	11.0	(6.4)
Impairment	27.4	5.3
Derecognition of deferred income tax asset	18.6	(1.4)
Tax impact of adjustments	(14.6)	(31.6)
Total significant items after tax	**50.4**	**72.2**
Underlying profit after tax[1]	**9.1**	**45.0**

[1] From H1 FY26, the Company is no longer adjusting for the NOGA levy in its underlying results due to it being a recurring expense. As a result of this, the FY25 comparatives have been re-stated, resulting in a decrease of $2.3 million on a pre-tax basis and $1.6 million on a post-tax basis

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 & 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.

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