AGL Energy Limited
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ASX & Media Release

Financial Results – Half-Year Ended 31 December 2025

11 February 2026

Attached are the following documents relating to AGL Energy Limited's results for the half-year ended 31 December 2025:

- Appendix 4D
- Half-Year Report

Authorised for release by AGL's Board of Directors.

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About AGL Energy

At AGL, we believe energy makes life better and are passionate about powering the way Australians live, move and work. Proudly Australian for more than 185 years, AGL supplies around 4.7 million[1] energy, telecommunications and Netflix customer services. AGL operates Australia's largest private electricity generation portfolio within the National Electricity Market, comprising coal and gas-fired generation, renewable energy sources such as wind, hydro and solar, and batteries and other firming and storage technology. We are building on our history as one of Australia's leading private investors in renewable energy to be a leader in the transition to a lower emissions and smart energy future in line with the goals of our Climate Transition Action Plan. We'll continue to innovate in energy and other services to enhance the way Australians live, work and move.

For more information visit agl.com.au

[1] Services to customers number is as at 31 December 2025.

Appendix 4D

AGL Energy Limited

ABN 74 115 061 375

Half-year Report

Results for announcement to the market
for the half-year ended 31 December 2025

				31 December 2025 $A million	31 December 2024[1] $A million
Revenue	**Down**	**0.9%**	to	**7,044**	7,110
Statutory Profit after tax attributable to shareholders	**Down**	**42.0%**	to	**94**	162
Underlying Profit after tax attributable to shareholders	**Down**	**6.4%**	to	**353**	377
				31 December 2025 cents	31 December 2024[1] cents
Statutory Earnings per share	**Down**	**41.9%**	to	**14.0**	24.1
Underlying Earnings per share	**Down**	**6.3%**	to	**52.5**	56.0
				31 December 2025 $A	30 June 2025[1] $A
Net tangible asset backing per share[2]	**Down**	**1.4%**	to	**2.07**	**2.10**
				Amount cents	Franked amount cents
Interim dividend per ordinary share				24.0	24.0
Prior interim dividend per ordinary share				23.0	23.0

[1] Balances have been restated to reflect the accounting adjustments as described in Note 1.5 of the Half-Year Financial Report.
[2] Net tangible asset backing per share includes lease right-of-use assets.

Record date for determining entitlements to the interim dividend:
25 February 2026 and payable 26 March 2026.

Brief explanation of Underlying Profit after tax and Underlying Earnings per share:
Statutory Profit after tax and Statutory Earnings per share are prepared in accordance with the Corporations Act 2001 and Australian Accounting Standards, which comply with International Financial Reporting Standards.

Statutory Profit after tax of $94 million includes $116 million loss after tax treated as significant items and a loss of $143 million after tax from the changes in the fair value of financial instruments. Excluding these items, the Underlying Profit after tax was $353 million, 6.4% down on the prior corresponding period.

Underlying Profit after tax is reported to give information to shareholders that provides a greater understanding of the performance of AGL Energy Limited's (AGL's) operations. AGL believes Underlying Profit after tax is useful as it removes significant items and timing mismatches between the fair value of derivatives and the underlying asset being hedged thereby facilitating a more representative comparison of financial performance between financial periods.

This report should be read in conjunction with the AGL Directors' Report (including the Operating and Financial Review) and the Half-Year Financial Report for the period ended 31 December 2025 released to the market on 11 February 2026.

The consolidated financial statements contained within the Half-Year Report, of which this report is based upon, have been reviewed by PricewaterhouseCoopers.

AGL Energy Half-Year Report

for the period ended 31 December 2025

ABN 74 115 061 375

agl Join the change

Contents

Acknowledgement of Country

AGL recognises the First Nations people as the Traditional Custodians of the lands on which we work, and acknowledges those communities' continuing connections to their lands, waters and cultures. We pay our respects to their Elders, past and present.

Directors' Report

for the half-year ended 31 December 2025

In accordance with a resolution of the Board, the Directors present their report on the consolidated entity consisting of AGL Energy Limited (AGL) and its controlled entities at the end of or during the half-year ended 31 December 2025 (the period). Financial comparisons used in this report are of results for the half-year ended 31 December 2024 (the prior corresponding period) for statement of profit or loss and cash flow analysis, and 30 June 2025 for statement of financial position analysis.

Directors in Office

The Directors of AGL Energy Limited who held office during or since the end of the half-year were:

	First Appointed
Current Directors	
Miles George	19 September 2022 (appointed as Chair with effect from 13 February 2025)
Damien Nicks	19 January 2023
Mark Bloom	1 July 2020
Graham Cockroft	1 January 2022
Vanessa Sullivan	1 March 2022
Christine Holman	15 November 2022
John Pollaers	15 November 2022
Kerry Schott	15 November 2022 (retired on 3 October 2025)
Mark Twidell	15 November 2022
Elizabeth (Betsy) Donaghey	3 October 2025

Review and results of operations

A review of AGL's operations during the half-year and the results of those operations is set out in the Operating & Financial Review, commencing on page 5.

During the period, the Group reviewed and restated its accounting relating to the classification of a number of renewable Power Purchase Agreements (PPAs). Refer to Section 5 of the Operating & Financial Review on page 30 and Note 1.5 of Notes to the Financial Statements on page 39 for further information.

Subsequent events

On 11 February 2026, AGL announced that it had entered into a binding agreement for the sale of certain telecommunications customer contracts and associated assets of Southern Phone Company Limited for $115 million, with consideration to be received in the form of equity instruments of the purchaser, a member of the Aussie Broadband Limited Group. Completion is anticipated in calendar year 2026, subject to customary conditions.

Apart from the matter identified above and in this Directors' Report and the Half-Year Financial Report, the Directors are not aware of any other matter or circumstance that has arisen since 31 December 2025 that has significantly affected or may significantly affect the operations of AGL, the results of those operations, or the state of affairs of AGL in the future.

Dividends

The Directors have declared an interim dividend of 24.0 cents per share, compared with 23.0 cents per share for the prior interim dividend. The dividend will be fully franked and will be paid on 26 March 2026. Shares will commence trading ex-dividend on 24 February 2026. The record date to determine shareholders' entitlements to the interim dividend is 25 February 2026.

AGL's dividend policy is to target a payout ratio of between 50% to 75% of annual Underlying Profit after tax. Before declaring the dividend, the Directors satisfied themselves that: AGL's assets exceeded its liabilities immediately before declaring the dividend and the excess was sufficient for the payment of the dividend; the payment of the dividend was fair and reasonable to AGL's shareholders as a whole; and the payment of the dividend would not materially prejudice AGL's ability to pay its creditors.

The AGL Dividend Reinvestment Plan (DRP) will not operate in respect of the 2026 interim dividend.

Non-IFRS Financial Information

The Operating & Financial Review attached to and forming part of this Directors' Report includes a number of non-International Financial Reporting Standards (IFRS) financial measures. AGL management uses these non-IFRS financial measures to assess the performance of the business and make decisions on the allocation of resources.

Principal among these non-IFRS financial measures is Underlying Profit. This measure is Statutory Profit/(Loss) adjusted for:

- significant items (which are material items of revenue or expense that are unrelated to the underlying performance of the business); and
- changes in the fair value of financial instruments recognised in the statement of profit or loss (to remove the volatility caused by mismatches in valuing financial instruments and the underlying asset differently).

AGL believes that Underlying Profit provides a better understanding of its financial performance than Statutory Profit/(Loss) and allows for a more relevant comparison of financial performance between financial periods.

Underlying Profit is presented with reference to the Australian Securities & Investment Commission (ASIC) Regulatory Guide 230 "Disclosing non-IFRS financial information", issued in December 2011. AGL's policy for reporting Underlying Profit is consistent with this guidance. The Directors have had the consistency of the application of the policy reviewed by the external auditor of AGL.

Rounding

AGL is an entity to which ASIC Corporations Instrument 2016/191 applies and, in accordance with that Instrument, amounts in the Half-Year Financial Report and this Directors' Report have been rounded to the nearest million dollars, unless otherwise stated.

Auditor's Independence Declaration

A copy of the Auditor's Independence Declaration as required under section 307C of the Corporations Act 2001 is set out on page 66

Miles George
Chair
11 February 2026

Operating & Financial Review
For the half-year ended 31 December 2025

Principal activities
The principal activities of AGL as of the reporting date comprised the operation of energy businesses and investments, including electricity generation, energy storage, the sale of electricity and gas to residential, business and wholesale customers and the retailing of broadband and mobile services.

1. Key Operating Metrics

Key Operating Metrics – These performance measures have a direct influence on AGL's H126 financial performance. The six key operating metrics comprise:

- Customer numbers and churn;
- Customer energy demand;
- Wholesale electricity prices;
- Generation volumes;
- Fuel costs; and
- Operating costs and capital expenditure.

1.1 Key Operating Metrics performance
A summary of performance in relation to the six key operating metrics over H126 is provided in the following sections.

1.1.1 Customer numbers and churn
Total services to customers increased 2.4% to 4.668 million, from 4.560 million as at 30 June 2025. The increase of 108,000 services was driven by strong energy service growth of 56,000 due to the acquisition of Ampol Energy's consumer base and underlying growth of 11,000, continued telecommunication services growth of 27,000 and Netflix services growth of 24,000.

Consumer Electricity services increased by 49,000, supported by gains in New South Wales and Queensland following the acquisition of Ampol Energy's consumer base, and a further 12,000 increase in Victoria driven by targeted growth. Consumer Gas services increased by 7,000, with growth of 10,000 in Victoria partly offset by a decline of 4,000 services in New South Wales.

Total Telecommunication services increased 7% to 408,000, from 380,000 as at 30 June 2025. The increase of 28,000 was driven by continued growth in broadband and mobile plans.

Services to customers	H126 ('000)	FY25 ('000)
Consumer Electricity	**2,573**	2,524
New South Wales	**898**	882
Victoria	**861**	849
South Australia	**352**	356
Queensland	**462**	437
Consumer Gas	**1,565**	1,558
New South Wales	**608**	612
Victoria	**615**	605
South Australia	**145**	143
Queensland	**85**	86
Western Australia	**112**	112
Total Consumer energy services	**4,138**	4,082
Dual fuel services[1]	**2,321**	2,318
Average consumer energy services	**4,137**	4,094
Total Large Business energy services	**15**	15
Total energy services	**4,153**	4,097
Total Telecommunication services	**408**	380
Total Other services[2]	**107**	83
Total services to customers[3]	**4,668**	4,560

1. Dual fuel volumes have been restated to align with current industry conventions.
2. Other services relate to Netflix services.
3. Excluding approximately 303,000 services to ActewAGL customers.

AGL churn remains lower than Rest of Market due to a focus on customer retention, improved customer experience and bundled offerings, which delivered significantly lower churn compared to energy only customers. AGL churn increased to 16.9% (an increase of 1.2 ppts from 15.7% at 30 June 2025), broadly in line with elevated churn across the market driven by FY26 price increases. Despite the uplift, AGL continues to maintain a strong relative position, with AGL churn 5.3 ppts lower than Rest of Market.

1.1.2 Customer energy demand

Total electricity customer sales volumes were 18,422 GWh, up 250 GWh or 1.4%.

- Consumer customer electricity sales volumes were 7,515 GWh, up 286 GWh or 4.0%, driven by an increase in average consumption and higher average services across the period.
- Large Business customer electricity sales volumes were 4,118 GWh, down 255 GWh or 5.8%, primarily driven by change in customer mix.
- Wholesale customer electricity sales volumes were 6,789 GWh, up 219 GWh or 3.3%, driven by higher consumption from AGL's wholesale customer base. This includes sales volumes for contracts with ActewAGL (H126: 919 GWh; H125: 854 GWh), and the Portland and Tomago aluminium smelters.

Customer electricity demand	H126 GWh	H125 GWh
Consumer customers electricity sales	**7,515**	7,229
Large Business customers electricity sales	**4,118**	4,373
Wholesale customers electricity sales	**6,789**	6,570
Total customer electricity sales volume	**18,422**	18,172

Total gas customer sales volumes were 54.3 PJ, up 0.6 PJ or 1.1%.

- Consumer customer gas sales volumes were 26.7 PJ, up 1.9 PJ or 7.7%, driven by higher average demand due to weather and higher average services across the period.
- Large Business customer gas sales volumes were 7.3 PJ, down 2.7%, primarily driven by competitive market conditions.
- Wholesale customer gas sales and internal gas volumes for power generation were 20.3 PJ, down 1.1 PJ or 5.1%, primarily driven by the roll-off of wholesale customer volumes, along with lower usage for power generation. This was partly offset by wholesale customer growth in Western Australia.

Customer gas demand	H126 PJ	H125 PJ[1]
Consumer customers gas sales	**26.7**	24.8
Large Business customers gas sales	**7.3**	7.5
Wholesale customers gas sales and generation	**20.3**	21.4
Total customer gas sales volume	**54.3**	53.7

1. Comparatives have been restated to reclass Perth Energy wholesale gas volume from Large Business to Wholesale.

1.1.3 Wholesale electricity prices

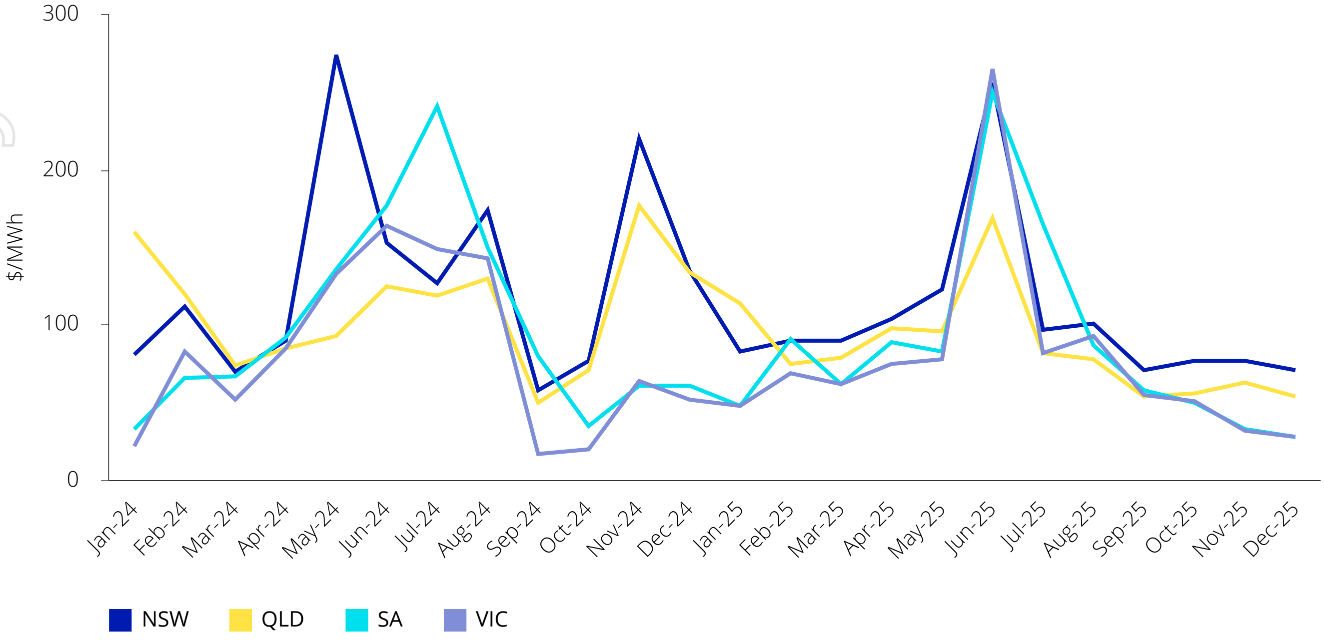
Wholesale electricity spot prices were on average lower across all states compared to the prior corresponding period due to lower volatility, and a reduction in interconnector issues and power station outages, which have previously placed upward pressure on prices.

Wholesale electricity prices in July and August 2024 were influenced by periods of significant volatility in South Australia due to interconnector constraints, cold weather, low wind generation, as well as planned and unplanned outages. Prices decreased in September and October 2024 as lower demand, mild weather, higher solar irradiance and higher wind volumes resulted in lower average pool prices across all regions. In November and December 2024, demand increased due to warmer weather in the northeastern regions. Average prices increased, with periods of significant volatility in New South Wales and Queensland regions. As a result, AEMO facilitated market responses due to the lack of reserve levels with a number of baseload and interconnector outages.

Prices in July 2025 traded lower due to strong renewable output whilst South Australia experienced high prices and some periods of volatility, driven by interconnector constraints. August 2025 recorded high demand and unplanned baseload outages but prices remained relatively stable. September to November 2025 recorded low average prices with New South Wales and Queensland experiencing short periods of volatility in November, while December 2025 saw prices decrease in Victoria and South Australia due to lower demand driven by colder weather and higher solar output.

Refer to Section 4.2 for details of the Electricity Portfolio Margin, including commentary on customer network and generation running costs.

Wholesale electricity prices (AEMO spot prices)



1.1.4 Generation volumes

AGL's generation mix has shifted towards higher renewable output, and reducing coalfired generation. Generation volumes sold to the pool were 15,397 GWh, a decrease of 2.8%. Lower generation at AGL's Coal power stations, due to lower commercial utilisation on higher availability, and lower running at Torrens Island Power Station was partly offset by higher wind generation in New South Wales due to the commencement of Rye Park Wind Farm operations, and increased availability across AGL's Victorian wind farm portfolio.

Pool generation volumes	H126 GWh	H125 GWh
Bayswater Power Station	**6,528**	7,035
AGL Loy Yang Power Station	**5,617**	5,704
Gas generation	**548**	741
Renewable generation[1]	**2,704**	2,362
Total pool generation volumes	**15,397**	15,842

1. Includes volumes from AGL's electricity generation portfolio contracted through Power Purchase Agreements.

1.1.5 Fuel costs

Total fuel costs for the electricity generation portfolio were $(353) million, down 3.8%.

- Coal costs were $(289) million, down 0.3%, primarily driven by lower generation at Bayswater Power Station due to lower commercial utilisation, offset by higher coal supply costs at Bayswater Power Station. On a per MWh basis, costs increased by $1.0 per MWh or 4.4%, driven by higher coal supply costs at Bayswater.
- Gas fuel costs were $(64) million, down 16.9%, driven by lower generation volumes at Torrens Island Power Station due to lower commercial utilisation. On a per MWh basis, costs increased by 12.4%, mainly due to enablement requirements from AEMO. AEMO also frequently requests Torrens Island Power Station units to be enabled for system security in South Australia. Costs relating to enablement requirements are recovered through revenue.

Generation fuel costs	H126 $m	H125 $m	H126 $/MWh	H125 $/MWh
Coal	**(289)**	(290)	**(23.8)**	(22.8)
Gas	**(64)**	(77)	**(116.8)**	(103.9)
Total generation fuel costs	**(353)**	(367)	**(22.9)**	(23.2)

Total wholesale gas costs were $(618) million, down 0.2%.

- Gas purchases costs were $(449) million, up 1.6%, mainly driven by increased consumer demand, along with rising gas costs due to the roll-off of lower cost legacy supply contracts. On a per GJ basis, costs increased by $0.1 per GJ, or 1.2%, driven by the roll-off of lower cost legacy supply contracts.
- Haulage, storage and other costs were $(169) million, down 4.5% driven by lower haulage capacity required following the roll-off of wholesale customers and large business customers. This was partly offset by haulage contracts rate escalation. On a per GJ basis, costs decreased by $0.2 per GJ or 6.1%, due to lower fixed costs spread across a higher customer base.

Total wholesale gas costs	H126 $m	H125 $m	H126 $/GJ	H125 $/GJ
Gas purchases	**(449)**	(442)	**(8.3)**	(8.2)
Haulage, storage and other	**(169)**	(177)	**(3.1)**	(3.3)
Total wholesale gas costs	**(618)**	(619)	**(11.4)**	(11.5)

1.1.6 Operating costs and capital expenditure

Total operating costs (excluding depreciation and amortisation) were $(877) million, down 3.0%, driven by the impact of organisation-wide productivity and optimisation initiatives and the divestment of the Surat Gas Project. This was partly offset by higher underlying net bad debt expense and continued investment in Cloud and Software as a Service (SaaS).

Operating costs	H126 $m	H125 $m
Customer Markets	**(311)**	(324)
Integrated Energy	**(396)**	(417)
Centrally Managed Expenses	**(170)**	(163)
Total operating costs (excluding depreciation and amortisation)	**(877)**	(904)

Total capital expenditure was $652 million, a decrease of $15 million:

- Sustaining capital expenditure was $438 million, an increase of $68 million. This included $343 million of expenditure on AGL's thermal power stations, up $44 million, due to an increase of $70 million on the FY26 major outages program. This was primarily due to turbine installations and an overhaul at AGL Loy Yang Power Station, an additional minor outage at Bayswater Power Station and additional work to minimise emissions. This increase was partly offset by the completion of the ash landfill cell at AGL Loy Yang Power Station in FY25.
- Growth capital expenditure was $213 million, a decrease of $84 million, primarily driven by a reduction in Liddell Battery costs as the project nears completion. This was partly offset by work commencing on the Tomago Battery having reached Final Investment Decision, and the purchase of turbines for the Kwinana Swift Gas 2 project.

Capital expenditure	H126 $m	H125 $m
Customer Markets	**53**	61
Integrated Energy	**558**	582
Centrally Managed Expenses	**40**	24
Total capital expenditure	**652**	667
Sustaining	**438**	370
Growth	**213**	297
Total capital expenditure	**652**	667

2. Group Financial Performance and Position

2.1 Group results summary

Statutory Profit after tax attributable to AGL shareholders was $94 million, a decrease of $68 million compared to the Statutory Profit of $162 million in the prior corresponding period. The principal drivers of the decrease were negative movements in the fair value of financial instruments and lower Underlying Profit after tax primarily driven by lower Trading & Origination – Electricity gross margin, higher depreciation and higher net financing costs.

2.1.1 Reconciliation of Statutory Profit to Underlying Profit

AGL uses Underlying Profit as a key measure of financial performance. Underlying Profit is derived from Statutory Profit, as measured in accordance with Australian Accounting Standards, and excluding significant items and movements in the fair value of financial instruments. The use of Underlying Profit enhances comparability of results by excluding non-recurring events and transactions that materially affect the financial results of AGL for the reporting period.

Underlying Profit after tax was $353 million, down 6.4% from the prior corresponding period. A description of the factors driving Underlying Profit is included in Section 2.1.4.

	H126 $m	H125 $m[1]
Statutory Profit after tax attributable to AGL shareholders	**94**	162
Adjusted for:		
Significant items after tax	**116**	160
Loss on fair value of financial instruments after tax	**143**	55
Underlying Profit after tax	**353**	377
Earnings per share on Statutory Profit	**14.0 cents**	24.1 cents
Earnings per share on Underlying Profit	**52.5 cents**	56.0 cents

1. Restated to reflect the accounting adjustment as described in Section 5.

Earnings per share (EPS) calculations have been based upon a weighted average number of ordinary shares of 672,747,233 (31 December 2024: 672,747,233).

2.1.2 Significant items

AGL recognised significant items of $(161) million, or $(116) million post-tax, primarily related to costs associated with the Retail Transformation Program and an increase in onerous contract provisions.

	H126 $m		H125 $m[1]	
	Pre-tax	Post-tax	Pre-tax	Post-tax
Retail Transformation	**(64)**	**(45)**	(64)	(45)
Revaluation of onerous contracts	**(59)**	**(42)**	(114)	(80)
Business restructuring and transactions	**(12)**	**(8)**	(8)	(7)
Impairments	**(17)**	**(15)**	(4)	(3)
Rehabilitation provision	**(9)**	**(6)**	-	-
Legal penalties	**-**	**-**	(25)	(25)
Total significant items	**(161)**	**(116)**	(215)	(160)

1. Restated to reflect the accounting adjustment as described in Section 5.

H126

During the period AGL recognised:

- $55 million pre-tax ($39 million post-tax) of costs related to the Retail Transformation Program and $9 million pre-tax ($6 million post-tax) for other transition costs.
- $59 million pre-tax ($42 million post-tax) for the revaluation of onerous provision relating to renewable asset power purchase agreements.
- $19 million pre-tax ($14 million post-tax) related to business restructuring activities, $6 million pre-tax ($4 million post-tax) for transaction and integration costs, partly offset by $6 million ($4 million post-tax) gain from the divestment of Waddi Wind Farm and $7 million pre-tax ($5 million post-tax) related to the derecognition of Bowmans Creek Wind Farm development project.
- $12 million pre-tax ($12 million post-tax) impairment loss for the Gippsland Skies Joint Venture and $5 million pre-tax ($3 million post-tax) in relation to costs for Torrens Island Power Station closure.
- $9 million pre-tax ($6 million post-tax) increase in rehabilitation provisions for which the rehabilitation assets were previously impaired.

H125

During the period AGL recognised:

- $59 million pre-tax ($41 million post-tax) of costs related to the Retail Transformation Program and $5 million pre-tax ($4 million post-tax) related to other transition costs.
- An increase in the onerous contract provision of $114 million pre-tax ($81 million post-tax) related to various renewable power purchase agreements primarily due to a decrease in large-scale generation certificate forward prices.
- $8 million pre-tax ($7 million post-tax) related to transaction and integration costs for the acquisition of Terrain Solar, Firm Power and other investments.
- $4 million pre-tax ($3 million post-tax) in costs related to the additional impairment of assets related to the Surat Gas Project which substantially divested in March 2025.
- $25 million pre-tax ($25 million post-tax) related to the Court ordered penalty in legal proceedings initiated by the Australian Energy Regulator (AER) in relation to Centrepay payments.

2.1.3 Earnings Before Interest and Tax (EBIT)

	H126 $m	H125 $m[1]
Statutory EBIT	**316**	404
Significant items	**161**	215
Loss on fair value of financial instruments	**205**	80
Underlying EBIT	**682**	699
Customer Markets	**163**	102
Integrated Energy	**713**	783
Investments	**9**	9
Centrally Managed Expenses	**(203)**	(195)
Underlying EBIT	**682**	699

1. Restated to reflect the accounting adjustment as described in Section 5.

2.1.4 Group financial performance

Underlying Profit after tax attributable to AGL shareholders was $353 million, down 6.4%. The principal drivers of the decrease were lower gross margin within the Trading and Origination - Electricity portfolio driven by lower generation due to lower commercial utilisation on higher availability at Bayswater Power Station and lower volatility captured compared to the prior corresponding period, as well as lower Eco Markets gross margin. This was partly offset by higher Consumer margin, driven by customer growth and higher revenue rates, and lower operating costs driven by enterprise-wide productivity and optimisation initiatives.

	H126 $m	H125 $m[1]
Revenue	**7,044**	7,110
Cost of sales	**(5,084)**	(5,120)
Other income	**9**	11
Gross margin	**1,969**	2,001
Operating costs (excluding depreciation and amortisation)	**(877)**	(904)
Underlying EBITDA	**1,092**	1,097
Depreciation and amortisation	**(410)**	(398)
Underlying EBIT	**682**	699
Net finance costs	**(181)**	(163)
Underlying Profit before tax	**501**	536
Income tax expense	**(148)**	(159)
Underlying Profit after tax	**353**	377

1. Restated to reflect the accounting adjustment as described in Section 5.

Refer to Section 3 for further analysis on the movement in gross margin for each operating segment and Section 1.1.6 for commentary on Group operating costs.

Depreciation and amortisation of $(410) million was up 3.0%, driven by a higher asset base at AGL Loy Yang and Bayswater power stations due to increased investment to deliver reliability and flexibility, partly offset by a decrease in environmental rehabilitation assets primarily at AGL Loy Yang with confirmation of the bulk water entitlement costs.

Net finance costs were $(181) million, up 11.0% primarily driven by higher debt facility costs.

Underlying tax expense was $(148) million, primarily reflecting the decrease in Underlying Profit before tax, resulting in an effective tax rate of 29.4%.

2.2 Cash flow

2.2.1 Reconciliation of Underlying EBITDA to cash movement

Operating cash flow before significant items, interest and tax was $836 million, up $24 million. The rate of conversion of EBITDA to cash flow was 77%, up from 74% in the prior corresponding period. Adjusting for margin calls and rehabilitation, the cash conversion rate was 91%, up from 67% in the prior corresponding period.

		H126 $m		H125 $m[1]
Underlying EBITDA		**1,092**		1,097
Equity accounted income (net of dividends received)		**(3)**		(2)
Accounting for onerous contracts		**(31)**		(11)
Other assets/liabilities and non-cash items[2]		**(7)**		(377)
Payments for rehabilitation		**(42)**		(44)
Working capital movements				
Decrease in receivables	**134**		146	
(Decrease) in payables	**(111)**		(25)	
(Increase) in inventories	**(60)**		(20)	
Net derivative premiums (paid)	**(25)**		(32)	
(Increase)/decrease in financial assets (margin calls)	**(117)**		123	
Net movement in green assets/liabilities	**17**		(6)	
Other working capital movements	**(11)**		(37)	
Total working capital movements		**(173)**		149
Operating cash flow before significant items, interest and tax		**836**		812
Net finance costs paid		**(116)**		(92)
Income taxes		**(85)**		(153)
Cash flow relating to significant items		**(90)**		(72)
Net cash provided by operating activities[3]		**545**		495
Net cash used in investing activities		**(758)**		(883)
Net cash provided by/(used in) financing activities		**201**		(291)
Net (decrease)/increase in cash and cash equivalents		**(12)**		(679)

1. Restated to reflect the accounting adjustment as described in Section 5.
2. Includes government bill relief of $381 million received in June 2024 which was remitted to customers during H125 and H126. A residual of approximately $124 million remaining as credits on customer accounts within payables as at 31 December 2024 and $26 million remaining as credits as at 31 December 2025.
3. Net cash provided by operating activities includes the effect of exchange rate changes on the balance of cash held in foreign currencies.

Total working capital movements were $(173) million, compared to $149 million in the prior corresponding period. Components of working capital movement were:

- Receivables cash flow of $134 million reflected an increase in debtors primarily driven by seasonality of consumer consumption which resulted in higher opening receivables balance at 1 July 2025 compared to 31 December 2025.
- Payables cash flow of $(111) million primarily reflected a decrease in payables driven by higher consumer network payments and AGL Loy Yang mine coal royalty payments, partly offset by increased solar PV system and battery inventory purchases to support consumer electrification.
- Inventory cash flow of $(60) million reflected increased solar PV system and battery inventory purchases to support consumer electrification following changes in government rebates, and an increase in price of contracted coal deliveries.
- Net derivative premiums paid of $(25) million reflected premiums associated with future hedging requirements, primarily over the counter derivatives.
- Financial assets/liabilities (margin calls) cash flow of $(117) million reflected the movement of initial and variation margins within the futures book.
- Green assets/liabilities cash flow of $17 million reflected increased sales of Large-Scale Renewable Energy Certificates (LREC), partly offset by higher purchases of Small-Scale Renewable Energy Certificates (SREC).

Accounting for onerous contracts $(31) million primarily reflected the onerous portion of payments made to suppliers under legacy wind farm offtake agreements.

Payments for rehabilitation of $(42) million included payments for the ongoing decommissioning and demolition of the Liddell and Torrens A power stations and rehabilitation of the Liddell Ash Dam, Ravensworth facility and Loy Yang Mine.

Cash tax payment of $(85) million reflected PAYG instalments for FY26 combined with the final tax payment for FY25.

Cash flows relating to significant items of $(90) million primarily reflected costs related to the Retail Transformation Program. Refer to Section 2.1.2 for further details on significant Items.

Investing cash flows of $(758) million primarily reflected capital expenditure, and the acquisition of South Australia's Virtual Power Plant (SA VPP). Refer to Section 1.1.6 for further details on capital expenditure.

Financing activities cash flows of $201 million primarily reflected the issuance of $500 million Australian Medium Term Notes, partly offset by $(168) million of dividend payments and $(152) million US Private Placement repayment.

2.2.2 Operating Free Cash Flow

AGL uses operating free cash flow as a key measure of financial performance to ensure the operational core business generates strong cash flows to support future investment in growth. Operating free cash flow is derived from net cash provided by operating activities excluding working capital movements for margin calls and cash flow related to significant items and adding sustaining capital expenditure on an accruals basis.

Operating free cash flow was $314 million, up $240 million from the prior corresponding period, primarily driven by the unwind of government bill relief to customers in the prior corresponding period and lower tax payments, partly offset by an increase in sustaining capital expenditure and a decrease in net payables.

	H126 $m	H125 $m[1]
Net cash provided by operating activities	**545**	495
Adjust for:		
Working capital movements for margin calls	**117**	(123)
Cash flow related to significant items	**90**	72
Sustaining capital expenditure (accruals basis)	**(438)**	(370)
Operating free cash flow	**314**	74

1. Restated to reflect the accounting adjustment as described in Section 5.

Refer to Section 2.2.1 for a description of the factors driving net cash provided by operating activities, working capital movements for margin calls and cash flow related to significant items. Refer to Section 1.1.6 for commentary on sustaining capital expenditure on an accruals basis.

2.3 Financial position

Summary Statement of Financial Position

At 31 December 2025, AGL's total assets were $15,773 million, a decrease from $16,550 million at 30 June 2025, due to a decrease in trade and other receivables, reflecting lower AEMO net receivables position due to a decrease in prices in December compared to June and reduced generation volumes. This was partly offset by an increase in property, plant and equipment.

AGL's total liabilities at 31 December 2025 were $11,038 million, a decrease from $11,773 million at 30 June 2025, due to a decrease in trade and other payables reflecting lower AEMO related trade payables positions due to a decrease of prices in December compared to June, and a decrease in the environmental rehabilitation provisions. This was partly offset by an increase in borrowings.

Total equity at 31 December 2025 was $4,735 million, down from $4,777 million, primarily reflecting dividends paid, partly offset by the Statutory Profit for the period.

	H126 $m	FY25 $m[1]
Assets		
Cash and cash equivalents	**307**	319
Other current assets	**3,720**	4,133
Property, plant and equipment	**6,573**	6,524
Intangible assets	**3,344**	3,365
Other non-current assets	**1,829**	2,209
Total assets	**15,773**	16,550
Liabilities		
Lease liabilities	**1,104**	1,116
Borrowings	**3,382**	3,039
Other liabilities	**6,552**	7,618
Total liabilities	**11,038**	11,773
Net assets/total equity	**4,735**	4,777

1. Restated to reflect the accounting adjustment as described in Section 5.

2.3.1 Net Debt Reconciliation

Net debt at 31 December 2025 was $3,249 million, up from $2,820 million as of 30 June 2025. Net debt was utilised to fund the acquisition of the SA VPP, and the growth project pipeline which includes the Liddell and Tomago batteries, and the Kwinana Swift Gas 2 project.

AGL's gearing (measured as the ratio of net debt to net debt plus adjusted equity) at 31 December 2025 was 38.5% compared with 34.9% at 30 June 2025. Changes arising from the restatement as described in Section 5 and adoption of AASB 16 *Leases* do not affect the definitions used in the calculation of debt covenants including gearing ratio. AGL remains compliant with all debt covenants.

AGL maintained its credit rating of Baa2 throughout the period as provided by Moody's Investors Service. Key metrics consistent with this credit rating at 31 December 2025:

- Interest cover: 6.4 times
- Funds from operations to net debt: 33.8%

	H126 $m	FY25 $m[1]
Net debt reconciliation		
Borrowings	**3,382**	3,039
Adjustment for lease liabilities[2]	**191**	185
Adjustment for cross currency swap hedges	**(17)**	(85)
Cash and cash equivalents	**(307)**	(319)
Net debt	**3,249**	2,820

1. Restated to reflect the accounting adjustment as described in Section 5.
2. Lease liabilities and retained earnings adjustment as a result of adoption of AASB 16 leases.

2.3.2 Movement in fair value of financial instruments

Approach to hedging

AGL's approach to managing energy price risks, through physical ownership of energy generation, contracting for energy supply and financial hedging, reflects the need to provide pricing certainty to customers and limit exposure to adverse wholesale market outcomes. AGL generates electricity or has contracted gas supply in excess of its customers' demand in some states. In other states, AGL has sources of supply less than its customers' demand.

AGL uses certain financial instruments (derivatives) to manage these energy price risks and to manage its exposure to interest and foreign exchange rates arising in the normal course of business, provided the overall AGL risk appetite is not exceeded. These derivatives do not qualify for hedge accounting under AASB 9 *Financial Instruments*. The majority of these financial instruments exchange a fixed price for a floating market-based price of a given commodity, interest rate, currency or a quoted asset, with the net differential being settled with the counterparty. AGL is exposed to price volatility on the sale and purchase of energy-related commodities in the normal course of business, and therefore enters into contracts that minimise the price risk to AGL on both sold and purchased forecast exposures.

AGL has in place a governance framework that establishes the policy guidelines under which energy hedging activities are conducted. Key components of that policy include segregation of duties, independent risk oversight, earnings-at-risk limits, compliance management and regular reporting to the Board. The risk policy represents AGL's commitment to an effective risk management function to ensure appropriate management and oversight of AGL's risks related to wholesale markets energy risk. The policy allows for commercial optimisation of the portfolio provided that AGL adheres to overall earnings-at-risk limits that reflect its risk appetite.

Energy price risk

AGL's energy-related derivatives recognised in profit or loss include sell and buy positions, where AGL receives or pays a fixed price from or to a counterparty in exchange for a floating price paid or received.

AGL is required to make margin payments in respect of futures contracts traded through the Australian Securities Exchange (ASX). Initial margin call payments are made at the time contracts are entered in order to manage intra-day credit exposure. The quantum of initial margin depends on the volume traded, the expected market volatility as well as forward electricity prices at the time. The initial margin call can move subsequently as forward prices move. AGL also receives or makes payments known as variation margin calls, which cover mark to market movements of AGL's open futures position. These typically reverse through future earnings as contract positions roll off.

Treasury related risk

AGL's treasury related risk primarily relates to interest and foreign currency rate fluctuations. Contracts to minimise the exposure to market-based fluctuations are executed pursuant to AGL's treasury risk management policy. These contracts primarily result in fixed interest rates and foreign currency exchange rates. These contracts are designated in hedge relationships when they can be matched to forecast transactions with sufficient probability of the forecast transaction occurring.

In addition to the above, AGL is counterparty to cross-currency interest rate swap arrangements to convert its fixed interest rate US dollar private placement borrowing instruments to floating interest rate Australian dollar equivalent borrowing instruments. The cross-currency interest rate swap arrangements are designated as fair value and cash flow hedge relationships.

Movement in fair value

The initial fair value of a derivative is the consideration paid or received (the premium). Fair value movements in any given period are a function of changes to underlying indices, market prices or currencies and the roll-off of realised contractual volumes or amounts. A reconciliation of the movements in financial instruments carried at fair value for H126 is presented in the following table.

Net assets/(liabilities)	H126 $m	FY25 $m[1]	Change $m
Energy derivative contracts	**(959)**	(785)	(174)
Treasury derivative contracts	**59**	96	(37)
Total net assets/(liabilities) for financial instruments	**(900)**	(689)	(211)
Change in net assets/(liabilities)	**(211)**		
Premiums paid	**(99)**		
Premium roll off	**74**		
Debt instrument accounted fair value	**(5)**		
Equity accounted fair value	**9**		
Total change in fair value	**(232)**		
Recognised in equity hedge and other reserve	**39**		
Recognised in borrowings	**(68)**		
Recognised in profit or loss – pre-tax	**(203)**		
Total change in fair value	**(232)**		

1. Restated to reflect the accounting adjustment as described in Section 5.

The movement in net derivative assets/(liabilities) in the period of $(211) million is expanded on within the table below.

	Unrealised fair value recognised in:							
	FY25 $m[1]	Profit or loss	Hedge reserve	Borrowings	Currency basis	Premiums and roll offs paid	H126 $m	Change $m
Energy derivative contracts	**(785)**	(199)	–	–	–	25	**(959)**	**(174)**
Treasury derivative contracts	**96**	1	30	(68)	–	–	**59**	**(37)**
Net assets/(liabilities)	**(689)**	**(198)**	**30**	**(68)**	**–**	**25**	**(900)**	**(211)**
Fair value recognised within debt instrument financial assets		(5)	–	–	–	–	**(5)**	
Fair value recognised within equity accounted investments		–	9	–	–	–	**9**	
Profit or loss		**(203)**						
Realised fair value to be recognised in cost of sales		(2)						
Fair value recognised in profit or loss		**(205)**						

1. Restated to reflect the accounting adjustment as described in Section 5.

The fair value movement driving the change in the net derivative liabilities position reflected in unrealised fair value movements is as follows:

- A decrease in the fair value of unrealised energy-related derivatives of $174 million was recognised in profit or loss (excluded from Underlying Profit). The net loss primarily reflected negative fair value movements in Level 1 and 2 electricity, oil and aluminium derivatives. This was partly offset by positive movements in Level 3 valuations, due to net negative cash flows expiring in periods up to 31 December 2025.
- A decrease in fair value of $37 million of treasury derivative contracts was mainly driven by the depreciation of the USD against the AUD and the settlement of matured cross currency interest rate swaps, partly offset by an increase in forward interest rate curves.

3. Segmental Analysis

AGL manages its business in three key operating segments: Customer Markets, Integrated Energy and Investments. Further detail on the activities of each operating segment is provided below.

AGL manages and reports a number of expense items including Technology within Centrally Managed Expenses. These costs are not reallocated to AGL's operating segments because their management is the responsibility of various corporate functions.

A reconciliation of segment results and Underlying Profit after tax is provided in the Consolidated Financial Statements Note 2 Segment information.

3.1 Customer Markets

Customer Markets comprises the Consumer and Large Business customer portfolios responsible for the retailing of electricity, gas, broadband/mobile/voice, solar and energy efficiency products and services to residential, small and large business customers. Customer Markets sources its energy from Integrated Energy at transfer prices that reflect wholesale energy costs in each state, along with energy provided by rooftop solar.

Customer Markets also includes sales, marketing, brand, AGL's customer contact and call centre operations, and AGL's electrification and innovation growth areas.

3.1.1 Underlying EBIT

Customer Markets Underlying EBIT was $163 million, up 59.8% mainly due to higher Consumer Electricity, Consumer Gas and Perth Energy gross margin, and lower operating costs.

	H126 $m	H125 $m
Consumer Electricity gross margin	**297**	270
Consumer Gas gross margin	**152**	138
Large Business Electricity gross margin	**16**	16
Large Business Gas gross margin	**1**	2
Fees, charges and other gross margin	**13**	10
Telecommunications gross margin	**22**	20
Perth Energy gross margin	**28**	23
Sustainable Business Energy Solutions gross margin	**3**	6
Gross margin	**532**	485
Operating costs (excluding depreciation and amortisation)	**(311)**	(324)
Underlying EBITDA	**221**	161
Depreciation and amortisation	**(58)**	(59)
Underlying EBIT	**163**	102

- Consumer Electricity gross margin was $297 million, up 10.0%, driven by customer growth and disciplined customer value management.
- Consumer Gas gross margin was $152 million, up 10.1%, driven by margin initiatives and higher volumes driven by colder weather.
- Large Business Electricity gross margin was $16 million, flat to the prior corresponding period.
- Large Business Gas gross margin was $1 million, down 50%, primarily driven by lower volumes due to competitive market conditions.
- Fees, charges and other gross margin were $13 million, up 30.0%, primarily due to increased sales of battery hardware as a result of the federal government rebate.
- Telecommunications gross margin was $22 million, up 10.0%, driven by growth in telecommunications services and higher margin rates.
- Perth Energy gross margin was $28 million, up 21.7%, driven by higher electricity margin due to higher revenue rates from customer re-contracting as well as higher value achieved from wholesale energy supply from favourable market conditions.
- Sustainable Business Energy Solutions (SBES) gross margin was $3 million, down 50.0%, mainly driven by a one-off gross margin adjustment on legacy contracts. Underlying performance was broadly flat, with project volumes temporarily impacted by extended contract execution timelines, partly offset by higher generation revenue, supported by continued growth in the Energy as a Service (EaaS) asset fleet.
- Depreciation and amortisation was $(58) million, broadly flat to the prior corresponding period.

3.1.2 Operating costs

Customer Markets operating costs (excluding depreciation and amortisation) were $(311) million, down 4.0% driven by the impact of disciplined cost management and initiatives to enhance operational efficiency. This was partly offset by higher net bad debt expense.

	H126 $m	H125 $m
Labour and contractor services	**(127)**	(131)
Net bad debt expense	**(65)**	(58)
Campaigns and advertising	**(65)**	(63)
Other expenditure	**(54)**	(72)
Operating costs (excluding depreciation and amortisation)	**(311)**	(324)
Add: depreciation and amortisation	**(58)**	(59)
Operating costs (including depreciation and amortisation)	**(369)**	(383)

- Labour and contractor services costs were $(127) million, down 3.1% driven by disciplined cost management.
- Net bad debt expense was $(65) million, up 12.1% due to lower government relief receipts compared to the prior corresponding period, higher revenue and impacts of cost-of-living on customer affordability.
- Campaigns and advertising costs were $(65) million, up 3.2% due to a targeted uplift in core marketing and brand spend to support customer retention and growth.
- Other expenditure was $(54) million, down 25.0%, due to lower cost to serve driven by focus on efficiency.

3.1.3 Consumer profitability and operating efficiency

Net operating costs per consumer service was $(58), down 3.3% compared to the prior corresponding period, driven by growth in average services and operational efficiency.

	H126	H125
Gross margin ($m)	**471**	428
Net operating costs ($m)[1]	**(263)**	(267)
EBITDA ($m)	**208**	161
Average consumer services ('000)[2]	**4,540**	4,458
Gross margin per consumer service ($)	**104**	96
Net operating costs per consumer service ($)[2]	**(58)**	(60)
EBITDA per consumer service ($)[2]	**46**	36
Net operating costs as a percentage of gross margin	**55.8%**	62.4%

1. Includes fees, charges, and recoveries. Excludes depreciation and amortisation, and the impact of digital uplift expenses (Software as a Service).
2. Excludes Netflix services.

Average consumer services increased 1.8% compared to the prior corresponding period primarily due to growth in Telecommunications services, and Electricity services due to the Ampol Energy acquisition.

Gross margin per consumer service increased compared to the prior corresponding period, reflecting improved customer value and portfolio management.

3.2 Integrated Energy

Integrated Energy comprises Energy Markets and Development portfolio, responsible for the managing the price risk associated with trading electricity and gas for AGL's customers, for managing AGL's obligations in relation to renewable energy schemes and the development of greenfield renewable and firming projects, and the Energy Assets portfolio, responsible for the construction, operation and decommissioning of AGL's power generation fleet.

Energy Markets and Development, which also controls the dispatch of AGL's owned and contracted generation assets, as well as grid-scale batteries, and the associated portfolio of energy hedging products, includes the following business units:

- Trading and Origination - Electricity reflects the trading of key fuel inputs, hedging of AGL's wholesale electricity requirements, and costs associated with power purchase agreements for solar and wind farms and other assets, as well as virtual storage agreements for batteries. It also includes Eco Markets, which reflects the management of AGL's liabilities relating to both voluntary and mandatory renewable and energy efficiency programs, which is reflected as green compliance costs.
- Trading and Origination - Gas reflects the sourcing and management of AGL's gas supply, storage and transportation portfolio. Trading and Origination - Gas is also responsible for the management of the price exposures related to AGL's oil-linked wholesale gas contracts.
- Power Development is focused on the development of greenfield growth opportunities related to renewable and firming capacity.
- Energy Markets and Development – Other reflects the Trading and Origination resourcing and support, the Decentralised Energy Resources business responsible for the management of other growth initiatives in AGL's orchestration pathway alongside Customer Markets, and the Energy Hubs business focused on the development of the Integrated Energy Hubs at Torrens Island, Latrobe Valley and the Hunter.

Energy Assets includes the following business units:

- Coal primarily comprises Bayswater Power Station and AGL Loy Yang.
- Gas Generation primarily comprises Torrens Island Power Station, Barker Inlet Power Station, Kwinana Swift Power Station and Somerton Power Station. In September 2025, AGL reached a legally binding agreement with the South Australian Government to extend the operational life of Torrens Island Power Station through to 30 June 2028 from the previously announced closure date of 30 June 2026.
- Renewables and Storage primarily comprises hydroelectric power stations, the operation of wind power generation, and the Torrens Island Battery and Broken Hill Battery. Operational costs to maintain the wind farms are reported within Trading and Origination – Electricity to align with the gross margin of the related power purchase agreements.
- Energy Assets - Other primarily consists of the Construction business, and technical and business support functions. It also includes Natural Gas, which primarily comprised of the Surat Gas Project until it was substantially divested in March 2025.

3.2.1 Underlying EBIT

Integrated Energy Underlying EBIT was $713 million, down $70 million or 8.9%, driven by lower Trading and Origination – Electricity and Trading and Origination – Gas margins, and higher depreciation and amortisation. This was partly offset by lower operating costs.

	H126 $m	H125 $m[1]
Gross margin	**1,428**	1,507
Operating costs (excluding depreciation and amortisation)	**(396)**	(417)
Underlying EBITDA	**1,032**	1,090
Depreciation and amortisation	**(319)**	(307)
Underlying EBIT	**713**	783

1. Restated to reflect the accounting adjustment as described in Section 5.

Gross margin was $1,428 million, down $79 million, due to lower margin in Trading and Origination - Electricity, driven by lower generation due to lower commercial utilisation on higher availability at Bayswater Power Station and lower volatility captured compared to the prior corresponding period. This was partly offset by higher wholesale electricity prices resetting through customer contract positions, and increased gross margin from AGL's grid-scale battery portfolio. The Eco Markets portfolio contributed to the margin decrease following the reset of customer tariffs, which reflected the lower price of LRECs.

Operating costs (excluding depreciation and amortisation) were $(396) million, a decrease of $21 million compared with the prior corresponding period due to the Surat Gas Project being substantially divested in March 2025, a reduction in unplanned outages at the thermal sites, and savings through productivity and optimisation initiatives. This was partly offset by higher labour costs driven by Enterprise Agreement wage escalations. For further details see Section 3.2.2.

The following table provides a breakdown of the contributors to Underlying EBITDA and Underlying EBIT:

	H126 $m	H125 $m[1]
Trading and Origination - Electricity	**1,116**	1,191
Trading and Origination - Gas	**240**	241
Power Development	**(6)**	(11)
Energy Markets and Development - Other	**(18)**	(18)
Coal	**(224)**	(236)
Gas Generation	**(24)**	(22)
Renewables and Storage	**(18)**	(19)
Energy Assets - Other	**(34)**	(36)
Underlying EBITDA	**1,032**	1,090
Depreciation and amortisation	**(319)**	(307)
Underlying EBIT	**713**	783

1. Restated to reflect the accounting adjustment as described in Section 5.

- Trading and Origination – Electricity gross margin was $1,116 million, down 6.3%, primarily driven by lower generation due to lower commercial utilisation on higher availability at Bayswater Power Station and lower volatility captured compared to prior corresponding period. This was partly offset by higher wholesale electricity prices resetting through customer contract positions, and increased gross margin from AGL's grid-scale battery portfolio. The Eco Markets portfolio contributed to the margin decrease following the reset of customer tariffs, which reflected the lower price of LRECs.
- Trading and Origination – Gas gross margin was $240 million, down 0.4%, driven by increased gas costs as a result of the roll-off of lower cost legacy supply contracts. This was offset by higher consumer demand due to colder weather.
- Power Development Underlying EBITDA was $(6), million up 45.5%, primarily driven by recoveries received for completed Gippsland Skies Joint Venture activities.
- Energy Markets and Development - Other Underlying EBITDA was $(18) million, flat to the prior corresponding period.
- Coal Underlying EBITDA was $(224) million, up 5.1%, due to higher revenue from the sale of coal to Loy Yang B Power Station, a reduction in unplanned outages, and savings through productivity and optimisation initiatives. This was partly offset by Enterprise Agreement wage escalations.
- Gas Generation Underlying EBITDA was $(24) million, down $2 million, primarily driven by non-routine maintenance at Barker Inlet Power Station.
- Renewables and Storage Underlying EBITDA was $(18) million, broadly flat to the prior corresponding period.
- Energy Assets - Other Underlying EBITDA was $(34) million, up 5.6%, primarily driven by the Surat Gas Project being substantially divested in March 2025, partly offset by higher engineering costs at Newcastle Gas Storage Facility.

3.2.2 Operating costs

Integrated Energy operating costs (excluding depreciation and amortisation) of $(396) million decreased by 5.0% compared with the prior corresponding period.

	H126 $m	H125 $m
Labour	**(205)**	(203)
Contracts and materials	**(131)**	(146)
Other	**(60)**	(68)
Operating costs (excluding depreciation and amortisation)	**(396)**	(417)

- Labour costs were $(205) million, up 1.0%, driven by Enterprise Agreement wage escalations, partly offset by the Surat Gas Project being substantially divested in March 2025, and productivity initiatives across the business.
- Contracts and materials costs were $(131) million, down 10.3%, driven by a reduction in unplanned outage costs at Bayswater and AGL Loy Yang power stations, the Surat Gas Project being substantially divested in March 2025, and savings through productivity and optimisation initiatives.
- Other operating costs were $(60) million, down 11.8%, driven by lower costs resulting from the Surat Gas Project being substantially divested in March 2025, and lower professional fees.

3.2.3 Depreciation and amortisation

Integrated Energy depreciation and amortisation of $(320) million increased by 4.2% compared with the prior corresponding period.

	H126 $m	H125 $m[1]
Coal	**(257)**	(239)
Gas Generation	**(14)**	(19)
Renewables and Storage	**(24)**	(23)
Other Integrated Energy	**(24)**	(26)
Depreciation and amortisation	**(319)**	(307)

1. Restated to reflect the accounting adjustment as described in Section 5.

- Coal depreciation and amortisation was $(257) million, up 7.5%, driven by a higher asset base due to increased investment to deliver reliability and flexibility at Bayswater and AGL Loy Yang power stations as part of long-term asset management plans, partly offset by a decrease in environmental rehabilitation assets primarily at AGL Loy Yang with confirmation of the bulk water entitlement costs.
- Gas Generation depreciation and amortisation was $(14) million, down 26.3%, driven by the extension of the operational life of Torrens Island Power Station by two years through to 30 June 2028.
- Renewables and Storage depreciation and amortisation was $(24) million, broadly flat to the prior corresponding period.
- Other Integrated Energy depreciation and amortisation was $(25) million, broadly flat to the prior corresponding period.

3.3 Centrally Managed Expenses

AGL manages and reports certain expense items including technology costs within Centrally Managed Expenses. These costs are not reallocated to AGL's operating segments as their management is the responsibility of various corporate functions.

Centrally Managed Expenses Underlying EBIT was $(203) million, down by 4.1%. Higher labour costs were driven by inflationary increases and uplift to support strategic initiatives. Higher IT hardware and software costs were due to inflationary increases and strategic investment in Cloud and Software as a Service (SaaS), partly offset by savings through productivity and optimisation initiatives. Depreciation and amortisation was $33 million, broadly flat to the prior corresponding period.

	H126 $m	H125 $m
Gross margin	**–**	–
Operating costs (excluding depreciation and amortisation)	**(170)**	(163)
Underlying EBITDA	**(170)**	(163)
Depreciation and amortisation	**(33)**	(32)
Underlying EBIT	**(203)**	(195)
Operating costs (excluding depreciation and amortisation)		
Labour	**(86)**	(83)
IT hardware and software costs	**(64)**	(58)
Consultants and contractor services	**(7)**	(6)
Insurance premiums	**(4)**	(4)
Other	**(9)**	(12)
Operating costs (excluding depreciation and amortisation)	**(170)**	(163)

3.4 Investments

Investments primarily comprises AGL's interests in the ActewAGL Retail Partnership (ActewAGL) and Tilt Renewables.

	H126 $m	H125 $m
ActewAGL	**8**	12
Tilt Renewables	**1**	(3)
Underlying EBIT	**9**	9

- ActewAGL contributed an equity share of profits of $8 million, a decrease of $4 million from prior corresponding period, mainly driven by lower sales margin.
- Tilt Renewables contributed an equity share of profits of $1 million which represents AGL's share of profit up to 4 September 2025 when it was classified as held for sale, an improvement of $4 million from the prior corresponding period.

3.5 Consolidated financial performance by operating segment

H126 $m	Customer Markets	Integrated Energy	Investments	Centrally Managed Expenses	Inter-segment	Total Group
Revenue	**5,357**	**4,225**	**–**	**–**	**(2,538)**	**7,044**
Cost of sales	**(4,825)**	**(2,797)**	**–**	**–**	**2,538**	**(5,084)**
Other income	**–**	**–**	**9**	**–**	**–**	**9**
Gross margin	**532**	**1,428**	**9**	**–**	**–**	**1,969**
Operating costs (excluding depreciation and amortisation)	**(311)**	**(396)**	**–**	**(170)**	**–**	**(877)**
Underlying EBITDA	**221**	**1,032**	**9**	**(170)**	**–**	**1,092**
Depreciation and amortisation	**(58)**	**(319)**	**–**	**(33)**	**–**	**(410)**
Underlying EBIT	**163**	**713**	**9**	**(203)**	**–**	**682**
Net finance costs						**(181)**
Underlying Profit before tax						**501**
Income tax expense						**(148)**
Underlying Profit after tax						**353**

H125 $m[1]	Customer Markets	Integrated Energy	Investments	Centrally Managed Expenses	Inter-segment	Total Group
Revenue	4,888	4,588	–	–	(2,366)	7,110
Cost of sales	(4,403)	(3,083)	–	–	2,366	(5,120)
Other income	–	2	9	–	–	11
Gross margin	485	1,507	9	–	–	2,001
Operating costs (excluding depreciation and amortisation)	(324)	(417)	–	(163)	–	(904)
Underlying EBITDA	161	1,090	9	(163)	–	1,097
Depreciation and amortisation	(59)	(307)	–	(32)	–	(398)
Underlying EBIT	102	783	9	(195)	–	699
Net finance costs						(163)
Underlying Profit before tax						536
Income tax expense						(159)
Underlying Profit after tax						377

1. Restated to reflect the accounting adjustment as described in Section 5.

4. Portfolio Review Summary

The portfolio review for the Electricity (Section 4.2) and Gas (Section 4.3) businesses outlines the margin achieved for each of AGL's portfolios across operating segments, and demonstrates how value is generated within each business. The portfolio reviews in Sections 4.2 and 4.3 start with volume information before summarising external customer revenue, customer network and other costs, fuel and gas costs net of hedging, and costs of managing and maintaining owned and contracted generation assets, to arrive at a portfolio's margin. A per unit rate ($/MWh for electricity and $/GJ for gas) is derived from each category of revenue and cost using the relevant associated volumes.

The tables in Sections 4.2 and 4.3 should be read in conjunction with Section 4.4 to reconcile the segmental revenue and costs allocated to each portfolio with Group Underlying EBIT.

4.1 Portfolio Review Summary to Underlying Profit after Tax

	H126 $m	H125 $m[1]
Electricity Portfolio		
Total revenue	**4,449**	4,078
Customer network, green compliance, and other cost of sales[2]	**(2,065)**	(1,853)
Fuel costs	**(353)**	(367)
Generation running costs	**(404)**	(377)
Depreciation and amortisation	**(296)**	(281)
Net portfolio management[2]	**(448)**	(272)
Electricity Portfolio Margin (a)	**883**	928
Gas Portfolio		
Total revenue	**1,441**	1,363
Customer network and other cost of sales	**(417)**	(349)
Gas purchases	**(449)**	(442)
Haulage, storage and other	**(169)**	(177)
Gas Portfolio Margin	**406**	395
Energy Assets - Other	**(1)**	(7)
Gas Portfolio Margin (including Energy Assets - Other) (b)	**405**	388
Other AGL		
Other margin[3]	**53**	50
Customer Markets operating costs	**(311)**	(324)
Integrated Energy other operating costs	**(64)**	(63)
Centrally Managed Expenses operating costs	**(170)**	(163)
Other depreciation and amortisation	**(114)**	(117)
Net finance costs	**(181)**	(163)
Income tax expense	**(148)**	(159)
Total Other AGL (c)	**(935)**	(939)
Underlying Profit after Tax (a + b + c)	**353**	377

1. Restated to reflect the accounting adjustment as described in Section 5.
2. Comparatives have been restated to reallocate Ovo Energy Australia hedging arrangements from other cost of sales to net derivative cost.
3. Other margin includes other income from investments, and gross margin from Customer Markets and Integrated Energy.

4.2 Electricity portfolio

The Electricity portfolio review combines the Integrated Energy's (Trading and Origination - Electricity), Energy Assets (Coal, Gas Generation, and Renewables and Storage), with Customer Markets (Consumer and Large Business) businesses to outline the portfolio's performance across operating segments.

All electricity volumes generated by AGL is sold into either the National Electricity Market (NEM) or Western Australian Wholesale Electricity Market (collectively "the pool") for which AGL receives pool generation revenue. Pool generation revenue is a function of volume and pool prices, which are set by the real-time market in each state. In the NEM, the total volume demanded by AGL customers is then purchased from the pool according to the geographical profile of customer demand and is reported as pool purchase volumes and costs. Where AGL's customer demand volumes exceed pool generation volumes, the generation volume deficit needs to be purchased from the pool by AGL.

	H126 GWh	H125 GWh	Movement %
Pool purchase volume to satisfy Consumer customers	**7,816**	7,419	5.4%
Pool purchase volume to satisfy Large Business customers and Wholesale customers	**10,965**	11,104	(1.3)%
Pool purchase volume[1]	**18,781**	18,523	1.4%
Add: Net generation volume deficit	**(3,384)**	(2,681)	(26.2)%
Pool generation volume	**15,397**	15,842	(2.8)%
Consumer customers sales	**7,515**	7,229	4.0%
Large Business customers sales	**4,118**	4,373	(5.8)%
Wholesale customers sales	**6,789**	6,570	3.3%
Total customer sales volume	**18,422**	18,172	1.4%
Energy losses	**359**	351	2.3%
Pool purchase volume	**18,781**	18,523	1.4%

1. Includes 2.0 TWh residential solar volumes purchased from consumers (H125: 1.7 TWh).

Refer to Section 1.1.4 for commentary on generation volumes.

Refer to Section 1.1.2 for commentary on customer energy demand.

	Portfolio Margin		Per Unit		Volume Denomination	
Revenue	H126 $m	H125 $m	H126 $/MWh	H125 $/MWh	H126 GWh	H125 GWh
Consumer customers	**2,877**	2,602	***382.8***	*359.9*	**7,515**	7,229
Large Business customers	**835**	841	***202.8***	*192.3*	**4,118**	4,373
Wholesale customers[1]	**671**	573	***98.8***	*87.2*	**6,789**	6,570
Energy Assets (ancillary revenue)	**66**	62	**–**	–	**–**	–
Total revenue	**4,449**	4,078	***241.5***	*224.4*	**18,422**	18,172

1. Wholesale customers revenue includes amounts from certain wholesale contracts that are treated as derivatives for statutory reporting purposes. In the statutory accounts the amounts associated with these contracts are recognised within cost of sales.

Total revenue was $4,449 million, up 9.1%.

- Revenue from Consumer customers was $2,877 million, up 10.6%, and directly correlated to increases in wholesale energy and network costs as well as higher volumes.
- Large Business customer revenue was $835 million, down 0.7%, driven by lower volumes, partly offset by increased revenue rates due to higher network costs and other costs of sales.
- Wholesale customer revenue was $671 million, up 17.1%, largely driven by higher volumes sold, and an increase in green certificates sold compared to the prior corresponding period at similar prices.
- Energy Assets revenue was $66 million, up 6.5%, primarily driven by higher external revenue from the sale of coal from AGL's mine at AGL Loy Yang to the Loy Yang B Power Station.

	Portfolio Margin		Per Unit		Volume Denomination	
Network and other cost of sales	H126 $m	H125 $m[1]	H126 $/MWh	H125 $/MWh[1]	H126 GWh	H125 GWh
Network costs	**(1,414)**	(1,291)	***(121.6)***	*(111.3)*	**11,633**	11,602
Consumer	**(1,129)**	(1,029)	***(150.2)***	*(142.3)*	**7,515**	7,229
Large Business	**(285)**	(262)	***(69.2)***	*(59.9)*	**4,118**	4,373
Green compliance costs	**(411)**	(333)	***(35.3)***	*(28.7)*	**11,633**	11,602
Consumer solar costs	**(86)**	(94)	***(42.4)***	*(53.6)*	**2,029**	1,753
Other cost of sales[2]	**(154)**	(135)	***(13.2)***	*(11.6)*	**11,633**	11,602
Total customer network and other cost of sales	**(2,065)**	(1,853)	**(177.5)**	(159.7)	**11,633**	11,602

1. Restated to reflect the accounting adjustment as described in Section 5.
2. Comparatives have been restated to reallocate Ovo Energy Australia hedging arrangements from other cost of sales to net derivative cost.

Total customer network and other costs of sales were $(2,065) million, up 11.4%.

- Total network costs were $(1,414) million, an increase of 9.5%, driven by higher consumer volumes and an increase in average network tariff rates reflecting regulatory determinations.
- Green compliance costs were $(411) million, an increase of 23.4%, primarily driven by an increase in green certificates sold and higher prices for Victoria Energy Efficiency Certificates (VEEC) compared to the prior corresponding period.
- Consumer solar costs were $(86) million, a decrease of 8.5%, due to a reduction in average feed-in-tariffs compared to the prior corresponding period, partly offset by an increase in solar volumes.
- Other cost of sales was $(154) million, an increase of 14.1% driven by higher metering costs due to the roll out of smart meters.

	Portfolio Margin		Per Unit		Volume Denomination	
Fuel costs	H126 $m	H125 $m[1]	H126 $/MWh	H125 $/MWh[1]	H126 GWh	H125 GWh
Coal	**(289)**	(290)	***(23.8)***	*(22.8)*	**12,145**	12,739
Gas	**(64)**	(77)	***(116.8)***	*(103.9)*	**548**	741
Renewables	–	–	–	–	**2,704**	2,362
Total fuel costs (a)	**(353)**	(367)	***(22.9)***	*(23.2)*	**15,397**	15,842

1. Restated to reflect the accounting adjustment as described in Section 5.

Refer to Section 1.1.5 for commentary on fuel costs.

Generation running costs						
Coal power plants	**(191)**	(196)	***(15.7)***	*(15.4)*	**12,145**	12,739
Gas power plants	**(29)**	(27)	***(52.9)***	*(36.4)*	**548**	741
Renewables and Storage	**(153)**	(116)	***(56.6)***	*(49.1)*	**2,704**	2,362
Other	**(31)**	(38)	***(2.0)***	*(2.4)*	**15,397**	15,842
Total generation running costs (b)	**(404)**	(377)	***(26.2)***	*(23.8)*	**15,397**	15,842

Total generation running costs were $(404) million, up 7.2%.

- Coal operating costs were $(191) million, down 2.6%, driven by a reduction in unplanned outages, and savings through productivity and optimisation initiatives. This was partly offset by Enterprise Agreement wage escalations.
- Gas operating costs were $(29) million, up 7.4%, primarily driven by non-routine maintenance at Barker Inlet Power Station.
- Renewables and Storage costs were $(153) million, up 31.9%, primarily due to the commencement of Rye Park Wind Farm operations, and higher maintenance costs to improve availability across the remaining wind farm portfolio.
- Other costs, which include coal royalties and grid connection charges, were $(31) million, down 18.4% compared to the prior corresponding period largely driven by lower net ancillary costs.

	Portfolio Margin		Per Unit		Volume Denomination	
	H126 $m	H125 $m[1]	H126 $/MWh	H125 $/MWh[1]	H126 GWh	H125 GWh
Depreciation and amortisation (c)	**(296)**	(281)	***(19.2)***	*(17.7)*	**15,397**	15,842

1. Restated to reflect the accounting adjustment as described in Section 5.

Depreciation and amortisation was $(296) million, up 5.3%, driven by a higher asset base due to increased investment to deliver reliability and flexibility at Bayswater and AGL Loy Yang power stations as part of long-term asset management plans. This was partly offset by a decrease in environmental rehabilitation assets primarily at AGL Loy Yang with confirmation of the bulk water entitlement costs, and the extension of the operational life of Torrens Island Power Station by two years through to 30 June 2028.

Net Portfolio Management

Pool generation revenue	**1,357**	1,966	***88.1***	*124.1*	**15,397**	15,842
Pool purchase costs	**(1,578)**	(2,420)	***(84.0)***	*(130.6)*	**18,781**	18,523
Net derivative (cost)/revenue[1]	**(227)**	182	***(14.7)***	*11.5*	**15,397**	15,842
Net Portfolio Management (d)[2]	**(448)**	(272)	***(24.3)***	*(15.0)*	**18,422**	18,172

1. Comparatives have been restated to reallocate Ovo Energy Australia hedging arrangements from other cost of sales to net derivative cost.
2. Pool generation revenue and pool purchase costs include amounts from certain wholesale contracts that are treated as derivatives for statutory reporting purposes. In the statutory accounts the amounts associated with these contracts are recognised within cost of sales.

Net pool generation revenue and pool purchase costs were $(221) million, up $233 million, reflecting AGL's net buy position at lower pool prices compared to the prior corresponding period. The net buy position was driven by higher purchases as a result of lower generation. Net derivative costs of $(227) million decreased by $(409) million, largely driven by a net-buy position in New South Wales, South Australia and Queensland where higher fixed hedged forward prices were settled at lower spot prices.

Total wholesale costs (a + b + c + d)	**(1,501)**	(1,297)	***(79.9)***	*(70.0)*	**18,781**	18,523
Total costs	**(3,566)**	(3,150)	***(193.6)***	*(173.3)*	**18,422**	18,172
Electricity Portfolio Margin	**883**	928	***47.9***	*51.1*	**18,422**	18,172
Consumer customers	**297**	270				
Large Business customers	**16**	16				
Trading and Origination - Electricity	**1,116**	1,191				
Perth Energy margin	**15**	9				
Energy Assets (Coal, Gas Generation, and Renewables and Storage)	**(561)**	(558)				

In addition to the commentary above, Electricity portfolio margin is discussed in Sections 3.1 and 3.2.

4.3 Gas portfolio

The gas portfolio review combines the Integrated Energy (Trading and Origination – Gas) and Customer Markets (Consumer and Large Business) businesses to outline the portfolio's performance across operating segments.

	H126 PJ	H125 PJ[1]	Movement %
Consumer customers sales	**26.7**	24.8	7.7%
Large Business customers sales	**7.3**	7.5	(2.7)%
Wholesale customer sales and internal generation usage volumes	**20.3**	21.4	(5.1)%
Total customer sales volume	**54.3**	53.7	1.1%
Energy losses	**1.7**	1.8	(5.6)%
Gas purchase volume	**56.0**	55.5	0.9%

1. Comparatives have been restated to reflect Perth Energy wholesale gas volume from Large Business to Wholesale.

Refer to Section 1.1.2 for commentary on customer energy demand.

	Portfolio Margin		Per Unit		Volume Denomination	
Revenue	H126 $m	H125 $m	H126 $/GJ	H125 $/GJ[1]	H126 PJ	H125 PJ[1]
Consumer customers	**1,073**	962	***40.2***	*38.8*	**26.7**	24.8
Large Business customers	**113**	118	***15.5***	*15.7*	**7.3**	7.5
Wholesale customers & internal generation	**255**	283	***12.6***	*13.2*	**20.3**	21.4
Total revenue	**1,441**	1,363	***26.5***	*25.4*	**54.3**	53.7

1. Comparatives have been restated to reclass Perth Energy wholesale gas volume from Large Business to Wholesale.

Total revenue was $1,441 million, up 5.7%.

- Revenue from Consumer customers was $1,073 million, up 11.5%, driven by higher consumption due to colder weather and increase in revenue rates due to increased network and other cost of sales.
- Large Business customer revenue was $113 million, down 4.2%, driven by lower consumption.
- Wholesale customers revenue was $255 million, down 9.9%, primarily driven by the roll-off of wholesale customer volumes from AGL's existing customer base, and lower internal consumption of gas volumes used for power generation in South Australia.

	Portfolio Margin		Per Unit		Volume Denomination	
Network and other cost of sales	H126 $m	H125 $m	H126 $/GJ	H125 $/GJ[1]	H126 PJ	H125 PJ[1]
Consumer network costs	**(316)**	(270)	***(11.8)***	*(10.9)*	**26.7**	24.8
Consumer other cost of sales	**(77)**	(66)	***(2.9)***	*(2.7)*	**26.7**	24.8
Large Business customers network costs	**(11)**	(12)	***(1.5)***	*(1.6)*	**7.3**	7.5
Large Business customers other cost of sales	**(13)**	(1)	***(1.8)***	*(0.1)*	**7.3**	7.5
Total network and other cost of sales	**(417)**	(349)	***(12.3)***	*(10.8)*	**34.0**	32.3

1. Comparatives have been restated to reclass Perth Energy wholesale gas volume from Large Business to Wholesale.

Total network costs and other cost of sales were $(417) million, up 19.5%, driven by an increase in network tariff and green compliance costs.

Wholesale costs						
Gas purchases	**(449)**	(442)	***(8.3)***	*(8.2)*	**54.3**	53.7
Haulage, storage and other	**(169)**	(177)	***(3.1)***	*(3.3)*	**54.3**	53.7
Total wholesale costs	**(618)**	(619)	***(11.4)***	*(11.5)*	**54.3**	53.7

See Section 1.1.5 for commentary on wholesale gas costs.

Total costs	**(1,035)**	(968)	***(19.1)***	*(18.0)*	**54.3**	53.7
Gas Portfolio Margin	**406**	395	***7.5***	*7.4*	**54.3**	53.7
Energy Assets - Other	**(1)**	(7)				
Gas Portfolio Margin (including Energy Assets - Other)	**405**	388				
Consumer customers	**152**	138				
Large Business customers	**1**	2				
Trading and Origination - Gas	**240**	241				
Perth Energy margin	**13**	14				
Energy Assets - Other	**(1)**	(7)				

Energy Assets - Other was $(1) million, up $6 million, primarily driven by the Surat Gas Project being substantially divested in March 2025.

In addition to the commentary above, Gas portfolio margin is discussed in Sections 3.1 and 3.2.

4.4 Portfolio review reconciliation

H126 $m	Electricity Portfolio	Gas Portfolio	Other AGL	Adjustments (a)	Total Group
Customer Markets	**3,712**	**1,186**	**265**	**45**	**5,208**
Integrated Energy	**737**	**255**	**10**	**834**	**1,836**
Revenue	**4,449**	**1,441**	**275**	**879**	**7,044**
Customer Markets	**(2,065)**	**(417)**	**(218)**	**319**	**(2,381)**
Integrated Energy	**(874)**	**(618)**	**(13)**	**(1,198)**	**(2,703)**
Cost of sales	**(2,939)**	**(1,035)**	**(231)**	**(879)**	**(5,084)**
Other income	**–**	**–**	**9**	**–**	**9**
Gross margin	**1,510**	**406**	**53**	**–**	**1,969**
Operating costs (excluding depreciation and amortisation)	**(331)**	**–**	**(546)**	**–**	**(877)**
Depreciation and amortisation	**(296)**	**–**	**(114)**	**–**	**(410)**
Portfolio Margin/Underlying EBIT	**883**	**406**	**(607)**	**–**	**682**

H126 $m	Electricity	Gas	Pool revenue	Other	Total Group
Portfolio Margin Reporting	**4,449**	**1,441**	**1,357**	**–**	**7,247**
Revenue reclass	**(355)**	**–**	**(120)**	**–**	**(475)**
Intragroup	**–**	**(91)**	**–**	**–**	**(91)**
Other	**(259)**	**(17)**	**45**	**594**	**363**
Note 3 - Revenue	**3,835**	**1,333**	**1,282**	**594**	**7,044**

H125 $m[1]	Electricity Portfolio	Gas Portfolio	Other AGL	Adjustments (a)	Total Group
Customer Markets	3,443	1,080	180	47	4,750
Integrated Energy	635	283	21	1,421	2,360
Revenue	4,078	1,363	201	1,468	7,110
Customer Markets	(1,853)	(349)	(155)	220	(2,137)
Integrated Energy	(678)	(619)	2	(1,688)	(2,983)
Cost of sales	(2,531)	(968)	(153)	(1,468)	(5,120)
Other income	–	–	11	–	11
Gross margin	1,547	395	59	–	2,001
Operating costs (excluding depreciation and amortisation)	(338)	–	(566)	–	(904)
Depreciation and amortisation	(281)	–	(117)	–	(398)
Portfolio Margin/Underlying EBIT	928	395	(624)	–	699

H125 $m[1]	Electricity	Gas	Pool revenue	Other	Total Group
Portfolio Margin Reporting	4,078	1,363	1,966	–	7,407
Revenue reclass	(357)	–	(134)	–	(491)
Intragroup	–	(95)	–	–	(95)
Other	(178)	(12)	10	469	289
Note 3 - Revenue	3,543	1,256	1,842	469	7,110

1. Restated to reflect the accounting adjustment as described in Section 5.

Notes

a. Key adjustments include:

- Integrated Energy electricity pool sales in the statutory accounts has been reallocated to cost of sales (net portfolio management) in the Portfolio Review where it is combined with pool purchase costs and derivatives to reflect AGL's net position.
- A portion of Integrated Energy other revenue in the statutory accounts has been reallocated to cost of sales (generation running costs) in the Portfolio Review.
- Within Integrated Energy, derivatives from certain wholesale contracts are recognised within cost of sales in the statutory accounts.
- In the Portfolio Review the revenue and costs have been separately disclosed. Intra-segment and inter-segment eliminations include: Gas sales from Trading and Origination - Gas to Trading and Origination - Electricity; gas sales from Natural Gas to Trading and Origination - Gas. Elimination adjustment also includes the reallocation of green costs from Trading and Origination - Electricity to Consumer and Business customer other cost of sales.
- Includes Natural Gas Underlying EBIT.

5. Restatement of comparative balances

During the period, the Group reviewed and restated its accounting relating to the classification of a number of renewable Power Purchase Agreements (PPAs). These PPAs have historically been accounted for as executory contracts with an associated onerous contract provision for both the electricity component and the green certificates of these contracts.

As a result of this review:

- four PPAs have been restated as leases, resulting in the recognition of a lease liability, and a right of use asset together with an associated impairment; and
- the electricity component of four PPAs have been restated as derivative financial instruments. The onerous contract provision for green energy certificates associated with these contracts has been retained.

Changes arising from the restatement and adoption of AASB 16 *Leases* do not affect the definitions used in the calculation of debt covenants including gearing ratio. AGL remains compliant with all debt covenants.

The following tables summarise the impacts on AGL's key financials.

5.1 Impact on Underlying Profit

	H125 Reported $m	Adjustment $m	H125 Restated $m	FY25 Reported $m	Adjustment $m	FY25 Restated $m
Revenue	7,132	(22)	**7,110**	14,393	(54)	**14,339**
Cost of Sales	(5,170)	50	**(5,120)**	(10,601)	99	**(10,502)**
Other Income/(Loss)	11	-	**11**	14	-	**14**
Gross Margin	1,973	28	**2,001**	3,806	45	**3,851**
Operating Costs (Excluding D&A)	(904)	-	**(904)**	(1,796)	-	**(1,796)**
Underlying EBITDA	1,069	28	**1,097**	2,010	45	**2,055**
Depreciation & Amortisation	(391)	(7)	**(398)**	(803)	(15)	**(818)**
Underlying EBIT	677	22	**699**	1,207	30	**1,237**
Net Finance Costs	(147)	(16)	**(163)**	(319)	(27)	**(346)**
Underlying Profit Before Tax	530	6	**536**	888	3	**891**
Income Tax Expense	(157)	(2)	**(159)**	(248)	(1)	**(249)**
Underlying Profit After Tax	373	4	**377**	640	2	**642**

5.2 Impact on Cash flow

	H125 Reported $m	Adjustment $m	H125 Restated $m	FY25 Reported $m	Adjustment $m	FY25 Restated $m
Underlying EBITDA	1,069	28	**1,097**	2,010	45	2,055
Equity accounted income (net of dividends received)	(2)	-	**(2)**	12	-	12
Accounting for onerous contracts	(43)	32	**(11)**	(98)	76	(22)
Other assets/liabilities and non-cash items	(378)	1	**(377)**	(248)	1	(247)
Payments for rehabilitation	(44)	-	**(44)**	(80)	-	(80)
Working capital movements	141	8	**149**	(147)	12	(135)
Operating cash flow before significant items, interest and tax	743	69	**812**	1,449	134	**1,583**
Net finance costs paid	(61)	(31)	**(92)**	(147)	(62)	(209)
Income taxes	(153)	-	**(153)**	(268)	-	(268)
Cash flow related to significant items	(72)	-	**(72)**	(188)	-	(188)
Net cash provided by operating activities	457	38	**495**	846	72	**918**
Net cash used in investing activities	(883)	-	**(883)**	(1,558)	-	**(1,558)**
Net cash used in financing activities	(253)	(38)	**(291)**	99	(72)	**27**

	H125 Reported $m	Adjustment $m	H125 Restated $m	FY25 Reported $m	Adjustment $m	FY25 Restated $m
Net (decrease)/increase in cash and cash equivalents	(679)	-	**(679)**	(613)	-	**(613)**

5.3 Impact on Operating Free Cash Flow

	H125 Reported $m	Adjustment $m	H125 Restated $m	FY25 Reported $m	Adjustment $m	FY25 Restated $m
Net cash provided by operating activities	457	38	**495**	846	72	**918**
Adjust for:						
Working capital movements for margin calls	(123)	-	**(123)**	85	-	**85**
Cash flow related to significant items	72	-	**72**	188	-	**188**
Sustaining capital expenditure (accruals basis)	(370)	-	**(370)**	(660)	-	**(660)**
Operating free cash flow	36	38	**74**	459	72	**531**

5.4 Impact on Summary Statement of Financial Position

	FY25 Reported $m	Adjustment $m	FY25 Restated $m
Assets			
Cash and cash equivalents	319	-	**319**
Other current assets	4,118	15	**4,133**
Property, plant and equipment	6,277	247	**6,524**
Intangible assets	3,365	-	**3,365**
Other non-current assets	2,125	84	**2,209**
Total assets	16,204	346	**16,550**
Liabilities			
Lease liabilities	268	848	**1,116**
Borrowings	3,039	-	**3,039**
Other Liabilities	8,039	(421)	**7,618**
Total liabilities	11,346	427	**11,773**
Net assets/total equity	4,858	(81)	**4,777**

Financial Report

Condensed Consolidated Statement of Profit or Loss

for the half-year ended 31 December 2025

	Note	31 Dec 2025 $m	31 Dec 2024 $m[1]
Continuing operations			
Revenue	3	**7,044**	7,110
Other income	4	**6**	-
Expenses	5	**(6,333)**	(6,315)
Share of profits of joint ventures	11	**9**	7
Profit before net financing costs, depreciation and amortisation		**726**	802
Depreciation and amortisation		**(410)**	(398)
Profit before net financing costs		**316**	404
Finance income	6	**5**	16
Finance costs	6	**(186)**	(179)
Net financing costs		**(181)**	(163)
Profit before tax		**135**	242
Income tax expense	7	**(41)**	(80)
Profit for the period		**94**	162
Earnings per share			
Basic earnings per share	18	**14.0 cents**	24.1 cents
Diluted earnings per share	18	**13.9 cents**	24.0 cents

1. December 2024 results have been restated (refer to Note 1.5 for further details).

The Condensed Consolidated Statement of Profit or Loss should be read in conjunction with the notes to the financial statements.

Condensed Consolidated Statement of Comprehensive Income

for the half-year ended 31 December 2025

	Note	31 Dec 2025 $m	31 Dec 2024 $m[1]
Profit for the period		**94**	162
Other comprehensive income			
Items that will not be reclassified subsequently to profit or loss			
Remeasurement gain/(loss) on defined benefit plans		**14**	(17)
Fair value (loss)/gain on the revaluation of equity instrument financial assets		**(1)**	3
Income tax relating to items that will not be reclassified subsequently to profit or loss	7	**(4)**	3
		9	(11)
Items that may be reclassified subsequently to profit or loss			
Cash flow hedges			
Gain in fair value of cash flow hedges		**10**	52
Reclassification adjustments transferred to profit or loss		**20**	(68)
Share of gain/(loss) attributable to joint ventures		**9**	(6)
Cost of hedging subject to basis adjustment		**-**	1
Income tax relating to items that may be reclassified subsequently to profit or loss	7	**(12)**	6
		27	(15)
Other comprehensive gain/(loss) for the period, net of income tax		**36**	(26)
Total comprehensive income for the period		**130**	136

1. December 2024 results have been restated (refer to Note 1.5 for further details).

The Condensed Consolidated Statement of Comprehensive Income should be read in conjunction with the notes to the financial statements.

Condensed Consolidated Statement of Financial Position

for the half-year ended 31 December 2025

	Note	31 Dec 2025 $m	30 Jun 2025 $m[1]	1 July 2024 $m[1]
Current assets				
Cash and cash equivalents		**307**	319	932
Trade and other receivables	9	**1,613**	2,440	2,204
Inventories		**457**	396	323
Other financial assets		**765**	796	1,007
Other assets		**556**	501	312
Assets classified as held for sale	10	**329**	-	83
Total current assets		**4,027**	4,452	4,861
Non-current assets				
Trade and other receivables	9	**158**	157	67
Other financial assets		**538**	608	734
Investments in joint ventures	11	**57**	380	404
Property, plant and equipment	12	**6,072**	6,017	5,452
Right-of-use assets	13	**501**	507	531
Intangible assets	14	**3,344**	3,365	3,100
Deferred tax assets		**1,028**	1,025	905
Other assets		**48**	39	80
Total non-current assets		**11,746**	12,098	11,273
Total assets		**15,773**	16,550	16,134
Current liabilities				
Trade and other payables		**1,864**	2,634	2,083
Lease liabilities		**108**	96	95
Borrowings	15	**215**	219	13
Provisions	16	**450**	410	397
Current tax liabilities		**65**	90	167
Other financial liabilities		**1,127**	1,083	1,273
Other liabilities		**118**	157	448
Liabilities relating to assets classified as held for sale		**-**	-	83
Total current liabilities		**3,947**	4,689	4,559
Non-current liabilities				
Lease liabilities		**996**	1,020	1,065
Borrowings	15	**3,167**	2,820	2,468
Provisions	16	**1,916**	2,231	1,856
Other financial liabilities		**722**	780	856
Other liabilities		**290**	233	190
Total non-current liabilities		**7,091**	7,084	6,435
Total liabilities		**11,038**	11,773	10,994
Net assets		**4,735**	4,777	5,140
Equity				
Issued capital	17	**5,918**	5,918	5,918
Reserves		**(37)**	(59)	19
Accumulated losses		**(1,146)**	(1,082)	(797)
Total equity		**4,735**	4,777	5,140

1. Balances have been restated (refer to Note 1.5 for further details).

The Condensed Consolidated Statement of Financial Position should be read in conjunction with the notes to the financial statements.

Condensed Consolidated Statement of Changes in Equity

for the half-year ended 31 December 2025

	Issued capital $m	Investment revaluation reserve $m	Employee equity benefits reserve $m	Hedge reserve $m	Other reserve $m	Retained earnings / (Accumulated losses) $m	Total Equity $m
Balance at 1 July 2025[1]	**5,918**	**28**	**5**	**(46)**	**(46)**	**(1,082)**	**4,777**
Profit for the period	**-**	**-**	**-**	**-**	**-**	**94**	**94**
Other comprehensive (loss)/income for the period, net of income tax	**-**	**(1)**	**-**	**27**	**-**	**10**	**36**
Total comprehensive (loss)/income for the period	**-**	**(1)**	**-**	**27**	**-**	**104**	**130**
Transactions with owners in their capacity as owners:							
Payment of dividends	**-**	**-**	**-**	**-**	**-**	**(168)**	**(168)**
Share-based payments	**-**	**-**	**(4)**	**-**	**-**	**-**	**(4)**
Balance at 31 December 2025	**5,918**	**27**	**1**	**(19)**	**(46)**	**(1,146)**	**4,735**
Balance at 1 July 2024	5,918	25	3	39	(48)	(506)	5,431
Prior period restatement	-	-	-	-	-	(291)	(291)
Restated balance at 1 July 2024	5,918	25	3	39	(48)	(797)	5,140
Profit for the period[1]	-	-	-	-	-	162	162
Other comprehensive income/(loss) for the period, net of income tax	-	2	-	(16)	1	(13)	(26)
Total comprehensive income/(loss) for the period	-	2	-	(16)	1	149	136
Transactions with owners in their capacity as owners:							
Payment of dividends	-	-	-	-	-	(235)	(235)
Share-based payments	-	-	(1)	-	-	-	(1)
Balance at 31 December 2024	5,918	27	2	23	(47)	(883)	5,040

1. Balances have been restated (refer to Note 1.5 for further details).

The Condensed Consolidated Statement of Changes in Equity should be read in conjunction with the notes to the financial statements.

Condensed Consolidated Statement of Cash Flows

for the half-year ended 31 December 2025

	Note	31 Dec 2025 $m	31 Dec 2024 $m[1]
Cash flows from operating activities			
Receipts from customers		**8,675**	**7,848**
Payments to suppliers and employees		**(7,935)**	**(7,116)**
Dividends received		**5**	**6**
Finance income received		**5**	**17**
Finance costs paid		**(85)**	**(72)**
Interest component of lease payments		**(36)**	**(37)**
Income taxes paid		**(85)**	**(153)**
Net cash provided by operating activities		**544**	**493**
Cash flows used in investing activities			
Payments for property, plant and equipment and other assets		**(737)**	**(661)**
Acquisition of a subsidiary, net of cash acquired		**-**	**(208)**
Payments for investments in associates and joint ventures		**(8)**	**(9)**
Return of payments for investments in associates and joint ventures		**2**	**-**
Payments for debt instrument financial assets		**(5)**	**-**
Loans to equity instrument investments		**-**	**(1)**
Loans to joint ventures		**(1)**	**(4)**
Receipt of deferred consideration		**6**	**-**
Payments of deferred consideration		**(15)**	**-**
Net cash used in investing activities		**(758)**	**(883)**
Cash flows from financing activities			
Purchase of shares on-market for equity based remuneration		**(8)**	**(5)**
Proceeds from borrowings		**2,042**	**335**
Repayment of borrowings		**(1,633)**	**(341)**
Principal component of lease payments		**(32)**	**(45)**
Dividends paid	8	**(168)**	**(235)**
Net cash provided by/(used in) financing activities		**201**	**(291)**
Net decrease in cash and cash equivalents		**(13)**	**(681)**
Cash and cash equivalents at the beginning of the financial period		**319**	**932**
Effect of exchange rate changes on the balance of cash held in foreign currencies		**1**	**2**
Cash and cash equivalents at the end of the financial period		**307**	**253**

1. Balances have been restated (refer to Note 1.5 for further details).

The Condensed Consolidated Statement of Cash Flows should be read in conjunction with the notes to the financial statements.

Notes to the Financial Statements

for the half-year ended 31 December 2025

1. Summary of material accounting policies

AGL Energy Limited (the Parent Entity) is a company limited by shares incorporated in Australia whose shares are publicly traded on the Australian Securities Exchange.

The half-year financial report includes the condensed consolidated financial statements which comprise the Parent Entity and its controlled entities (together referred to as AGL).

1.1 Statement of compliance

The half-year financial report is a general purpose financial report which has been prepared in accordance with the *Corporations Act 2001* and AASB 134 *Interim Financial Reporting*. Compliance with AASB 134 ensures compliance with International Financial Reporting Standard IAS 34 *Interim Financial Reporting*.

The half-year financial report does not include notes of the type normally included in an annual financial report and should be read in conjunction with the most recent annual financial report.

1.2 Basis of preparation

The condensed consolidated financial statements have been prepared on the basis of historical cost, except for derivative financial instruments, debt and equity instrument financial assets, which are measured at fair value. Cost is based on the fair values of the consideration given in exchange for assets. All amounts are presented in Australian dollars, unless otherwise noted.

The Parent Entity is a company of the kind referred to in ASIC Corporations Instrument 2016/191, dated 24 March 2016, and in accordance with that Instrument, amounts in the half-year financial report are rounded off to the nearest million dollars, unless otherwise indicated.

Except as outlined in Note 1.5, the accounting policies and methods of computation adopted in the preparation of the half-year financial report are consistent with those adopted and disclosed in AGL's 2025 annual financial report for the year ended 30 June 2025. These accounting policies are consistent with Australian Accounting Standards and with International Financial Reporting Standards.

1.3 Adoption of new and revised Standards and Interpretations

AGL has applied the required amendments to Standards and Interpretations that are relevant to its operations and effective for the current reporting period for the first time for the period commencing 1 July 2025. These did not have any material impact on the disclosures or on the amounts recognised in AGL's consolidated financial statements.

1.4 Standards and Interpretations in issue not yet adopted

The following accounting standards, accounting standard amendments and interpretations are due for adoption for the year ending 30 June 2027 or later:

- AASB 2024-2 *Amendments to Australian Accounting Standards – Classification and Measurement of Financial Instruments;*
- AASB 2024 20-3 *Amendments to Australian Accounting Standards – Annual Improvements Volume 11*
- AASB 2025-1 *Amendments to Australian Accounting Standards – Contracts Referencing Nature-dependent Electricity;*
- AASB 2014-10 *Amendments to Australian Accounting Standards – Sale or Contribution of Assets between an Investor and its Associate or Joint Venture;*
- *IFRIC Agenda Decision on Classification of Cash Flows related to Variation Margin Calls on 'Collateralised-to-Market' Contracts;*
- *IFRIC Agenda decision on Recognition of Intangible Assets from Climate-related Expenditure; and*
- *IFRIC Agenda Decision on Guarantees Issued on Obligations of Other Entities*

The standards and interpretations listed above are not expected to have a material impact on AGL's financial results or financial position on adoption but will affect presentation and disclosure in the consolidated financial statements.

AASB 18 *Presentation and Disclosure in Financial Statements* was also issued which is due for adoption for the year ending 30 June 2028. It will not change the recognition and measurement of items in the financial statements but will affect presentation and disclosure in the consolidated financial statements

1. Summary of material accounting policies (Continued)

1.5 Restatement of comparative balances for the half-year ended 31 December 2024 and year ended 30 June 2025

Change to accounting classification of renewable Power Purchase Agreements

During the period, the Group reviewed and restated its accounting relating to the classification of a number of renewable Power Purchase Agreements (PPAs). These PPAs have historically been accounted for as executory contracts with an associated onerous contract provision for both the electricity component and the green certificates of these contracts.

As a result of this review:

- four PPAs have been restated as leases, resulting in the recognition of a lease liability, and a right of use asset together with an associated impairment; and
- the electricity component of four PPAs have been restated as derivative financial instruments. The onerous contract provision for green energy certificates associated with these contracts has been retained.

Together with the corresponding reduction in the onerous contract provisions, the above restatements resulted in an overall net asset impact of ($81) million at 30 June 2025 and ($291) million at 1 July 2024.

Changes arising from the restatement and adoption of AASB 16 *Leases* do not affect the definitions used in the calculation of debt covenants including gearing ratio. AGL remains compliant with all debt covenants.

The following tables summarise the retrospective impacts of these changes on the Group's consolidated financial statements.

i. Impact on Consolidated Statement of Financial Position

	30 Jun 2025 Reported $m	Adjustment $m	30 Jun 2025 Restated $m	1 July 2024 Reported $m	Adjustment $m	1 Jul 2024 Restated $m
Current assets						
Other financial assets[1]	774	22	796	988	19	1,007
Other assets	508	(7)	501	330	(18)	312
Non-current assets						
Other financial assets[1]	559	49	608	653	81	734
Right-of-use assets[2,3]	260	247	507	265	266	531
Deferred tax assets	990	35	1,025	780	125	905
Current liabilities						
Trade and other payables	2,641	(7)	2,634	2,101	(18)	2,083
Other financial liabilities[1]	1,063	20	1,083	1,257	16	1,273
Lease liabilities[4]	19	77	96	22	73	95
Provisions[5]	488	(78)	410	466	(69)	397
Non-current liabilities						
Lease liabilities[4]	249	771	1,020	225	840	1,065
Provisions[5]	2,958	(727)	2,231	2,231	(375)	1,856
Other financial liabilities[1]	409	371	780	559	297	856
Net assets	**4,858**	**(81)**	**4,777**	**5,431**	**(291)**	**5,140**
Equity						
Retained earnings	(1,001)	(81)	(1,082)	(506)	(291)	(797)
Total equity	**4,858**	**(81)**	**4,777**	**5,431**	**(291)**	**5,140**

1. 'Other financial assets' and 'Other financial liabilities' have been adjusted, with a net impact of $320 million recognised as at 30 June 2025 and $213 million as at 1 July 2024, reflecting the restatement of four PPA related contracts as derivatives.
2. 'Right–of–use assets' are now presented as a separate line item in the Consolidated Statement of Financial Position. In prior periods, these assets were reported within the 'Property, plant and equipment' line item. Right-of-use assets have been adjusted by $247 million as at 30 June 2025 and $266 million as at 1 July 2024, reflecting the restatement of certain PPA-related contracts as leases.
3. Movement from prior reported balance includes a $6 million reclassification from right-of-use assets to property, plant and equipment.
4. In prior periods, lease liabilities were included within 'Borrowings'. Following the restatement, all lease liabilities including those arising from the four restated PPA contracts have been presented within 'Lease liabilities'. Lease liabilities of $848 million have been recognised as at 30 June 2025, and $913 million as at 1 July 2024.
5. 'Provisions' have been adjusted to reflect the derecognition of the onerous contract provision as a result of change in accounting treatment for certain PPA-related contracts. The adjustment reflects a total reduction of $805 million as at 30 June 2025 and $444 million as at 1 July 2024 in Onerous contract provision.

Notes to the Financial Statements

for the half-year ended 31 December 2025

1. Summary of material accounting policies (Continued)

ii. Impact on Consolidated Statement of Profit or Loss

	Year ended 30 Jun 2025 Reported $m	Adjustment $m	Year ended 30 Jun 2025 Restated $m	Half-year ended 31 December 2024 Reported $m	Adjustment $m	Half-year ended 31 December 2024 Restated $m
Revenue	14,393	(54)	14,339	7,132	(22)	7,110
Expenses	(13,432)	397	(13,035)	(6,452)	137	(6,315)
Share of profits of joint venture	37	-	37	7	-	7
Profit before net financing costs, depreciation and amortisation	998	343	1,341	687	115	802
Depreciation and amortisation	(803)	(15)	(818)	(391)	(7)	(398)
Profit before net financing costs	**195**	**328**	**523**	**296**	**108**	**404**
Finance income	22	-	22	16	-	16
Finance costs	(341)	(27)	(368)	(163)	(16)	(179)
Net financing costs	**(319)**	**(27)**	**(346)**	**(147)**	**(16)**	**(163)**
(Loss)/profit before tax	**(124)**	**301**	**177**	**149**	**93**	**242**
Income tax benefit/(expense)	26	(91)	(65)	(52)	(28)	(80)
(Loss)/profit for the period	**(98)**	**210**	**112**	**97**	**65**	**162**

1. Summary of material accounting policies (Continued)

iii. Impact on Consolidated Statement of Cash Flows

	Year ended 30 Jun 2025 Reported $m	Adjustment $m	Year ended 30 Jun 2025 Restated $m	Half-year ended 31 December 2024 Reported $m	Adjustment $m	Half-year ended 31 December 2024 Restated $m
Cash flows from operating activities						
Receipts from customers	15,106	(54)	**15,052**	7,870	(22)	**7,848**
Payments to suppliers and employees	(13,875)	188	**(13,687)**	(7,207)	91	**(7,116)**
Interest component of lease payments[1]	(12)	(62)	**(74)**	(6)	(31)	**(37)**
Net cash provided by operating activities	841	72	**913**	455	38	**493**
Cash flows used in investing activities						
Net cash used in investing activities	(1,558)	-	**(1,558)**	(883)	**-**	**(883)**
Cash flows from financing activities						
Principal component of lease payments[2]	(3)	(72)	**(75)**	(7)	(38)	**(45)**
Net cash provided by/(used in) financing activities	99	(72)	**27**	(253)	(38)	**(291)**
Net decrease in cash and cash equivalents	(618)	-	**(618)**	(681)	-	**(681)**
Cash and cash equivalents at the beginning of the financial period	932	-	**932**	932	-	**932**
Effect of exchange rate changes on the balance of cash held in foreign currencies	5	-	**5**	2	-	**2**
Cash and cash equivalents at the end of the financial period	319	**-**	**319**	253	**-**	**253**

1. Cash outflows relating to the 'Interest component of lease payments' are now presented separately in the Consolidated Statement of Cash Flows. In prior periods, these amounts were included within the 'Finance costs paid' line item.
2. Cash outflows relating to the 'Principal component of lease payments' are now presented separately in the Consolidated Statement of Cash Flows. In prior periods, these amounts were included within the 'Repayment of borrowings' line item.

Notes to the Financial Statements

for the half-year ended 31 December 2025

1. Summary of material accounting policies (Continued)

iv. Impact on total earnings per share

	Year ended 30 Jun 2025 Reported	Adjustment	Year ended 30 Jun 2025 Restated	Half-year ended 31 December 2024 Reported	Adjustment	Half-year ended 31 December 2024 Restated
Statutory earnings per share						
Basic earnings per share	(14.6 cents)	31.3 cents	16.7 cents	14.4 cents	9.7 cents	24.1 cents
Diluted earnings per share	(14.6 cents)	31.2 cents	16.6 cents	14.4 cents	9.6 cents	24.0 cents
Underlying earnings per share						
Basic earnings per share	95.1 cents	0.5 cents	95.6 cents	55.4 cents	0.6 cents	56.0 cents
Diluted earnings per share	94.8 cents	0.4 cents	95.2 cents	55.2 cents	0.6 cents	55.8 cents

2. Segment information

Operating segments

AGL manages its business in three key operating segments.

Segments

- **Customer Markets** comprises the Consumer and Large Business customer portfolios responsible for the retailing of electricity, gas, broadband/mobile/voice, solar and energy efficiency products and services to residential, small and large business customers. Customer Markets sources its energy from Integrated Energy at transfer prices that reflect wholesale energy costs in each state, along with other energy costs such as those arising from environmental schemes. Customer Markets also includes sales, marketing, brand, and AGL's customer contact and call centre operations.
- **Integrated Energy** operates AGL's power generation portfolio and other key assets, including coal, gas and renewable generation facilities, natural gas storage and production facilities, battery storage, and development projects. Integrated Energy runs a large trading operation to manage price risk associated with procuring electricity and gas for AGL's customers, manages AGL's obligations in relation to renewable energy schemes, and controls the dispatch of AGL's owned and contracted generation assets, gas offtake agreements and associated portfolio of energy hedging products.
- **Investments** comprises AGL's interests in the ActewAGL Retail Partnership, Tilt Renewables, Energy Impact Partners Europe and other investments.

In the segment financial results, the 'Other' category consists of various Corporate activities. These are not considered to be reportable segments.

Segment financial results

The measurement of segment results is in line with the basis of information presented to the Board of Directors for internal management reporting purposes. The performance of each segment is measured based on their Underlying earnings before interest and tax (Underlying EBIT) contribution to AGL. Certain items of income and expense are excluded from the segment results to show a measure of underlying performance. These items include changes in fair value of financial instruments and significant items.

AASB 8 *Operating Segments* requires AGL to report segment information on the same basis as the internal management structure. As a result, the Customer Markets segment reports the revenue and margin associated with satisfying the gas, electricity and telecommunication requirements of AGL consumer and large business customer portfolio and Integrated Energy reports the revenue, expenses and margin related to AGL's operating sites and AGL's wholesale energy portfolio.

2. Segment information (Continued)

Period ended 31 December 2025	Customer Markets $m	Integrated Energy $m	Investments $m	Other $m	Total $m
Revenue					
Total segment revenue	**5,209**	**4,134**	**-**	**-**	**9,343**
Inter-segment revenue	**(2)**	**(2,297)**	**-**	**-**	**(2,299)**
External revenue	**5,207**	**1,837**	**-**	**-**	**7,044**
Underlying earnings before interest, tax, depreciation and amortisation (Underlying EBITDA)	**221**	**1,032**	**9**	**(170)**	**1,092**
Depreciation and amortisation	**(58)**	**(320)**	**-**	**(32)**	**(410)**
Underlying EBIT	**163**	**712**	**9**	**(202)**	**682**
Net financing costs					**(181)**
Underlying profit before tax					**501**
Underlying income tax expense					**(148)**
Underlying profit after tax					**353**
At 31 December 2025					
Segment assets	**2,997**	**9,527**	**407**	**236**	**13,167**
Segment liabilities	**894**	**3,543**	**-**	**202**	**4,639**
Other segment information					
Share of profits of joint ventures	**-**	**-**	**9**	**-**	**9**
Investments in associates and joint ventures	**-**	**12**	**45**	**-**	**57**
Additions to non-current assets	**131**	**579**	**-**	**41**	**751**
Other non-cash expenses	**(65)**	**-**	**-**	**(4)**	**(69)**

2. Segment information (Continued)

Period ended 31 December 2024[1]	Customer Markets $m	Integrated Energy $m	Investments $m	Other $m	Total $m
Revenue					
Total segment revenue	4,757	4,416	-	-	9,173
Inter-segment revenue	(6)	(2,057)	-	-	(2,063)
External revenue	4,751	2,359	-	-	7,110
Underlying earnings before interest, tax, depreciation and amortisation (Underlying EBITDA)	161	1,090	9	(163)	1,097
Depreciation and amortisation	(59)	(307)	-	(32)	(398)
Underlying EBIT	102	783	9	(195)	699
Net financing costs					(163)
Underlying profit before tax					536
Underlying income tax expense					(159)
Underlying profit after tax					377
At 30 June 2024[1]					
Segment assets	2,969	8,941	469	203	12,582
Segment liabilities	1,241	3,606	-	210	5,057
Period ended 31 December 2024					
Other segment information					
Share of profits of joint ventures	-	-	7	-	7
Investments in associates and joint ventures	-	14	394	-	408
Additions to non-current assets	68	878	-	22	968
Other non-cash expenses	(58)	-	-	(8)	(66)

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Segment Underlying EBIT reconciliation to the Condensed Consolidated Statement of Profit or Loss

Reconciliation of segment Underlying EBIT to profit before tax is as follows:

	31 Dec 2025 $m	31 Dec 2024 $m[1]
Underlying EBIT for reportable segments	**884**	894
Other	**(202)**	(195)
	682	699
Amounts excluded from underlying results:		
- loss in fair value of financial instruments	**(205)**	(79)
- significant items	**(161)**	(215)
Finance income	**5**	16
Finance costs	**(186)**	(179)
Profit before tax	**135**	242

1. Restated to reflect the accounting adjustment as described in Note 1.5.

3. Revenue

Revenue by product and customer type is disaggregated below:

Period ended 31 December 2025	Consumer $m	Business $m	Wholesale $m	Other $m	Total $m
Electricity	**2,985**	**686**	**163**	**-**	**3,834**
Generation sales to pool	**-**	**-**	**1,282**	**-**	**1,282**
Gas	**1,103**	**67**	**163**	**-**	**1,333**
Telecommunication Services	**113**	**-**	**-**	**-**	**113**
Engineering, procurement and construction services	**-**	**15**	**-**	**-**	**15**
Other services	**50**	**18**	**28**	**29**	**125**
Other revenue	**-**	**104**	**184**	**54**	**342**
Total revenue	**4,251**	**890**	**1,820**	**83**	**7,044**

Period ended 31 December 2024[1,2]	Consumer $m	Business $m	Wholesale $m	Other $m	Total $m
Electricity	2,695	712	136	-	3,543
Generation sales to pool	-	-	1,842	-	1,842
Gas	994	75	185	2	1,256
Telecommunication Services	95	-	-	-	95
Engineering, procurement and construction services	-	22	-	-	22
Other services	33	15	65	24	137
Other revenue	1	43	118	53	215
Total revenue	3,818	867	2,346	79	7,110

1. Restated to reflect the accounting adjustment as described in Note 1.5.
2. Certain reclassifications have been made to comparative balances to conform with the current year presentation.

4. Other income

	31 Dec 2025 $m	31 Dec 2024 $m
Sale of Waddi Wind Farm[1]	**6**	-
Total other income	**6**	-

1. Consideration received from Waddi Wind Farm due to a contractual milestone being met in the current period.

Notes to the Financial Statements

for the half-year ended 31 December 2025

5. Expenses

	31 Dec 2025 $m	31 Dec 2024 $m[1]
Cost of sales	**5,084**	5,120
Administrative expenses	**132**	130
Employee benefits expenses	**382**	376
Other expenses		
Loss on fair value of financial instruments	**203**	76
Contracts and materials	**140**	155
Impairment losses on trade receivables (net of bad debts recovered)	**65**	58
Retail transformation costs	**64**	64
Movement in onerous contract provision[2]	**59**	114
Marketing expenses	**30**	28
Short term lease and outgoings expenses	**19**	18
Restructuring and related costs	**18**	-
Impairment loss on investment in joint ventures[3]	**12**	-
Movement in rehabilitation provision[4]	**9**	-
Transaction costs	**6**	8
Impairment losses on inventory	**5**	-
Legal penalties[5]	**-**	25
Impairment losses on assets held for sale[6]	**-**	4
Other	**105**	139
Total expenses	**6,333**	6,315

1. Restated to reflect the accounting adjustment as described in Note 1.5.
2. Refer to Note 16.
3. Impairment losses recognised in relation to Gippsland Skies wind farm following the decision to withdraw from the project.
4. Movement in environmental rehabilitation provision relates to changes in estimate recognised through the consolidated statement of profit or loss due to the associated rehabilitation asset being previously impaired. Refer to Note 16.
5. In the year ended 30 June 2025, the Group was subject to a $25 million Court ordered penalty in legal proceedings initiated by the Australian Energy Regulator (AER) in relation to Centrepay payments.
6. AGL completed the disposal of Surat Gas Project in March 2025, resulting in an impairment loss of $4 million.

6. Net financing costs

	Note	31 Dec 2025 $m	31 Dec 2024 $m[1]
Finance income			
Interest income		**5**	16
Total financing income		**5**	16
Finance costs			
Interest expense[2]		**73**	59
Lease interest expense		**38**	40
Unwinding of discounts on provisions and other liabilities	16	**67**	69
Unwinding of discount on deferred consideration		**4**	5
Other finance costs		**4**	6
Total financing costs		**186**	179
Net financing costs		**181**	163

1. Restated to reflect the accounting adjustment as described in Note 1.5.
2. Interest expense for the half-year ended 31 December 2025 is presented net of capitalised interest of $16 million (31 December 2024: $10 million).

7. Income tax

Numerical reconciliation between tax expense and pre-tax accounting profit

The prima facie income tax expense on pre-tax accounting profit reconciles to the income tax expense/(benefit) in the financial statements as follows:

	31 Dec 2025 $m	31 Dec 2024 $m[1]
Profit before tax	**135**	242
Income tax expense calculated at the Australian tax rate of 30% (31 December 2024: 30%)	**40**	73
Non-deductible expenses	**1**	10
Impairment loss on non-current assets	**4**	-
Adjustments in relation to current tax of prior years	**(5)**	(4)
Other	**1**	1
Total income tax expense	**41**	80

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Income tax recognised in other comprehensive income

	31 Dec 2025 $m	31 Dec 2024 $m[1]
Deferred tax		
Cash flow hedges	**12**	(6)
Remeasurement loss on defined benefit plans	**4**	(5)
Fair value gain on the revaluation of equity instrument financial assets	**-**	2
Total income tax recognised in other comprehensive income	**16**	(9)

1. Restated to reflect the accounting adjustment as described in Note 1.5.

8. Dividends

Recognised amounts

	31 Dec 2025 $m	31 Dec 2024 $m
Final dividend		
Final dividend for 2025 of 25.0 cents per share, fully franked, paid 25 September 2025 (2024: Final dividend for 2024 of 35.0 cents per share, unfranked, paid 24 September 2024).	**168**	235
Dividends paid as per the Condensed Consolidated Statement of Cash Flows	**168**	235

Unrecognised amounts

	31 Dec 2025 $m	31 Dec 2024 $m
Since the end of the financial year, the Directors have declared an interim dividend for 2026 of 24.0 cents per share, fully franked, payable 26 March 2026 (2025: 23.0 cents per share, fully franked, paid 27 March 2025).	**161**	155

Notes to the Financial Statements

for the half-year ended 31 December 2025

9. Trade and other receivables

	31 Dec 2025 $m	30 June 2025 $m
Current		
Trade receivables	**1,142**	1,813
Unbilled revenue	**637**	779
Allowance for expected credit loss	**(183)**	(178)
	1,596	2,414
Other receivables	**17**	26
Total current trade and other receivables	**1,613**	2,440

	31 Dec 2025 $m	30 June 2025 $m
Non-current		
Loans to joint ventures	**23**	22
Other	**135**	135
Total non-current trade and other receivables	**158**	157

Expected credit loss assessment

The following table provides information about the exposure to credit risk and expected credit losses for trade receivables and unbilled revenue:

	31 Dec 2025		30 June 2025	
	Total $m	Allowance $m	Total $m	Allowance $m
Unbilled revenue	**637**	**(23)**	779	(29)
Not past due	**701**	**(26)**	1,455	(27)
Past due 0 – 30 days	**122**	**(18)**	96	(17)
Past due 31 – 60 days	**57**	**(14)**	48	(14)
Past due 61 – 90 days	**50**	**(14)**	31	(11)
Past 90 days	**212**	**(88)**	183	(80)
Total	**1,779**	**(183)**	2,592	(178)

10. Assets classified as held for sale

Tilt Renewables is a joint venture in which the Group holds 20% ownership. It consists of renewable energy generation projects. AGL is in the process of divesting 19.9% of this joint venture. The expected completion of this transaction is within 12 months from 31 December 2025. This joint venture is included in the Investments operating segment.

	31 Dec 2025 $m	30 Jun 2025 $m
Investments in associates and joint ventures	329	-
Assets classified as held for sale	**329**	-

11. Investments in joint ventures

	31 Dec 2025 $m	30 Jun 2025 $m
Investments in joint ventures - unlisted[1]	**57**	380
Total investments in joint ventures	**57**	380

1. The joint venture with Tilt Renewables is classified as held for sale at at 31 December 2025. AGL is in the process of divesting 19.9% of its 20% ownership in this joint venture. Refer to Note 10.

		Ownership interest		Contribution to profit	
	Principal activities	31 Dec 2025 %	30 Jun 2025 %	31 Dec 2025 $m	31 Dec 2024 $m
Joint ventures					
ActewAGL Retail Partnership	Gas and electricity retailer	**50**	50	**8**	12
Tilt Renewables[1]	Development and owner of renewable energy generation projects	**20**	20	**1**	(5)
Pottinger Renewables	Development and owner of renewable energy generation projects	**50**	50	**-**	-
Muswellbrook Pumped Hydro	Pumped hydro energy generation project	**50**	50	**-**	-
Gippsland Skies[2]	Offshore wind energy generation project	**20**	20	**-**	-
Total contribution to profit				**9**	7

1. The joint venture with Tilt Renewables is classified as held for sale at at 31 December 2025. AGL is in the process of divesting 19.9% of its 20% ownership in this joint venture. Refer to Note 10.
2. AGL recognised an impairment of its investment in Gippsland Skies wind farm following the decision to withdraw from the project. AGL retains a 20% interest in the entity which is expected to be deregistered.

Notes to the Financial Statements

for the half-year ended 31 December 2025

12. Property, plant and equipment

31 December 2025	Plant and equipment $m	Other $m[1]	Total $m
Balance at 1 July 2025, net of accumulated depreciation and impairment	**5,918**	**99**	**6,017**
Additions	**662**	**3**	**665**
Change in estimate related to provision for environmental rehabilitation[2]	**(311)**	**-**	**(311)**
Depreciation expense	**(299)**	**-**	**(299)**
Balance at 31 December 2025 net of accumulated depreciation and impairment	**5,970**	**102**	**6,072**

1. Includes land, buildings and leasehold improvements.
2. Refer to Note 16.

Balance at 1 July 2025			
Cost (gross carrying amount)	**12,403**	**122**	**12,525**
Accumulated depreciation and impairment	**(6,485)**	**(23)**	**(6,508)**
Net carrying amount	**5,918**	**99**	**6,017**

Balance at 31 December 2025			
Cost (gross carrying amount)	**12,753**	**125**	**12,878**
Accumulated depreciation and impairment	**(6,783)**	**(23)**	**(6,806)**
Net carrying amount	**5,970**	**102**	**6,072**

30 June 2025[1]	Plant and equipment $m	Other $m	Total $m
Balance at 1 July 2024, net of accumulated depreciation and impairment	5,365	87	5,452
Additions	1,017	12	1,029
Impairment loss recognised in profit or loss	(19)	-	(19)
Change in estimate related to provision for environmental rehabilitation	148	-	148
Depreciation expense	(593)	-	(593)
Balance at 30 June 2025 net of accumulated depreciation and impairment	5,918	99	6,017

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Balance at 1 July 2024[1]			
Cost (gross carrying amount)	11,272	110	11,382
Accumulated depreciation and impairment	(5,907)	(23)	(5,930)
Net carrying amount	5,365	87	5,452

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Balance at 30 June 2025[1]			
Cost (gross carrying amount)	12,403	122	12,525
Accumulated depreciation and impairment	(6,485)	(23)	(6,508)
Net carrying amount	5,918	99	6,017

1. Restated to reflect the accounting adjustment as described in Note 1.5.

13. Right-of-use assets

31 December 2025	Right-of-use plant and equipment $m	Other Right-of-use assets $m	Total $m
Balance at 1 July 2025, net of accumulated depreciation and impairment[1]	**346**	**161**	**507**
Additions	**17**	**1**	**18**
Reversal of impairment	**-**	**3**	**3**
Depreciation expense	**(15)**	**(7)**	**(22)**
Capitalised depreciation to inventory	**(5)**	**-**	**(5)**
Balance at 31 December 2025 net of accumulated depreciation and impairment	**343**	**158**	**501**

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Balance at 1 July 2025[1]			
Cost (gross carrying amount)	**1,578**	**274**	**1,852**
Accumulated depreciation and impairment	**(1,232)**	**(113)**	**(1,345)**
Net carrying amount	**346**	**161**	**507**

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Balance at 31 December 2025			
Cost (gross carrying amount)	**1,595**	**275**	**1,870**
Accumulated depreciation and impairment	**(1,252)**	**(117)**	**(1,369)**
Net carrying amount	**343**	**158**	**501**

30 June 2025[1]	Right-of-use plant and equipment $m	Other Right-of-use assets $m	Total $m
Balance at 1 July 2024, net of accumulated depreciation and impairment	365	166	531
Additions	18	9	27
Depreciation expense	(25)	(14)	(39)
Capitalised depreciation to inventory	(12)	-	(12)
Balance at 30 June 2025 net of accumulated depreciation and impairment	346	161	507

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Balance at 1 July 2024[1]			
Cost (gross carrying amount)	1,560	274	1,834
Accumulated depreciation and impairment	(1,195)	(108)	(1,303)
Net carrying amount	365	166	531

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Balance at 30 June 2025[1]			
Cost (gross carrying amount)	1,578	274	1,852
Accumulated depreciation and impairment	(1,232)	(113)	(1,345)
Net carrying amount	346	161	507

1. Restated to reflect the accounting adjustment as described in Note 1.5.

14. Intangible assets

31 December 2025	Goodwill $m	Software $m	Licences $m	Development Assets $m	Contracts and Other $m	Total $m
Balance at 1 July 2025, net of accumulated amortisation and impairment	**2,593**	**338**	**251**	**148**	**35**	**3,365**
Additions	**-**	**56**	**-**	**3**	**9**	**68**
Amortisation expense	**-**	**(78)**	**(5)**	**-**	**(6)**	**(89)**
Balance at 31 December 2025, net of accumulated amortisation and impairment	**2,593**	**316**	**246**	**151**	**38**	**3,344**
Balance at 1 July 2025						
Cost (gross carrying amount)	**3,220**	**1,286**	**306**	**148**	**133**	**5,093**
Accumulated amortisation and impairment	**(627)**	**(948)**	**(55)**	**-**	**(98)**	**(1,728)**
Net carrying amount	**2,593**	**338**	**251**	**148**	**35**	**3,365**
Balance at 31 December 2025						
Cost (gross carrying amount)	**3,220**	**1,342**	**306**	**151**	**142**	**5,161**
Accumulated amortisation and impairment	**(627)**	**(1,026)**	**(60)**	**-**	**(104)**	**(1,817)**
Net carrying amount	**2,593**	**316**	**246**	**151**	**38**	**3,344**

30 June 2025	Goodwill $m	Software $m	Licences $m	Development Assets $m	Contracts and Other $m	Total $m
Balance at 1 July 2024, net of accumulated amortisation and impairment	2,446	369	260	-	25	3,100
Additions	-	131	-	18	7	156
Amortisation expense	-	(162)	(9)	-	(14)	(185)
Acquisitions through business combinations[1]	147	-		130	19	296
Impairment loss recognised in profit or loss	-	-	-	-	(2)	(2)
Balance at 30 June 2025, net of accumulated amortisation and impairment	2,593	338	251	148	35	3,365

1. On 12 September 2024, the Group acquired 100% of the shares and units in Firm Power and Terrain Solar and their associated entities. Additions include goodwill, development rights and customer contracts.

Balance at 1 July 2024	Goodwill $m	Software $m	Licences $m	Development Assets $m	Contracts and Other $m	Total $m
Cost (gross carrying amount)	3,073	1,768	314	-	107	5,262
Accumulated amortisation and impairment	(627)	(1,399)	(54)	-	(82)	(2,162)
Net carrying amount	2,446	369	260	-	25	3,100
Balance at 30 June 2025						
Cost (gross carrying amount)	3,220	1,286	306	148	133	5,093
Accumulated amortisation and impairment	(627)	(948)	(55)	-	(98)	(1,728)
Net carrying amount	2,593	338	251	148	35	3,365

14. Intangible assets (Continued)

Impairment testing for goodwill and intangibles with indefinite useful lives

Goodwill, that is significant in comparison to AGL's total carrying amount of intangible assets with indefinite lives, has been allocated to cash-generating units (CGUs) for the purpose of impairment testing as follows:

	31 Dec 2025 $m	30 Jun 2025 $m
Customer Markets	**1,093**	1,093
Wholesale Gas	**1,353**	1,353
Generation Fleet	**-**	-
Flexible Generation	**147**	147
Wind Assets	**-**	-
Total goodwill and intangibles with indefinite useful lives	**2,593**	2,593

CRITICAL ACCOUNTING ESTIMATES AND ASSUMPTIONS

AGL regularly reviews the carrying values of its assets to test for impairment. An assessment of indications of impairment for each cash generating unit (CGU) is performed at each reporting period end, and if indications of impairment exist, a recoverable amount assessment is performed using value in use methodology. Notwithstanding the above, the recoverable amount of a CGU containing goodwill, intangible assets with indefinite useful lives or intangible assets in development is determined at least annually in December each year.

AGL's main CGUs are:

- Generation Fleet
- Flexible Generation
- Wholesale Gas
- Customer Markets
- Wind Assets

Impairment testing methodology

AGL is subject to a number of external factors that impact the performance of its CGUs. This includes, but is not limited to, market prices, external regulatory and social factors that may impact the life of assets, competitor behaviour and new entrants and technological change. To respond to the range of potential outcomes that can result from these factors, AGL applies a scenario analysis approach in determining the recoverable amount of assets. To estimate the recoverable amount of the CGU overall, each scenario is assigned a probability weighting. The methodology of analysing several modelled outcomes is consistent with AGL's external reporting disclosures including the Task Force on Climate-Related Financial Disclosures (TCFD) reports and Climate Transition Action Plan (CTAP). The scenarios modelled represent a range of outcomes including differing wholesale market prices, expected generation volume, station closure dates, asset lives, and growth rates.

If the recoverable amount of a CGU is estimated to be less than its carrying amount, the carrying amount of the CGU is reduced to its recoverable amount with any impairment loss recognised immediately in the statement of profit or loss.

Generation Fleet CGU

For AGL's fleet of finite life generation assets, cash flow forecasts are based on discrete and long-term cash flow forecasts that reflect the life of the assets. The long-term modelling reflects AGL's view of the cash flows anticipated from operations, factoring in both known events such as planned outages and expectations, and allows for quantification of sensitivities and scenarios.

The following key assumptions were applied to determine the recoverable amount of the Generation Fleet CGU at 31 December 2025:

- Two scenarios of forecast electricity pool prices over the life of the relevant station based on short term market forecasts for electricity pricing and longer term external and internal modelled pricing outlook;
- Station closure dates consistent with those announced in the CTAP;
- Discount rates used are the post-tax Weighted Average Cost of Capital (WACC) discount rate of 9.0% (Dec 24: 9.25%), the pre-tax equivalent being 14.0% (Dec 24: 13.4%);
- Generation volumes for each relevant station based on historical and forecast generation and availability including planned outages; and
- Assumptions associated with regulatory outcomes impacting upon operations.

The derived recoverable amount resulted in no impairment charge to the carrying value of the CGU nor a requirement to reverse previously recognised impairment at 31 December 2025.

Sensitivity analysis

When considering variables in isolation, AGL's Generation Fleet CGU recoverable amount estimate is sensitive to changes in electricity pool prices. There is a high degree of uncertainty when forecasting pool prices over long-term periods where long-run secular changes can impact supply and demand dynamics.

14. Intangible assets (Continued)

CRITICAL ACCOUNTING ESTIMATES AND ASSUMPTIONS

In practice, changes in variables are rarely mutually exclusive and the relationships and interactions between these variables are highly complex. Alterations in the external operational landscape, such as closure of major electricity consumers, substantial additions to generation capacity, postponements in the closure of power stations not owned by AGL, or modifications to government policies, have the potential to bring about fluctuations in pool prices. Additionally, these changes may decrease the operational lifespan of AGL's assets, possibly leading to additional impairments.

Flexible Generation CGU

The following key assumptions were applied to determine the recoverable amount of the Flexible Generation CGU at 31 December 2025:

- Assumed cap prices derived from internal and external market modelling to reflect the ability to capture prices during high demand events;
- Useful life of the generation assets, which includes gas peaker stations and renewable generation and storage assets;
- Discount rates used are the post-tax WACC discount rate of 7.75% (Dec 24: 8.0%), the pre-tax equivalent being 10.0% (Dec 24: 9.8%);
- Generation volumes for each relevant asset based on historical and forecast generation and availability including planned maintenance; and
- Terminal growth rate of 2.5% (Dec 24: 2.75%).

The recoverable amount of the Flexible Generation CGU exceeded the carrying value at 31 December 2025.

Sensitivity analysis has been performed for the Flexible Generation CGU. There were no reasonable possible changes in assumptions that would result in an impairment.

Customer Markets CGU

The following key assumptions were applied to determine the recoverable amount of the Customer Markets CGU at 31 December 2025:

- Gross margin outcomes based on actual regulatory decisions for the current reporting period, which are publicly available, together with AGL's expectations of regulated network prices and regulated pricing (Victorian Default Market Offer/Default Market Offer) beyond the current reset period;
- Future gross margin in unregulated markets is determined with reference to historically achieved revenue rates, AGL's expectations of future price changes and impact of expected customer discounts;
- Customer numbers and consumption volumes over a 10-year forecast period are estimated based on historical experience, marketing strategies for the retention and winning of customers and the expected competition from new entrants;
- Discount rates used are the post-tax WACC discount rate of 7.75% (Dec 24: 8.0%), the pre-tax equivalent being 9.2% (Dec 24: 10.1%); and
- Terminal growth rate of 2.75% (Dec 24: 2.75%).

The recoverable amount of the Customer Markets CGU exceeded the carrying value at 31 December 2025.

Sensitivity analysis

The recoverable amount of the Customer Markets CGU is sensitive to changes in a number of key assumptions.

In the impairment assessment performed at 31 December 2025, any reasonably possible adverse changes in a key assumption, when considered in isolation and holding other assumptions constant, would result in the recoverable amount of the Customer Markets CGU falling below its carrying value and therefore give rise to impairment.

The analysis above considers changes in individual assumptions in isolation. In practice, changes in market conditions often affect multiple assumptions simultaneously, and the interactions between these variables are complex.

Wholesale Gas CGU

The following key assumptions were applied to determine the recoverable amount of the Wholesale Gas CGU at 31 December 2025:

- Probability-weighted scenarios for gas sales volumes, pricing and procurement costs with an estimate of future market and contracted margins and volumes beyond the period of the actual contracted portfolio based on expected new supply sources and demand;
- Discount rates used are the post-tax WACC discount rate of 7.75% (Dec 24: 8.0%), the pre-tax equivalent being 12.7% (Dec 24: 15.4%);
- Terminal growth rate range between 0% to 1.5% (Dec 24: 0% to 1.5%); and
- Five-year forecast period with various scenarios reflecting different assumptions regarding the operational life of the CGU were evaluated.

The recoverable amount of the Wholesale Gas CGU exceeded the carrying value at 31 December 2025 and consequently no impairment loss was recognised in relation to this CGU.

Sensitivity analysis

The recoverable amount of the Wholesale Gas CGU is sensitive to changes in the forecast gas margin assumption. At 31 December 2025, a reasonable possible change in

14. Intangible assets (Continued)

CRITICAL ACCOUNTING ESTIMATES AND ASSUMPTIONS

this assumption will not result in an impairment. However, it is possible a significant and/or sustained change in this assumption due to changing market factors could result in impairment or reversal of previously recognised impairment in future periods.

The Wholesale Gas CGU benefits from favourable supply costs associated with existing contractual arrangements and the recoverable amount at 31 December 2025 includes probability-weighted scenarios on gross margins based on new supply sources and demand. As the existing contracts lapse and where gross margin on new supply sources are lower than forecast, the recoverable amount of the Wholesale Gas CGU could potentially decrease.

Wind Assets CGU

The review of accounting for a number of renewable power purchase agreements resulted in the retrospective recognition of ROU assets (Note 1.5) and the recognition of a new Wind Assets CGU.

An impairment relating to prior period arises from the retrospective recognition of these assets and has therefore been recognised as a prior-period adjustment in opening retained earnings at 1 July 2024. As noted below, no additional impairment, nor any reversal of previously recognised impairment, was required at 31 December 2025.

The following key assumptions were applied to determine the recoverable amount of the Wind Assets CGU at 31 December 2025:

- Two scenarios of forecast electricity pool prices over the life of the relevant wind assets based on short term market forecasts for electricity pricing and longer term external and internal modelled pricing outlook;
- Discount rates used are the post-tax WACC discount rate of 7.75% (Dec 24: 8.0%), the pre-tax equivalent being 12.4% (Dec 24: 14.6%);
- Generation volumes for each relevant wind assets based on historical and forecast generation and availability including planned outages; and
- Assumptions associated with regulatory outcomes impacting upon operations.

The derived recoverable amount resulted in no impairment charge to the carrying value of the CGU nor a requirement to reverse previously recognised impairment at 31 December 2025.

Sensitivity analysis

The recoverable amount of the Wind Assets CGU is sensitive to changes in electricity pool prices. In the impairment assessment performed at 31 December 2025, reasonably possible adverse changes in electricity pool prices, when considered in isolation and holding other assumptions constant, would result in the recoverable amount of the Wind Assets CGU falling below its carrying value and therefore give rise to impairment.

In practice, movements in electricity pool prices are influenced by broader market conditions and may interact with other assumptions used in the impairment assessment, which can affect outcomes.

15. Borrowings

	31 Dec 2025 $m	30 Jun 2025 $m
Current		
Bank loans - unsecured	**150**	-
USD senior notes - unsecured	**50**	205
CPI bonds - unsecured	**15**	14
Total current borrowings	**215**	219
Non-current		
Bank loans - unsecured	**1,288**	1,368
USD senior notes - unsecured	**1,392**	1,457
Medium term notes - unsecured	**500**	-
CPI bonds - unsecured	**7**	15
Deferred transaction costs	**(20)**	(20)
Total non-current borrowings	**3,167**	2,820

USD senior notes

- On 20 November 2023, AGL issued A$467 million (USD 100 million and AUD 313 million) of fixed rate unsecured senior medium term notes in the US private placement market, with maturity ranging from 10 to 12 years.
- On 8 June 2023, AGL issued A$386 million (USD 131 million and AUD 188 million) of fixed rate unsecured senior notes in the US private placement market, with maturity ranging from 7 to 15 years.
- On 8 December 2016, AGL issued A$572 million (USD 395 million and AUD 50 million) of fixed rate unsecured senior notes in the US private placement market, with maturity ranging from 10 to 15 years.
- On 8 September 2010, AGL issued A$152 million (USD 135 million) of fixed rate unsecured senior notes in the US private placement market. These notes matured on 8 September 2025 and were settled in accordance with their terms.
- All USD senior notes are converted back to AUD through cross currency interest rate swaps.

Medium term notes

- On 30 September 2025, AGL issued A$500 million of senior unsecured fixed rate Medium Term Notes, with maturity ranging from 7 to 10 years.

Bank loans

- On 14 December 2023, AGL executed a A$510 million Asian term loan facility, with maturity ranging from 5 to 7 years. As at 31 December 2025, A$470 million of this was utilised.
- On 10 April 2025, AGL executed an Amending Deed to upsize and extend the syndicated facility agreement originally executed on 28 April 2023. The extended syndicated facility agreement was upsized to A$1,518 million and includes a A$500 million green capital expenditure facility. The facility tranches have maturities ranging from 3 to 7 years. As of 31 December 2025, A$968 million of this was utilised.
- The remaining A$400 million of bank debt facilities comprises of bilateral facilities, with the full amount remaining unutilised at 31 December 2025.

CPI bonds

- CPI bonds rank pari passu with other unsecured debt and will mature in May 2027.

16. Provisions

	31 Dec 2025 $m	30 Jun 2025 $m[1]
Current		
Employee benefits	**221**	250
Environmental rehabilitation	**116**	81
Onerous contracts	**98**	63
Restructuring	**4**	6
Other	**11**	10
Total current provisions	**450**	410
Non-current		
Employee benefits	**6**	6
Environmental rehabilitation	**1,361**	1,692
Onerous contracts	**519**	508
Restructuring	**30**	25
Total non-current provisions	**1,916**	2,231

1. Restated to reflect the accounting adjustment as described in Note 1.5.

The movements in the environmental rehabilitation provision, restructuring provision and onerous contract provision are set out below:

	Environmental rehabilitation $m	Restructuring $m	Onerous Contracts $m[1]	Total $m
Balance at 1 July 2025	**1,773**	**31**	**571**	**2,375**
Changes in estimated provision	**(302)**	**-**	**59**	**(243)**
Additional provisions recognised	**-**	**8**	**-**	**8**
Provisions utilised and derecognised	**(43)**	**(5)**	**(31)**	**(79)**
Unwinding of discount	**49**	**-**	**18**	**67**
Balance at 31 December 2025	**1,477**	**34**	**617**	**2,128**

1. Restated to reflect the accounting adjustment as described in Note 1.5.

CRITICAL ACCOUNTING ESTIMATES AND ASSUMPTIONS

Provision for environmental rehabilitation

AGL estimates the future removal and rehabilitation costs of electricity generation assets, oil and gas production facilities, wells, pipelines, mine and related assets at the time of installation of the assets. In most instances, removal of these assets will occur many years into the future. The requirement for rehabilitation is also subject to community and regulatory expectations which may evolve over time and in practice, negotiation is required to arrive at a practical rehabilitation strategy. The calculation of this provision requires management to make assumptions regarding the removal date, application of environmental legislation, the extent of rehabilitation activities required and available technologies. The assumptions are highly judgemental and represents management's best estimate of the present value of the expenditure required to settle the obligation, given known facts and circumstances at a point in time.

At 31 December 2025, changes in estimates for the provision for environmental rehabilitation reflect an increase in the discount rate to 6.97% (FY25: 6.12%), revised cost estimates, and updated assumptions regarding the timing of rehabilitation activities and related cash flows.

In line with AGL's accounting policy, the provisions for environmental rehabilitation are reviewed on a regular basis.

Provision for onerous contracts

Following the review of accounting for certain renewable PPAs (Note 1.5), the green certificates associated with some of these agreements continue to be recognised as onerous contracts under AASB 137 *Provisions, Contingent Liabilities and Contingent Assets*. Under these agreements, AGL makes unavoidable payments for the green certificates generated by the underlying assets at prices that exceed the economic benefits expected to be received from those renewable energy certificates.

In line with AGL's accounting policy, the onerous contract provisions are reviewed on a regular basis.

Notes to the Financial Statements

for the half-year ended 31 December 2025

17. Issued capital

	31 Dec 2025		30 Jun 2025	
	$m	Number of shares	$m	Number of shares
Balance at beginning of reporting period	**5,918**	**672,747,233**	5,918	672,747,233
Balance at reporting date	**5,918**	**672,747,233**	5,918	672,747,233

Ordinary shares entitle the holder to participate in dividends and the proceeds on winding-up of the Parent Entity in proportion to the number of shares held. Every ordinary Shareholder present at a meeting of the Parent Entity, in person or by proxy, is entitled to one vote per share.

18. Earnings per share

	31 Dec 2025	31 Dec 2024[1]
Statutory earnings per share		
Basic earnings per share	**14.0 cents**	24.1 cents
Diluted earnings per share	**13.9 cents**	24.0 cents
Underlying earnings per share		
Basic earnings per share	**52.5 cents**	56.0 cents
Diluted earnings per share	**52.3 cents**	55.8 cents

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Earnings used in calculating basic and diluted earnings per share

	31 Dec 2025 $m	31 Dec 2024 $m[1]
Statutory earnings used to calculate basic and diluted earnings per share attributable to owners of AGL	**94**	162
Significant expense items after income tax	**116**	160
Loss in fair value of financial instruments after income tax	**143**	55
Underlying earnings used to calculate basic and diluted earnings per share	**353**	377

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Weighted average number of ordinary shares

	31 Dec 2025 Number	31 Dec 2024 Number
Number of ordinary shares used in the calculation of basic earnings per share	**672,747,233**	672,747,233
Effect of dilution	**2,491,741**	2,476,268
Number of ordinary shares used in the calculation of diluted earnings per share	**675,238,974**	675,223,501

19. Acquisition and disposal of subsidiaries and businesses

31 December 2025

Acquisition of SA VPP
On 1 July 2025, the Group acquired SA VPP Project Trust (SA VPP) for purchase consideration of $82 million. SA VPP is an aggregated rooftop virtual power station in South Australia owned by Tesla Group. The acquisition has been accounted for as an asset acquisition.

Capital Contribution to Pottinger Renewables
During the financial period, AGL made a $7 million capital contribution to Pottinger Renewables.

30 June 2025

Acquisition of Upper Hunter Hydro projects
On 4 April 2025, the Group acquired the Upper Hunter Hydro portfolio for purchase consideration of $18 million which includes development projects for renewable energy and storage projects. The agreed total consideration includes future milestone payments which are contingent on completion of project stage gates. The acquisition has been accounted for as an asset acquisition.

Disposal of Surat Gas Project
AGL completed the disposal of Surat Gas Project in March 2025, resulting in a net loss on disposal of $17 million (including $4 million impairment loss). Surat Gas Project consisted of upstream gas assets and liabilities located at Silver Springs and Wallumbilla. The project was included in the Integrated Energy operating segment.

Investment in Kaluza
On 28 January 2025, AGL completed the acquisition of 20% investment in Kaluza (a UK-based entity) in the form of preference shares for a consideration of $151 million. The investment is classified as debt instrument at fair value through profit or loss.

Acquisition of Firm Power and Terrain Solar
On 12 September 2024, AGL acquired 100% of the shares and units in Firm Power and Terrain Solar and their associated entities for a total consideration of $239 million. Firm Power is a Battery Energy Storage System (BESS) developer and Terrain Solar is a solar project developer.

Joint venture with Outback Carbon
In September 2024, AGL entered into an unincorporated joint venture with Outback Carbon (subsidiary of Mitsui). The joint venture will undertake carbon farming projects with a focus in the Wheatbelt region of Western Australia. The arrangement is accounted for as a joint operation.

Capital Contribution to Gippsland Skies
During the financial period, AGL made a $13 million capital contribution to Gippsland Skies.

Notes to the Financial Statements

for the half-year ended 31 December 2025

20. Commitments

20.a Capital expenditure commitments

	31 Dec 2025 $m	30 Jun 2025 $m
Not later than one year	**651**	276
Later than one year and not later than five years	**168**	-
	819	276

There are nil (2025: nil) joint operations capital commitments and AGL's share of associates' commitments is nil (2025: nil).

20.b Joint venture commitments

AGL's share of commitments made jointly with other investors relating to its joint ventures is $7 million (2025: $2 million).

21. Contingent assets and liabilities

Regulatory reviews and investigations

AGL and its businesses are subject to a range of laws and regulations and AGL is subject to reviews and investigations by the government and regulatory bodies from time to time. Regulatory investigations and reviews may result in enforcement action, litigation, and penalties. Consideration has been given to such matters and whilst at this stage a present obligation may be possible, at this time, it is expected that the resolution of these contingent events will not have a material impact on the financial position of AGL.

Legal actions and claims

Certain entities in AGL are party to various legal actions and claims which have arisen in the ordinary course of business. Any liabilities arising from such legal actions and claims are not expected to have a material adverse effect on AGL.

22. Financial instruments

22.a Fair value measurements

The following table provides an analysis of financial instruments that are measured subsequent to initial recognition at fair value, grouped into Levels 1 to 3 based on the degree to which the fair value is observable.

- Level 1 fair value measurements are those derived from quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 fair value measurements are those derived from inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (as prices) or indirectly (derived from prices).
- Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market data (unobservable inputs).

31 December 2025	Carrying Amount $m	Level 1 $m	Level 2 $m	Level 3 $m	Total $m
Financial assets					
Debt instrument financial assets at FVTPL					
Debt instruments	**163**	**-**	**-**	**163**	**163**
Equity instruments at FVOCI					
Unlisted equity securities	**24**	**-**	**-**	**24**	**24**
Unlisted investment funds	**9**	**-**	**-**	**9**	**9**
Derivative financial instruments					
Cross currency swap contracts - cash flow and fair value hedges	**34**	**-**	**34**	**-**	**34**
Interest rate swap contracts - cash flow hedges and fair value hedges	**49**	**-**	**49**	**-**	**49**
Forward foreign exchange contracts - cash flow hedges	**1**	**-**	**1**	**-**	**1**
Energy derivatives - economic hedges	**785**	**121**	**102**	**562**	**785**
Total financial assets	**1,065**	**121**	**186**	**758**	**1,065**
Financial liabilities					
Derivative financial instruments					
Cross currency swap contracts - cash flow and fair value hedges	**(23)**	**-**	**(23)**	**-**	**(23)**
Interest rate swap contracts - cash flow hedges	**(1)**	**-**	**(1)**	**-**	**(1)**
Forward foreign exchange contracts - cash flow hedges	**(1)**	**-**	**(1)**	**-**	**(1)**
Energy derivatives - economic hedges	**(1,744)**	**(320)**	**(873)**	**(551)**	**(1,744)**
Total financial liabilities	**(1,769)**	**(320)**	**(898)**	**(551)**	**(1,769)**

22. Financial instruments (Continued)

30 June 2025[1]	Carrying Amount $m	Level 1 $m	Level 2 $m	Level 3 $m	Total $m
Financial assets					
Debt instrument financial assets at FVTPL					
Debt instruments	164	-	-	164	164
Equity instruments at FVOCI					
Unlisted investment funds	24	-	-	24	24
Other	10	-	-	10	10
Derivative financial instruments					-
Cross currency swap contracts - cash flow and fair value hedges	86	-	86	-	86
Interest rate swap contracts - cash flow and fair value hedges	44	-	44	-	44
Forward foreign exchange contracts - cash flow hedges	1	-	1	-	1
Energy derivatives - economic hedges	941	165	142	634	941
Total financial assets	1,270	165	273	832	1,270
Financial liabilities					
Derivative financial instruments					
Cross currency swap contracts - cash flow and fair value hedges	(14)	-	(14)	-	(14)
Interest rate swap contracts - cash flow and fair value hedges	(11)	-	(11)	-	(11)
Forward foreign exchange contracts - cash flow hedges	(10)	-	(10)	-	(10)
Energy derivatives - economic hedges	(1,726)	(277)	(303)	(1,146)	(1,726)
Total financial liabilities	(1,761)	(277)	(338)	(1,146)	(1,761)

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Estimation of fair values

The following summarises the major methods and assumptions used in estimating the fair values of financial instruments:

- Receivables/payables with a remaining life of less than six months, the notional amount is deemed to reflect the fair value. All other receivables/payables are discounted to determine the fair value if the effect of discounting is material.
- The fair value of forward foreign exchange contracts, interest rate and cross currency swaps is calculated as the present value of expected future cash flows estimated and discounted based on the applicable yield curves derived from quoted interest rates that reflect the credit risk of various counterparties.
- The fair value of borrowings is determined as the present value of future contracted cash flows and credit adjustments. Cash flows are discounted using standard valuation techniques at applicable market yield having regard to timing of cash flows
- The fair value of energy derivatives is determined as the present value of future contracted cash flows and credit adjustments. Cash flows are discounted using standard valuation techniques at applicable market yields, having regard to the timing of the cash flows and risks specific to the instrument, including credit risk.
- The fair value of debt instrument financial assets is calculated using a valuation methodology based on key assumptions such as customer volume, unit pricing, and market multiples in line with industry standards.
- The fair value of lease liabilities is estimated as the present value of future cash flows discounted where the effect of discounting is material.

22. Financial instruments (Continued)

The following table provides a reconciliation of fair value movements in Level 3 financial instruments.

	31 Dec 2025 $m	30 Jun 2025 $m[1]
Opening balance	**(314)**	(379)
Total gains or losses recognised in profit or loss		
Settlements during the year	**(44)**	(444)
Changes in fair value	**181**	366
Transfer from Level 3 to Level 2	**379**	-
Premiums	**-**	(18)
Purchases	**5**	161
Closing balance	**207**	(314)

1. Restated to reflect the accounting adjustment as described in Note 1.5.

Fair value gains or losses on energy derivatives are included in other expenses in the line item "Loss/(gain) on fair value of financial instruments" in Note 5.

The sensitivity of Level 3 contracts with significant unobservable inputs, where the inputs are higher by 10 percent is a $24 million increase to Level 3 derivative contract fair values and lower by 10 percent is a $(24) million decrease to Level 3 derivative contract fair values. Input changes were applied to forward prices with references to electricity market and emissions schemes, cost-based indexes, contract volumes and management's assumptions on long-term commodity curves.

22.b Capital risk management

AGL's objectives when managing capital are to safeguard its ability to continue as a going concern, so that it can continue to provide returns for shareholders, benefits for other stakeholders and to maintain an appropriate capital structure of debt and equity.

In order to maintain or adjust the capital structure, AGL may adjust the amount of dividends paid to shareholders, return capital to shareholders, fund incremental projects with debt or issue new shares.

The capital structure of AGL consists of net debt (borrowings offset by cash and cash equivalents) and total equity (comprising issued capital, reserves and retained earnings).

During the period, AGL reassessed the accounting treatment for certain renewable Power Purchase Agreements (PPAs). As outlined in Note 1.5, this reassessment resulted in some of these contracts being accounted for as leases under AASB 16 *Leases*, leading to a restatement of lease liabilities, including both current and non–current balances.

AGL monitors capital on the basis of the gearing ratio and funds from operations (FFO) to interest expense cover.

The gearing ratio is calculated as net debt divided by adjusted total capital. Net debt is calculated as total borrowings and adjusted lease liabilities, adjusted for cross currency swap hedges and deferred borrowing costs, less cash and cash equivalents. Under AGL's lending agreements, changes arising from the adoption of AASB 16 *Leases* do not affect the definitions used in the calculation of debt covenants including gearing ratio. The adjustments presented in the table reflect the application of this exemption. Adjusted total capital is calculated as total equity less the hedge reserve and adjusted retained earnings plus net debt. AGL remains compliant with all debt covenants.

Notes to the Financial Statements
for the half-year ended 31 December 2025

22. Financial instruments (Continued)

The gearing ratio at the end of the reporting period was as follows:

	31 Dec 2025 $m	30 Jun 2025 $m[1]
Current borrowings	**215**	219
Non-current borrowings	**3,167**	2,820
Total borrowings	**3,382**	3,039
Adjustment to lease liabilities[2]	**191**	185
Adjustment for cross currency swap hedges and deferred borrowing costs	**(17)**	(85)
Adjusted total borrowings	**3,556**	3,139
Cash and cash equivalents	**307**	319
Net debt	**3,249**	2,820
Total equity	**4,735**	4,777
Adjustment to retained earnings[2]	**427**	430
Hedge reserve	**19**	46
Adjusted equity	**5,181**	5,253
Net debt	**3,249**	2,820
Adjusted total capital	**8,430**	8,073
Gearing ratio	**38.5%**	34.9%

1. Restated to reflect the accounting adjustment as described in Note 1.5.
2. Lease liabilities and retained earnings adjustment as a result of adoption of AASB 16 Leases.

23. Subsequent events

On 11 February 2026, AGL announced that it had entered into a binding agreement for the sale of certain telecommunications customer contracts and associated assets of Southern Phone Company Limited for $115 million, with consideration to be received in the form of equity instruments of the purchaser, a member of the Aussie Broadband Limited Group. Completion is anticipated in calendar year 2026, subject to customary conditions.

Apart from the matters identified above and in the financial statements or notes thereto, there has not been any matter or circumstance that has arisen since 31 December 2025 that has significantly affected or may significantly affect the operations of AGL, the results of those operations, or the state of affairs of AGL in the future.

Directors' Declaration

for the half-year ended 31 December 2025

The Directors of AGL Energy Limited declare that, in their opinion:

(a) there are reasonable grounds to believe that AGL Energy Limited will be able to pay its debts as and when they become due and payable;

(b) the attached financial statements and notes of AGL Energy Limited and its controlled entities for the half-year ended 31 December 2025 are in accordance with the *Corporations Act 2001*, including:

(i) giving a true and fair view of the financial position and performance of AGL Energy Limited and its controlled entities for the half-year ended 31 December 2025; and

(ii) complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*.

Signed in accordance with a resolution of the Directors

Miles George
Chair

11 February 2026

Auditor's Independence Declaration

As lead auditor of AGL Energy Limited's financial report for the half-year ended 31 December 2025, I declare that to the best of my knowledge and belief, there have been:

a) no contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the review of the financial report; and

b) no contraventions of any applicable code of professional conduct in relation to the review of the financial report.

Trevor Johnston
Partner
PricewaterhouseCoopers

Melbourne
11 February 2026

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Independent auditor's review report to the members of AGL Energy Limited

Report on the half-year financial report

Conclusion

We have reviewed the half-year financial report of AGL Energy Limited (the Company) and the entities it controlled during the half-year (together the Group), which comprises the condensed consolidated statement of financial position as at 31 December 2025, the condensed consolidated statement of comprehensive income, condensed consolidated statement of profit or loss, condensed consolidated statement of changes in equity, condensed consolidated statement of cash flows, for the half-year ended on that date, material accounting policy information and selected explanatory notes and the directors' declaration.

Based on our review, which is not an audit, we have not become aware of any matter that makes us believe that the accompanying half-year financial report of AGL Energy Limited does not comply with the *Corporations Act 2001* including:

1. giving a true and fair view of the Group's financial position as at 31 December 2025 and of its performance for the half-year ended on that date;
2. complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*.

Basis for conclusion

We conducted our review in accordance with ASRE 2410 Review of a Financial Report Performed by the Independent Auditor of the Entity (ASRE 2410). Our responsibilities are further described in the Auditor's responsibilities for the review of the half-year financial report section of our report.

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Independent Auditor's Review Report

We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional & Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to the audit of the annual financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

Responsibilities of the directors for the half-year financial report

The directors of the Company are responsible for the preparation of the half-year financial report, in accordance with Australian Accounting Standards and the *Corporations Act 2001*, including giving a true and fair view, and for such internal control as the directors determine is necessary to enable the preparation of the half-year financial report that is free from material misstatement whether due to fraud or error.

Auditor's responsibilities for the review of the half-year financial report

Our responsibility is to express a conclusion on the half-year financial report based on our review. ASRE 2410 requires us to conclude whether we have become aware of any matter that makes us believe that the half-year financial report is not in accordance with the *Corporations Act 2001* including giving a true and fair view of the Group's financial position as at 31 December 2025 and of its performance for the half-year ended on that date, and complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*.

A review of a half-year financial report consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

PricewaterhouseCoopers

PricewaterhouseCoopers

Trevor Johnston

Trevor Johnston
Partner

Melbourne
11 February 2026

Corporate Directory

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