

2026 Forecasting Assumptions Update

August 2026

For use in the 2026 National
Electricity Market Electricity
Statement of Opportunities





We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

AEMO is proud to have launched its Innovate [Reconciliation Action Plan](#) (RAP) in June 2026. Pictured left and featuring on the cover of the Innovate RAP is Wiradjuri artist Lani Balzan's 'Journey of unity: AEMO's Reconciliation Path', a visual representation of our ongoing journey towards reconciliation – a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

AEMO publishes this 2026 Forecasting Assumptions Update in accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines (FBPG), pursuant to National Electricity Rules (NER) 4A.B.1(e). This report includes information on updated assumptions to apply in the Reliability Forecast (and other publications, as named in this report, for the National Electricity Market (NEM) and Wholesale Electricity Market (WEM)). This publication is generally based on information available to AEMO as at 1 July 2026 unless otherwise indicated.

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Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

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Version control

Version	Release date	Changes
1.0	25/08/2026	Initial release

Executive summary

AEMO delivers a range of forecasting and planning publications for the National Electricity Market (NEM) and Wholesale Electricity Market (WEM), including the NEM *Electricity Statement of Opportunities* (NEM ESOO), WEM *Electricity Statement of Opportunities* (WEM ESOO) and the *Integrated System Plan* (ISP). Key inputs and assumptions for the ISP are published biennially as part of the *Inputs, Assumptions and Scenarios Report* (IASR). The most recent IASR, used to prepare the 2026 ISP, is the 2025 IASR¹.

Many of the same inputs and assumptions are applied in preparing the NEM ESOO, WEM ESOO, East Coast Gas Market *Gas Statement of Opportunities* (GSOO), and WA Gas Market *Gas Statement of Opportunities* (WA GSOO), which are produced annually.

This report therefore complements the 2025 IASR and provides updated assumptions and inputs for the 2026 NEM ESOO.

Summary of updated assumptions

This 2026 *Forecasting Assumptions Update* and associated 2026 *Forecasting Assumptions Update* Workbook (the Updated Assumptions Book) outline updates to various forecasting components. The updates reflect both:

- updated component forecasts that have been prepared in accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines (FBPG)², and
- re-baselined elements to reflect the latest actual market observations.

Forecasting components that reflect updated drivers and forecasts (rather than changes based on more recent actual observations) include:

- updated data centre consumption forecasts, including a revised project pipeline assessment and new connection data from network service providers (NSPs),
- increased distributed battery forecasts reflecting stronger-than-anticipated uptake driven by the Cheaper Home Batteries Program (CHBP) and WA Residential Battery Scheme (WA RBS), together with increased battery size, storage duration and revised virtual power plant (VPP) participation rate assumptions,
- updated electric vehicle (EV) forecasts with revised vehicle efficiency and charging type assumptions,
- updated generator availability assumptions through an expanded outage forecasting methodology representing long-duration unplanned outages, forced outages, planned outages and maintenance outages,
- newly incorporated station-level operational energy limits for scheduled generating units,
- updated demand side participation (DSP) target levels, with the New South Wales Peak Demand Reduction Scheme (PDRS) no longer expected to influence these levels, and
- updated gas price forecasts used in the 2026 GSOO.

¹ At <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios>.

² At https://www.aer.gov.au/system/files/2026-06/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2005%20June%202026_3.pdf.



Contents

Executive summary	3
1 Introduction	7
1.1 Consultation process	7
1.2 Approach taken to update key forecasting inputs	9
1.3 Supporting material	9
2 Updated assumptions	11
2.1 Energy consumption and demand updates	11
2.2 Existing generators and transmission	51
2.3 New entrant technical parameters	59
2.4 Fuel price assumptions	60
2.5 Transmission network modelling	62

Tables

Table 1	Stakeholder engagement on the <i>Forecasting Assumptions Update</i>	8
Table 2	Stakeholder feedback summary to the Draft 2026 <i>Forecasting Assumptions Update</i> consultation	8
Table 3	Stakeholder feedback summary from the Forecasting Reference Group	8
Table 4	Additional information and data sources	9
Table 5	Status and update for key inputs and assumptions	11
Table 6	EV charging profiles and description	29
Table 7	High-level mapping of price input settings by scenario	39
Table 8	Price elasticities of demand for various appliances and sectors	39
Table 9	Project status explanations	45
Table 10	Forecast DSP for each NEM region, summer, 2026-27 to 2055-56, <i>Step Change</i> scenario (MW)	50
Table 11	Status and update process for key inputs and assumptions for existing generation and transmission	51
Table 12	Updated outage forecasting definitions	52
Table 13	Existing generators – long duration unplanned outages	53
Table 14	Inter-regional transmission flow path unplanned outage rates	58

Figures

Figure 1	Actual and projected rooftop PV installed capacity for the NEM, 2014-15 to 2055-56 (gigawatts [GW] degraded)	14
Figure 2	Actual and projected rooftop PV installed capacity for the WEM, 2014-15 to 2055-56 (GW degraded)	14
Figure 3	Actual and projected PVNSG capacity for the NEM, 2014-15 to 2055-56 (GW degraded)	15
Figure 4	Actual and projected PVNSG capacity for the WEM, 2014-15 to 2055-56 (GW degraded)	15
Figure 5	Actual and projected distributed PV installed capacity for the NEM, 2014-15 to 2055-56 (GW degraded)	16
Figure 6	Actual and projected distributed PV installed capacity for the WEM, 2014-15 to 2055-56 (GW degraded)	16
Figure 7	Actual and projected distributed battery forecast for the NEM, 2020-21 to 2055-56 (GW)	18
Figure 8	Actual and projected distributed battery forecast for the NEM, 2020-21 to 2055-56 (GWh degraded)	19
Figure 9	Actual and projected distributed battery forecast for the WEM, 2020-21 to 2055-56 (GW)	19
Figure 10	Actual and projected distributed battery forecast for the WEM, 2020-21 to 2055-56 (GWh degraded)	20
Figure 11	Projected VPP participation rate for the NEM, 2025-26 to 2055-56	21
Figure 12	Projected VPP capacity for the NEM, 2025-26 to 2055-56 (GW)	22
Figure 13	Projected VPP storage capacity for the NEM, 2025-26 to 2055-56 (GWh, degraded)	22
Figure 14	Projected VPP participation rate for the WEM, 2025-26 to 2055-56	23
Figure 15	Projected VPP capacity for the WEM, 2025-26 to 2055-56 (GW)	23
Figure 16	Projected VPP storage capacity for the WEM, 2025-26 to 2055-56 (GWh, degraded)	24
Figure 17	Actual and projected BEV and PHEV fleet size (NEM and WEM) by scenario, 2016-17 to 2055-56	25
Figure 18	Projected sales share and fleet share by vehicle technology type for <i>Step Change</i> (NEM and WEM) comparing 2025 IASR (2024-25 to 2054-55) and 2026 <i>Forecasting Assumptions Update</i> (2025-26 to 2055-56)	26
Figure 19	Projected PHEV fleet size (NEM and WEM) by scenario, 2016-17 to 2055-56	27
Figure 20	Projected BEV and PHEV electricity consumption (NEM and WEM) by scenario, 2021-22 to 2055-56 (terawatt hours [TWh])	28
Figure 21	Split of charging types for medium residential vehicles (New South Wales): 2025 IASR (left) and 2026 <i>Forecasting Assumptions Update</i> (right) for <i>Step Change</i> scenario, 2025-26 to 2055-56	30
Figure 22	Static after-diversity charging profiles of different EV charging types for medium residential vehicles (New South Wales) in 2030 (kW per vehicle)	31
Figure 23	Aggregate other non-scheduled generation installed capacity by NEM region and technology type (MW)	33
Figure 24	Number of other non-scheduled generating units by NEM region and technology type	34
Figure 25	Forecast NEM-wide other non-scheduled generation capacity (MW)	35
Figure 26	Actual and forecast NEM residential connections, 2019-20 to 2055-56	36
Figure 27	Forecast residential appliance uptake (NEM), 2025-26 to 2055-56 (TWh)	37



Figure 28	Forecast NEM residential real retail price index, 2025-26 to 2055-56	38
Figure 29	Forecast energy efficiency savings (NEM), 2025-26 to 2055-56 (TWh)	40
Figure 30	Forecast electrification for residential, commercial, industrial and non-road transport (NEM), 2025-26 to 2055-56 (TWh)	41
Figure 31	NEM LIL consumption actuals and forecasts, 2019-20 to 2055-56 (TWh)	43
Figure 32	NEM Standing Information Request – 2026 data centre connection pipeline (GW)	44
Figure 33	NEM Standing Information request – 2025 data centre connection pipeline (GW)	44
Figure 34	Actual and forecast NEM data centre consumption (project-based), 2025 NEM ESOO and 2026 NEM ESOO, 2019-20 to 2055-56 (TWh)	46
Figure 35	Actual and forecast NEM data centre consumption (economics-based), 2025 NEM ESOO and 2026 NEM ESOO, 2019-20 to 2055-56 (TWh)	47
Figure 36	Actual and forecast NEM data centre consumption, 2025-26 to 2055-56 (TWh)	48
Figure 37	Actual and forecast CSG electricity consumption, 2019-20 to 2055-56 (TWh)	49
Figure 38	Forecast electricity consumption for hydrogen production, 2025-26 to 2055-56, all scenarios (TWh per annum)	51
Figure 39	Actual and forecast equivalent forced outage rates for coal generation technologies, 2021-22 to 2035-36	54
Figure 40	Actual and forecast equivalent forced outage rates for all gas and liquid aggregate, battery, and hydro technologies, 2021-22 to 2035-36	55
Figure 41	Actual and projected equivalent planned and maintenance outage rates for coal generation technologies, 2025-26 to 2035-36	57
Figure 42	Actual and forecast equivalent planned and maintenance outage rates for all gas and liquid aggregate, battery, and hydro technologies, 2025-26 to 2035-36	57
Figure 43	Comparison of aggregated daily and annual energy limits assumptions of coal, gas, and liquid fuel generators applied in the 2025 and 2026 ESOO (monthly GWh)	59
Figure 44	Forecast industrial gas prices by scenario – Melbourne, 2025-26 to 2055-56 (\$AUD/GJ)	61
Figure 45	Forecast industrial gas prices by region – <i>Step Change</i> , 2025-26 to 2055-56 (\$AUD/GJ)	62

1 Introduction

AEMO produces several forecasting and planning publications that use the scenarios and their assumptions that are described in the IASR, such as the NEM ESOO, WEM ESOO, GSOO for the East Coast Gas Market, WA GSOO, and ISP. These publications complement each other, providing adequacy assessments of the electricity and gas systems, as well as optimal developments needed within the power system to deliver reliable and secure electricity at least cost for homes and businesses, while supporting government policy and emissions reduction objectives.

AEMO forecasts and models plausible futures in these publications through a scenario planning approach, relying on scenario assumptions that are documented in the IASR. This 2026 *Forecasting Assumptions Update* complements the biennial IASR, which provides the broader assumptions deployed across AEMO's forecasting and planning activities. This document outlines several updated inputs and assumptions that apply to the 2026 NEM ESOO. In many instances, assumptions applied in the NEM ESOO are unchanged since the 2025 IASR; these are not repeated in this publication.

The information in this report is supported by the 2026 *Forecasting Assumptions Update* Workbook (the Updated Assumptions Book)³, which provides more granular detail for these updated inputs and assumptions.

All dollar values provided in this report are in real July 2025 Australian dollars unless stated otherwise.

1.1 Consultation process

In accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines (FBPG)⁴, AEMO has consulted with stakeholders transparently and openly regarding the updated assumptions in this *Forecasting Assumptions Update*. **Table 1** summarises the consultation activities undertaken for this purpose.

AEMO received 12 written submissions and one verbal submission from stakeholders to the Draft 2026 *Forecasting Assumptions Update* consultation. Key themes in the feedback are summarised in **Table 2**.

³ At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/2026-Forecasting-Assumptions-Update-Workbook.

⁴ At <https://www.aer.gov.au/industry/registers/resources/guidelines/forecasting-best-practice-guidelines>.

Table 1 Stakeholder engagement on the Forecasting Assumptions Update

Topic for consultation	Consultation mechanism	Consultation
Consumer energy resources (CER)	Draft 2026 <i>Forecasting Assumptions Update</i>	23 December 2025 to 2 February 2026
Existing generation and transmission technical parameters	Draft 2026 <i>Forecasting Assumptions Update</i>	23 December 2025 to 2 February 2026
GenCost 2025-26 Consultation draft feedback	Draft 2026 <i>Forecasting Assumptions Update</i>	23 December 2025 to 2 February 2026
Demand forecasting methodology improvements	Forecasting Reference Group (FRG) consultation	25 March to 8 April 2026
Economic, population, households and connections forecasts	FRG consultation	29 April to 13 May 2026
Updated large industrial load (LIL) forecasts	FRG consultation	13 to 27 May 2026
Data centre consumption forecasts	FRG consultation	13 to 27 May 2026
Updated inputs affecting consumption forecasts: <ul style="list-style-type: none"> • electrification (non-EV) • electricity price indices • energy efficiency • appliance uptake 	FRG consultation	13 to 27 May 2026
Updated inputs affecting demand forecasts	FRG consultation	15 to 29 June 2026
Updated DSP forecasts	FRG consultation	15 to 29 June 2026
Unplanned outages affecting inter-regional power transfers	FRG consultation	15 to 29 June 2026
Scheduled generator unplanned outage rates	FRG consultation	15 to 29 June 2026

Table 2 Stakeholder feedback summary to the Draft 2026 Forecasting Assumptions Update consultation

Topic	Recommendations
Distributed photovoltaics (PV) systems	Uptake forecast may be too high; impact of Solar Sharer Offer; provide tariff and payback assumptions; incorporate regional load variations.
Embedded energy storage	Consider impact of government schemes on uptake; provide transparency on assumptions.
VPPs	Reduce participation rate and separate it from tariff type; use different assumptions for WEM.
EVs	Consider sales impact on incentives and charging infrastructure; test time-varying availability factor; increase peak-shaving by residential EVs; more granular public charging profiles; enhance efficiency and seasonality assumptions.

AEMO received written submissions from three stakeholders and material recommendations verbally from six stakeholders through Forecasting Reference Group (FRG) consultation in 2026. Key themes in the feedback are summarised in **Table 3**.

Table 3 Stakeholder feedback summary from the Forecasting Reference Group

Topic	Recommendations
Demand forecasting methodology improvements	Rerun temperature response regression; publish distributed PV generation data; explain LIL outage assumptions.
Economic forecasts	Consider the impacts of tax policies on dwelling forecasts; analyse consumption forecast uncertainties.
Data centre forecasts	Quantify demand based on data centre applications; provide intra-day load profiles and diversity; assess demand uncertainties through sensitivities.
Consumption forecasts	Provide more detail on demand for different battery sizes; publish PV forecasting assumptions and LIL project list.

AEMO documented the material stakeholder feedback arising during its consultation and its consideration of the stakeholder feedback in its 2026 *Forecasting Assumptions Update Consultation Summary Report*⁵. AEMO thanks all stakeholders who engaged with these consultation opportunities.

1.2 Approach taken to update key forecasting inputs

AEMO has applied two forms of updates in the updated inputs and assumptions since the 2025 IASR:

- **updated assumptions**, reflecting holistic updates since the 2025 IASR, applying the same, or similar, methodologies to derive new component forecasts, and
- **rebased assumptions**, reflecting an updated starting point for the 2025 IASR scenario-based trajectories or trends, rebased to apply more recent actual data.

This *Forecasting Assumptions Update* outlines the method for each assumption update in each subsection. All other component forecasts remain unchanged since the 2025 IASR.

1.3 Supporting material

Table 4 documents additional information on AEMO's inputs and assumptions.

Table 4 Additional information and data sources

Organisation	Document/source	Link
AEMO	2025 <i>Inputs, Assumptions and Scenarios Report</i>	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf
AEMO	2026 <i>Distributed PV and Batteries/VPP Forecast Report</i>	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/2026-Distributed-PV-and-Batteries-VPP-Forecast-report
AEMO	2026 <i>Forecasting Assumptions Update Workbook</i>	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/2026-Forecasting-Assumptions-Update-Workbook
AEMO	2026 <i>Forecasting Assumptions Update Detailed EV Workbook</i>	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/2026-Forecasting-Assumptions-Update-Detailed-EV-Workbook
ACIL Allen	ACIL Allen gas price forecast for 2026 GSOO	https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-acil-allen-2025-projections.pdf
CSIRO	2025-26 GenCost report	https://www.csiro.au/en/research/technology-space/energy/Electricity-transition/GenCost
CSIRO	<i>Electric vehicle projections 2025</i>	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-electric-vehicle-projections.pdf
CSIRO	<i>Small-scale Solar PV and Battery Projections 2025-26 report</i>	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-small-scale-solar-pv-and-battery-projections-2025-26-report.pdf

⁵ At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/2026-Forecasting-Assumptions-Update-Consultation-Summary-Report.

Organisation	Document/source	Link
GEM	<i>Projections for Distributed Energy Resources – Solar PV and Stationary Energy Battery Systems</i> report	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/gem-projections-for-der-solar-pv-stationary-energy-battery-systems-report.pdf
GHD	<i>2026 Energy Technology Cost and Technical Parameter</i> report	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/GHD-Cost-and-technical-parameters-review-report
GHD	<i>2026 Energy Technology Cost and Technical Parameter tables</i>	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/GHD-Cost-and-technical-review-Excel
GHD	<i>2026 Energy Technology Cost and Technical Parameter tables review</i>	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/GHD-Cost-and-technical-review-Excel-response
Oxford Economics Australia	<i>Data Centre Energy Demand – 2026 Forecast Update</i>	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/Oxford-Economics-Australia-Data-Centre-Energy-Demand-2026-Forecast-Update

2 Updated assumptions

2.1 Energy consumption and demand updates

AEMO updates its projections of energy consumption and demand at least annually⁶, and undertakes significant stakeholder engagement through the FRG⁷ and industry engagement via surveys for large loads, in accordance with the AER's FBPG. This engagement focuses on key influences and outcomes from AEMO's forecasting models within the Forecasting Approach of each sector and sub-sector affecting energy consumption and peak demands. **Table 5** describes the status of key inputs and assumptions for energy consumption and demand in this *Forecasting Assumptions Update*.

Table 5 Status and update for key inputs and assumptions

Input	Status
Historical data	<ul style="list-style-type: none"> Updated
CER (including distributed PV, distributed battery storage and EVs)	<ul style="list-style-type: none"> Updated and rebased for distributed PV Updated and rebased for battery storage Updated for EVs
Other non-scheduled generation	<ul style="list-style-type: none"> Updated
Economics and population	<ul style="list-style-type: none"> Economics unchanged
Dwellings and connections	<ul style="list-style-type: none"> Updated
Appliance uptake	<ul style="list-style-type: none"> Rebased
Electricity prices	<ul style="list-style-type: none"> Updated
Energy efficiency	<ul style="list-style-type: none"> Rebased
Electrification (excluding EVs)	<ul style="list-style-type: none"> Rebased
Large industrial loads, including coal seam gas extraction and data centres	<ul style="list-style-type: none"> Updated
DSP	<ul style="list-style-type: none"> Updated
Hydrogen electrolyzers	<ul style="list-style-type: none"> Rebased

2.1.1 Consumer energy resources (CER)

Input vintage	April 2026
Source	<ul style="list-style-type: none"> AEMO (2026 Distributed PV and Batteries/VPP Forecast report) CSIRO (Small-scale Solar PV and Battery Projections 2025-26 report) Updated market data from the Clean Energy Regulator
Updates since 2025 IASR	<p>Updated with new forecasts, April 2026</p> <p>Distributed PV forecasts rebased with latest installations data to end of March 2026</p> <p>Battery forecasts rebased with latest installations data to end of March 2026</p> <p>Updated after stakeholder consultation feedback on Draft 2026 <i>Forecasting Assumptions Update</i></p>

⁶ Updated forecasts within a year can be re-issued in case of material change to input assumptions.

⁷ See <https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg>.

CER includes consumer-owned devices that can generate or store electricity as individual units and which may have the ‘smarts’ to actively manage energy import and export. CER can also refer to other resources that enable greater demand flexibility. This section includes forecasts of rooftop and other small-scale solar (which includes photovoltaic [PV] non-scheduled generation, known as PVNSG), battery storage, and EVs.

AEMO acknowledges that while rooftop solar is a mature technology, forecasting the decisions that individual consumers and businesses are making to invest in it is not trivial. Some of the factors contributing to this complexity are changing incentives, exposure to energy price changes, influence of economic confidence or uncertainty, integration and coordination opportunities, technological advancements, and the co-development influence of other consumer investment options (including EVs, batteries, energy efficiency investments, and non-energy investments such as housing, education and travel). These factors continue to provide uncertainty for rooftop solar uptake, with even greater uncertainty in emerging CER devices, such as EVs and consumer batteries.

As a result, AEMO has engaged consultants CSIRO and Green Energy Markets to inform the forecasting, as well as developing an AEMO CER forecasting approach⁸ with the intent to increase transparency, accuracy and responsiveness to continued change. The forecasts presented in this section have been influenced by the consultant forecasts, alongside AEMO’s own forecasting capability, across scenarios.

In this *Forecasting Assumptions Update*, AEMO applied the forecasts from AEMO’s forecasting approach and from CSIRO in the combination that best maintains the scenario spread that is described by the scenario narratives. AEMO considers that the following combination most appropriately reflects the spread of potential consumer outcomes, such that:

- **distributed PV forecasts** use *Step Change* and *Accelerated Transition* from AEMO’s CER forecasting approach; and *Slower Growth* uses CSIRO’s forecasts,
- **distributed battery and VPP forecasts** use *Step Change* and *Accelerated Transition* from AEMO’s CER forecasting approach, exploring a future where the recent high rates of consumer battery adoption persist; and the *Slower Growth* forecast uses CSIRO’s forecasts projecting a slower rate of consumer adoption, and
- **EV forecasts** use all scenarios from CSIRO’s forecast for the 2025 IASR, rebased to reflect the most recent vehicle sales insights.

Distributed PV

This section includes forecasts for rooftop PV (defined as residential and commercial systems up to 100 kilowatts [kW]) and PVNSG (larger PV systems between 100 kW and 30 megawatts [MW]), which together make up total distributed PV at the end of the section.

Relative to the draft forecasts, the forecasts presented here have been:

- rebased to reflect the latest actual installation data to end of March 2026,
- adjusted to incorporate the estimated impact of the Solar Sharer Offer in applicable regions, and the Victorian Midday Power Saver Offer, which result in a minor decrease in PV uptake as they reduce the financial attractiveness of PV

⁸ AEMO’s CER forecasting uplift was described at AEMO’s FRG on 22 October 2025. The initiative applies a consumer adoption modelling approach and seeks to enhance transparency and forecast accuracy through an integrated modelling process led by AEMO and informed by expert consultants. See <https://aemo.com.au/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg>.

systems (not coupled to a battery), by reducing the anticipated energy cost savings and thus worsening the payback period, and

- updated with the latest retail tariff forecasts for the WEM.

Rooftop PV and PVNSG current installed capacity estimates are based on data published by the Clean Energy Regulator. The Clean Energy Regulator's postcode-level dataset includes system additions and replacements in addition to new installations. Because system additions increase the capacity of existing systems, and system replacements substitute existing systems rather than adding new ones, AEMO applied adjustments using installation-level data obtained directly from the CER that identifies these categories⁹. In complex environments with evolving definitions and data collection processes, historical 'actuals' are often estimates rather than fixed historical values. For this forecast, AEMO reviewed the historical PV dataset and made adjustments to incorporate this additional information on system additions and replacements, resulting in lower estimates of historical PV installations and capacity than previously reported. Consequently, some figures in this report contain a slight discontinuity between the revised historical series (as seen below in **Figure 1**) and earlier forecasts, which were based on higher historical estimates.

Rooftop PV

The rooftop PV forecasts include inputs from the 2024-25 GenCost¹⁰, retail price trends, and PV installation size trends based on Clean Energy Regulator data. The GenCost report forecasts a continued slow decline in the cost of rooftop PV systems. AEMO anticipates ongoing increase in the average PV system size, although with lesser growth of average system size in the medium term to recognise that dwellings have limited rooftop area on which to install panels.

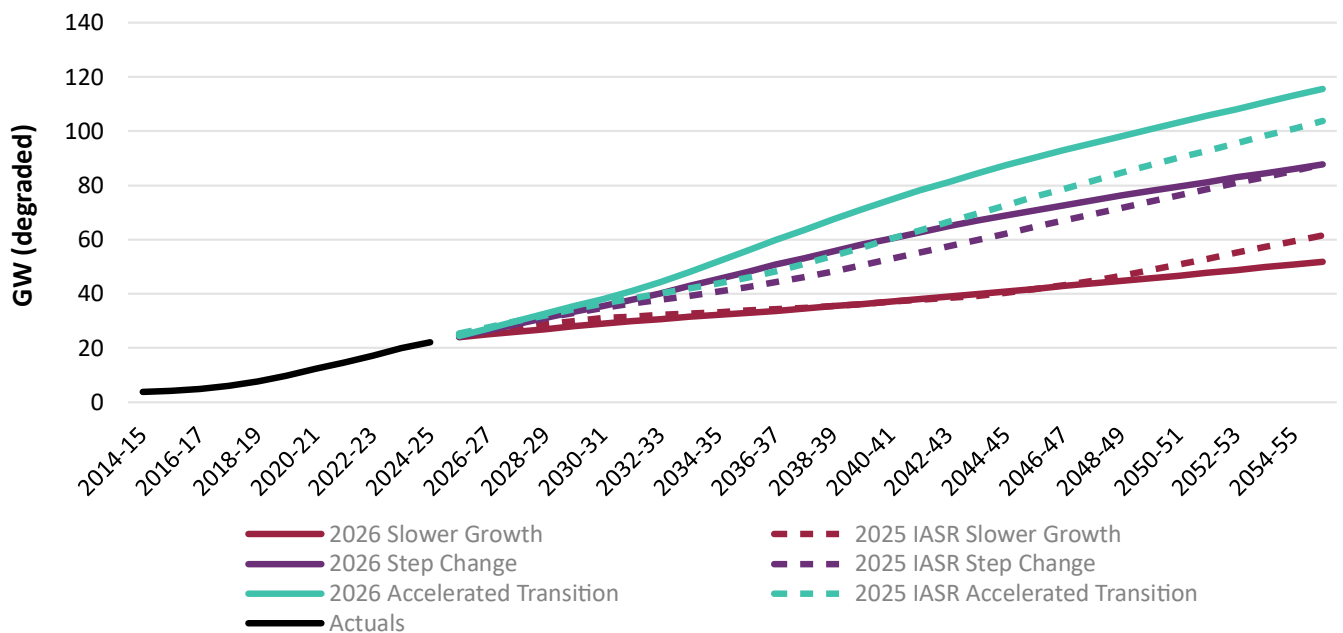
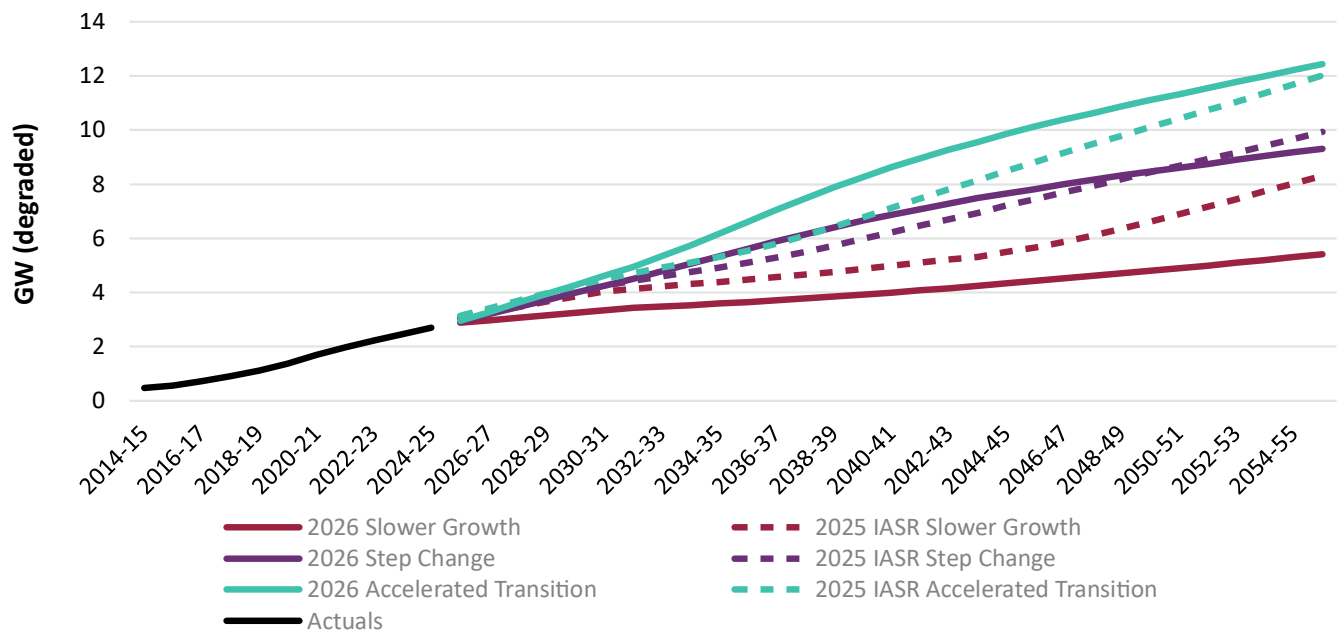
Considering the factors above, growth in rooftop PV capacity is projected to continue to increase at a similar pace as in recent years, with medium to long term uncertainty captured by the scenario spread (**Figure 1** and **Figure 2**). Across scenarios, the rate of uptake starts to slow down in the late 2040s, as the PV market (that is, PV-suitable dwellings and some commercial buildings) becomes increasingly saturated. The scenario-specific saturation levels depend on a range of variables, starting from economic forecasts of housing growth, and including scenario specific parameter settings.

Relative to the 2025 IASR, this *Forecasting Assumptions Update* shows an increased uptake of rooftop PV in *Accelerated Transition* across the forecast period, an increased uptake in *Step Change* in the medium term, and a slightly reduced long-term uptake for *Slower Growth*. The increases in *Accelerated Transition* and *Step Change* are largely driven by assumed increased PV system sizes along with improved calibration of the consumer response to changes in payback, and more explicit inclusion of market size effects¹¹. The long-term reduction in *Slower Growth* relative to the 2025 IASR is largely the result of projected increased PV costs, which impacts the WEM more significantly due to lower and flat projected energy tariffs impacting the payback forecast in that market. Beyond the medium term, uptake slows in *Accelerated Transition* and *Step Change* as some challenges exist for remaining potential installations, such as sub-optimal shading, limited roof space, higher installation costs relative to capacity to pay, or where the owner may accrue less benefits (such as landlords).

⁹ The postcode level data is publicly available from the Clean Energy Regulator (<https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data#postcode-data-files>). AEMO supplements this dataset with installation-level information provided directly by the Clean Energy Regulator to identify system additions and replacements and adjust installed capacity estimates accordingly.

¹⁰ See <https://doi.org/10.25919/yfbi-4k58>. Note that for this Forecasting Assumptions Update, AEMO has chosen to use the latest Final GenCost release available at the time (i.e., final 2024-25 GenCost), rather than the Draft 2025-26 GenCost release, which was still open to stakeholder feedback and subject to change.

¹¹ Market size effect refers to the slowdown in uptake rate as the percentage of the available market (in this case, PV-suitable dwellings without a PV system) reduces as overall uptake increases. This effect can be observed in Figure 5 in the tapering off in growth towards the end of the forecast.

Figure 1 Actual and projected rooftop PV installed capacity for the NEM, 2014-15 to 2055-56 (gigawatts [GW] degraded)**Figure 2** Actual and projected rooftop PV installed capacity for the WEM, 2014-15 to 2055-56 (GW degraded)

PVNSG

The PVNSG forecast (systems between 100 kW and 30 MW that are either rooftop or ground-mounted, installed by larger energy consumers or by market developers) in **Figure 3** and **Figure 4** shows ongoing growth, reflecting continuation of recent trends in near term, and anticipated decreases in system costs over time¹². However, the forecasts for *Accelerated*

¹² See details in https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/Draft-2026-FAU/AEMO-2025-Distributed-PV-and-Batteries-VPP-Forecast-report.

Transition and *Step Change* in the NEM also show long-term saturation as the cumulative number of systems increases and therefore reduce the size of the available market for new PVNSG systems, (without significant improvements in their financial attractiveness that would increase the willingness to invest and drive further growth in uptake).

Relative to the 2025 IASR forecasts, the short-term PVNSG outlook for the NEM increases, reflecting the growth trend observed from recent actuals. In the medium- to long-term forecasts, uptake slows as assumed saturation levels are reached across scenarios. For the WEM, the forecasts are higher across the full outlook period, reflecting growth in the actual installations as well as improvements to the underlying model, to better capture how the historical relationship between payback and uptake is reflected in the forecast¹³.

Figure 3 Actual and projected PVNSG capacity for the NEM, 2014-15 to 2055-56 (GW degraded)

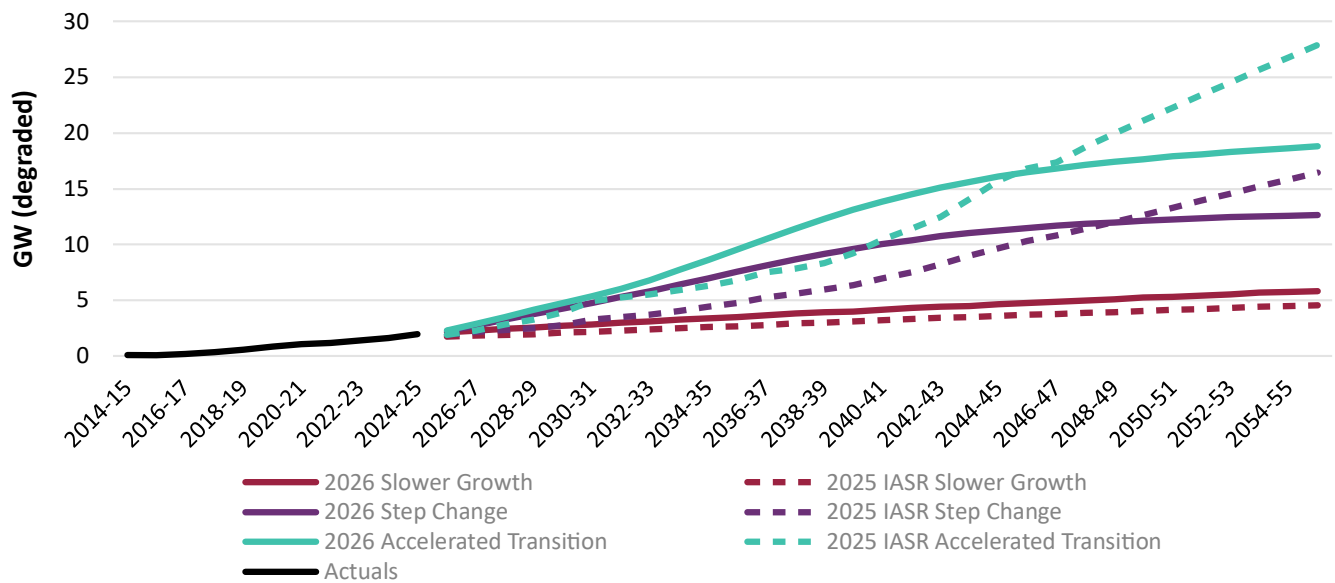
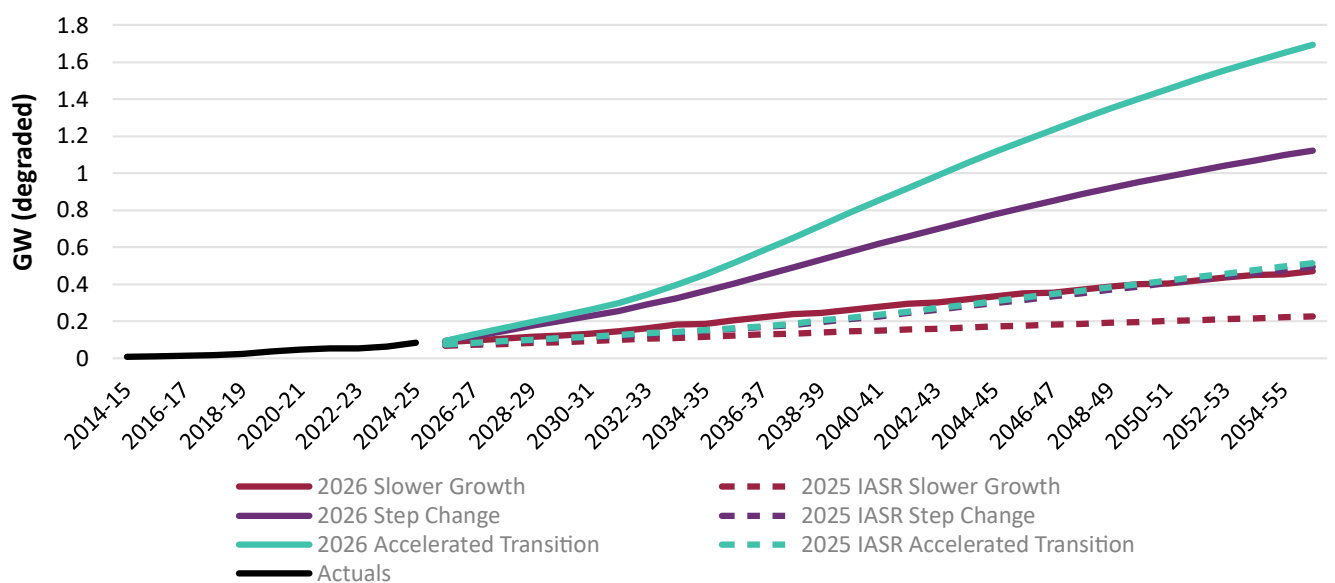


Figure 4 Actual and projected PVNSG capacity for the WEM, 2014-15 to 2055-56 (GW degraded)



¹³ See details in Section 2 of the supporting 2026 *Distributed PV and Batteries/VPP Forecast* report.

Distributed PV – totals

Figure 5 and **Figure 6** below aggregate rooftop PV and PVNSG, which together make up the total distributed PV forecast (with rooftop PV accounting for approximately 90% of the total capacity).

Figure 5 Actual and projected distributed PV installed capacity for the NEM, 2014-15 to 2055-56 (GW degraded)

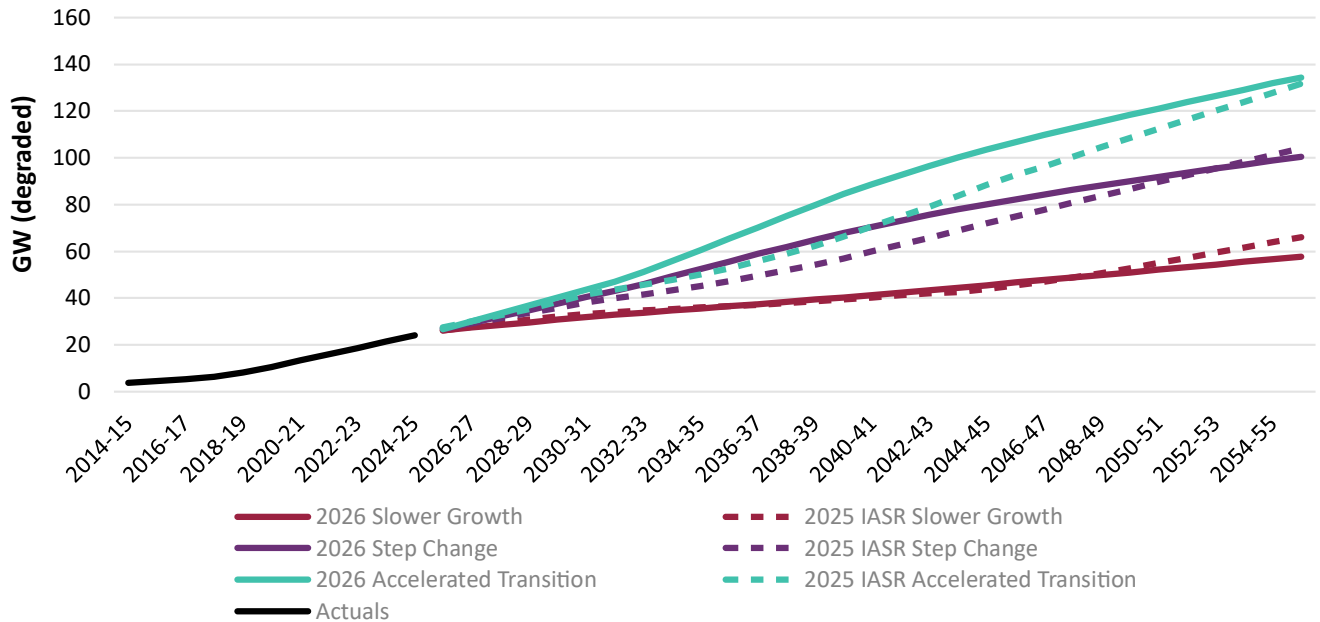
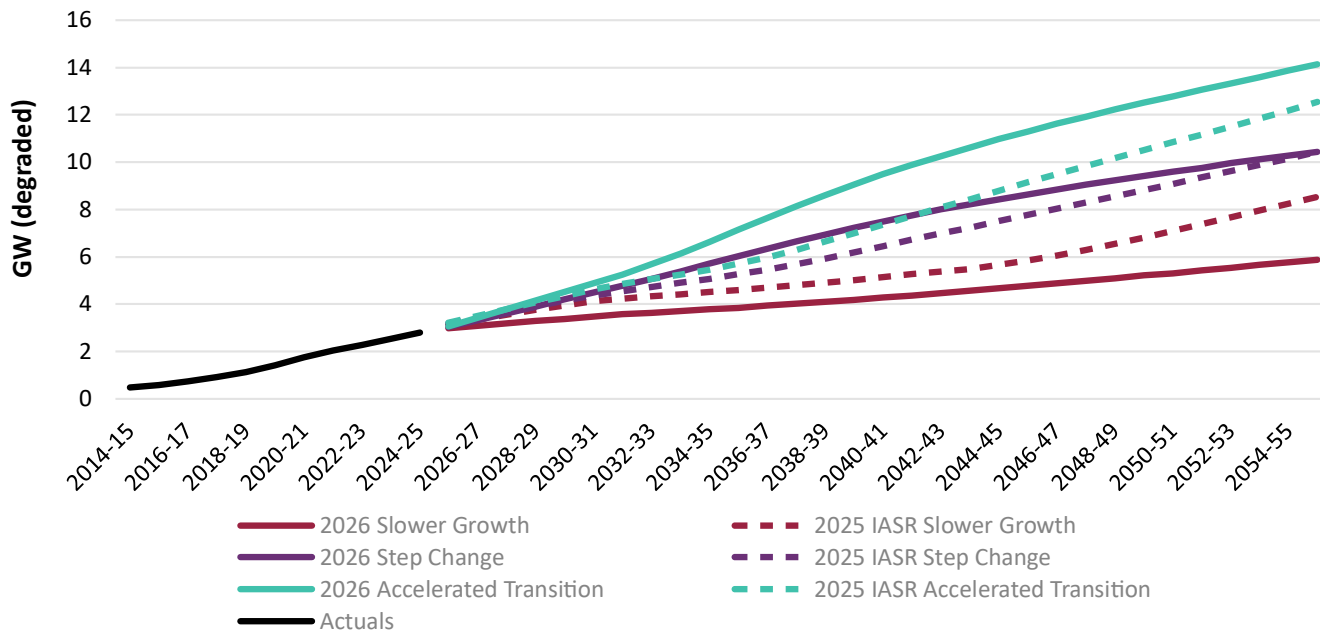


Figure 6 Actual and projected distributed PV installed capacity for the WEM, 2014-15 to 2055-56 (GW degraded)



Distributed batteries

Distributed battery installations have accelerated considerably since June 2025, driven primarily by two policies:

- the introduction of the CHBP¹⁴, delivering significant subsidies to consumers installing residential or small commercial battery systems – since the program commenced in July 2025, it has been evident that AEMO’s consideration of the subsidy program in the 2025 IASR forecasts was below what has been observed, and reflecting stakeholder feedback, AEMO has increased forecast capacity, as well as the battery sizes installed, and
- the WA RBS¹⁵, which includes a subsidy that is additional to the CHBP and requires consumers to sign up to a VPP for a minimum of two years.

Since the Draft 2026 *Forecasting Assumptions Update*, battery forecasts have been updated to include:

- revisions to the CHBP announced in December 2025, including a reduction in the level of subsidy,
- updated data on battery installations from the Clean Energy Regulator until the end of March 2026,
- updated future battery size assumptions, including region-specific average battery sizes and an increase in the average storage duration from 2.5 hours to approximately three hours, based on the observed increase since the introduction of the CHBP,
- updated PV forecasts incorporating the estimated impacts of the Solar Sharer Offer and the Victorian Midday Power Saver offer,
- reduced levels of VPP participation for NEM regions, and
- specific consideration of VPP participation in the WEM incorporating data from the WA RBS.

There is considerable uncertainty around whether the strong rates of consumer adoption since the start of the CHBP will be sustained, and how subsidy levels, structure, and their impacts on consumer adoption may change through to the scheduled program completion of the CHBP in 2030. In December 2025, for example, the Federal Government announced expanded funding and changes to the amount of support that will be provided for different battery sizes.

Since the 2025 IASR, the forecasts have been updated to reflect the stronger than anticipated response to the CHBP, as supported by feedback from stakeholders. Accordingly, the forecasting approach for battery uptake in the NEM and WEM was:

- *Step Change and Accelerated Transition* using AEMO’s CER forecasting approach, exploring the potential that recent high rates of consumer adoption and shift in consumer preference for higher capacity batteries persist, and
- *Slower Growth* applying CSIRO’s forecasts projecting a slower rate of consumer adoption.

Step Change and Accelerated Transition account for:

- an anticipated reduction in battery capital costs, consistent with the trends of the previous GenCost publication (2024-25)¹⁶ adjusted to account for the increased average system size,

¹⁴ See <https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries>.

¹⁵ See <https://www.wa.gov.au/organisation/energy-policy-wa/wa-residential-battery-scheme>.

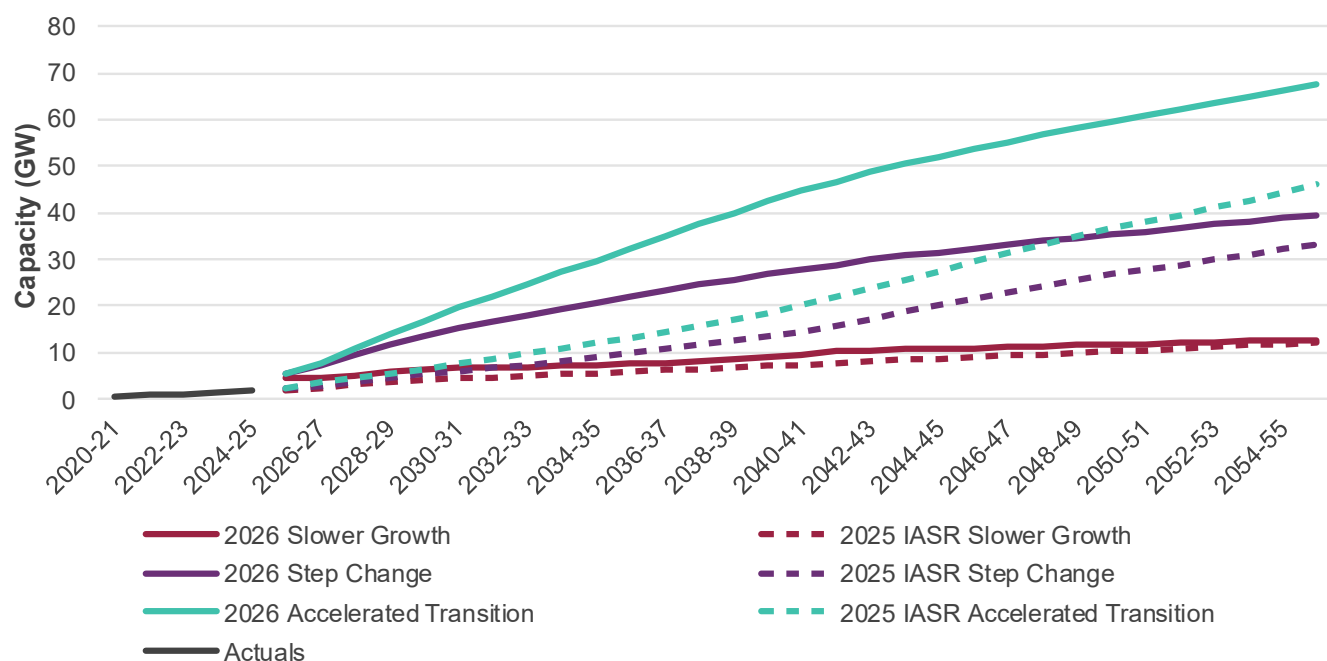
¹⁶ See <https://doi.org/10.25919/yfbi-4k58>.

- an increase in the adoption rate of distributed batteries, consistent with the recently observed high uptake from consumers in response to the increased subsidies that are improving the investment payback, and
- increased battery sizes chosen by consumers, informed by post-June 2025 data from the Clean Energy Regulator.

All scenarios incorporate data from the Clean Energy Regulator since the recent policies came into effect, with over 300,000 new battery installations from July 2025 through March 2026 resulting in approximately 2.6 gigawatts (GW) of additional capacity and over 8 gigawatt hours (GWh) of additional storage. This represents an increase of more than 100% since June 2025. The scenarios differ in their response to changes in payback as the subsidy declines over the five years.

As shown in **Figure 7** through **Figure 10**, the above points lead to a significantly higher uptake in the *Step Change* and *Accelerated Transition* scenarios relative to the 2025 IASR, and the larger battery sizes contribute to significantly higher capacity (GW) and storage capacity (GWh degraded¹⁷). *Slower Growth* shows more rapid uptake in the early years of the forecast, driven by the CHBP and WA RBS, but flattens due to longer payback times in the long term, driven largely by higher assumed battery costs along with lower PV uptake.

Figure 7 Actual and projected distributed battery forecast for the NEM, 2020-21 to 2055-56 (GW)



¹⁷ AEMO estimated the gradual degradation over time of battery storage capacity from the initial as-installed value, and used this degraded storage capacity in the detailed modelling.

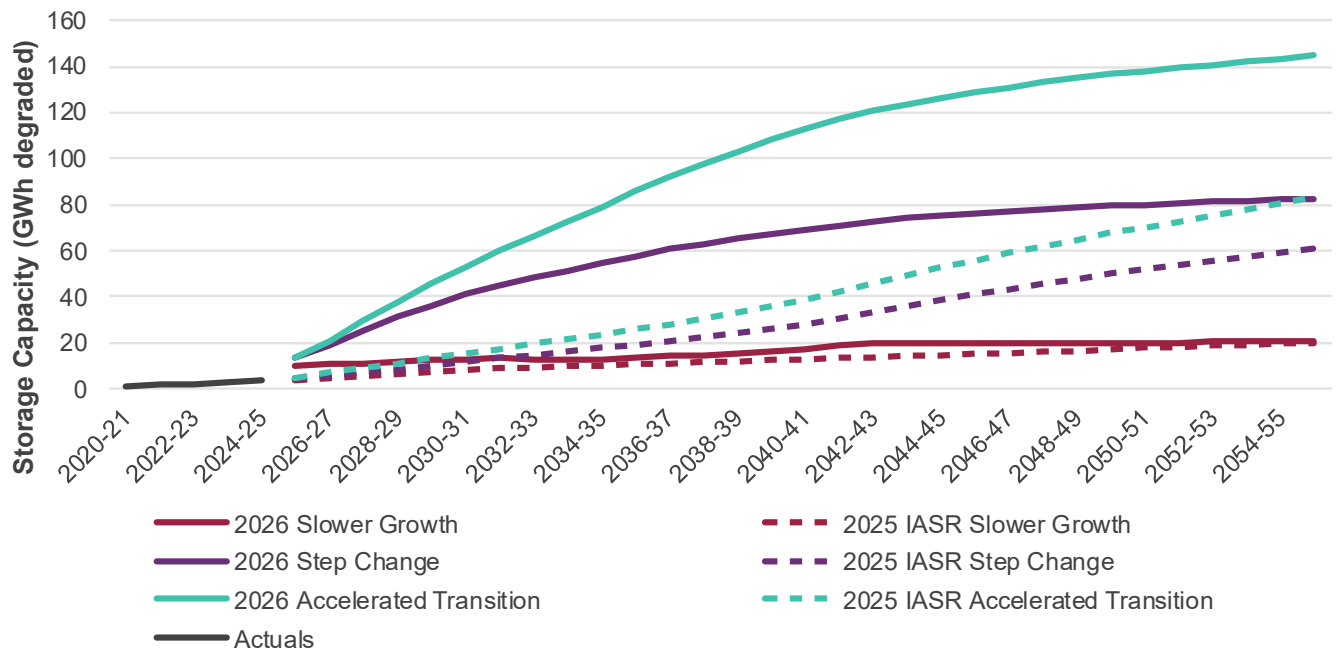
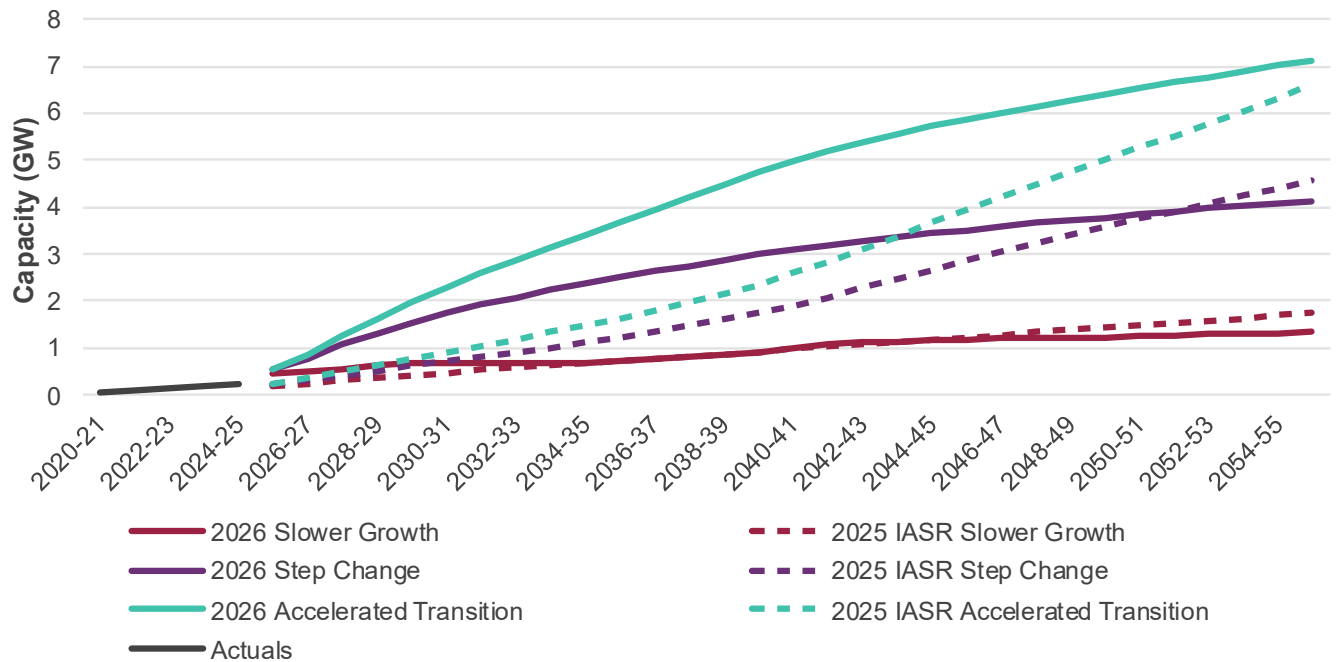
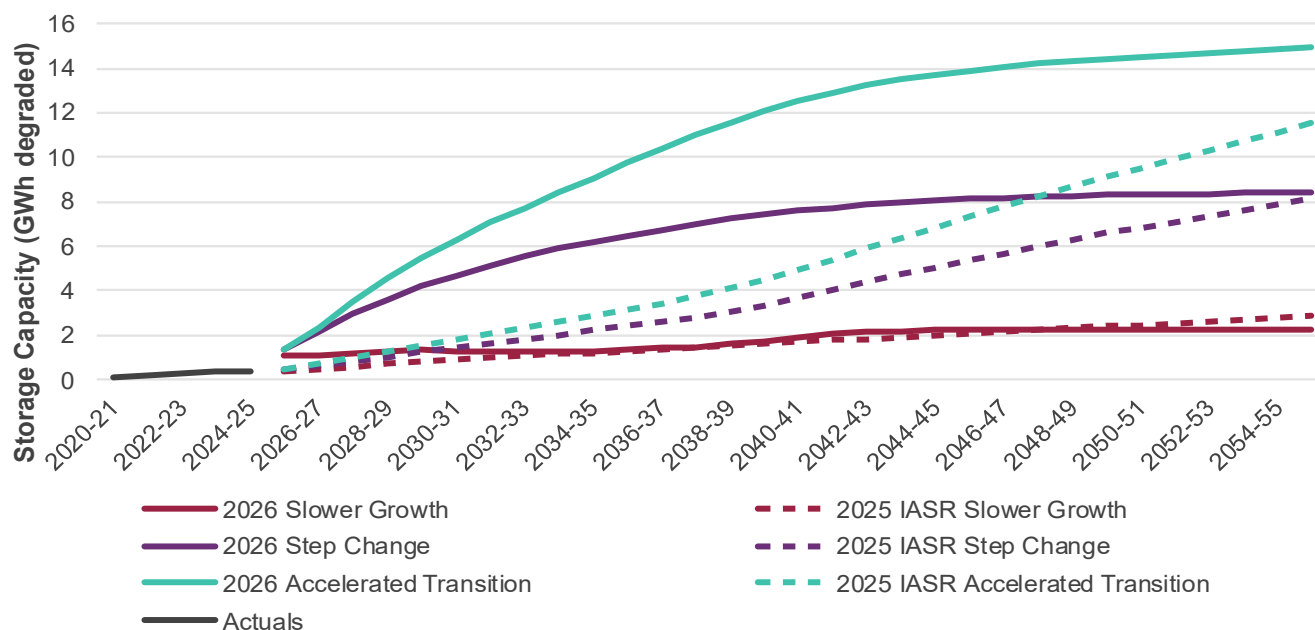
Figure 8 Actual and projected distributed battery forecast for the NEM, 2020-21 to 2055-56 (GWh degraded)**Figure 9** Actual and projected distributed battery forecast for the WEM, 2020-21 to 2055-56 (GW)

Figure 10 Actual and projected distributed battery forecast for the WEM, 2020-21 to 2055-56 (GWh degraded)

For regional forecasts, refer to the accompanying 2026 *Forecasting Assumptions Update* Workbook.

AEMO recognises that the development of vehicle-to-home (V2H) and vehicle-to-grid (V2G) technology, allowing EV batteries to discharge into the home or grid, may impact the uptake of stationary batteries. The scale and direction of this impact is highly uncertain. Stationary batteries can allow consumers to store excess solar during the day which may then be used to charge an EV overnight, implying a positive synergy between EV adoption and stationary batteries. Conversely, some consumers may adopt V2H/V2G technology allowing them to use their EV battery in place of a stationary system. As both the EV and stationary battery markets are still considered to be immature, AEMO has not explicitly included these interactions in either the battery or EV forecasts.

Virtual power plants (VPPs)

CER can be ‘coordinated’ with technologies that enable them to respond to market signals. This is done by bundling CER through a retailer or an independent service, to form a VPP. In AEMO’s modelling, VPP is used to refer only to coordinated consumer batteries, with other consumer devices such as controlled hot water being included in other categories. VPPs may be operated in a variety of ways in response to market signals, in contrast with uncoordinated batteries that are operated primarily to meet an individual consumer’s energy needs.

There are currently around 15 VPP providers operating in the NEM and WEM. These providers offer a range of products and services, precluding a comprehensive definition of a VPP. For CER modelling purposes, AEMO assumes that consumers who coordinate their assets within a VPP voluntarily share control with a central aggregator. Other types of controllable assets are modelled separately; see AEMO’s forecasts for DSP.

While there are significant differences across regions, AEMO estimates the current overall VPP participation rate is around 13% in the NEM, meaning 13% of battery owners are engaged in a VPP¹⁸.

¹⁸ SunWiz Annual Battery Market Report 2025, also <https://www.accc.gov.au/about-us/publications/serial-publications/inquiry-into-the-national-electricity-market-2018-26-reports/inquiry-into-the-national-electricity-market-report-july-2025>.

AEMO's forecasts of VPP participation rates are based on:

- consistency with the scenario narratives (high VPP participation in *Accelerated Transition*, low in *Slower Growth*), and
- the estimated impact of government subsidies, specifically, the CHBP, the WA RBS and the New South Wales PDRS:
 - The WA RBS requires consumers to join a VPP for a minimum of two years to access a rebate on a home battery system. It is available to the first 95,000 batteries, estimated to be reached by 2027, and is additional to the CHBP.
 - The New South Wales PDRS provides a direct subsidy payment to consumers who sign up to an approved VPP.
 - The CHBP requires that batteries be VPP-capable but does not require VPP participation.

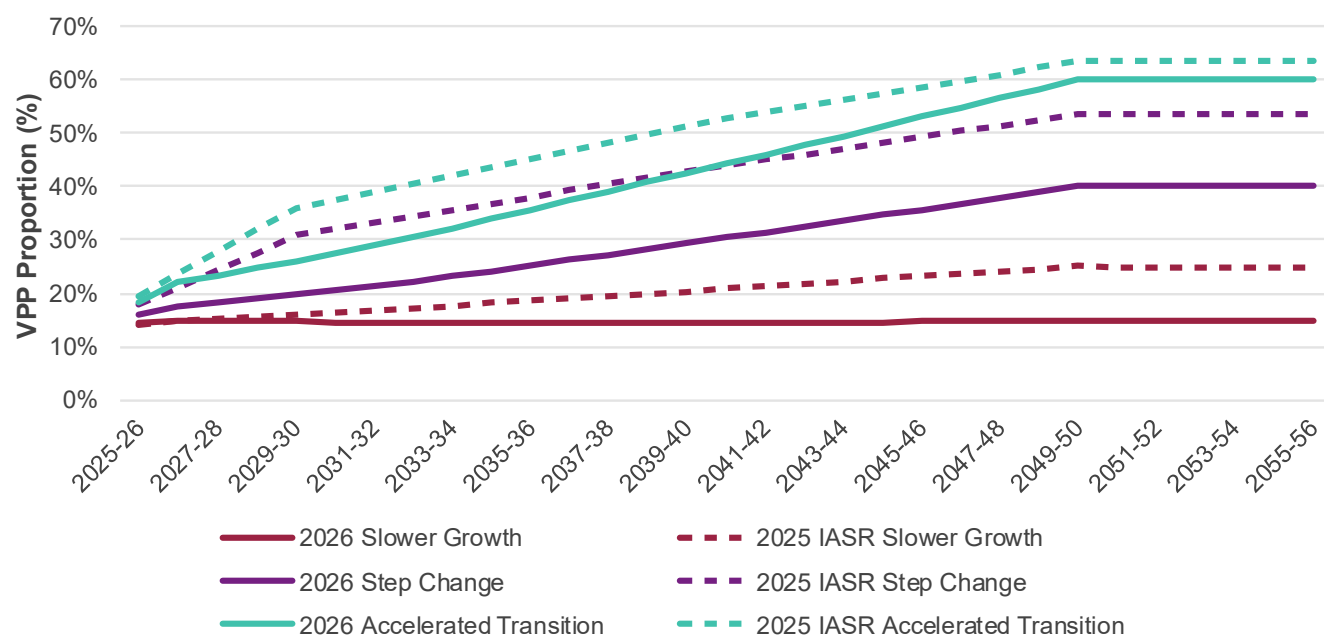
Since the Draft 2026 *Forecasting Assumptions Update*, AEMO has revised long-term assumed VPP proportions in the NEM regions downwards, based on feedback from stakeholders. For the WEM, the forecasts of VPP participation have also been refined to account for updated information reflecting the WA RBS.

The VPP forecast shown in **Figure 11** reflects the assumed VPP participation rates over time for the NEM (averaged over the NEM regions); the forecast for the WEM is shown in **Figure 14**.

The projected VPP capacity (GW) and storage capacity (GWh, degraded) shown in **Figure 12** and **Figure 13** for the NEM, and **Figure 15** and **Figure 16** for the WEM, reflect the assumed VPP participation rate multiplied by the capacity and storage capacity of the corresponding battery forecasts.

For NEM regional VPP forecasts, refer to the accompanying 2026 *Forecasting Assumptions Update* Workbook.

Figure 11 Projected VPP participation rate for the NEM, 2025-26 to 2055-56



Note: represents the average participation for all NEM regions; for regional participation assumptions, see the accompanying 2026 *Forecasting Assumptions Update* Workbook.

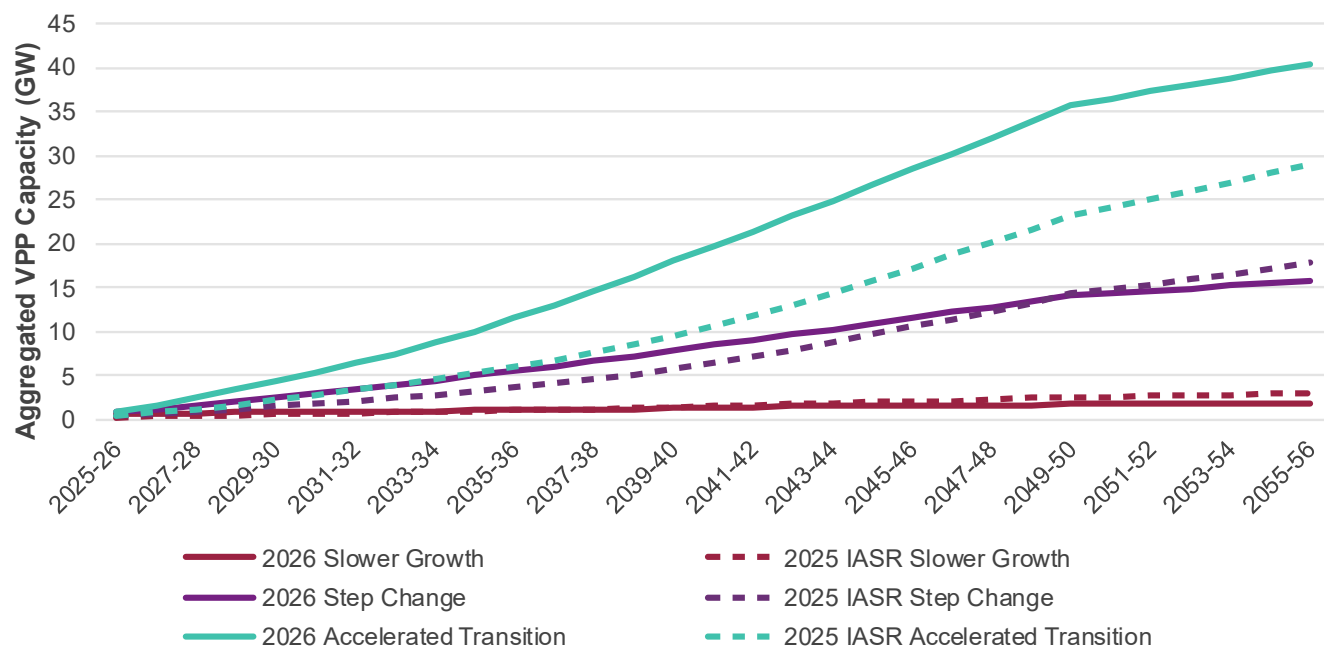
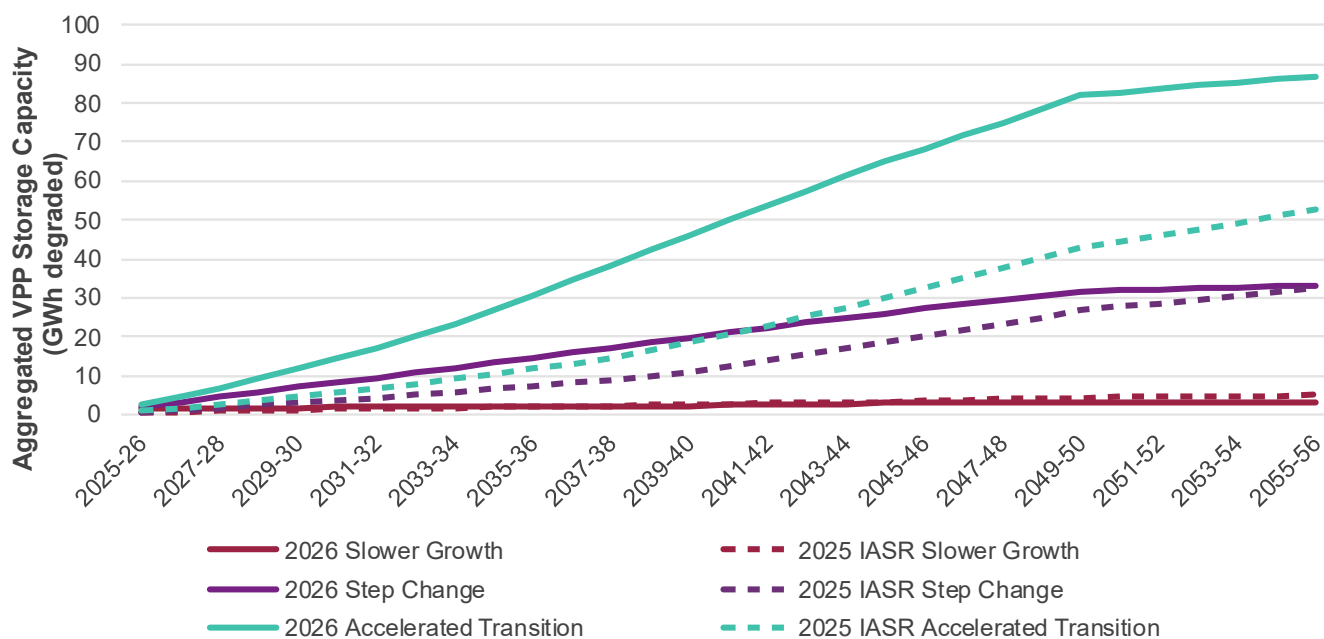
Figure 12 Projected VPP capacity for the NEM, 2025-26 to 2055-56 (GW)**Figure 13** Projected VPP storage capacity for the NEM, 2025-26 to 2055-56 (GWh, degraded)

Figure 14 Projected VPP participation rate for the WEM, 2025-26 to 2055-56

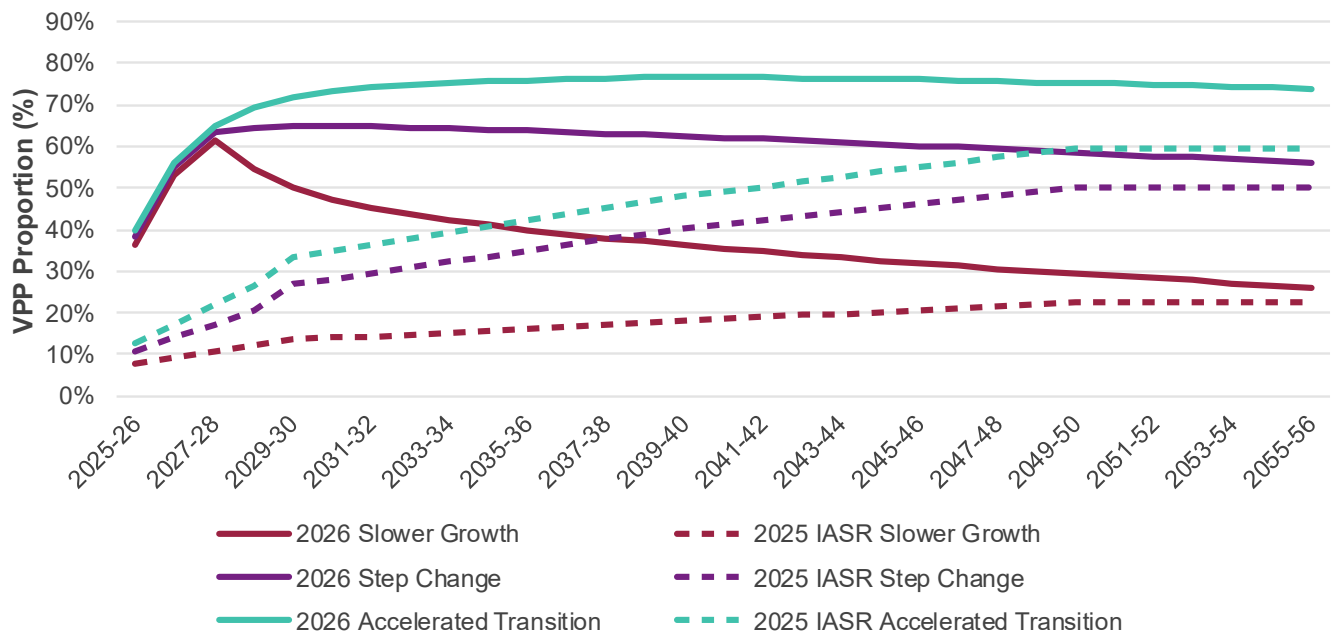


Figure 15 Projected VPP capacity for the WEM, 2025-26 to 2055-56 (GW)

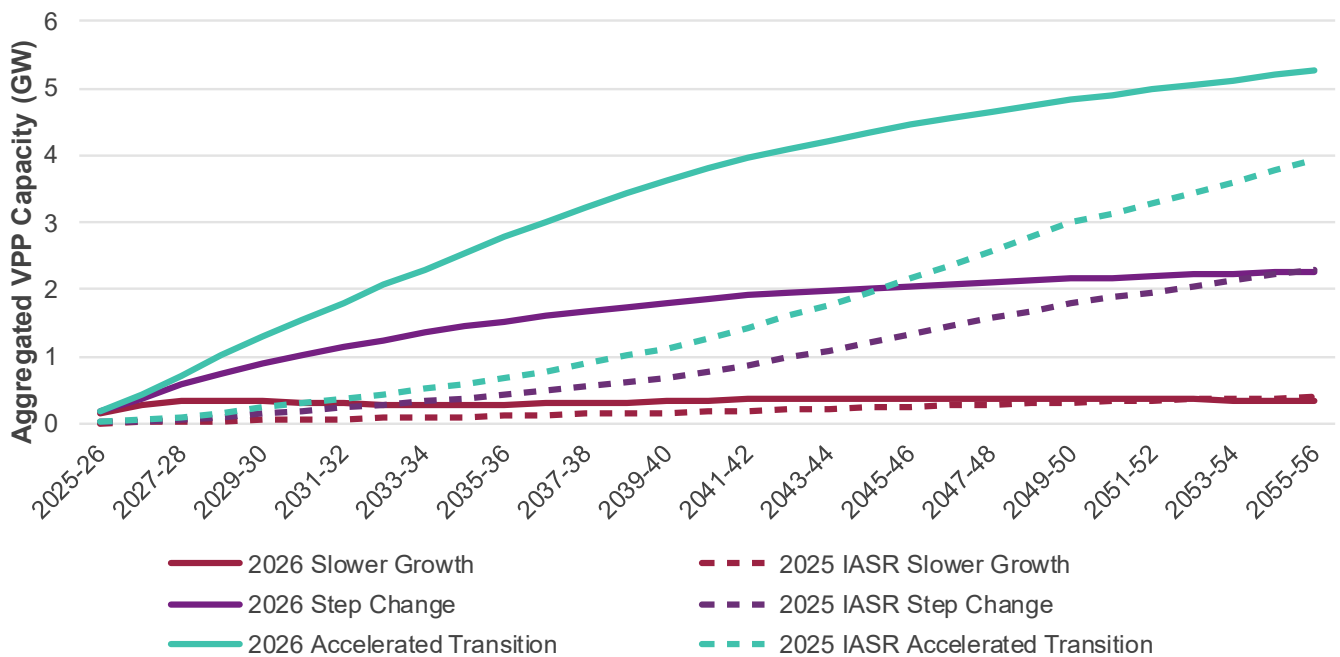
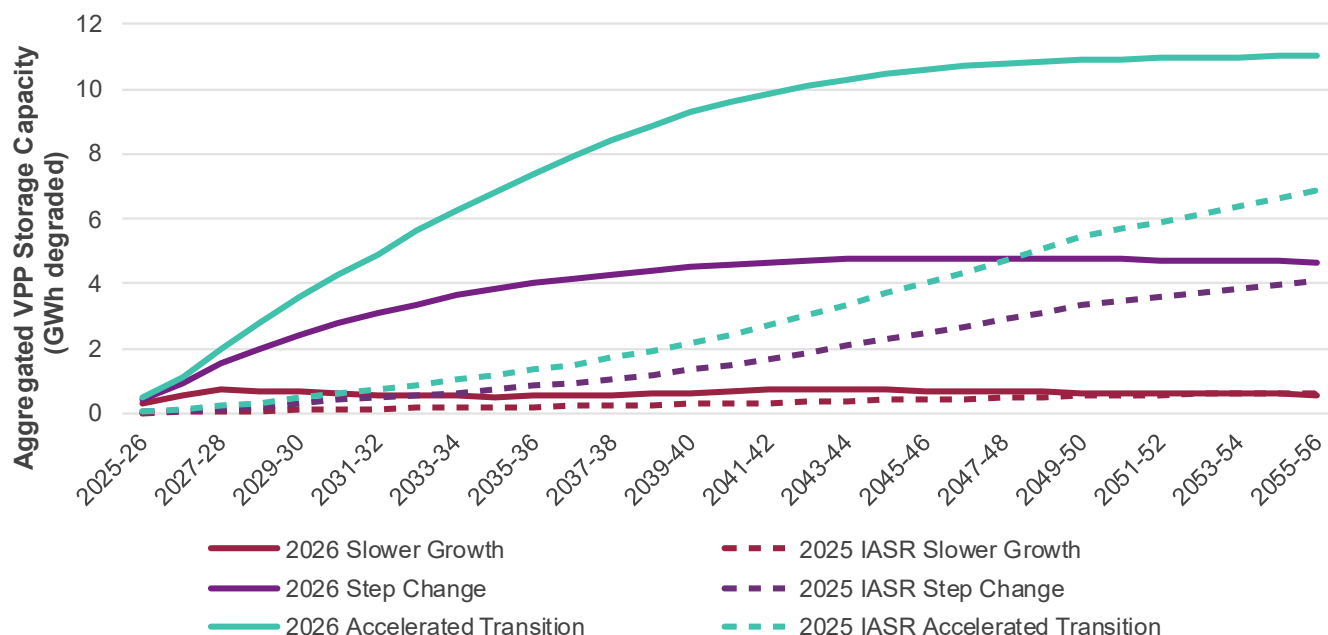


Figure 16 Projected VPP storage capacity for the WEM, 2025-26 to 2055-56 (GWh, degraded)

VPP participation in the WEM is forecast to be significantly different to the NEM, driven by the WA RBS requirement to join a VPP for a minimum of two years to access the rebate. The trajectories shown in **Figure 14** reflect the combination of:

- an assumed sign-on rate consistent with the rate observed since July 2025, with the rate varying by scenario, and
- an assumed drop-off rate, which is highest in *Slower Growth* and lowest in *Accelerated Transition*.

AEMO recognises that VPP participation may be fluid, with consumers opting into, or out of, such arrangements based on various circumstances. The VPP forecasts across each scenario implicitly assume that sufficient incentives and social licence will exist to retain customer participation in VPPs.

Electric vehicles (EVs)

EV uptake

Input classification	Final
Input vintage	May 2026
Source	CSIRO, Australian Automobile Association <i>Electric Vehicle Index</i> , EV Council ¹⁹ , Federal Chamber of Automotive Industries <i>VFACTS</i>
Updates since 2025 IASR	EV model rebased with updated EV sales to March 2026 and updated efficiency and charging data

EV use is impactful to the reliability, security and operability of the power system. Consumer electric charging behaviours and the supporting infrastructure will play a central role in power system outcomes as the fleet mix gradually shifts away from petrol and diesel fuelled vehicles. Consumer participation in schemes that allow coordination of charging will allow EVs to support both consumers and power system needs. This section describes updates to uptake of various types of EVs, their aggregate electricity use, and the mix and shape of EV charging profiles.

¹⁹ Known to be approximate only, but considered by the EV Council to be a reasonable estimate.

Annual electricity consumption figures include the NEM and the WEM, and the term 'EVs' is used as the collective term for battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs).

Supporting infrastructure will play a central role in power system outcomes as the fleet mix gradually shifts away from petrol and diesel fuelled vehicles. Consumer participation in schemes that allow coordination of charging will allow EVs to also support power system needs, benefiting all consumers.

The 2025 IASR incorporated the New Vehicle Efficiency Standard (NVES)²⁰ and Fringe Benefits Tax exemption²¹ and other state incentives included in the Australian Energy Market Commission (AEMC) Emissions Targets Statement²² for Victoria, Queensland and South Australia.

With the latest policy drivers, CSIRO carried out detailed modelling of EVs in the Australian transport sector to support the Draft 2026 *Forecasting Assumptions Update* using:

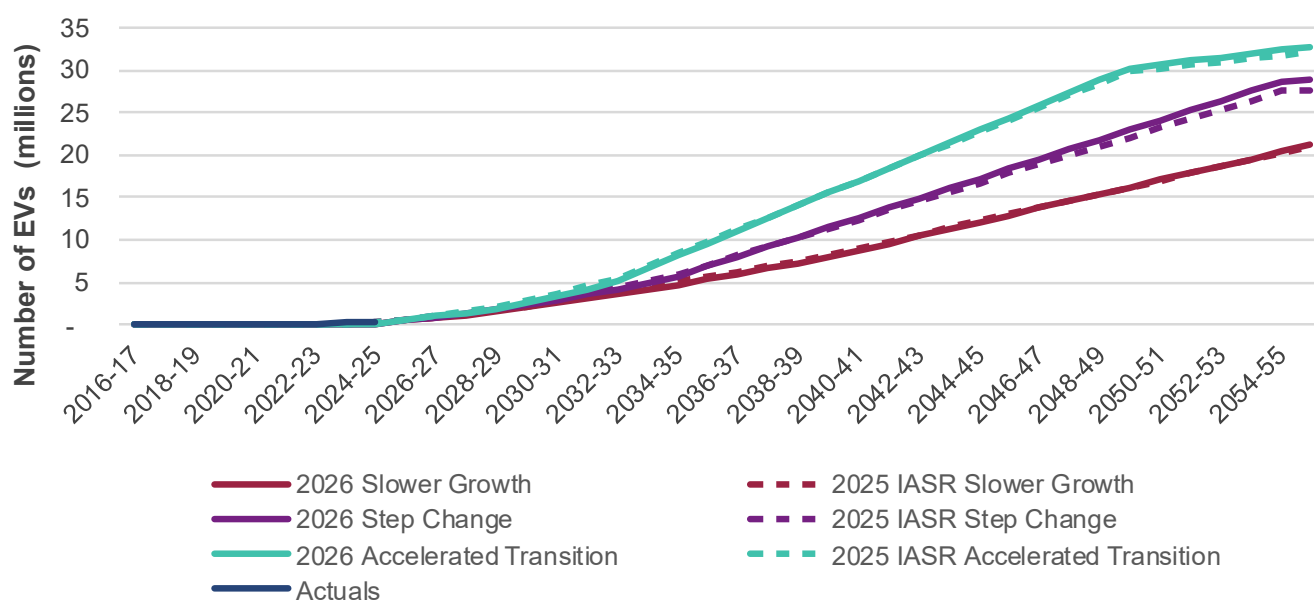
- new data on electricity kilometres for PHEV based on real world driving,
- trial and public charging data to refine the percentage of home and kerbside charging, and
- updated fuel efficiency assumptions for vehicle types including hybrids and articulated trucks.

These forecasts have since been rebased using:

- the latest actual vehicle sales figures (until March 2026) which show growth for BEVs and PHEVs, particularly since restrictions on the supply of oil from the Persian Gulf began in March 2026, and
- a recalibrated charging load profile for residential EVs using observed tariff data.

Figure 17 shows the EV fleet size projections in the NEM and WEM by scenario.

Figure 17 Actual and projected BEV and PHEV fleet size (NEM and WEM) by scenario, 2016-17 to 2055-56



²⁰ See <https://www.legislation.gov.au/C2024A00034/asmade/text>. This was considered in the 2024 *Forecasting Assumptions Update* and the 2025 IASR.

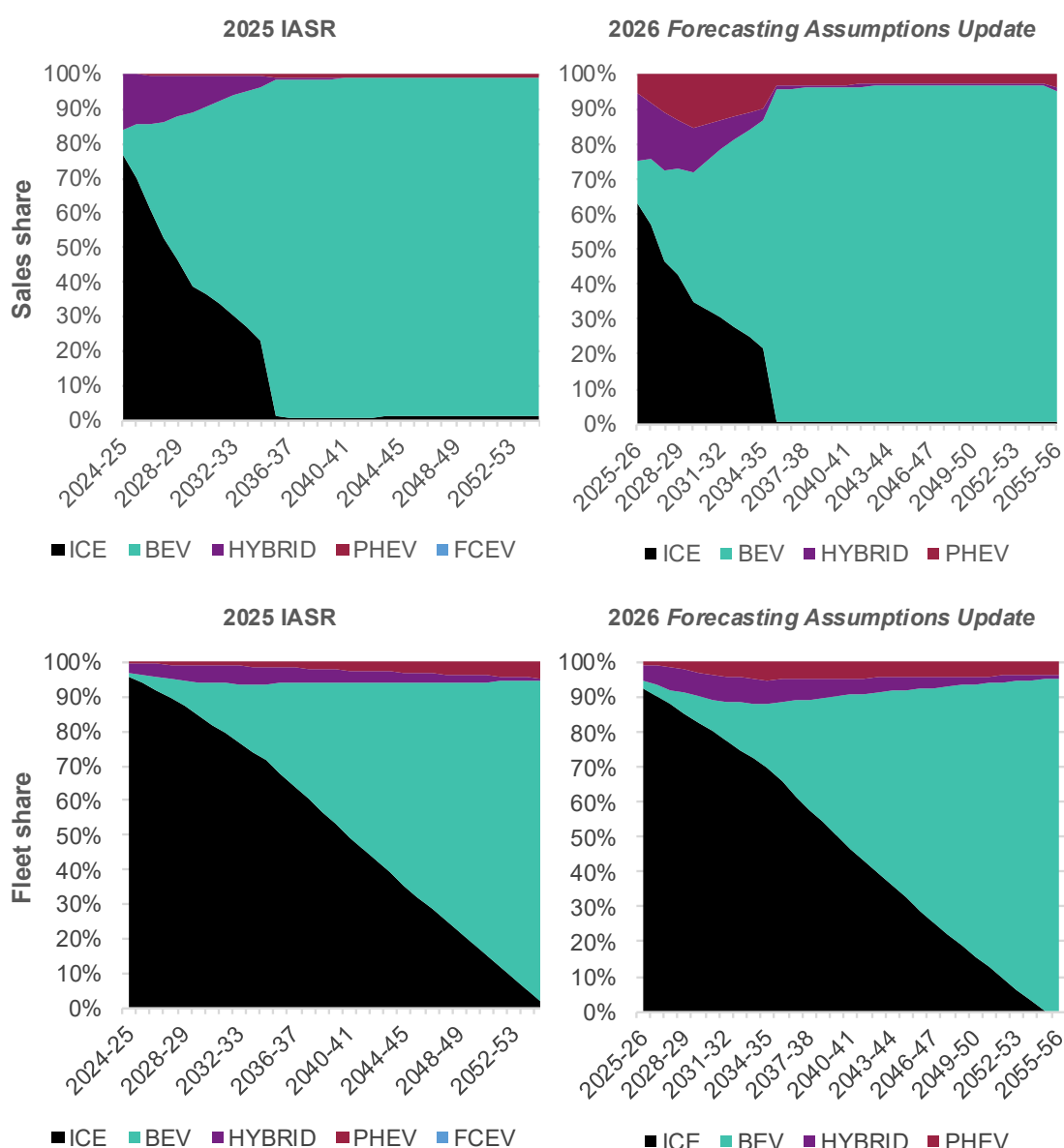
²¹ See <https://www.ato.gov.au/businesses-and-organisations/hiring-and-paying-your-workers/fringe-benefits-tax/types-of-fringe-benefits/fbt-on-cars-other-vehicles-parking-and-tolls/electric-cars-exemption>.

²² See <https://www.aemc.gov.au/regulation/targets-statement-emissions> (September 2025).

Vehicle numbers are similar to the 2025 IASR for all scenarios, and are projected to reach between 16 million and 30 million (66% to 98% of the whole fleet) by 2050 across the scenarios. In the *Accelerated Transition* scenario, EV numbers are projected to reach market saturation by 2050, meaning EVs will have almost fully replaced the internal combustion engine (ICE) fleet.

Figure 18 shows the actual and projected mix of vehicle sales²³ and fleet share of residential and light commercial vehicles, per vehicle technology type.

Figure 18 Projected sales share and fleet share by vehicle technology type for Step Change (NEM and WEM) comparing 2025 IASR (2024-25 to 2054-55) and 2026 Forecasting Assumptions Update (2025-26 to 2055-56)



FCEV: fuel cell EV.

²³ Vehicle sales refer to all motorcycles, passenger vehicles and light commercial vehicles, and excludes buses and trucks (rigid and articulated).

In *Step Change*, only a small share of new ICE sales (0.1%) is projected after the mid-2030s, particularly for remote driving, heavy-duty towing, long-distance travel or vehicular preferences (such as sports vehicles or four-wheel drives). However, ICE vehicles are projected to remain a part of the fleet for much longer (falling below 10% only after 2050) while owners maintain their vehicles and second-hand markets remain. The projected fleet share is the combined result of growth in EV sales share and a corresponding decline in ICE. Declining fuelling and maintenance service availability is assumed to eventually reduce the commercial value of ICE ownership, encouraging scrapping across all scenarios at varying timeframes²⁴. While fuel cell EV (FCEV) cars are not available in the *Slower Growth* and *Step Change* scenarios, FCEV trucks were assumed available, though with a very low penetration. FCEV cars were assumed to be available over time in *Accelerated Transition*.

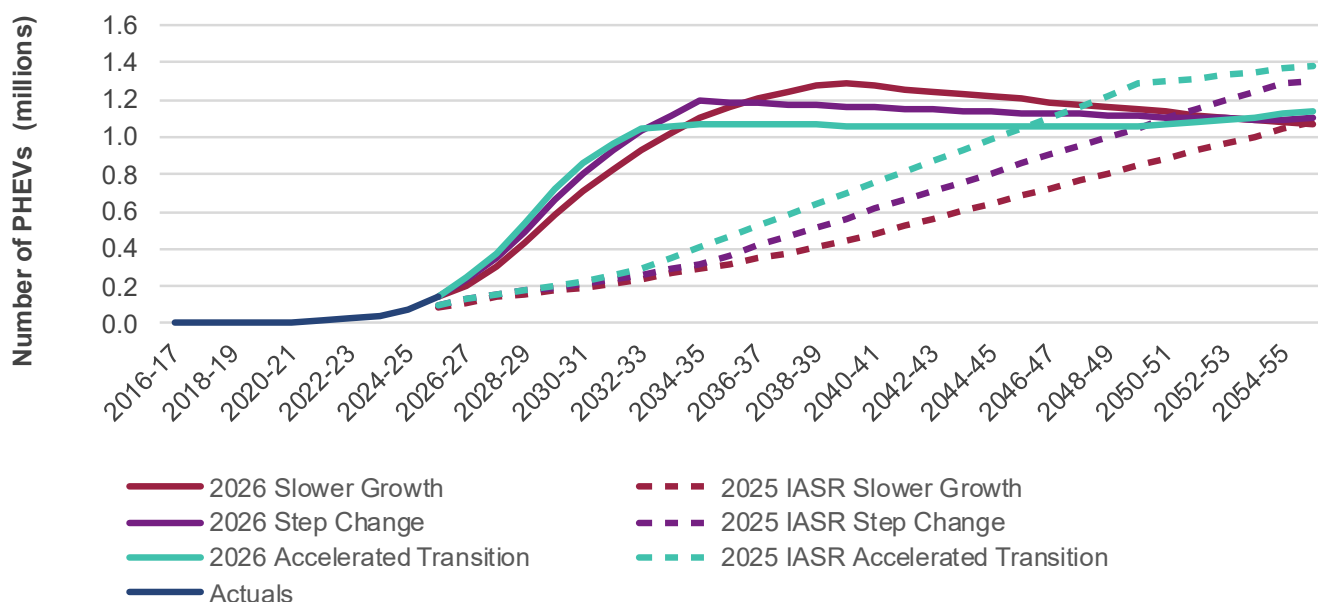
The 2026 *Forecasting Assumptions Update* provides an amended outlook for EV fleet size since the 2025 IASR, due to:

- **relevant state policy targets** – since the 2025 IASR, the Queensland Government amended its QFleet Vehicle Emissions Reduction Strategy 2025-2030 (targeting a 10% reduction in tailpipe emissions by 2030)²⁵, and
- **updated sales data** – updated data to March 2026 shows the EV share of new sales rising to 19%, which represents significant year-on-year growth in new sales.

BEV costs were assumed to continue to fall, while costs of maintaining PHEVs were assumed to be higher, due to their dual-drive train design. The recent growth in new sales of PHEVs relative to previous forecasts does not materially change long-term projections that favour BEVs, driven by declining battery costs and manufacturer commitments through NVES.

Figure 19 shows projected PHEV sales numbers across the outlook period, with a significantly higher share of PHEVs projected by 2030 than previously forecast.

Figure 19 Projected PHEV fleet size (NEM and WEM) by scenario, 2016-17 to 2055-56



²⁴ See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-electric-vehicle-projections.pdf.

²⁵ See https://www.forgov.qld.gov.au/_data/assets/pdf_file/0033/594339/qfleet-vehicle-emissions-reduction-strategy-2025-230-web-version.pdf.

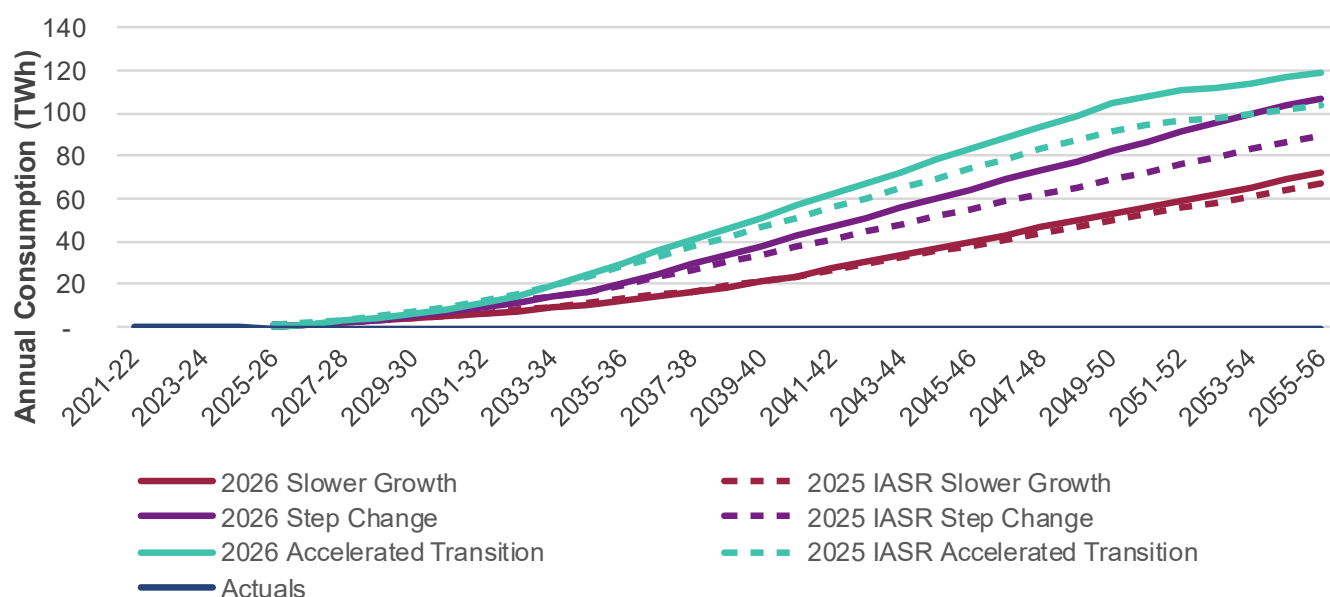
Electricity consumption to support the use of EVs

EV users are expected to adopt a wide range of charging behaviours that will likely change over time as electrified transport becomes more common, and infrastructure, charging technologies and tariffs adapt. Individual users may switch between different charging methods frequently, depending on the convenience of each option given their personal circumstances, and the incentives that encourage them. AEMO's EV electricity consumption forecast allows for:

- the availability, popularity, and technical characteristics of home, business and public charging facilities,
- an evolving vehicle mix (including motorcycles, passenger and commercial vehicles of different sizes, trucks and buses),
- varying travelling distances, and
- on-road efficiencies which are up to 20% worse²⁶ than the efficiencies achieved in standard road tests due to real-life factors such as air conditioning, acceleration beyond the standard driving test, and idle and parked use of energy.

This section presents annual electricity consumption forecasts that reflect the EV uptake presented in the previous section, as well as normalised vehicle charging profiles that represent the average vehicle across the population considering all these factors, rather than any individual consumer behaviour. **Figure 20** shows projected electricity consumption from EVs, compared to the 2025 IASR, with a similar forecast of annual consumption until the 2040s, when consumption is projected to grow more quickly than the previous forecast. The rise in electricity consumption in the later years is due to a small increase in the number of articulated electric trucks which increases the electricity consumption rate per km on average for all EVs relative to the 2025 IASR. Due to their large power requirements, these changes have a large impact on the overall electricity consumption from EVs.

Figure 20 Projected BEV and PHEV electricity consumption (NEM and WEM) by scenario, 2021-22 to 2055-56 (terawatt hours [TWh])



²⁶ See <https://www.aaa.asn.au/2024/02/new-tests-identify-real-world-fuel-consumption-gaps/>.

EV charging profiles

AEMO uses several static and dynamic vehicle charging profiles that are reviewed and updated annually:

- **Static charging** refers to charging that is unaffected by wholesale electricity prices and grid conditions, typically reflective of chargers available at homes, car parks, shopping centres or workplaces.
- **Dynamic charging** refers to charging that adjusts based on grid conditions due to weather, operational demand and considering a vehicle's state of charge. Dynamic charging may be encouraged by cheaper tariffs to compensate users for potential loss of flexibility. Although typical home chargers can be used for dynamic charging with manual adjustments, dynamic charging is expected to be more commonly provided through smart L2 chargers (unidirectional) or V2G chargers (bidirectional), which use advanced algorithms to optimise charging sessions.

The different charging types are described in **Table 6**, relating tariffs and charger types to charging behaviour and hence the time-specific load on the power system.

Table 6 EV charging profiles and description

Type	Charging profile name	Description
Static	Unscheduled	Unscheduled home charging that occurs on a flat tariff, typically using home chargers. <i>An EV owner adopting this charge profile typically charges their vehicle when returning home each evening, with some additional workplace or carpark charging. This simple charging preference has little regard to electricity costs.</i>
	Off-peak and solar	Traditional time of use (TOU) tariff without day incentives, other than use of home solar. <i>An EV owner adopting this charge profile typically has high overnight charging predominantly at home, but after the household's peak evening loads. Some charging occurs in the day, if convenient, to benefit from the user's own PV generation.</i>
	TOU Grid solar	Newly emerging TOU tariff which includes middle-of-the-day charging incentives with reduced daytime pricing such that all customers (both those with and without PV systems) are incentivised to use electricity during daytime hours, for example, through the Solar Sharer Offer tariff structure. <i>An EV owner adopting this charge profile typically takes advantage of daytime charging opportunities at home, or away from home, absorbing low-cost solar production.</i>
	Public	Public L2 and fast charge. <i>An EV owner adopting this charge profile typically charges rapidly while stopped at public charging facilities, on highways, at car parks, or workplaces with dedicated facilities. Given these activities typically occur during daytime hours, this profile has a daytime bias. This category also includes charging that occurs near drivers' homes, typically overnight.</i>
Dynamic	TOU Dynamic	TOU tariff, but dynamically priced to reflect solar energy availability day-to-day, and within each day. <i>This profile does not include energy flows from the EV battery to the home or grid.</i>
	V2G/V2H	The EV owner opts into a dynamic charging scheme that allows use of the vehicle as a battery, storing energy which can be called on by a retailer or aggregator to supply back into the grid (V2G) or home (V2H).

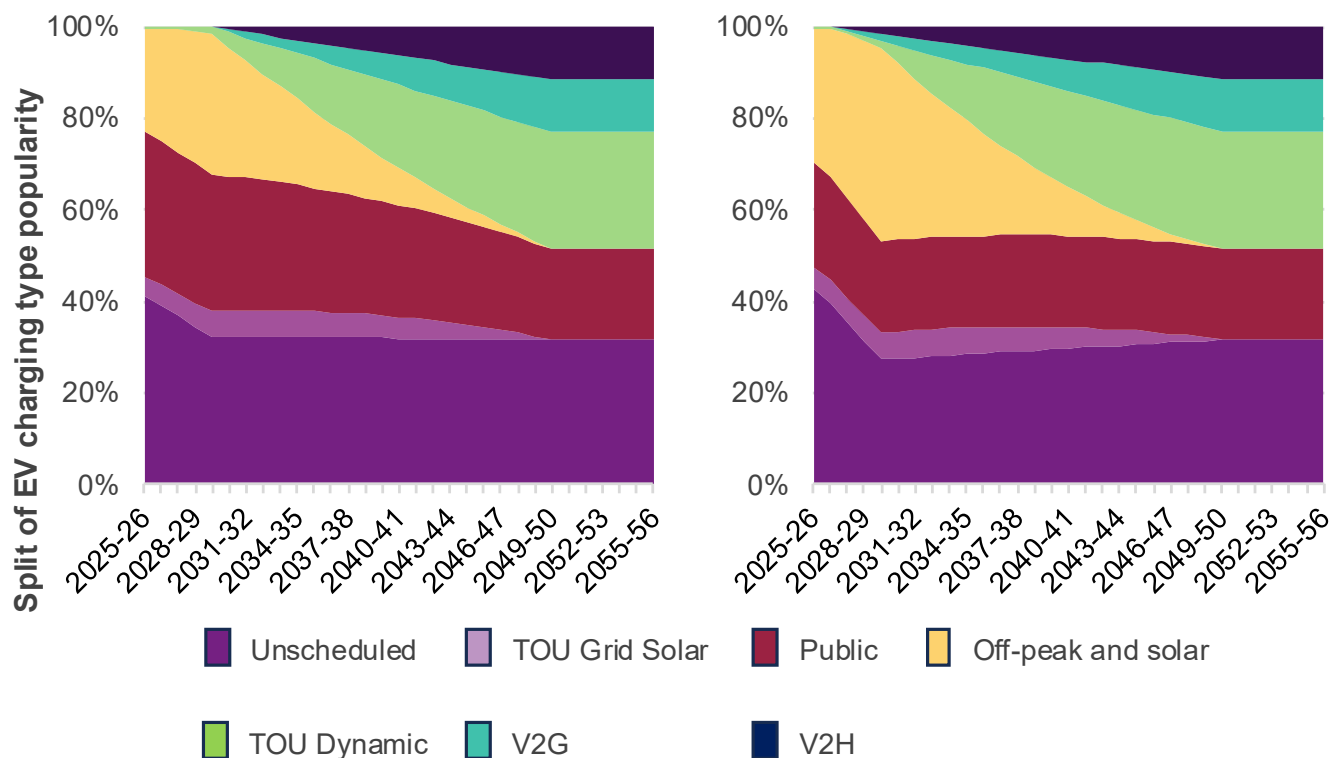
Figure 21 shows the mix of charging types assumed for the 2025 IASR (left) and this 2026 *Forecasting Assumptions Update* (right) for medium residential vehicles in New South Wales in the *Step Change* scenario. The mix is similar across other states. Key updates to the outlook for future charging behaviours include:

- Public charging share has been reduced consistent with verifiable trial data. It has also lowered relative to the 2025 IASR due to higher penetration of PHEVs, particularly to 2030, with these vehicles less likely to use public charging due to their smaller battery. The projected public charging share in 2050 remains broadly similar to the 2025 IASR projection.

- The TOU Dynamic profile was assumed to have greater proportional share over time, reflecting growing adoption of smart charging technologies, dynamic tariffs and consumer preferences for charging during periods of abundant solar generation where they can fit it into their lifestyle.
- TOU Off-peak and solar is assumed to be customer-preferred in the near term with incentives to charge during traditional off-peak hours remaining common, while daytime charging incentives are emerging and becoming increasingly popular.
- TOU Grid solar is expected to be suitable for homeowners working from home, retired, or with an EV that is less frequently used (for example, as a second vehicle to their commuter vehicle).

For this forecast, the average vehicle availability derating (assumed to be 55%, and reflecting the proportion of time that all V2G-enabled vehicles are parked and able to connect to charging infrastructure) has been applied to the V2G capacity (MW). Additionally, it was assumed that 50% of the battery depth was reserved to restrict the coordinated discharge of the battery, so the driver could retain the vehicle for its primary purpose (transportation), meaning V2G systems could not empty a battery below half its driving range. This application ensures that battery capacity (MW and megawatt hours [MWh]) is treated consistently, reflecting the assumed availability of connected vehicles to participate in charging or discharging coordination. More details of the profiles and electricity consumption forecasts are in the 2026 *Forecasting Assumptions Update* Workbook.

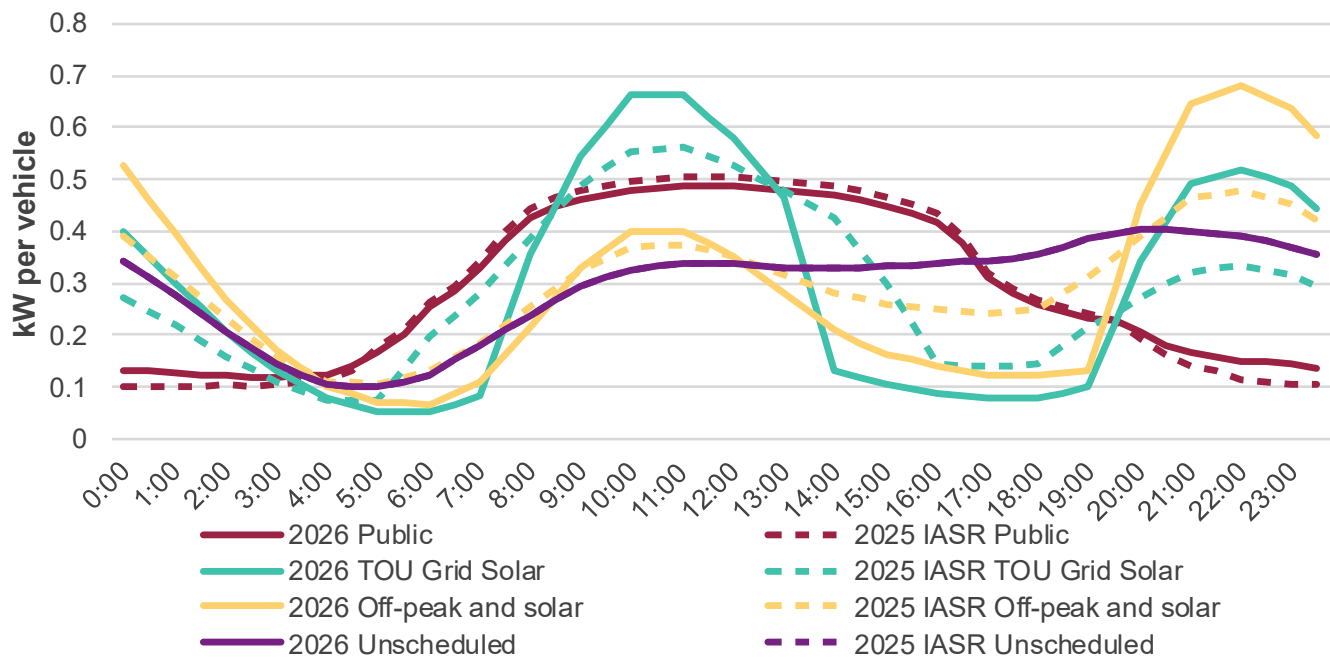
Figure 21 Split of charging types for medium residential vehicles (New South Wales): 2025 IASR (left) and 2026 Forecasting Assumptions Update (right) for Step Change scenario, 2025-26 to 2055-56



EV charging profile shape

AEMO develops half-hourly charging profiles using Australian charging data trends observed from multiple trials (Energex and Ergon Energy Network²⁷, AGL²⁸, Jemena²⁹, Origin Energy³⁰, and the University of Queensland/Electric Vehicle Council of Australia³¹). These profiles (see **Figure 22** below) vary over NEM regions, vehicle type, time (months, years), and day types (weekdays/weekends), independent of the popularity of the profile.

Figure 22 Static after-diversity charging profiles of different EV charging types for medium residential vehicles (New South Wales) in 2030 (kW per vehicle)



Note: The Unscheduled charging profile is unchanged between the 2025 and 2026 charging profiles.

The charging profiles of different types of EVs are similar to the 2025 IASR. The key changes are:

- TOU profiles have higher charging demand during daylight hours based on consideration of local charging profiles and the availability of consumer incentives (such as the Solar Sharer Offer).
- Customers on Off-peak and solar tariffs are projected to decrease average load in the evening peak (based on industry feedback).

The 2026 *Forecasting Assumptions Update Detailed EV workbook*³² provides more details of the EV forecast.

²⁷ Energex and Ergon Energy Network 2023, at https://www.energex.com.au/_data/assets/pdf_file/0008/1096496/EV-SmartCharge-Queensland-Insights-Report.pdf.

²⁸ AGL Electric Vehicle Orchestration Trial 2023, at <https://arena.gov.au/assets/2023/08/20230703-AGL-Electric-Vehicle-Orchestration-Trial-Final-Report.pdf>.

²⁹ Jemena Dynamic Electric Vehicle Charging Trial Project 2023, at <https://arena.gov.au/assets/2023/04/jemena-ev-grid-trial-knowledge-sharing-report.pdf>.

³⁰ Origin EV Smart Charging Trial 2021, 2022, at <https://arena.gov.au/assets/2022/05/origin-energy-electric-vehicles-smart-charging-trial-lessons-learned-2.pdf>.

³¹ See *Driving and charging an EV in Australia: A real-world analysis 2022*, at https://australasiantransportresearchforum.org.au/wp-content/uploads/2022/05/ATRF2022_Resubmission_80.pdf.

³² At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/2026-Forecasting-Assumptions-Update-Detailed-EV-Workbook.

2.1.2 Other non-scheduled generation

Input vintage	Economic forecasts unchanged, connections revised in June 2026
Source	<ul style="list-style-type: none">Australian Bureau of Statistics (ABS)Deloitte Access Economics (DAE)AEMO meter database
Updates since 2025 IASR	Forecasts developed in 2024 for the 2025 IASR, subsequent updates delivered in 2025 and 2026.

Other non-scheduled generation (ONSG) refers to non-scheduled generation smaller than 30 MW that is not classified as distributed PV³³. In practice, ONSG includes non-scheduled generating units that do not participate in central dispatch as scheduled generators, such as hydro, landfill gas, wastewater gas, bioenergy and some wind generators.

AEMO reviews and maintains a list of ONSG using information from AEMO’s Generation Information dataset and the Distributed Energy Resources (DER) Register. These datasets are complemented with information provided by network operators and other publicly available sources.

Through these sources, AEMO maintains a consolidated view of ONSG records, including site specific information and relevant generator status information. AEMO uses each generator’s Dispatchable Unit Identifier (DUID) or National Metering Identifier (NMI) to collect historical generation output at half-hourly frequency.

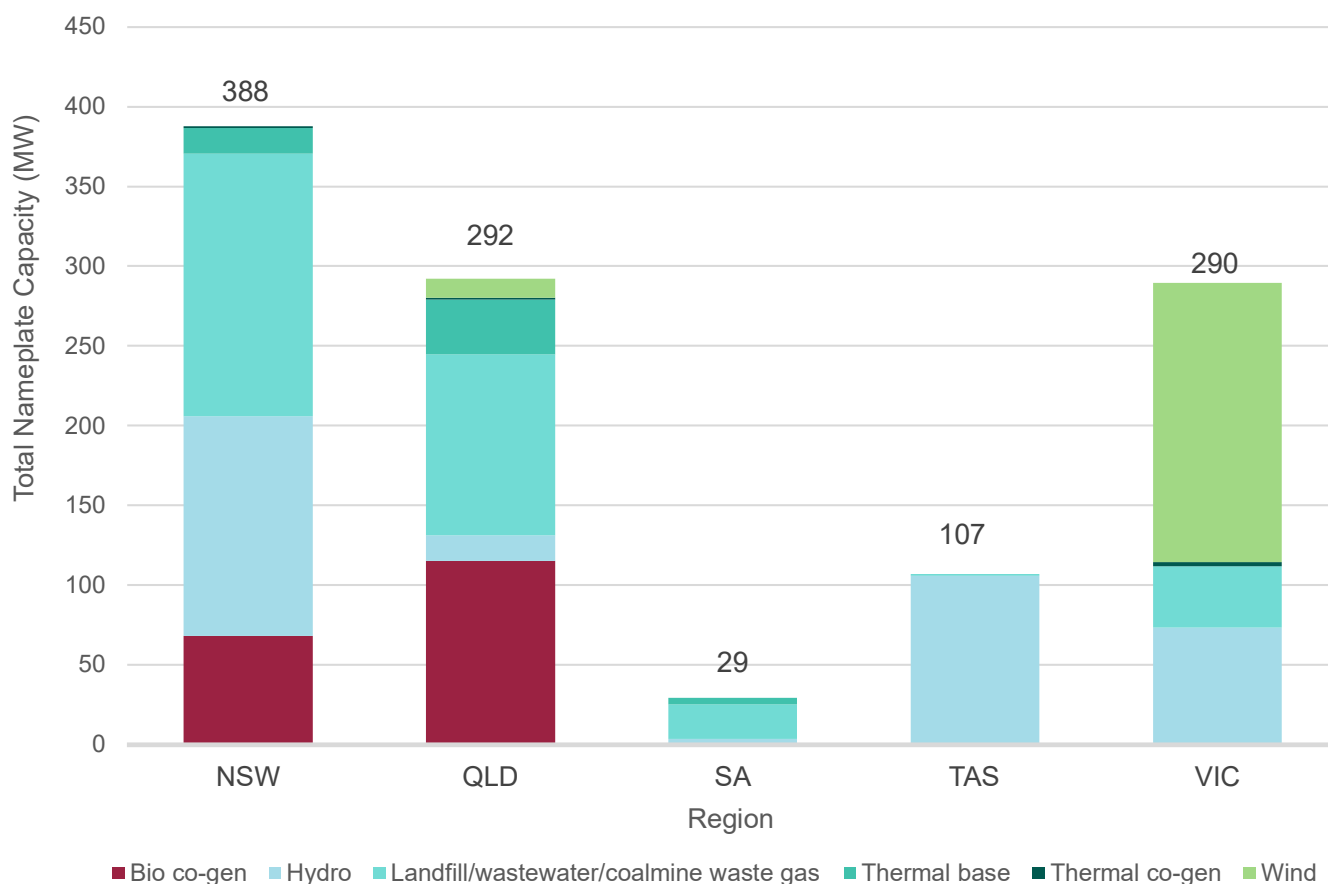
The ONSG generator list underpinning the forecast is derived from the latest Generation Information dataset available at the time the forecasts are prepared. For the 2026 ESOO demand forecasts, that is the April 2026 Generation Information dataset. Updates to generator registrations, retirements, and operational status are incorporated in each release.

AEMO forecasts the connection and withdrawal of ONSG generators based on firm commitment status in the short term, and by applying historical trends by fuel type in the long term. Further details on the ONSG forecasting methodology are in AEMO’s *Electricity Demand Forecasting Methodology*³⁴.

AEMO’s current view of ONSG is illustrated in **Figure 23**, which shows aggregate installed capacity by NEM region and technology type based on the April 2026 Generation Information release. New South Wales remains the largest contributor, followed by Queensland and Victoria, while Tasmania’s ONSG capacity is largely driven by hydro generation and South Australia has a comparatively smaller contribution.

³³ At <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-planning-guidelines>.

³⁴ At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2026/2026-Electricity-Demand-Forecasting-Methodology.

Figure 23 Aggregate other non-scheduled generation installed capacity by NEM region and technology type (MW)

In addition to installed capacity, **Figure 24** presents the number of generating units by region and technology type, providing context on the composition of the ONSG fleet.

The distribution of units broadly aligns with capacity across regions, with New South Wales, Queensland and Victoria each comprising a relatively large number of smaller units, while Tasmania and South Australia consist of fewer units overall. Differences between installed capacity and unit counts reflect variation in average unit size and technology composition, with smaller landfill gas and bioenergy units more prevalent in New South Wales and Queensland, and larger hydro units dominating in Tasmania. Unit counts are presented for descriptive purposes only; ONSG forecasts are developed using aggregated installed capacity by region and technology type.

Figure 24 Number of other non-scheduled generating units by NEM region and technology type

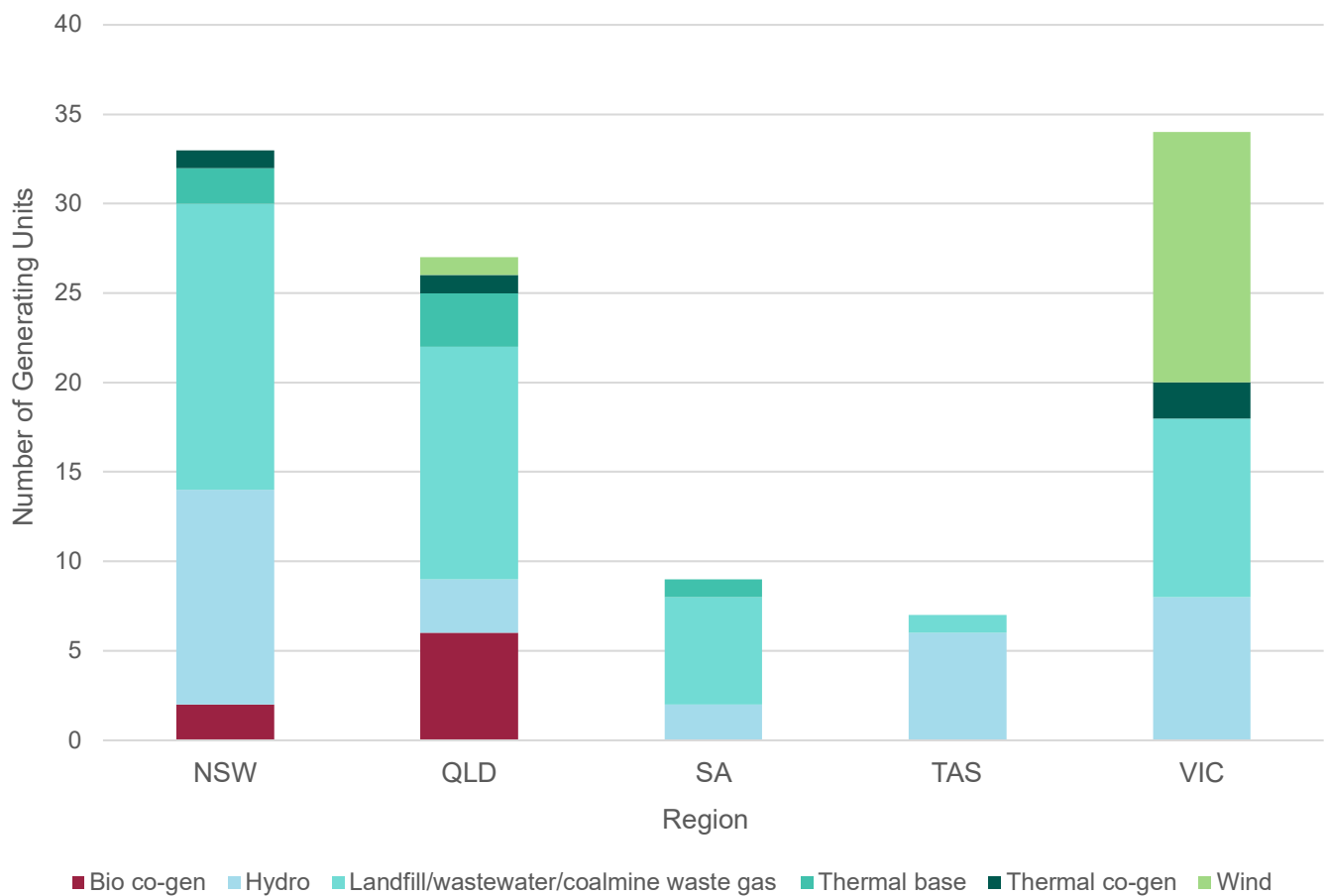
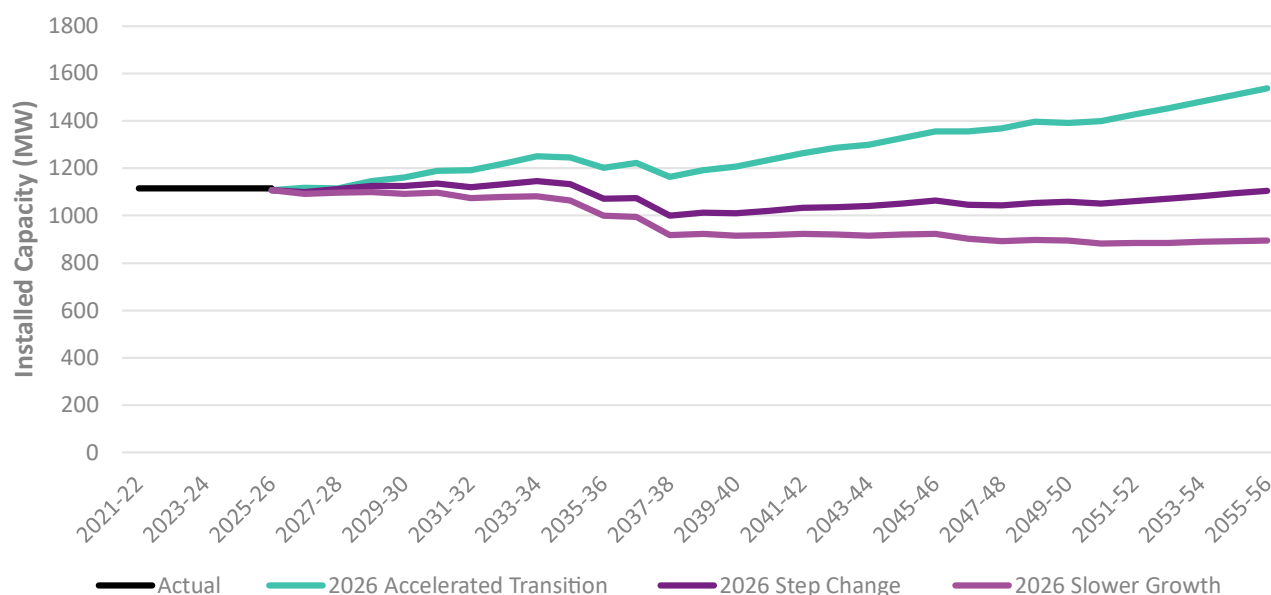


Figure 25 shows forecast ONSG capacity trajectories. The forecast reflects assumed additions and withdrawals for non-scheduled generation over the outlook period.

Figure 25 Forecast NEM-wide other non-scheduled generation capacity (MW)

Scenario differences arise from differing assumptions regarding future generator connections and retirements, resulting in higher ONSG capacity outcomes in the *Accelerated Transition* scenario, while the *Step Change* and *Slower Growth* scenarios reflect more moderate growth or relatively stable capacity outcomes. The projections over time are not always smooth; variations reflect updates to generator closure dates and changes in generator status incorporated in successive releases of the Generation Information dataset, rather than underlying structural changes in technology deployment. As such, differences between forecast trajectories across successive updates may partly be attributable to revisions in the ONSG generator list.

2.1.3 Economic and residential customer connections forecasts

Input vintage	Economic forecasts unchanged, connections revised in June 2026
Source	<ul style="list-style-type: none"> • ABS • Deloitte Access Economics (DAE) • AEMO meter database
Updates since 2025 IASR	Forecasts developed in 2024 for the 2025 IASR, subsequent updates delivered in 2025 and 2026.

AEMO engaged Deloitte Access Economics (DAE) to develop long-term economic forecasts for each Australian State and Territory as a key input to AEMO's demand forecasts. DAE projected three scenarios in alignment with the 2025 IASR³⁵. The forecasts include projections for Gross Domestic Product (GDP), Gross State Product (GSP), Gross Value Added by industry, inflation, population, and dwelling construction. DAE delivered the economic forecasts in October 2024³⁶, and two subsequent updates in June 2025 and February 2026. The two updates assessed changing economic conditions but did not include full forecast updates³⁷ and were provided as supporting materials for the ESOO and WEM ESOO in June 2025 and

³⁵ See <https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-iasr>.

³⁶ See Deloitte Access Economics, *Economic forecasts 2024-25*, 30 October 2024, at <https://www.aemo.com.au/-/media/files/major-publications/isp/2025/deloitte-access-economics-2024-economic-forecast.pdf>.

³⁷ The economic forecast updates compared DAE's internal 'baseline' forecasts over various years and the *Step Change* scenario.

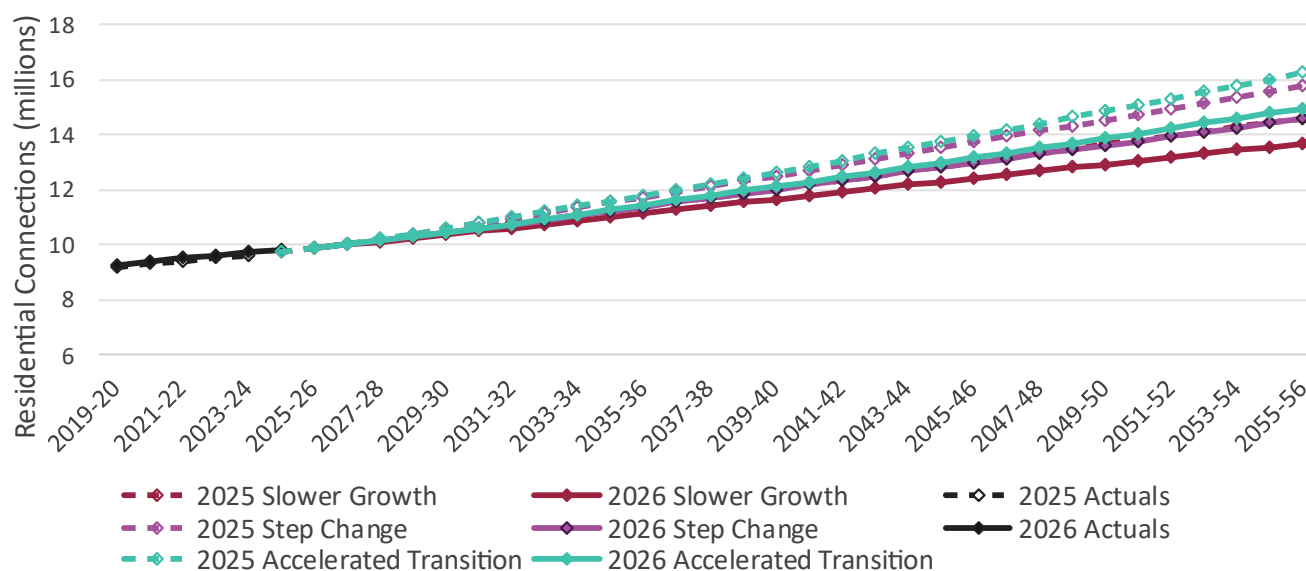
February 2026. Both updates determined that no significant, long-term changes to the economic forecasts had occurred since the October 2024 forecasts. AEMO continued to apply the October 2024 forecasts as the basis for the 2026 NEM ESOO projections, with no changes from the 2024 component forecasts, consistent with the advice received in 2025 and 2026.

Dwellings and residential customer connections forecasts

AEMO's forecast of residential electricity consumption is driven by growth in the number of electricity connections. For the 2026 NEM ESOO, AEMO's customer connections forecast projected residential electricity connections using a combination of historical connection data and growth driven by new dwelling construction. The initial number of customer connections was derived from AEMO meter data counts. Future connections growth was determined by dwelling stock projections constructed from Australian Bureau of Statistics (ABS) dwelling data and forecast dwelling completions data sourced from the February 2026 economic projections provided by DAE.

Figure 26 compares residential connection forecasts from the 2026 ESOO and 2025 ESOO for the NEM. Revised WEM forecasts have already been published in the 2026 WEM ESOO³⁸. Despite higher initial connection numbers, across all scenarios the 2026 ESOO connection forecast has approximately 1,000,000 fewer connections by 2055-56, when compared against the 2025 ESOO. This reflects updated dwelling stock forecasts received from DAE in February 2026 (including completions and demolitions), which indicate more subdued growth in the near-to-medium term and a flatter long-term growth trajectory. The distribution of new connections is different between regions across the NEM, however, fewer connections are expected in all regions compared to the 2025 ESOO.

Figure 26 Actual and forecast NEM residential connections, 2019-20 to 2055-56



³⁸ See <https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo>.

2.1.4 Appliance uptake forecast

Input vintage	Rebased in March 2026
Source	<ul style="list-style-type: none"> Department of Industry, Science, Energy and Resources (DISER), 2021 Residential Baseline Study for Australia and New Zealand for 2000 – 2040, available at www.energyrating.gov.au Economic forecast – DAE
Updates since 2025 IASR	Appliance uptake forecasts have been rebased to a 2025-26 base year.

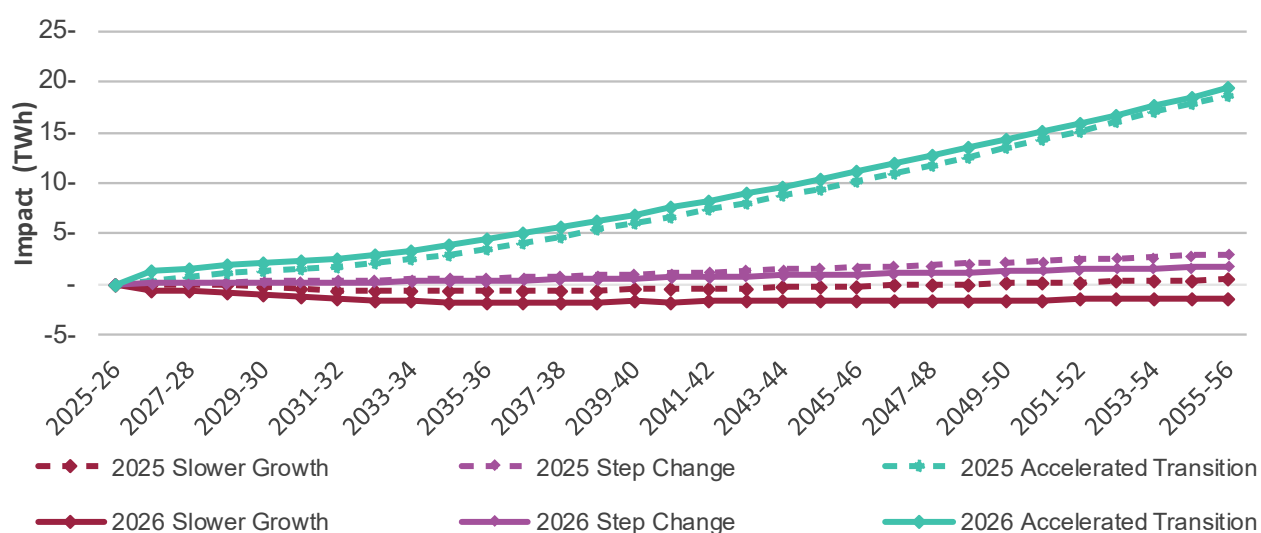
The appliance uptake forecasts represent the quantity of energy services supplied by electricity to meet the growth in household appliances over the outlook period.

The underlying data was sourced from the Department of Climate Change, Energy, the Environment and Water's (DCCEEW's) *2021 Residential Baseline Study*, the most recent available dataset of this type. This data was used to forecast the growth in appliances per connection in the residential sector and enables AEMO to estimate changes in the level of energy services supplied by electricity per households across the NEM.

Energy services are measured based on the number of appliances per appliance category across the NEM, their usage hours, and their capacity and size. See Appendix A5 of AEMO's *Electricity Demand Forecasting Methodology* for details on the methodology used³⁹.

The 2026 appliance uptake forecast for the NEM (see **Figure 27**) has been rebased from the 2025 IASR to reflect a new starting year. As a result, the appliance uptake under the 2026 *Step Change* scenario closely resembles the 2025 forecast with minimal variation across the outlook period. The impact of revised WEM forecasts has already been published in the 2026 WEM ESOO⁴⁰.

Figure 27 Forecast residential appliance uptake (NEM), 2025-26 to 2055-56 (TWh)



Note: change relative to base year (2025-26).

³⁹ At <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-planning-guidelines>.

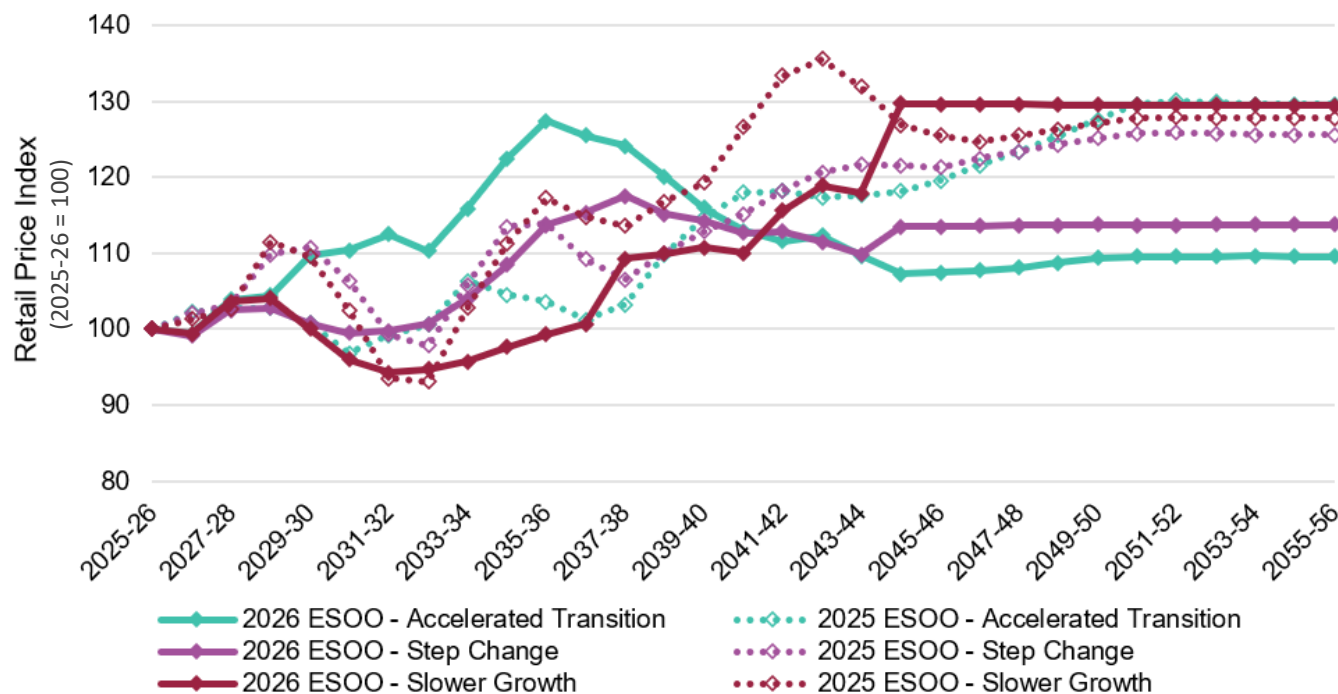
⁴⁰ At <https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo>.

2.1.5 Electricity price indices

Input vintage	Updated in June 2026
Source	<ul style="list-style-type: none"> • AEMO internal wholesale price forecasts. • Transmission costs from the 2026 ISP's optimal development path • ASX Energy Electricity Futures • AER Determinations and Access Arrangements. • AEMC annual Residential Electricity Price Trends report, 2025 forecasts • Australian Competition and Consumer Commission (ACCC) Inquiry into the National Electricity Market report, November 2022 (not updated in this report)
Updates since 2025 IASR	Retail price forecasts have been updated with components from the latest available AER pricing proposals and transmission determinations, the latest ASX Energy Electricity Futures data, AEMO 2026 wholesale price projections, and transmission costs associated with the 2026 ISP.

Electricity prices are assumed to influence consumption through short-term behavioural changes (such as how electricity devices are used or energy consumption is managed), and longer-term structural changes (such as decisions to invest in CER). The retail price index represents the forecast directional price path for the average consumer in the NEM relative to today, where a number above 100 represents a real increase, and a number below 100 represents a real decrease. AEMO constructed the NEM retail price index using weighted retail price projections for each state and territory in the NEM. **Figure 28** shows the retail price index assumed in 2026 for the *Step Change*, *Slower Growth*, and *Accelerated Transition* scenarios.

Figure 28 Forecast NEM residential real retail price index, 2025-26 to 2055-56



Note: price weighted by household consumption per region.

The Australian economy transitions to net zero emissions by 2050 in all scenarios. The timing and pace of investment in this transition varies by scenario and, among other things, impacts expected energy prices. Retail price forecast trajectories are divergent and volatile across scenarios and through the 2030s as coal generation is phased out and replaced by renewables.

with firming from utility-scale storage and gas, and new network investment, consistent with the optimal development path in the 2026 ISP. Investment in transmission and energy infrastructure is recovered by regulated consumer costs in all scenarios.

The retail price forecasts were formed from bottom-up projections of the various components of retail prices. **Table 7** shows the high-level mapping of the various price components used, and their incorporation into the 2026 scenarios.

Table 7 High-level mapping of price input settings by scenario

Component	Input settings
Wholesale component	Short term (up to FYE2029): Blend of ASX Futures and 2026 ISP. Longer term (FYE2030 onwards): Solely based on ISP wholesale price forecast.
Transmission costs	Short term (up to FYE 2034): AER pricing proposals and determinations actuals (latest available). Longer term (FYE 2034 onwards): Forecast charges based on forecast transmission network augmentations per the 2026 ISP.
Distribution costs	Short term (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). Longer term (FYE 2030 onwards): Same growth trajectory as transmission costs.
Environmental costs	AEMC (2025) to FYE2035 the constant in real terms.
Retail component	ACCC (2022) derived residual.

Consumption forecasts consider the price elasticity of demand, which refers to the percentage change in demand for a given change in price. The price elasticity of demand is used alongside the retail price index to determine impacts to consumption forecasts from changes in price, with a negative value reflecting that consumers tend to reduce consumption as the cost of electricity rises. The price elasticities of demand are as per the 2025 IASR (see **Table 8** below).

Table 8 Price elasticities of demand for various appliances and sectors

Scenario	Slower Growth	Step Change	Accelerated Transition
Residential: Baseload appliances	0	0	0
Residential: weather-sensitive appliances	-0.10	-0.10	-0.10
Business: all load components	-0.10	-0.10	-0.05

Note: negative elasticities indicate that electricity consumption will reduce from a price increase.

2.1.6 Energy efficiency forecast

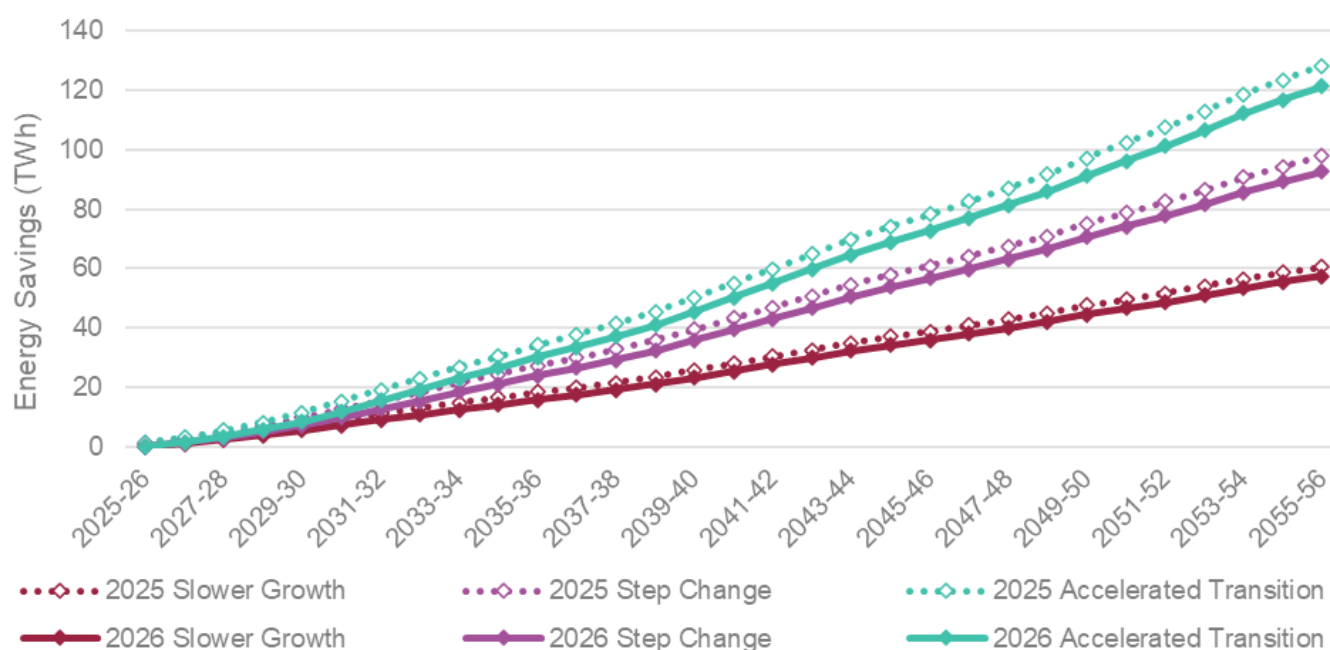
Input vintage	Rebased in May 2026
Source	Strategy. Policy. Research. (SPR), 2025
Updates since 2025 IASR	Energy efficiency forecasts have been rebased to a base year of 2025-26.

Australia's governments have developed a range of measures to mandate or promote energy efficiency uptake across the economy. These policy-led savings are complemented by market-led savings, which are driven by factors such as technology change and consumer preferences. AEMO's energy efficiency forecasts were developed for the 2025 IASR, with support from *Strategy. Policy. Research.*, and were influenced by the outcomes affecting economic, population, housing, and connections growth for each scenario. The assumed duration of current policies, and potential extended applications of

policy support that differ across scenarios, also inform energy efficiency forecasts for each scenario⁴¹. More information is available in Section 3.3.12 of the 2025 IASR.

Figure 29 shows the total energy efficiency savings for residential and commercial sectors applied as reductions to electricity consumption across the modelled scenarios for the NEM. Revised WEM forecasts have already been published in the 2026 WEM ESOO⁴². AEMO rebased the 2025 IASR's energy efficiency savings for the 2026 *Forecasting Assumptions Update*, resulting in a marginal decline at the start of the forecast.

Figure 29 Forecast energy efficiency savings (NEM), 2025-26 to 2055-56 (TWh)



2.1.7 Electrification (excluding electric vehicles)

Input vintage	Rebased since the 2025 IASR
Source	CSIRO and Climateworks Centre (multi-sector modelling)
Updates since 2025 IASR	Electrification forecasts have been rebased to a base year of 2025-26.

Decarbonisation of the Australian economy requires emissions-intensive energy sources for residential, commercial and industrial processes to shift towards low and no emissions alternatives. In considering electrification, AEMO includes the potential electrification of future NEM and WEM loads, and expansion of existing grid-connected loads. While AEMO also forecasts the electrification of transport, it is not included in this section's projections, rather within the EV forecasts presented in Section 2.1.1.

⁴¹ AEMO removes the future savings from activities that took place prior to the base year of the forecasts. For more information, see the *Electricity Demand Forecasting Methodology* information paper, at <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-planning-guidelines>.

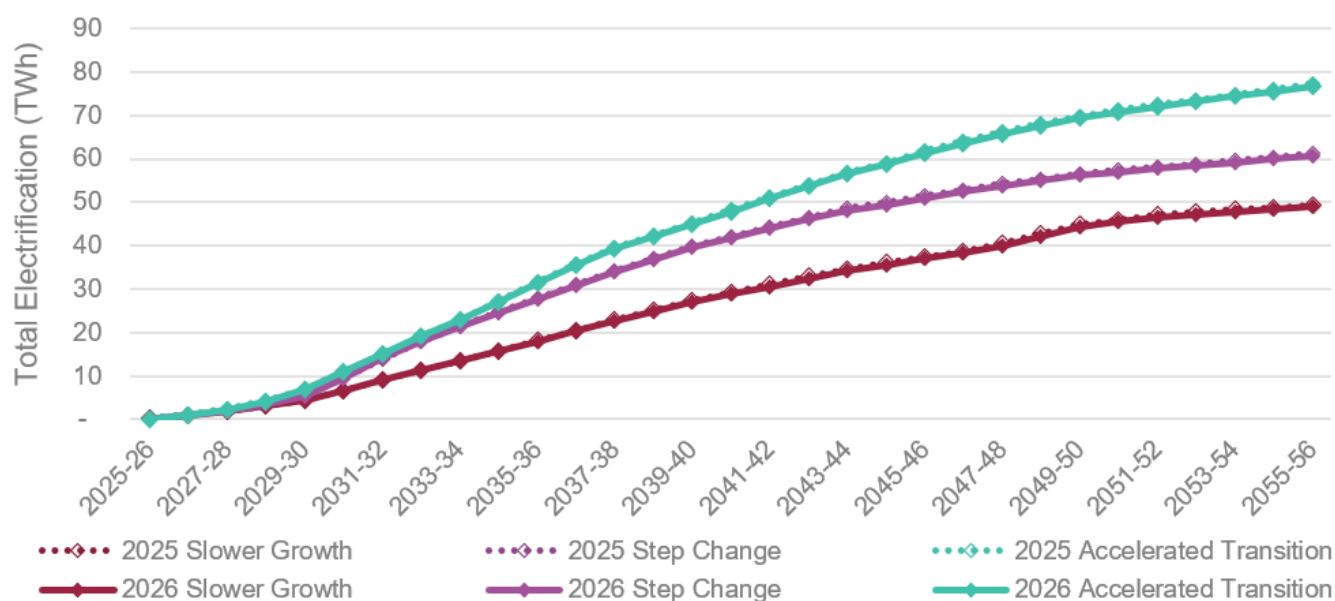
⁴² At <https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo>.

For many end uses, electricity is already the most economic choice of energy forms⁴³. Continued technological advancement in heat pumps, electric water heaters, and electric cooktops may see the cost of these units decrease, and support accelerated uptake in all scenarios. Greater electrification is also spurred by other drivers and market conditions that are less supportive of non-electric options, such as from the influence of Victoria's Gas Substitution Roadmap, as well as the Australian Capital Territory government and some local New South Wales' council bans on new gas connections. Continued improvements in cost competitiveness will support some of this acceleration. However, additional policy support may be required wherever cost barriers remain, such as for the electrification of many industrial processes that currently use gas for heat.

More information is available in Section 3.3.5 of the 2025 IASR.

Figure 30 shows the total electrification forecast across the modelled scenarios for the NEM. Revised WEM forecasts have already been published in the 2026 WEM ESOO⁴⁴. AEMO rebased the 2025 IASR's electrification forecast for the 2026 *Forecasting Assumptions Update*. Given the relatively low levels of electrification assumed initially, the forecasts remain near identical.

Figure 30 Forecast electrification for residential, commercial, industrial and non-road transport (NEM), 2025-26 to 2055-56 (TWh)



⁴³ AER (2025), *State of the energy market 2025*, Figure 6.10, at <https://www.aer.gov.au/documents/state-energy-market-2025-full-report>.

⁴⁴ At <https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo>.

2.1.8 Large loads

Input vintage	Updated in June 2026
Source	<ul style="list-style-type: none"> • Interviews/surveys with customers including self-reported forecasts in the medium term • Historical consumption from the AEMO meter database • NSPs • Media search/announcements • Economic forecast for data centre consumption (Oxford Economics Australia [OEA]), aligned with the economic forecasts (DAE) • Market research • International Energy Agency data and reports
Updates since 2025 IASR	<p>Updated based on new survey data provided by large customers.</p> <p>Revised classification of customers between business mass market (BMM), LIL, Data Centre and coal seam gas (CSG) categories considering more recent meter data analysis</p> <p>Outage rates applied to correct for persistent over-forecast in survey responses</p> <p>Refinement of forecast methodology for prospective data centre loads</p> <p>Updated Economic forecast for data centre consumption</p>

AEMO segments and forecasts large industrial loads (LILs), data centres and coal seam gas (CSG) extraction separately to small and medium commercial enterprises, because the broader econometric model used to forecast other business customers may not provide appropriate accuracy for these larger customers that have more unique circumstances to the remainder of business customers.

Large industrial loads

AEMO identified LILs by analysing AEMO's meter data and working with transmission and distribution network operators for each region to cross-reference loads where demand exceeds at least 10 MW for greater than 10% of the latest financial year. This threshold aims to capture the most energy-intensive consumers in each region.

AEMO currently sources information regarding LILs from:

- surveys sent out to the LIL customers, and follow-up interviews for a subset of customers where clarification is needed,
- AEMO's standing information requests from distribution and transmission network service providers (DNSPs and TNSPs) regarding prospective and newly connecting loads,
- AEMO's metering data for transmission and distribution connected NMI's associated with the LILs, and
- media searches and company announcements.

AEMO's 2026 LIL forecast is lower than in the 2025 IASR, due to the reallocation of about 90 sites from the 2025 IASR's LIL sector to the business mass market (BMM) sector. As consulted on at the March 2026 FRG, many sites removed were large but not industrial in nature, while others did not surpass the 10 MW size threshold in the 2025 financial year.

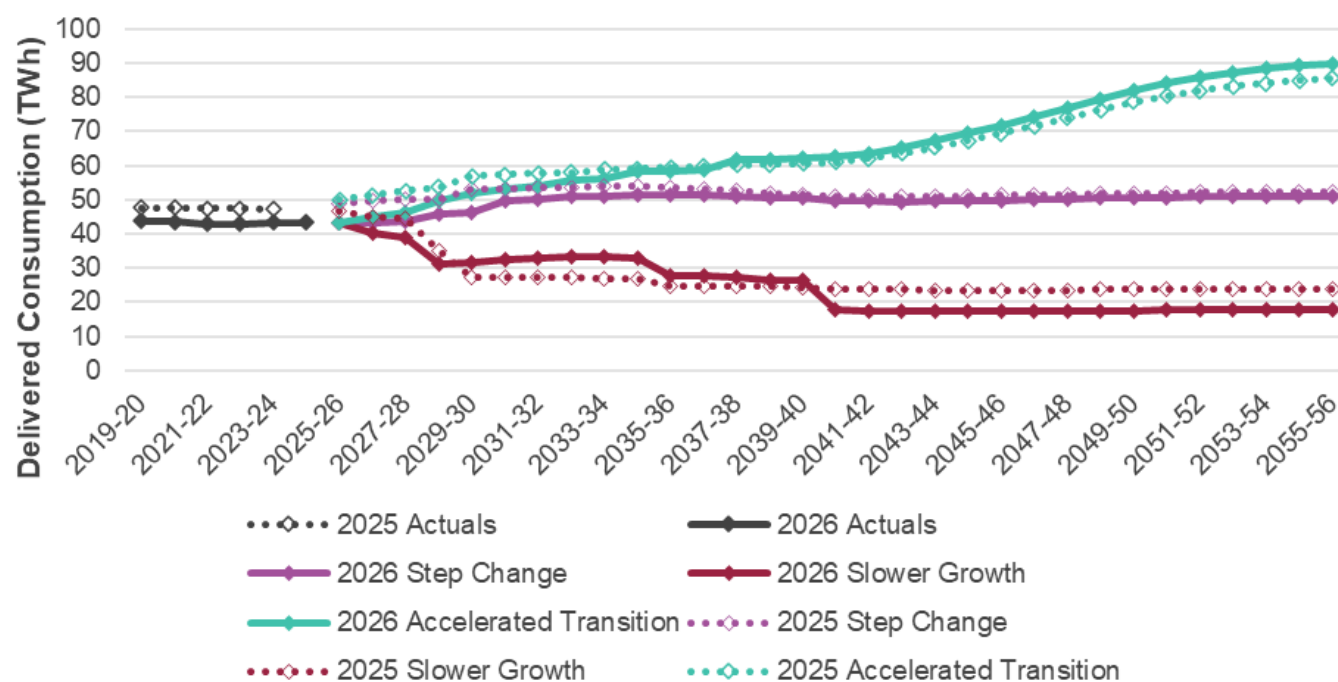
Other observed changes in the LIL forecast are:

- Some industrial operators have advised closure, mothballing or production slowdowns in the last year, which is reflected by a small drop from 2024-25 actuals to the 2025-26 forecast.

- Some new prospective loads have progressed in their development to become operational or to start construction, pushing up the *Step Change* and *Accelerated Transition* forecasts through the 2030s.
- Some very large loads have had their energy supply contracts extended, which delays their closure dates previously assumed in the *Slower Growth* scenario.

The LIL consumption forecast for all scenarios is shown in **Figure 31** for the NEM. Revised WEM forecasts have been published in the 2026 WEM ESOO⁴⁵.

Figure 31 NEM LIL consumption actuals and forecasts, 2019-20 to 2055-56 (TWh)



Note: actuals data is lower in 2026 data because of the reclassification of around 90 sites from the LIL to the BMM.

Data centres

The rapid growth of cloud computing and artificial intelligence (AI) has led to growth in forecast data centre electricity consumption. Due to the pace of development and uncertainty in scale, location and delivery timelines, AEMO assesses these loads separately from traditional industrial loads.

AEMO's *Electricity Demand Forecasting Methodology* outlines the approach used to forecast data centre load. This approach averages the forecast derived from project-level information for existing, planned and prospective data centres, with the forecasts that reflects macroeconomic demand drivers. These macroeconomic demand drivers include factors linked to AI adoption and broader digital transformation, aligned with each scenario's economic assumptions.

⁴⁵ At <https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo>.

Project-based forecast

NSPs reported increased grid connection interest through the 2026 Standing Information Request. **Figure 32** shows grid connection interest in March 2026 and can be compared to **Figure 33** which shows interest in March 2025. Over the year, total capacity across all development stages more than doubled, from 37.9 GW to 67.1 GW.

This increase, together with two years of information from NSPs specific to data centres, led to a revised approach to assessing planned and prospective project data.

Figure 32 NEM Standing Information Request – 2026 data centre connection pipeline (GW)

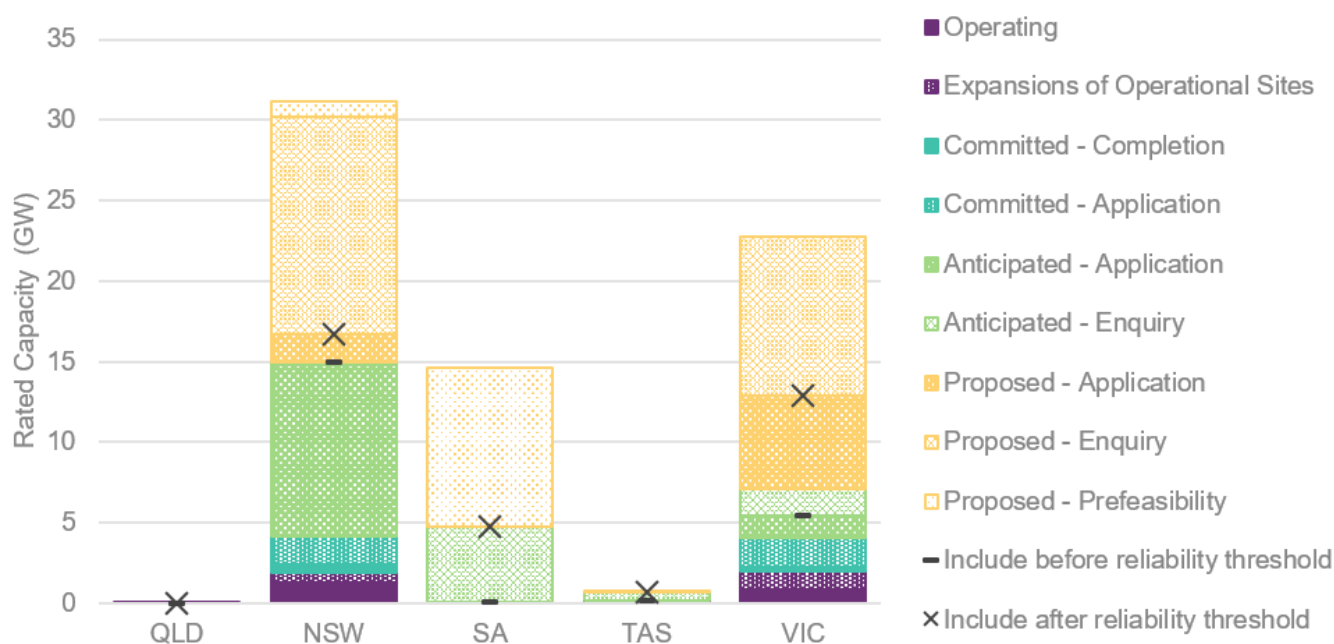
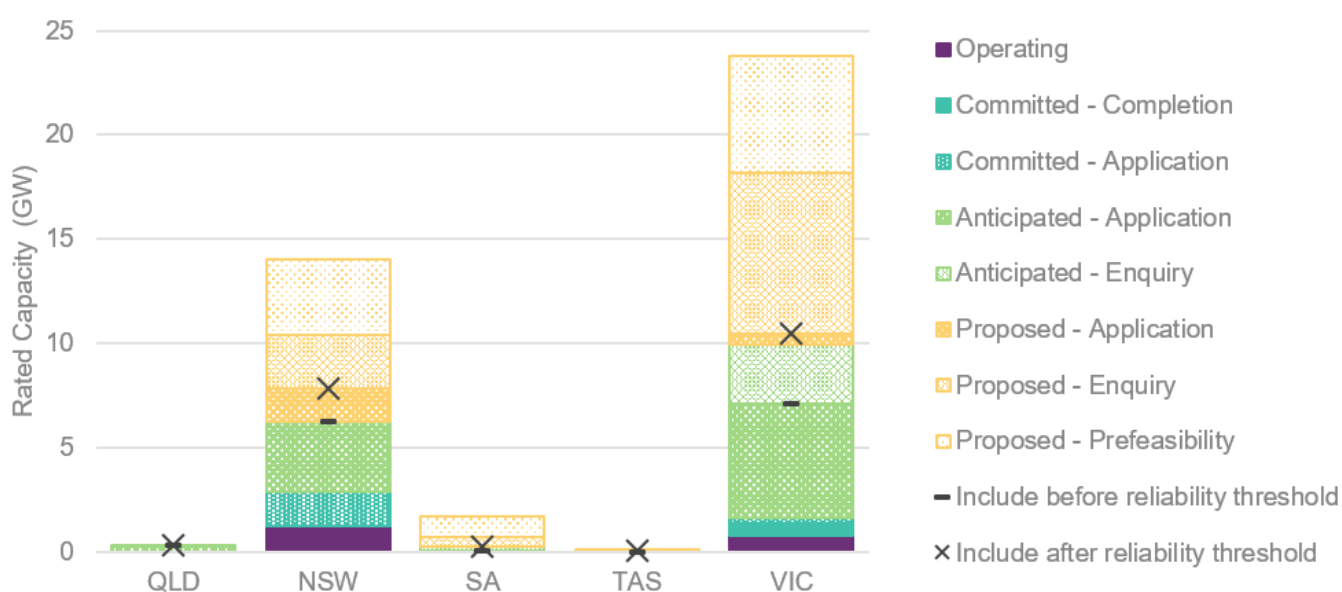


Figure 33 NEM Standing Information request – 2025 data centre connection pipeline (GW)



To assist AEMO in applying a Load Realisation Factor, Oxford Economics Australia (OEA) applied a logistic regression model to assess changes of 185 projects between the two years of data. This model derived a probability weighting for each project progressing through the development pipeline to final connection. The logistic regression model used project status, connection status, developer size, localised project competition, and the realism of the proposed development timeline as inputs to estimate the likelihood of a project progressing. Further detail, such as a detailed description of the model, as well as a breakdown of the count of projects in probability bands by project status, is in the updated OEA report⁴⁶.

The introduction of project-level weighting enabled inclusion of all applications and enquiries, including projects classified as proposed only. **Table 9** explains the project statuses.

Table 9 Project status explanations

Project status	Explanation
Constructed – not operational	Under construction, but not yet connected to the grid
Committed	Very high likelihood of being developed – that is, reached final investment decision (FID)
Anticipated	High likelihood of being developed – that is, at least in enquiry stage in connection process, with environmental and planning approvals progressing
Proposed	Project is at pre-feasibility or early stage in connection process

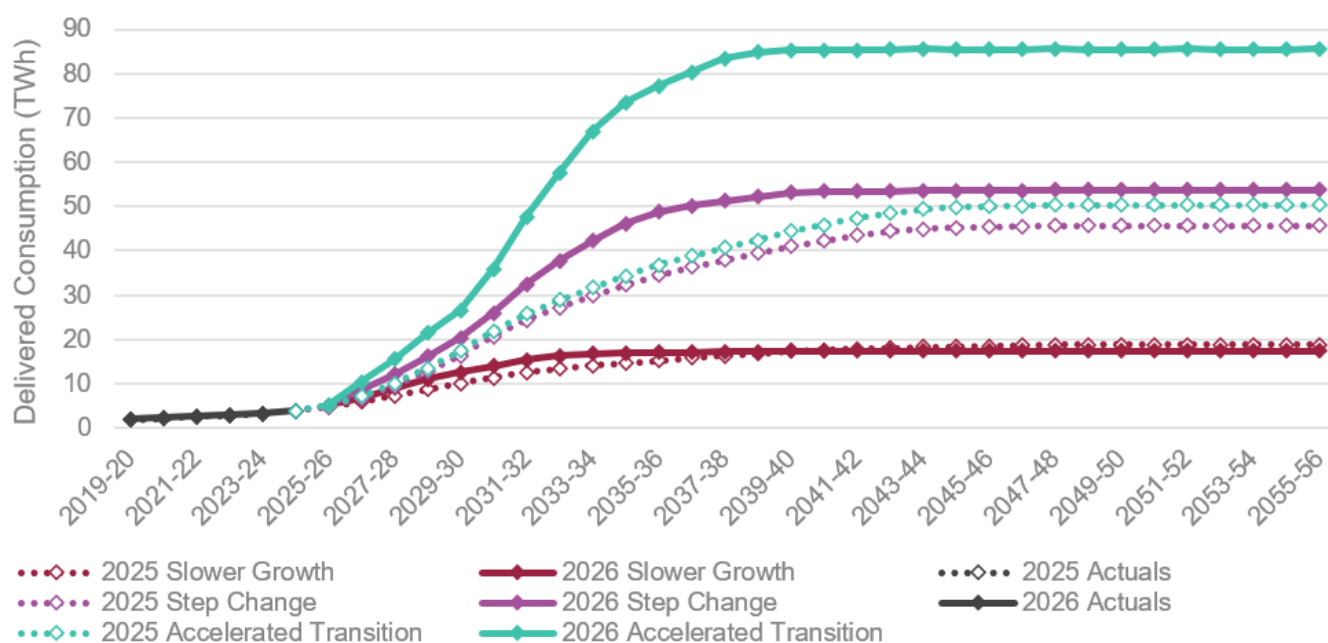
The main interest in data centre development is concentrated in a few NEM regions, with lower interest in Western Australia (for more detail see the 2026 WEM ESOO⁴⁷). The final project-level forecast, which incorporates included projects, the load realisation factor, and assumed ramping towards maturity over five to 10 years, is shown in **Figure 34**. For a detailed description of the project approach and more detailed terminology descriptions, please refer to AEMO's *Electricity Demand Forecasting Methodology*⁴⁸.

⁴⁶ At <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

⁴⁷ At <https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo>.

⁴⁸ At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2026/2026-Electricity-Demand-Forecasting-Methodology.

Figure 34 Actual and forecast NEM data centre consumption (project-based), 2025 NEM ESOO and 2026 NEM ESOO, 2019-20 to 2055-56 (TWh)



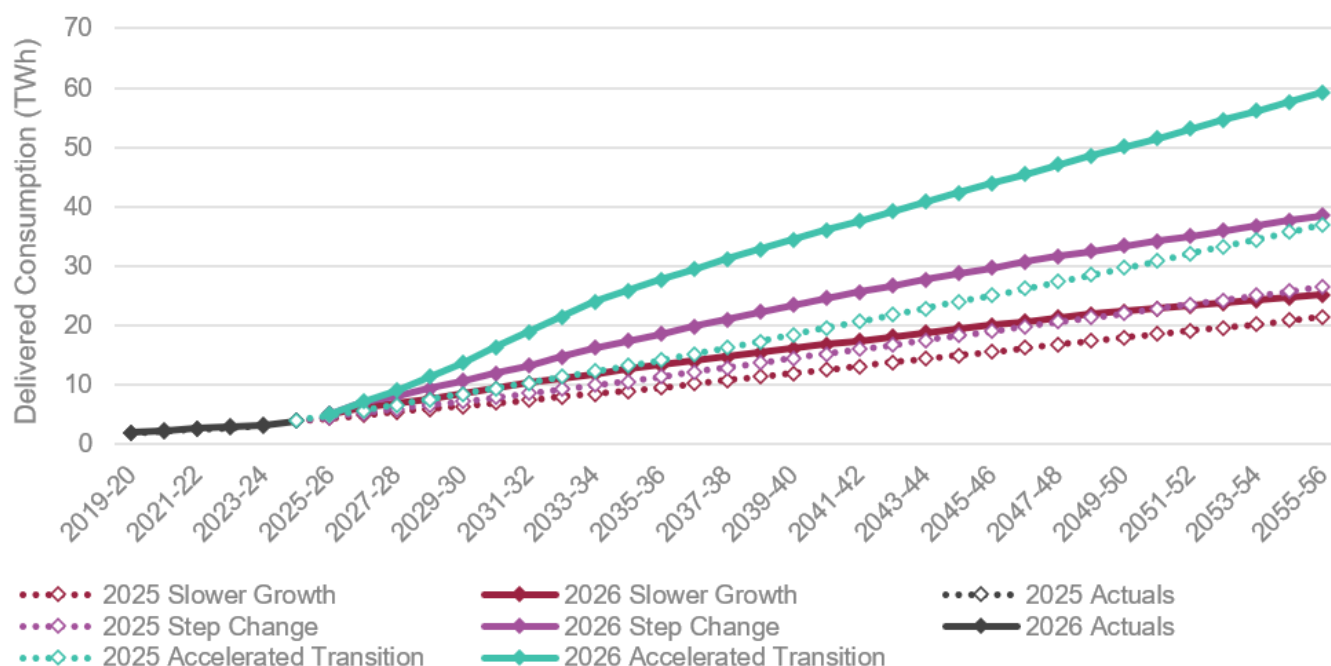
Economics-based forecast

Developments in AI adoption and the data centre landscape prompted an update to the economic data centre outlook used for the 2025 NEM ESOO and the 2026 ISP. In addition to updated consumption data and an improved understanding of the data centre market, AEMO commissioned an updated economic based forecast of data centres from OEA. Further, an international demand component was introduced to the economic data centre forecast to better capture Australia's potential as a data centre hub in the Asia-Pacific region⁴⁹.

Figure 35 compares this updated economics-based data centre projection for the 2026 NEM ESOO with the outlook published in the 2025 NEM ESOO (also used in the 2026 ISP).

⁴⁹ At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/Oxford-Economics-Australia-Data-Centre-Energy-Demand-2026-Forecast-Update.

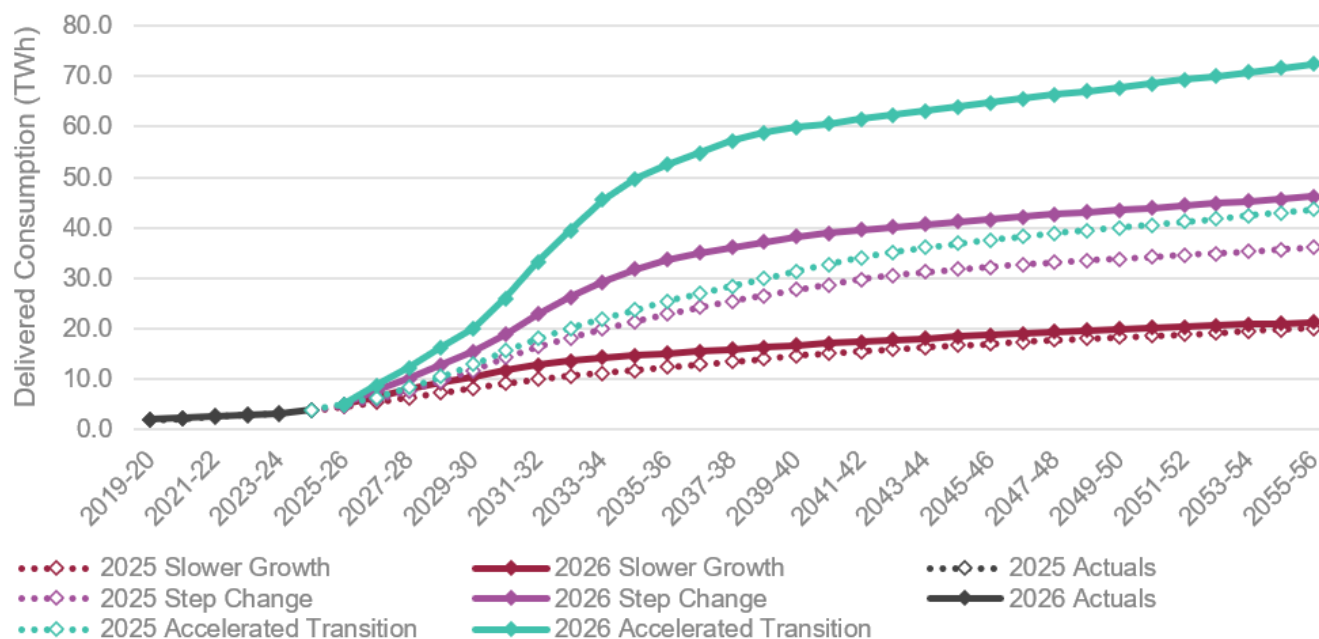
Figure 35 Actual and forecast NEM data centre consumption (economics-based), 2025 NEM ESOO and 2026 NEM ESOO, 2019-20 to 2055-56 (TWh)



Final blended forecast

The final blended data centre consumption forecast applies both project- and economic-based outlooks with a 50:50 weighting. **Figure 36** shows the 2026 NEM ESOO compared to the 2025 NEM ESOO (and 2026 ISP) forecast for all scenarios. In 2025-26, data centres consumed around 5 TWh of electricity across the NEM, accounting for approximately 3% of grid-supplied electricity. This is about 7% more than forecast in the 2025 ESOO.

Under the *Step Change* scenario, the compound annual growth of data centre electricity consumption over the next five years is 30%, up from 25% in the prior forecast for this scenario. With this increase, the sector's electricity consumption is projected to reach around 15 TWh by 2029-30, equivalent to 8% of the NEM's wholesale-supplied electricity, up from 12 TWh and 12% of the wholesale supplied demand forecast in the 2025 ESOO. Growth in the five years between 2030 and 2035 is forecast to be particularly strong, with data centre consumption doubling over that period and reaching 30 TWh, up from the previous forecast of 21 TWh.

Figure 36 Actual and forecast NEM data centre consumption, 2025-26 to 2055-56 (TWh)

Coal seam gas (CSG) extraction

CSG extraction in Queensland that supports domestic gas use and liquefied natural gas (LNG) export represents a substantial electricity load, consuming approximately 4% of NEM wholesale-supplied electricity in 2025-26. Due to this significance, AEMO forecasts CSG extraction separately for improved transparency.

Figure 37 shows the forecast electricity consumption for CSG loads for the 2026 ESOO, which aligns with the LNG forecast in the 2026 GSOO for the East Coast Gas Market.⁵⁰

The CSG forecasts used data provided by the LNG consortia via the GSOO survey process. This data considers the anticipated operating life of CSG facilities and the volumes of gas they process. The 2026 forecast has a higher starting point than the 2025 forecast because it includes the recent electrification of a CSG facility, as advised by the CSG operator.

Recognising that long-term forecasts are highly uncertain, the forecasts remain on a similar trajectory to the 2025 forecasts, although in scenarios where LNG exports were assumed to decline, the forecasts now assume an orderly shutdown of LNG processing trains, resulting in steps in the forecast electricity used for CSG extraction.

AEMO shaped the long-term trajectory of scenarios in the GSOO LNG forecasts based on trends observed in the 2025 International Energy Agency World Energy Outlook (WEO)⁵¹, whereby:

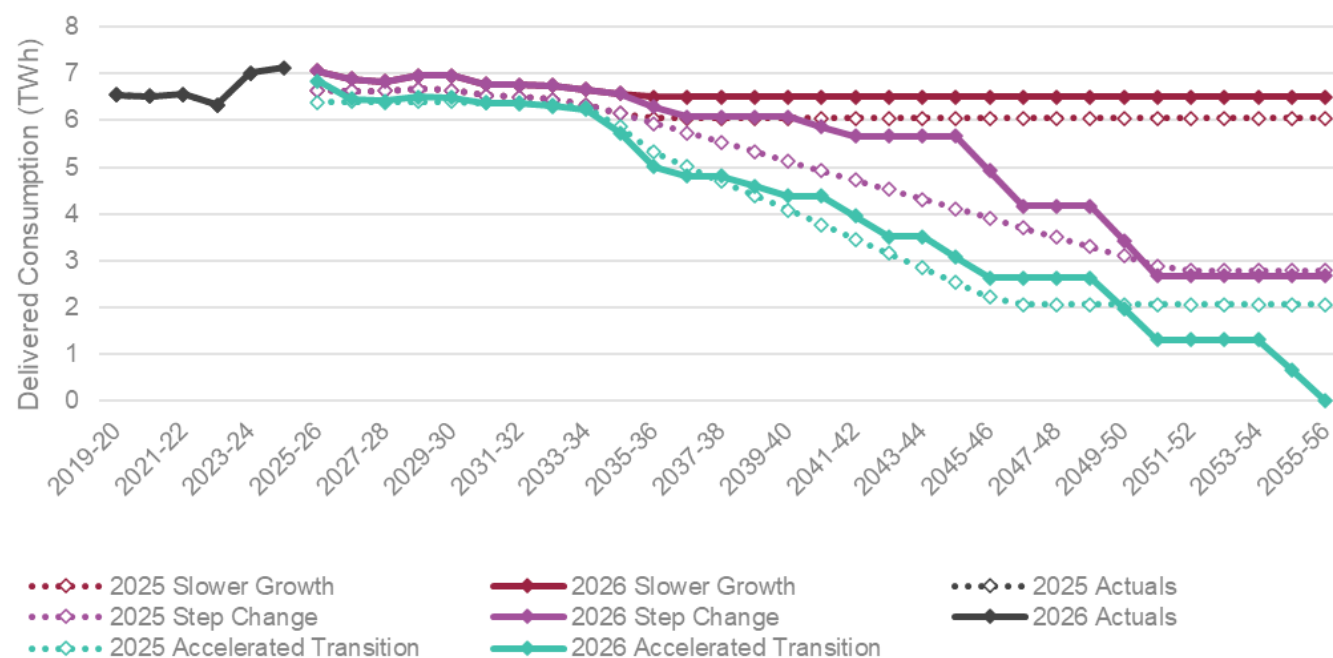
- In the *Slower Growth* scenario, reduced action towards global decarbonisation means east coast LNG exports have been assumed to be flat across the horizon.
- The *Step Change* and *Accelerated Transition* scenarios assumed increasing levels of decarbonisation action globally to lower energy sector emissions leads to lower global demand for LNG and reduced levels of assumed east coast LNG export.

⁵⁰ At <https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo>.

⁵¹ See International Energy Agency 2025 World Energy Outlook, at <https://www.iea.org/reports/world-energy-outlook-2025>.

The wide range in long-term forecasts for CSG extraction electricity consumption highlights the significant uncertainty surrounding future LNG export demand across different scenarios.

Figure 37 Actual and forecast CSG electricity consumption, 2019-20 to 2055-56 (TWh)



Note: this forecast may look slightly different to the LNG export forecast published in the 2026 GSOO, as this figure is presented in financial years instead of calendar years, and the forecast horizon has been extended out past the GSOO horizon.

2.1.9 Demand side participation (DSP)

Input vintage	Updated forecast in June 2026
Source	<ul style="list-style-type: none"> Historical meter data analysis and information submitted to the DSP Information Portal in April 2026 Information about policy-driven programs
Updates since 2025 IASR	Forecast DSP for New South Wales are no longer influenced by the New South Wales PDRS ⁵²

AEMO's forecasting approach considers DSP explicitly and dynamically in its market modelling, meaning that demand forecasts reflect what demand would be in the absence of DSP to avoid double-counting. The forecast for DSP in the upcoming year was produced following AEMO's *Demand Side Participation Forecast Methodology*⁵³. This method examined estimated DSP at various price levels, including the amount of voluntary maximum estimated demand reduction possible to avoid unserved energy during lack of reserve (LOR) conditions (which is known as the reliability response). For all regions, the DSP estimates for the upcoming year were used for the whole horizon of the ESOO for all scenarios, as no other data source is available to provide a reference for future trends in DSP growth or decline.

For the 2026 NEM ESOO, the New South Wales PDRS is no longer considered in AEMO's DSP forecast. While initially designed to incentivise summer peak demand reduction through targeted appliance upgrades, recent changes to the scheme⁵² have shifted its focus toward long-term efficiency improvements and battery storage uptake. These measures

⁵² At <https://www.energy.nsw.gov.au/government-and-regulation/energy-security-safeguard/peak-demand-reduction-scheme>.

⁵³ At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/forecasting-approach/2023-dsp-forecast-methodology.pdf.

provide passive or distributed benefits over time rather than dispatchable, event-driven demand response. As a result, the PDRS no longer necessarily delivers coordinated peak reduction aligned with AEMO's reliability or price-responsive DSP triggers. Accordingly, it has been removed from the summer DSP forecast assumptions. Its impact is instead captured within the underlying demand forecast⁵⁴.

Table 10 Forecast DSP for each NEM region, summer, 2026-27 to 2055-56, Step Change scenario (MW)

Region	NSW	QLD	SA	TAS	VIC
DSP reliability response	190	299	35	37	524

2.1.10 Hydrogen forecast

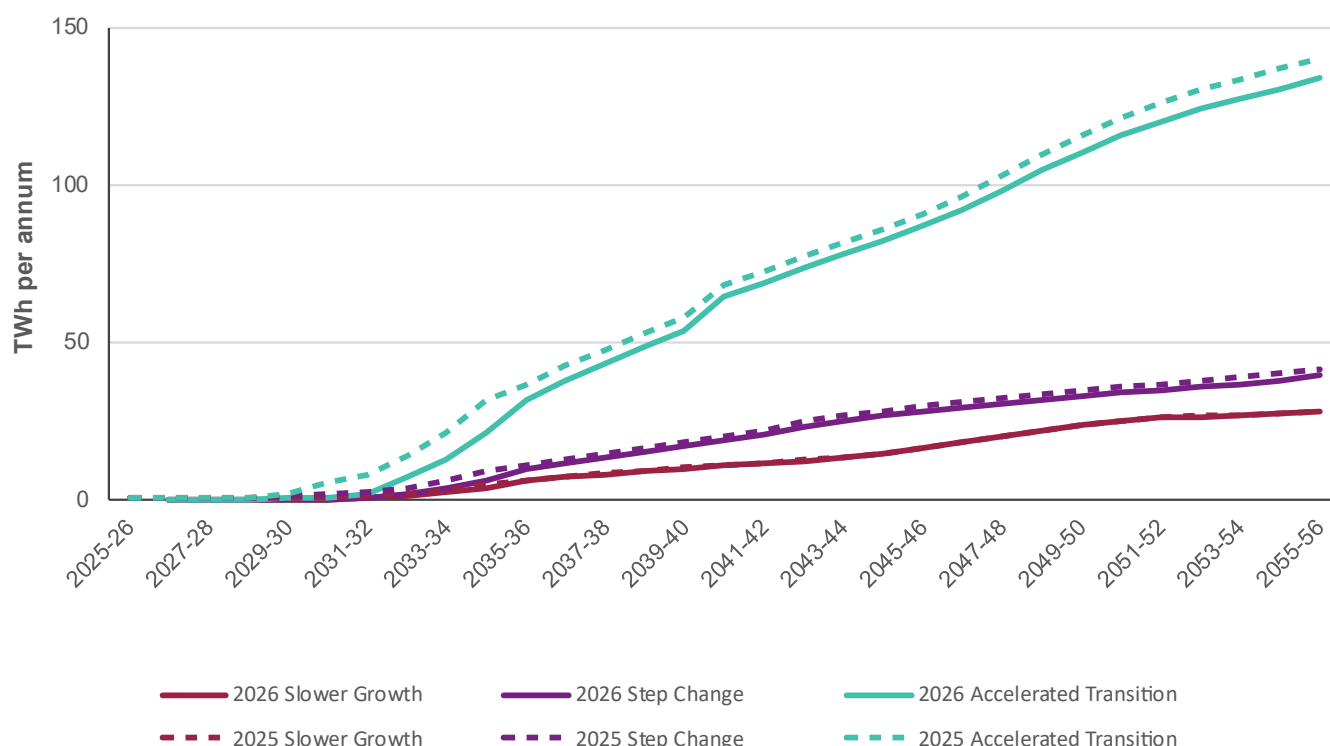
Input vintage	Updated forecast in June 2026
Source	Latest project listing from HyResource website (CSIRO) ⁵⁵
Updates since 2025 IASR	Updated projects from HyResource website (CSIRO) and reduced volumes in various sectors.

The 2026 NEM ESOO hydrogen forecast used the CSIRO multi-sectoral modelling (MSM) outputs from the 2025 IASR⁵⁶, and CSIRO's HyResource project list, updated to recognise developments have not progressed in this emerging industry. The updated projection for each scenario applied a delayed start and ramp to the 2025 IASR projection, with additional reductions considering updates to CSIRO's HyResource project list, resulting in a slower, lower hydrogen forecast across all scenarios (see **Figure 38**). Further details are in the 2026 *Forecasting Assumptions Update* Workbook.

⁵⁴ This is for the New South Wales state only. The NEM region of New South Wales also includes the Australian Capital Territory, so adjustments have been made to ensure the target reflects the New South Wales state demand only.

⁵⁵ At <https://research.csiro.au/hyresource/projects/>. CSIRO provides a database of active, proposed and cancelled hydrogen projects in Australia.

⁵⁶ At <https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-iasr>.

Figure 38 Forecast electricity consumption for hydrogen production, 2025-26 to 2055-56, all scenarios (TWh per annum)

2.2 Existing generators and transmission

AEMO uses a range of data to describe the existing NEM generators in its models. This data is updated through established processes and documented methodologies. Key inputs and assumptions are outlined in **Table 11** below.

Table 11 Status and update process for key inputs and assumptions for existing generation and transmission

Input	Input vintage	Sources and updates since 2025 IASR
Generation Information data	Updated in July 2026	<ul style="list-style-type: none"> Updated based on NEM July 2026 Generation Information published on AEMO's Generation Information website^a. This data is collected and published in accordance with the Generation Information Guidelines^b.
Marginal loss factors (MLFs), inter-regional loss flow equations, and loss proportion factors	Updated in June 2026	<ul style="list-style-type: none"> Initial MLFs, loss equations, and proportioning factors are based on the MLFs for the 2026-27 Financial Year report – July 2026^c. Inter-regional loss equations and proportion factors are varied based on inter-regional network augmentations, as outlined in the <i>ISP Methodology</i>^d.
Scheduled generator long duration unplanned, forced, maintenance, and planned outage rates	Updated in June 2026	<ul style="list-style-type: none"> Outage rates were updated based on historical and forward-looking outage data provided by registered participants in accordance with National Electricity Rules (NER) 3.13.3A(d). The data was collected in April 2026 so accounts for generator performance over the 2025-26 summer. Based on the methodology outlined in the <i>ESOO and Reliability Forecast Methodology</i>^e, AEMO calculated outage rates for all scheduled generators. The draft outage rates were presented to the FRG in June 2026.
Unplanned outages affecting inter-regional power transfers	Updated in June 2026	<ul style="list-style-type: none"> AEMO engaged with stakeholders through FRG consultation in June 2026 where the most recent interregional unplanned outage rates were presented.
Generator energy limits	Updated in June 2026	<ul style="list-style-type: none"> The energy limits were updated based on forward-looking energy limit data provided by registered participants in accordance with NER 3.13.3A(d). The data was collected in April 2026 and the draft energy limit forecasts were presented to the FRG in June 2026.

Input	Input vintage	Sources and updates since 2025 IASR
Transmission network modelling	Updated in June 2026	<ul style="list-style-type: none"> Updates to transmission network project timing and constraint equations based on latest available information. Project timing and status updates are reported in the NEM Transmission Augmentation Information June 2026^G.

A. See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

B. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/final-generation-information-guidelines.pdf.

C. See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries>.

D. See <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/isp-methodology>.

F. See <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

G. See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

2.2.1 Generator outage rates

Generator outage assumptions are a key input to the ESOO reliability assessment and represent the expected availability of existing scheduled generating units over the outlook period.

Following consultation through the 2025 *Forecast Improvement Plan* (FIP)⁵⁷, AEMO expanded the outage forecasting methodology for the 2026 NEM ESOO to better represent different forms of generator unavailability.

The updated methodology separately represents four outage categories, as shown in **Table 12**.

Table 12 Updated outage forecasting definitions

Outage type	Description	Timing
Long duration unplanned	Major equipment failures requiring extended outages with little or no opportunity for rescheduling (unplanned outages longer than five months)	Inflexible
Forced outages	Unexpected outages or deratings caused by equipment failures with limited scheduling flexibility.	Inflexible
Planned outages	Outages scheduled well in advance and generally undertaken during periods of lower system risk.	Moderately flexible
Maintenance outages	Short-notice or opportunistic maintenance activities that can be scheduled with greater operational flexibility.	Flexible

These outage definitions were developed in consultation with participants and are broadly aligned with IEEE 762 standards⁵⁸. Long duration unplanned and forced outages are represented as stochastic outages, while planned and maintenance outages are scheduled by the optimisation model to reflect the flexibility available to generators when undertaking maintenance. Together, these improvements provide a more representative assessment of expected generator availability than previous NEM ESOOs, which represented only unplanned outages, on the assumption that planned outages could be scheduled to avoid low reserve conditions.

Further information on the outage calculation, forecast and implementation methodology is in the *ESOO and Reliability Forecast Methodology Document*.

As part of the 2025 FIP consultation, AEMO expanded its annual outage survey of existing scheduled production units to support the revised outage forecasting methodology. The survey was expanded for the 2026 NEM ESOO to collect

⁵⁷ At <https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-forecast-improvement-plan-consultation>.

⁵⁸ See <https://standards.ieee.org/ieee/762/6856/>.

information on planned outages and to adopt more detailed categories for forced and maintenance outages, replacing the previous unplanned outage classification.

Participants provided historical outage data detailing the timing, duration and capacity derating of all outages that occurred in the previous year. Operators of coal and large gas-powered generators also submitted forced, maintenance and planned outage rate projections, considering expected changes in plant reliability as units age, approach retirement, or undergo maintenance. Historical observations and participant forecasts were combined to develop outage assumptions for individual coal and large gas generators for the modelling across the 10-year outlook. Participant forecasts were applied where appropriate, including applying participant-submitted Medium Term Projected Assessment of System Adequacy (MT PASA) planned outage schedules for coal generators in the first three outlook years, where detailed maintenance schedules are available.

To preserve participant confidentiality, AEMO reports aggregated 'All Coal' outage rates for unplanned, planned and maintenance outages from 2028-29 onwards. This approach maintains a representative outlook for coal generator reliability in public reporting.

As part of the annual survey, AEMO collected data on the timing, duration and de-rating of historical outages, which were used to develop forecasts of full and partial outage rates for each generator across the ESOO outlook period, consistent with the *ESOO and Reliability Forecast Methodology Document*.

For small peaking and hydro generators, outage rate assumptions were derived using technology-level aggregates. Where participants provided projections of future outage rates, AEMO incorporated these forecasts following consultation with the relevant station owners and operators.

To assess the reliability implications of these outage rate assumptions, AEMO applied them probabilistically through a Monte Carlo simulation framework. This approach is based on a large number of simulations⁵⁹, which allow a broad range of potential generator outage outcomes to be represented in the reliability assessment. This enables expected unserved energy (USE) estimates to converge as the number of simulations increases.

Long duration unplanned outages

For the 2026 NEM ESOO, AEMO modelled long duration unplanned outages (duration longer than five months) for each region and technology class, using the last 16 years of historical outage data, from 2010-11 to 2025-26, for calculating the forecast unplanned outage rates (UORs). The long duration unplanned outages used in 2026 NEM ESOO modelling, and in other reliability assessments such as MT PASA and the Energy Adequacy Assessment Projection (EAAP), are shown in **Table 13**.

Table 13 Existing generators – long duration unplanned outages

Fuel type/technology	Long duration unplanned outage rate (%)	Mean time to repair (hours)
All coal	0.90%	5,861
Hydro	0.29%	5,093
All gas and liquids	0.55%	6,217
Battery	0.12%	6,966

⁵⁹ For example, the 2026 NEM ESOO model is designed to run up to 1,200 simulations for each year in the forecast horizon, in each sensitivity. For more information, refer to the *ESOO and Reliability Forecast Methodology Document*.

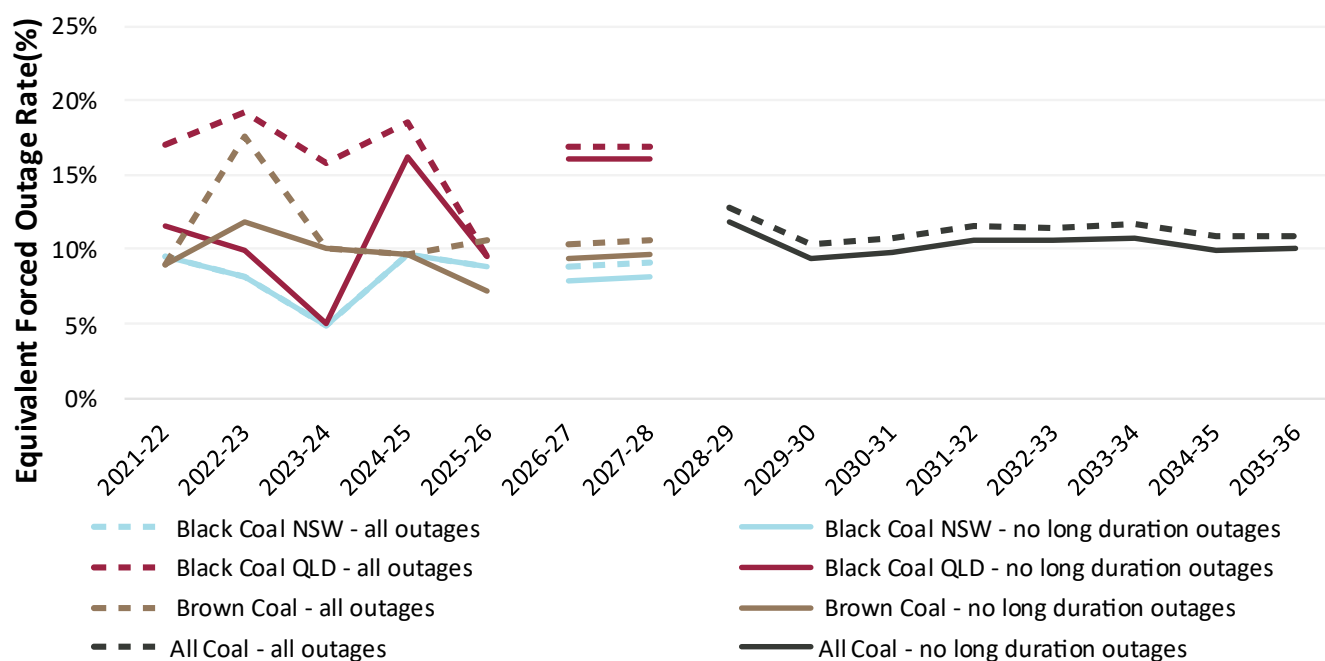
Equivalent forced outage rate trajectories

For coal-fired and large gas-powered generators, the forced outage rate (FOR) forecasts were based on participant projections, taking into consideration recent historical performance and applied at an individual station level. These trajectories excluded long-duration unplanned outages.

Overall, equivalent FOR projections for coal-fired generators are lower than those developed for the 2025 NEM ESOO, reflecting improved recent operating performance and lower participant FOR forecasts. Queensland black coal is expected to benefit from the Queensland Government's Electricity Maintenance Guarantee Scheme⁶⁰.

Figure 39 shows the 10-year projections for the equivalent FOR⁶¹ for coal-fired generators.

Figure 39 Actual and forecast equivalent forced outage rates for coal generation technologies, 2021-22 to 2035-36



For hydro, smaller gas and liquid-fired generators and batteries, FOR forecasts were based on the average FOR of the most recent four-year historical performance and applied at technology level.

All gas and liquid fuel generators equivalent FORs increased in both 2024-25 and 2025-26. The 2026 NEM ESOO projected performance remaining broadly consistent with those applied in the 2025 NEM ESOO, reflecting recent historical experience and participant submissions for large gas generators.

Hydro forced outage performance deteriorated significantly in 2024-25 and remained high in 2025-26. As forward outage forecasts are not collected for hydro generators, the projected FORs are based on the average performance over the most recent four years and are therefore higher than those applied in the 2025 NEM ESOO.

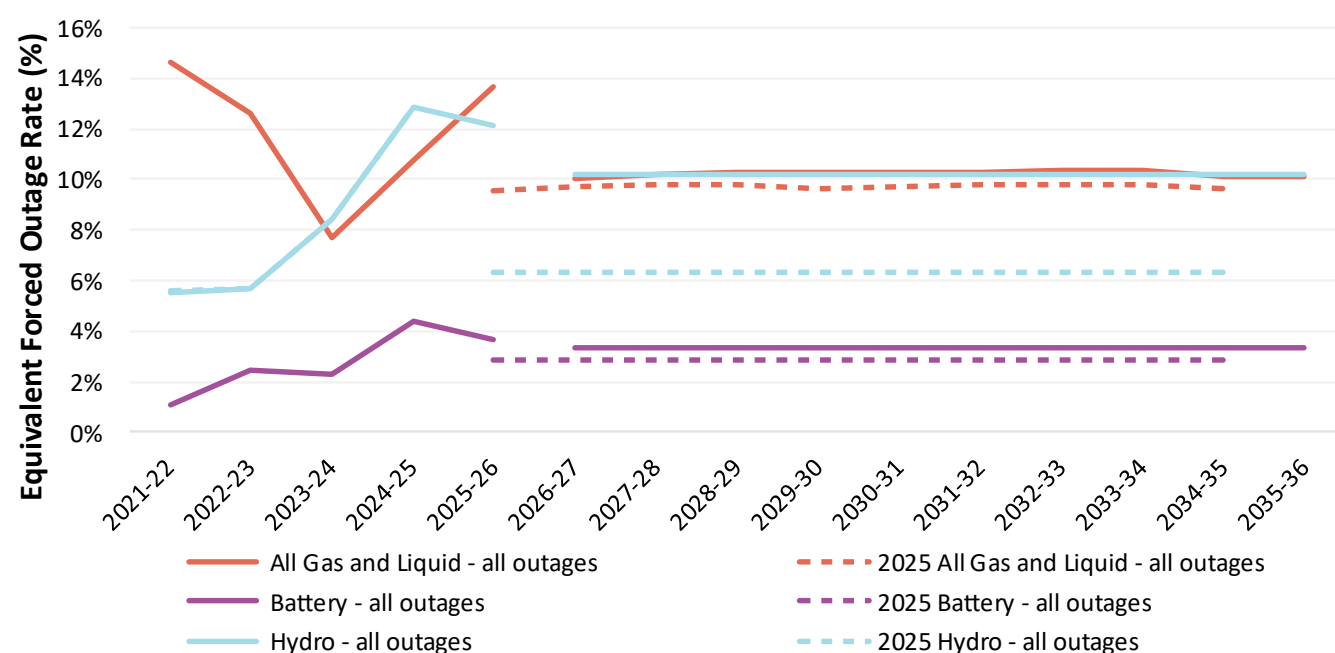
⁶⁰ At <https://www.treasury.qld.gov.au/files/Queensland-Energy-Roadmap-2025-25-043.pdf>.

⁶¹ Where equivalent full UOR = Full UOR + partial UOR x average partial derating.

Grid-scale batteries improved in forced outage performance over the last year. However, the forecast FOR is higher than that applied in the 2025 NEM ESOO, because it is now based on four years of operating history rather than the three-year average used previously. This reflects the broader operating history now available, rather than a deterioration in recent battery performance.

Figure 40 shows the FORs for gas and liquid fuel, battery and hydro technologies. These annual equivalent FORs reflect changes in assumed reliability and generator retirements over the forecast horizon⁶².

Figure 40 Actual and forecast equivalent forced outage rates for all gas and liquid aggregate, battery, and hydro technologies, 2021-22 to 2035-36



Planned and maintenance outages

For the first time, the 2026 NEM ESOO explicitly represents planned outages. As developed through stakeholder consultation in the 2025 FIP, planned outage rate (POR) forecasts were developed from a combination of participant-provided projections, MT PASA availability submissions, and historical technology-level outage observations.

For coal-fired generators, MT PASA planned outage schedules were used during the first three years of the outlook horizon, reflecting participant-submitted planned outage programs. Beyond this period, participant-provided annual POR projections were applied.

For large gas-fired generators, participant annual POR forecasts were used throughout the outlook period.

For hydro generators, small gas and liquid-fuelled generators, and batteries, PORs were based on technology-level historical performance, currently derived from the 2025-26 outage observations⁶³, and were assumed to remain constant across the

⁶² Generator retirement assumptions were consistent with information published in the July 2026 Generator Information, at <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planningdata/generation-information>.

⁶³ AEMO has commenced data collection on planned outages, starting with the 2026 NEM ESOO. Future ESOOs will draw on a larger outage dataset to refine these assumptions.

modelling horizon. Annual PORs were then converted into monthly outage rate profiles that allow planned maintenance to be preferentially scheduled during periods of lower expected reliability risk while preserving the annual PORs.

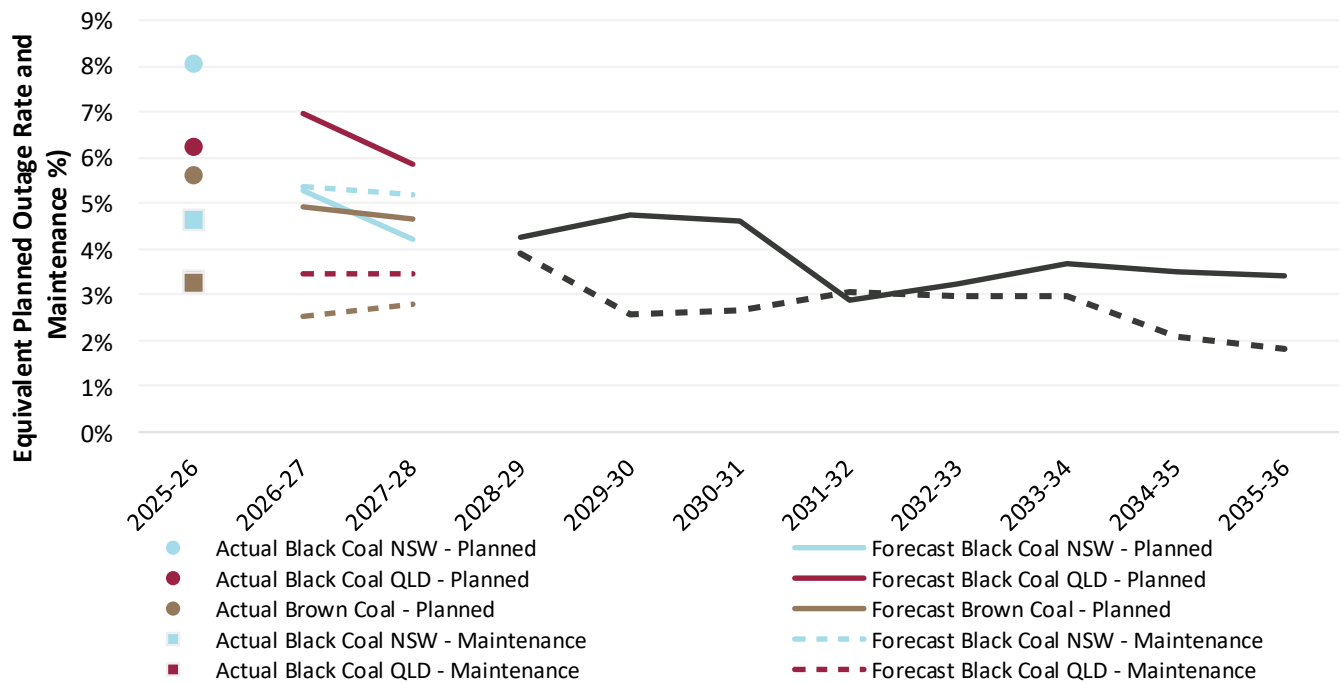
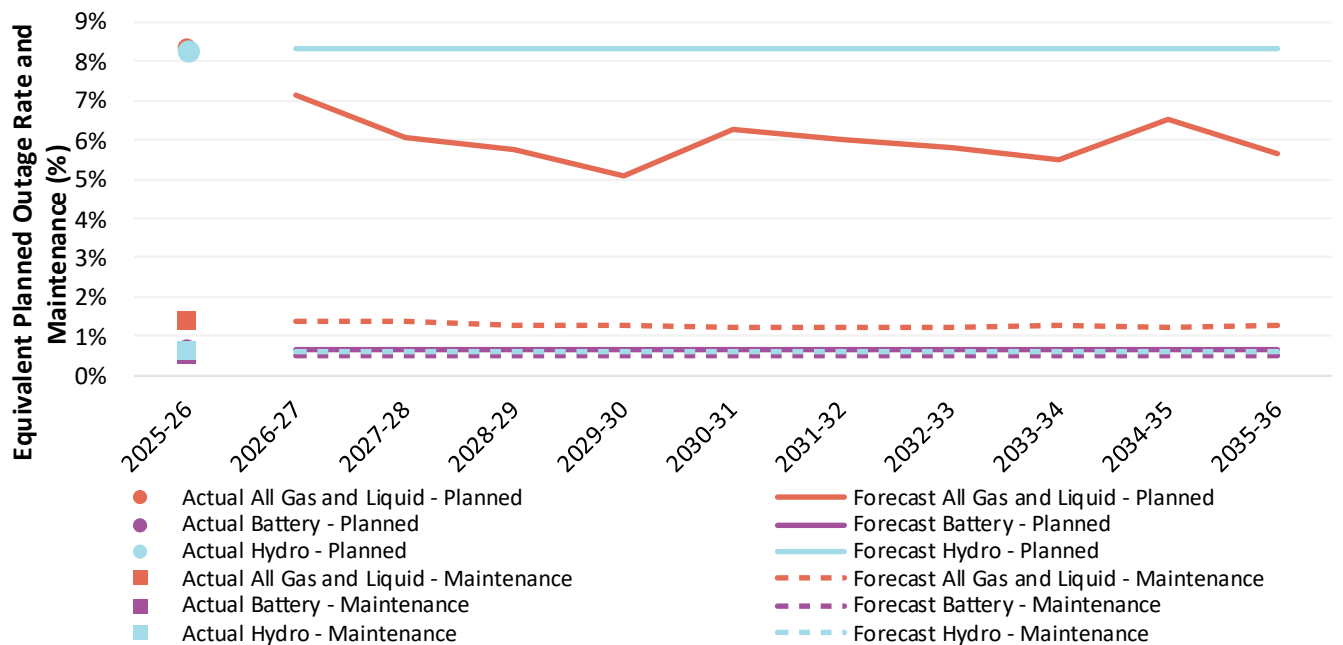
Maintenance outages represent shorter duration maintenance activities that have greater flexibility in scheduling than planned outages. Maintenance outage rates (MORs) were based on participant-provided projections for coal-fired and large gas generators. For hydro generators, small gas and liquid-fuelled generators, and batteries, MORs were based on historical technology-level maintenance observations. For the 2026 NEM ESOO, these were derived from observed 2025-26 MORs⁶⁴ and assumed to remain constant across the outlook period. Annual maintenance assumptions were then converted into weekly maintenance profiles that allow maintenance to be preferentially scheduled during periods of higher reserve margins while preserving the annual maintenance requirements.

Figure 41 and Figure 42 present the equivalent PORs and MORs by technology.

Figure 41 shows that New South Wales coal recorded the highest PORs in 2025-26. Based on MT PASA submissions, Queensland coal was projected to have the highest PORs from 2026-27 to 2028-29, while coal-fired generators in New South Wales and Victoria were projected to maintain lower and broadly similar POR levels. Coal MORs also varied across regions, ranging from approximately 3% to 5% in 2025-26. These rates were assumed to decline over the outlook period, reflecting participant forecasts, coal fleet retirements and changing maintenance requirements.

As shown in **Figure 42**, POR and MOR projections for non-coal technologies remain relatively stable across the outlook period. For gas and liquid-fuelled generators, PORs are expected to decline from 8% in 2025-26 to around 6% in 2035-36, while MORs remain broadly steady at around 1.5%. These forecasts are based on a combination of participant forecasts and recent observed performance. For hydro generators and batteries, PORs and MORs were based on observed 2025-26 performance and were assumed to remain constant across the outlook period. Hydro planned outage rates remain substantially higher than maintenance outage rates, reflecting the longer duration of scheduled overhaul activities. For batteries, both planned and maintenance outage rates remain below 1%, consistent with the relatively young age profile of the current battery fleet and indicating that forced outages are presently the dominant source of battery unavailability. As the battery fleet matures, planned and maintenance outage rates may increase over time as more assets require scheduled refurbishment, augmentation, or replacement activities.

⁶⁴ AEMO has commenced data collection on maintenance outages, starting with the 2026 NEM ESOO and will draw on a larger outage dataset for subsequent publications.

Figure 41 Actual and projected equivalent planned and maintenance outage rates for coal generation technologies, 2025-26 to 2035-36**Figure 42** Actual and forecast equivalent planned and maintenance outage rates for all gas and liquid aggregate, battery, and hydro technologies, 2025-26 to 2035-36

2.2.2 Inter-regional transmission unplanned outage rates

AEMO modelled some unplanned outages on a limited selection of transmission flow paths that are required for inter-regional power transfer. Consistent with the NER 3.9.3C definition of unserved energy, AEMO does not consider any planned or unplanned outages on transmission elements that do not contribute to inter-regional energy transfer.

Information was collected on the timing, duration, and severity of the transmission outages to inform transmission forced outage rate forecasts. **Table 14** shows the rates and method used in the 2026 ESOO. The selection of inter-regional flow paths was consistent with the updated *ESOO and Reliability Forecast Methodology*⁶⁵.

All rates are annual and static over the 10-year horizon, except for those on the Mortlake – South East flow path. The rate for this path is set to 0% when Project EnergyConnect Stage 2 is modelled to release full capacity⁶⁶, as the impact of a single circuit outage is less impactful when there are more circuits interconnecting South Australia.

Table 14 Inter-regional transmission flow path unplanned outage rates

Flow path	2026 ESOO transmission UOR (%)	2026 ESOO mean time to repair (hours)	Outage rate method
Liddell – Bulli Creek (QNI) Credible Contingency	0.27	21.1	Annual static
Liddell – Bulli Creek (QNI) Reclassification	1.79	3.8	Annual static
Murraylink – Credible Contingency	1.26	56.6	Annual static
Basslink – Credible Contingency	4.22	159.6	Annual static
Mortlake – South East (VSA) Credible Contingency	0.03	2.1	Annual, set to 0% post commissioning of Project EnergyConnect stage 2
Mortlake – South East (VSA) Reclassification	0.01	4.7	Annual, set to 0% post commissioning of Project EnergyConnect stage 2

2.2.3 Generator energy limits

For the 2026 NEM ESOO, AEMO collected station-level operational energy limits for scheduled generating units (excluding batteries⁶⁷). Participants provided energy limits at one or more time resolutions, including daily, weekly, monthly, quarterly, and half-yearly. These limits represent the participant-submitted physical and operational constraints on the amount of energy that generating units can produce over different time horizons and are intended to exclude market or commercial considerations.

Compared with previous NEM ESOOs, the 2026 NEM ESOO reliability assessment explicitly incorporated these submitted generator energy limits into the reliability assessments. This reflects the increasing importance of energy availability as the generation mix transitions towards higher shares of renewable generation and storage. The 2025 NEM ESOO generator maintenance sensitivity demonstrated that constraining generator energy availability could materially affect expected unserved energy outcomes for most regions.

Figure 43 compares the aggregated daily and annual energy limit assumptions applied in the 2025 and 2026 NEM ESOOs for coal, gas, and liquid fuel generators. The participant-submitted daily and annual energy limits have been converted and expressed as equivalent monthly energy limits across the 10-year modelling horizon.

⁶⁵ See <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

⁶⁶ AEMO does not separately model transmission outages associated with the commissioning of new transmission infrastructure. Transmission outage assumptions are informed by historical transmission outage performance.

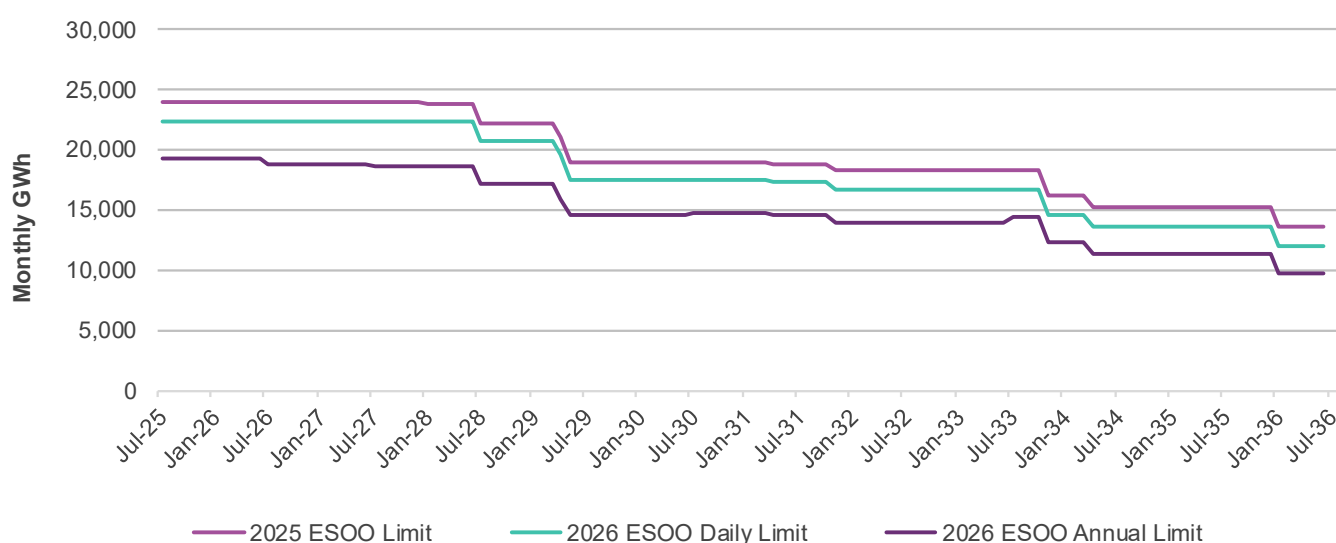
⁶⁷ The ESOO reliability forecasts assumed a default annual limit of 365 equivalent cycles, unless a different annual cycling limit was provided by participants.

Participant submissions indicate lower available energy than represented in the 2025 NEM ESOO. In that assessment, explicit energy availability limits were not applied for coal, gas and liquid fuel generators, resulting in higher assumed energy availability than in the current assessment.

The comparison also highlights that available generation can vary depending on the period over which an energy limit is applied. The time resolution of energy limits can therefore influence modelled dispatch and reliability outcomes, both within the ESOO and across other reliability assessments such as MT PASA and EAAP⁶⁸.

Further detail on the treatment and implementation of generator energy limits is in the NEM ESOO and *Reliability Forecast Methodology Document*.

Figure 43 Comparison of aggregated daily and annual energy limits assumptions of coal, gas, and liquid fuel generators applied in the 2025 and 2026 ESOO (monthly GWh)



Note: because energy limits were not explicitly included in the 2025 NEM ESOO, energy limits for this are derived from participant submitted nameplate capacity in the July 2025 Generator Information, converted to megawatt hours of energy.

2.3 New entrant technical parameters

AEMO used a variety of technical parameters in the 2026 NEM ESOO for existing and new entrant generators. AEMO also recognises that many stakeholders, including proponents of regulatory investment tests, leverage these assumptions in considering their own planning activities.

As part of supporting the development of the annual GenCost publication, AEMO engaged GHD to provide updates to the economic and technical parameters related to existing and emerging energy technologies that could be deployed across the NEM. This information is used in forecasting and planning studies such as the development of CSIRO's *GenCost 2025–26* report⁶⁹, which is AEMO's primary source of capital cost assumptions. The parameters are published in the supporting material from GHD⁷⁰, which describes in detail the approach, methodology, and outcomes of each technology considered.

⁶⁸ The MT PASA applies weekly energy limits and the EAAP applies monthly energy limits.

⁶⁹ At <https://www.csiro.au/en/research/technology-space/energy/Electricity-transition/GenCost>.

⁷⁰ See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/final/GHD-Cost-and-technical-parameters-review-report.

Information was gathered on a wide range of energy technologies including generation, storage, and hydrogen production, by considering and estimating a typical new entrant project in the NEM. The complete list of technologies considered is available in the GHD report.

2.4 Fuel price assumptions

Gas prices

Input vintage	Updated November 2025
Source	ACIL Allen Consulting
Updates since 2025 IASR	Updated forecasts for use in the 2026 GSOO

AEMO sourced updated natural gas price forecasts from ACIL Allen Consulting in November 2025. These gas prices were used for the 2026 GSOO.

The gas price forecasts considered fundamental inputs including forecast gas production costs from existing and developing fields, reserves, gas network infrastructure and pipelines, in addition to international gas prices, oil prices and economic indicators. The forecasts were also based on assumptions about the influence of international prices on east coast gas prices through LNG netback pricing, and the local level of competition.

These forecasts considered the impact of the Federal Government’s mandatory Gas Market Code (Code)⁷¹. The Code was published in July 2023, and includes a reasonable pricing framework of \$12/gigajoule (GJ) price cap for wholesale gas contracts and pricing rules for non-urgent transactions (outside three days) at the Gas Supply Hubs⁷². Small producers (less than 100 petajoules [PJ] per year) supplying the domestic market are exempt from the pricing rules, while other producers can apply for conditional exemptions.

The natural gas price forecasts considered gas policies and the regulatory framework in their form as at November 2025. The forecasts did not include consideration of the Federal Government’s Gas Market Review⁷³ report, which was published on 22 December 2025, or the consequently announced Australian domestic gas reservation policy.

As forecasts are as of November 2025, they did not consider the impact of more recent geopolitical events in the Middle East on the LNG netback price, international oil price, or Asian LNG price. The gas price forecasts will be updated for the 2027 GSOO for the East Coast Gas Market, and published in the Draft 2027 IASR.

The gas price forecasts took into account the change in costs that might arise from new infrastructure and supply, or changing utilisation of existing infrastructure.

Figure 44 compares industrial gas price forecasts at Melbourne across scenarios, and **Figure 45** shows the pricing relationship between regions. Complete industrial gas price forecasts for all other regions and scenarios are provided in the accompanying 2026 *Forecasting Assumptions Update* Workbook, and detailed commentary is available in the report by ACIL

⁷¹ At <https://www.dcccew.gov.au/energy/markets/gas-markets/gas-market-code>.

⁷² The Gas Supply Hub is a wholesale market that supports the efficient trade and movement of gas between regions. Through an electronic exchange, Gas Supply Hub participants trade short-term physical gas products at the pipelines in Wallumbilla (in western Queensland) and Moomba (in northern South Australia). The gas supply hub is voluntary, and complements trades that occur outside of the market.

⁷³ At: https://www.dcccew.gov.au/energy/markets/gas-markets/gas-market-review-reforms#toc_3.

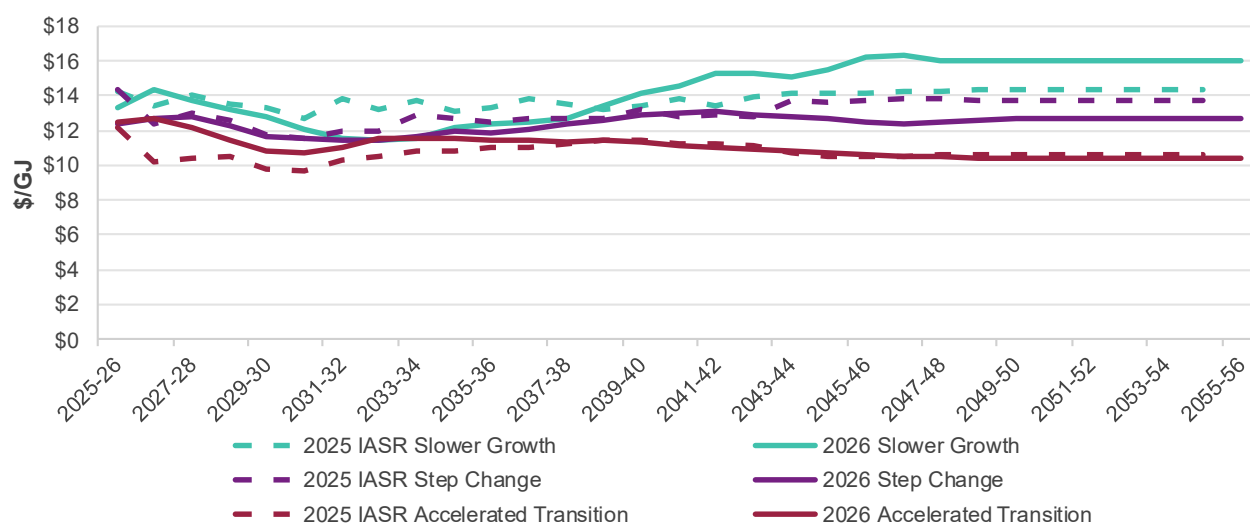
Allen⁷⁴. The industrial gas price forecasts assumed that new gas production becomes available when required, and made no assumptions around access to finance for new gas developments. They reflect the marginal cost for new wholesale gas supply in each region, excluding retail and distribution costs.

In the short term, prices were projected to remain largely influenced by the Federal Government's Code and gas price cap, with gas prices in most markets expected to remain at levels around \$12-13/GJ (with Brisbane prices slightly lower). Following this, the price forecasts decline to a minimum in the early 2030s, largely driven by a forecast reduction in LNG netback prices. Gas prices in the long term are forecast to gradually increase, resulting from the combination of decreasing supply and increasing real production costs. Brisbane prices diverge from Southern markets over the mid-term as a result of the source of local gas supply assumed to concentrate in Queensland and the Northern Territory in these projections, resulting in higher transportation costs and potential reliance upon higher cost LNG regasification terminals for southern markets (depending on the infrastructure that is developed to provide access to additional supply to southern customers). Prices are highest in Tasmania due to additional transport costs.

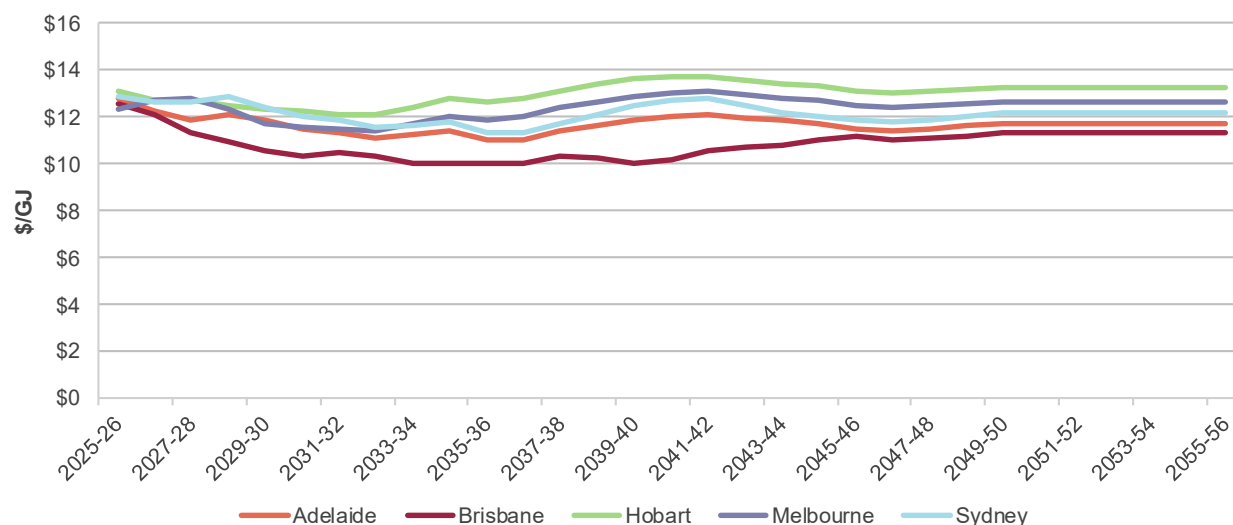
Across scenarios, the spread in gas prices is attributable to scenario-dependent assumptions of gas demand, long-term underlying costs of supply, and international oil prices.

Gas prices associated with each gas-fired generator are also provided in the accompanying 2026 *Forecasting Assumptions Update* Workbook. The costs include regional pricing, considering the supply options and the relevant cost of pipeline transmission.

Figure 44 Forecast industrial gas prices by scenario – Melbourne, 2025-26 to 2055-56 (\$AUD/GJ)



⁷⁴ At https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-acil-allen-2025-projections.pdf.

Figure 45 Forecast industrial gas prices by region – Step Change, 2025-26 to 2055-56 (\$AUD/GJ)

2.5 Transmission network modelling

Input vintage	Updated since the 2025 IASR
Source	<ul style="list-style-type: none"> 2026 ISP NEM Transmission Augmentation Information June 2026⁷⁵ TNSPs
Updates since 2025 IASR	Described below, and in the 2026 NEM ESOO

Most of the transmission network modelling assumptions applied in the 2026 NEM ESOO are consistent with those canvassed through the 2026 ISP. The following changes were made to reflect the most up to date information available:

- updates to the committed and anticipated projects, including updated project scopes, timing and status consistent with the Transmission Augmentation Information Page,
- the actionable transmission network projects, including updated project scopes, timing and status consistent with the Transmission Augmentation Information Page,
- updates to proportioning factors for inter-regional losses for existing flow paths, to align with AEMO's marginal loss factor (MLF) publication for 2026-27⁷⁶. Details are provided in the 'Network losses' tab of the Updated Assumptions Book.
- updates to transmission constraint equations to reflect the latest constraints used in the NEM Dispatch Engine (NEMDE), and subsequent updates to forecast those constraints for the ESOO time horizon. The 2026 ESOO model provides the constraint equations used for the 2026 NEM ESOO.

⁷⁵ At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/transmission-augmentation-information/2026/nem-transmission-augmentation-information-june-2026.xlsx.

⁷⁶ At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2026-27/marginal-loss-factors-for-the-2026-27-financial-year.pdf.