AEMO

AUSTRALIAN ENERGY MARKET OPERATOR

2025 Distributed PV and Batteries/VPP Forecast Report

December 2025

For use in connection with the Draft 2026 Forecasting Assumptions Update

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.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate 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 Distributed PV and Batteries/VPP Forecast Report in accordance with the Australian Energy Regulator's Forecasting Best Practice Guidelines. This report includes key information and context for the inputs and assumptions used in AEMO's Forecasting and Planning publications for the National Electricity Market (NEM). This publication is generally based on information available to AEMO as at 31 October 2025 unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

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

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Executive summary

The purpose of this report is to document AEMO's distributed photovoltaic (PV) and distributed battery forecast methodology, assumptions, and results, providing transparency on the derivation of key forecasts informing the Draft 2026 *Forecasting Assumptions Update.* When finalised by August 2026, the 2026 *Forecasting Assumptions Update* will provide the key assumptions, alongside the 2025 *Inputs, Assumptions and Scenarios Report* (IASR), that underpins the 2026 Wholesale Electricity Market (WEM) and National Electricity Market (NEM) Electricity Statements of Opportunities (ESOOs).

The **forecast methodology** applied the *Generalised Bass Diffusion Model*, a proven methodology that considers the historical uptake, societal response, technology change, prices, and the potential market size.

Scenarios were elaborated to frame a set of alternative plausible future outcomes consistent with the 2025 IASR. These include *Slower Growth,* which reflects lower global climate action and more challenging economic conditions, *Step Change*, which reflects an energy transformation consistent with Australia's contribution to global decarbonisation agreements, and *Accelerated Transition,* which reflects very strong decarbonisation activity beyond existing commitments.

Policies affecting distributed PV and battery uptake were identified and their impact estimated by translating specific targets and incentives into inputs and assumptions. Key policies include the Small-scale Renewable Energy Scheme (SRES), the Large-scale Renewable Energy Target (LRET), and a suite of state-specific policies. The recently introduced Cheaper Home Batteries Program (CHBP) has already had a significant impact on battery uptake and capacity since its commencement in July 2025, and its consideration in the forecast has therefore been refined.

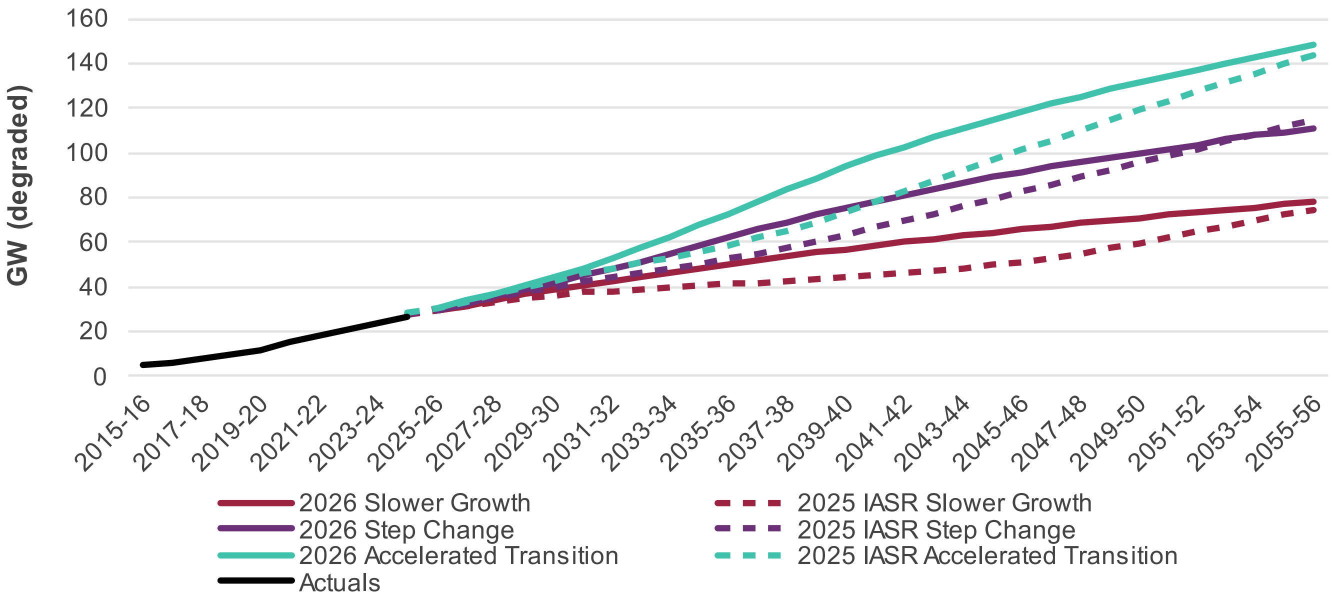
I**nputs and assumptions** are set out and justified in this report, including system costs, system sizes, retail tariffs, dwellings/commercial building numbers, actuals data, self-consumption rates, degradation, and market sizes.

Areas of enhancement in this year's forecast include the targeted application of assumed PV and battery market sizes, adjusted PV and battery system sizes, and improved accounting for historical PV system replacements and additions.

Distributed PV capacity has increased in the medium-term forecast, compared to the 2025 IASR

The total distributed PV forecast for the NEM and WEM including residential, commercial and PV non-scheduled generation (PVNSG) is shown in Figure 1.

Figure 1 Actual and forecast distributed PV installed capacity (NEM and WEM), 2015-16 to 2055-56 (gigawatts [GW] degraded)



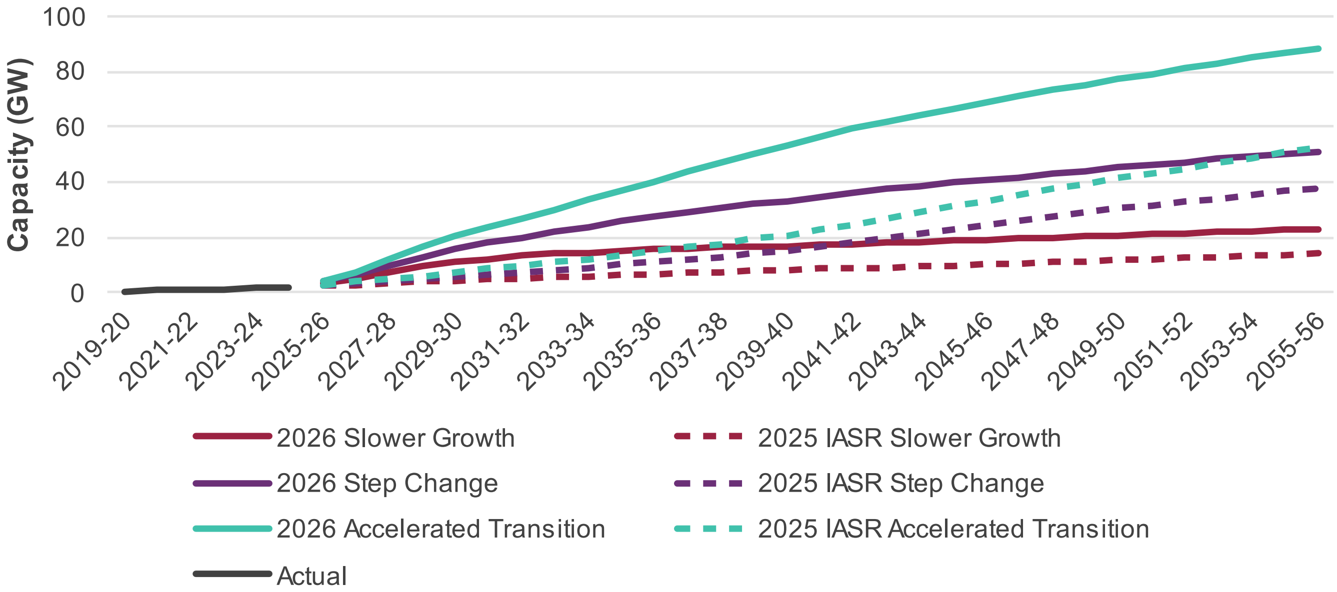
The **distributed PV forecast results** yield an uplift in forecast uptake in the medium term, reflecting residential, small commercial and PVNSG all benefitting from shorter payback, with growth slowing at the forecast horizon as these sectors approach market saturation. In total, the distributed PV forecast increases 19% relative to the 2025 IASR *Step Change* forecast in 2040. Regarding the specific distributed PV forecast components:

- The **residential PV forecast** is 19% higher, reaching a total installed capacity across NEM and WEM of 60 gigawatts (GW) by 2040 in *Step Change*. The forecast shows modest increases in the medium term, more pronounced for *Accelerated Transition*, as ongoing system size increases, housing growth and economic prosperity outweigh a flattening of PV system costs. The PV system size was assumed to increase following the historical trend of continual growth, with tapering off aligned to the scenario descriptions. The medium-term results reflect improvements to the treatment of the payback-uptake relationship and market saturation effects in the consumer adoption model. The market saturation effect tracks uptake from innovators and early adopters, and rapid uptake by the majority, through to eventual market saturation.
- The **commercial PV forecast** capacity increases by 22%, reaching 10 GW by 2040 in *Step Change*. The forecast features a modest increase in the medium term, and a slight decline in annual growth in the long term where the model recognises modest commercial building growth and range of economic circumstances are outpaced by a saturation effect – in that timeframe, most businesses that reasonably can install PV have done so.
- Larger commercial PV, called **PVNSG**, makes up only around 10% of PV output, and the forecasts show a much greater short- and medium-term pace, before exhausting market potential. Reflecting the latest year of actuals data and trends in suitable locations, stable costs and effective retail energy cost avoidance, capacity grows by 47% in 2040 *Step Change*.

Distributed battery forecasts have substantially increased since the 2025 IASR

The distributed battery forecast for the NEM and WEM is shown in Figure 2.

Figure 2 Distributed battery forecast for the NEM and WEM, 2015-16 to 2055-56 (GW)



The **distributed battery forecasts** are substantially increased from last year (combined 121% increase for 2040 *Step Change*), reflecting the uncertain nature of this emerging market and multiple drivers aligning:

- The Cheaper Home Batteries Program is exceeding expectations in uptake and early indications show that average residential battery system size has doubled as a result of the program.
- GenCost continues to forecast double digit percentage battery unit cost reductions.
- Battery market potential has increased due to higher forecast numbers of PV installations.

The 121% increase is comprised of residential (134% bigger), small commercial (101% bigger) and large commercial (68% smaller).

Virtual power plants (VPPs) are still in the very early stage of market development, so a limited amount of market data is available. Given the significant uncertainties in this sector, AEMO assumed, rather than forecast, comparable levels of uptake with the 2025 IASR.

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1 Introduction

1.1 Forecasting approach

AEMO's forecasting approach for consumer energy resources (CER) is to produce a causal demand-driven forecast, with a tractable set of bottom-up drivers examined in detail and synthesised together in a clearly communicated model structure. The methodology seeks to produce an exogenous forecast to the planning process, that is, a forecast prior to potential optimisations. The approach for inclusion of government policy and targets is as described in the 2025 IASR (Section 3.1) and the 2025 IASR Addendum (Section 2). The specific inclusions are listed in Section 3.2 of this report.

This approach is justified by the need for simplicity, and ability to delineate forecasts from plans and optimisations.

The CER forecasts leverage AEMO's 2025 IASR scenario set, which describe the actions of consumers, government and the energy industry. These scenarios inform the respective scenario-based forecasts.

This report describes the methodology, assumptions, and results of AEMO's consumer adoption-based CER forecast according to the above approach.

1.2 Scope and definitions

The scope of this document includes uptake forecasts of the following CER components:

- **residential PV** – PV systems installed on residential dwellings,
- **commercial PV** – PV systems installed on commercial premises up to and including 100 kilowatts (kW) in rated power capacity,
- **PVNSG** – commercial PV systems larger than 100 kW and not exceeding 30 megawatts (MW) in rated power capacity, excluding those systems registered as wholesale market participants,
- **residential batteries** – stationary battery systems installed in residential dwellings,
- **small commercial batteries** – stationary battery systems installed in commercial premises and not exceeding 50 kW in rated power capacity,
- **large commercial batteries** – stationary batteries installed in commercial premises with a rated power capacity of more than 50 kW but not exceeding 5 MW (note that this includes "community" batteries funded under the Community Batteries for Household Solar[1] program), and
- **residential/commercial VPP** – residential/commercial batteries that are participating in a VPP.

Note that electric vehicles (EVs) and associated vehicle-to-grid (V2G) are not forecast in this report. Please refer to the Draft 2026 *Forecasting Assumptions Update* for details.

AEMO briefly defines two types of market size here, and explains further in Section 4.21:

[1] See https://www.dcceew.gov.au/energy/renewable/community-batteries.

- Gross market size is the ultimate long-term potential uptake considering only technical constraints. For example, in the case of residential PV, the number of residential buildings where rooftop PV installations are possible.
- Net market size is the ultimate long-term potential uptake considering consumer behaviour under the prevailing scenario's circumstances, including economic, market and societal factors. For example, in the case of residential PV, the maximum practical uptake of residential PV when considering the scenario narrative and settings.

In forecasting, 'actuals' is commonly thought of as unambiguous historical data. However, in complex environments with emerging definitions and data gathering processes, actuals are often estimated figures. AEMO's references to PV installation actuals are of that nature. As part of the CER modelling work, AEMO reviewed PV actuals and identified an opportunity to reform the data processes and account for additions and replacements PV installations, which led to a restatement of PV actuals. This may be seen in some graphs of this report as a discontinuity between newly stated historical actuals and historical forecasts. The historical forecasts use the original actuals. More information is in Appendix A1.

All information in this report pertains to the NEM and Western Australia's WEM unless otherwise noted, and results are provided at an annual timescale.

The results from the modelling presented in this report are considered along with those from the independent consultants, for inclusion in the Draft 2026 *Forecasting Assumptions Update*.

Note that the methodology for PV generation and battery use profiles associated with the above CER uptakes is set out in the *Electricity Demand Forecasting Methodology*, and the results consulted on via Forecasting Reference Group (FRG) meetings as needed.

AEMO described this report's CER methodology to stakeholders at the FRG meeting 22 October 2025[2], and has updated its assumptions and the methodology description as a result.

[2] See https://www.aemo.com.au/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

2 Methodology

2.1 Methodology overview

AEMO's CER uptake modelling consisted of the following elements:

- **High level guidance from scenarios** – AEMO adopted a scenario-based approach to forecasting and planning, and developed three scenarios in the 2025 IASR to inform its scenario planning approach used across its forecasting and planning publications to examine a plausible range of variations in the pace and directions of the energy transition. The scenarios are described in Section 3.1 below.
- **Specific adoption of policies** – AEMO adopted policies and targets into its forecasts, as described in Section 3.1 of the 2025 IASR. These are listed in Section 3.2.
- **Preparation of input data** to support uptake model – a wide variety of information is required to suitably forecast PV and batteries.
- **Assumptions** – key uncertainties were explored by using a range of assumptions for variables including PV and battery system sizes and costs.
- **The uptake model** – in reality, a wide number of factors influence uptake, however, a tractable modelling exercise selects the most significant of them. AEMO adopted the Generalised Bass Diffusion Model (GBDM), which is a data-driven method whereby the model structure uses historical data to calibrate uptake considering parameters for social, technological and price factors, set within a context of market size. This uptake model is explained further below.
- **Outputs** – various considerations were integrated to provide data in required format. For example, PV forecasts were tracked over time and degradation applied.

Modelling was performed at regional level, then disaggregated to postcode level based on postcode level actuals data from the Clean Energy Regulator. Postcode level data is then aggregated up to sub-regional information for AEMO publications as needed.

2.2 The uptake model

The GBDM is the foundation of AEMO's PV and batteries uptake modelling methodology. The model is widely applied for forecasting adoption, especially of consumer durables (such as cars, appliances, furtniture) which are purchased infrequently and involve a significant investment. There is a wealth of research available on the use and performance of the GBDM and its variations[3].

GBDM-based forecasts produce a sigmoid shaped adoption curve that appears like an elongated 'S', which matches intuitive understanding that initial uptake begins slowly, followed by a period of popularity with a high rate of uptake, followed by a slowing ascent towards eventual saturation of the market.

The technical definition of the GBDM is:

[3] For example, see https://www.mdpi.com/2571-9394/4/2/26.

$\frac{f(t)}{1-F(t)} = \big(p + qF(t)\big)x(t)$, where

- F(t) is uptake as a proportion of the net market size,
- f(t) = F'(t) is the rate of change of F,
- p and q are model parameters (innovation and imitation), and
- x(t) is the generalised price term.

The GBDM's structure determines how historical uptake data sets the model's internal parameters for uptake due to the following:

- **Imitation** (also known as social contagion) is the consideration of how social interactions help to drive uptake. It recognises the dynamics behind consumer adoption models that describe innovators, early adopters, early majority, late majority and laggards. The consideration encompasses everything that helps spread uptake behaviour among people, and includes traditional media, social media, and social trends.
- **Innovation** is the consideration of how technology improves, and in doing so, increases the desirability of the product or service. Innovators, and to a lesser extent early adopters, tolerate earlier models which may offer fewer benefits and have elements of risk in terms of performance, obsolescence and features. Early majority and later enjoy products which are increasingly reliable and feature-rich with less chance of obsolescence.
- **Price** (or price-like factors) considers how consumers respond to changing prices. AEMO adopts a simple Return On Investment (ROI) calculation as the basis on which price-like decisions are made. The use of an ROI allows consideration of both the system cost and the prevailing retail tariffs that would be avoided through uptake of the CER. Note that ROI has an inverse relationship with price, but this is automatically accounted for in the model.

To calculate the imitation, innovation and response to price, the model is calibrated (also known as tuned or trained) with the historical uptake data. This is performed via a least square error model fit, which is a standard statistical process to provide accurate model tuning. AEMO recognises that consumers' decisions to purchase batteries may be driven by a variety of factors additional to financial, such as increased reliability and avoiding curtailment of PV generation. The GBDM incorporates historical purchase patterns into its projections.

The uptake model only accounts for interactions between CER uptake in a very limited way; the PV markets sets the market size for batteries, as AEMO currently assumes that the majority of benefit from battery use is in storing self-generated PV energy, and there is insufficient value to arbitrage differently priced energy throughout the day if not self-supplied. AEMO acknowledges that real-world interactions between CER uptake are more complex and likely increasing. For now, qualitative understanding of likely interactions may be considered when estimating market size.

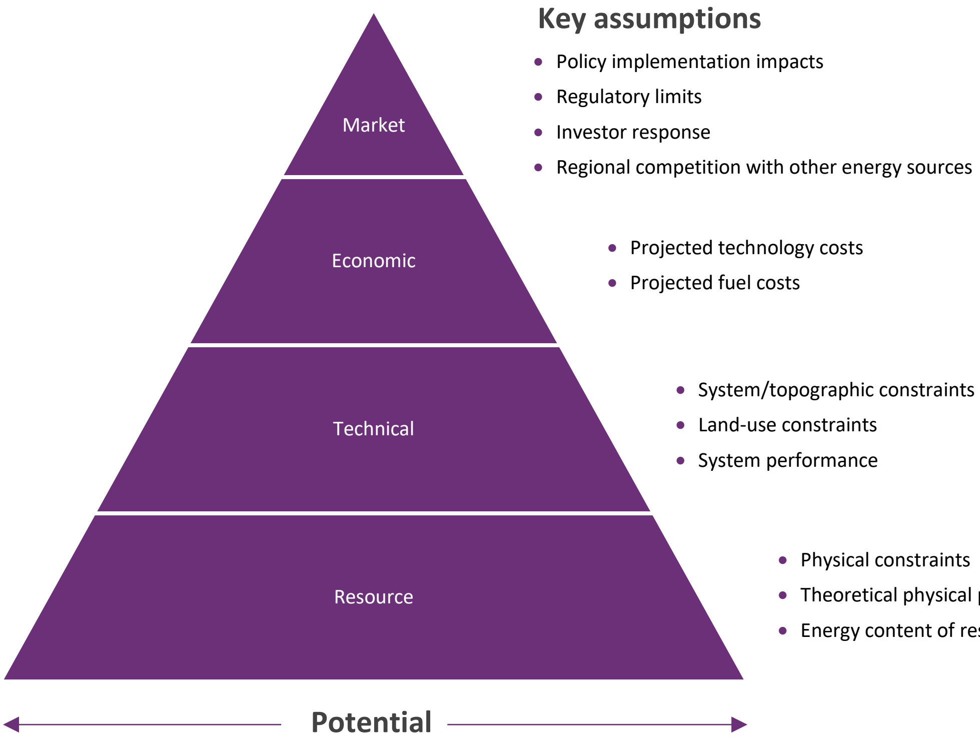
2.3 Market size estimation

Estimating potential market size is a sound practice when forecasting; potential market size defines a plausible envelope for forecasts. AEMO notes the National Renewable Energy Laboratory (NREL) Development Potential framework[4], and considers it suitable for estimating the market size in AEMO's CER forecasts.

[4] See https://www.nrel.gov/gis/re-potential.

While focus on direct uptake drivers in a model is understandable, to do so without recognition of potential market size risks over-forecasting in the long term, and (due to the S-shaped consumer adoption curve) under-forecasting in the medium term. Using market size estimates does not, however, constitute a silver bullet for long-term forecasting – in fact, the development of market size estimates is every bit as challenging as the rest of the forecast process, or more so. However, the uncertainty faced in estimating market size reflects, rather than increases, the underlying uncertainty inherent in long-term forecasting.

Figure 3 Development potential framework (adapted from NREL)



AEMO reviewed the technical layer to determine *Gross Market Size*. In the case of residential PV, resource constraints refer to solar energy falling on the NEM's land surface, which is a necessary but not sufficient consideration for PV uptake. Assuming that PV panels are mounted on residential roofs, the technical constraint defined as the number and area of residential roofs is a more useful Gross Market Size.

Gross Market Size can change over time. For example, in the case of residential PV, the number of suitable rooftops grows over time, according to scenario-based forecasts.

To determine a practical market size for CER forecasts, AEMO assumed and applied Market Size Factors based on economic and market conditions that pertain to the scenario narratives and settings. The NREL framework shows two relevant considerations:

- **Economic** – scenario narratives describe the relative economic conditions of the scenarios, and thus the Market Size Factors follow a spread from low to high. In the case of residential PV, consumers have greater economic capacity to invest in a stronger economy such as in the *Accelerated Transition* scenario.

- **Market** – this term captures a variety of considerations including the motivation, capability and capacity of society to uptake CER which is technically possible. In the case of residential PV, the 2025 IASR described the role of consumers' role in CER uptake as 'Lower' 'High' and 'Higher' across the scenarios in the parameter settings table.

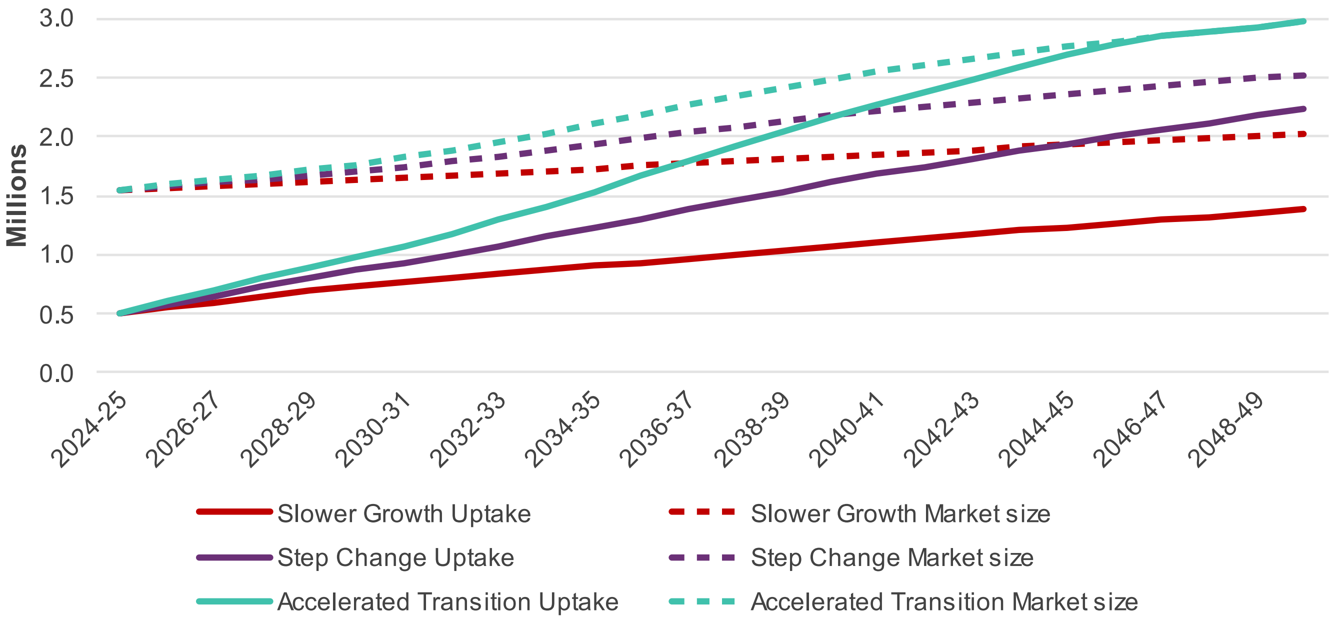
For each scenario, Net Market Size = Gross Market Size x Market Size Factor.

These Net Market Sizes can be considered 'terminal' values for the uptake model, meaning that eventually the uptake forecasts would attain that value, although it may occur beyond the forecast horizon.

Market Size Factors linearly scale Gross Market Size to create Net Market Size, but do not drive a linear scaling of the forecast values at a given point in time. Rather, Market Size Factors scale the timeframe for eventual saturation, which may be beyond the forecast horizon. The S-shaped nature of consumer adoption means that Net Market Size does not scale saturation time linearly; doubling Net Market Size does not necessarily double the saturation time frame.

Figure 4 shows a hypothetical uptake, where the upper bound of the uptake forecast is the scenario-based Net Market Size curves. The scenario-based forecasts tend towards the Net Market Size over time at different rates determined by the historical data (not shown in the figure), and it can be seen that the resultant forecasts hold different ratios to the Net Market Sizes. Furthermore, as shown by the *Slower Growth* and *Step Change* scenarios, the forecasts need not necessarily reach their Net Market Size within the forecast horizon.

Figure 4 Indicative relationship between Market Size and uptake



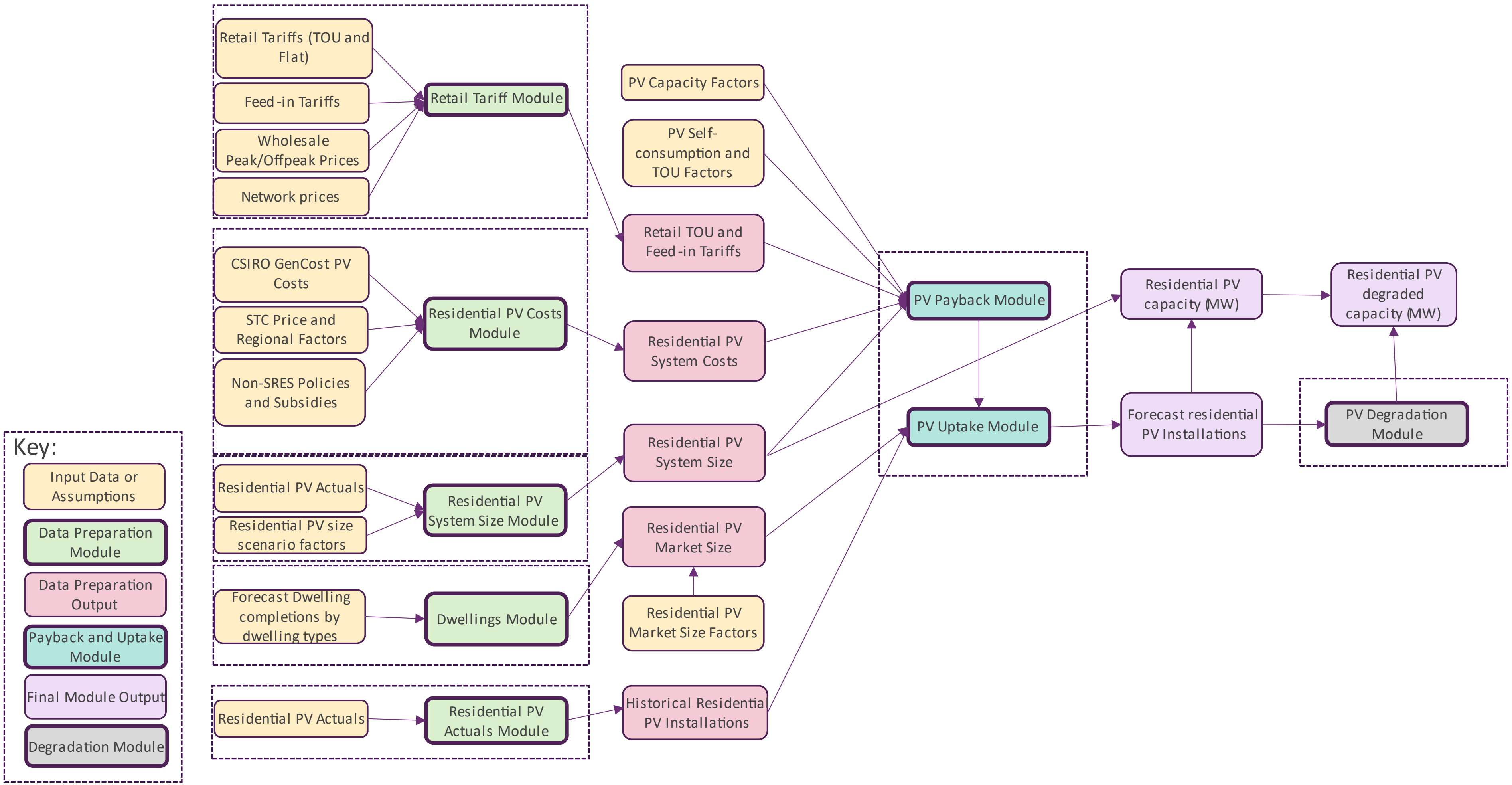
2.4 Model design

AEMO provides block diagrams of its model structures to aid transparency. Specifically, the diagrams are intended to:

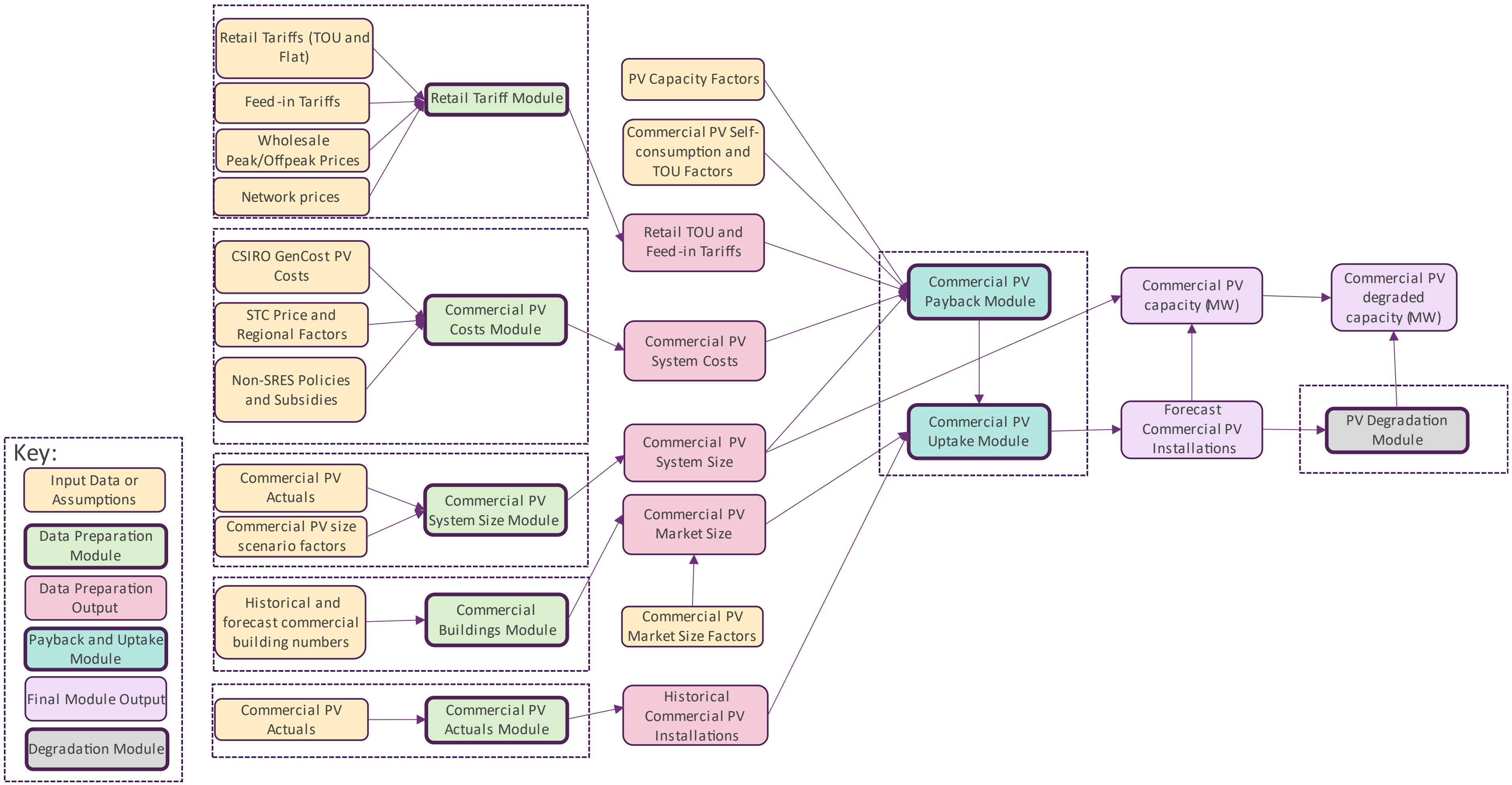
- provide a convenient representation of the model structure, and
- indicate the drivers influencing the results, and the linkages between the many input elements to each forecast.

The block diagrams are described in the following sections.

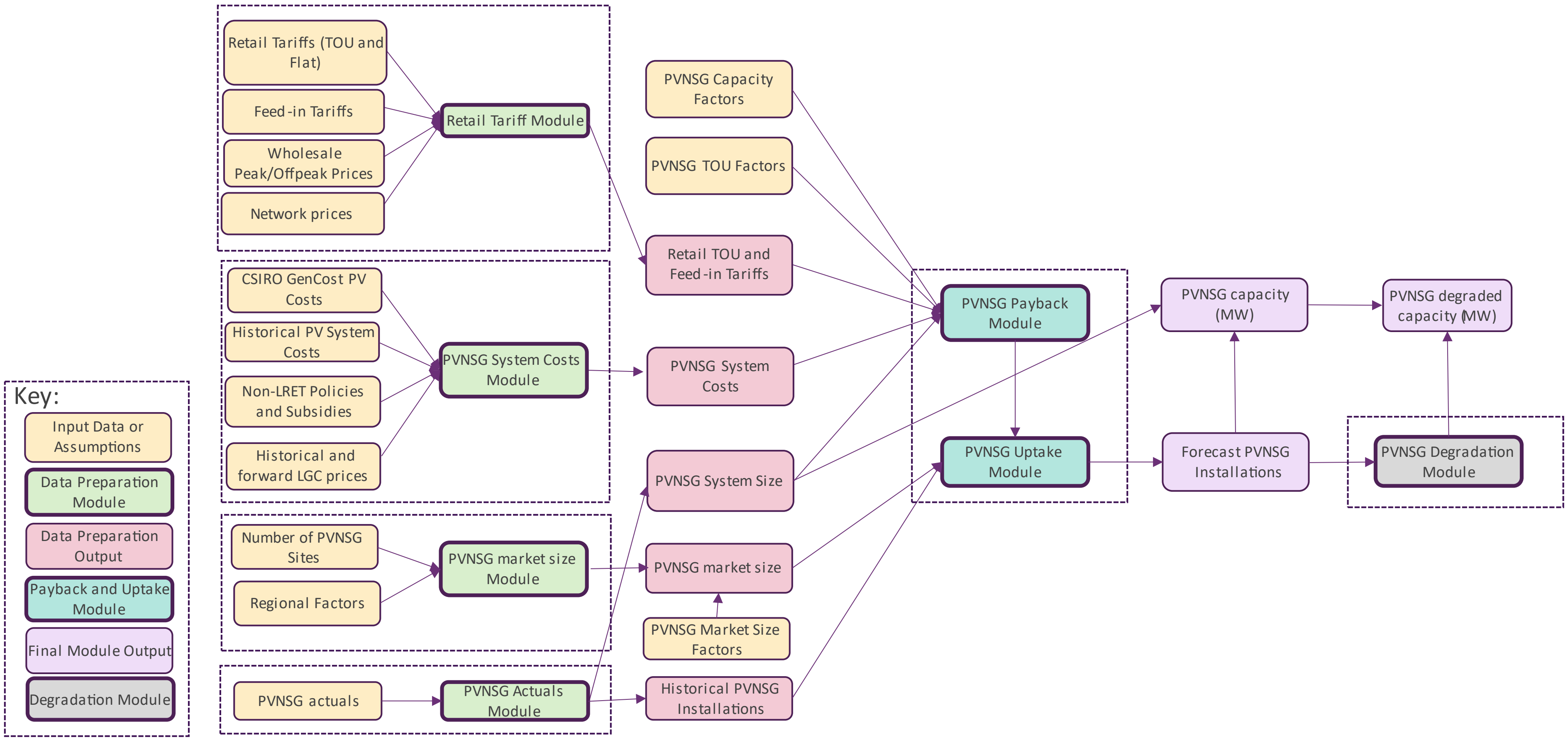
2.4.1 Residential PV uptake model diagram



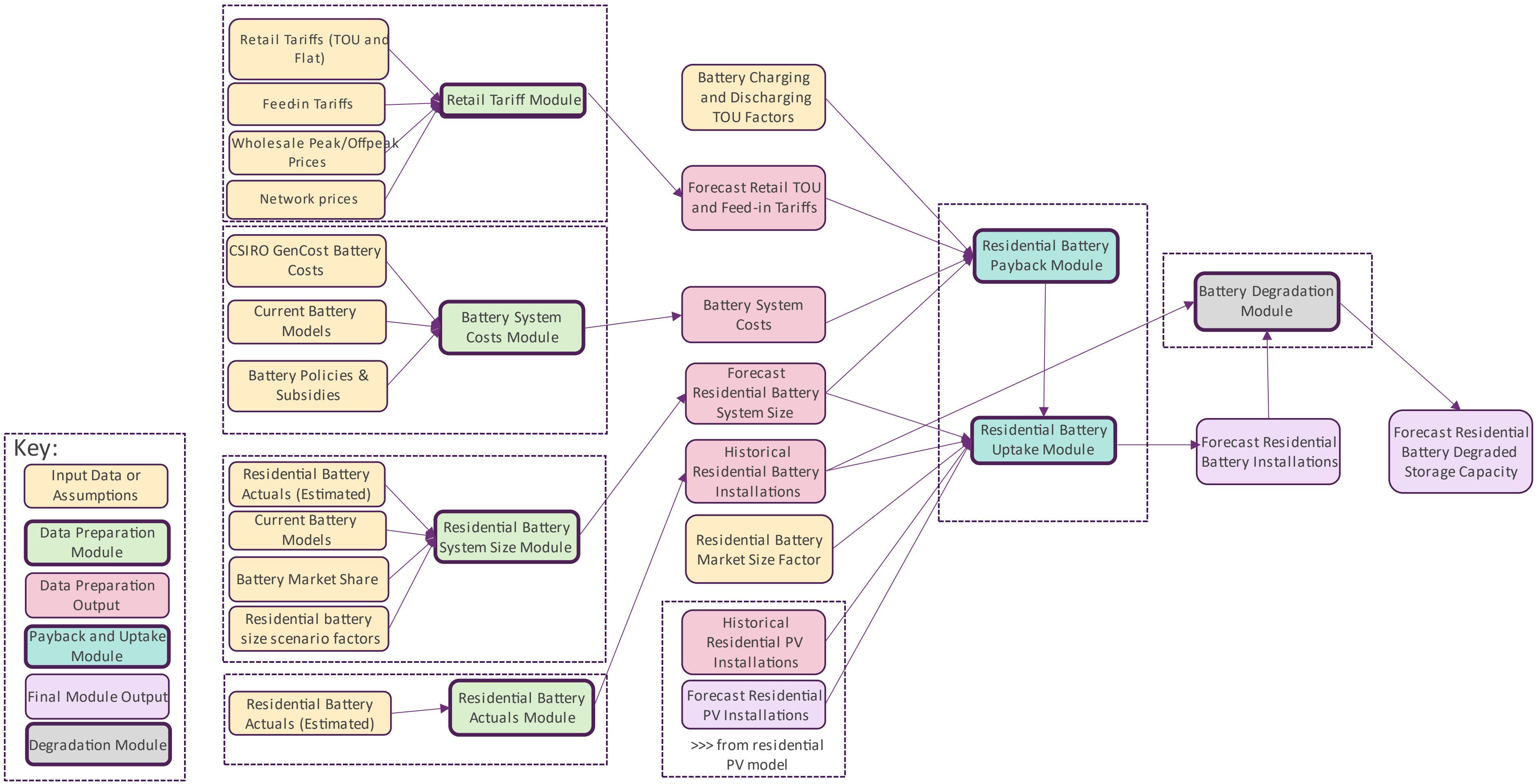
2.4.2 Commercial PV uptake model diagram



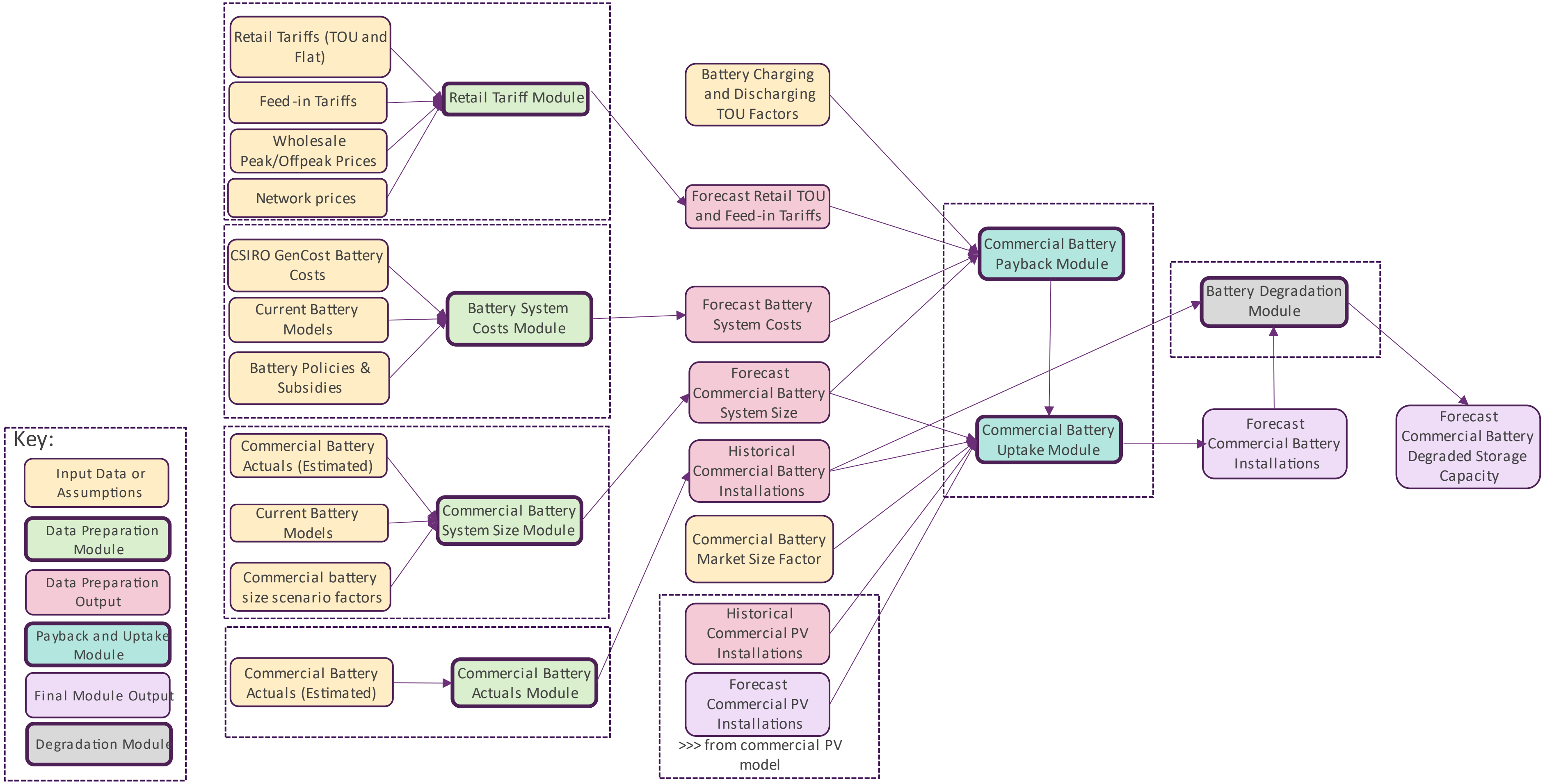
2.4.3 PVNSG uptake model diagram



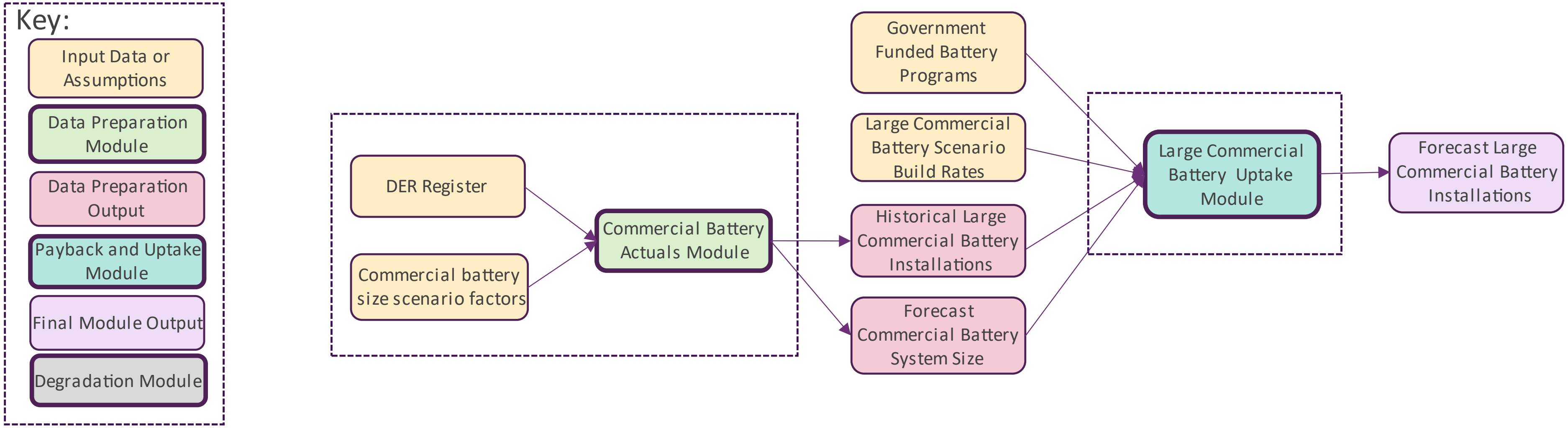
2.4.4 Residential battery uptake model diagram



2.4.5 Small commercial battery uptake model diagram



2.4.6 Large commercial battery uptake model diagram



3 Scenarios and policies

3.1 Scenarios

The use of scenario planning is an effective practice when planning in highly uncertain environments. Scenarios are a critical aspect of forecasting, enabling the assessment of future risks, opportunities, and development needs in the energy industry. Scenarios are designed to cover the breadth of potential and plausible futures impacting the energy sector and capture the key uncertainties and material drivers of these possible futures in an internally consistent way. AEMO uses a scenario planning approach to assess system adequacy with existing and expected investments, and (coupled with cost benefit analysis) to determine economically efficient ways to provide reliable and secure energy to consumers through the energy transition.

AEMO developed three scenarios to inform its scenario planning approach used across its recent and upcoming forecasting and planning publications to examine a plausible range of variations in the pace and directions of the transition. For the 2026 *Forecasting Assumptions Update*, AEMO adopted the scenarios defined in the 2025 IASR. They are described below in narrative form, and the characteristics of the scenarios that provide context or directly drive the CER forecasts are noted in Table 1.

- ***Step Change*** – achieves the objectives of Australia's government policies in transitioning the energy system, and reflects a scale of global and domestic action that limits global temperature rise to below 2°C compared to pre-industrial levels. Similar to the 2023 *Step Change* scenario, consumers continue to embrace opportunities to support the transition through continued investment in CER, energy efficiency and electrification, or other investments that can contribute to reducing emissions. While consumers' own energy assets (that is, investments in rooftop solar, batteries and EVs) are a key part of the transition, consumers are more tentative to share control and coordinate the operation of their energy devices through a third party than previously assumed in the 2023 IASR's *Step Change*. In this scenario, Australia's economy grows similarly to historical trends, while emerging trends in artificial intelligence and other data-heavy applications encourage growth in data centres in Australia.
- ***Slower Growth*** – achieves the objectives of Australia's government policies in transitioning the energy system, and reflects domestic action to contribute to lesser global ambition to extend specific commitments to limit temperature rise. It is a future that is challenged by lesser economic growth and greater challenges than other scenarios, and AEMO has reflected on stakeholder concerns that the previous *Progressive Change* name did not reasonably convey this key distinguishment relative to other scenarios. The new *Slower Growth* name provides increased clarity that while Australia's economy continues to grow in the long term, it has slower growth and lesser continued action beyond current commitments. Amid weaker domestic and international economic conditions, Australia's energy-intensive industry and businesses are at greater operating risk, and a material proportion of the business sector closes in this scenario in the short to medium term. Energy efficiency, CER and electrification investments are naturally lower due to the weaker economic circumstances, and consumers lower their enthusiasm for offering their assets for third-party coordination.
- ***Accelerated Transition*** – achieves the objectives of Australia's government policies in transitioning the energy system, and provides an 'upside alternative' that explores the possible drivers for rapid emissions reduction domestically and globally. The scenario refines the 2023 *Green Energy Exports* scenario – it continues to feature a rapid transformation of Australia's energy sectors, greater than that required by current domestic and global decarbonisation commitments, to

limit temperature rise to 1.5°C above pre-industrial levels. This acceleration in the energy transition is fundamental to the scenario, and the scenario's new name captures this key driver more clearly than previous names that described a specific solution. The acceleration in investments across the economy is supported by positive economic conditions domestically and internationally, increasing the local population through migration and assuming a faster growing economy than other scenarios. With these conditions, consumers' own investments in CER, energy efficiency and electrification, and emerging opportunities in green commodity development, all provide key contributions to consumers' energy demand. Compared to the 2023 *Green Energy Exports* scenario, the role for hydrogen production is significantly lower, reflecting current uncertainties affecting commercial investment and supportive policy.

Table 1 Key parameters, by scenario

Parameter	*Slower Growth*	*Step Change*	*Accelerated Transition*
National decarbonisation targets	At least 43% emissions reduction by 2030, net zero by 2050	At least 43% emissions reduction by 2030, net zero by 2050	At least 43% emissions reduction by 2030, net zero by 2050
Global economic growth and policy coordination	Slower economic growth, lesser coordination	Moderate economic growth, stronger coordination	High economic growth, stronger coordination
Australian economic and demographic drivers	Lower, with near-term economic growth calibrated with current economic conditions	Moderate economic growth, with near-term economic growth calibrated with current economic conditions	Higher, with near-term economic growth calibrated with current economic conditions
Coordination of CER (VPP and V2G)	Low long-term coordination, with gradual acceptance of coordination	Moderate long-term coordination, with gradual acceptance of coordination	High long-term coordination, with faster acceptance of coordination
CER investments (batteries, PV and EVs)	Lower	High	Higher

3.2 Policies

AEMO adopted policies and targets into its forecasts, as described in Section 3.1 of the 2025 IASR[5]. Table 2 lists policies and targets incorporated into the CER forecasts, taken from Table 4 of the 2025 IASR, with policies for the WEM explicitly added.

Table 2 CER forecast policies and targets

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland	South Australia	Tasmania	Victoria	Western Australia (WEM)
CER-related policies	Small-scale Renewable Energy Scheme (SRES) Large-scale Renewable Energy Target (LRET) Cheaper Home Batteries Program	Sustainable Households Scheme and other CER incentives	Funded actions under New South Wales Consumer Energy Strategy		Voluntary retailer contributions feed in tariff		Solar Homes Program and Solar for Business Program	WA Residential battery scheme Distributed Energy Buyback Scheme (DEBS)

[5] See 2025 IASR, Section 3.1, at 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?rev=63268acd3f044adb9f5f3a32b6880c27&sc_lang=en.

Table 3 describes the implementation of the policies.

Table 3 AEMO incorporation of policies affecting consumer demand

Policy	Description of how this policy is applied
Small-scale Renewable Energy Scheme (SRES)	Discount on residential and commercial total PV installation cost of around $300/kW in 2025-26 (27% of total PV installation costs). Progressively declines to zero by end of 2030 and varies slightly by region.
Large-scale Renewable Energy Target (LRET)	Discount on PV non-scheduled generation (PVNSG) of $61/kW in 2025-26 (7% of total PVNSG installation costs), progressively declining to zero by end of 2030. Varies slightly by region.
Australian Carbon Credit Units (ACCU) Scheme	Average discount on PVNSG of $80/kW (varying significantly by region) in 2025-26 (8% of total PVNSG installation costs), progressively declining to zero by end of 2036.
Cheaper Home Batteries Program (CHBP)	The Cheaper Home Batteries Program delivers a rebate to residential and commercial customers installing batteries up to 50 kW in rated capacity. The rebate is calculated on the usable storage in kilowatt hours (kWh) and is estimated at $354/kWh in 2025-26, declining each year before ending at 31 December 2030[A].
Victorian Energy Upgrades (VEU) (Victoria only)	Discount on PVNSG-scale systems of $253/kW in 2025-26 (22% of total PVNSG installation costs), progressively declining to zero by 2036. This discount cannot be combined with LGCs.
Victoria Solar Rebate	Discount on residential PV cost of $171/kW in 2025-26 (13% of total PV installation costs), ending by end of 2028 (calendar year).
WEM:	
• **WA Residential Battery Scheme**	A fixed rebate of $1,300 applies to the first 95,000 residential batteries approved and installed[6]. As the rebate requires households to join an approved VPP for a minimum of two years, this has also been implemented as an uplift in VPP participation in the WEM.
• **Distributed Energy Buyback Scheme (DEBS)**	Implemented via assumed feed-in tariffs.

A. See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries/small-scale-technology-certificates.

There are some targets and policies in the Australian Energy Market Commission (AEMC) target statement for which PV and batteries are relevant, such as the Solar Homes Program and Solar for Business Program in Victoria, and rooftop solar's contribution to the Federal Government's 82% Renewable Energy Target.

[6] The rebate is available to the first 100,000 with 95,000 included in AEMO modelling for the South West Interconnected System (SWIS) with the remaining 5,000 outside. See https://www.wa.gov.au/organisation/energy-policy-wa/wa-residential-battery-scheme-questions-answers. Also included in AEMO modelling is no-interest loans available for up to $10,000 to households with a combined annual income of less than $210,000. Loan repayment periods will be up to 10 years. See https://www.wa.gov.au/organisation/energy-policy-wa/wa-residential-battery-scheme.

4 Assumptions

The assumptions required to generate the PV and battery forecasts are described in the following sections. Where possible, they are based on listed available data sources; where data is limited AEMO has made assumptions, at a level of detail considered sufficient to produce forecasts suitable for their purpose.

4.1 PV assumptions

4.1.1 Retail tariffs

AEMO used retail time of use (TOU) and feed-in tariffs to support payback estimation.

Retail electricity price forecasts from Section 3.3.14 of the 2025 IASR were used. These forecasts are based on the 2024 ISP results and incorporate wholesale costs, transmission and distribution costs, environmental costs, and a retail residual cost. For more details, see Table 19 in the 2025 IASR. The flat retail price forecast was transformed into TOU tariffs based on historical tariff data from various sources such as Default Market Offer price reports and the peak/off-peak wholesale price relativities from the 2024 ISP.

A solar feed-in tariff was derived from the solar-weighted wholesale spot price, from the 2024 *Integrated System Plan* (ISP).

Historical prices were adjusted to real value using the same consumer price index (CPI) source as used throughout the IASR.

4.1.2 PV system costs

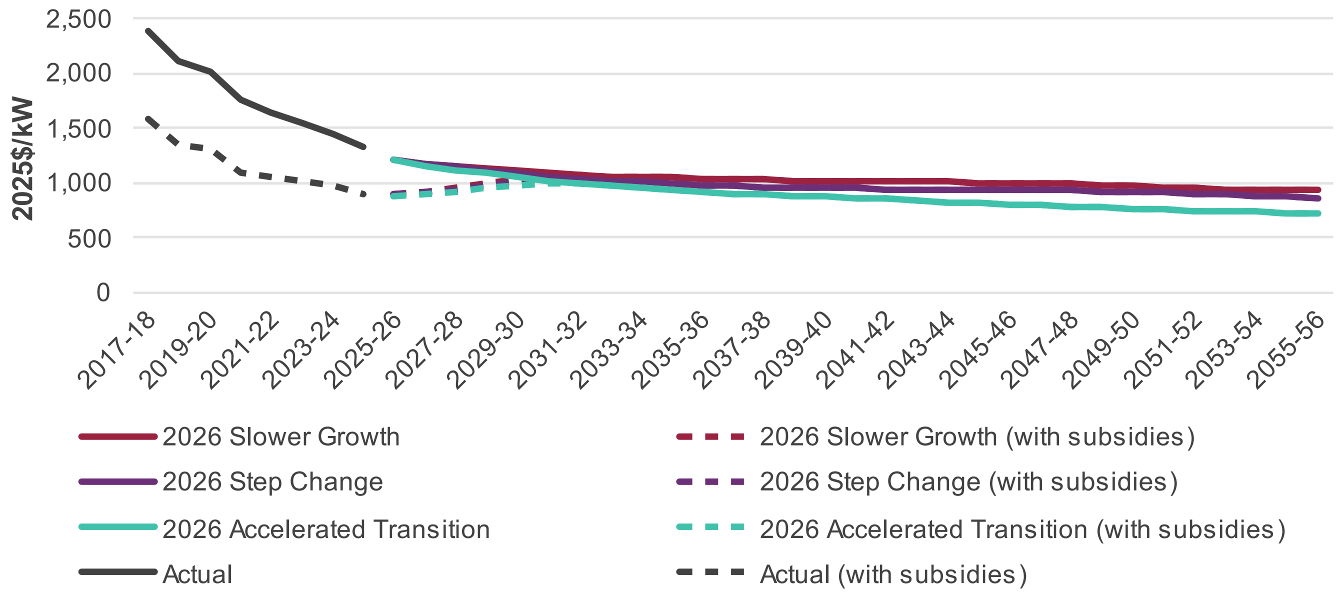
AEMO adopted small-scale (‘rooftop’) PV system costs from CSIRO’s 2024-25 GenCost report[7] and applied Small Scale Technology Certificate (STC) rebates[8] and non-SRES (Small-scale Renewable Energy Scheme) policies and subsidies, to arrive at a net system cost to the residential or small commercial consumer.

The assumed PV system costs for the 2026 models with and without subsidies are shown in Figure 5, and a comparison with 2025 assumptions, with subsidies, is shown in Figure 6.

[7] See https://www.csiro.au/en/research/technology-space/energy/electricity-transition/GenCost.

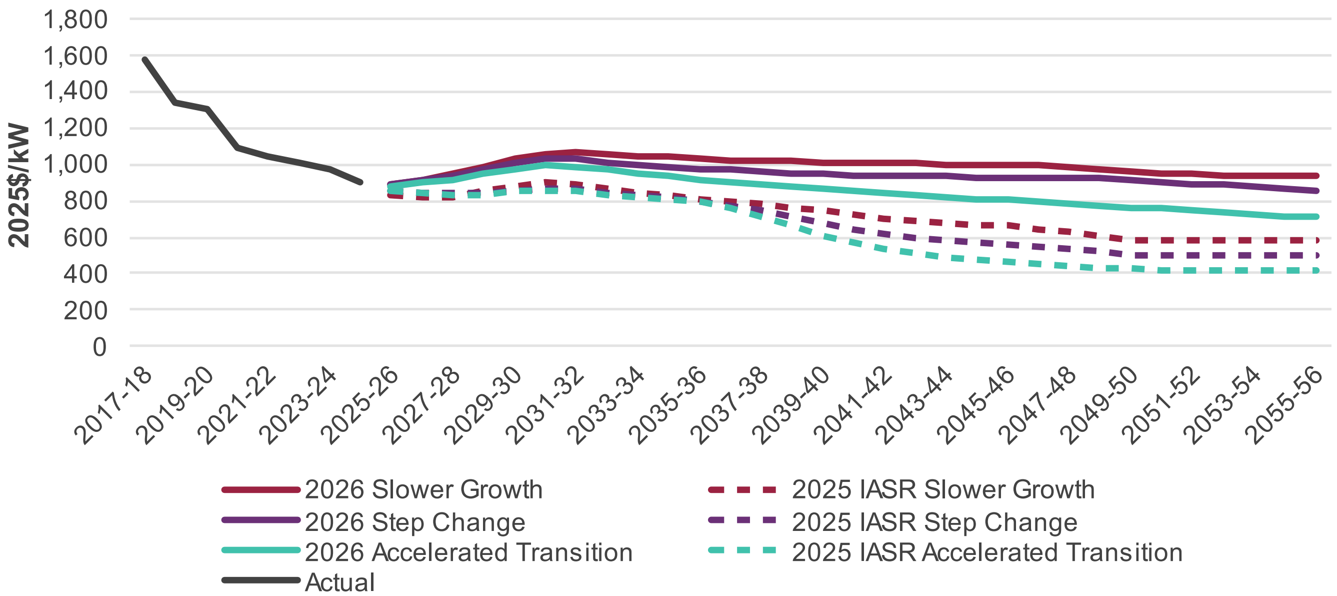
[8] See https://cer.gov.au/schemes/renewable-energy-target/small-scale-renewable-energy-scheme/small-scale-renewable-energy-systems.

Figure 5 Assumed residential PV costs (with and without subsidies, 2025$/kW)



The cost curve reflects a mature market with remaining opportunities for further economies of scale reducing over time, with SRES subsidies declining.

Figure 6 Assumed residential PV costs (with subsidies) compared to equivalent values from 2025 IASR based on 2023-24 GenCost (2025$/kW)



The increased cost relative to prior forecasts is driven by the refined GenCost methodology. The 2024-25 GenCost took into account a lower learning rate on installation of rooftop solar compared to large-scale solar, as Australia already has an experienced workforce in rooftop solar. In addition, installation costs increased across all technologies this year.

AEMO estimated fixed versus variable PV costs from Solar Choice[9] system sizes and costs. AEMO scaled GenCost's systems costs from a fixed 7 kW basis to the assumed system size for each scenario.

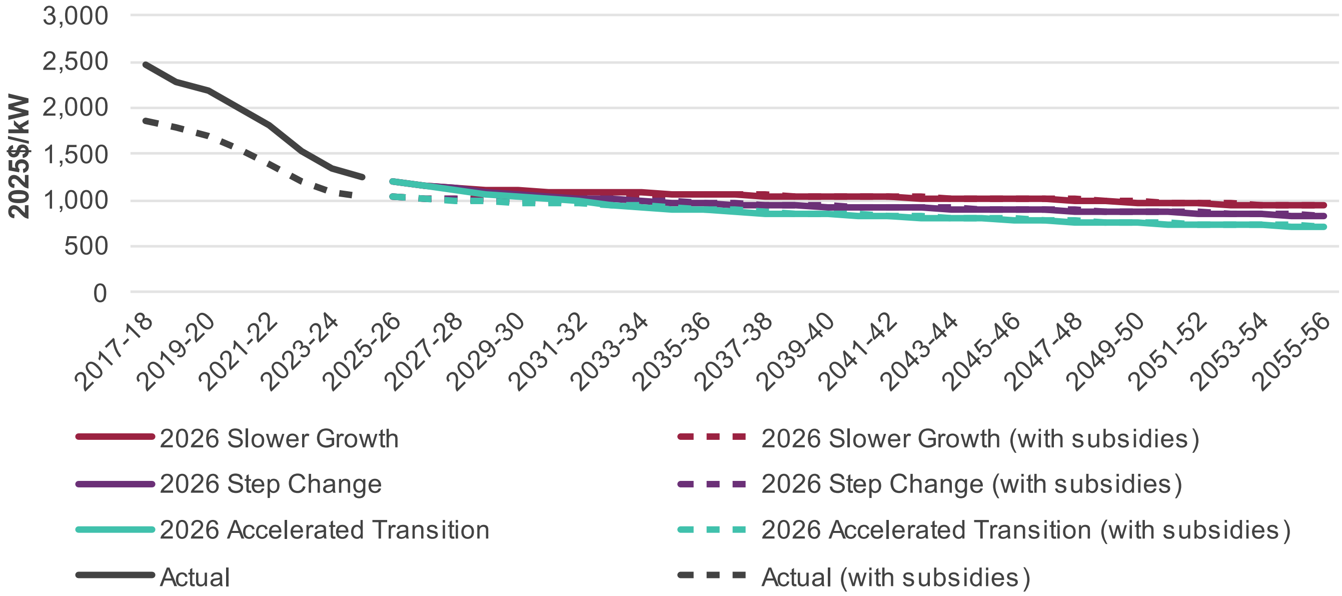
The price of STCs was approximately $40/STC in 2025[10], and this price (adjusted for CPI) was assumed for modelling purposes until the end of calendar year 2030, when the STC rebate is legislated to end. This value, multiplied by the number of deeming years (to financial year 2031) and regional factors[11] set by the Clean Energy Regulator, produced the STC discount applied in the model. As a reference, the average rebate across the NEM and WEM was $346/kW in 2025 (about 27% of total PV installation costs).

Victoria's additional non-SRES solar rebate was modelled, currently $1,400 per system, and declining progressively to zero towards the end of 2028[12]. This value was converted to a $/kW basis using AEMO's PV system size projection, resulting in a discount of $175/kW in 2025 for residential consumers.

4.1.3 PVNSG system costs

Figure 7 shows the historical and projected PVNSG costs trajectory with and without subsidy discounts.

Figure 7 Actual and forecast PVNSG system costs (2025$/kW)



Given PVNSG encompasses a mix of smaller rooftop systems (usually below 5 MW) and larger ground-mounted systems (5-30 MW) which more closely resemble the economics of large-scale systems, PVNSG costs were obtained by a weighted average of small- and large-scale ('rooftop') PV system costs from CSIRO's GenCost (2024-25). The average was weighted to

[9] See https://www.solarchoice.net.au/solar-panels/solar-power-system-prices/.

[10] See https://cer.gov.au/markets/renewable-energy-certificates.

[11] Regional factors are set by the Clean Energy Regulator by categorising postcodes into four different zones across Australia (see https://cer.gov.au/schemes/renewable-energy-target/small-scale-renewable-energy-scheme/small-scale-technology-certificates/calculate-small-scale-technology-certificate-entitlements). An average of these factors by regions was estimated and used for modelling purposes, which were 1.38 for New South Wales, Queensland, South Australia, and Western Australia, and 1.19 for Tasmania and Victoria.

[12] See https://www.solar.vic.gov.au/solar-panel-rebate.

60% small-scale costs, and 40% large-scale costs, based on the distribution of PVNSG capacity of systems below and above 5 MW in 2025.

The following subsidies and rebates were then applied as discounts to the capital costs:

- **Large-scale generation certificates** (LGCs) were calculated by multiplying estimated average annual PVNSG generation with LGC price, which varies by year according to regulatory changes by the Clean Energy Regulator and other factors[13]. LGCs are currently set to decline progressively towards the end of 2030. In 2025, the average discount across regions was $88/kW (about 7% of total PVNSG installation costs).
- **Australian Carbon Credit Units** (ACCUs) are part of the Emissions Reduction Fund (ERF) legislation, which applies to emission avoidance projects like solar PV. This discount was calculated by multiplying estimated average annual PVNSG generation with the ACCU price and an emissions factor, which are set as per the National Greenhouse Accounting standards[14]. In 2025, the average discount across regions was $95/kW (about 8% of total PVNSG installation costs), which declines progressively to zero by 2036 (when the scheme is expected to end).
- **Victorian Energy Efficiency Certificates** (VEECs) under the Victorian Energy Upgrades (VEU) program applies to systems over 200 kW and cannot be combined with LGCs. This discount is calculated by multiplying estimated average annual PVNSG generation with the VEEC price and an emissions factor, which are set by Victoria's Essential Services Commission[15]. In 2025, the average discount across regions was of $278/kW (about 22% of total PVNSG installation costs), which declines progressively to zero by 2036 (when the scheme is expected to end).

4.1.4 Distributed PV system size

PV system size was estimated by taking the history of consumer PV system installations from the Clean Energy Regulator, and applying scenario narrative based assumptions. Figure 8 shows the assumed sizes for new residential PV systems.

AEMO used public[16] and confidential data from the Clean Energy Regulator to estimate historical PV system size across both residential and small commercial sectors, taking into account replacements and additions.

There is uncertainty in future PV system sizes, and AEMO considered a scenario-based spread appropriate to reflect that uncertainty. The assumed trajectories of PV system sizes broadly represent, from top to bottom, 'continued high growth' 'modest growth' and 'flatline'. These assumptions align with the scenario narratives' degree of consumer engagement and ability to pay (state of the economy). It is noted that the PV system size assumptions are increased from last year. This is expected where each year of actual data shows continued linear growth. AEMO considered that, logically, there should be a tapering in growth of new system sizes, so each year that linear growth continues, an uplift to the projections of that tapered growth is required.

AEMO observes that historical data shows that system size multiplied by costs per kW remains essentially constant over time, which is to say that consumer outlay for PV systems is stable over the years. The system size projections above stay true to that historical pattern.

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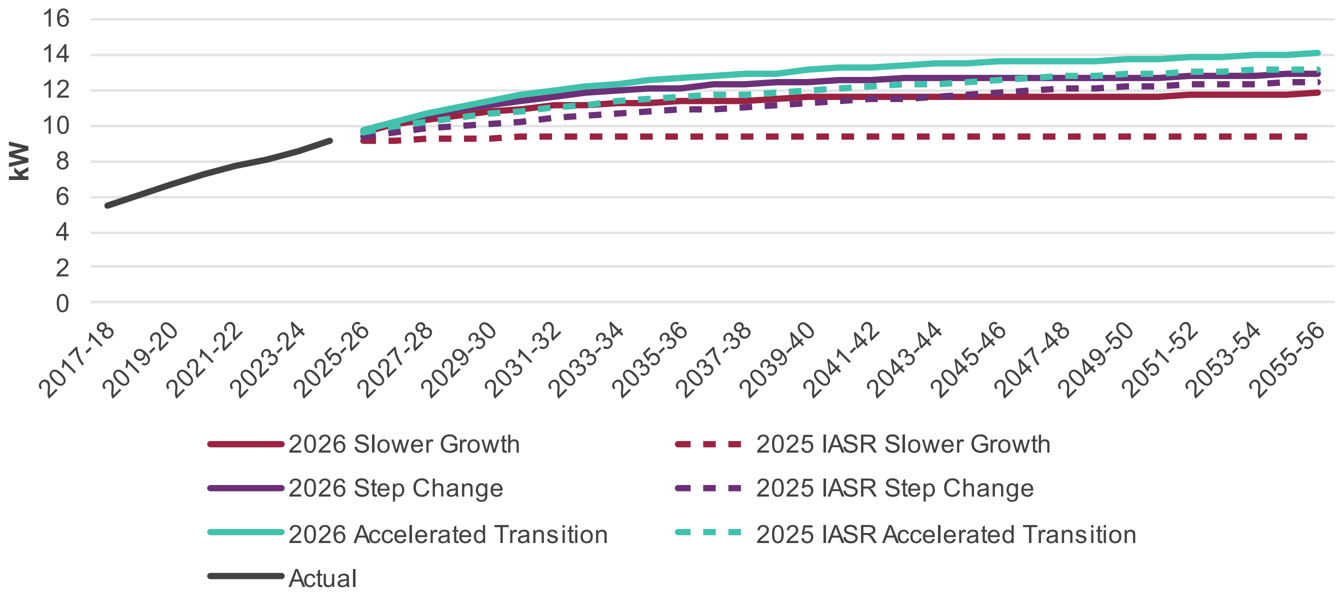
[13] See https://cer.gov.au/markets/reports-and-data/quarterly-carbon-market-reports/quarterly-carbon-market-report-march-quarter-2025/large-scale-generation-certificates-lgcs.

[14] See https://www.dcceew.gov.au/climate-change/emissions-reduction/accu-scheme.

[15] See https://www.vic.gov.au/sites/default/files/2025-05/Victorian-Energy-Efficiency-Target-Amendment-%28Targets%29-Regulations-2025-Regulatory-Impact-Statement.pdf.

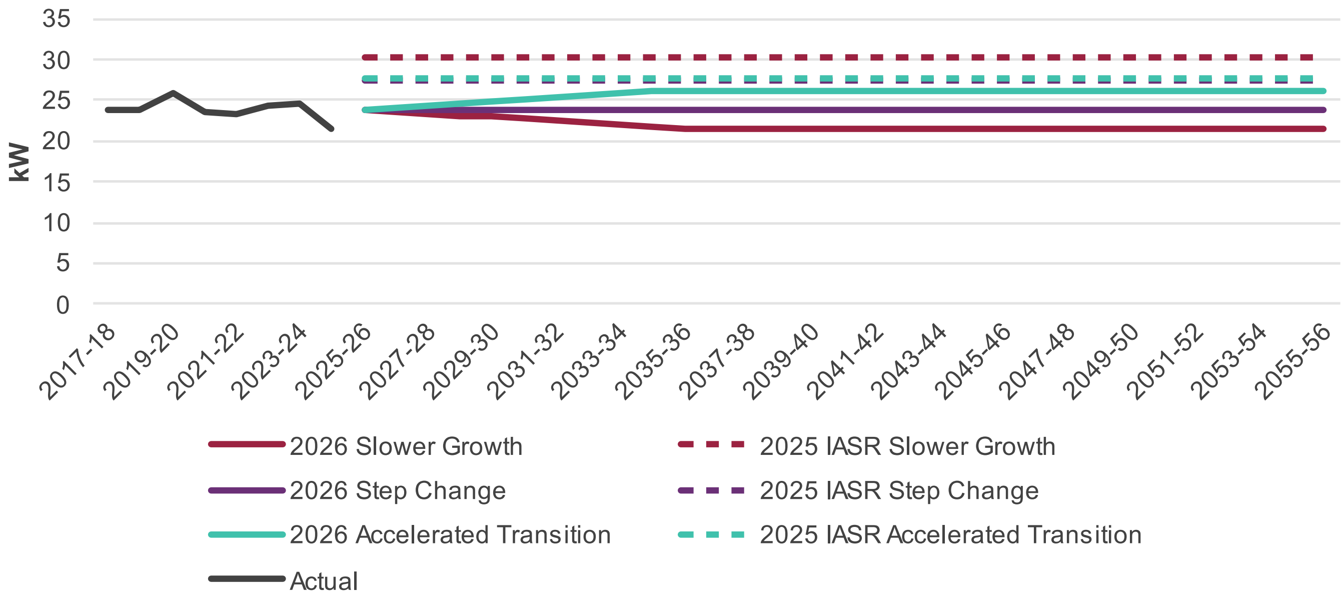
[16] See https://cer.gov.au/schemes/renewable-energy-target/small-scale-renewable-energy-scheme/small-scale-renewable-energy-systems/rooftop-solar.

Figure 8 Actual and forecast residential new PV system size



AEMO also notes uncertainty in relation to small commercial system size (see Figure 9), and once again adopted a scenario-based spread.

Figure 9 Actual and forecast small commercial new PV system size (kW)



The average size of commercial PV systems has fluctuated over the years but remains relatively flat overall with no clear trend. Therefore, AEMO assumed a flat system size trajectory for this sector that matches the historical average for the *Step Change* scenario. The other scenarios assumed a proportional increase (*Accelerated Transition*) and decrease (*Slower Growth*) around the average level, with a progressive change towards those stable values.

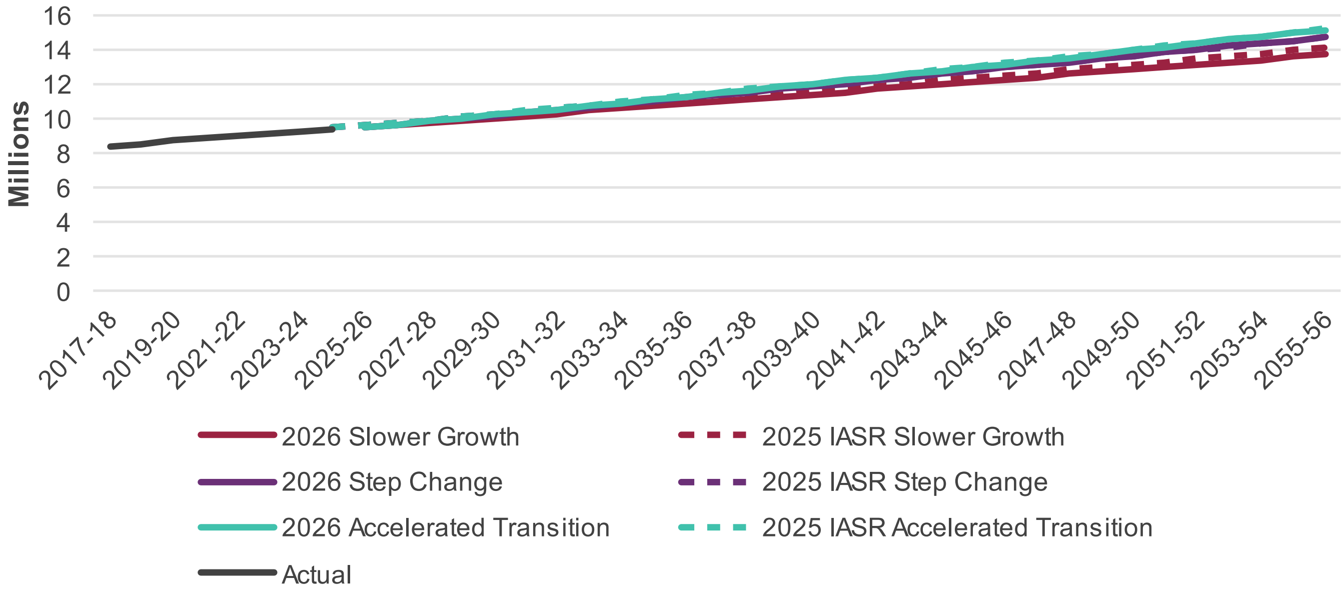
The average size of PVNSG systems has remained relatively constant in time, so this was assumed constant throughout the forecast period and across scenarios. The average size varies by region, with an average across the NEM and WEM of 723 kW in 2025.

4.1.1 Dwellings

Scenario-based dwelling completion forecasts (by dwelling type) were provided by AEMO's economics consultants, and appended to ABS census data on historical dwelling numbers[17] to create an actual/forecast time series of dwelling numbers by dwelling type.

AEMO considered dwellings for residential PV purposes as either (standalone) houses, semi-detached, or flats/apartments. Houses plus semi-detached homes define the Gross Market Size for residential PV – see Figure 10.

Figure 10 Actual and forecast number of houses and semi-detached dwellings



4.1.2 Commercial buildings

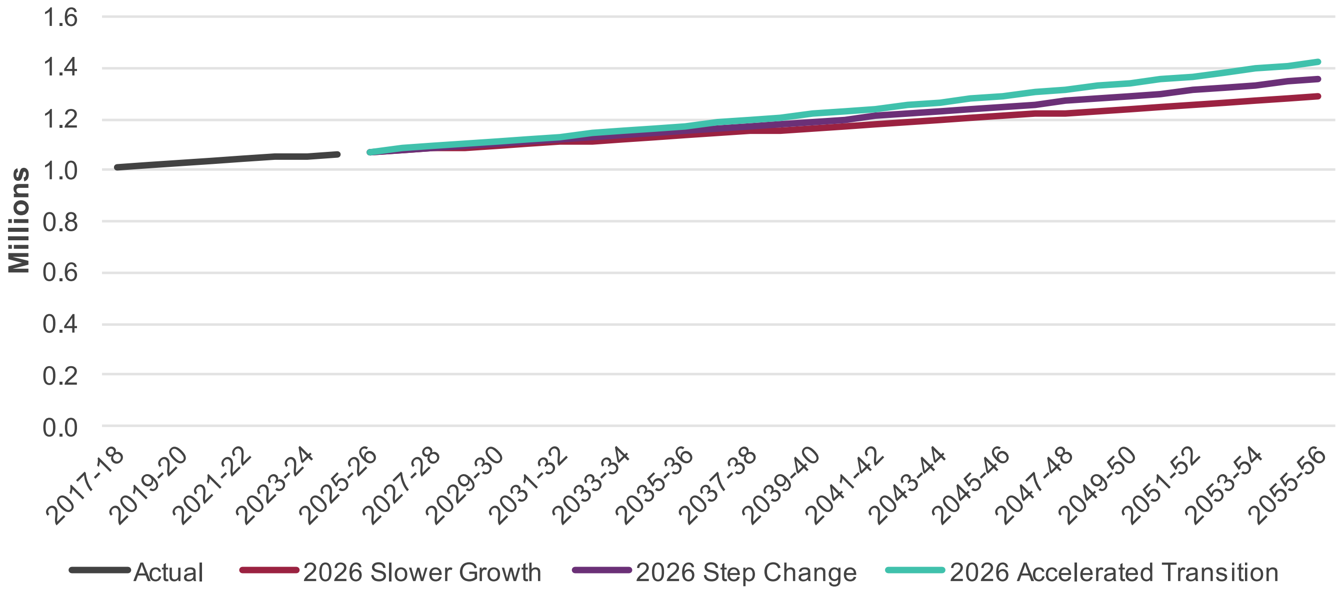
Historical and projected commercial building numbers broken down by primary use and state/territory[18] and overlaid with scenario parameters were used to create a combined actual/forecast time series for each scenario – see Figure 11.

The breakdown of commercial building numbers by primary use informs market size assumptions for the small commercial PV. This in turn is a component for setting small commercial battery market size.

[17] See https://www.abs.gov.au/statistics/people/housing/housing-census/latest-release and detailed data at https://www.abs.gov.au/statistics/microdata-tablebuilder/tablebuilder.

[18] See https://www.dcceew.gov.au/energy/publications/commercial-building-baseline-study-2024.

Figure 11 Actual and forecast number of commercial buildings



The breakdown of commercial building numbers by primary use informs market size assumptions for the small commercial PV. This in turn is a component for setting small commercial battery market size.

4.1.3 PV actuals

The history of consumer PV system installations from the Clean Energy Regulator, incorporating replacements and additions data, was used to arrive at system count and capacity.

AEMO used public and confidential data from the Clean Energy Regulator to estimate historical figures for system replacements and additions across residential and small commercial sectors. The results were presented at an FRG meeting on 22 October 2025[19]; summary charts by region are in Appendix A1.

4.1.4 PV self-consumption and TOU factors

PV self-consumption refers to the proportion of PV generation used by the household or small commercial premise.

AEMO assumed the following proportions of PV generation used for self-consumption, informed from AEMO's historical PV generation and consumption data.

For residential sites, the self-consumption figure started at 40% reflecting current system size, and declined to 25% over the longer term as PV system sizes increase. For small commercial buildings, self-consumption was assumed flat at 70%, as these customers are considered to more closely match their PV size to their energy needs.

TOU factors refer to the spread of PV self-consumption across retail Peak, Shoulder and Off-Peak windows.

AEMO referenced its generation and consumption data to estimate TOU factors, which AEMO assumed are constant over time and across market sectors, with a split of 70% consumption during shoulder TOU and 30% peak TOU.

[19] See FRG Meeting pack at https://www.aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/frg/2025/frg-meeting-pack-7.zip?rev=dbab22073a264b85b2ab775ed051047b&sc_lang=en.

4.1.5 PV payback

The residential or small commercial returns from PV investment were estimated using inputs developed above according to the forecasting model block diagrams. This process considered PV system size and generation profiles, scale and timing of self-consumption, the avoided cost of grid-supplied energy on a TOU tariff.

The PV capacity factors used to calculate the total energy output from a PV system were calculated from AEMO's normalised generation profiles on a regional basis. The weighted average capacity factor across all regions modelled was 13.9%.

For the subsequent purpose of a 'price-like' input to the GBDM, AEMO used the following metric:

Simple Return on Investment = Retail bill savings (1 year)/System cost

where:

- retail bill savings = (Self-consumed PV generation per TOU period x avoided retail TOU price per period) + (exported PV generation x Feed-in tariff)
- system size for generation and cost purposes equals the scenario-specific system size projections.

For PVNSG systems, AEMO assumed 100% self-consumption, as these systems tend to be sized to very closely match the consumption needs on site. AEMO acknowledges this assumption is most appropriate for PVNSG sites under 5 MW which constitute the majority of sites and generation capacity, and has less relevance for larger sites up to 30 MW.

4.1.6 PV degradation and replacements

PV panels degrade over time, producing less output each year. AEMO assumed a reduction in capacity of 0.5% pa. This assumption was informed by multiple data sources[20].

PV systems are assumed to be replaced after some time. AEMO's analysis of Clean Energy Regulator replacement data showed the average age at which replacements occur to be 12 years, 15 years, and 20 years for residential, commercial, and PVNSG systems respectively. However, the Clean Energy Regulator's replacement information extends only for four years. To address the uncertainty associated with that short data period, AEMO used the current replacement rate of 1.7% of the PV fleet per annum. The difference between the rate implied by the average replacement age, and the actual replacement rate, may be understood by recognising that not all replacements occur due to end-of-life reasons.

4.2 PV market size

In developing the Market Size Factors which translate from Gross Market Size (Technical potential) to Net Market Size (Market potential), AEMO considered the scenario narratives, relevant parameters and data:

- **Economic parameters** such as the growth of the economy. A more robust economy provides confidence that available funds can be directed towards discretionary purchases such as CER, and also provides easier access to credit.

[20] See https://www.powermag.com/analysis-of-performance-degradation-of-pv-modules/, and https://www.exponent.com/article/shedding-light-solar-panel-degradation.

- **Census data** concerning dwellings includes occupancy type (for example, owner/occupier or renter). AEMO assumed, per the scenario narratives, that the *Accelerated Transition* shows success in social and government programs to assist renter access to PV. In contrast, *Slower Growth* shows a low level of success with similar programs. AEMO notes that approximately 65% of houses are owner-occupier and consequently assumed in *Step Change* that 65% of houses are available to take up PV. Of course, in practice, not all owner-occupied houses will take up PV, but such details may be assumed to offset by other factors, such as an owner-occupied property installing PV and then being sold to an investor.

The resulting Market Size Factors are in Table 4 below. The table should be interpreted as 'For residential PV in the *Step Change* scenario, AEMO assumed that 65% of houses may potentially take up PV, based on the scenario parameters'.

Table 4 PV and PVNSG market size factors

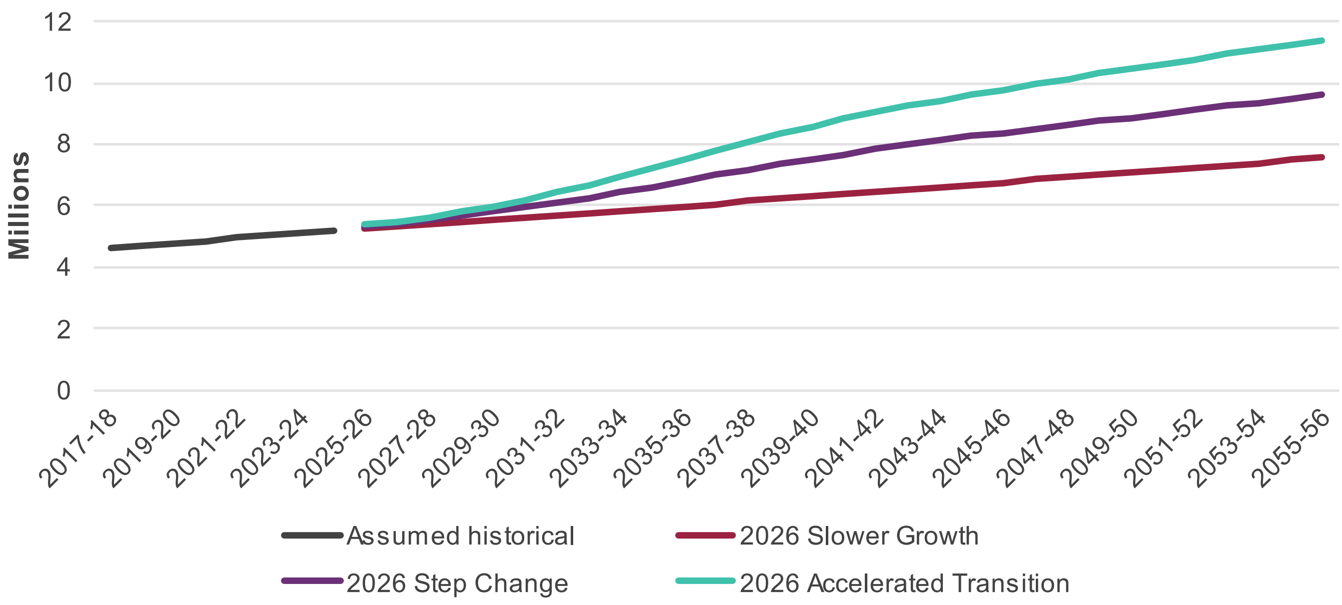
Sector	*Slower Growth*	*Step Change*	*Accelerated Transition*
Residential PV	55%	65%	75%
Commercial PV	50%	60%	70%
PVNSG	30%	45%	60%

Similarly to the residential Market Size Factors, the small commercial factors reflect a range of scenario-based economic activity, with the assumption being that this influences PV uptake for this sector. Similarly to residential, the scenarios also embody government and non-government success in programs to encourage broad PV uptake within this sector.

PVNSG market size factors reflect a variety of scenario-based market cases. The *Accelerated Transition* trajectory reflects a wealth of market opportunities, awareness, and pro-active engagement of all involved decision makers. *Slower Growth* represents the other end of this spectrum, with *Step Change* in the middle.

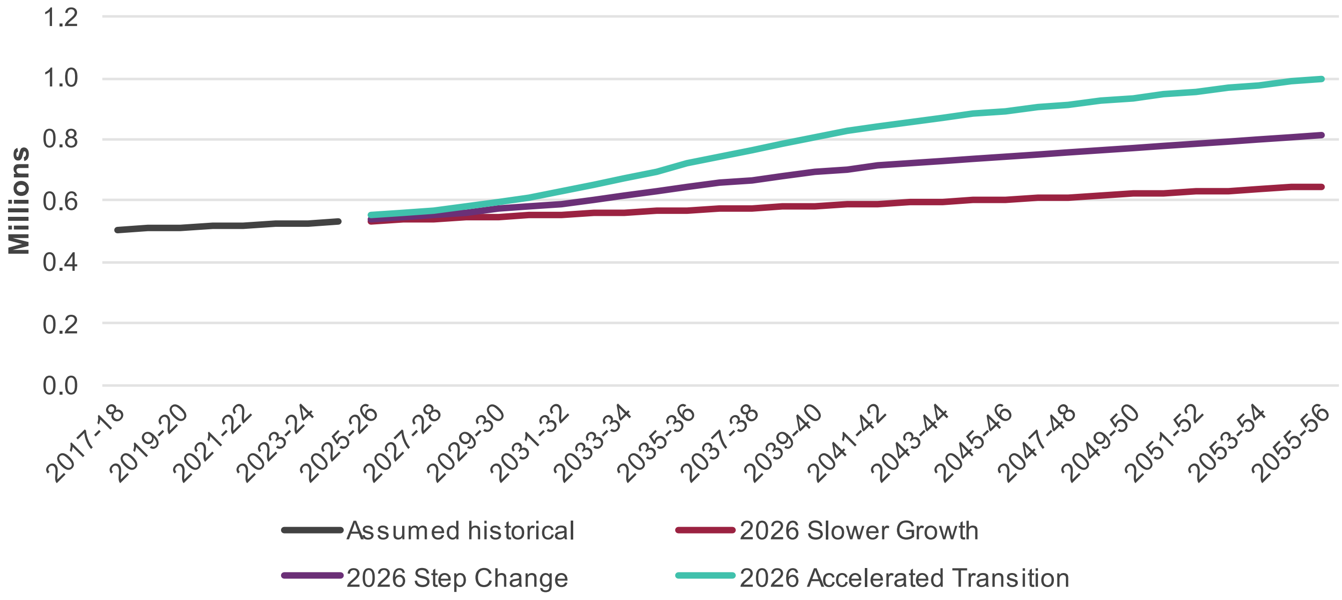
Residential PV market size (houses + semi-detached dwellings multiplied by above market size factor) yields the following Net Market Sizes. Note that the numbers increase as the economic forecasts of housing stock grow – see the Dwellings inputs and assumptions.

Figure 12 Actual and forecast residential Net Market Size



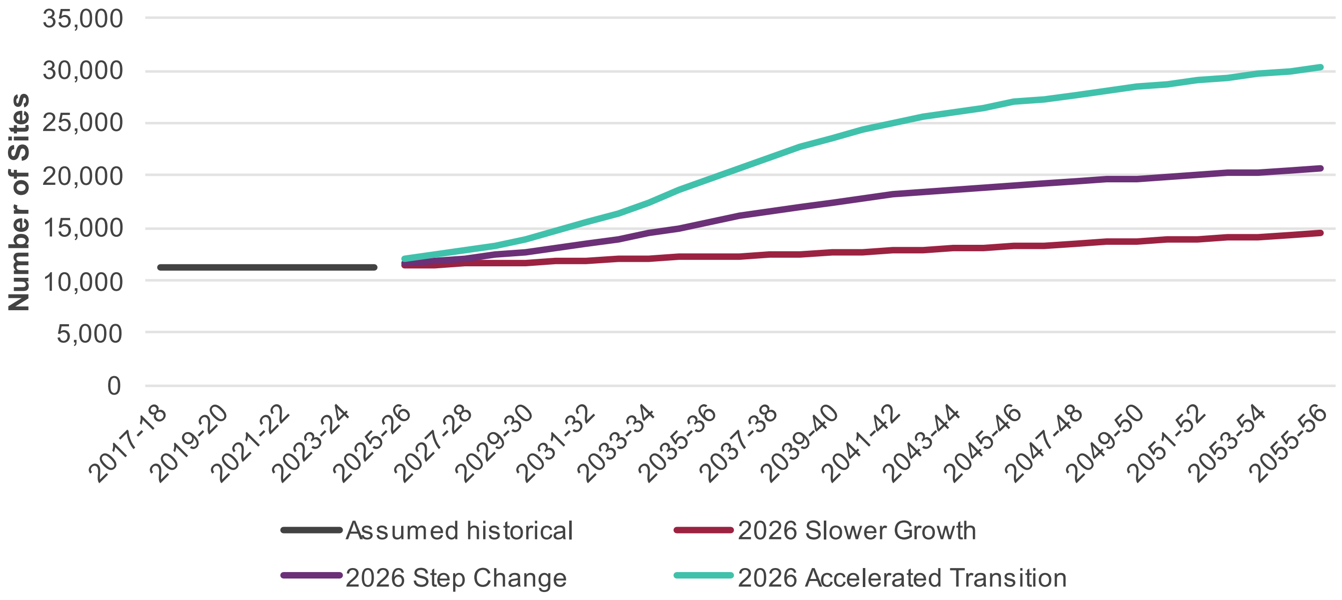
Small commercial PV market sizes were developed from the market size factors multiplied by the commercial building outlook.

Figure 13 Actual and forecast small commercial Net Market Size



PVNSG Net Market Size is the Market Size Factor multiplied by the number of practical PVNSG sites. The graph increases to the right, as economic activity increases the number of sites over time.

Figure 14 Actual and forecast PVNSG Net Market Size



4.3 Battery assumptions

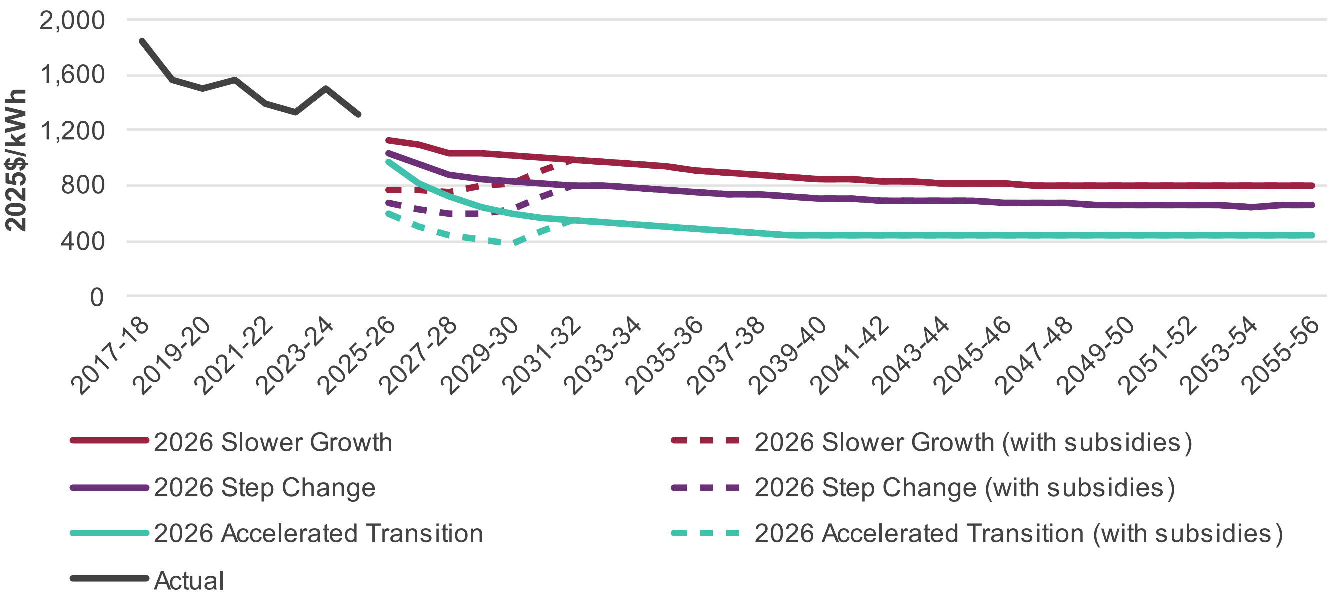
4.3.1 Retail tariff

See *Retail tariffs* under Section 4.1.1.

4.3.2 Battery system costs

Small-scale battery system costs were adapted from the GenCost (2024-25) utility-scale battery costs, with STC rebates[21] and non-RET policies and subsidies applied to arrive at a net cost to the consumer – see Figure 15.

Figure 15 Actual and forecast residential battery cost with and without subsidies (2025$/kWh)



Relative to the PV cost curve, batteries are at an earlier point in their life cycle and the graph anticipates ongoing cost reductions.

AEMO notes that consumer battery systems, as installed, consist of a number of cost elements:

- physical batteries,
- wholesale distribution,
- installer margin, and
- installer fixed costs.

Some of the above cost elements vary with battery size (kilowatt hours [kWh]) and some do not, necessitating AEMO's use of average system size as the basis of calculating an average system cost per kWh. AEMO used the historical and future average battery size to express the costs on a $/kWh basis. This approach has been adopted in developing the battery system costs.

[21] See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries/small-scale-technology-certificates.

Figure 16 shows clear year-on-year battery costs reductions (battery and balance of plant in total), with GenCost stating that battery costs "have decreased significantly by 11% to 36% depending on the duration".

Figure 16 Actual and forecast residential battery costs (without subsidies) compared to blended costs from 2025 IASR (2025$/kWh)

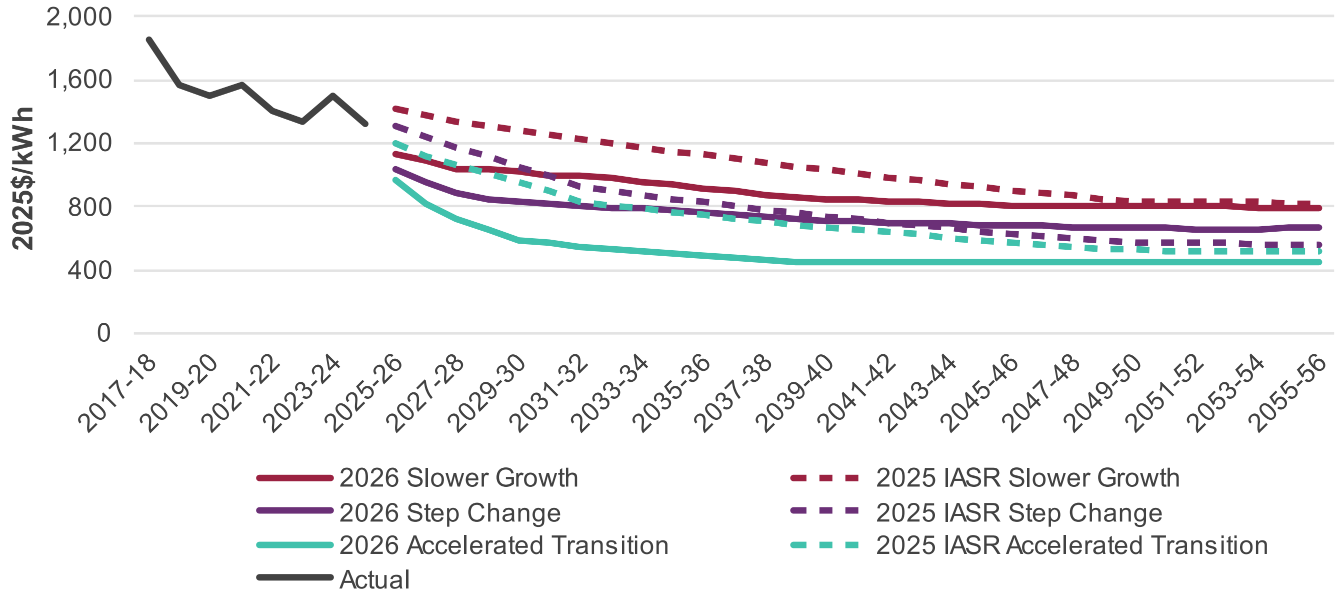
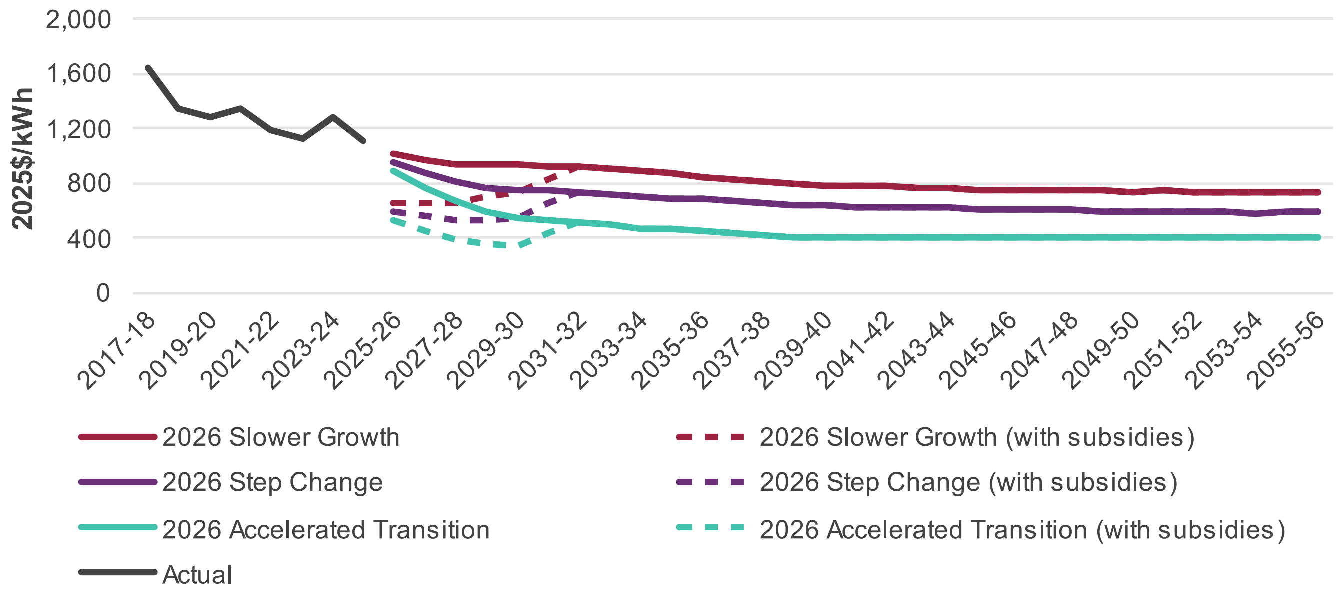


Figure 17 shows the small commercial battery costs, which are marginally lower than the residential batteries due to the larger system sizes.

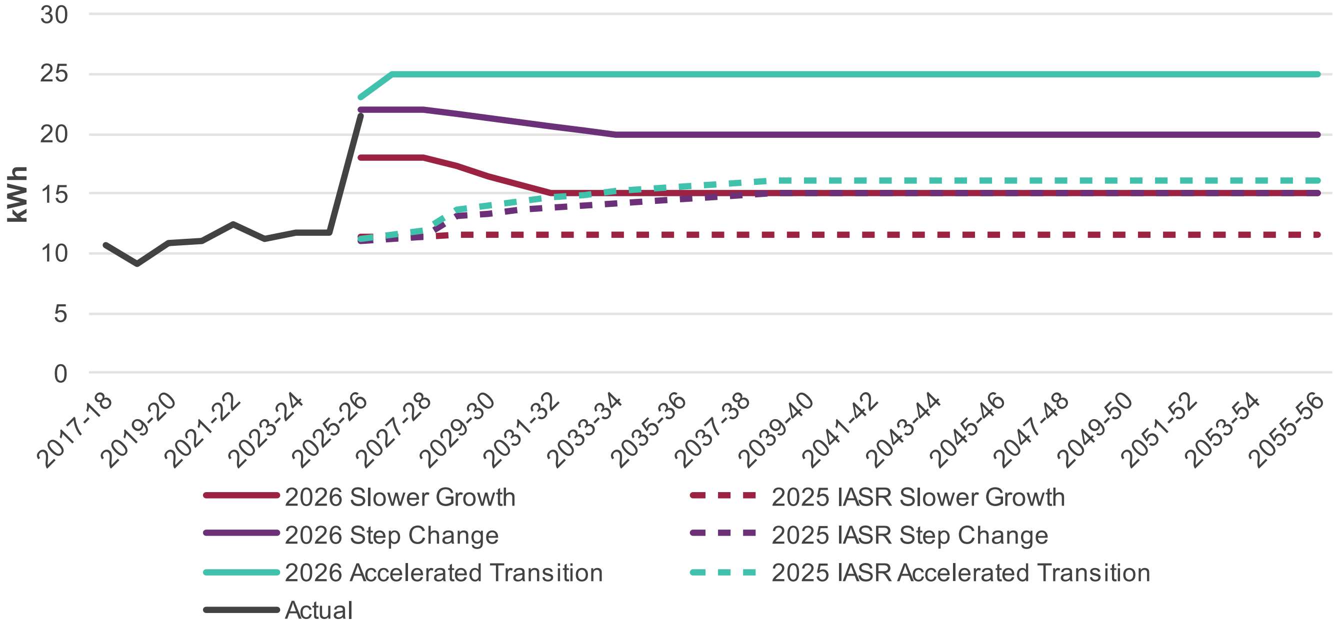
Figure 17 Actual and forecast small commercial battery cost with and without subsidies (2025$/kWh)



4.3.3 Battery system size

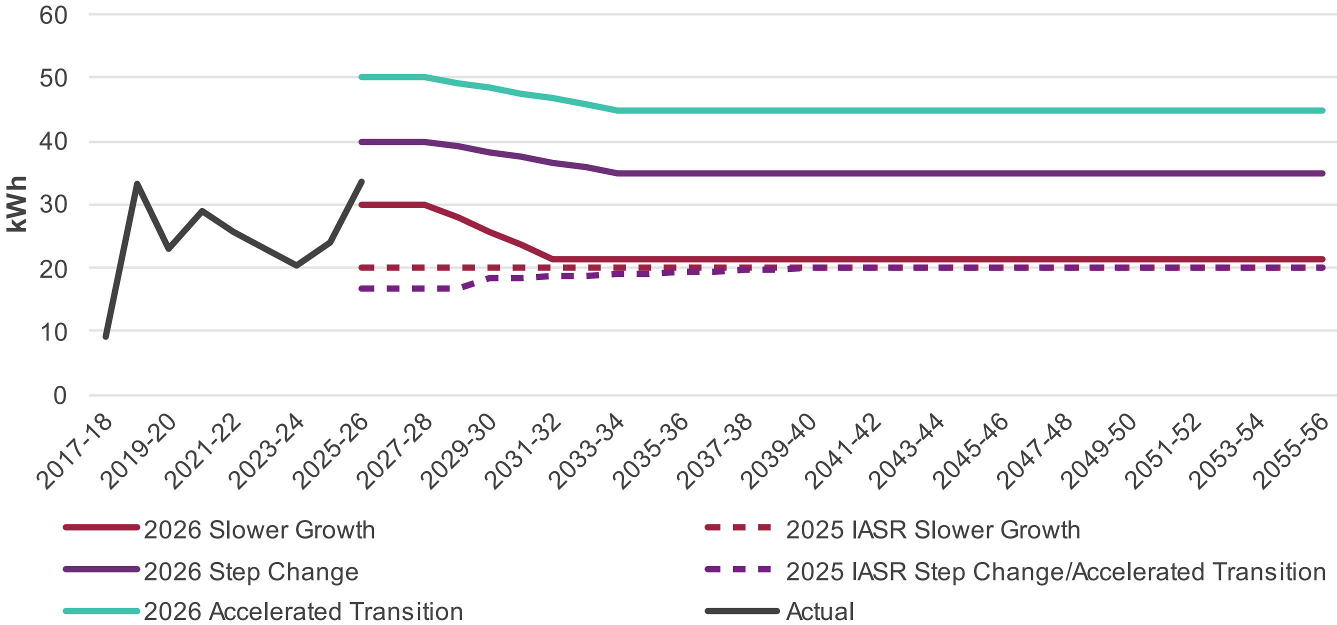
The history of residential and small business battery system installations was taken from the Clean Energy Regulator[22], and scenario narratives and parameters used to develop the battery system size outlooks, shown in Figure 18 and Figure 19.

Figure 18 Actual and forecast residential battery new system size (kWh)



Note: Actual data for 2025-26 covers June to October 2025 only.

Figure 19 Actual and forecast commercial battery new system size (kWh)



Note: Actual data for 2025-26 covers June to October 2025 only.

[22] See https://cer.gov.au/batteries.

AEMO used data from the Clean Energy Regulator to estimate system size across residential and small commercial sectors since the CHBP began. Prior historical battery size data was sourced from SunWiz.

There are a variety of views on the trajectories of battery system size, stemming from the notion that strong early uptake of the CHBP reveals pent-up demand, which AEMO considers most closely aligns with desire for larger system sizes. Thus, the average residential battery new system size adopted scenario-based trajectories that show a spectrum from sustained enthusiasm through to honeymoon effect where enthusiasm declines significantly.

4.3.4 PV installations

Residential and small commercial PV installation forecasts were used as the gross battery Market Size because AEMO assumed that the market for residential and small commercial batteries is limited to those houses and commercial buildings with PV – in other words, there is insufficient payback associated with battery only installations to forecast them.

Table 5 Battery market size factors

Sector	*Slower Growth*	*Step Change*	*Accelerated Transition*
Residential batteries	50%	65%	75%
Small commercial batteries	40%	50%	60%
Large Commercial	N/A	N/A	N/A

The market size factors reflect practical matters:

- There are numerous practicalities limiting residential battery installations – safety regulations place significant restrictions on where a battery may be physically installed, and remaining locations may have aesthetic concerns or competing uses.
- Similar dynamics were assumed for Small Commercial battery size factors, but moreso as many small commercial premises have no 'sides' due to common walls with adjacent shops/industrial units.For example, the front side may be public facing where a battery may be damaged or unsightly, and the back of the premise may have forklifts, delivery drivers, lack of space or lack of security.

4.3.5 Battery actuals

AEMO determined historical residential and small business battery installations from SunWiz[23], supplemented by data from the Clean Energy Regulator [24]and AEMO's Distributed Energy Resources (DER) Register. Following the introduction of the Cheaper Home Batteries program in July 2025, Clean Energy Regulator data was applied as it provides more comprehensive data than the traditional sources on battery installations.

4.3.6 Battery payback

The economic returns from battery investment were computed considering PV generation, scale and timing of self-consumption, the avoided cost of grid-supplied energy, and battery size.

[23] See https://www.sunwiz.com.au/battery-market-report-australia-2025/.

[24] See https://cer.gov.au/batteries.

AEMO calculated battery payback based on avoided retail costs from a daily charge/discharge cycle. It assumed charging from excess solar PV and discharging into periods with no PV output. The discharging was assumed to be divided across the TOU periods with 30% in peak, 50% in off-peak, and 20% in shoulder periods. Because of the increase in battery sizes with the introduction of the CHBP, AEMO assumed only a portion of the battery's storage capacity is cycled each day. The proportions are 100% for *Slower Growth*, 90% for *Step Change*, and 80% for *Accelerated Transition*.

4.3.7 Battery properties, degradation, and replacement

Battery storage capacity degrades over time. CSIRO's battery degradation regime was adopted[25], which assumed 1.8% annual degradation of battery storage capacity (kWh).

Battery round trip efficiency was assumed to be 90%, which is based on data from multiple battery manufacturers.

As for PV, battery systems were assumed to be replaced over time. For residential systems, all batteries were assumed to be replaced after 12 years, and 15 years for commercial systems.

[25] See Appendix A of CSIRO's report at https://www.aemo.com.au/-/media/files/major-publications/isp/2025/csiro-2024-solar-pv-and-battery-projections-report.pdf?rev=e8a158794c6d4327a1eb66ae15d86ca8&sc_lang=en.

5 Forecast results

5.1 Residential PV Results

The residential PV uptake and capacity forecasts are shown in Figure 20 and Figure 21.

Figure 20 Actual and forecast residential PV uptake (number of installations), NEM and WEM

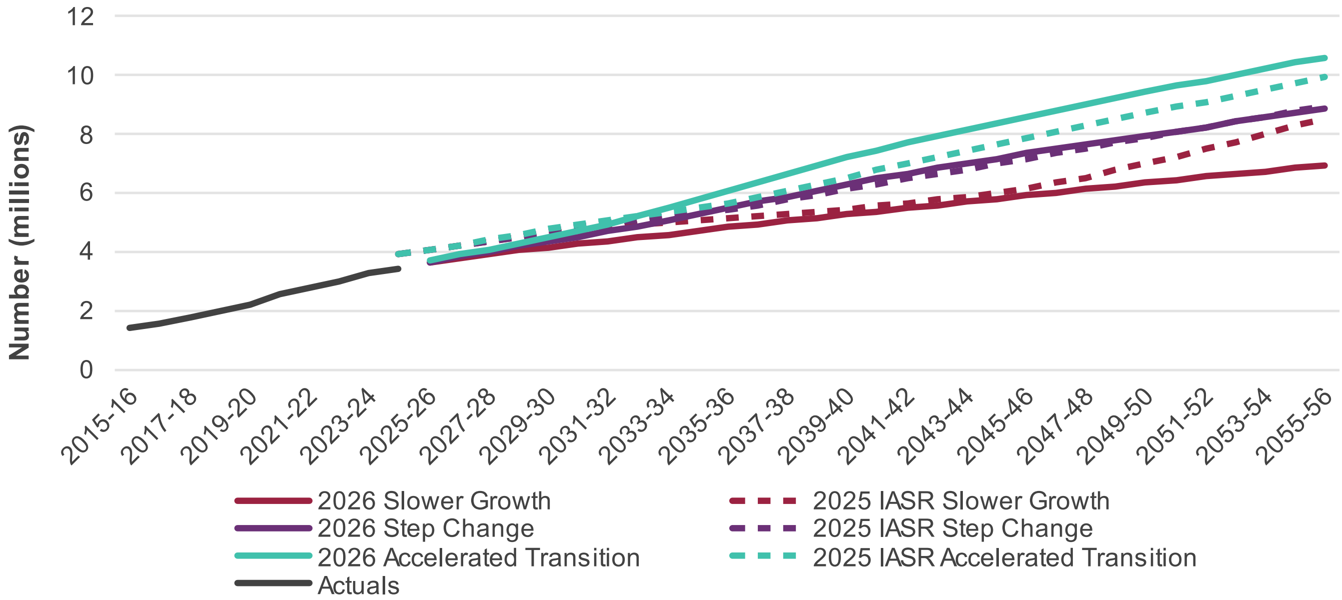
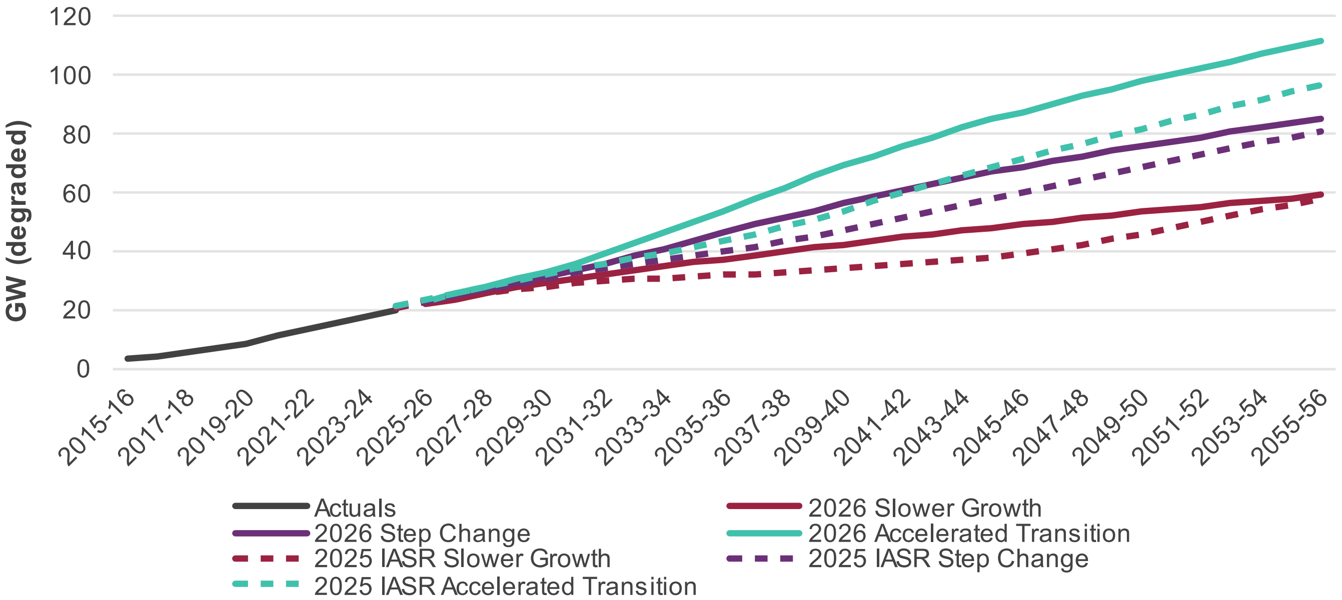


Figure 21 Actual and forecast residential PV capacity, NEM and WEM (GW degraded)



Compared to the 2025 IASR, capacity has risen in the medium term across all scenarios, largely driven by the increase in assumed system size. This is despite the forecast number of residential PV installations having fallen slightly in the short term, owing to the downwards revision of the estimated number of actual installations, and several other drivers for PV easing.

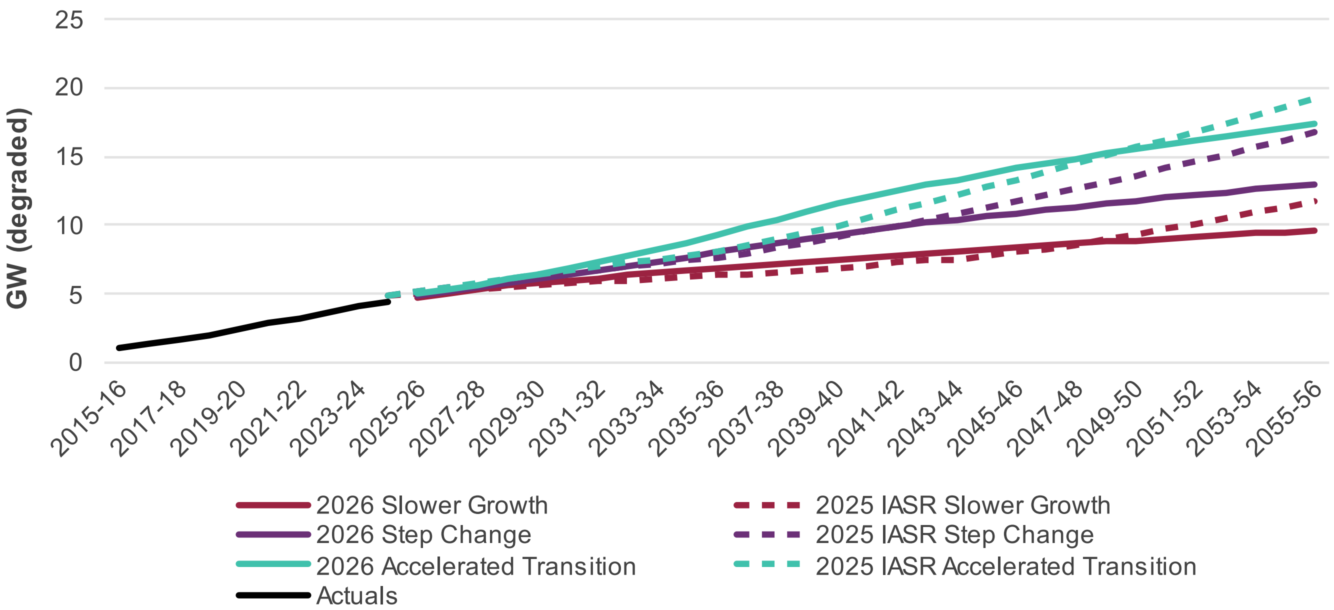
Calibration of payback to historical data was improved, increasing the accuracy of forecast for this driver. Payback is largely driven by avoided grid imports, as feed-in-tariffs reduce quickly. After the existing subsidies end, payback worsens slightly in all scenarios, but then improves again as PV costs reduce further and energy prices are assumed to increase. The residential PV forecasts lift in the medium term before slowing due to market saturation effects in the consumer adoption model. The market saturation effect tracks uptake from innovators and early adopters, to rapid uptake by the majority, through to eventual market saturation.

The end of the forecast horizon shows little change in the *Slower Growth* and *Step Change* scenarios compared to the 2025 IASR, as AEMO's recognition of Net Market Size shapes the long-term growth. The *Accelerated Transition* scenario shows longer ongoing growth as the higher Net Market Size provides more headroom.

5.2 Commercial PV Results

The small commercial PV forecast is shown in Figure 22, and demonstrates a similar pattern to residential.

Figure 22 Actual and forecast commercial PV capacity, NEM and WEM (GW degraded)



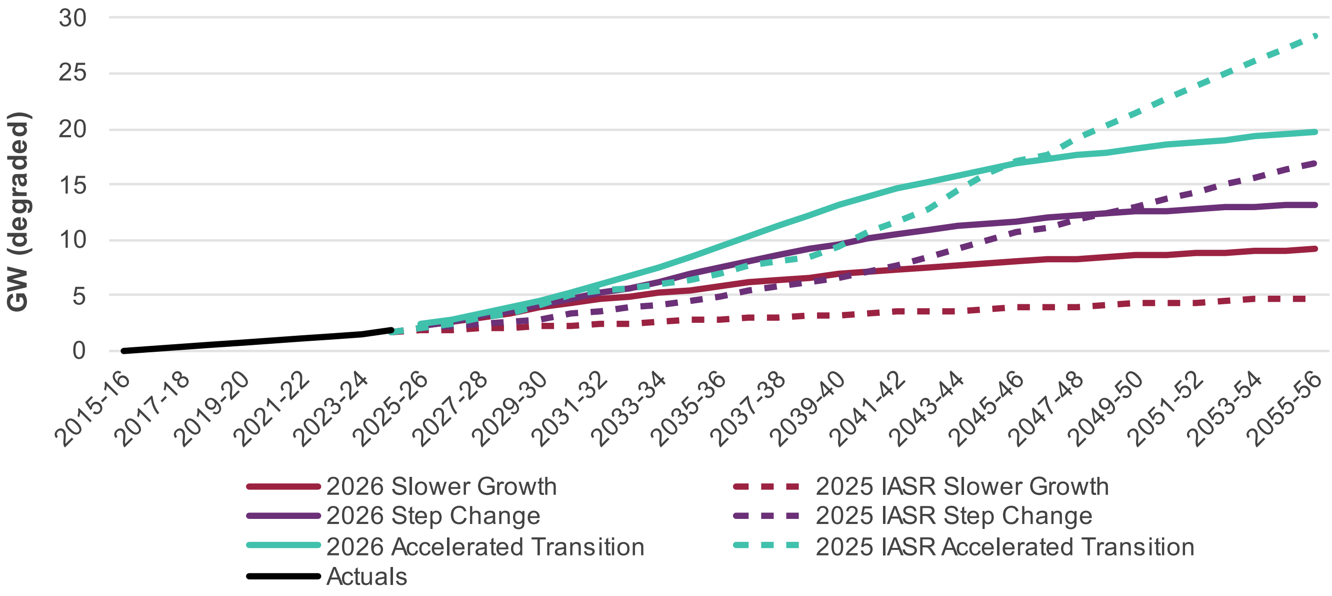
Compared to the 2025 IASR, despite system sizes remaining fairly flat, a fuller consideration of market size drives more 'S'-shaped forecasts, showing an uplift in medium-term values and a more pronounced taper as the scenario forecasts approach their market sizes.

The small commercial sector is less inclined to oversize PV investments. This may be driven by a more calculated payoff mindset, and/or more pressing space limitations in commercial premises.

5.3 PVNSG results

The PVNSG forecast is shown in Figure 23.

Figure 23 Actual and forecast PVNSG, NEM and WEM capacity (GW degraded)



Although it is still early in the life cycle of PVNSG, the steady growth of recent years indicates that future PVNSG uptake has medium-term potential, although longer-term growth is constrained by the limited number of PVNSG sites available. Once the existing Large-scale Renewable Energy Target ends, payback worsens initially but then improves as PV costs fall and electricity prices increase.

5.4 Residential battery results

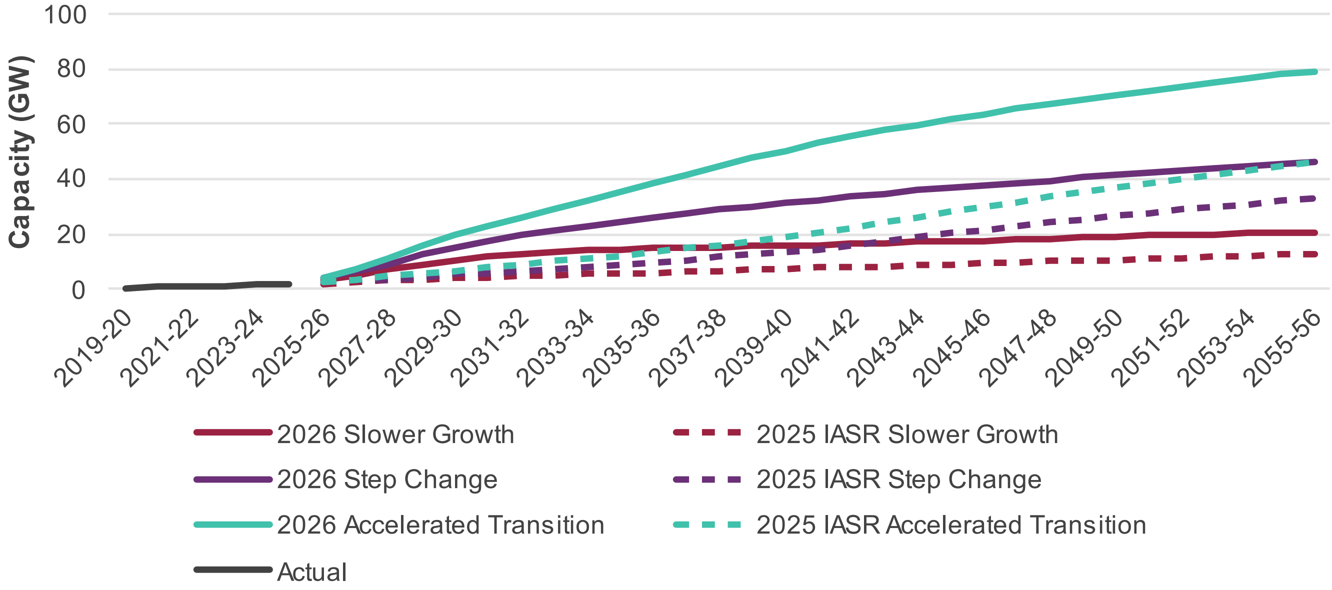
The residential battery forecast is shown in Figure 24.

The increase in forecast residential battery capacity compared to the 2025 IASR is driven by a number of factors, including ongoing strong PV uptake, the increasing sizes of both PV and battery systems, falling battery prices, and the significant short-term impact of the CHBP. The WA Residential Battery Scheme provides additional incentives for consumer purchases in WA, as it can be combined with the CHBP subsidy. The high forecast impact of the CHBP is due to the substantial rebate provided by the scheme to 2030 and assumed reducing battery costs (expected to continue in the medium term). The overall installed capacity increases due to both number and size of systems growing, as consumers may be incentivised to purchase larger systems to maximise the amount of rebate received. This drives up the battery volumes, which contributes to decreasing costs in the medium term.

There is considerable uncertainty around whether these strong rates of consumer adoption 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 system sizes; the effect of these changes will be unclear until they impact customers, from May 2026. The forecasts presented here were finalised prior to this announcement, and were based on the assumption that the CHBP scheme would be uncapped, and continue in its current form, with subsidies ramping down until 2030.

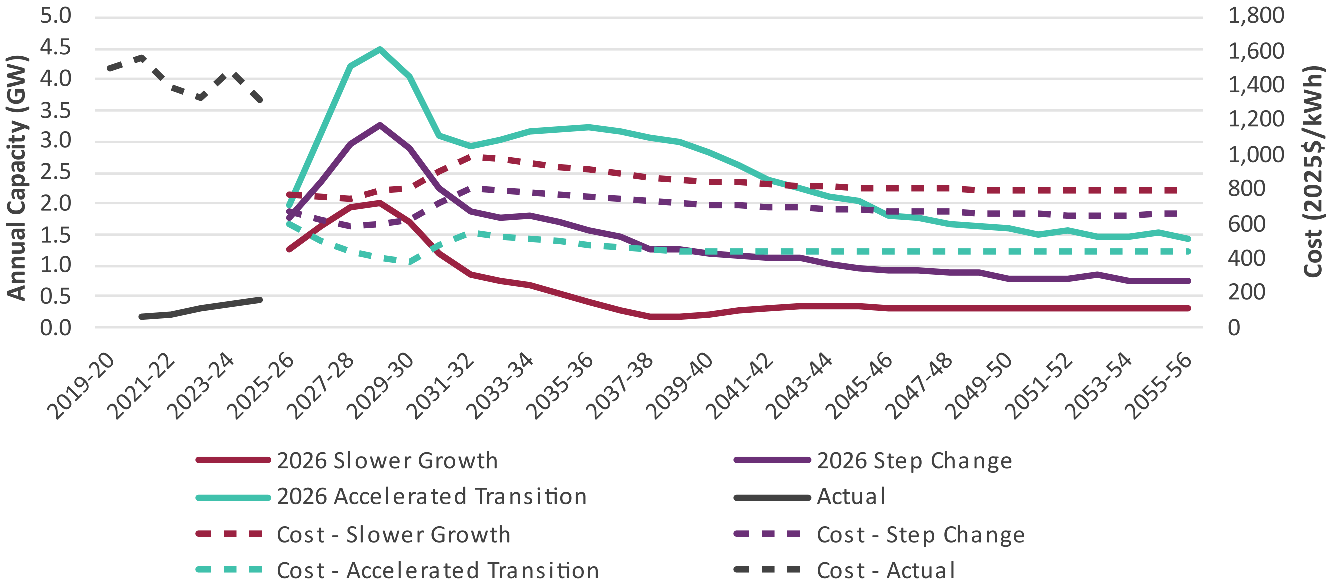
While the 2025 IASR forecast included the assumed impact of the CHBP, the initial uptake has exceeded industry expectations. Although the increase in forecast battery capacity is large, it is not uncommon for new products to have highly uncertain futures, and for that uncertainty to drive substantial forecast-on-forecast revisions.

Figure 24 Actual and forecast residential battery uptake – installed capacity for NEM and WEM (GW)



The timescale and S-shaped nature of uptake may make it difficult to observe the effect of the CHBP on uptake. For that reason, Figure 25 overlays annual growth rate with subsidised battery system cost, and shows a clear spike in uptake corresponding with the lower-cost period of the CHBP subsidy. As mentioned above, this forecast was based on the assumption that the CHBP would be uncapped – the future implementation of the policy is uncertain at this time.

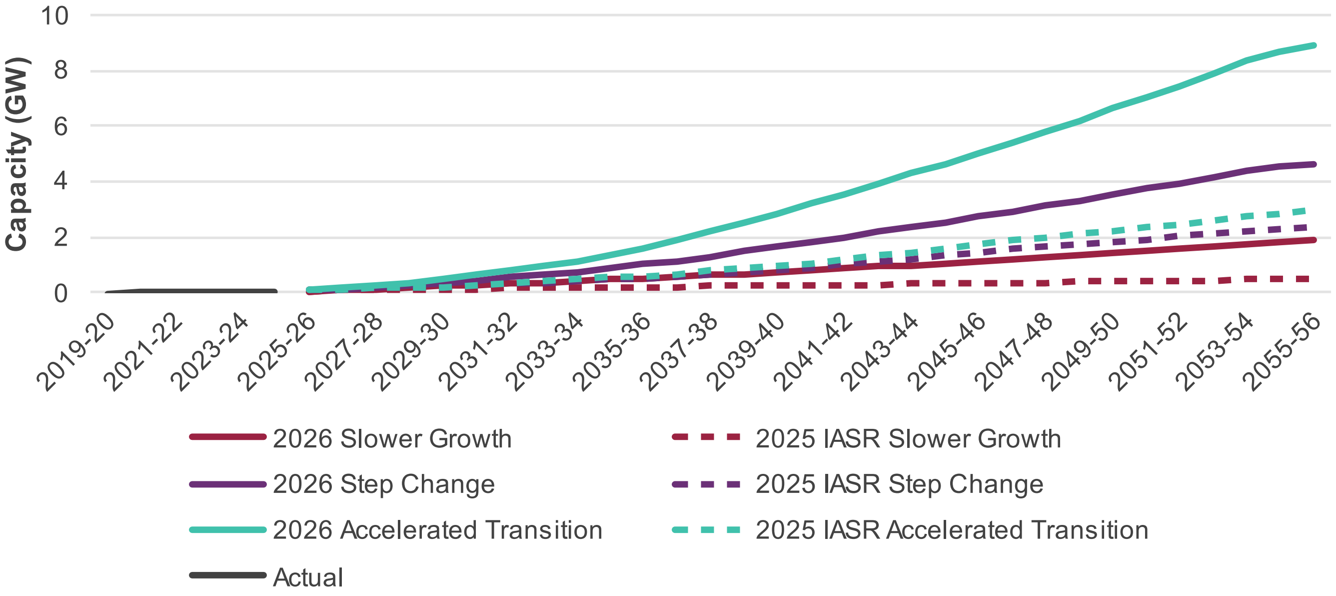
Figure 25 Actual and forecast residential battery uptake – annual addition to installed capacity (LH axis) and battery cost (RH axis) for NEM and WEM (GW)



5.5 Small commercial battery results

The small commercial results show a comparable increase to residential batteries, relative to the 2025 IASR. Similar factors to the residential batteries apply.

Figure 26 Actual and forecast small commercial battery uptake – installed capacity for NEM and WEM (GW)

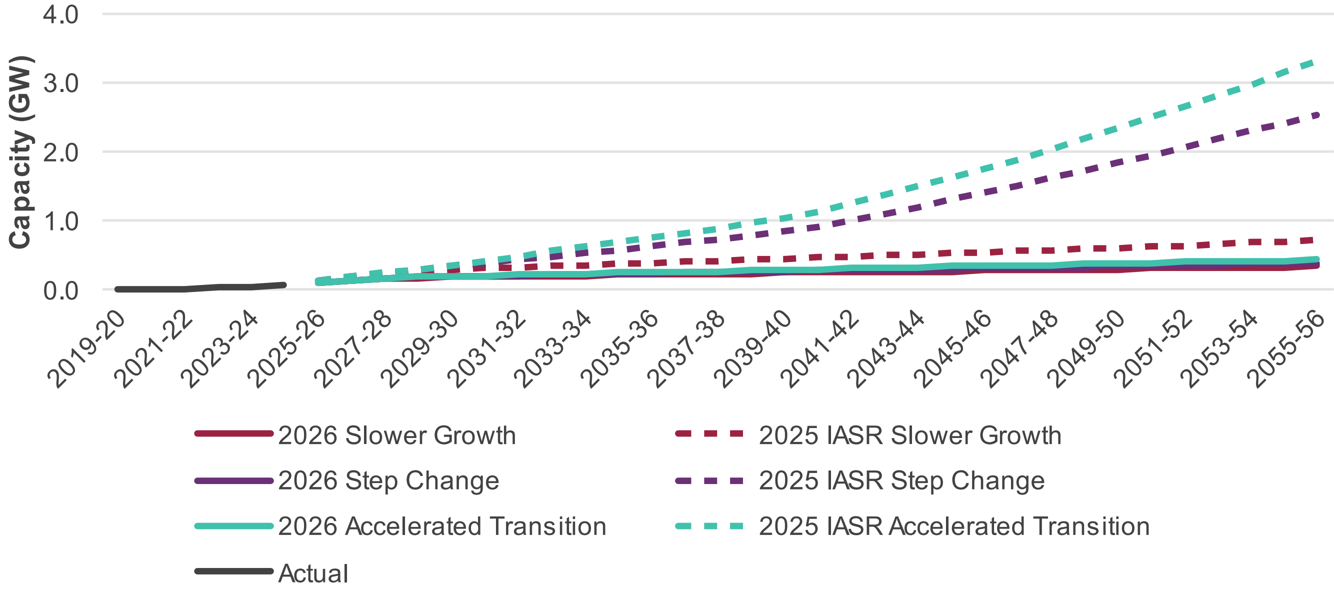


5.6 Large commercial battery results

The very limited uptake to date on large commercial batteries drives a limited outlook for the sector – see Figure 27. The drivers for large commercial batteries are challenging. Although battery costs are similar per unit to medium-scale premises, larger premises face lower avoided retail prices to offset their investment. Large commercial sites are expected to apply robust financial metrics to their investment decisions, and may have a host of competing projects requiring capital.

This category includes community batteries, which tend to be funded through grants rather than standalone commercial objectives.

Figure 27 Actual and forecast large commercial battery uptake – installed capacity for NEM and WEM (GW)



5.7 Residential and commercial VPP

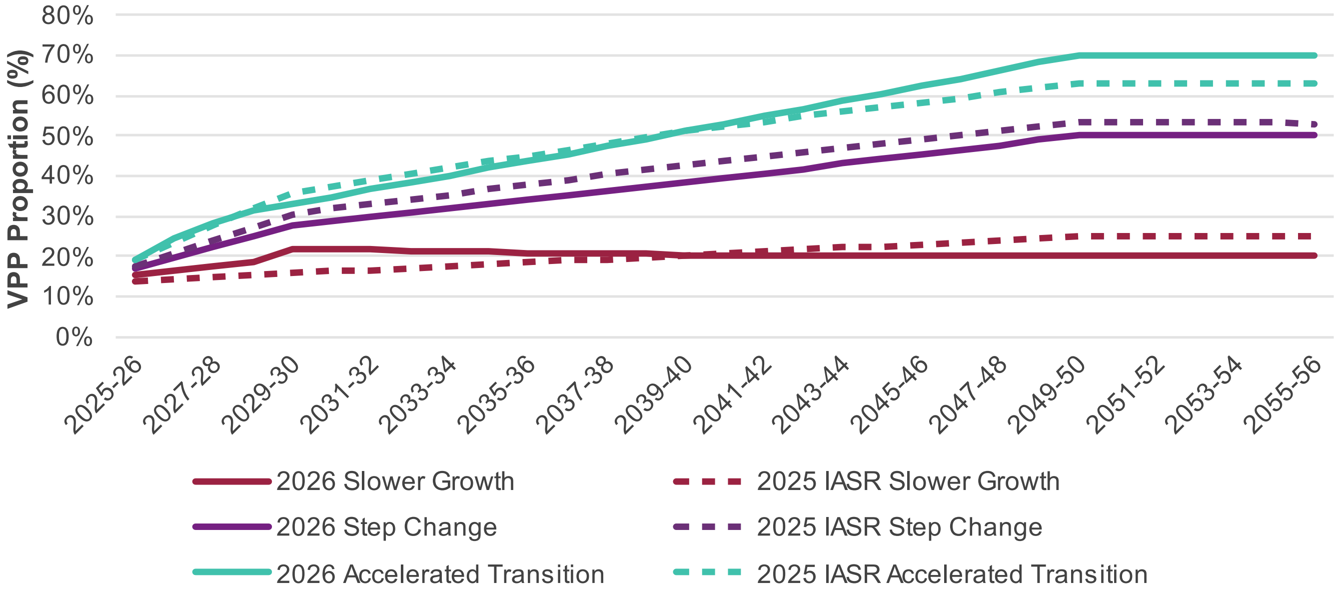
The assumed VPP participation rates are shown in Figure 28. The vertical axis of the graph, VPP Proportion (%), refers to the percentage of the battery uptake that is forecast to be under VPP operation.

Residential and commercial VPP uptake is highly uncertain. No data exists on commercial VPPs, so it was assumed to be the same as residential. The forecasts are not data-driven, but assumptions based on the 2025 IASR scenario parameters, which describe 'Low', 'Moderate' and 'High' levels of coordination.

The WEM's Residential Battery Scheme requires participation in a VPP, and will be a lead indicator of future VPP popularity. This report will be updated with data from that scheme as it becomes available. More than 4,500 batteries have been installed under the scheme to date[26].

[26] See https://www.wa.gov.au/government/media-statements/Cook Labor Government/Western-Australians-leading-the-charge-with-home-battery-rebates-20251117.

Figure 28 Assumed residential and commercial VPP participation rate for NEM and WEM



A1. Historical PV installations by region and system type

Historical PV installations data is sourced from the Clean Energy Regulator, including postcode level data published online[27] and installation level data provided by the Clean Energy Regulator directly to AEMO.

However, this data (and the postcode level aggregates) includes system replacements and additions, which have been increasing significantly in recent years. Replacements are when the original system is removed and replaced by a new system (usually but necessarily of bigger size), while additions mean more panels are added to the original system without removal, increasing its size. Neither of those categories add to the total count of operative rooftop PV systems at any given time. Additionally, when a system is replaced, the capacity of the removed original system does not add to the total tally of operative PV capacity. Consequently, not accounting for system replacements and additions results in an overestimation of PV systems count and capacity.

Figure 29 below shows a regional breakdown of historical PV installations, including AEMO's estimates for count and capacity of new systems, replacements, additions, and operative systems.

To improve the accuracy of the total operative PV system count and capacity in time, AEMO adjusted the postcode level data from the Clean Energy Regulator by accounting for system replacements and additions. To do so, AEMO estimated the size and rate of replacements and additions by month and region using the additional information in the installation level data provided by the Clean Energy Regulator, and matching system replacements to original systems where possible.

Across the NEM and WEM, and by 2024-25, this resulted in an overall decrease in the estimated number of PV systems of 11% (around 404,000 systems fewer than previously estimated), and an overall decrease of 3% in installed PV capacity (around 750 MW less than previously estimated).

[27] See https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data#postcode-data-files.

Figure 29 Historical PV installations by region and system type, NEM and WEM, including count and capacity (GW)