Australia's National
Science Agency

Small-scale solar PV and battery projections 2025-26

Commissioned for AEMO's draft 2026 Forecasting Assumptions Update

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Acknowledgments

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Executive summary

This report updates CSIRO's projections of small-scale solar PV and battery uptake. The report was completed in 2025 but has been commissioned as an input to AEMO's draft 2026 Forecasting Assumptions Update. This update follows CSIRO's last projection report completed in 2024. The key trends since 2024 are:

1. The introduction of the Cheaper Home Batteries Program is substantially ramping up both the number of battery installations and their average size.
2. Expectations that rooftop solar PV costs will decline more slowly than the 2024 projections and this will occur at the same time that existing subsidies are declining toward their ultimate removal date in December 2030 and retail prices are expected to have stabilised.
3. Continued increases in the size of residential solar PV systems before saturating in the long run. However, a revision of historical categorisation of systems means that average system sizes are significantly lower in that market segment.

These trends mean that the updated outlook is mixed with projected capacity to be weaker for solar PV (particularly commercial) and significantly stronger for batteries compared to 2024 projections.

1 Introduction

This report provides projections for three scenarios of small-scale solar PV and battery storage adoption. The analysis also includes simulations of the operation of small-scale batteries by residential and business customers under different tariffs.

The scope includes all the National Electricity Market (NEM) states of New South Wales, Victoria, Queensland, South Australia and Tasmania. This area excludes some postcodes in those five states that are not connected to the NEM. Only areas of Western Australia that are a part of the South West Interconnected System (SWIS) are included.

Projections for small-scale solar include residential and commercial systems below 100kW and separate projections for larger solar PV systems in the following ranges: above 100kW to 1MW, above 1MW to 5MW, above 5MW to 10MW and above 10MW to 30MW. For batteries, projections include residential systems and a small and large category for commercial systems.

The three scenarios are *Slower Growth, Step Change* and *Accelerated Transition*. These are described further in the body of this report.

The report is set out in five sections. Section 2 provides a description of the projection methodology. Section 3 describes the scenarios and their broad settings. Section 4 describes the scenario assumptions in detail. Finally, the projection results are presented in Section 5.

2 Methodology

2.1 Overview

The projections undertaken are for periods of months, years and decades. Consequently, our projection approach aims to be robust over both shorter- and longer-term projection periods.

Longer term projection approaches tend to be based on a theoretical model of the relevant drivers including human behaviour and physical drivers and constraints. These models can overlook short term variations from the theoretical model of behaviour because of imperfect information, unexpected shifts in key drivers and delays in observing the current state of the market.

Shorter term projection approaches tend to be based on extrapolation of recent activity without an underlying theory of the drivers. These include regression analysis and other types of trend extrapolation. While trend analysis will generally perform the best in the short term, extrapolating a trend indefinitely will lead to poor results since eventually a fundamental driver or constraint on the activity will assert itself, changing the activity away from past trends.

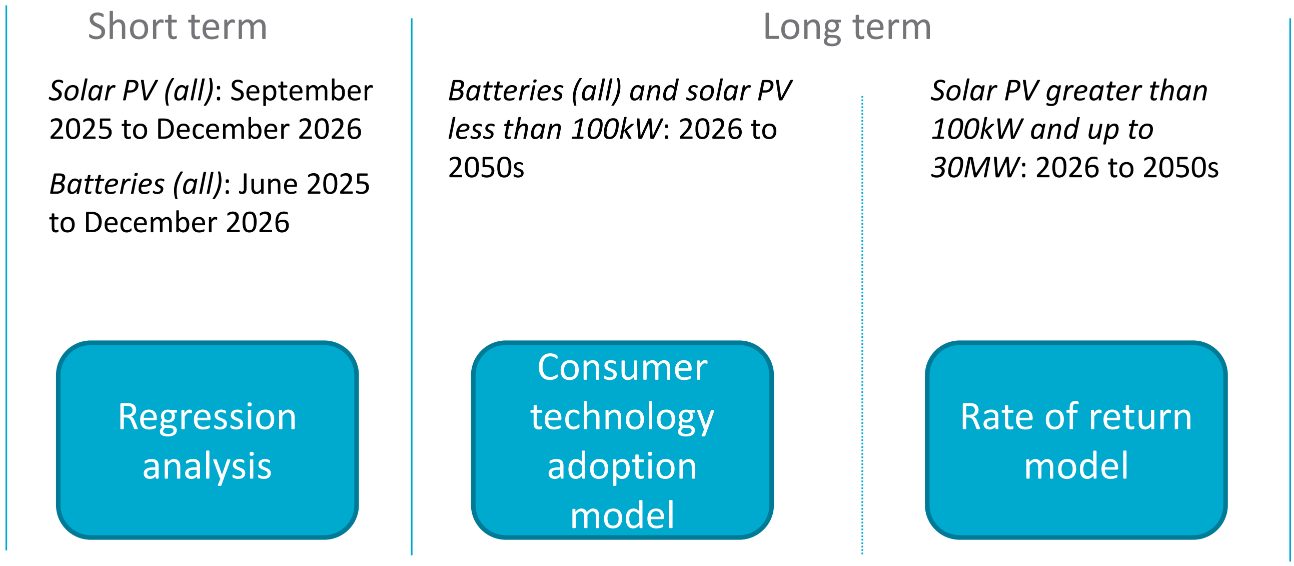

Figure 2-1 Short- and long-term projection approaches applied to the technology groups

Based on these observations about the performance of short- and long-term projection approaches, and our need to deliver both long and short projections, this report applies a combination of short-term trend models and two types of long-term projection models depending on the size of the technology (Figure 2-1).

2.1.1 Short-term trend model

From the point where historical data ends[1], trend analysis is applied to produce projections of installations[2] to December 2023. The trend analysis for batteries is not a regression but a simple extrapolation of recent monthly trends due to the large spike in installations caused by recent availability of subsidies. In this case a regression would perform poorly because the current rate of installations is not representative of historical years.

For solar PV, the trend is estimated as a linear regression against 5 years of monthly data with dummy variables against each month to account for trends in monthly sales. A non-linear relationship was explored but was not preferred because the scenarios themselves can be used to impose additional downside or upside risk against the linear trend and as a result explore non-linear outcomes (this is explained further below). The solar PV regression takes the following form:

$$X_m = f(month\ in\ sequence, month\ of\ year\ dummy\ variable)$$

Where X is the (m) monthly activity of either solar PV installations and generation capacity by residential and commercial segments. This requires around 10,000 regressions – two activity types by two customer types by around 2,500 postcodes across the National Electricity Market and the South West Interconnected System. Information from both installations and capacity is also used to observe the short term trends in average system size.

For solar PV systems less than 100kW, regressions are calculated at the postcode level, while the regressions for larger systems are calculated at the state level[3]. For larger non-scheduled solar PV, we also use the monthly data but unlike systems less than 100kW, there will often be several months without a deployment.

The regression results for residential (Figure 2-2) and commercial (Figure 2-3) rooftop solar installations indicate a mostly linear growth trend. As discussed, we only use data back from the last four years to emphasise recent trends in creating the forecast but show earlier data for context. NSW growth has been stronger than other states in recent years. This is consistent with being at a lower point on the consumer technology adoption curve.

Around August 2025 for solar and June 2025 for batteries when this report was being developed. In both cases the data is supplied by AEMO based mainly on Clean Energy Regulator data.

[2] We separately make an assumption about solar PV system sizes. As such the projections for the capacity of solar PV is the multiple of the new installations projections and the assumed new system sizes over time added to historical capacity. The system size assumptions are outlined in Section 4.2.

[3] Postcode level installations of larger scale systems are too infrequent to support trend analysis at that level.

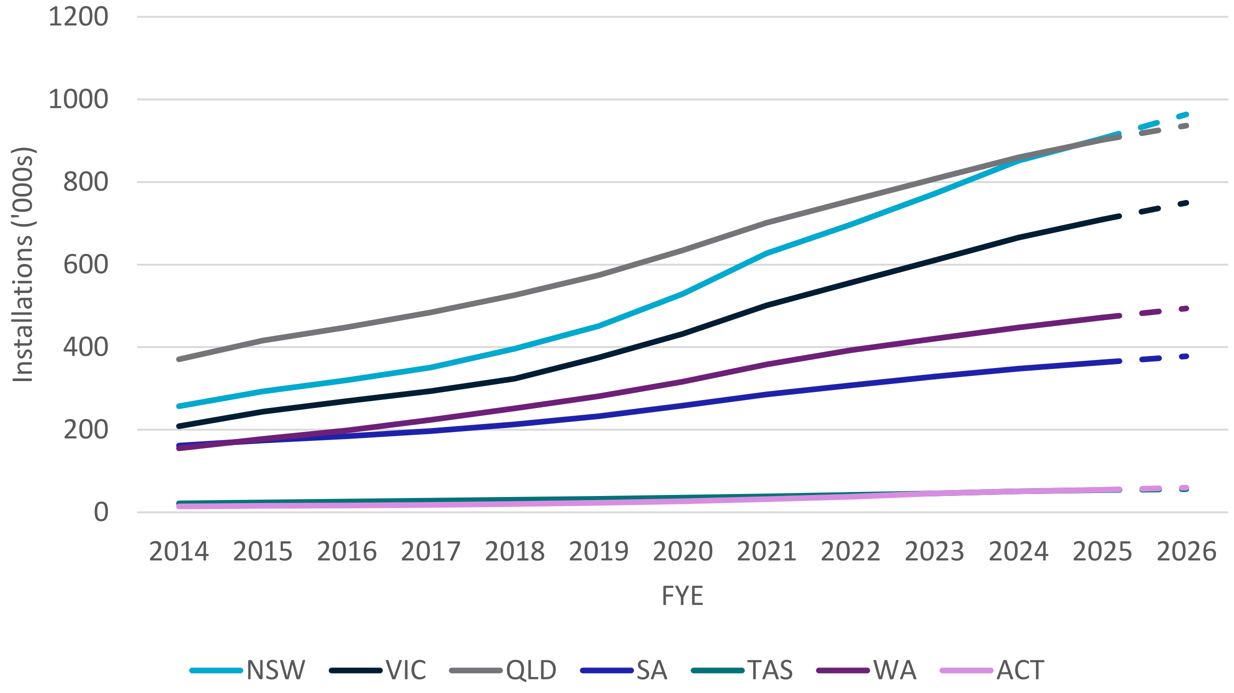

Figure 2-2 Regression results for residential rooftop solar installations by region

Commercial systems have not followed residential systems in terms of state rankings. NSW commercial installations have been below Victoria but recently caught up. South Australia also has relatively higher ranking for commercial installations than in residential installations.

These trends are applied differently to each scenario by applying differing scale factors to the December 2026 projection and linearly interpolating that factor back to August 2025. This approach allows for the possibility that some scenarios will grow faster or slower than a linear trend and creates a short-term uncertainty range. The scale factors themselves hold no particular meaning. Rather they are designed such that for both residential and commercial systems *Slower Growth* is slower than the current trend, *Step Change* continues the current trend and *Accelerated Transition* exceeds the current trend (the scenarios are outlined in more detail in Section 3).

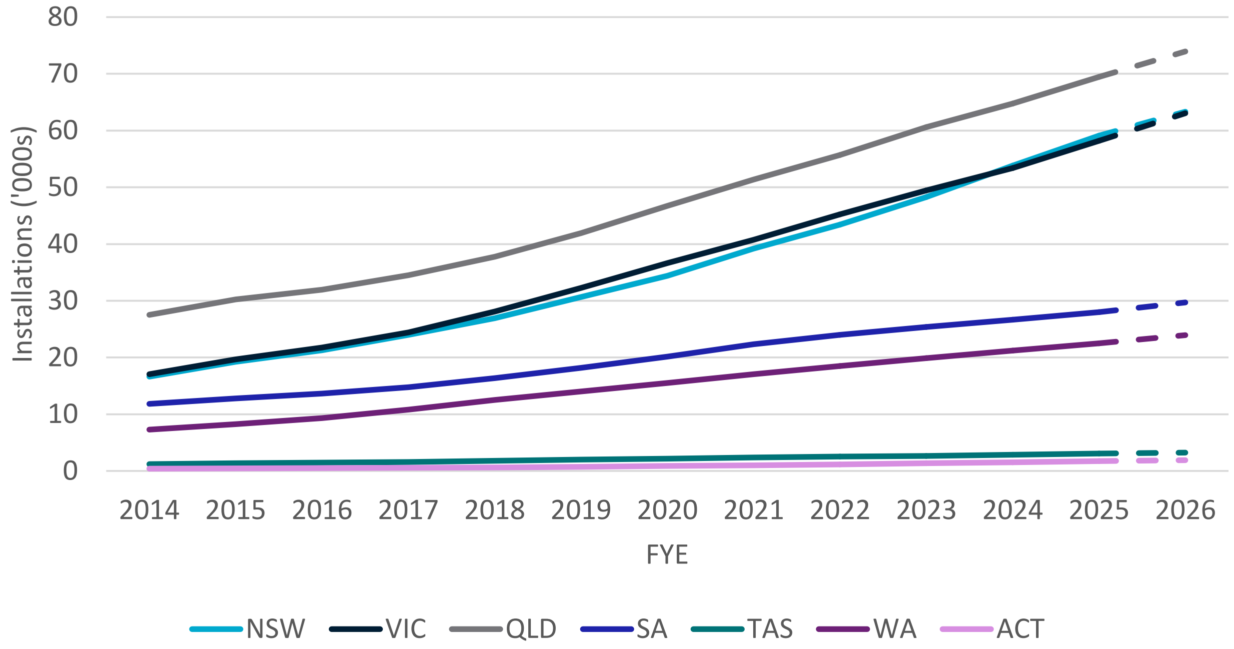

Figure 2-3 Regression results for commercial (<100kw) rooftop solar installations by region

2.1.2 Consumer technology adoption model

The consumer technology adoption curve is a whole of market scale property that we can exploit for the purposes of projecting adoption, particularly in markets for new products. The theory posits that technology adoption will be led by an early adopter group who, despite high payback periods, are driven to invest by other motivations such as values, autonomy and enthusiasm for new technologies. As time passes, fast followers or the early majority take over and create the most rapid period of adoption. In the latter stages, the late majority or late followers may still be holding back due to constraints they may not be able to nor wish to overcome, even if the product is attractively priced. These early concepts were developed by authors such as Rogers (1962) and Bass (1969).

In the last 50 years, a range of market analysts seeking to use the concept as a projection tool have experimented with a combination of price and non-price drivers to calibrate the shape of the adoption curve for any given context. Price can be included directly or as a payback period or return on investment. Payback periods are relatively straightforward to calculate and compared to price also capture the opportunity cost of staying with the existing technology substitute. A more difficult task is to identity the set of non-price demographic or other factors that are necessary to capture other reasons which might motivate a population to slow or speed up their rate of adoption. CSIRO has previously studied the important non-price factors and validated how the approach of combining payback periods and non-price factors can provide good locational predictive power for rooftop solar and electric vehicles (Higgins et al 2014; Higgins et al 2012).

In Figure 2-4 we highlight the general projection approach including some examples of the demographic or other factors that could be considered for inclusion. We also indicate an important interim step, which is to calibrate the adoption curve at appropriate spatial scales (due to differing demographic characteristics and electricity prices) and across different customer segments (due to differences between customers' electricity load profiles which are discussed in Appendix A).

Once the adoption curve is calibrated for all the relevant factors, we can evolve the rate of adoption over time by altering the inputs according to the scenario assumptions. For example, differences in technology costs and prices between scenarios alter the payback period and lead to a different position on the adoption curve. Note that unlike a traditional x-axis (or horizontal axis), the payback period starts at the current level and is declining along the x-axis, not increasing.

Non-price scenario assumptions such as available roof space in a region result in different adoption curve shapes (particularly the height at saturation). Data on existing market shares (after it has been extrapolated forward by the trend analysis) determines the starting point on the adoption curve.

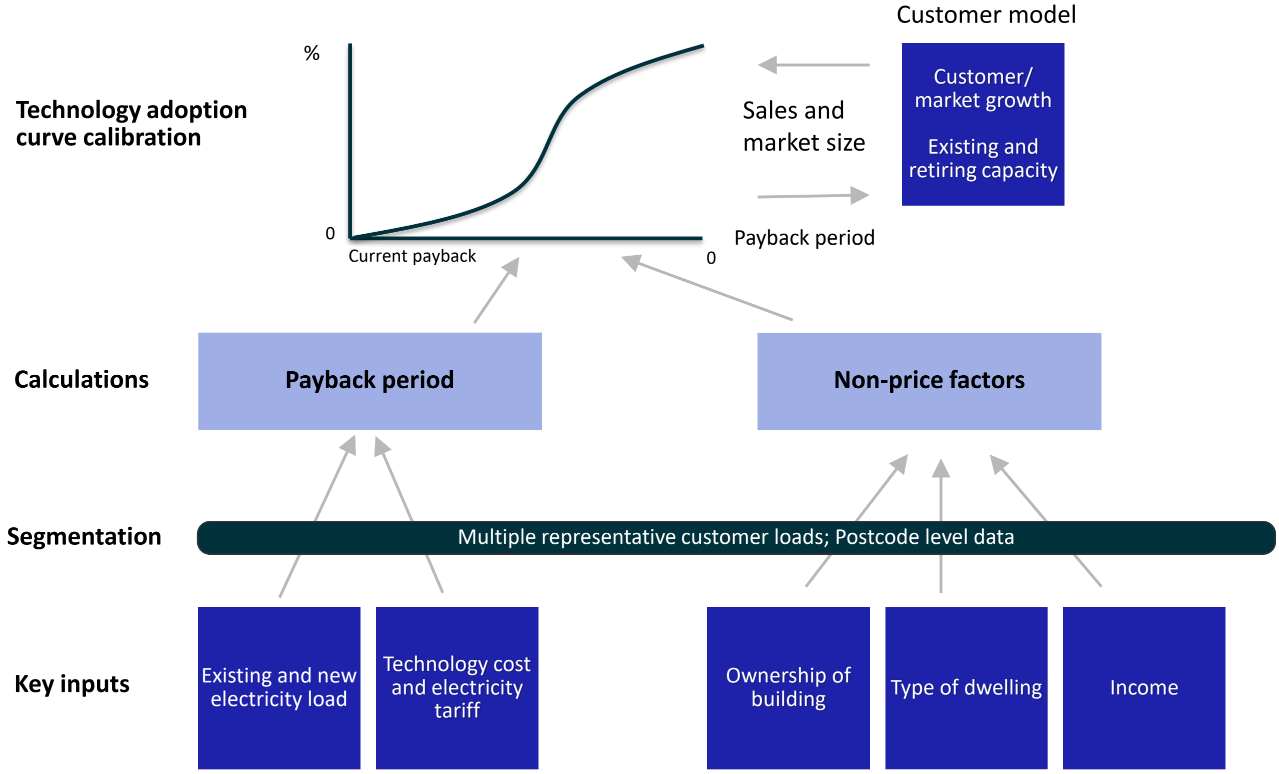

Figure 2-4 Adoption model methodology overview

The methodology also considers the total available market size, which can differ between scenarios. While we may set a maximum market share for the adoption curve based on various non-financial constraints, maximum market share is only reached if the payback period falls. However, we also include some minimum progression in installations in the methodology, and the total number of households are also growing each year. Maximum market share assumptions are outlined in the Data Assumptions section (Table 4-3).

All calculations are carried out at the postcode level, but results are presented here at the state or NEM level for brevity by aggregating the appropriate postcodes.

The above technology adoption curve model is used for storage and all solar installations below 100kW. We regard these technology markets as "consumer" markets in the sense that investment decisions are driven by a combination of financial and non-financial drivers so that adoption will broadly follow the consumer technology adoption curve. For larger solar installations, we take the view that such decisions should be regarded as more purely financial investment decisions, therefore we apply the more financially driven "rate-of-return" model as described in the following section.

2.1.3 Rate of return model (larger-scale installations)

For projecting solar panel installations and capacity above 100kW and up to 30MW, we employ a different approach. The difference in approach is justified on the basis that larger projects require special purpose financing and, as such, are less influenced by non-financial factors in terms of the decision to proceed with a project. In other words, financiers will be primarily concerned with the project achieving its required return on investment when determining whether the project will receive financing. Commercial customer equity financing is of course possible, but it is more common that businesses have a wide range of important demands on available equity, so this is only a very limited source of funding (as compared to being the main source of small-scale solar investment).

The projected uptake of solar panels between 100kW and 30MW is based on determining whether the return on investment for different size systems meets a required rate of return threshold. If they do, investment proceeds in that year and region. For less than 5MW capacity generation, we assume investment proceeds if revenue is 10% higher than that which would have been required to break even. For plants with generation capacity larger than 5MW, we assume that revenue must be sustained at this rate of return for more than five years (does not need to be consecutive)[4]. Solar generation costs, electricity prices and any additional available renewable energy credits are the strongest drivers of the rate of return. Where investment can proceed, we impose a build limit rate based on an assessment of past construction rates and typical land/building stock cycles.

2.2 Demographic factors and weights

The projection methodology includes three non-price factors (see Table 2-1) drawn from accessible demographic data to calibrate the consumer technology adoption curve. Our methodology assigns different weights to each factor to reflect their relative importance. The multiple of the weights by the postcode level demographic data is used to create a demographic score for that postcode. The demographic score is used as part of the calibration of the local maximum market share. The set of factors and weights as shown in Table 2-1 and was estimated to reasonably approximate historical deployment.

Reliable battery storage sales data is not available below the state or territory level. Consequently, it is not possible to calculate a set of historically validated combination of weights and factors. In

[4] These factors represent CSIRO's own judgement. They are essentially trying to capture the premium that might be required to overcome two concepts in investment theory – risk and competing investment options. More revenue upside sustained over a longer period of time can help to offset downside risks in an expected net present value analysis. Furthermore, higher and sustained revenue upside makes a project more likely to be selected for investment when there are several competing investment opportunities which is often the case for any business venture.

the absence of such data, we assume the same weights apply to battery storage as for rooftop solar.

Table 2-1 Weights and factors for residential rooftop solar and battery storage

Factor	Weight
Average income	0.25
Share of separate dwelling households	1
Share of owned or mortgaged households	0.25

For commercial systems less than 100kW we do not apply any demographic weights since none were found to be highly explanatory. However, the existing location of commercial systems tends to be a strong indicator of future deployment in a postcode region. Besides commercial businesses clustering together, this could also indicate a network effect whereby awareness of deployment of solar neighbours inspires adoption.

3 Scenario definitions

The three scenarios defined in this section are *Slower Growth*, *Step Change* and *Accelerated Transition*. The AEMO scenario definitions are described in narrative form and then by their key drivers in Table 3-1. Further detail is available in AEMO (2025). To implement the solar and battery projections, CSIRO has developed an additional set of extended scenario definitions based on more detailed road transport sector drivers that are covered in the broader scenario design process.

3.1.1 AEMO's scenario narratives and definitions

Slower Growth

This scenario 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. Amidst 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 naturally lower due to the weaker economic circumstances, and consumers lower their enthusiasm for offering their assets to third-party coordination.

Step Change

This scenario 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 consumer energy resources (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 electric vehicles) 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 this scenario, relative to the 2023 IASR's *Step Change*. In this scenario, Australia's economy grows similar to historical trends, while emerging trends in artificial intelligence and other data-heavy applications encourage growth in data centres in Australia.

Accelerated Transition

This scenario 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 3-1 AEMO scenario definitions (current at time of modelling)

	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
Electrification	Electrification is tailored to meet existing emissions reduction commitments, with slower adoption given weaker economic circumstances	High electrification to meet emissions reduction commitments, with pace of adoption reflecting economic conditions	Higher electrification efforts to meet aggressive emissions reduction objectives, with faster pace of adoption
Emerging commercial and industrial loads	Emerging sectors such as data centres experience lower growth as weaker economic circumstances limit technology uptake	Emerging sectors such as data centres match opportunities associated with moderate domestic economic drivers	Emerging sectors such as data centres match opportunities associated with higher domestic economic drivers
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
Energy efficiency	Moderate	High	Higher

Hydrogen use and availability	Low production for domestic use, with no export hydrogen	Moderate-low production for domestic use, with no export hydrogen	Moderate production for domestic industries and green commodities, with no export hydrogen
Industrial load closures	Weak economic conditions provide challenging commercial conditions, resulting in closures of industrial loads	No specific load closures	No specific load closures
Demand-side participation uptake	Lower	Moderate	Higher
CER investments (batteries, PV and EVs)	Lower	High	Higher
Renewable gas blending in the gas distribution network (vol%)	Up to 5% hydrogen blending by 2050, with unlimited blending opportunity for biomethane and other renewable gases	Up to 2% hydrogen blending by 2050, with unlimited blending opportunity for biomethane and other renewable gases	Negligible hydrogen blending by 2050, with unlimited blending opportunity for biomethane and other renewable gases
Potential for supply chain limitations affecting demand forecasts	High	Moderate	Low
Global/domestic temperature settings and outcomes	Applies Representative Concentration Pathway (RCP) 4.5 where relevant, consistent with a global temperature rise of ~ 2.6°C by 2100	Applies RCP 2.6 where relevant, consistent with a global temperature rise of ~ 1.8°C by 2100	Applies Representative Concentration Pathway (RCP) 1.9 where relevant, consistent with a global temperature rise of ~ 1.5°C by 2100
International Energy Agency (IEA) 2024 World Energy Outlook scenario alignment	Stated Policies Scenario (STEPS)	Announced Pledges Scenario (APS)	Net Zero Emissions by 2050 NZE

3.2 Financial and non-financial scenario drivers

In addition to the scenario assumptions defined above, the scenarios also explore uncertainty in various financial and non-financial drivers.

3.2.1 Direct economic drivers

Whilst the general buoyancy of the economy is a factor in projecting adoption of small-scale technologies, here we are concerned with the direct financial costs and returns. The key economic drivers which alter the outlook for rooftop solar and battery storage adoption scenarios are shown in Table 3-2.

Table 3-2 Economic drivers of rooftop solar and batteries and approach to including them in scenarios

Driver	Approach to including in scenarios
Any available subsidies or low interest loans	Outlined in Section 3.2.4 and 3.2.5
Installed cost of rooftop solar and battery storage systems and any additional components such as advanced metering	Varied by scenario and outlined in Section 4.1.1 and 4.1.3
Current and perceived future level of retail electricity prices	Varied by scenario and outlined in Section 4.4.1
The level of feed in tariffs (FiTs) which are paid for exports of rooftop solar electricity and wholesale (generation) prices which may influence the future level of FiTs	FiTs sourced from solar PV production time weighted wholesale prices.
The shape of the customer's load curve	Not varied by scenario but a range of representative customers are included. See Appendix A

3.2.2 Infrastructure drivers

One of the key reasons for the already significant adoption of rooftop solar has been its ease of integrating with existing building infrastructure. Battery storage has also been designed to be relatively easily incorporated into existing spaces. However, there are some infrastructure limitations which are relevant over the longer term.

Table 3-3 Infrastructure drivers for rooftop solar and battery systems and approach to including them in scenarios

Driver	Approach to including in scenarios
The quantity of residential or commercial roof space or vacant adjacent land, of varying orientation, ideally free of shading relative to the customer's energy needs (rooftop solar)	Varied by scenario and expressed as maximum market share constraints in Section 4.7
Garage or indoor space, ideally air conditioned, shaded and ventilated (battery storage)	Varied by scenario and expressed as maximum market share constraints in Section 4.7
The quantity of buildings with appropriate roof and indoor space that are owned or mortgaged by the occupant, with an intention to stay at that location (and who therefore would be able to enjoy the	Varied by scenario and expressed as maximum market share constraints in Section 4.7

benefits of any longer-term payback from solar or integrated solar and storage systems)	
Distribution network constraints relating to connection of solar photovoltaic projects in the 1MW to 30MW range	A common limit applied to all scenarios
The degree to which the NEM and WEM management of security and reliability begins to place limits on the amount of large- and small-scale variable renewables that can be accepted during peak supply and low demand periods (e.g., to maintain a minimum amount of dispatchable or FCAS serving plant)	AEMO has commissioned a relatively unconstrained projection from CSIRO with the aim of managing this issue downstream of forecasting, within the ISP process.
The degree to which solar can be integrated into building structures (flat plate is widely applicable but alternative materials, such as thin film solar, could extend the amount of usable roof space)	Varied by scenario and expressed as maximum market share constraints in Section 4.6

3.2.3 Disruptive business model drivers

New business models can disrupt economic and infrastructure constraints by changing the conditions under which a customer might consider adopting a technology. Table 3-4 explores some emerging and potential business models which could drive higher adoption. The degree to which these potential business model developments apply by scenario is expressed primarily through their ability to change the maximum saturation levels for rooftop solar PV and batteries as outlined in Section 4.6.

Virtual power plants are an example of an existing business model that incentivises further uptake of batteries by providing greater value from the battery than simply shifting local solar generation.

Table 3-4 Emerging or potential disruptive business models to support solar and battery adoption

Name	Description	Constraint reduced
Building as retailer	Apartment, car park or shopping centre building body corporate as retailer	Rooftop solar is more suitable for deployment in dwellings which have a separate roof
Peer-to-peer	Peer-to-peer selling as an alternative to selling to a retailer	Owners may generate more from solar if they could trade directly with a related entity (e.g., landlords and renters, corporation with multiple buildings, families and

Name	Description	Constraint reduced
		neighbours) without a retailer distorting price reconciliation
Landlord-tenant intermediary	An intermediary (such as the government) sets up an agreement for cost and benefit sharing	Neither the landlord nor tenant are adequately incentivised to adopt solar because neither party can be assured of accessing the full benefits.
Virtual power plant	Retailers, aggregators, networks or an independent market operator reward demand management through direct payments, alternative tariff structures or direct ownership and operation of battery to reduce costs elsewhere in the system	Given the predominance of volume-based tariffs, the main value for customers of battery storage is in reducing rooftop solar exports. The appetite for demand management participation could be more directly targeted than current incentives.
Going off-grid	Standalone power system is delivered at lower cost than new distribution level connections greater than 1km from existing grid and decreasing over time (e.g., WA[5])	Except for remote area power systems and edge of grid, it is cost effective to connect all other customers to the grid
Solar/battery new housing packages	New housing developments include integrated solar and batteries on new housing either as a branding tool and to reduce distribution network connection costs or due to building code mandates	Integrated solar and battery systems represent a discretionary and high upfront cost
Vehicle battery second life	Electric vehicle batteries are sold as low-cost home batteries as a second life application	Battery storage represents a high upfront cost and discretionary investment.

[5] https://www.westernpower.com.au/our-energy-evolution/grid-technology/stand-alone-power-system/

3.2.4 Existing Commonwealth policy drivers

CSIRO have followed the policy inclusion as detailed in AEMO's Stage 1 Draft 2025 Input, Assumptions and Scenarios Report, whereby policies and targets listed in the AEMC (2025) *Emissions targets statement* under the national energy laws are included in the forecast.

There are a variety of commonwealth policy drivers which impact solar and battery adoption. We outline how we have chosen to include them and describe them in further detail below.

Table 3-5 Summary of Commonwealth policies and their inclusion in scenarios

Policy	Approach to including in scenarios
Small-scale renewable energy scheme	Assumed to continue as planned to 2030 in all scenarios
Large scale renewable energy target	Certificate prices maintained at current levels
Australian Carbon Credit Unit (ACCU) Scheme	Available to PVNSG phasing down to 2035

Small-scale Renewable Energy Scheme and Large-scale Renewable Energy Target

Rooftop solar currently receives a subsidy under the Small-scale Renewable Energy Scheme whereby rooftop solar is credited with creating small scale technology certificates (STCs) which Renewable Energy Target (RET) liable entities have a legal obligation to buy. Rooftop solar purchases typically surrender their rights to these certificates in return for a lower upfront cost. The amount of STCs accredited is calculated using a formula that recognises location/climate, based on the renewable electricity generation that will occur over the life of the installation. The amount of STCs accredited to rooftop solar installation will decline over time to reflect the fact that the Renewable Energy Target policy closes in 2030 and therefore renewable electricity generated beyond that time is of no value in the scheme.

STCs can be sold to the Clean Energy Regulator (CER) through the STC Clearing House for $40 each. However, the CER makes no guarantees about how quickly a sale will occur. Consequently, most STCs are sold at a small discount directly to liable entities on the STC open market.

The Large-scale Renewable Energy Target (LRET) is a requirement on retailers to purchase large-scale generation certificates (LGCs). This represents a subsidy for large scale renewable generation but is relevant for any solar system above 100kW as they are not eligible for STCs. In this report we are interested in any solar system up to 30MW, hence the price of LGCs is a relevant driver for adoption. The requirements for the LRET are largely met within existing and under construction plant as the target currently plateaus from 2020 and remains at that level until 2030. However, the LGC price or an equivalent mechanism is expected to be maintained at least through to 2030 due to additional demand from voluntary corporate and other institutional renewable generation targets[6]. Beyond 2030 their value is expected to decline because the purpose of voluntary targets beyond 2030 will be less clear once the wider electricity system becomes less emission intensive.

Australian Carbon Credit Unit (ACCU) Scheme

Historically the government was the sole buyer of ACCUs under schemes such as The Emissions Reduction Fund (ERF) and Climate Solutions Fund. However, under voluntary schemes and a revised safeguards mechanism industry has now the largest buyer. The supply of ACCUs is developed based on several methods for emission reduction under which projects may be eligible to claim emission reduction and make offers for ACCUs.

To earn ACCUs from solar generation, the relevant method in this case is the *Carbon Credits (Carbon Farming Initiative - Industrial Electricity and Fuel Efficiency) Methodology Determination 2015*. Their abatement is measured against grid electricity and so the abatement potential of solar is declining as grid emissions decline. It is assumed that incentives from this scheme are effectively zero post-2035.

3.2.5 State policy drivers

The Victorian government is providing a subsidy for solar systems of $1400 for households and means-tested interest free loans. Another feature is a landlord-tenant agreement whereby renters can also access the scheme.

Large Victorian solar projects are also eligible for Victorian Energy Efficiency Certificates (VEECs). These are administratively less complex than applying for ACCUs. As with the emissions reduction fund, this potential subsidy source will become attractive only once LGC prices have declined. Like ACCUs their value is phased down to zero post-2035.

Feed-in tariffs

Feed-in tariffs (FiTs) were historically provided by most state governments to support rooftop solar adoption but have largely been replaced by voluntary retailer set FiTs for new solar customers. These legacy government FiTs are in some cases still being received by those customers who took them up when they were available.

The current FiTs set by retailers recognise some combination of the value of the exported solar electricity to the retailer and the value to the retailer of retaining a rooftop solar customer. Retailer designed FiTs vary mostly in the range of 3-7 c/kWh across most states but there are some large outliers.

The exceptions, where state government policy or state-owned retailers set the FiT, are as follows:

- Queensland: Recognising lower competition, regional Queensland FiTs are set by the state government and were 8.66c/kWh from July 2025[7].

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[6] Businesses buy LGCs as part of meeting their upstream 2030 corporate emission targets. These voluntary actions are in addition to electricity retailer obligations which end in 2030. Business demand for LGCs or another equivalent certificate not yet available may not end in 2030 because if it did than many businesses would need to report that their upstream emissions have increased post-2030 (unless they can find alternative offsets).

[7] https://www.qca.org.au/wp-content/uploads/2024/12/solar-fit-fact-sheet.pdf

- Western Australia: The Distributed Energy Buyback Scheme will pay[8]:
    - 2 cents for each kilowatt-hour of solar electricity fed into the grid for most of the day, and
    - 10 cents for each kilowatt-hour exported from 3:00 pm in the afternoon until 9:00 in the evening.

  This averages about 3c/kWh.
- Victoria: The current minimum feed-in tariff of 4c/kWh is set by the government[9]. It applies to retailers with more than 5000 customers and generation from any renewable energy less than 100kW. A time varying feed-in rate is also available from July 2024 with prices of between 0 and 6.57c/kWh depending on the time of day.
- Tasmania: The feed-in tariff for residential and commercial customers is 8.782c/kWh from July 2025[10].

While not binding on retailers, the NSW government has called on NSW energy retailers to offer solar customers feed-in tariffs that meet a benchmark set by the Independent Pricing and Regulatory Tribunal (IPART). The benchmark range for the 2024-25 financial year is 4.8 to 7.3c/kWh [11]. It also advises on time of day rates ranging from 3.1 to 37.6c/kWh.

3.2.6 Regulations, standards and curtailment

The Australian Energy Market Commission (AEMC) can make changes to regulations which are consistent with the goals set out in relevant electricity law. In general, the electricity market rules were written at a time that did not envisage such a large and competitive role for customer energy resources. The current customer obligations placed on networks are focussed on reliability of supply and power quality. There is no explicit statement to ensure that customers with rooftop solar can export their excess generation, although this does intersect with power quality requirements. If too many embedded solar systems try to export generation relative to local demand, then voltage rises. Inverters are set to trip off solar generation once voltage exceeds the set point, which then reduces the returns to customers from owning rooftop solar.

The technical specification of many older installed inverters was not as high as they could have been to address the issue of voltage rise. Improved inverter standards, if appropriately set when installed, will contribute to reducing the occurrence of voltage issues associated with high rooftop solar exports onto the local distribution network. They provide reactive power which limits the impact of exports on voltage. However, if rooftop solar penetration is very high (the exact limit depends on the feeder), improved inverters will be unable to continually prevent voltage changes that result in inverter trip off. Also, reactive power uses 20% of the available real power and so still

[8] Energy Buyback Schemes (www.wa.gov.au)

[9] https://engage.vic.gov.au/minimum-feed-in-tariff-review-202526

[10] https://www.economicregulator.tas.gov.au/electricity/pricing/feed-in-tariffs#:~:text=From%201%20July%202025%2C%20the,is%208.782%20cents%20per%20kWh.

[11] All day solar feed-in tariffs | IPART (nsw.gov.au)

represents an impact on rooftop solar customer returns from a lack of distribution network capacity.

Operational demand experience and projections have identified that some states are at risk of negative load without intervention from the system operator. This results in the need for some combination of curtailment, demand management and standby generation to maintain system stability.

It is difficult to predict the electricity system reform process and subsequent impacts on customers, regarding the degree of lost solar production and exports as a result of distribution network congestion or efforts to manage state loads for stability. AEMO has indicated that, in response to feedback on this topic, they intend to manage the process of estimating optimal levels of curtailment of the system relative to the net benefits of increase penetration of consumer energy resources downstream in the ISP process. We therefore avoid double accounting of this issue and make no judgements on physical curtailment in the assumptions or projections herein.

However, we do impose a financial penalty of declining export revenues which impact the overall payback period from installing solar PV (if without storage). The declining export revenue assumption is designed to capture declining feed-in tariffs and potential export fees.

4 Data assumptions

This section outlines the key data assumptions applied to implement the scenarios. Some additional data assumptions which are used in all scenarios are described in Appendix A.

4.1 Technology costs

4.1.1 Solar photovoltaic panels and installation

The costs of installed rooftop or small-scale solar installations for each scenario is shown in Figure 4-1 and compared to previous assumptions in CSIRO's 2024 projections. The updated costs are sourced from the GenCost 2024-25 final report by Graham et al. (2025)[12]. The GenCost report contains three global cost projection scenarios called Current policies, Global NZE post 2050 and Global NZE by 2050. *Slower Growth* is assigned the Current policies cost projections and *Step Change* is assigned Global NZE post 2050 cost projections. *Accelerated Transition* is assigned the fastest cost reduction projection which is Global NZE by 2050.

There are two key trends the updated data. Solar PV has recovered faster than expected from the recent global supply chain constraints that temporarily increased the cost of most energy technologies in recent years. This, together with larger systems, has resulted in lower near term capital costs. The second trend is that GenCost has introduced a lower rate of improvement in installation costs. This reflects the view that rooftop solar PV is a mature industry and consequently has fewer opportunities to deliver further costs reductions in the installation component of capital costs.

[12] Some adjustments have been made to the GenCost data series. In collaboration with AEMO, the exact levels are adjusted to match other information sources that are more recent such as Solar Choice given GenCost 2024-25 is based on July 2024 observed costs.

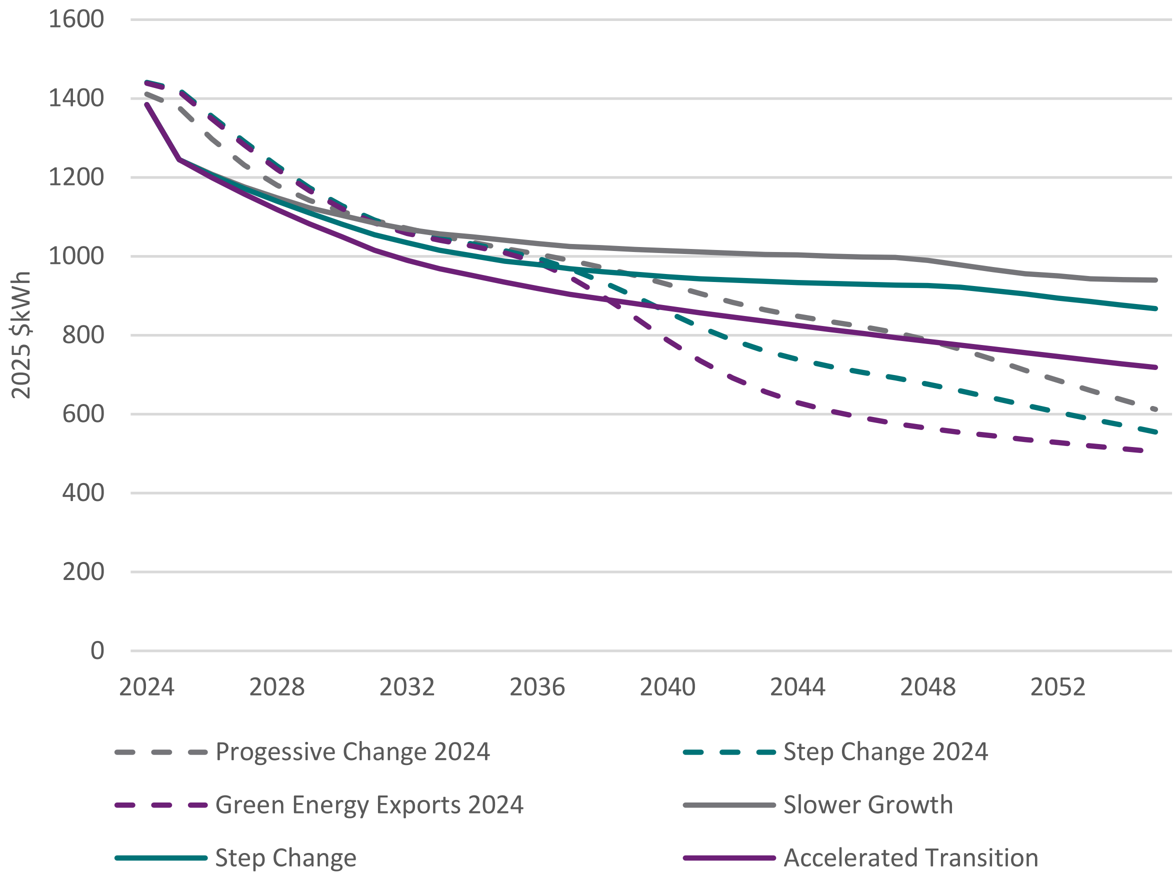

Figure 4-1 Assumed capital costs for rooftop and small-scale solar installations by scenario (excluding STCs or other subsidies)

4.1.2 Small-scale technology certificates (STCs)

STCs reduce the upfront cost of rooftop solar systems beyond that shown in Figure 4-1. While there is the option to sell to the STC Clearing House for $40/MWh, the value of STCs is largely determined on the open market and vary according to demand and supply for certificates. The number of certificates generated depends roughly on the solar capacity factor in different states although this calculation is not spatially detailed (i.e., involves some significant averaging across large areas). Solar generation is calculated over the lifetime, but any life beyond calendar year 2030 is not counted as it is beyond the scheme period. Over time the eligible solar generation is declining. Multiplying the eligible rooftop solar generation by the STC price gives the projected STC subsidy by state shown in Figure 4-2. These STC subsidies are assumed to prevail across all scenarios ending in December of financial year 2030-31.

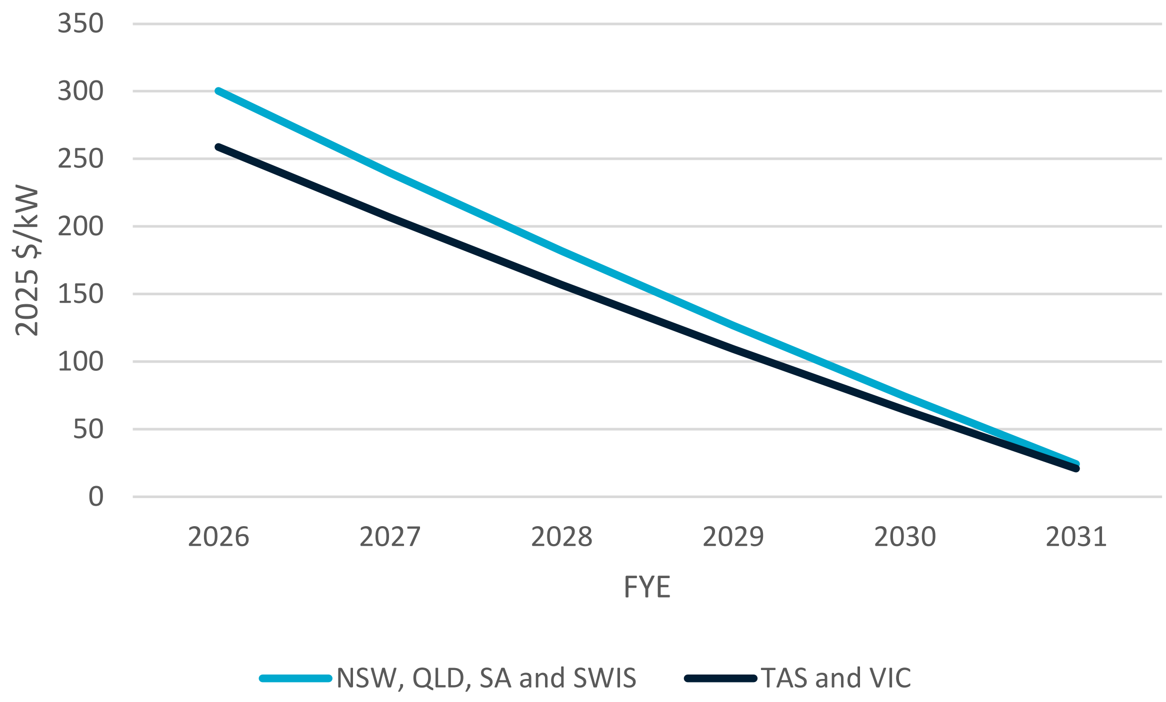

Figure 4-2 Assumed STC subsidy available to rooftop solar and small-scale solar systems by state

4.1.3 Batteries

GenCost does not supply a small-scale battery projection. In the 2024 scenario projections, CSIRO used the large-scale battery projection but modified it to be more linear recognising that small-scale batteries had historically not kept up with large-scale battery changes.

In the revised projection, the trend reverts to the large-scale battery pathway. This recognises that the small-scale sector is currently undergoing major deployment that is likely to deliver competition and installation cost learning and experience that was previously not as strong.

These are upfront battery capital costs and do not take account of degradation or cost of disposal at end of life. Asset life and degradation assumptions are included in the modelling and are outlined in Appendix A. Currently most batteries can be sent to battery collection points at end of life free of charge. Lithium-ion battery recycling facilities have emerged in countries that have more mature battery deployment (e.g. Norway which has a large electric vehicle fleet as the feedstock source). The lithium recycling industry in Australia will not be able to reach scale until there are more end of life batteries to recycle therefore it is difficult to say whether there will be any new charges associated with their recycling. Consequently, at this point it is not appropriate to add any battery disposal costs.

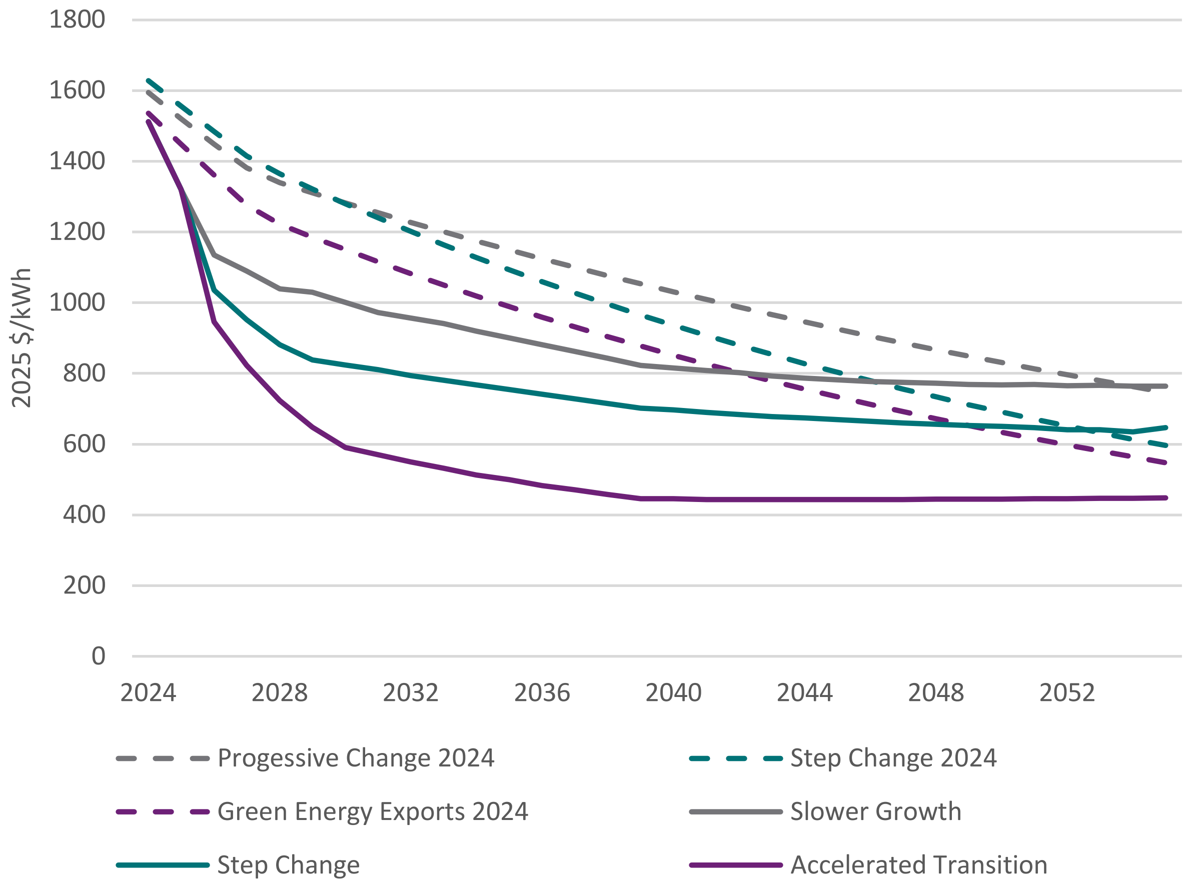

Figure 4-3 Assumed capital costs for battery storage installations by scenario

4.2 New solar system sizes (less than 100kW)

Assumed new residential and commercial new solar system sizes as shown in Figure 4-4 and Note: The change reflects a change in historical categorisation of solar PV systems rather than commercial system size preferences

Figure 4-6 and compared to the 2022 projections. These are the size of the panels, while inverters are the same size or smaller.

Residential rooftop solar systems are advertised with panel to inverter capacity ratios greater than 1. This likely reflects the fact that subsidies are available on rooftop solar capacity. Licensing conditions for installers require that the inverter is no less than 75% capacity of the solar panels. For example, a 6.6kW solar panel with a 5kW inverter meets this criteria. The average for new residential systems has been above 6.6kW and sits at 9.3kW in 2025[13] (averaged over those systems deployed in that year). This continued increase in residential system sizes supports an assumed increasing trend. However, over the longer term we assume system sizes will begin to plateau and there are a number of considerations supporting that (Figure 4-5).

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[13] Noting that the public CER data does not differentiate between residential and commercial systems and so the average new size for both residential and commercial systems is much higher.

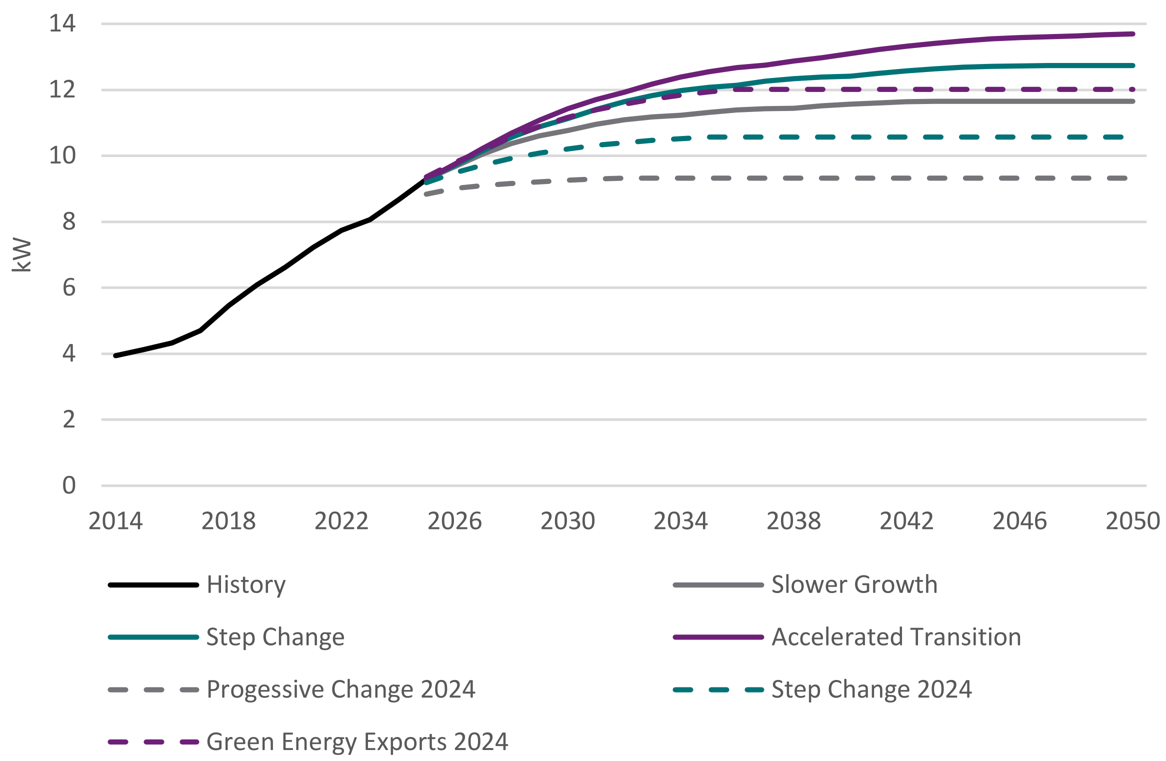


Figure 4-4 Historical and assumed future size of new residential solar systems

Networks are evolving signals they send about their host capacity (the ability of the system to support more distribution connected solar generation without crossing desired power quality thresholds) from kW per phase installation limits to more dynamic operational export limits. This represents a message to consumers that they cannot always use their full capacity for export. Physical roof size is of course another limit to maximum average system size. However, that with lower solar panel costs, improving panel efficiency and acceptance of the use of non-north facing roof areas will allow for continued growth in panel capacity.

Government subsidies per watt of solar power capacity are declining (see discussion of STCs in the body of the report) which could contribute to a slow reduction in attractiveness of larger systems. A 10kW system would provide around 13,000kWh per annum which is more than an average household can use per annum, even considering an expected 50% increase in electricity consumption due to adoption of electric vehicles (average household consumption is currently around 6000kWh). Storage will be more prevalent in the long run and can assist in increasing own consumption but does not create significant new demand as storage losses are low. Larger systems therefore imply significantly more exports at a time when the value of exports are expected to decline owing to congestion and possible export fees.

On a positive note, the recent substantial reduction in battery costs net of subsidies is a supporting factor for larger rooftop solar PV system sizes, reducing the amount needed to be exported.

Based on these drivers, we assume the recent increasing system size trend will eventually slow. For residential customers, *Accelerated Transition* saturates at 13.7kW, *Step Change* at 12.7kW and *Slower Growth* at 11.7kW. These saturation levels are significantly higher than those assumed in the 2024 projections. The higher outlook for system sizes is justified on the basis of the ongoing historical trend and continued reduction in costs which means that the overall system expenditure is not significantly increasing.

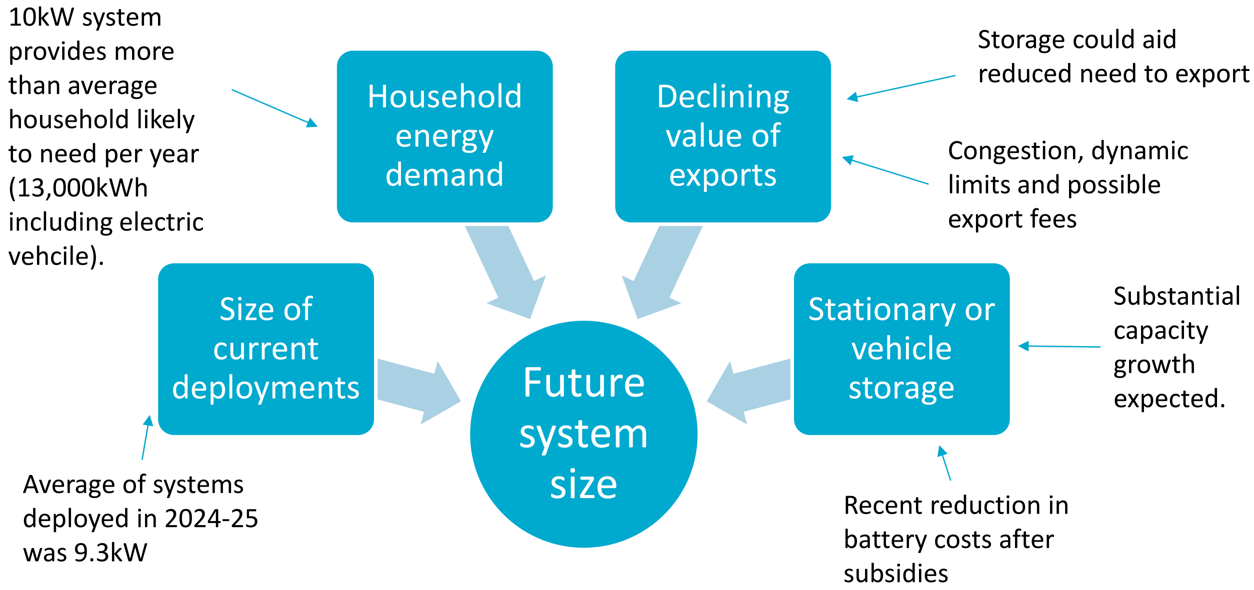
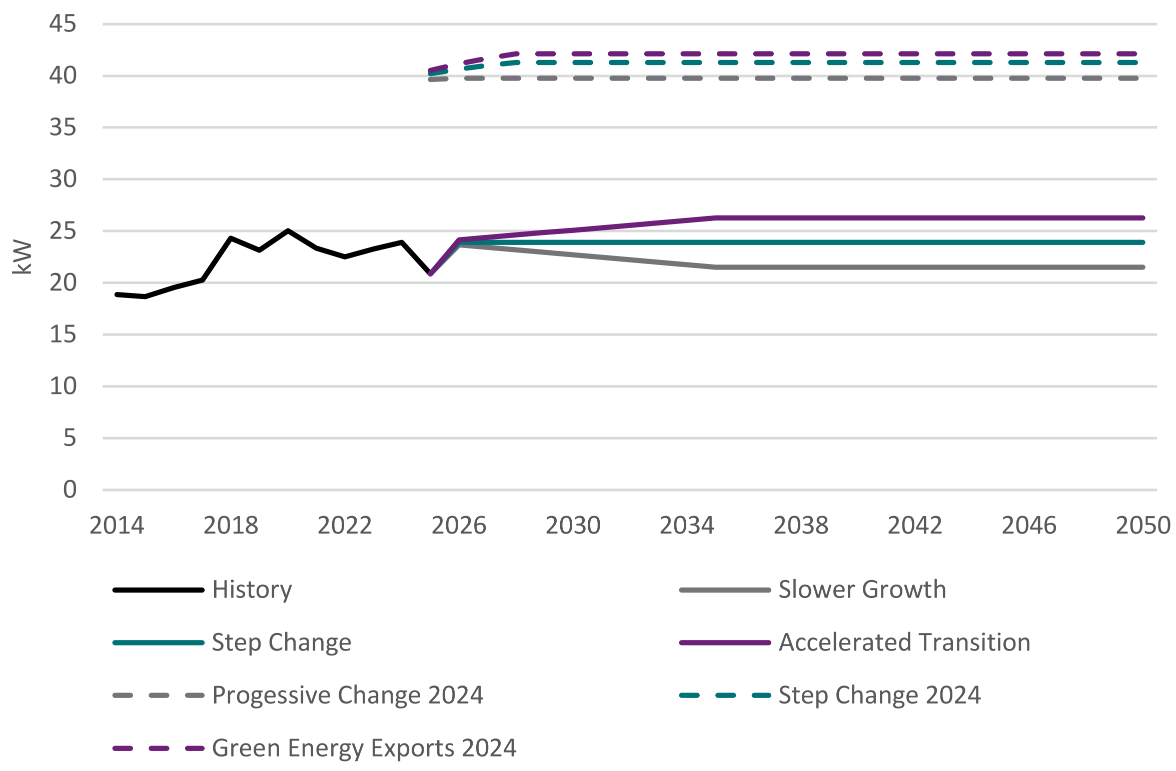


Figure 4-5 Summary of drivers of future solar PV system size

For business customers, while we impose an average trend across all customers, we assume that individual customers will continue to match their solar systems to meet local needs such as supplying their average daily peak-period load. That is, they may be less focussed on earning export revenue, but rather reducing their peak-period time of use charges which are more prevalent in business retail tariffs. For these reasons commercial solar system sizes are assumed to plateau from the beginning rather than follow the growing trend over time in residential systems.

Setting the level of business solar PV systems has been difficult due historical data for both residential and business being assigned the wrong category. This has impacted business more because its market is smaller. A growing trend was evident until around 2020 but that has been partially reversed and flattened in the remaining historical years. For the 2024 projections the range reflected the previous understanding of baseline system sizes and provided a small future range reflecting the uncertainty. The same approach is taken for the updated projections with the range reflecting historical uncertainty based on the new baseline data.



Note: The change reflects a change in historical categorisation of solar PV systems rather than commercial system size preferences

Figure 4-6 Historical and assumed future average size of new commercial solar systems (in the up to 100kW category)

4.3 New battery systems

Battery systems sizes have been historically stable and so typically battery system sizes were assumed to remain constant into the future. However, the deployment of the Cheaper Home Batteries Program has changed the size preferences of battery installations. When subsidies are provided on a per energy capacity basis installer can offer larger system at a lower marginal cost relative to smaller systems since they can attract more subsidy without necessarily increasing the balance of system costs at the same rate. Accordingly early data for 2025-26 has indicated a large jump in battery sizes which is still increasing week on week. This creates a challenge for projecting both current and future battery sizes given the subsidy is slowly declining and ends in 2030.

The assumed trend in average new battery sizes for residential and commercial sectors is shown in Figure 4-7and Figure 4-8 respectively. In the residential sector all projections are higher than the previous assumptions. However, the new assumptions allow for a wide range of potential outcomes during and after the Cheaper Home Batteries Program subsidy concludes. *Accelerated Transition* allows for the possibility that system sizes will continue to increase not only this year but into the following financial year and will be sustained at that level even after the subsidies end. *Step Change* is a mid-range estimate of current system sizes and assumes that system sizes steadily decline as the subsidy declines but somewhat slowly. Slower Growth is a low estimate of current system sizes and assumes that system sizes fall in line with the subsidy timetable stabilising shortly after the program ends.

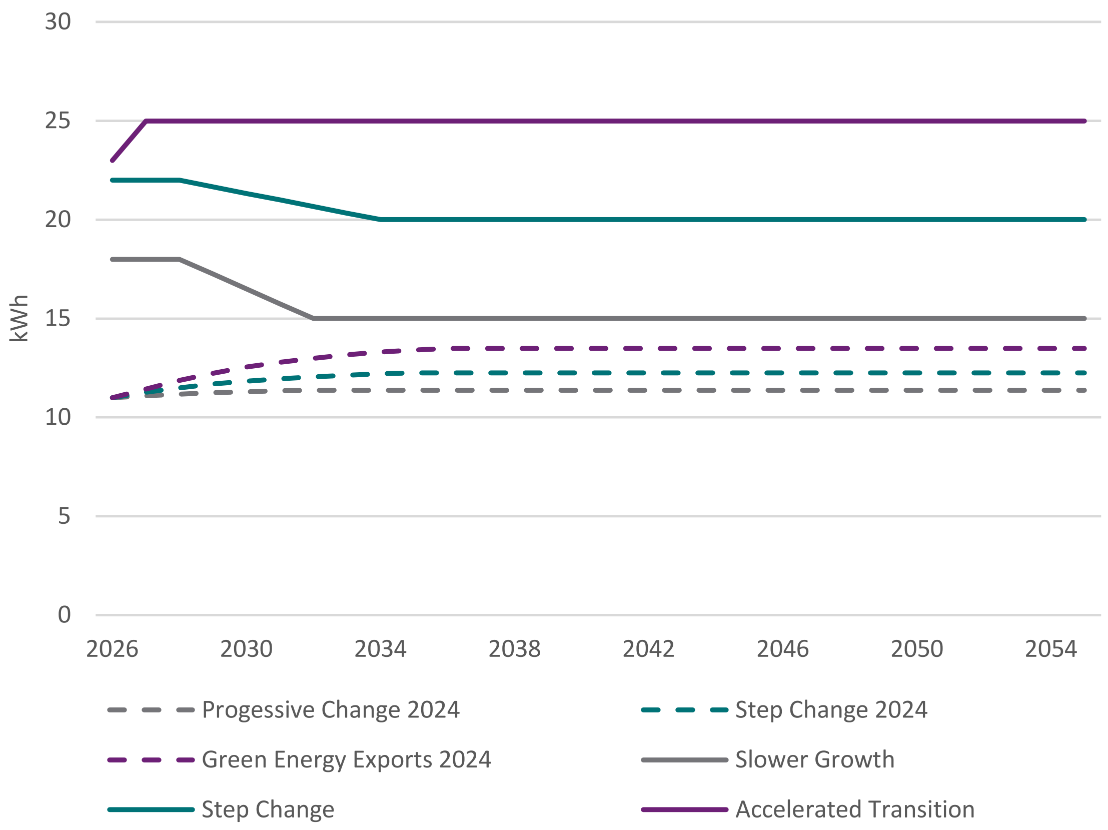


Figure 4-7 Projected new residential battery sizes relative to the 2024 projections

Figure 4-8 Projected new commercial battery sizes relative to the 2024 projections

The commercial sector can only invest in batteries less than 50kW under the Cheaper Home Batteries Program and so this makes for a natural ceiling on the system size assumptions. *Accelerated Transition* is assigned this value as the current average new size and it is assumed to slowly decline. *Step Change* is assigned a mid-range value with the same decline rate. Slower Growth is a low range estimate of the current new commercial system size and has the fastest decline in size, closely following the timeline of the subsidy program. This results in a battery size slightly below the 2024 assumptions which were the same for all scenarios.

4.4 Electricity tariffs, battery management and virtual power plants

4.4.1 Assumed trends in retail and generation prices

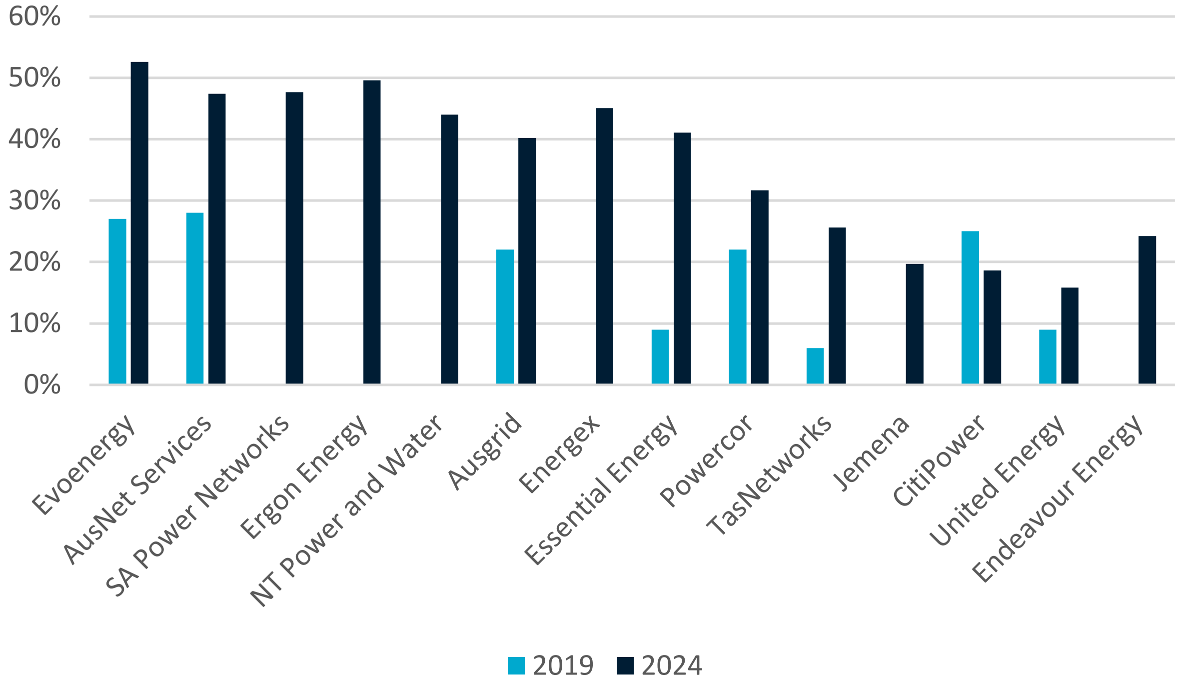
Retail electricity prices increased significantly in recent years reflecting the impact of the Ukraine War on global fossil fuel prices which flowed through to domestic generation costs. Other factors such as generator outages also played a part. Global fossil fuel prices have declined but it will take some time to unwind their impact into forward electricity prices and hedging positions. Modest increases in generation and retail prices are assumed later in the projection period as higher electricity generation prices are required to support investment necessary for replacement of retiring generation capacity and to meet new demand growth.

4.4.2 Current electricity tariff status

Electricity tariff structures are important in determining the return on investment from customer adoption of solar PV and batteries and, perhaps importantly for the electricity system, how they operate those technologies. One type of tariff structure that residential and business customers have is ‘flat’ tariff structure which consists of a daily charge of $0.80 to $1.20 per day and a fee, depending on the region of approximately 25 to 40c for each kWh of electricity consumed regardless of the time of day or season of the year. Customers with rooftop solar will have an additional element which is the feed-in tariff rate for solar exports (see Section 3.2.5). Customers in some states have an additional discounted ‘controlled load’ rate which is typically connected to hot water systems.

The second group of tariffs are ‘time-of-use’ (TOU) or ‘demand’ tariffs with TOU being more common. In addition to a daily charge, TOU tariffs specify different per-kWh rates for different times of day. Demand tariffs impose a capacity charge in $/kW per day in addition to kWh rates (with the kWh rates usually discounted relative to other tariff structures). Demand tariffs are more common for larger businesses. TOU and demand tariffs may also be combined. Both types of tariff structures seek to provide a signal that there are times when it is more expensive to supply electricity. These tariff structures are not perfectly aligned with daily wholesale market price fluctuations but are a better approximation of wholesale prices than a flat tariff. In that sense, TOU and demand tariffs are also described as being more ‘cost reflective’ or as ‘smart’ tariffs.

Distribution networks have led a growing trend of assigning customers to TOU tariffs. Network tariffs are the tariffs that networks charge retailers for use of their system. In most cases networks are increasingly charging retailers a TOU tariff for residential customers and the share of customers assigned to cost reflective tariffs has risen sharply in recent years (Figure 4-9). Retailers are not obliged to pass this network tariff structure through in their retail tariffs and there are no publicly available statistics on TOU share of residential customer retail tariffs. However, retailers take on additional risk if they do not pass through the TOU structure and so this represents an incentive to do so.



Note: No value in 2019 does not reflect a lack of data but rather 0% share in 2019
Figure 4-9 Change in the share of residential consumers assigned to cost reflective tariffs by electricity distribution networks, AER (2025)

Access to smart meters are a technical limit on the full roll out of TOU tariffs since older meters are not capable of recording daily electricity usage patterns[14]. However, smart meters have also been increasing rapidly in recent years outside Victoria. Victoria already has complete coverage of smart meters due to an earlier statewide change over. It is therefore interesting that Victoria has some of the lowest cost reflective network tariff assignment. This reflects the fact that, under the rules of the statewide change over, Victorian customers had to opt-in to TOU tariffs. However, in other jurisdictions, customers are assigned cost reflective tariffs when they have a smart meter and have to opt-out. Smart meters are installed whenever rooftop solar is installed and so the deployment of rooftop solar has been strong driver of smart meter deployment and TOU tariff assignment by networks. There are no readily available statistics on the degree to which customers assigned TOU tariffs have later opted out and returned to flat tariffs.

Some customers with home batteries have also participated in virtual power plant (VPP) trials where battery owners are rewarded for system controlled battery charging and discharging. AEMO (2021) reported that around a quarter of all registered battery owners had participated in trials. With some trials ending, this share was estimated to have reduced to 14%[15]. There has also

[14] Instead they accumulate electricity consumption and are read manually once a quarter.

[15] SunWiz

been some negative reporting of VPP experiences[16]. On the other hand the recent large increase in battery sizes, well beyond what a household can use, suggests some customers are buying batteries with the purpose of earning revenue from the grid through a VPP scheme or schemes that offer direct pass through of the wholesale price.

4.4.3 Future developments in battery owner incentives and management

Changes to customer connections and network charges to retailers have been the most impactful policy arrangements in place for changing the tariff structures that customers face. Historical research has shown that customers do not necessarily want more complicated tariffs[17] but there are clearly cases, such as in the adoption of VPP contracts or full wholesale market exposure tariffs, where customers have demonstrated a willingness to adopt more complex tariffs.

There are long term issues with relying too heavily on TOU tariffs as the main incentive and control mechanism for customer energy resources. Once batteries reach a greater critical mass, TOU tariffs will result in new coincident charging behaviours during the transition from peak to off-peak pricing. Consequently, in theory, as the scale of batteries increases, the electricity system will favour more dynamic schemes than TOU such as VPP arrangements.

This report does not outline the operation of VPPs under direct control schemes – this is estimated by AEMO in their market modelling. CSIRO only estimates the number of batteries expected to be participating in such schemes and their participation, in turn, influences battery uptake as it can represent improved payback from battery ownership.

Simulations by CSIRO indicate that, in order to have no increase in their electricity bill, battery owners would need to be compensated an average $15 per year to participate in 10 half hour calls which discharge all available capacity (mainly in the period 6pm to 10pm). This indicates the minimum battery owners would need to be compensated but not what they would accept. In recent years, there have been more than ten high prices events in some states. Also, this calculation only values their energy, but they could provide other services to the system. AEMO (2020) found in one trial that an energy services company operating a VPP for the purposes of participating in the FCAS market could earn an average $78.52 per month per participating household in South Australia[18]. In a fully commercial project, the proportion of this revenue that might be shared with the owner of the batteries is unknown.

In reviewing various VPP contracts the terms vary considerably. Some offer rebates on battery purchases, others offer an upfront joining fee and ongoing monthly or event based credits. Others offer generous feed-in tariffs for energy from the battery of around 40c/kWh. Some have a combination of feed-in tariffs and credits.

For the purposes of projecting uptake of batteries, our simplified assumption is that, an incentive equivalent to around $250 per year in all scenarios is available to residential customers (i.e.,

[16] https://www.abc.net.au/news/2025-05-09/claims-agl-drained-household-batteries-spark-trust-warning/105234050

[17] Stenner et al (2015) provide further insights on customer's responses to alternative tariffs.

[18] This period did include some significant market events and so may be the higher end of the possible range.

implemented as a rebate) and a higher amount for commercial customers proportional to their battery size.

For the minority of customers on flat tariffs (more likely in Victoria), customers will set their battery to solar shifting mode which has two key principles:

- If solar exports are detected and the battery is not full, charge
- If electricity imports are detected and the battery is not empty, discharge.

This is a relatively simple onsite algorithm to implement and generally comes as part of the battery manufacturer's standard available settings. Those on a TOU tariff will add more complicated rules which are designed to minimise their exposure to peak price periods, discharging the battery during peak pricing periods and occasionally charging the battery from the grid during off-peak times (not just from solar generation) to ensure the battery is full prior to peak pricing periods.

The assumed proportion of customers on each tariff contract type and the subsequent battery storage operating mode by scenario is shown in Table 4-1. The tariff assignments are CSIRO's judgement of the combined impacts of the payback available from participating in each tariff type, the outcome of increasing assignment of cost reflective network tariffs and smart meter uptake and the long term needs of the electricity system[19].

Table 4-1 Assumed proportions of tariffs and subsequent battery storage operating modes by scenario

		Flat tariff (Solar shift mode)		Time-of-use tariff		VPP contract (Aggregated mode)	
		Residential	Commercial	Residential	Commercial	Residential	Commercial
2030	Slower Growth	24%	34%	60%	54%	16%	12%
	Step Change	18%	27%	62%	57%	21%	16%
	Accelerated Transition	11%	22%	60%	56%	29%	22%
2050	Slower Growth	10%	11%	64%	69%	25%	20%
	Step Change	6%	7%	53%	60%	41%	33%
	Accelerated Transition	6%	7%	38%	49%	56%	45%

Relative to the 2024 projections the flat tariff or solar shift share of battery operating modes has been decreased to recognise the strong growth in allocation of cost reflective network tariffs (predominantly TOU). However, we assume there is not a perfect pass through of these tariff types by retailers. Furthermore, with more customers participating on TOU tariffs, this increases the need to eventually shift them to VPP contracts to avoid growing coincident charging behaviour.

[19] This is not to suggest investors in batteries are not obliged to consider the electricity systems needs. However, whatever outcome most supports the electricity system needs is likely to offer the greatest rewards to consumers.

4.4.4 Community batteries

Community batteries are an emerging type of battery that can complement household and utility-scale batteries. A community battery is a shared battery system located in a neighbourhood and enables customers to store excess electricity generated by rooftop PV which the community can use later (e.g., in the evenings) to reduce the need to import electricity from large coal generators. Additionally, a community battery can be used to support the operation of the local distribution grid. Network support services include demand management and reducing adverse effects on the local grid due to surges of rooftop solar PV, therefore reducing the need for network upgrades.

Community batteries have been included in the projections for the first time as commercial battery systems. In Appendix B of CSIRO's 2022 projections (Graham and Mediwaththe, 2022) we outlined a number of community battery projects that were completed or planned. These are now in the historical data for large commercial batteries. Going forward the key growth in community batteries is from the commonwealth government. In the October 2022 Federal Budget, the government provided $200 million for the Community Batteries for Household Solar Budget Measure to deploy 420 community batteries across Australia for a total of up to 281MWh of storage capacity. It is assumed most of the remaining batteries will be deployed in the next year.

Challenges for implementing community batteries

Although there are widely accepted socio-techno-economic benefits of community batteries, deploying this type of battery system faces challenges. The key challenges for community batteries are:

- Management of service contracts to multiple parties, e.g., retailers, DNSPs and/or other third parties (e.g., a local council, a community group, a private investor). This is particularly challenging in the disaggregated NEM. For instance, operating the battery for network support services by a DNSP and operating the battery for market/customer retail services by a retailer at the same time.
- Balancing the provision of services among multiple parties to benefit all stakeholders (customers, DNSPs, retailers, and other third parties like local governments or community energy groups etc) and ensuring the benefits are distributed fairly among all stakeholders
- How best can DNSPs procure the services that storage can provide from non-distributor-owned storage within the current framework
- Social acceptance challenges are also potential due to the lack of community confidence in transparency, fairness and trust in the energy sector business models

In addition, ownership-related challenges include:

- DNSPs in the NEM can own a battery system to provide distribution network services (voltage management and/or electricity demand management), but cannot use a battery to provide contestable services (electricity retail services, customer side generation solutions such as batteries and solar, energy consultancy services) mainly due to the *ring-fencing guideline*
- Retailer-owned models face challenges in social acceptance due to the lack of community trust and transparency of existing retail market models including pricing

- Local council or community groups do not have the resources and expertise to manage the storage asset (the possible workaround would be to contract a third party such as a DNSP or a retailer)

Battery ownership and business models

Primarily, three community-battery ownership models have been identified and are being trialled by the industry:

- DNSP-owned model
  - DNSP incurs the capital investment, battery maintenance and operational costs
  - Priorities of the battery operation would be to achieve network support, including network capacity and power reliability
  - The DNSP can lease the battery capacity to a retailer where the retail partner can provide customer offerings and the market services incl. FCAS or wholesale spot market energy trading
  - Customers may buy any product related to the battery via the retailer
- Third-party owned model
  - A third party can include either a community-based organisation or a local government or a not-for-profit entity. A third party owns and operate the battery and incurs all the capital investment, maintenance and operational cost of the battery
  - A third party may operate the battery in response to the requests for network support services
  - Also, the capacity can be leased to a retailer or market services incl. FCAS and wholesale arbitrage
  - To offer customer-related products, the third party can partner with a retailer
- Retailer or DER aggregator-owned model
  - A retailer or a DER aggregator is the owner and operator of the battery and incurs battery capital investment, maintenance and operational costs
  - The battery can be operated to respond to the requests of network support services
  - Also, the battery can be used to trade energy in the wholesale electricity market
  - The retailer or the aggregator can provide a *virtual battery service* directly to customers

Although ownership models have been identified, the complexity of business models for operating a community battery is a significant barrier to wider commercial uptake of community batteries.

4.5 Gross state product

Gross state product (GSP) assumptions by scenario are presented in Table 4-2 and these are provided by AEMO and their economic consultant. These assumptions assist in determining the relative weighting of solar PV and battery adoption by postcode which is assumed to be partially influenced by income levels. Housing type and ownership is also a strong driver of differences in adoption between locations and overall market size and is discussed next.

Table 4-2 Average annual percentage growth in GSP to 2050 by state and scenario, source: AEMO and economic consultant

	New South Wales	Victoria	Queensland	South Australia	Western Australia	Tasmania	Australian Capital Territory
Slower Growth	1.4	1.5	1.5	1.0	1.2	1.1	1.6
Step Change	1.9	2.0	1.9	1.5	1.7	1.5	2.0
Accelerated Transition	2.6	2.8	2.6	2.2	2.4	2.1	2.7

4.6 Separate dwellings and home ownership

Owing to rising land costs in large cities where most residential customers reside, there is a trend towards building of apartments or town houses, compared to detached and semi-detached houses (also referred to as separate dwellings in housing statistics). As a result, it is expected that the share of separate dwellings will fall over time in all scenarios (Figure 4-10). The trend is strongest in the larger states of NSW, Queensland and Victoria with the trend being flatter to very slightly rising in others. This assumption does not preclude periods of volatility in the housing market where there may be over and undersupply of apartments relative to demand. The assumptions have been provided by AEMO and their economic consultant.

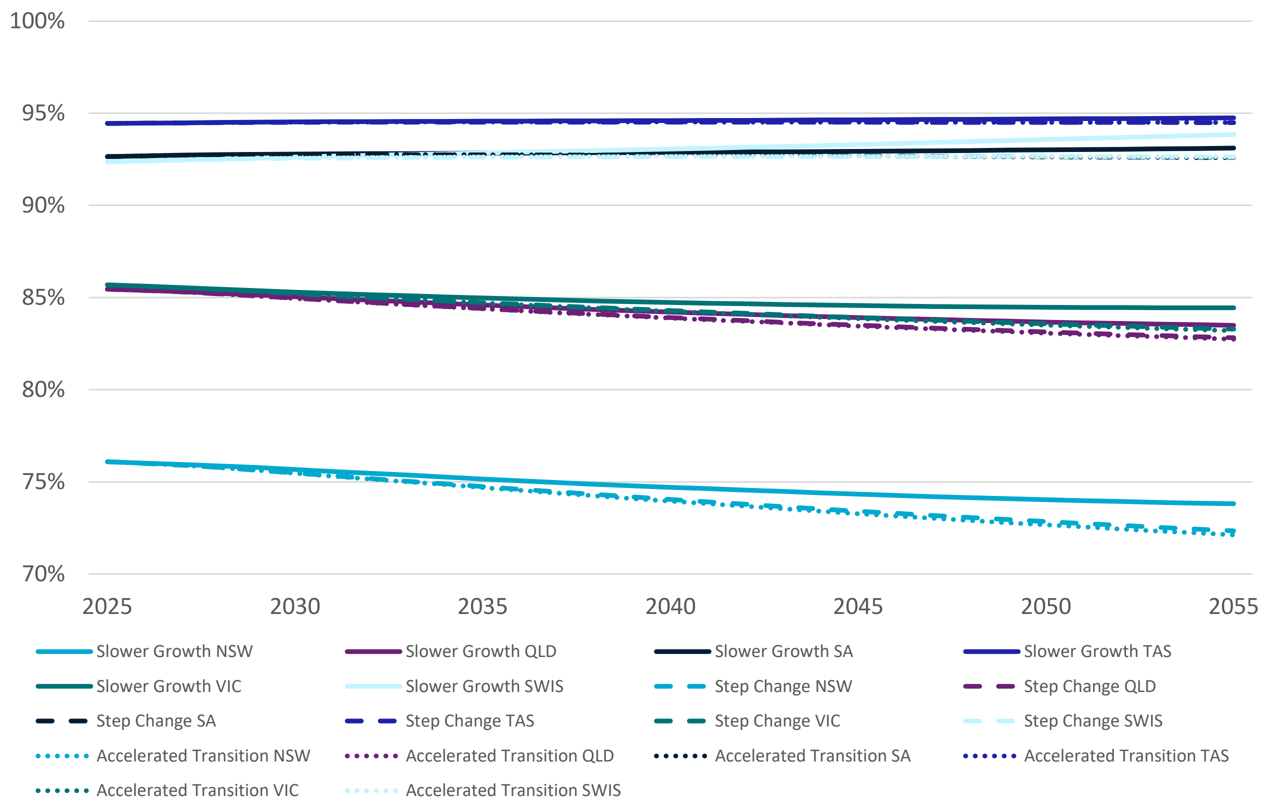


Figure 4-10 Assumed share of separate dwellings in total dwelling stock by scenario

AEMO's consultant does not provide home ownership projections. Home ownership projections are shown in Figure 4-11 with home ownership being higher the stronger the economic growth and climate policy ambition. If housing is less affordable then it will be more difficult to attract labour to the required locations and there will be less political support for higher order concerns such as health of the environment.

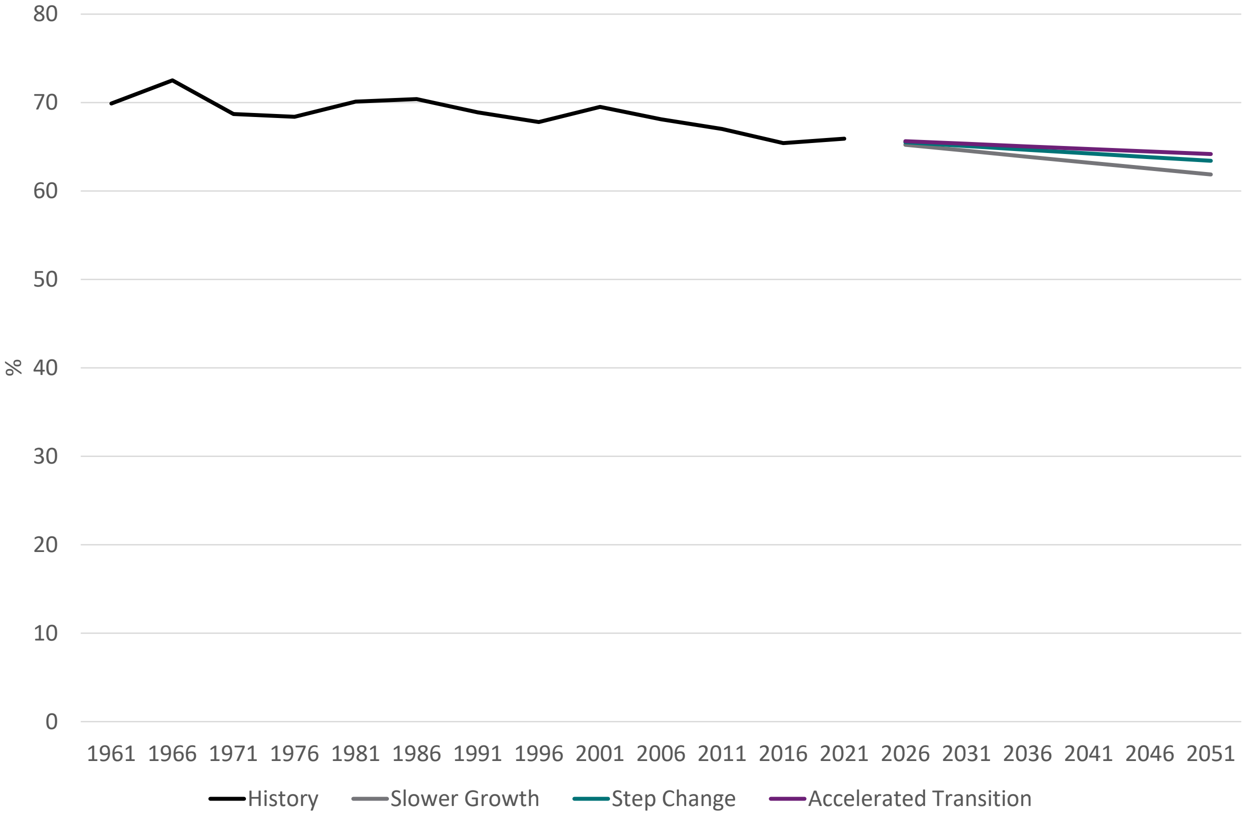


Figure 4-11 Projected home ownership rates by scenario

4.7 Rooftop solar and battery storage maximum market sizes

For both residential and commercial customers, the market that can most easily adopt rooftop solar are those with a separate owner-occupied building. Multi-occupant buildings or those that are not owner-occupied require more complex arrangements (business models) to extract and share the value of rooftop solar. This latter group is therefore a smaller market segment. Table 4-3 outlines the maximum size the rooftop solar and battery markets by 2055. The residential maximum market size is highly influenced by the share of separate dwellings and housing ownership data with range representing the uncertainty around the opportunity to reach every owner-occupied separate dwelling and to go beyond that into rental properties. These barriers are assumed to be higher for commercial buildings and so their maximum market size is accordingly lower.

The market share limits are imposed on average. However, the modelling allows individual locations (modelled at the postcode level) to vary significantly from the average according to their demographic characteristics.

The battery storage market is assumed to be a subset of the rooftop solar market since the main motivation for storage is improving the utilisation and financial returns from rooftop solar. Consequently, the maximum market size for batteries is expressed in relation to the number of residential or commercial buildings with solar PV. The maximum size of the commercial battery market is assumed to be a lower share of solar systems than residential because a significant number of commercial buildings will have very low demand for electricity after daytime hours and so are not in the market for a battery.

Table 4-3 Maximum market size for residential and commercial sectors by 2055

		Definition	Slower Growth	Step Change	Accelerated Transition
Rooftop solar PV	Residential	Share of residential separate dwellings	55%	65%	75%
	Commercial	Share of commercial buildings	50%	60%	70%
Battery	Residential	Share of residential buildings with rooftop solar	50%	65%	75%
	Commercial	Share of commercial buildings with rooftop solar	40%	50%	70%

5 Projections results

The projection results are presented in terms of megawatts (MWs) or megawatt hours (MWhs) after taking account of capacity degradation. While historical data is commonly reported in terms of non-degraded or nameplate capacity, only the capacity after degradation matters for forecasting and planning of electricity system generation and demand.

CSIRO's projections may be one of several sources of solar PV and battery projections commissioned or developed by AEMO. AEMO will also occasionally rebase commissioned projections when new historical data becomes available. As such, none of the current or previous projections presented will necessarily align directly with the final projections published by AEMO. In its published work, AEMO will usually provide a table that indicates which projection source it has used, whether it has used it directly or some other alternative method (for example, an average of the two sources).

With this context, our approach in this section is to use the CSIRO 2024 projections (Graham and Mediwaththe, 2024) as the key source of comparison to the current projections rather than an AEMO source document. CSIRO's previous projections use the same modelling approach. The 2024 CSIRO projections provide the best basis for understanding how changes in the scenario assumptions have impacted the projection.

The projections include all solar capacity from residential and business systems up to 100kW as well as non-scheduled generation greater than 100kW to 30MW. In some figures and text, we group up all sizes less than 30MW. In others we may only include residential or business roof mounted systems 100kW and below. In others we may focus on greater than 100kW to 30MW systems which are more likely to be ground mounted.

All projections are shown for the sum of the National Electricity Market and the Western Australian Wholesale Electricity Market (NEM + WEM) regions.

5.1 Small-scale solar PV

5.1.1 Year ahead projection

As discussed in the methodology section, we use trend extrapolation to project 2026. To create diversity between the projections we also overlay an assumed uncertainty range across the scenarios. Relative to the 2024 projections the lower end of the range projected came to be realised with the level of new capacity added falling in 2024-25 (after allowing for the change in historical data series[20]). Capacity additions have been very consistent in the 2.5 to 3GW range in the past five years. The same approach is used for the 2025-26 projections with a similar uncertainty range applied except for a slight upward bias to recognise the tendency of a

[20] The adjustments to the historical data series are mainly due to reassessment of whether data was correctly ascribed as a replacement or new system. There can also be issues with correct assignment as residential or commercial.

convergence towards the historical mean. This approach applies to all system sizes up to 30MW (Figure 5-1).

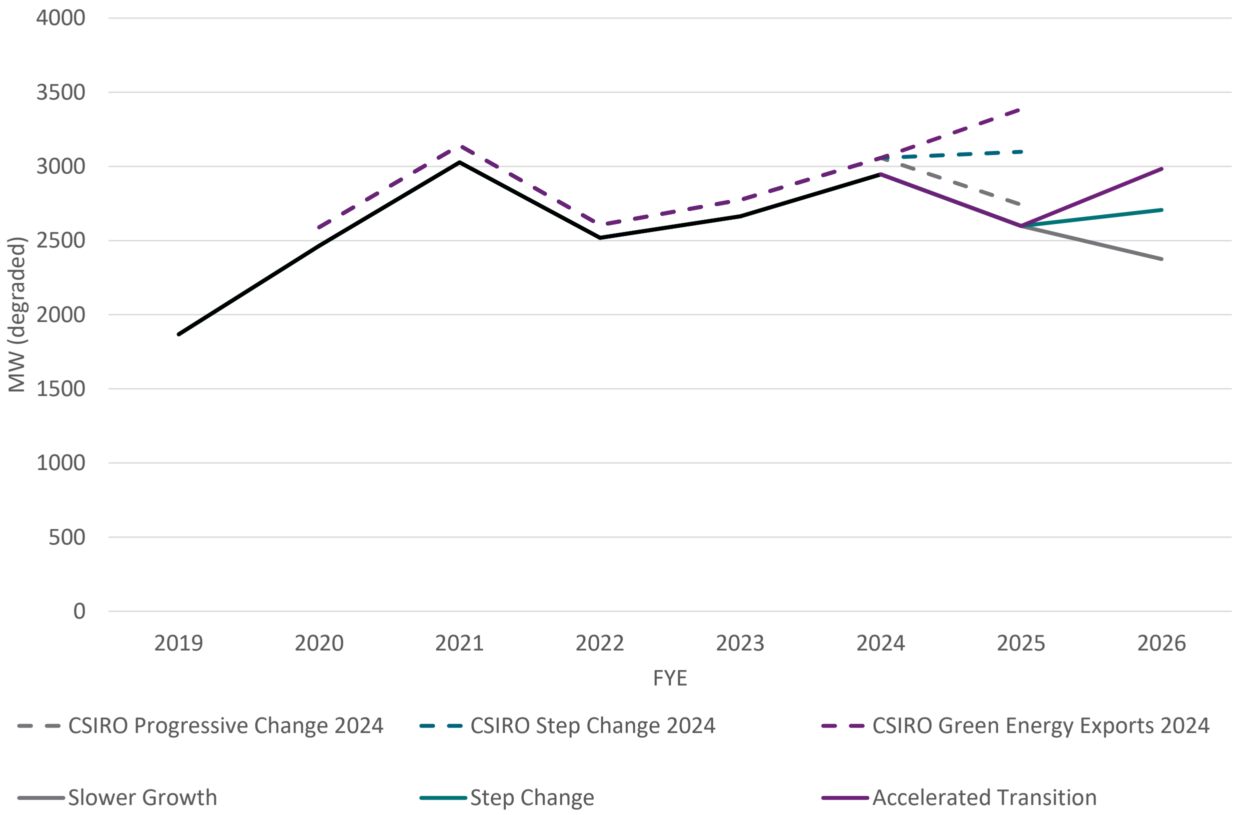


Figure 5-1 Year ahead projection of all solar PV (<30MW) capacity additions, NEM + WEM

5.1.2 Residential solar PV

The projected capacity of small-scale solar PV for the residential customer segment in the NEM and WEM for the whole projection period is shown in Figure 5-2. To generate these projections, after 2026, our second projection methodology is implemented which takes account of various financial and non-financial drivers that inform an adoption curve (see Section 2 for more details). Compared to the 2024 projections the key positive driver is higher assumed residential system sizes. However, most other drivers have worsened. Retail prices are assumed to have stabilised, solar PV costs are expected to be declining but higher than 2024 and small-scale technology subsidies are declining each year and ending completely in December 2030.

The outlook for export revenue from rooftop solar PV has not worsened but remains poor with an expected higher incidence of curtailment in various forms including voltage-based curtailment due to increased local solar PV generation and directed curtailment for system security. With this context, future growth in deployment is not driven by an improving payback period but rather underlying growth in households numbers (though no increase in growth compared to previous projections), higher system sizes over time (this trend is higher than previous projections) and late adopters taking advantage of an already low payback period.

The outlook for payback period improvements is weakest in the next decade with the decline of subsidies. Previously it was assumed installers would seek to cushion consumers from the decline in subsidies and that rooftop solar costs would fall faster. However, in the updated projections subsidies end without other support[21] and costs are higher than previously projected. This results in a projected slower growth capacity in the next decade compared to the 2024 projections.

Longer term, the modest cost improvements eventually accumulate to offset lost subsidies and lead to incremental reductions in payback. This supports a slight increase in the rate of growth of capacity. However, overall, the updated projections are lower than the 2024 projections for all scenarios.

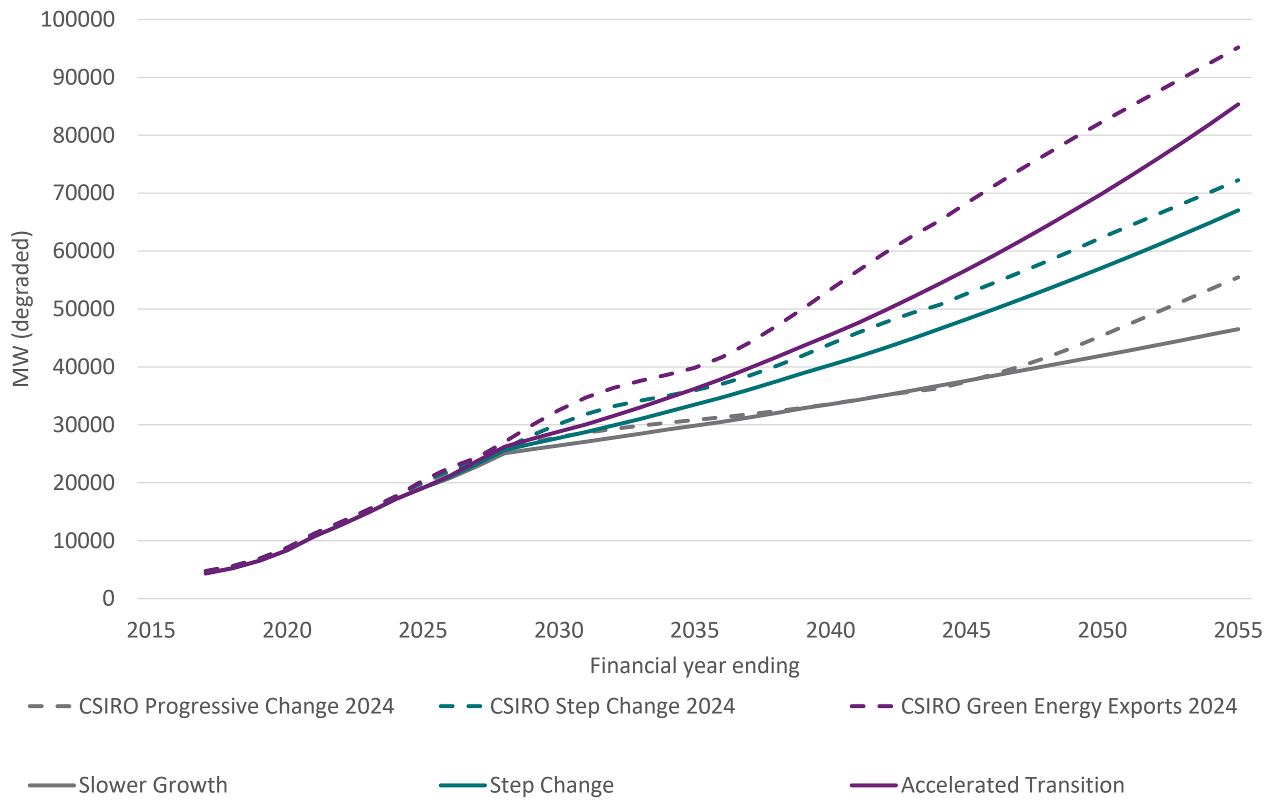


Figure 5-2 Projected capacity of residential small-scale (<100kW) solar PV in the NEM and WEM

Besides the negative financial factors, the projections are also limited by non-financial factors which are mostly infrastructure related. Solar PV is installed most readily on owner occupied separate dwellings which represent about 50 to 60% of households depending on the state, declining slightly over time as home ownership declines. This means that to exceed this share of households in residential rooftop solar deployments, installations must occur in either a rental property or multi-occupancy building.

The problem of split incentives arises if the dwelling or place of business is rented. The tenant is not incentivised (and may not be authorised) to upgrade the home to solar because they are unlikely to be staying long enough to gain the product lifetime benefits. Likewise, the landlord receives no benefit other than potentially recovering costs through higher rent (except in some

[21] This change was made on the basis that, while installers have demonstrated an ability to maintain prices as subsidies fall this may reflect increasing system sizes which attract more subsidies and this strategy may be difficult to maintain as subsidies decline.

cases where the landlord pays for utilities). For higher adoption scenarios, *Step Change* and *Accelerated Transition,* these challenges are assumed to be more easily overcome through either business model innovation or some previously owned buildings entering the rental market through changed circumstances. For *Slower Growth,* overcoming these challenges is assumed to be less successful, and fewer renters can access solar. Some governments (e.g., Victoria) are providing incentives for landlords and renters to reach a benefit sharing agreement.

The modelling is designed to only reach these infrastructure saturation limitations if the payback period continues to decline. The payback does not decline as much as in the 2024 projections and this is another reason why all scenarios are lower than the 2024 projections. However, Queensland, South Australia and Western Australia achieve the highest household penetration of rooftop solar given their strong historical uptake and the latter two states have a higher existing share of separate dwellings in their housing stock.

5.1.3 Commercial solar PV

Commercial solar PV less than 100kW

For the commercial sector (Figure 5-3) the same financial drivers result in a slower outlook for growth in small-scale solar PV capacity relative to the 2024 projections. In addition to the financial factors of higher system costs and loss of subsidies, average commercial system sizes have been almost halved. This additional driver compared to residential systems means that the rate of growth in commercial capacity up to 100kW is more significantly impacted by the changes in financial drivers than the residential sector. Growth is significantly slower in the next decade compared to 2024. Growth recovers in the 2040s and 2050s as solar PV costs reductions accumulate, but not enough to reach the 2024 capacity levels.

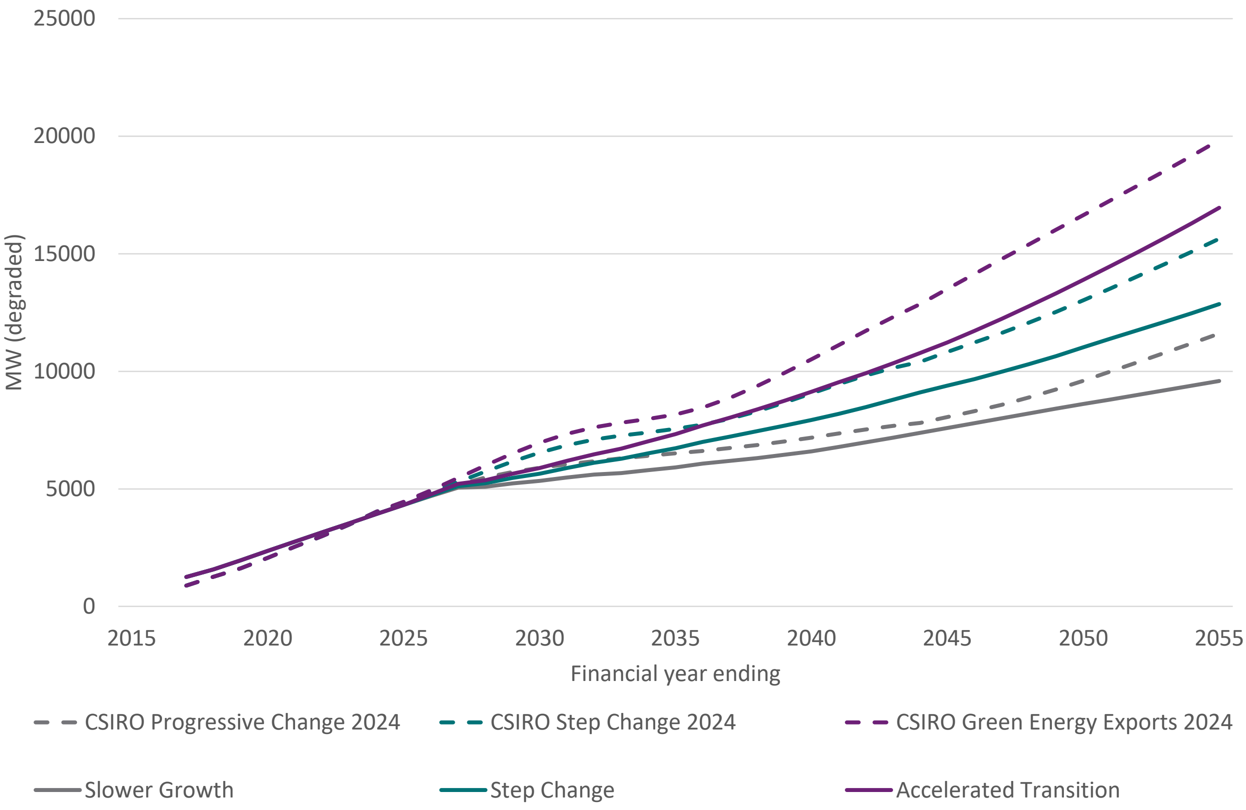


Figure 5-3 Projected capacity of business small-scale (<100kW) solar PV in the NEM and WEM

Larger-scale solar PV (100kW to 30MW)

Investment in larger scale solar PV in the range of above 100kW to 30MW (also called non-scheduled generation) is less driven by infrastructure and more by the potential financial rate of return. The projected capacity of non-scheduled solar PV generation for the NEM and WEM are shown in Figure 5-4. The projections exhibit some variability year to year which reflects the intermittent installation of projects at the larger end of the spectrum. These tend to occur in a narrower set of regions and make for larger steps in capacity additions.

With the large-scale technology certificates decreasing in value over time, a potential new source of subsidy for these projects is state and commonwealth offset schemes such as the Australian Carbon Credit Unit scheme, state energy efficiency schemes and corporate or voluntary emission reduction targets. The potential incentives under these other incentive schemes are not likely to be as strong as that previously available from large-scale technology certificates. However, we allow for the offset certificate prices of these schemes to increase over time consistent with the greenhouse gas ambitions of each scenario. This is the main driver of the spread of the projected capacity across the scenarios.

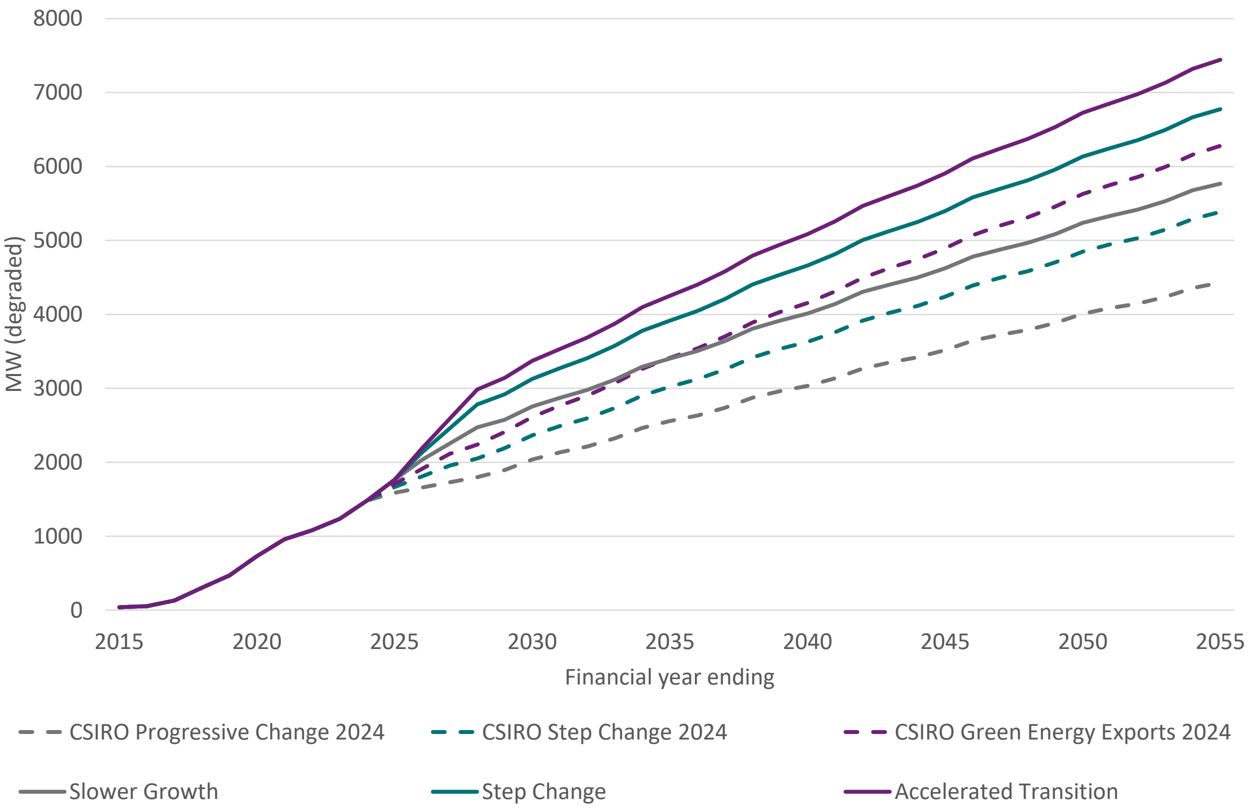


Figure 5-4 Projected capacity of non-scheduled generation solar PV (greater than 100kW to 30MW) in the NEM and SWIS

The increase in the projections relative to the 2024 projections largely reflects the development of some larger deployments in the historical series. Our projection approach uses historical build rates to inform the future build rates. As a consequence, once a state has deployed a large (>5MW) project, the projection method assumes they are more likely to experience growth in that category. Despite this increase relative to the 2024 projections, the overall trend is for non-scheduled solar PV generation is linear growth despite some evidence of faster than linear growth in the past. This reflects the reduction in financial incentives following the closure of the large-scale technology certificate scheme.

5.2 Batteries

Battery projections are developed in the same way as solar PV with most of the same methods applied. However, in the year ahead projection it was not appropriate to employ a regression analysis because monthly data was already indicating that the trend for 2025-26 new capacity additions would have no relationships with past trends. This is because the introduction of a battery subsidy scheme, the Cheaper Home Batteries Program, has resulted in a rate of deployment around 4 time stronger than in the past. Commercial customers deploying batteries less than 50kW are also eligible.

The updated year ahead projection with uncertainty range across the scenarios is shown in Figure 5-5. The uncertainty range implies different levels of possible increases in both deployment and system sizes. Over the next year there is also a commonwealth government funded program for deployment of community batteries. These larger-scale commercial batteries are also included in the year ahead projection supporting capacity growth in addition to the Cheaper Home Batteries Program. Community batteries account for 5% of the increase in 2026.

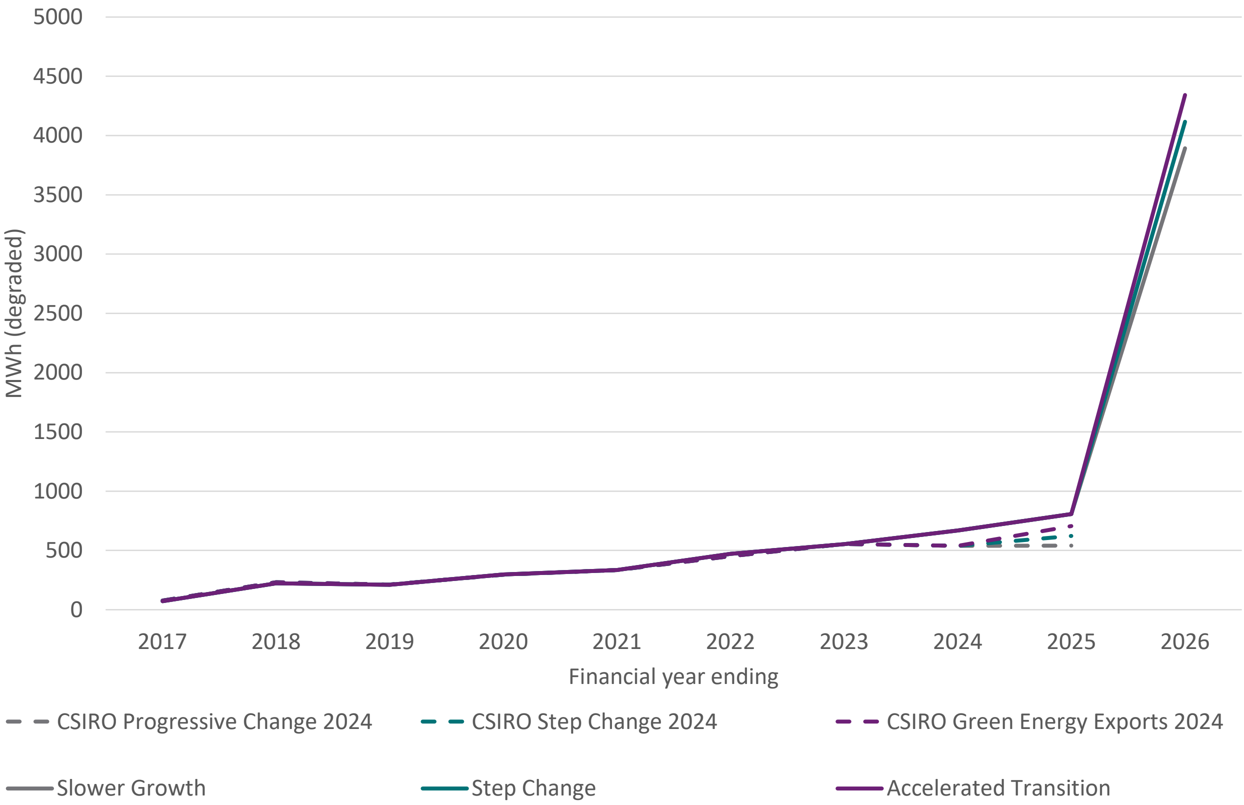


Figure 5-5 Year ahead projection for total residential and commercial battery additions, NEM and WEM

The previous 2024 projections included a nationwide subsidy in the *Step Change* and *Accelerated Transition* scenarios starting a year later and at a lower level of subsidy than the Cheaper Home Batteries Program. Consequently, the updated residential projections ramp up more quickly and to a higher level than the 2024 projections, particularly in the period until the end of the scheme in 2030 (Figure 5-6). From a technology cost perspective battery costs are also lower in the next decade before subsidies which also supports their improved financial viability during that period compared to the 2024 projections. Battery costs are similar, however, to the 2024 projections post-2040.

Another positive driver of growth in battery capacity is that the average size of new residential battery installations is approximately 20% to 100% larger than in the 2024 projections. In the *Step Change* and *Slower Growth* scenarios the size is assumed to fall as the Cheaper Home Batteries Program subsidy declines. However, the new battery size remains above that of the 2024 projections throughout the projection period.

A negative driver of residential battery uptake is that there are fewer residential solar installations compared to the 2024 projections due to the weakened outlook for the financial returns from solar ownership. This decreases the total market size for residential battery deployment. The combination of these positive and negative factors means that the projections are significantly higher than the 2024 projections for most of the projection period, with the exception of *Slower Growth* which converges towards the previous projections by 2055.

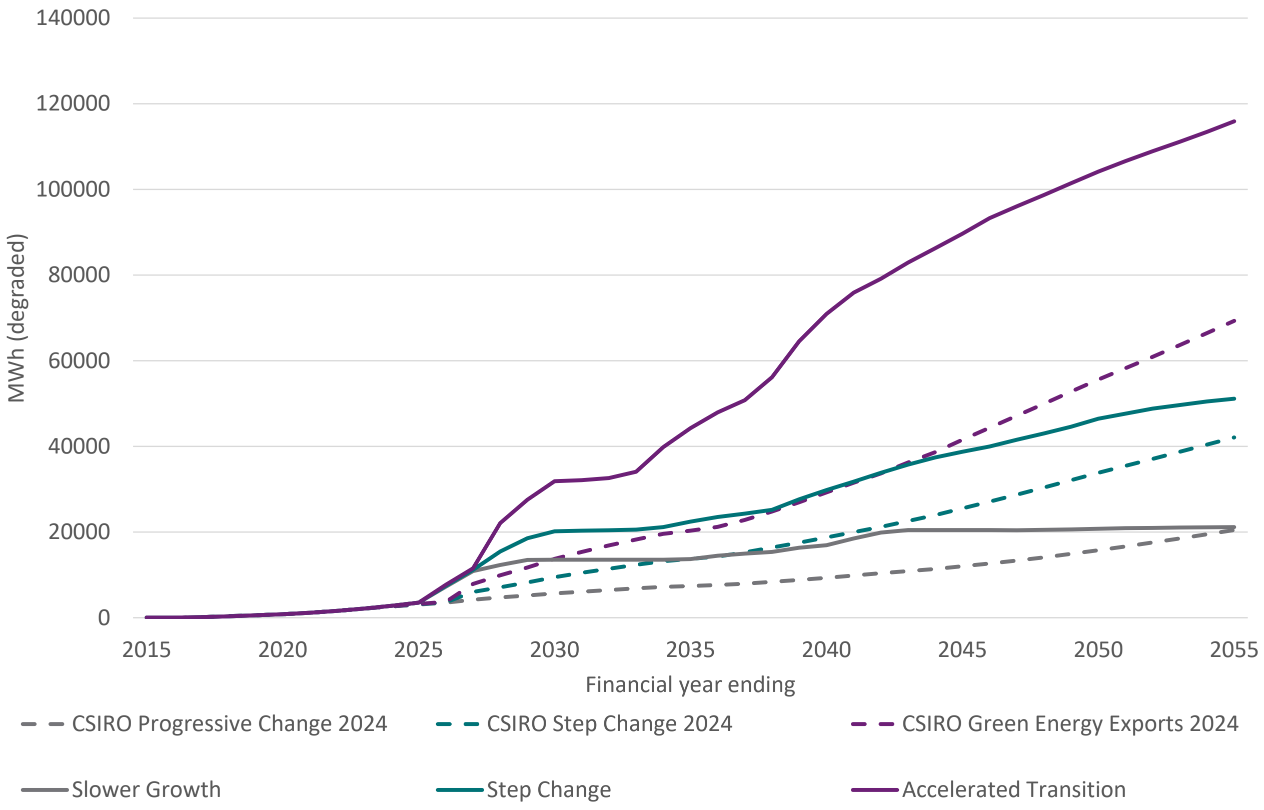


Figure 5-6 Projected capacity of residential batteries in the NEM and WEM

For the business sector, the projected outlook for battery capacity is significantly higher than the 2024 projections (Figure 5-7). The key drivers of this outcome are an average new battery system size up to 100% larger, faster reduction in technology costs and subsidies. The wide uncertainty range captures the downside risks that battery sizes may only be temporarily large while the subsidy is in place, that some commercial customers need less storage due relatively low non-daylight operation and lower uptake of commercial solar PV due to a weaker financial outlook for solar PV.

Upside risks also captured in this range are a possible longer term preference for large battery sizes following significant rapid cost reductions in batteries and a stronger embrace of electricity cost independence from the grid by the commercial sector to manage their electricity costs. The projection model assumptions have increased the market size for commercial batteries compared to the 2024 assumptions which in effect accepts that more businesses will consider battery uptake. This has resulted in a projection range significantly wider than the 2024 projections.

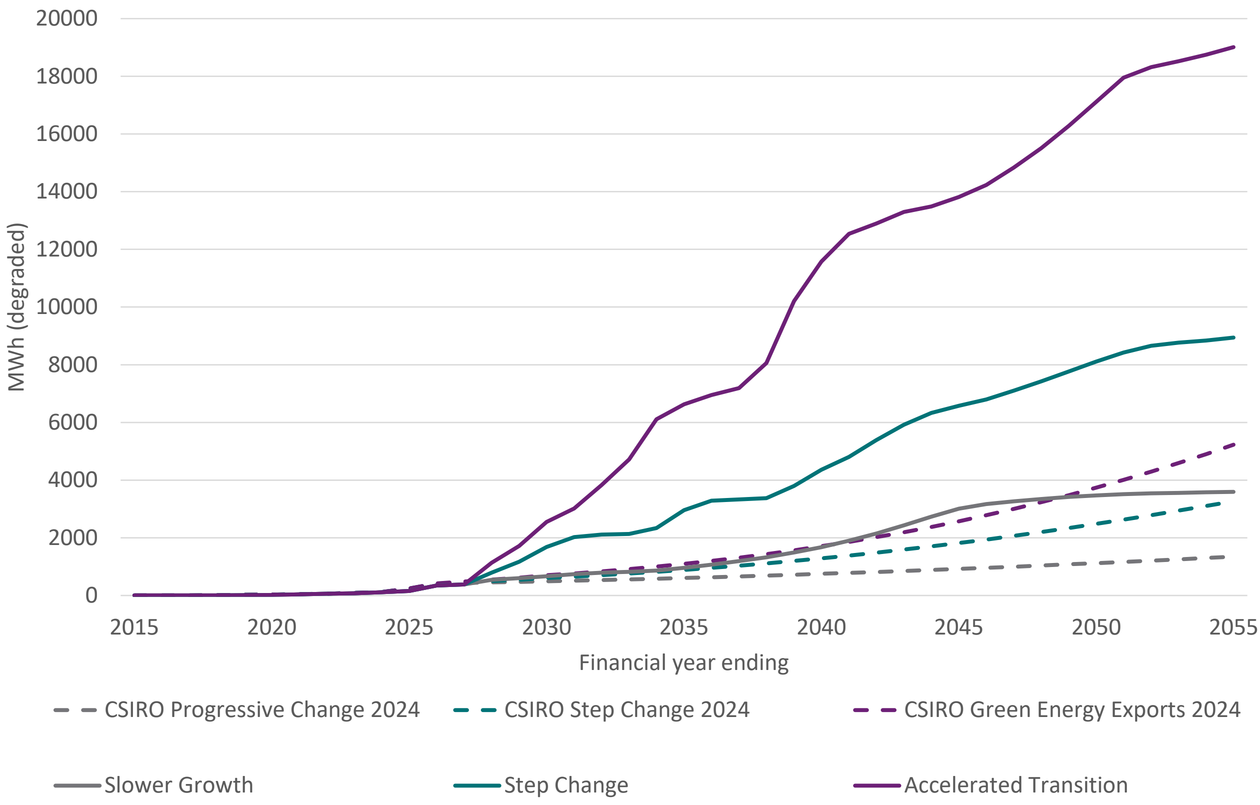


Figure 5-7 Projected capacity of business batteries in the NEM and WEM

The current and projected share of residential and commercial solar PV owners who also own batteries is presented in Figure 5-8. The battery share for residential and commercial customers with solar is expected to increase over time for all scenarios. The share increases rapidly, particularly for residential customers in the period to 2030 as this represents the period when the Cheaper Home Batteries Program subsidy is available.

There is another increase in battery share in the mid to late 2030s and early 2040s, particularly in the *Step Change* and *Accelerated Transition* scenarios. This reflects the faster rate of increase in batteries during this period relative to solar PV uptake after which the rate of uptake of both technologies is more aligned and the rate of increase in the battery share stabilises.

The range of battery shares reflects uncertainty in whether stationary batteries will be the primary source of storage or whether electric vehicles may provide competition in the long run. The commercial share of batteries is appropriately lower given that some parts of the commercial sector do not operate at night and consequently will get limited benefit from storage. This expresses itself as a lower payback period from battery ownership for some commercial electricity load shapes.

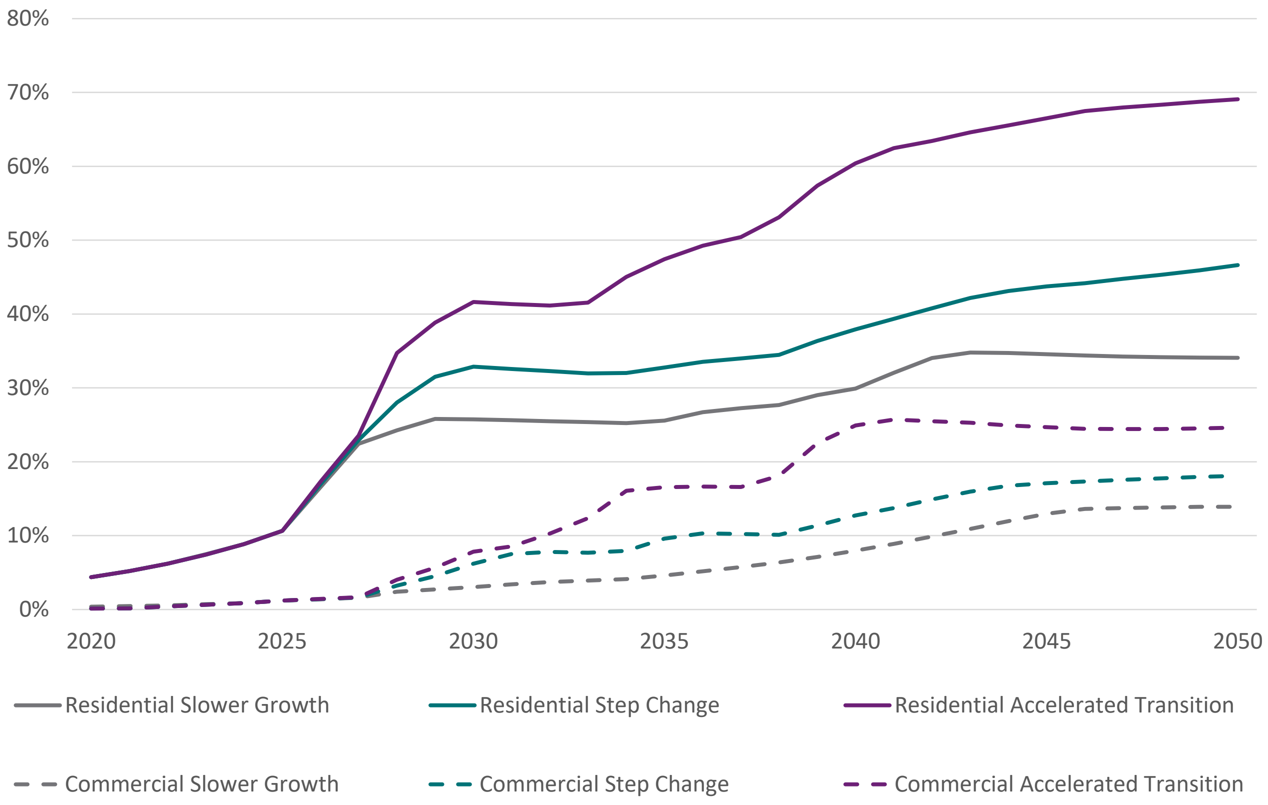


Figure 5-8 Projected share of residential and commercial solar-PV systems with a battery

Appendix A Additional data assumptions

In this appendix we outline some key additional assumptions that were used to develop the adoption projections in addition to the scenario specific assumptions discussed in the body.

A.1 Technology performance data

Each technology can be described by a small number of performance characteristics with energy efficiency being a common one whilst others are specific to the technology. The following tables outline key performance data for rooftop solar and battery storage.

A.1.1 Rooftop solar

Rooftop solar generation profiles were sourced from AEMO. Table A.1 shows the average capacity factors from these production profiles.

Apx Table A.1 Rooftop solar average annual capacity factor by region

	Capacity factor
New South Wales	0.146
Victoria	0.134
Queensland	0.152
South Australia	0.148
Tasmania	0.129
Western Australia (SWIS)	0.155
Northern Territory	0.148

Rooftop solar capacity degradation is assumed to be 0.5% per annum based on Jordan and Kurtz (2012). Warranties imply closer to 1% annual degradation but include a margin to be conservative. This is a stock wide assumption and does not preclude better or worse performing product variations.

Solar systems are replaced on average every 12, 15 and 20 years for residential solar, commercial solar up to 100kW and commercial solar over 100kW respectively.

A.1.2 Battery storage

The degradation rate is a function of many factors including temperature, depth of discharge and battery design. There are a wide variety of models for understanding how degradation occurs (Reniers at al., 2019) which can give diverse predictions about degradation rates. We have chosen a rate consistent with loss of 30% battery capacity by the end of a 5000-cycle life which assumes moderate temperatures, the battery is not fully charged or discharged and there is only one cycle per day.

Apx Table A.2 Battery storage performance assumptions

Characteristic	Assumption
Round trip efficiency	90%
Degradation rate	1.8% per annum on kWh capacity
Average replacement time	12-20 years depending on size

Shortened forms

Abbreviation	Meaning
ABS	Australian Bureau of Statistics
ACCU	Australian Carbon Credit Unit
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
APVI	Australian Photovoltaic Institute
BOP	Balance of plant
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DNSP	Distribution network service provider
EE	Energy Efficiency
ERF	Emissions Reduction Fund
FCAS	Frequency Control Ancillary Services
FiT	Feed-in Tariff
GDP	Gross Domestic Product
GSP	Gross State Product
hrs	Hours
IPART	Independent Pricing and Regulatory Tribunal
ISP	Integrated System Plan
kW	Kilowatt

kWh	Kilowatt hour
LGC	Large-scale Generation Certificates
LRET	Large-scale Renewable Energy Target
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NSG	Non-Scheduled Generation
PV	Photovoltaic
QRET	Queensland Renewable Energy Target
RET	Renewable Energy Target
SA2	Statistical Area Level 2
SGSC	Smart Grid Smart Cities
STC	Small-scale Technology Certificates
SWIS	South-West Interconnected System
TOU	time-of-use
UNFCCC	United Nations Framework Convention on Climate Change
VEEC	Victorian Energy Efficiency Certificate
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Target
WEM	Wholesale Electricity Market (WA)

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