Australia's National Science Agency

Small-scale solar PV and battery projections 2022

Commissioned for AEMO's draft 2023 Input, Assumptions and Scenarios Report

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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. It has been commissioned as an input to AEMO's various planning and forecasting tasks. This update is occurring around 18 months since CSIRO produced its previous solar PV and battery projections in May 2021. The key changes are:

1. Weaker growth to 2030 for both batteries and solar PV
2. Lower cost solar PV in the long term

Since the 2021 projections the most significant market development has been a slowdown in deployments for solar PV in the first half of 2022. The slower rate of deployment will still represent strong growth in solar PVs, but not as strong as the previous year.

The slower growth likely reflects a change in spending habits post-pandemic as well as global supply chain constraints. This development is significant because the rate of new installations had grown the previous three years, including the period throughout the pandemic. On the other hand, the benefits of solar PV ownership have never been higher due to the current high electricity prices which suggests the rate of sales is likely to level out or recover in the short-term.

The change in outlook means that the updated solar PV projections are mostly below that of the 2021 projections up to around 2030. However, in the 2030 to 2050 period uptake projections are generally higher. This reflects a reduction in the projected long-term cost of solar PV (based on updated GenCost 2021-22 data).

In contrast to solar PV, battery sales have been steady in the last 2 years and the sales rate has not significantly changed since the 2021 projections. The lack of historical growth in sales means that it is difficult to have confidence in any strong growth in the short-term. As such, updated projections to 2030 have also been downgraded for batteries relative to 2021 projections.

However, in the long term the outlook for batteries is slightly improved by the stronger growth in solar PV installations. The primary purpose for installing batteries is to shift solar power to later in the day when it is needed. As a result, the greater the solar PV deployment, the greater the market for batteries. At high installations of solar PV, export (feed-in) prices for excess solar generation will be lower and owners may also face greater incidences of curtailment (either due to high local voltages or for system security purposes). These changing conditions, together with lower battery costs, also support greater uptake of batteries in the 2030 to 2050 period.

1 Introduction

This report has been commissioned by AEMO to assist in producing electricity consumption and maximum/minimum demand forecasts. Specifically, the report provides projections for four scenarios of small-scale solar PV and battery storage adoption. The analysis also includes operation of small-scale batteries.

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 four scenarios are *Progressive Change, Exploring Alternatives, Step Change* and *Hydrogen Export*. 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.

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.

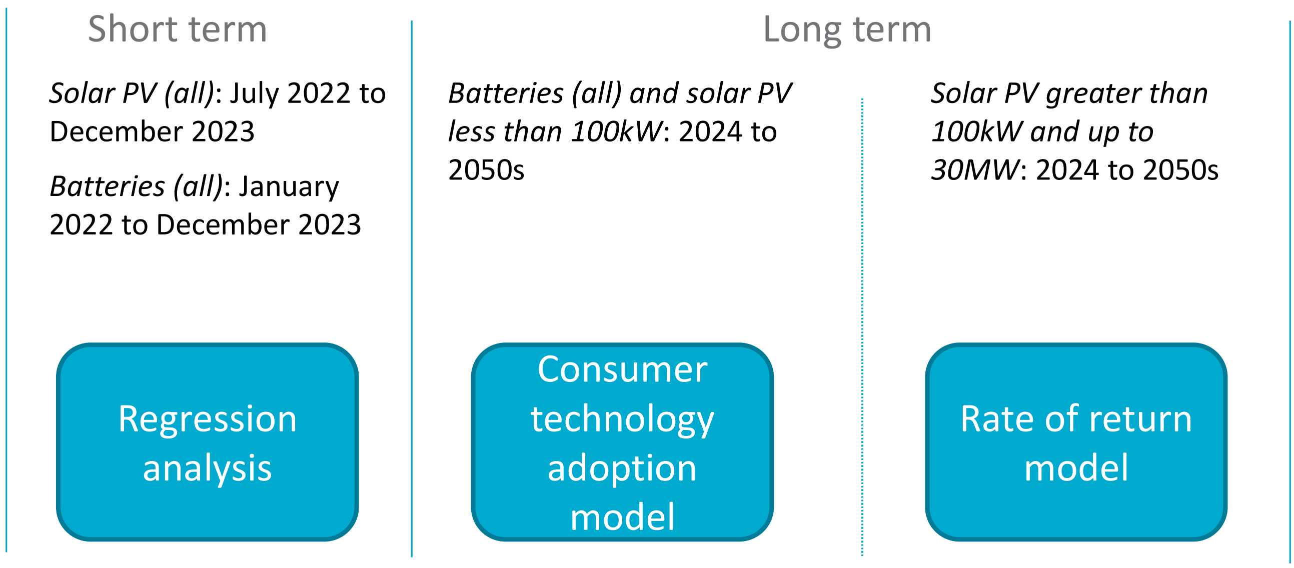

Figure 2-1 Short- and long-term projection approaches applied to the technology groups

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 conducted on annual data at the state level from 2021 (SunWiz, 2022) and going back several years[3] as monthly data sources for that technology are incomplete. For solar PV, the trend is estimated as a linear regression against 2 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). Compared to previous projections we have shortened the historical data used in the linear projection to ensure it is tracking the most recent trends. As such, 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 and project the 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[4]. For some larger non-scheduled solar PV, we also use the last 24 months of 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 strong growing trend. As discussed, we only use data back to the beginning of 2019 to emphasise recent trends in creating the forecast but show earlier data for context. The historical residential profile is relatively smooth with obvious differences in slope and scale between states. For example, NSW and Victoria which have lagged QLD in terms of residential rooftop solar penetration caught up in 2019 through 2021. This is consistent with being at a lower point on the consumer technology adoption curve (which we discuss further in the next section).

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[1] Around August 2022 for solar and end of 2021 for batteries when this report was being developed. The historical solar PV data is supplied by AEMO but is originally from the Clean Energy Regulator.

[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. Battery sizes have been relatively stable and are listed in Appendix A.

[3] We do not have a strict number of years used in the trend analysis. We select based on what period looks representative. For example, we may go back an extra year if there is an outlier year dominating an otherwise clear trend.

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

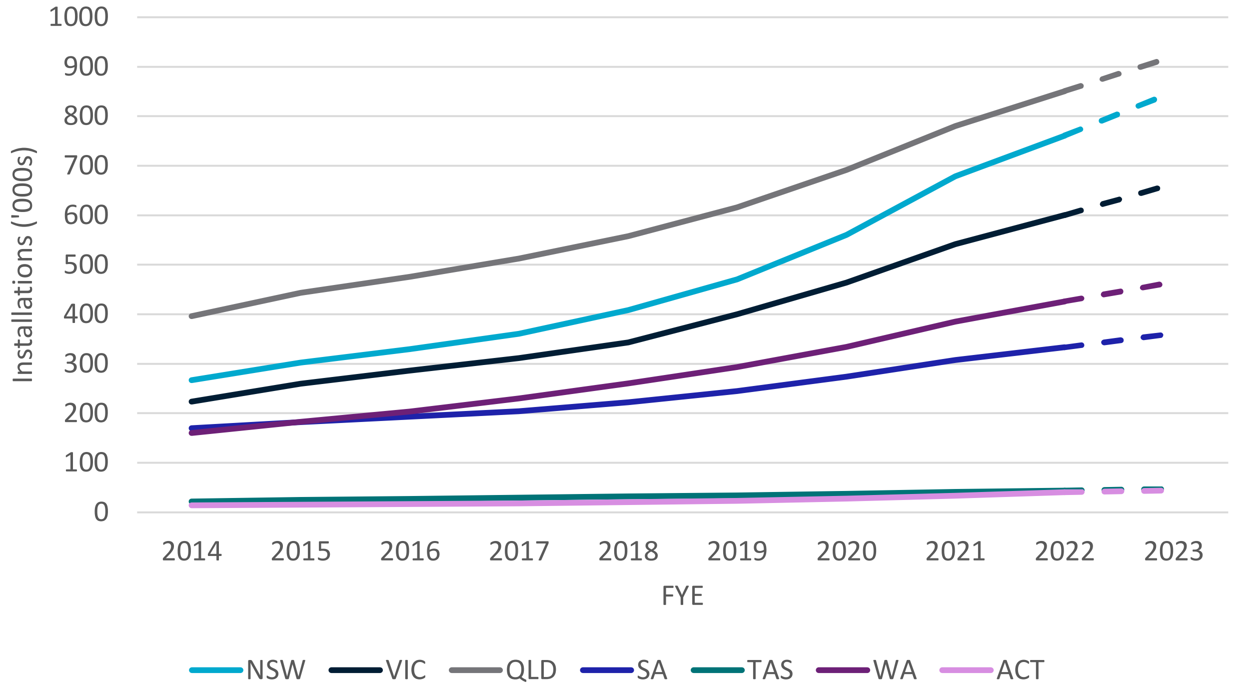

Figure 2-2 Regression results for residential rooftop solar installations by region

Commercial systems have not followed residential systems in terms of state rankings. NSW has the highest number of commercial installations whereas Queensland is the leading state for residential installation. 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 between -1.5% and 3% to the December 2023 projection and linearly interpolating that factor back to August 2022. 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 for each scenario applying to both residential and commercial systems are: *Progressive Change* -1.5%; *Exploring Alternatives* 0.75%; *Step Change* 1.5%; *Hydrogen Export* 3% (the scenarios are outlined in more detail in Section 3).

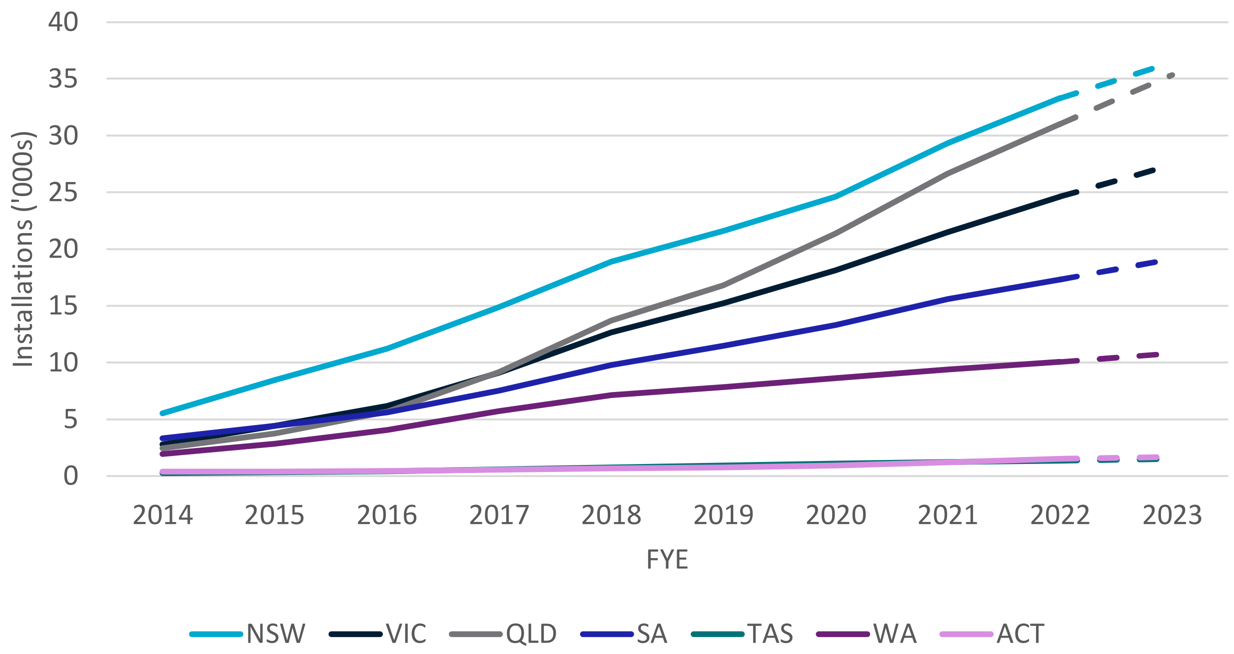

Figure 2-3 Regression results for commercial (<100kw) rooftop solar installations by region

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. 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.

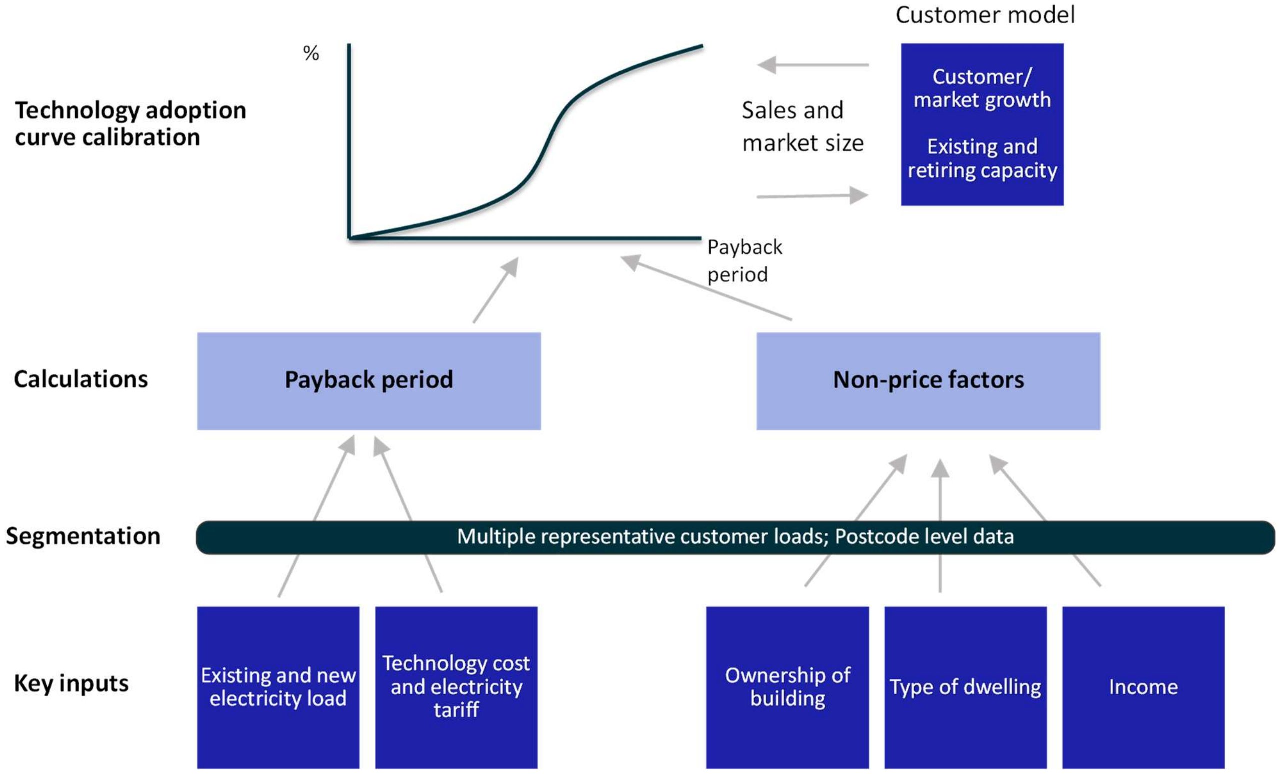

Figure 2-4 Adoption model methodology overview

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. Maximum market share assumptions are outlined in the Data Assumptions section (Table 4-5 and Table 4-6).

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). 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.

Higgins et al (2014) validated prediction of historical sales for rooftop solar by combining a weighted combination of factors such as income, dwelling density and share of Greens voters. While these factors performed well when the model was calibrated for 2010, given the time that has passed and 2010 being very much an early adopter phase of the market we recalibrated a new set of factors and weights as shown in Table 2-1.

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 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. This indicates a network effect whereby awareness of deployment of solar neighbours inspires adoption.

2.3 Role of economic growth in projection method

Economic growth is a closely tracked indicator of changes in residential and business income and the general health of the economy. As a result, we provide an overview of how changes in economic growth impact the projections. Overall, changes in economic growth are directly responsible for only small changes in the projections. Indeed, income receives only a 17% weight in the demographic score, and growth assumptions only operate on a fraction of that weight.

Income which is a function of GDP enters the calculations through the annual calibration of the adoption curve. Economic growth extends the number of locations over time which receive a high demographic score, thus raising the height (saturation level) of the adoption curve. This rise in saturation is, however, offset by declining scores from assumed reductions in home ownership and decreases in separate dwellings (discussed in Section 4). In fact, because these other drivers are stronger or equal to income, on balance, the growth in income does not increase the saturation level and principally serves to reduce the rate of decline in the market saturation point (i.e., by partially offsetting the other factors which are causing a decline in the saturation point). The saturation point changes the shape of the adoption curve when it is fitted. The adoption curve shape influences the potential number of installations (but movement along the curve is mostly driven by changes in the payback period).

There is another way economic growth could impact projections. If higher GDP/income means more residential or commercial connections to the grid this could increase uptake. The projected adoption rate is directly multiplied by connections and therefore higher connections increase adoption proportionally.

3 Scenario definitions

The four scenarios are *Progressive Change, Exploring Alternatives, Step Change* and *Hydrogen Export*. The AEMO scenario definitions are described in narrative form and then by their key drivers in Table 3-1. To implement the solar PV and battery projections, CSIRO has developed an additional set of extended scenario definitions based on consideration of additional economic, infrastructure and policy drivers. These are summarised and then each of the financial and non-financial drivers are described in more detail.

Progressive Change

In this scenario:

- The COVID-19 recovery is slow – followed by other epidemiological scares (like Monkeypox), supressing global growth, investment, and employment levels, and resulting in lower levels of growth in Australia. More insular trade policies and increased protectionism take hold globally. Australia's population growth is relatively lower than other scenarios, with falling birth rates and immigration levels, partly due to sustained impacts on global mobility.
- In search of cost savings, consumers continue to install distributed PV, though at lower rates than recently – the reduction partly due to relatively higher costs of panels and inverters due to supply chain issues.
- Similarly, investment in household battery storage and EVs does not grow as fast as other scenario forecasts, due to more muted cost reductions, the impact of lower disposable incomes, vehicle supply chain issues, softening in peak demand price signals, and longer vehicle replacement cycles.
- Investment in alternative heating appliances to transition away from gas is more muted due to challenging economic conditions. This may pick up in time.
- Government policy reflects current commitments, particularly 43% emissions reduction by 2030 and net zero emissions by 2050 (as well as key state-based commitments). Lower economic activity reduces total energy requirements, lowering the needed reduction relative to other scenarios. Internationally, current policy settings are insufficient to achieve the objectives of the Paris Agreement regarding temperature control.

Exploring Alternatives

In this scenario:

- Moderate growth in the global and domestic economy is observed following recovery from the pandemic and Ukrainian crisis.
- Australia achieves its updated nationally determined contribution of reducing emissions by 43% on 2005. Existing legislated and planned state VRE policies and targets are a key driver in the short term, but additional actions are required both at state and federal level to deliver this overall target.

- Investment in alternative gas production retains a more diverse set of solutions in the longer term, and enabling Australia to still sufficiently contribute to what is required to limit global temperature increase to well below 2°C.
- Uptake of DER, energy efficiency measures, and the electrification of the transport sector reflect current trends in distributed investments and policy considerations.
- The costs of VRE and storage technologies continue to fall and are increasingly competitive with existing fossil-fuelled generation. Climate and economic factors influence coal closures.
- Investment in green gas production, in particular biomethane, strengthens the role of the gas network during the transition, limiting the need for as much electrification of gas end-use relative to Step Change and Hydrogen Export.
- Hydrogen production costs do not fall sufficiently to dominate domestic or global energy markets, resulting in limited economic uptake in the NEM.
- While Australia does deliver on its 2030 Paris commitments, global carbon reduction commitments and ambitions do not keep sufficient pace with what is necessary to achieve a longer-term temperature increase to below 2°C.

Step Change

In this scenario:

- Moderate growth in the global and domestic economy is observed following recovery from the pandemic and Ukrainian crisis.
- High levels of awareness towards the impacts of climate change from increasingly energy literate consumers result in a greater degree of individual consumer action to reduce emissions. DER uptake is driven by consumers taking greater ownership over their consumption, increasing the level of active participation by consumers in energy use. This is aided by continued advancement in digital technologies, innovation in business models enabling consumer engagement, and market reforms. This extends the strong uptake in DER technologies, to allow consumers to manage their energy use efficiently and provide flexibility to the system through enhanced energy use monitoring and optimisation of use of flexible loads to meet system needs.
- Strong climate action underpins rapid transformation of the energy sector (and broader global economy) to achieve the Paris Agreement's goal of limiting global temperature rises to well below 2°C, ideally by 1.5°C, relative to pre-industrial levels. Domestically, government policy and corporate objectives are aligned with the need to decarbonise the Australian economy, going beyond existing climate policy.
- Currently legislated or materially funded state-based VRE policies and targets are achieved, with future electricity sector investments influenced by policy measures that reduce cumulative emissions over time. Limiting emissions may lead to earlier withdrawals of emissions-intensive generation sources, and increased shifts towards low-emission electrical alternatives to coal, gas, oil, and diesel-powered processes.

- Decarbonisation ambition provides some opportunity for domestic hydrogen or biofuel substitution for traditional gas users as manufacturing and other sectors innovate to decarbonise.
- This scenario assumes that the scale of hydrogen production connected to the NEM is limited, either technically or economically, such that hydrogen production does not materially impact the NEM's investment or operation. Only limited Hydrogen Export facilities are connected to the NEM in this scenario.
- The degree of electrification is high, particularly from the transport sector, where EVs soon become the dominant form of road passenger transportation. This includes continued innovation in transport services, such as ride-sharing and autonomous vehicles, that may influence charge and discharge behaviours of the EV fleet, including vehicle-to-home discharging trends.
- Consumers also switch from gas to electricity to heat their homes. Strong electrification from other sectors is expected as a means to decarbonise manufacturing and other industrial activities.
- Overall, the scenario assumes relatively stronger rates of technology cost decline for consumer devices such as DER, and energy efficiency and energy management systems penetrate much more into mainstream technology adoption.
- The scenario incorporates some growth in carbon sequestration, particularly within the land-use sector that offset emissions that are hardest to abate, to get towards net zero emissions without needing to rely so heavily on electrification of the most challenging industrial processes.

Hydrogen Export

In this scenario:

- Strong global support to address climate change and reduce emissions hasten action to decarbonise. This is enabled through strong economic activity and global investments to meet the preferred objective of the Paris Agreement to limit global temperature rise to 1.5°C. To achieve this, and as part of commensurate global action, Australia targets net zero emissions before 2050.
- Capitalising on significant renewable resource advantages and economic and technological improvements in hydrogen production, Australia establishes strong hydrogen export partnerships to meet international demand for clean energy.
- The export of green hydrogen and other energy-intensive products such as green steel, supports stronger domestic economic outcomes relative to other scenarios, which again causes a higher rate of migration to Australia.
- Both domestic and export hydrogen demand is fuelled, at least in part, by NEM-connected electrolysis powered by additional VRE development.
- Strong economy-wide decarbonisation objectives provide significant opportunities to fuel switch towards electricity and hydrogen. The energy transition in Australia is embraced by consumers, as they seek clean energy and energy efficient homes and vehicles.

Table 3-1 AEMO scenario definitions

Scenario	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Decarbonisation target	43% emissions reduction by 2030. Net zero by 2050 (RCP 4.5)	At least 43% emissions reduction by 2030. Net zero by 2050 (RCP 3.4) Australia's emissions trajectory consistent with limiting warming to well below 2°C, but some countries are lagging globally	At least 43% emissions reduction by 2030. Net zero by 2050 (RCP 2.6) Emissions trajectory to limit warming to well below 2°C	At least 43% emissions reduction by 2030. Net zero by 2050 (RCP 1.9) Emissions trajectory to limit warming to <1.5°C
Global economic growth and policy coordination	Slower economic growth, lesser coordination	Moderate economic growth, moderate coordination	Moderate economic growth, stronger coordination	High economic growth, stronger coordination
Australian economic and demographic drivers	Lower	Moderate	Moderate	Higher (partly driven by hydrogen export)
DER uptake (i.e., rooftop PV, batteries and EVs)	Lower	Moderate	Higher	Higher
Consumer engagement e.g., in uptake of VPP and DSP	Lower	Moderate	Higher	Higher
Energy Efficiency	Lower	Moderate	Higher	Higher
Hydrogen use	Allowed	Allowed	Allowed	Faster cost reduction. High production for domestic and export use
Biomethane/synthetic methane	Allowed	10% blending target for reticulated gas by 2030. Faster cost reductions	Allowed	Allowed
Electrification (excl. EV)	Allowed (endogenous)	Allowed (endogenous)	Higher (exogeneous?)	Allowed (endogenous)
Social license to develop energy infrastructure	Limited social licence impacting the speed and scale of transformation	Moderate social licence	Moderate social licence	Moderate social licence
Supply Chain barriers	More challenging	Moderate	Moderate	Less challenging
Shared Socioeconomic Pathway	SSP3	SSP2	SSP1	SSP1
IEA 2021 World Energy Outlook scenario	STEPS	APS	SDS	NZE
Generation cost estimates (GenCost)	Current Policies	Global NZE post 2050	Global NZE post 2050	Global NZE by 2050

3.1.1 Extended scenario definitions

The AEMO scenario definitions have been extended by CSIRO in Table 3-2 by adding additional detail on the economic, infrastructure and business model drivers. The purpose is to fill out more detail about how the scenarios are implemented whilst remaining consistent with the higher level AEMO scenario definitions. The extended table remains a summary and does not include all scenario assumptions. We discuss what has been considered and included for each driver in more detail below.

Table 3-2 Extended scenario definitions

Driver	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Commonwealth SRES subsidy	Continues to 2030 phasing down	Continues to 2030 phasing down	Continues to 2030 phasing down	Continues to 2030 phasing down
NSG solar subsidies available in addition to LGCs	ACCU and VEEC subsidies available and increasing 2% p.a.	ACCU and VEEC subsidies available and increasing 3% p.a.	ACCU and VEEC subsidies available and increasing 3% p.a.	ACCU and VEEC subsidies available and increasing 5% p.a.
State rooftop solar and battery storage subsidies or support schemes (detailed in Section 3.2.5)[5]	Current state policies	Current state policies	Current state policies.	Current state policies.
Growth in apartment share of dwellings	High	Medium	Medium	Low
Decline in home ownership	High	Medium	Medium	Low
Tariff and DER incentive arrangements[1]	Slow transition	Moderate transition	Stronger energy management incentives	Stronger energy management incentives
System architecture changes support greater incentives to DER participation	Low	Medium	High	High
Feasibility of participation of apartment dwellers and renters in DER	Low	Medium	High	High

1. The assumed shares of TOU tariffs and more direct control measures such as Virtual Power Plant are outlined in Table 4-2 .

The scenario definitions are in some cases described here in general terms such as “high” or “Low”. More specific scenario data assumptions are outlined in the next section and in Section 4.

[5] Many of these state schemes only provide for subsidies for a few years into the future. Victoria’s solar scheme is the longest running ending in 2028. We do not extend any of these schemes except for state abatement credits.

3.2 Financial and non-financial scenario 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 3-3.

Table 3-3 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	Varied by scenario and 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 4.3.1
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 varied over time to converge towards the wholesale market price which is varied by scenario and outlined in Section 4.3.1
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 3-4 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 4.6
Garage or indoor space, ideally air conditioned, shaded and ventilated (battery storage)	Varied by scenario and expressed as maximum market share constraints in Section 4.6
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 benefits of any longer-term payback from solar or integrated solar and storage systems)	Varied by scenario and expressed as maximum market share constraints in Section 4.6
Distribution network constraints imposed on small-scale systems as a result of hosting capacity constraints (e.g., several distribution networks have set rules that new rooftop system sizes may be no larger than 5kW per phase)	Varied by scenario and expressed as maximum rooftop system sizes outlined in Section 4.6
Distribution network constraints relating to connection of solar photovoltaic projects in the 1MW to 30MW range	Not included or varied by scenario due to lack of data
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)	Ability to export degrades at a rate of 1% per annum for systems without batteries in all scenarios but each scenario has a unique level of battery uptake
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

Expanding further on the penultimate dot point, South Australia has pioneered control or curtailment of rooftop solar PV exports during periods of low minimum demand. The projections assume that these or more sophisticated solutions will be implemented in other states over time to avoid breaching security and reliability limits without putting additional explicit limitations on DER uptake.

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 3-5 explores some emerging and potential business models which could drive higher adoption. Demand management is an example where there have been trials and rule changes which are the basis of emerging business models which could become more established in the long run. 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 accessing and rewarding greater value from the battery than simply shifting local solar generation.

Table 3-5 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 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	Given the predominance of volume-based tariffs, the main value for customers of battery storage is in reducing rooftop solar exports. The appetite for

Name	Description	Constraint reduced
	tariff structures or direct ownership and operation of battery to reduce costs elsewhere in the system	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[6])	Except for remote area power systems and edge of grid, it is cost effective to connect all other customers to the grid
Going off-grid and green	Energy service companies sell suburban off-grid solar and battery systems plus a non-petroleum back-up system yet to be identified but suitable for suburban areas	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.

3.2.4 Commonwealth policy drivers

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.

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

Table 3-6 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	Assumed to continue as planned with significantly lower prices due to scheme saturation in all scenarios
Emission reduction fund and Climate solutions fund	Price of emission credits grows at 2% per annum in *Progressive Change*, 3 % in *Exploring Alternatives* and 5% in *Step Change* and *Hydrogen Export*.

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. While the LGC price has increased at times post-2020 reflecting the strengthening climate ambitions of corporations, the LGC price is expected to decline to low levels in the next few years as the quantity of renewable generation continue to grow above the required level.

Emissions Reduction Fund and Climate Solutions Fund

The Emissions Reduction Fund (ERF) was extended by the Climate Solutions Fund announced in 2019. The ERF consists of several methods for emission reduction under which projects may be eligible to claim emission reduction and bid for Australian Carbon Credit Units (ACCUs) which are currently awarded via auction. There price was in the range of $10-15/tCO$_2$e for many years but has been trending at twice that in the last year reflecting growing corporate demand for offsets.

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*. As the price of LGCs declines it may become more attractive to seek ACCUs under this method rather than LGC payments. Although we might expect the ACCU price to increase over time, they are not expected to provide as strong a signal as LGC prices have been in the past – more in the order of a $20/MWh subsidy compared to almost $90/MWh for LGCs at their peak.

3.2.5 State policy drivers

The policies discussed here are drawn from several state government websites[7]. While we summarise them all, we do not include each one in the modelling. The approach to including them in the scenarios is outlined in Table 3-7. Feed-in tariffs are addressed separately (in the following section) since they are a mix of market forces and government regulation.

NSW, Queensland and Victoria have policies that will work in addition to the Commonwealth RET. They are the NSW Electricity Infrastructure Roadmap, Victorian Renewable Energy Target (VRET) and Queensland Renewable Energy Target (QRET). Under current auction arrangements, VRET is only open to renewable generators above 10MW which is relevant for some small-scale solar but not rooftop solar. Although technically eligible, we do not expect either of these schemes to be available in practice to non-scheduled generation below 30MW because they will be less competitive than larger scale solar farms.

The Victorian government is providing a subsidy of $1400 for households, $3500 for businesses and means-tested interest free loans. The subsidies are available for residential solar systems with around 70,000 subsidies available each year but with some variation (the government updates the annual amount available each year). Up to 15,000 small businesses have been eligible since the scheme started. Another feature is a landlord-tenant agreement whereby renters can also access the scheme. The longer-term target is for 700,000 home solar systems over a ten-year period (from late 2018) including 50,000 targeting solar for rental properties together with 17,500 batteries and 60,000 hot water systems.

For batteries, the Victorian scheme has been expanded to include 17,500 systems over the next three years. Rebates up to $2,950 are available.

Large Victorian solar projects are also eligible for Victorian Energy Efficiency Certificates (VEECs). These are administratively less complex than applying for ACCUs and the price of VEECs is currently more attractive at around $30/tCO$_2$e. As with the emissions reduction fund, this potential subsidy source will become attractive only once LGC prices have declined further.

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[7] Solar panel (PV) rebate | Solar Victoria

Ensuring more Victorian households and small businesses have access to solar energy | Solar Victoria

Next Generation Renewables - Environment, Planning and Sustainable Development Directorate - Environment (act.gov.au)

Peak Demand Reduction Scheme | Energy NSW

The Queensland government accepted a recommendation to not include any incentives under the QRET for rooftop solar in addition to the Commonwealth Small-scale Renewable Energy Scheme. There are no current schemes for rooftop solar and batteries in Queensland.

The NSW Electricity Infrastructure Roadmap is not open to small scale solar or batteries. The key small-scale NSW policy is to provide 3kW solar systems to low-income groups already receiving the Low Income Household Rebate. The NSW government also has a Regional Community Energy Program and a Smart Batteries for Key Government Buildings Program. These are niche programs to fund solar or batteries for selected community and government infrastructure. Finally, the NSW government is planning a Peak Demand Reduction Scheme which may offer additional revenue for batteries once installed.

The South Australia government's policy of providing subsidies to 40,000 homes to install batteries operated over several years and has been fully allocated.

The ACT government is making available a subsidy targeting deployment of 5000 batteries under its Next Generation Energy Storage scheme. The overall target is for 36 MW of battery storage. The rebate available is $3,500 (excluding GST) or 50% of the battery price (excluding GST) for households – whichever is lowest and for businesses, the rebate is $35,000 (excluding GST) or 33% of the battery price (excluding GST) – whichever is lowest

Table 3-7 Summary of state policies supporting solar and batteries and their inclusion in scenarios

	Policy	Approach to including across all scenarios
NSW	3000 3kW solar systems to low-income groups already receiving the Low Income Household Rebate	Not included. Assumed non-additional design is targeted at customers already receiving bill relief.
NSW	The proposed Peak Demand Reduction Scheme may offer additional revenue for batteries once installed	Included through general virtual power plant tariff and payments considerations
VIC	Renewable energy target of 50% by 2030	Not included. These subsidies are not targeted at small scale solar PV.
VIC	700,000 home solar systems over ten years. Policies include a subsidy of half the cost of solar (up to a value of $1,400) including means-tested interest free loans. Another feature is a landlord-tenant agreement whereby renters can also access an additional 50,000 systems.	Minimum addition of 70,000 residential solar systems per year to 2028-29 with some allowance for variation between scenarios in first two years to reflect uncertainty and updated scheme subsidy availability (the exact subsidies available is announced annually and can vary year to year)
VIC	The Solar Homes policy includes battery subsidies for up to 17,500 homes (Victorian premier, 2018). Rebates of up to $2,950 are available.	Minimum addition of 5,000 residential battery systems the next three years, not falling below that rate thereafter.
VIC	In the Victorian Energy Saver Incentive Scheme, embedded solar systems not claiming large- or small-scale technology certificates are eligible to create Victorian Energy Efficiency Certificates.	The value of certificates is assumed to increase 2% per annum in *Progressive Change*, 3 % in *Exploring Alternatives* and 5% in *Step Change* and *Hydrogen Export*
QLD	Renewable energy target of 50% by 2030	Not included. These subsidies are not targeted at small scale solar PV.

	Policy	Approach to including across all scenarios
ACT	The ACT government is making available an $3,500 residential subsidy ($35,000 for business) targeting deployment of 36MW of battery storage under its Next Generation Energy Storage scheme.	Minimum addition of 5000 batteries by 2023
ACT	Pensioners who own their home are eligible for up to 50% (with a cap of $2500) of a home solar system.	Minimum addition of 5000 systems over five years
All	State feed-in tariffs	Varied over time to converge towards generation price which is varied by scenario and outlined in Section 4.3.1

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 5-10 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:

- Northern Territory: 9.13c/kWh for both residential and commercial customers[8].
- Queensland: Recognising lower competition, regional Queensland FiTs are set by the state government and were 9.3c/kWh from July 2022[9].
- Western Australia: From 31 August 2020, residential, non-profit and educational premises who were eligible for the Renewable Energy Buyback Scheme' for new residential solar power systems installed in Western Australia will no longer receive the Fit of 7.135 cents per kilowatt-hour. Instead, they will receive the DEBS or 'Distributed Energy Buyback Scheme' that will instead pay[10]:
    - 2.5 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.

[8] Solar Update | Jacana Energy

[9] Solar feed-in tariff for regional Queensland | Homes and housing | Queensland Government (www.qld.gov.au)

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

- Victoria: The current minimum feed-in tariff of 5.2c/kWh is set by the government[11]. 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 2022 with prices of 7.1 and 6.9c/kWh during off-peak and peak respectively and the daytime feed-in tariff at 5.0c/kWh.
- Tasmania: The feed-in tariff for residential and commercial customers is 8.883c/kWh from July 2022[12].

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 2020/21 financial year is 6.2 to 10.4 cents per kilowatt hour[13].

Overall, feed-in tariffs set by the states have fallen reflecting the lower value of solar exports as the number of solar systems operating at the same time increases, reducing demand for grid generated electricity at these times.

3.2.6 Regulations and standards

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

Previous projections of operational demand have identified that some states may experience negative load in the 2020s and 2030s if forecasts of rooftop and non-scheduled solar generation projections are realised. This raises the prospect that the electricity system will need to prepare

[11] Minimum feed-in tariff (energy.vic.gov.au)

[12] Feed-in Tariffs (economicregulator.tas.gov.au)

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

contingencies for some combination of curtailment, demand management and standby generation to maintain system stability.

Given the difficulty of predicting the electricity system reform process and subsequent impacts on customers, we have made no assumptions about the degree of lost solar production and exports as a result of distribution network congestion or efforts to manage state loads for stability. The issue is partially addressed in the projections method by imposing a financial penalty of declining export revenues and in a technical sense by assumed maximum inverter capacity connection limits and dynamic export controls.

AEMC has recently consulted on allowing networks to include export prices in their pricing structure. The direct impact of this restructure of tariffs is to reduce returns from exports. In some ways this is not new and fits with the general outlook for a decline in feed-in tariffs that is expected to continue over the long term. Indirectly, it provides a limited incentive to take up batteries. That is, for as long as the upfront cost of batteries remains high cost, the avoidance of an export tariff likely only features as a small driver of uptake.

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 was sourced from the GenCost 2021-22 final report by Graham et al. (2022). The GenCost report contains three global cost projection scenarios called Current policies, Global NZE post 2050 and Global NZE by 2050. *Progressive Change* is assigned the Current policies cost projections. *Exploring Alternatives* and *Step Change* are assigned Global NZE post 2050 cost projections. *Hydrogen Export* is assigned the fastest cost reduction projection which is Global NZE by 2050.

The 2022 costs shown imply that a 6.6kW system ought to be advertised for approximately $6,400 (6.6 × (1340-365)[14]). However, we also see 6.6kW systems advertised in the range of $4000 installed (or $970/kW before subsidies) reflecting significant differences in the quality of products and the scale of installation businesses (that is, economies of scale may support discounting). However, we include the higher current cost estimate on the basis that the cost trajectory applied is steep enough to allow for a greater prevalence of the lower observed prices over time.

It is also evident that locations that are further from capital cities pay a remoteness premium for installations, and we have factored this in as a one third premium in low population density regions. A full survey of regional market prices was not in scope.

[14] $1340/kW for the solar capital cost before subsidies and $365/kW for the small-scale technology certificates.

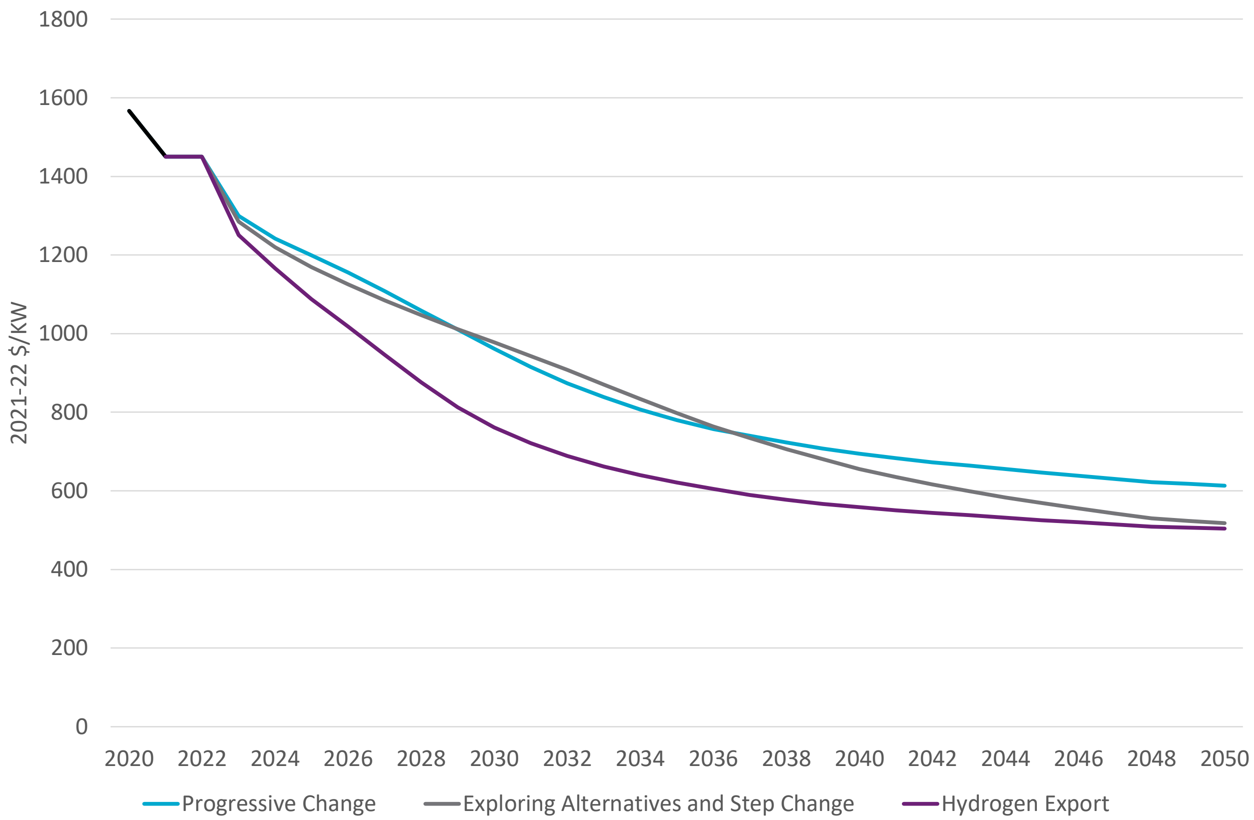

Figure 4-1 Assumed capital costs for rooftop and small-scale solar installations by scenario (excluding STCs or other subsidies)

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 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.

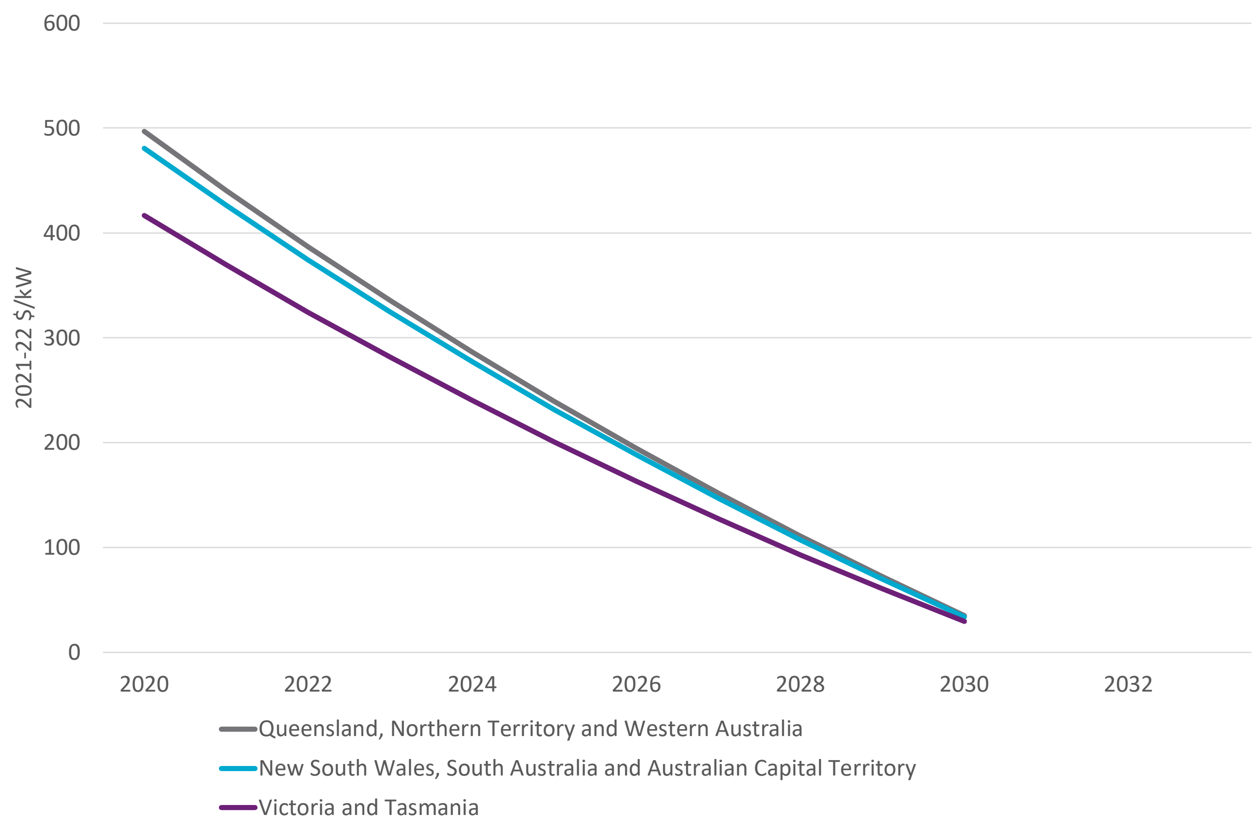

Figure 4-2 Assumed STC subsidy available to rooftop solar and small-scale solar systems by state

4.1.3 Batteries and installation

The current capital cost of small-scale batteries is sourced from GenCost 2021-22 which draws on Aurecon (2022). The cost trajectory over time is aligned with changes in large-scale battery capital costs presented in GenCost 2021-22 (Graham et al. 2022). Small-scale systems have a significant premium over large scale systems that is not as evident in the relationship between small-scale solar and large-scale solar. If this premium were too narrow over time, the cost reduction for small-scale batteries would be faster than the large-scale solar cost reduction rate. However, so far there is no sign of this potential phenomenon, and it is not included in the assumptions.

The scenarios are assigned to the corresponding GenCost cost projection scenarios in the same way as solar - *Progressive Change* to current polices, *Exploring Alternatives* and *Step Change* to Global NZE post 2050 and *Hydrogen Export* to Global NZE by 2050. 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. King et al. (2018) found that only 2% of lithium-ion batteries were collected for offshore recycling compared to 98% of lead acid batteries. However, Norway has constructed recycling facilities for lithium-ion batteries (likely reflecting its large electric vehicle fleet as the feedstock source). We make no assumptions about disposal costs given the relative lack of maturity of the Australian lithium-ion battery recycling industry.

GenCost 2021-22 projects a steady but slowing rate of cost reduction. The battery pack falls at a faster rate but the inverters which are the largest balance of plant cost fall more slowly reflecting their relative maturity. Other elements of balance of system are system integration and installation.

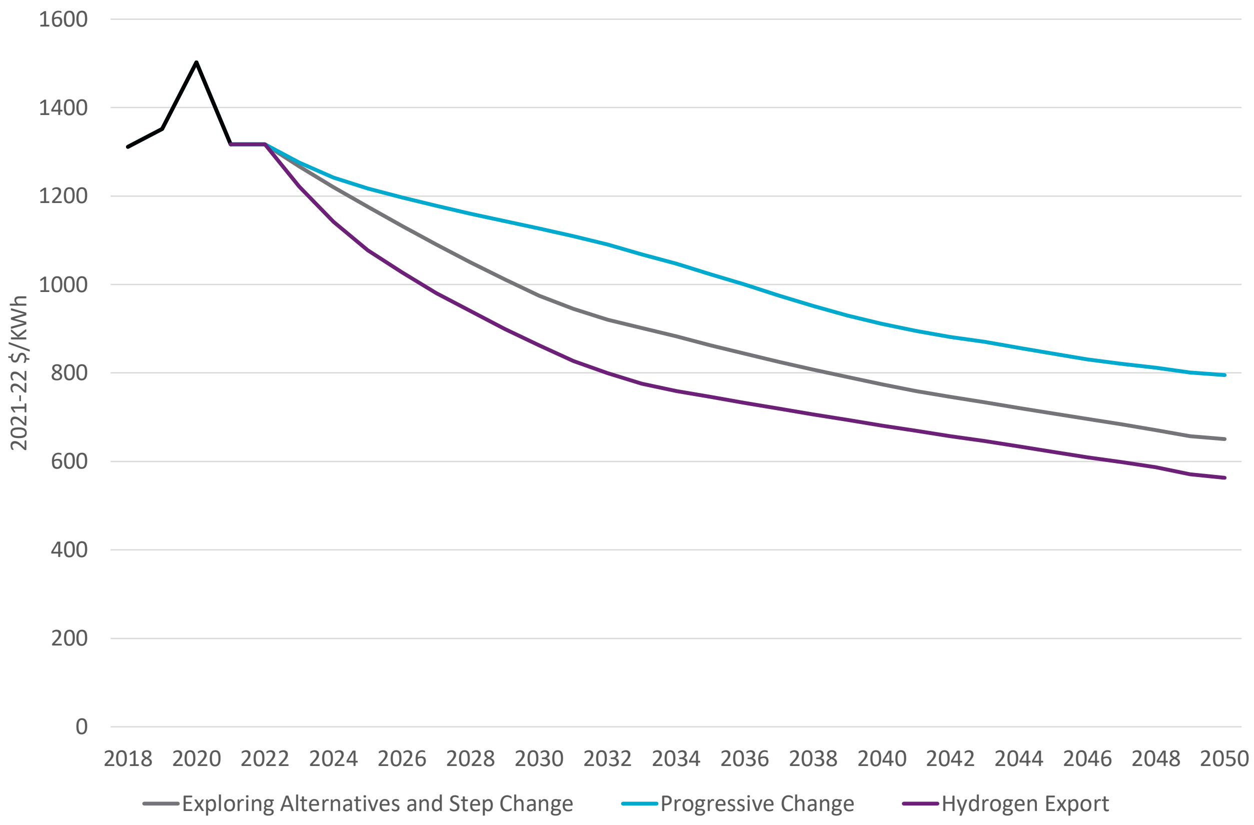

Figure 4-3 Assumed capital costs for battery storage installations by scenario

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 Figure 4-5. These are the size of the panels, while inverters are the same size or smaller. We impose a trend in 2023 and then impose different assumptions by scenario from 2024 to 2050.

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. Hence, we commonly see offers for 6.6kW solar with a 5kW inverter[15]. The average for new residential systems has been above 6.6kW and sits at 7.6kW in 2022 so at least a portion of customers are pursuing larger systems (noting that the public CER data does not differentiate between residential and commercial systems and so the 6.6 threshold was crossed around 2017 from a combined residential and commercial systems perspective). This continued increase in residential system sizes has led to an assumed increasing trend in the short term. Over the longer term we assume system sizes will plateau and there are a number of considerations supporting that.

[15] We assume this ratio will become the norm as these systems increase their penetration.

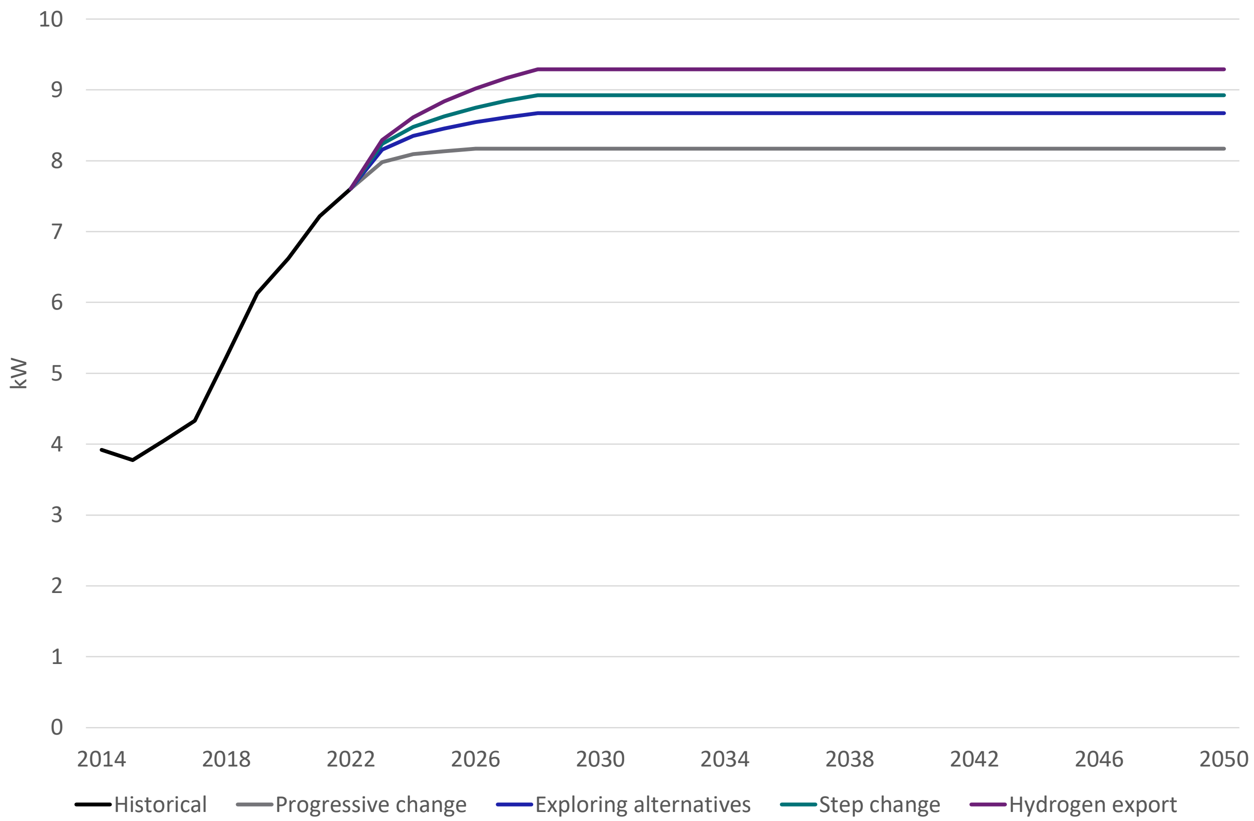

Figure 4-4 Historical and assumed future size of new residential solar systems

Many networks impose a connection limit of 5kW per phase and these may tighten in the future as hosting capacity (the ability of the system to support more distribution connected solar generation without crossing desired power quality thresholds) declines. Dynamic connection levels are also being explored as an alternative, but these also represent a message to consumers that they cannot use their full capacity at all times for export. While most homes have one phase, for those with two or three phases a limit per phase is less constraining on PV size installation. Government subsidies per watt of solar power capacity are declining (see also discussion of STCs in the body of the report) and being replaced with rebates or low interest loans. Based on these drivers, we assume the recent increasing system size trend will continue for several years but ultimately saturate in the long run in the residential sector reflecting expected declining revenue for export solar and general tightening of either static or dynamic network connection limits (both of which could significantly reduce the payback on marginal capacity). Physical roof size is of course another ultimate limit to system size. However, we expect that with lower solar panel costs and improving panel efficiency, acceptance of the use of non-north facing roof areas will continue to grow.

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 at a faster rate than residential systems.

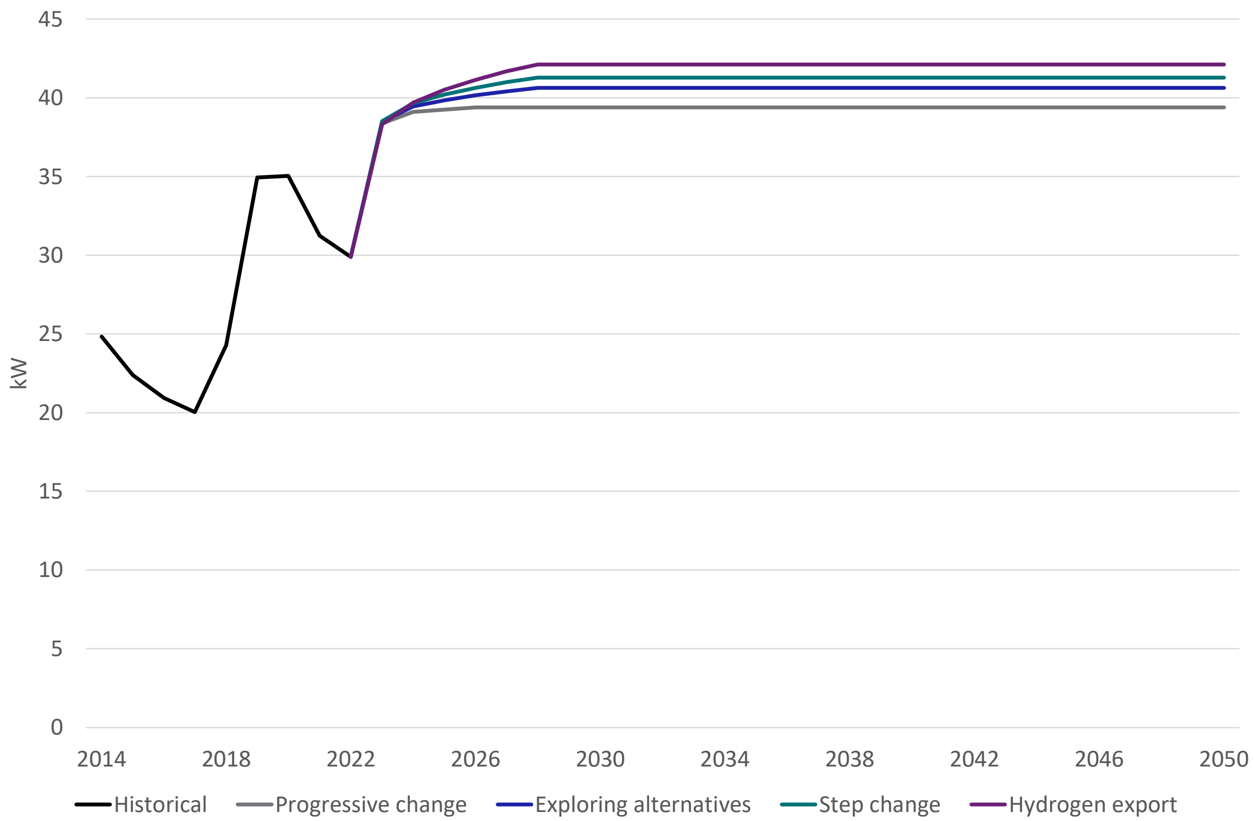

Figure 4-5 Historical and assumed future size of new commercial solar systems

4.3 Electricity tariffs, battery management and virtual power plants

4.3.1 Assumed trends in retail and generation prices

Retail electricity prices have increased significantly in 2022-23 reflecting the impact of high international fossil fuel prices on generation costs. These higher generation costs are expected to ease in the next few years as international circumstances improve and increasing non-fossil fuel capacity is brought into the generation market. Some 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. The non-generation components of the retail price are expected to be more stable.

Retail electricity prices in Western Australia are set by government and are therefore less volatile. Commercial retail prices are assumed to follow residential retail price trends for all scenarios, although under different tariff structures.

Day time generation prices and feed-in prices

Day time generation prices are important as a long-term anchor point for feed in tariffs. Feed-in tariffs do not have to reflect daytime generation prices as retailers will have their own pricing strategies for recruiting and retaining customers. This can mean export prices are higher than their wholesale value. Other issues like changes in tariff structures (e.g., export fees) and curtailment also impact the export revenue. Based on unpublished CSIRO electricity modelling of similar scenarios, we have made assumptions about the long-term trajectory of rooftop solar PV production weighted generation electricity prices, and we use the financial impact of this assumption to capture all of the broad range of factors that are likely to reduce the value of exports.

We assume that feed-in prices will converge towards their state rooftop solar PV production weighted price which, by 2050, on average, will fall by the amounts shown in Table 4-1. *Progressive Change* has the greatest impact because it has low system demand growth. The decrease in daytime prices is the least in *Hydrogen Export* because, despite strong growth in large and small scale solar it has a large hydrogen industry which is expected to match some of its load to supply countering the dampening effect of coincident large- and small-scale solar output on prices. *Step Change* has high solar PV deployment, but stronger demand is also assumed to partially offset this factor.

Table 4-1 Assumed reduction in rooftop solar production weighted wholesale market prices by 2050 relative to 2022

Scenario	Reduction
Progressive Change	50%
Exploring Alternatives	43%
Step Change	40%
Hydrogen Export	33%

4.3.2 Current electricity tariff status

Electricity tariff structures are important in determining the return on investment from customer adoption of EVs and, perhaps importantly for the electricity system, how they operate those technologies. The majority of residential and some small-scale business customers have what is called a ‘flat’ tariff structure which consists of a daily charge of $0.80 to $1.20 per day and a fee of approximately 20 to 30c 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. Customers in some states have an additional discounted ‘controlled load’ rate which is typically connected to hot water systems.

Except where flat tariffs are available to smaller businesses, in general, business customers generally face one of two tariff structures: ‘time-of-use’ (TOU) or ‘demand’ tariffs. 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 business tariff structures reflect the fact that, at a wholesale level, the time at which electricity is consumed and at what capacity does affect the cost of supply. These tariff structures are not perfectly aligned with daily wholesale market price fluctuations but are a far better approximation than a flat tariff. In that sense, TOU and demand tariffs are also described as being more ‘cost reflective’ or ‘smart’ tariffs.

A smaller but increasing proportion of residential customer also have TOU retail tariffs. Some more technically savvy customers have determined that TOU tariffs give them the best opportunity to manage their costs, particularly if they have a home battery system. In other cases, flat retail tariff customers have been moved to TOU retail tariffs when they connect to solar PV or make other significant changes to their connection.

There is also a class of tariffs called network tariffs. These are the tariffs that networks charge retailers. In most cases networks are increasingly charging retailers a TOU tariff for residential customers and the share of customers assigned to the tariffs is projected to rise (Figure 4-6). 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.

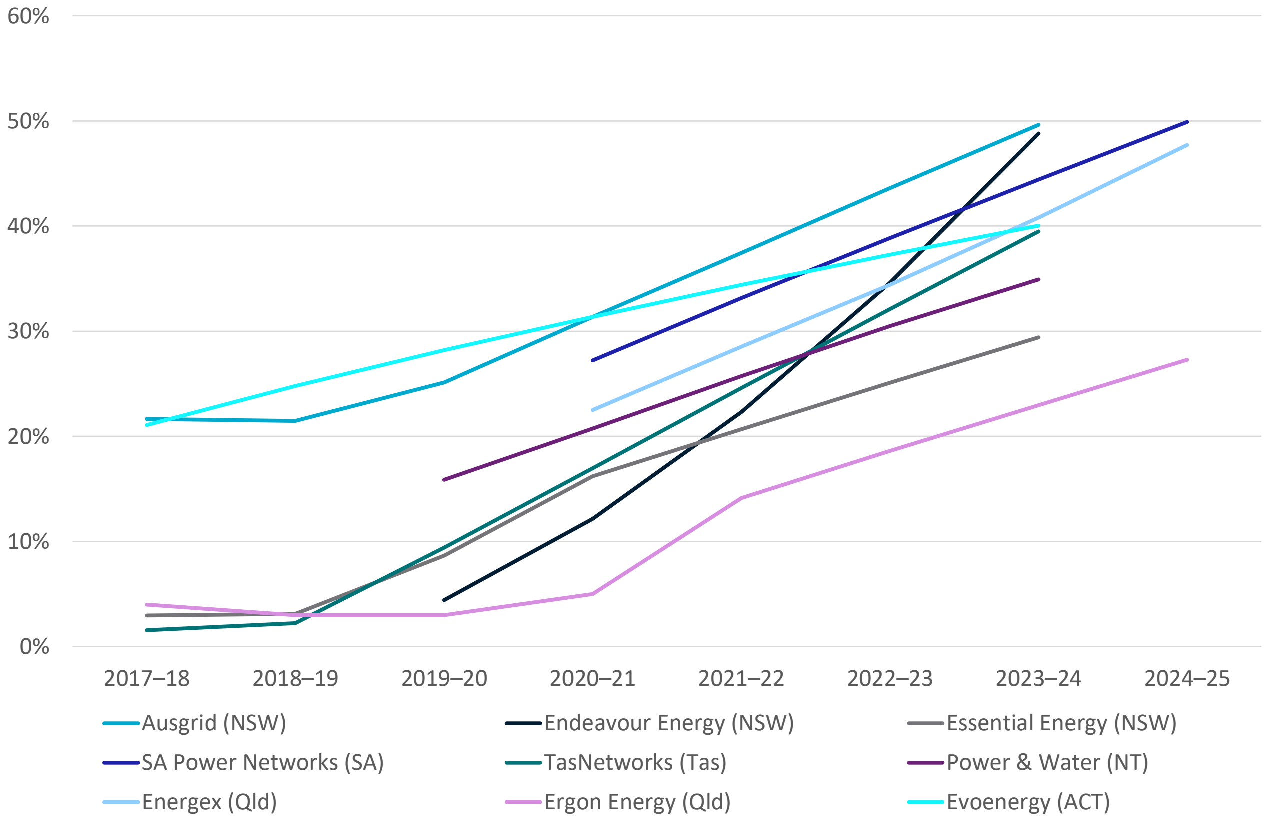

Figure 4-6 Projected assignment of cost-reflective tariffs for residential consumers by electricity distribution networks, AER (2021)

Some customers with home batteries have also participated in virtual power plant (VPP) trials. AEMO (2021) reported that around a quarter of all registered battery owners had participated in trials. Given the propensity for trial offers to be more generous than market offers its unclear how well this may translate out of trials. However, it is an indicator that battery ownership is a facilitator for customer adoption of more complex tariffs. This likely reflects that customers are less invested in how their batteries operate (of all home appliances, their daily operation does not impact directly on household amenity and comfort).

4.3.3 Future developments in battery owner incentives and management

Changes to customer connections and network charges to retailers are the main policy arrangements in place for changing the tariff structures that battery owners face. Historical research has shown that customers do not necessarily want more complicated tariffs[16] but there are clearly cases, such as in the recent VPP trials, where customers are willing to adopt new approaches. Retailers have already demonstrated success in offering cost savings for battery owners to charge and discharge at times that are lower cost for the system and reward owners.

There are long term issues with relying too heavily on TOU tariffs as the main incentive and control mechanism. Once batteries reach a greater critical mass, TOU tariffs will result in new peak charging behaviours during the transition from peak to off-peak pricing. Consequently, this report also considers more direct control measures 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 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. 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[17]. In a fully commercial project, the proportion of this revenue that might be shared with the owner of the batteries is unknown.

For the purposes of projecting uptake of batteries, our assumption is that, with more refinement of VPP markets, an incentive of around $250 per year in all scenarios is available to residential customers (i.e., implemented as a rebate) and a higher amount for commercial customers proportional to their battery size. We also assume that commercial customers will be moved over to VPP schemes in a less voluntary way than residential customers as the effectiveness of time-based tariff structures for controlling loads with DER devices wanes[18].

In the absence of inclusion in a VPP program (or when VPP mode is not active), most other battery owners are assumed to be solar shifting with current TOU customers being shifted to VPP by 2030. Under flat tariffs customers will set their battery to do two things:

- 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. The assumed proportion of customers on each tariff contract type and the subsequent battery storage operating mode by scenario is shown in Table

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

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

[18] Time-based tariffs such as TOU and demand tariffs induce coincident DER responses which are of little concern while adoption is low. As adoption increases, to avoid creating coincident DER loads, TOU or demand price structures may need to be flattened or withdrawn altogether in favour of direct control.

4-2. The tariff assignments reflect the degree of technological success, expected political will or consumer interest to implement stronger energy demand management.

Table 4-2 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	Progressive Change	59%	18%	30%	72%	10%	10%
	Exploring Alternatives	56%	17%	28%	68%	15%	15%
	Step Change	50%	15%	25%	60%	25%	25%
	Hydrogen Export	51%	16%	26%	62%	23%	23%
2050	Progressive Change	53%	16%	26%	64%	20%	20%
	Exploring Alternatives	46%	14%	23%	56%	30%	30%
	Step Change	33%	10%	17%	40%	50%	50%
	Hydrogen Export	36%	11%	18%	44%	45%	45%

4.3.4 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 they 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 costly network upgrades.

Community batteries are not yet part of the projections. This discussion is provided to commence consideration of the relevant business models and market opportunities with a view to possible inclusion in future projection reports.

Installed and planned community batteries

Community batteries are beginning to be rolled out in Australia and several trials are underway. Many of the implemented batteries thus far are owned by Distribution Network Service Providers (DNSPs). However, one trial is owned and operated by the not-for-profit community organisation Yarra Energy Foundation (YEF) in Victoria in partnership with a local energy retailer. Appendix B summarises existing implementations and plans for future installations of community batteries in Australia. Furthermore, there have been several government announcements to support the rollout of community batteries in Australia (e.g., “Power to the People”; a $200m program to install 400 community batteries across the country (Reputex Energy, 2021); The Victorian Government’s $10m neighbourhood battery initiative to support project development, implementation-ready projects and research[19]; The ACT government's Big Canberra Battery Initiative[20]).

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

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[19] https://www.energy.vic.gov.au/batteries-and-energy-storage/neighbourhood-battery-initiative

[20] https://www.climatechoices.act.gov.au/policy-programs/big-canberra-battery

- 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 lack of viable business models for operating a community battery is a significant barrier to wider commercial uptake of community batteries.

4.4 Income and customer growth

4.4.1 Gross state product

Gross state product (GSP) assumptions by scenario are presented in Table 4-3 and these are provided by AEMO and their economic consultant, BIS Oxford Economics. These assumptions have been applied to project income growth which is relevant for calibrating adoption functions where income is part of the adoption readiness score. However, in our projection methodology, movement along the adoption curve is largely driven by factors other than economic growth. As such, economic growth assumptions have only a marginal impact on projections (for more discussion see Section 2.3).

Table 4-3 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
Progressive Change	1.8	2.1	2.0	1.4	2.1	1.3	2.0
Exploring Alternatives	2.1	2.4	2.3	1.7	2.3	1.5	2.3
Step Change	2.1	2.4	2.3	1.7	2.3	1.5	2.3
Hydrogen Export	2.7	3.0	2.8	2.1	2.7	1.9	2.6

4.4.2 Customer connections

Customer connections growth assumptions by scenario are shown in Table 4-4. These assumptions are relevant for establishing the current market share of solar and batteries per customer connection and converting projected adoption shares back to number of installations.

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

	New South Wales	Victoria	Queensland	South Australia	Western Australia	Tasmania	Australian Capital Territory
Progressive Change	1.0%	1.4%	1.3%	0.9%	1.6%	0.7%	1.7%
Exploring Alternatives	1.1%	1.6%	1.4%	1.0%	1.7%	0.8%	1.8%
Step Change	1.1%	1.6%	1.4%	1.0%	1.7%	0.8%	1.8%
Hydrogen Export	1.2%	1.8%	1.7%	1.1%	2.0%	0.9%	2.0%

4.5 Separate dwellings and home ownership

4.5.1 Separate dwellings

Owing to rising land costs in large cities where most residential customers reside, there is a trend towards building of apartments that are stratas, compared to 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 4-7). 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 assumption for *Exploring Alternatives* and *Step Change* was built by extrapolating past trends resulting in separate dwellings occupying a share of 45% by 2050, around 18 percentage points lower than the 2021 ABS Census data. The *Progressive Change* and *Hydrogen Export* assumptions were developed around that central projection with *Hydrogen Export* experiencing a less rapid shift to apartments which supports higher rooftop solar and battery adoption.

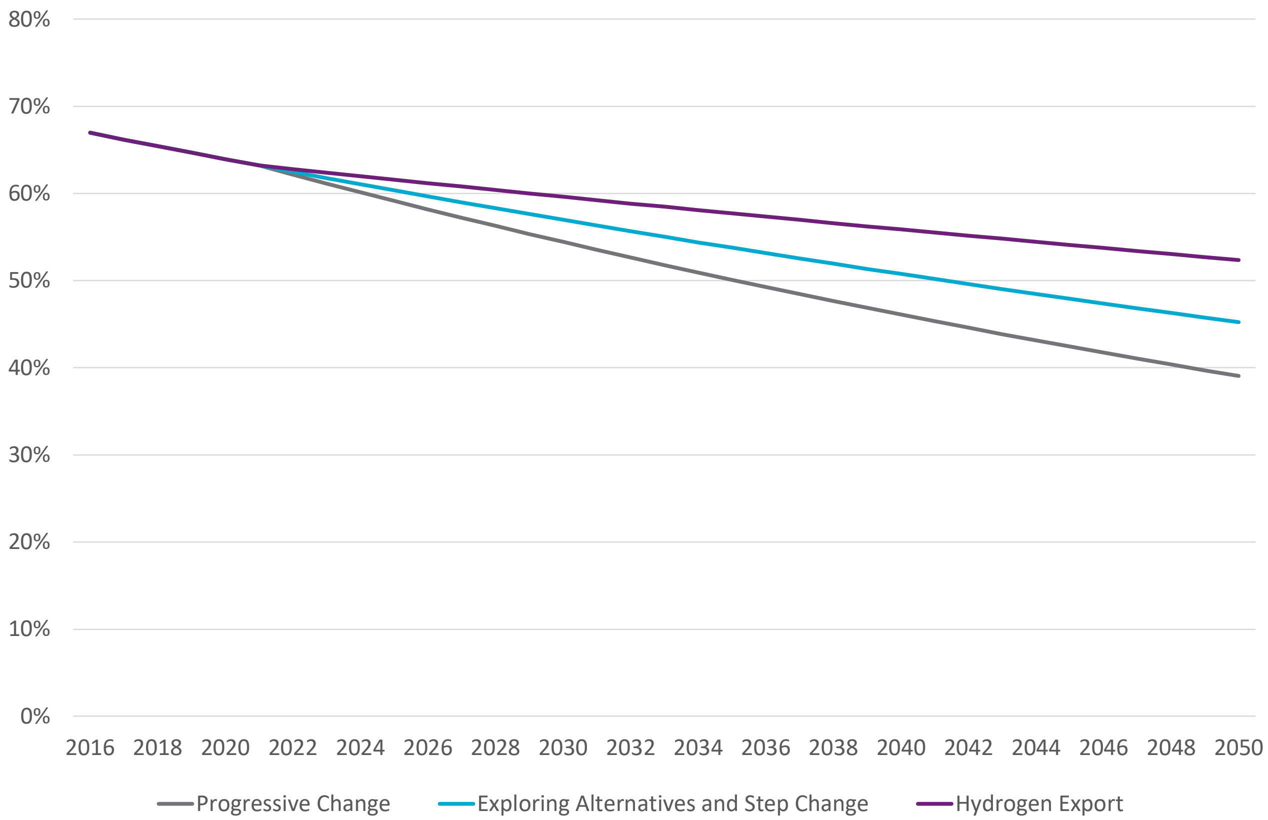


Figure 4-7 Assumed share of separate dwellings in total dwelling stock by scenario

4.5.2 Home ownership

While not a hard constraint, home ownership increases the ability of occupants to modify their house to include small-scale solar PV and batteries. Home ownership (which includes homes owned outright and mortgaged) increased rapidly post-World War II and was steady at around 70% for the last century. However, in the following 15 years home ownership declined to 2016 and increased slightly to 65.9% in the 2021 ABS Census (Figure 4-8). Ownership rates are not even amongst age groups with stronger declines in ownership among young people (25 to 34).

Under the *Exploring Alternatives* and *Step Change* scenarios, the declining trend in home ownership is assumed to continues to wane to 2050 at a rate consistent with the last 10 years. For the *Progressive Change* scenario, a declining trend consistent with that of the last 20 years is assumed, leading to a slightly faster reduction in home ownership rates. For the *Hydrogen Export* scenario, consistent with higher solar and battery installation, a slower rate of decline in home ownership is assumed consistent with the last 25 years (Figure 4-8).

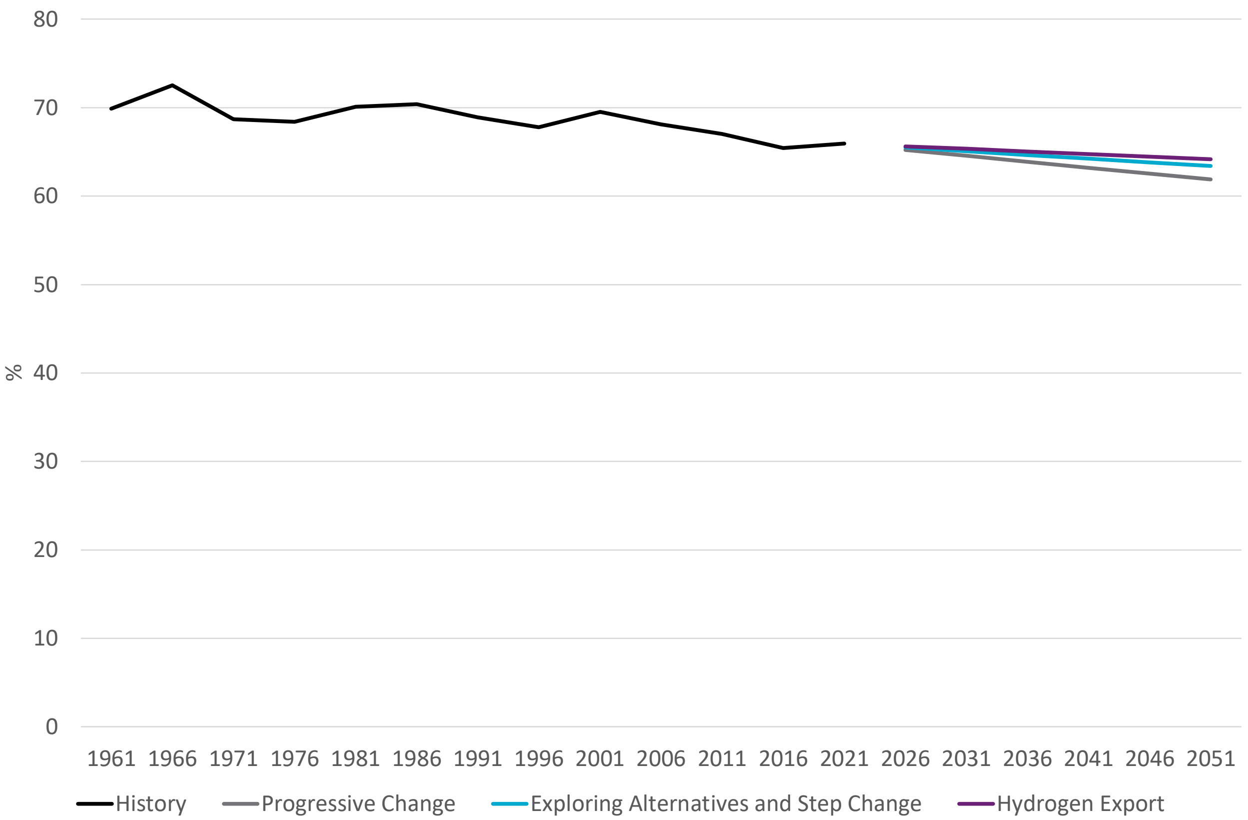


Figure 4-8 Historical (ABS Census) and projected share of homes owned outright or mortgaged

4.6 Rooftop solar and battery storage market segmentation

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 4-5 and Table 4-6 outline how large these market segments are assumed to be in each scenario and their implications for the overall size of the rooftop solar market. The assumptions are based on housing and ownership data discussed elsewhere in this report. The availability of commercial building data is not as good as residential, and consequently there is greater uncertainty in those assumptions.

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. In reality, there may be a small residential and commercial battery only market. For example, commercial customers may use storage to minimise capacity costs, particularly in the South West Interconnected System (SWIS) where capacity market costs are shared out according to customer contribution to demand peaks.

We impose the rooftop solar maximum market shares on the batteries' adoption curves. However, since the payback period for solar with integrated batteries lags behind the level of solar alone, in practice, batteries only reach a fraction (between a third to three quarters depending on the scenario and period) of the total addressable market (all solar owners) in the projections[21].

Table 4-5 Non-financial limiting factors and maximum market share for residential rooftop solar

		Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export	Rationale/formula
Limiting factors						
Separate dwelling share of households	A	39%	45%	45%	52%	Based on housing industry forecasts
Share of homeowners	B	62%	63%	63%	64%	Based on historical trends
Multi-occupant buildings able to set up internal retailing of solar	C	10%	10%	15%	18%	Scenario assumption
Single occupant building owners able to sell directly to occupant or another peer (virtually)	D	5%	5%	6%	9%	Scenario assumption. Landlords of single occupant buildings have more barriers to retailing
Rooftop solar maximum market share		39%	44%	50%	61%	Formula=(A*B)+C+D

[21] In some states the payback period for a solar and battery system can eventually match that of a solar only system, however, it would still take many years beyond the projection period to fully saturate the solar owner's market.

Table 4-6 Non-financial limiting factors and maximum market share for commercial rooftop solar

		Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export	Rationale/formula
Limiting factors						
Separate dwelling share of businesses	A	38%	40%	40%	43%	Data limited. Scenario assumption
Share of business building owners	B	27%	28%	28%	29%	Data limited. Scenario assumption
Multi-occupant buildings able to set up internal retailing of solar	C	5%	7%	10%	15%	Scenario assumption
Single occupant building owners able to sell directly to occupant or another peer (virtually)	D	3%	4%	5%	8%	Scenario assumption. Landlords of single occupant buildings have more barriers to retailing
Rooftop solar maximum market share		18%	22%	26%	35%	Formula=(A*B)+C+D

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 most commonly reported in terms of un-degraded or nameplate capacity, only the capacity after degradation matters for forecasting and planning of electricity system generation and demand.

CSIRO's projections are one of two sources of solar PV and battery projections commissioned 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 2021 projections[22] as the key source of comparison to the current projections rather than an AEMO source document (Graham 2021). CSIRO's previous projections uses the same modelling approach. Those projections therefore provide the best basis for understanding how changes in the scenarios and key assumptions have impacted the projection.

5.1 Small-scale solar PV

The projected capacity of small-scale solar PV for the NEM and SWIS is shown in Figure 5-1 and Figure 5-2 respectively. These projections include all solar capacity from residential and commercial systems up to 100kW as well as non-scheduled generation greater than 100kW to 30MW. All the 100kW or smaller residential and commercial systems are eligible for small-scale technology certificates under the national renewable energy target. This subsidy is slowly declining to zero by 2030. The greater than 100kW systems remain eligible for large-scale renewable energy certificates. The value of large-scale certificates has varied over time. However, with only more large- scale renewables being deployed their value is also expected to decline . As such both commonwealth schemes are in the process of reducing their financial incentives. Of the states, Victoria currently offers the largest state subsidies for up to 700,000 solar PV systems by 2027-28. As a result, the uptake of solar PV systems in that state is less impacted by other factors up to that period.

Despite ongoing reductions in incentives in most regions, both large- and small-scale PV have continued to grow historically. There has been a slowdown in sales in the first half of 2022 likely reflecting changes in spending patterns post-pandemic and global supply chain constraints. On the other hand, wholesale and retail electricity prices have been historically high since the second

[22] For the convenience of AEMO stakeholders we have modified the scenario names used in the CSIRO 2021 report to reflect more recent scenario naming conventions. For the purposes of the 2021 projections the following scenario names are equivalent: Slow Growth: Slow Growth, Sustainable Development: Step Change, Export Superpower: Hydrogen Superpower.

quarter of 2022 providing stronger incentives to generate power at a lower cost from solar PV onsite.

As discussed in the methodology section, we use trend extrapolation to project to the end of 2023. To create diversity between the projections we overlay an assumed uncertainty range across the scenarios. In the 2021 projections we mainly added upside uncertainty to the trend since most short-term drivers were positive. However, in these updated projections we allow for both upside and downside uncertainty to reflect current short-term drivers, particularly the impacts of global supply chain challenges. As a result of both updated historical data and more downside risk, all of the updated projections are lower to the year 2023 than in the previous 2021 projections.

After 2023 a different projection methodology takes over which takes account of various financial and non-financial drivers. The key positive financial drivers are, high retail and wholesale electricity prices, low payback period, ongoing reductions in solar PV costs and government incentive schemes. On the negative side, there is falling commonwealth subsidies and various developments that are expected to reduce the value of solar PV exports. Some networks are considering the possible introduction of export charges to tariff structures or dynamic export constraints. Greater uptake of rooftop solar PV could also increase the incidence of curtailment in various forms – voltage-based curtailment due to increased local solar generation and directed curtailment for system security.

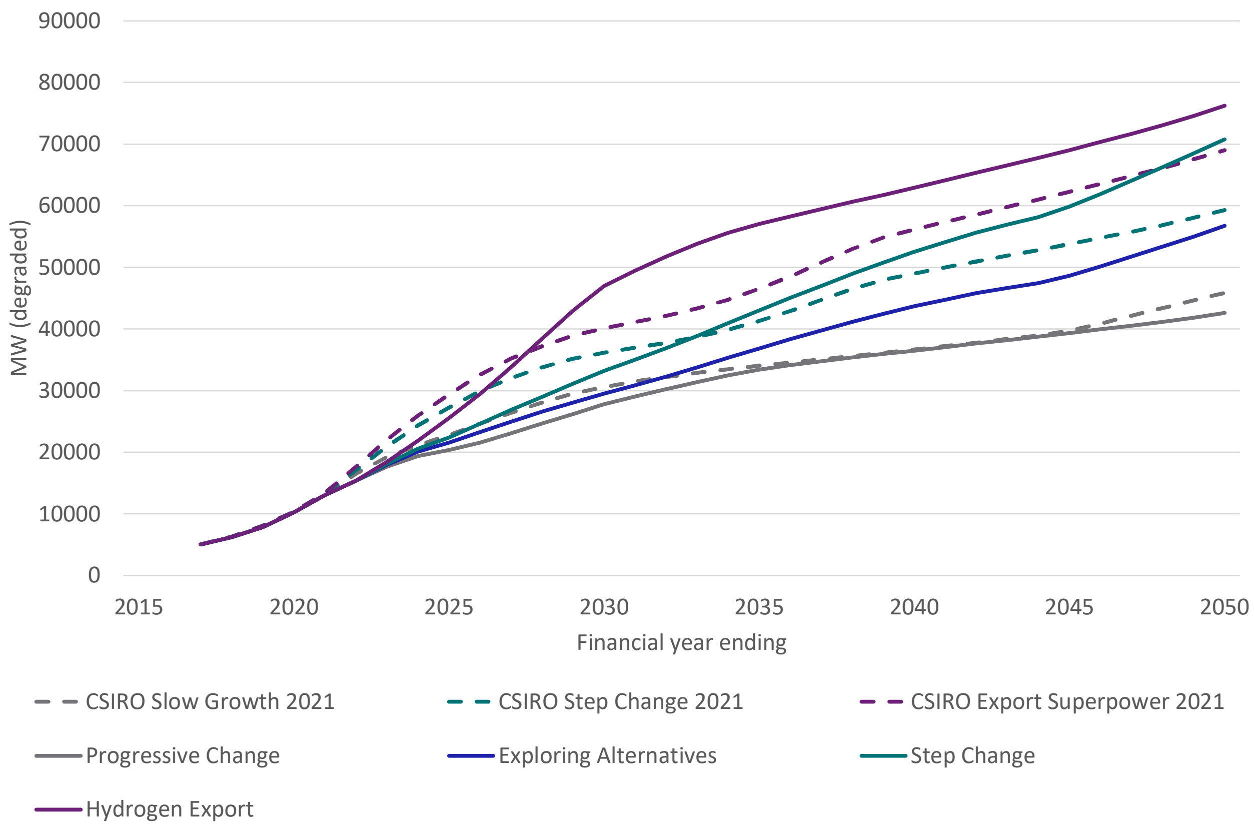


Figure 5-1 Projected capacity of small-scale (<30MW) solar PV in the NEM

Besides the negative financial factors, the projections are also limited by non-financial factors which are mostly infrastructure related. Solar PV is installed easiest on owner occupied separate dwellings which represent about 45% of households, and even fewer of commercial buildings.

Updated 2021 census data included in these projections has indicated that the share of separate dwellings is falling faster than previously expected.

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 cases where the landlord pays for utilities). For *Step Change* and *Hydrogen Export* we allow for this problem to be partially overcome through business model innovation. For *Progressive Change* and *Exploring Alternatives,* business model innovation is assumed to be less successful and fewer renters are able to access solar. Some governments (e.g., Victoria) are also providing incentives for landlords and renters to reach a benefit sharing agreement. The differences between the states represent the historical legacy of the support of solar PV in each state and their climate conditions. Queensland, South Australia, and Western Australia have been leading rooftop solar adoption for a long period. As premises change hands, there is an increasing chance they will already have solar installed which helps to bring some systems into the rental market or drive adoption amongst those who were not otherwise in the mainstream adoption group. As a result, their projected minimum and maximum adoption levels across the scenarios are higher than other regions. Tasmania has the poorest solar resource, and its grid electricity is already renewable reducing the benefits of rooftop solar PV relative to other states. However, our modelling suggests that Tasmanian households are sensitive to system costs and will invest in the lowest cost scenario (*Hydrogen Export*). The ACT has good average income, but its share of separate dwelling is 9.1 percentage points below the national average. Its home ownership share is also 2.7 percentage points below the national average with both factors inhibiting solar PV adoption.

Table 5-1 shows the projected outcomes from the scenarios of the share of households with rooftop solar PV. *Hydrogen Export* represents the maximum household share for all states and *Progressive Change* represents the minimum share.

The differences between the states represent the historical legacy of the support of solar PV in each state and their climate conditions. Queensland, South Australia, and Western Australia have been leading rooftop solar adoption for a long period. As premises change hands, there is an increasing chance they will already have solar installed which helps to bring some systems into the rental market or drive adoption amongst those who were not otherwise in the mainstream adoption group. As a result, their projected minimum and maximum adoption levels across the scenarios are higher than other regions. Tasmania has the poorest solar resource, and its grid electricity is already renewable reducing the benefits of rooftop solar PV relative to other states. However, our modelling suggests that Tasmanian households are sensitive to system costs and will invest in the lowest cost scenario (*Hydrogen Export*). The ACT has good average income, but its share of separate dwelling is 9.1 percentage points below the national average. Its home ownership share is also 2.7 percentage points below the national average with both factors inhibiting solar PV adoption.

Table 5-1 Share of households with rooftop solar PV in 2050

	Minimum across scenarios	Maximum across scenarios
New South Wales	32%	47%
Victoria	35%	47%

Queensland	43%	55%
South Australia	46%	57%
Western Australia	39%	50%
Tasmania	27%	47%
Australian Capital Territory	31%	46%
NEM	36%	48%

While these infrastructure limits could be considered negative non-financial drivers there are two important positive non-financial drivers. They are increasing rooftop system sizes and growth in household and business connections which reflect different levels of economic and population growth across the scenarios. Residential system sizes grow throughout but at a declining rate. System size growth is strongest for *Hydrogen Export* and weakest for *Progressive Change*.

The result of the combination of all these drivers is that there is continuing growth which is mostly linear in the case of *Step Change*, faster in *Hydrogen Export* and slower in *Exploring Alternatives* and *Progressive Change*.

The stronger projected capacity in the long term in *Exploring Alternatives*, *Step Change* and *Hydrogen Export* compared to 2021 projections mostly reflects lower long term solar PV cost projections (around $100/kW or 17% lower by 2050). For *Hydrogen Export*, the period to 2030 in particular has stronger cost reductions resulting in strong growth during that period. Reductions in costs slow thereafter at the same time that small-scale technology certificates reach zero value and the Victorian subsidy scheme has ended two years earlier. As such there is a more modest rate of growth in the remaining 20 years.

The SWIS demonstrates similar trends as the NEM with projections lower than the 2021 projections in the short-term and growing at similar rates to the NEM thereafter. However, the updated projections are much closer to the 2021 projection in the long term. This is because the SWIS is closer to its saturation point than the NEM and unlike the NEM is not held back by regions that have historically low solar PV uptake. The SWIS also has a more stable retail electricity price regime. As such, the SWIS has a more limited range in which to move when assumptions are changed.

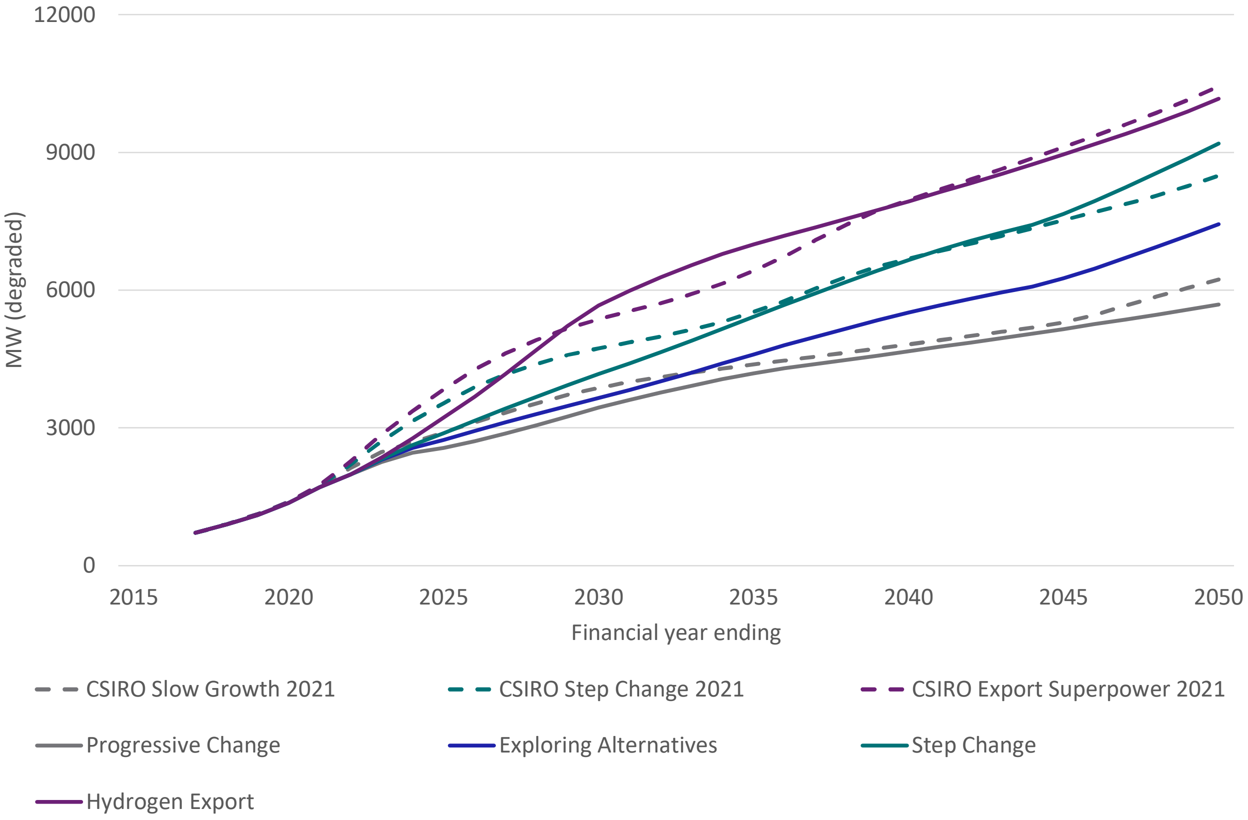


Figure 5-2 Projected capacity of small-scale (<30 MW) solar PV in the SWIS

Investment in larger scale solar PV in the range of 100kW to 30MW (also called non-scheduled generation) is less driven by infrastructure and more by potential financial rate of return. The projected capacity of non-scheduled solar PV generation for the NEM and SWIS are shown in Figure 5-3 and Figure 5-4 respectively. This capacity was already included in Figure 5-1 and Figure 5-2 but its drivers are different and so deserve a separate discussion. The projections exhibit some discontinuity 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 emission reduction fund, state energy efficiency schemes and corporate 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 increases 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.

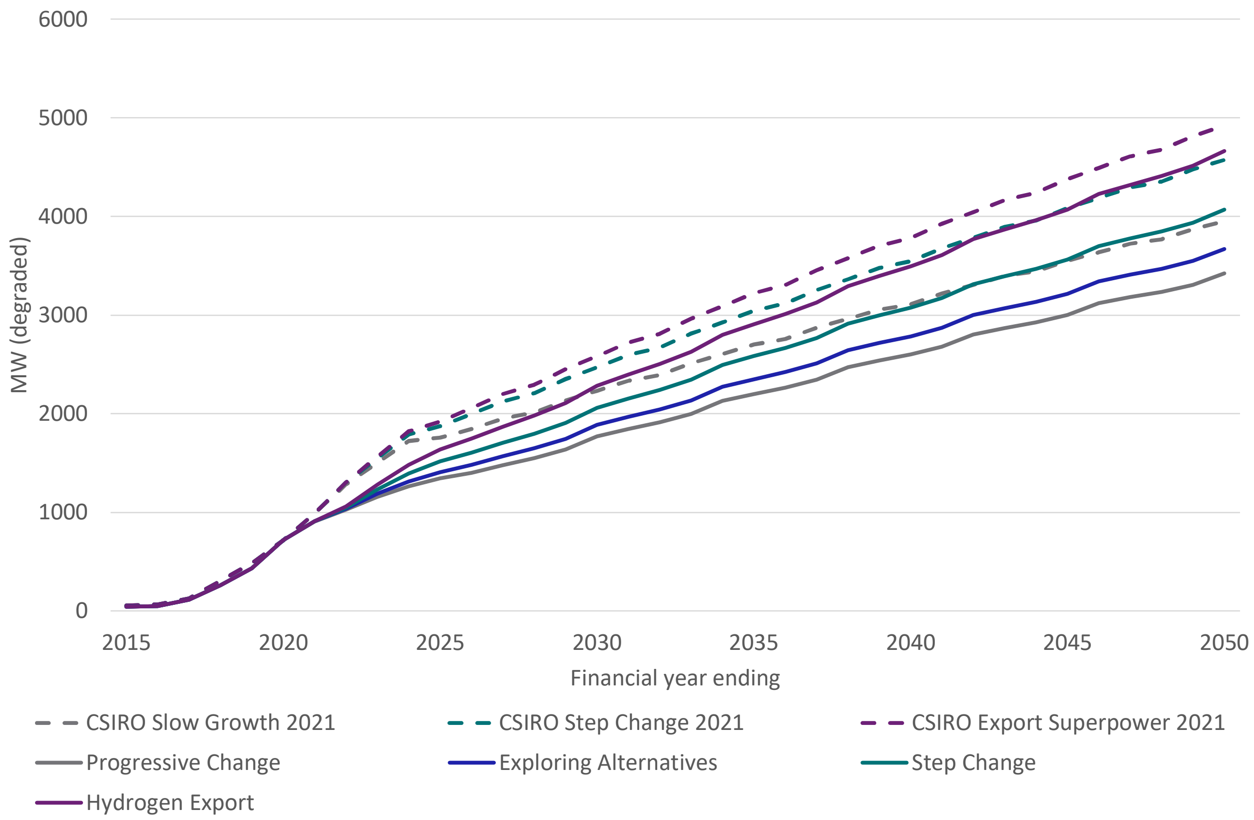


Figure 5-3 Projected capacity of non-scheduled generation solar PV (greater than 100kW to 30MW) in the NEM

The reduction in the projections in the NEM relative to 2021 projections largely reflects the short-term slowdown in deployment due to global supply chain issues. In the long term the prospects remain largely the same but the significant lost deployment in the early 2020s is never recovered despite slightly stronger growth rates due to lower technology costs. We also see again that the difference in the new short-term trend is stronger for the NEM than the SWIS. The data for the SWIS does not demonstrate a short-term slowdown and is in fact slightly higher than expected. As a result, the long term SWIS projection is higher than the 2021 projections, consistent with lower solar PV technology costs.

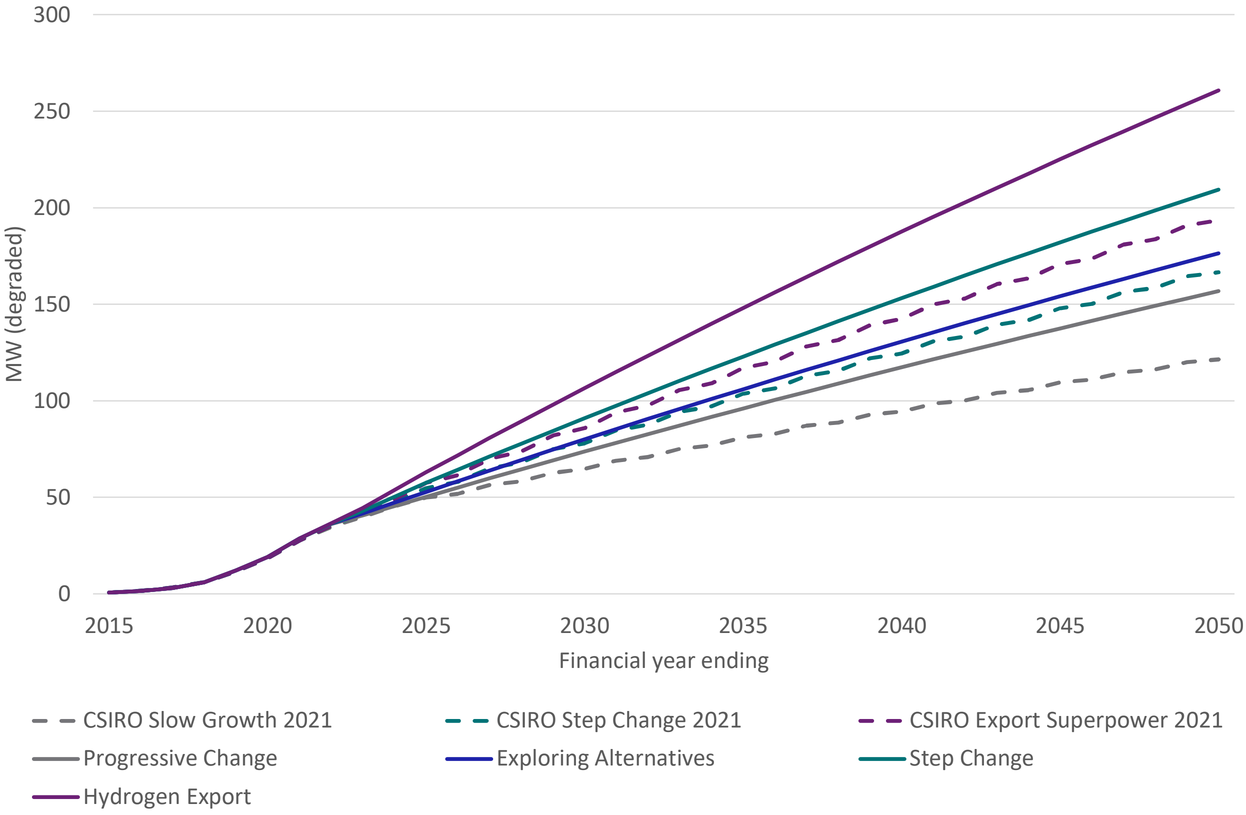


Figure 5-4 Projected capacity of non-scheduled generation solar PV (greater than 100kW to 30MW) in the SWIS

5.2 Batteries

Small-scale battery projections are developed in the same way as solar PV with most of the same information and constraints applied. In the short-term we apply a combination of regression analysis and an uncertainty range across the scenarios. However, for Victoria, which has a battery subsidy scheme limited by a quota, we assume the battery subsidy quota is exactly met in the *Exploring Alternatives* scenario, is under-achieved in *Progressive Change* and is slightly over-achieved in *Step Change* and *Hydrogen Export.*

The short-term outlook for batteries has not improved since the 2021 projections with recorded sales at the same level as the previous year and no improvement in technology costs. Small scale battery cost reductions have been difficult to predict since their trajectory has been flatter than large-scale batteries in recent years. However, our assumption is that this is a temporary feature of an emerging market, and that the trajectory of small-scale batteries will more closely align with the larger scale market over time (the projections of which are sourced from GenCost 2021-22).

Another positive factor for batteries is that the outlook for solar PV has improved in the long run. Our expectation is that most batteries are installed for the purposes of shifting solar generation. As a result, the larger the solar PV capacity the larger the potential battery deployment. A large solar deployment also increases the incidence of curtailment, which is another incentive for battery adoption, reducing exposure to changes in export conditions.

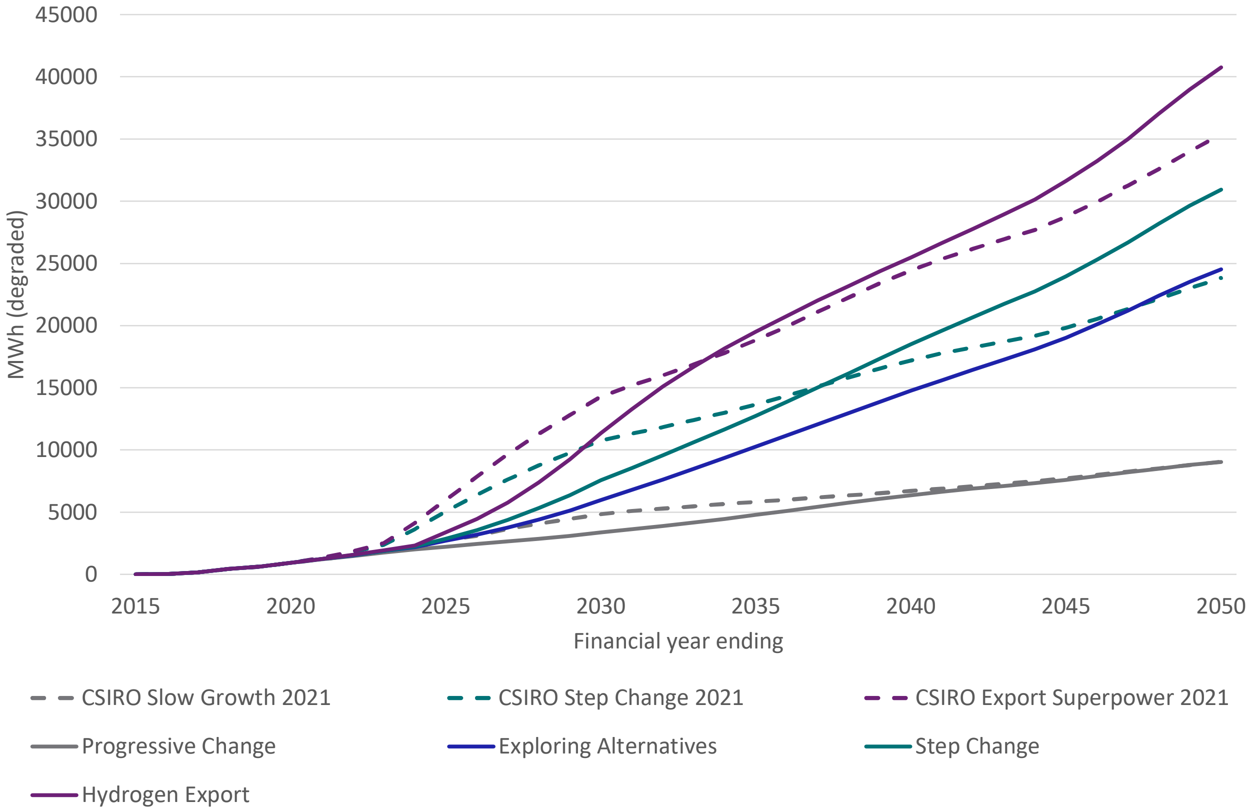


Figure 5-5 Projected capacity of small-scale batteries in the NEM

Compared to the 2021 projection, growth in battery uptake is significantly lower through to the early 2030s. A significant increase in uptake is not expected until after 2025 based on current trends and the need for cost reductions to become available. Historically, cost reductions have been occurring in the large-scale battery sector but have not been filtering through to the small-scale sector. With large-scale cost reductions now in doubt in the short-term due to global supply chain constraints, cost reductions in the small-scale sector are more likely to be delayed. In the NEM, the higher uptake of solar PV in the post-2030 period widens the market for batteries resulting in higher capacity deployed compared to the 2021 projections. In the SWIS, a weaker short term adoption rate compared to the 2021 projections is also expected. However, the post-2030 outlook is fairly similar to the 2021 projections reflecting that the outlook for solar PV ownership has not changed significantly in that region.

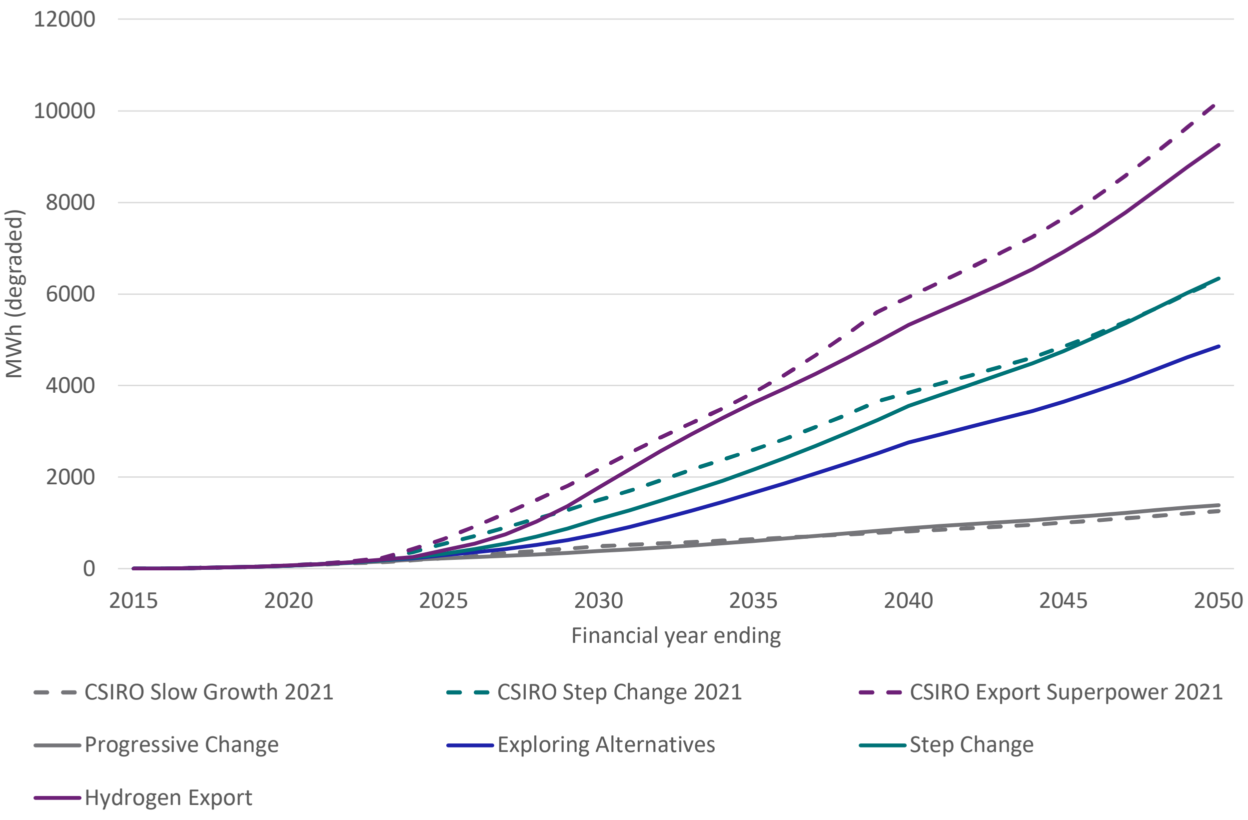


Figure 5-6 Projected capacity of small-scale batteries in the SWIS

The current and projected share of solar PV owners with batteries by customer type is presented in Figure 5-7. The current share is negligible for commercial customers and a few percent for residential customers. The battery share for residential customers is expected to improve from 2024 for residential customers and from the late 2030s for commercial customers under most scenarios. The long-term trend is more divergent with *Progressive Change* only improving its share slightly over the remainder of the projection year relative to the strong growth expected in the remaining scenarios. The *Hydrogen Export* scenario is projected to result in just over 60% of residential solar PV owners integrating a battery in their system. This high rate of battery uptake does not necessarily conflict with the potential future use of electric vehicles for home energy storage. Up to a third of electric vehicles are assumed to be used as household or grid batteries by 2050 (Graham, 2022).

For commercial customers the share of solar PV systems with batteries is about half that of residential customers. This reflects limitations of batteries in a commercial customer setting. For commercial customers, solar PV generation is already reasonably well aligned with their average load shape. A such, adding batteries to shift load to other parts of the day produce less of a benefit. A stronger driver is avoiding peak and shoulder period pricing which is a more common feature of commercial tariffs. However, the peak and shoulder periods make up most of the daylight and evening hours which is a long period for a battery to cover. That a battery may run out before the evening peak has ended is of less of a concern to customers on flat tariffs. For this reason, growth in commercial battery shares is more delayed and are in the range of 6% to 33%.

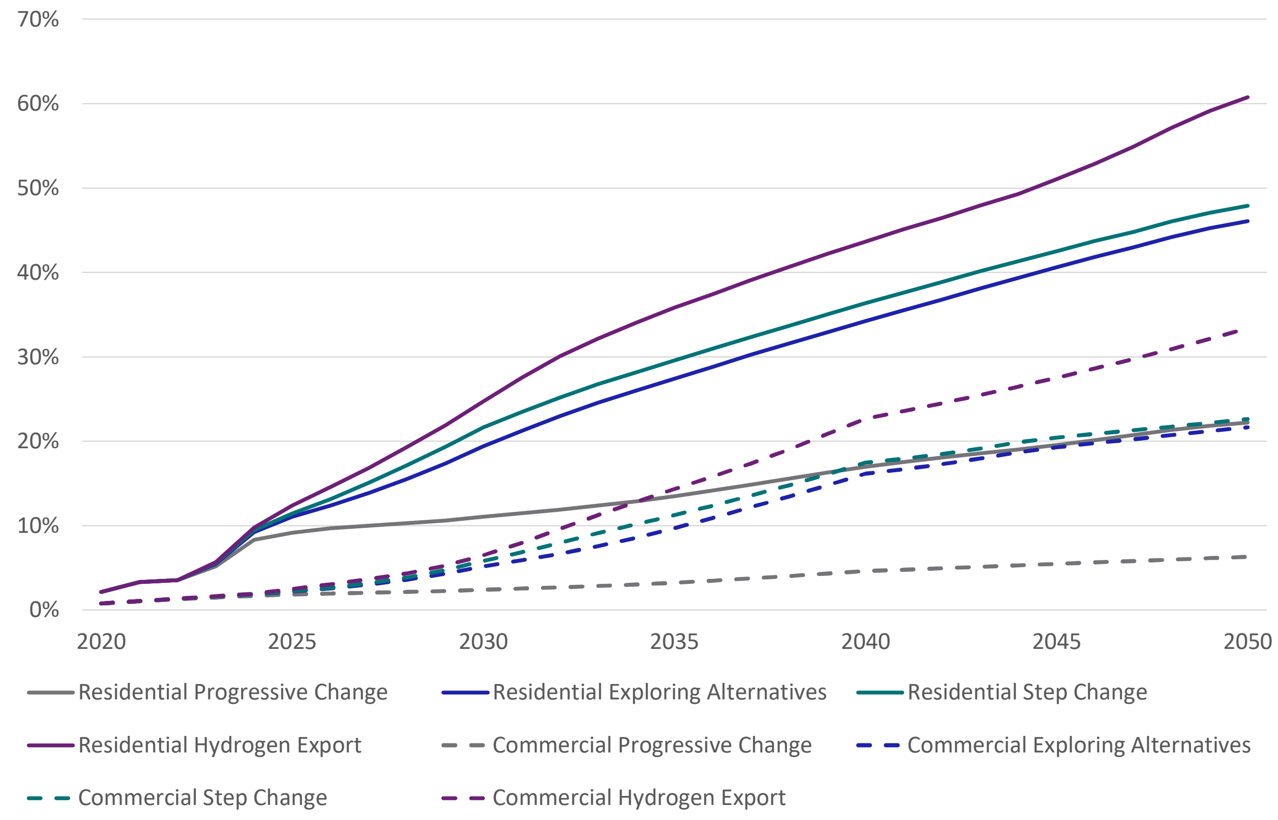


Figure 5-7 Projected share of solar-PV systems with a battery by customer type

5.3 Battery operation profiles

The operation of batteries was simulated for different weather years and customer and tariff types. A flat tariff was simulated which results in a solar shifting operational profile. In this profile, the battery tends to charge to avoid exports since the most financially advantageous use of any solar generation is on site once a battery is installed. The battery will also discharge to avoid imports as much as the battery capacity will allow. The battery capacity was not optimised but rather fixed at observed current average battery sizes (detailed in Appendix A).

The results for the solar shifting profile are presented in Figure 5-8. In summer the charging profile is wider and flatter indicating less coincident behaviour because longer daylight hours allow a longer period over which to charge the battery. With the exception of Western Australia[23], the residential customer loads we use have higher electricity consumption in the summer months (see Apx Figure A.2). The lower winter electricity demand reflects the use of electrical cooling in summer but, on average, lower use of electricity as a heating source in winter. As a result, there is less peak charge available to go into the battery in summer. This higher demand is partially offset by longer hours in which to charge the battery. In winter, lower electricity demand and narrower daylight period means that charging is more coincident, resulting in a peakier shape.

[23] Some southern states have a higher share of gas combined with coolers for summer (which cannot provide heating in winter. Western Australia has reverse cycle heats pumps closer to shares observed in northern states but with cooler winters resulting in a different average residential load curve.

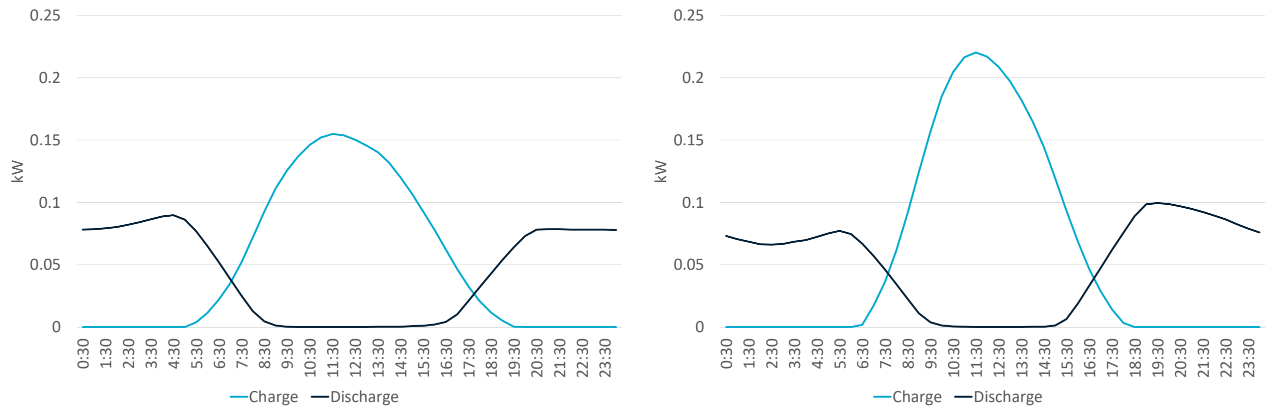


Figure 5-8 Summer (left) and winter (right) solar shift residential battery operation profiles

A peak avoidance profile was simulated based on typical time of use incentives which impose a higher retail price from around 7:00am (local time), a further step up in prices between 6pm and 10pm and low prices 10pm until 7:00am (these times and their individual rates vary slightly between jurisdictions, and these have been included in the detailed modelling). From a charging perspective the shape of the daily curve is similar during solar production times. However, there is additional charging (from the grid rather than onsite solar PV) as soon as off-peak pricing commences at night. This behaviour is to ensure the battery has sufficient charge to be ready to discharge during the commencement of increasing prices in the morning. The behaviour is stronger in winter because the battery has a poorer charge during the day and solar production will likely be lower and later in the morning and so it can be less relied on to assist with reducing imports from the grid. Some off-peak charging from the grid may continue until early morning.

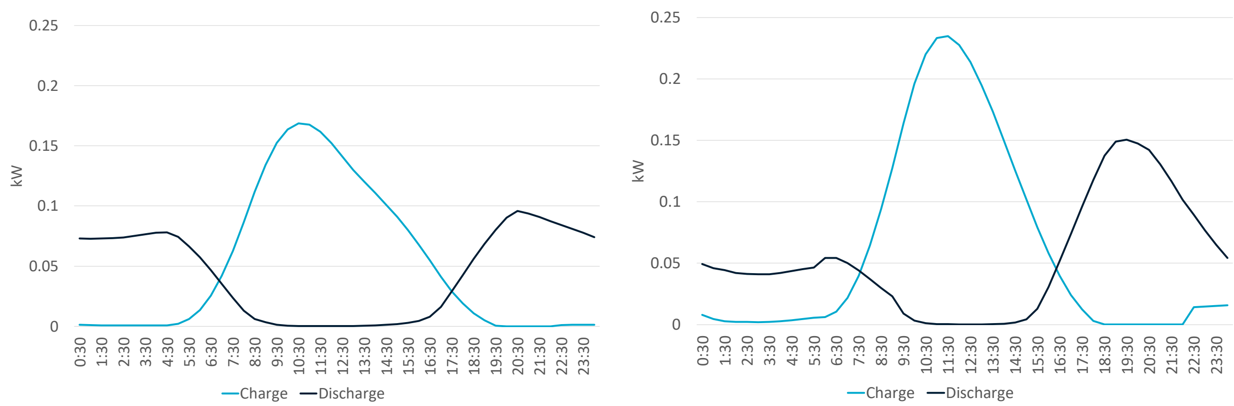


Figure 5-9 Summer (left) and winter (right) peak avoidance residential battery operation profiles

The discharge profile for the peak avoidance profile is also different from the solar shift profile. Not surprisingly, there is a more pronounced discharging peak during the peak pricing period of 6:00pm to 10:00pm. There can also be a second peak discharge around 7:00am on days with low solar output at this time. These discharges are more prominent in winter when the state of charge is lower due to lower solar input, and the need to preserve the battery charge for the peak period rather than just overnight. In summer the amount of charge is more able to cover residential demand in the peak periods and overnight to reduce imports from the grid.

For commercial customers, given better alignment of load with solar production and shorter duration batteries, discharge focusses mostly on the early evening period in the solar shift profile without the sustained discharge through the night. Under the peak avoidance profile, the same off-peak charging and peak discharging occurs but again with even lower emphasis on night or off-peak discharge.

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

The share of installed rooftop solar with a north orientation appears to be around 90%, with mostly West followed by east being the remainder. We assume the ratio of north-facing falls to 70% by 2050 (with the other orientations proportionally gaining) owing to those buildings with less favourable orientations being in the late follower group and larger systems potentially requiring to be laid at on more than one aspect. There is also expected to be a greater incentive for west orientation due to more customers responding to incentives to reduce demand during peak times.

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.

Rooftop solar capacity is also lost to breakdown of equipment before scheduled end of life due to quality or misadventure (e.g., hail). This data is not available. Our assumption is that the survival rate of 1 to 10 years old systems is very high at 99.5% and 10 to 20 years old systems is 97% per year. While replacements do not add to the total number of installations, they can impact installed capacity. This is because replacement systems may be larger than existing capacity, particularly during periods where system size is rising such as over the next few years. This means that for the next few years replacements are adding to capacity (we estimate there are around 40,000 replacements adding around 200MW per annum net in the NEM). In our system size trend assumptions, as the trend flattens over time, the impact of replacements on total installed capacity begins to wane significantly.

A.1.2 Battery storage

For the battery storage capacity projections, we assume one average battery size for each of the three segments: residential, small commercial and large commercial. However, when we are developing the battery operational profiles, we allow the model to optimise the residential battery size for each customer.

The value of 11kWh for residential customers matches the reported average size in SunWiz (2022) for 2021. It is also reasonably consistent with the average size in the battery operation optimisations which was 9kWh for customers with time-of-use tariffs and 10.9kWh for customers with flat tariffs.

There is no reliable publicly available data on the historical size of commercial battery systems. However, we do know the historical average size of commercial solar systems is 24kW. We set the smaller commercial system size to be of a similar ratio of residential battery to solar system size – 36kWh. The larger commercial system size is set at four times larger (145 kWh) to suit those commercial customers with solar systems closer to the top end of the zero to 100kW range.

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 20% 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.

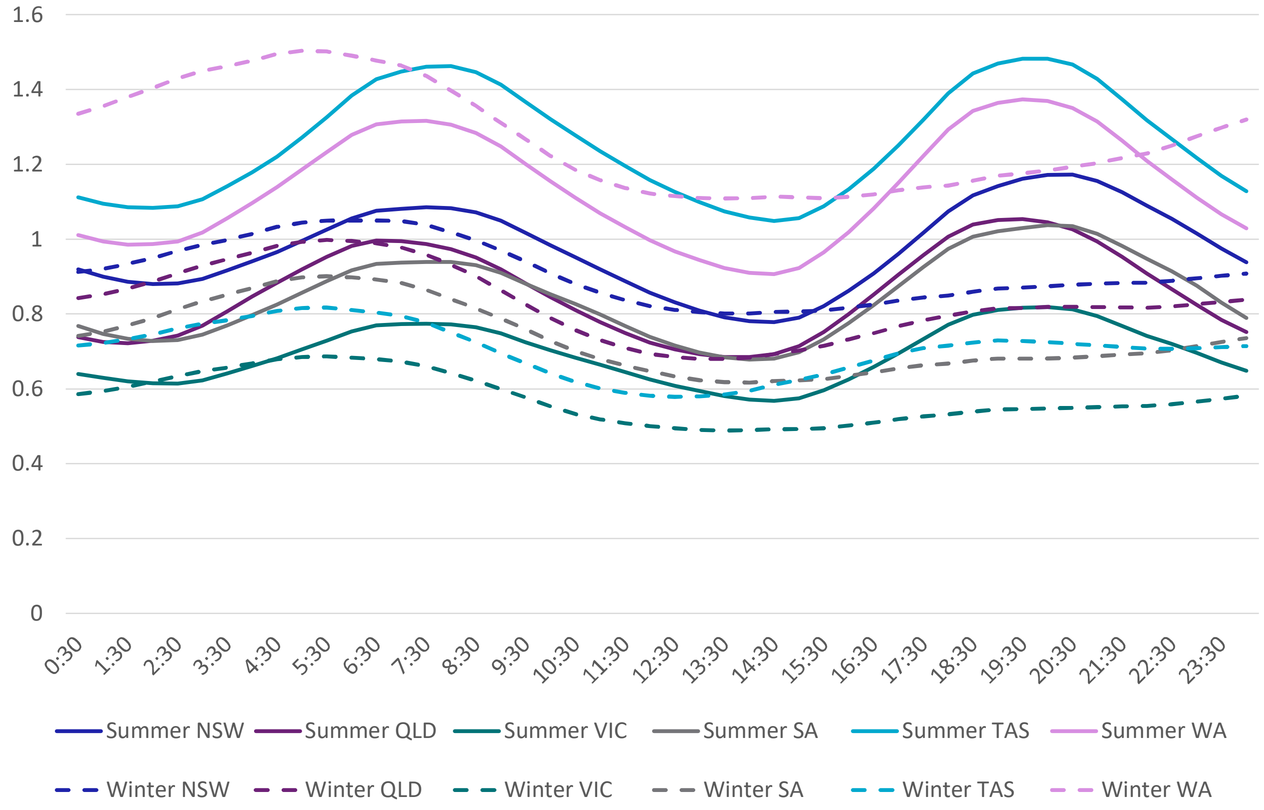
Apx Table A.2 Battery storage performance assumptions

Characteristic	Assumption
Round trip efficiency	85%
Maximum charge or discharge of rated capacity	85%
Rated capacity projections	Residential: 11kWh
	Small commercial: 36kWh Large commercial: 145kWh
Rated capacity operation profiles	Optimised for each residential customer profile but average is 9 kWh for TOU customers and 10.9 kWh for flat tariff customers
Maximum power in kW	Residential: Rated capacity divided by 2.2 Commercial: Rated capacity divided by 1.5
Degradation rate	1.6% per annum on kWh capacity
Life	Financing period: 10 years, Asset life: 5000 cycles

A.2 Customer load profiles

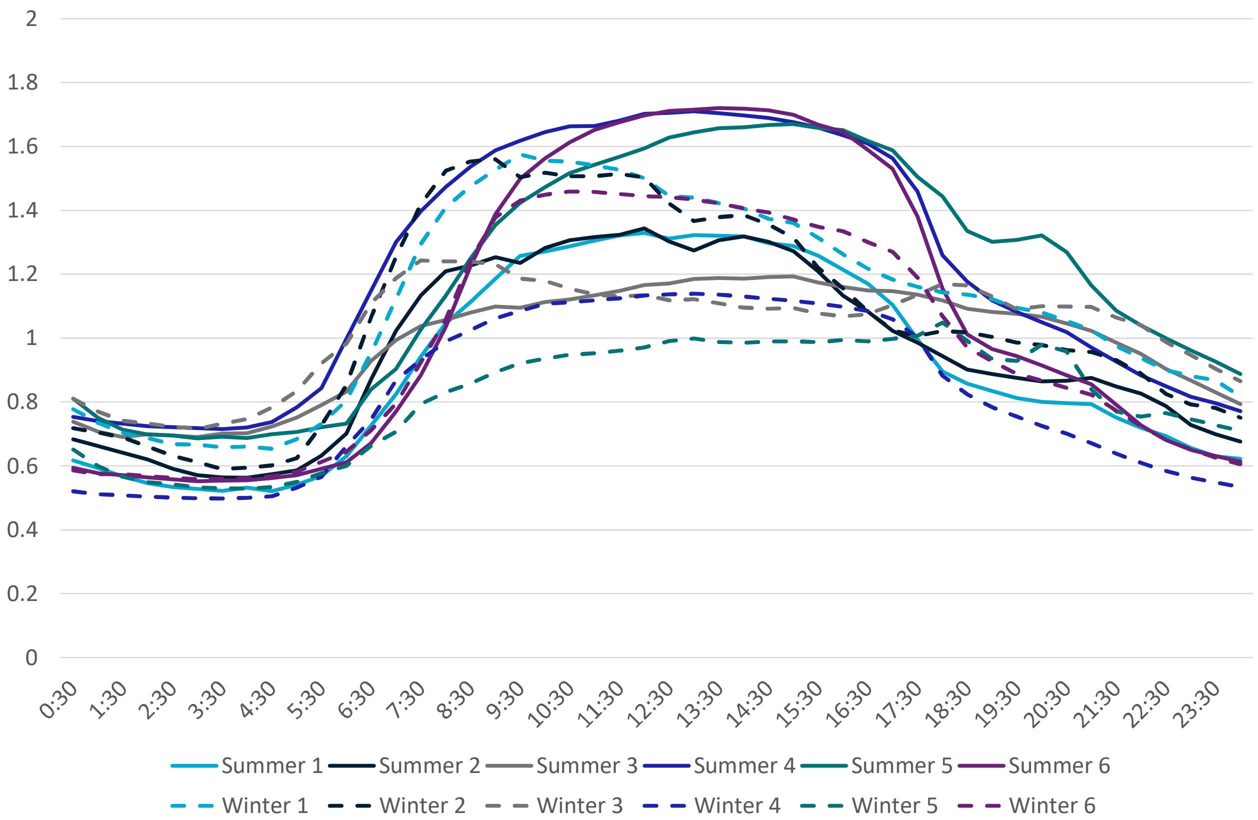
Australia still faces difficulty in accessing public load profiles due to privacy considerations. For that reason, we use a mixture of synthetic and real customer load profiles. For residential data we started with around 5000 New South Wales Ausgrid profiles from the Smart Grid Smart Cities program and found the 5 most representative profiles and their nine nearest neighbours using clustering analysis. We then synthetically created profiles for each other distribution network area by subtracting the difference between the most residential zone substation in each network relative to Ausgrid's most residential zone substation. This process should adjust for differences in timing (daytime hours) and climate but is probably insufficient to account for all differences in gas versus electricity use, for example, between different states. The SGSC data set did include people with and without gas and with and without hot water control, but the proportions will not match other states. The average summer and winter profile for each region is shown in Figure A.2.

These loads are electricity only and therefore do not reflect the use of natural gas, LPG and wood for space heating, water heating and cooking. For this reason, summer loads (with the exception of Western Australia) are higher with electricity being the dominant as a cooling technology.



Apx Figure A.1 Index of average half hourly residential summer and winter loads by region, normalised to average load

For commercial load profiles we use a small number from previous work and do not adjust them by region. In using a smaller set our assumption is that commercial profiles vary less than residential between customers and regions (Figure A.3). The commercial data has a stronger summer load, biased towards the evening. The winter load is biased towards the morning. This indicates a greater reliance on electrical space heating and cooling in both seasons than the residential data.



Apx Figure A.2 Index of average half hourly summer and winter loads for six commercial customers

Appendix B Current and planned community battery projects

Apx Table B.1 summarises the business models that are being explored and trialled in the existing community battery pilot projects around Australia.

Apx Table B.1 Implemented and future plans for community batteries in Australia

	Region	Battery owner	Business model
Installed	WA	PowerBank Western Power/Synergy (DNSP-Retailer Owned)	• Households who are part of the PowerBank trials can *virtually* store up to 6 kWh or 8 kWh of excess or unused solar power in the battery from 7am to 3pm (capacity allocated is based on the customer's existing energy usage) • Customers will be paid the Solar Energy Buyback Rate defined by Synergy for the energy they exported to the battery from 7am to 3pm • Additionally, a daily subscription fee is paid by the customer in addition to the usage charges 6kWh storage option: $1.20 (GST incl.) 8kWh storage option: $1.40 (GST incl.) More details: https://www.synergy.net.au/UtilityLinks/Terms-and-conditions/PowerBank-Saver-Plan-8kwh
	NSW	Ausgrid (DNSP-owned)	• Participating customers (solar customers) can virtually store up to *10kWh* of excess solar energy each day. • This excess energy is credited against their electricity use for that day. Every quarter Ausgrid will deposit community battery credits into participating customers' nominated bank account • There are no costs to participate and customers don't need to change their electricity retailer.
	VIC	Yarra Energy Foundation (YEF) (Third-party owned) – in partnership with a local retailer Acacia Energy and the DNSP CitiPower	The opportunity for customers to co-invest in the battery is being explored. So far there's no direct interaction between the battery and the customers; however, the battery is being operated for wholesale energy arbitrage (battery discharges at wholesale spot market price) and FCAS markets and YEF will earn revenue via these services https://www.acaciaenergy.com.au/projects/yarra-energy-foundation-yef-community-battery/
		United Energy (DNSP-owned)- in partnership with the energy retailer Simply Energy	• Pole-top batteries are charged at times when there is low electricity demand or when local rooftop solar is exported to the network. Batteries are discharged later in the day when demand is high and solar systems are no longer generating. • For DNSP-owned batteries – The retailer pays a fixed access charge (0.8 c/kWh) for contract storage capacity which is set out in a lease agreement • New network tariffs for the battery operation are being trialled (CitiPower, PowerCor or United Energy will be using the same set of network tariffs for their batteries)

			https://media.powercor.com.au/wp-content/uploads/2022/02/28084618/Community-Battery-Trial-Tariff-factsheet.pdf
Planned	VIC	Powercor (DNSP) https://www.powercor.com.au/network-planning-and-projects/network-innovation/electric-avenue/electric-avenue-feasibility-study/ https://www.powercor.com.au/network-planning-and-projects/major-projects/tarneit-community-battery-project	
		City of Melbourne (local government) https://www.melbourne.vic.gov.au/about-melbourne/sustainability/power-melbourne/Pages/power-melbourne.aspx	
	NSW	Endeavor Energy (DNSP) https://www.endeavourenergy.com.au/your-energy/batteries-explained https://www.endeavourenergy.com.au/news/media-releases/nsw-south-coast-to-get-its-first-community-microgrid	
	ACT	Ginninderry community battery project – owned and managed by CWP storage in partnership with the local DNSP Evoenergy https://ginninderry.com/inspire-post/power-to-the-people/	
	QLD	Energy Queensland https://onestepoffthegrid.com.au/tesla-community-battery-nears-completion-in-coastal-queensland-town/	

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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