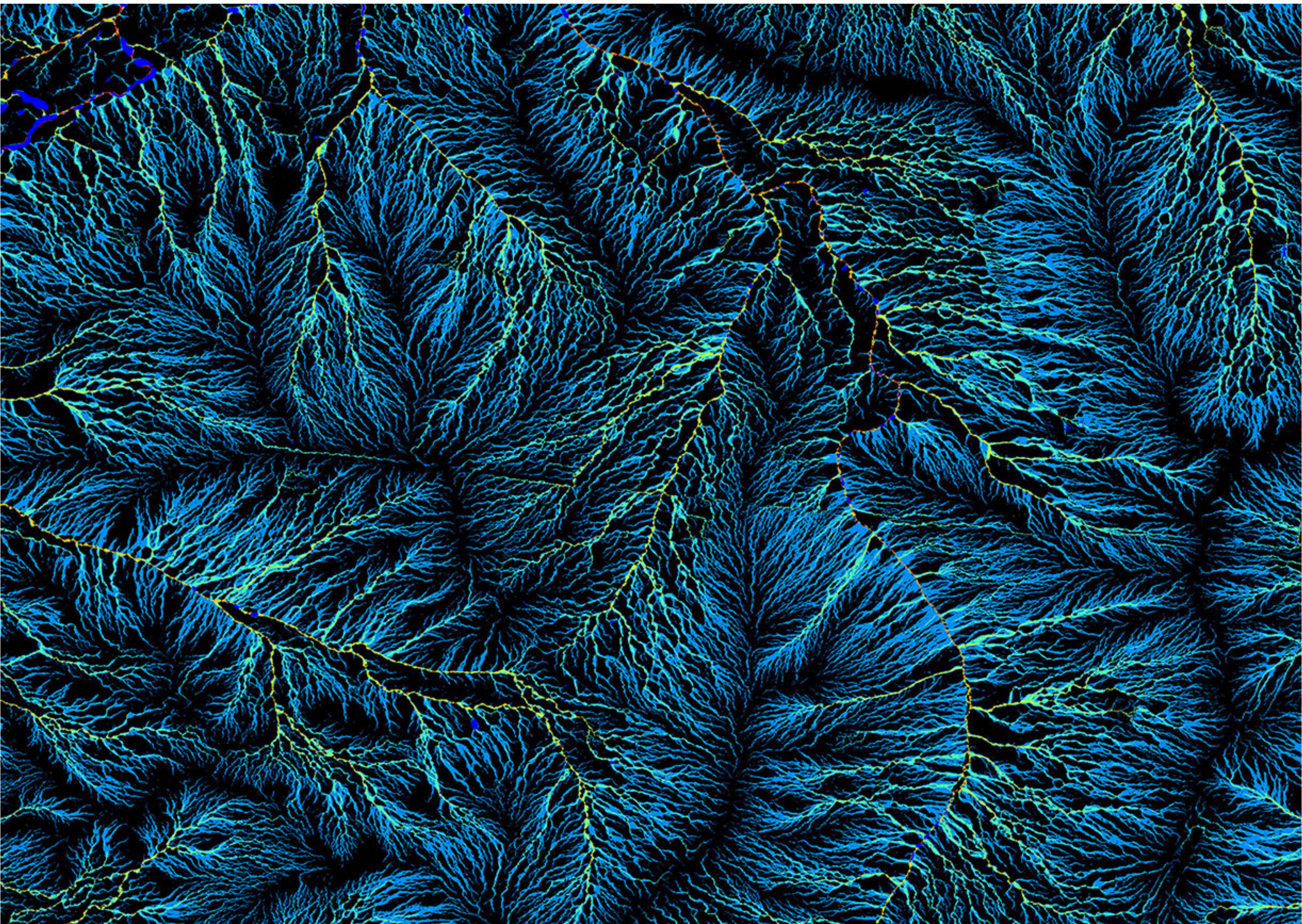
Australia's National
Science Agency

Small-scale solar and battery projections 2021

Paul Graham

May 2021



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Acknowledgments

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Executive summary

This report was commissioned by AEMO to provide a record of the methodology, assumptions and outputs of small-scale solar PV and battery projections provided by CSIRO to support their planning and forecasting tasks. Projections are provided for five scenarios – Slow Growth, Current Trajectory, Net Zero, Sustainable Growth and Export Superpower – plus a Rapid Decarbonisation sensitivity case. Compared to previous projections by CSIRO, this scenario set has a stronger emphasis on net zero greenhouse gas emission targets for Australia of which the electricity sector would be expected to be a leading contributor owing to the availability of low cost zero emission technologies. The scenario set is sourced from an updated scenario development process by AEMO with strong stakeholder engagement and recognition of the widening embrace of net zero targets at different levels of government and in the corporate community.

Another major development in the external environment is that the rooftop solar sector has completed another strong year of growth in 2020. This growth was somewhat unexpected, at least during the early stages of the COVID-19 pandemic when the economic impacts were less well understood. CSIRO's projection methodology explicitly places stronger weight on building historical trends into the first two years of our projections. Consequently, we are projecting a continuation of the recent strong trends in rooftop solar PV deployment in the short term.

Beyond the next two years a combination of financial and non-financial developments such as reductions in subsidies and moderating export returns (owing to changes in daytime generation prices, tariff structures and curtailment) are expected to slow the rate of deployment. By 2050, deployment is strongest under the Export Superpower scenario reaching a 50% household penetration rate. At the other end of the spectrum, the Slow Growth scenario has the weakest level of deployment, with 40% of households having rooftop solar.

Small-scale battery deployment continues to grow, but the market remains in an early adopter phase owing to high purchase costs. Subsidies in Victoria, South Australia and the Australian Capital Territory as well as some modest cost reduction will support moderate growth in the early 2020s. More substantial cost reductions and deployment are expected in the longer term as the product matures. The increasing limitations on export returns from solar PV systems will also increase the incentives for battery ownership. Overall, by 2050, 20% to 60% of rooftop solar owners are expected to install a battery across the scenarios.

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 five scenarios and a sensitivity case of small-scale solar PV and battery storage adoption. The analysis also includes operation of the small-scale batteries. The five scenarios are Slow Growth, Current Trajectory, Net Zero, Sustainable Growth and Export Superpower as well as a Rapid Decarbonisation sensitivity case. 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 all 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 a long-term adoption model for technologies below 100kW. For technologies above 100kW (and less than 30MW), the long-term model applied is a rate of return threshold approach.

2.1.1 Short-term trend model

In months up to the end of 2022, trend analysis is applied to produce projections based on historical solar data. 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. 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 regression takes the following form:

$$X_{m=f(month\ in\ sequence, month\ of\ year\ dummy\ variable)}$$

Where X is the (m) monthly activity of the following possible activities Solar PV installations and capacity by residential and commercial segments. The installation trend is more important because we also carry out a regression on system size trends and use the multiple of system size and installation projections to project PV capacity (before degradation or other capacity losses).

For solar PV systems less than 100kW, regressions are calculated at the postcode level, while the remainder of activities are calculated at the state level. For some larger non-scheduled solar PV, we have only used the last 24 months of data due to significant inactivity. For batteries, annual state data is often only available and so the regression is simply a function of the year.

The regression results for residential (Figure 2-1) and commercial (Figure 2-2) 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 2017 and 2018 data for context. The historical residential profile is relatively smooth with obvious differences in slope and scale between states. For example, NSW which has lagged other states in terms of residential rooftop solar penetration appears to be experiencing the strongest growth. This is consistent with being at a lower point on the consumer technology adoption curve (which we discuss further in the next section).

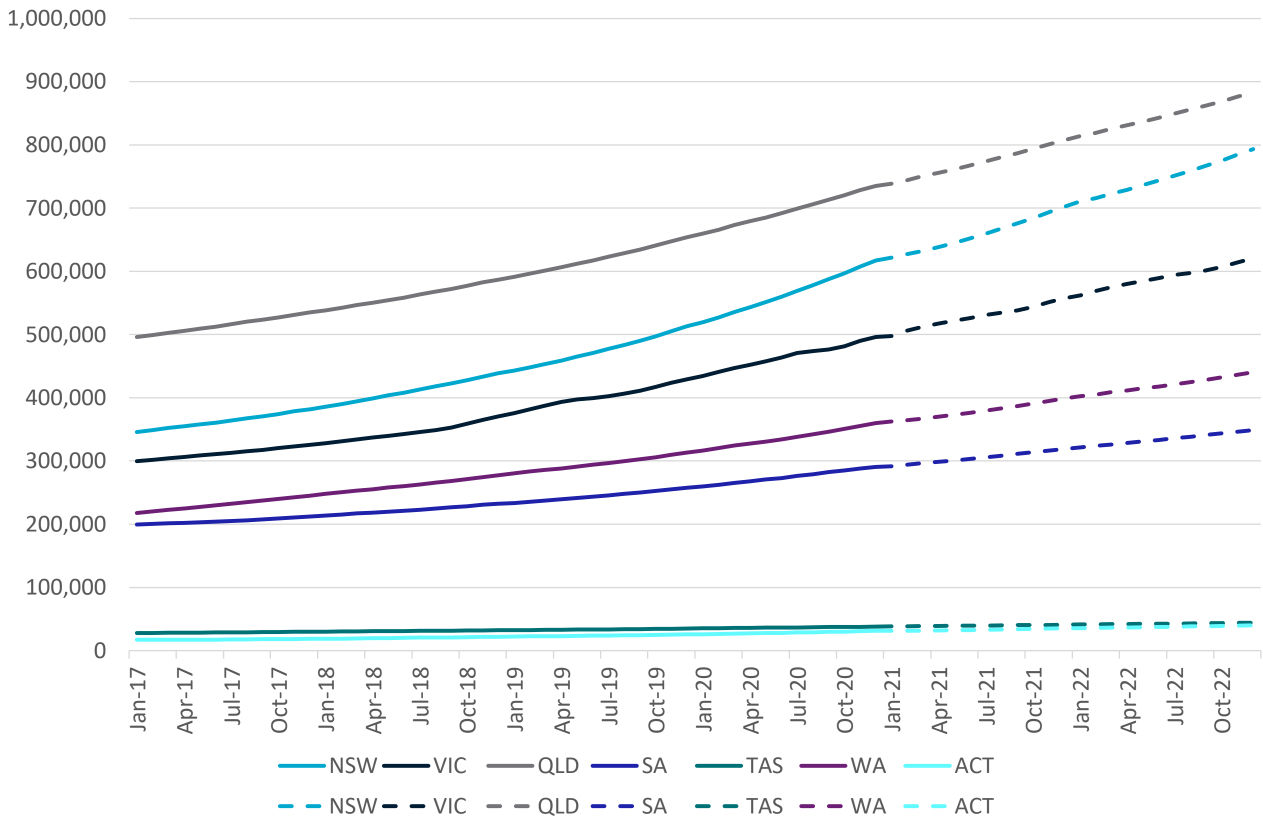

Figure 2-1 Regression results for residential rooftop solar installations by region

The commercial systems have a more prominent monthly profile with a jump in installations occurring towards the end of the calendar year and falling in January. The monthly components of the regression equations have been able to capture these. QLD has the strongest growth trend of all the regions and is projected to catch up to the NSW level of commercial installations by the end of 2022.

The trend is applied differently to each scenario by applying differing scale factors between 1 and 1.2 to the June 2022 trend projection and linearly interpolating that factor back to January 2021. This approach allows for the possibility that some scenarios will grow faster than a linear trend and creates a short-term uncertainty range. We assume that no scenarios will grow slower than a linear trend. The scale factors for each scenario applying to both residential and commercial systems are: Current Trajectory 1.0; Slow Growth 1.05; Net Zero 1.05; Sustainable Growth 1.1; Export Superpower and Rapid Decarbonisation 1.2. (The scenarios are outlined in more detail in Section 3.) In 2020, CSIRO projections included an uncertainty range was that imposed slower than linear growth to reflect COVID-19 impacts. However, these did not eventuate.

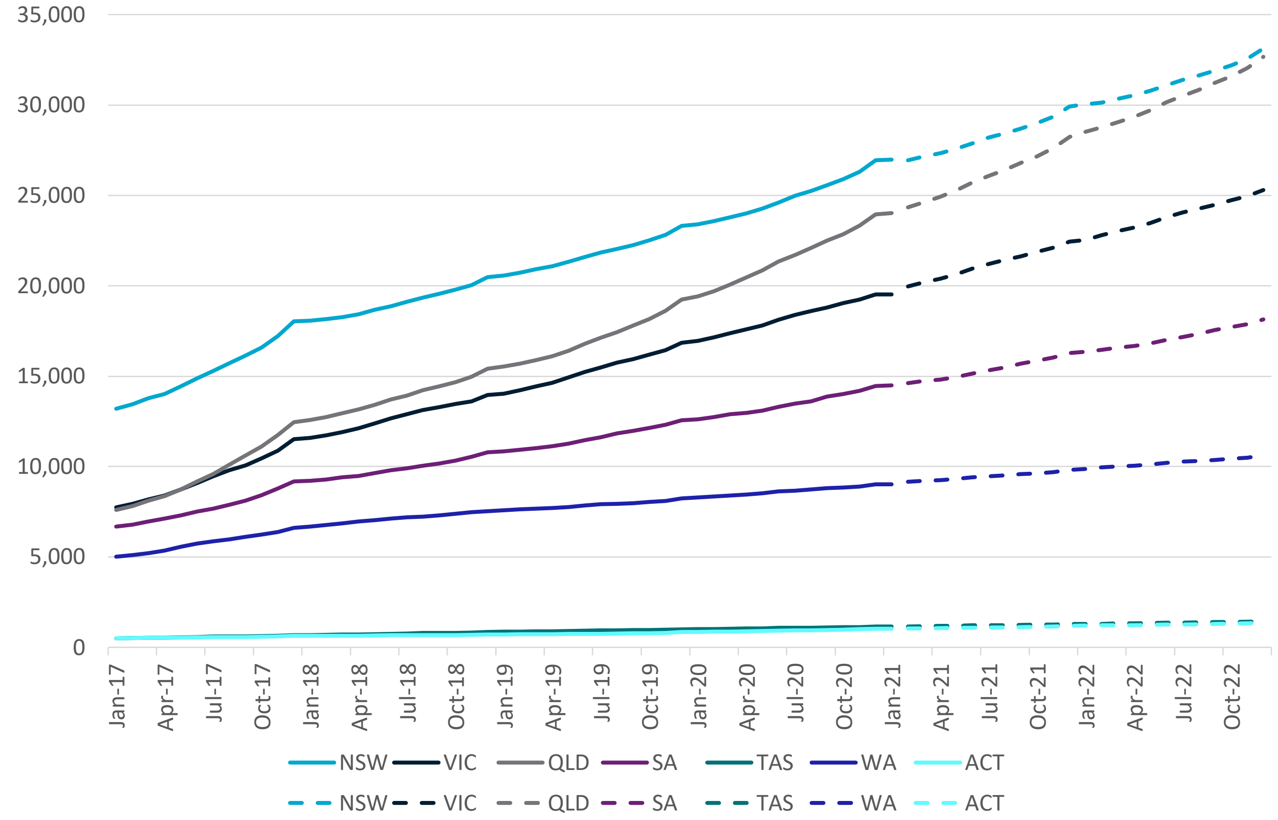

Figure 2-2 Regression results for commercial (<100kw) rooftop solar installations by region

2.1.2 Long-term adoption model: consumer technology markets

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 2-3 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[1]. 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 2 years by the trend analysis) determines the starting point on the adoption curve.

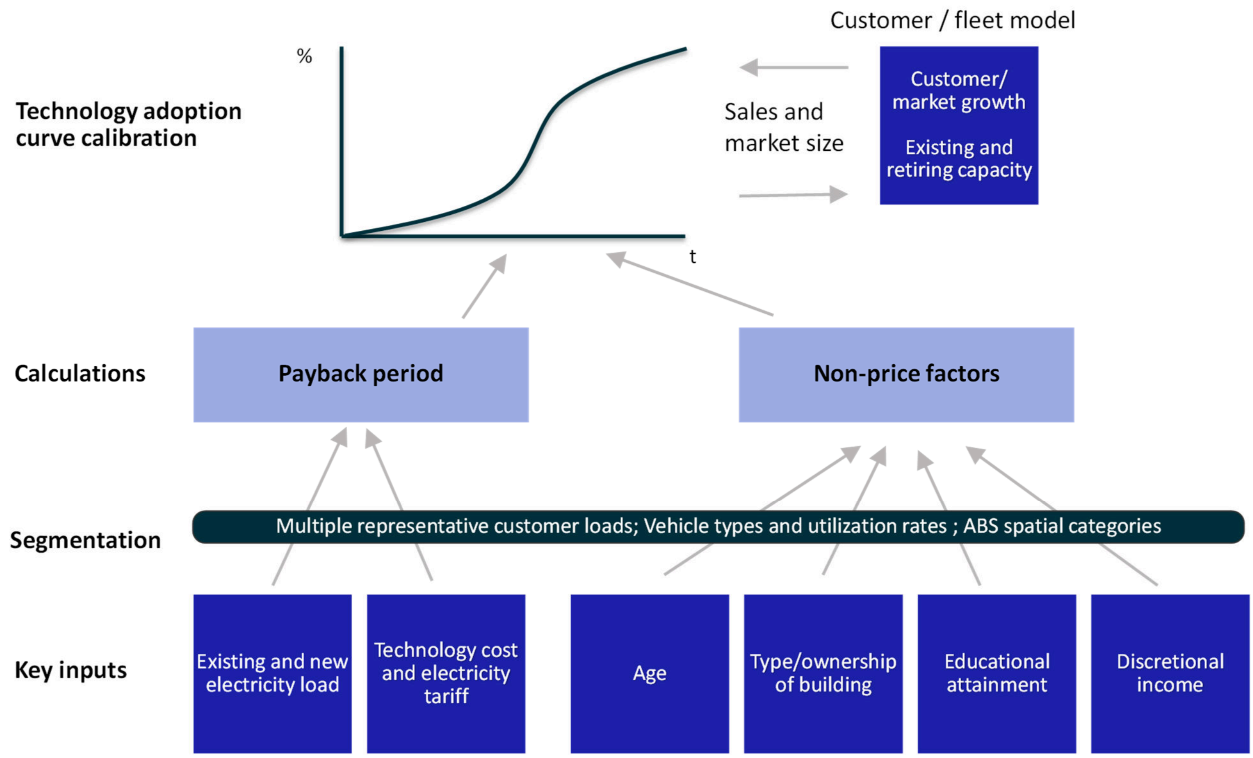

Figure 2-3 Adoption model methodology overview

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 Australian Bureau of Statistics Statistical Area Level 2 (SA2), as this level aligns to the available demographic data. However, we convert the technology data

[1] Note that to "join" the short- and long-term projection models we assume that the trends projected to 2021-22 are seen as historical fact from the perspective of the long-term projection model and calibrate the adoption curve from that point.

back to postcodes or aggregate up to the state level as required. The Australian Bureau of Statistics publishes correspondence files which provide conversion factors for moving between alternative commonly used spatial disaggregations. Each spatial disaggregation can also be associated with a state for aggregation purposes.

CSIRO applies a common structural model for storage and all solar panels 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 large solar systems, we take the view that such decisions should be regarded as more purely financial investment decisions, therefore we apply a mostly financially driven projection method.

2.1.3 Adoption of larger technology investments

For solar panel sales and capacity above 100kW, 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 above 100kW 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 meet a real 7% rate of return on investment. For plant 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 adoption.

Where investment can proceed, we impose a build limit rate based on an assessment of past construction rates and typical land/building stock cycles. Figure 2-4, Figure 2-5, Figure 2-6 and Figure 2-7 show the historical total deployment in four solar plant ranges: 0.1MW to 1MW, 1MW to 5MW, 5MW to 10 MW and 10MW to 30MW (sourced from APVI (2021))[2]. They indicate the trends in build rates across each state and the trend in cumulative national capacity. In size ranges up to 10MW, deployment has been growing at an increasing rate. Deployment slowed in 2019-20 for the 10 to 30MW rage. Data from the first quarter of 2020-21 indicates a slowing in the rate across all sizes but will need to be updated further before final projections. Deployment activity is most frequent and more evenly spread across states in the smaller ranges, particularly 0.1MW to 1MW. 10MW to 30MW systems are less frequent and concentrated in New South Wales, ACT and Queensland.

[2] 2020-21 data only includes the 3 months to September 2020.

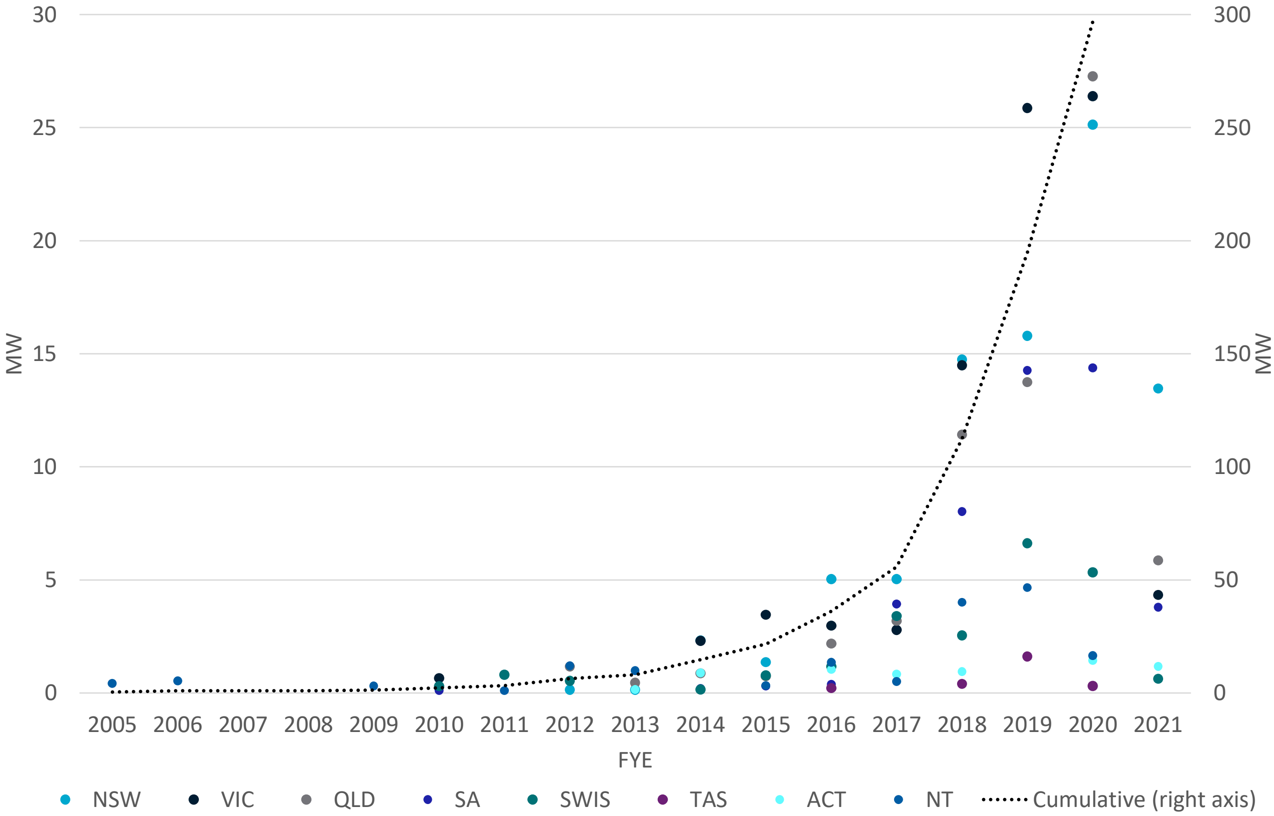

Figure 2-4 Historical deployment by state of solar systems of size 0.1 to 1 MW

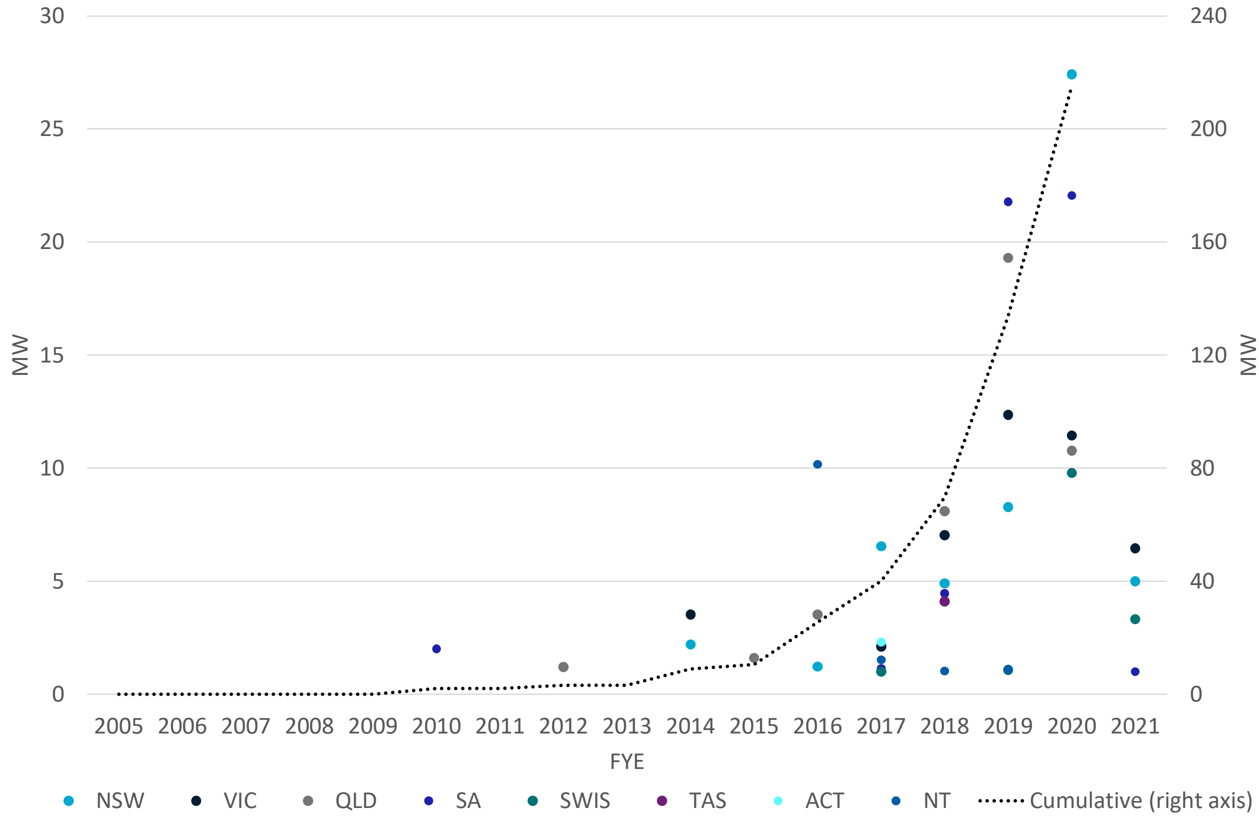

Figure 2-5 Historical deployment by state of solar systems of size 1 to 5 MW

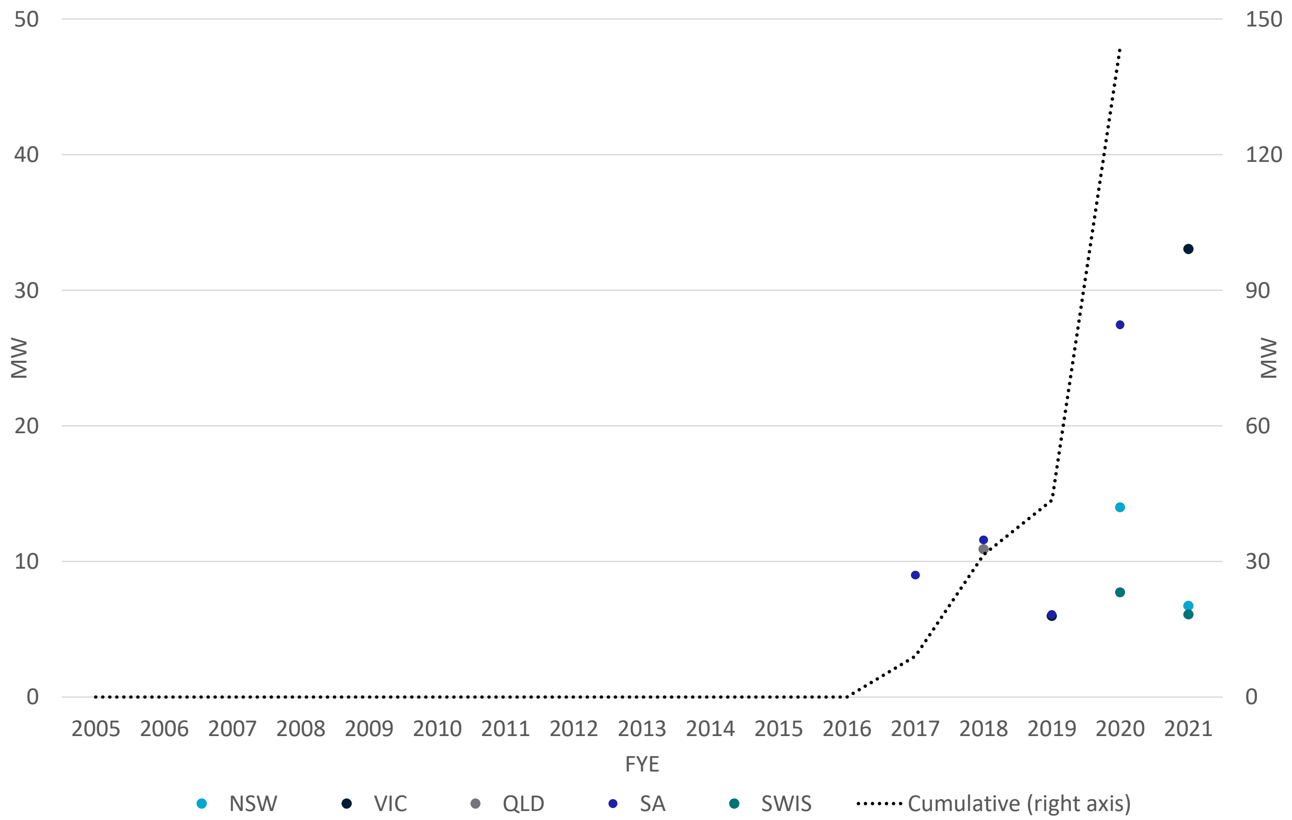

Figure 2-6 Historical deployment by state of solar systems of size 5 to 10 MW

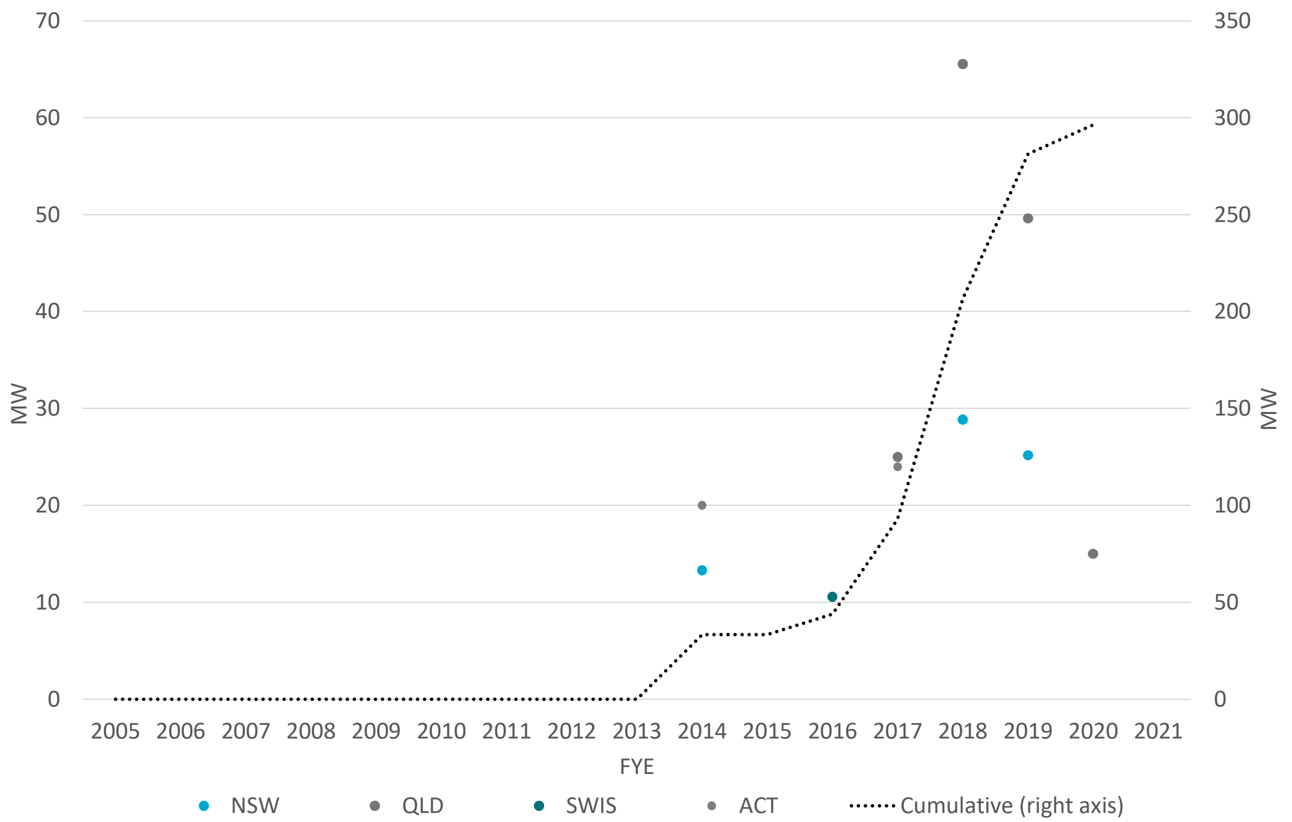

Figure 2-7 Historical deployment by state of solar systems of size 10 to 30 MW

2.2 Demographic factors and weights

The projection methodology includes selecting a set of non-price factors, typically drawn from accessible demographic data to calibrate the consumer technology adoption curve. An optional second step is to assign different weights to each factor to reflect their relative importance.

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 tested a new set of factors as shown in Table 2-1. We have also chosen our weights based on data that is readily available in the Statistical Area Level 2 format.

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 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 an SA2 region. This indicates a network effect where awareness of deployment of solar nearby or by 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/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. 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 connections this could increase uptake. The projected adoption rate is directly multiplied by connections and therefore higher connections increase adoption proportionally.

The same relationships apply to economic and customer connections growth for batteries as for solar, because (as noted above) of a lack of spatial data on batteries with which to train the model to create battery specific weighting factors.

3 Scenario definitions

The five scenarios are Current Trajectory, Slow Growth, Net Zero, Sustainable Growth and Export Superpower. Rapid decarbonisation is a sensitivity of Export Superpower. The AEMO scenario definitions are provided as short narratives and settings for key drivers in Table 3-1. For the solar PV and battery projections, we provide an extended scenario definition table based on a deeper consideration of the economic, infrastructure and policy drivers. We then describe each of the financial and non-financial drivers in more detail.

Current Trajectory scenario

The Current Trajectory scenario reflects a future energy system based around current government policies and best estimates of all key drivers. This scenario represents the current transition of the energy industry under current policy settings and technology trajectories, where the transition from fossil fuels to renewable generation is generally led by market forces. Uptake of DER, energy efficiency measures and the electrification of the transport sector proceeds in line with AEMO's current best estimates. The relevant purpose for this scenario for these consulting services is:

- To provide a basis on which to assess the development of the system under currently funded and/or legislated policies and commitments, using the most probable value/best estimate for each input.

Net Zero scenario

This reflects a world that is similar to Current Trajectory in the first decade but with a shift in policy towards achieving net zero greenhouse gas emissions economy wide by 2050.

Sustainable Growth scenario

Higher decarbonisation ambitions are supported by rapidly falling costs for battery storage and VRE, which drive consumers' actions and higher levels of electrification of other sectors. Economic and population growth are similar to Current Trajectory. The main differences to Current Trajectory are:

- Economy wide Net Zero emissions by 2050.
- Increased cost-competitiveness of VRE and batteries relative to fossil fuel generation.
- DER uptake is driven by consumers seeking to take a greater degree of ownership over their consumption, choosing when and how to consume energy. This is also aided by continued technological advances that extend the strong uptake in DER technologies. Participation in vital power plant (VPP) aggregation schemes is higher.
- There are high levels of electrification of transport and energy efficiency.

The relevant purposes for this scenario are:

- To understand the impact of strong decarbonisation and DER uptake on the needs of the electricity system, and in particular to explore the potential risk of under-investment in the infrastructure required to facilitate this transition.

- To explore the system security impact of high penetration of DER and potential issues and challenges in distribution and transmission networks, and what investments could address these.

Slow Growth scenario

This scenario includes the lowest level of economic growth following the global COVID-19 pandemic, which increases the likelihood of industrial load closures. Decarbonisation at a policy level takes a back seat, but strong uptake of distributed PV continues, particularly in the short-term in response to a number of incentives.

- The rate of technological development and cost reductions stagnates, as falling private investment reduces the speed of cost reductions in technologies such as battery storage.
- In search of cost savings and in response to low interest rates and government incentives to aid the recovery from COVID-19, consumers continue to install distributed PV at high rates, continuing the trends observed during 2020, where uptake has held up and in many regions increased, despite adverse economic conditions. Over time these impacts dissipate and distributed PV uptake moderates.

Key differences to the Current Trajectory scenario include:

- Lower levels of decarbonisation ambitions both internationally and domestically.
- Very low economic activity and population growth.
- Lower levels of electrification.
- Stronger level of DER uptake in the near term

The relevant purposes for this scenario for these consulting services are:

- To assess the risk of over-investment in the power system, in a future where operational demand is much lower, and some less certain policy drivers do not proceed.
- To explore operational and system security risks associated with falling levels of minimum demand.

Export Superpower scenario

This scenario represents a world with very high levels of electrification and hydrogen production, fuelled by strong decarbonisation targets and leading to strong economic growth. Key differences to the Current Trajectory scenario include:

- Economy wide net zero emission by early 2040s.
- The highest level of international decarbonisation ambition, consistent with a target of limiting the global temperature rise to 1.5^{o}C by 2100 over pre-industrial levels – this also results in the strongest decarbonisation requirement in the NEM across the scenarios.
- Stronger economic activity and higher population growth.
- Continued improvements in the economics of hydrogen production technologies that enable the development of a large NEM connected hydrogen production industry in Australia for both export and domestic consumption.

- Higher levels of electrification across many sectors, with strong light vehicle electrification but fewer large electric trucks due to competition from hydrogen fuel-cell trucks.

The relevant purpose for this scenario for these consulting services is:

- To understand the implications and needs of the power system under conditions that result in the development of a renewable generation export economy which significantly increases grid consumption and necessitates developments in significant regional renewable energy generation.
- To assess the impact, and potential benefits, of large amounts of flexible electrolyser load.

Rapid Decarbonisation sensitivity

The Rapid Decarbonisation sensitivity has the same scenario settings as Export Superpower but without a large NEM connected hydrogen industry.

Table 3-1 AEMO scenario definitions

Scenario/sensitivity	SLOW GROWTH	CURRENT TRAJECTORY	NET ZERO	SUSTAINABLE GROWTH	EXPORT SUPERPOWER	RAPID DECARBONISATION
Economic growth and population outlook*	Low	Moderate	Moderate	Moderate	High	High
Energy efficiency improvement	Low	Moderate	Moderate	High	High	High
DSP	Low	Moderate	Moderate	High	High	High
Distributed PV (per capita uptake tendency)	Moderate, but elevated in the short term	Moderate	Moderate	High	High	High
Battery storage installed capacity	Low	Moderate	Moderate	High	High	High
Battery storage aggregation / VPP deployment by 2050	Low	Moderate	Moderate	High	High	High
Battery Electric Vehicle (BEV) uptake	Low	Moderate	Moderate	High	High*	High
BEV charging time switch to coordinated dynamic charging by 2030	Low	Moderate	Moderate	High	Moderate/High	High
Electrification of other sectors	Low	Low/Moderate	Moderate	Moderate/High	Moderate/High	High
Hydrogen uptake	Minimal	Minimal	Minimal	Minimal	Large NEM-connected export and domestic consumption	Minimal
Shared Socioeconomic Pathway (SSP)	SSP3	SSP2	SSP2	SSP1	SSP1	SSP1
International Energy Agency (IEA) 2020 World Energy Outlook (WEO) scenario	Delayed Recovery Scenario (DRS)	Stated Policy Scenario (STEPS)	Stated Policy Scenario (STEPS)	Sustainable Development Scenario (SDS)	Net Zero Emissions by 2050 case (NZE2050)	Net Zero Emissions by 2050 case (NZE2050)

Scenario/sensitivity	SLOW GROWTH	CURRENT TRAJECTORY	NET ZERO	SUSTAINABLE GROWTH	EXPORT SUPERPOWER	RAPID DECARBONISATION
Representative Concentration Pathway (RCP) (mean temperature rise by 2100)	RCP7.0 (~4°C)	RCP4.5 (~2.6°C)	RCP4.5 (~2.6°C)	RCP2.6 (~1.8°C)	RCP1.9 (<1.5°C)	RCP1.9 (<1.5°C)
Decarbonisation target	No explicit decarbonisation target.	26-28% reduction by 2030.	26-28% reduction by 2030 Economy-wide Net Zero target by 2050.	Consistent with limiting temperature rise to 2 degrees. Economy-wide before 2050	Consistent with limiting temperature rise to 1.5 degrees. Economy-wide Net Zero by early 2040s	Consistent with limiting temperature rise to 1.5 degrees. Economy-wide Net Zero by early 2040s
Generator and storage build costs	CSIRO GenCost Central	CSIRO GenCost Central	CSIRO GenCost Central	CSIRO GenCost High VRE	CSIRO GenCost High VRE	CSIRO GenCost High VRE
Generator retirements	In line with expected closure years, or earlier if economic to do so.	In line with expected closure years, or earlier if economic.	In line with expected closure years, or earlier if economic or driven by decarbonisation objectives beyond 2030.	In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	In line with expected closure year, or earlier if economic or driven by decarbonisation objectives
Relative project finance costs	Lower than Central, reflecting lower rates of return with lower economic growth	In line with current long-term financing costs appropriate for a private enterprise	In line with current long-term financing costs appropriate for a private enterprise	As per Central	As per Central	As per Central

3.1.1 Extended scenario definitions

The AEMO scenario definitions have been extended 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:		Slow Growth	Current Trajectory	Net Zero	Sustainable Growth	Export Superpower	Rapid Decarbonisation
Economic							
	Commonwealth SRES subsidy	Continues to 2030 phasing down	Continues to 2030 phasing down	Continues to 2030 phasing down	Continues to 2030 phasing down	Continues to 2030 phasing down	Continues to 2030 phasing down

Driver:		Slow Growth	Current Trajectory	Net Zero	Sustainable Growth	Export Superpower	Rapid Decarbonisation
	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 3% p.a.	ACCU and VEEC subsidies available and increasing 5% 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)[3]	Current state policies	Current state policies	Current state policies	Current state policies. National $2000 battery subsidy	Current state policies. National $2000 battery subsidy	Current state policies. National $2000 battery subsidy
Infrastructure							
	Growth in apartment share of dwellings	High	Medium	Medium	Medium	Low	Low
	Decline in home ownership	High	Medium	Medium	Medium	Low	Low
Business model							
	Tariff and DER incentive arrangements[1]	Slow change	Moderate change	Moderate change, strengthening from 2030	Stronger energy management incentives	Stronger energy management incentives	Stronger energy management incentives
	System architecture changes support greater incentives to DER participation	Medium (solar) Low (batteries)	Medium	Medium	High	High	High
	Feasibility of participation of apartment dwellers and renters in DER	Medium (solar) Low (batteries)	Medium	Medium	High	High	High

[3] 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. Where available, these are assumed to continue with credits growing at 2% in value in Current Trajectory and Slow Growth and growing at 5% per annum under the remainder of scenarios reflecting net zero emission targets.

1. Time-of-use tariffs are expected to be around 10% of the market by 2030 and these are taken into consideration in addition to more direct control measures such as Virtual Power Plant. See Table 4-2 for details.

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.

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 **Error! Reference source not found.**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 generation 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 4.5
Garage or indoor space, ideally air conditioned, shaded and ventilated (battery storage)	Varied by scenario and expressed as maximum market share constraints in Section 4.5
The quantity of buildings with appropriate roof and indoor space that are owned or mortgaged by the tenant, 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 4.5
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 4.5
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 4.5

Expanding further on the penultimate dot point, it is not yet clear what mechanisms will be put in place to allow the system to curtail or re-direct rooftop solar exports when state level operational demand drops to near zero levels. There are proposals which allow for greater monitoring and orchestration of consumer energy resources which could include curtailment of rooftop solar but would also seek to shift the charging times of technologies such as batteries to create additional demand, mitigating the need for curtailment. The solar forecasts assume that solutions will be put in place to avoid breaching security and reliability limits without putting additional 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 market shares for rooftop solar PV and batteries as outlined in Section 4.5.

Table 3-5 Emerging or potential disruptive business models to support solar and battery adoption

Name	Description	Constraint reduced
Building as retailer	Apartment 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.
Solar exports become a network customer obligation	Networks are incentivised through regulatory changes, such as those proposed by AEMC in the Access and	Network hosting capacity imposes restrictions on rooftop solar uptake through size of connection constraints and financial impact of

Name	Description	Constraint reduced
	Pricing review, to purchase voltage management services	curtailment (through inverter tripping, even after accounting for improved inverter standards)
Virtual power plant	Retailers, aggregators, networks or an independent market operator reward demand management through direct payments, alternative tariff structures or direct ownership and operation of battery to reduce costs elsewhere in the system	Given the predominance of volume-based tariffs, the main value for customers of battery storage is in reducing rooftop solar exports. The appetite for demand management participation could be more directly targeted than current incentives.
Going off-grid	Standalone power system is delivered at lower cost than new distribution level connections greater than 1km from existing grid	Except for remote area power systems, 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, 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 for new homeowners
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 in and describe them in further detail below.

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 Slow Growth, 3 % in Current Trajectory and Net zero and 5% in Sustainable Growth, Export Superpower and Rapid Decarbonisation.
New policies (not currently government policy)	It is assumed that a subsidy for batteries becomes available by 2025 of $2000 in Sustainable Growth, Export Superpower and Rapid Decarbonisation.

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 in 2020 and remains at that level until 2030. Consequently, the LGC price is expected to decline to low levels in the next few years.

Emissions Reduction Fund and Climate Solutions Fund

The Emissions Reduction Fund (ERF) has been 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 at around $15/t$CO_2$e. 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 $10/MWh subsidy compared to almost $90/MWh for LGCs at their peak.

Potential changes to Commonwealth renewable energy and climate policy

While there are currently no announced changes to renewable energy and climate policy, given Australia's nationally determined commitment at the Paris UNFCCC meeting, there may be future adjustments to those policies. At this stage, given the lack of support for price-based policies, any new policies are more likely to take the form of direct actions such as auctions and lower interest finance of low emission technologies. In particular, batteries have a higher payback period and so might be targeted by more subsidies by future governments. To deliver the expected higher deployment of batteries consistent with Sustainable Growth , Export Superpower and Rapid Decarbonisation we have assumed a $2000 subsidy is available from 2025. The subsidy could equally be delivered as new or extended state policies.

3.2.5 State policy drivers

The policies discussed here are drawn from several state government websites[4]. 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.

Queensland and Victoria have policies that will work in addition to the Commonwealth RET. They are the 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

[4] Empowering Homes solar battery loan offer | NSW Government

Solar rebates | Solar Victoria

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

South Australia's Home Battery Scheme |

Next Generation Renewables - Environment, Planning and Sustainable Development Directorate - Environment (act.gov.au) 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 half the cost of solar (up to a value of $1,888) including 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 will be eligible over the next 3 years. 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 ten years including 50,000 targeting solar for rental properties together with 18,500 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 $4,838 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_2e. As with the emissions reduction fund, this potential subsidy source will become attractive only once LGC prices have declined further.

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 policy is to provide interest-free loans of up to $9,000 for a rooftop solar and up to $14,000 for solar plus storage through a 10-year Empowering Homes program that will target up to 300,000 households. Eligible households must be in selected postcodes (likely to be widened), be owner-occupiers and have an annual household income of up to $180,000 (NSW government, 2020). The NSW government also has an existing scheme providing 3000 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 has a policy of providing subsidies to 40,000 homes to install batteries. The subsidy will be scaled with the size of the battery at $200/kWh capped at $3000 ($300/kWh for concession holders). It is being delivered in collaboration with the CEFC. A set of minimum technical requirements for battery systems has been developed to ensure the batteries are capable of being recruited into virtual power plant (VPP) schemes (NSW and Victoria have also adopted these). It appears the scheme has taken several years to reach around 20,000 installations[5] and the 40,000 target may take several more.

[5] South Australia's Virtual Power Plant to boost capacity | Growth State

The ACT government is making available an $825/kW subsidy targeting deployment of 5000 batteries under its Next Generation Energy Storage scheme. The overall target is for 36 MW of battery storage.

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

	Policy	Approach to including across all scenarios
NSW	Interest-free loans of up to $9,000 for a rooftop solar and up to $14,000 for solar plus storage through a 10-year Empowering Homes program that will target up to 300,000 households. Eligible households must be owner-occupiers and have an annual household income of up to $180,000	Not included. Assumed that low interest loan funds non-additional activity since the benefit of avoided interest is not large enough to be the original motivation
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 $1,888) 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 $4,838 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 at 2% per annum in Slow Growth and Current Trajectory and at 5% per annum in Net Zero, Sustainable Growth, Export Superpower and Rapid Decarbonisation
QLD	Renewable energy target of 50% by 2030	Not included. These subsidies are not targeted at small scale solar PV.
SA	Subsidies are to be provided to 40,000 homes to install batteries. The subsidy will be scaled with the size of the battery and capped at $3000.	Minimum addition of 20,000 residential batteries over the next three years
ACT	The ACT government is making available an $825/kW subsidy targeting deployment of 36MW of battery storage under its Next Generation Energy Storage scheme.	Minimum addition of 5000 batteries by 2023

	Policy	Approach to including across all scenarios
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 7-10 c/kWh across most states. While not calculated directly via this formula, this FiT level did have some resemblance to the average generation price over a year until the fall in generation prices in 2020.

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

- Northern Territory: Residential and commercial customers with solar systems installed before 14 April 2020 receive 26.05c/kWh and 30.32c/kWh respectively. New systems after that date receive 9.13c/kWh for both residential and commercial customers[6].
- Queensland: Recognising lower competition, regional Queensland FiTs are set by the state government and were 7.861c/kWh from July 2020[7].
- 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:
    - 3 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.
- Victoria: The current minimum feed-in tariff of 10.2c/kWh is set by the government[8]. 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 2020 with

[6] Renewable energy - Jacana Energy

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

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

prices of 9.1 and 12.5c/kWh during off-peak and peak respectively and the daytime feed-in tariff at 9.8c/kWh.

- Tasmania: The feed-in tariff for residential and commercial customers is 8.471c/kWh from July 2020[9].

While not binding on retailors, 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 6.0 to 7.3 cents per kilowatt hour[10].

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

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

[10] IPART - Solar feed-in tariffs 2020/21 (nsw.gov.au)

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 from a financial perspective in assumed declining export revenues and in a technical sense by assumed maximum inverter capacity connection limits.

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 2020-21 consultation report by Graham at al. (2020). The Slow Growth, Current Trajectory and Net Zero scenarios are assigned the equivalent GenCost Central scenario. Sustainable Growth, Export Superpower and Rapid Decarbonisation are assigned the fastest cost reduction by applying the High VRE GenCost scenario.

The 2020 costs shown imply that a 6.6kW system ought to be advertised for approximately $5900 (6.6 × (1400-500 for small-scale technology certificates). However, we also see 6.6kW systems advertised in the range of $3500 installed (or $1000/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.

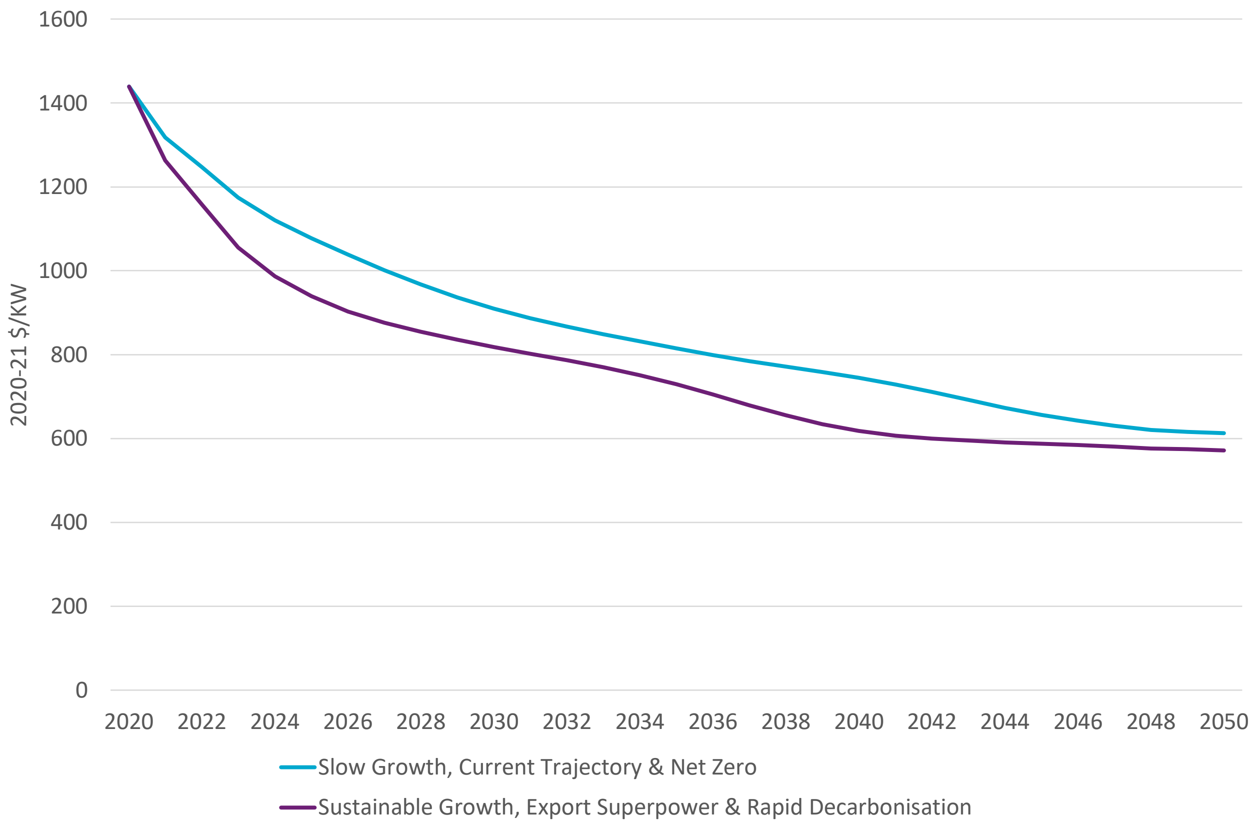

Figure 4-1 Assumed capital costs for rooftop and small-scale solar installations by scenario (excluding STCs or other subsidies)

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.

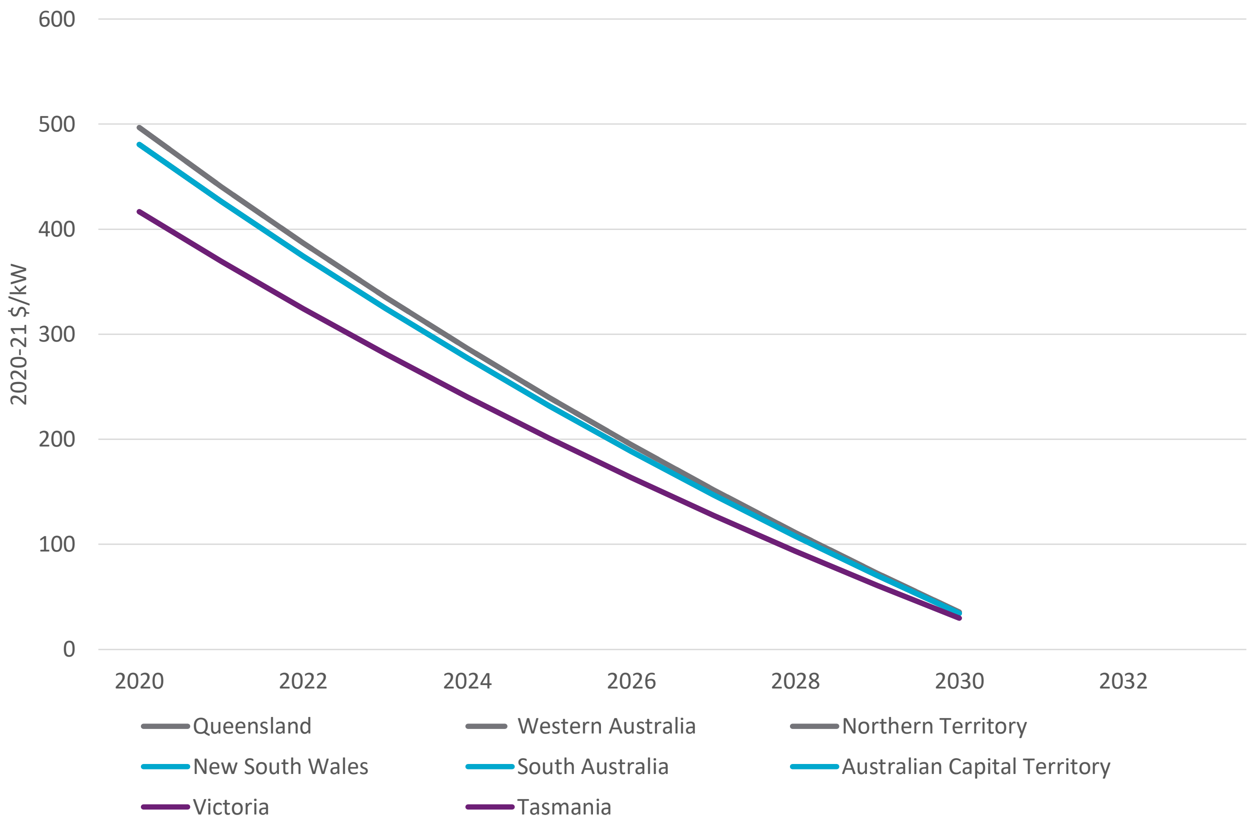

Figure 4-2 Assumed STC subsidy available to rooftop solar and small-scale solar systems by state

4.1.3 Batteries and installation

The current capital cost of small-scale batteries is source from the median price of systems presented in SunWiz (2021) and the cost trajectory over time is aligned with changes in large-scale battery capital costs presented in GenCost 2020-21 (Graham et al. 2020). The Slow Growth, Current Trajectory and Net Zero scenario battery costs are assumed to align with the GenCost 2020-21 Central scenario. These are upfront costs and do not take account of degradation or cost of disposal at end of life. End of 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 recently begun construction of recycling facilities for lithium-ion batteries[11] (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 2020-21 projects fast cost reductions to the 2030s across all scenarios after which cost reductions are steady but at a slower rate. The battery pack falls at a faster rate but the inverters which are the largest balance of plant cost fall more slowly given their relative maturity. Other elements of balance of system are system integration and installation. For Sustainable Growth , Export Superpower and Rapid Decarbonisation, battery costs are assumed to align with the High

[11] Renewable-powered lithium-ion battery recycling plant in Norway begins construction | Energy Storage News (energy-storage.news)

VRE scenario which is the lowest cost trajectory in GenCost 2020-21 owing to strong global deployment of batteries in the global transport and electricity sectors.

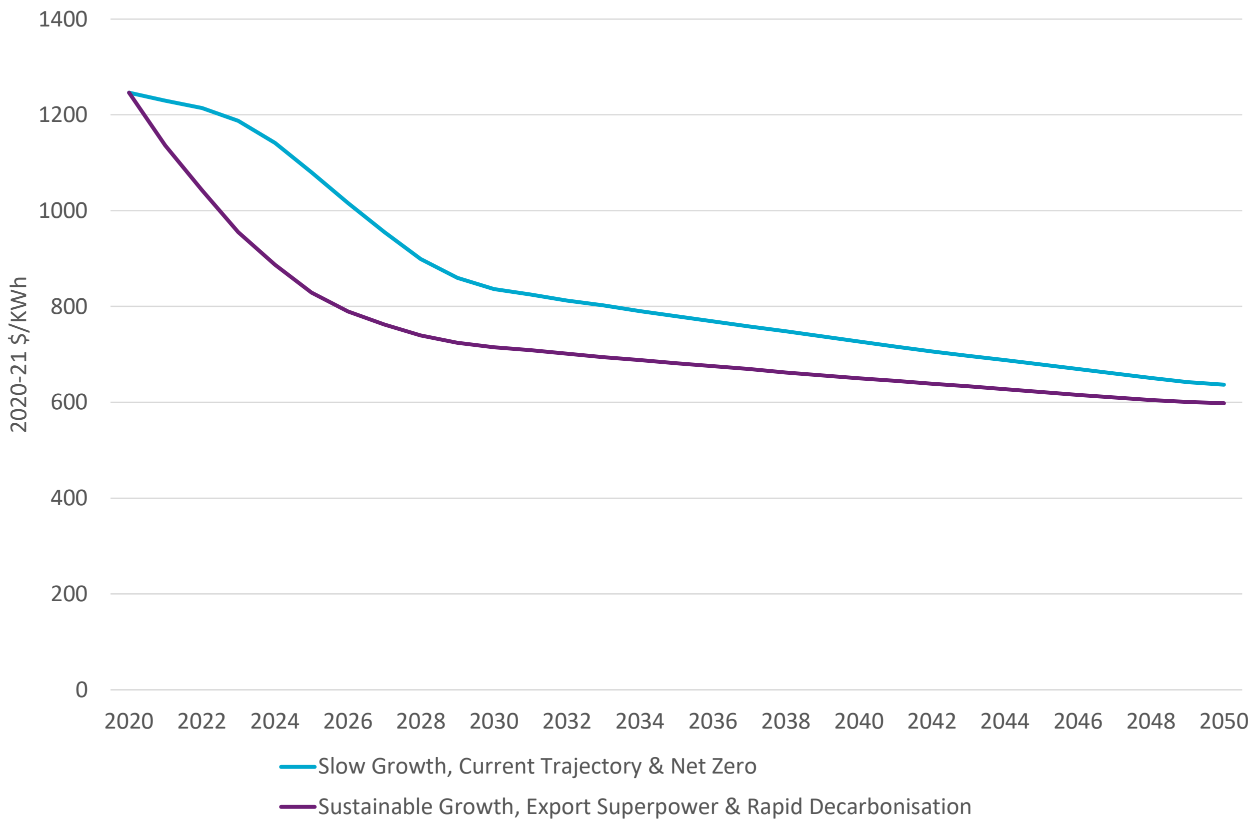

Figure 4-3 Assumed capital costs for battery storage installations by scenario

4.2 New solar system sizes (less than 100kW)

Assumed new residential and commercial new solar system sizes as shown in Figure 4-4. These are the size of the panels, while inverters are the same size or smaller. We impose a trend in the next year and then impose different assumptions by scenario to 2050. For business customers, while we impose an average, we assume that they match their solar systems to meet their average daily peak load since this strategy would appear to be most financially rewarding. The June to June system size trend implies an increasing commercial system size. However, we have included a breakout with the monthly data from 2017. The monthly trend implies commercial systems sizes are either flattening out or slightly falling. We've assigned a flat trend to the Export Superpower and Sustainable Growth scenarios. The remainder of the scenarios experience a slight decline in commercial system sizes. While we are using a flat to falling commercial system size, it remains higher than assumptions used in 2020 projections due to updated data on commercial system sizes (Graham and Havas, 2020).

Residential rooftop solar systems have been advertised with higher panel to inverter capacity ratios recently. 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[12]. The average for new residential systems has been above 6.6kW and sits just over 7kW in early 2021 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 updated data has led to a higher assumed trend in residential rooftop system sizes compared to 2020 projections (Graham and Havas, 2020).

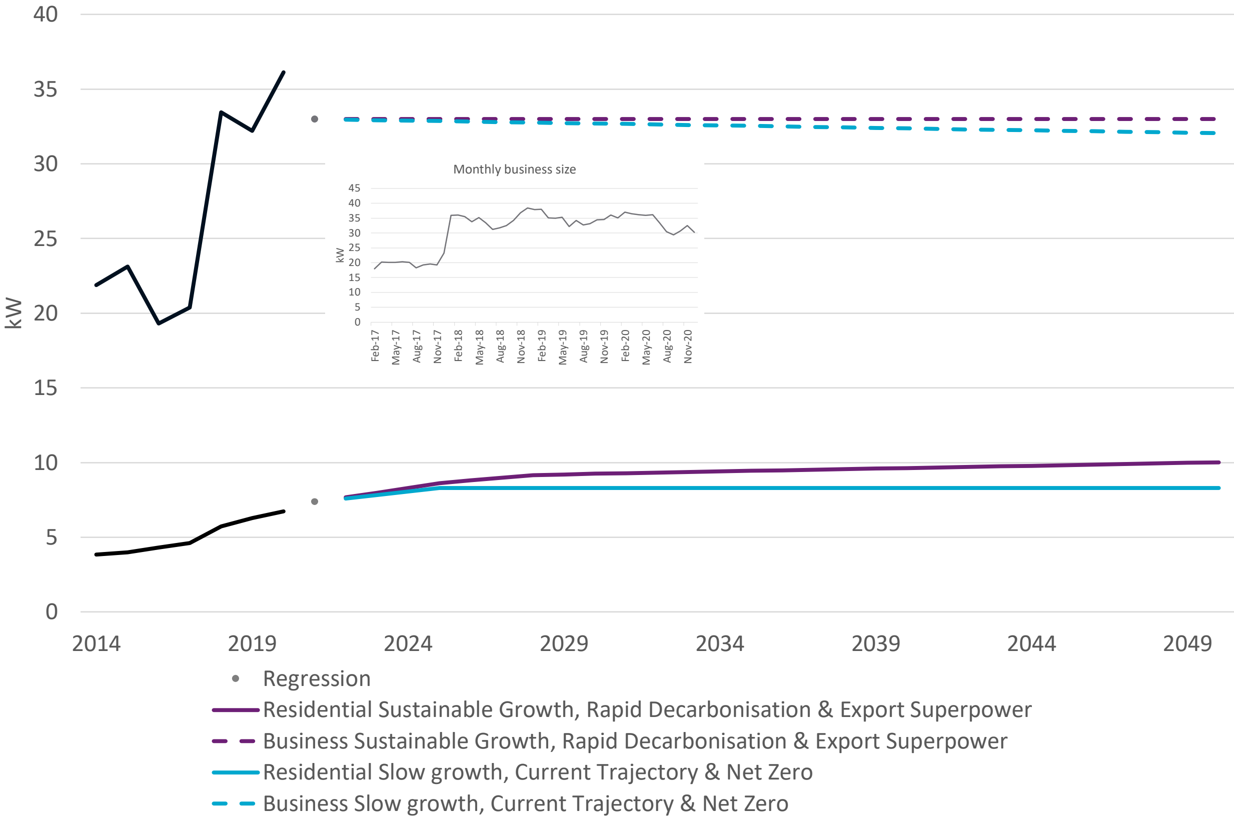

Figure 4-4 Historical and assumed future size of new residential and commercial solar systems

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. Most homes have more than one phase, so a limit per phase is not a hard limit but rather a consideration. Subsidies per watt of solar power capacity are declining (see 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 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

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

improving panel efficiency, acceptance of the use of non-north facing roof areas will continue to grow. We assign two system size saturation levels across the scenarios as shown in Figure 4-4.

4.3 Electricity tariffs, battery management and virtual power plants

4.3.1 Assumed trends in retail and generation prices

Retail prices are reasonably stable throughout the projection period and by design are not a strong driver of uptake trends or differences between scenarios. While there have been periods where rooftop solar and battery uptake coincided with rising retail electricity prices, the relationship has not been strong in the last year. This likely reflects that, whatever the retail price, payback periods have reached a low enough point that adoption will continue even when electricity prices fall.

Broadly speaking retail electricity generation prices are expected to ease in the short term reflecting a relaxed electricity supply-demand balance. Some modest increases 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 electricity price are expected to be more stable.

Retail electricity prices in Western Australia and Northern Territory 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. Slow Growth has the greatest impact because it has two factors which lead to low day time prices – moderate growth in small-scale solar PV and low system demand. The decrease in daytime prices is the least in Export Superpower because, despite strong growth in large and small scale solar it has a 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. Current Trajectory and Net Zero have high solar PV deployment but stronger demand than Slow Growth. Sustainable Growth also has stronger demand growth but in this case its significantly higher solar PV is the stronger factor and so prices are slightly lower than Current Trajectory and Net Zero.

Table 4-1 Assumed reduction in rooftop solar production weighted generation prices by 2050 relative to 2021

Scenario	Reduction
Slow Growth	49%
Current Trajectory	46%
Net Zero	43%
Sustainable Growth	48%
Export Superpower	33%

4.3.2 Current electricity tariff status

Electricity tariff structures are important in determining the return on investment from customer adoption of small-scale embedded technologies and, importantly for the electricity system, how they operate those technologies. The vast 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 and more recently there have been proposals for export prices which would reduce returns on 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.

4.3.3 Future developments in DER incentives and management

While retailers make business-like TOU and demand tariff structures available to residential customers in addition to flat tariffs, their adoption is low (0 to 20% depending on the state). For both efficiency and equity purposes, both regulators (e.g. AEMC, 2012) and the electricity supply chain (e.g. CSIRO and ENA, 2017) would prefer to see greater residential adoption of the more cost reflective TOU and demand tariffs.

The AEMC in collaboration with distribution networks has had some success in changing network tariffs charged to retailers to include more TOU and demand elements. Also, some battery and electric vehicle owners currently engage a third party (such as an energy service company or retailer) to control their devices to reduce electricity costs (e.g. optimising battery charging or discharging against a TOU tariff or including electric vehicles in controlled device tariffs usually applied to hot water systems). Our calculations show shifting from a flat tariff to a TOU tariff saves around 7% on a customer's bill with an uncertainty range around that depending on the tariff structure in your network zone. Customers are not given any guarantee that current TOU pricing structures or levels will continue. If TOU pricing structures shift over time such that the middle of the day becomes the main off-peak period (due to higher large- and small-scale solar production), this could have two separate effects. The first is the TOU tariffs become less attractive to existing solar owners because their current attractiveness is based on consumers accessing low cost energy at night when solar is not producing. The second effect is that it reduces the incentives for non-solar owners to take up rooftop solar since the new TOU tariffs would represent an alternative way of accessing low daytime electricity costs.

There are no current policies which would substantially increase residential customer adoption of alternative tariff structures. As such, given the self-evident lack of uptake of available alternatives, the prospects for greater residential adoption are considered low[13]. Consequently, in the context of understanding DER behaviour, it is appropriate to focus on more direct control measures. Direct control measures are collectively called Virtual Power Plant (VPP) programs since a large aggregation of devices can be equivalent in scale to a large power plant and perform similar functions for the electricity system. Operation of batteries in VPP mode is not demonstrated in this report since it is a function of system needs and is typically estimated by AEMO as part of their electricity market simulations. However, it is important to understand the financial impact of participation in VPP programs for the purposes of projecting battery uptake.

Simulations 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 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[14]. 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[15].

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:

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

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

[15] 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.

- 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 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	Current Trajectory	76%	14%	6%	56%	18%	30%
	Slow Growth	84%	16%	4%	64%	12%	20%
	Net Zero	68%	12%	8%	48%	24%	40%
	Export Superpower	48%	7%	13%	28%	39%	65%
	Sustainable development	44%	6%	14%	24%	42%	70%
2050	Current Trajectory	68%	12%	2%	48%	30%	40%
	Slow Growth	76%	14%	2%	56%	23%	30%
	Net Zero	44%	6%	4%	24%	53%	70%
	Export Superpower	36%	4%	4%	16%	60%	80%
	Sustainable development	32%	3%	4%	12%	64%	85%

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 is sourced from AEMO and their economic consultant. These assumptions are used 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

Scenario	New South Wales	Victoria	Queensland	South Australia	Western Australia	Tasmania	Australian Capital Territory
Slow Growth	1.6	2.0	1.8	1.4	2.1	1.3	2.1
Current Trajectory	2.0	2.3	2.1	1.7	2.4	1.6	2.4
Net zero	2.0	2.3	2.1	1.7	2.4	1.6	2.4
Sustainable Growth	2.0	2.3	2.2	1.8	2.6	1.7	2.6
Export Superpower	2.5	3.0	2.6	2.2	2.8	1.9	2.8
Rapid Decarbonisation	2.5	3.0	2.6	2.2	2.8	1.9	2.8

4.4.2 Customers

Customer growth assumptions by scenario are shown in Table 4-4. These assumptions are relevant for establishing the current market share of solar and battery customers 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
Slow Growth	1.0	1.4	1.3	0.9	1.6	0.7	1.7
Current Trajectory	1.2	1.6	1.5	1.0	1.7	0.8	1.8
Net zero	1.2	1.6	1.5	1.0	1.7	0.8	1.8
Sustainable Growth	1.2	1.6	1.4	1.0	1.7	0.8	1.8
Export Superpower	1.2	1.8	1.6	1.1	2.0	0.9	2.0
Rapid Decarbonisation	1.2	1.8	1.6	1.1	2.0	0.9	2.0

4.5 Separate dwellings and home ownership

The assumptions for the share of home ownership and separate dwellings feed into calculations of the maximum market share or saturation level of the adoption curve for each scenario.

4.5.1 Separate dwellings

Owing to rising land costs in our large cities where most residential customers live, there has been a trend towards faster building of apartments compared to detached houses (also referred to as separate dwellings in housing statistics). As a result, we expect the share of separate dwellings to fall over time in all scenarios (Figure 4-5). This assumption does not preclude periods of volatility in the housing market where there may be over and undersupply of apartments relative to demand. The assumptions for the Current Trajectory, Net Zero and Sustainable Growth scenario were built by extrapolating past trends resulting in separate dwellings occupying a share of just below 60% by 2050, around 6 percentage points lower than today (calculated from ABS Census data). The Slow Growth, Export Superpower and Rapid Decarbonisation assumptions were developed around that most likely projection with the latter two scenarios experiencing a less rapid shift to apartments which supports higher rooftop solar and battery adoption.

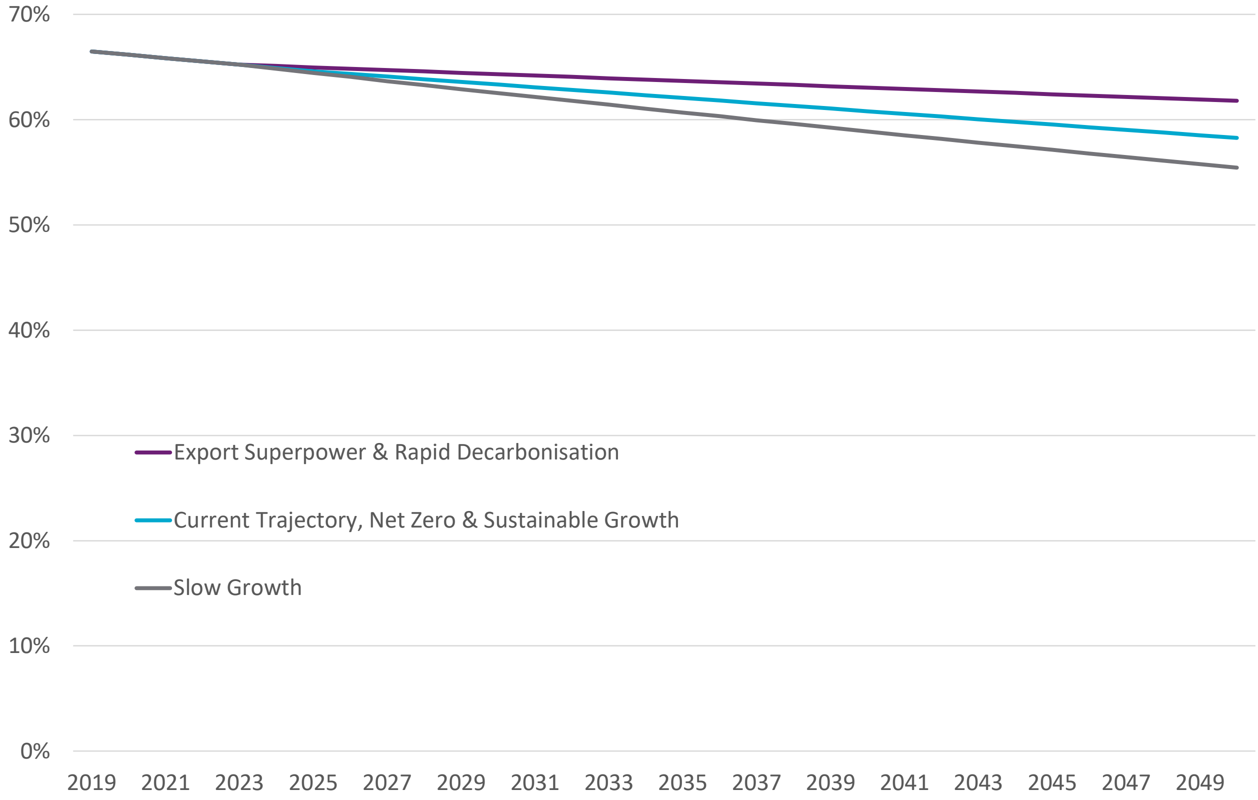


Figure 4-5 Assumed share of separate dwellings in total dwelling stock by scenario

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 embedded technologies. Home ownership (which includes homes owned outright as well as mortgaged) increased rapidly post-World War II and was steady at around 70% for the remainder of last century. However, in the last 15 years ABS Census data as reported by AIHW (2017) shows that home ownership has been declining and was an average 65.5% in 2016 with the largest declines amongst young people (25 to 34), although all ages below 65 experienced a consistent decline between Censuses.

In the long run, we might expect the housing market to respond by providing more affordable home ownership opportunities. However, we must also acknowledge that 15 years represents a persistent trend. As such, under the Current Trajectory, Net Zero and Sustainable Growth scenarios, we assume the trend continues and we apply the rate of decline in the last 15 years to the year 2050. Under the Slow Growth scenario, we assume the slightly faster trend of the last 5 years prevails, leading to a slightly faster reduction in home ownership rates. Under Export

Superpower and Rapid Decarbonisation, consistent with higher DER adoption, we assume a slower rate of decline in home ownership consistent with the trend of the last 25 years representing a slowing in the rate of decline relative to recent history (Figure 4-6).

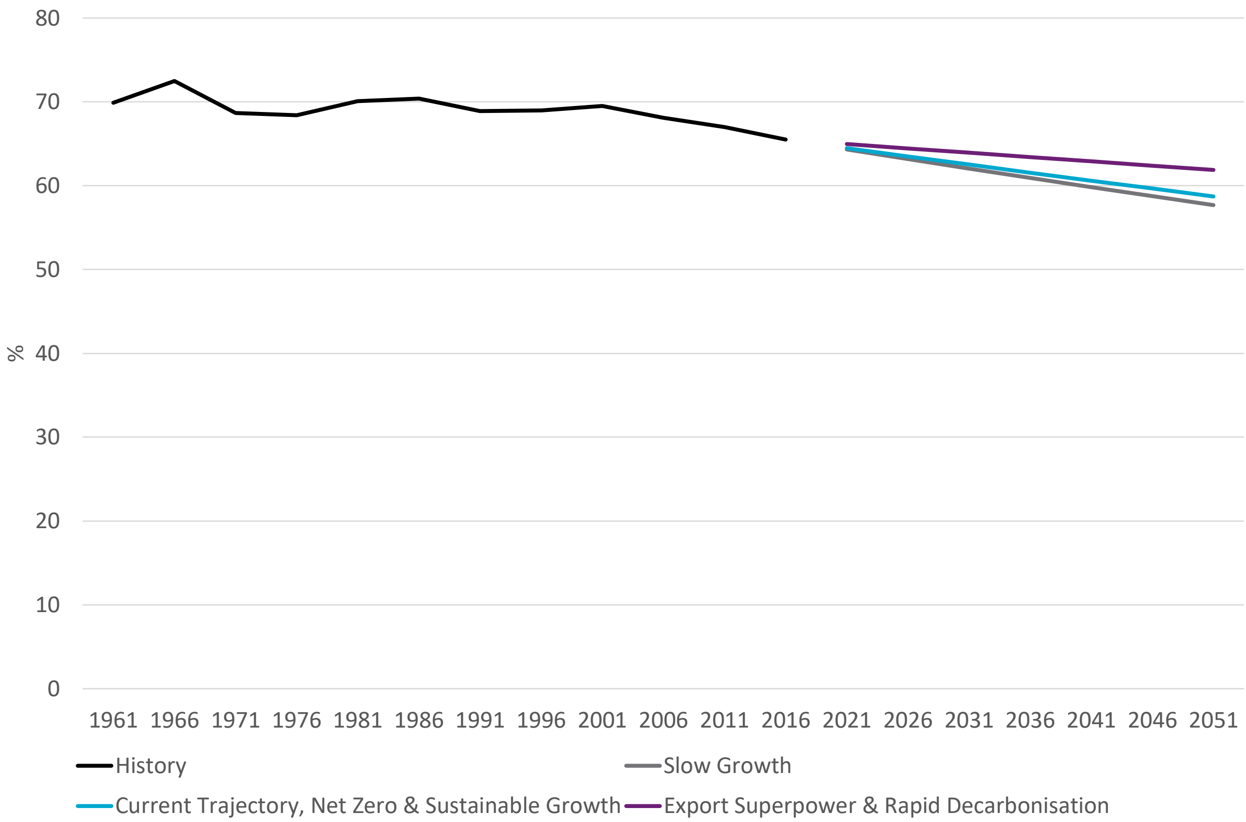


Figure 4-6 Historical (ABS Census) and projected share of homes owned outright or mortgaged, source AIHW (2017)

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 ABS statistical area level 2) 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[16]. An exception is Slow Growth where we assume the battery market share is even further limited than the solar market share in keeping with the scenario objective which is to explore the impact of low minimum demand (which higher battery uptake would reduce).

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

		Slow Growth	Current Trajectory	Net Zero	Sustainable Growth	Export Superpower	Rapid Decarbonisation	Rationale/formula
Limiting factors								
Separate dwelling share of households	A	58%	58%	58%	58%	62%	62%	Based on housing industry forecasts
Share of homeowners	B	59%	59%	59%	59%	62%	62%	Based on historical trends
Multi-occupant buildings able to set up internal retailing of solar	C	5%	5%	7%	10%	15%	15%	Scenario assumption
Single occupant building owners able to sell directly to occupant or another peer (virtually)	D	3%	3%	4%	6%	8%	8%	Scenario assumption. Landlords of single occupant buildings have more barriers to retailing
Rooftop solar maximum market share		42%	42%	45%	50%	61%	61%	Formula=(A*B)+C+D

[16] 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 factor and maximum market share for commercial rooftop solar

		Slow Growth	Current Trajectory	Net Zero	Sustainable Growth	Export Superpower	Rapid Decarbonisation	Rationale/formula
Limiting factors								
Separate dwelling share of businesses	A	38%	40%	40%	40%	43%	43%	Data limited. Scenario assumption
Share of business building owners	B	24%	24%	24%	24%	27%	27%	Data limited. Scenario assumption
Multi-occupant buildings able to set up internal retailing of solar	C	5%	5%	7%	10%	15%	15%	Scenario assumption
Single occupant building owners able to sell directly to occupant or another peer (virtually)	D	3%	3%	4%	5%	8%	8%	Scenario assumption. Landlords of single occupant buildings have more barriers to retailing
Rooftop solar maximum market share		17%	17%	20%	24%	34%	34%	Formula=(A*B)+C+D

5 Results

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

The 2021 scenario set has not been developed before, but commonalities exist between the 2020 Central and 2021 Current Trajectory, and 2020 Step Change and 2021 Sustainable Growth. They share common assumptions about saturation levels (maximum adoption) and government policies. We therefore provide these for comparison purposes. 2021 Slow Growth is similar to 2020 Slow Change for battery projections only. The Slow Growth solar projection is designed to be more aligned with Current Trajectory or the older Central as the goal is to explore a low operational demand scenario which is consistent with moderately strong rooftop solar uptake and low battery uptake.

There are also differences between CSIRO's projection of these 2020 scenarios (Graham and Havas, 2020) and what was used in the 2020 Electricity statement of Opportunities (2020 ESOO). CSIRO's original projection was typically combined with another consultant's projection and the two projections averaged. We therefore also provide the AEMO ESOO 2020 projection as well.

A deeper look at the short term solar PV projection is provided in Appendix B.

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. However, certificate prices have fallen considerably since the target for the large-scale scheme was met. As such both schemes are in the process of reducing their financial incentives; Despite pending reductions in incentives, both large- and small-scale PV shows strong signs of growth in recent historical data in both the NEM and the SWIS.

The projection results to 2021-22 represent a combination of trend extrapolation and an imposed uncertainty range across the scenarios. The Central scenario uses straight linear regression results[17] while the other scenarios are assigned slightly stronger growth to allow for the possibility of a non-linear trend. This update of the short-term trend is the main cause of difference between these projections and the previous Central and Step Change projections. The previous projections

[17] Victoria is one exception to this where in place of a regression we directly impose as the new installations amount the planned cap on available rooftop solar subsidies in the Central scenario with some variation allowed in the other scenarios.

had started by applying a similar regression approach but then overlaid an assumed range of negative COVID-19 impacts which never eventuated.

The short-term regression allows for strong historical growth to be extended before a different projection methodology takes over which takes account of various financial and non-financial drivers. The key positive financial drivers are the already achieved low payback period, ongoing reductions in solar PV costs and state incentive schemes. (Victoria has the strongest and longest running state incentive scheme with ongoing subsidies planned to 2027-28.) However, there are more negative financial drivers including falling commonwealth subsidies, falling retail electricity prices and various developments that are expected to reduce the value of solar PV exports. Among the developments expected to reduce the value of solar exports are falling daytime wholesale electricity prices which could limit the value of unregulated feed-in tariffs, falling regulated feed-in tariffs and possible introduction of export charges to tariff structures and increasing curtailment in various forms – system size curtailment through connection limits, voltage based curtailment due to increased local solar generation and directed curtailment for system security.

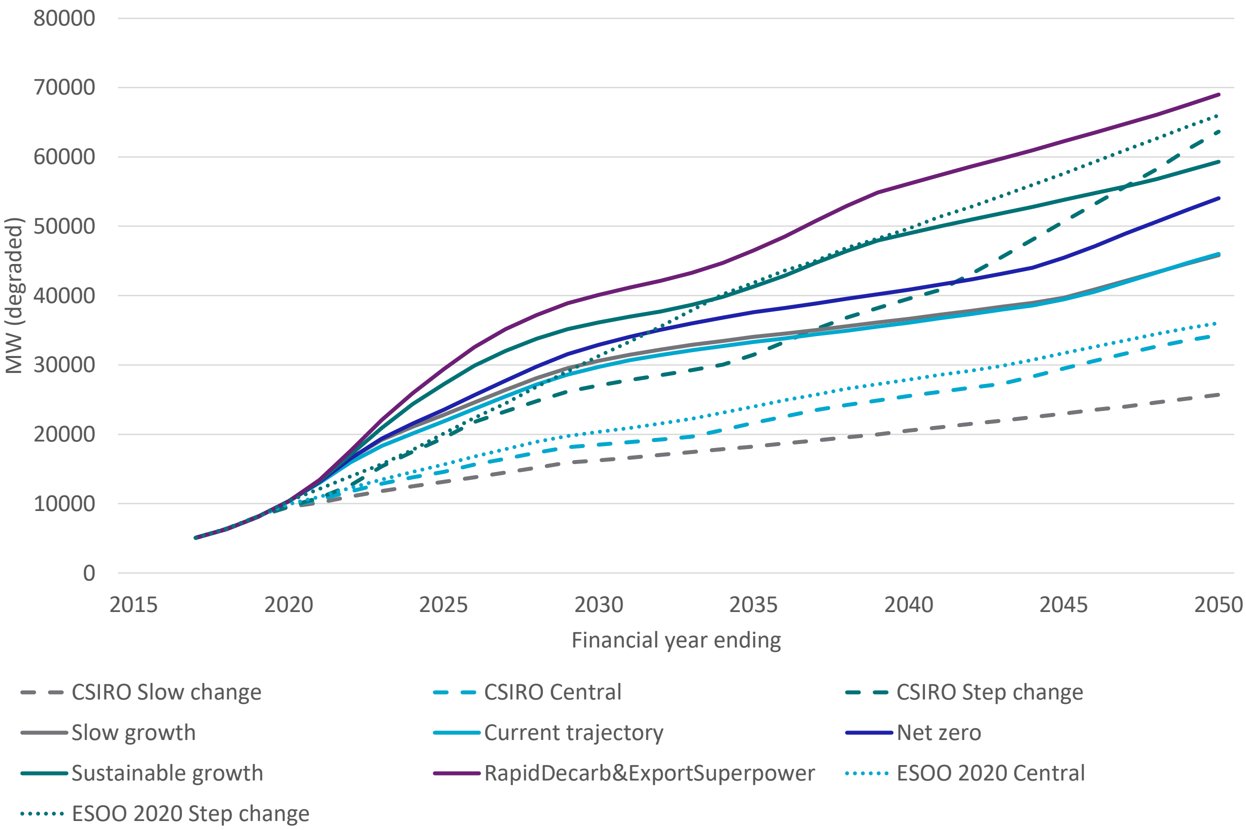


Figure 5-1 Projected capacity of small-scale (<100 kW) solar PV in the NEM

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.

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. For Net Zero, Sustainable Growth and Export Superpower we allow for the possibility of overcoming this problem through business model innovation. Export Superpower represents the maximum household share for all states and Central or Slow Growth (which have been designed with similar assumptions) represents the minimum share (There is also an historical legacy to the projections. 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 minimum and maximum adoption levels across the scenarios are higher than other regions.

Table 5-1).

There is also an historical legacy to the projections. 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 minimum and maximum adoption levels across the scenarios are higher than other regions.

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

	Minimum across scenarios	Maximum across scenarios
New South Wales	35%	48%
Victoria	39%	47%
Queensland	53%	64%
South Australia	57%	67%
Western Australia	48%	59%
Tasmania	27%	36%
Australian Capital Territory	29%	36%
NEM	40%	50%

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 Sustainable Growth, Export Superpower and Rapid Decarbonisation. Current and projected residential and business rooftop solar system sizes are higher than 2020 projections reflecting updated data on the trends in those markets.

The result of the combination of all these drivers is that there is continuing growth but moderated over time to varying degrees across the scenarios owing to declining financial incentives and limitations to household and business infrastructure. 2030 is a key turning point. In 2030 small-scale technology certificates reach zero value and the Victorian subsidy scheme has ended two years earlier. After this point the subsidies can decline no further and other positive changes, such as increasing retail prices and further falls in solar PV costs can have a positive effect on adoption without being offset by subsidy reductions. For Current Trajectory, Slow Growth and Net Zero the post-2030 solar PV cost reductions are greater because the pre-2030 cost was higher leading to some slightly stronger growth in the 2040s compared to the other scenarios.

In the previous CSIRO projections, we had allowed the expected increase in retail electricity prices in the latter half of the projection period (owing to stronger investment in low emission generation technologies) to drive stronger growth in solar PV uptake (see CSIRO Step Change). However, the assumed responsiveness of rooftop solar uptake to retail price changes has been reduced in the projection methodology to better represent recent observations of this relationship.

The SWIS has slightly slower growth in the short term relative to the NEM partly because some large-scale systems which have or would likely be included in the WEM capacity mechanism are not included in the historical or projected non-scheduled generation category to avoid double counting (limited systems greater than 1MW and no systems larger than 5 MW are included). Also, the short-term trend regressions are carried out on postcode level and so capture regional trends and the SWIS appears to have a lower historical growth than the NEM.

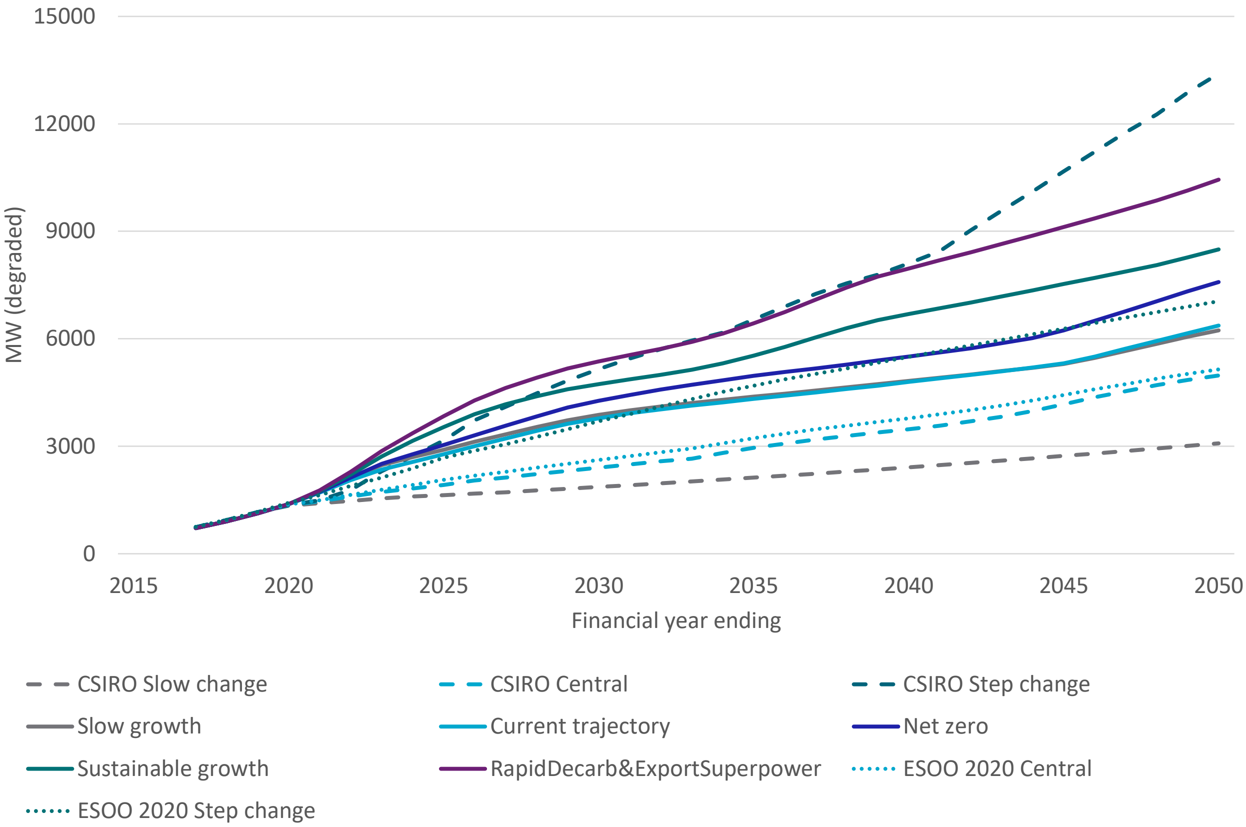


Figure 5-2 Projected capacity of small-scale (<100 kW) solar PV in the SWIS

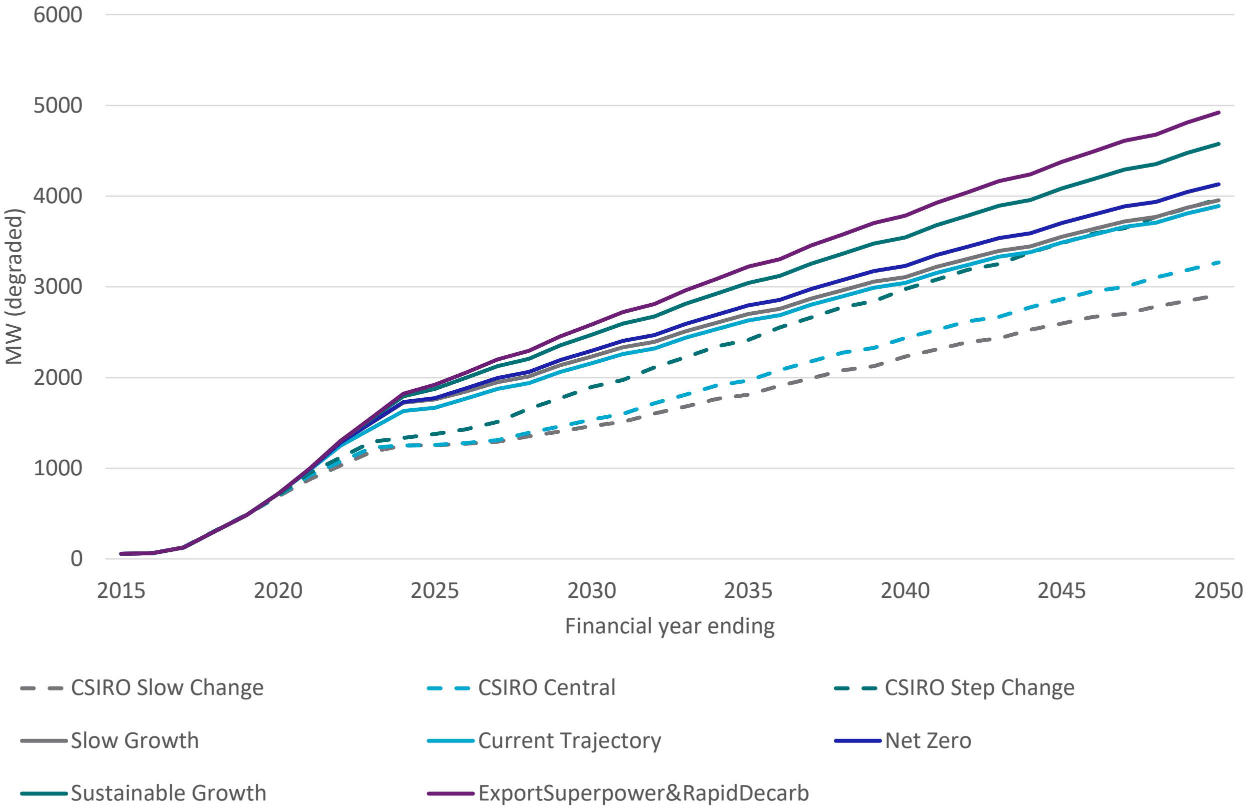


Figure 5-3 Projected capacity of non-scheduled generation solar PV (greater than 100kW to 30MW) in the NEM

The projected capacity of non-scheduled solar PV generation (greater than 100kW to 30MW) 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. All projects in this size range are more strongly driven by return on investment even if motivated in part by corporate environmental targets. With the large-scale technology certificates fallen in value, a potential new source of subsidy for these projects is state and commonwealth offset schemes such as the emission reduction fund and state energy efficiency schemes. The potential subsidy under these schemes is presently only a fraction of what was 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.

As with the small-scale solar the removal of any COVID-19 related impacts also puts non-scheduled generation capacity projections above any of the previous CSIRO projections. We also see again that the difference in the new short-term trend is stronger for the NEM than the SWIS.

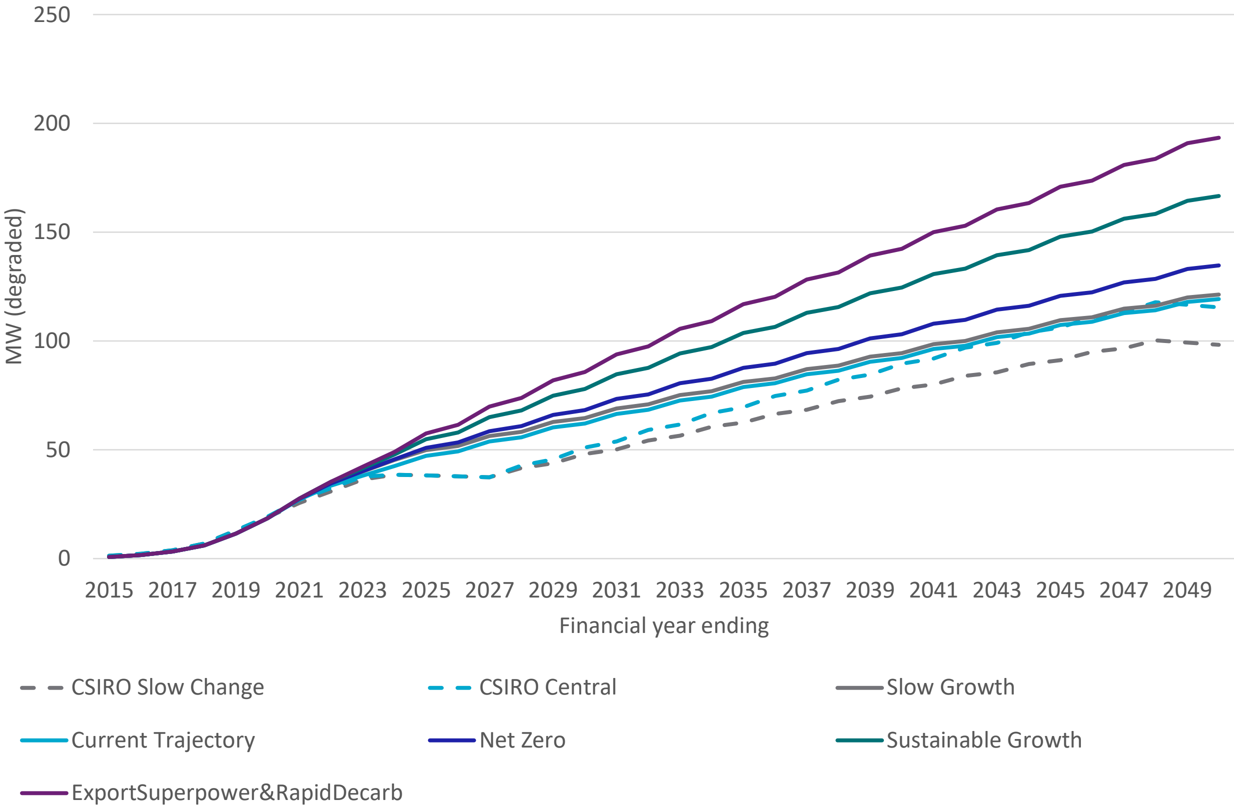


Figure 5-4 Projected capacity of non-scheduled generation solar PV (greater than 100kW to 30MW) in the SWIS

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, South Australia and the Australian Capital Territory we more directly assume the successful take up of available battery subsidy schemes in the Central scenario for the new installation projections with some variations allowed in other scenarios. Were this historical trend to continue indefinitely then battery capacity growth would be low in the NEM and even lower in the SWIS. To achieve a lift in the growth rate will require a change in several financial and non-financial drivers.

A key positive driver is an expected fall in battery 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 2020-21). A second positive financial factor for batteries that applies to all scenarios is that the value of solar exports is falling due to market pressures and various types of curtailment.

Sustainable Growth, Export Superpower and Rapid Decarbonisation are assumed to have the strongest battery cost reductions and so respond with stronger growth. These scenarios also have assumed lower market saturation limits (which take account of a variety of non-financial drivers), so the addressable market is larger. Conversely, for Slow Growth, Current Trajectory and Net Zero the battery cost reductions are slower, and the addressable market is smaller.

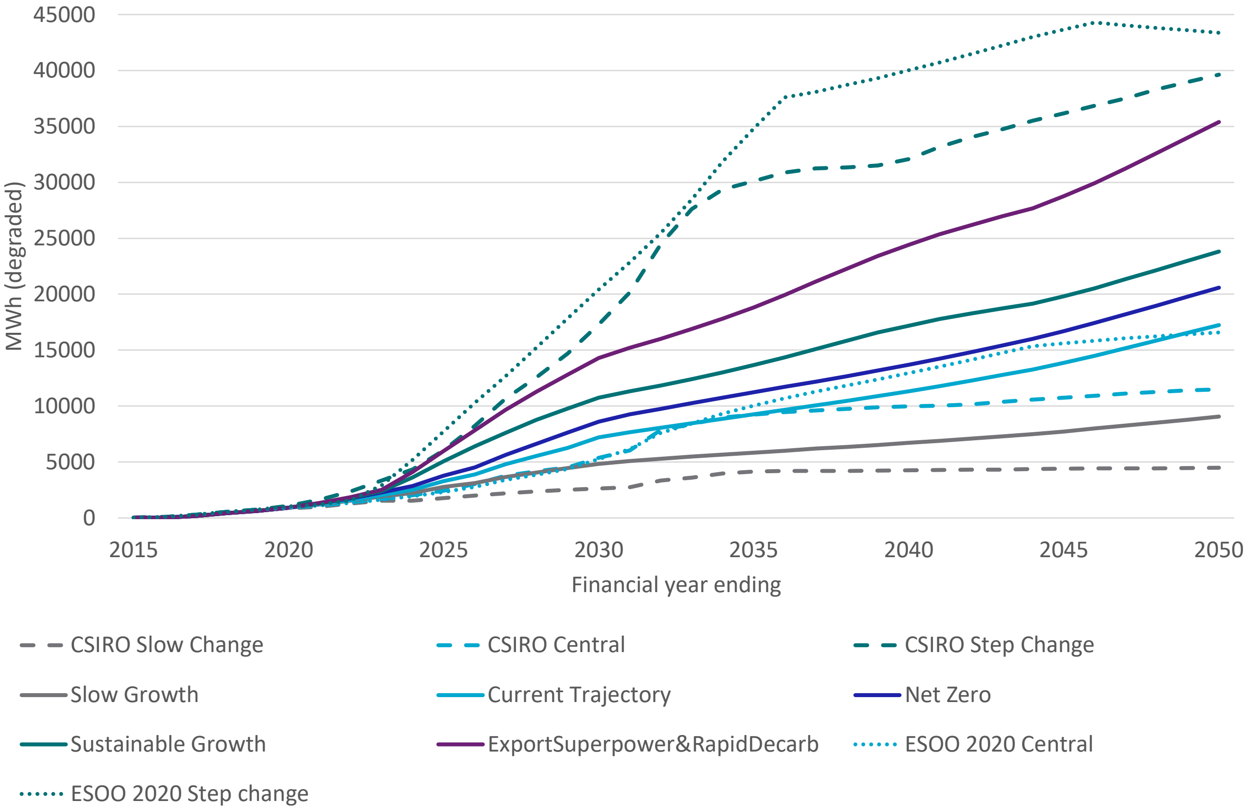


Figure 5-5 Projected capacity of small-scale batteries in the NEM

Compared to the 2020 projection, the range of outcomes is narrower for the NEM and slightly higher for the SWIS. For the NEM, we have better data on the progress and expected available caps on the main subsidy schemes in South Australia, Victoria and the Australian Capital Territory. This narrows the uncertainty for the NEM in the next few years and this starting point contributes to tightening the range over the remainder of the projection period. For the SWIS there are no significant government incentives for battery adoption and so the updated range reflects updates to the historical trend in sales. While there are some issues with the robustness of historical data, current information suggests reasonably well sustained growth in the SWIS which supports greater potential for stronger growth in later years. However, we also allow for the possibility, in the Slow Growth scenario, that lack of incentives and slower cost reduction will result in slower uptake.

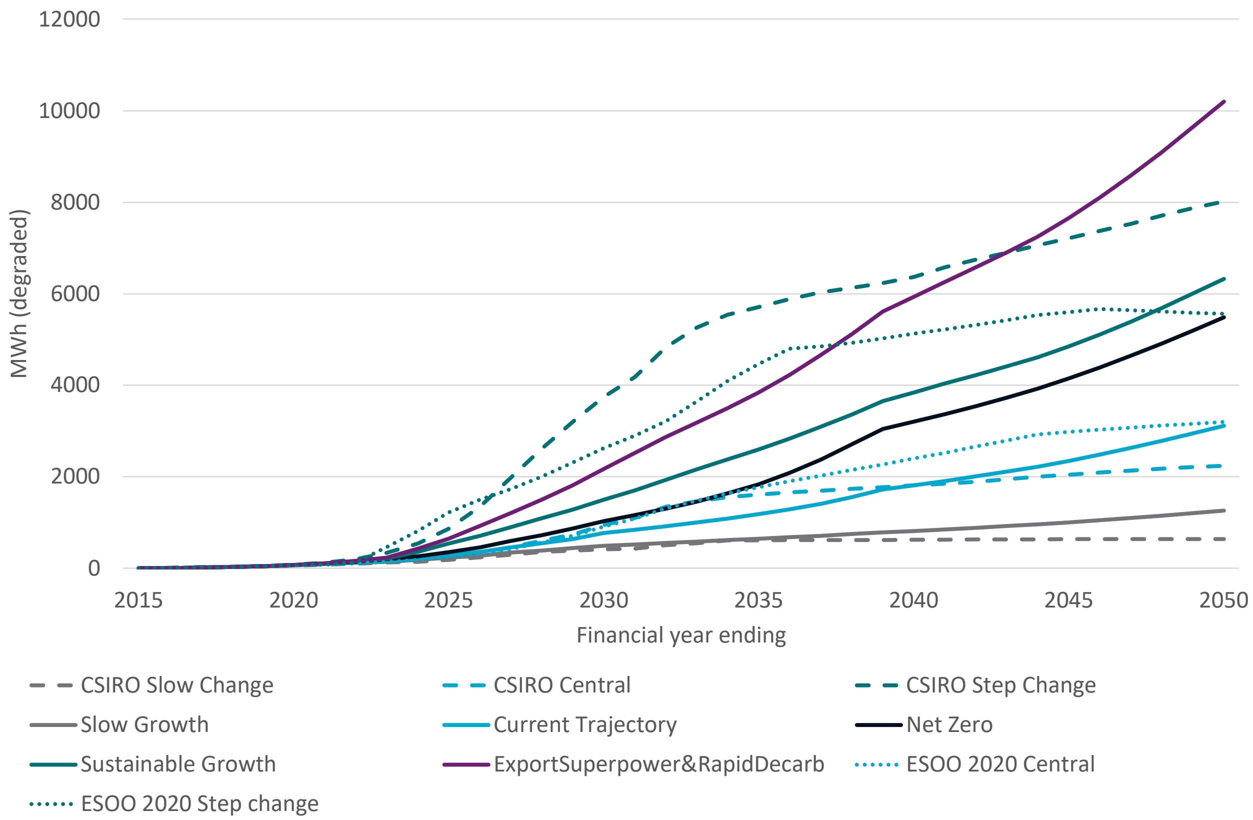


Figure 5-6 Projected capacity of small-scale batteries in the SWIS

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 increase rapidly for most scenarios other than Slow Growth in the next few years reflecting improving economics and state subsidy schemes. By 2050, Slow Growth has the lowest residential solar PV owner battery share at 20%. Export Superpower and Rapid Decarbonisation have a share of just over 60%.

Commercial shares are lower and 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 battery to shift load to other parts of the day is less of a driver. 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 are more delayed and are in the range of 5% to 50%.

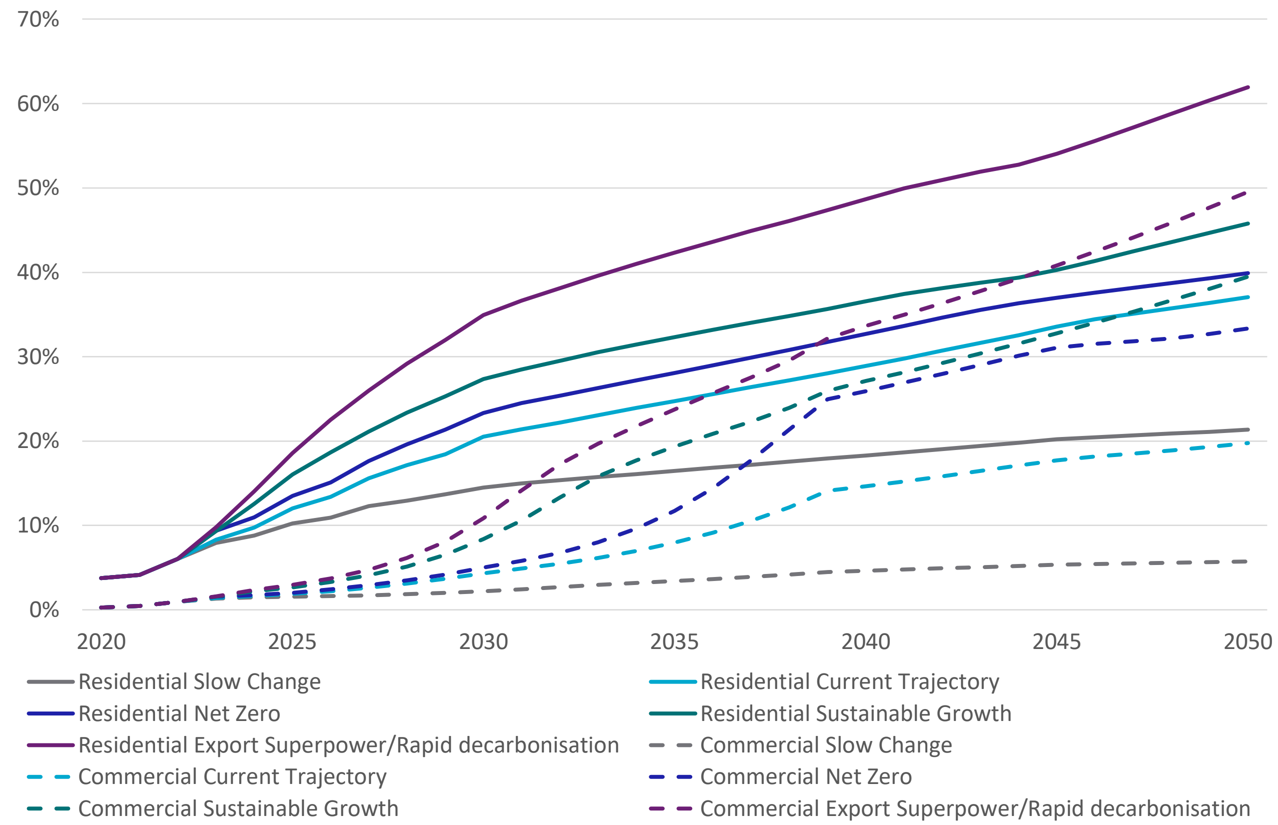
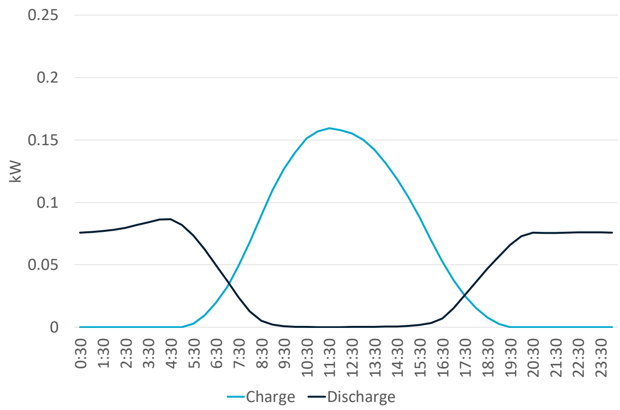


Figure 5-7 Projected share of solar-PV systems with a battery by customer type

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. The battery is charged enough in summer to allow, on average, a steady discharge through the non-solar production period.

In winter, the narrower daylight period means that charging is more coincident, and this makes the charge appear higher. However, this is on a normalised basis. On a total energy basis, the available solar energy charge is lower during winter months. As a consequence of the lower charge the discharge falls almost immediately and is unable to be maintained at the initial level through the non-daylight period.



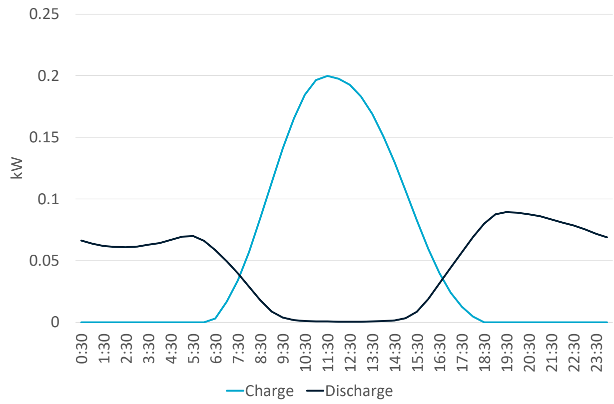
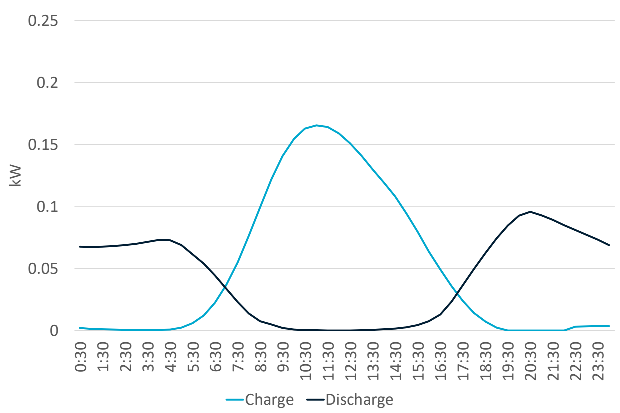


Figure 5-8 Summer (left) and winter (right) solar shift residential battery operation profiles

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.



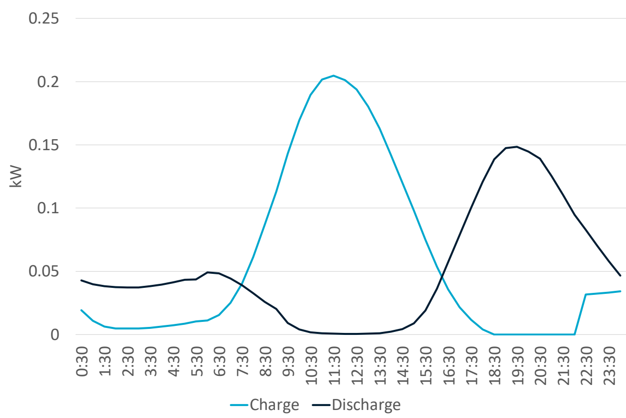


Figure 5-9 Summer (left) and winter (right) peak avoidance residential battery operation profiles

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	0.147
Victoria	0.135
Queensland	0.153
South Australia	0.148
Tasmania	0.129
Western Australia (SWIS)	0.155
Northern Territory	0.147

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 10kWh for residential customers matches the reported average size in SunWiz (2020) for 2019. 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.

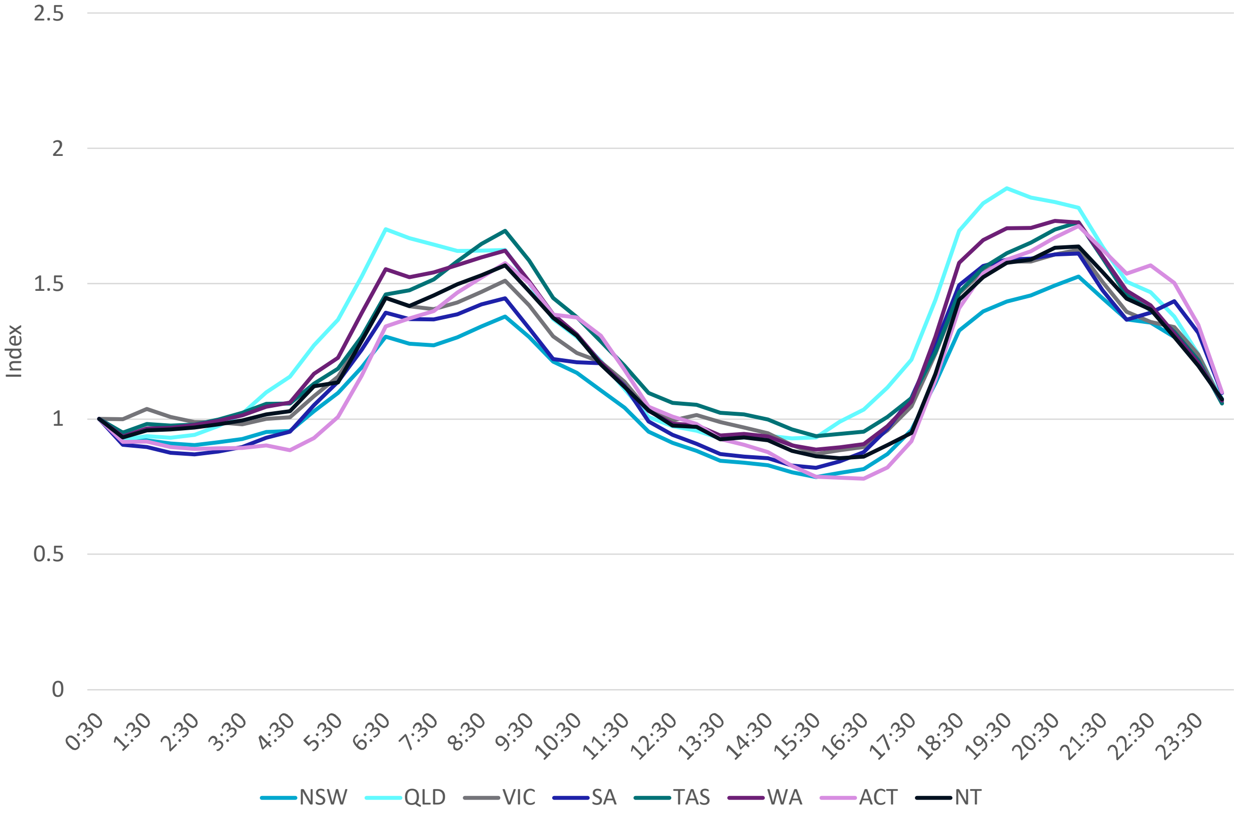
Apx Table A.2 Battery storage performance assumptions

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 1.0
Degradation rate	1.6% per annum on kWh capacity
Life	3650 cycles or 10 years

A.2 Customer load profiles

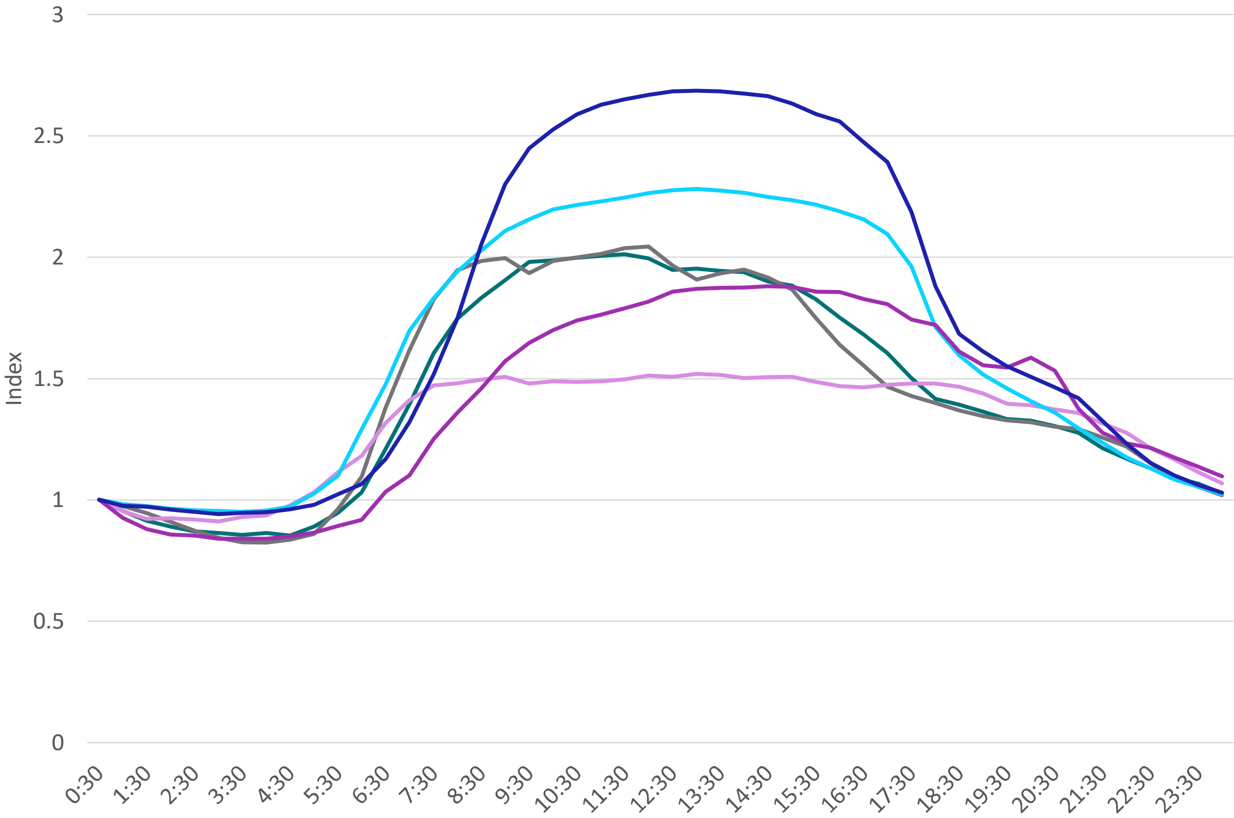
Australia still faces difficulty in accessing public load profiles due to privacy considerations. For that reason, we use a mixture of synthetic and real customer load profiles. For residential data we started with around 5000 New South Wales Ausgrid profiles from the Smart Grid Smart Cities program 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 profile for each region is shown in Figure A.2. The non-daylight savings regions of the SWIS, Northern Territory and Queensland are evident in the differences in timing of demand. The main difference in load is that New South Wales stands out as the least extreme profile reflecting its relatively milder weather than either the northern or southern states.

Otherwise they follow the same double peak/trough trend reflecting daytime activity and sleep cycles. One more notable difference is the timing of controlled hot water at night in South Australia and the Australian Capital Territory.



Apx Figure A.1 Index of average half hourly residential summer loads by region

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).



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

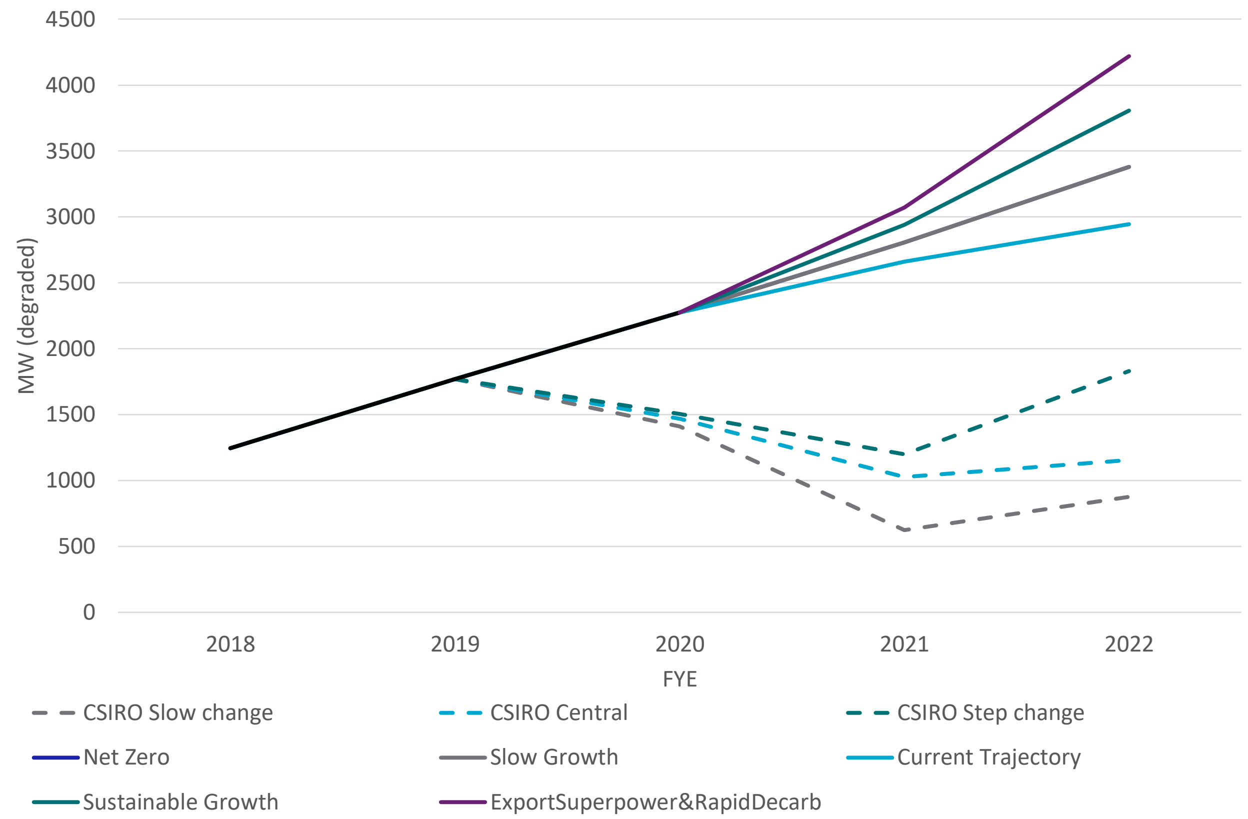
Appendix B Short term solar PV projection

The short-term solar PV projection provided in Graham and Havas (2020) was substantially lower than 2020 actuals and this section provides a brief explanation of why that occurred, and changes made to the projection method to address it. In 2020, the short-term projection methodology began with a linear trend which remains the approach in 2021. However, CSIRO then imposed a slower than linear growth on all scenario projections to account for the then unknown impact of the COVID-19 pandemic on rooftop solar PV sales. The expected negative impacts of COVID-19 did not eventuate and have been removed from 2021 projections. We also identified other improvements:

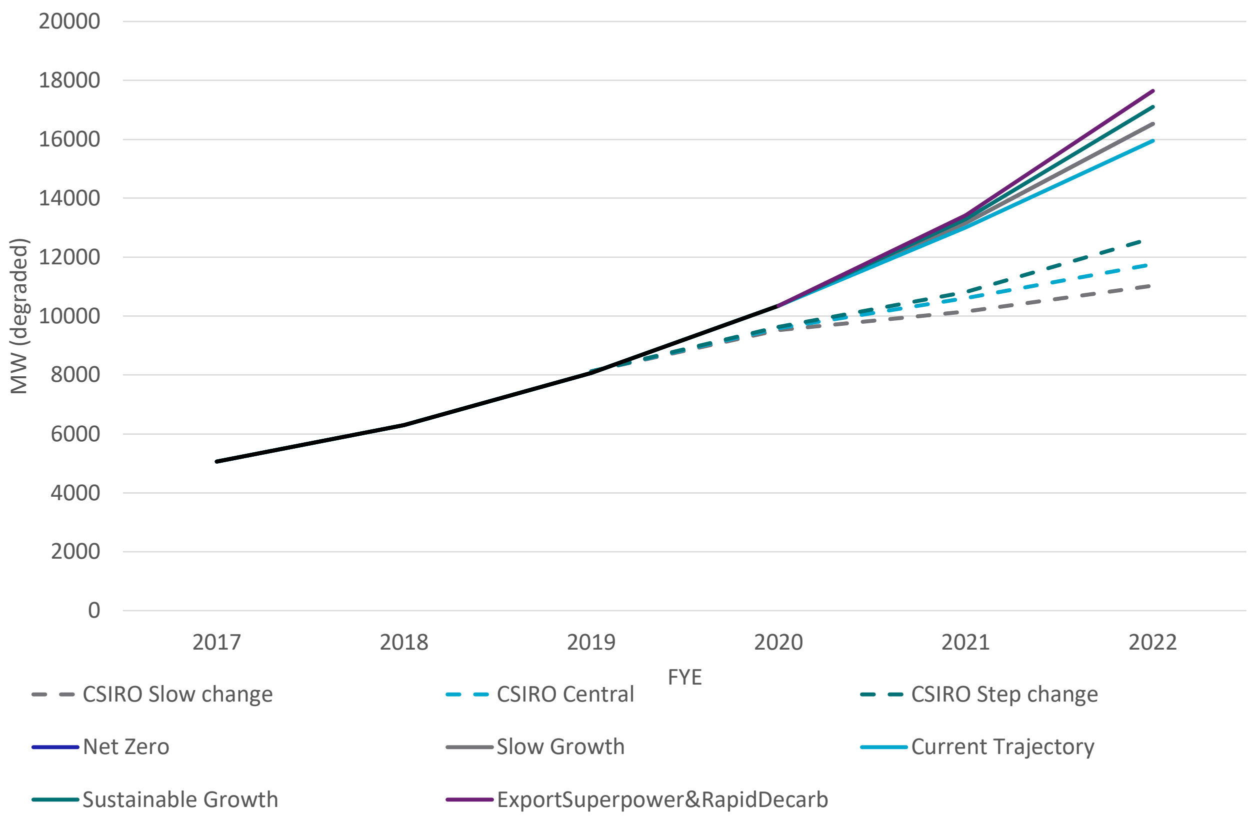
- A shorter regression period (last two years only) to more closely follow recent trends
- Most recent months of CER data discarded. Such data tends to be lower than actuals once it is revised by the CER

In 2021, we continue to impose additional assumptions on the linear trend, but the additional assumptions are designed to represent uncertainty in the projections and capture potential non-linearities in the trend rather than a specific event. As discussed in the section on the short-term trend model, we add up to 20% to the linear trend across the scenarios to recognise that most of the uncertainty has been on the upside in recent years. No scenario is assumed to grow slower than a linear trend.

Apx Figure B.1 and Apx Figure B.2 show the impact of these changes on the projections. It shows that the 2019-2020 projections for annual capacity installed were around 1GW lower than actuals. In 2020-21 and 2021-22, the new projections of annual additions to capacity continue to be 1GW to 2.5GW higher than the 2020 projections. From a cumulative capacity point of view, by 2021-22 the updated projections are 4GW to 5GW higher than the 2020 projections.



Apx Figure B.1 Comparison of 2020 and 2021 short-term projections for annual additions to solar PV capacity



Apx Figure B.2 Comparison of 2020 and 2021 short-term projections for cumulative solar PV capacity

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
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	Western Electricity Market

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