Projections for distributed energy resources – solar PV and stationary energy battery systems

Report for AEMO

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1 Executive Summary

The Australian Energy Market Operator (AEMO) has engaged Green Energy Markets Pty Ltd (GEM) to provide several scenario-based projections to 2050 of solar and stationary battery uptake for a sub-segment of this market that does not participate in AEMO's scheduled dispatch system.

Our results are divided into several system size brackets:

- Residential which are assumed to cover solar systems up to 15kW in size and their associated battery systems, which for modelling purposes were assumed to average 10kWh in size.
- Small commercial which are assumed to be between 15kW and 100kW in scale and their associated battery systems, which for modelling purposes were assumed to also average 10kWh in size.
- Large commercial which are assumed to be above 100kW and up to 1 megawatt and their associated batteries, which for modelling purposes were assumed to be sized between 90kWh to 150kWh depending upon the state.
- Small power stations which are assumed to be between 1MW and 30MW in scale.

Green Energy Market's projections of non-scheduled sub-30MW solar systems and stationary battery energy storage systems are driven primarily by changes in their financial attractiveness based on the combination of the revenue they earn (which includes the electricity grid purchases they avoid) versus the cost involved in installing them. This provides us with a payback period - the years it takes for revenue to exceed the installation cost - which we can then compare against payback periods in the past. At a simplified level our approach is based on an assumption that installation levels in the past and associated paybacks provide a guide for likely levels of installs in the future. If paybacks deteriorate (get longer) then installations will decline and if paybacks improve (get shorter) then installations rise. This is then moderated by:

- the expected impact of market saturation in each state;
- the rate of new dwelling construction; and
- expected replacement cycles for systems.

In addition, we also account for the influence of non-financial factors such as changes in customer awareness and solar industry competitiveness and marketing which are informed by industry interviews.

In trying to evaluate financial attractiveness of project installations Green Energy Markets has segmented this into two core segments for the purposes of our analysis:

1. What are commonly referred to as "behind-the-meter" installations which are embedded within an end-consumer's premises;
2. In front of the meter installations which are entirely focussed on exporting electricity to the grid and do not offset customer consumption from the grid.

For systems within segment 1 (behind-the meter) we specifically analyse financial attractiveness and then subsequent uptake based upon Green Energy Market's solar and battery system payback model.

For systems within segment 2 (small power stations) we take a different approach where we tie installation levels back to the level of scheduled large solar power station capacity installs projected within the draft Integrated System Plan.

1.1 Results

1.1.1 Solar PV

Figure 1-1 details the cumulative installed solar PV capacity (DC basis) projected for each scenario on a national basis, taking into account the degradation of solar panel output over time. At the beginning of the projection (the conclusion of the 2018-19 financial year) cumulative installed degraded capacity is expected to stand at almost 9,400MW. Under Central the cumulative degraded capacity reaches just over 44,000MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Step Change scenario reaches 75,000MW, while the lower bound represented by Slow Change is close to 33,000MW.

Figure 1-1 National cumulative degraded megawatts of solar PV by scenario

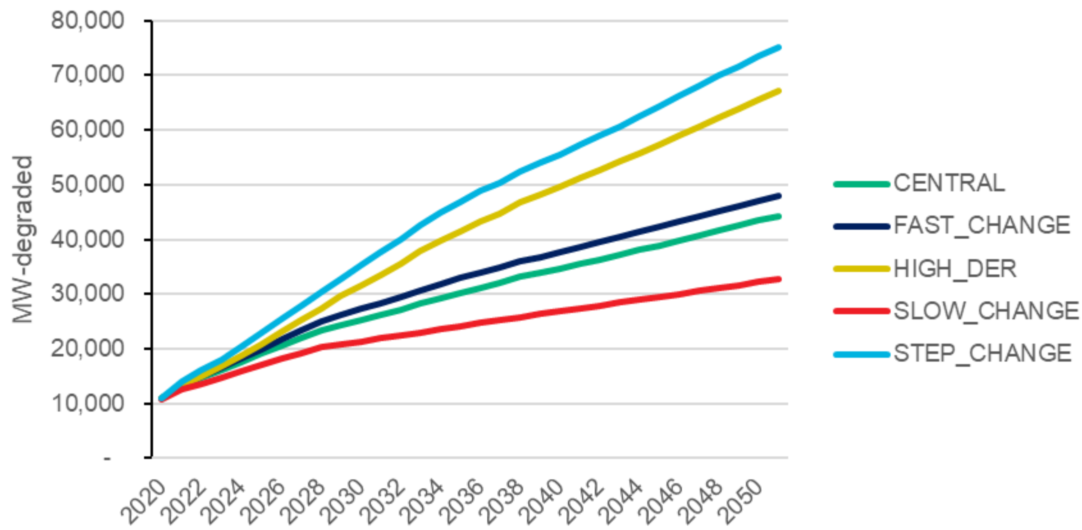
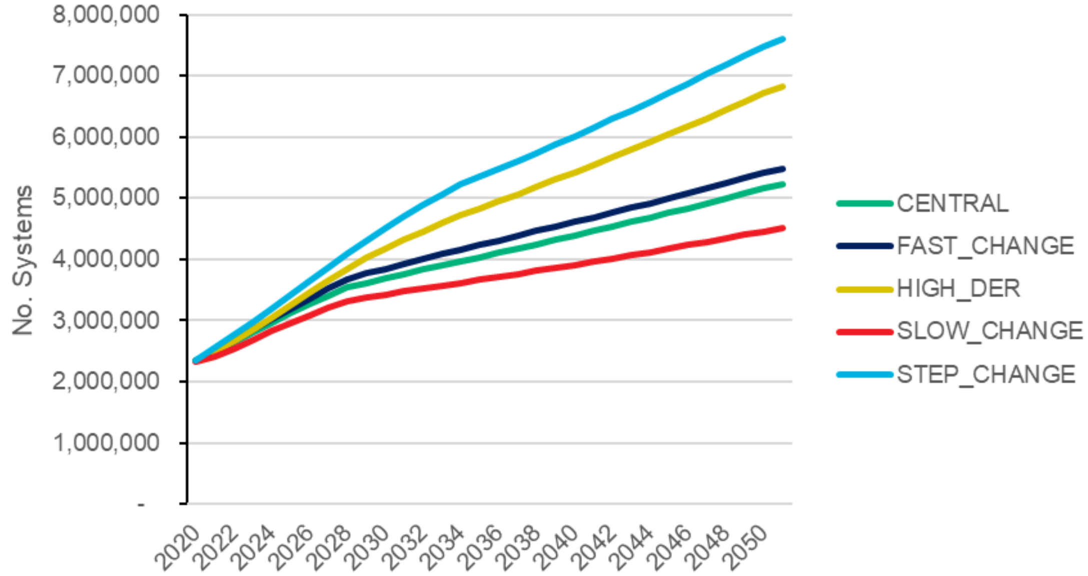


Figure 1-2 details projections for the cumulative number of solar PV systems by scenario on a national basis. At the beginning of the projection (the conclusion of the 2018-19 financial year) the cumulative number of systems stands at 2.08 million. Under Central the cumulative number of systems grows to 5.2 million by the end of the 2050-51 financial year. The upper bound represented by the Step Change scenario reaches 7.6 million, while the lower bound represented by Slow Change is 4.5 million systems at the end of the 2050-51 financial year.

Figure 1-2 National cumulative number of PV systems by scenario

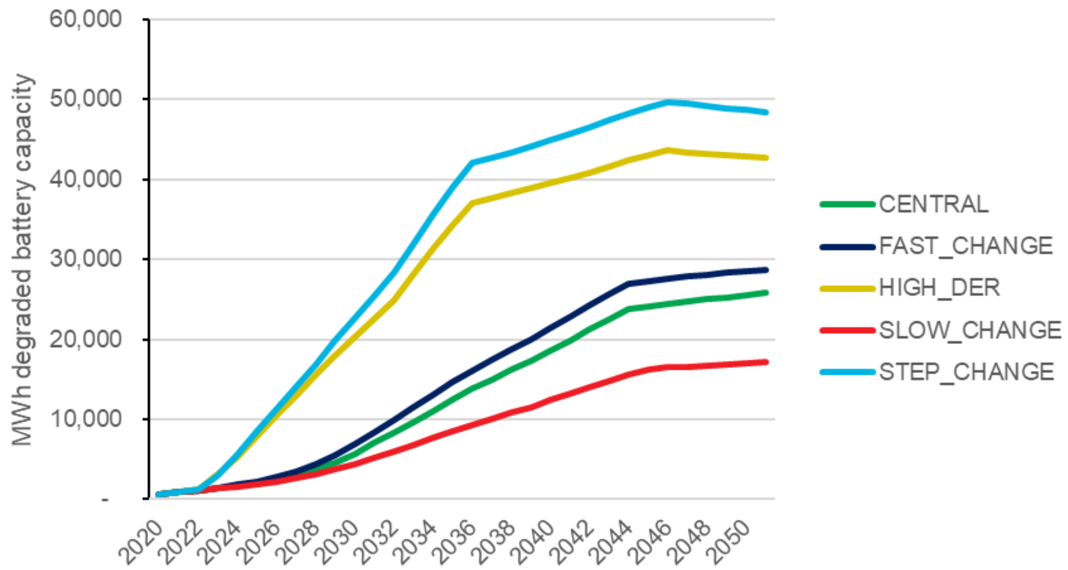


To put these system numbers in context the total number of residential electricity connections is expected to grow to just under 15m by 2050. The number of systems under Central equates to around 35% of all residential connections and Step Change is slightly more than 50%.

1.1.2 Battery energy storage

In terms of behind the meter stationary battery systems Figure 1-3 details the cumulative installed megawatt-hours of battery capacity projected for each scenario on a national basis, taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2018-19 financial year) cumulative degraded battery capacity is estimated to stand at 482MWh. Under Central the cumulative degraded capacity reaches almost 26,000MWh by the end of the projection in 2050-51 financial year. The upper bound represented by the Step Change scenario reaches almost 48,500MWh, while the lower bound represented by Slow Change is just above 17,200MWh by the end of the projection in 2050-51 financial year.

Figure 1-3 National cumulative degraded megawatt-hours of battery capacity by scenario



The reason that battery capacity under the High DER and Step Change scenario begins slowly declining from 2047 is because the degradation of the existing installed stock of batteries begins exceeding additions of new stock. This is because the model assumes rapid uptake of batteries up until a large proportion of the pre-existing stock of solar systems are augmented with a battery. Once most of these systems have a battery in place, additions of new batteries capacity abruptly fall to a much lower level in line with additions of solar systems to the stock on premises that did not previously have a solar system. After a lag the degradation of the existing battery stock builds up to a point where it exceeds the new additions to the battery stock from 2047 onwards.

Figure 1-4 illustrates the maximum instantaneous megawatt output available from the from the projected stock of battery systems. The projection begins with an installed stock of 209MW at the end of 2018-19 financial year. Under Central this grows to 14,500MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Step Change scenario reaches almost 30,000MW, while the lower bound represented by Slow Change is just under 10,000MW by the end of the projection in 2050-51 financial year. The projections are based on an assumption that the instantaneous output that can be extracted from a battery is not subject to degradation and that the average system when first installed will have maximum output equal to 40% of its original megawatt-hours of storage.

Figure 1-4 National cumulative megawatts of battery capacity by scenario

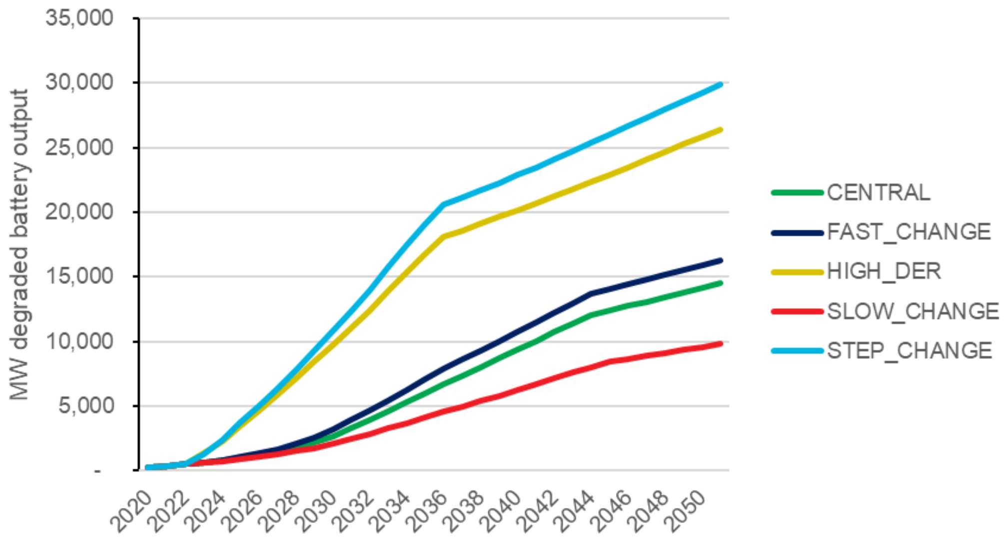
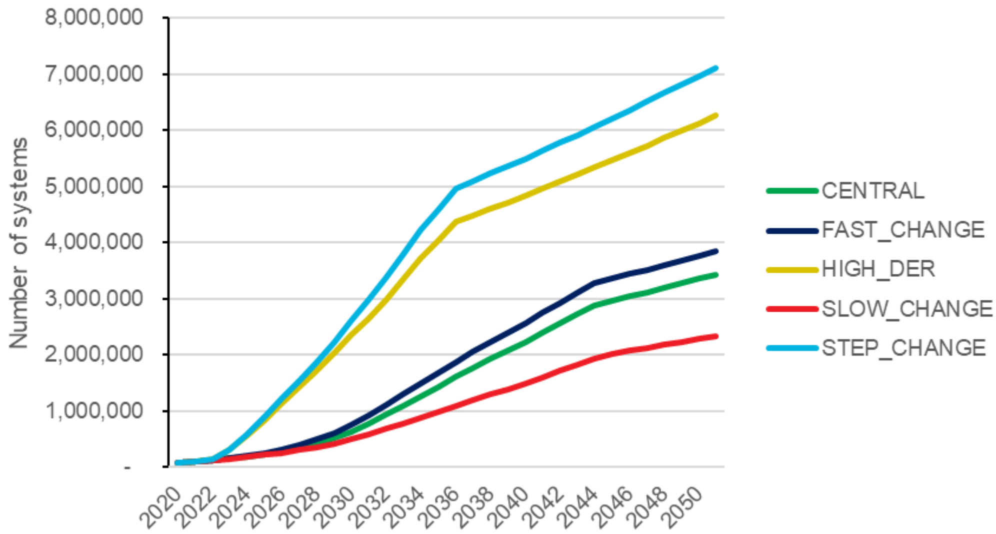


Figure 1-5 details projections for the cumulative number of battery systems by scenario on a national basis. At the beginning of the projection (the end of the 2018-19 financial year) the cumulative number of grid-connected battery systems stands at 52,420. Under Central the cumulative number of systems grows to 3.4 million by the end of the projection in 2050-51 financial year. The upper bound represented by the Step Change scenario reaches 7.1 million, while the lower bound represented by Slow Change is 2.3 million systems by the end of the projection in 2050-51 financial year.

Figure 1-5 National cumulative number of battery systems by scenario



2 Introduction

The Australian Energy Market Operator (AEMO) has engaged Green Energy Markets Pty Ltd (GEM) to provide several scenario-based projections to 2050 of solar and battery uptake for a sub-segment of this market that does not participate in AEMO's scheduled dispatch system. It is optional for systems below 30MW in capacity to be scheduled[1] and so this report only considers systems below this size.

Our results are divided into several system size brackets:

- Residential which are assumed to cover solar systems up to 15kW in size and their associated battery systems which for modelling purposes were assumed to average 10kWh in size.
- Small commercial which are assumed to be between 15kW and 100kW in scale and their associated battery systems which for modelling purposes were assumed to also average 10kWh in size.
- Large commercial which are assumed to be above 100kW and up to 1 megawatt and their associated batteries which for modelling purposes were assumed to be sized between 90kWh to 150kWh depending upon the state.
- Small power stations which are assumed to be between 1MW and 30MW in scale.

Section 3 of this report explains our approach for how we estimated solar and battery uptake.

Section 4 explains the scenarios we used for determining the potential range of solar and battery uptake and the underpinning assumptions of those scenarios.

Section 5 provides the results of our projections and seeks to explain with reference to the Central Scenario what are the underlying drivers or causes behind our results.

[1] Note that in the Western Australian Market the threshold is lower at 10MW.

3 Methodology and Approach

3.1 Overview

This report seeks to project uptake for sub-segment of the total solar market which excludes AEMO-scheduled solar systems controlled by their dispatch system. In the NEM it is optional for systems below 30MW in capacity to be scheduled and so this report only considers systems below this size[2]. In addition, we also project uptake of stationary (non-transport) battery energy storage systems used by end-consumers of electricity.

Our results are divided into several system size brackets:

- Residential which are assumed to cover solar systems up to 15kW in size and their associated battery systems which for modelling purposes were assumed to average 10kWh in size.
- Small commercial which are assumed to be between 15kW and 100kW in scale and their associated battery systems which for modelling purposes were assumed to also average 10kWh in size.
- Large commercial which are assumed to be above 100kW and up to 1 megawatt and their associated batteries which for modelling purposes were assumed to be sized between 90kWh to 150kWh depending upon the state.
- Small power stations which are assumed to be between 1MW and 30MW in scale.

Green Energy Market's projections of non-scheduled sub-30MW solar systems and stationary battery energy storage systems are driven primarily by changes in their financial attractiveness based on the combination of the revenue they earn (which includes the electricity grid purchases they avoid) versus the cost involved in installing them. This provides us with a payback period (the years it takes for revenue to exceed the installation cost) which we can then compare against the payback periods in the past. At a simplified level our approach is based on an assumption that installation levels in the past and associated paybacks provide a guide for likely levels of installs in the future. If paybacks deteriorate (get longer) then installations will decline and if paybacks improve (get shorter) then installations rise. This is then moderated by:

- the expected impact of market saturation in each state;
- the rate of new dwelling construction; and
- expected replacement cycles for systems.

In addition, we also account for the influence of non-financial factors such as changes in customer awareness and solar industry competitiveness and marketing which are informed by industry interviews.

In trying to evaluate financial attractiveness of project installations Green Energy Markets has segmented this into two core segments for the purposes of our analysis:

1. What are commonly referred to as "behind-the-meter" installations which are embedded within an end-consumer's premises and can be used to avoid the need to purchase power from the grid at retail electricity rates; as well as potentially exporting electricity to the grid for other customers to consume;

[2] In the Western Australian Market the threshold is 10MW.

2. In front of the meter installations which are entirely focussed on exporting electricity to the grid and do not offset customer consumption from the grid and so their predominant revenue is set by wholesale electricity market rates, not retail rates.

For systems within segment 1 (behind-the meter) we specifically analyse financial attractiveness and then subsequent uptake based upon Green Energy Market's solar and battery system payback model.

For systems within segment 2 (small power stations) we take a different approach where we tie installation levels back to the level of scheduled large solar power station capacity installs projected within the draft Integrated System Plan. Small solar power stations below 30MW are likely to experience very similar cost and revenue drivers as solar power stations above 30MW. So if market conditions within the ISP are conducive to building large solar farm capacity then these will also be favourable conditions for smaller, non-scheduled in-front-of-the meter systems.

For solar and battery systems within segment 1, for the purposes of modelling convenience the solar systems are assumed to be no more than 1 megawatt in size. Meanwhile in front of the meter systems are assumed to be larger than 1 megawatt. In practice there are circumstances where a small number of behind the meter systems are larger than a megawatt and those in front of the meter are sometimes smaller than a megawatt. However better precision is not realistically achievable given the large uncertainties involved in forecasting this area. Given the vast majority of capacity installed below 1 megawatt is behind the meter installations (and the size of most facilities constrains potential for systems much larger than this) while the vast majority of capacity installed above 1 megawatt is in front of the meter installations, this generalisation is likely to provide a reasonably good guide to capacity installed within the different system size brackets.

A further element in this modelling exercise was an adjustment to the first 3 years of the projection to account for the potential impact of the COVID-19-induced economic slow-down.

Further explanation of the components of the model are detailed in the headings below.

3.2 The payback model

The payback model evaluates the revenues and costs associated with a solar system and a coupled battery system based on three different customer types:

1. Residential – which cover solar systems up to 15kW in capacity and associated battery systems and which generally face electricity charges recovered on the basis of the amount of kilowatt-hours of electricity consumed plus a fixed daily charge;
2. Small commercial – which cover solar systems up to 100kW in capacity and who are assumed to face similar electricity tariff structures as residential consumers;
3. Large commercial – which cover solar systems above 100kW up to 1 MW and are assumed to face large consumer electricity tariffs. These typically involve network charges which involve some kind of demand-based tariff where costs are recovered based on a short 30 minute peak in demand over a month or year as well as the amount of overall kilowatt-hours of consumption.

3.2.1 Costs

Costs for solar systems and any discounts or other financial benefits associated with government policy support are detailed section 4.2 while those for batteries are in section 4.3.

As explained in further detail in section 4.2.1 the financial benefit flowing from government support policies is taken into account in the model as an upfront deduction on the purchase price of the solar or battery system rather than as revenue to simplify calculation processes.

3.2.2 Revenue estimations

In terms of revenues the model examines the degree to which generation from a solar system would:

- Reduce the need for electricity that would otherwise be imported from the grid to meet the customers' demand. This is then multiplied by the electricity price associated with those displaced imports;
- Be exported to the grid which is then multiplied by the expected feed-in tariff.

It then also calculates the degree to which a battery system could provide additional benefit to a consumer through:

- Taking electricity from the solar system that would otherwise be exported to the grid at the feed-in tariff rate and using it at a later period to displace electricity imported from the grid at a higher retail rate;
- On days where exported electricity is insufficient to charge the battery to full capacity, charge from the grid during a time when retail electricity prices were lower in order to avoid electricity imported from the grid when retail electricity prices were higher.

The formula that governs the charging of the battery operates in a manner that is able to perfectly predict the amount of solar exports in a day. If this is insufficient to charge the battery to its full capacity then it charges from the grid for the difference over 8am until 11am. While historically this has not been been thought of as an off-peak period, with the increasingly high prevalence of solar in the generation mix this is likely to change.

The model does these calculations via an hour by hour breakdown across a 12 month period for:

- an archetype customer's load for the three customer types (residential/small commercial/large commercial);
- solar generation based on each state/territory's capital city generation profile; and
- different tariffs applying to each hour including whether the day is a weekday or a weekend with these being adjusted depending upon the state/territory and the customer type.

This 12 month period is then replicated out to 2050 but with changes across each year reflective of each year's assumptions for electricity prices.

This hourly breakdown allows for an estimate of how much of the solar generation is absorbed by the customer's load versus being exported and the degree to which the battery can be charged by the grid versus solar generation that would otherwise be exported, and also how much of the customer's imports from the grid can be offset by the battery. It also estimates the extent to which the customer's peak demand (which affects the network demand charge) is reduced by the solar and battery system.

Load profile

For residential consumers the load profile is derived from the smart meter consumption data made available from Ausgrid's Smart Grid, Smart City trial[3]. This provides consumption data for 300 residential sites which were separately metered from their solar generation allowing the impact of a solar system to be analysed independently. The model uses an averaged load profile of these 300 sites.

For both small and large commercial customers the load profile is based on the load for a substation that predominantly services non-residential customers – United Energy's Dandenong Substation[4]. The use of a single sub-station was in order to simplify and speed-up the calculation process. To ensure that this was a reasonable representation of commercial loads in other states it was cross checked against load data for substations serving mainly commercial customers in other states to ensure reasonable similarity in time profile of consumption across hours of the day, weekends versus weekdays and seasons.

The substation load profile was then scaled down to be representative of:

- a small commercial customer likely to use the average-sized commercial solar system claiming STCs, which is close to 20kW; and
- a large commercial customer using a 300kW solar system which is representative of a behind the meter solar system claiming LGCs.

This was guided by feedback from interviews with solar industry participants that they typically apply a rule of thumb in sizing solar systems that aims to keep exported generation (or spilled generation where the system is prevented from exporting) to around 20% or less of total annual solar generation. Industry feedback is that the financial attractiveness of a system to customers usually significantly deteriorates once exports exceed 20% of total annual generation.

3.2.3 Payback outputs

For each year of the projection period the model estimates a payback for a solar system alone and a solar system combined with a battery system. This uses the capital cost of the system for the year in question after deducting the value of government policy support mechanisms and then divides this by the estimated average annual revenue the system will deliver for the next three years.

The consideration of only the next three years' revenue rather than a longer period is based on information gathered from interviews from solar industry participants about customer purchasing behaviour. This suggests that customers do not typically use long-term forecasts about future electricity prices in evaluating the financial attractiveness of a solar or battery system. Instead they will tend to use their current electricity prices with potentially an adjustment to account for where electricity prices will go over the remaining duration of their electricity contract (in the case of large commercial customers); or some

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[3] This dataset is available from Ausgrid's website here: https://www.ausgrid.com.au/Industry/Our-Research/Data-to-share/Solar-home-electricity-data

[4] This data is available from the website of Australia's National Energy Analytics Research Program here: https://near.csiro.au/assets/003fe785-401d-4871-a26d-742cb1776a2f

rule of thumb adjustment based on their expectation of electricity prices a small number of years into the future (e.g. inflation rate plus 3%).

3.3 Residential demand

We have used detailed historical data for solar PV installations provided by the Clean Energy Regulator (CER). Residential and commercial installations have been segmented based on the “property installation type” classification in the registry data provided by the CER. We have used the CER’s delineation from 2015 when a full years data was available. For systems installed prior to 2015 we have assumed that systems greater than 10 kW were commercial and those less than 10kW were residential.

We forecast the level of new residential demand for each state with reference to the following four factors:

- Relative financial attractiveness - as represented by simple payback index for each year with 2015 as the base;
- Relative level of saturation – represented by scaling factor that reduces as the proportion of owner-occupied detached and semi-detached dwellings with solar within a state increases. We have calibrated this as being 1.0 (no discount) where 20% or less of owner-occupied detached/semi-detached dwellings have solarand this then reduces to 0.5 (50% discount) at saturation levels of 80%. The discount is lower at 0.37 for NSW and Victoria to reflect higher urban density and significant amounts of older established homes with shading. This is then also converted into an index with 2015 as the base;
- Relative customer awareness – heightened media concerns over high power prices has been demonstrated (through market interviews) to be a major contributing factor to customer preparedness to consider solar. We have developed a scaling factor that considers the impact in each year and then convert this into an index with 2015 as the base; and
- Relative solar industry competitiveness and marketing – the level of new market entrants (and exit), general industry competitive environment together with the level of marketing and promotion will also have an impact on solar PV uptake. We have developed a scaling factor that considers the impact in each year and then convert this into an index with 2015 as the base.

The last two factors (customer awareness and industry competitiveness and marketing) are extremely subjective but have clearly impacted on the level of demand particularly since 2017.

The five years from 2015 to 2019 provide a reasonable timeframe and cover new residential installations rising from 124,000 systems in 2015 to 245,000 systems in 2019. This now represents 5 years of reasonable data that is not complicated by solar credits multipliers or extremely attractive feed-in tariffs. The residential market sector can be seen to be mature and enables us to have confidence in this approach, albeit with some subjective factors. Interviews with industry participants have been a key component in gauging factors and issues that are actually working on the ground influencing customer purchasing decisions, beyond just financial attractiveness.

We have used systems installed in 2015 as the base level of demand for 2015 which is our base year. We have used 2016 level installations as base data in the case of WA, SA and NT as this was seen to be more representative.

Our approach can be represented by the following formula:

Demand (year) = Base year installations x Relative Financial Attractiveness Index (year) x Relative Level of Saturation (year) x Relative Customer Awareness Index (year) x Relative Solar Industry Competitive Index (year)

Average system size has increased dramatically over the last 5 years increasing from 4.1 kW per system in 2015 to 6.7 kW per system in 2020. We expect continued modest increases in system size rising to 7.3 kW per system by 2030 and 8.1 kW per system by 2050. We expect the benefit of the continued increase in the performance and efficiency of panels to be countered by electricity network constraint whereby it is a much easier process to connect systems where the inverter export capacity is 5kW or less (with oversizing of the panel capacity by a third of the inverter capacity). Yet in spite of this constraint we expect growth in system size will continue, albeit much slower than the past, because module price reductions will mean larger systems make financial sense even though they will be lose a greater portion of their output due to the inverter export constraint.

3.4 Commercial demand up to 100kW systems

The commercial or non-residential sector's demand for solar systems up to 100kW in size continues to be seen as an attractive market by the solar industry, now representing over 20% of installed capacity.

This market sector is not as mature as the residential market and we use 2019 installations as our base level of demand. Similar to our approach for the residential market we project the level of installations based on relative financial attractiveness (relative to the 2019 base year). We also incorporated a scaling factor to reflect the level of saturation and relative customer awareness and relative industry competitiveness and attractiveness similar to the process adopted for the residential sector.

Average system size has been reasonably stable over the last 5 years at around 22 kW per system. We expect modest increases in system size rising to 25 kW per system by 2030 and 29 kW per system by 2050 due to the continued increase in the performance and efficiency of panels.

3.5 Modelling upgrades and replacements of residential and commercial systems up to 100kW

This market sector is increasing albeit from a very low base. Many small systems (less than 1.6 kW) were installed over the 2010 to 2013 period (see Figure 4-2 on page 26) and a number of the customers are expanding their` systems in response to higher power prices and lower panel prices. While this market sector is still relatively small, we expect it to continue to grow and become a much more important feature of the industry in future years as saturation increases.

The commercial upgrade market at an estimated 48 MW in 2019 is currently not that material, however we believe it is worth separating as it has scope to grow in future and it is also important to exclude these systems when considering saturation levels.

We have developed a profile of projected future replacement systems based on (i) relative financial attractiveness and (ii) observed historical level of replacements. We expect that the solar industry will increasingly target this sector particularly as installed battery costs fall and larger new solar and battery packages become more attractive.

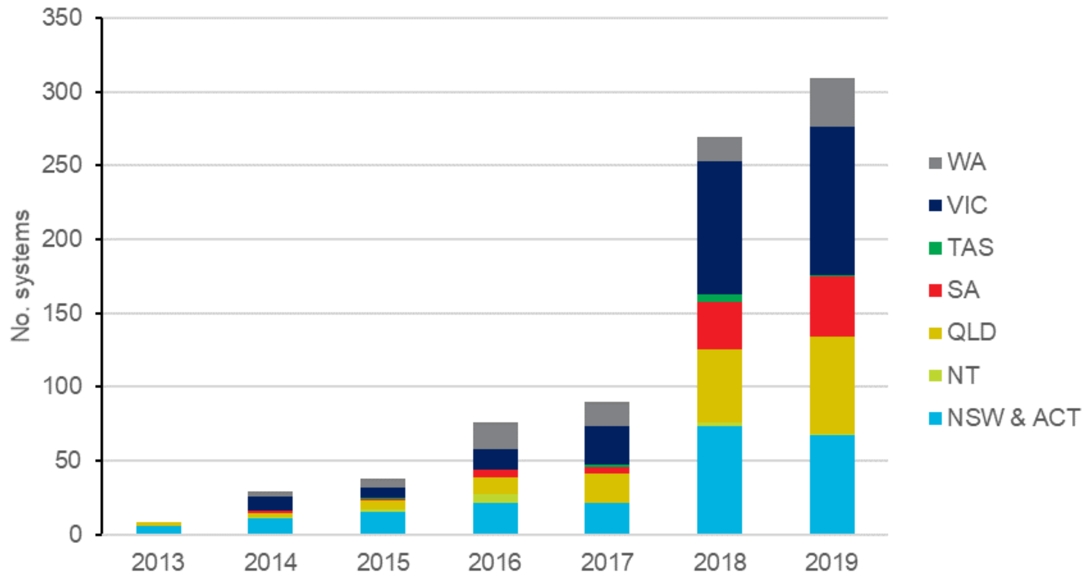
3.6 Large commercial behind the meter systems (above 100kW)

Projecting uptake within this narrow sub-sector of the solar market is subject to considerable uncertainty because the market is highly immature, highly complex and still undergoing rapid development and change.

The market has only really emerged at any noticeable level in the last three years as a result of significant reductions in system costs, and a dramatic increase in the wholesale price of electricity in the east-coast National Electricity Market.

Figure 3-1 illustrates that the number of systems being installed nationally per year has only just broken through 300 last year and as recently as 2017 the annual number of systems still lay below 100. At state level only Victoria has so far managed to record 100 systems in a year and in 2017 all states recorded less than 30 systems. Note that this includes systems that are larger than 1MW but which are known to be behind-the-meter systems.

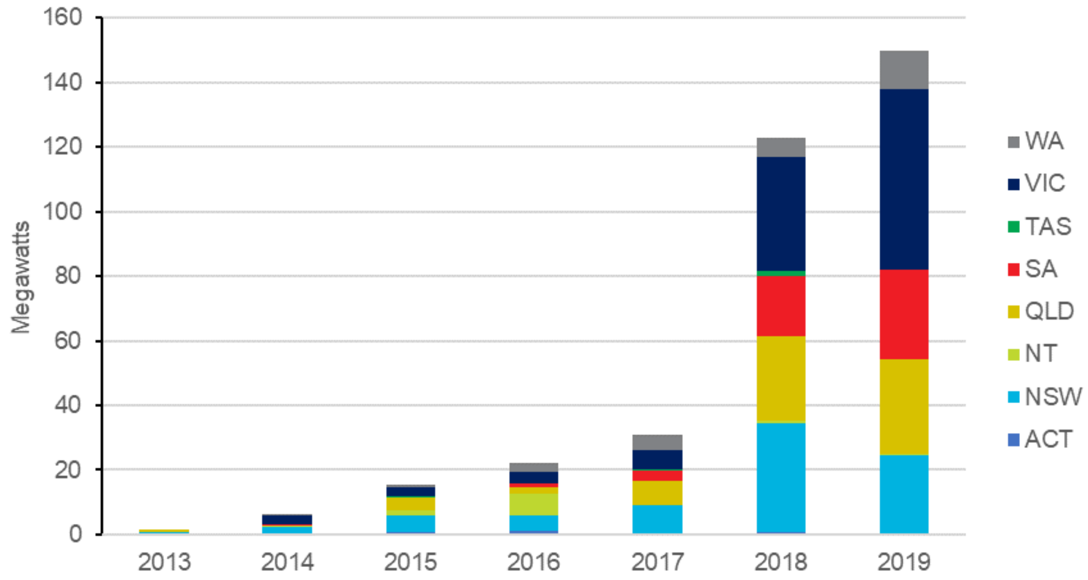
Figure 3-1 Number of solar systems -behind-the-meter large commercial solar (by year of accreditation)



The lack of a suitably large and representative sample set of solar system installations, stretching back over several years and the rapid changes in this market, provide a less than ideal basis for assessing how uptake might change over time in response to different environmental variables. Nonetheless changes in payback periods provide a useful benchmark or guidepost to inform how future mid-scale solar uptake might unfold. The rapid rise in uptake that began in 2016 and has continued into 2019 was preceded by large rises in power prices faced by large commercial customers and rapid reductions in system costs and so uptake in this market is clearly tied to financial payback just as one might logically expect businesses to behave.

To guide our projections of uptake we have used 2019 behind the meter capacity installs (inclusive of systems above 1MW) and likely customer evaluations of payback (which tend to be heavily biased towards market conditions in the recent past and what is expected only a year or two into the future) as a baseline to calibrate our model. To provide a lower bound guidepost as to how much capacity accredited could fall as paybacks deteriorate, we've used 2016 installation levels as a benchmark which we assume were a product of payback periods based on 2015 market prices. While it varies between states and customer-types, payback periods based on 2015 market conditions were roughly twice to three times as long as what they were in 2019. Figure 3-2 illustrates large commercial solar capacity by accreditation year illustrating that 2016 involved slightly more than 20MW of capacity while 2019 was close to 150MW.

Figure 3-2 Capacity of behind the meter large commercial solar PV (by year of accreditation)



While these historical benchmarks provide a useful guide for how uptake might change if payback remains the same as it was around 2018 and 2019 or deteriorates, we lack a guide for how uptake might increase above 2019 levels if paybacks get shorter than recent levels. While it seems unlikely that power prices will increase substantially above the levels experienced in the last 3 years in the NEM (our projections assume they decline), it is very likely that system costs will decline. Also if governments seek to follow through on their ambitious long-term emission reduction commitments then policy support could also increase (see section 4.2.1 and 4.3.1 for assumptions on government policy support for emission reductions by scenario). We have assumed that if paybacks were to halve from 2018-2019 levels then capacity installs would double but should acknowledge that this is subject to considerable uncertainty.

Paybacks and uptake are calibrated to installation levels in each state however with some adjustments to uptake in South Australia and NSW.

Figure 3-2 illustrates that in 2019 South Australia's share of solar PV installs in this segment are vastly greater than their share of total electricity consumption, population or GDP. They installed 10% more than NSW, yet NSW's business sector consumes over five times the electricity of South Australia's business sector. While one would expect that South Australia would have a higher rate of solar PV installs amongst businesses than other states given it has higher electricity prices, it seems unlikely such an out of proportion share would persist due to saturation effects. South Australia also has higher solar PV installation rates in the residential sector relative to other states but their share of the national residential market comes nothing close to what is seen for large commercial (SA represented 9% of Australian residential capacity additions but 20% of large-commercial behind the meter capacity in the 2019 calendar year). Our view is that SA's large commercial solar market is more advanced and mature than the rest of the country because it has had high electricity prices for longer than other states. But as a consequence, SA will also approach challenges with market saturation sooner than other states which will slow sales. We therefore scale back SA uptake such that if paybacks were to replicate conditions in 2019, they would install 40% of the capacity that occurred in 2019. We also make one further modification to SA uptake in the 2021 and 2022 financial year to add in capacity from SA Water's roll-out of 154MW of solar. This single company's roll-out is equal to more than the entire national 2019 level of installs and so required a one-off external adjustment.

Another adjustment was deemed necessary to scale-up NSW uptake levels to a level of capacity greater than what was installed in 2019 and closer to levels that occurred in 2018. Because the market still involves relatively small numbers of systems there is likely to be some volatility in figures from year to year that it is random rather than a function of long-term fundamentals. While all other mainland states recorded significant growth in annual capacity additions between 2018 and 2019, NSW annual capacity additions declined by 27% even though paybacks had not deteriorated. Also, our estimates are that paybacks on solar systems in NSW are not much worse than those in Victoria yet NSW installed less than half the capacity of Victoria.

3.7 Power stations 1MW - 30MW

As mentioned earlier for solar systems larger than a megawatt in scale, these are assumed to be in front of the meter power station installations. This means their revenue is derived solely from wholesale electricity markets. They are not embedded within an electricity consumer's site and offsetting electricity that would otherwise need to be purchased from the grid at retail rates.

For power stations rather than driving uptake via a specific financial evaluation of this category of systems we instead tie installation levels back to the level of scheduled large solar power station capacity installs projected within the draft Integrated System Plan. Small solar power stations below 30MW are likely to experience very similar cost and revenue drivers as solar power stations above 30MW. So if market conditions at a time within the ISP scenarios are conducive to building large solar farm capacity then these will also be favourable conditions for smaller, non-scheduled in-front-of-the meter systems. Likewise, if market conditions within the ISP are not conducive to building new large-scale solar capacity, they are also unlikely to support additions of non-scheduled, small solar power stations.

For 2020-21 we use our own estimates of installations based on bottom-up information gathering from a range of solar developers and equipment providers. Then from 2021-22 the model installs above 1MW solar when the draft ISP also envisages large scheduled solar capacity to be installed.

Under Central, Fast Change and Slow Change the amount of 1MW+ capacity installed is 6% of the scheduled solar installed in each year as estimated in the draft ISP. This is in line with the proportion of sub-30MW power station capacity accredited in 2019 relative to those 30MW or greater.

For High DER and Step Change it is increased to 10% of the scheduled solar installed in each year as estimated in the draft ISP. The higher proportion of sub-30MW capacity is to reflect the following guiding themes for these scenarios:

- The Step Change scenario involves a very rapid replacement of fossil fuel generators with zero emission renewables. Given the scale and speed of the build-out of renewables it is likely that developers will be pushed via higher demand towards a broader scope of supply options than needed under other scenarios. While sub-30MW projects are generally less financially attractive to developers than larger projects under a rapid build out of renewables, constraints and in particular transmission capacity, would likely push developers to pursue a greater proportion of sub-30MW projects than they would under a slower build-out.

- The High DER scenario is intended to represent a future where energy resources are biased towards smaller, distributed supply options. One possible event that might encourage this to occur could be that challenges are encountered in expanding transmission capacity such as local community opposition. This would then force developers to pursue a greater proportion of capacity from smaller projects that can be more readily incorporated within the existing transmission capacity.

3.8 Adjusting for the short-term impact of COVID-19

Part way through this modelling project Australian State and Federal Governments as well as governments overseas introduced a range of measures to prevent the spread of the COVID-19 virus. These have had rapid and significant impact in reducing economic activity and incomes including a significant increase in unemployment.

As a result of the significant change in economic circumstances AEMO requested us to make adjustments to projections to try to account for the potential impact of this economic downturn on solar PV and battery uptake.

Given solar and battery systems represent a reasonably significant capital purchase for both households and businesses, one would expect that they would experience a reduction in demand during an economic downturn just like we typically see with other major consumer durable equipment and business capital equipment. However, because solar PV systems have only relatively recently become a mass-market product, while battery energy storage systems are still to achieve mass-market scale, past history does not provide a useful guide of what we might expect. The last significant economic downturn occurred in 2008-09 at a time when solar PV systems experienced a dramatic reduction in purchase price and entered a dramatic growth phase. In addition solar PV has experienced record sales over the last 12 months prior to COVID-19 restrictions, when the Australian economy was experiencing slow or negative per capita GDP growth.

To try to assess the impact of the economic downturn we undertook a survey over the first week of April in conjunction with PV Magazine of solar industry businesses[5]. This survey asked them the extent to which customer inquiries had either increased or decreased since the COVID 19 social distancing restrictions were introduced - relative to the prior 6-12 months. This was complemented by direct discussions with a small number of industry participants that had access to customer solar system inquiry information across a significant proportion of the Australian market.

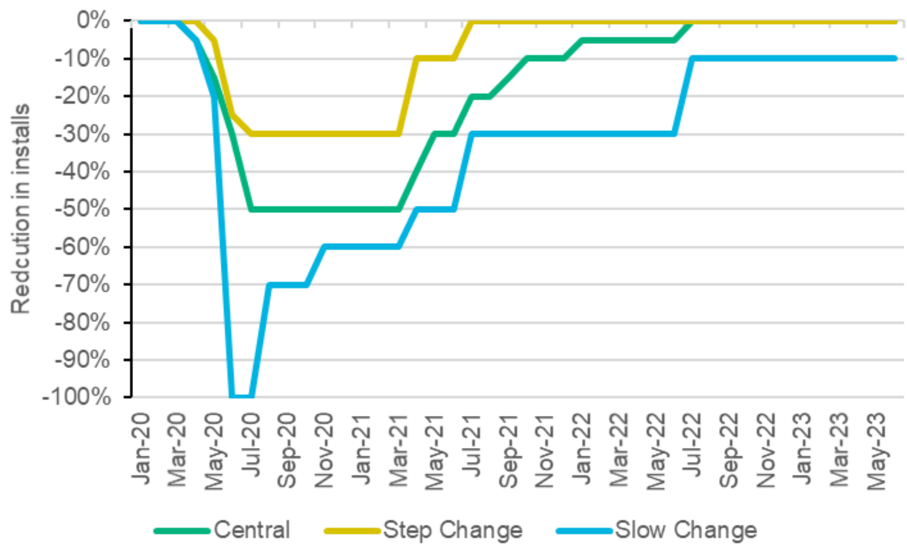
This market research suggested that customer inquiries for solar systems had dropped significantly, with a decline of inquiries in realm of 25% to 50% being most common but some experiencing a complete collapse. On the other hand battery inquiries had noticeably increased and only a small number of confirmed solar or battery orders were being cancelled. In addition, interviews indicated that preceding the COVID-19 restrictions the solar market was extremely buoyant. A large proportion of suppliers had an installation backlog of around 6 weeks with some extending to as long as 3 months.

[5] Article documenting findings and observations of survey is available here: https://www.pv-magazine-australia.com/2020/04/09/survey-covid-19-to-cause-50-decline-in-rooftop-solar-segment/

This information was then used to develop a pessimistic, optimistic and most probable impact on solar installation levels relative to our initial projections. These were finalised in the second week of April.

Figure 3-3 illustrates the reductions we have made to solar PV installations on a monthly basis relative to our model's original projections based on the input assumptions. Please note that the High DER and Fast Change scenarios are adjusted by the same percentage amounts as Central. Consistent with feedback from interviews about most solar businesses having a 6 week backlog, there is little adjustment downward in installations relative to original projections for the months of March to May. Under Slow Change installations drop to zero in June and July. This was to cater for the possibility that governments moved to completely ban solar installations. With the benefit of hindsight this now looks excessively pessimistic but when the COVID-19 adjustments were being developed in late March and early April such a ban could not be ruled out and was in place in New Zealand.

Figure 3-3 Downward adjustment in solar system projections to account for COVID-19 impact



4 Scenarios and associated assumptions

4.1 About the scenarios

Projections for solar and battery uptake have been developed for five different scenarios that are intended to be consistent with AEMO's planning and assumptions for its overall electricity system planning process.

Table 4-1 provides a summary of the approach we have taken with the main modelling input assumptions or factors across each scenario. To assist with consistency we have used the CSIRO's Draft 2019-20 GenCost analysis[6] for guidance on the capital cost and LCOE of various power generation and storage technologies. However, in the case of distributed solar and batteries we have applied our own judgement about what cost reductions are likely to be achieved based on our own analysis of market data and interviews with solar industry participants.

[6] Graham, Hayward, Foster, Havas (2019) GenCost 2019-20: preliminary results for stakeholder review – December 2019

Table 4-1 Overview of modelling assumptions for each scenario

Modelling factor	SCENARIO				
	Central	Slow change	Step Change	High DER	Fast Change
Guiding themes	Continuation of existing technology trends. No new climate policies introduced even though Paris and State's 2050 targets will not be met.	Significant slowing in renewable energy technological progress. Regression in policy concern for emission reductions. Low fossil fuel prices.	Rapid technological progress. Governments globally make concerted effort to contain global warming below 2 degrees.	DER technologies continue to achieve strong technological progress and enthusiastic adoption. Slower progress with centralised generation technologies. Minimal nationally co-ordinated action on emissions but some state government efforts.	Rapid technological progress. Further action taken to contain carbon emissions but falls short of 2 degree goal.
Distributed solar & battery technology cost reductions	Continuation of existing trends. Residential follows GEM developed pathway slower than CSIRO GenCost Central. Commercial aligned with CSIRO GenCost Central	Slow - nominal price constant, real price declines at 2%	Very Rapid. Residential & Commercial based on CSIRO GenCost Low Cost	Residential based on CSIRO GenCost Central. Commercial based on CSIRO GenCost low cost.	Residential based on CSIRO GenCost Central. Commercial based on CSIRO GenCost low cost
Centralised wholesale generation costs	Continuation of existing trends. Ongoing improvement in solar technology drives down wholesale costs in middle of day	Cost reductions for new technologies are slow, but wholesale energy costs kept lower than Central due to lower fossil fuel costs and extension of coal plant life.	Costs are higher in short-term than Central, but fall below Central over time due to faster technological improvement.	Costs are similar to Central.	Costs are higher in short-term than Central, but fall below Central over time due to faster technological improvement.

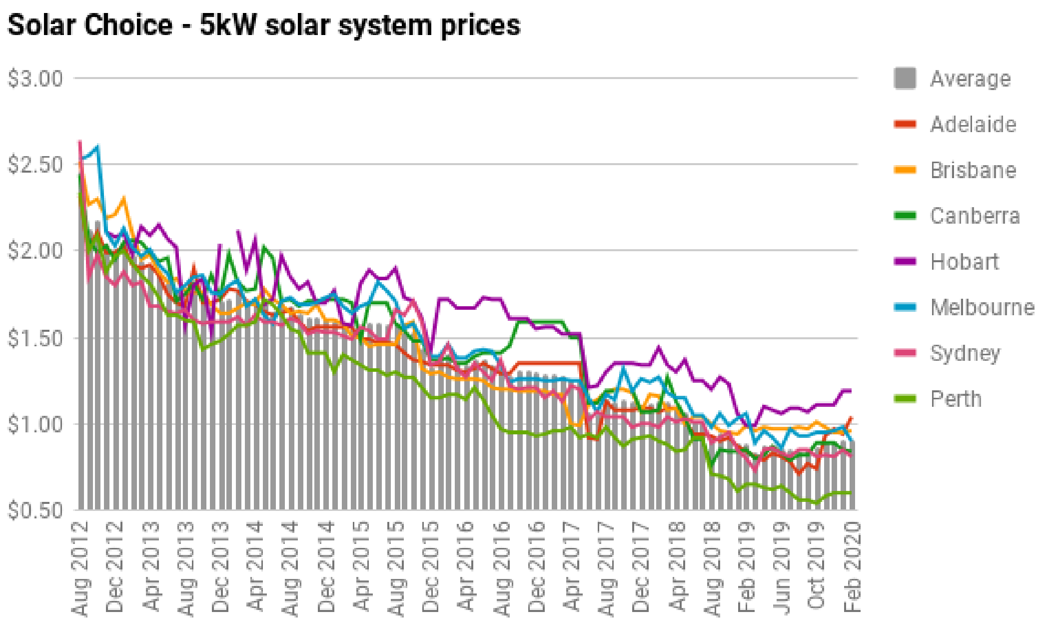
Table 4-1 Overview of modelling assumptions for each scenario (cont.)

Modelling factor	SCENARIO				
	Central	Slow change	Step Change	High DER	Fast Change
Government support for batteries	Only includes existing policies which are in force (not proposed)	Existing rebate programs cancelled in 2023-24.	National rebate introduced in 2021-2022 for batteries across all sectors to 2050.	Several states join VIC and SA in offering battery rebates in 2021-22, these remain in place until 2050. Also rebates are expanded to commercial.	Only includes existing policies which are in force (not proposed)
Government support for solar	Only includes existing policies which are in force (not proposed)	Market for Australian Carbon Credit Units and Victorian efficiency certificates wound up before 2025 but Renewable Energy Target remains unchanged.	Climate Solutions Fund and Safeguard Mechanism drive very high demand for Australian Carbon Credit Units from Solar	Several states support solar through state-based abatement certificate programs but less support than under Step Change.	Climate Solutions Fund and Safeguard Mechanism drive demand for Australian Carbon Credit Units from solar out to 2050 but much less valuable than in Step Change.
Network charges and role of virtual power plants	Network charges balance between fixed and variable similar to today but tariff structure transitions to variable time of day basis by 2030. VPPs slowly but steadily become more common.	Greater proportion of network charges shift to fixed but tariff structure otherwise the same as Central. VPP adoption slow and modest.	Network charges and tariff structure same as Central. Rapid growth of VPPs to high proportion of systems	Greater proportion of network charges shift to variable but tariff structure otherwise the same as Central. VPPs grow to high proportion of battery systems but slower than Step Change.	Network charges and tariff structure the same as Central. VPPs grow to high proportion of battery systems but slower than Step Change.

4.2 Capital cost - PV

To help calibrate solar uptake to payback relative to historical levels we maintain records of system costs over time and use the Solar Choice Price Index as one of our inputs. As shown in Figure 4-1 illustrating solar system prices after the STC discount since August 2012, suppliers of solar have historically managed to achieve substantial and steady cost reductions over time. Critically, these cost reductions have managed to outpace the reductions that have been made to the value of the STC discount which stepped down substantially in 2013 and then further annual reductions after 2016 as the deeming period has been reduced. However, over the last 12 months prices post the STC discount look to have levelled out.

Figure 4-1 Installed system Costs (after STCs) for 5kW system ($/Watt)

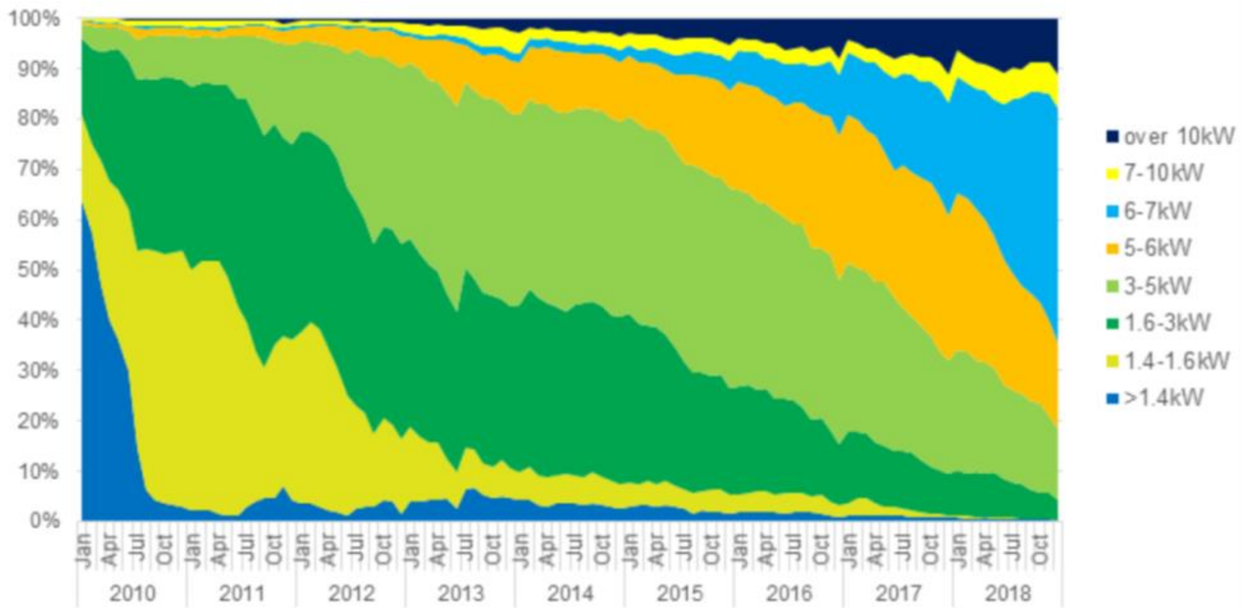


Source: https://www.solarchoice.net.au/blog/residential-solar-pv-price-index-february-2020/

Cost reductions to date have been due to a combination of factors, including; declines in module prices, lower labour and balance of system equipment costs per watt installed through gains in solar module conversion efficiency and increasing system size.

Figure-2 shows just how substantial the increases have been in typical residential system capacity over 2010 to 2018 and this has continued to recent times.

Figure 4-2 Proportion of solar systems within different capacity bands - National

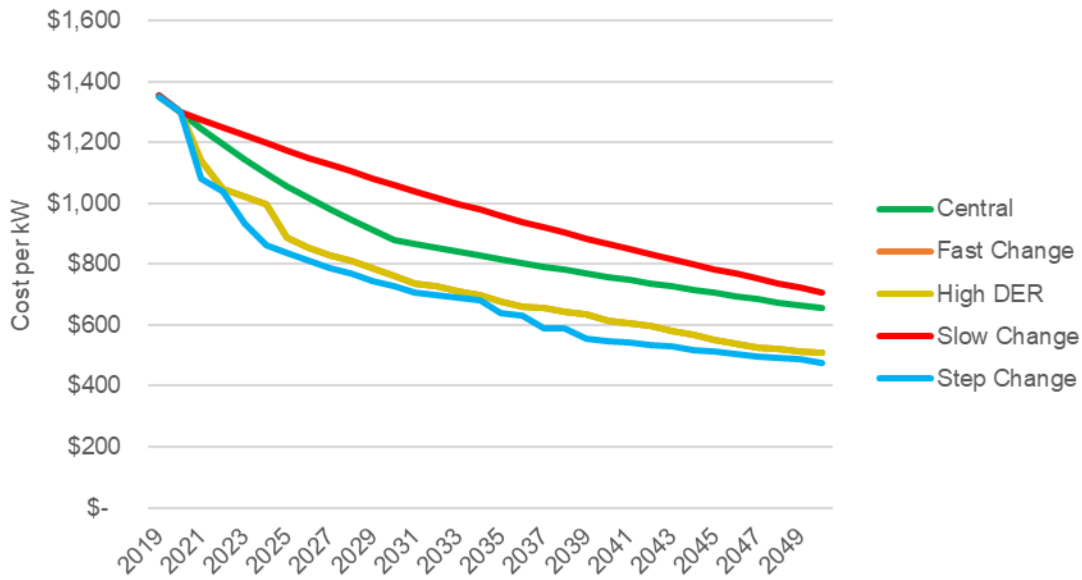


The sale and installation of solar systems involves a significant portion of labour costs which are fixed per system irrespective of its size. The sales and design process as well as travel to site, site set-up, inverter installation, administrative paper-work, and customer engagement involve much the same amount of labour time whether a 1kW or a 10kW system is installed. So the fact that the industry has moved from systems usually below 1.4kW to systems closer to 7kW now has delivered substantial cost savings per watt of capacity. In addition, the increasing amount of capacity installed since 2016 has meant fixed administration and sales and marketing costs have been easier to cover.

Whilst we expect to see modest reductions in module prices and continued gains in conversion efficiency, we expect to see constraints on continued increases in system size in the residential sector. This is because the typical residential system has now reached 6.6 kilowatts which comes up against a constraint point where distribution networks impose a 5kW export limit on solar system inverters for automatic connection approval, while eligibility for STCs limits the oversizing of module capacity to a third greater than inverter capacity. This will therefore hinder the industry achieving ongoing savings per watt and therefore per kWh of electricity generated. We also expect that lead generation and sales and marketing costs will increase as solar reaches higher levels of market saturation.

Due to these developments we have used more pessimistic capital cost assumptions for residential solar systems than outlined in the 2019-20 Draft GenCost publication prepared for AEMO. These are illustrated in Figure 4-3 below. Please note that Fast Change has the same cost trajectory as High DER and so is obscured by the yellow line.

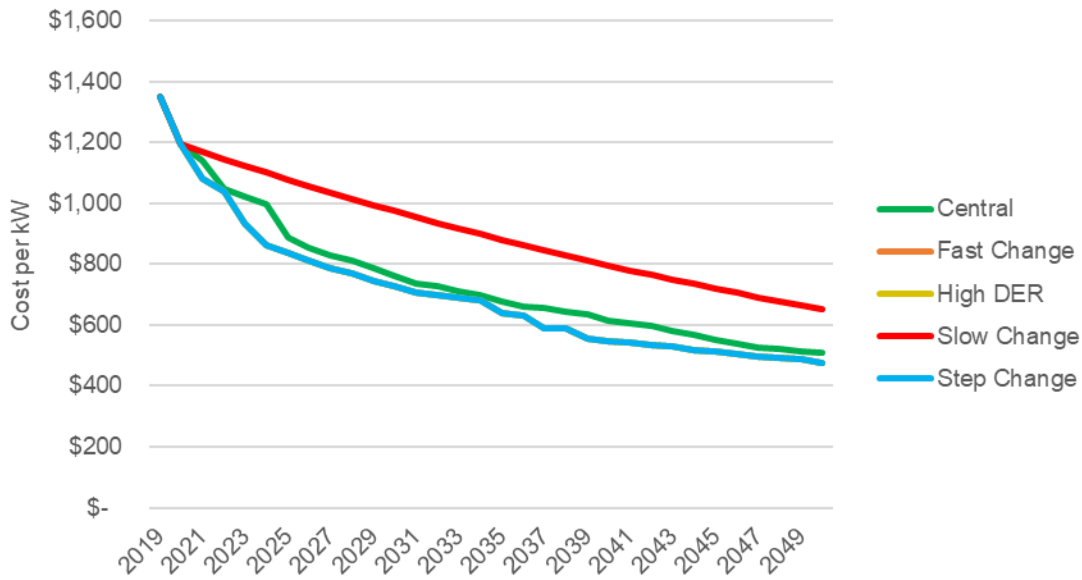
Figure 4-3 Fully installed residential solar system price per kW by scenario (excludes discounts from-government support measures e.g. STCs)



Sources: Central based on Green Energy Markets' analysis of most likely cost trajectory, Slow Change is based on a 2% per annum decrease in real terms, Fast Change and High DER based on CSIRO GenCost preliminary results – Central; Step Change is based on CSIRO GenCost preliminary results – High VRE (low cost).

For commercial sized systems (systems greater than 15kW), network connection requirements place less of a constraint on the industry's capacity to achieve reductions in labour costs per watt installed by taking advantages of expected improvements in module efficiency. Consequently, there are faster cost reductions under Central scenario (the green line) which is based on CSIRO's Central Scenario GenCost assumptions. Also High DER and Fast Change Scenarios follow a faster cost reduction trajectory that is the same as the Step Change scenario which, like residential, is based on CSIRO's low cost High VRE scenario.

Figure 4-4 Fully installed commercial solar system price per kW by scenario (excludes discounts from-government support measures e.g. STCs)



Note: High DER and Fast Change follow the same cost path as the blue line indicated by Step Change. Sources: Slow Change is based on a 2% per annum decrease in real terms; Central based on CSIRO GenCost preliminary results – Central; Fast Change, High DER and Step Change based on CSIRO GenCost preliminary results – High VRE (low cost).

4.2.1 Incorporating impact of government support policies

To ease the calculation process the value of any government support policies to solar or batteries are estimated in the model as an upfront financial discount that is deducted from capital cost of the solar and/or battery system, rather than as an annual revenue flow. In terms of STCs this is what already occurs and is also the case for a range of solar and battery rebate programs offered at present to residential consumers. While such upfront discount offers are not yet common in terms of policy support delivered via abatement certificates such as LGCs or ACCUs, given customers will often estimate the discounted cash flow impact of such certificates in evaluating a purchase, our approach still provides an effective representation of how customers would evaluate such an investment.

STCs under the Small Scale Renewable Energy Scheme

For solar systems up to 100kW the model estimates the upfront discount the solar system would receive from STCs with the model valuing an STC at $38 fixed until the scheme ends in 2031. The number of STCs a solar system receives are determined by the deemed generation estimated by the Clean Energy Regulator based on each state and territory's capital city. The years of deemed generation steps down by a year until 2031 when the program ends.

LGCs under the Large Scale Renewable Energy Target

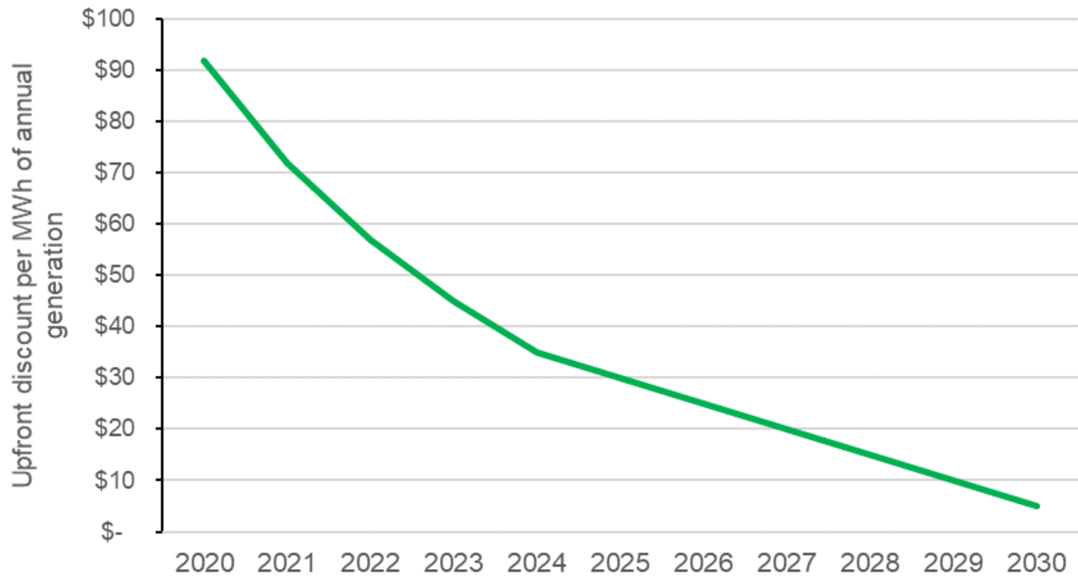
As an alternative to STCs, solar systems can instead claim Large-Generation Certificates or LGCs which electricity retailers and some other large electricity consumers are obligated to purchase in order to achieve the national Renewable Energy Target. LGCs are awarded to a solar system owner on the basis of one LGC per MWh of electricity generated by the system. There is no system capacity eligibility requirement for claiming

LGCs, however a system that claims STCs is not eligible to also claim LGCs. In the model we assume that only solar systems greater than 100kW will claim LGCs with those 100kW or smaller all opting for STCs.

As touched upon earlier, while in practice an LGC is only awarded to a solar system after it generates a megawatt-hour of electricity, in the model we estimate the lifetime of megawatt-hours the system would generate that are eligible for LGCs and the real financial value of those LGCs. This is then deducted from the capital cost of the solar system, similar to what already occurs with the deeming of STCs.

Figure 4-5 illustrates the upfront, one-off capital cost discount or reduction the model applies based on the system's expected annual MWh of production. This declines over time because the LRET scheme ends in 2030 and so the amount of generation that will be eligible for LGCs gets shorter as we get closer to 2030. In addition, the price per LGC is expected to fall significantly over the next few years due to supply of LGCs growing beyond the level of mandated demand under the Renewable Energy Act. The upfront discount value applied from LGCs is the same across all scenarios.

Figure 4-5 Upfront discount to a solar system from LGCs (Applies to all scenarios)



To explain how this works with an example, a 300 kilowatt solar system installed in Sydney can be expected to generate an average of 427MWh per year. The upfront reduction applied to the purchase price of such a solar system installed in 2020 in the model is 427 multiplied by $92, whereas a system installed 2025 receives 427 multiplied by $30.

Victorian Government Solar Homes Program

In 2018 the Victorian Government announced that it would seek to achieve an additional 650,000 solar systems on residential dwellings by 2028 via a Solar Homes Program. This program involved a rebate capped at a maximum of $2,225 per system (for a 4kW system) plus an interest-free four year loan to cover the remaining out of pocket costs, also up to a maximum of $2,225 per system. The Government has since indicated that the amount of the rebate will step down over time and it reduced it to a maximum of

$1,888 per system on 1 January 2020 and reduced the loan to the same amount. It will make a further reduction in the rebate and loan to 1,850 from July 2020.

The model takes this into account through assuming that the Victorian government will achieve its target of 65,000 systems. Until very recently the rebate program has been over-subscribed, and the system installations are on track to achieve this target of 65,000 systems.

State Governments' Energy Efficiency Schemes

At present the only state government energy efficiency certificate scheme that solar systems can claim abatement/energy saving certificates is the Victorian Energy Upgrades scheme. To date, solar systems are yet to claim certificates under the scheme, instead opting for either STCs or LGCs. However, LGC prices in the forward market fall substantially over the next few years and it appears likely that owners of solar systems larger than 100kW will be better off in the next year or so claiming Victorian Energy Efficiency Certificates (VEECs) instead for the grid imports a solar system displaces and the associated avoided emissions.

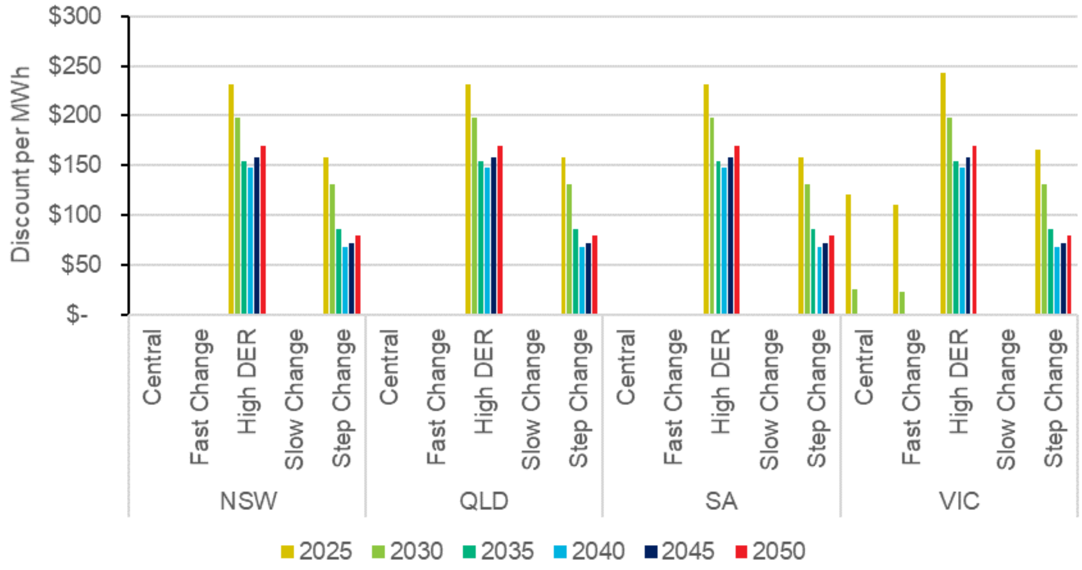
The value of these VEECs is taken into account in the model for solar systems above 100kW in Victoria in circumstances where these provide a higher value than claiming LGCs or Australian Carbon Credit Units. Under Central and Fast Change the value is calculated based on generation up to the year 2030 whereas under High DER and Step Change it is assumed the scheme continues throughout the outlook. Under Slow Change the value is assumed to be zero.

For the High DER and Step Change scenarios it is assumed that NSW and SA modify their existing efficiency schemes and QLD introduces a similar scheme that awards energy efficiency abatement certificates to behind the meter solar PV. In addition, in these scenarios the value of the state-based certificates are taken into account for systems below 100kW and the schemes across the states are merged into a single scheme by 2030. However, in the Step Change scenario system owners are usually better off claiming ACCUs instead.

The amount of grid imported electricity displaced by the solar system is converted into an amount of abatement certificates by multiplying it by the average grid emissions intensity for the NEM as a whole. This is based on electricity emissions estimated in AEMO's draft ISP for each scenario.

Figure 4-6 details the capital cost discount applied for each state and scenario (it is assumed NT, WA and TAS do not introduce such schemes because they do not have a scheme in place, nor have they initiated a consultation process to consider one).

Figure 4-6 Upfront discount to a solar system from state efficiency schemes



To explain how this discount works with an example, a 300 kilowatt solar system installed in Melbourne can be expected to generate an average of 393MWh per year, but only that which is consumed on-site (not exported to the grid) is eligible for certificates. Our model assumes 15.9% of VIC system generation is exported for a large commercial customer, so certificates are only created for 331MWh which are consumed on site.

The upfront reduction applied to the purchase price of such a solar system installed in 2025 in the model under the Central scenario is 331 multiplied by $121, whereas a system installed 2030 receives significantly less because the scheme is assumed to end in that year and only gets 331 multiplied by $25.

Climate Solutions Fund and Safeguard Mechanism ACCUs

Under the Industrial Electricity and Fuel Efficiency Methodology solar systems located behind the meter are eligible to create Australian Carbon Credit Units (ACCUs) for the abatement they deliver in offsetting/avoiding the use of fossil fuels over a 7 year project crediting period. These ACCUs can then be sold to either:

- The Federal Government via the Emission Reduction Fund or Climate Solutions Fund;
- Entities that are short of sufficient ACCUs to honour their abatement delivery contracts with the Federal Government;
- Emitting facilities that are liable under the Federal Government’s Safeguard Mechanism to keep their emissions below a regulated emission baseline
- Entities that are voluntarily seeking to reduce emissions.

To date solar systems have not created ACCUs because it has been administratively easier and more financially rewarding to create LGCs or STCs. However, with LGCs likely to fall in value and with the LRET coming to an end in 2030, it is conceivable that creating ACCUs may be preferable for systems above 100kW.

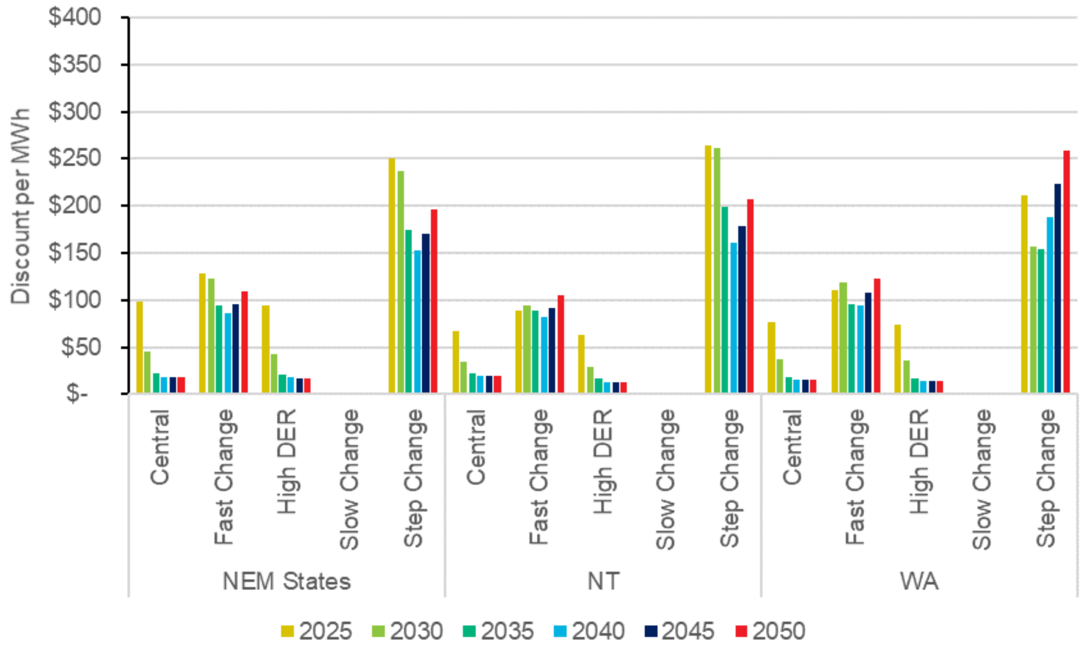
The value of these ACCUs based on 7 year’s worth of self-consumption of generation is taken into account in the model for solar systems above 100kW on a national basis where these provide a higher value than claiming LGCs or, where applicable, state-based abatement certificate entitlements. It is assumed there will be a market for ACCUs out to 2050 under all scenarios except Slow Change. Also under Step Change it is assumed the crediting period for abatement for solar systems is extended from 7 years to 10 years. It is also assumed that ACCUs are awarded for all generation, not just generation which displaces imports of power from the grid.

In the Fast Change, High DER and Step Change scenarios it is assumed that changes are made to make it administratively easier to claim ACCUs such that systems below 100kW in size also claim ACCUs not just those above 100kW.

The amount of grid imported electricity displaced by the solar system is converted into an amount of abatement certificates by multiplying it by the average grid emissions intensity assumed for the respective state in which the system is installed. For the NEM states this is based on electricity emissions estimated in AEMO's draft ISP for each scenario. SWIS and DKIS emissions intensity at the start of the projection is based on historical emissions data with declines over time then calibrated to get to similar levels of emissions intensity as the NEM achieves under each scenario.

Figure 4-7 details the upfront discount applied according to the scenario and location the solar system is installed. Under Central we are only able to incorporate demand for ACCUs based on existing legislated and funded initiatives and consequently demand for ACCUs fall precipitously from 2030 onwards as a result of the Climate Solutions Fund coming to an end and remaining demand being largely voluntary. The same is assumed under High DER, while under Slow Change the Climate Solutions Fund is assumed to be abandoned. The Step Change and Fast Change scenarios assume that abatement effort is substantially scaled up beyond the current settings for the Climate Solutions Fund and Safeguard Mechanism. This means the value of ACCUs in these two scenarios is bolstered relative to Central across the entire outlook period to 2050.

Figure 4-7 Upfront discount to a solar system from ACCUs



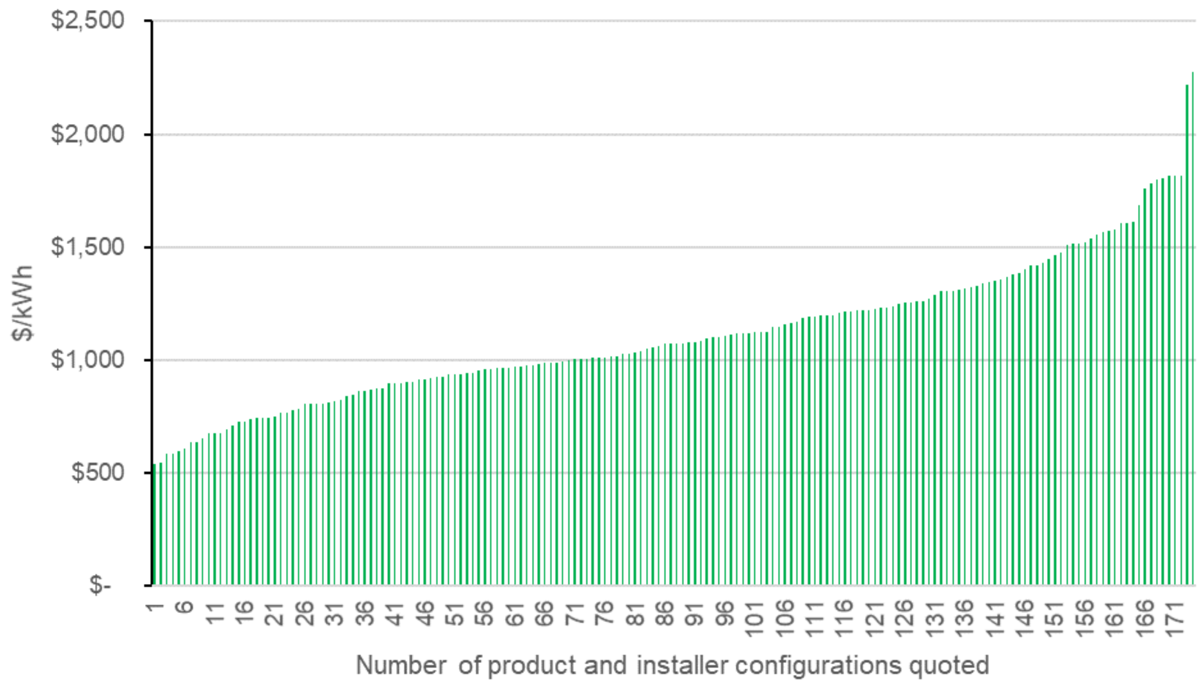
As noted previously the way the discount is calculated is based on only the generation which is consumed on site (not exported) for all scenarios except Step Change where is based on all generation from the solar system irrespective of whether consumed on-site or exported. So the LGC example of how the model calculates the purchase price discount applies for Step Change, while the State energy efficiency schemes example applies for the other scenarios.

4.3 Capital cost - Batteries

To inform our starting point of battery costs we have made use of the large dataset of battery system quotes provided by the South Australian Government's Home Battery Rebate Scheme complemented with interviews with several solar-battery industry participants.

Figure 4-8 illustrates the distribution of battery system quotes (excluding the rebate) that were available in January 2020, which range between $500 per kWh up to as much as $2,300 (excluding GST). Of course, not all of these quotes are ultimately accepted by end consumers, who will naturally tend towards accepting quotes at the lower end of the scale. Feedback from industry interviews suggested that $1,000 per kWh (including GST) was a reasonable rule of thumb for recent purchase prices of battery systems retrofitted to an existing solar system on a national basis.

Figure 4-8 Installed cost quotes per kWh for battery systems under SA rebate program (Excl. GST and rebate)



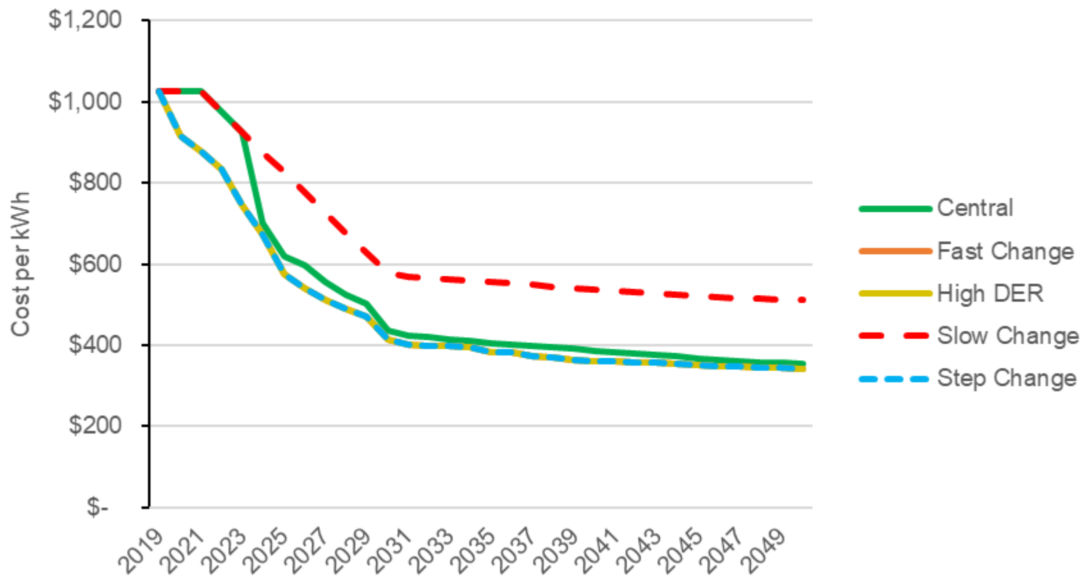
Source: : South Australian Government's Home Battery SchemeSystem Price Guide - https://homebatteryscheme.sa.gov.au/system/files/documents/System-Price-Guide.pdf

In many cases going forward batteries will be installed simultaneously with installation of a new solar system or an upgraded replacement solar system. This is likely to achieve savings in both install labour and the associated sales and back-office activities. We estimate this saving at $200 per kWh of battery capacity which provides a cost close to

CSIRO's 2019-20 draft GenCost assessment for a combined solar and battery system (once the solar system cost is backed out).

Figure 4-9 illustrates the assumed capital cost adopted for a battery system retrofitted to a residential solar system by scenario in the model. Please note that the High DER and Fast Change Scenarios follow the same path as Step Change. Costs for commercial systems are assumed to be 20% less due to larger sizes capturing savings per kWh in labour install costs and inverter-chargers.

Figure 4-9 Assumed capital cost per kWh for residential battery system by scenario (Incl. GST)



The cost or purchase price in High DER, Fast Change and Step Change scenarios are all based on CSIRO's GenCost 2019-20 assessment under its High Variable Renewable Energy scenario, which represents its rapid cost reduction trajectory.

The costs we have adopted for our Central Scenario however are higher than the GenCost 2019-20 Central Scenario prior to 2027. The GenCost assessment incorporates a large drop in battery costs in the year 2020, however the latest market data suggests no reduction in prices has occurred. This continues a trend we have observed over the past few years of little to no reduction in home battery system prices in Australia. We expect that price reductions will remain modest for the next few years but will eventually be followed by quite rapid reductions in prices. A variety of information sources suggest that electric vehicle manufacturers have been able to attain quite significant reductions in battery pack purchase prices over the last few years which are reflective of lower battery cell production costs[7]. However, these have not flowed through to lower prices for customers purchasing stationary energy systems at behind-the-meter scale. We suspect that battery manufacturers are prioritising the far larger electric vehicle market over small

[7] For example see the results of Bloomberg New Energy Finance surveys of vehicle manufacturer's reported battery pack prices here: https://about.bnef.com/blog/behind-scenes-take-lithium-ion-battery-prices/ and https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/

scale stationary energy storage which is a much smaller market opportunity. But eventually prices will inevitably follow costs downward as new competitors enter the market and as its growing scale induces suppliers to compete more vigorously. Such a pattern occurred in the solar PV industry where price reductions pretty much stalled over 2003 to 2007 yet production costs were continuing to fall. However, the entry of a number of Chinese suppliers then led to solar module prices plummeting extremely rapidly.

Another factor that has delayed reductions in battery system prices in the Australian market has been the introduction of stricter installation standards to control fire risk that have added significant cost. These standards have gone beyond what is common internationally and a relaxation of the standard seems likely as fire authorities gain comfort with what is still a relatively new household technology.

While the timing for such a price shake-out are extremely uncertain, the history of Solar PV suggests a shake-out within the next five years is reasonably likely and we have timed it to begin in 2024.

4.3.1 Incorporating impact of government support policies

SA Government Rebate

The South Australian Government has a target of rolling out 40,000 home battery energy storage systems over 2018 to 2022 which it has supported with $100m in funding for rebates.

However, based on data up to January when this project commenced, uptake of the rebate program had reached 6,000 which was below levels targeted[8]. Our projections expect the target will ultimately be achieved but under the Central scenario it occurs a few years later than targeted. While the SA Government released information in April suggesting uptake of the rebate had accelerated[9] this was too late to incorporate within the projections. Nonetheless, our forecast of 145MWh of battery capacity being installed in SA over 2018 to 2020 accords closely with the SA Government's projection for 146MWh.

Victorian Government Rebate

A sub-component of the Victorian Government's Solar Homes Program involves a rebate program targeting 10,000 battery systems by 2028 retrofitted to households that already have a solar system in place or 1000 systems per annum. While the uptake under the program had been running below target, a series of changes this year have significantly broadened eligibility. Feedback from Solar Victoria suggests that they are now on track to achieve the 1000 systems targeted. Our projections assume the target is met. But given it represents a minority of the total Victorian residential battery market based on historical data, it doesn't fundamentally change projections of expected battery uptake.

Other current battery support programs

Several other State and Territory governments have made rebates and/or low interest loans available to support battery uptake. However, in most cases these are relatively

[8] Media release from Hon Dan Van Holst Pellekaan – Battery bonus for new home buyers – 29 January 2020.
[9] Media release from Hon Dan van Holst Pellekaan – Homes batteries going like hot cakes – 17 April 2020.

modest in scale or we suspect they will not be materially alter customers willingness to adopt batteries (particularly the provision of loans)[10]. Consequently, these are not explicitly part of the modelling process for battery uptake over the next decade.

Potential future battery support via energy-efficiency or demand management schemes

Both the Victorian and NSW Governments have indicated that they are considering changes to their energy efficiency certificate schemes to reward benefits from either peak demand reductions or carbon abatement (via supporting increased PV generation) flowing from battery systems. Also the SA Government has indicated its desire to amend its energy efficiency scheme to incentivise activities that reduce peak demand[11], which would presumably include battery systems. However, because these changes are not yet enshrined in either legislation or regulations, they are unable to be included within the Central Scenario. Yet given several state governments as well as the Federal Labor Opposition have indicated an intention to provide incentives to encourage battery system adoption, we explore the impact of a long term program that would act to reduce the cost of batteries to 2050 in the High DER and Step Change scenarios across not just residential, but also commercial installations. In the High DER scenario this is confined to NSW, SA, VIC, QLD that either have or have canvassed introducing broad-based schemes for encouraging energy efficiency. WA is also included by virtue of its market design awarding capacity credits to demand response measures, and so providing a payment to remunerate battery capacity was considered a reasonable element of a High DER scenario. In Step Change a national battery rebate program is assumed.

The support for batteries is modelled as a $500 per kWh discount to the cost of a battery system from 2022, which then progressively declines as battery costs reduce to reach $200 per kWh by 2034.

4.3.2 The impact of Virtual Power Plant payments

Virtual power plants (VPPs) involve owners of battery systems handing over control to discharge or charge their battery system to a company which can then bid some or all of the battery's capacity into wholesale energy and frequency control markets operated by AEMO. There are now a number of companies which operate these virtual power plants and offer customers a variety of forms of compensation in return for being given at least partial control over the discharge/charging of the battery. Some of the offers on the market noticeably improve the financial attractiveness of a battery system[12].

However, this market is still very immature and it is highly uncertain how it might evolve over time and the amount of financial benefit battery owners might receive into the future. In addition, from a macro perspective, while consumers may receive a direct benefit from participating in Virtual Power Plants, as these become a significant source of supply they have the potential to lower power prices. This will then reduce revenue to solar and battery owners, partly offsetting the gain from the payment received from signing up to a Virtual Power Plant.

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[10] In the case of the Northern Territory battery rebate this was announced very recently and too late to be incorporated in our modelling.
[11] Government of South Australia - Department for Energy and Mining (2019) Review into the South Australian Retailer Energy Efficiency Scheme Directions Paper – October 2019
[12] See here for details on the VPP offers currently available to residential battery owners: https://www.solarquotes.com.au/battery-storage/vpp-comparison/

Given this uncertainty we have not explicitly accounted for the potential impact of VPP payments on battery paybacks. Although we would note that state governments have shown an interest in tying government support to customers participation in VPPs. Also, some VPPs structure their remuneration much like a rebate that reduces the effective upfront cost of a battery system (e.g. Tesla's VPP). Given these facts we suspect that scenarios such as High DER and Step Change – which incorporate widespread and long-lived rebates for batteries – are reflective not just of environments where government support for batteries is forthcoming, but also where VPP payments/battery discounts remain significant.

4.4 Electricity prices

4.4.1 Overview

In estimating the revenue or bill savings behind-the-meter solar and battery systems deliver to consumers we need to consider two different electricity prices:

- Import replacement price: this is the variable electricity price that can be avoided by that level of solar generation that is consumed by the household or business. It is important to recognise that a large proportion of electricity charges are fixed and can not be reduced through installation of solar or a battery unless the site completely disconnects from the grid; and
- Export price: this is the variable electricity price that is received through the export of electricity to the grid.

Our payback model time series incorporates the Australian Energy Market Commission's (AEMC) latest residential price trend projections[13] but are adjusted to exclude fixed standing charges utilising AEMC typical demand estimates.

For large commercial businesses we use a combination of a bottom-up estimate of the various bill components and advertised offers by electricity retailers.

For the purposes of forecasting ahead these prices we utilise the AEMC methodology of breaking down electricity costs into the following cost components:

- Wholesale energy
- Network charges
- Retail margin
- Environmental charges

We then add another component to this which is the feed-in tariff or export price. For the NEM states this is based on advertised feed-in tariffs offered by electricity retailers or, where applicable, the regulated rate for the year 2019-20, but after this it is tied to the wholesale energy market cost customers are assumed to pay. For Western Australia it is based on the buy-back price set by the government up until 2021-22. From 2022-23 until 2029-30 the feed-in tariff transitions steadily towards the wholesale energy market cost customers are assumed to pay and then remains tied to the wholesale energy market cost. On April 5 this year the Northern Territory Government announced that it would be

[13] Australian Energy Market Commission (2019) Final Report – Residential Electricity Price Trends 2019, December 2019

significantly reducing the feed-in tariff new solar systems would be eligible to receive (reducing it from 23.68c/kWh to 8.3c/kWh GST exclusive). However, this was unable to be incorporated into this modelling exercise, which by that date was almost complete. Instead the modelling assumed that new solar systems would receive the prior regulated rate (now classified as the premium rate) until 2023-24. From 2024-25 until 2029-30 the feed-in tariff would then transition steadily towards the wholesale energy market cost customers are assumed to pay, and then remain tied to the wholesale energy market cost.

4.4.2 Tariff structure and network charges

Customers with sub-100kW systems

For both residential and small commercial customers the model applies a single uniform import price for electricity across all hours of the day up until 2021-22, which is derived from the AEMC's projections with adjustment to remove fixed charges.

This smeared uniform price then gradually unwinds over 2022-23 until 2029-30 towards a three part, time of day tariff network charging structure of the following:

- Peak – 3pm to 9pm
- Solar soak – 9am to 3pm
- Off-peak – all other times

Network charges applying during the peak period are set at 2.9 times the anytime smeared network charge in place in 2021-22. Meanwhile the solar soak and off-peak charge are both set at half the anytime smeared network charge in place in 2021-22. Network charges are assumed to remain constant in real terms across the period from 2021-22 until 2050.

In addition, wholesale energy costs are recovered based on a similar time structure but with the peak period only applying on weekdays and lasting until 10pm.

The model has adopted an assumption that tariff structures will change. This is because maintaining a single uniform smeared price is coming up against the challenge that solar capacity is reaching such large levels that it is substantially hollowing out demand and reducing costs in the middle of the day, but leaving the costs to service demand at other periods unchanged. This is seen by an increasing incidence of negative pricing events in some states' wholesale markets during daytime periods when demand is relatively low such as weekends and public holidays. To make better use of low cost solar there is a need to encourage greater electricity consumption in the middle of the day, while discouraging consumption during periods where more expensive supply options are required. Prices that reflect the lower cost of energy when solar power is plentiful while providing higher prices particularly during the demand peak (generally between 3pm to 9pm for residential areas) should help to do this.

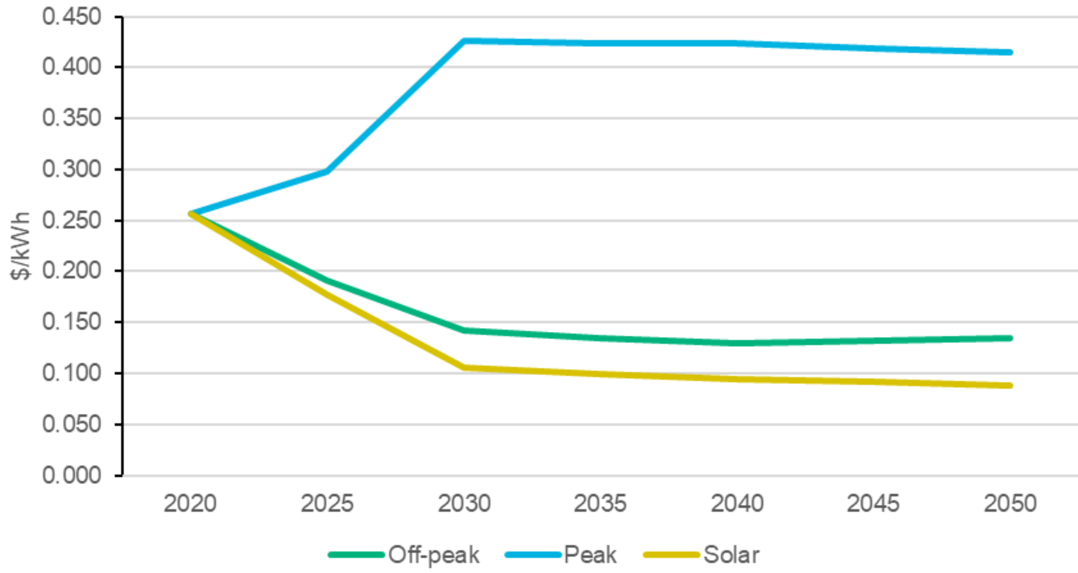
In the NEM states the move towards tariffs with more differentiated pricing is reflected in AEMC rule changes requiring a shift towards more cost-reflective tariffs by network businesses, and also its requirement for the roll-out of interval or smart meters. The installation of such a meter is mandatory where a solar system is installed, and they should reach a large proportion of the other stock of buildings by 2030.

In Western Australia the government has also indicated in its Distributed Energy Resources Roadmap[14] that it will seek to restructure tariffs to be time differentiated as a result of increasingly high solar penetration. While the NT has not yet made such a statement, they have recently taken a step in this direction through substantially reducing the feed-in tariff offered to solar exports from the retail rate down to a rate closer to wholesale energy costs[15].

The time periods chosen for this tariff structure reflect a combination of our own analysis of residential substation load data and wholesale energy market data, as well as tariff structures proposed by some network businesses like Ausgrid and SA Power Networks to deliver more "cost-reflective" price signals.

To illustrate with an example how this change in tariff structure (as well as solar-induced reductions in wholesale prices) plays out, Figure 4-10 illustrates the import price per kWh a NSW residential consumer would pay for the 3 different time intervals in the Central Scenario over time. In 2020 they pay the same price irrespective of time interval but by 2030 there is a large difference between the peak period versus the solar and off-peak period. The other states and other scenarios see similar changes.

Figure 4-10 Assumed changes in NSW residential power price by time interval (Central scenario, Incl. GST)



To also reflect potential alternative pathways for how electricity tariff reform might unfold we made the following scenario adjustments:

- For the Slow Change scenario we reduced the network charges per kWh relative to Central by 3 cents per kWh for small consumers on the assumption that this

[14] Government of Western Australia – Energy Transformation Taskforce (2020) Distributed Energy Resources Roadmap, December 2019

[15] See Jacqueline Breen (2020) One-to-one solar feed-in tariff scrapped, battery subsidies announced in NT renewables changes, ABC News, 9 April 2020 available here: https://www.abc.net.au/news/2020-04-09/nt-scraps-one-to-one-solar-power-feed-in-tariff-renewables/11928988

scenario involves a situation where networks move to recover a greater proportion of their costs through fixed daily charges.

- For the High DER scenario we increased the charges per kWh relative to Central in the peak and solar periods based on the assumption this scenario involves a situation where networks are pushed to reduce fixed charges and move a greater proportion of their charges out of the off-peak period and into periods when demand is higher.

Large commercial customers installing systems larger than 100kW

For large commercial customers that install solar systems larger than 100kW, we generally assume they already face time differentiated tariffs for wholesale energy and also are on what are referred to as demand-based network tariffs. Under these network tariff structures, customers face much lower charges for the kilowatt-hours they consume relative to residential or small commercial customers. Although they face significant network charges based on their maximum demand for over a 30 minute interval across a monthly period or sometimes a yearly period.

For evaluating solar payback without a battery in place we assume that the solar system only delivers savings in the network's kWh charges, not the demand-based charge. Charges per kWh are derived from the network's current tariff charges although in states with multiple distribution businesses we have attempted to use an approximate composite.

Large commercial businesses tend to have co-incident peaks in demand earlier in the day than residential consumers. In addition, the proportion of load covered by distribution network embedded solar generation is much smaller than residential and is likely to remain that way for the foreseeable future. As a result we apply the following network charging time profile where the kWh charges are differentiated between peak and off-peak:

- Peak – 11am to 8pm
- Off-peak – all other times

In addition, when evaluating the battery payback we take into account the likely impact of the battery plus the solar system in reducing the customer's network peak demand charge. This is based on feedback from solar businesses that customers tend to be unwilling to incorporate a saving on their demand charge from a solar system due to concerns about solar output variability. But if a battery is being installed then customers have greater confidence in applying savings on the demand charge delivered by the solar system as well as the battery. We have assumed the peak demand charge is only assessed based on demand during the peak period (11am to 8pm). The demand charge is set at $110 per annum per kW of peak demand for all states except QLD where it is set at $190 (this is because QLD distributors set their cents per kWh charges especially low and recover most of their costs in the demand charge). Also for Tasmania we have used the commercial time of use tariff structure rather than the demand charge in payback calculations.

Wholesale energy costs are recovered on the same structure as for residential consumers.

4.4.3 Wholesale energy

Up until 2021-22 we use AEMC projections for wholesale energy by time of day except for WA and NT where prices reflect current retail pricing.

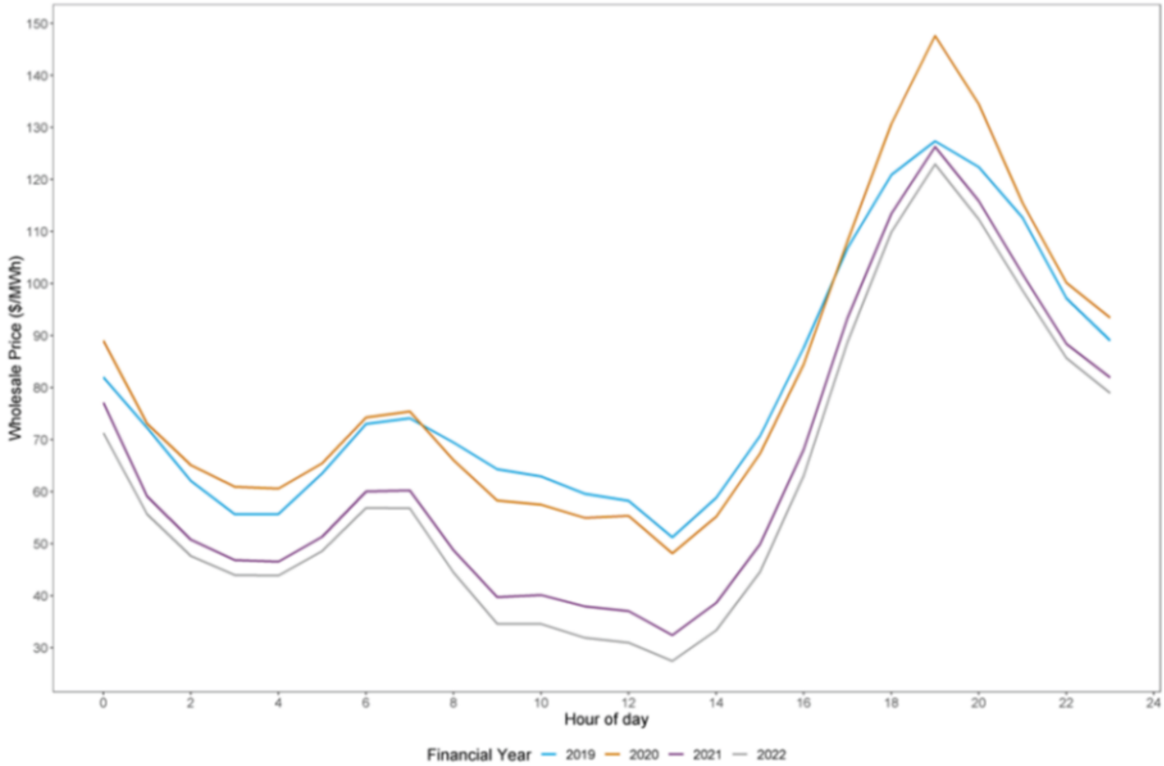
After 2021-22 wholesale energy prices then follow a linear path towards prices set from 2030 onwards based on CSIRO GenCost LCOE estimates and in Central and Slow Change scenarios also short-run marginal cost of existing coal. These are adjusted to suit themes within each scenario for differing levels of emission reductions and technological advancement.

For the first five to ten years of the projection wholesale price differences across time periods are smeared/averaged in final retail prices in line with current retail pricing practices. As explained in the prior section, the model assumes the smearing is gradually unwound to 2030 whereby wholesale energy costs are charged according to three time periods or intervals:

- Peak – 3pm to 10pm weekdays
- Solar soak – 9am to 3pm all days
- Off-peak – all other times

The reason for needing to distinguish wholesale costs by a solar period is because the scale of both rooftop and solar farm capacity being added to grids across the country is very large relative to overall supply. As a result, we expect that wholesale market prices (during sunlight hours) will drop considerably over the period to 2023. The AEMC in their 2019 Residential Price Trends report also recognised the expected drop in the wholesale price during daylight hours from the 2021 financial year. Figure 4-11, taken from the AEMC report illustrates the noticeable depression in prices in the middle of the day for Queensland, while prices during the peak period in the late afternoon and evening remain high. Such a development is likely to be replicated in other regions given they are also adding large amounts of solar capacity.

Figure 4-11 Average wholesale electricity prices by hour of day in QLD



Source: AEMC (2019) Residential Electricity Price Trends 2019

In addition, even if demand in the middle of the day were to grow substantially we expect that any price increases will be constrained by the fact that the new entrant price required for solar farms is envisaged to fall to low levels under all the CSIRO GenCost scenarios.

For the off-peak and peak periods cost falls relative to 2020 levels are expected to be less significant because we envisage that they will continue to depend heavily on dispatchable sources of capacity such as gas, coal, pumped hydro or batteries.

Figure 4-12 details the assumed wholesale energy costs by time interval faced by a residential consumer in NSW for each scenario. Note that the model assumes a single NEM-wide price to apply from 2030 onwards for modelling simplicity and because the Draft AEMO ISP indicates that considerable interconnection capacity will be added over the next two decades. So this chart is also illustrative of expected costs across the other NEM states as well from 2030 onwards.

Figure 4-12 Assumed wholesale energy costs by time interval for NSW (and NEM from 2030) (excl GST)

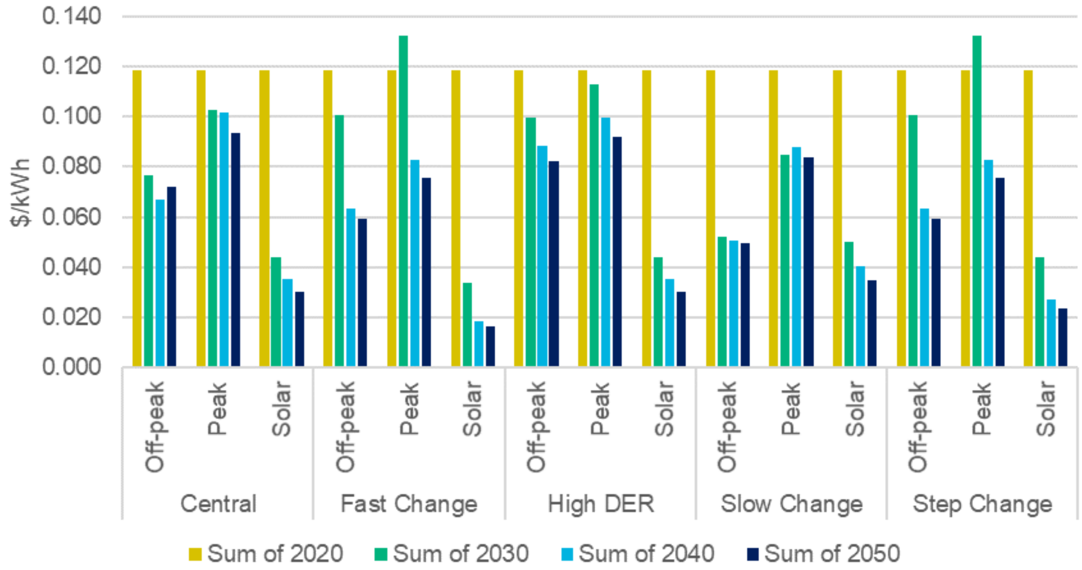


Figure 4-13 details the assumed wholesale energy costs by time interval faced by a residential consumer in WA for each scenario.

Figure 4-13 Assumed wholesale energy costs by time interval for WA (excl GST)

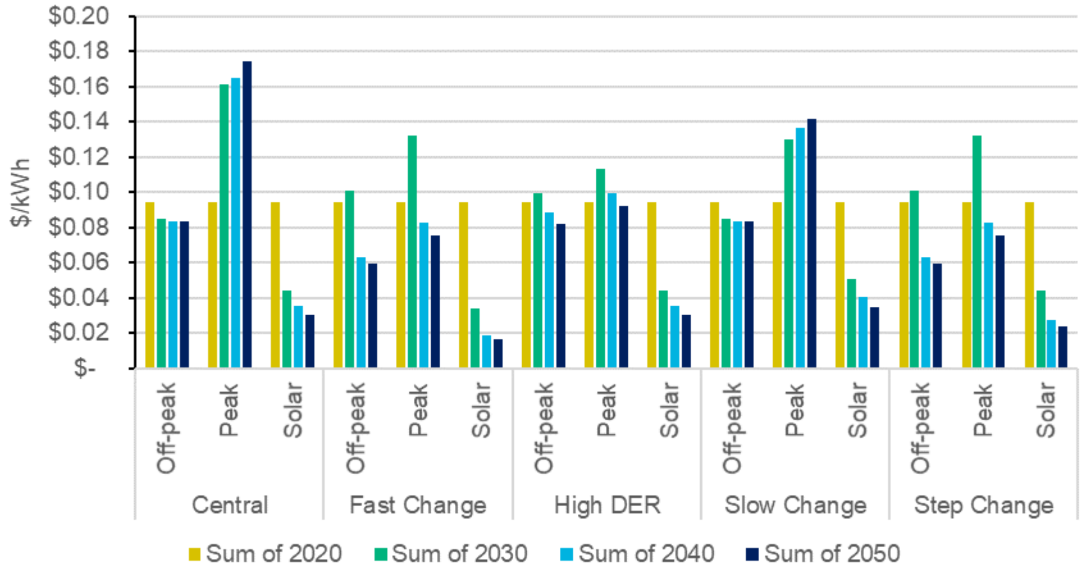
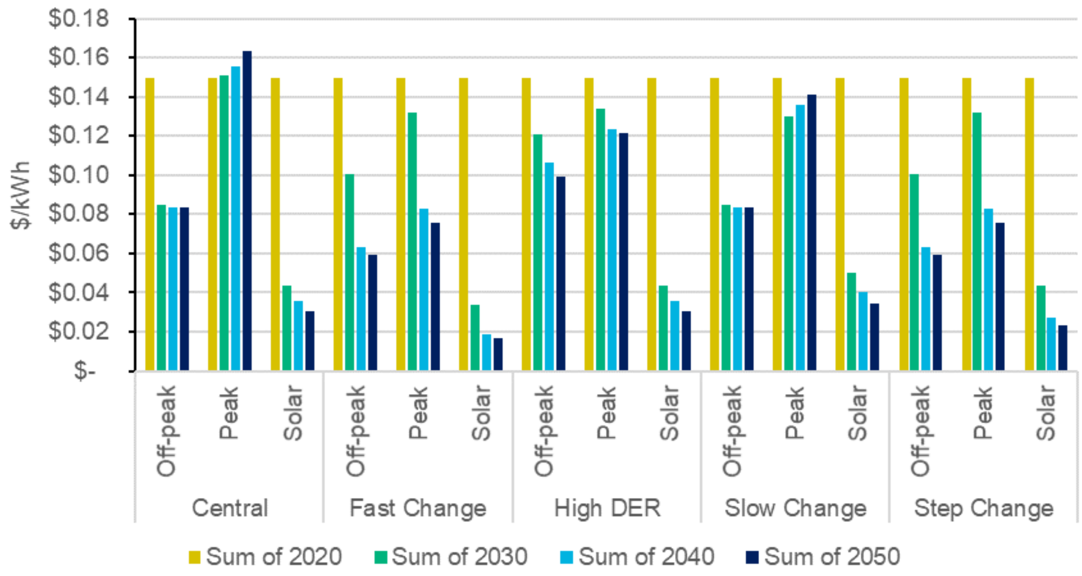


Figure 4-14 details the assumed wholesale energy costs by time interval faced by a residential consumer in NT for each scenario.

Figure 4-14 Assumed wholesale energy costs by time interval for NT (excl GST)



Flow through of wholesale energy costs to prices paid for exported electricity from solar systems

As explained earlier, feed-in tariffs for exported generation for the 2019-20 year reflect an average of current offers from major retailers by state (or the regulated rate). But these are then assumed to adjust to align with our projected wholesale prices by time of day. This happens in 2020-21 for NEM states but for WA and NT feed-in tariffs transition from their current rates to wholesale prices gradually and it is not until 2029-30 that they fully reflect wholesale market rates.

4.4.4 Retail charges

For large commercial customers we assume a retail margin charge of 1 cent per kilowatt-hour.

Retail charges for residential and small commercial consumers are varied by region depending on differences between observed advertised retail offers to customers and underlying bottom-up estimates of network, environmental and wholesale energy costs per kWh of consumption. What this means in practice is that in some states the retail charge is zero or even negative in the model. For example, in Victoria retailers tend to shift a portion of the variable kWh costs they face into the daily fixed charge as well as recovering all their own costs in the fixed charge. So this led to the retail charge in the model being a negative value for residential consumers as the retailers effectively cross subsidise kWh consumption via increases in the fixed charge. In NT, as another example, the retail charge was also negative, but this was in part to reflect government subsidies for electricity rather than a cost shift of costs associated with consumption into the fixed charge.

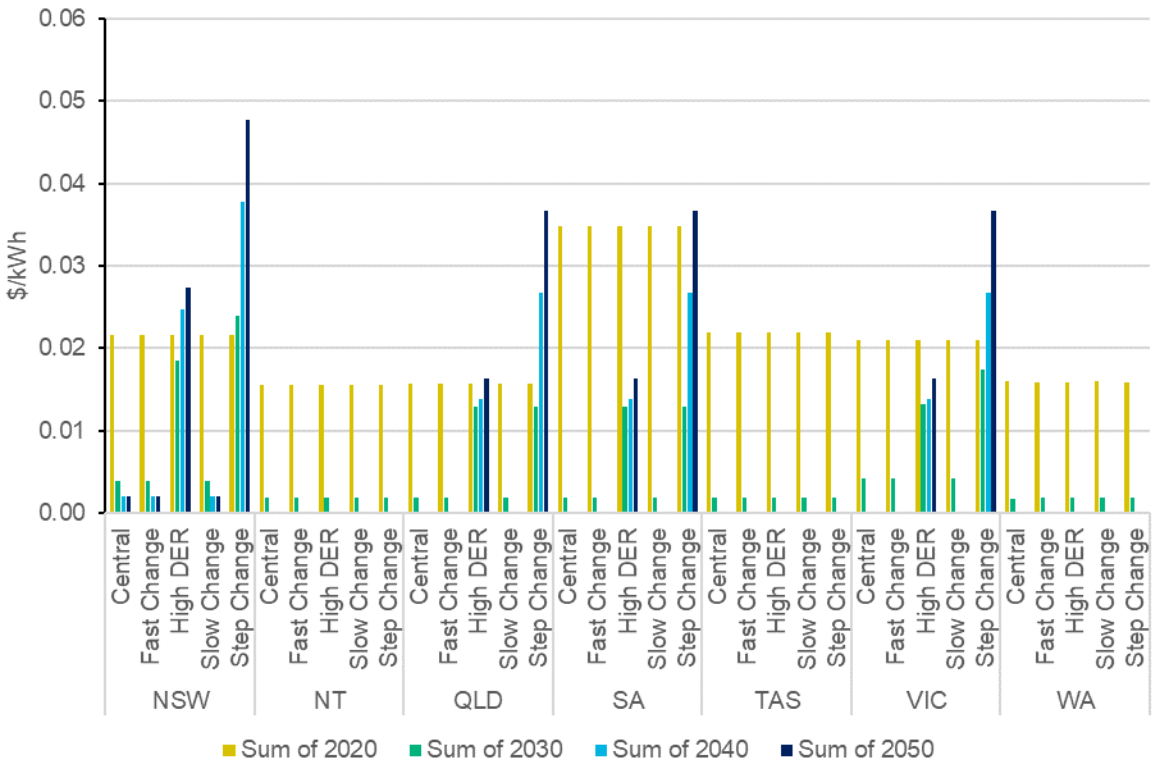
Retail charges are also held constant throughout the outlook.

4.4.5 Environmental charges

Figure 4-15 details assumptions used for environmental charges as applied to residential consumers by scenario and state. Small and Large commercial faces the same charges but with GST deducted. While large industrial energy consumers are typically exempt from a range of environmental charges – they represent such a small proportion of solar capacity being installed that it was

The level of environmental charges in each scenario are related to assumptions about the continuation or expansion of emission reduction programs currently funded via electricity charges such as the Renewable Energy Target, State-based energy efficiency schemes, and programs like premium feed-in tariffs and the NSW Climate Change Fund. Under Central, Slow Change and Fast Change it is assumed emission reduction programs funded via electricity charges to a large degree cease after 2030 (with the exception of NSW's Energy Savings Scheme). However, under the High DER and Step Change scenarios energy efficiency abatement certificate schemes are expanded across the mainland NEM states. NSW is also assumed to expand the funding to its Climate Change Fund.

Figure 4-15 Environmental charges by state and scenario for residential consumers (incl. GST)



4.5 Technical characteristics of solar and battery systems

4.5.1 Solar systems

The amount of electricity per kilowatt of solar PV used in the payback model is based on daily average generation figures provided by the Clean Energy Council for each capital city of the respective state or territory being analysed[16]. These average figures are then converted into generation per hour across every day of the year based on Bureau of Meteorology historical measurements of irradiance between 1990 and 2015.

In developing the degraded capacity of the solar PV installed base we applied an annual degradation factor of 99.3%[17]. So a system that had an original capacity of 1kW would be multiplied by 0.993 after a year to give a degraded capacity of 0.993kW and then this degraded capacity would be multiplied again by 0.993 for its second year to give 0.986kW of degraded capacity and on and on for each consecutive year until the system was retired).

4.5.2 Battery systems

The following assumptions were adopted for the modelled battery stock:

- Conversion efficiency – both charging and discharging of the battery was assumed to be 95% efficient (round trip efficiency of 90.25%)[18]
- The maximum output/input of the battery in behind the meter applications was assumed to be 40% of the kilowatt-hour rated capacity of the battery. So a 10kWh battery system was assumed to have a maximum output and charge capability of 4 kilowatts.[19]
- Batteries kWh capacity was assumed to degrade to 60% of its original rated capacity after 10 years[20] and at this point would be retired and replaced by its owner.

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[16] Clean Energy Council (2011) Consumer guide to buying household solar panels

[17] This level of degradation is in line with warranted performance of modules manufactured by Jinko - the world's largest producer. Some module suppliers provide warrantees for lower levels of degradation (SunPower, LG, Longi) but their share of the market is noticeably smaller. See here for further detail: https://www.solarquotes.com.au/blog/solar-panel-degradation/#:~:text=Solar%20panel%20performance%20warranties%20generally,in%20their%20first%20few%20hours. A literature review by The US National Renewable Energy Laboratory (see: https://www.nrel.gov/docs/fy12osti/51664.pdf) suggests median degradation for crystalline silicon panels in the realm of 0.5% per annum but with averages being higher which supports the use of Jinko's warranted performance as a conservative (lower_bound) value of likely future output of solar systems.

[18] This is based on a combination of stated performance provided by battery system vendors servicing the Australian market (available here: https://www.solarquotes.com.au/battery-storage/comparison-table/#) and field testing results from ITP's Battery Test Centre (see test result reports here: https://batterytestcentre.com.au/reports/)

[19] This is informed by a review of the kW to kWh ratios of a range of commercial battery systems offered into the Australian market based on SolarQuotes Battery Comparison table (available here: https://www.solarquotes.com.au/battery-storage/comparison-table/#). While there is wide variation a kW to kWh ratio of 0.4 is considered a reasonable approximation of what is being sold in the Australian market. This is heavily weighted by the fact the two most popular brands are LG Chem (whose batteries have a ratio of 0.5 to 0.6) and Tesla (with a ratio of 0.36 for the Powerwall 2).

[20] This is based on a combination of LG Chem's warranted performance and also informed by field testing results from ITP's Battery Test Centre (see test result reports here: https://batterytestcentre.com.au/reports/) .

5 Results

5.1 Overview

5.1.1 Solar PV

Figure 5-1 details the cumulative installed solar PV capacity (DC basis) projected for each scenario on a national basis taking into account the degradation of solar panel output over time. At the beginning of the projection (the conclusion of the 2018-19 financial year) cumulative installed degraded capacity is expected to stand at almost 9,400MW. Under Central the cumulative degraded capacity reaches just over 44,000MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Step Change scenario reaches 75,000MW, while the lower bound represented by Slow Change is close to 33,000MW by the end of the projection in 2050-51 financial year.

Figure 5-1 National cumulative degraded megawatts of solar PV by scenario

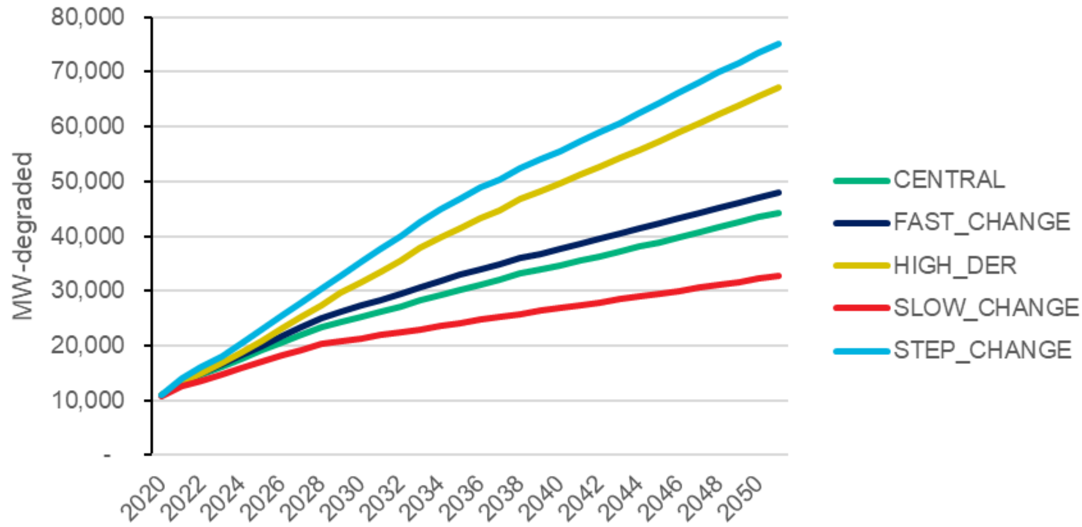
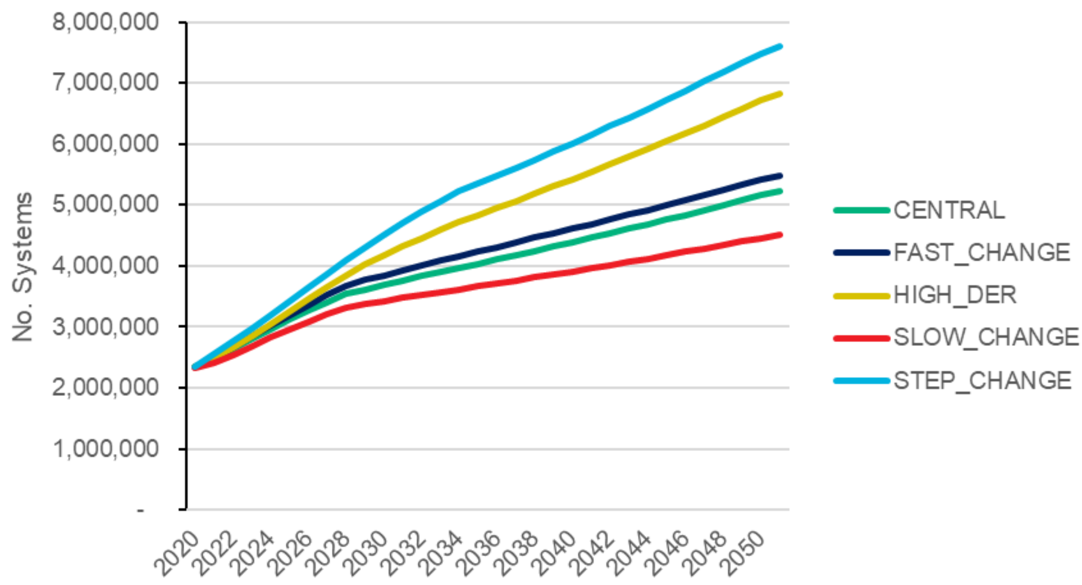


Figure 5-2 details projections for the cumulative number of solar PV systems by scenario on a national basis. At the beginning of the projection (the conclusion of the 2018-19 financial year) the cumulative number of systems stands at 2.08 million. Under Central the cumulative number of systems grows to 5.2 million by the end of the projection in 2050-51 financial year. The upper bound represented by the Step Change scenario reaches 7.6 million, while the lower bound represented by Slow Change is 4.5 million systems by the end of the projection in 2050-51 financial year.

Figure 5-2 National cumulative number of solar PV systems by scenario



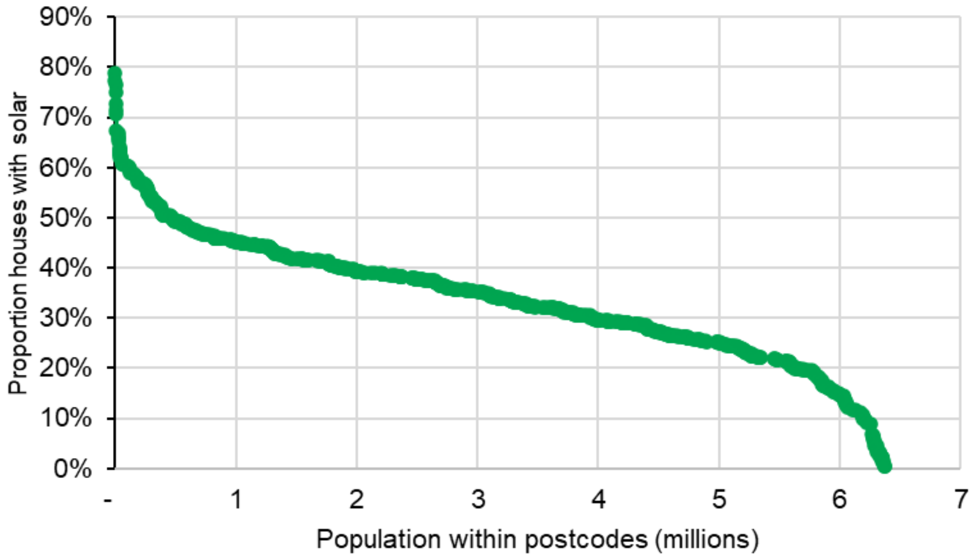
To put these system numbers in context the total number of residential electricity connections is expected to grow to just under 15m by 2050. The number of systems under Central equates to around 35% of all residential connections and Step Change is slightly more than 50%.

Of course, some of these connections will be for dwellings in multi-storey apartments which are unable to have a system of their own. In terms of detached and semi-detached dwellings the 2016 census recorded 8.3m in Australia, which represented 85% of total dwellings.

Meanwhile Australia's population is expected to grow by about 13.8m people between 2016 and 2050 which will require around 5.3m new dwellings. If 60% of the new dwellings were detached or semi-detached this results in about 11.5m detached and semi-detached dwellings by the end of projection. Central equates to 45% of detached and semi-detached dwellings and Step Change equates to 66%.

In the states which have the highest solar penetration in Australia – Queensland and South Australia - such levels of penetration are already being realised across a number of postcodes. Figure 5.3 plots South Australian and Queensland postcodes in terms of the proportion of households within the postcode with a solar PV system and then on the horizontal axis we accumulate the amount of population residing within the postcodes. This shows that postcodes representing around 1m people within QLD and SA have already reached or exceeded 45% penetration of total dwellings with solar suggesting such penetration is achievable. 66% remains rare but examples do already exist, and this is in circumstances with almost no usage of batteries. Meanwhile our projections envisage that by the end of the projection period almost all solar systems will be coupled with batteries.

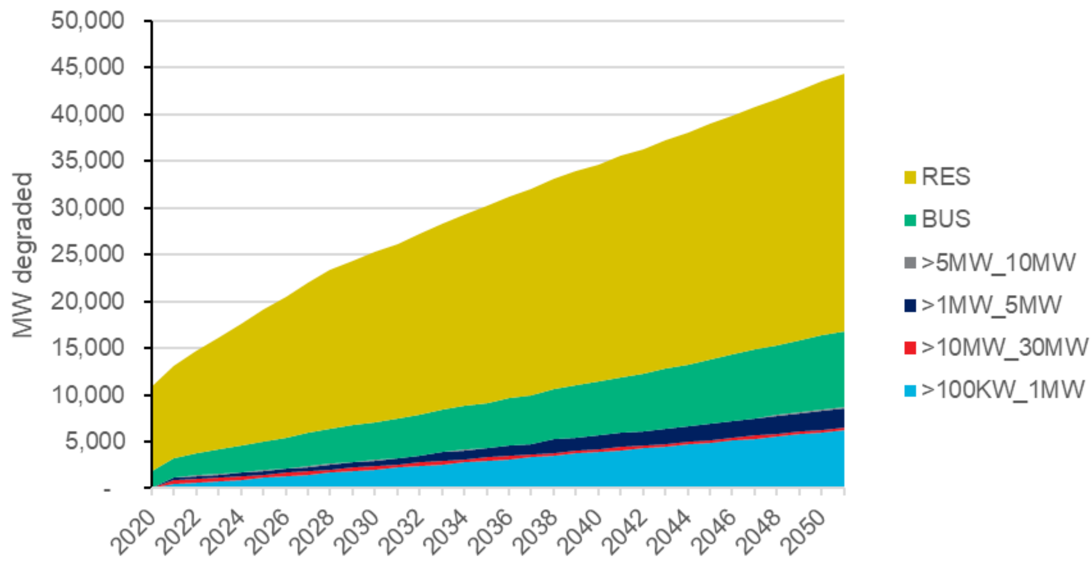
Figure 5-3 SA & QLD postcodes' solar penetration relative to population



Break-down by end-customer type and state

Figure 5-4 illustrates how the projected solar capacity is distributed across end-customer types under the Central Scenario. Residential (RES) remains by far away the dominant sector throughout the outlook period but behind the meter commercial systems at both the sub 100kW (denoted as BUS) and the 100kW to 1MW scale increasing in importance over time.

Figure 5-4 Cumulative degraded megawatts of national solar PV capacity by sector (Central Scenario)

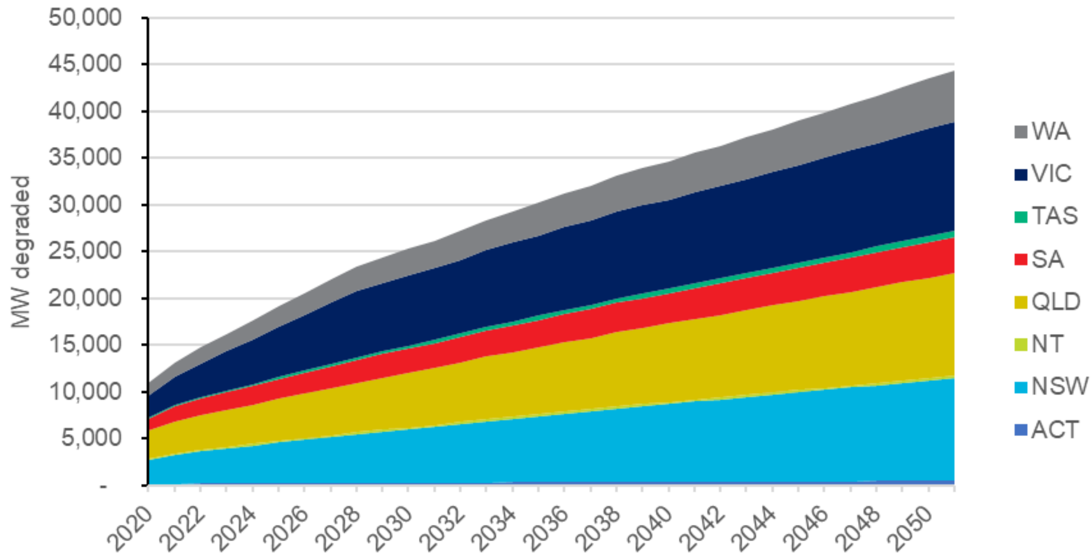


In front of the meter systems denoted by the segments greater than 1 megawatt in scale remain a relatively minor segment, with developers of solar power stations expected to favour much larger systems above 30MW in scale.

The sectoral breakdown is relatively similar across the other scenarios analysed.

Figure 5-5 illustrates how the projected solar capacity is distributed across states and territories under the Central Scenario (Note ACT is within the NSW electricity region). The relative distribution across states is relatively similar across the other scenarios.

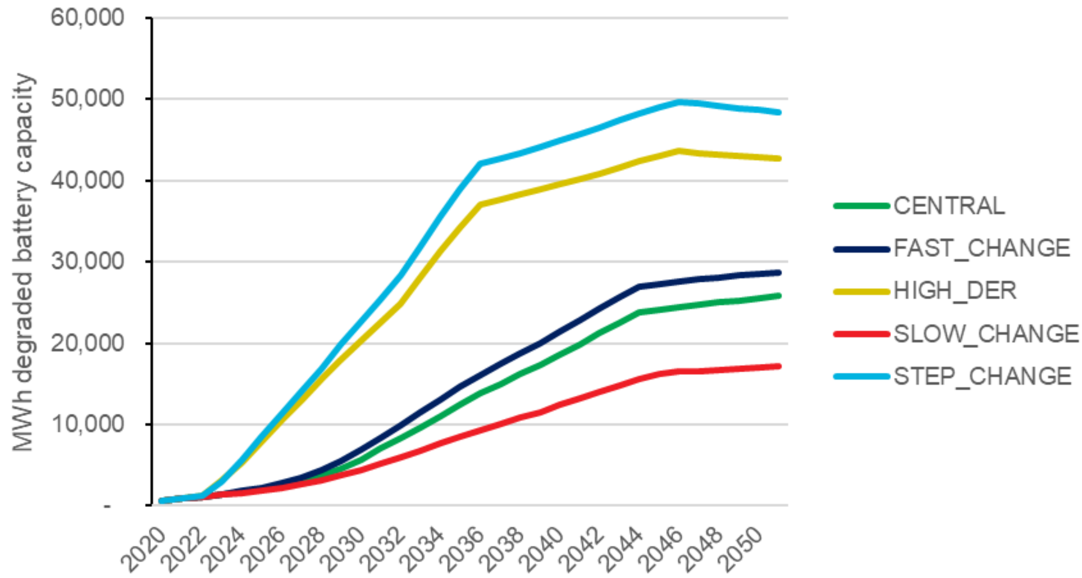
Figure 5-5 Cumulative degraded megawatts of solar PV capacity by state (Central Scenario)



5.1.2 Battery energy storage

In terms of behind the meter stationary battery systems Figure 5-6 details the cumulative installed megawatt-hours of battery capacity projected for each scenario on a national basis taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2018-19 financial year) cumulative degraded battery capacity is estimated to stand at 482MWh. Under Central the cumulative degraded capacity reaches almost 26,000MWh by the end of the projection in 2050-51 financial year. The upper bound represented by the Step Change scenario reaches almost 48,500MWh, while the lower bound represented by Slow Change is just above 17,200MWh by the end of the projection in 2050-51 financial year.

Figure 5-6 National cumulative degraded megawatt-hours of battery capacity by scenario



The reason that battery capacity under the High DER and Step Change scenario begins slowly declining from 2047 is because the degradation of the existing installed stock of batteries begins exceeding additions of new stock. This is because the model assumes rapid uptake of batteries up until a large proportion of the pre-existing stock of solar systems are augmented with a battery. Once most of these systems have a battery in place, additions of new batteries capacity abruptly fall to a much lower level in line with additions of solar systems to the stock on premises that did not previously have a solar system. After a lag the degradation of the existing battery stock builds up to a point where it exceeds the new additions to the battery stock from 2047 onwards.

Figure 5-7 illustrates the maximum instantaneous megawatt output available from the from the projected stock of battery systems. The projection begins with an installed stock of 209MW at the end of 2018-19 financial year. Under Central this grows to 14,500MW by the end of the projection in 2050-51 financial year. The upper bound represented by the Step Change scenario reaches almost 30,000MW, while the lower bound represented by Slow Change is just under 10,000MW by the end of the projection in 2050-51 financial year. The projections are based on an assumption that the instantaneous output that can be extracted from a battery is not subject to degradation and that the average system when first installed will have maximum output equal to 40% of its original megawatt-hours of storage.

Figure 5-7 National cumulative megawatts of battery capacity by scenario

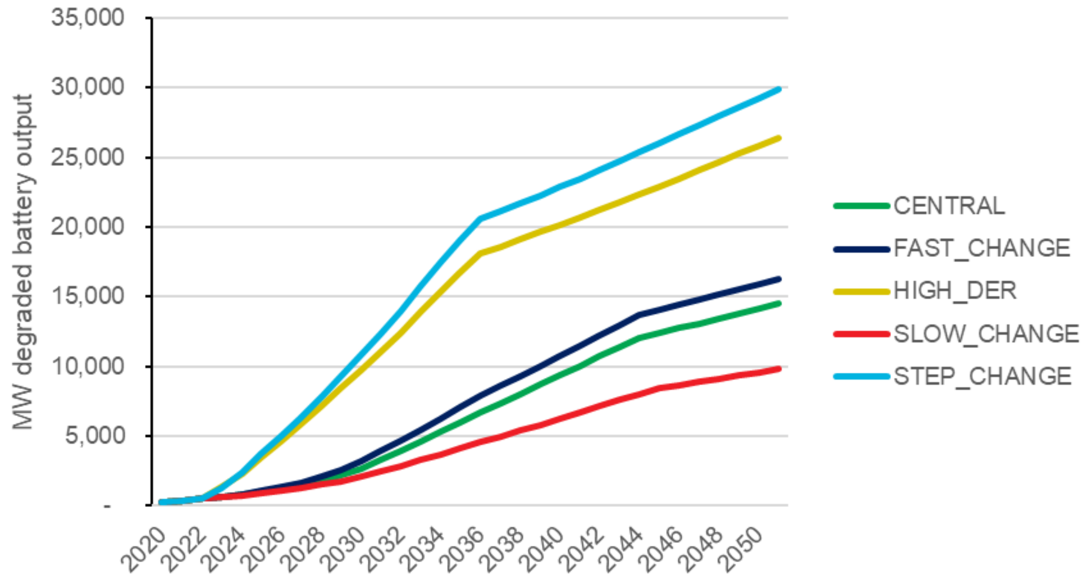
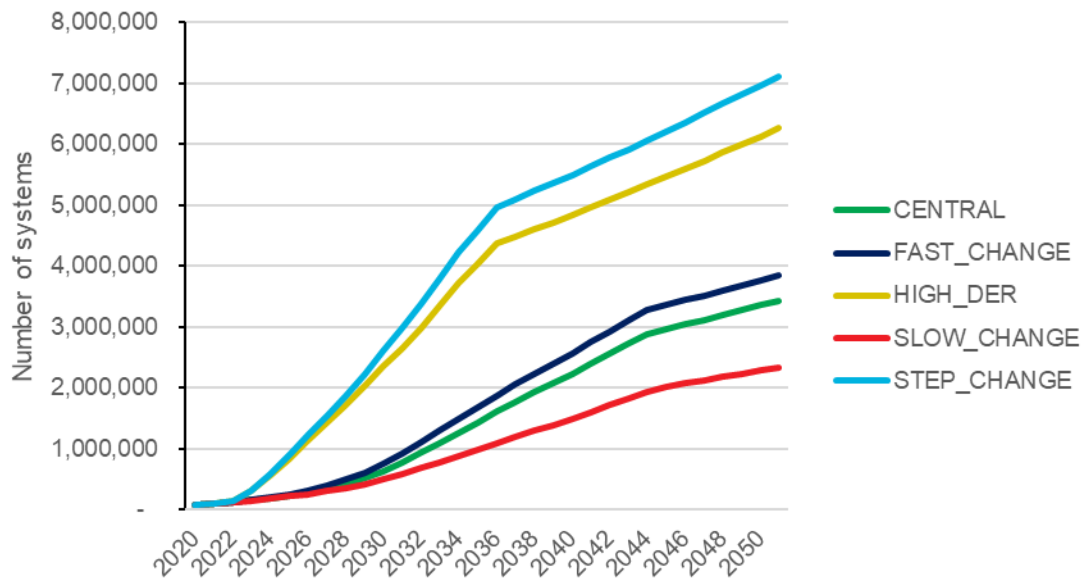


Figure 5-8 details projections for the cumulative number of battery systems by scenario on a national basis. At the beginning of the projection (the end of the 2018-19 financial year) the cumulative number of grid-connected battery systems stands at 52,420. Under Central the cumulative number of systems grows to 3.4 million. The upper bound represented by the Step Change scenario reaches 7.1 million, while the lower bound represented by Slow Change is 2.3 million systems by the end of the projection in 2050-51 financial year.

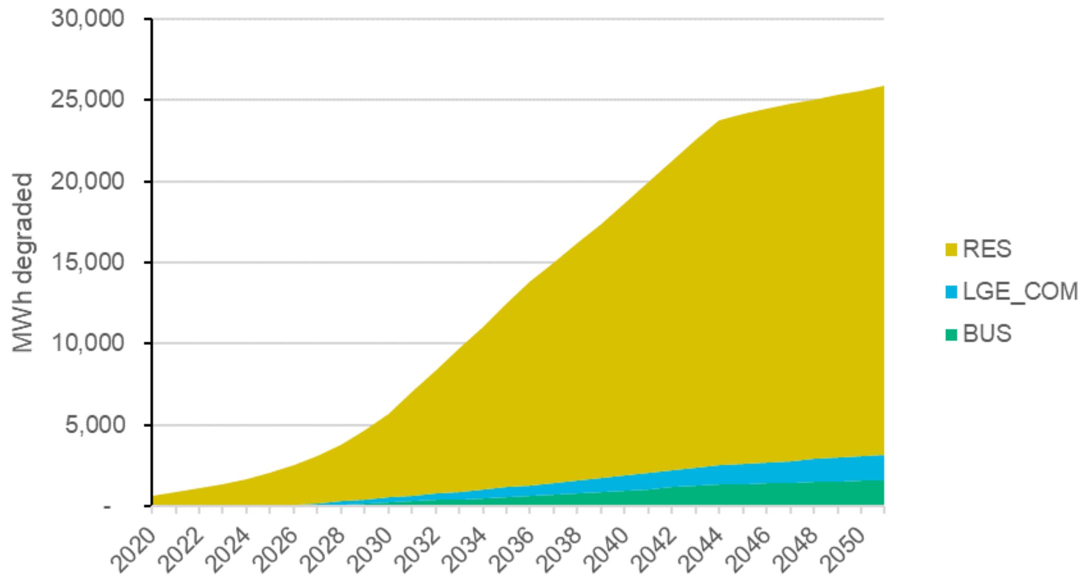
Figure 5-8 National cumulative number of battery systems by scenario



Break-down by end-customer type and state

Figure 5-9 illustrates how the projected battery capacity is distributed across end-customer types under the Central Scenario. Just as in solar, Residential (RES) remains by far away the dominant sector throughout the outlook period.

Figure 5-9 Cumulative degraded megawatt-hours of battery capacity by sector (Central Scenario)

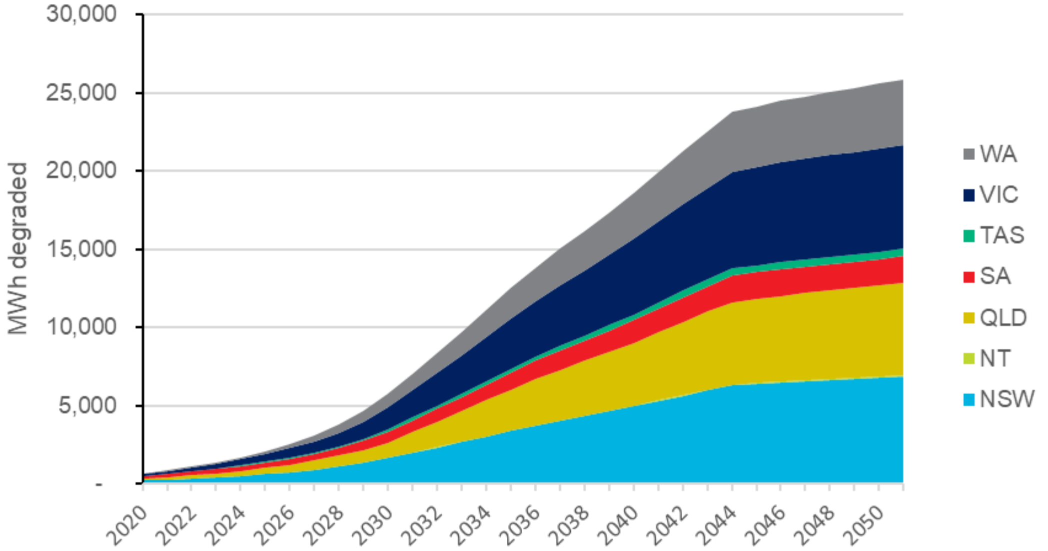


Note: Residential (RES) batteries are assumed to have average size of 10kWh as are small commercial (BUS), while large commercial customers' (LGE_COM) batteries are assumed to have sizes averaging between 90kWh to 150kWh depending upon state. In practice though battery sizes will probably vary quite widely within these segments which are intended to be average archetypes for customers installing solar systems of: below 15kW – Residential; 15kW-100kW – small commercial; greater than 100kW but behind the meter – Large commercial.

The sectoral breakdown is relatively similar across the other scenarios analysed.

Figure 5-10 illustrates how the projected battery capacity is distributed across states and territories under the Central Scenario. The relative distribution across states is relatively similar across the other scenarios.

Figure 5-10 Cumulative degraded megawatt-hours of battery capacity by state (Central Scenario)

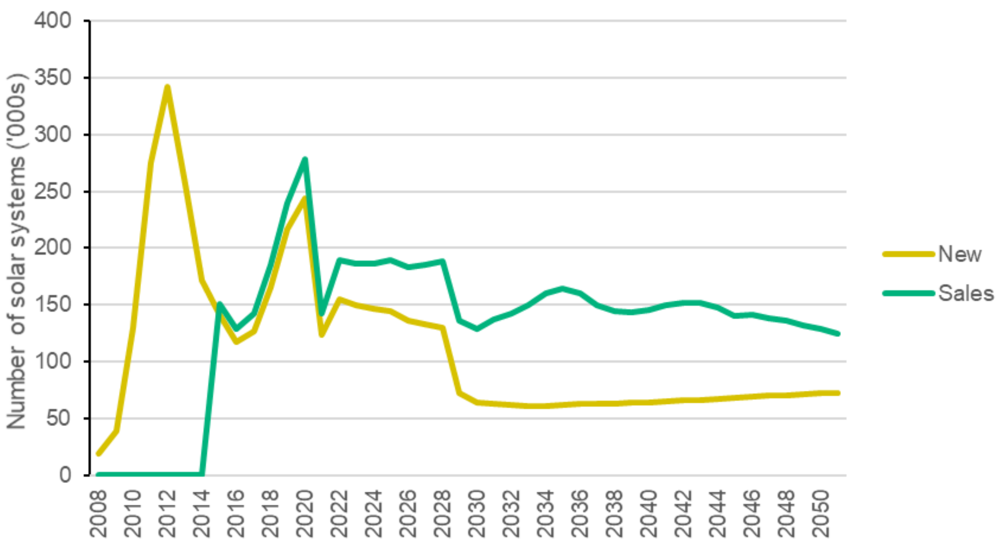


5.2 Residential solar and battery systems

As shown in Figure 5-4 and Figure 5-9 in the prior section, systems installed in residential premises make up the vast bulk of both solar and battery capacity in our projections.

To more clearly illustrate and explain how solar uptake changes over time Figure 5-11 details the number of solar systems that are sold in each individual year (not cumulative). To provide some context, this chart details historical numbers stretching back to 2008, as well as projections from 2019-20 onwards for the Central Scenario. The chart also details the number of these system sales which are new solar systems, as opposed to systems replacing a pre-existing solar system. The difference between total sales versus new incremental systems is only tracked from 2015 onwards because prior to this almost all solar systems sold were new additions rather than replacements.

Figure 5-11 Number of solar systems installed per annum (Historical and Central Scenario)



5.2.1 Historical context

Prior to 2008 solar installations were very small, but then grew dramatically from 2009 as a result of plunging system costs combined with high feed-in tariff rates in the realm of $0.44 to $0.60 per kilowatt-hour and a high STC rebate for the first 1.5kW of a system. By 2010-11 more than 275,000 systems were installed compared to just 19,000 in 2007-08. In 2011-12 they peaked at almost 342,000 and remained high in 2012-13 at 256,744. However, while the underlying cost of a solar system continued to fall, the rapid wind-back of feed-in tariffs by state governments and also reductions in the value of the STC rebate reduced the financial attractiveness of solar for residential consumers. At the same time retail-delivered price rises for electricity began to moderate after 2013 which reduced the extent to which residential consumers faced a psychological push factor leading them to investigate options to reduce their electricity bills. Consequently, the number of solar system sales fell significantly, to 171,000 in 2013-14, and then continued to decline before bottoming out at 129,000 in 2015-16.

Yet by the next year solar began a sales recovery. This was driven by ongoing declines in the purchase price of solar systems that managed to outpace the reduction in the value of the STC rebate, as well as another large jump in retail delivered electricity prices (particularly significant in the NEM states). What made this particular jump in power prices especially beneficial for solar in the NEM states was that the increase was due to higher wholesale electricity market prices, which also led to a lifting in the feed-in tariff for exported electricity from solar systems. We also suspect that increasing media attention on electricity prices and reliability during this time helped to focus and amplify householder concern about electricity prices. Another factor that has been important in this growth was the Victorian Government’s introduction of a rebate of $2,225 per system from October 2018 (which stepped down to $1,888 from January 2020). Although it is important to note that solar system sales have increased significantly across almost all states, not just Victoria.

By the 2018-19 financial year sales had lifted to 239,000 systems, up 85% on their 2015-16 trough. This growth in system sales has managed to continue into the 2019-20 financial year and we expect that close to 279,000 systems will be sold by the end of June.

5.2.2 COVID 19 brings end to second boom

Figure 5-11 illustrates a rapid contraction in solar system numbers for the 2020-21 year. The main factor behind this is an expected downturn in consumers’ willingness to make large purchases due to concerns about the potential impact of the COVID-19 Virus induced economic downturn on their financial circumstances, such as loss of employment. As discussed in section 3.8 of this report, surveys and other information gathered from solar industry participants indicated that there had been a significant decline in solar system purchase inquiries in the first few weeks after social-distancing measures were introduced and resulting large increases in unemployment had become evident. Under the Central Scenario illustrated in Figure 5-11 there is an almost 50% drop is system sales in 2020-21 relative to the prior year. The impact on other scenarios varies and is described in further detail in section 3.8.

5.2.3 The next decade – declining daytime wholesale prices, and restructured tariffs lead to deteriorating outlook for residential solar systems.

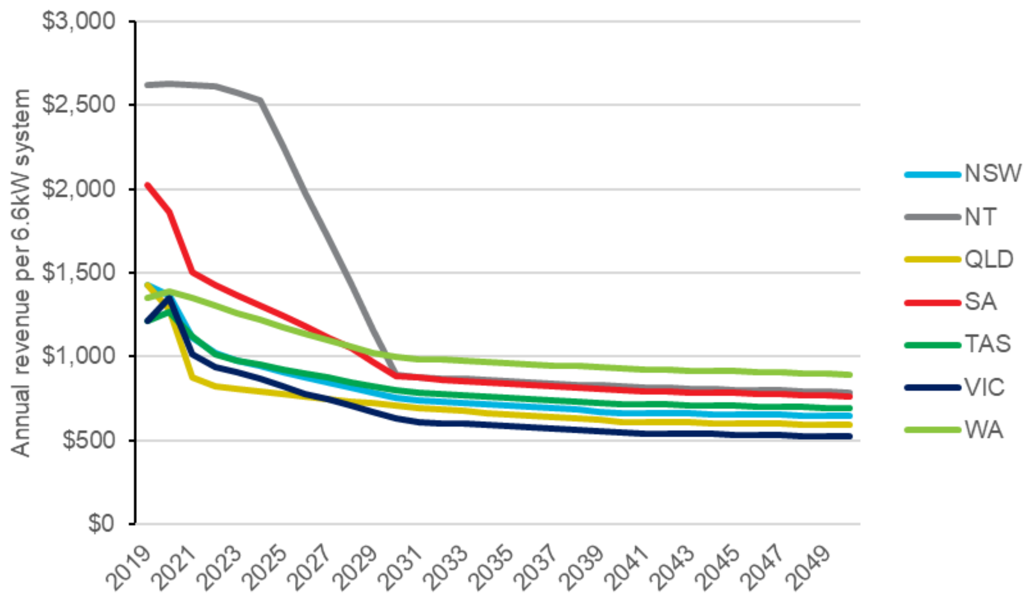
Sales of residential solar systems are expected to recover significantly by the 2021-22 year in line with an expected economic recovery, although still remain well below the peaks of 2018-19 and 2019-20. In 2021-22 sales lift to 189,000 and then remain above 185,000 until 2028. Sales are then expected to drop significantly in 2029 to just under 137,000 as a result of the Victorian Government's Solar Homes rebate program coming to an end after it achieves the target of adding 650,000 additional systems. They then oscillate around 150,000 per annum until 2043, after which they steadily decline.

The reason that sales never recover to their prior highs and instead remain near to the historical lows between 2014 to 2016 is because we expect a general deterioration in paybacks for solar systems under the central scenario relative to the last few years.

As detailed in section 4.4.3 we expect that wholesale energy market prices during daylight hours will decline substantially from recent levels as a result of a substantial amount of both rooftop and large-scale solar capacity that has been added to the grid over the past few years and what is forthcoming from committed projects. Prices should then remain low because they should be tied to the levelized cost of new entrant solar farms. These lower wholesale flows through directly to feed-in tariffs offered for solar exports and also indirectly to retail electricity prices.

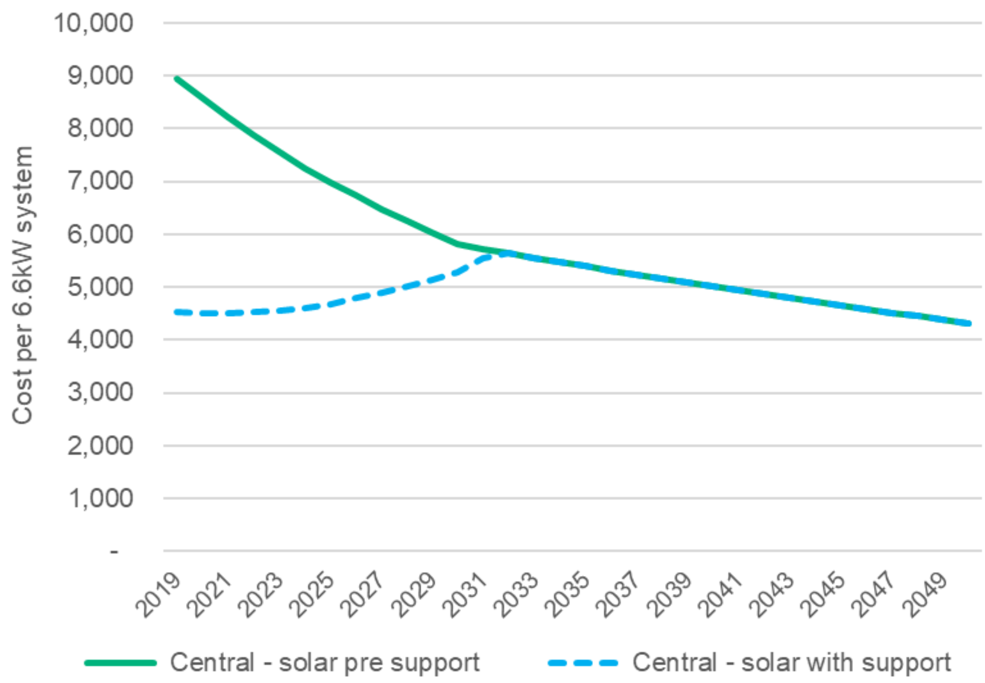
In addition, as detailed in section 4.4.2, the model assumes that residential electricity tariff structures shift the way costs are allocated across times of day. This involves a move away from an smoothed average single price per kilowatt-hour across all times of the day, to a structure where network and wholesale energy charges are lower over the daytime period until 3pm and then rise substantially over the peak demand period from 3pm until 9pm before subsiding during an off-peak period. The combination of the expected decline in the wholesale energy price during daylight periods and the shift of network charges towards the late afternoon and evening leads to a significant decline in revenue residential solar systems are expected to provide to owners (if not coupled with a battery system). This decline in revenues is universal across all states and all scenarios and is illustrated for the Central scenario in Figure 5-12.

Figure 5-12 Annual revenue generated by a residential solar system (6.6kW) 2019 to 2051 (Central Scenario)



During this period of declining revenues the underlying cost of a solar system is also declining. However, under the Central Scenario, we assume that these cost reductions are outpaced by the declining value of government support for residential solar systems via STCs as the deeming rate declines. Consequently, as shown in the blue line in Figure 5-13, householders see an increase in the purchase price of a solar system over the next decade.

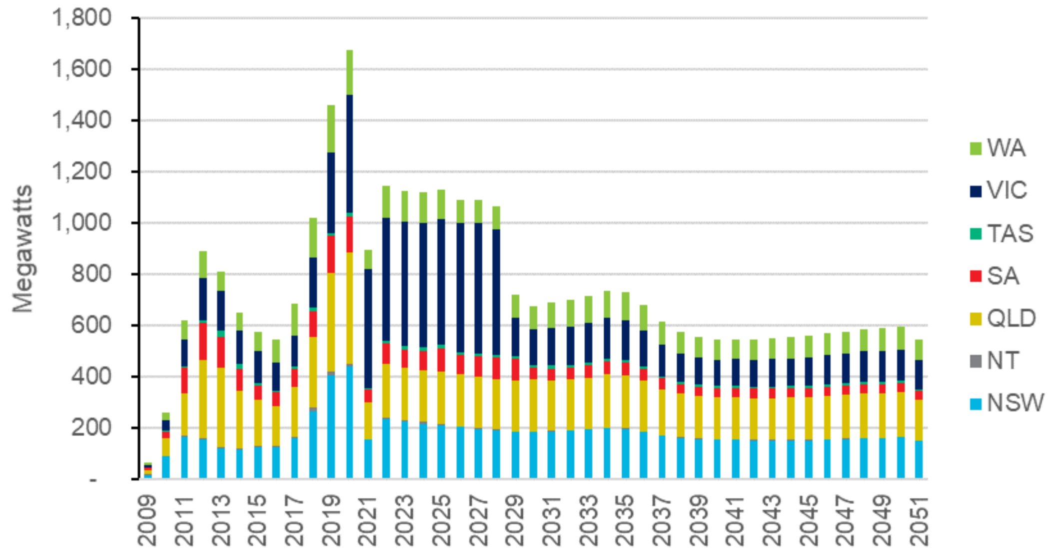
Figure 5-13 Underlying cost of a 6.6kW solar system and out of pocket cost to householders after STC discount (Central Scenario)



5.2.4 Decline in market moderated by Victorian rebate and emergence of system replacement and upgrade demand

In spite of the large decline in revenues and a small rise in the purchase price householders see for a solar system, solar sales over the next decade still manage remain noticeably above the levels seen back in 2015 and 2016 (when wholesale energy prices dropped to levels similar to those we anticipate during daytime periods). Also, as illustrated in Figure 5-14 megawatts of added capacity in the residential sector over the next decade remain substantially higher than they were during 2015 and 2016.

Figure 5-14 Megawatts of residential PV capacity added each year to the installed stock after deducting retirements (Central Scenario)



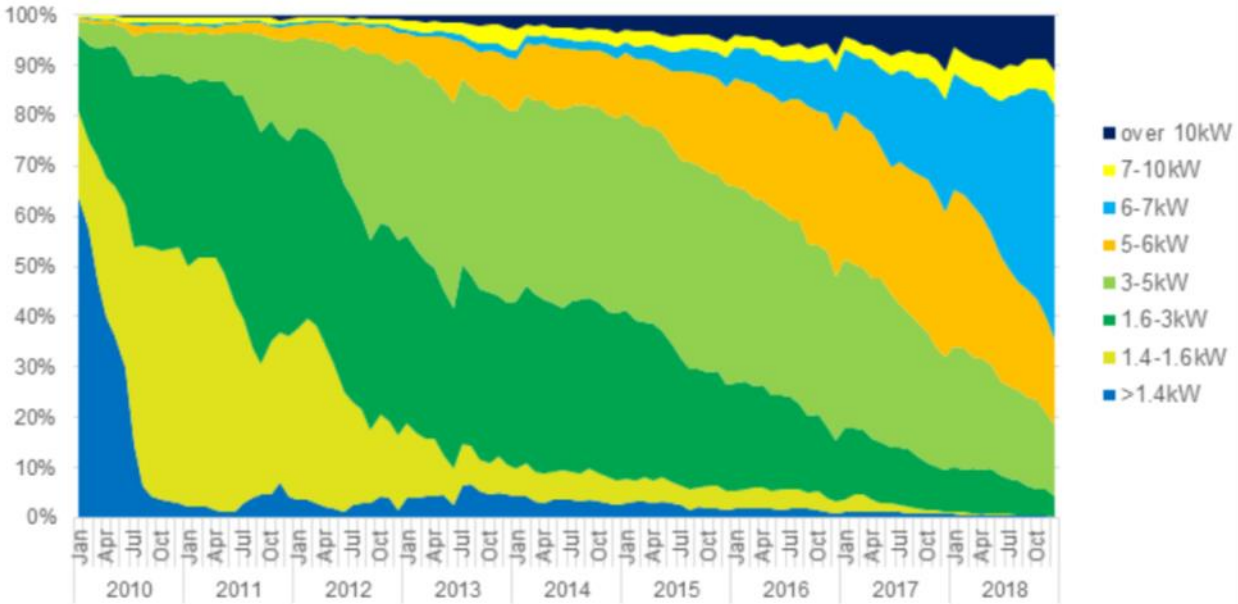
The reasons for why capacity additions remain above those seen in the years preceding the recent boom, in spite of a large fall in revenues, is a product of three factors:

1. The model assumes the Victorian Government will achieve its target to add 65,000 solar systems per annum to 2028;
2. As a result of module prices per watt being significantly lower than they were over 2010-2016 the solar industry is heavily geared towards installing much larger capacity per system than over 2010-2016.
3. A new source of sales emerges in replacing and upsizing the large number of small solar systems installed in the first solar boom over 2009-10 to 2013-14.

Point 1 is self-explanatory and its impact is clearly seen by the outsized contribution of the Victorian dark blue segment in Figure 5-14 between 2021 to 2028.

In terms of point 2, while the number of system sales over the next decade average less than they did between 2010 to 2014, the capacity of each system is likely to be significantly larger than they were back then. Figure 5-15 illustrates how the Australian solar market has progressively evolved from 2010 to 2018 from being dominated by systems smaller than 3kW to systems larger than 5kW. This trend has continued into today and the market is now dominated by systems larger than 6kW.

Figure 5-15 Proportion of solar systems within different capacity bands



In terms of the third point we expect that replacement of the old systems from the first boom in solar over 2011 to 2013 will emerge as a new source of sales in this decade.

The growing gap in Figure 5-11 between the green sales line and the yellow line of completely new solar system sites is a function of the increasing number of old solar systems being replaced. Replacement is not necessarily because the solar modules have failed. Solar modules from large, established solar producers have proven to be remarkably durable, often still functioning quite well at 20 years of age, but replacements will also be spurred by inverters progressively breaking down (which typically have shorter warranted lives than modules) and also because households decide that they would be better off with a much larger capacity system than was originally installed.

While these replacement systems do not add to the cumulative number of systems shown in Figure 5-2, they will increase the amount of cumulative capacity. This is because, as shown in Figure 5-15 most of the systems installed over the first solar boom were far smaller capacity than what is typically installed now and what is economically optimal for households now given the large fall in solar module prices and the increase in their conversion efficiency. Furthermore, improvement in panel performance means that the average solar module installed today is about 50% more powerful than what was typically installed in 2011-12. So even if they replaced just the existing modules and added no extra they'd increase system capacity by 50%.

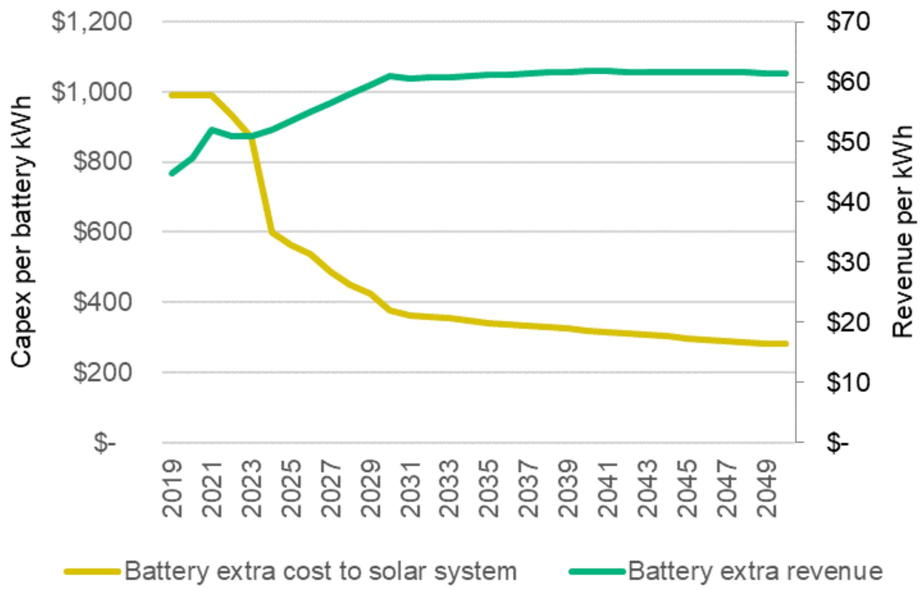
When older systems from 2010 to 2014, which were installed in large numbers, are replaced we expect most will be replaced with systems closer to the current industry standard of above 6kW.

5.2.5 Beyond 2030 – market supported by the emergence of cost-effective batteries and ongoing construction of new dwellings

The decline to solar revenues which unfolds over 2030 is expected to be a permanent feature that lasts until the end of the projection. However, expected declines in the cost of battery systems opens up the potential for households to cost-effectively store solar generation that would otherwise be exported at low feed-in tariffs and then use it after 3pm when both network charges and wholesale energy costs are expected to be significantly higher. This then helps to bolster solar sales as people elect to install them in conjunction with the battery system.

Figure 5-16 illustrates how under the Central Scenario revenue for a battery system (shown by the green line) rises while the capital cost for a battery (yellow line) plunges.

Figure 5-16 Revenue vs cost per kWh for household batteries (Central Scenario)



In the first few years of the 2020's paybacks for batteries are quite long, in fact they exceed the typical warranted life of a battery of around 10 years until the mid 2020's under the Central scenario. Consequently, they don't help improve the financial attractiveness of solar. Yet in spite of long paybacks there is already a market for residential battery systems. Because this market is relatively small and immature, we don't yet have a good understanding of the underlying drivers of uptake and how consumer uptake might respond in the future to changing financial attractiveness. Feedback from those involved in the solar and battery industry suggest that these customers adopt batteries based on either one or a combination of the following:

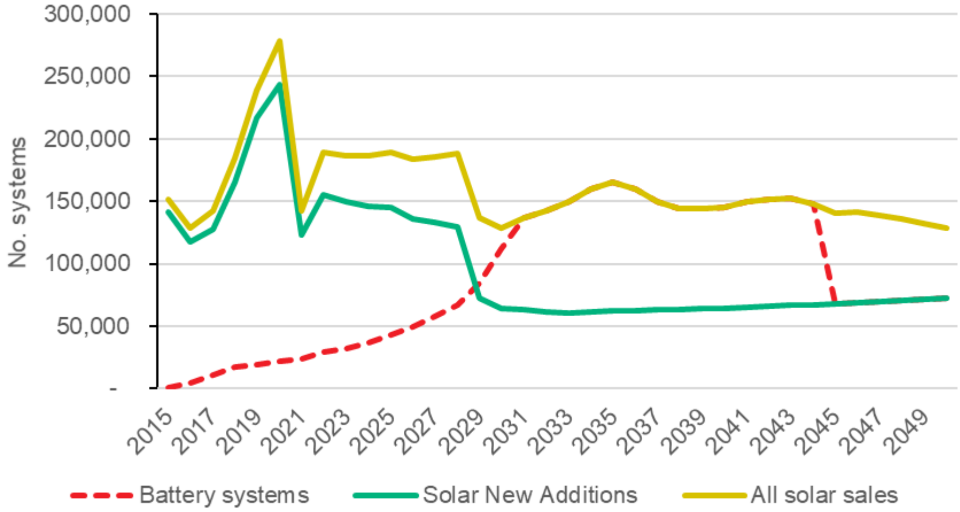
- Enhanced reliability of supply with the ability to maintain power in the event of grid outages;
- A strong affection for what is perceived as cutting-edge technology and the perceived status or bragging rights that comes with owning such technology;
- A desire to do their bit in addressing global warming by supporting a transition of the grid to variable renewable energy power supplies;
- A misapprehension that the battery will leave them financially better off or at least shield them from what they believe will be further large rises in electricity prices. This is often coupled with strong mistrust or resentment of electricity suppliers and a sense of injustice that exports from their solar system receive a price far below what they pay to import electricity from the grid.

We are not aware of any rigorous evaluation of the prevalence and strength of these kinds of motivational drivers amongst the Australian population and the degree to which they might drive purchasing behaviour of batteries at different purchase price points or paybacks. However, interviews with industry participants indicate that customers of solar systems almost always express a strong interest in adopting batteries, but they consider the current cost to be prohibitive. These suppliers expect that demand for batteries will be of similar size to that of solar systems, but only once batteries achieve substantial reductions in cost – with a halving in cost sometimes cited as a rule of thumb for an inflection in uptake.

Given the lack of rigorous data on likely purchasing behaviour the projections of battery uptake assume that historical levels of growth in battery installations will continue over the short to medium term given the ongoing reductions in battery prices assumed under the various scenarios. This is the case even though paybacks appear to be unattractive given alternative investment options. Both South Australian and Victorian projections assume full take-up of their battery rebate programs. As paybacks approach similar levels as available for solar then we assume uptake will follow that of solar sales.

Figure 5-17 illustrates in the red dashed line the model's Central Scenario projection of annual additional battery systems (excludes systems replacing an existing battery system) in the residential sector, relative to solar system sales and additions. It is only by around 2029 in the Central Scenario that we envisage that batteries act to reduce the payback period for a solar system and it is around that time that we project a large uptick in battery uptake (note this inflection point occurs several years earlier in Step Change and High DER a few years later in Slow Change while Fast Change follows similar timing as Central). By 2031 the model envisages in the Central scenario that all new solar system sales will be coupled with a battery and hence the yellow and red lines merge. This continues until 2045 when additional battery systems follow in line with solar system additions (systems that installed on a dwelling that has not previously had a solar system). The departure from battery additions in line with total solar sales to just additional battery systems is because by 2045 batteries will have been installed across a large proportion of the existing stock of solar systems. Consequently, new incremental additions to the battery stock only occur in circumstances where the premise is not replacing an existing solar system.

**Figure 5-17 Number of additional residential battery systems relative to solar system additions and sales
(Central Scenario)**



The implications of these system numbers in terms of megawatt-hours of battery capacity are illustrated in Figure 5-18 below, broken down by state.

**Figure 5-18 Megawatt-hours of residential batteries added to stock by year
(Central Scenario)**

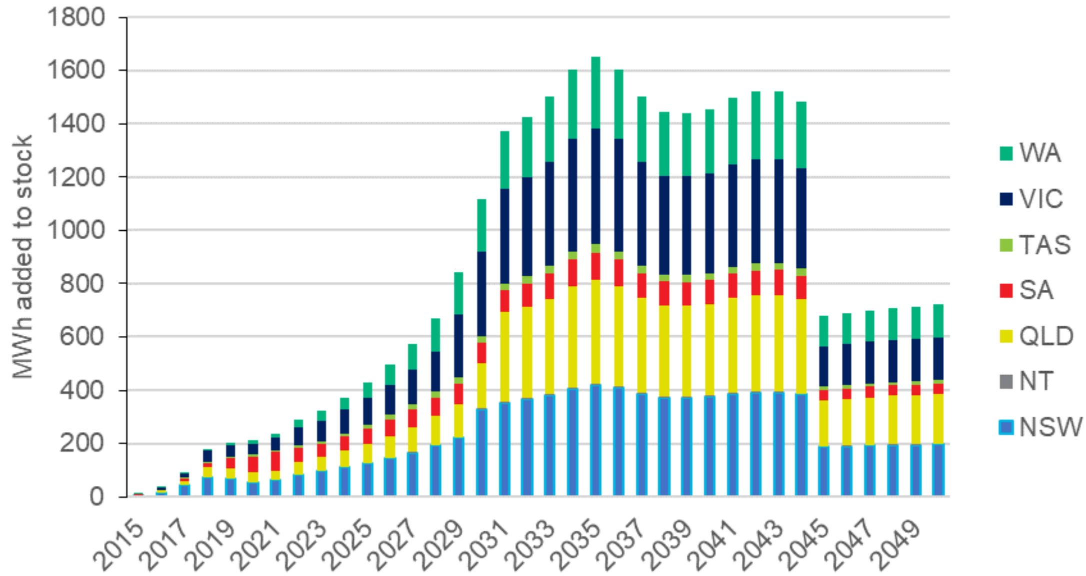


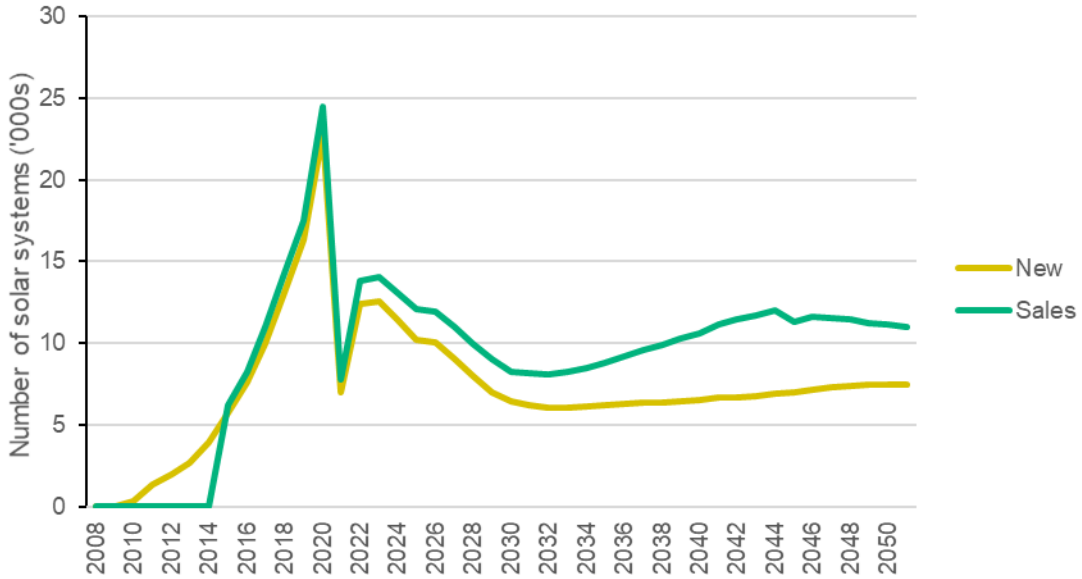
Figure 5-17 shows that after 2028 when the Victorian Solar Rebate is assumed to end, new solar additions fall to a relatively steady base of 60,000 to 70,000 systems. This base level of new additions is tied to an assumption that Australia is assumed to build around 100,000 new detached or semi-detached dwellings each year, as part of ongoing population growth. Historical data indicates that solar adoption rates tend to be highest in areas of Australia that are subject to substantial new dwelling construction. The level of new solar additions (and batteries from 2045 onwards) is in line with these historical adoption patterns.

5.3 Commercial solar systems up to 100kW and associated batteries

Solar systems installed on commercial premises have historically been a much smaller proportion of installed capacity than residential but have been growing more quickly and now represent around 20% of installed rooftop solar capacity within the STC scheme.

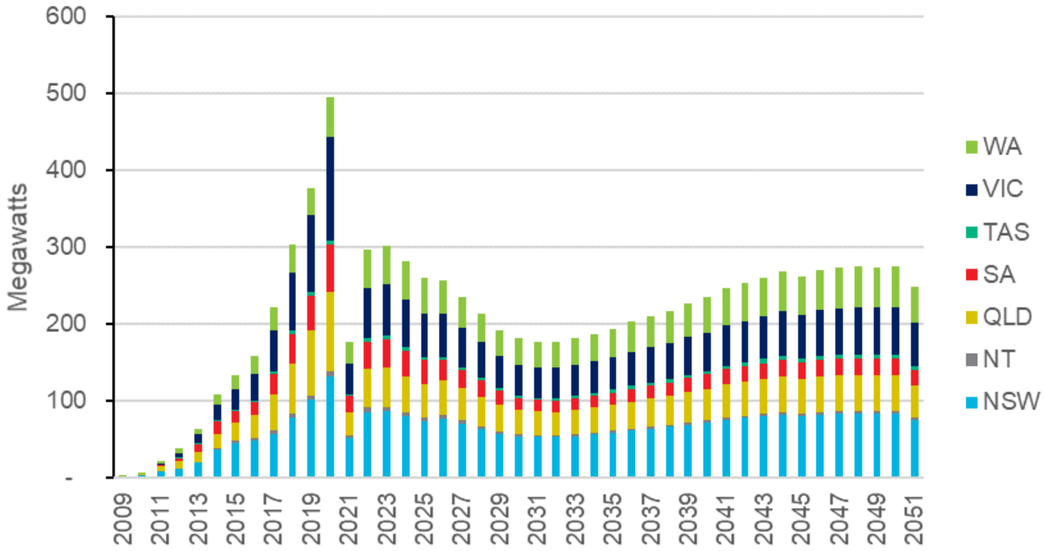
Figure 5-19 details the number of small commercial solar systems that are sold in each individual year (not cumulative). To provide some context, this chart details historical numbers stretching back to 2008, as well as projections from 2019-20 onwards for the Central Scenario. The chart also details the number of these system sales which are new solar systems, as opposed to systems replacing a pre-existing solar system. The difference between total sales versus new incremental systems is only tracked from 2015 onwards because prior to this almost all solar systems sold were new additions rather than replacements and indeed there is still little difference between the two figures so far to date.

Figure 5-19 Number of commercial sub 100kW solar systems installed per annum (Historical and Central Scenario)



While the number of solar systems within the sub-100kW commercial segment is small relative to residential, because each system is noticeably larger than in residential it is significant in terms of capacity, which is detailed in Figure 5-20 below.

Figure 5-20 Capacity of commercial sub-100kW solar systems added to stock per annum (Historical and Central Scenario)



5.3.1 Historical context

The commercial segment of the solar market only passed 100MW of annual installations by the 2013-14 financial year but has continued to grow rapidly and is expected to reach close to 500MW by the end of 2019-20. It missed the boom and subsequent-bust that unfolded over 2010 to 2015 period that residential experienced because it was not offered the premium feed-in tariffs, and the STC multiplier only applied to the first 1.5kW of a system and so made little impact on the larger commercial systems.

5.3.2 COVID 19 brings end to boom

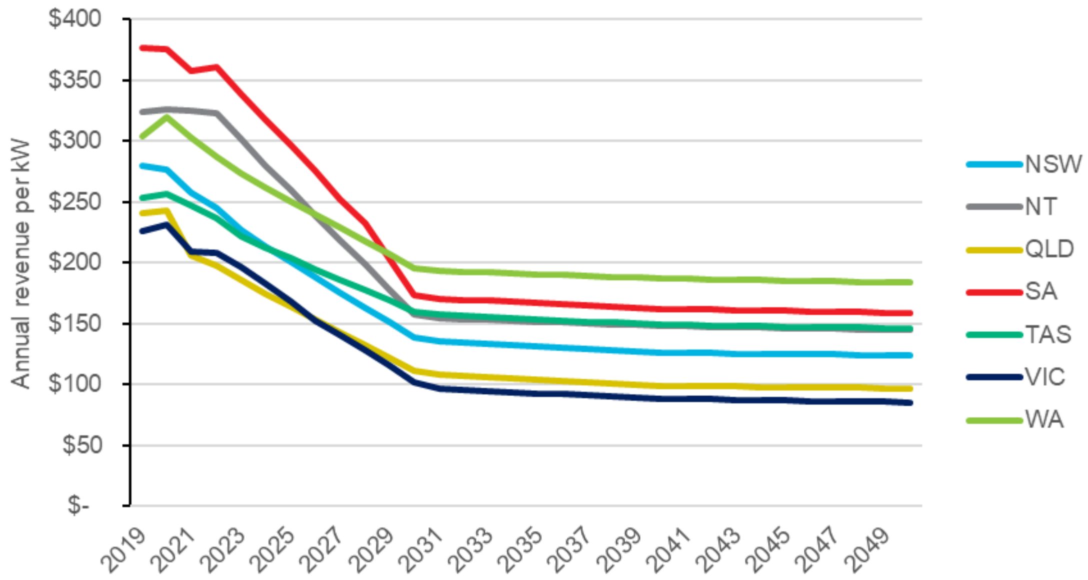
Similar to residential, we expect that the COVID-19 economic downturn will lead businesses to pull back on capital investment leading to dramatic reduction in capacity installed in the next financial year 2020-21. However, the scale of the dip in 2021 capacity relative to 2020 is not solely a function of COVID-19. Even without the impact of the COVID-19, anticipated falls in the daytime wholesale power price were expected to reduce installs significantly.

5.3.3 The next decade – commercial suffers similar fall in revenues as residential but more significant decline in sales

The sub-100kW segment follows a similar path as residential over the next decade. Like residential it experiences a recovery in sales and capacity in 2022, but it's decline after that is more noticeable due to the lack of support under the Victorian Solar Homes rebate program and less scope for capacity growth via the replacement of old systems with larger solar systems.

The reason for the decline in sales and capacity to 2030 in commercial is similar to that as residential. It sees a large decline in revenue, as it is assumed to face similar tariff structures and electricity costs as residential. In addition, the withdrawal of STC policy support to 2030 outpaces underlying cost reductions.

Figure 5-21 Annual revenue generated by a commercial solar system (per kW) 2019 to 2051 (Central Scenario)



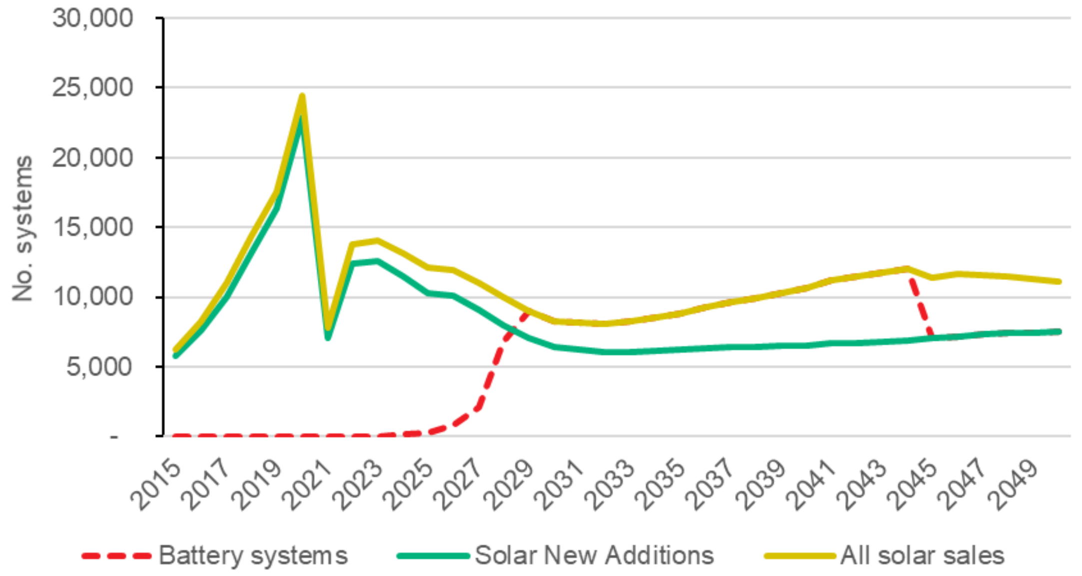
5.3.4 Commercial regains growth in 2030's and 2040's

However, unlike residential, capacity begins to grow again over the 2030's and 2040's. This is a product of assumed lower capital costs for both solar systems and batteries relative to the residential sector, and also because the commercial sector is characterised by lower levels of market saturation.

5.3.5 Battery adoption follows similar path to residential

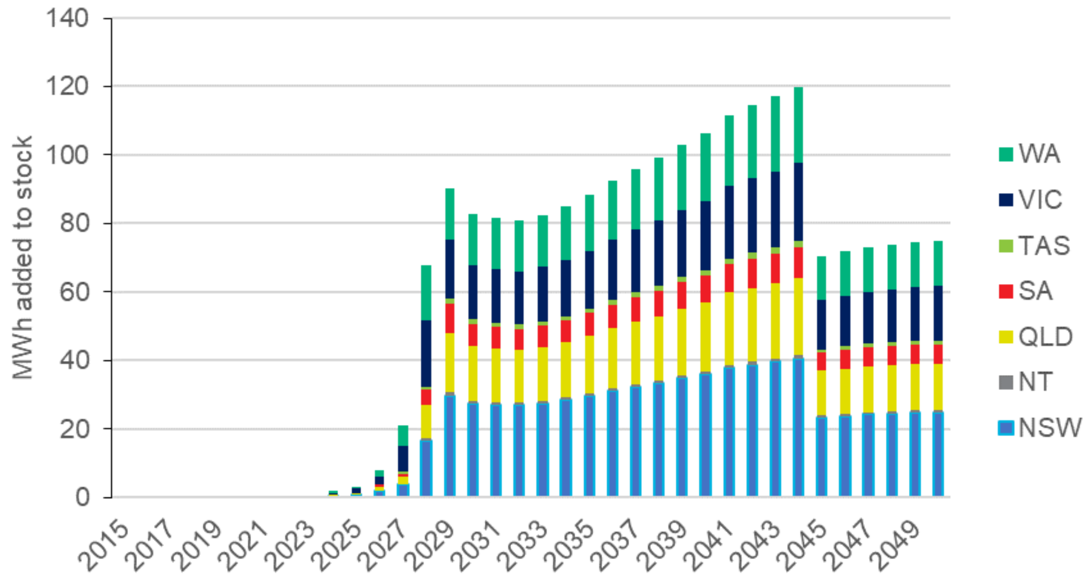
Figure 5-22 details the number of commercial battery systems added to the stock under the Central Scenario relative to solar system sales and new additions. Just as in residential, the payback on a battery system is not expected to reach levels close to those of solar systems until towards the end of the 2020's. However, unlike residential, we do not expect to see any noticeable levels of installations until that point is reached. This is based on the assumption that the emotional factors which motivate households to install batteries are not material factors influencing the battery purchasing decision of businesses. Just as in residential, by around 2029 we expect all solar systems sold will be installed in conjunction with a battery system as the combination provides a superior payback than each in isolation. Also battery system additions to the stock drop down the level of new solar additions in 2045 just like residential as the majority of the existing stock of solar systems are expected by that time to have a battery coupled with them.

Figure 5-22 Number of additional commercial battery systems relative to solar system additions and sales (Central Scenario)



The implications of these system numbers in terms of megawatt-hours of battery capacity are illustrated in Figure 5-23 below, broken down by state.

Figure 5-23 Megawatt-hours of commercial batteries added to stock by year (Central Scenario)

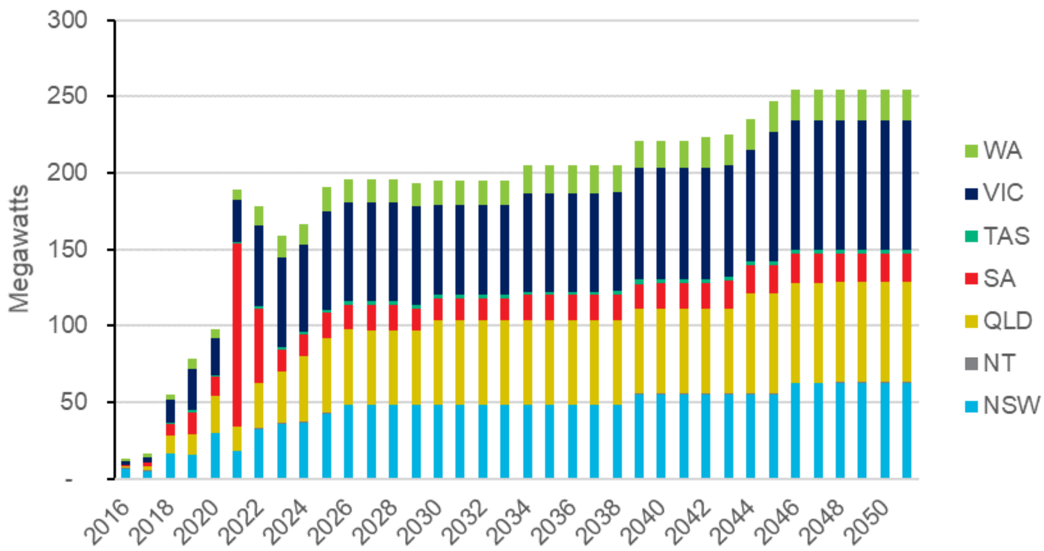


5.4 Large commercial behind the meter systems (above 100kW)

As explained in section 3.6, the market for behind the meter solar systems above 100kW has only very recently emerged at a noticeable scale of capacity and still remains small relative to the residential sector.

Figure 5-24 details the amount of large commercial solar capacity installed by year and state historically and then our projections of capacity to the end of the projection period under the Central Scenario. One can see how the market has experienced a rapid growth phase from 2016, which we expect will last through to the 2021 financial year. It then suffers a decline to 2023 after which it resumes more modest growth to 2026 and then stabilises. Subsequent growth is small and occurs in steps followed by static sales which are a function of the model applying growth only once payback passes from one band to another.

Figure 5-24 Capacity of large commercial solar systems added to stock per annum (Historical and Central Scenario)



5.4.1 Historical context

Prior to 2016 solar systems installed above 100kW in scale in behind the meter installations were driven by non-financial motivations such as demonstrating a commitment to addressing climate change and installation levels were inconsequential relative to the residential solar market and the broader electricity market. The reason solar systems of this scale were not as attractive in financial terms as they were in the residential sector were a function of two things:

- Customers with enough electricity demand to support a system larger than 100kW tend to face much lower electricity prices per kWh of consumption, due mainly to a large proportion of network costs being recovered via demand charges;
- Government policy financial support for systems of this scale have historically been less than that provided to the residential market.

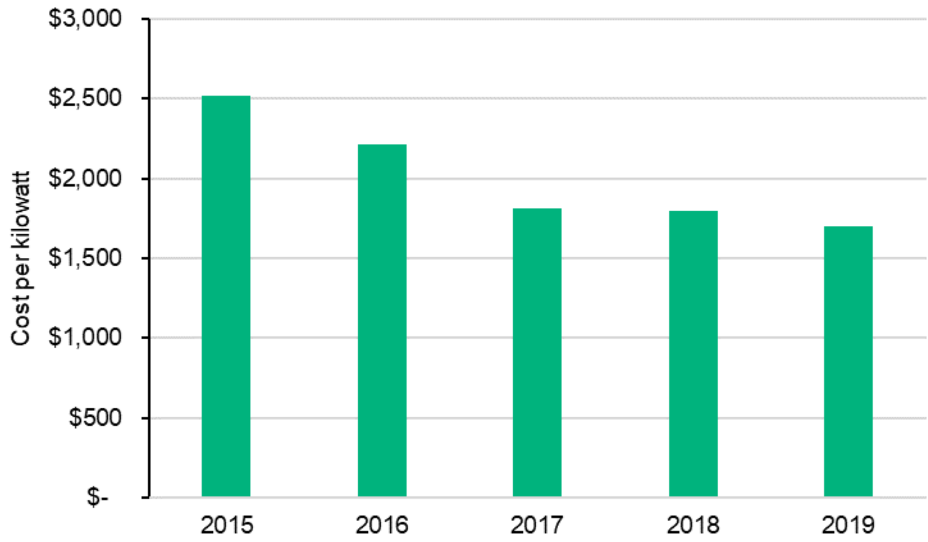
However, the market entered a significant growth phase beginning in 2016 driven by:

- Substantial reductions in capital costs;
- A large and rapid rise in wholesale energy market prices in the NEM;
- A large increase in the value of LGCs; and

- Increasing sophistication of the solar industry that enhanced its ability to service and market to large commercial customers that present a more complicated market than residential and small business.

Figure 5-25, based on the sample set provided by the Clean Energy Regulator, shows that system cost per kilowatt for large commercial systems declined by 29 percent between 2015 and 2018.

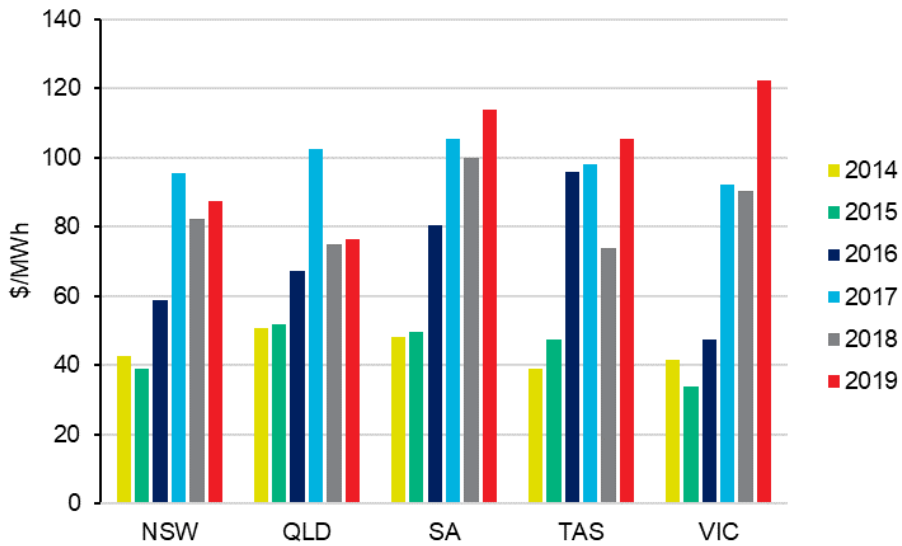
Figure 5-25 Cited installed cost of mid-scale systems per kilowatt by year (excluding off-grid/remote grid systems)



Note: Off-grid or remote grid systems have been excluded because these usually involve substantial additional costs not faced by mains grid-connected systems which then act to skew the cost data upwards in years in which off-grid systems were accredited.

Meanwhile, over the same period we saw a dramatic rise in wholesale electricity prices in the east-coast National Electricity Market. The jump in prices began in 2016 but was greatest in 2017 for NSW, QLD and Victoria.

Figure 5-26 Average time-weighted wholesale electricity spot price by NEM state



Note: 2019 prices are for the period January to August. This is likely to excessively inflate prices for Victoria which experienced extremely high pricing peaks for a few days in Summer. Victoria tends to experience lower prices over the remaining months of the year which will act to lower the time-weighted average.

The final factor that helped drive a dramatic improvement in the financial attractiveness of 100kW+ solar systems around 2016 was a significant rise in the LGC spot price that rose from close to $30 in January 2015 to surge above $80 by 2016 and remain there until the last quarter of 2018.

Combining the decline in system costs with the increase in revenue from higher wholesale prices and higher LGCs prices, we estimate the payback period on solar systems roughly halved for a range of customer sites likely to be suitable for 100kW+ behind the meter systems.

Coupled with this dramatic improvement in financial attractiveness was an increasing sophistication and capability of the solar industry that has made them better able to convert customer interest into a solar installation. It is important to recognise that Australia's solar industry has traditionally been dominated by selling and installing small, generic solar systems to residential households. Selling and installing such residential systems is usually much simpler than what's required for large commercial systems. Commercial clients have more varied tariff types, need a more tailored approach to system design, take a more involved and sophisticated approach in evaluating whether to purchase solar, are more prone to landlord-tenant split incentives, and the technical requirements of such systems are more difficult, in particular the grid connection process. Another factor that has been more important in the commercial sector than residential has been the provision of financing that avoids the need for clients to commit their own upfront capital to purchasing the system.

As the financial attractiveness of large commercial solar systems has improved and the levels of interest in installing solar has grown, the solar industry has gained much greater experience in the sale and installation of these larger systems. This has allowed them to become better at presenting and explaining the investment proposition for solar to clients involving multiple decision makers and detailed evaluation processes. In addition, they have become more adept at dealing with the needs and concerns of electricity networks, and likewise electricity networks have gained greater comfort and understanding in having 100kW+ solar systems operating within their network. Also financing products have been developed with more attractive terms such as lower interest rates, longer repayment periods, and repayments tied to consumption of electricity from the solar system otherwise known as power purchase agreements. These have helped to at least somewhat mitigate tenant-landlord split incentives, and the often myopic approach businesses take to allocating capital to non-core elements of their business (a problem of bounded rationality which is a well understood factor behind sub-optimal levels of investment in energy efficiency[21]).

5.4.2 COVID 19 impact brings end to boom but obscured by SA Water solar roll-out

Similar to residential, we expect that the COVID-19 economic downturn will lead businesses to pull back on capital investment leading to dramatic reduction in capacity installed in the next financial year 2020-21. We have scaled-down large commercial

[21] Sanstad and Howarth (1994) Consumer Rationality and Energy Efficiency, available here: https://www.aceee.org/files/proceedings/1994/data/papers/SS94_Panel1_Paper21.pdf

installations on the same basis as residential and detailed in section 3.8 of this report. However, over this same period we have made another adjustment to the projection to incorporate a 154MW roll-out of solar across SA Water's sites. This is illustrated in Figure 5-24 by the red segment representing SA capacity expanding substantially in 2021 to become larger than all other states combined. SA Water's roll-out is anticipated to continue into 2022 and so also inflates capacity in this year that is independent of expected changes in payback.

5.4.3 Short decline followed by recovery to prior boom heights

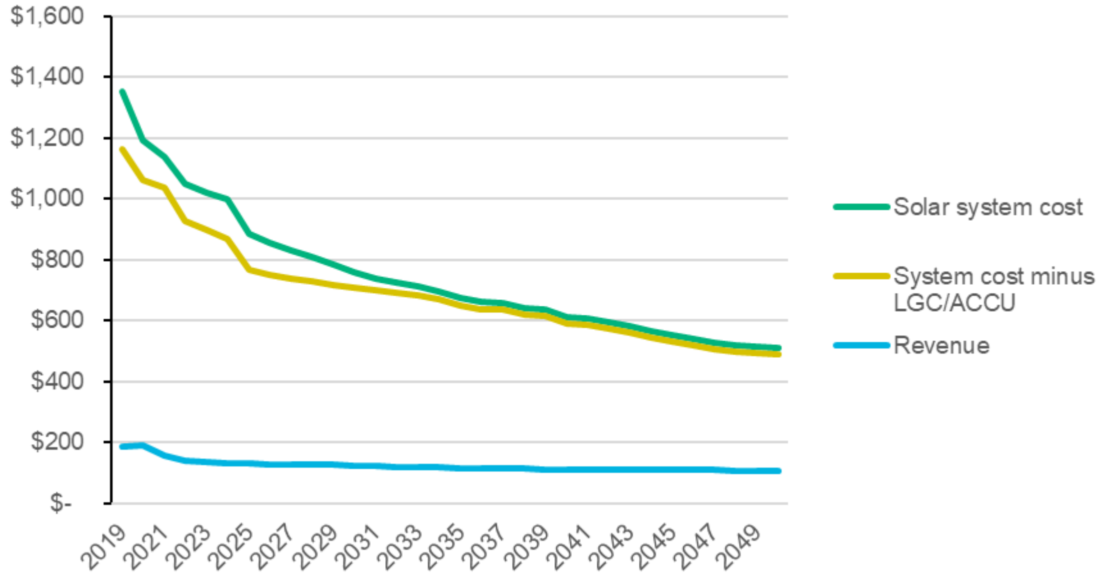
While capacity installs of large commercial decline after the 2021 boost from the SA Water solar roll out, this decline is relatively shallow and short and growth resumes by 2024 and by 2025 large commercial is back to its prior boom levels of capacity.

Like the sub-100kW sector our model envisages that revenue for large commercial solar systems will decline significantly over this decade. However, the scale of the decline in revenue is far smaller than sub-100kW, because large commercial customers are assumed to be on demand-based network tariffs. Consequently revenues aren't reduced by the shifting of a large proportion of network charges out of 9am to 3pm period and into 3pm to 9pm.

At the same time the model assumes a faster capital cost decline for large commercial systems than for residential because the installation productivity gains offered by improved module efficiency can be more readily achieved than residential (which is constrained by networks limiting inverter export to 5kW).

Figure 5-27 illustrates how system cost reductions manage to outpace revenue reductions. Consequently, large commercial, unlike residential, manages to achieve declining paybacks and this leads to a recovery in capacity installs unlike residential. In addition, unlike residential, we do not envisage significant market saturation effects that hinder uptake.

Figure 5-27 Annual revenue for NSW large commercial solar relative to capital cost (per kW) (Central Scenario)

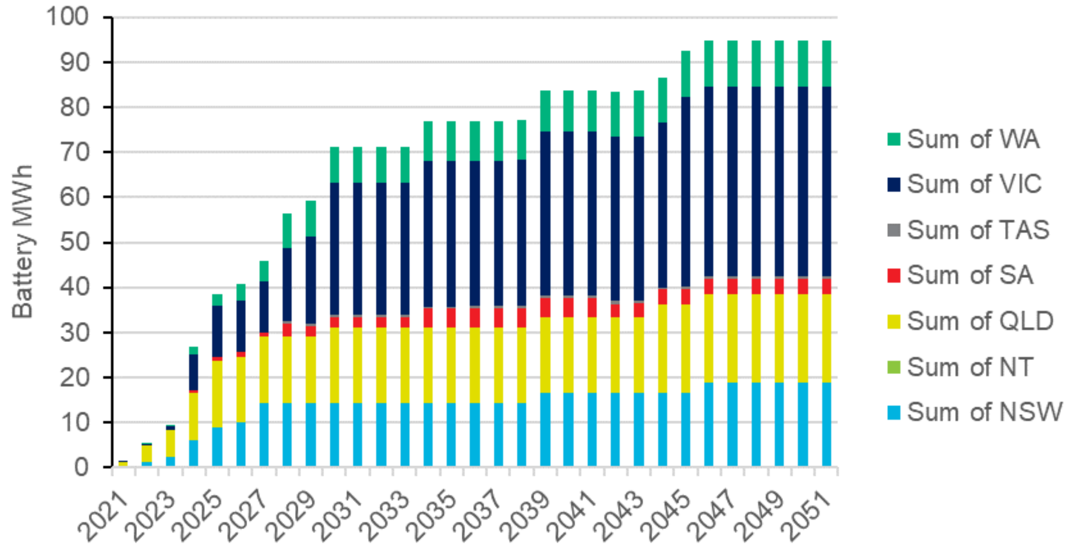


5.4.4 Battery adoption surges from 2024

While the market for batteries in the large commercial sector is currently very small, the model envisages batteries achieve attractive economics in this sector sooner than residential. This is a function primarily of batteries allowing customers to capture reductions in their demand charge on their own but crucially also by firming-up the demand charge reductions delivered by the solar system.

As a result, battery uptake is expected to increase rapidly from 2024 onwards in the Central Scenario and by 2030 almost all solar systems are installed coupled with a battery.

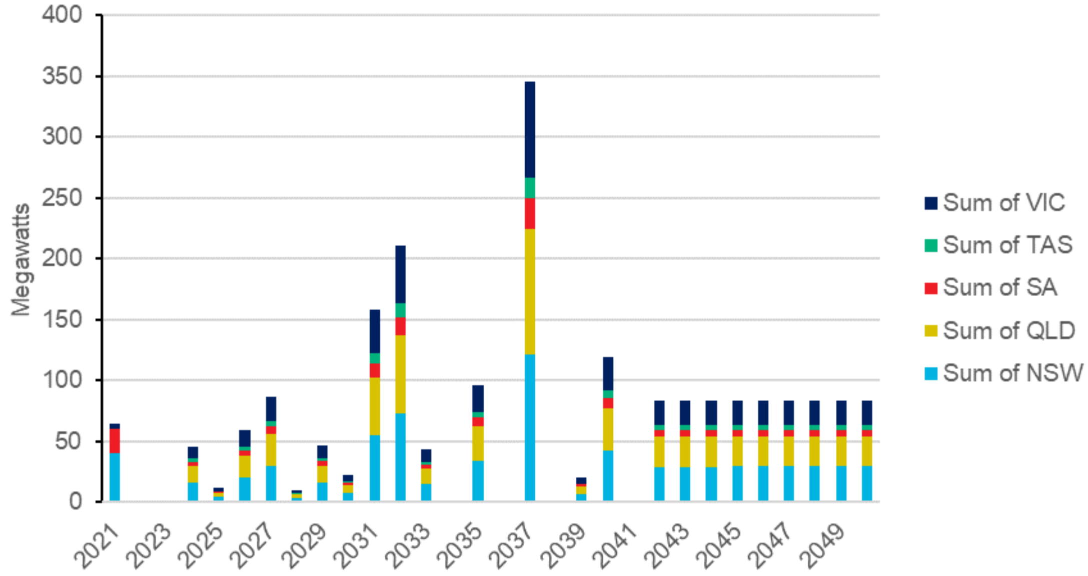
Figure 5-28 Megawatt-hours of commercial batteries added to stock by year (Central Scenario)



5.5 Power stations 1MW - 30MW

Figure 5-29 details the sub-30MW capacity projected to be installed by year in the Central Scenario. It illustrates wide variation in installations across years until the last decade with this variation reflective of the Draft ISP projections of solar installs for 30MW+ projects. As a point of comparison to the past, there was 113MW of sub-30MW power stations accredited in 2019 calendar year, 140MW in 2018, 59MW in 2017 and 25.3MW in 2016. However, projects representing a significant proportion of this capacity elected to be semi-scheduled.

Figure 5-29 Capacity of sub-30MW power station capacity added to stock per annum (Central scenario)



5.6 Battery system charge and discharge profiles

To assist AEMO in assessing the possible aggregate impact of non-scheduled batteries on electricity demand and supply, the algorithm used within the payback model to assess the incremental additional revenue that a battery might deliver to a consumer was run using AEMO supplied historical 30 minute interval data of estimated solar output stretching back several years.

The payback model algorithm/formula which governs the battery's charging seeks to get the battery to always charge to full capacity in advance of the defined peak period, preferencing solar generation to charge that would otherwise be exported. The formula assesses if solar exports for the day ahead are inadequate to charge to full capacity and if so, then extra charge from the grid is taken during the solar tariff period. The way the formula is designed assumes that battery software would be capable of perfectly forecasting that day's level of solar exports which is unlikely to be possible. However systems are capable of reasonably accurately forecasting a solar system's output 12 hours ahead and considerable software development is being dedicated to learning algorithms that aim to forecast a household or business' electricity consumption by monitoring how energy consumption changes relative to a range of other measured variables such as weather, the day of the week and other factors such as production schedules.

The battery is discharged to cover a consumer site's residual consumption left over after solar during the peak period (3pm-9pm) first and will then continue discharging until 2am if it still has charge.

It is worth noting that this algorithm has been designed in a way that is designed to function reasonably well with the single tariff structure we have assumed (although it is far from optimised). In reality customers will face a range of tariff structures and this will change what is the best way to charge and discharge the battery.

Figure 5-32 illustrates the averaged quarterly pattern of the battery's charging (green dashed line) and discharging (blue line) behaviour per kW of battery capacity by hour of day for a NSW residential consumer assumed to have a 6.6kW solar system and 10kWh battery capable of a maximum charge or discharge of 4kW. The yellow line shows the quarterly averaged hourly solar generation profile per kW of capacity. Note that the green charging profile reflects charging flow into the battery without distinguishing the source – whether solar or from the grid. However, in our model, it was rare for the residential consumer to charge the battery from the grid, with solar exports usually being more than sufficient to charge the battery to full charge.

Figure 5-30 Quarterly averaged charge-discharge profile NSW residential example

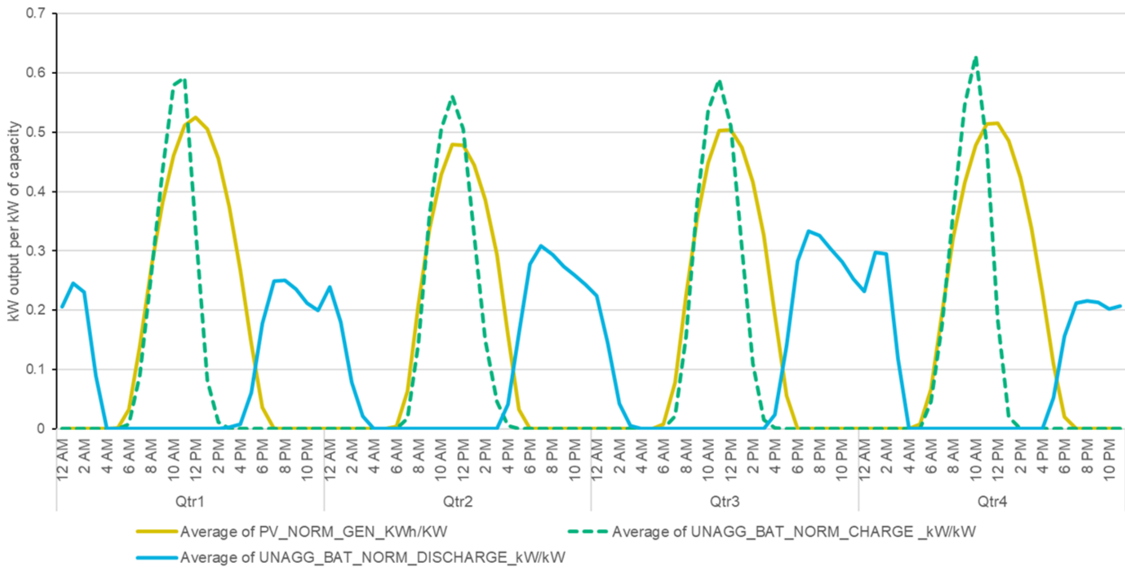
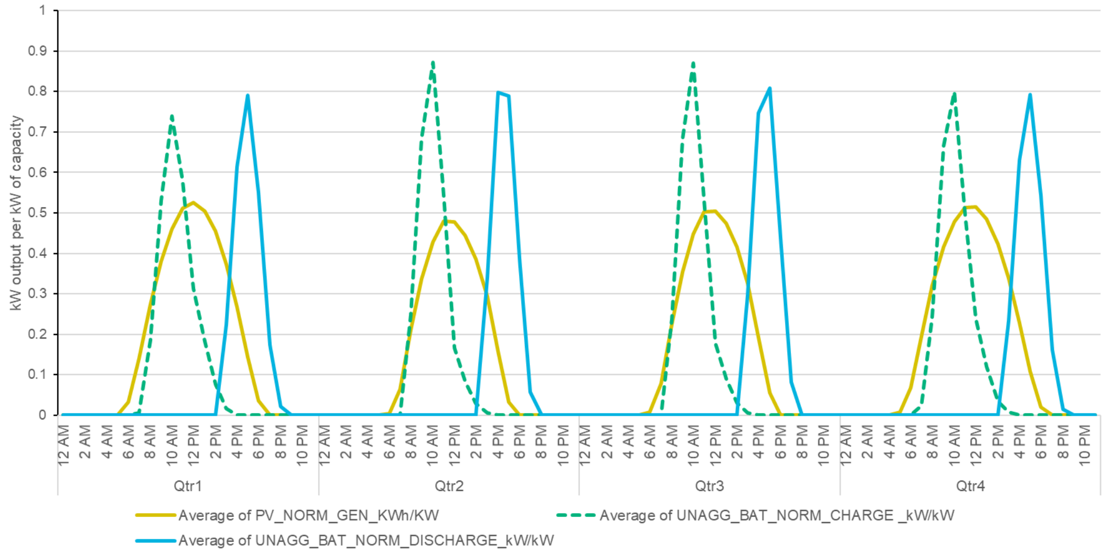


Figure 5-33 below illustrates the charge-discharge profile for a battery held by a NSW small commercial consumer assumed to have a 20kW solar system and 10kWh battery capable of a maximum charge or discharge of 4kW. The solar profile is exactly the same as residential, however our model sizes the solar system in a way that is intended to keep exports reasonably low (20% or less of total solar generation compared to about 70% for the residential consumer). This means load tends to exceed solar generation earlier in the day so the battery discharges earlier and is fully discharged sooner than for residential.

Figure 5-31 Quarterly averaged charge-discharge profile NSW small commercial example



Lastly Figure 5-32 shows the charge-discharge profile estimated for a battery held by a large commercial customer. The assumed solar system of the modelled customer is 300kW. The profile illustrated below is for such a customer in NSW which is assumed to have a 90kWh battery capable of a maximum charge or discharge of 36kW. The same was assumed for QLD, however in other states it made sense for larger battery systems to be installed (120kWh in the case of NT and 150KWh for the remaining states while the ratio of kW to kWh remains the same at 0.4). In this customer case AEMO's supplied solar generation profile provides higher output per kW of capacity installed, presumably assuming better orientation and more efficient components. Just as for small commercial our model sizes the solar system so that exports are kept low (below 20% of total solar generation). Therefore, load also exceeds solar output earlier in the day than residential and battery discharges sooner and faster than for the residential example.

Figure 5-32 Quarterly averaged charge-discharge profile NSW large commercial example