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

Report for AEMO

December 2024

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1 Executive Summary

1.1 Overview of project scope and approach

The Australian Energy Market Operator (AEMO) has engaged Green Energy Markets Pty Ltd (GEM) to provide several scenario-based projections to 2059-60 of solar and stationary battery uptake for the part 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 at the beginning of the projection[1] and increase to a maximum of 20kWh by 2040.
- ***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 at the beginning of the projection and increase to a maximum of 20kWh[2].
- ***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 at 500kWh.
- ***Small power stations*** - which are assumed to be between 1MW and 30MW in scale.

Green Energy Markets' 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 historical payback periods. 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

1 Informed by information within Sunwiz (2024) Australian Battery Market Report 2024

2 Small commercial battery systems are a similar size to residential systems because even though these premises have a larger load and are assumed to install a larger solar system than residential, the solar system is aligned more closely with daytime load and so has less generation surplus to load that would otherwise be exported to the grid. This substantially reduces the scale of arbitrage the battery can provide in taking power that would be otherwise be exported at a rate tied to wholesale energy costs and instead using it for self-consumption tied to retail rates.

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 solar and battery systems.

In addition, in the short term 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 Markets’ solar and battery system payback model.

For systems within segment 2 (small power stations) installations are guided by forecasts of utility-scale solar capacity additions by scenario as estimated in AEMO’s 2024 Integrated System Plan.

1.2 Results

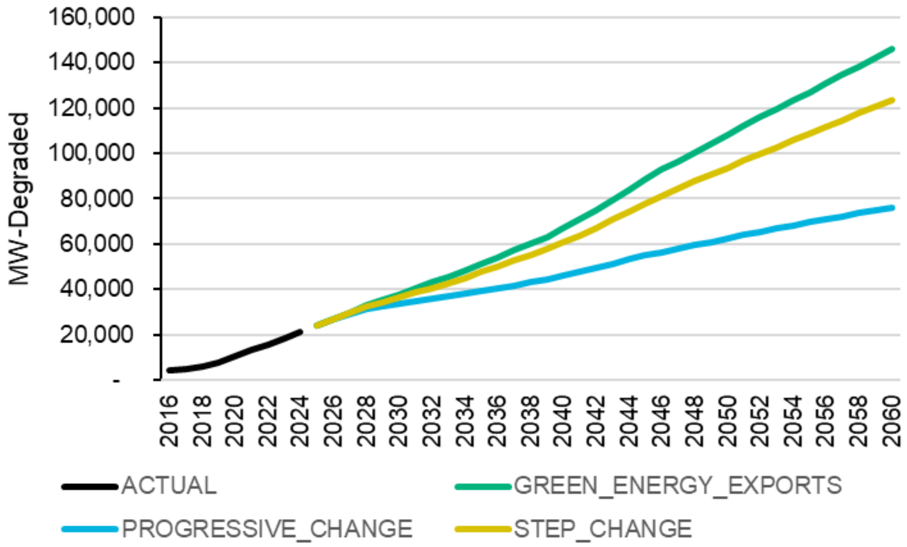
1.2.1 Solar PV

Readers should note that the projections below are for the solar DC panel capacity, not the capacity of inverters which convert solar panel generation into electricity that is usable by consumers. In the model we project that towards the end of the projection period new residential solar systems’ average panel capacity will be close to 13kw to 15kW (it is currently at around 9kW). However, many network distributors in Australia apply restrictions on the amount of capacity inverters can export to the grid, with 5kW per phase common, although dynamic controls can allow up to 10kW. Consequently, during periods of high solar output and low household electricity demand a significant portion of the generation from the projected panel capacity will be automatically curtailed due to export constraints. While dynamic export limits are in the process of being rolled out in several states that will allow for greater exports than 5kW, they would still act to automatically curtail output in circumstances where demand was low and aggregate solar output was very high such that voltages became too high. Furthermore, across all three scenarios it is envisaged that a substantial proportion of solar systems will be coupled with batteries which will further reduce the extent of solar DC panel capacity which is exported to the grid. This is important because the residential sector makes up the vast bulk of projected capacity under all scenarios. So, while the amount of panel capacity projected reaches high levels relative to overall electricity demand, the likely peak output that ultimately flows from inverters to satisfy electricity demand will be much lower.

National Electricity Market

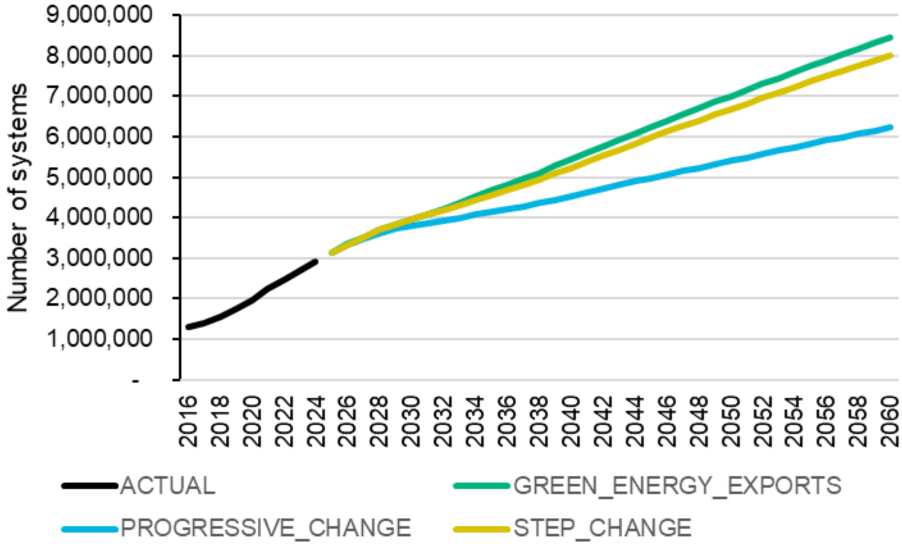
Figure 1-1 details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the National Electricity Market (NEM), taking into account the degradation of solar panel output over time. At the beginning of the projection (the conclusion of the 2023-24 financial year) cumulative installed degraded capacity is expected to stand at close to 21,400MW. By the end of the projection in 2059-60 the cumulative degraded capacity reaches around 76,000MW at the low end, under Progressive Change, and close to 146,000MW at the upper bound represented by the Green Energy Exports scenario.

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



The figure below details projections for the cumulative number of solar PV systems by scenario within the NEM. At the beginning of the projection the cumulative number of systems stands at about 2.9 million. At the low end under Progressive Change, the cumulative number of systems grows to around 6.2 million by the end of the 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches 8.4 million.

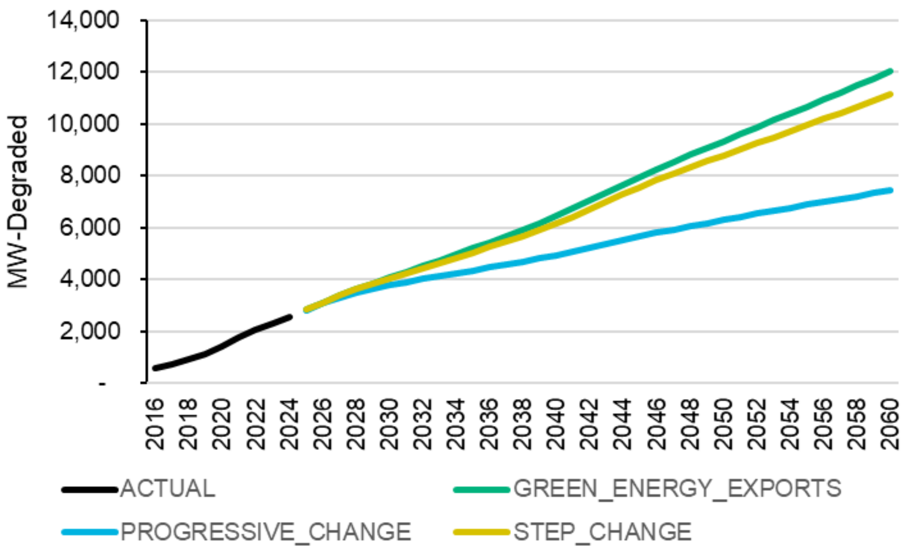
Figure 1-2 NEM cumulative number of solar PV systems by scenario



Western Australian South-West Interconnected System

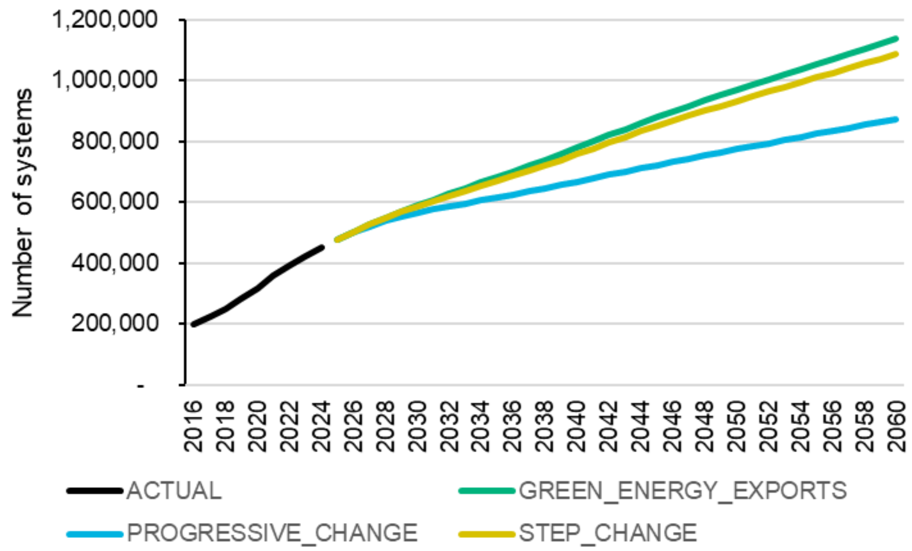
Figure 1-3 details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the WA South-West Interconnected System (SWIS), taking into account the degradation of solar panel output over time. At the beginning of the projection (the conclusion of the 2023-24 financial year) cumulative installed degraded capacity is expected to stand at slightly above 2,500MW. At the low end, under Progressive Change, the cumulative degraded capacity reaches 7,400MW by the end of the projection in 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches 12,000MW. Note that for the SWIS, unlike the NEM, the projection does not include any capacity for in-front-of-the-meter power stations due to different registration requirements that reduce the extent of power stations operating outside of the central dispatch process.

Figure 1-3 WA SWIS cumulative degraded megawatts of solar PV by scenario



The figure below details projections for the cumulative number of solar PV systems by scenario for the SWIS. At the beginning of the projection the cumulative number of systems stands at a bit more than 450,000. At the low end under Progressive Change, the cumulative number of systems grows to 874,000 by the end of the 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches around 1.1 million.

Figure 1-4 WA SWIS cumulative number of PV systems by scenario



Solar household penetration levels

To put these solar system numbers into context the total number of detached and semi-detached dwellings in the NEM states is expected to grow from around 8.3m in the 2023-24 financial year to around 13m to 14m by the end of the projection (the residential sector accounts for the vast bulk of solar system numbers). Meanwhile the total number of detached and semi-detached dwellings in the WA SWIS is expected to grow from 1.08m in 2023-24 to reach between around 1.55m to 1.67m by the end of the projection period[3].

Within the NEM under Progressive Change around 43% of detached and semi-detached dwellings are expected to have a solar system by the end of the projection period, while at the upper end under Green Energy Exports it reaches around 53% of all residential detached and semi-detached dwellings. In the WA SWIS under Progressive Change around 54% of detached and semi-detached dwellings are expected to have a solar system by the end of the projection period, while at the upper end under Green Energy Exports it reaches 65%.

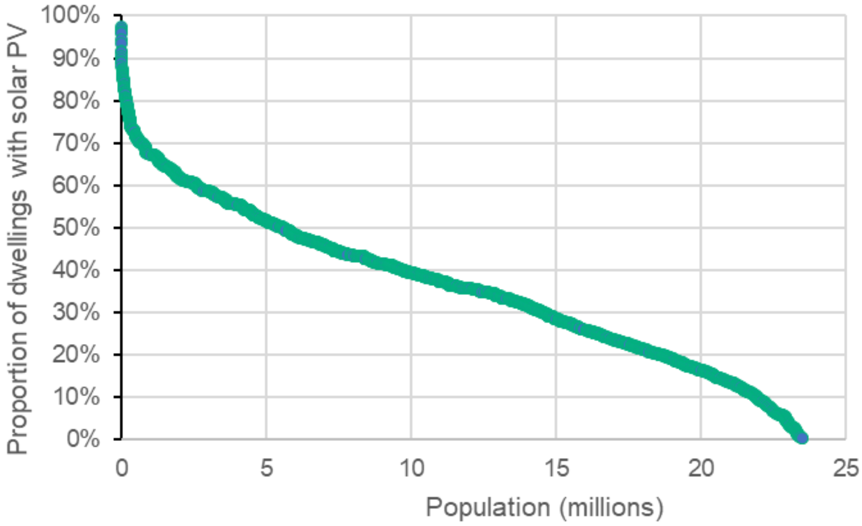
While this may appear to be quite a high proportion of households, such levels of penetration are already common across many postcodes in Australia.

Figure **1-5** details the profile of solar penetration for each postcode within Australia relative to population within the postcode as of 2023. There are now over 800 postcodes in Australia where 50% or more of households have a solar system. These postcodes encompass over 5 million of Australia's population and this has been accommodated within distribution networks with very little usage of battery energy storage systems.

[3] Dwelling numbers for both the NEM and SWIS sourced from Deloitte economic forecasts provided to AEMO – November 2024

Meanwhile our projections envisage that almost all new solar systems installed from the 2040's will be coupled with batteries.

Figure 1-5 Proportion of households with solar by postcode relative to population



Sources: Clean Energy Regulator for number of solar systems per postcode, Australian Bureau of Statistics 2021 Census for number of households and population by postcode.

Such high levels of penetration imply that solar and battery systems are likely to spread beyond owner-occupied housing and into a portion of houses that are rented. This doesn't actuallysuggest that we expect landlords will voluntarily choose to purchase solar systems to assist renters to lower their electricity bills. This has historically been extremely rare and we expect this will continue. Instead, other factors are likely to lead solar systems to penetrate into the rental stock. The first and most important is that some houses which are owner occupied will turnover into rental properties and the renter will in effect inherit a solar system from the previous occupant, rather than having it installed by a landlord. Another factor that could drive a gradual increase in solar in the rental stock are housing energy-efficiency standards. Historically such standards were focussed on thermal shell improvements, but these are now moving towards incorporating a Whole-of-Home annual energy use budget for fixed appliances (hot water, heating and cooling, lighting and pool and spa pumps) with potential to offset with rooftop solar[4]. Lastly, the solar industry overseas has developed small, portable solar systems which in Germany can be simply plugged into a conventional power socket to provide power to the dwelling (often referred to as balcony solar systems). Australian standards do not currently support such installations, but we are aware of companies currently investigating the technical scope to make such systems feasible in Australia.

1.2.2 Battery energy storage

National Electricity Market (NEM)

[4] Victorian Government Department of Energy, Environment and Climate Action (2024) *Fact sheet for Building Practitioners – New home energy efficiency standards explained*, weblink: https://www.energy.vic.gov.au/__data/assets/pdf_file/0016/670300/7-star-new-homes-standards-factsheets-building-practitioners.pdf

In terms of behind the meter stationary battery systems the figure below details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the National Electricity Market (NEM), taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2023-24 financial year) cumulative degraded battery capacity is estimated to stand close to 2,174MWh[5]. At the low end, under Progressive Change, the cumulative degraded capacity reaches 52,000MWh by the end of the projection in 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches 124,000MWh.

[5] Historical battery system numbers and capacity are derived from Sunwiz (2024) Battery Market Report – Australia 2024.

Figure 1-6 NEM cumulative degraded megawatt-hours of battery capacity by scenario

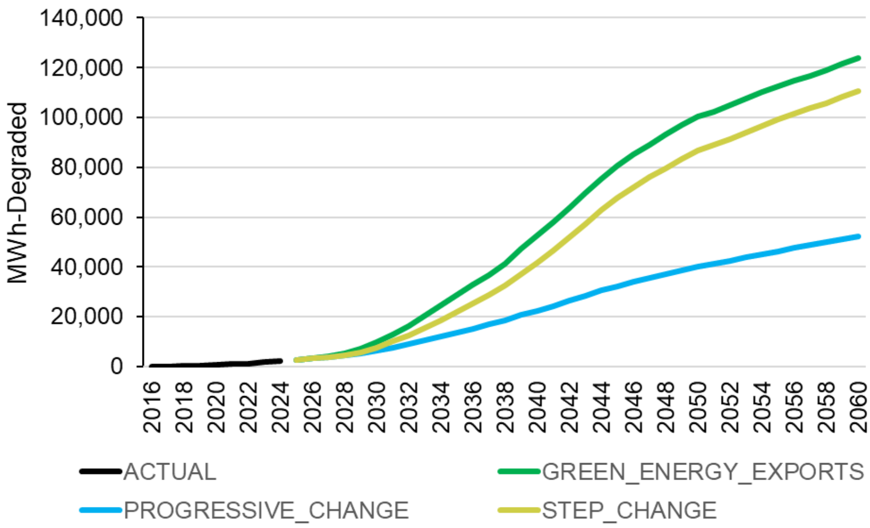
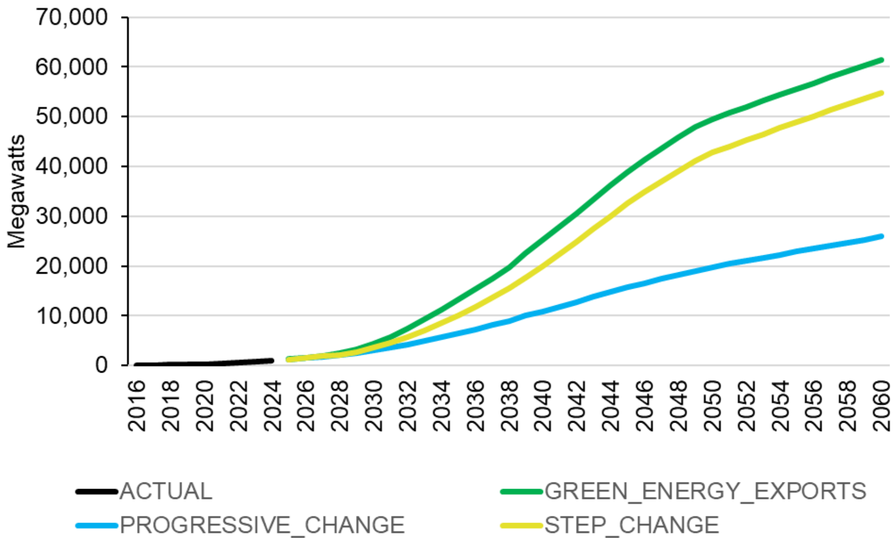


Figure 1-7 below shows the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 994MW at the end of 2023-24 financial year. Under Progressive Change this grows close to 26,000MW by the end of the projection in 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches more than 61,000MW. The projections are based on an assumption that the instantaneous output which can be extracted from a battery is not subject to degradation (although the kilowatt-hours of storage is still subject to degradation) with the average battery having 2.5 hours of storage relative to it's sustained peak output rating. So a 10 kilowatt-hour battery, as an example, could output a maximum of 4 kilowatts for 2.5 hours.

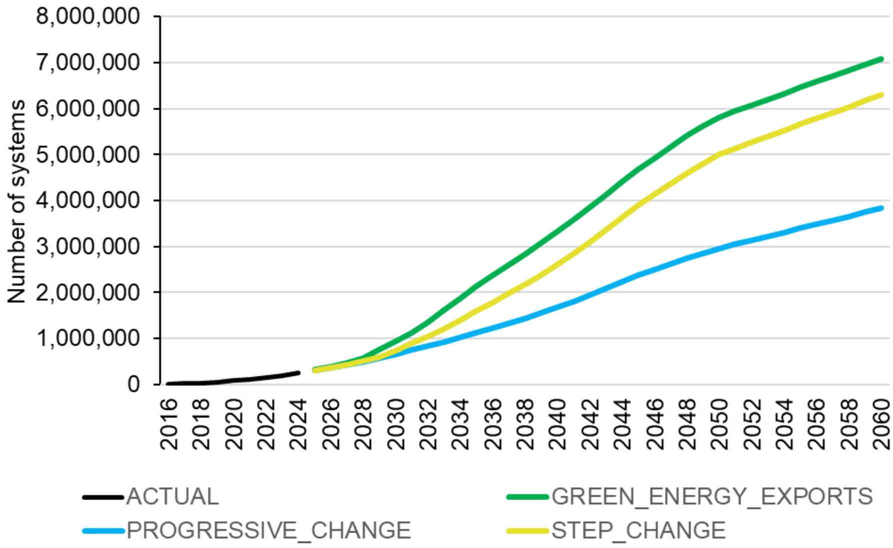
Figure 1-7 NEM cumulative megawatts of battery capacity by scenario



The figure below details projections for the cumulative number of battery systems by scenario in the NEM. At the end of the 2023-24 financial year the cumulative number of grid-connected battery systems is estimated at close to 250,000. Under Progressive

Change this grows to 3.8 million by the end of the projection with 26% of detached and semi-detached residential dwellings owning a battery system. The upper bound represented by Green Energy Exports reaches 7 million, with 45% of detached and semi-detached dwellings owning a battery system.

Figure 1-8 NEM cumulative number of battery systems by scenario



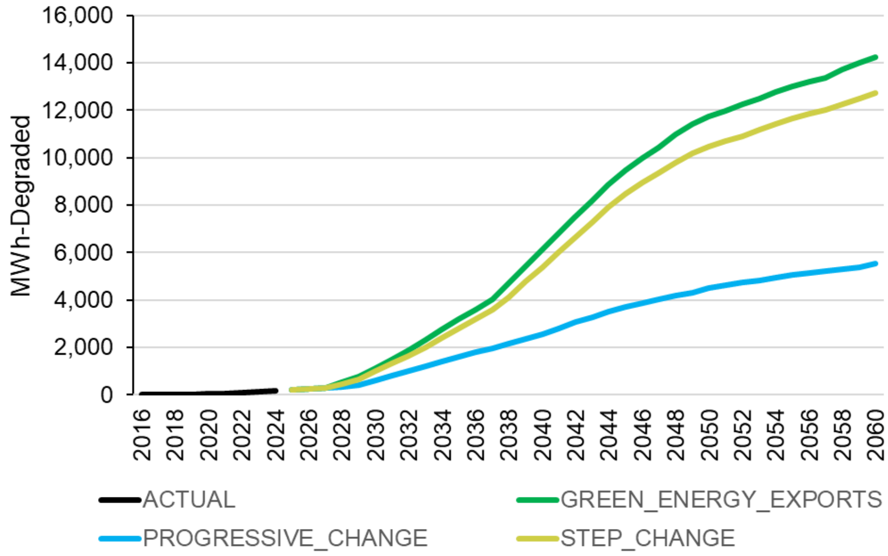
As some perspective, at the low end under Progressive Change 61% of solar systems in the NEM would be coupled with a battery, while at the high end represented by Green Energy Exports, 84% of solar systems are coupled with a battery.

The noticeable slowing in the growth of the stock of battery systems shown by the inflection or knee point of the blue and yellow lines close to 2050 is a product of batteries having penetrated a large proportion of the existing stock of households with solar systems around this point in time (for the Green Energy Exports and Step Change scenarios). After this point, while sales of battery systems remain high, many of these are systems which are replacing retiring battery systems, so they don't increase the overall installed stock of battery systems.

Western Australian South-West Interconnected System

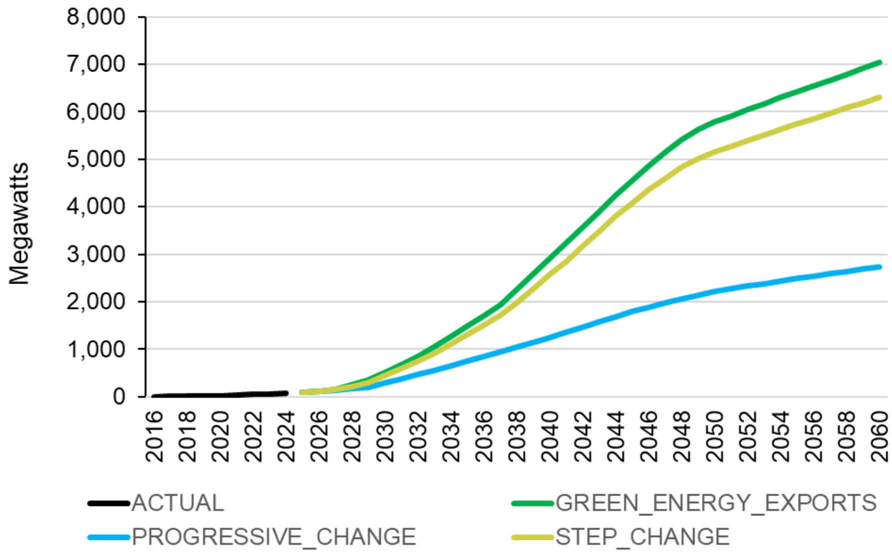
The figure below details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the WA SWIS, taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2023-24 financial year) cumulative degraded battery capacity is estimated to stand at almost 176MWh. Under Progressive Change the cumulative degraded capacity reaches 5,500MWh by the 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches 14,200MWh.

Figure 1-9 WA SWIS cumulative degraded megawatt-hours of battery capacity by scenario



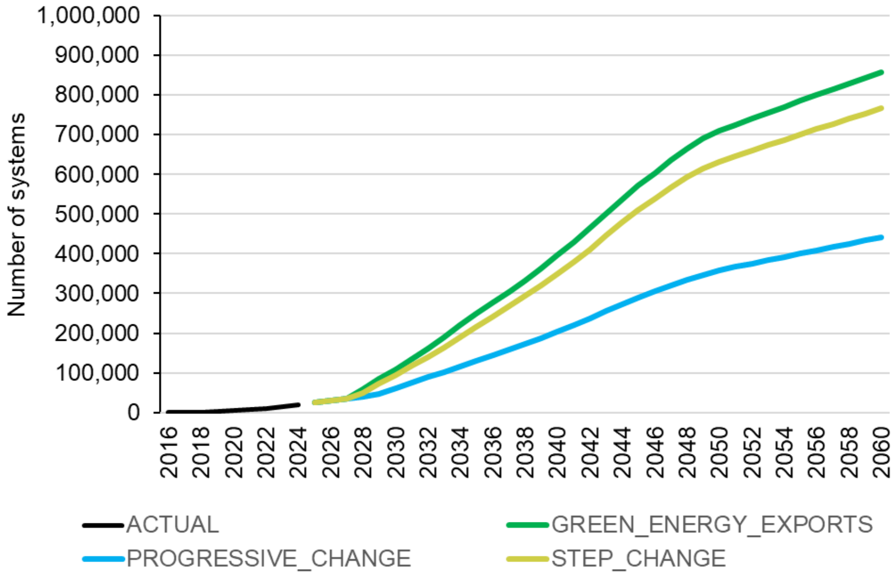
The figure below illustrates the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 77MW at the end of 2023-24 financial year. Under Progressive Change this grows to around 2,740MW by the end of the projection. The upper bound represented by the Green Energy Exports scenario reaches around 7,000MW.

Figure 1-10 WA SWIS cumulative megawatts of battery capacity by scenario



The figure below details projections for the cumulative number of battery systems by scenario in the WA SWIS. At the end of the 2023-24 financial year the cumulative number of grid-connected battery systems stands at close to 19,700. Under Progressive Change the cumulative number of systems grows to around 441,000 by the 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario has close to 858,000 battery systems.

Figure 1-11 WA SWIS cumulative number of battery systems by scenario



As some perspective, under Progressive Change 50% of solar systems in the SWIS would be coupled with a battery by 2059-60. At the high end represented by Green Energy Exports 75% of all solar systems are coupled with a battery.

1.3 Summary of key drivers behind projection results

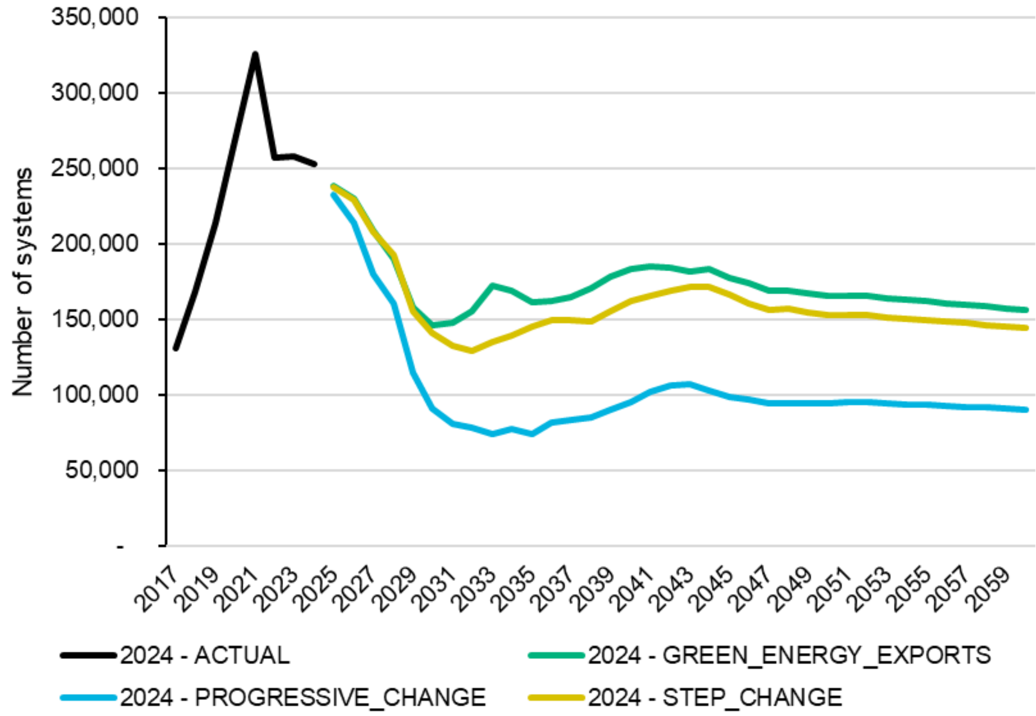
This section provides a brief summary of key drivers affecting solar PV and battery uptake in this projection, with a more detailed explanation provided in section 5.2. Note these key drivers reflect trends that have been evident for several years and were a prominent influence in last year's projections as well.

1.3.1 Number of system installations expected to slow due to falling revenue and saturation effects

While the aggregate results detailed above show solar and batteries accumulating to reach a very large level of cumulative capacity, these cumulative results obscure the fact that the number of solar systems being added to the stock each year is expected to fall considerably relative to the levels achieved in the last few years.

The chart below illustrates our projections for the number of new solar systems being added to the aggregate stock each year after deducting system retirements. Across all scenarios the number of solar system additions are expected to fall rapidly over the remainder of this decade before regaining modest growth in the 2030s (as batteries become economic) but at levels still well below what was experienced over 2019 to 2024.

Figure 1-12 National annual number of solar system additions to stock



This fall in solar system additions isn't because we expect the decline in the cost of solar or battery systems to abruptly end, instead we expect ongoing substantial falls in system costs, particularly for batteries.

However, three key headwinds act to mitigate the benefit of falls in solar system costs in particular:

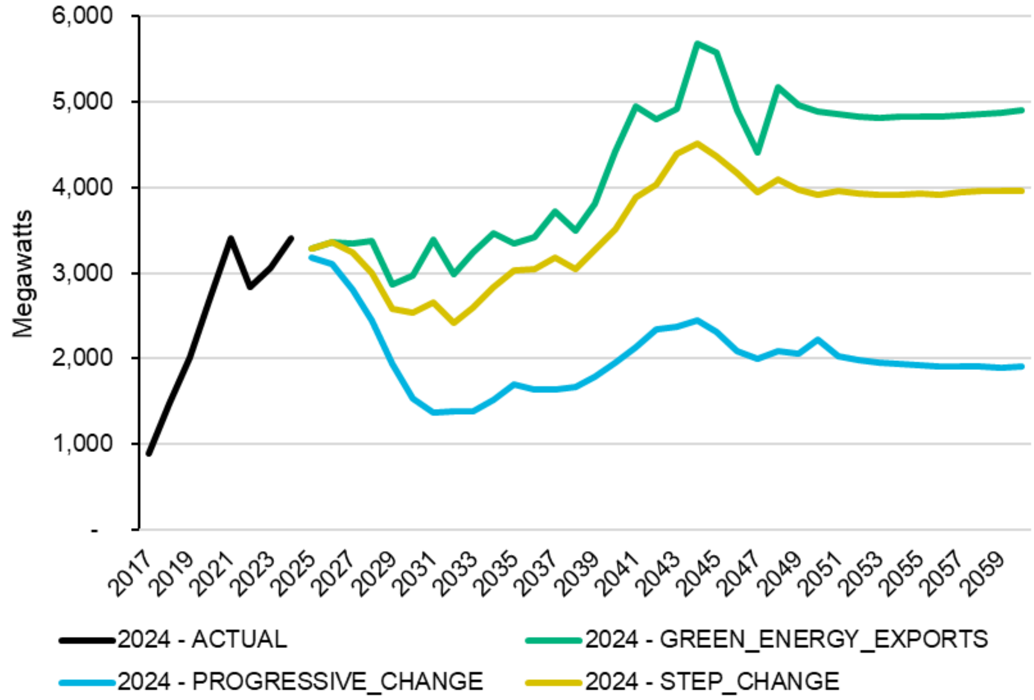
1. The wholesale market price for electricity during sunny periods has been falling steadily over the last few years (excepting the temporary surge over 2022 due to the Russian-induced spike in international gas and coal prices) thanks to the large surge in supply from increased solar capacity. Our expectation, embedded within the model's assumptions, are that daytime average wholesale prices will be very low throughout the projection period across all scenarios.

2. The level of financial support provided by government emission reduction policies which have been important to the economics of distributed solar - the Small Scale Renewable Energy Scheme and the Large Scale Renewable Energy Target - are being wound down as we approach the 2030 end date for these initiatives.
3. The AEMC mandated move to greater use of “cost reflective” network tariffs is anticipated to lead to declining retail prices charged during daytime hours (but with compensating higher prices in the evening) which reduces the effectiveness of a solar system (especially when not coupled to a battery) to reduce energy bills.

1.3.2 Ongoing trend towards larger capacity residential solar systems offsets falling system numbers

While the number of new system additions to stock is expected to fall noticeably over the outlook period, we don’t see the same large fall unfold with annual additions of megawatts of capacity as shown in the chart below.

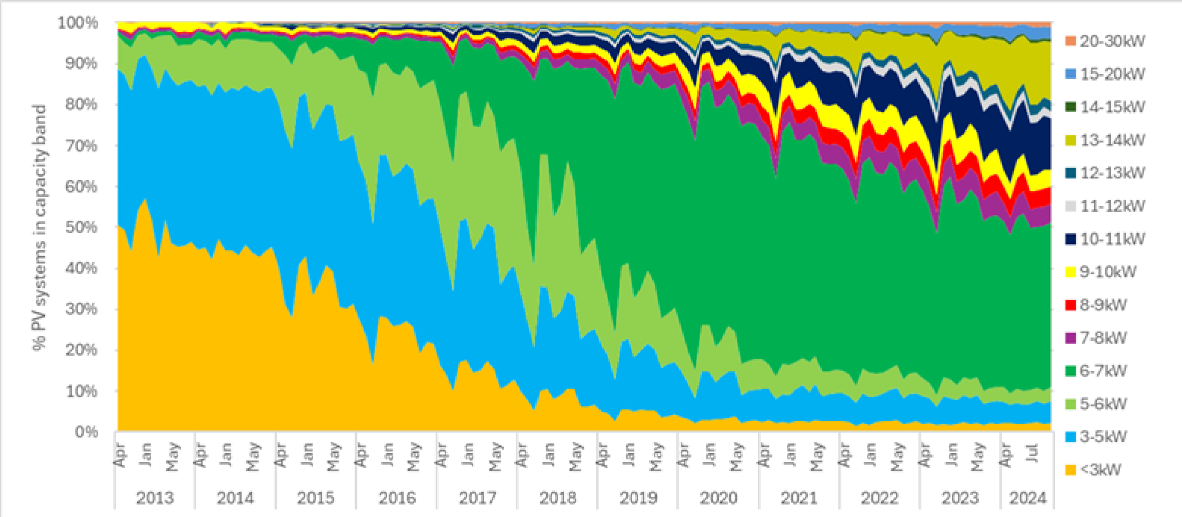
Figure 1-13 National megawatts of solar additions to stock by scenario



The reason that megawatts of capacity don’t fall in line with system numbers is partly a function of an expected rising share of capacity being installed in the commercial sector (which are bigger than residential systems), but mainly due to the average residential solar system becoming bigger over time.

The chart below illustrates the share of PV systems by different capacity bands since 2013 to mid 2024. Systems smaller than 3kW dominated the Australian residential market back in 2013, representing around half of all systems. By 2019 they were less than 5% of the market and systems between 6 to 7kW were dominant. In 2024 we can now see these sized systems look to be on the way out. Meanwhile systems larger than 10kW now represent over 30% of all residential systems, yet they were less than 1% of residential systems just 8 years ago.

Figure 1-14 Share of residential solar systems installed by system size band



Source: Green Energy Markets analysis of Clean Energy Regulator STC systems data

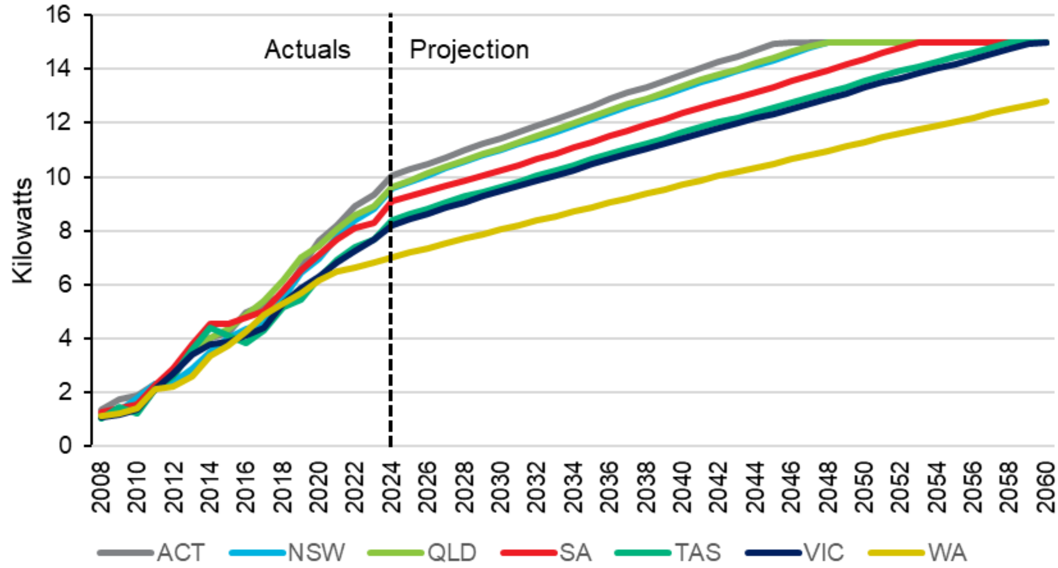
The appendix to this report provides further detail on the historical distribution of residential systems by capacity size band that is broken down by state.

We anticipate that this trend towards ever larger residential systems will continue, although at a slower rate than what has occurred historically[6], before they top out at a maximum of 15kW average size[7] under the Step Change and Green Energy Exports scenarios and 13kW under the Progressive Change scenario. The historical pattern for residential system size and our projections are detailed below, broken down by state.

[6] Factors expected to slow growth include the scale-back in the Federal Government's STC rebate per unit of capacity; falling feed-in tariffs and increasing curtailment; an expected slowing in panel conversion efficiency improvement; and household rooftop physical size limitations.

[7] Note we acknowledge that 15kW is not an absolute physical limit as there are already residential systems being installed that are larger than 15kW. But when considering the overall average across the entire residential market we expect that constraints will become increasingly prevalent as the overall market average approaches 15kW.

Figure 1-15 Average residential solar system size by installation year and by state (Step Change and Green Energy Exports)

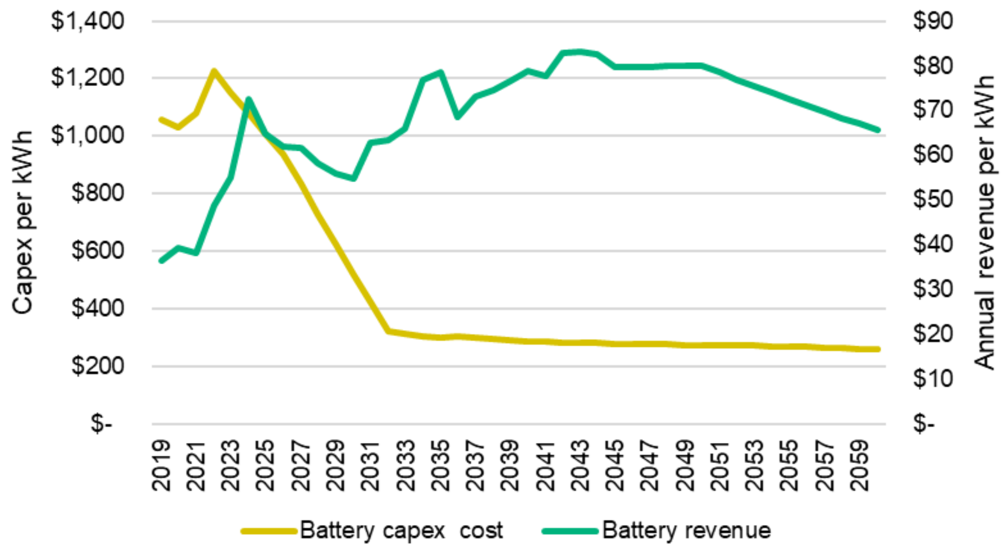


1.3.3 Falling battery system costs provide means to mitigate falling daytime prices for solar

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 as we approach 2030 opens up the potential for consumers 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.

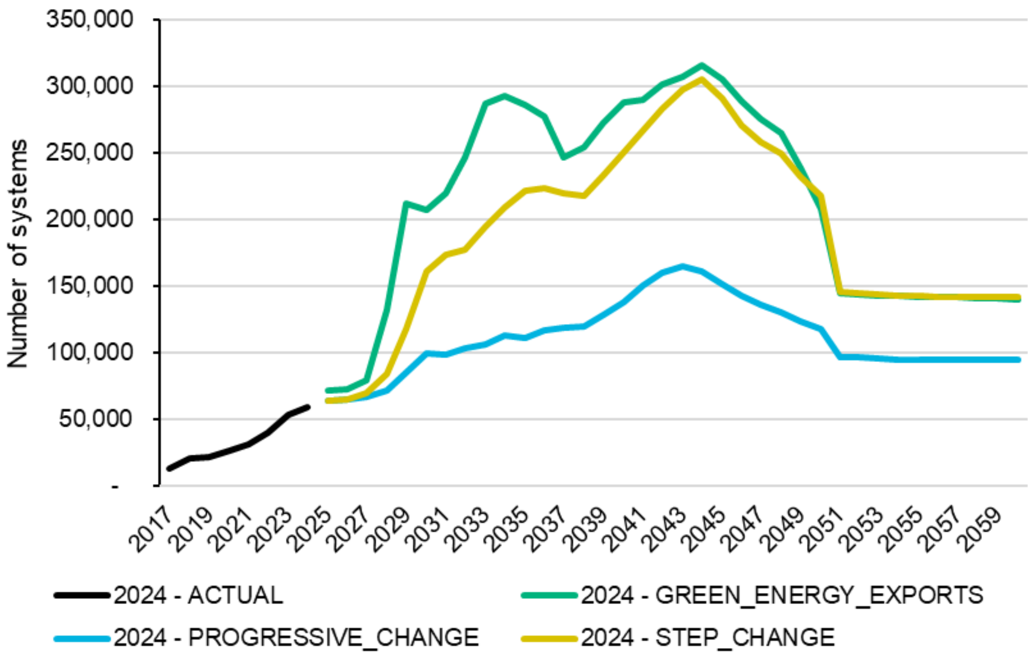
The figure below illustrates how under the Step Change scenario revenue for a battery system (shown by the green line) rises while the capital cost for a battery (yellow line) plunges.

Figure 1-16 Revenue vs cost per kWh for household batteries (Step Change Scenario - NSW)



This improvement in the economics of batteries, in conjunction with the assumed introduction of additional government and virtual power plant incentives for batteries under the Step Change and Green Energy Export scenarios, leads to a surge in the installation of battery systems in the late 2020's as shown in the figure below. This is also important to arresting the decline in ongoing solar system additions.

Figure 1-17 National annual number of battery system additions to stock



Please note that rapid drop-away in battery system additions to stock around the mid 2040's are not actually reflective of a drop in sales of battery systems but rather a drop in battery systems being installed in premises which have not previously had a system. Battery system additions to stock experience a level of rapid growth as they progressively penetrate into households that already have a solar system but not a battery. However, over time this market becomes saturated and ongoing sales of batteries to this segment of the market are simply replacing a pre-existing retired battery system and so make no difference to the overall stock of battery systems. This market saturation effect is explained in further detail in section 5.2.5 of this report.

1.4 Changes to the modelling relative to last year's estimates

The Figure 1-18 immediately below illustrates this year's projection of annual solar PV system additions (shown in the solid lines) compared last year's projection (dashed lines). Meanwhile the subsequent Figure 1-19 shows the same comparison for battery system additions.

Figure 1-18 National annual number of solar system additions to stock - 2023 (dashed) vs 2024 (solid) projections

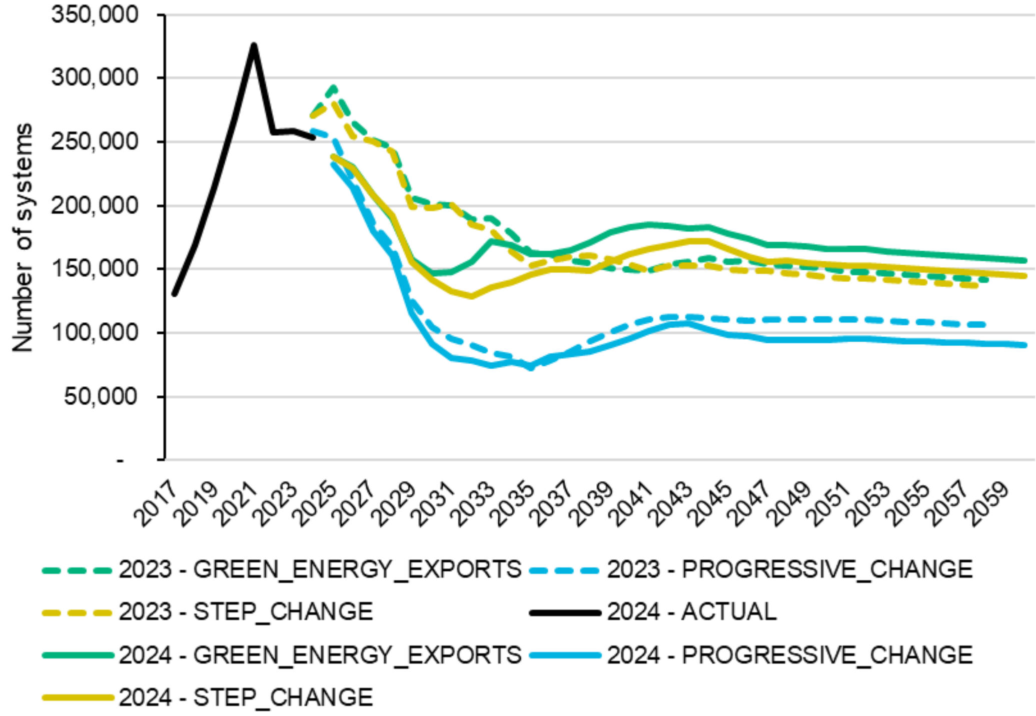
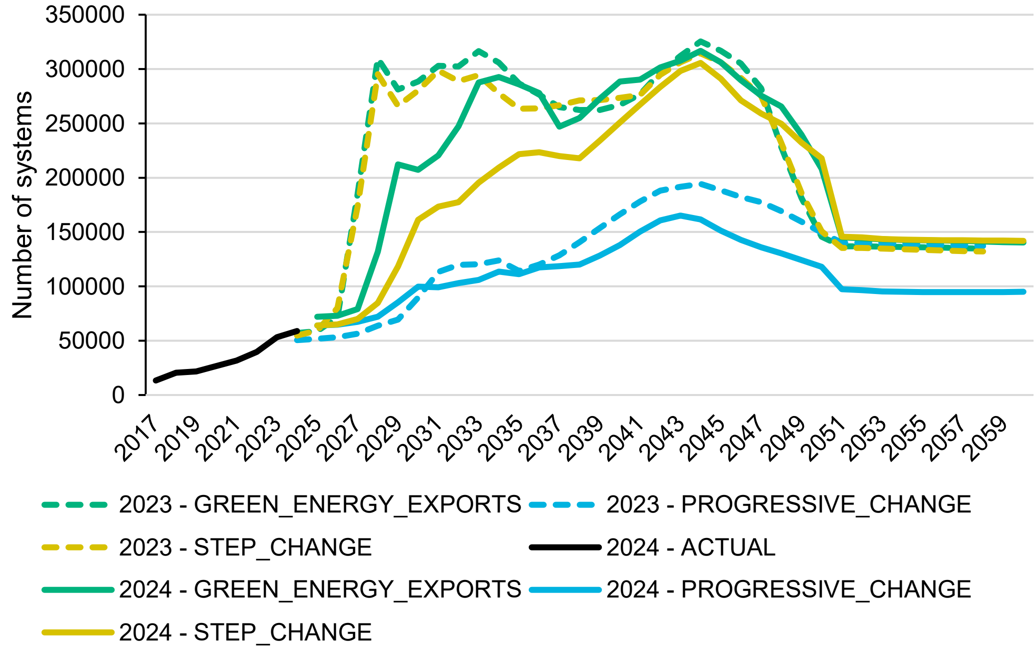


Figure 1-19 National annual number of battery system additions to stock - 2023 (dashed) vs 2024 (solid) projections



The most notable difference is that both solar and battery system additions are lower for the first decade of this year's projection compared to last year's under the Step Change and the Green Energy Export scenarios. This is mainly explained by a decision to reduce the scale of government and Virtual Power Plant incentive value which is assumed to be introduced in these two scenarios as part of an effort to accelerate emission reductions, consistent with the emissions objectives of these two scenarios. Last year's projection assumed government support incentives were introduced in the mid 2020's which had an effect akin to reducing the out of pocket price for consumers by 50% of capex and that consumers would also be offered an inducement of $100 per kWh to join a Virtual Power Plant arrangement. This year it was decided that this level of support should be scaled back to 33% of the capex cost for Green Energy Exports and 25% of capex under Step Change (inclusive of both government policy support and VPP inducement). This was considered appropriate given several state governments have scaled back their rebates; the NSW Peak Demand Reduction Scheme value is noticeably lower than 50% of capex; and the Federal Government has not publicly declared an interest in providing financial support for behind the meter batteries.

However, later on in the projection around the mid to late 2030's solar system additions in this year's projection rise above last year's for both Step Change and Green Energy Exports. This is because solar and battery system revenue in this year's projections for these two scenarios are slightly higher than last year's. Meanwhile the value of the government and VPP support incentive is phased down over time and so is not as much of a distinguishing feature as time goes on.

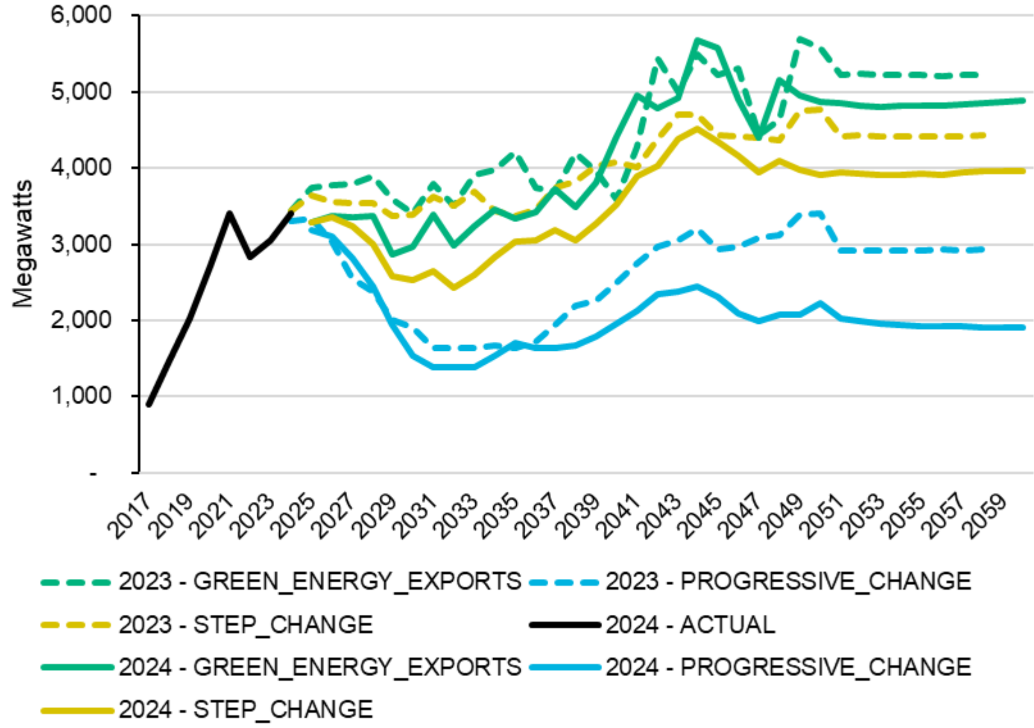
In terms of the Progressive Change scenario, system numbers are very similar this year relative to last year, although battery numbers this year are down from the late 2030's onwards. This is mainly due to an adjustment in how we've derived our battery capex assumptions. Our approach to estimating DER battery capex has been to assume it will decline over the next decade to get close to the cost of a 2 hour utility scale battery (on a per kilowatt-hour basis) as estimated in CSIRO's Gencost publication[8], but with a premium added that is reflective of the premium we currently see for Australian household solar systems relative to utility-scale solar systems. This premium has been around 10% to 15% in recent years. However, at present the premium between a small-scale battery and a utility-scale battery is much higher than this – closer to 50%. Given the highly modular nature of battery system components, and the simplicity of a household battery install we expect this premium will diminish substantially over the next decade, but this is subject to uncertainty. To better reflect this uncertainty, in this year's projection under the Progressive Change scenario we assume only a small narrowing in the cost difference between utility-scale and small-scale battery systems such that small scale systems carry a 40% premium over 2 hour utility-scale systems.

If we then look at megawatts of capacity as shown in the figure below, we again see for Step Change and Green Energy Exports that numbers are lower in this year's projection compared to last year for the first half of the projection period. This is largely a function of the lower system numbers explained above. In the later part of the projection however megawatts of capacity follow a different pattern to system numbers. The reason for why megawatts are down in this year's projection when system numbers are up is due mainly to lower levels of projected capacity from the 1MW to 5MW sector which are tied to projections of large scale solar farm capacity in the 2024 ISP.

[8] Graham, Hayward, Foster (2024) GenCost 2023-24 – Final Report – May 2024

In terms of Progressive Change, megawatts, just like system numbers, are down compared to last year's projection from the late 2030's, although more noticeably so for megawatts. This is largely due to assuming a smaller average residential system size limited to a maximum of 13kW in this year's projection.

Figure 1-20 National megawatts of solar additions to stock 2022 vs 2023 projections



2 Introduction

The Australian Energy Market Operator (AEMO) has engaged Green Energy Markets Pty Ltd (GEM) to provide several scenario-based projections to 2059-60 of solar and battery uptake for a part 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[9] 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 at the beginning of the projection and increase to a maximum of 20kWh.
- 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 at the beginning of the projection and increase to a maximum of 20kWh[10].
- Large commercial which are assumed to be above 100kW and up to 1 megawatt and their associated batteries, which were assumed to be sized at 500kWh.
- 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.

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[9] Note that in the Western Australian Market the threshold is lower.

[10] Commercial battery systems are a similar size to residential systems because even though these premises have a larger load and are assumed to install a larger solar system than residential, the solar system is aligned more closely with daytime load and so has less generation surplus to load that would otherwise be exported to the grid. This substantially reduces the scale of arbitrage the battery can provide in taking power that would be otherwise be exported at a rate tied to wholesale energy costs and instead using it for self-consumption tied to retail rates.

3 Methodology and Approach

3.1 Overview

This report seeks to project uptake for the section of the 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[11]. 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 as noted earlier:

- Residential;
- Small commercial;
- Large commercial; and
- Small power stations.

Green Energy Markets' 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 historical payback periods. 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 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.

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

For systems within segment 1 (behind-the meter) we specifically analyse financial attractiveness and then subsequent uptake based upon Green Energy Markets' 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 AEMO's 2024 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:

a. 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); and

b. 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.

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 20kW 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. While government support policies can take a wide variety of shapes including discounted loans, revenue supplements to reward such things as carbon abatement and peak demand reductions as well as upfront reductions in capital cost, the net effect is that they enhance financial attractiveness of investments in solar and batteries and so should shorten payback times. That is what we try to capture in the model rather than a precise reflection of the workings of the policy mechanism itself.

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 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 2054 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[12]. 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 load for a substation that predominantly services non-residential customers[13]. To ensure that this was a reasonable representation of commercial loads across 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 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%).

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

[13] 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

3.3 Residential demand

We have used detailed historical data for solar PV installations provided by the Clean Energy Regulator (CER) which provides a break-down on whether systems have been installed on a residential or commercial premise.

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.
- Relative level of saturation – as solar and battery systems penetrate an increasingly large proportion of residential dwellings, to achieve further growth it needs to expand to customers that are likely to represent a more difficult sales proposition. This may be because their roof is less well suited to solar (for example it is shaded), or they are a small consumer of electricity, or the house is rented. This is accounted for via a discount factor which adjusts downwards the level of uptake for a given level of payback as solar reaches increasingly high proportions of residential dwellings. We have calibrated this as being 1.0 (no discount) at saturation levels of 20% or less and then reduces to 0.5 (50% discount) at saturation levels of 80%. This is then also converted into an index with an average of 2019 as the base year.
- 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 2019 as the base year; 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 2019 as the base year.

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.

Our baseline year is an average of the 2019 and 2020 level of installations by state. This provides a reasonably large market size ranging from around 230,000 new systems in 2019 to 275,000 systems in 2020. Interviews with industry participants have been a key component in gauging factors and issues that are actually working on the ground to influence customer purchasing decisions, beyond just financial attractiveness.

We have developed linear equations that represent the relationship between the level of installation and the adjusted payback in that year.

Our approach can be represented by the following formula:

Demand (year) = Systems derived from Payback equation (year) x Relative Level of Saturation (year) x Relative Customer Awareness Index (year) x Relative Solar Industry Competitive Index (year)

3.4 Commercial demand up to 100kW systems

This market sector is also now reasonably mature, and we use a similar approach to new residential systems with an average of 2019 and 2020 installations as our baseline. Forecast installations are based on relative financial attractiveness (relative to the 2019/20 base year). We have also incorporated a consumer awareness and industry competitiveness scaling factor to reflect improved industry attractiveness as more solar businesses target this sector.

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

The upgrade market has recently emerged as an increasingly important segment of the market. New system information collected by the CER from late 2020 indicates that the level of upgrades was more than 70% higher as it now includes both the upgrade of existing system as well as the replacement of older systems.

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 and a number of customers are expanding their systems in response to higher power prices and lower panel prices. We expect it to continue to grow and become a much more important feature of the industry in future years as saturation increases and customers come off attractive historical feed-in tariffs. We use expected 2021 installations as the baseline and then overlay this with relative financial attractiveness and then allow for an additional 15% per annum growth rate to reflect a progressive replacement of smaller older systems as they age beyond 10 years.

The commercial upgrade market at an estimated 80 to 100 MW is probably 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.

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

As detailed in prior years' projections, assessing the likely trajectory of installations for mid-scale solar systems (defined as those 100 kilowatts and up to 30 megawatts in capacity) is subject to considerable uncertainty.

Factors making it difficult to predict future installations include the fact that the market is immature and still undergoing rapid development and change. Prior to 2016 solar systems larger than 100kW were not really a commercial proposition to electricity customers where a large proportion of network charges are recovered via demand-based tariffs.

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 of megawatts installed in the last six 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. However, the number of installations remains small at a between 200 to 300 systems nationally per annum.

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, even though the limited sample set constrains the ability to develop a precise and confident relationship between uptake and plausible variables that influence uptake, what is clear is that the behind the meter market's rapid growth from 2016 to 2018 was predominately a function of changes in the financial attractiveness of solar systems relative to end consumers buying power from the grid.

The rapid rise in uptake that began in 2015 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. Further reinforcing this observation is that the rapid growth in installations halted and system numbers fell in 2020-21 year as wholesale energy market costs declined both in terms of the spot market but also the forward contract market (as shown in ASX Energy futures contracts). More recent data indicates installations have risen since electricity prices spiked upwards in 2022.

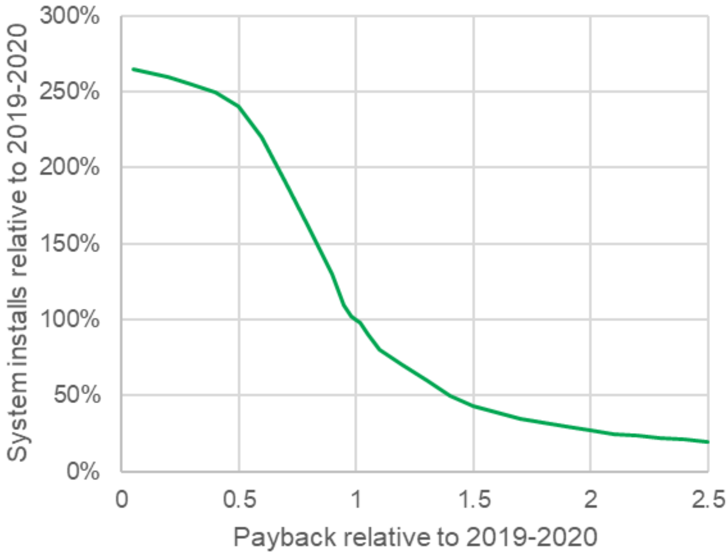
We have attempted to evaluate how uptake of behind the meter solar is likely to change by assessing payback periods on solar systems relative to a baseline of the 2019 and 2020 years. Given the noticeable lags affecting the mid-scale solar market we believe 2019 and 2020 installation levels are a reasonable reflection of the likely sustained customer solar uptake in response to the large electricity price and system cost changes that unfolded over 2016 to 2018.

The number of solar system applications for accreditations in 2019 and 2020 by state are used as our reference or benchmark for evaluating how changes in payback relative to these years will change uptake of LGC registered behind the meter solar capacity.

To provide a lower bound guidepost as to how much capacity accredited could fall as paybacks deteriorate (become longer), 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 more than twice as long as what they were in 2019/20. Mid-scale behind the meter solar capacity accredited in 2016 (excluding remote or off-grid power) was 22MW.

With these reference points we have constructed an uptake curve that estimates how the capacity of behind-the-meter large commercial solar installs are assumed to change as paybacks lengthen. Both uptake and paybacks are referenced relative to 2019 and 2020 levels. So, if the payback period in a future year was the same as this time (a value of 1) then the capacity accredited would be the same, or 100%, of what it was on average over 2019 and 2020. If the payback period is twice as long as what it was in 2019/20 then uptake is assumed to drop down, although not quite as low as what it was in 2016.

Figure 3-1 Large commercial solar uptake curve



However, on top of the payback evaluation we also overlay an underlying growth factor to account for the fact that:

- the solar industry is expected to become more capable and competitive in the sale and installation of solar systems;
- customers have growing understanding and confidence with solar systems' ability to reduce electricity costs; and
- the size of the economy and population grows over time, expanding the number of potential facilities where large commercial solar systems are suitable.

This growth factor steadily increases the baseline capacity that will be induced by given payback and is varied depending upon the scenario with a highest growth factor applied for the Green Energy Export scenario and the lowest growth factor applied for Progressive Change.

3.7 Battery uptake for behind the meter systems

Batteries are yet to reach levels of financial attractiveness (across all the behind the meter market segments analysed) that would support mass-market uptake. While the current modest levels of uptake and relatively poor paybacks give us a minimum baseline for uptake, they aren't particularly useful in guiding how uptake might rise if paybacks improve materially.

Our model currently assumes that battery uptake only takes place once the paybacks on a battery plus solar system reach close to parity with the payback on a solar system alone. Battery uptake is assumed to follow similar rates of system uptake relative to payback as what we assess for solar systems in each of the customer segments analysed. Although given a range of safety restrictions imposed by the battery installation standard, the level of battery systems installed is restrained slightly below that of solar systems.

This approach however results in a gap in the first few years of the projection where the model projects zero battery uptake or battery uptake well below historical levels, because battery paybacks are so long (noticeably greater than warranty period) in these years. For this interim period between historical actuals and when the model starts to estimate significant battery uptake, we assume battery uptake follows a transition path of growth that is partly informed by how paybacks are estimated to improve over time in each scenario.

3.8 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 AEMO's 2024 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.

The amount of 1MW+ capacity installed is calibrated at 6% of the scheduled solar installed in each year as estimated in the ISP. This is in line with the proportion of sub-30MW power station capacity accredited in 2019 relative to those 30MW or greater.

4 Scenarios and associated assumptions

4.1 About the scenarios

Projections for solar and battery uptake have been developed for three 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 2023-24 GenCost analysis[14] 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 adapted these to a degree based on 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.

[14] Graham, Hayward, Foster (2024) GenCost 2023-24 – Final Report – May 2024

Table 4-1 Overview of modelling assumptions for each scenario

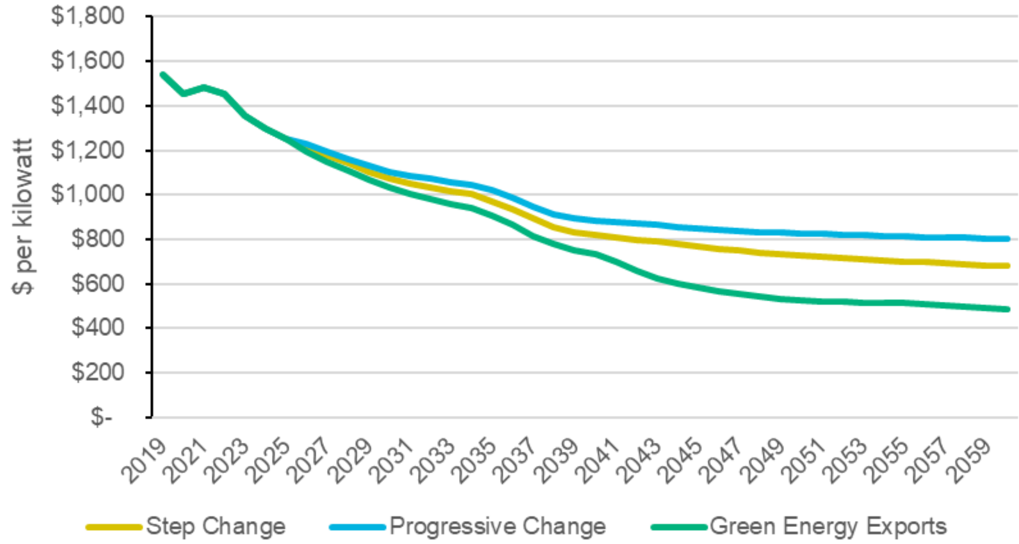
Component	Step Change	Progressive Change	Green Energy Exports
Guiding themes	Rapid emission reductions and technological advancement with growth of distributed solar and batteries playing a leading role.	Slower emission reductions and technological advancement. Distributed energy plays a lesser role in decarbonisation.	Entire globe mobilises to contain global warming to 1.5 degrees. Rapid economic and energy demand growth and technological improvement.
Distributed solar and battery cost declines	Rapid. Aligned with CSIRO Gencost's Global NZE post 2050 scenario, although residential solar adjusted upwards for labour-related costs.	Slowest. Aligned with CSIRO Gencost's Current Policies scenario although residential solar adjusted upwards for labour-related costs.	Very Rapid. Aligned with CSIRO GenCost Global Net Zero by 2050 Scenario
Decarbonisation policy support (IEA shadow carbon price scenario)	Significant in reducing cost to consumers. Aligned with IEA's Sustainable Development Scenario	Minor - Aligned with IEA's Stated Policies	Significant - Aligned with IEA's Net Zero Scenario
Level of policy and VPP support for batteries	National policy support plus VPP incentive equal to 25% of capex introduced in 2027 and steadily declines from 2040 onwards	Existing state policies	National policy support and VPP incentive equal to 33% of capex introduced in 2027 and then steadily declines from 2040 onwards.

4.2 Capital cost - PV

To help calibrate solar uptake to payback relative to historical levels we maintain records of system costs over time informed by a combination of interviews with industry participants, wholesaler price data, and the Solar Choice Price Index and the SolarQuotes Price Index as key inputs which are cross checked through interviews of industry participants.

In Figure 4-1 we detail assumed solar system costs per kW by scenario before the impact of any government financial support such as STCs or rebates.

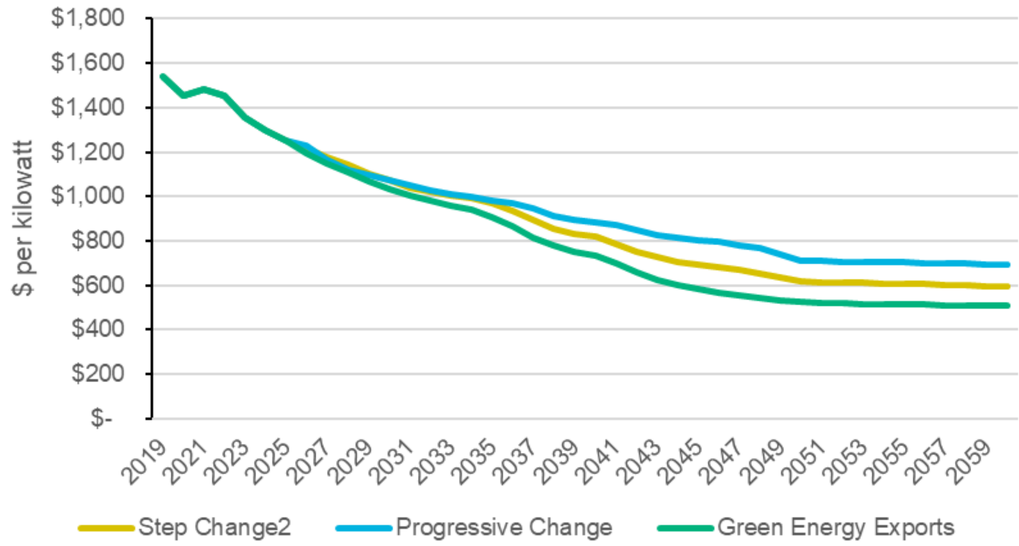
Figure 4-1 Fully installed residential solar system price per kW by scenario (includes GST, excludes discounts from-government support measures e.g. STCs)



Sources: Green Energy Markets' residential system costing model in combination with CSIRO Gencost 2023-24 . Note – includes GST.

Figure 4-2 below provides our capital cost assumptions for commercial-sized systems which are only slightly different to residential.

Figure 4-2 Fully installed commercial solar system price per kW by scenario (excludes discounts from-government support measures e.g. STCs)



Sources: Green Energy Markets' analysis of conceivable range of cost trajectories up until 2030 after which it is aligned with CSIRO GenCost 2023-24 Trajectory which aligns with each scenario. Note – excludes GST.

4.2.1 Incorporating the 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 $38.50 fixed in nominal terms 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

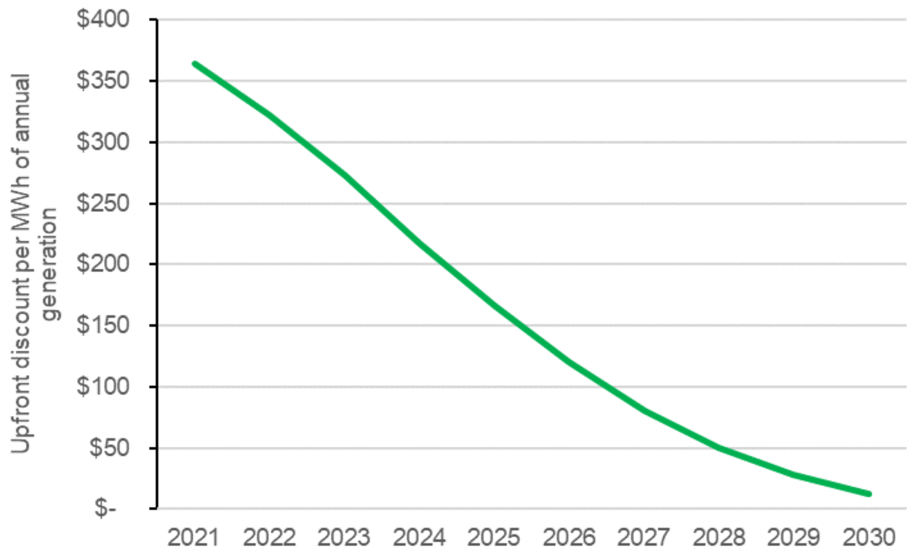
As an alternative to STCs, solar systems can instead claim Large-Generation Certificates or LGCs which electricity retailers and some other large electricity consumers are obligated to purchase in order to achieve the national Renewable Energy Target. LGCs are awarded to a solar system owner on the basis 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.

The figure below 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 based on forward market pricing (as at August 2024) due to substantial growth in LGC supply over that time. The upfront discount value applied from LGCs is the same across all scenarios.

Figure 4-3 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 2021 in the model is 427 multiplied by $364, whereas a system installed 2025 receives 427 multiplied by $167.

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. It then subsequently extended the program to also provide rebates to landlords installing solar on their rental properties and expanded the target to 700,000 solar systems. 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 now stands at a maximum of $1,400 per system.

Emissions Reduction Fund and Safeguard Mechanism ACCUs

Solar systems located behind the meter have the potential to assist firms covered by the safeguard mechanism to reduce their emissions and thereby avoid the need to purchase Australian Carbon Credit Units (ACCUs) or potentially also allow them to credits for undershooting their emission baselines.

The value of the avoided need for ACCUs is taken into account in the model for solar systems above 100kW on a national basis assuming there will be a market for ACCUs out to 2050 under all scenarios. Also under Green Energy Exports and the Step Change Scenarios it is assumed that the ACCU scheme is broadened to also award ACCUs (on a ten year project eligibility basis) to solar systems outside of the safeguard facilities irrespective of their system size.

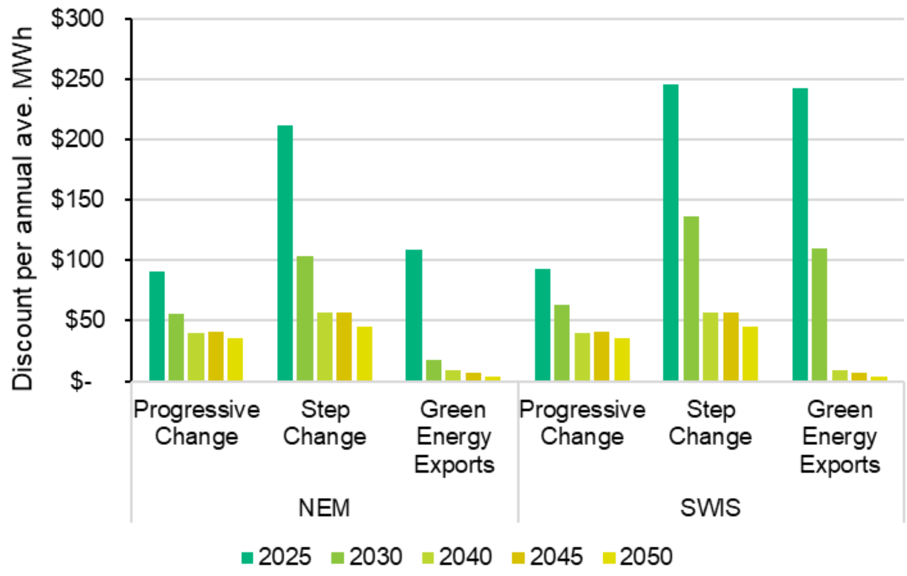
The amount of grid imported electricity displaced by the solar system is converted into an amount of abatement certificates by multiplying it by the average grid emissions intensity for the respective grid in which the system is installed. This is derived from a combination of data from the 2024 Integrated System Plan and the 2023 Australian Government Emissions Projections (with some modification to reflect scenario changes).

The value per ACCU is derived from carbon prices estimated under the IEA World Energy Outlook Scenarios with the following correspondence to the AEMO scenarios:

- Step Change – IEA's Sustainable Development
- Green Energy Exports – IEA's Net Zero Emissions
- Progressive Change – IEA's Stated Policies but with adjustment to reflect Australian market prices for ACCUs.

Figure 4-4 details the upfront discount applied according to the scenario and grid in which the solar system is installed. In the end the value of the ACCU discount in the model falls to quite low levels because the emissions intensity of electricity is anticipated to fall quite significantly, particularly under Green Energy Exports.

Figure 4-4 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 Progressive Change until 2027. After 2027 ACCUs are assumed to be awarded for all generation from the solar system whether consumed on site or exported and this is also the case for Step Change and Green Energy Exports from 2025 onwards.

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. Over the past two years a growing proportion of Victorian systems larger than 100kW have been opting to create these energy saving certificates.

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. The value of VEECs to 2025-26 is in line with recent forward trade prices close to $100. However in the subsequent year it is assumed to then fall to the average traded price over the past five years of close to $70 and remain at that level over the remainder of the outlook period under Step Change and Progressive Change. While in the Progressive Change scenario where it progressive declines to $30 by 2030 and then remains at this level for the remainder of the projection.

Interaction between different government support options for solar systems

Solar system owners potentially have a choice of several government support programs that they can elect to take advantage of. However, in most cases owners can only choose one program and are not allowed to claim benefits from two programs simultaneously, nor can they switch between programs from one year to the next. The exception to this rule is the Victorian Government Solar Rebate which can be claimed simultaneously with the STC program benefit, however this is only applicable to the residential sector.

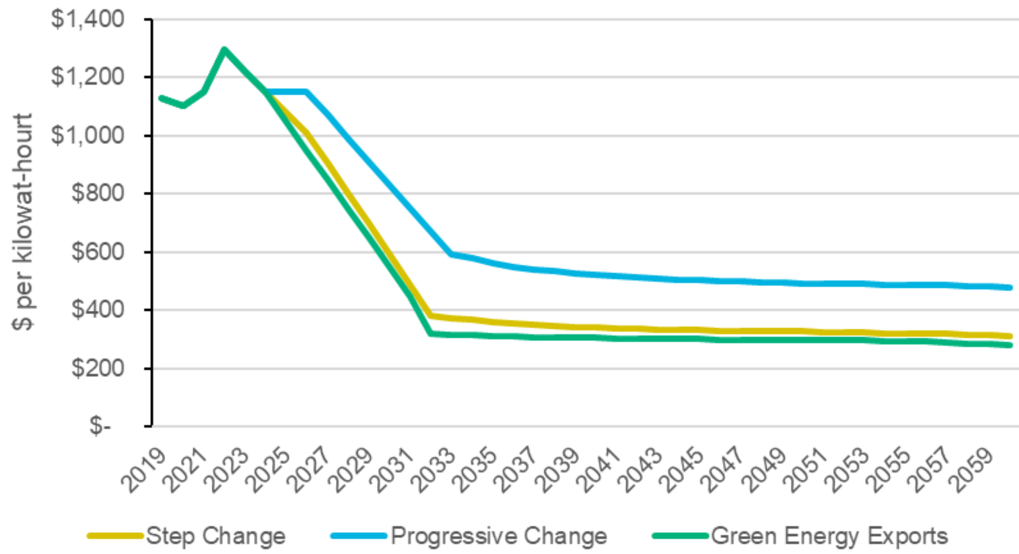
To deal with the requirement that an owner must elect to choose only one program, in each year the model evaluates which government program is expected to deliver the greatest financial benefit over the lifetime of the system and uses that value to allocate an upfront discount to the capital cost of the system.

4.3 Capital cost - Batteries

To inform our battery costs we have used a combination of sources including Solar Quotes, Solar Choice's Battery Price Index, wholesaler price data, and interviews with several solar-battery industry participants.

Figure 4-5 illustrates the assumed capital cost adopted for a battery system retrofitted to a residential solar system by scenario in the model. Costs for commercial systems are assumed to be similar to residential systems.

Figure 4-5 Assumed capital cost per kWh for residential battery system by scenario (Incl. GST)



In many cases batteries are likely to 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 $700 per residential system declining to $500 by 2036 onwards. For commercial batteries the saving is estimated at $50 per kWh of battery capacity which declines progressively over time to reach $20 per kWh by the end of the projection period.

Our monitoring of the residential-scale battery market suggests that prices for systems had shown little significant price reductions over several years and had even risen for several popular brands over 2021 to 2023. However, prices have very recently begun to decline. 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 (prior to recent inflation over the past 12 to 18 months) which are reflective of lower battery cell production costs[15]. 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 have been prioritising the far larger electric vehicle market over small 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.

We have used CSIRO's GenCost estimates for the cost of a utility-scale 2 hour duration battery to inform our assumptions of distributed battery price reductions over the long term. We assume that distributed batteries close the gap in cost per kWh with utility scale systems over time to approach a similar narrow differential as is currently achieved in Australia with distributed solar versus utility-scale solar (a 11% premium). We believe that given battery technology is based on modular components (just like solar) that are simply replicated in larger numbers of units for utility scale relative to smaller behind the meter applications, there is good reason to believe small, mass produced, household battery units will achieve costs not that much greater than utility-scale systems once they are rolled out in large numbers. Also, home battery storage systems are highly self-contained with simple plug and play architecture, so installation should be a straightforward and relatively quick process for electricians.

Under Step Change and Green Energy Exports the fall in prices occurs sooner and faster to converge with utility scale system costs by 2032 (but with a 11% scale premium). Progressive Change meanwhile illustrates a future where a competitive shake out and price falls take longer to play out and it is only by 2027 that prices in real terms manage to fall to where they were in 2020. Prices then follow a steady path downward. Also unlike Step Change and Green Energy Exports, it is assumed small-scale battery's continue to suffer from a significant price premium relative to utility-scale systems of 40% which holds from 2033 until the end of the outlook period.

4.3.1 Incorporating impact of government support policies

NSW Energy Security Safeguard (Peak Demand Reduction Scheme) and Consumer Energy Strategy

In May 2020 the NSW Government legislated changes to the *Electricity Supply Act 1995* which reconstituted the Energy Savings Scheme as the Energy Security Safeguard. This augmented the Energy Savings Scheme to create a new class of tradeable certificates which are awarded for initiatives which deliver reductions in electricity demand during periods of very high system-wide electricity demand. Like the Energy Savings Scheme, the scheme places a peak demand reduction obligation on liable parties – mainly electricity retailers – to procure these certificates.

[15] For example see the results of Bloomberg New Energy Finance surveys of vehicle manufacturer's reported battery pack prices here: https://www.bloomberg.com/news/articles/2023-11-26/battery-prices-are-falling-again-as-raw-material-costs-drop

Under this scheme behind the meter batteries qualify for peak demand reduction certificates by providing power to the premise where they are located at peak demand periods and reducing demand for power from the grid. A Peak-demand Reduction Certificate (PRC) is awarded for a technology which is deemed capable of delivering 0.1kW of demand reduction for an hour's duration whenever a peak demand period occurs for a given year.

We use the current methodology for estimating the amount of PRCs a residential battery is eligible for inclusive of the VPP reward (91 PRCs per kWh) and assume a PRC price of $2 which is then gradually reduced from 2029 onwards. This set of assumptions are the same across all scenarios.

We note that the NSW Government recently unveiled a Consumer Energy Strategy which sets a target for 1 million households and small businesses having access to both a rooftop solar and battery system by 2035. At this stage the government has not legislated this target nor spelt out the policy mechanisms it will implement to achieve this target and the current settings for the Peak Demand Reduction Scheme aren't expected to deliver this number of batteries. Nonetheless, we have assumed new policies will be implemented to achieve this target within the Green Energy Export scenario.

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 modest in scale, have ceased or we suspect they will not materially alter customers willingness to adopt batteries (particularly the provision of loans)[16]. Consequently, these are not explicitly part of the modelling process for battery uptake over the next decade.

Potential future battery support via new policy initiatives

To account for the fact that the Step Change and Green Energy Exports scenario narratives aim to represent a future involving very ambitious emission reduction efforts by governments where DER plays a significant part, we have assumed that a national government program to support battery uptake is introduced across both residential and commercial sectors beginning in 2026-27. This program (in combination of VPP incentives detailed below) is assumed to begin at a value equal to a third of the capital cost of a battery under Green Energy Exports and 25% under Step Change. This makes a significant impact in accelerating uptake of battery systems from 2027 onwards.

We also assume that scale of this financial incentive as a proportion of battery capex is steadily phased down from 2040 onwards.

4.3.2 The impact of Virtual Power Plant incentives

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. Usually this is only for a small number of occasions or a limited amount of capacity, leaving the battery owner free to use the battery how they wish for the majority of the time or majority of the capacity. There are now a number of companies which operate these virtual power plants and offer customers a variety of forms of compensation

[16] In the case of the Northern Territory battery rebate this was announced very recently and too late to be incorporated in our modelling.

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[17].

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.

While there remains significant uncertainty, the offers currently available are sufficiently attractive to some consumers that it would be sensible to take them into account. So, in addition to government rebates, we have also incorporated the potential for an upfront VPP payment that acts to reduce the purchase price of the battery in the model. While not all VPPs deliver payments via a purchase price discount, this is a simple and straightforward way to account for VPP payments in the model. These are assumed to only be offered in states where there is significant competition amongst retailers for residential and small business customers (NSW, Victoria, Queensland and SA). Also it is expected that the level of the VPP payment will decline over time as batteries become more numerous and decline in cost. In Step Change the model assumes the combination of an upfront VPPs discount on a battery and a government support program is equal to 25% of battery capex and 33% for Green Energy Exports. Under Progressive Change where there is no government rebate assumed (except for NSW Peak Demand Certificates) the VPP incentive is set at $50 per kWh throughout the outlook period.

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 cannot 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 data on historical retail market offers and the Australian Energy Market Commission's (AEMC) residential price trends information[18] but are adjusted to exclude fixed standing charges.

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[17] See here for details on the VPP offers currently available to residential battery owners: https://www.solarquotes.com.au/battery-storage/vpp-comparison/

[18] Australian Energy Market Commission (2021) Residential Electricity Price Trends 2021, November 2021

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

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 to the year 2023-24, 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 which stands at 10c/kWh for the period between 3pm and 9pm and 2.5c/kWh for all other times. We assume this rate remains at this level in real terms throughout the outlook period.

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 2023-24, which is derived from information within the Australian Energy Regulator's Default Market Offer estimates[19]. These are adjusted to remove fixed charges and reflect the fact non-regulated market offers are usually lower than the AER Default Market Offer.

This smeared uniform price then gradually unwinds over 2024-25 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 times the anytime smeared network charge in place in 2024-25. Meanwhile the solar soak and off-peak charge are both set at 45% of the anytime smeared network charge in place in 2024-25. Network charges are assumed to remain constant in real terms across the period from 2024-25 until the end of the projection period.

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.

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.

[19] Australian Energy Regulator (2023) Default market offer Prices 2023-24 final determination

In Western Australia the government has also indicated in its Distributed Energy Resources Roadmap[20] that it will seek to restructure tariffs to be time differentiated as a result of increasingly high solar penetration.

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, Endeavour and SA Power Networks to deliver more "cost-reflective" price signals.

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 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 installers that business 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 varies depending on the state with Victoria and South Australia having the lowest rate at $110 per annum per kW of peak demand. NSW is set at $160 and QLD 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). For Tasmania and WA we have used the commercial time of use tariff structure rather than the demand charge in payback calculations.

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

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

4.4.3 Wholesale energy

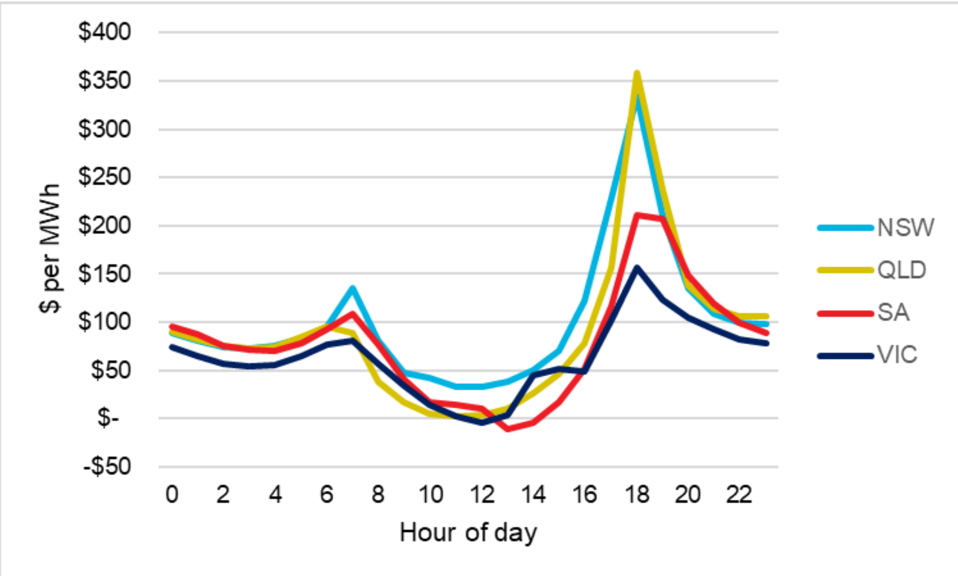
Projected wholesale energy costs are derived from a combination of AEMO's residential retail price index over the longer term and in the shorter term from electricity market contract prices and wholesale spot market historical patterns.

For the first few 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, there is now a significant discount across most regions in wholesale market prices during daylight hours relative to other time periods. As the level of installed solar capacity grows this daytime discount is likely to become even more marked. Figure 4-6, illustrates the noticeable depression in prices in the middle of the day in the wholesale electricity spot market across NEM mainland states, while prices during the peak period in the late afternoon and evening remain high. A similar pattern is also evident in the WA SWIS short-term energy market.

Figure 4-6 Average 2023-24 wholesale electricity prices by hour of day across NEM mainland

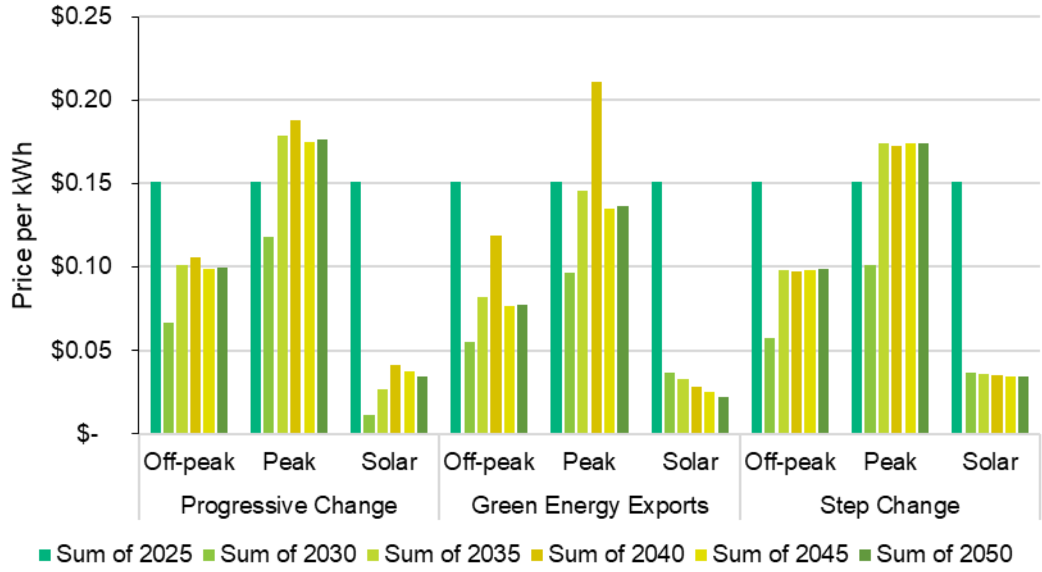


Source: Green Energy Markets analysis of NEM wholesale spot market prices

Looking longer term to the 2030's and beyond, while it is possible demand in the middle of the day could grow significantly, 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.

Figure 4-7 details the assumed wholesale energy costs by time interval faced by a residential consumer in NSW for each scenario. Similar patterns are observed in other NEM states within the model.

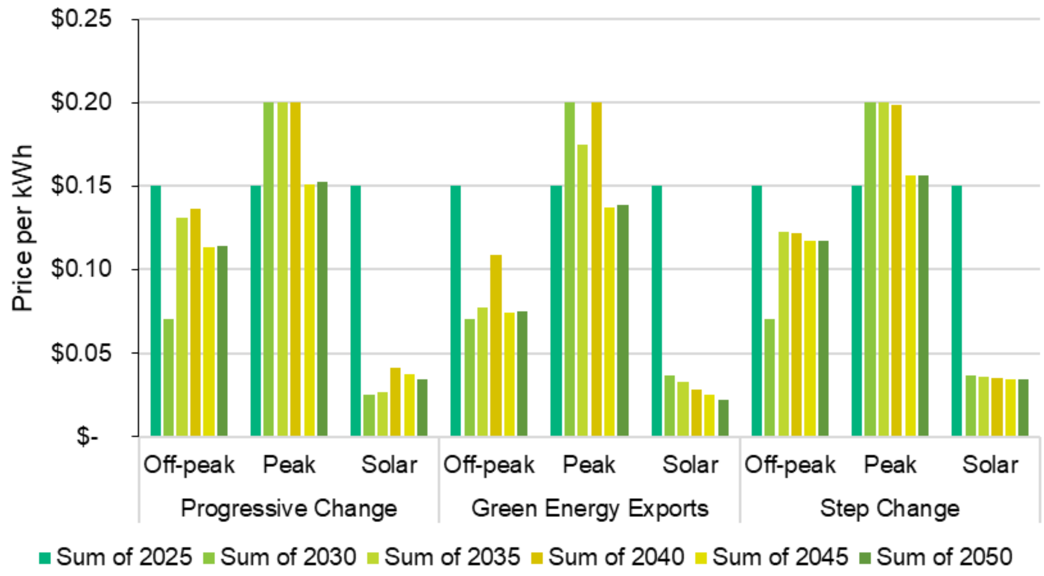
Figure 4-7 Assumed wholesale energy cost retail pass through by time interval for NSW



Note: A large part of the change in prices between 2021 and 2030 of each time period is to do with the removal of smearing of costs in small consumer retail prices across time periods rather than underlying changes in wholesale energy costs during the hours covered by the Off-Peak, Solar and Peak periods.

The figure below details the assumed wholesale energy costs by time interval faced by a residential consumer in WA for each scenario, note this is complicated by the existence of a capacity market where costs are recovered through a charge per kWh which we have assumed is concentrated into the peak period.

Figure 4-8 Assumed wholesale energy cost retail pass through by time interval for WA



Note: A large part of the change in prices between 2021 and 2030 of each time period is to do with the removal of smearing of costs in small consumer retail prices across time periods rather than underlying changes in wholesale energy costs during the hours covered by the Off-Peak, Solar and Peak periods.

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.

Retail charges are also held constant throughout the outlook.

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[21]. These average figures are then converted into generation per hour across every day of the year based on data provided by Solcast to AEMO to produce historical generation time profiles for rooftop solar by state.

In developing the degraded capacity of the solar PV installed base we applied an annual degradation factor of 99.3%[22]. 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%)[23]
- Battery systems have a 2.5 hour energy storage duration. So the maximum output/input of the battery 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.[24]
- Batteries kWh capacity was assumed to degrade to 60% of its original rated capacity after 10 years[25] and at this point would be retired and replaced by its owner.

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

[22] 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.

[23] 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/)

[24] 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).

[25] 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

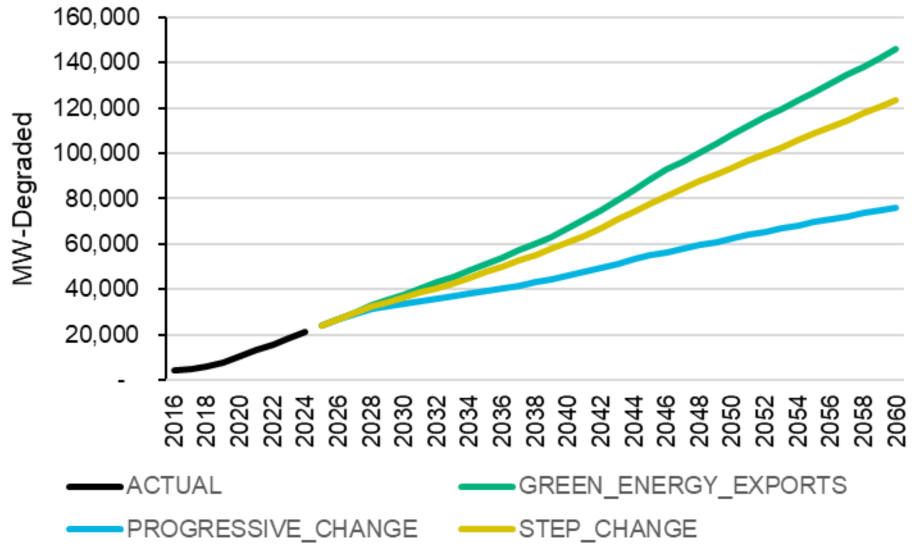
5.1.1 Solar PV

Readers should note that the projections below are for the solar DC panel capacity, not the capacity of inverters which convert solar panel generation into electricity that is usable by consumers. In the model we project that towards the end of the projection period new residential solar systems' average panel capacity will be close to 13kw to 15kW (it is currently at around 9kW). However, many network distributors in Australia apply restrictions on the amount of capacity inverters can export to the grid, with 5kW per phase common, although dynamic controls can allow up to 10kW. Consequently, during periods of high solar output and low household electricity demand a significant portion of the generation from the projected panel capacity will be automatically curtailed due to export constraints. While dynamic export limits are in the process of being rolled out in several states that will allow for greater exports than 5kW, they would still act to automatically curtail output in circumstances where demand was low and aggregate solar output was very high such that voltages became too high. Furthermore, across all three scenarios it is envisaged that a substantial proportion of solar systems will be coupled with batteries which will further reduce the extent of solar DC panel capacity which is exported to the grid. This is important because the residential sector makes up the vast bulk of projected capacity under all scenarios. So, while the amount of panel capacity projected reaches high levels relative to overall electricity demand, the likely peak output that ultimately flows from inverters to satisfy electricity demand will be much lower.

National Electricity Market

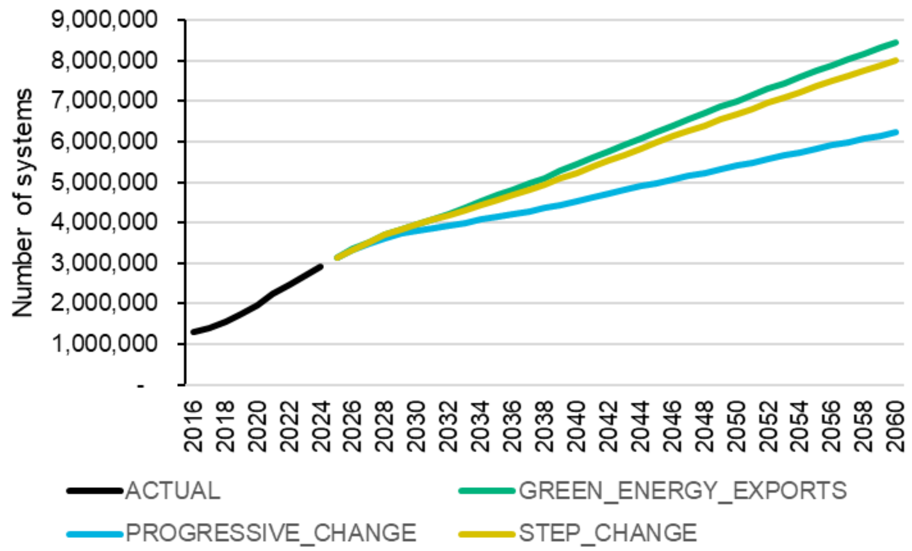
Figure 5-1 details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the National Electricity Market (NEM), taking into account the degradation of solar panel output over time. At the beginning of the projection (the conclusion of the 2023-24 financial year) cumulative installed degraded capacity is expected to stand at close to 21,400MW. By the end of the projection in 2059-60 the cumulative degraded capacity reaches around 76,000MW at the low end, under Progressive Change, and close to 146,000MW at the upper bound represented by the Green Energy Exports scenario.

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



The figure below details projections for the cumulative number of solar PV systems by scenario within the NEM. At the beginning of the projection the cumulative number of systems stands at about 2.9 million. At the low end under Progressive Change, the cumulative number of systems grows to around 6.2 million by the end of the 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches 8.4 million.

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

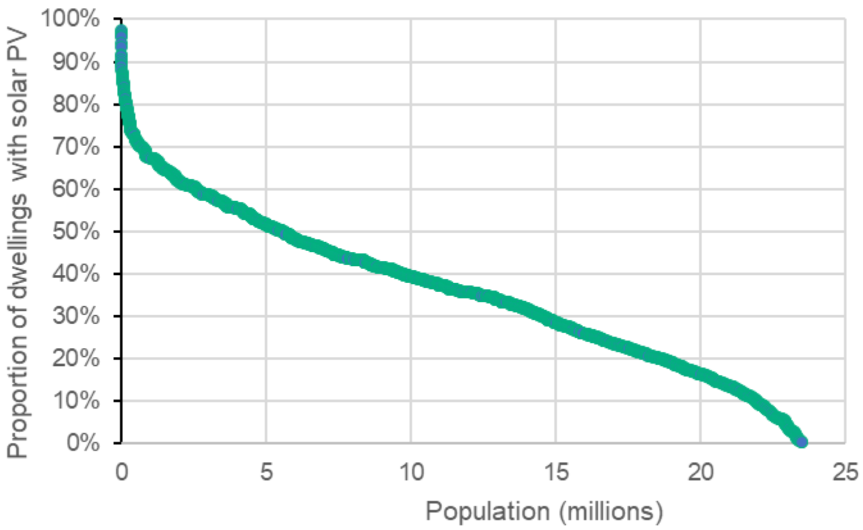


To put these solar system numbers into context the total number of detached and semi-detached dwellings in the NEM states is expected to grow from around 8.3m in the 2023-24 financial year to around 13m to 14m by the end of the projection (the residential sector accounts for the vast bulk of solar system numbers). Within the NEM under Progressive

Change around 43% of detached and semi-detached dwellings are expected to have a solar system by the end of the projection period, while at the upper end under Green Energy Exports it reaches around 53% of all residential connections.

While this may appear to be quite a high proportion of households, such levels of penetration are already common across many postcodes in Australia. Figure 5-3 details the profile of solar penetration for each postcode within Australia relative to population within the postcode as of 2023. There are now over 800 postcodes in Australia where 50% or more of households have a solar system. These postcodes encompass over 5 million of Australia's population and this has been accommodated within distribution networks with very little usage of battery energy storage systems. Meanwhile our projections envisage that almost all new solar systems installed from the 2040's will be coupled with batteries.

Figure 5-3 Proportion of households with solar by postcode relative to population

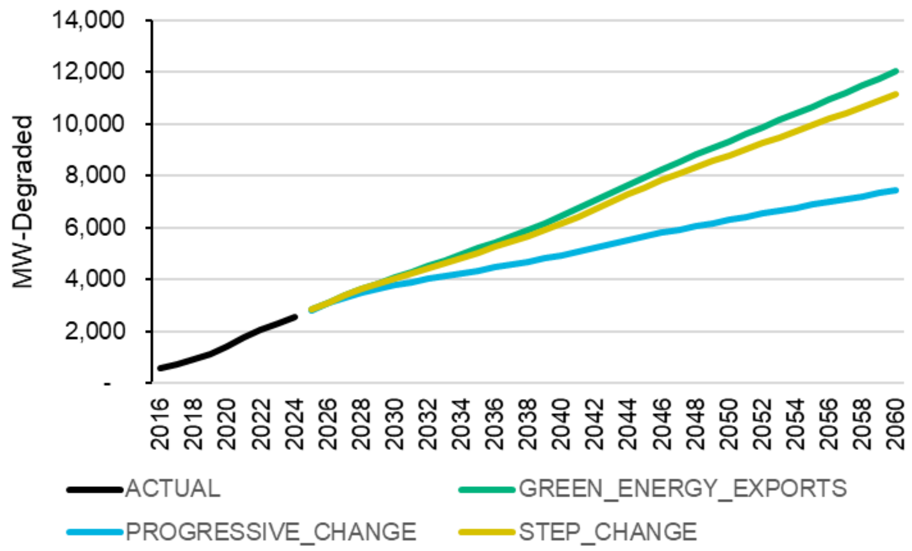


Sources: Clean Energy Regulator for number of solar systems per postcode, Australian Bureau of Statistics 2021 Census for number of households and population by postcode.

Western Australian South-West Interconnected System

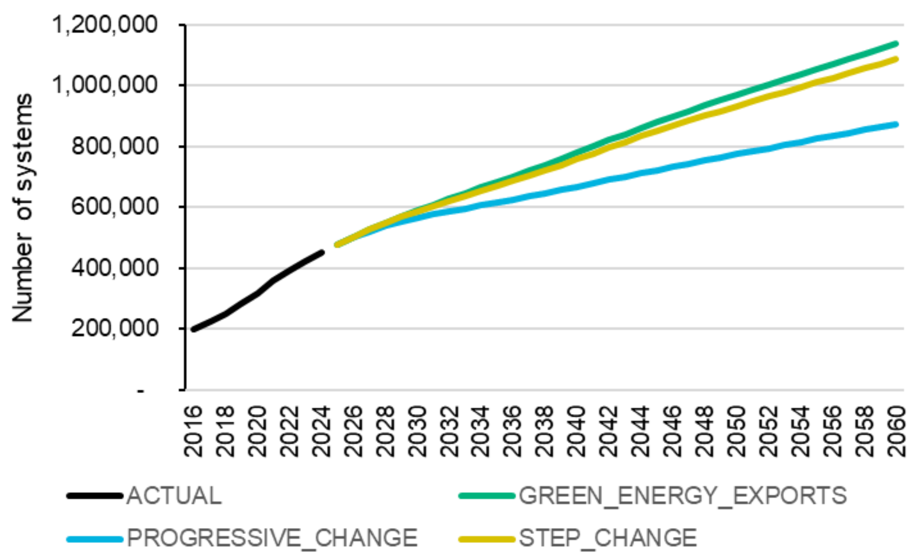
Figure 5-4 details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the WA South-West Interconnected System (SWIS), taking into account the degradation of solar panel output over time. At the beginning of the projection (the conclusion of the 2023-24 financial year) cumulative installed degraded capacity is expected to stand at slightly above 2,500MW. At the low end, under Progressive Change, the cumulative degraded capacity reaches 7,400MW by the end of the projection in 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches 12,000MW. Note that for the SWIS, unlike the NEM, the projection does not include any capacity for in-front-of-the-meter power stations.

Figure 5-4 WA SWIS cumulative degraded megawatts of solar PV by scenario



The figure below details projections for the cumulative number of solar PV systems by scenario for the SWIS. At the beginning of the projection the cumulative number of systems stands at a bit more than 450,000. At the low end under Progressive Change, the cumulative number of systems grows to 874,000 by the end of the 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches around 1.1 million.

Figure 5-5 WA SWIS cumulative number of PV systems by scenario

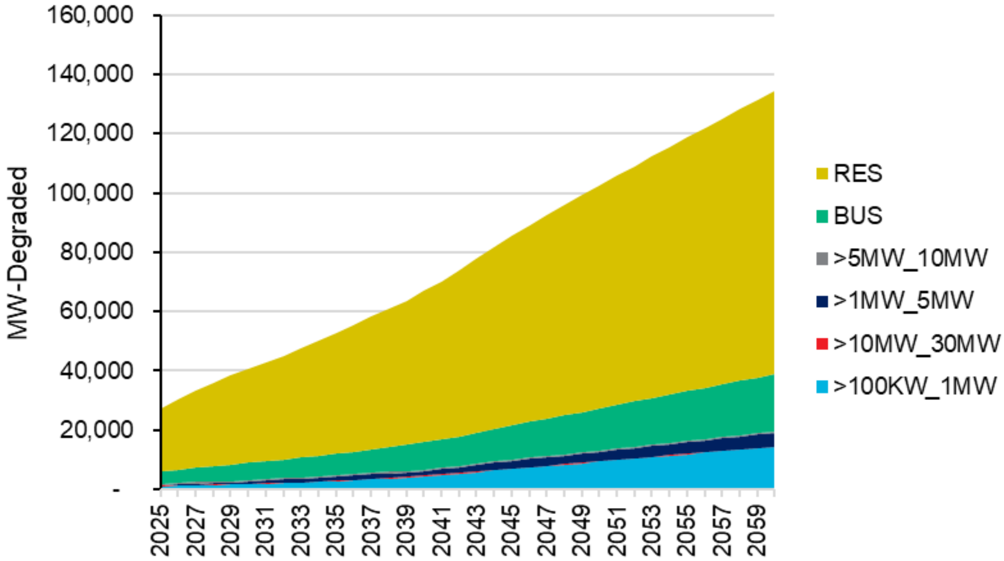


To put these system numbers in context the total number of detached and semi-detached dwellings in the WA SWIS is expected to grow from 1.08m in 2023-24 to reach between around 1.55m to 1.67m by the end of the projection period. Under Progressive Change around 54% of detached and semi-detached dwellings are expected to have a solar system by the end of the projection period, while at the upper end under Green Energy Exports it reaches 65%.

Break-down by end-customer type and state (both NEM & SWIS)

Figure 5-6 illustrates how the projected solar capacity is distributed across end-customer types under the Step Change Scenario. Residential (RES) remains by far away the dominant sector throughout the outlook period but with 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 5-6 Cumulative degraded megawatts of national solar PV capacity by sector (Step Change Scenario)

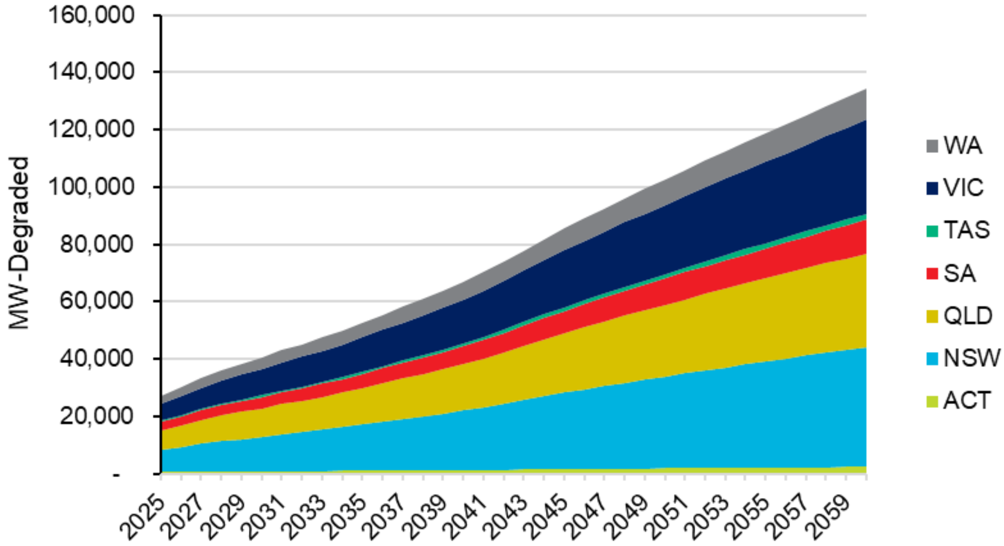


In front of the meter systems denoted by the segments greater than 1 megawatt in scale remain a relatively minor segment, with developers of solar power stations expected to favour much larger systems above 30MW in scale.

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

Figure 5-7 illustrates how the projected solar capacity is distributed across states and territories under the Step Change Scenario. The relative distribution across states is reasonably similar across the other scenarios.

Figure 5-7 Cumulative degraded megawatts of solar PV capacity by state (Step Change Scenario)



5.1.2 Battery energy storage

National Electricity Market

In terms of behind the meter stationary battery systems Figure 5-8 details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the National Electricity Market (NEM), taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2023-24 financial year) cumulative degraded battery capacity is estimated to stand close to 2,174MWh[26]. At the low end, under Progressive Change, the cumulative degraded capacity reaches 52,000MWh by the end of the projection in 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches 124,000MWh.

[26] Historical battery system numbers and capacity are derived from Sunwiz (2023) Battery Market Report – Australia 2023.

Figure 5-8 NEM cumulative degraded megawatt-hours of battery capacity by scenario

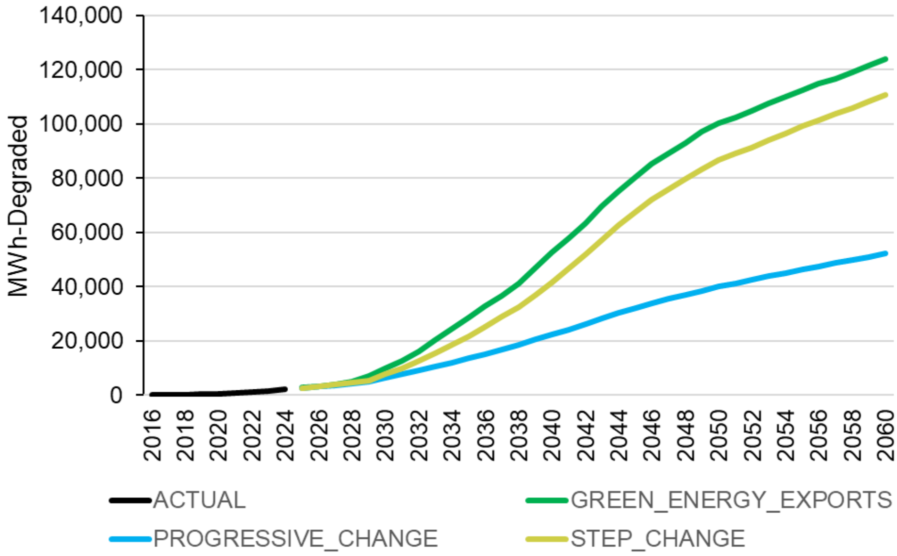
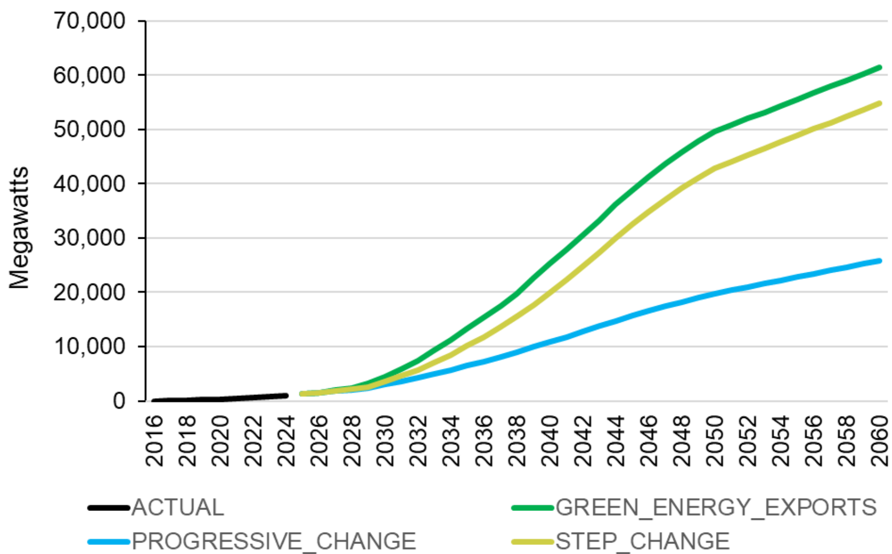


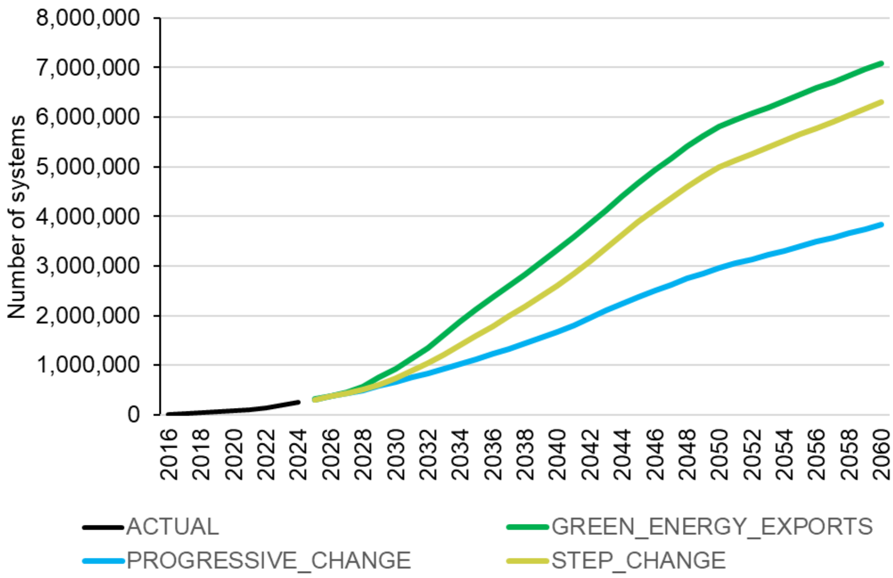
Figure 5-9 below shows the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 994MW at the end of 2023-24 financial year. Under Progressive Change this grows close to 26,000MW by the end of the projection in 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches more than 61,000MW. The projections are based on batteries holding 2.5 hours of energy storage relative to their maximum rated output capacity with an assumption that the instantaneous output which can be extracted from a battery is not subject to degradation (although the kilowatt-hours of storage is still subject to degradation).

Figure 5-9 NEM cumulative megawatts of battery capacity by scenario



The figure below details projections for the cumulative number of battery systems by scenario in the NEM. At the end of the 2023-24 financial year the cumulative number of grid-connected battery systems is estimated at close to 250,000. Under Progressive Change this grows to 3.8 million by the end of the projection with 26% of detached and semi-detached residential dwellings owning a battery system. The upper bound represented by Green Energy Exports reaches 7 million, with 45% of detached and semi-detached dwellings owning a battery system.

Figure 5-10 NEM cumulative number of battery systems by scenario



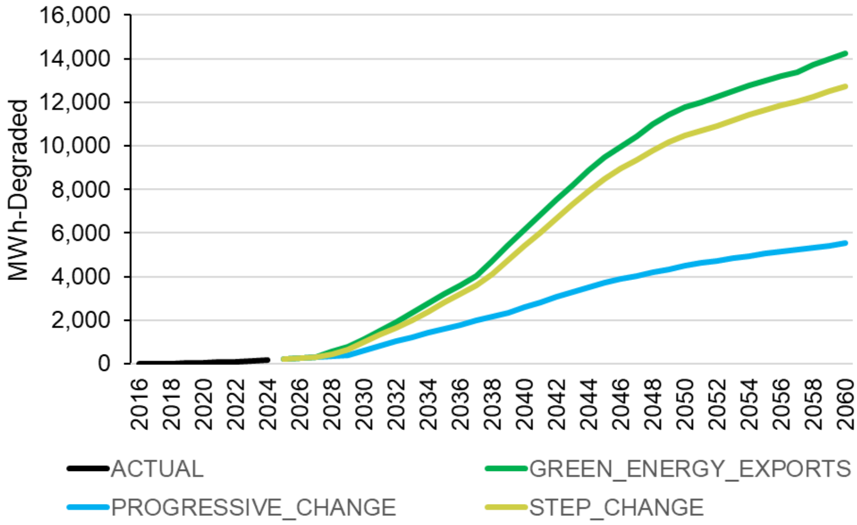
As some perspective, at the low end under Progressive Change 61% of solar systems in the NEM would be coupled with a battery, while at the high end represented by Green Energy Exports, 84% of solar systems are coupled with a battery.

The noticeable slowing in the growth of the stock of battery systems shown by the inflection or knee point of the blue and yellow lines close to 2050 is a product of batteries having penetrated a large proportion of the existing stock of households with solar systems around this point in time (for the Green Energy Exports and Step Change scenarios). After this point, while sales of battery systems remain high, many of these are systems which are replacing retiring battery systems, so they don’t increase the overall installed stock of battery systems.

Western Australian South-West Interconnected System

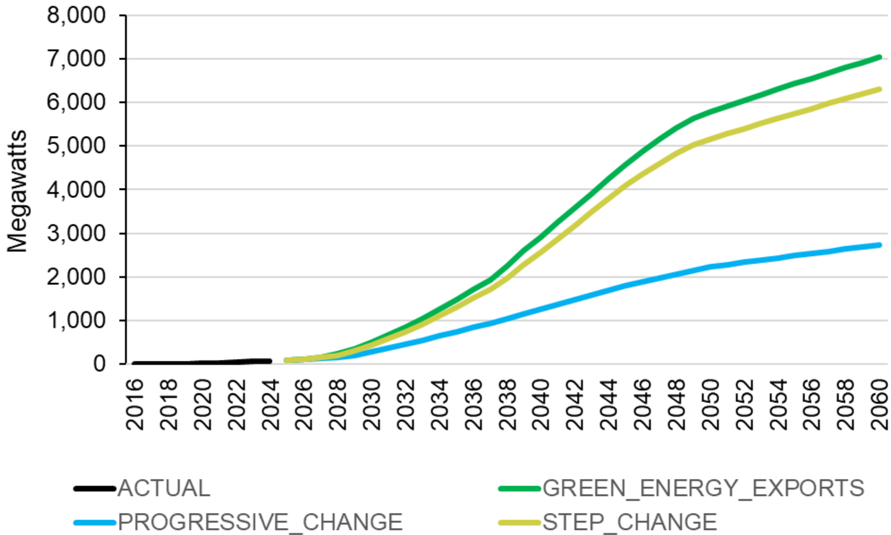
The figure below details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the WA SWIS, taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2023-24 financial year) cumulative degraded battery capacity is estimated to stand at almost 176MWh. Under Progressive Change the cumulative degraded capacity reaches 5,500MWh by the 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario reaches 14,200MWh.

Figure 5-11 WA SWIS cumulative degraded megawatt-hours of battery capacity by scenario



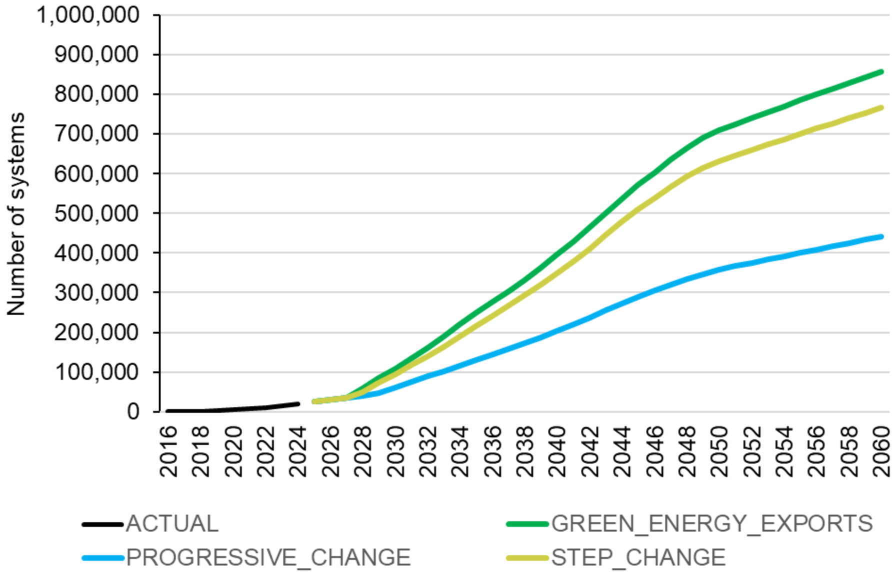
The figure below illustrates the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 77MW at the end of 2023-24 financial year. Under Progressive Change this grows to around 2,740MW by the end of the projection. The upper bound represented by the Green Energy Exports scenario reaches around 7,000MW.

Figure 5-12 WA SWIS cumulative megawatts of battery capacity by scenario



The figure below details projections for the cumulative number of battery systems by scenario in the WA SWIS. At the end of the 2023-24 financial year the cumulative number of grid-connected battery systems stands at close to 19,700. Under Progressive Change the cumulative number of systems grows to around 441,000 by the 2059-60 financial year. The upper bound represented by the Green Energy Exports scenario has close to 858,000 battery systems.

Figure 5-13 WA SWIS cumulative number of battery systems by scenario



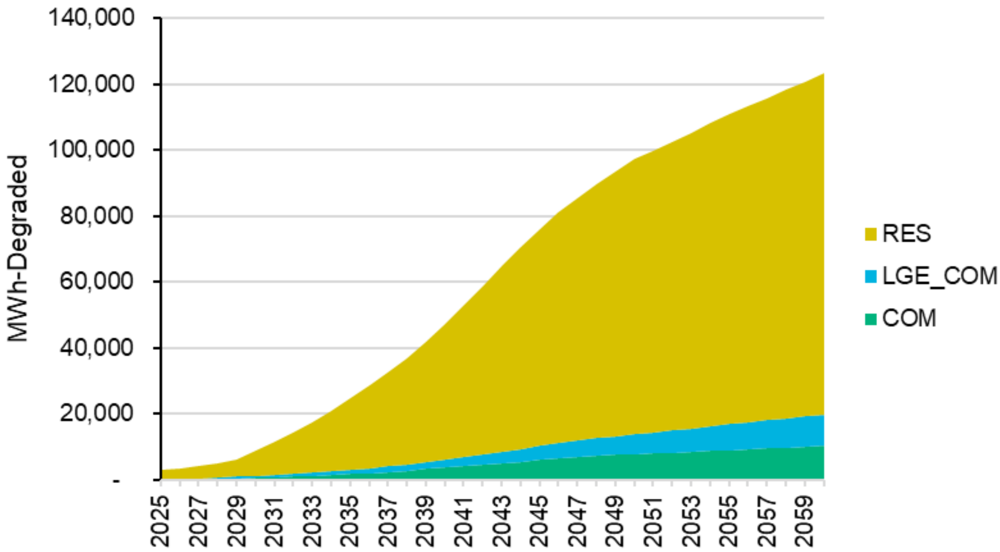
As some perspective, under Progressive Change 50% of solar systems in the SWIS would be coupled with a battery by 2059-60. At the high end represented by Green Energy Exports 75% of all solar systems are coupled with a battery.

The noticeable slowing in the growth of the battery stock in the mid 2040's under Green Energy Exports and Step Change in the SWIS is due to batteries having penetrated a substantial proportion of the existing stock of households with solar at this point in time, just as what unfolds in the NEM states.

Break-down by end-customer type and state

The figure below illustrates how the projected battery capacity is distributed across end-customer types under the Step Change Scenario. Just as in solar, Residential (RES) remains by far away the dominant sector throughout the outlook period.

Figure 5-14 Cumulative degraded megawatt-hours of battery capacity by sector (Step Change Scenario)

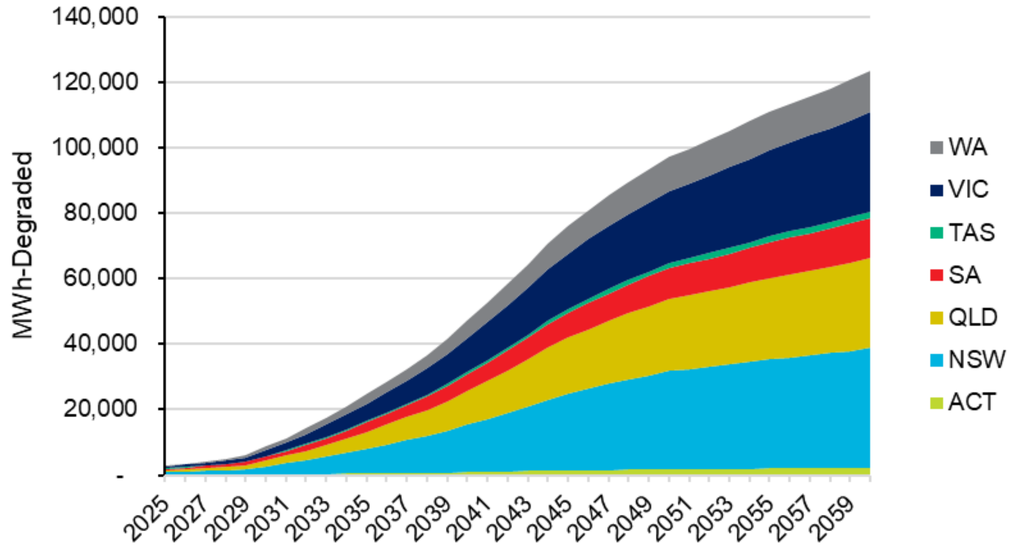


Note: Residential (RES) batteries are assumed to have average size of 10kWh as are small commercial (BUS) at the beginning of the projection period which then grows to 15kWh by the 2030's and then continues to grow to 20kWh by the end of the outlook period, while large commercial customers' (LGE_COM) batteries are assumed to have sizes averaging 500kWh. In practice though battery sizes will probably vary quite widely within these segments which are intended to be average archetypes for customers within these segments.

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

Figure 5-15 illustrates how the projected battery capacity is distributed across states and territories under the Step Change Scenario. The relative distribution across states is relatively similar across the other scenarios.

Figure 5-15 Cumulative degraded megawatt-hours of battery capacity by state (Step Change Scenario)

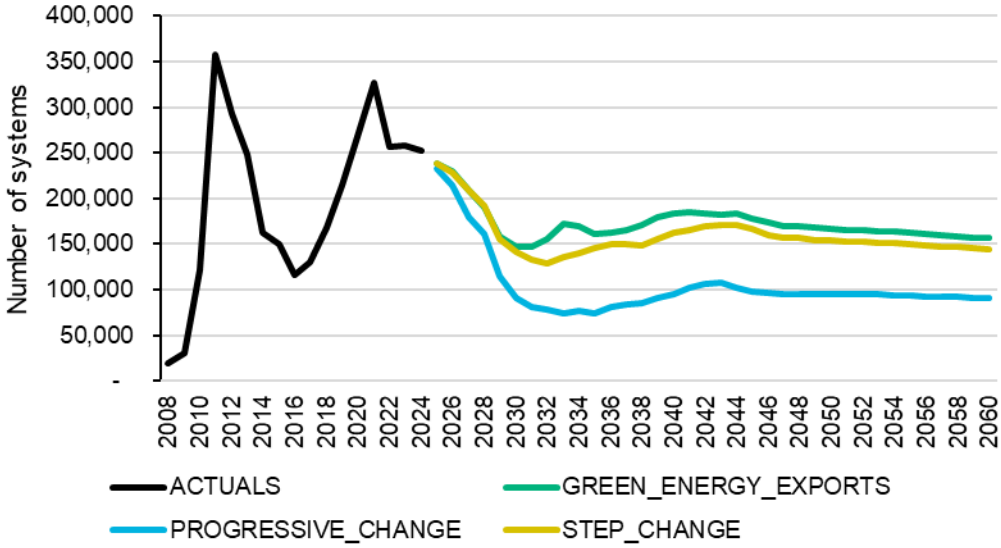


5.2 Underlying drivers of uptake

5.2.1 Number of annual system additions to decline

To more clearly illustrate and explain how solar uptake changes over time Figure 5-16 details the number of new solar systems that are added to the existing stock in each individual year (not cumulative) across both the NEM and SWIS. To provide some context, this chart details historical numbers stretching back to 2008, as well as projections from 2023 onwards for each scenario. Note that additions to stock remove the growing number of systems which are being installed to replace an existing system.

Figure 5-16 Number of solar system additions to stock each year



This illustrates that across all scenarios we project new additions of solar systems will steadily decline from the levels experienced over recent years. This decline in system additions is expected to continue until the 2030's when additions stabilise under Green Energy Exports and Step Change. Progressive Change experiences a more marked decline which bottoms out in 2035 at a level of system additions not seen since 2009. System additions grow after 2035 but fail to recover to levels any higher than those achieved back in 2010.

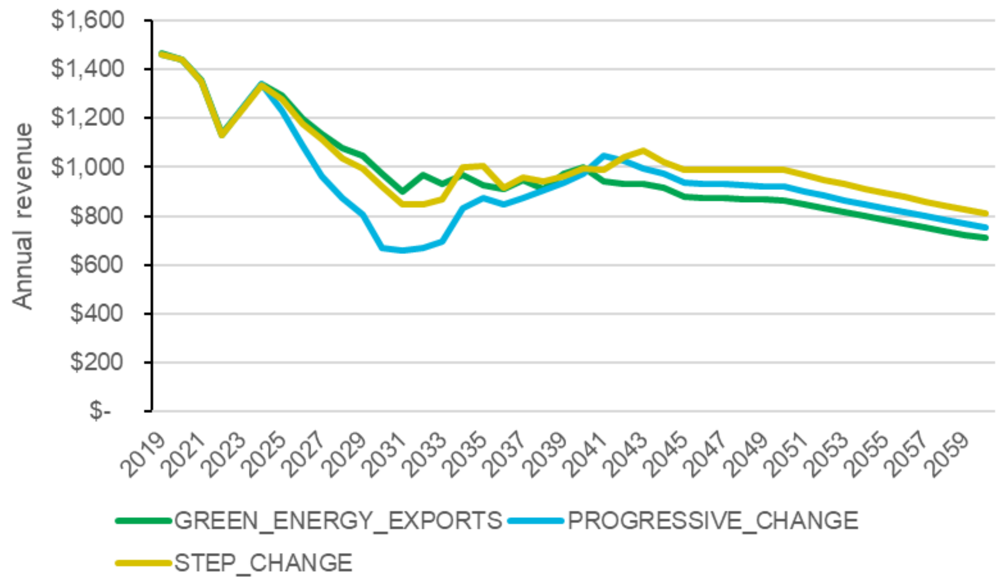
5.2.2 Declining solar system revenue

A key reason for why we project that annual solar system additions will decline, and in some scenarios markedly fall, is an expectation that amount of revenue (or energy bill savings) a solar system can deliver will fall over time. This is especially marked in the residential sector which is the most significant market for rooftop solar systems in capacity terms.

As detailed in section 4.4.3, after a short-term reprieve due to the Russian-Ukraine war related rise in international coal and gas prices, we expect that wholesale energy market prices during daylight hours will remain at very low 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 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 a 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 in Figure 5-17 using an average of revenue across states.

Figure 5-17 Annual revenue per solar system over time - average across states

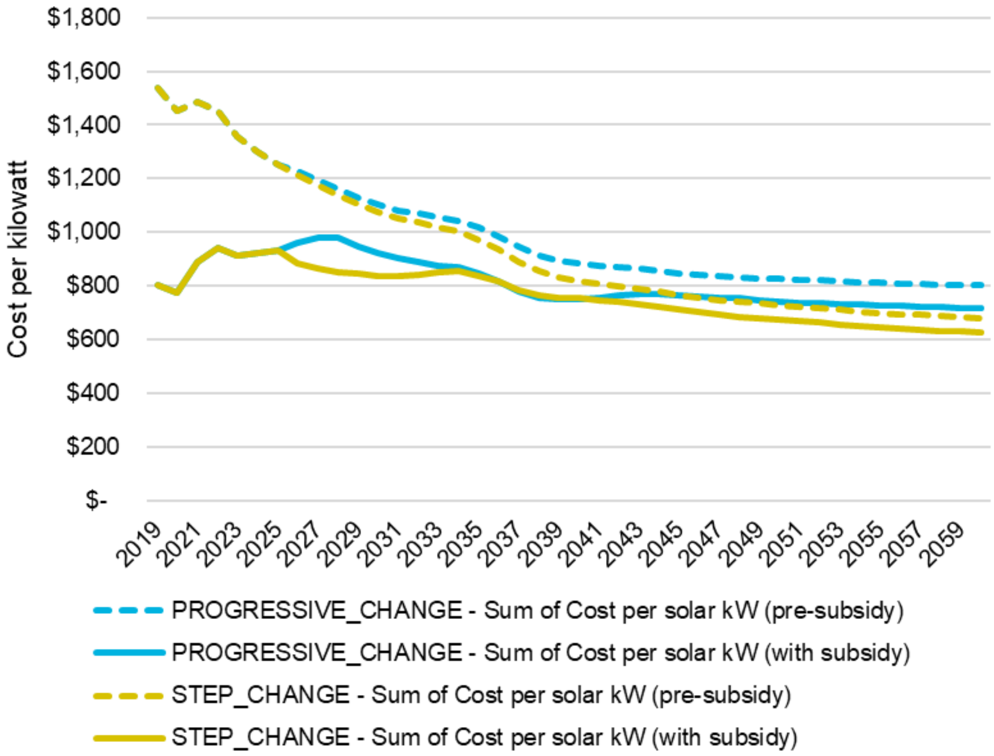


5.2.3 The next decade – declines in out of pocket system prices stall without new policy support

Meanwhile in terms of the cost of a solar system, the purchase price faced by consumers after deducting policy subsidies isn't expected to decline for the next decade based on current policy settings. The main form of policy support provided to solar systems in Australia is the rebate provided by the Small Scale Renewable Energy Scheme (SRES). The level of this rebate is being steadily phased down each year until it is completely phased out by 2031. Even though we expect the underlying cost of solar systems will decline into the future, it isn't expected to be sufficient to outpace the loss from the fall in the value of the SRES rebate.

In Figure 5-18, one can see in the dashed light blue line the modelled assumption of the underlying cost of a residential solar systems per kW of capacity in the Progressive Change Scenario prior to any policy support. The solid blue line then illustrates the out-of-pocket cost faced by consumers after deducting the SRES rebate. This shows that the underlying cost of a solar system is expected to fall significantly over the remainder of this decade. However, this is entirely countered by drops in the level of the SRES rebate, such that the out-of-pocket cost faced by households to purchase a solar system in 2030 remains higher than it was in 2019.

Figure 5-18 Underlying cost of solar per kilowatt and out of pocket cost to householders after policy support
(Progressive change vs Step Change Scenario)



The combination of a stagnant purchase price for solar, while revenue declines, means that payback deteriorates and consequently the model projects system additions decline substantially over the next decade under the Progressive Change scenario.

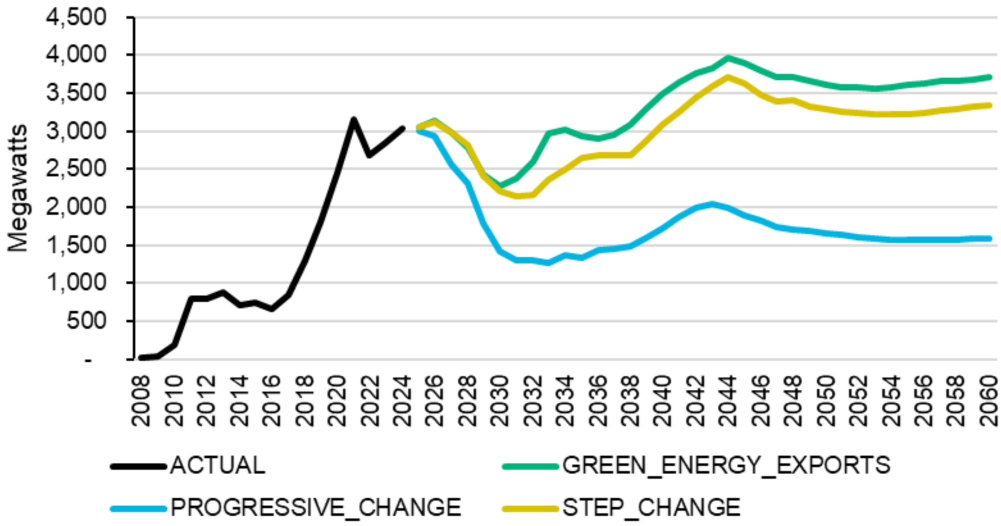
Under the Step Change Scenario on the other hand, underlying system costs are assumed to decline faster, but what makes an important difference is an assumption that governments will implement new policies to reward the carbon abatement delivered by solar systems (see section 4.2.1) which partly offsets the wind-down of the SRES. This is shown in Figure 5-18 above by the difference between the dashed yellow line (system cost with no policy in the Step Change scenario) and the solid yellow line which represents the out of pocket cost to a consumer after deducting the value of government policy support.

The introduction of new policy support under the Step Change scenario (as well as more attractive economics for batteries also assisted by assumed new government policy) means that the payback of a solar system doesn't deteriorate to the same degree as under Progressive Change and consequently annual system additions hold up significantly higher over the 2020's.

5.2.4 Ongoing growth in system size and emergence of system upgrade demand helps to offset declines in new system numbers

In terms of megawatts of solar PV capacity added, the market remains more buoyant than it would seem based on system numbers alone. Figure 5-19 shows that megawatts of added capacity, while lower than recent years for the first ten years of the projection, by around the mid 2030's to late 2030's they recover under the Step Change and Green Energy Exports scenarios to levels similar to the boom period of 2020 to 2024. Then from the 2040's onwards they reach levels higher than anything achieved so far to date. Capacity additions in Progressive Change on the other hand fall significantly over the 2020's but even at their lowest point, they still manage to remain above historical levels experienced up to 2018.

Figure 5-19 Megawatts of Residential and small commercial PV capacity added each year to the installed stock after deducting retirements

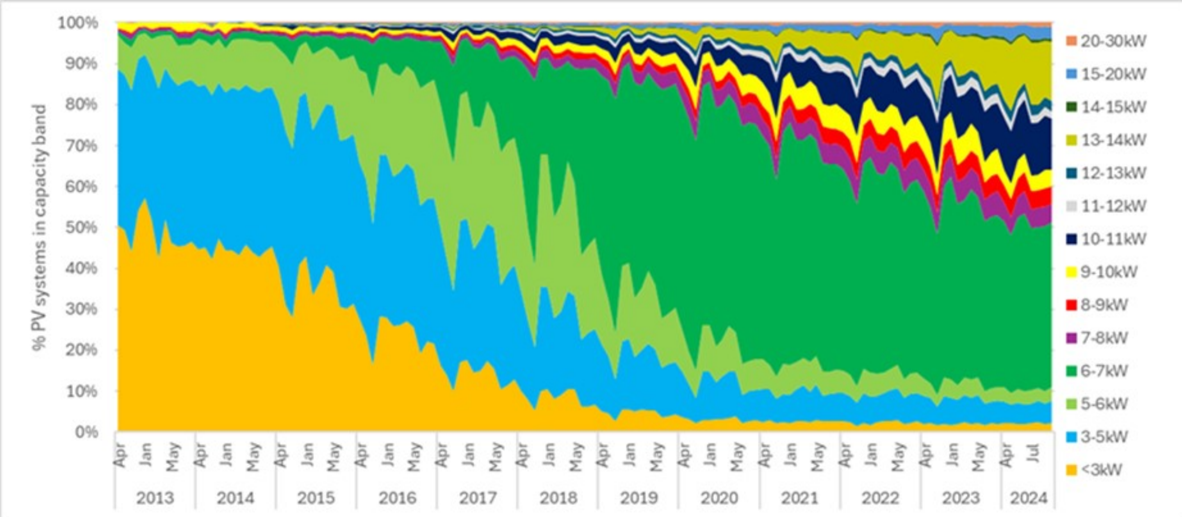


The reasons for why capacity additions remain above those seen in the years preceding the recent boom, in spite of a large fall in revenues and a fall in new system additions is a product of three factors:

1. 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.
2. 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.
3. The Victorian Government's solar rebate program helps to maintain solar system sales in Victoria over the period of the program to 2028;

Point 3 is self-explanatory. In terms of point 1, while the number of system additions over the next decade across all scenarios averages less than historical highs, the average capacity per system is likely to be significantly larger than they have been in the past. The figure below illustrates how the Australian solar market has progressively evolved from towards larger and larger systems. The Appendix to this report provides a further, numerical, breakdown by state.

Figure 5-20 Proportion of residential solar systems within different capacity bands – National



Source: Green Energy Markets analysis of Clean Energy Regulator STC registry data. See the Appendix for a numerical break-down by state.

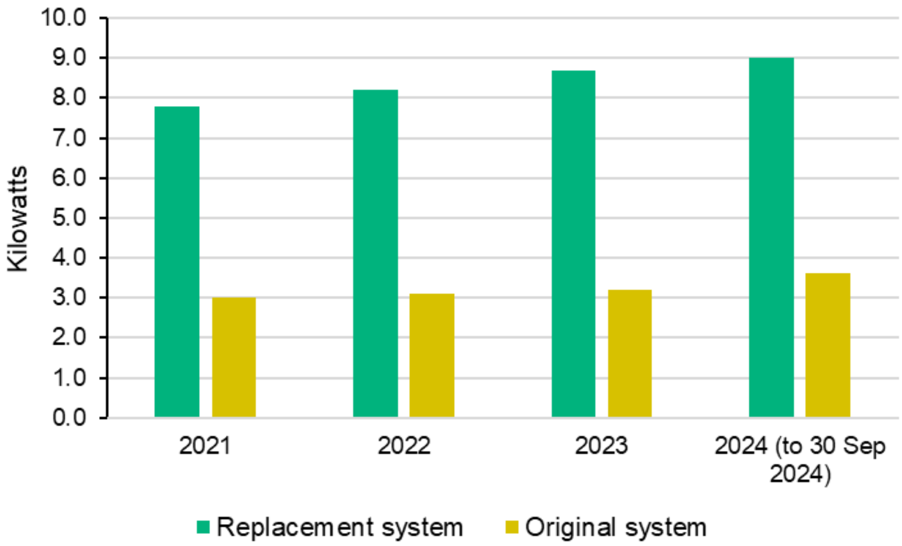
In terms of the third point, the replacement of the old systems from the first boom in solar over 2011 to 2013 is emerging as a new source of capacity growth in this decade. It is important to note that replacement is not necessarily because the solar modules have failed. Solar modules from large, established solar producers have proven to be remarkably durable, often still functioning quite well at 20 years of age. But replacements can also be spurred by inverters progressively breaking down (which typically have shorter warranted lives than modules). Also upgrades commonly occur 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 and Figure 5-5, they will increase the amount of cumulative capacity. This is because, as shown in the figure above, 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..

When older systems from 2010 to 2013, which were installed in large numbers, are replaced we expect most will be replaced with systems closer to the current industry standard of 9kW. The figure below, using data provided by the Clean Energy Regulator[27], illustrates how this upsizing of old systems to new replacement systems has already been unfolding over the years 2021 to 2024.

[27] Clean Energy Regulator (2024) Quarterly Carbon Market Report – September Quarter 2024

Figure 5-21 Average capacity of replacement solar systems relative to original systems they are replacing

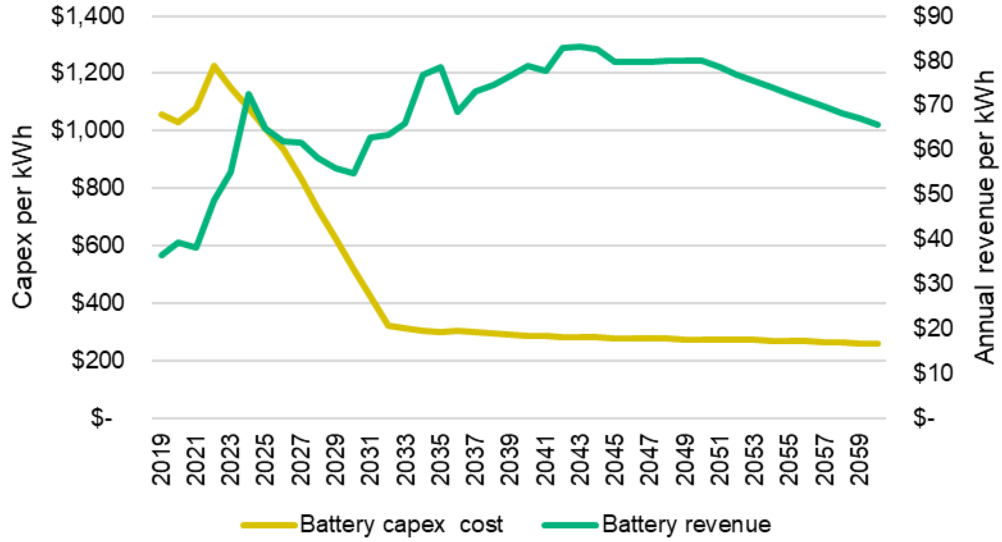


5.2.5 Beyond 2030 – market supported by the emergence of cost-effective batteries and ongoing construction of new dwellings

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 consumers 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 5-22 illustrates how under the Step Change scenario revenue for a battery system (shown by the green line) rises while the capital cost for a battery (yellow line) plunges.

Figure 5-22 Revenue vs cost per kWh for household batteries (Step Change Scenario - NSW)



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 to late 2020's depending upon the 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.

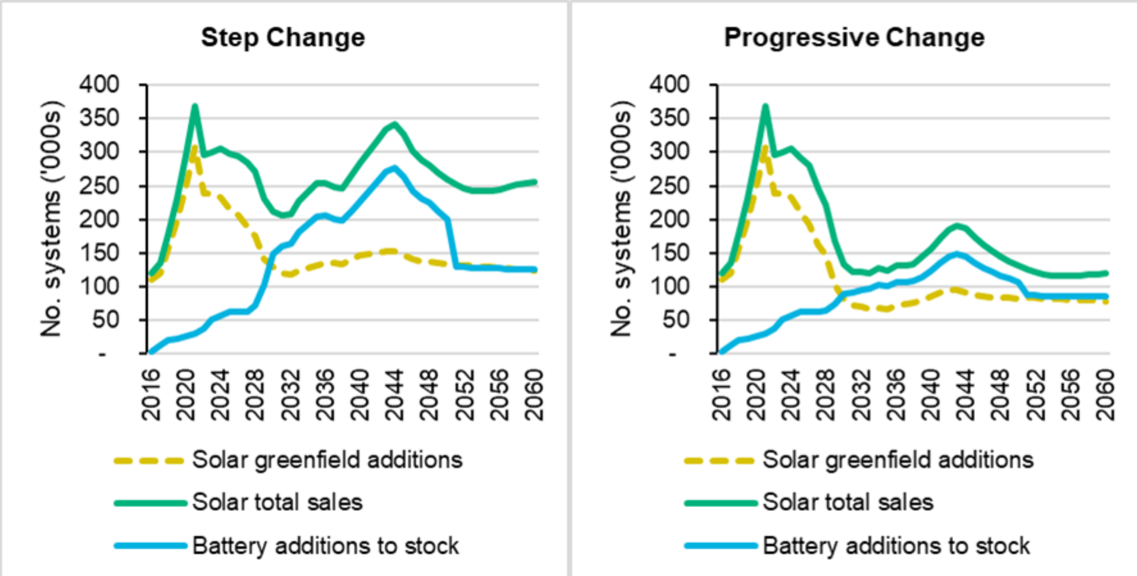
We are not aware of any rigorous evaluation of the prevalence and strength of these kinds of motivational drivers amongst the Australian population and the degree to which they might drive purchasing behaviour of batteries at different purchase price points or paybacks. However, interviews with industry 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. As paybacks approach similar levels as available for solar then we assume uptake will follow that of solar sales.

In Figure 5-23 we have illustrated the projected relationship between uptake of battery systems and solar systems for the Step Change and Progressive Change scenarios as examples. The blue line details the model's projection of annual additional battery systems (excludes systems replacing an existing battery system) in the residential and commercial sector, relative to solar system sales and solar additions to stock. It is only by the 2030's in the Progressive Change 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 noticeable uptick in battery uptake. From 2031 onwards the model envisages in this scenario that almost all new solar system sales will be coupled with a battery and hence the green and blue lines almost merge.

In the Step Change scenario we see a similar pattern emerge, except that it unfolds more rapidly and at higher numbers. The point at which the addition of batteries to solar enhances payback of the system as a whole occurs far earlier, in part because of assumed faster capital cost reductions, but mainly due to the assumption of a new nation-wide government program plus VPP incentives which act in a manner equivalent to reducing the out-of-pocket purchase price of a battery for consumers by a quarter. Battery additions continue in close alignment with solar system sales continues until close to 2050 when additional battery systems subside down in line with solar system greenfield additions (systems installed on a building that has not previously had a solar system). The fall of battery additions away from total solar sales down to just solar system greenfield additions is because by 2050 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 5-23 Number of additional residential battery systems relative to solar system additions and sales



5.3 Battery system charge and discharge behaviour

To assist AEMO in assessing the potential impact of the projected stock of distributed batteries on electricity demand and supply we were asked to provide projections of the potential share of batteries operating in the three control modes explained below.

1) Solar Shift Mode

In this mode the battery only charges up when solar generation is excess to the site load (until it is charged to its full kilowatt-hours) of capacity. It then only discharges to cover load where this is excess to the solar system's output. It will discharge until it is fully depleted or until solar generation covers or exceeds load again. The battery never exports power offsite to the grid, instead only seeking to cover load within the site.

2) Tariff Optimisation Mode

Just like in the solar shift mode, the battery charges up when solar generation is excess to the site load but in addition it will also charge from grid imports in circumstances where the solar excess to the load for the day is insufficient to fully charge the battery. 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 but unlike the solar shift mode it will only begin discharging during the peak period (3pm-9pm) first and will then continue discharging until 3am 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 that might evolve over time and this will change what is the best way to charge and discharge the battery.

3) Virtual Power Plant (VPP) Mode

This mode involves the owner of the battery delegating control of the battery's charge and discharging to a business such as an electricity retailer who will seek to optimise charging and discharging with reference to wholesale electricity market prices (and potentially also payments to support network requirements such as local voltage or capacity limits).

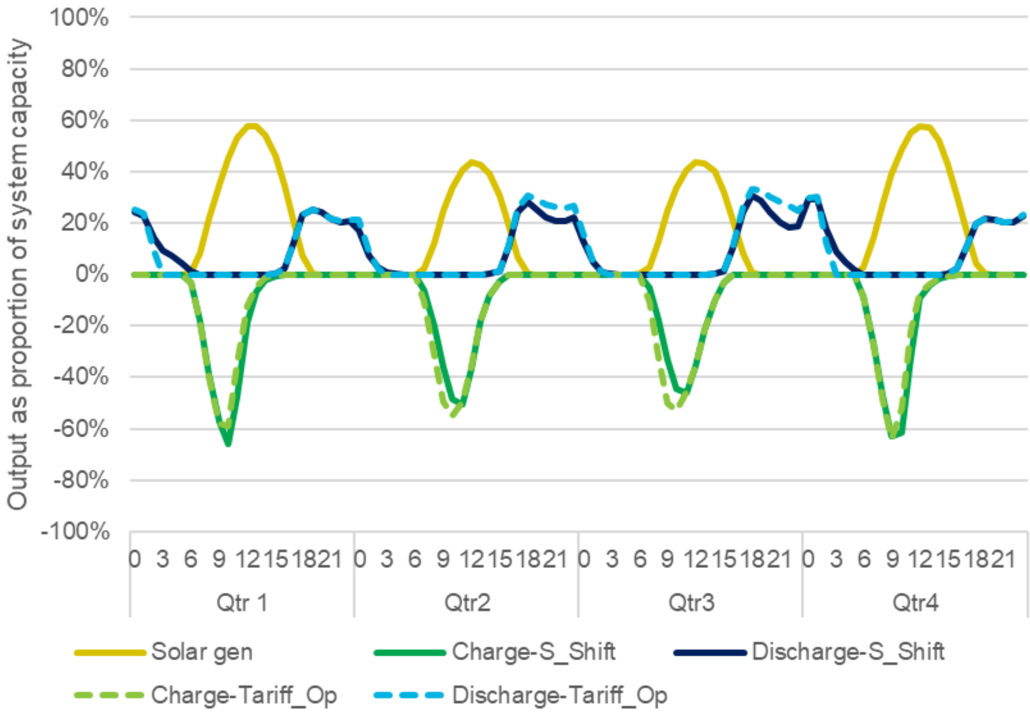
5.3.1 Charge-Discharge profiles

In the virtual power plant or VPP mode batteries' charging and discharging patterns can be expected to be driven by wholesale energy market price signals and so can be expected to operate in a very similar manner to a scheduled utility-scale battery system. For the Solar Shift and Tariff Optimisation we used AEMO supplied historical 30 minute interval data of estimated solar output stretching back to the 2000's within our payback model to assess how the battery would charge or discharge its power.

The figure below illustrates the averaged quarterly pattern of the battery's charging (green lines) and discharging (blue lines) behaviour per kW of battery capacity by hour of day for a Victorian residential consumer assumed to have a 6.6kW solar system and 10kWh battery capable of a maximum charge or discharge of 4kW (these solar and battery system size assumptions are the same across all states and the two modes for residential sector). The yellow line shows the quarterly averaged hourly solar generation profile per kW of capacity. The dashed, lighter coloured lines represent the Tariff Optimisation mode while the solid, darker coloured lines covers the Solar Shift mode. For the residential sector there is relatively little difference in the battery charge-discharge behaviour across the modes because:

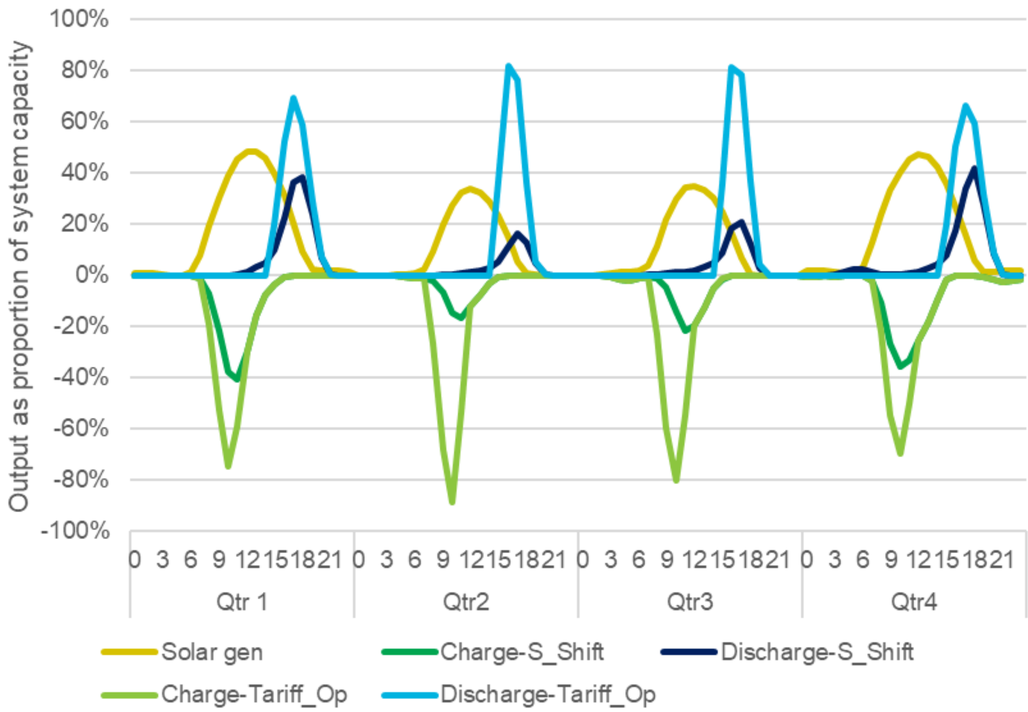
1. the solar system almost always generates enough power excess to the load to fully charge up the battery
2. It is rare that load exceeds solar generation before 3pm so batteries in the solar shift mode usually tend to discharge after 3pm and so don't behave all that differently to the tariff optimisation mode that only allows discharge after 3pm when the peak tariff period commences.

Figure 5-24 Quarterly averaged charge-discharge profile VIC residential example



Things look quite different in the chart below which illustrates the charge-discharge profile for a battery held by a Victorian large commercial consumer assumed to have a 300kW solar system and 150kWh battery capable of a maximum charge or discharge of 60kW (these solar and battery system size assumptions are the same across all states and the two modes for small commercial). 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 leads to a far more marked difference in battery charge and discharge behaviour across the modes than occurs in residential.

Figure 5-25 Quarterly averaged charge-discharge profile VIC large commercial example



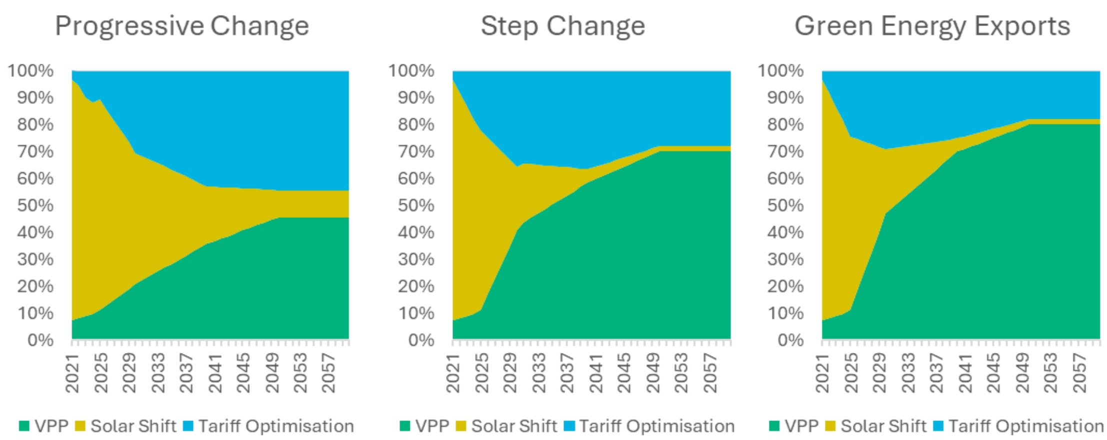
Firstly, in the solar shift mode the battery rarely gets fully charged due to insufficient solar excess, while the Tariff Optimisation mode uses grid imports to top-up the battery to full capacity where solar excess is insufficient for the day. The second thing is that under solar shift mode the battery will begin discharging sooner than the 3pm peak because solar output is insufficient to cover the site's load sooner in time than what is common for residential solar sites. This also results in a greater contrast between the two battery operation modes relative to the residential sector because Tariff Optimisation only allows discharging after 3pm to ensure it takes advantage of higher prices during this period. One other critical difference of note between commercial and residential is that the battery in a Commercial setting under Tariff Optimisation fully discharges its battery far faster than residential. This is because the site's load is far larger relative to the battery size than a residential site.

In terms of the archetype modelled small commercial customer, they display an almost identical battery charge and discharge profile as large commercial. This is because of a similar time profile for electricity consumption and similar approach to sizing the solar system to reduce the extent to which generation exceeds the load.

5.3.2 Share of batteries in each mode

Illustrated in Figure 5-26 are the projected shares of each battery charge-discharge mode across the three scenarios. At present most batteries are assumed to operate in the solar-shift mode. However, it is expected that over time this mode will cede share to tariff optimisation and VPPs across all scenarios. Tariff optimisation is expected to become more prevalent due to the fact that the AEMC has required networks to roll-out "cost reflective" tariffs to all customers, and time of use tariffs are likely to offer greater savings to customers with batteries who have the capacity to shift their demand for grid-sourced power out of peak periods and into off-peak periods. VPPs are also expected to become more prevalent over time due to the fact that this option should allow for consumers to increase the financial value they can extract from a battery by exporting power to the grid during high-priced periods. In addition, as batteries become more common there is increased potential value that retailers/aggregators can capture from developing a VPP capability which should incentivise greater marketing effort. Lastly, VPP offerings are an immature market, and it is likely that over time VPP operators will become more skilled at marketing this offering and customers will become more knowledgeable and comfortable with enrolling in VPPs.

Figure 5-26 Projected share of battery modes by scenario -average across all states



Due to the fact that both batteries themselves and VPP offerings in particular are an immature market; and there is poor data available on how batteries are currently being operated; the shares shown above should be considered indicative and subject to considerable uncertainty. Also, the rapid rise in the VPP share shown in Step Change and Green Energy Exports (as per these two scenario's narratives) are based on an assumption there will be a concerted strategy by government and industry to provide greater financial incentives to encourage battery owners to join VPP programs.

6 Appendix – Historical patterns in residential PV system size

Figure 6-1 Proportion of residential PV systems by system size band and state since 2017 (Financial year)

Residential PV Systems <30kW	<3kW	3-5kW	5-6kW	6-7kW	7-8kW	8-9kW	9-10kW	10-11kW	11-12kW	12-13kW	13-14kW	14-15kW	15-20kW	20-30kW	Grand Tot
ACT															
2017	7.4%	31.9%	34.2%	14.2%	4.5%	2.8%	2.6%	1.4%	0.3%	0.2%	0.2%	0.0%	0.1%	0.1%	100.0%
2018	6.0%	27.2%	26.3%	25.4%	5.2%	2.4%	3.5%	1.8%	0.6%	0.4%	0.5%	0.2%	0.6%	0.1%	100.0%
2019	1.8%	16.7%	16.1%	41.0%	5.6%	2.9%	7.4%	3.0%	1.3%	1.4%	1.3%	0.1%	0.9%	0.4%	100.0%
2020	2.2%	6.4%	8.3%	48.3%	6.9%	3.7%	6.8%	5.8%	2.5%	2.9%	4.0%	0.3%	1.6%	0.2%	100.0%
2021	3.9%	4.1%	5.0%	43.1%	6.7%	4.0%	8.0%	7.5%	3.7%	3.2%	7.5%	0.2%	2.8%	0.5%	100.0%
2022	1.7%	3.0%	3.3%	34.3%	8.7%	6.8%	9.6%	11.4%	3.9%	3.4%	10.0%	0.7%	2.8%	0.3%	100.0%
2023	0.8%	2.1%	2.5%	29.5%	7.2%	7.0%	9.8%	14.6%	3.3%	3.7%	13.3%	1.1%	4.8%	0.4%	100.0%
2024	1.6%	2.6%	3.0%	27.8%	5.6%	6.6%	6.0%	15.9%	2.9%	3.0%	15.4%	1.1%	7.2%	1.3%	100.0%
NSW															
2017	18.6%	33.0%	29.7%	9.5%	2.0%	1.5%	1.5%	2.4%	0.6%	0.4%	0.2%	0.2%	0.4%	0.2%	100.0%
2018	9.5%	21.3%	27.7%	26.5%	3.5%	2.5%	2.5%	3.1%	1.0%	0.8%	0.4%	0.2%	0.7%	0.3%	100.0%
2019	5.3%	13.8%	14.9%	46.2%	4.5%	2.8%	3.5%	3.7%	1.3%	1.1%	1.3%	0.2%	0.8%	0.4%	100.0%
2020	3.2%	9.6%	8.4%	49.0%	6.4%	3.5%	6.1%	5.0%	1.9%	1.7%	3.5%	0.2%	1.1%	0.4%	100.0%
2021	2.2%	8.0%	6.0%	42.7%	6.4%	5.2%	8.3%	8.6%	2.6%	2.1%	5.7%	0.3%	1.5%	0.6%	100.0%
2022	1.9%	6.6%	4.9%	37.9%	7.2%	5.6%	8.7%	10.9%	2.7%	2.5%	7.9%	0.5%	1.9%	0.8%	100.0%
2023	1.7%	5.7%	3.5%	33.4%	6.0%	5.7%	8.5%	12.7%	3.2%	3.1%	12.1%	0.7%	2.6%	1.1%	100.0%
2024	1.7%	5.1%	3.2%	29.8%	5.5%	5.4%	5.6%	15.3%	2.9%	3.5%	16.6%	0.7%	3.4%	1.3%	100.0%
QLD															
2017	9.2%	20.1%	33.4%	31.3%	1.0%	0.7%	0.7%	1.4%	0.5%	0.7%	0.2%	0.1%	0.7%	0.1%	100.0%
2018	5.7%	12.5%	21.2%	48.3%	2.2%	1.3%	1.6%	2.7%	0.8%	1.3%	1.0%	0.2%	1.1%	0.2%	100.0%
2019	3.5%	7.6%	10.7%	59.5%	3.2%	2.0%	2.8%	4.0%	0.9%	1.2%	2.7%	0.2%	1.4%	0.2%	100.0%
2020	3.2%	6.2%	7.6%	55.6%	4.0%	2.7%	4.5%	6.7%	1.0%	1.4%	4.8%	0.2%	1.9%	0.3%	100.0%
2021	3.5%	5.8%	5.9%	46.1%	3.9%	4.0%	6.4%	10.3%	1.7%	1.9%	7.7%	0.3%	2.3%	0.4%	100.0%
2022	3.4%	6.1%	4.6%	42.1%	4.5%	3.9%	5.6%	11.8%	2.1%	2.1%	10.5%	0.4%	2.4%	0.5%	100.0%
2023	3.4%	5.9%	3.4%	38.3%	4.4%	3.8%	5.0%	13.1%	2.3%	2.2%	14.4%	0.5%	2.7%	0.7%	100.0%
2024	3.7%	5.1%	3.2%	32.8%	3.4%	3.7%	3.2%	15.2%	1.5%	2.5%	21.0%	0.6%	3.4%	0.8%	100.0%
SA															
2017	13.8%	29.9%	33.5%	9.6%	2.7%	2.1%	4.0%	2.3%	0.6%	0.3%	0.3%	0.2%	0.5%	0.3%	100.0%
2018	7.0%	21.4%	27.4%	29.8%	2.7%	1.8%	3.3%	2.6%	0.8%	0.9%	0.6%	0.3%	0.9%	0.4%	100.0%
2019	3.8%	13.7%	14.7%	49.9%	3.7%	1.8%	2.8%	3.4%	1.2%	1.2%	1.8%	0.2%	1.3%	0.4%	100.0%
2020	2.6%	6.8%	8.1%	58.3%	5.7%	1.8%	3.7%	4.4%	1.3%	1.2%	3.4%	0.3%	1.9%	0.3%	100.0%
2021	1.8%	5.3%	6.7%	53.4%	5.7%	3.1%	4.8%	6.9%	1.9%	1.7%	5.7%	0.3%	2.2%	0.4%	100.0%
2022	2.2%	7.2%	6.3%	47.0%	5.9%	3.2%	5.3%	8.0%	2.0%	1.8%	7.7%	0.5%	2.4%	0.5%	100.0%
2023	2.0%	5.5%	5.1%	42.5%	6.6%	3.3%	5.1%	9.6%	3.2%	2.0%	11.1%	0.8%	2.7%	0.6%	100.0%
2024	2.2%	3.7%	2.8%	39.8%	6.6%	3.3%	4.2%	12.4%	2.5%	2.0%	14.9%	1.4%	3.4%	0.8%	100.0%
TAS															
2017	17.3%	33.1%	37.1%	5.0%	2.0%	1.3%	2.3%	0.8%	0.2%	0.1%	0.1%	0.1%	0.2%	0.3%	100.0%
2018	12.8%	29.2%	36.9%	11.8%	1.9%	1.2%	4.0%	0.7%	0.5%	0.2%	0.0%	0.2%	0.4%	0.3%	100.0%
2019	7.5%	27.1%	28.6%	24.8%	3.7%	1.6%	4.0%	0.8%	0.4%	0.3%	0.2%	0.2%	0.3%	0.3%	100.0%
2020	4.1%	18.5%	16.3%	37.6%	10.6%	1.8%	6.8%	1.0%	0.7%	0.6%	0.9%	0.3%	0.5%	0.3%	100.0%
2021	1.8%	13.2%	11.5%	40.0%	16.3%	3.9%	3.4%	2.8%	1.6%	1.5%	2.6%	0.2%	0.9%	0.4%	100.0%
2022	1.0%	7.6%	10.7%	41.3%	21.0%	3.9%	2.7%	3.3%	1.6%	1.4%	3.9%	0.2%	0.9%	0.4%	100.0%
2023	1.1%	5.5%	6.3%	36.4%	27.0%	5.7%	3.1%	3.5%	1.9%	2.2%	5.6%	0.2%	1.0%	0.5%	100.0%
2024	0.9%	3.2%	4.6%	32.3%	21.3%	13.9%	3.2%	5.5%	1.8%	2.7%	8.4%	0.3%	1.2%	0.6%	100.0%
VIC															
2017	16.6%	43.2%	28.2%	5.4%	1.3%	1.0%	1.4%	1.4%	0.3%	0.3%	0.2%	0.2%	0.4%	0.2%	100.0%
2018	8.6%	24.4%	33.7%	24.7%	1.7%	1.2%	1.6%	1.8%	0.5%	0.4%	0.3%	0.2%	0.5%	0.2%	100.0%
2019	5.0%	19.1%	21.7%	45.7%	2.0%	1.2%	1.4%	1.6%	0.5%	0.5%	0.5%	0.2%	0.5%	0.2%	100.0%
2020	3.3%	12.1%	13.3%	58.7%	2.6%	1.5%	2.6%	2.1%	0.8%	0.7%	1.1%	0.2%	0.8%	0.2%	100.0%
2021	3.0%	8.2%	9.6%	60.2%	3.1%	2.4%	4.2%	3.5%	1.3%	1.0%	1.8%	0.2%	0.9%	0.3%	100.0%
2022	2.8%	8.0%	7.3%	53.4%	4.5%	3.9%	4.8%	6.6%	1.7%	1.4%	3.3%	0.4%	1.4%	0.5%	100.0%
2023	1.6%	6.5%	5.2%	51.1%	4.8%	4.5%	5.5%	8.8%	1.9%	1.6%	5.4%	0.6%	1.8%	0.6%	100.0%
2024	1.5%	5.4%	4.6%	48.6%	4.4%	5.1%	4.2%	12.1%	1.4%	1.8%	7.7%	0.7%	1.9%	0.7%	100.0%
WA															
2017	13.0%	27.8%	27.0%	30.8%	0.2%	0.2%	0.2%	0.3%	0.1%	0.1%	0.0%	0.0%	0.2%	0.1%	100.0%
2018	9.8%	24.0%	14.5%	49.6%	0.2%	0.2%	0.3%	0.4%	0.2%	0.3%	0.2%	0.0%	0.2%	0.1%	100.0%
2019	4.9%	17.2%	9.1%	66.8%	0.3%	0.2%	0.2%	0.6%	0.1%	0.1%	0.2%	0.0%	0.2%	0.0%	100.0%
2020	2.0%	10.5%	5.7%	78.9%	0.4%	0.2%	0.3%	0.9%	0.1%	0.2%	0.5%	0.0%	0.2%	0.1%	100.0%
2021	1.6%	8.1%	3.2%	80.9%	0.9%	1.0%	0.7%	2.2%	0.2%	0.3%	0.7%	0.0%	0.2%	0.1%	100.0%
2022	1.1%	7.2%	2.4%	78.3%	1.3%	2.1%	1.6%	2.5%	0.5%	0.6%	1.6%	0.2%	0.4%	0.1%	100.0%
2023	1.2%	7.3%	1.7%	77.2%	2.2%	1.3%	1.7%	2.4%	0.9%	0.5%	2.6%	0.4%	0.6%	0.1%	100.0%
2024	1.1%	6.1%	1.3%	75.8%	2.4%	1.3%	2.1%	3.2%	1.1%	0.8%	3.7%	0.4%	0.8%	0.1%	100.0%