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

Report for AEMO

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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 2053-54 of solar and stationary battery uptake for the sub-segment of this market that does not participate in AEMO's scheduled dispatch system.

Our results are divided into several system size brackets:

- ***Residential*** - which are assumed to cover solar systems up to 15kW in size and their associated battery systems, which for modelling purposes were assumed to average 10kWh in size 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 150kWh.
- ***Small power stations*** - which are assumed to be between 1MW and 30MW in scale.

Green Energy Market's projections of non-scheduled sub-30MW solar systems and stationary battery energy storage systems are driven primarily by changes in their financial attractiveness based on the combination of the revenue they earn (which includes the electricity grid purchases they avoid) versus the cost involved in installing them. This provides us with a payback period - the years it takes for revenue to exceed the installation cost - which we can then compare against 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 (2021) Australian Battery Market Report 2021

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

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

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

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

For systems within segment 2 (small power stations) we have assumed that installs will be modest throughout the outlook. This is due to the fact that behind the meter installs are expected to effectively displace the market opportunity for these solar systems. These levels of installs though are adjusted depending on the scenario, with higher uptake in the scenarios intended to encapsulate greater levels of emission reduction policy ambition.

1.2 Context for modelling the evolution of the DER market

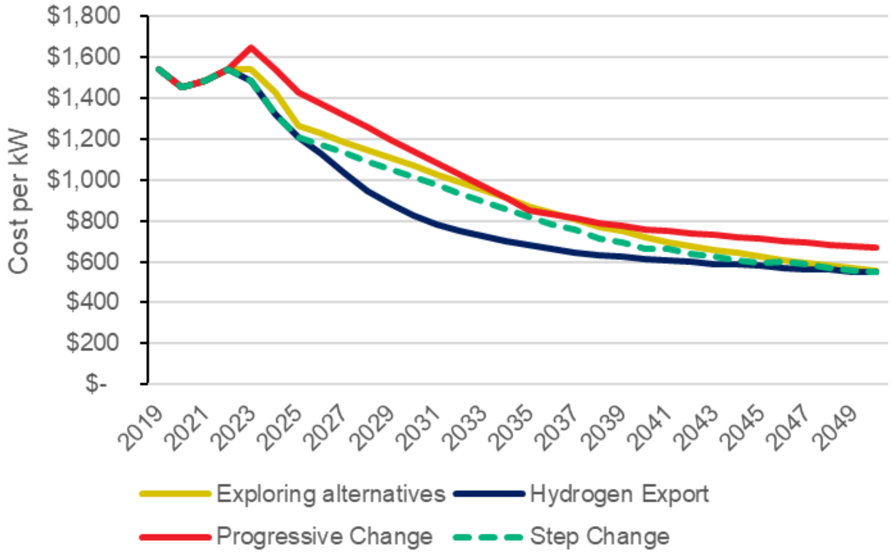
The Australian market for distributed energy systems is rapidly evolving, with the prospect of considerable technological and economic changes over the projection period. This means there is considerable uncertainty about how the uptake of solar and stationary energy battery systems will change over time. However, there are some key trends and drivers which are expected to unfold over the outlook period which act as potential tailwinds that support growth or headwinds which hinder uptake. Some of the main tailwinds and headwinds driving the projection results are touched upon below with further detail within the sections of the main report.

Long-term tailwind: ongoing capital cost declines.

One of the most critical aspects underpinning projected ongoing growth in cumulative capacity of solar PV and an expected surge in battery installations later this decade is an expectation that the cost of both solar and battery systems will decline substantially over the outlook period.

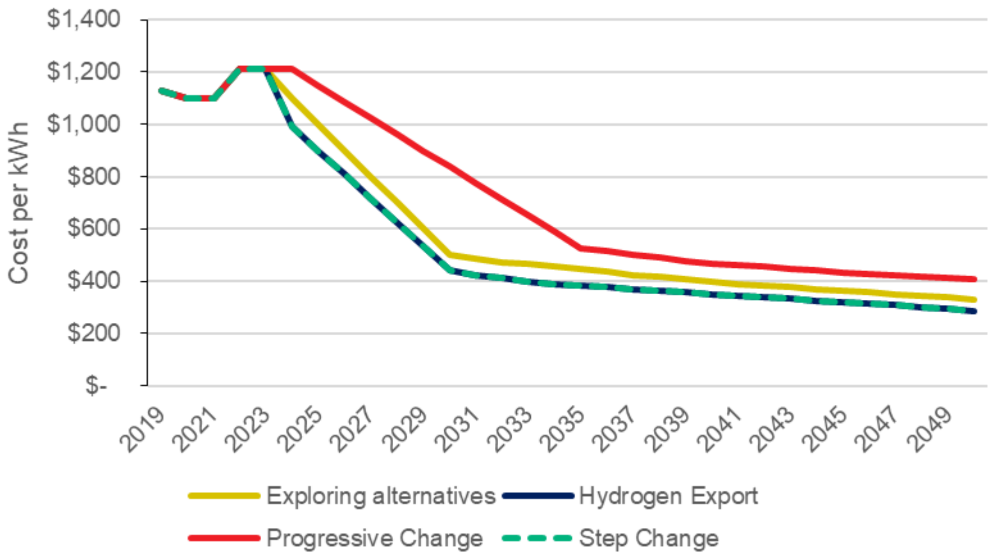
The figure below illustrates the assumed fully installed cost of a residential solar system by scenario over time. While the cost of solar systems has increased recently, this is expected to be relatively short-lived, and by the end of the projection period costs are expected to have more than halved.

Figure 1-1 Fully installed cost of solar system per kW by scenario
(excludes impact of government policy support



Cost reductions for stationary battery systems are assumed to be even more significant. While prices are expected to remain quite high for the next few years, a large surge in production capacity of batteries and their associated inputs eventually results in an increase in supplier rivalry and a competitive shake-out in the industry, with prices declining closer to underlying production costs. This leads to a rapid drop in purchase prices faced by consumers between the mid-2020's to 2030, although in the case of Progressive Change, cost reductions are much slower (although still very substantial).

Figure 1-2 Fully installed cost of a battery system per kWh by scenario
(excludes impact of government policy support

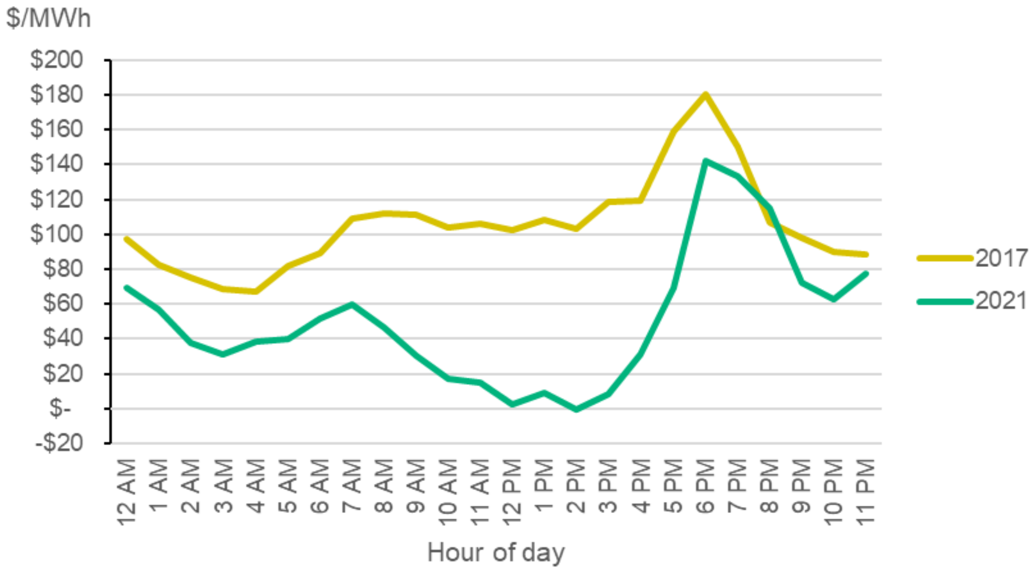


For further information on capital cost assumptions see sections 4.2 and 4.3.

Long-term headwind: Solar market saturation
Solar PV capacity has grown incredibly rapidly relative to the size of the overall electricity market in both the NEM and the SWIS. Total solar capacity across rooftops and power stations across these two grids now exceeds that of any other individual fuel type including coal and gas. The large scale of that capacity now leads to a material discount in wholesale electricity market prices during sunny periods. In some regions where solar

penetration is particularly high such as South Australia, the SWIS and Queensland, wholesale power prices have regularly reached negative levels during daytime periods when overall demand for electricity is low. The change in wholesale price dynamics by time of day is best exemplified by wholesale prices in South Australia in 2021 compared to 2017, as shown in Figure 1-3, where prices fall to very low levels in the middle of the day.

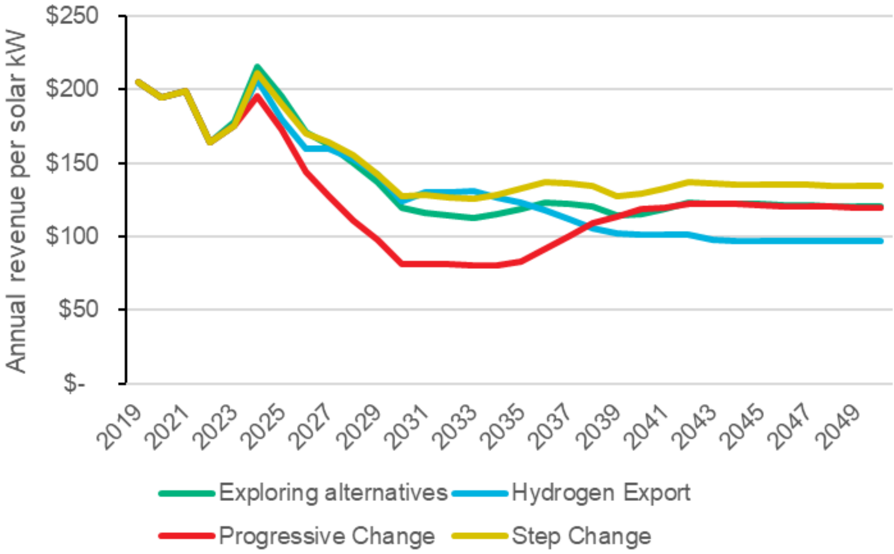
Figure 1-3 Average SA wholesale prices by hour – 2017 vs 2021



As solar capacity grows, the wholesale market value of the electricity can be expected to decline. While there has been a respite in this decline due to a surge in international prices for coal and gas, once the impact of the Russian withdrawal of supply subsides, we expect daytime prices will continue to follow a downward trajectory. We expect this will flow through to retail feed-in tariffs. In addition, with a move towards more time differentiated small consumer tariffs (supported by the roll-out of smart meters) this daytime discount can also be expected to flow through to retail grid-import electricity prices.

This means that our model assumes a substantial decline in the revenue (bill savings) a solar system delivers to a customer. This is the case across all scenarios considered as shown in Figure 1-4, in this case for NSW, but similar patterns are observed for the other states.

Figure 1-4 Annual revenue per kW of residential solar - NSW



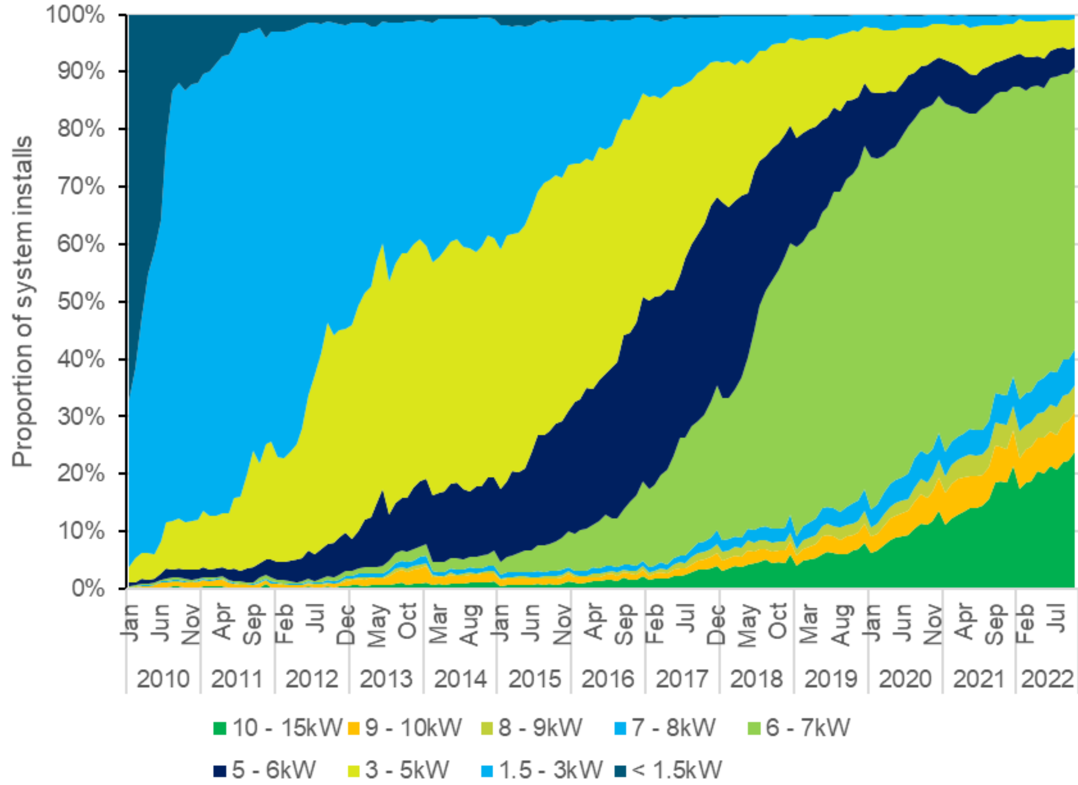
For further information about electricity price assumptions see section 4.4.

Another market saturation factor that slows solar uptake over the long term is that a large proportion of residential dwellings now already have a solar system. Over time for solar to continue to grow faster than new dwelling construction, it needs to expand to customers that 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 becomes more important within our modelling towards the second half of the projection period where the modelled average household payback on a solar and battery systems becomes quite attractive (due to substantial accumulated cost declines), but this is offset by the more challenging nature of the remaining market that is yet to install a solar system.

Short-term tailwind: Emergence of replacement market upgrading to larger systems

Over 2009-10 to 2012-13, Australia experienced its first boom in solar installations, with around a million systems installed over that period. As **Figure 1-5** shows, the kilowatt size of these systems was far smaller than what is typically favoured by householders today. Over the 2020's we expect a significant proportion of the systems installed over this first boom will be retired and replaced. We also expect that when they are replaced, it will be with a system that is similar in kilowatt capacity to what is popular across the broader market. This means large numbers of pre-existing systems of 1kW to 3 kilowatts in capacity will likely be upgraded over the 2020's to systems of 6 or more kilowatts, which then noticeably boosts capacity additions in the projections.

Figure 1-5 Proportion of residential solar systems within different capacity bands – National



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

Long-term headwind: Network connection restrictions

A pivotal factor in the ongoing growth of residential solar capacity in Australia has been the steady shift towards larger sized systems, as shown in Figure 1-5 above. For example, the number of new residential systems installed in 2020-21 was 19% less than what was installed in 2010-11. Yet the amount of generating capacity that was added in 2020-21 was three times greater than in 2010-11, because the generating capacity of each individual system was so much larger in 2020-21.

However, we expect that the growth in the size of residential systems is likely to slow due to network connection restraints. Across Australia, distribution networks as a general rule will only grant automatic connection access for systems where the inverter is restricted to exporting no more than 5 kilowatts of power (per phase) to the grid. As Figure 1-5 above shows, the vast majority of systems being installed today already have PV panel capacity that exceeds this export limit (given the vast majority of households have single phase power). While this 5 kilowatt export limit has little impact in constraining the usable output of a solar system with say 6.6 kilowatts of panel capacity (because it is rare that panels will produce at their maximum capacity, and there is usually some on-site electricity consumption), it becomes increasingly significant as the PV panel capacity grows. This reduces the value to a consumer of purchasing a larger system and therefore should lead to a slowing in system size growth.

Long-term possible tailwind: Governments emission reduction commitments to address climate change

Electricity currently represents the largest source of greenhouse gas emissions in Australia[3]. In addition, electricity is widely expected to play an important role in replacing other forms of energy for transport and heat purposes[4]. Therefore, reducing the emissions associated with generating electricity will be a vital element of Australian Governments' goals to achieve net zero emissions.

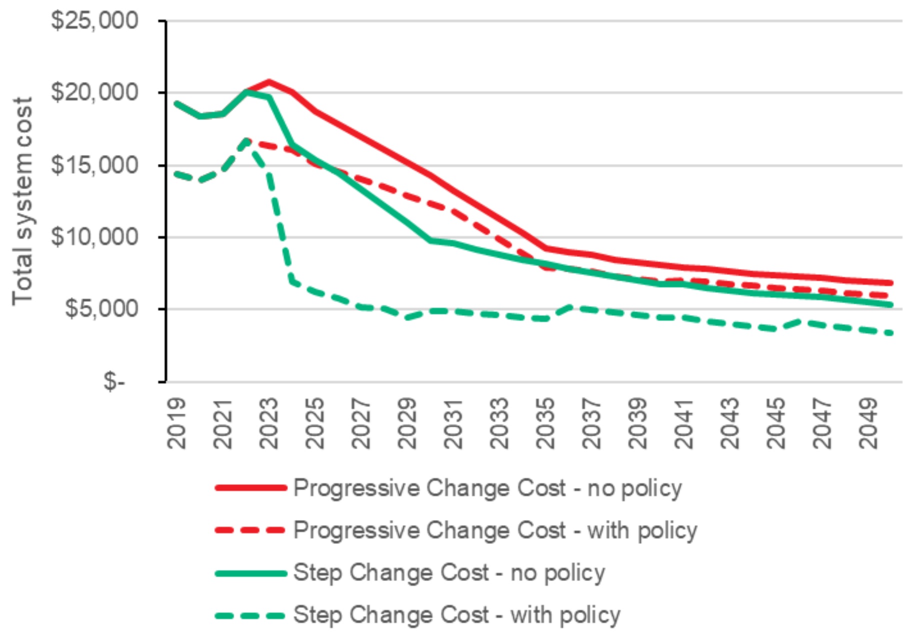
Encouraging the installation of solar systems via mechanisms such as electricity retailer obligations, rebates or rewards for abatement have historically been used by Australian governments to help decarbonise electricity supply. In addition, several governments have also acted in various ways to support the installation of batteries to support further uptake and integration of renewable energy within the electricity system. However, looking forward there is a degree of uncertainty about the policies Federal, State and Territory Governments will implement to achieve their net zero emission commitments and the role distributed energy might play. Under the Step Change and Hydrogen Export scenarios, the model assumes governments implement significant new emission reduction policies where distributed energy is eligible. Meanwhile policy support for DER under the Progressive Change scenario is more constrained and Exploring Alternatives sits in between these two alternative approaches.

Figure **1-6** below shows the impact of different assumptions about emission reduction policy support on the purchase price residential consumers face for a combined solar and battery system under the Step Change Scenario contrasted with the Progressive Change scenario. The solid lines indicate the purchase price without taking into account policy support mechanisms, while the dashed lines show the price once discounts are taken into account as a result of policy support. Under Progressive Change the level of policy support is assumed to decline substantially from current levels such that the difference between the price with and without policy support narrows substantially over time. Under Step Change meanwhile, the level of policy support is lifted substantially in 2024 on the assumption of a major step-up in policy efforts to encourage DER to meet the rapid emission reduction goals of this scenario.

Figure 1-6 Combined solar & battery system cost with and without policy support
Step Change compared to Progressive Change (6.6kW solar + 10kWh battery system)

[3] Australian Government Department of Climate Change, Energy, the Environment and Water (2022) Quarterly Update of Australia's National Greenhouse Gas Inventory: March 2022.

[4] For example see ClimateWorks Australia (2020) Decarbonisation Futures – Solutions Actions and benchmarks for a net zero emissions Australia.



1.3 Results

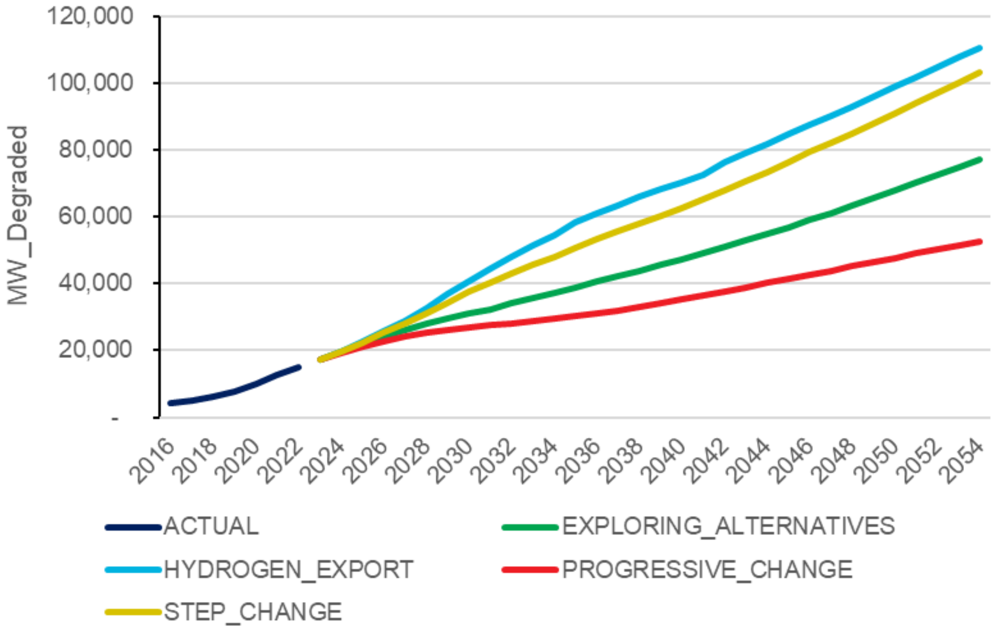
1.3.1 Solar PV

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 8.5kW (it is currently at around 7.5kW). However, network distributors generally only allow inverters to export a maximum of 5kW to the grid. 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. 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 noticeably lower.

National Electricity Market (NEM)

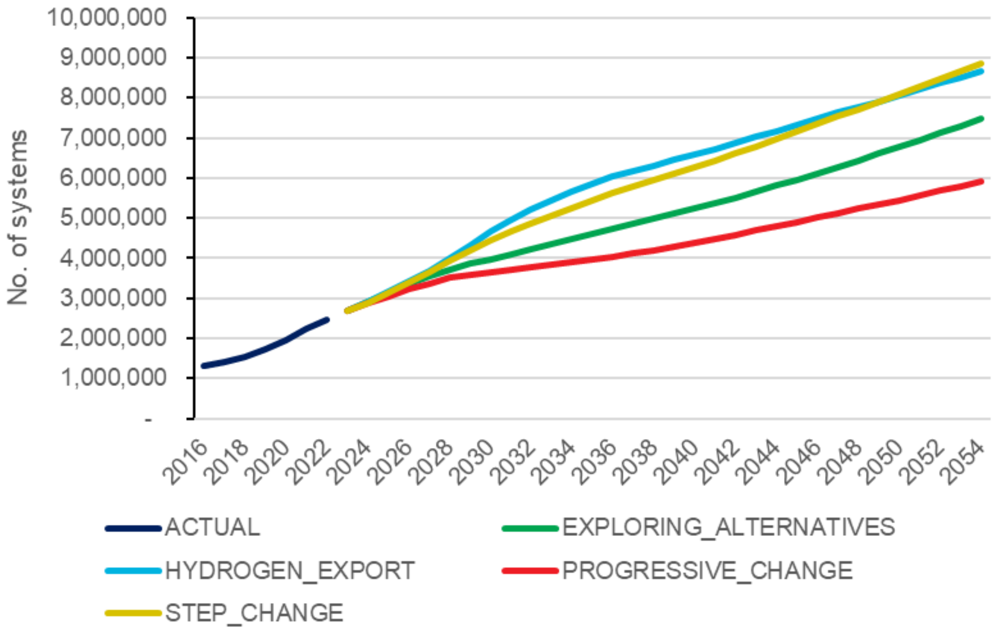
Figure 1-7 details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the National Electricity Market (NEM), taking into account the degradation of solar panel output over time and adjusting for systems that are replaced. At the beginning of the projection (the conclusion of the 2021-22 financial year) cumulative installed degraded capacity is expected to stand at almost 15,000MW. By the end of the projection in 2053-54 the cumulative degraded capacity reaches almost 53,000MW, at the low end, under Progressive Change, and around 110,000MW at the upper bound represented by the Hydrogen Export scenario.

Figure 1-7 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 almost 2.4 million. At the low end under Progressive Change, the cumulative number of systems grows to around 5.9 million by the end of the 2053-54 financial year. The upper bound represented by the Step Change scenario reaches close to 8.9 million. Initially the number of DER PV system installs are higher under the Hydrogen Export scenario than in Step Change, in large part due to assumed faster capital cost reductions. However, under the Hydrogen Export scenario due to an expansion in demand for bulk power from hydrogen production, there is a substantial expansion in front-of-the meter solar farm capacity (including from sub-30MW non-scheduled projects). This provides a side benefit to end consumers in lower electricity prices which then reduces the attractiveness of them installing solar on their own premises. Consequently, DER PV system numbers in Hydrogen Export fall behind those in Step Change towards the end of the projection period. This cross-over is not seen in terms of megawatts of capacity detailed in Figure 1-7 above, because our projection of non-scheduled power station capacity (which represents a large amount of capacity, but a small portion of the number of systems) is much larger in Hydrogen Export than Step Change.

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

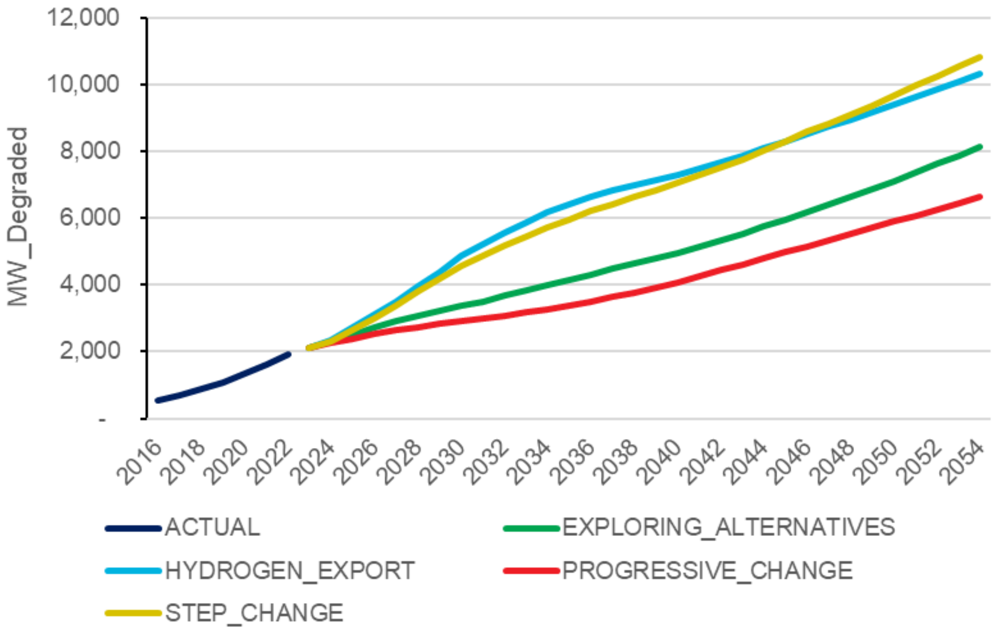


To put these system numbers in context the total number of NEM residential electricity connections is expected to grow from 9.4m in the 2021-22 financial year to between 13.5m and 14.8m by 2053 (the residential sector accounts for the vast bulk of solar system numbers). Under Progressive Change around 39% of residential dwellings are expected to have a solar system around the end of the projection period, while at the upper end under Step Change it reaches almost 55% of all residential connections.

Western Australian South-West Interconnected System

The figure below 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 and replacement of existing systems. At the beginning of the projection (the conclusion of the 2021-22 financial year) cumulative installed degraded capacity is expected to stand at almost 1,908MW. At the low end, under Progressive Change, the cumulative degraded capacity reaches 6,600MW by the end of the projection in 2053-54 financial year. The upper bound represented by the Step Change scenario reaches around 10,800MW. Note that for the SWIS, unlike the NEM, the projection does not include any capacity for in-front-of-the-meter power stations.

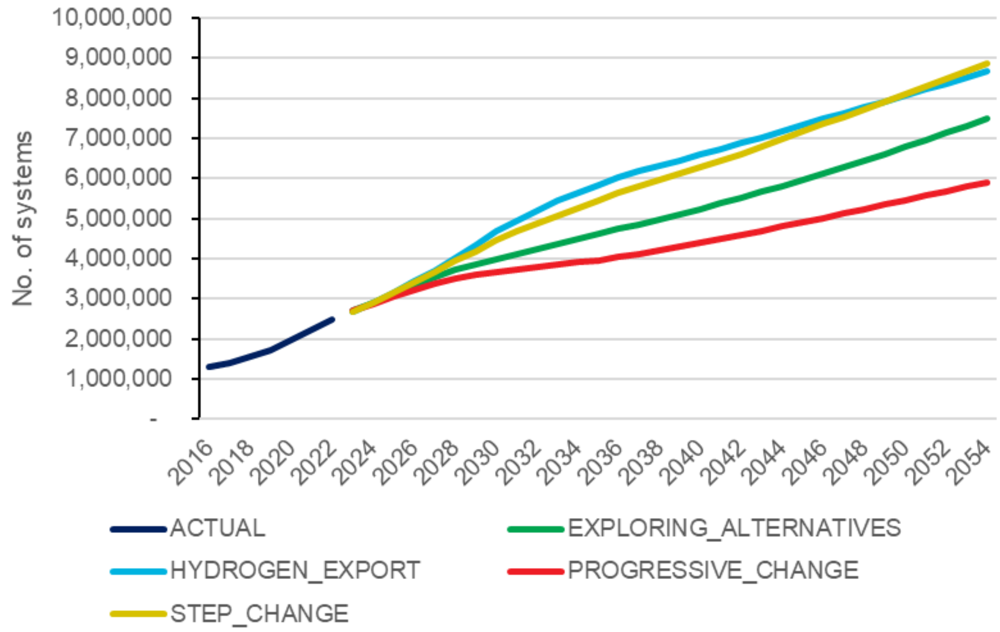
Figure 1-9 WA SWIS cumulative degraded megawatts of solar PV by scenario



The figure below details projections for the cumulative number of solar PV systems by scenario on a national basis. At the beginning of the projection the cumulative number of systems stands at almost 400,000. At the low end under Progressive Change, the cumulative number of systems grows to around 981,000 by the end of the 2053-54 financial year. The upper bound represented by the Step Change scenario reaches just under 1.4 million.

Note that the SWIS follows the same pattern as projections for the NEM where the number of DER PV system installs are initially higher under the Hydrogen Export scenario than in Step Change, in large part due to assumed faster capital cost reductions. However, under the Hydrogen Export scenario due to an expansion in demand for bulk power from hydrogen production, there is a substantial expansion of solar farm capacity. This provides a side benefit to end consumers in lower electricity prices which then reduces the attractiveness of them installing solar on their own premises. Consequently, DER PV system numbers in Hydrogen Export fall behind those in Step Change towards the end of the projection period. Unlike the NEM, this cross-over is also evident in terms of projections of megawatts of capacity detailed in Figure 1-9 above, because the SWIS projections are only for behind the meter systems and exclude sub-30MW power stations.

Figure 1-10 WA SWIS cumulative number of PV systems by scenario



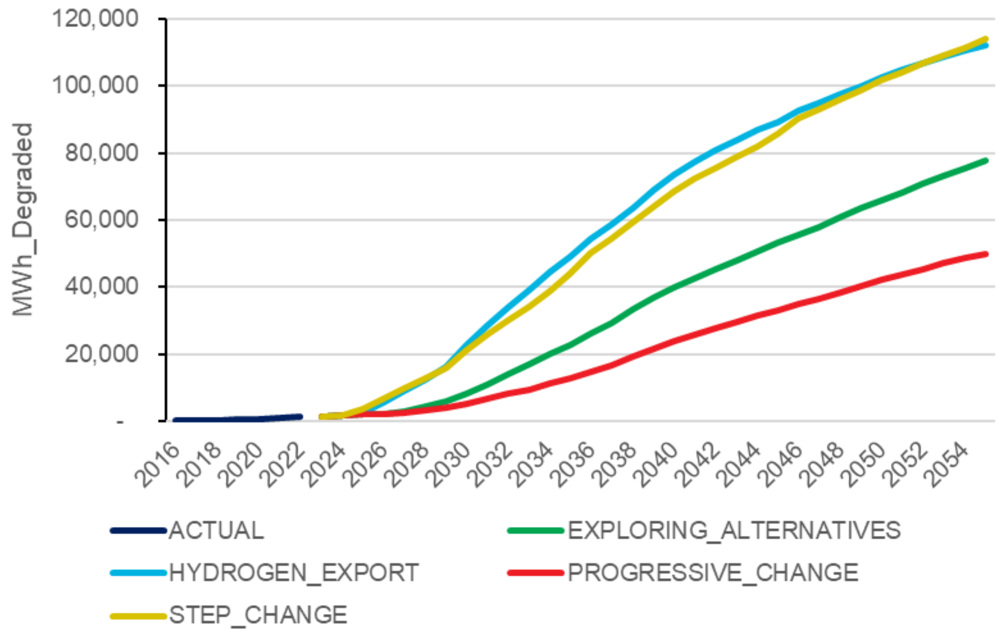
To put these system numbers in context the total number of residential electricity connections is expected to grow from 1.06m in 2021-22 to reach between 1.7m to 2.0m by 2053. Under Progressive Change around 53% of residential dwellings are expected to have a solar system around the end of the projection period, while at the upper end under Step Change it reaches 68% of all residential connections.

1.3.2 Battery energy storage

National Electricity Market (NEM)

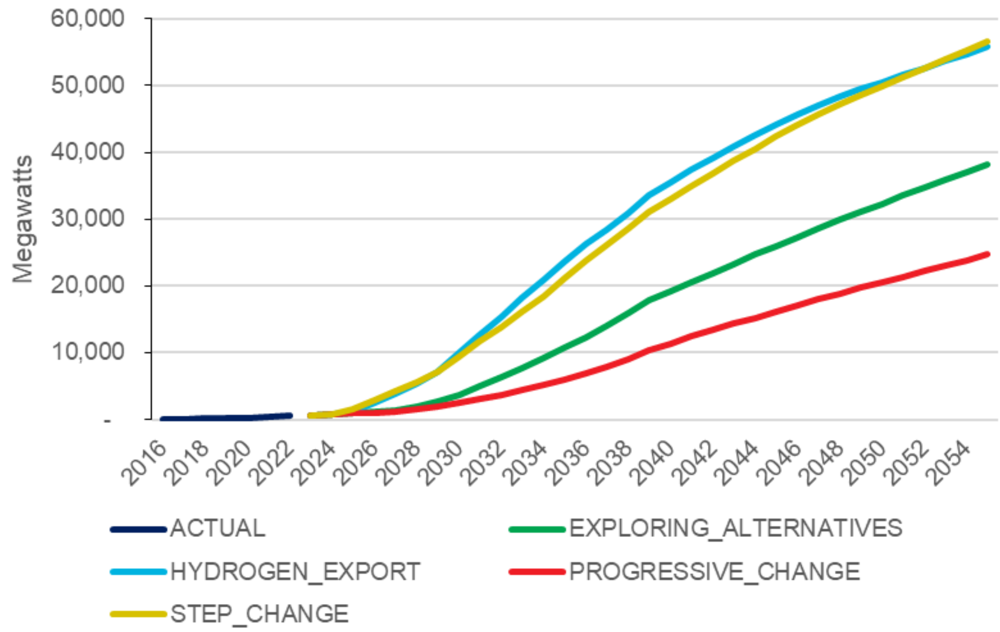
In terms of behind the meter stationary battery systems Figure 1-11 details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the National Electricity Market (NEM), taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2021-22 financial year) cumulative degraded battery capacity is estimated to stand at 1,251MWh. At the low end, under Progressive Change, the cumulative degraded capacity reaches 50,000MWh by the end of the projection in 2053-54 financial year. The upper bound represented by the Step Change scenario reaches around 114,000MWh.

Figure 1-11 NEM cumulative degraded megawatt-hours of battery capacity by scenario



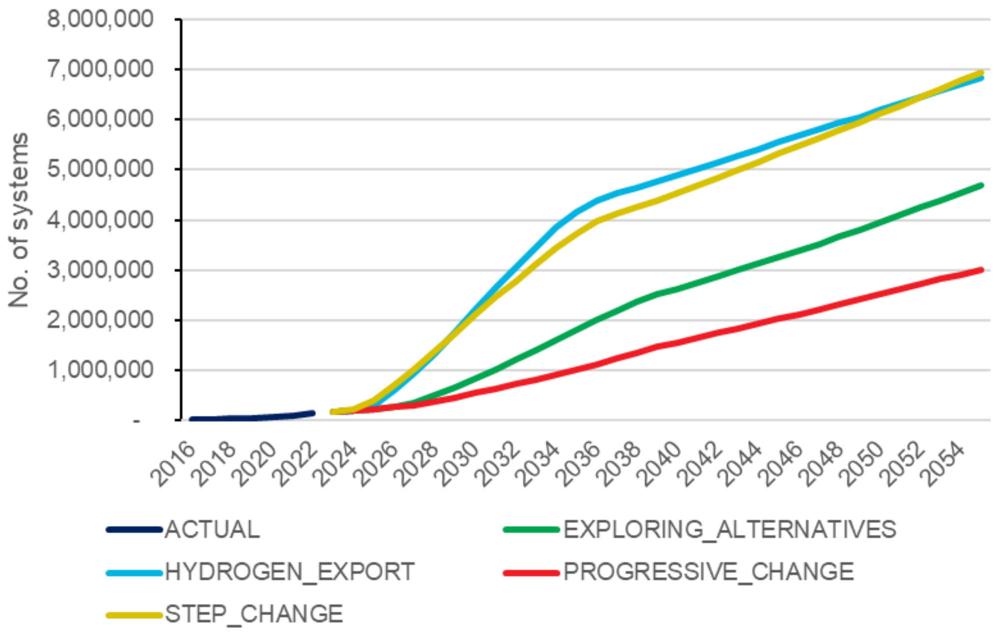
The figure below shows the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 553MW at the end of 2021-22 financial year. Under Current Trajectory this grows to 20,700MW by the end of the projection in 2050-51 financial year. Under Progressive Change, megawatt capacity reaches close to 25,000MW by the end of the projection in 2053-54 financial year. The upper bound represented by the Step Change scenario reaches close to 57,000MW. The projections are based on an assumption that the instantaneous output that can be extracted from a battery is not subject to degradation (although the kilowatt-hours of storage is still subject to degradation) and that the average system when first installed will have maximum output equal to 40% of its original megawatt-hours of storage.

Figure 1-12 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 2021-22 financial year the cumulative number of grid-connected battery systems is around 136,000. Under Progressive Change this grows to 2.9 million by the end of the projection with 18% of residential customers owning a battery system. The upper bound represented by Step Change reaches almost 6.8 million, with almost 41% of residences owning a battery system.

Figure 1-13 NEM cumulative number of battery systems by scenario

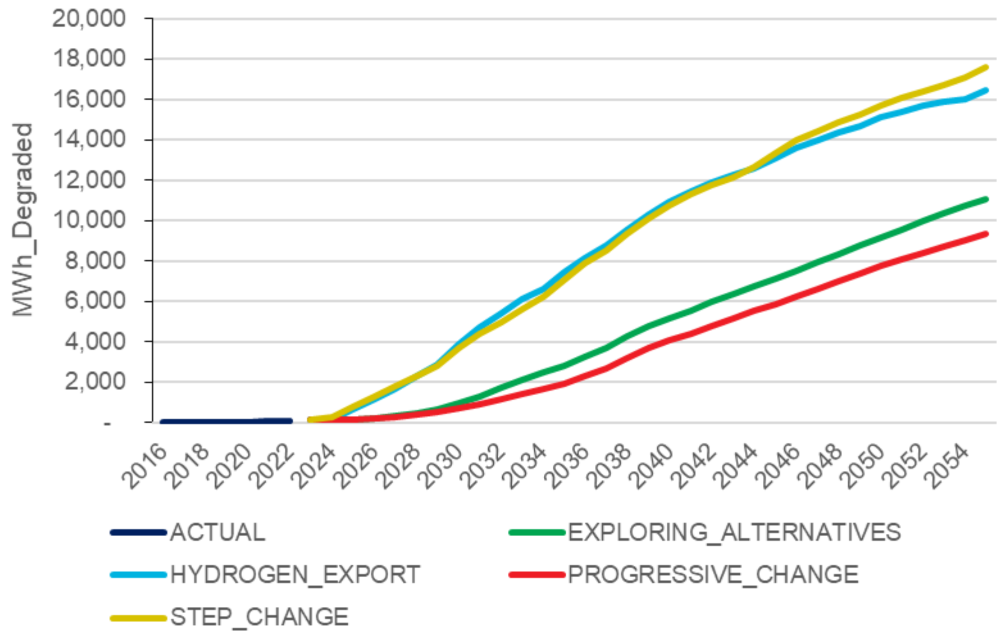


The noticeable slowing in the growth of the stock of battery systems shown by the inflection or knee point of the blue and yellow lines in the mid 2030's is a product of batteries having penetrated much of the existing stock of households with solar systems around this point in time (for the Hydrogen Export 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. Further explanation of this inflection point is detailed in section 5.2.5 of the report.

Western Australian South-West Interconnected System (SWIS)

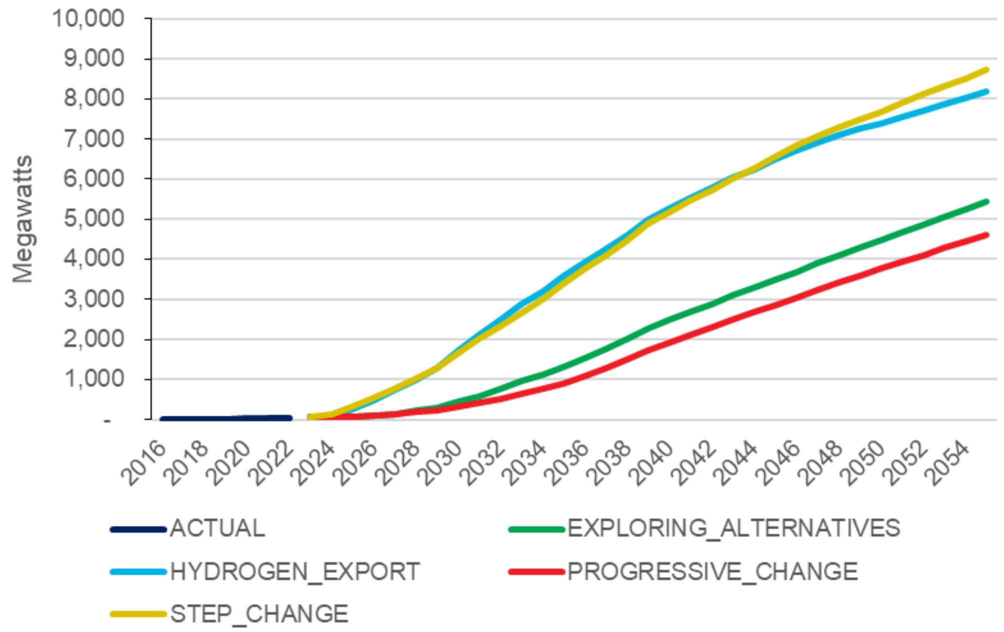
The figure below details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the WA SWIS, taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2021-22 financial year) cumulative degraded battery capacity is estimated to stand at 100MWh. Under Progressive Change the cumulative degraded capacity reaches around 9,000MWh by 2053-54 financial year. The upper bound represented by the Step Change scenario reaches 17,000MWh.

Figure 1-14 WA SWIS cumulative degraded megawatt-hours of battery capacity by scenario



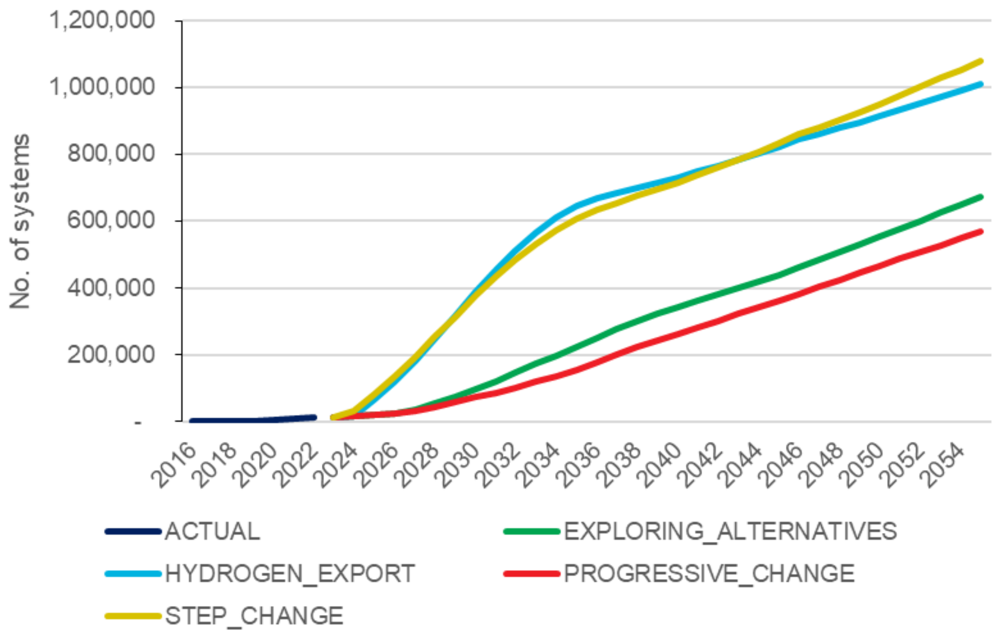
The figure below illustrates the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 43MW at the end of 2021-22 financial year. Under Progressive Change this grows to 4,600MW by the end of the projection. The upper bound represented by the Step Change scenario reaches 8,700MW.

Figure 1-15 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 2021-22 financial year the cumulative number of grid-connected battery systems stands at close to 11,000. Under Progressive Change the cumulative number of systems grows to almost 550,000 by the 2053-54 financial year, with almost 30% of residential connections. The upper bound represented by the Step Change scenario reaches 1.0 million with 54% of residential connections hosting a battery system.

Figure 1-16 WA SWIS cumulative number of battery systems by scenario



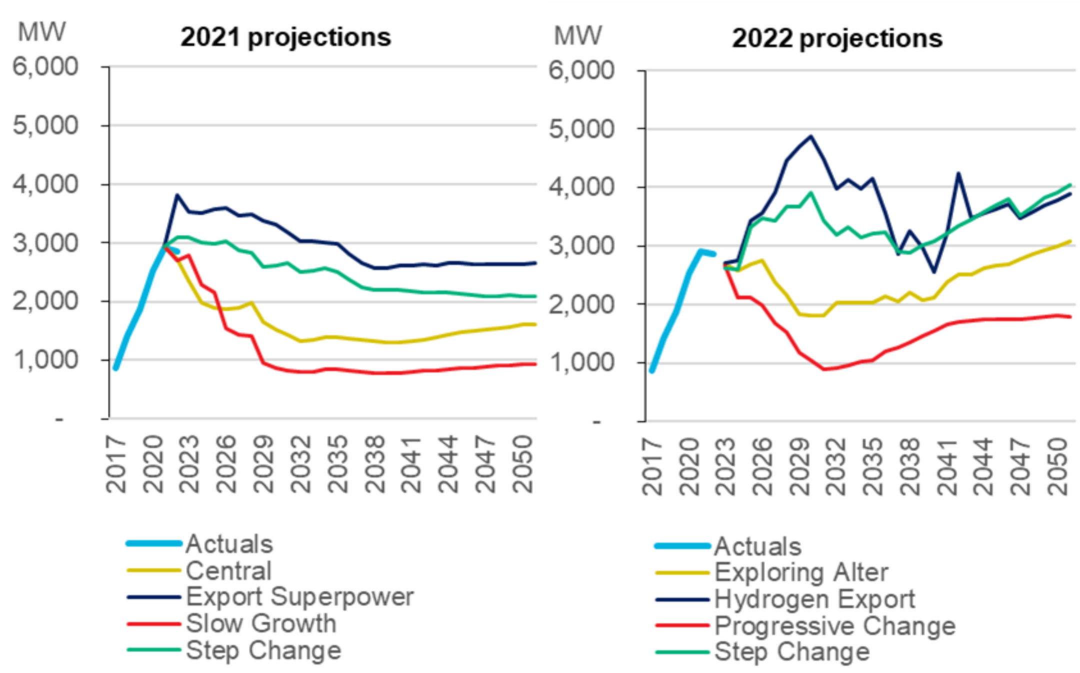
The noticeable slowing in the growth of the battery stock in the mid 2030's under Hydrogen Export and Step Change in the SWIS is due to batteries having penetrated most of the existing stock of households with solar at this point in time, just as what unfolds in the NEM states.

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

1.4.1 Solar PV

We have substantially increased estimates of both solar and battery capacity installations this year relative to last year's modelling exercise. Figure 3-3 shows GEM projections for annual capacity additions to stock (after deducting retired capacity) in 2021 on the left, with updated 2022 projections on the right. Capacity additions are up across all scenarios relative to the scenarios adopted in last year's modelling.

Figure 1-17 National annual PV Megawatt additions to stock 2021 vs 2022 projections



There are three main reasons for these increases in projected solar capacity which are detailed in the headings below.

1- Demand more resilient than expected to deteriorating financial returns for solar

GEM's modelling framework is built upon research that indicates that the main driver for consumers' purchasing a solar system is to seek a financial gain and therefore changes in investment payback time are a useful guide for overall solar market installations. Over the last few years GEM's modelling indicated that paybacks on solar systems would noticeably deteriorate. Consequently, we had originally expected that system installs would peak in 2019 and then subsequently decline.

While our assumptions about deteriorating financial returns largely eventuated, demand for solar systems has proven more resilient than we had originally estimated. Demand for solar has ultimately begun to decline but this decline has unfolded later and at less steep rate than originally estimated.

Part of this was due to the one-off impact of a COVID-lockdown induced shift in household expenditure away from services to household durable goods. However, the level of demand has been sufficiently robust to justify a longer-term adjustment upwards in demand for systems at a given payback level.

2 – Large rise in energy costs over the short-term

As noted in prior reports, wholesale power market prices had increasingly displayed a daytime depression effect as the extra supply from solar has acted to increase competition and displace higher cost generators. Consequently, GEM's prior years' projections modelling had assumed energy prices during daytime periods would reach very low levels.

However, due to very large rises in the international price for gas and coal (which have flowed through to higher costs for marginal Australian power generators), NEM wholesale electricity prices have surged to unprecedented highs. This has necessitated significant upward revisions in our retail electricity price and feed-in tariff assumptions which then increase the level of financial savings a solar system delivers.

3 –Emission reduction settings for scenarios more ambitious

While the Step Change and Hydrogen Export scenarios adopt similar emission reduction ambitions to last year's Step Change and Export Superpower scenarios, there are a further two new scenarios this year – Exploring Alternatives and Progressive Change – which assume faster emission reduction efforts than the other scenarios used in last year's modelling (Slow Change and Central).

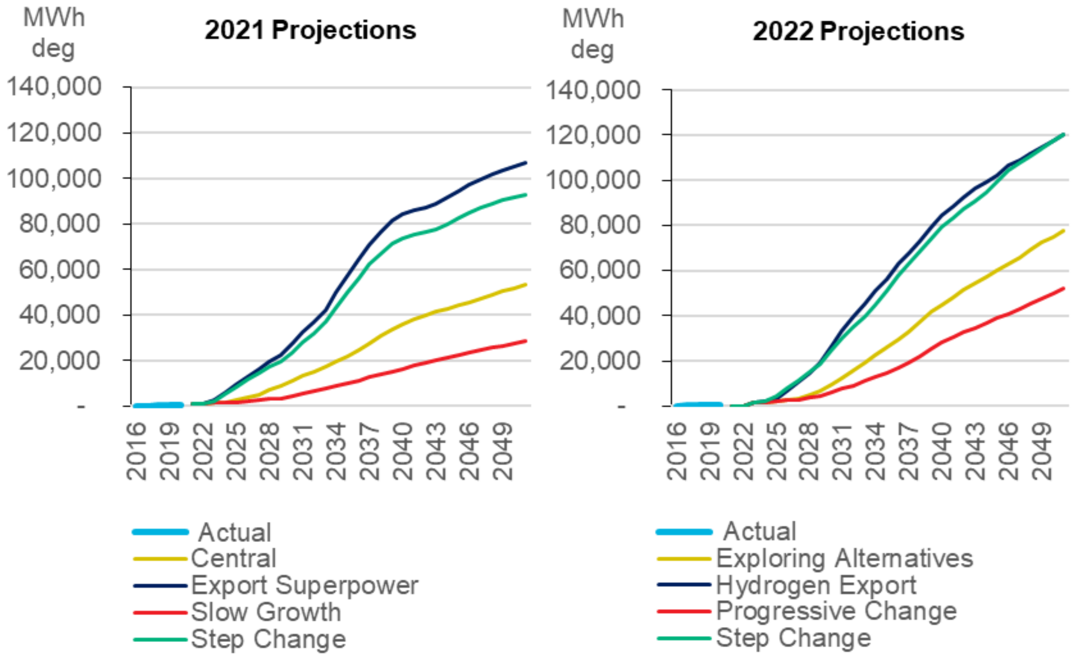
Under the prior modelling exercise, the Central Scenario involved no new emission reduction policies affecting DER, while existing policy measures were only included up to the date at which they were explicitly legislated or budgeted. No account was made for extension of existing policies or new policies to support DER as part of meeting stated emission pledges made by governments. Meanwhile Slow Change assumed a range of existing DER support policies were rolled back or ended prematurely.

By contrast in this year's modelling, AEMO guidance for Exploring Alternatives and Progressive Change is that government policy will reflect a 43% emission reduction by 2030. Longer term, policy under Progressive Change will reflect a goal of achieving net zero emissions by 2050. Meanwhile under Exploring Alternatives Australian governments are expected to implement longer term policies consistent with the country's commitment under the Paris Climate Agreement of supporting a global goal of containing global warming to less than 2 degrees Celsius.

1.4.2 Batteries

The amount of battery capacity projected in this year's modelling has also increased relative to last year's estimates, as shown in the figure below.

Figure 1-18 Degraded cumulative MWh battery capacity- 2021 vs 2022 projections



There are two main reasons for the increase in projected battery capacity. The first is that battery uptake is tied to our model's expectations of solar uptake and solar uptake has been significantly increased in this year's forecasts. The second is that we now assume that the typical battery system capacity for households and small businesses will grow steadily from 15 kWh in 2030 to reach 20kWh by 2040, whereas last year we assumed battery size remained constant at 15kWh after 2030.

However, one other important change of note is that battery uptake is much slower in the short-term under this year's modelling. This is due to increases to assumed battery system costs over the 2020's to reflect higher prices being seen in the market right now, as well as supply constraints that have become increasingly evident. These constraints indicate it will take several years for expansions in production capacity to catch-up with demand such that it results in meaningful increases in competitive rivalry and reduced prices.

For further detail on changes compared to last year's modelling exercise please see section 3.9.

2 Introduction

The Australian Energy Market Operator (AEMO) has engaged Green Energy Markets Pty Ltd (GEM) to provide several scenario-based projections to 2053-54 of solar and battery uptake for a sub-segment of this market that does not participate in AEMO's scheduled dispatch system. It is optional for systems below 30MW in capacity to be scheduled[5] 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[6].
- 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 150kWh.
- Small power stations which are assumed to be between 1MW and 30MW in scale.

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

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

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

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

[6] 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 sub-segment of the total solar market which excludes AEMO-scheduled solar systems controlled by their dispatch system. In the NEM it is optional for systems below 30MW in capacity to be scheduled and so this report only considers systems below this size[7]. 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 Market's projections of non-scheduled sub-30MW solar systems and stationary battery energy storage systems are driven primarily by changes in their financial attractiveness based on the combination of the revenue they earn (which includes the electricity grid purchases they avoid) versus the cost involved in installing them. This provides us with a payback period (the years it takes for revenue to exceed the installation cost) which we can then compare against 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.

[7] 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 Market's solar and battery system payback model.

For systems within segment 2 (small power stations) we take a different approach where we tie installation levels back to the level of scheduled large solar power station capacity installs projected within the 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 15kW in capacity and associated battery systems and which generally face electricity charges recovered on the basis of the amount of kilowatt-hours of electricity consumed plus a fixed daily charge;
2. Small commercial – which cover solar systems up to 100kW in capacity and who are assumed to face similar electricity tariff structures as residential consumers;
3. Large commercial – which cover solar systems above 100kW up to 1 MW and are assumed to face large consumer electricity tariffs. These typically involve network charges which involve some kind of demand-based tariff where costs are recovered based on a short 30 minute peak in demand over a month or year as well as the amount of overall kilowatt-hours of consumption.

3.2.1 Costs

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

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

3.2.2 Revenue estimations

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

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

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

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

The formula that governs the charging of the battery operates in a manner that is able to perfectly predict the amount of solar exports in a day. If this is insufficient to charge the battery to its full capacity then it charges from the grid for the difference over 8am until 11am. While historically this has not been 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[8]. 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[9]. 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%).

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

[9] 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). Residential and commercial installations have been segmented based on system size, with systems below 15kW deemed to be residential except in cases prior to 2015 where they are deemed residential if less than 10kW.

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.
- 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; 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.

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.

We have re-assessed our baseline year to be an average of the 2019 and 2020 level of installations by state, compared to 2015 in last year's modelling. We believe that this better reflects the current market characteristics and reflects a level of market maturity. This provides a reasonably large market size ranging from 234,000 new systems in 2019 to 309,000 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

The commercial or non-residential sector continues to be seen as an attractive market by the solar industry, now representing over 20% of installed capacity.

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 base. 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 is more extensive than we had previously estimated. 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. Only 5 months of data was available using the new data field and we have pro-rated these levels back to 2015.

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. While this market sector is still relatively small, we expect it to continue to grow and become a much more important feature of the industry in future years as saturation increases 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.

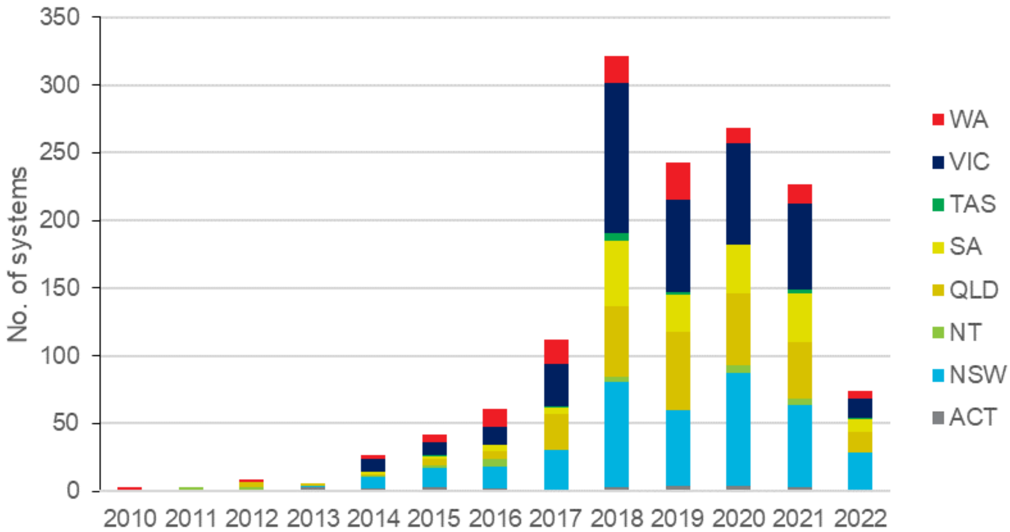
Factors making it difficult to predict future installations include the fact that the market is immature and still undergoing rapid development and change. Prior to 2016 solar systems larger than 100kW were not really a commercial proposition to electricity customers where a large proportion of network charges are recovered via demand-based tariffs. Lastly, solar was substantially more expensive than wind power and so uncompetitive for provision of LGCs and electricity for the wholesale market.

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

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

Figure 3-1 illustrates that the number of systems installed in Australia (note that this includes systems that are larger than 1MW but which are known to be behind-the-meter systems) prior to 2016 was very small, with just 42 systems accredited in 2015, 31 in 2014 and an average of just 8 per annum from 2010 to 2013. The most installed in any single state was just 15 prior to 2016. This very small sample set over a short period of time makes it difficult to draw confident inferences about how the market responds to different factors likely to influence uptake. Also while the market was characterised by rapid growth in system numbers over 2014 to 2018, this abruptly ended in the subsequent year. While numbers were then subsequently steady to 2021, the rate of applications seen so far over 2022 indicate a collapse in the market, particularly behind the meter systems. This may recover somewhat over the back half of 2022 given the spike in wholesale electricity market prices, but shows that the large commercial solar market is currently highly volatile.

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



Note: 2022 numbers are only up to July. Some of the systems counted within this chart are projects which have applied for accreditation but are yet to be accredited. For these projects, as well as those accredited, the system is recorded against the year in which the application was received.

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 and then the subsequent fall 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 2018 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 last 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). While COVID-19 restrictions and the accompanying economic downturn cloud the picture somewhat in that they may have negatively influenced the sales environment for the commercial sector, it's clear that the rapid growth path evident after 2015 has now ended.

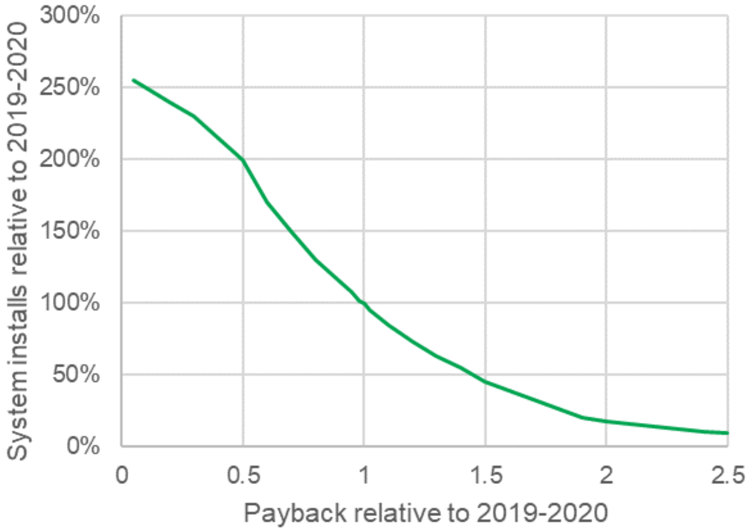
We have attempted to evaluate how uptake of behind the meter solar is likely to change by assessing payback periods on solar systems in 2023 to 2027 relative to a baseline of the 2019 and 2020 years. Given the noticeable lags affecting the mid-scale solar market we believe 2019 and 2020 installation 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. This is a slight change from prior projections prepared for AEMO which used the accreditation date rather than application date for assessing how many systems and capacity were installed in the benchmark year. Application date is now used because it provides a more accurate representation of the date in which a system installation took place.

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. As a further refinement in this year's analysis, we've also made use of the 2022 year to July level of accreditation application levels as a another guidepost for how installs could change in response to changes in payback. It is assumed the purchasing decision for these systems was informed by 2021 paybacks.

With these three 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 3-2 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. It is varied depending upon the scenario with the range adopted in the first three years aiming to reflect the degree of uncertainty over whether this market segment may have further rapid growth potential in line with what unfolded over 2015 to 2018, or may have already reached full maturity as evidenced by the lack of growth in subsequent years. From 2025/26 the growth factor is calibrated relative to the economic growth expected for each respective scenario.

The uptake curve is structured in such a way that once paybacks lengthen beyond 1.5 times 2019 levels, then uptake becomes less sensitive to lengthening payback. This is based on feedback from industry participants and observations of the market that suggest there is an underlying level of demand for solar installations that is heavily driven by non-financial motivations. This source of demand is much less sensitive to payback periods. But as payback shortens from 1.5 times 2019 levels then uptake accelerates, which is consistent with the rapid growth the market experienced from 2016 to 2018. Unfortunately, we do not have any experience to draw from to understand how uptake might respond if paybacks were to noticeably improve/shorten relative to 2019/20 levels. Our current hypothesis is that uptake would accelerate noticeably as payback moved towards a halving from 2019/20 levels. This is because at such a point solar would provide such a rapid payback that most businesses would find it attractive to install. However as noted earlier, given the lack of historical experience and the small sample of systems installed to date our estimates of uptake responsiveness are highly uncertain.

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 very low 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 the recent 2022 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.

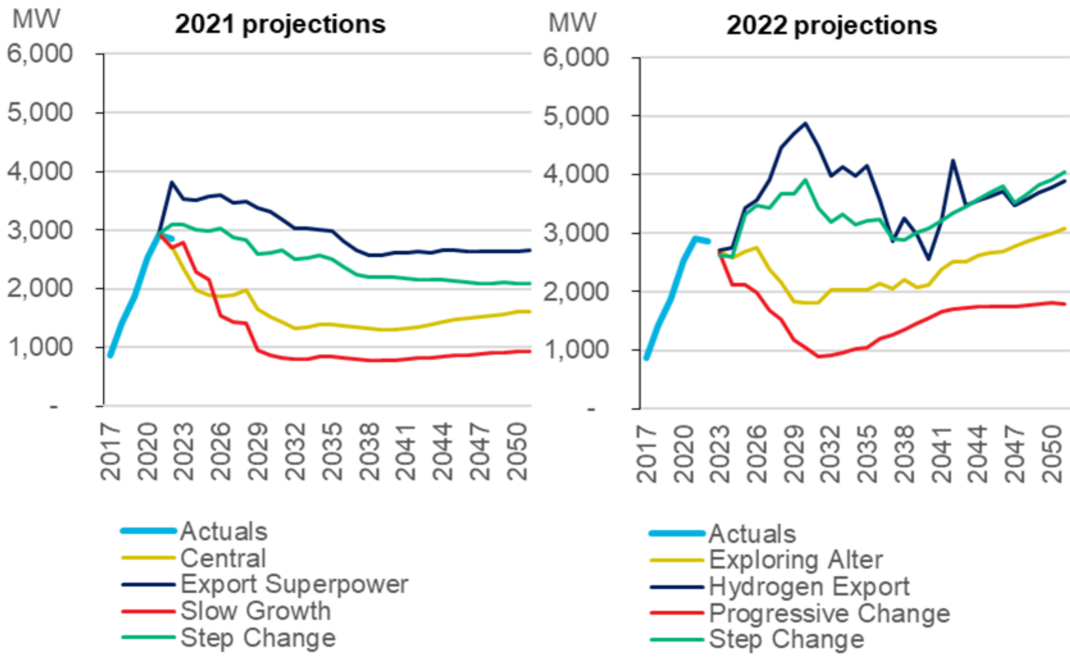
The amount of 1MW+ capacity installed is calibrated at 6% of the scheduled solar installed in each year as estimated in the ISP. This is in line with the proportion of sub-30MW power station capacity accredited in 2019 relative to those 30MW or greater.

3.9 Changes to the modelling approach relative to last year's estimates

3.9.1 Solar PV

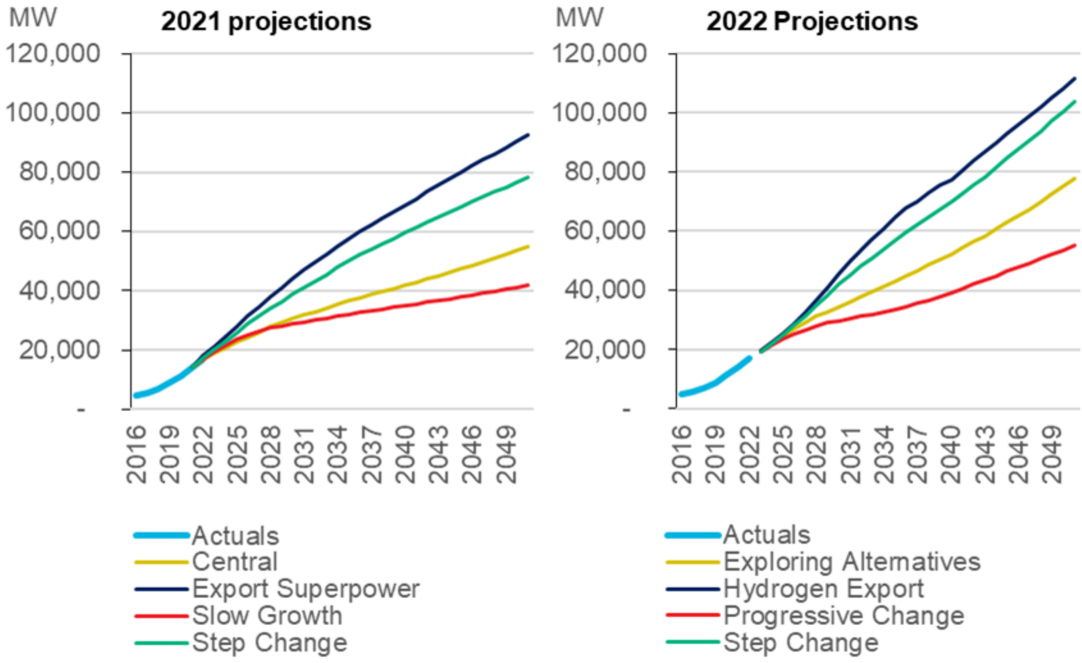
We have substantially increased estimates of both solar and battery capacity installations this year relative to last year's modelling exercise. Figure 3-3 shows GEM projections for annual capacity additions to stock (after deducting retired capacity) in 2021 on the left, with updated 2022 projections on the right. Capacity additions are up across all scenarios relative to the scenarios adopted in last year's modelling. While we continue to cater for the potential for annual capacity additions to decline substantially from current levels in two of the scenarios (Progressive Change and Exploring Alternatives), unlike last year's projections, installations then rebound substantially in the 2030's. Meanwhile in this year's Step Change and Hydrogen Export scenarios solar capacity additions continue to grow over the next few years to levels well above recent historical highs. While they ultimately contract in the 2030's, they still remain at levels above recent years. This is unlike last year's projections where capacity additions in the Step Change and Export Superpower scenarios peaked before the mid-2020's and then steadily declined to reach levels below what unfolded over 2020 and 2021.

Figure 3-3 National annual PV Megawatt additions to stock 2021 vs 2022 projections



These increases to annual additions accumulate to quite large changes in the accumulated installed stock of solar megawatts (after accounting for panel output degradation) relative to the 2021 projections, as shown in Figure 3-4.

Figure 3-4 Cumulative degraded PV capacity- 2021 vs 2022 projections



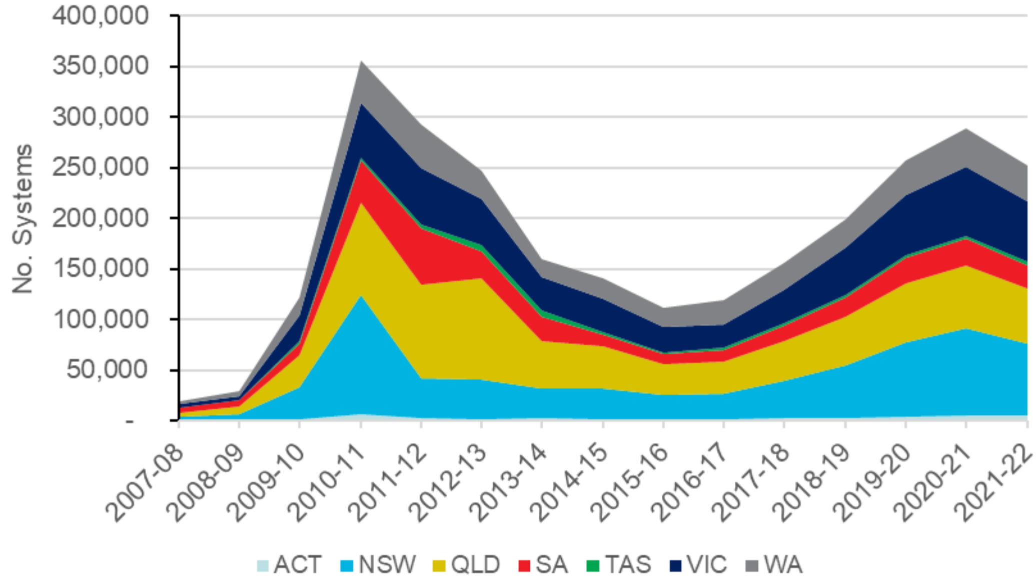
There are three main reasons for these increases in projected solar capacity which are detailed in the headings below.

1- Demand more resilient than expected to deteriorating financial returns for solar

GEM's modelling framework is built upon research that indicates that the main driver for consumers' purchasing a solar system is to seek a financial gain and therefore changes in investment payback time are a useful guide for overall solar market installations. Over the last few years GEM's modelling indicated that paybacks on solar systems would noticeably deteriorate. This was due to expected declines in retail electricity rates and also feed-in tariffs, as well as the steady drop away in the rebate provided by the Federal Government's Small Scale Renewable Energy Scheme outpacing falls in solar system costs. Consequently, we had originally expected that system installs would peak in 2019 and then subsequently decline.

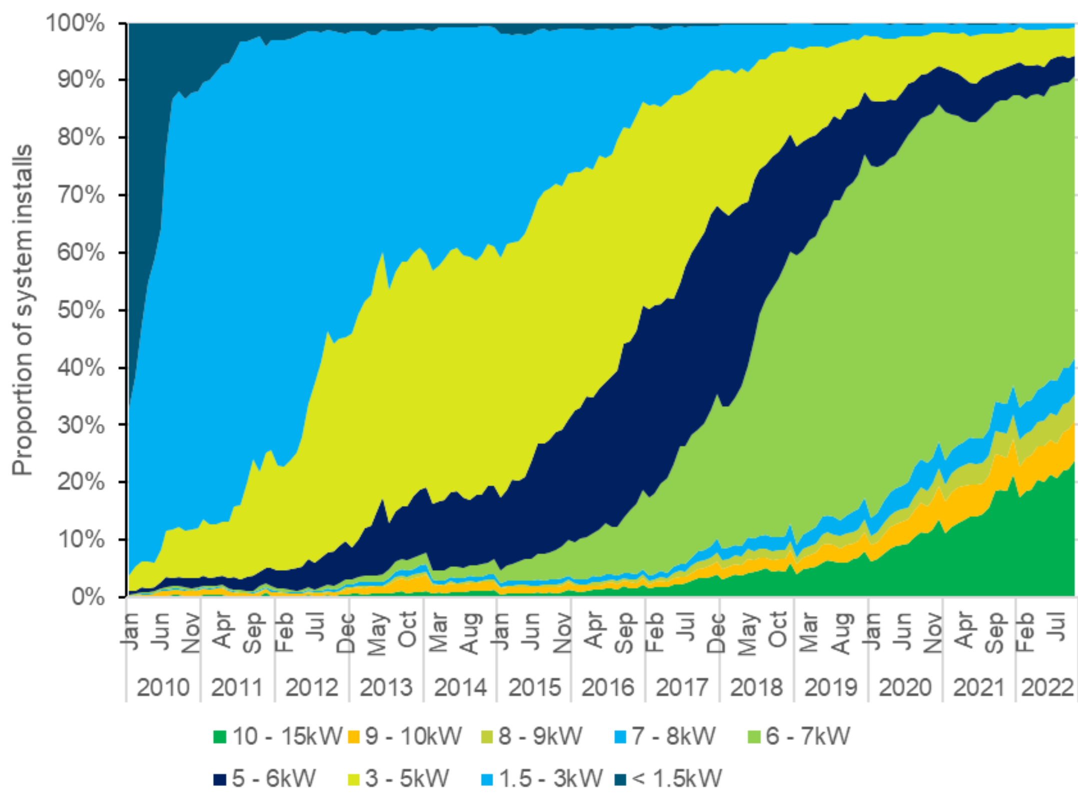
While our assumptions about deteriorating financial returns largely eventuated, demand for solar systems has proven more resilient than we had originally estimated. Demand for solar has ultimately begun to decline as can be seen in the system installation numbers shown below, but this decline has unfolded later and at less steep rate than originally estimated.

Figure 3-5 Number of residential solar system installs by state



Part of this was due to the one-off impact of a COVID-lockdown induced shift in household expenditure away from services to household durable goods. However, the level of demand has been sufficiently robust to justify a longer term adjustment upwards in demand for systems at a given payback level. This is supported by the fact that the historical trend towards larger solar systems is continuing, even though the average system has DC panel capacity noticeably higher than the 5kW export limit imposed by most Australian distribution networks.

Figure 3-6 Proportion of residential solar systems within different capacity bands – National

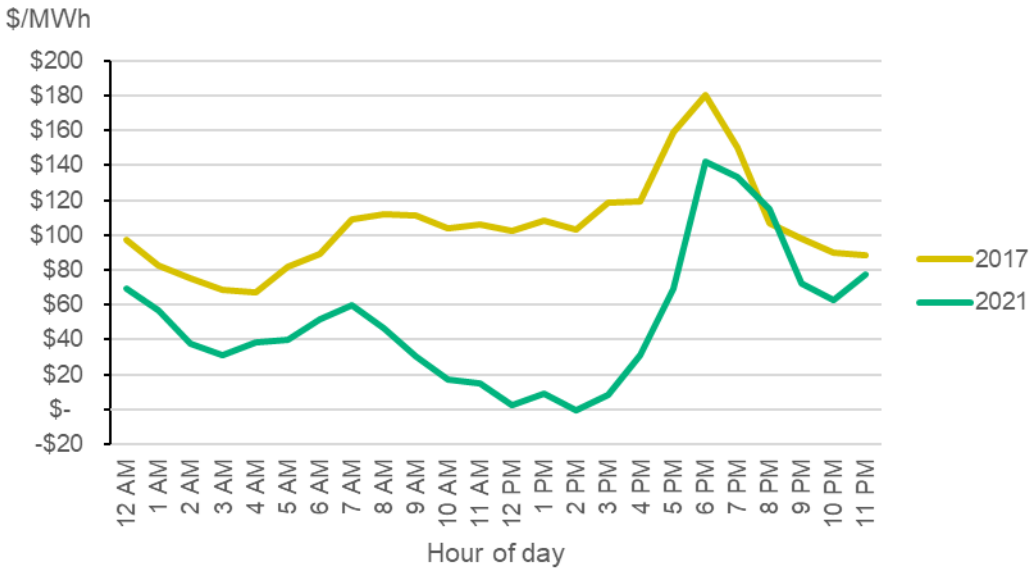


Source: Green Energy Markets analysis of Clean Energy Regulator STC registry data

2 – Large rise in energy costs over the short-term

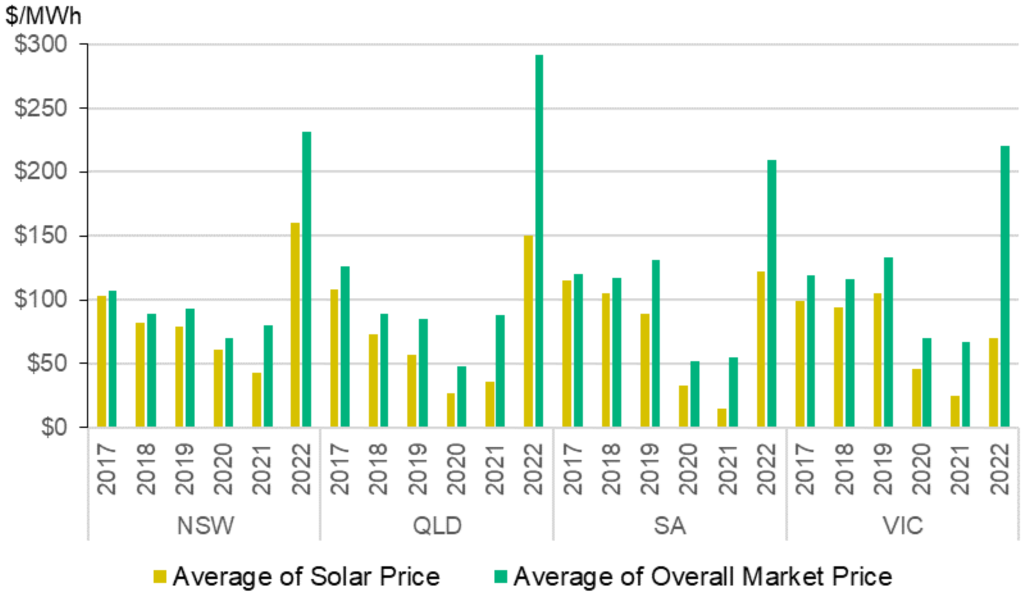
As noted in prior reports, wholesale power market prices had increasingly displayed a daytime depression effect as the extra supply from solar has acted to increase competition and displace higher cost generators. Consequently, GEM's prior years' projections modelling had assumed energy prices during daytime periods would reach very low levels. This was informed by forecasts by the Australian Energy Market Commission and wholesale market outcomes experienced in regions with high penetration of solar, exemplified by South Australia's wholesale market in 2021 relative to 2017 as shown below.

Figure 3-7 Average SA wholesale prices by hour – 2017 vs 2021



However, due to very large rises in the international price for gas and coal (which have flowed through to higher costs for marginal Australian power generators), NEM wholesale electricity prices have surged to unprecedented highs. This has necessitated significant upward revisions in our retail electricity price and feed-in tariff assumptions which then increase the level of financial savings a solar system delivers. While solar generation continues to see a large discount in the wholesale value it can capture relative to the overall market, in 2022 wholesale spot prices for solar generation were still very high by historical standards across all NEM states bar Victoria (see Figure 3-8).

Figure 3-8 Average wholesale spot price for solar versus overall market



3 –Emission reduction settings for scenarios more ambitious

While the Step Change and Hydrogen Export scenarios adopt similar emission reduction ambitions to last year's Step Change and Export Superpower scenarios, there are a further two new scenarios this year – Exploring Alternatives and Progressive Change – which assume faster emission reduction efforts than the other scenarios used in last year's modelling (Slow Change and Central).

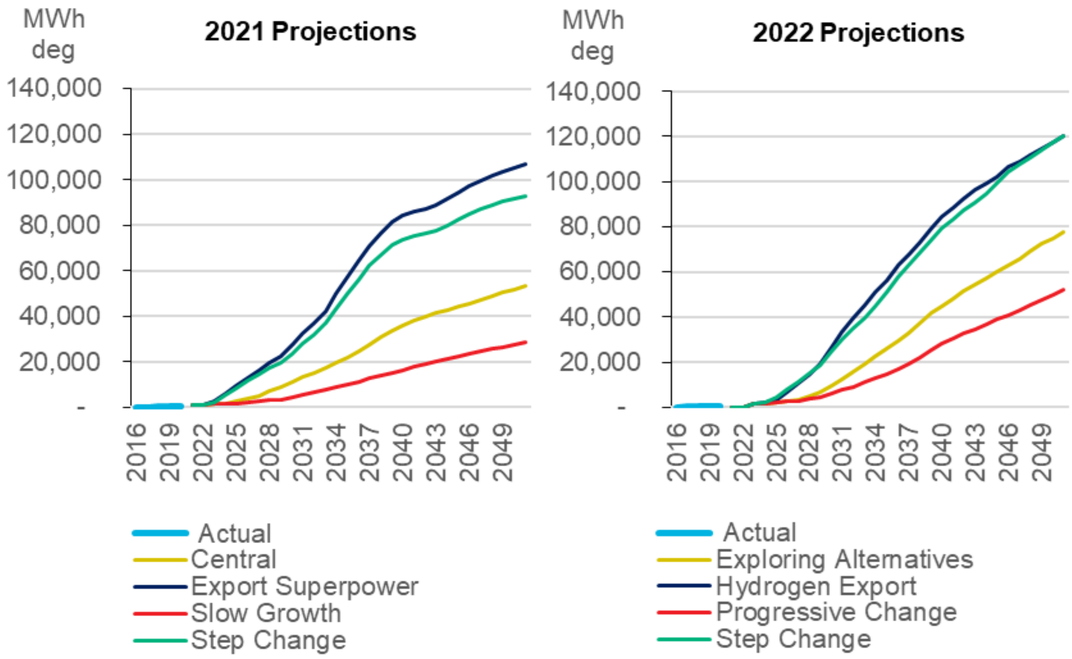
Under the prior modelling exercise, the Central Scenario involved no new emission reduction policies affecting DER, while existing policy measures were only included up to the date at which they were explicitly legislated or budgeted. No account was made for extension of existing policies or new policies to support DER as part of meeting stated emission pledges made by governments. Meanwhile Slow Change assumed a range of existing DER support policies were rolled back or ended prematurely.

By contrast in this year's modelling, AEMO guidance for Exploring Alternatives and Progressive Change is that government policy will reflect a 43% emission reduction by 2030. Longer term, policy under Progressive Change will reflect a goal of achieving net zero emissions by 2050. Meanwhile under Exploring Alternatives Australian governments are expected to implement longer term policies consistent with the country's commitment under the Paris Climate Agreement of supporting a global goal of containing global warming to less than 2 degrees Celsius.

3.9.2 Batteries

The amount of battery capacity projected in this year's modelling has also increased relative to last year's estimates, as shown in the figure below.

Figure 3-9 Degraded cumulative MWh battery capacity- 2021 vs 2022 projections



There are two main reasons for the increase in projected battery capacity. The first is that battery uptake is tied to our model's expectations of solar uptake and solar uptake has been significantly increased in this year's forecasts. The second is that we now assume that the typical battery system capacity for households and small businesses will grow steadily from 15 kWh in 2030 to reach 20kWh by 2040, whereas last year we assumed battery size remained constant at 15kWh after 2030. While a 20 kWh battery provides a level of capacity that will often exceed a household's daily requirements (mainly during Spring, Autumn and Summer), this increase was deemed appropriate given expected significant reductions in the per unit cost of batteries over this time period and observations of how the residential solar market has evolved. In the solar market as the equipment costs per unit of capacity have declined, solar retailers have taken advantage of this fall by upselling households to larger capacity systems which allow for greater profit margins given sales and installation costs are largely fixed irrespective of system size. These solar systems have reached an average capacity which generate vastly more power than households are capable of consuming.

However, one other important change of note is that battery uptake is much slower in the short-term under this year's modelling. This is due to increases to assumed battery system costs over the 2020's to reflect higher prices being seen in the market right now, as well as supply constraints that have become increasingly evident. These constraints indicate it will take several years for expansions in production capacity to catch-up with demand such that it results in meaningful increases in competitive rivalry and reduced prices.

4 Scenarios and associated assumptions

4.1 About the scenarios

Projections for solar and battery uptake have been developed for four 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 2020-21 GenCost analysis[10] 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.

[10] Graham, Hayward, Foster, Havas (2022) GenCost 2021-22 – Final Report – July 2022

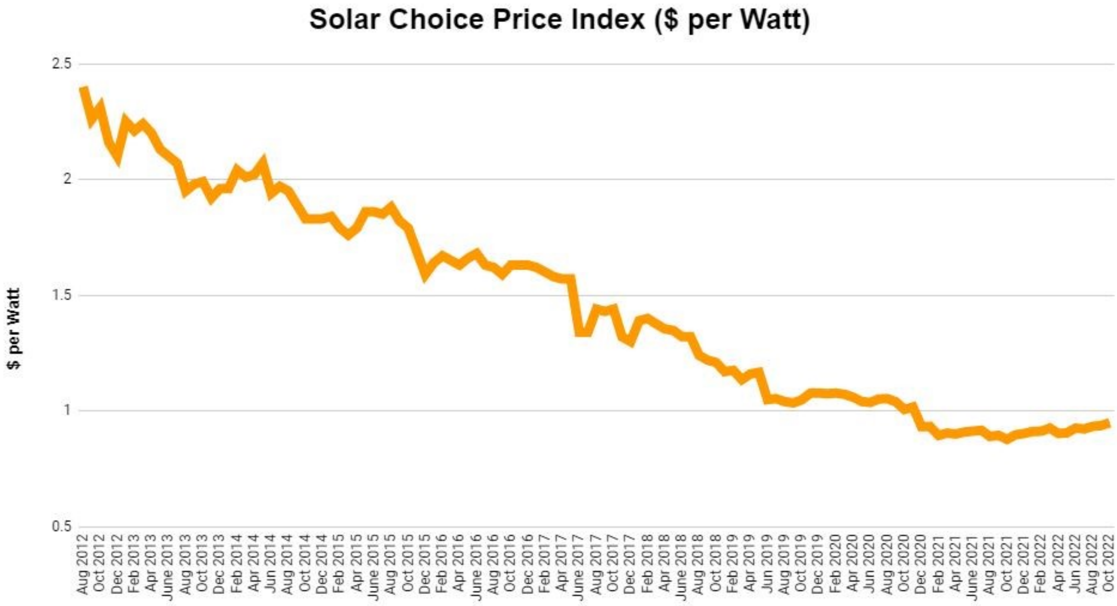
Table 4-1 Overview of modelling assumptions for each scenario

Component	Step Change	Progressive change	Exploring Alternatives	Hydrogen Export
Guiding themes	Rapid emission reductions and technological advancement with growth of DER playing a leading role.	Slower emission reductions and technological advancement.	While significant emission reductions are achieved, there is slower rate of change and uptake of DER than Step Change with greater reliance by households on gas network	Entire globe mobilises to contain warming below 1.5 degrees, rapid economic and energy demand growth and technological improvement.
Distributed solar & battery cost declines	Rapid for DER but slightly slower than Hydrogen Export	Supply constraint induced rises in short term then slowest decline over longer term (GenCost Current Policies)	Slower than Step Change but faster than Progressive Change (Gencost Global Net Zero post 2050)	Very rapid (Gencost Global Net Zero by 2050)
Economic and electricity demand growth	Households electrify heating & transport appliances increasing their demand for electricity.	Slow	Moderate	Very high in part due to production of hydrogen and green metals for export.
Decarbonisation policy support (IEA shadow carbon price scenario)	Aligned with IEA's Sustainable Development	Aligned with IEA's Stated Policies	Aligned with IEA's Announced Pledges	Aligned with IEA's Net Zero
Level of battery policy support	National rebate equal to 50% of capex introduced in 2024 and then steadily declines over time	Existing state policies	Existing state policies	National rebate equal to 50% of capex introduced in 2024 and then steadily declines over time
Level of Virtual Power Plant incentive	Highest	Lowest	Medium	Highest

4.2 Capital cost - PV

To help calibrate solar uptake to payback relative to historical levels we maintain records of system costs over time and use the Solar Choice Price Index and the SolarQuotes Price Index as key inputs which are cross checked through interviews of industry participants. As shown in Figure 4-1, the Solar Choice Index (price after SRES STC rebate) illustrates suppliers of solar have historically managed to achieve substantial and steady cost reductions between 2012 and 2020. Critically, these cost reductions have managed to outpace the reductions that have been made to the value of the SRES STC discount which stepped down substantially in 2013 and then further annual reductions after 2016 as the deeming period has been reduced. Although what we can also see is since 2021 the out-of-pocket price to consumers after the rebate has essentially remained flat and has not managed to outpace the fall in the STC rebate. In fact, other sources of price information, including the SolarQuotes Price Index, show a substantial rise in prices faced by consumers since 2021.

Figure 4-1 Customer out of pocket installed system costs (after STCs) per watt of system capacity



Source: https://www.solarchoice.net.au/blog/solar-power-system-prices

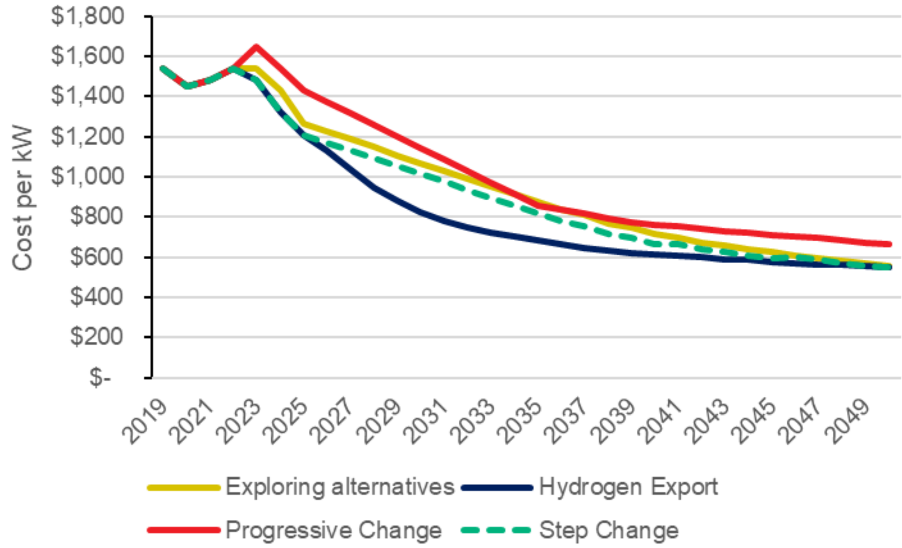
Cost reductions to date have been due to a combination of factors, including:

- declines in module prices; and
- lower labour and balance of system equipment costs per watt installed through gains in solar module conversion efficiency and increasing system size.

Our research indicates the more recent rises in prices are due to a combination of COVID-induced constraints in international supply chains for solar equipment components and an Australian-based labour shortage of qualified installers. Feedback from industry interviews suggests that the international constraints affecting solar equipment are likely to be overcome within the short-term given large ongoing additions to production capacity and ongoing technological improvements. This should mean equipment price falls should resume in the next few years. However, the point when domestic labour shortages might be relieved is harder to judge.

In Figure 4-2 we detail assumed solar system costs per kW by scenario before the impact of any government financial support such as STCs or rebates.

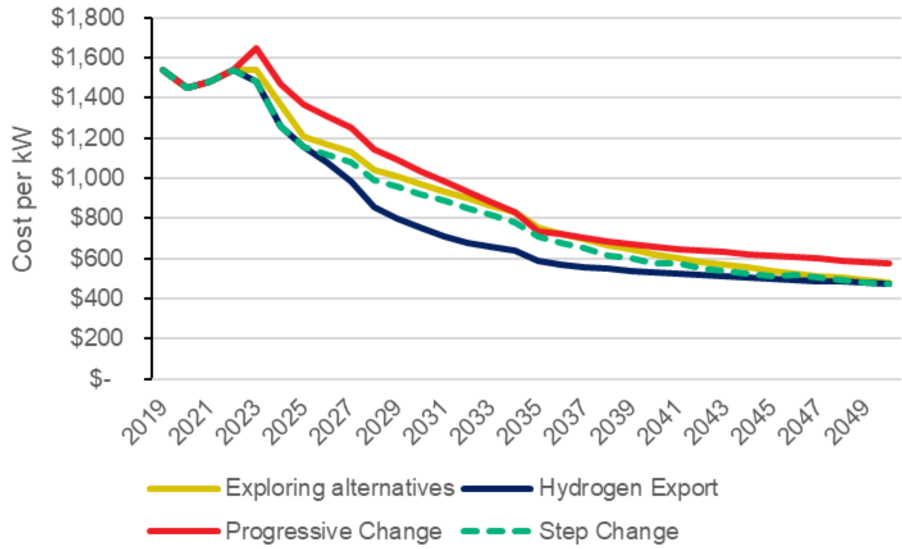
Figure 4-2 Fully installed residential solar system price per kW by scenario (excludes discounts from-government support measures e.g. STCs)



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

Figure 4-3 below provides our capital cost assumptions for commercial-sized systems which are only slightly different to residential.

Figure 4-3 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 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

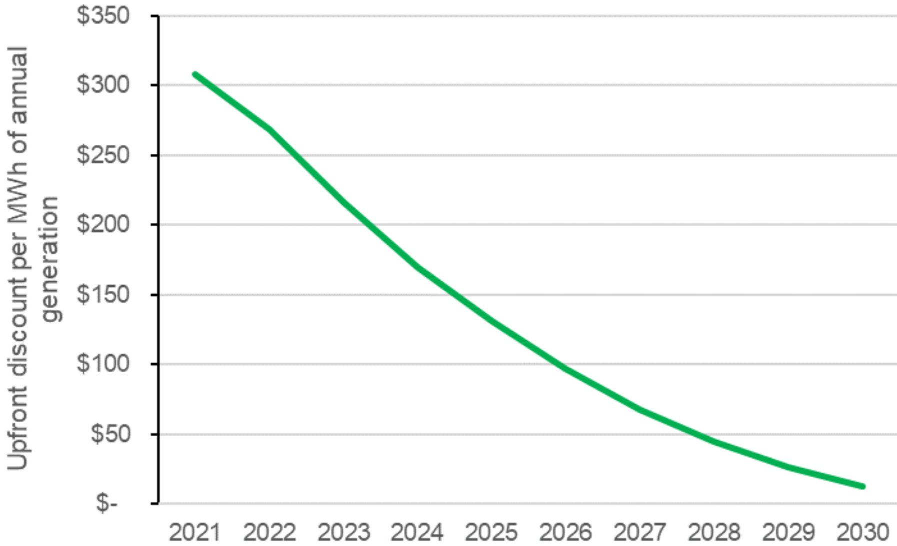
As an alternative to STCs, solar systems can instead claim Large-Generation Certificates or LGCs which electricity retailers and some other large electricity consumers are obligated to purchase in order to achieve the national Renewable Energy Target. LGCs are awarded to a solar system owner on the basis 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 28 July 2022) due to substantial growth in LGC supply over that time. The upfront discount value applied from LGCs is the same across all scenarios.

Figure 4-4 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 $308, whereas a system installed 2025 receives 427 multiplied by $131.

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.

The model takes this into account through assuming that the Victorian government will more or less achieve its target of 70,000 systems per annum over the period of the program.

Emissions Reduction Fund and Safeguard Mechanism ACCUs

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

- The Federal Government via the Emission Reduction Fund or Climate Solutions Fund;
- Entities that are short of sufficient ACCUs to honour their abatement delivery contracts with the Federal Government;

- Emitting facilities that are liable under the Federal Government's Safeguard Mechanism to keep their emissions below a regulated emission baseline
- Entities that are voluntarily seeking to reduce emissions.

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

The value of these ACCUs based on 7 year's worth of self-consumption of generation is taken into account in the model for solar systems above 100kW on a national basis where these provide a higher value than claiming LGCs or, where applicable, state-based abatement certificate entitlements. It is assumed there will be a market for ACCUs out to 2050 under all scenarios. Also under Hydrogen Export and the Step Change Scenarios it is assumed the crediting period for abatement for solar systems is extended from 7 years to 10 years. It is also assumed that ACCUs are awarded for all generation, not just generation which displaces imports of power from the grid in Export Superpower and Step Change. In addition, it is also assumed that changes are made by 2025 to make it administratively easier to claim ACCUs such that systems below 100kW in size also claim ACCUs not just those above 100kW.

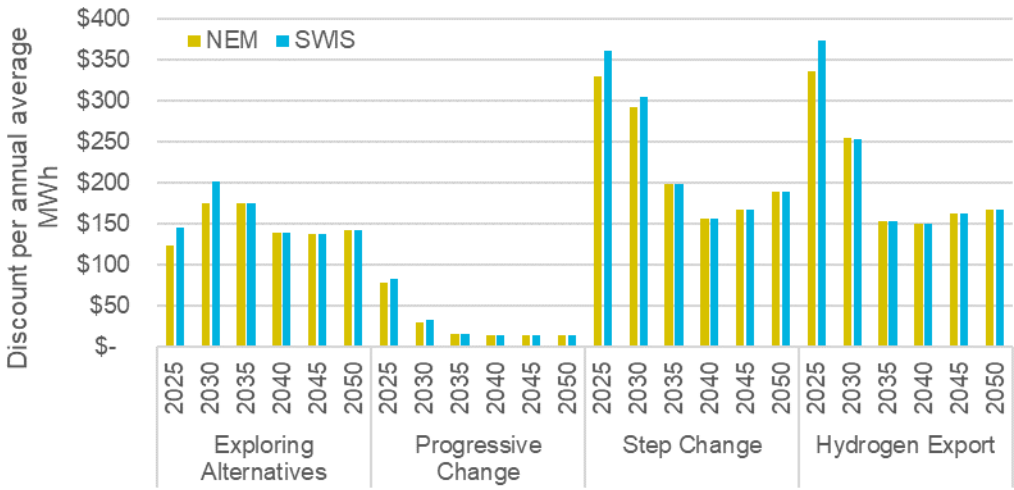
The amount of grid imported electricity displaced by the solar system is converted into an amount of abatement certificates by multiplying it by the average grid emissions intensity for the respective grid in which the system is installed. This is derived from a combination of data from the 2022 draft of the Integrated System Plan and the 2021 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
- Exploring Alternatives – IEA's Announced Pledges
- Hydrogen Export – IEA's Net Zero Emissions
- Progressive Change – IEA's State Policies but with adjustment to reflect Australian market prices for ACCUs.

Figure 4-5 details the upfront discount applied according to the scenario and grid in which the solar system is installed.

Figure 4-5 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 and Exploring Alternatives up until 2030. After 2030 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 Hydrogen Export from 2024 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. To date, only a small number of solar systems have claimed certificates under the scheme, instead opting for either STCs or LGCs. However, with LGC prices expected to progressively fall over time based on forward market trading, it appears likely that owners of solar systems larger than 100kW will be better off in the next few years by opting to claim Victorian Energy Efficiency Certificates (VEECs) instead for the grid imports a solar system displaces and the associated avoided emissions.

The value of these VEECs is taken into account in the model for solar systems above 100kW in Victoria in circumstances where these provide a higher value than claiming LGCs or Australian Carbon Credit Units. The value of VEECs is assumed to remain close to the recently traded price of $70 over the outlook period except in the Progressive Change scenario where it declines to $30 and the scheme is wound up after 2030.

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.

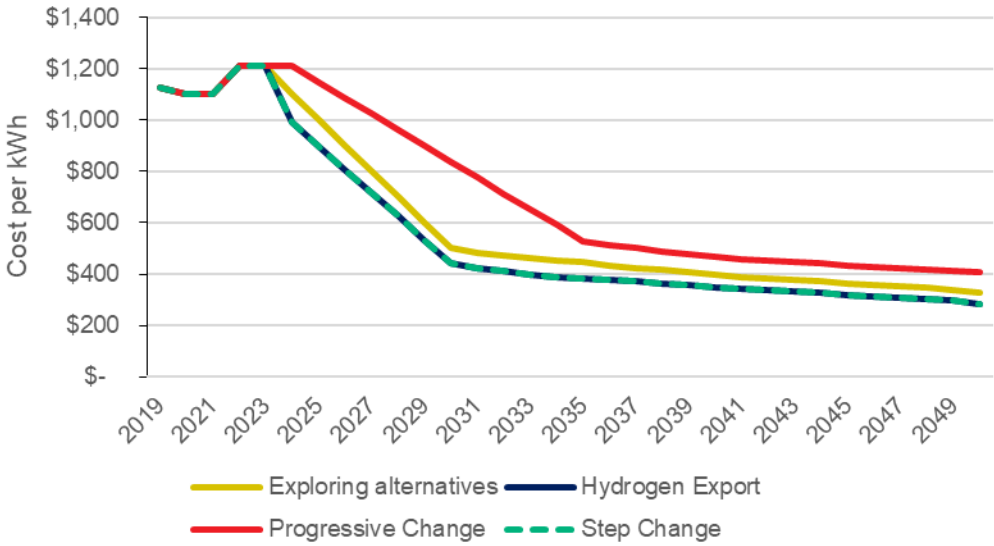
To deal with the requirement that an owner must elect to choose only one program, in each year the model evaluates which government program is expected to deliver the greatest financial benefit over the lifetime of the system and uses that value to allocate an upfront discount to the capital cost of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

4.3 Capital cost - Batteries

To inform our starting point of battery costs we have used a combination of battery quotes data provided by the now defunct South Australian Government's Home Battery Rebate Scheme, Solar Choice's Battery Price Index and interviews with several solar-battery industry participants.

Figure 4-6 illustrates the assumed capital cost adopted for a battery system retrofitted to a residential solar system by scenario in the model. Please note that Step Change and Hydrogen Export follow the same price trajectory. Costs for commercial systems are assumed to be similar to residential systems.

Figure 4-6 Assumed capital cost per kWh for residential battery system by scenario (Incl. GST)



In many cases going forward 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 $200 per kWh of battery capacity.

Our monitoring of the residential-scale battery market suggests that prices for systems are yet to demonstrate any significant price reductions for several years and have more recently begun to rise for several popular brands. We expect that price reductions will remain modest for the next few years but will eventually be followed by quite rapid reductions in prices. A variety of information sources suggest that electric vehicle manufacturers have been able to attain quite significant reductions in battery pack purchase prices over the last few years (prior to recent inflation over the past 12 to 18 months) which are reflective of lower battery cell production costs[11]. However, these have not flowed through to lower prices for customers purchasing stationary energy systems at behind-the-meter scale. We suspect that battery manufacturers are prioritising the far larger electric vehicle market over small 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.

In the latest edition of the GenCost publication, CSIRO did not publish an estimate of the capital cost of a distributed battery and solar system for us to utilise as a benchmark.

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

Instead, 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 time. 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. 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.

Similar to what we have done in prior years' modelling exercises, we assume price reductions will be minimal or non-existent for the next two years. Progressively though we expect battery and associated input materials production capacity will build-up leading eventually to competitive shake-out that then leads to dramatic falls in price as they are reduced closer to underlying costs and as suppliers achieve a critical mass of volume that allows them to tolerate lower margins per sale.

Under Step Change and Hydrogen Export the fall in prices occurs sooner and faster. Progressive Change meanwhile illustrates a future where capacity constraints afflict the industry for some time, leading to current very elevated prices remaining until 2024, and it is only by 2026 that prices in real terms manage to fall slightly below where they were in 2020. Prices then follow a steady path downward until 2035 after which further price reductions slow. Exploring Alternatives involves a more rapid fall where real prices fall below 2020 levels by 2025 and follow slightly behind the trajectory in Step Change and Hydrogen Export.

4.3.1 Incorporating impact of government support policies

Victorian Government Rebate

A sub-component of the Victorian Government's Solar Homes Program provides a rebate of up to $2,950 per battery system which is intended to operate until 2028.

NSW Energy Security Safeguard (Peak Demand Reduction Scheme)

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. According to the NSW Government's Energy Security Target and Safeguard Consultation Paper[12], under this reconstituted program the Energy Savings Scheme element will continue but they will also establish a certificate scheme to reward the deployment of dependable peak demand reduction capacity. Like the Energy Savings Scheme, the scheme will place a peak demand reduction obligation on liable parties – mainly electricity retailers.

Under this scheme behind the meter batteries could 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

[12] NSW Government Department of Planning, Industry and Environment (2020) Energy Security Target and Safeguard Consultation Paper - https://energy.nsw.gov.au/media/2031/download

certificate 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. In the case of a battery with 10kWh of usable capacity, which has sufficient inverter capacity to discharge all its energy within the peak demand period window, it could claim 100 certificates in a year (10 divided by 0.1).

At the time of modelling no reported trades have taken place for peak demand reduction certificates which could be used to inform our assumptions about their potential value. In lieu of this information we have assumed that these certificates trade at 75% of the nominal shortfall penalty ($2.26) which equates to $1.70 per certificate.

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 be materially alter customers willingness to adopt batteries (particularly the provision of loans)[13]. 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

In the Step Change and Hydrogen Export scenarios - which are intended to cater for the possibility there will be large scale up in the use of DER technologies - we have assumed that the Federal Government introduces a national program to support battery uptake across both residential and commercial sectors. The rebate value under this program is assumed to begin at a value equal to half the capital cost of a battery but then is progressively scaled back as batteries fall in price.

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 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[14].

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

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[13] In the case of the Northern Territory battery rebate this was announced very recently and too late to be incorporated in our modelling.
[14] See here for details on the VPP offers currently available to residential battery owners: https://www.solarquotes.com.au/battery-storage/vpp-comparison/

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. Figure 4-7 details the level of the VPP discount over time by scenario which is incorporated within the model as a reduction in the purchase price of a battery.

Figure 4-7 Assumed upfront VPP payment per kWh of battery capacity

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 the Australian Energy Market Commission's (AEMC) latest residential price trend projections[15] but are adjusted to exclude fixed standing charges utilising AEMC typical demand estimates.

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

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

- Wholesale energy
- Network charges
- Retail margin

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 2022-23, 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 the AEMC's projections with adjustment to remove fixed charges.

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 2.9 times the anytime smeared network charge in place in 2023-24. Meanwhile the solar soak and off-peak charge are both set at half the anytime smeared network charge in place in 2021-22. Network charges are assumed to remain constant in real terms across the period from 2021-22 until 2050.

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

The model has adopted an assumption that tariff structures will change.

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

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

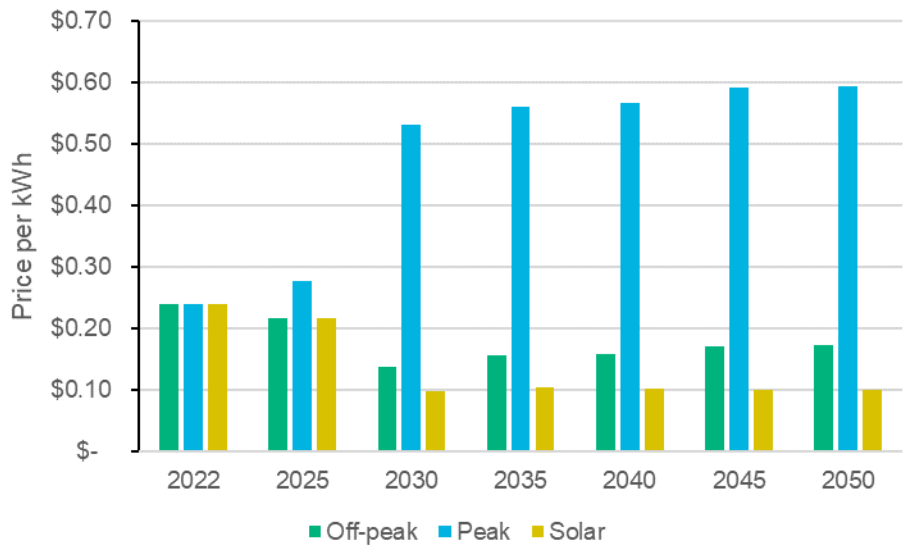
installation of such a meter is mandatory where a solar system is installed, and they should reach a large proportion of the other stock of buildings by 2030.

In Western Australia the government has also indicated in its Distributed Energy Resources Roadmap[16] 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 and SA Power Networks to deliver more "cost-reflective" price signals.

To illustrate with an example how this change in tariff structure (as well as solar-induced reductions in wholesale prices) plays out, Figure 4-8 illustrates the import price per kWh that a NSW residential consumer would pay for the 3 different time intervals in the Central Scenario over time. In 2020 they pay the same price irrespective of time interval but by 2030 there is a large difference between the peak period versus the solar and off-peak period. The other states and other scenarios see similar changes.

Figure 4-8 Assumed changes in NSW residential power price by time interval (Step Change scenario)



Large commercial customers installing systems larger than 100kW

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

For evaluating solar payback without a battery in place we assume that the solar system only delivers savings in the network's kWh charges, not the demand-based charge.

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

Charges per kWh are derived from the network's current tariff charges although in states with multiple distribution businesses we have attempted to use an approximate composite.

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

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

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

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

4.4.3 Wholesale energy

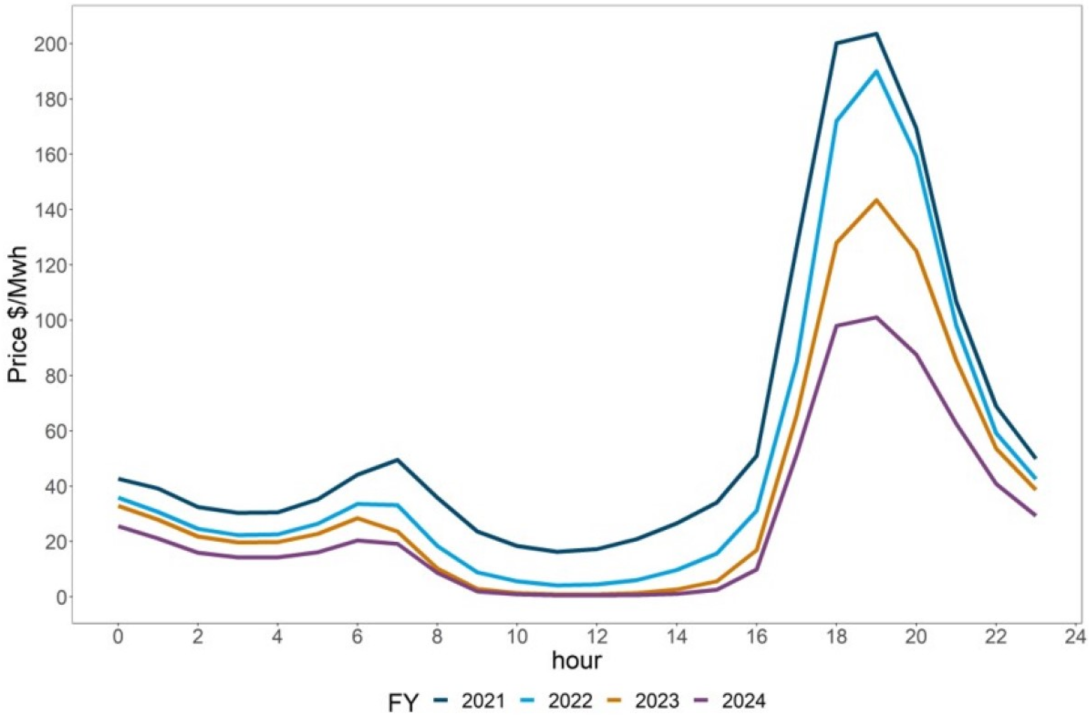
Projected wholesale energy costs are derived from a combination of AEMO's residential retail price index and CSIRO's GenCost 2021-22 estimates.

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 as projected by the AEMC in their 2021 Residential Price Trends report. Figure 4-9, taken from the AEMC report illustrates the noticeable depression in prices in the middle of the day for Queensland, while prices during the peak period in the late afternoon and evening remain high. Such a development is likely to be replicated in other regions given they are also adding large amounts of solar capacity. While this year's surge in international gas and coal prices, has meant wholesale power prices across all time periods have increased rather than fallen, contrary to the AEMC's forecast, the large daytime discount has remained.

Figure 4-9 Average wholesale electricity prices by hour of day in QLD

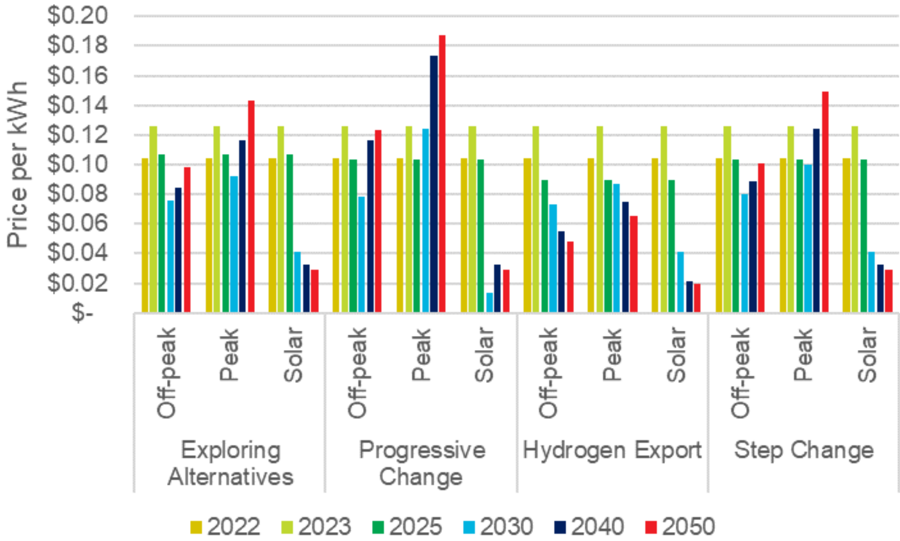


Source: AEMC (2021) Residential Electricity Price Trends 2021

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 4-10 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.

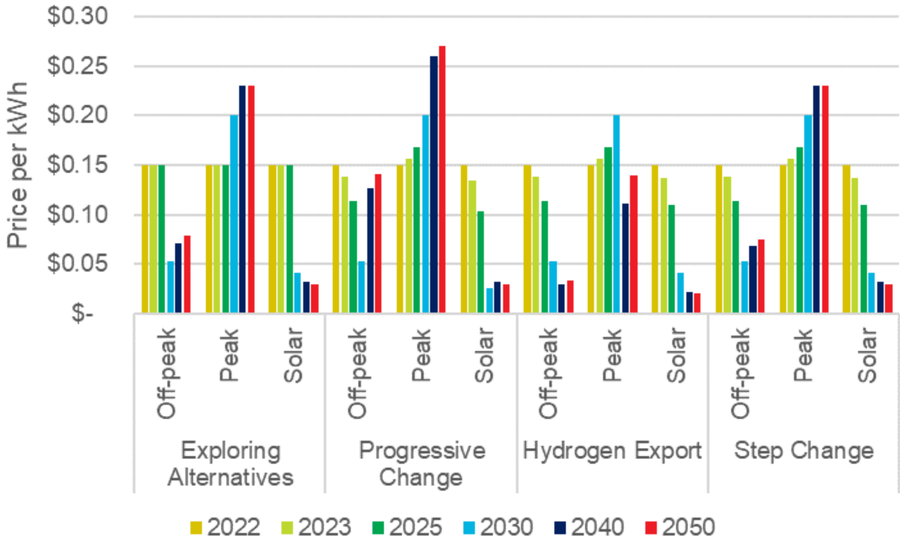
Figure 4-10 Assumed wholesale energy cost retail pass through by time interval for NSW



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 4-11 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. For example, in Victoria retailers tend to shift a portion of the variable kWh costs they face into the daily fixed charge as well as recovering all their own costs in the fixed charge. So this led to the retail charge in the model being a negative value for residential consumers as the retailers effectively cross subsidise kWh consumption via increases in the fixed charge.

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[17]. These average figures are then converted into generation per hour across every day of the year based on Bureau of Meteorology historical measurements of irradiance between 1990 and 2015.

In developing the degraded capacity of the solar PV installed base we applied an annual degradation factor of 99.3%[18]. 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:

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

[18] 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.

- Conversion efficiency – both charging and discharging of the battery was assumed to be 95% efficient (round trip efficiency of 90.25%)[19]
- The maximum output/input of the battery in behind the meter applications was assumed to be 40% of the kilowatt-hour rated capacity of the battery. So a 10kWh battery system was assumed to have a maximum output and charge capability of 4 kilowatts.[20]
- Batteries kWh capacity was assumed to degrade to 60% of its original rated capacity after 10 years[21] and at this point would be retired and replaced by its owner.

[19] 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/)

[20] 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).

[21] 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

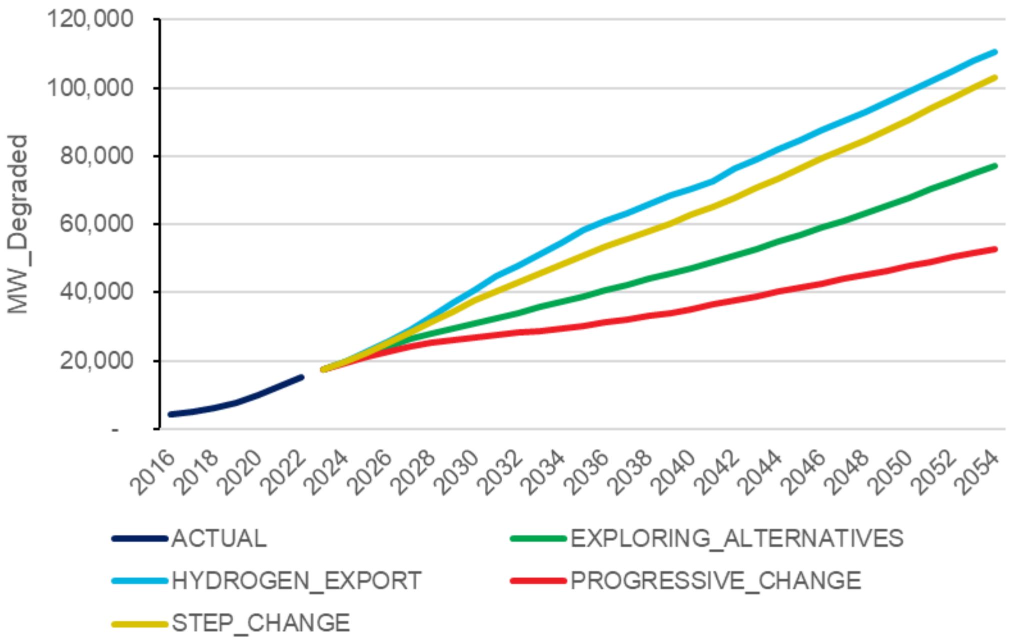
5.1.1 Solar PV

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 10kW (it is currently at around 7.5kW). However, network distributors generally only allow inverters to export a maximum of 5kW to the grid. 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 may be introduced in the future that would 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. 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

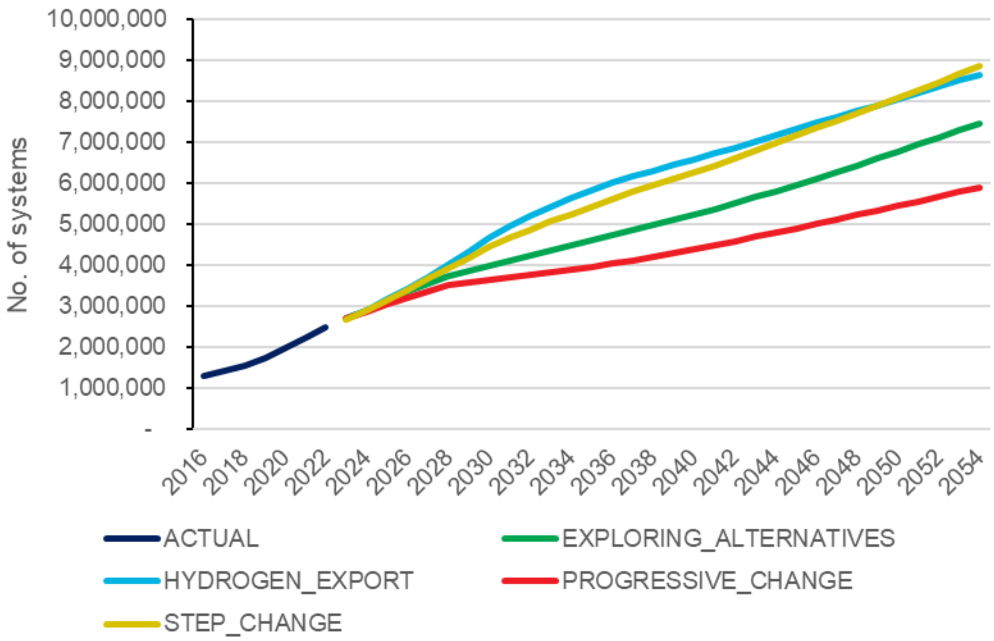
Figure 5-1 details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the National Electricity Market (NEM), taking into account the degradation of solar panel output over time. At the beginning of the projection (the conclusion of the 2021-22 financial year) cumulative installed degraded capacity is expected to stand at almost 15,000MW. By the end of the projection in 2053-54 the cumulative degraded capacity reaches almost 53,000MW, at the low end, under Progressive Change, and around 110,000MW at the upper bound represented by the Hydrogen Export 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 almost 2.4 million. At the low end under Progressive Change, the cumulative number of systems grows to around 5.9 million by the end of the 2053-54 financial year. The upper bound represented by the Step Change scenario reaches close to 8.9 million. Initially the number of DER PV system installs are higher under the Hydrogen Export scenario than in Step Change, in large part due to assumed faster capital cost reductions. However, under the Hydrogen Export scenario due to an expansion in demand for bulk power from hydrogen production, there is a substantial expansion in front-of-the meter solar farm capacity (including from sub-30MW non-scheduled projects). This provides a side benefit to end consumers in lower electricity prices which then reduces the attractiveness of them installing solar on their own premises. Consequently, DER PV system numbers in Hydrogen Export fall behind those in Step Change towards the end of the projection period. This cross-over is not seen in terms of megawatts of capacity detailed in Figure 1-7 above, because our projection of non-scheduled power station capacity (which represents a large amount of capacity, but a small portion of the number of systems) is much larger in Hydrogen Export than Step Change.

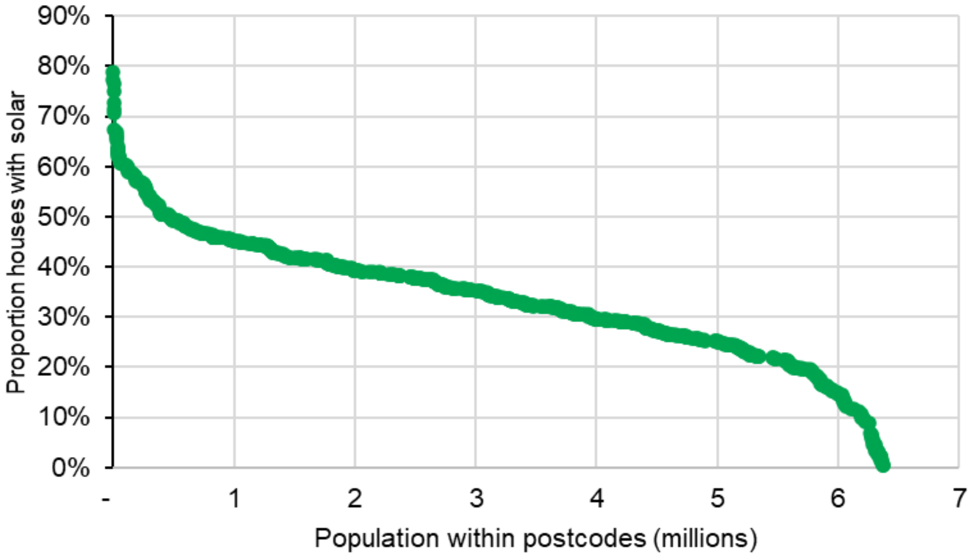
Figure 5-2 NEM cumulative number of solar PV systems by scenario



To put these system numbers in context the total number of NEM residential electricity connections is expected to grow from 9.4m in the 2021-22 financial year to between 13.5m and 14.8m by 2053 (the residential sector accounts for the vast bulk of solar system numbers). Under Progressive Change around 39% of residential dwellings are expected to have a solar system around the end of the projection period, while at the upper end under Step Change it reaches almost 55% of all residential connections.

In the states which have the highest solar penetration in Australia – Queensland and South Australia - such levels of penetration are already being realised across a number of postcodes. The figure below plots South Australian and Queensland postcodes in terms of the proportion of households within the postcode with a solar PV system and then on the horizontal axis we accumulate the amount of population residing within the postcodes. This shows that postcodes representing around 1m people within QLD and SA have already reached or exceeded 45% penetration of total dwellings with solar suggesting such penetration is achievable. 55% remains rare, but examples do already exist, and this is in circumstances with almost no usage of batteries. Meanwhile our projections envisage that by the end of the projection period almost all new solar systems will be coupled with batteries.

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

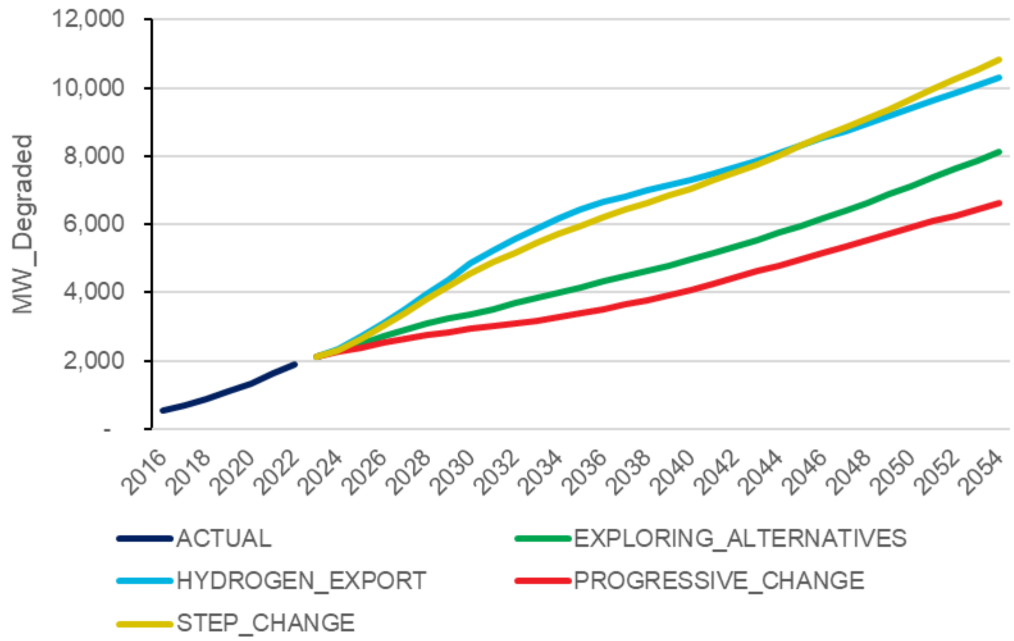


Sources: Clean Energy Regulator for number of solar systems per postcode, Australian Bureau of Statistics for number of households and population by postcode.

Western Australian South-West Interconnected System

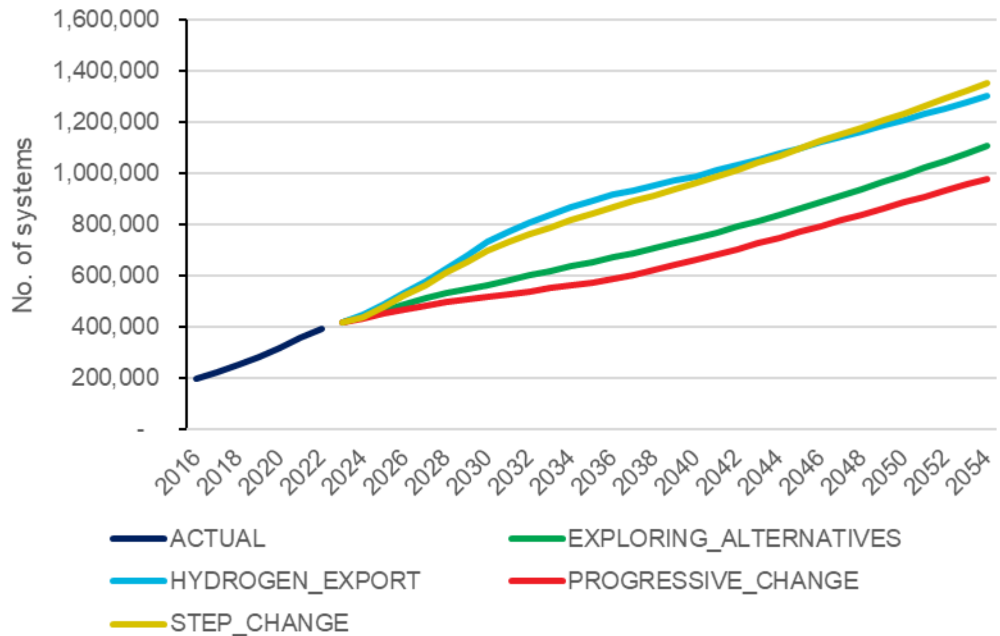
Figure 5-4 details the cumulative installed solar PV capacity (DC basis) projected for each scenario within the WA South-West Interconnected System (SWIS), taking into account the degradation of solar panel output over time. At the beginning of the projection (the conclusion of the 2021-22 financial year) cumulative installed degraded capacity is expected to stand at almost 1,908MW. At the low end, under Progressive Change, the cumulative degraded capacity reaches 6,600MW by the end of the projection in 2053-54 financial year. The upper bound represented by the Step Change scenario reaches around 10,800MW. 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 on a national basis. At the beginning of the projection the cumulative number of systems stands at almost 400,000. At the low end under Progressive Change, the cumulative number of systems grows to around 981,000 by the end of the 2053-54 financial year. The upper bound represented by the Step Change scenario reaches just under 1.4 million.

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

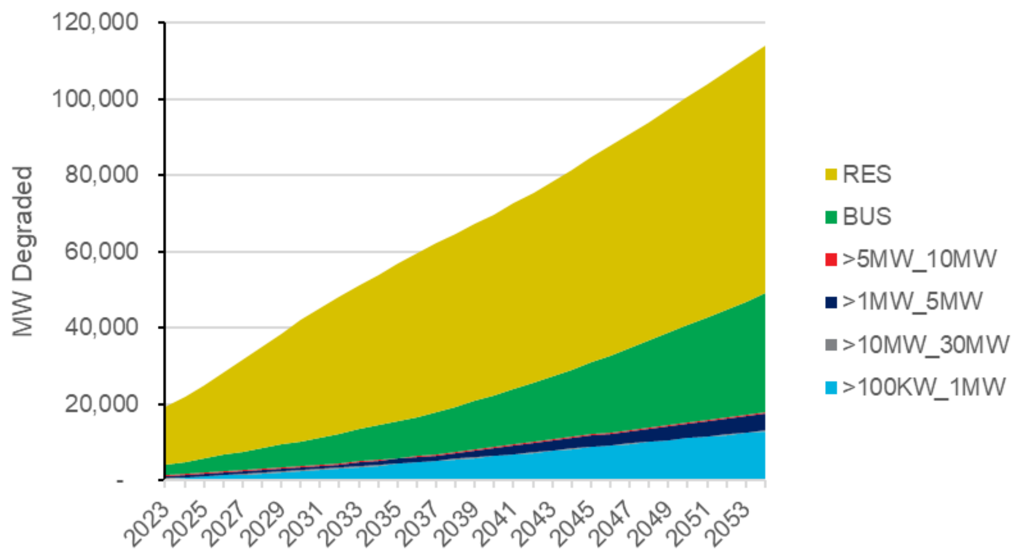


To put these system numbers in context the total number of residential electricity connections is expected to grow from 1.06m in 2021-22 to reach between 1.7m to 2.0m by 2053. Under Progressive Change around 53% of residential dwellings are expected to have a solar system around the end of the projection period, while at the upper end under Step Change it reaches 68% of all residential connections.

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 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)

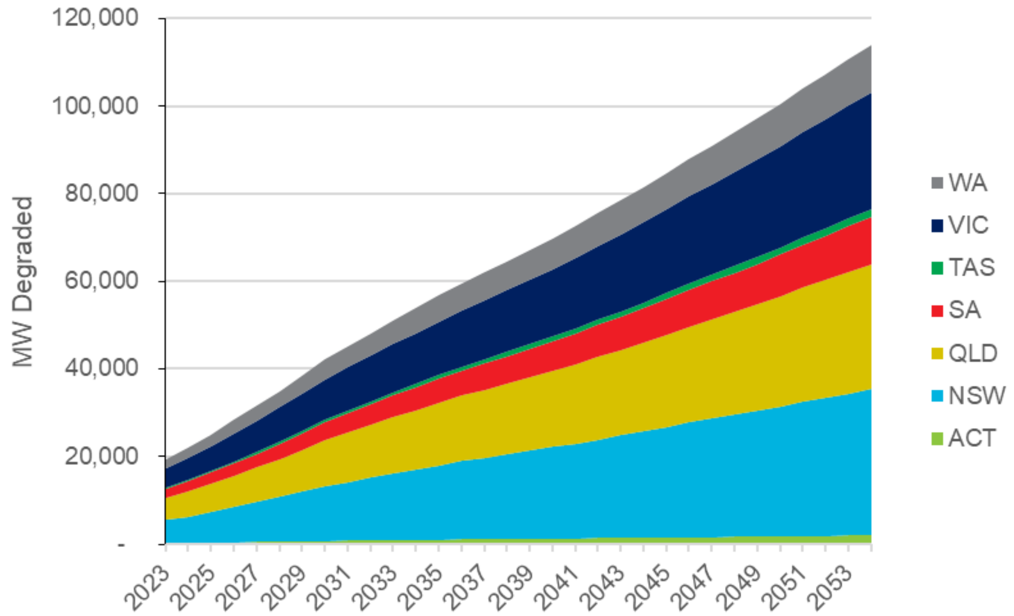


In front of the meter systems denoted by the segments greater than 1 megawatt in scale remain a relatively minor segment, with developers of solar power stations expected to favour much larger systems above 30MW in scale.

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 Current Trajectory Scenario. The relative distribution across states is relatively 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 2021-22 financial year) cumulative degraded battery capacity is estimated to stand at 1,251MWh. At the low end, under Progressive Change, the cumulative degraded capacity reaches 50,000MWh by the end of the projection in 2053-54 financial year. The upper bound represented by the Step Change scenario reaches around 114,000MWh.

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

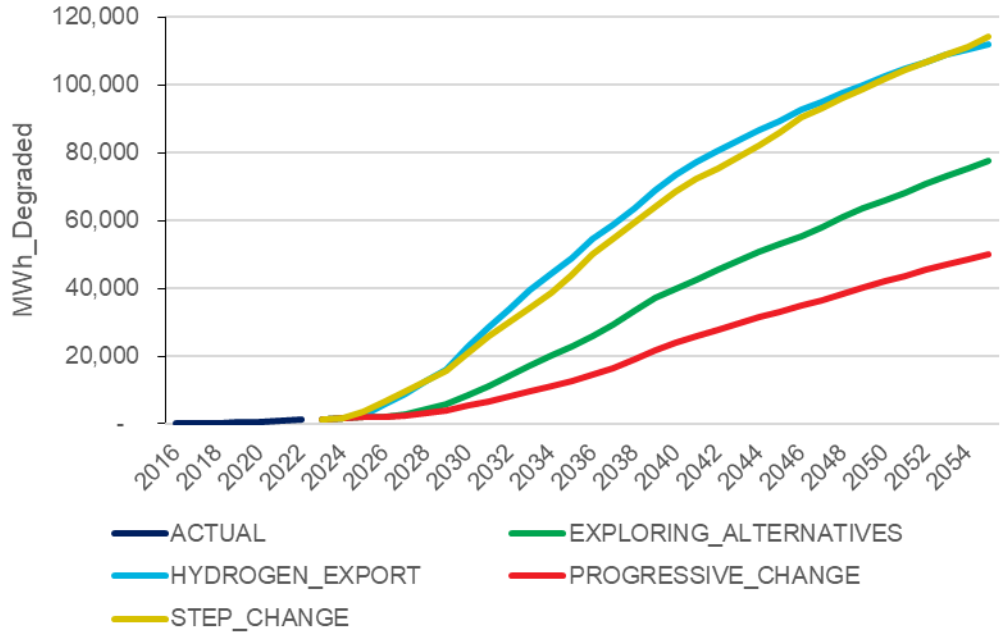
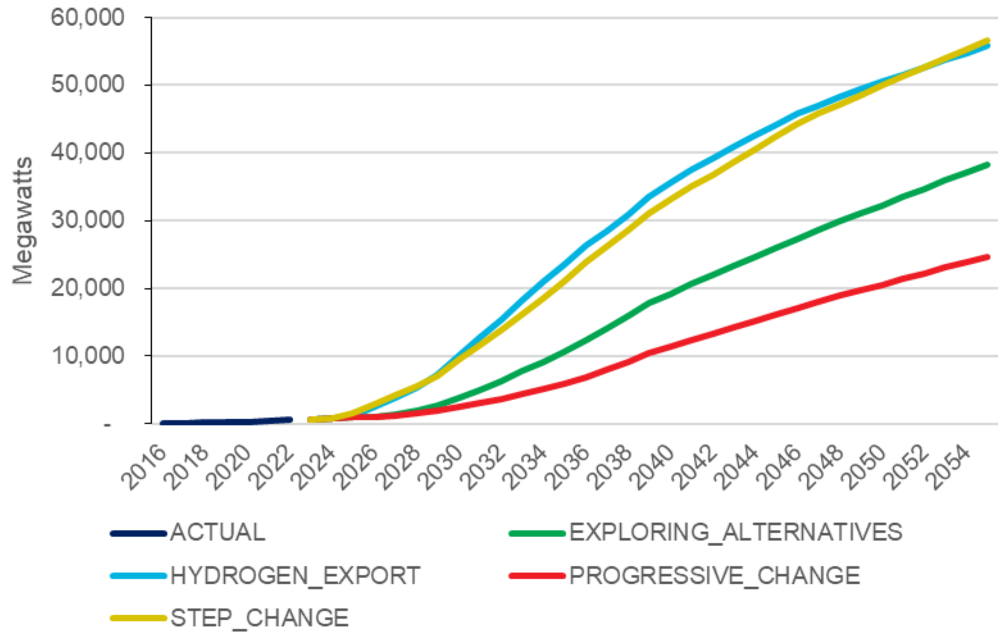


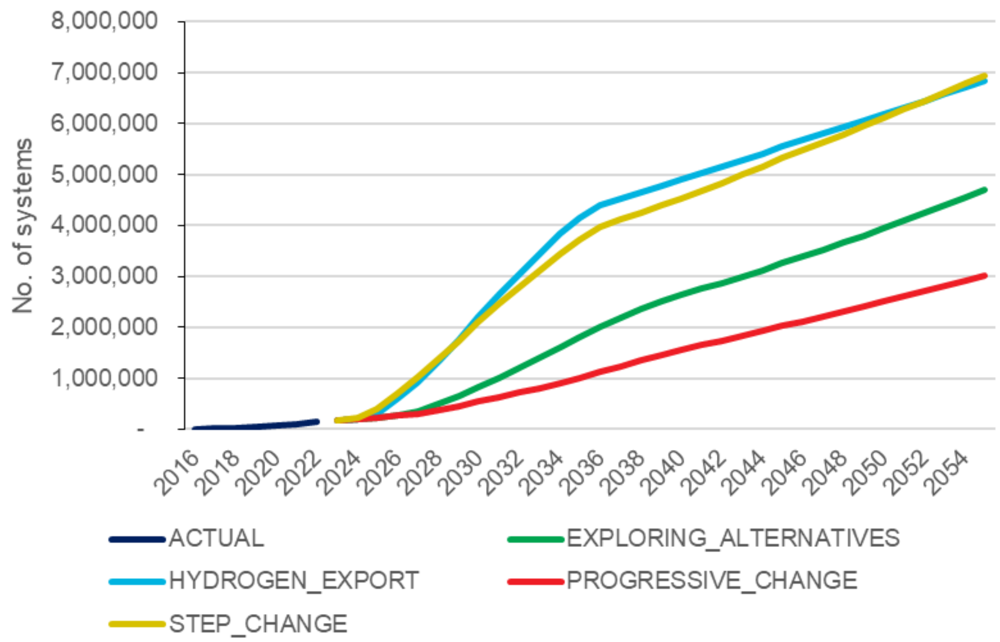
Figure 5-9 below shows the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 553MW at the end of 2021-22 financial year. Under Current Trajectory this grows to 20,700MW by the end of the projection in 2050-51 financial year. Under Progressive Change, megawatt capacity reaches close to 25,000MW by the end of the projection in 2053-54 financial year. The upper bound represented by the Step Change scenario reaches close to 57,000MW. The projections are based on an assumption that the instantaneous output that can be extracted from a battery is not subject to degradation (although the kilowatt-hours of storage is still subject to degradation) and that the average system when first installed will have maximum output equal to 40% of its original megawatt-hours of storage.

Figure 5-9 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 2021-22 financial year the cumulative number of grid-connected battery systems is around 136,000. Under Progressive Change this grows to 2.9 million by the end of the projection with 18% of residential customers owning a battery system. The upper bound represented by Step Change reaches almost 6.8 million, with almost 41% of residences owning a battery system.

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



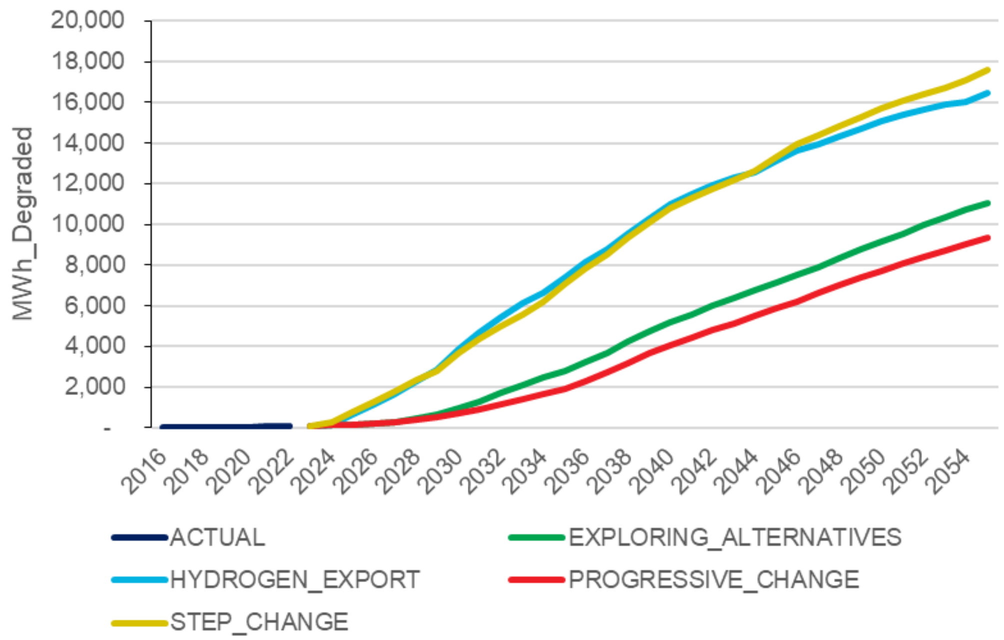
As some perspective, at the low end under Progressive Change 49% of solar systems in the NEM would be coupled with a battery, while at the high end represented by Step Change, 76% of solar systems are coupled with a battery.

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 in the mid 2030's is a product of batteries having penetrated much of the existing stock of households with solar systems around this point in time (for the Hydrogen Export 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. Further explanation of this inflection point is detailed in section 5.2.5 of the report.

Western Australian South-West Interconnected System

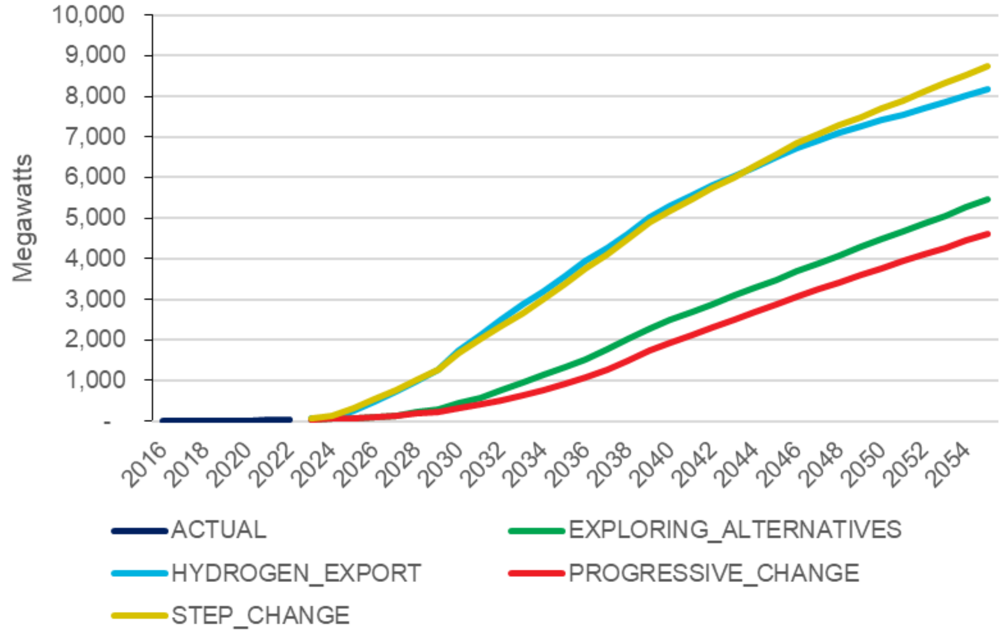
The figure below details the cumulative installed megawatt-hours of battery capacity projected for each scenario in the WA SWIS, taking into account the degradation of battery storage capacity over time. At the beginning of the projection (end of 2021-22 financial year) cumulative degraded battery capacity is estimated to stand at 100MWh. Under Progressive Change the cumulative degraded capacity reaches around 9,000MWh by 2053-54 financial year. The upper bound represented by the Step Change scenario reaches 17,000MWh.

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



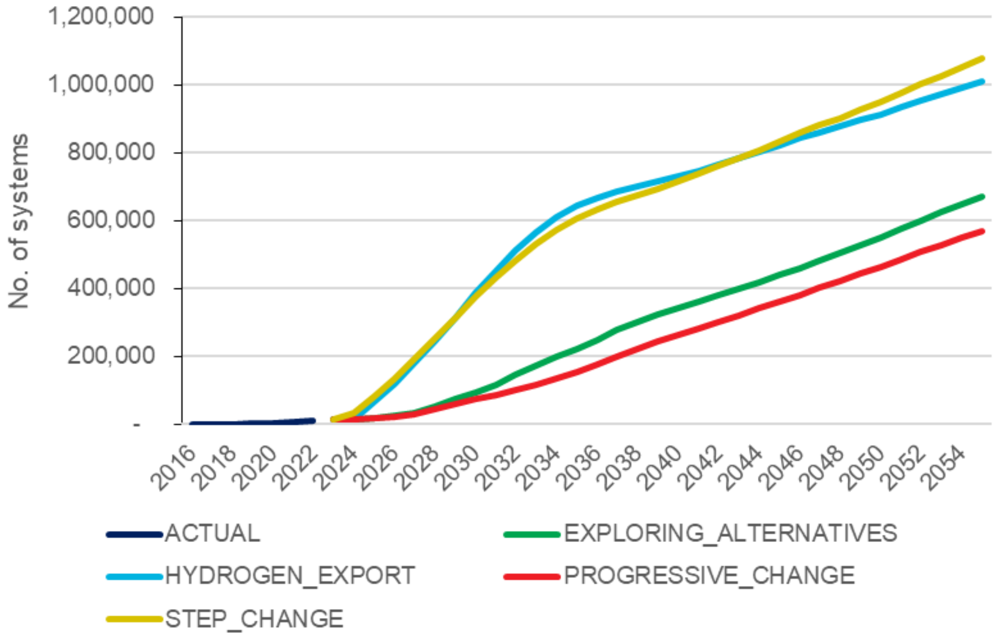
The figure below illustrates the maximum instantaneous megawatt output available from the projected stock of battery systems. The projection begins with an installed stock of 43MW at the end of 2021-22 financial year. Under Progressive Change this grows to 4,600MW by the end of the projection. The upper bound represented by the Step Change scenario reaches 8,700MW.

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 2021-22 financial year the cumulative number of grid-connected battery systems stands at close to 11,000. Under Progressive Change the cumulative number of systems grows to almost 550,000 by the 2053-54 financial year. The upper bound represented by the Step Change scenario reaches 1.0 million.

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



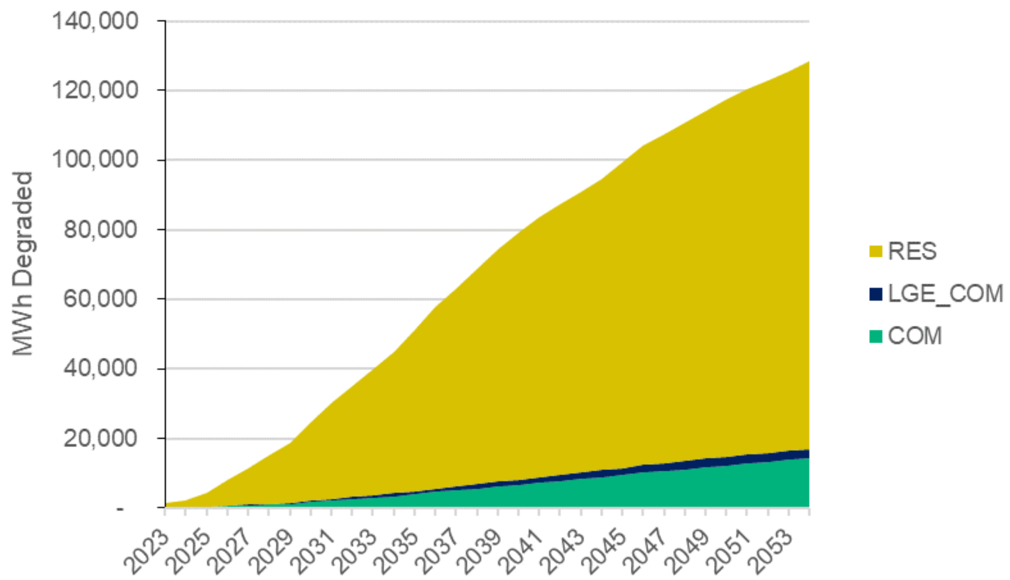
As some perspective, under Progressive Change 56% of solar systems in the SWIS would be coupled with a battery by 2053-54. At the high end represented by Step Change 78% of all solar systems are coupled with a battery.

The noticeable slowing in the growth of the battery stock in the mid 2030's under Hydrogen Export and Step Change in the SWIS is due to batteries having penetrated most 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)

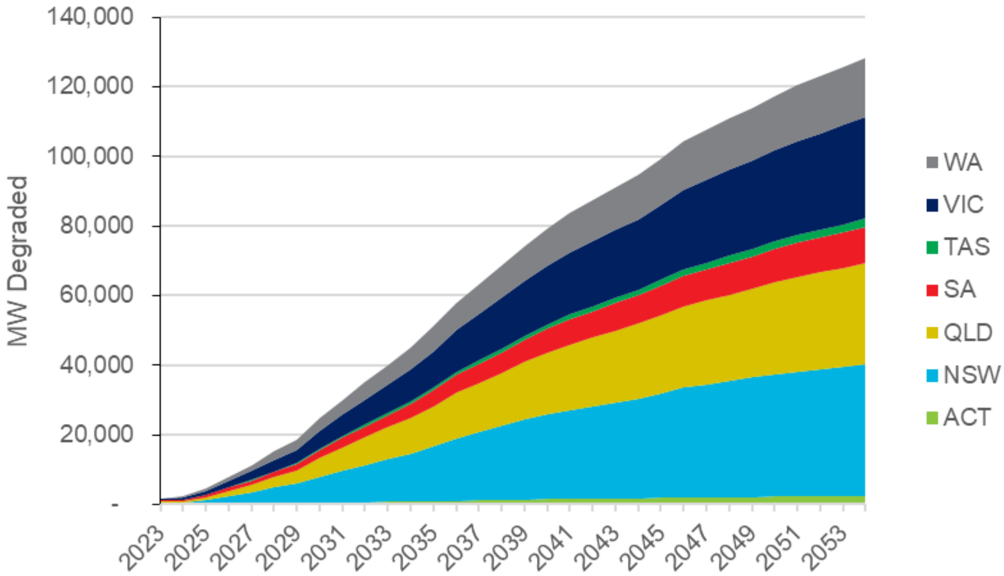


Note: Residential (RES) batteries are assumed to have average size of 10kWh as are small commercial (BUS) at the beginning of the projection period which then grows to 15kWh by the 2030's and then continues to grow to 20kWh by the end of the outlook period, while large commercial customers' (LGE_COM) batteries are assumed to have sizes averaging 150kWh. In practice though battery sizes will probably vary quite widely within these segments which are intended to be average archetypes for customers installing solar systems of: below 15kW – Residential; 15kW-100kW – small commercial; greater than 100kW but behind the meter – Large commercial.

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

Figure 5-15 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)

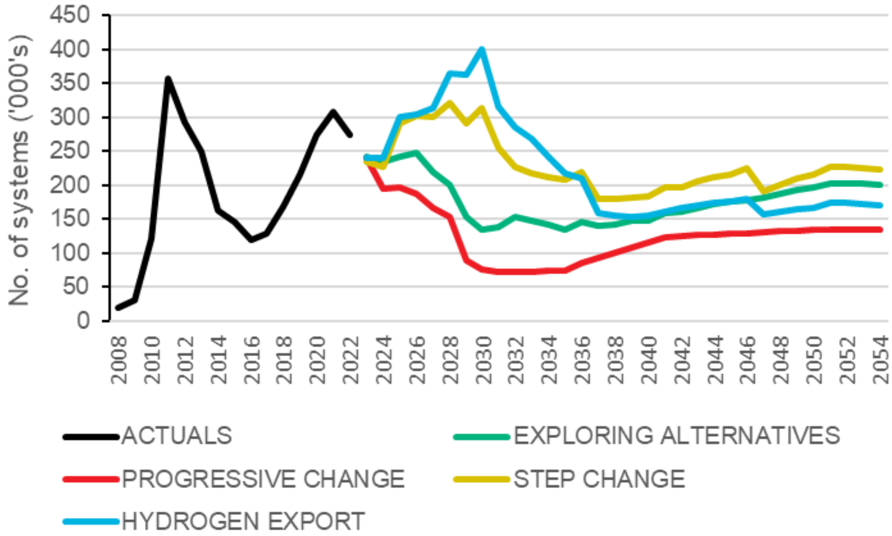


5.2 Residential and small commercial

As detailed in the prior section, systems installed in residential premises make up the vast bulk of both solar and battery capacity in our projections.

To more clearly illustrate and explain how solar uptake changes over time Figure 5-16 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 under both Progressive Change and Exploring Alternatives we project new additions of solar systems will steadily decline from the levels experienced over 2020 and 2021 before stabilising and recovering from 2030. Indeed under Progressive Change system numbers fall below the nadir of 2015-16 and even below 2010 levels. However under Step Change and Hydrogen Export system numbers manage to rapidly recover from a slump in the 2022-23 year. Under Step Change they recover back to similar numbers as in 2020-21, while in Hydrogen Export they rise to new record highs reaching a peak of 400,000 of annual system additions. But after this initial surge, system additions to stock then decline over the 2030's before stablising around 2040.

5.2.1 Historical context

Prior to 2008 solar installations were very small, but then grew dramatically from 2009. This was as a result of plunging system costs combined with high feed-in tariff rates in the realm of $0.44 to $0.60 per kilowatt-hour, and a high STC rebate for the first 1.5kW of a system. By 2009-10 more than 121,000 systems were installed across the NEM and SWIS, compared to just 19,000 in 2007-08. In 2010-11 they peaked at almost 356,000 and remained high for the next two years at 292,000 in 2011-12 and 246,000 in 2012-13. However, while the underlying cost of a solar system continued to fall, the rapid wind-back of feed-in tariffs by state governments and also reductions in the value of the STC rebate reduced the financial attractiveness of solar for residential consumers. At the same time retail-delivered price rises for electricity began to moderate after 2013 which reduced the extent to which residential consumers faced a psychological push factor leading them to investigate options to reduce their electricity bills. Consequently, the number of solar system sales fell dramatically to 160,000 in 2013-14, and then continued to decline before bottoming out at close to 138,000 in 2015-16.

Yet by the next year solar began a sales recovery. This was driven by ongoing declines in the purchase price of solar systems that managed to outpace the reduction in the value of the STC rebate, as well as another large jump in retail delivered electricity prices (particularly significant in the NEM states). What made this particular jump in power prices especially beneficial for solar in the NEM states was that the increase was due to higher wholesale electricity market prices, which also led to a lifting in the feed-in tariff for exported electricity from solar systems. We also suspect that increasing media attention on electricity prices and reliability during this time helped to focus and amplify householder concern about electricity prices. Another factor that has been important in this growth was the Victorian Government's introduction of a rebate of up to $2,225 per system from October 2018 (which has been progressively stepped down and currently is set at a maximum per system of $1,400). Although it is important to note that solar system sales have increased significantly across almost all states, not just Victoria.

By the 2020-21 financial year sales had reached over 370,000 systems (new additions to stock meanwhile were 308,000), up over 260% on their 2015-16 trough.

While this passage of growth since 2016 has captured considerable attention, it is important to note that in terms of system sales they still remain below the peak almost a decade ago. The reality is that in terms of customer sales the residential solar market is not a story of continuous ongoing growth, but rather two booms and a depression. The idea that solar sales might decline may be surprising to those that have been watching the very large and growing amounts of megawatts of capacity installed in the past few years. But when viewed in terms of numbers of system sales, rather than capacity, and with a longer timeframe, it is apparent that customers' interest in solar can wane as concerns about electricity price rises subside and financial attractiveness of a solar system deteriorates. And over the prior 12 month period, as the price of solar systems increased, and power prices fell, system sales dropped by 8%.

5.2.2 The next decade – after brief Russian-induced reprieve, daytime wholesale prices, and restructured tariffs lead to deteriorating revenue

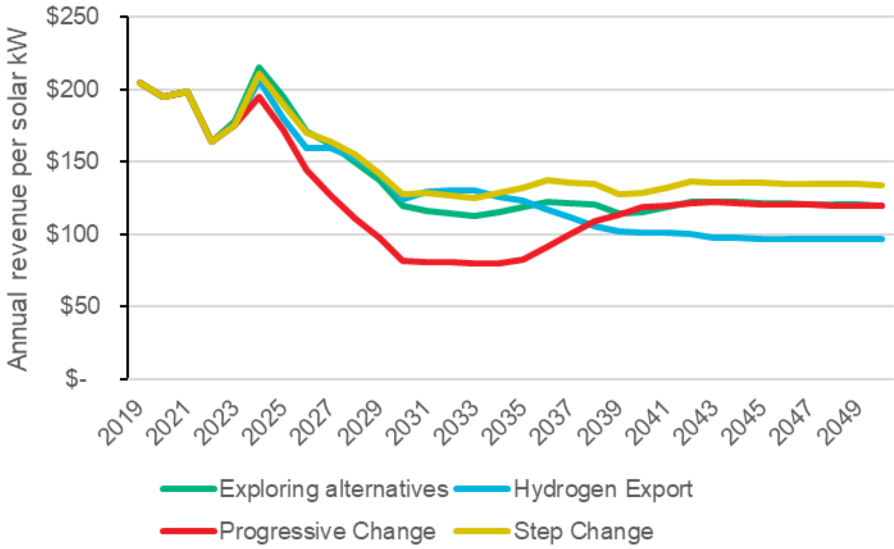
The reason for why we project that the recent growth in annual solar system numbers will moderate, and in some scenarios markedly fall, is a function of an expectation that amount of revenue (or energy bill savings) a solar system can deliver will fall over time.

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

In addition, as detailed in section 4.4.2, the model assumes that residential electricity tariff structures shift the way costs are allocated across times of day. This involves a move away from 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 NSW as an example.

Figure 5-17 Annual revenue per kW of solar capacity over time- NSW example

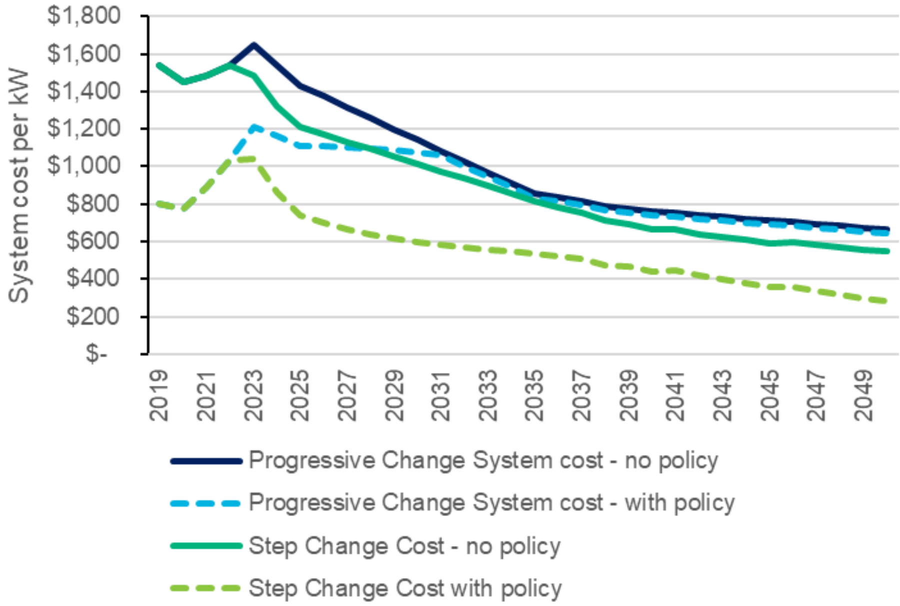


5.2.3 The next decade – declines in system prices stall without new policy support

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 recommence a steadily decline after 2023, it may not 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 dark 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 light blue dashed line then illustrates the out-of-pocket cost faced by consumers after deducting the SRES rebate. This shows that the ultimate price faced by householders will have increased quite substantially between 2020 and 2023. After 2023 the underlying cost of a solar system is expected to resume its past downward trajectory. 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 remains largely constant to 2030.

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.

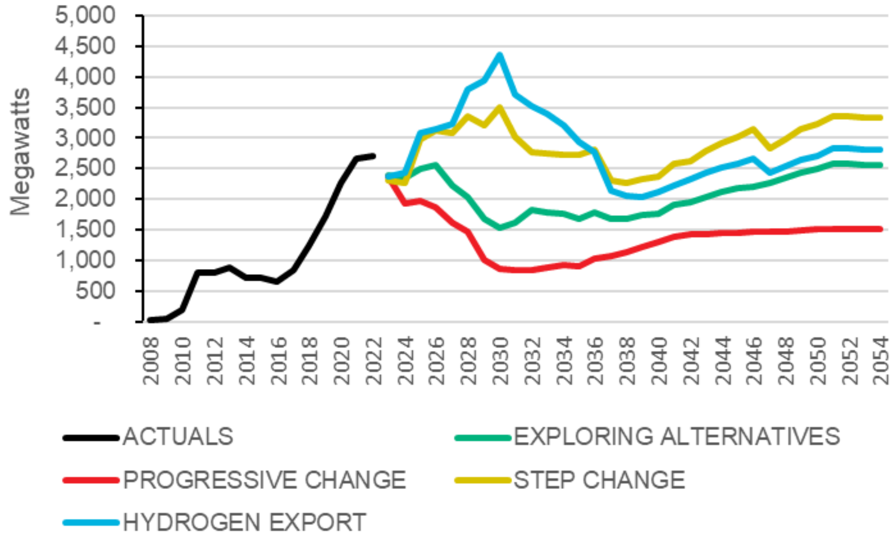
Under the Step Change Scenario on the other hand, underlying system costs are assumed to decline faster, but what makes the most critical difference is an assumption that governments will implement new policies to reward the carbon abatement delivered by solar systems (see section 4.2.1). This is shown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

The introduction of this new policy support under the Step Change scenario means that the payback of a solar system remains attractive in spite of falling revenue and consequently annual system additions manage to remain at similar levels over the decade to what they were around 2020-21.

5.2.4 Ongoing growth in system size and emergence of system upgrade demand helps to inflate capacity

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 are projected over the next decade to be substantially higher under the Step Change and Exploring Alternatives scenarios than anything achieved historically. While they subsequently decline in the 2030's as the market saturates, they then manage to climb over the 2040s to again exceed recent historical highs. Capacity additions in Progressive Change and Exploring Alternatives on the other hand fall significantly over the 2030's but still manage to remain above historical levels experienced up to 2017.

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

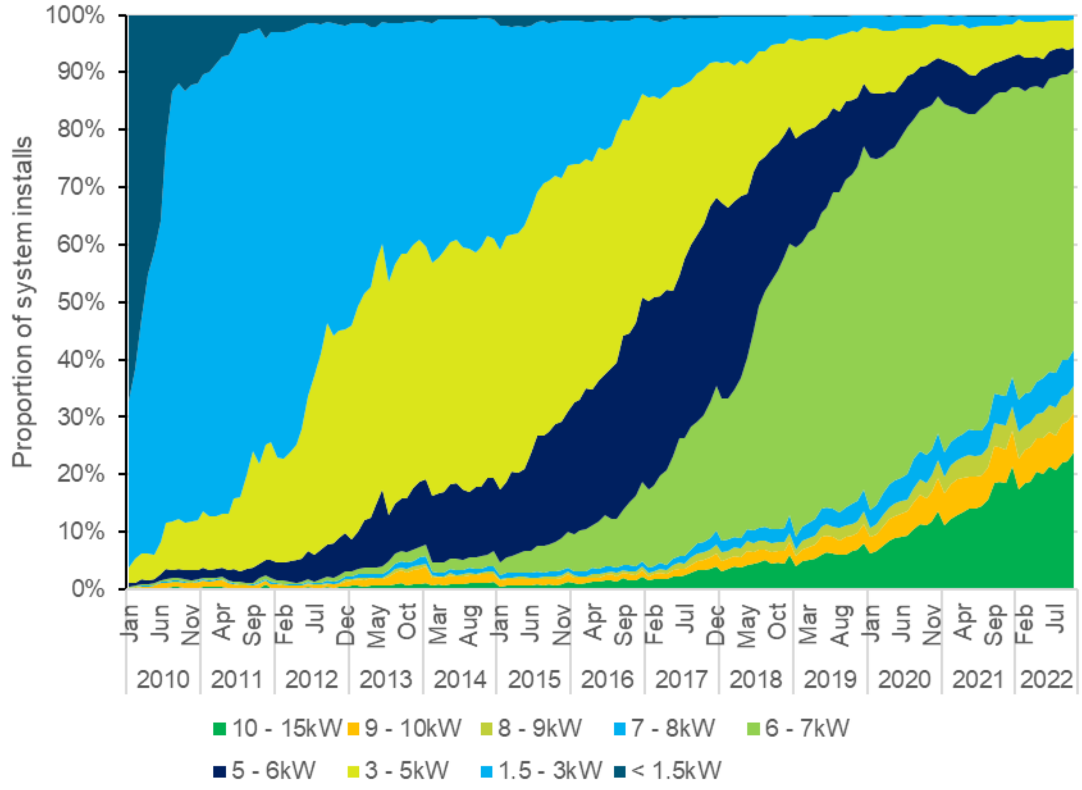


The reasons for why capacity additions remain above those seen in the years preceding the recent boom, in spite of a large fall in revenues, is a product of three factors:

1. The model assumes the Victorian Government will achieve its target to add close to 70,000 solar systems per annum to 2028;
2. As a result of module prices per watt being significantly lower than they were over 2010-2016 the solar industry is heavily geared towards installing much larger capacity per system than over 2010-2016.
3. A new source of sales emerges in replacing and upsizing the large number of small solar systems installed in the first solar boom over 2009-10 to 2013-14.

Point 1 is self-explanatory. In terms of point 2, while the number of system sales over the next decade under Exploring Alternatives and Progressive Change average less than they did between 2010 to 2014, the capacity of each system is likely to be significantly larger than they were back then. The figure below illustrates how the Australian solar market has progressively evolved from towards larger and larger systems. This trend also extends back to the 2010s when the predominant solar system was below 2kW in size..

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

In terms of the third point, we expect that replacement of the old systems from the first boom in solar over 2011 to 2013 will emerge as a new source of sales in this decade. 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), and also because households decide that they would be better off with a much larger capacity system than was originally installed.

While these replacement systems do not add to the cumulative number of systems shown in Figure 5-2 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. Furthermore, improvement in panel performance means that the average solar module installed today is about 50% more powerful than what was typically installed in 2011-12. So even if they replaced just the existing modules and added no extra, they'd increase system capacity by 50%.

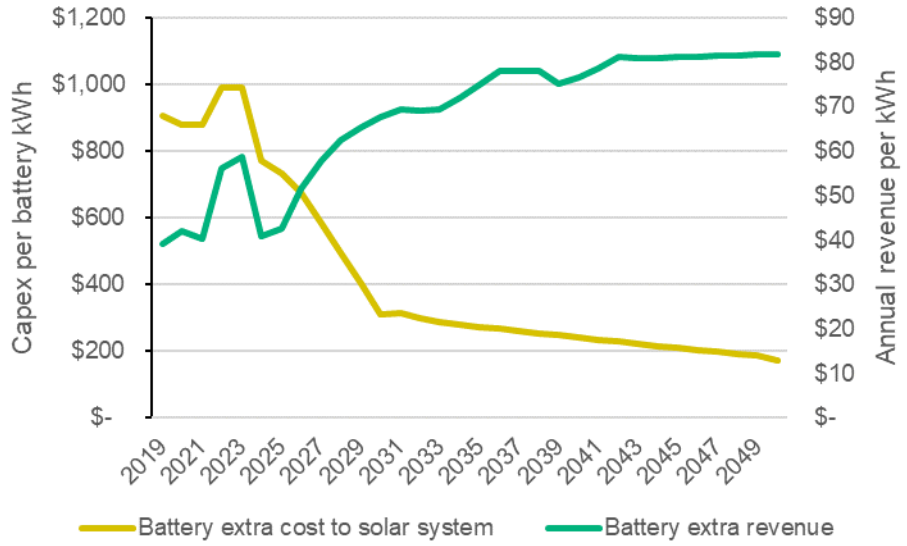
When older systems from 2010 to 2014, which were installed in large numbers, are replaced we expect most will be replaced with systems closer to the current industry standard of 6 to 8kW.

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

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

Figure 5-21 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 5-21 Revenue vs cost per kWh for household batteries (Step Change Scenario)



In the first few years of the 2020's paybacks for batteries are quite long, in fact they exceed the typical warranted life of a battery of around 10 years until the mid 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.

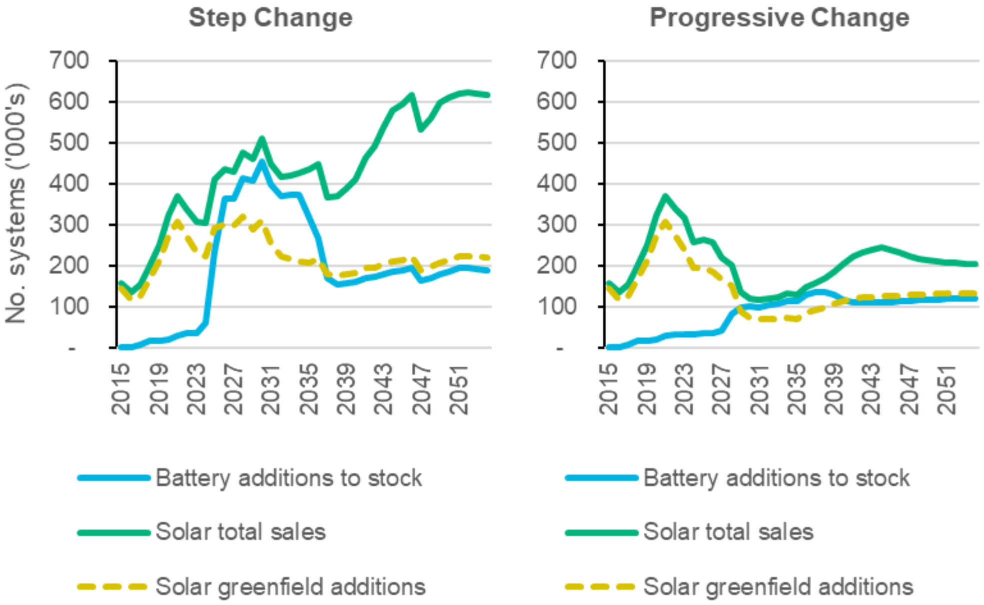
We are not aware of any rigorous evaluation of the prevalence and strength of these kinds of motivational drivers amongst the Australian population and the degree to which they might drive purchasing behaviour of batteries at different purchase price points or paybacks. However, interviews with industry 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 5-22 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 small consumer sector, relative to solar system sales and solar additions to stock. It is only by around the mid to late 2020'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 large uptick in battery uptake. By 2029 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 just about merge. This continues until the late 2030's when additional battery systems subside down in line with solar system additions (systems that installed on a dwelling that has not previously had a solar system). The departure from battery additions in line with total solar sales to just additional solar systems is because by 2040's 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.

In the Step Change scenario we see a very similar pattern 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 a nation-wide rebate is introduced that halves the out-of-pocket purchase price of battery for consumers.

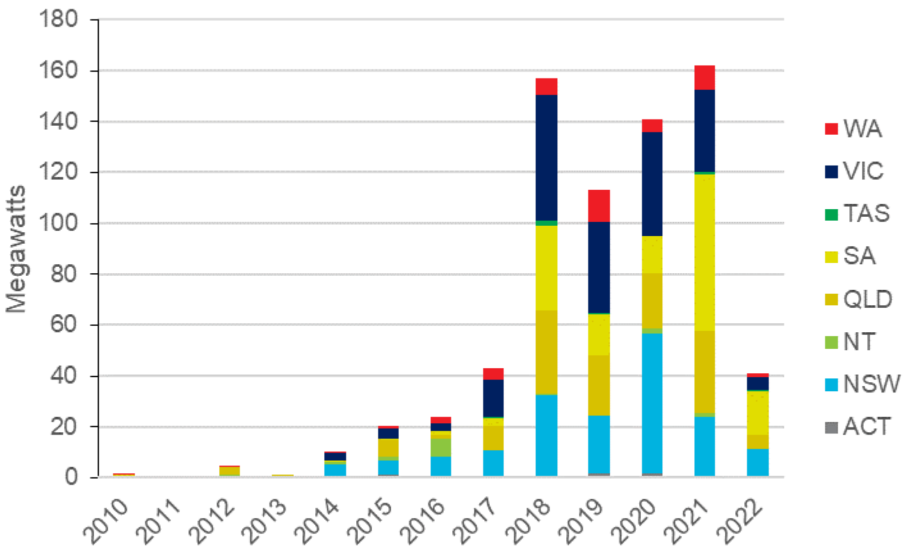
Figure 5-22 Number of additional residential battery systems relative to solar system additions and sales



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

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

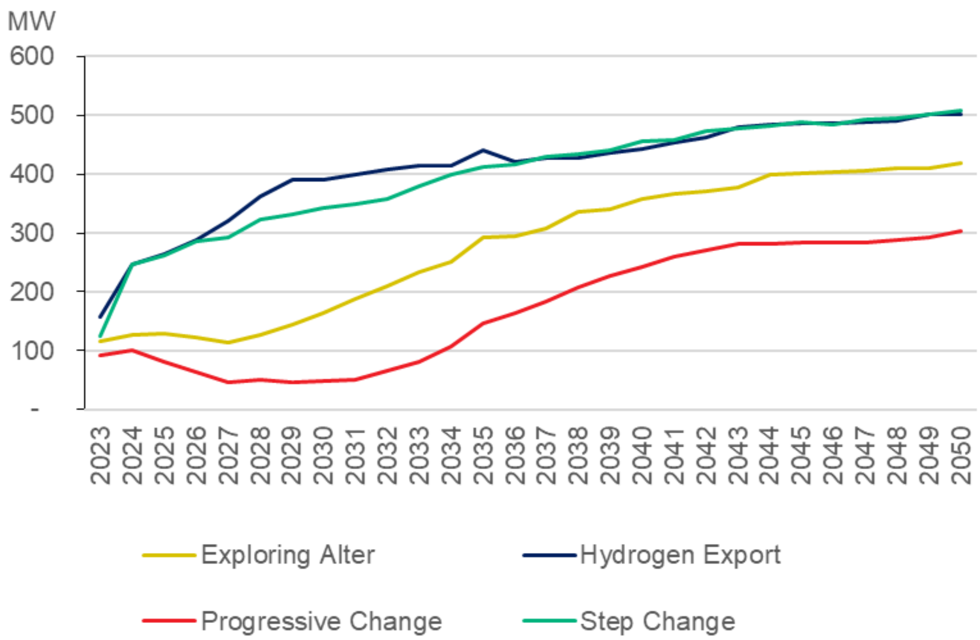
Figure 5-23 Capacity of behind the meter large commercial solar PV (by year of application for accreditation)



Note: 2022 numbers are only up to July. Some of the capacity within this chart incorporates projects which have applied for accreditation but are yet to be accredited. For these projects, as well as those accredited, capacity is recorded against the year in which the application was received.

Figure 5-24 details the amount of large commercial behind the meter solar capacity added to stock by year for each scenario. After a contraction in installations over 2022 we expect a significant and rapid rebound in installs under the Step Change and Hydrogen Export scenarios supported by the large rises in wholesale power prices that have recently unfolded. Growth is then sustained, albeit at a slower rate for the remainder of the outlook period. Under Exploring Alternatives the market is envisaged to recover from the 2022 contraction but capacity additions remain relatively stable up to 2027, before recommencing growth which lasts across the remainder of the outlook period. Under the Progressive Change scenario the market contracts from 2025 until 2027 and capacity additions remain at relatively low and stagnant levels all the way to 2032, before meaningful growth resumes in 2032 until 2043 after which the market again stagnates, although at much higher annual capacity additions than what has unfolded so far to date.

Figure 5-24 Capacity of large commercial solar systems added to stock per annum (Current Trajectory Scenario)



5.3.1 Historical context

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

- Customers with enough electricity demand to support a system larger than 100kW tend to face much lower electricity prices per kWh of consumption, due mainly to a large proportion of network costs being recovered via demand charges;

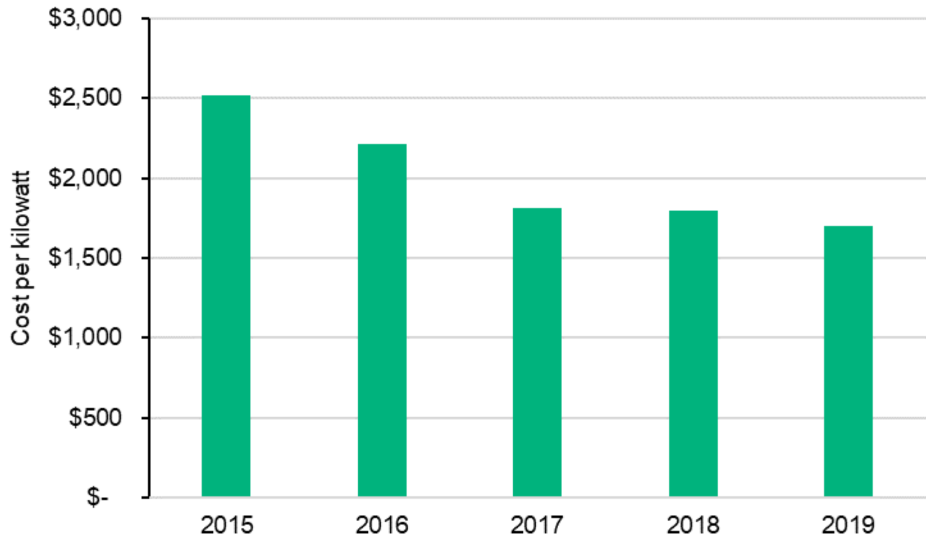
- Government policy financial support for systems of this scale have historically been less than that provided to the residential market.

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

- Substantial reductions in capital costs;
- A large and rapid rise in wholesale energy market prices in the NEM;
- A large increase in the value of LGCs; and
- Increasing sophistication of the solar industry that enhanced its ability to service and market to large commercial customers that present a more complicated market than residential and small business.

Figure 5-25, based on the sample set provided by the Clean Energy Regulator, shows that system cost per kilowatt for large commercial systems declined by 36 percent between 2015 and 2019.

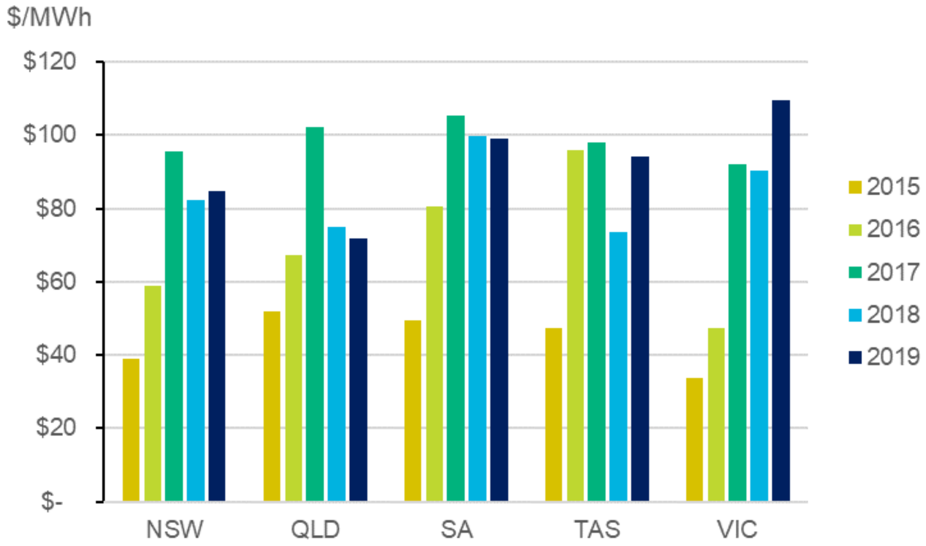
Figure 5-25 Cited installed cost of mid-scale systems per kilowatt by year (excluding off-grid/remote grid systems)



Note: Prices are GST excluded. These numbers are drawn from a sample which is adjusted to remove both low and high-end price outliers. In addition off-grid or remote grid systems have been excluded because these usually involve substantial additional costs not faced by mains grid-connected systems which then act to skew the cost data upwards in years in which off-grid systems were accredited.

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

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



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

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

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

As the financial attractiveness of large commercial solar systems has improved and the levels of interest in installing solar has grown, the solar industry has gained much greater experience in the sale and installation of these larger systems. This has allowed them to become better at presenting and explaining the investment proposition for solar to clients involving multiple decision makers and detailed evaluation processes. In addition, they have become more adept at dealing with the needs and concerns of electricity networks, and likewise electricity networks have gained greater comfort and understanding in having 100kW+ solar systems operating within their network. Also financing products have been developed with more attractive terms such as lower interest rates, longer repayment periods, and repayments tied to consumption of electricity from the solar system otherwise known as power purchase agreements. These have helped to at least somewhat mitigate tenant-landlord split incentives, and the often myopic approach businesses take to allocating capital to non-core elements of their business (a problem of bounded rationality which is a well understood factor behind sub-optimal levels of investment in energy efficiency[22]).

5.3.2 Short decline followed by recovery to prior boom heights

While annual solar capacity additions for the large commercial segment have declined over 2022, we project that this contraction is likely to be short-lived and the market will return to growth in 2023 across all scenarios.

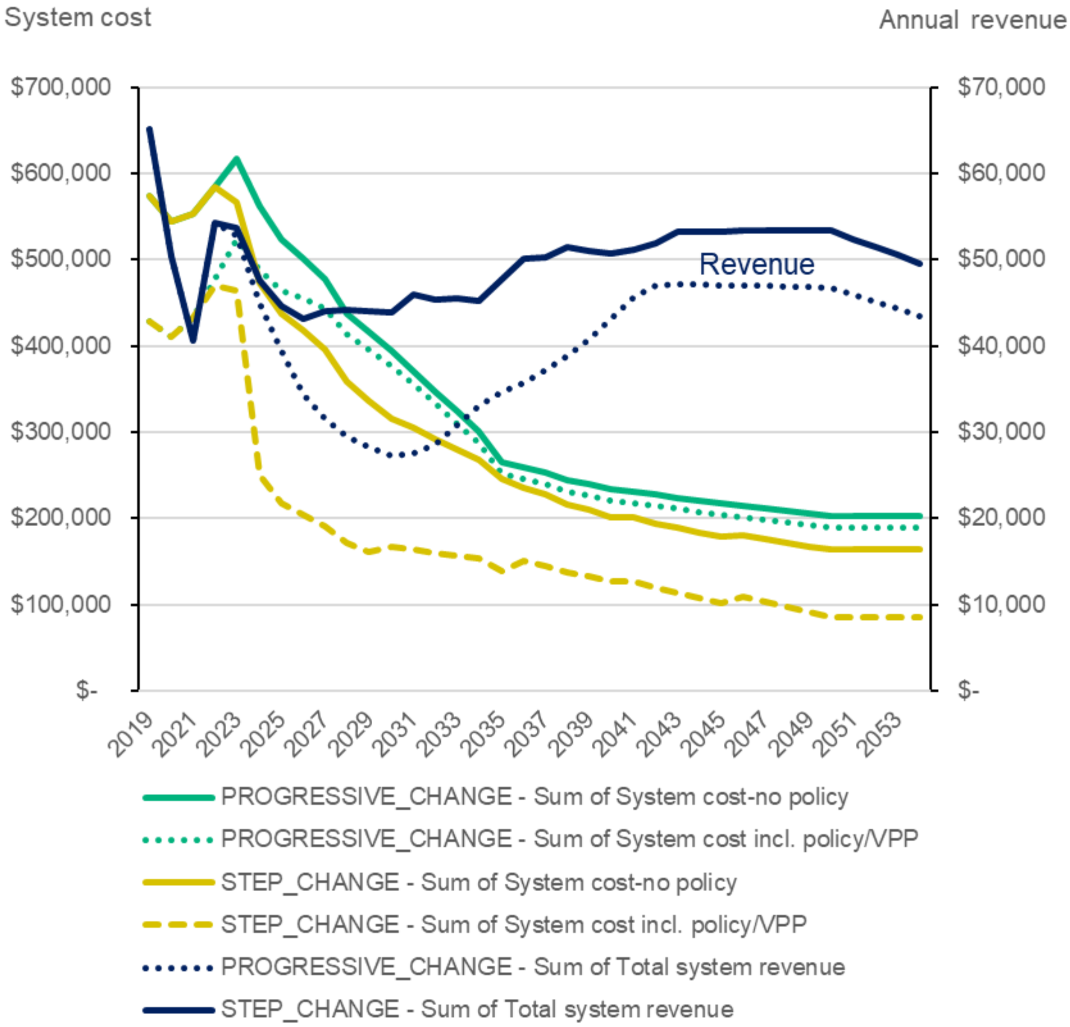
While revenue is estimated to have sharply declined between 2019 and 2021, this should substantially recover next year. While this higher level of revenue is not expected to be sustained, overall solar system revenue doesn't suffer the same degree of drop as the sub-100kW segment. This is because large commercial solar systems aren't as exposed to export feed-in tariffs, and they are assumed to be on demand-based network tariffs. Consequently, revenues aren't reduced by the shifting of a large proportion of network charges out of 9am to 3pm period and into 3pm to 9pm.

At the same time because large commercial solar systems receive less generous government support than sub-100kW systems, the capital cost declines achieved by solar systems are less obscured by simultaneous loss of government policy support.

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

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

Figure 5-27 Annual revenue for VIC large commercial solar + battery system relative to capital cost (Step Change vs Progressive Change Scenario)

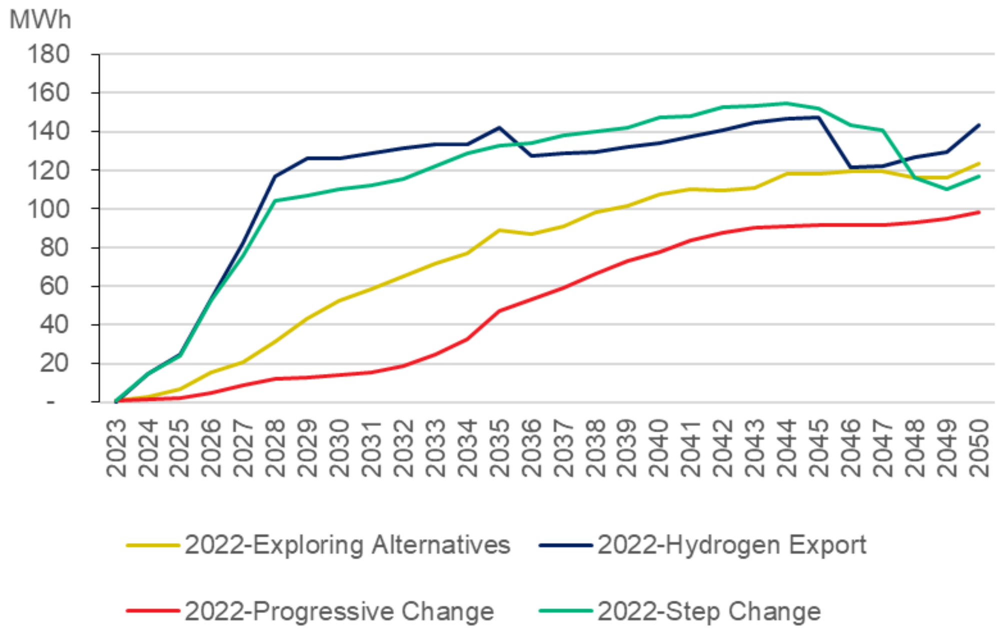


5.3.3 Battery adoption surges from 2026

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

As a result, battery uptake is expected to increase rapidly from 2026 onwards in Step Change, Exploring Alternatives and Hydrogen Export Scenarios, while for Progressive Change the uptick occurs two year later. By the late 2020's or early 2030's (depending on the state and scenario) almost all solar systems are installed coupled with a battery.

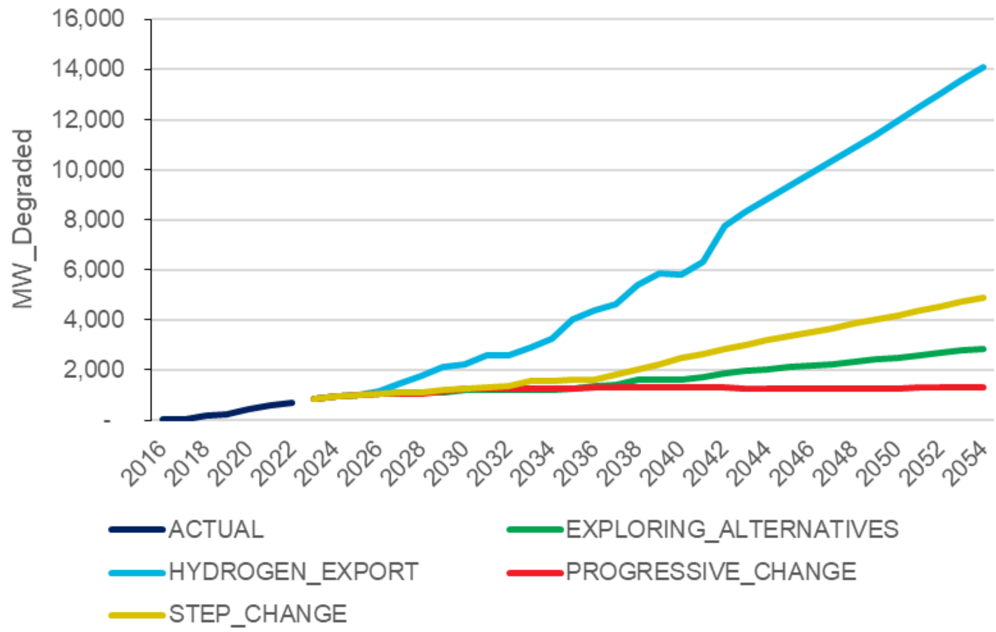
Figure 5-28 Megawatt-hours of commercial batteries added to stock by year



5.4 Power stations 1MW - 30MW

The figure below details cumulative installed degraded capacity of power stations (operated outside of AEMO dispatch) projected under each scenario. It illustrates how capacity additions are expected to slow over the next few years. Although under Hydrogen Export strong growth resumes by the mid 2020's and by the mid 2030's it also resumes under Step Change. Levels of additions don't recover to recent historical levels until the late 2030's in the Exploring Alternatives scenario, while capacity barely grows from the current installed base in the Progressive Change scenario.

Figure 5-29 Cumulative degraded capacity of sub-30MW power stations



5.5 Battery system charge and discharge profiles

To assist AEMO in assessing the possible aggregate impact of non-scheduled batteries on electricity demand and supply, we used AEMO supplied historical 30 minute interval data of estimated solar output stretching back several years within our payback model to assess how the battery would charge or discharge its power under two different battery operation modes Solar Shift and Tariff Optimisation which are both explained in the respective headings below:

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.

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 and this will change what is the best way to charge and discharge the battery.

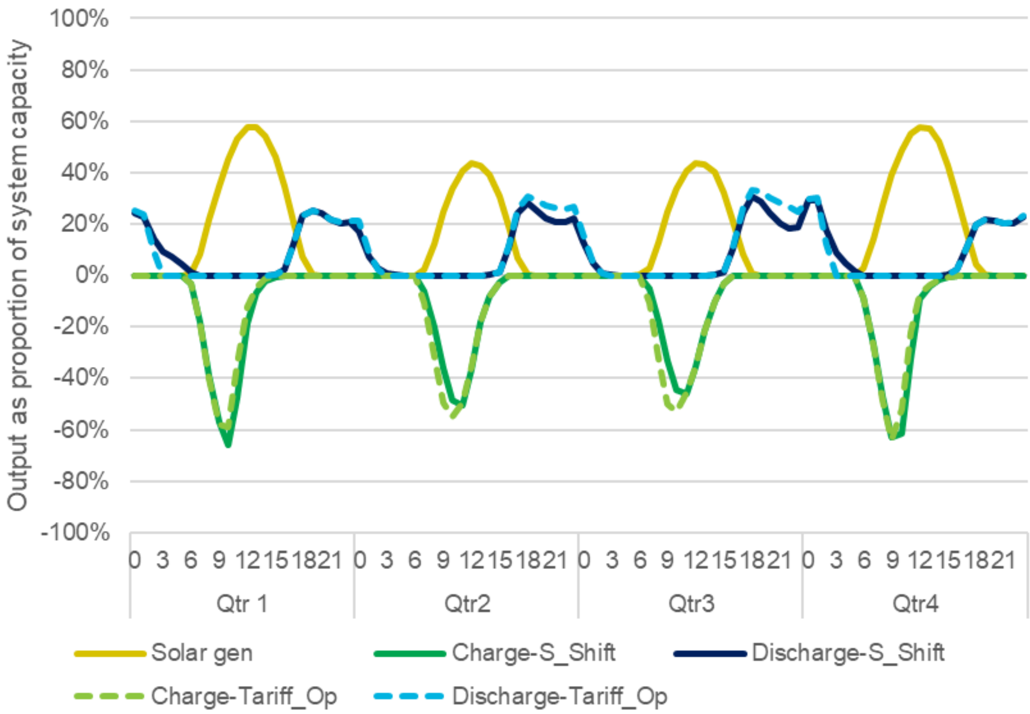
5.5.1 Results

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

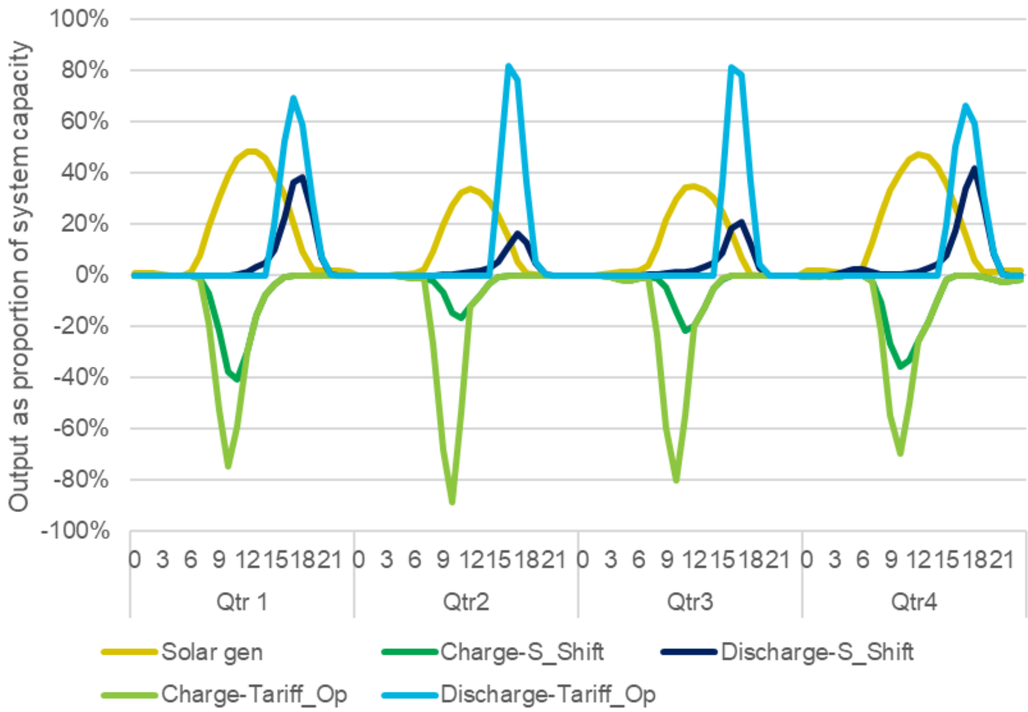
2. It is rare that load exceeds solar generation before 3pm so batteries in the solar shift mode usually tend to discharge after 3pm and so don't behave all that differently to the tariff optimisation mode that only allows discharge after 3pm when the peak tariff period commences.

Figure 5-30 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 5-31 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.