Australia's National
Science Agency

Projections for small-scale embedded technologies

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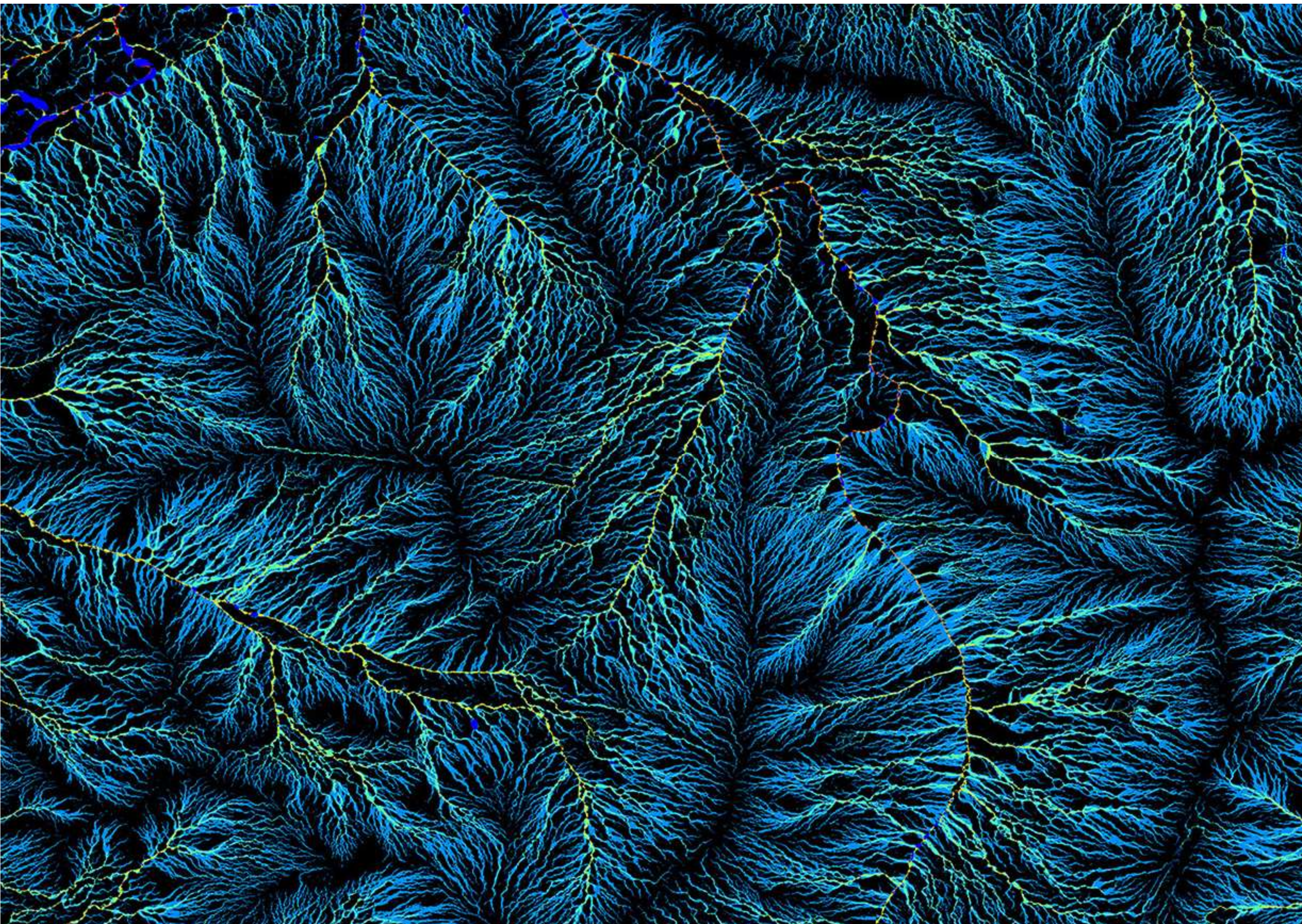
June 2020



Citation

Graham, P.W. and Havas, L. 2020, *Projections for small-scale embedded technologies*, CSIRO, Australia.

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Acknowledgments

Preliminary results, including a description of the methodology and assumptions, for the distributed energy resource projections were shared with the AEMO Forecasting Reference Group in the period February through April 2020. Together with direct feedback from AEMO, this input is gratefully acknowledged. Any errors or omissions remain the responsibility of the authors.

Executive summary

This report provides projections of the future capacity of small-scale embedded technologies, namely rooftop solar, batteries and electric vehicles. The projections have been commissioned by AEMO for input into their forecasting and planning processes. All projections are compared where possible to updated historical data and projections CSIRO provided for the same purpose in 2019.

CSIRO is committed to improving the performance of its projection methodology and in this report introduced an additional short term forecasting method to improve our ability to align with recent trends, in addition to its standard technology adoption curve approach which is designed to incorporate changes in the many financial and non-financial factors that impact small-scale technology uptake over the longer-term. In this year's projections, a major additional challenge was to incorporate the impacts of the COVID-19 pandemic on new installations and sales before any real data was available to see that impact. To address this challenge, we have considered several principles regarding how the pandemic is impacting residential and business customers willingness to invest to underpin our assumptions about the impact on projections. The impact has been varied across the scenarios so that we are able to capture some of the uncertainty.

Historical rooftop solar capacity growth has been particularly strong in 2019. While we expect this trend to be impacted by the COVID-19 pandemic in the short term, this strong historical growth together with strong policies in Victoria has contributed to higher updated projections relative to 2019 projections.

In contrast, battery sales stagnated in 2019 and this has led to a revaluation of the degree of alignment between the rooftop solar PV and battery markets. Consequently, we allow updated battery projections to follow their own path. Battery adoption is projected to accelerate with falling costs over the next decade, and slowing from the mid-2030s as battery costs stabilise.

Electric vehicles experienced stronger growth in 2019 which was aligned with previous expectations. Consequently, there is only a slight upward revision to projections. However, the inclusion of more detailed classes of trucks in the fleet modelling has increased expectations of electricity demand from electrification. Furthermore, the step change scenario, which explores a zero emission road transport sector by 2050, has provided an almost complete fleet electrification, thereby defining the upper bound for road transport's contribution to future electricity demand.

1 Introduction

This report has been commissioned by AEMO to assist in producing electricity consumption and maximum/minimum demand forecasts. Specifically, the report provides projections for five scenarios of small-scale embedded technologies which include solar photovoltaic systems (solar PV), battery storage and electric and fuel cell vehicles. The projection data includes installations, capacity, location and the normalised operational profiles of batteries and electric vehicles.

CSIRO employs a variety of forecasting techniques to deliver the projections and in 2020 there is a special emphasis on including the impacts of the COVID-19 pandemic in forecasts. The projection process commences with establishing the current trend in deployment out to two years from the present based on the most recent available deployment data[1]. Next we impose an assumed impact of the pandemic on this trend. Finally, we calibrate our consumer technology adoption curve model to the two-year end point of this pandemic impacted trend. The consumer technology adoption curve approach is particularly useful in the context of consumer investment decision making because it provides a way of accounting for financial and non-financial drivers over the long term. Trend analysis will not work over the long term because fundamental drivers will shift. For example, electric vehicle uptake is currently dominated by an early adopter group who is less sensitive to vehicle cost. However, at a later stage, mainstream adoption will need to be triggered by lower costs. We provide more detail about the projection methodology in the next section this report.

There are many diverse drivers for distributed energy resources technology adoption and scenarios are used to explore the ranges of potential outcomes. Consequently, the third section of this report is concerned with outlining the scenarios and the fourth with outlook for various drivers which have been matched to those scenarios. We conclude with a discussion of the projections and how they have been shaped by the underlying assumptions.

The projections are not just about the physical capacity of distributed energy resources but also how they will operate. One aspect of the operation of technology we present is the share of distributed energy resources assumed to be operating under different incentive regimes (the options for which we define for each technology). A second aspect of the operation of technology is its daily profile. The development of daily operational profiles for battery storage and electric vehicles is difficult in isolation from market feedback. The way customers operate their distributed energy resources will impact the market and in response the market may adjust the price signals to customers to incentivise operation that improves the efficiency of the electricity system. Completing this loop is not within the scope of this report. Instead, we make assumptions. We assume that avoiding adding to load during the peak evening period will always be of value, that shifting demand to the night time period is still valued in the medium term and that shifting load

[1] Batteries: Sunwiz 2019 battery report purchased March 2020; Electric vehicles: FCAI December 2019 quarterly VFACTS sourced in March 2020; Less than 100kW solar PV: CER data to March 2020; Solar PV greater than 100kW: APVI large scale solar power station data accessed April 2020

to the day time period will be most valued in the longer term due to the increasing amount of solar generation.

2 Methodology

2.1 Adoption projections method overview

The projections undertaken are for periods of months, years and decades. Consequently, the projection approach needs to be robust over both shorter- and longer-term projection periods. Longer term projection approaches tend to be based on a theoretical model of all the relevant drivers including human behaviour and physical drivers and constraints. These models can overlook short term variations from the theoretical model of behaviour because of imperfect information, unexpected shifts in key drivers and delays in observing the current state of the market. To improve the short-term performance of theoretical models, we ideally need a second more accurate shorter-term projection approach to correct for short term variations. In the context of the COVID-19 pandemic, it is especially true that we need to pay close attention to immediate short-term impacts.

Shorter term projection approaches tend to be based on extrapolation of recent activity without an underlying theory of the drivers. These include regression analysis and other types of trend analysis. While trend analysis will generally perform the best in the short term, extrapolating a trend indefinitely will lead to poor results since eventually a fundamental driver or constraint on the activity will assert itself, changing the activity away from past trends.

Based on these observations about the performance of short- and long-term projection approaches, and our need to deliver both long and short projections, this report applies a combination of short-term trend models and a long-term theory-based adoption model.

The COVID-19 pandemic sits in between a short- and long-term modelling approach. While occurring in the short term, for the purposes of the timing of this report, none of the historical data available had yet shown any impacts and therefore its impact could not be captured by regression analysis. Our longer-term models are designed to start two years after the short-term models, after the pandemic will likely have finished and would therefore also fail to capture its impact. Therefore, we modified our approach to include a third model which is essentially to apply an assumed global pandemic impact on the short-term trend model.

2.1.1 Trend model

For periods of monthly to several years (up to June 2021-22), trend analysis is applied to produce the projections based on historical data. The trend is estimated as a linear regression against 3 years of monthly data with dummy variables against each month to account for trends in monthly sales. As such, the regression takes the following form:

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

Where X is the (m) monthly activity of the following possible activities:

- Solar PV installations and capacity (by residential or commercial grouping)
- Battery installations and capacity (by residential or commercial grouping)

- EV sales (by road vehicle and engine configuration type such as electric or plug-in hybrid).

For solar PV system less than 100kW, regressions are calculated at the postcode level, while the remainder of activities are calculated the state level. For some larger non-scheduled solar PV, we have only used the last 24 months of data due to significant inactivity. For batteries and electric vehicles, annual state data is often only available and so the regression is simply a function of the year. We only considered linear regression. The choice between linear or nonlinear functional forms has only minor impact when applied over a two-year projection period.

2.1.2 Assumed impact of global pandemic on short term trend

The COVID-19 pandemic is an event which has not occurred at a similar scale since the 'Spanish Flu' of the early 1900s. There is therefore significant uncertainty in its impacts and no real analogous modern-day event from which to calibrate impact assumptions. Our aim is therefore to summarise the observed societal response from which we propose to base a new set of impact assumptions. The observations as follows were as at April 2020, when the projections were prepared:

- The banning of activities which result in close proximity between community members means that a significant proportion of the services sector and households with a member who work for that sector can expect a large reduction in income for an extended period (subject to government payments discussed below). Public announcements have stated that some bans would likely stay in place for 6 months
- Government expenditure programs are mitigating several aspects of these bans:
    - Businesses subject to the ban will receive income support. This income support is aimed at the level of preventing bankruptcy, not replacing all revenue lost. The goal is to increase the probability that business will be able to resume trading in the future, not to restore all losses
    - Business can apply to have staff who were employed from March 1 paid by the government up to a cap of $1500 per fortnight. Wage subsidy payments to businesses would start in May (but can be back dated to March)
    - The government has raised the former Newstart allowance by $550 a fortnight for those with no partner or a partner with an income less than $80,000 (start end of April)
- Many people will have fallen out of work in March, and while there are some back-dating elements to the mitigation policies, the general reaction will have been to tighten all non-essential spending
- The rate of increase in unemployment and the pace at which it occurred due to the particular mechanism of activity bans is unprecedented. This means that historical changes in solar installations in states merely experiencing slower growth (e.g. WA post-GFC decline in minerals prices) are a poor guide to the impact of the current change in economic growth.

- Installers may be reluctant to continue operating because the risks associated with visiting other people's houses or simply assembling the installation crew. It may be possible to change these activities to incorporate more physical distance but perhaps not completely to the satisfaction of all customers or businesses.
- There may be deeper bans implemented in various stages of the COVID-19 pandemic which mean that non-essential services such as installation of optional rooftop solar, batteries or car sales are not allowed for a period. These stricter bans may be for only a shorter period such as 2-4 weeks.
- Government support programs were put in place under the assumptions that it might be possible for normal business to resume with all subsidies removed after a potential 6 months. Ideally the economy would resume growth. If state or commonwealth governments find that the economy needs more government expenditure to resume growth, it is possible that broader expenditure programs could include more subsidies for rooftop solar PV and batteries, particularly in states where these schemes are not as generous.
- Business self-mitigation / diversification: some businesses have adapted by shifting their retailing online, selling their products in a different way (e.g. a la cart to takeaway) or re-tooling to produce different products (alcohol to hand sanitiser)
- Ordering delays: Some quotes concluded before the virus outbreak may still be delivered owing to having too much momentum to stop (customers may be reluctant to cancel orders or may have paid a deposit). Electric vehicle orders are known for lengthy delays. Solar PV adoption will help with keeping future electricity costs down. There might be an element of seeing batteries as providing some independence from a society being somewhat deconstructed by dealing with the pandemic (although there has been no incidence of supply interruptions, articles about planning to keep essential services running implies there is a risk to be managed and so such thinking is not totally irrational)
- We might see some bargain hunters come into the market if for example electric vehicles were to be offered at substantially lower prices
- Virus dynamics: Close tracking of the peak will impact the public mood. An obvious peak and decline would be positive. A second-round infection period would be detrimental. These are major drivers of the length of the impact, but their timing and occurrence are unknown the time of preparing this report.

Based on these observations and the lack of any analogous recent event we have devised a set of assumed impacts which we outline in Section 4.

2.1.3 Adoption in consumer technology markets

The consumer technology adoption curve is a whole of market scale property that we can exploit for the purposes of projecting adoption, particularly in markets for new products. The theory posits that technology adoption will be led by an early adopter group who, despite high payback periods, are driven to invest by other motivations such as values, autonomy and enthusiasm for new technologies. As time passes, fast followers or the early majority take over and this is the most rapid period of adoption. In the latter stages the late majority or late followers may still be holding back due to constraints they may not be able to overcome, nor wish to overcome even if the product is attractively priced. These early concepts were developed by authors such as Rogers (1962) and Bass (1969).

In the last 50 years, a wide range of market analysts seeking to use the concept as a projection tool have experimented with a combination of price and non-price drivers to calibrate the shape of the adoption curve for any given context. Price can be included directly or as a payback period or return on investment. Payback periods are relatively straightforward to calculate and compared to price also capture the opportunity cost of staying with the existing technology substitute. A more difficult task is to identity the set of non-price demographic or other factors that are necessary to capture other reasons which might motivate a population to slow or speed up their rate of adoption. CSIRO has previously studied the important non-price factors and validated how the approach of combining payback periods and non-price factors can provide good locational predictive power for rooftop solar and electric vehicles (Higgins et al 2014; Higgins et al 2012).

In Figure 2-1 we highlight the general projection approach including some examples of the types of demographic or other factors that could be considered for inclusion. We also indicate an important interim step, which is to calibrate the adoption curve at appropriate spatial scales (due to differing demographic characteristics and electricity prices) and across different customer segments (due to differences between customers' electricity load profiles which are discussed in Appendix A, travel needs, fleet purchasing behaviour and vehicle utilisation).

Once the adoption curve is calibrated for all the relevant factors, we can evolve the rate of adoption over time by altering the inputs according to the scenario assumptions[2]. For example, differences in technology costs and prices between scenarios will alter the payback period and lead to a different position on the adoption curve. Non-price scenario assumptions such as available roof space or educational attainment in a region will result in different adoption curve shapes (particularly the height at saturation). Data on existing market shares determines the starting point on the adoption curve.

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

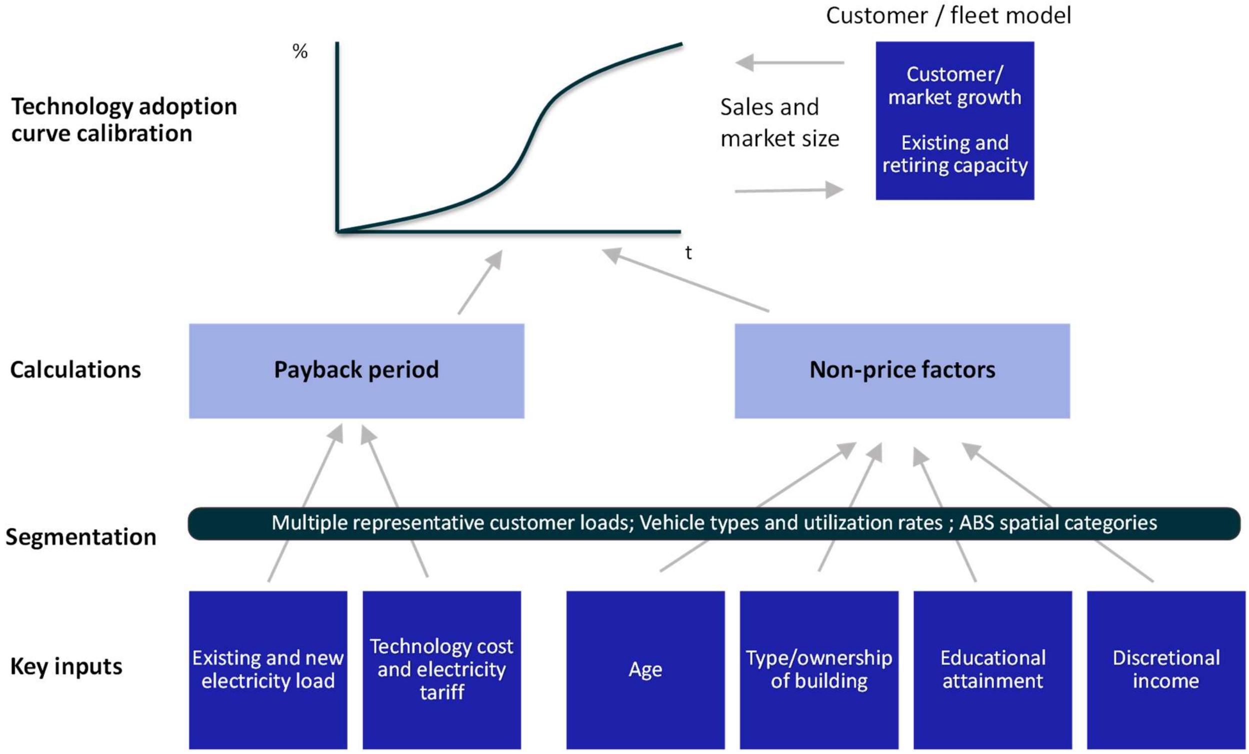

Figure 2-1 Adoption model methodology overview

The methodology also takes account of the total size of market available and this can differ between scenarios. For example, the total vehicle fleet requirement is relevant for electric vehicles, while the number of customer connections is relevant for rooftop solar and battery storage. The size of these markets is influenced by population growth, economic growth and transport mode trends and we discuss the latter further in the scenario assumptions section. While we may set a maximum market share for the adoption curve based on various non-financial constraints, maximum market share is only reached if the payback period falls. Maximum market share assumptions are outlined in the Data Assumptions section.

All calculations are carried out at the Australian Bureau of Statistics Statistical Area Level 2 (SA2) as this aligns to the available demographic data. However, we convert the technology data back to postcodes or aggregate up to the state level as required. The Australian Bureau of Statistics publishes correspondence files which provide conversion factors for moving between alternative commonly used spatial disaggregations. Each spatial disaggregation can also be associated with a state for aggregation purposes.

CSIRO applies a common structural model for electric vehicles, storage and all solar panels below 100kW. We regard these technology markets as “consumer” markets in the sense that investment decisions are driven by a combination of financial and non-financial drivers so that adoption will broadly follow the consumer technology adoption curve. For large solar systems, we take the view that such decisions should be regarded as more pure financial investment decisions and therefore we apply a mostly financially driven projection method.

2.1.4 Adoption of larger technology investments

For solar panel sales and capacity above 100kW, we employ a different approach. The difference in approach is justified on the basis that larger projects require special purpose financing and, as such, are less influenced by non-financial factors in terms of the decision to proceed with a project. In other words, financiers will be primarily concerned with the project achieving its required return on investment when determining whether the project will receive financing. Commercial customer equity financing is of course possible, but it is more common that businesses have a wide range of important demands on available equity, so this is only a very limited source of funding (as compared to being the main source of small-scale solar investment).

The projected uptake of solar panels above 100kW is based on determining whether the return on investment for different size systems meets a required rate of return threshold. If they do, investment proceeds in that year and region. For less than 5MW capacity generation, we assume investment proceeds if revenue is 10% higher than that which would have been required to meet a real 7% rate of return on investment. For plant with generation capacity larger than 5MW, we assume that revenue must be sustained at this rate of return for more than five years (does not need to be consecutive). Solar generation costs, electricity prices and any additional available renewable energy credits are the strongest drivers of adoption.

Where investment can proceed, we impose a build limit rate based on an assessment of past construction rates and typical land/building stock cycles. Figure 2-2, Figure 2-3, Figure 2-4 and Figure 2-5 show the historical total deployment in each of solar plants in the 0.1MW to 1MW, 1MW to 5MW, 5MW to 10 MW and 10MW to 30MW ranges respectively (sourced from APVI (2020))[3]. They indicate the trends in build rates across each state. Deployment activity is most frequent and more evenly spread across states in the smaller ranges, particularly 0.1MW to 1MW. 10MW to 30MW systems are less frequent and concentrated in New South Wales, ACT and Queensland. 5MW to 10MW systems are even more concentrated with South Australia leading this size range.

[3] 2019-20 data only includes to December 2019.

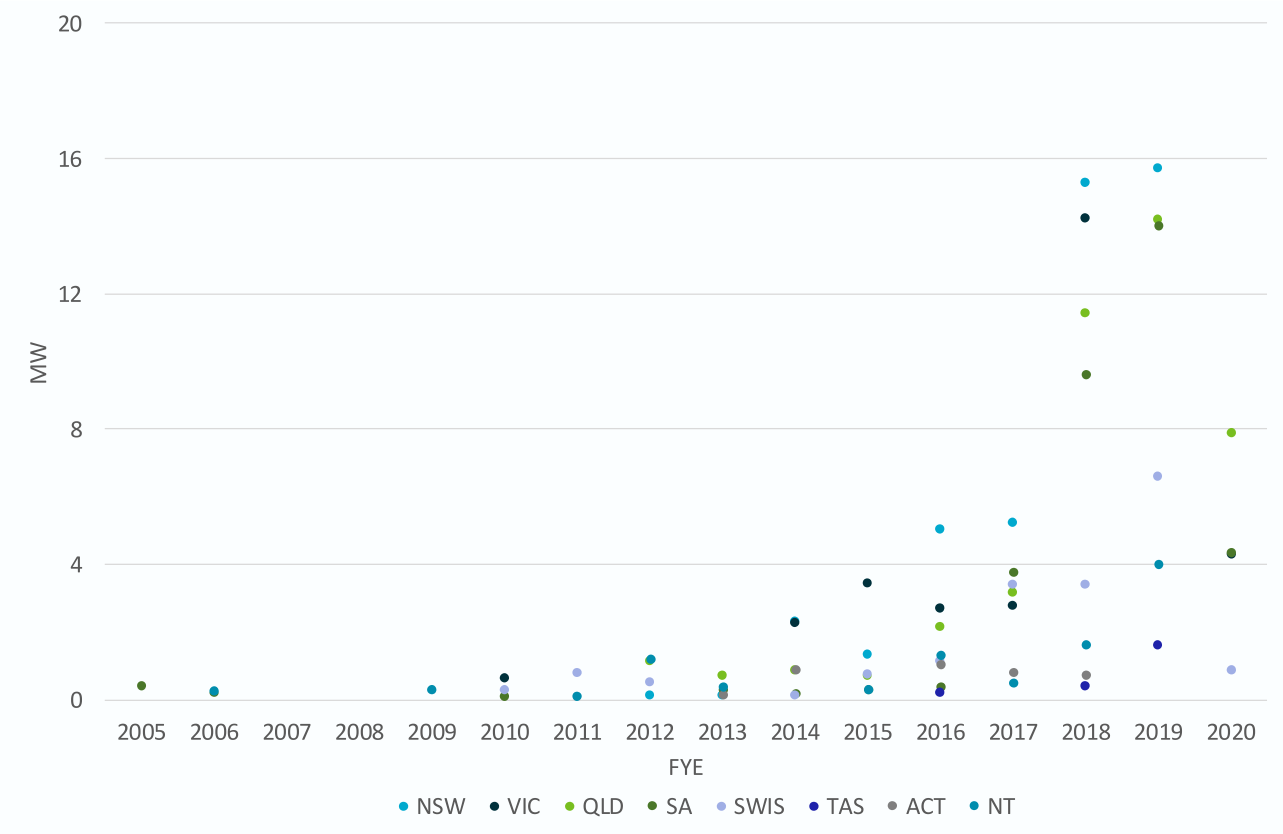

Figure 2-2 Historical deployment by state of solar systems of size 0.1 to 1 MW

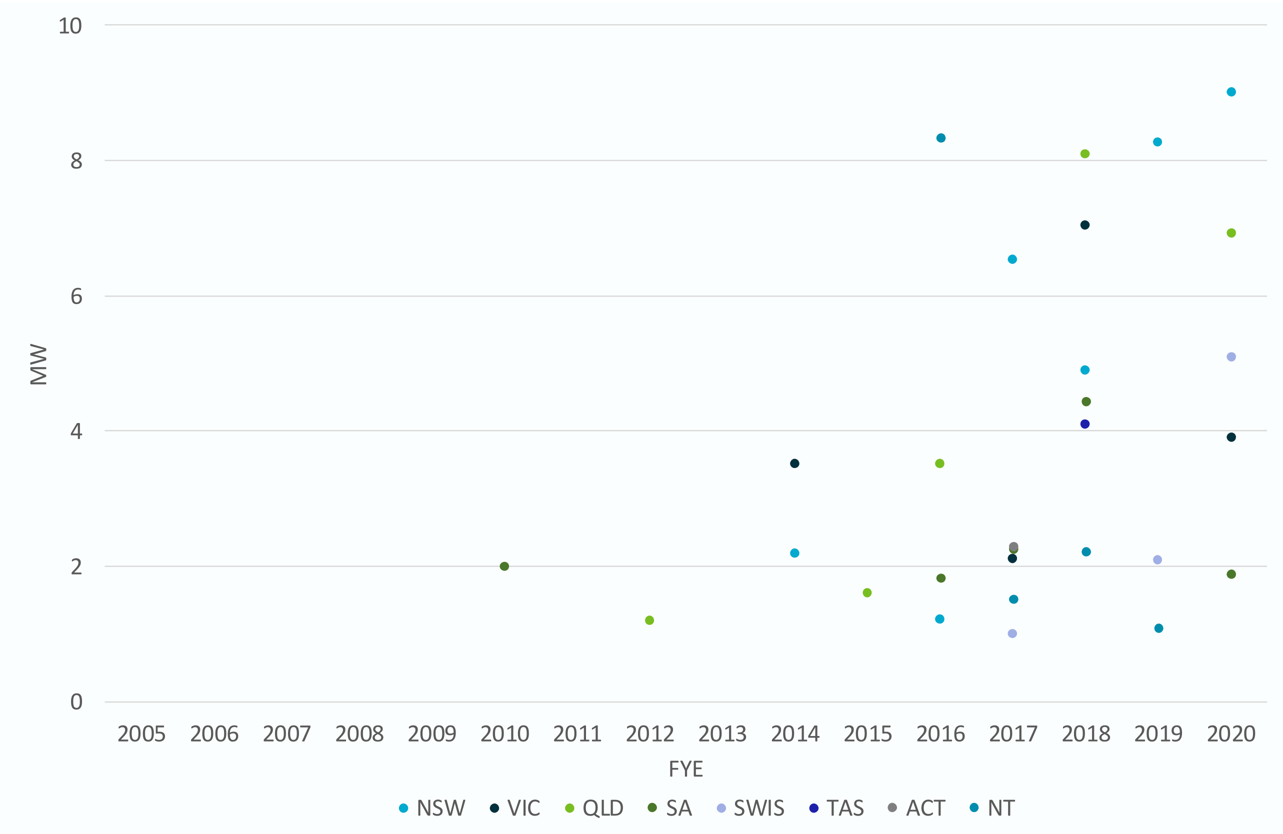

Figure 2-3 Historical deployment by state of solar systems of size 1 to 5 MW

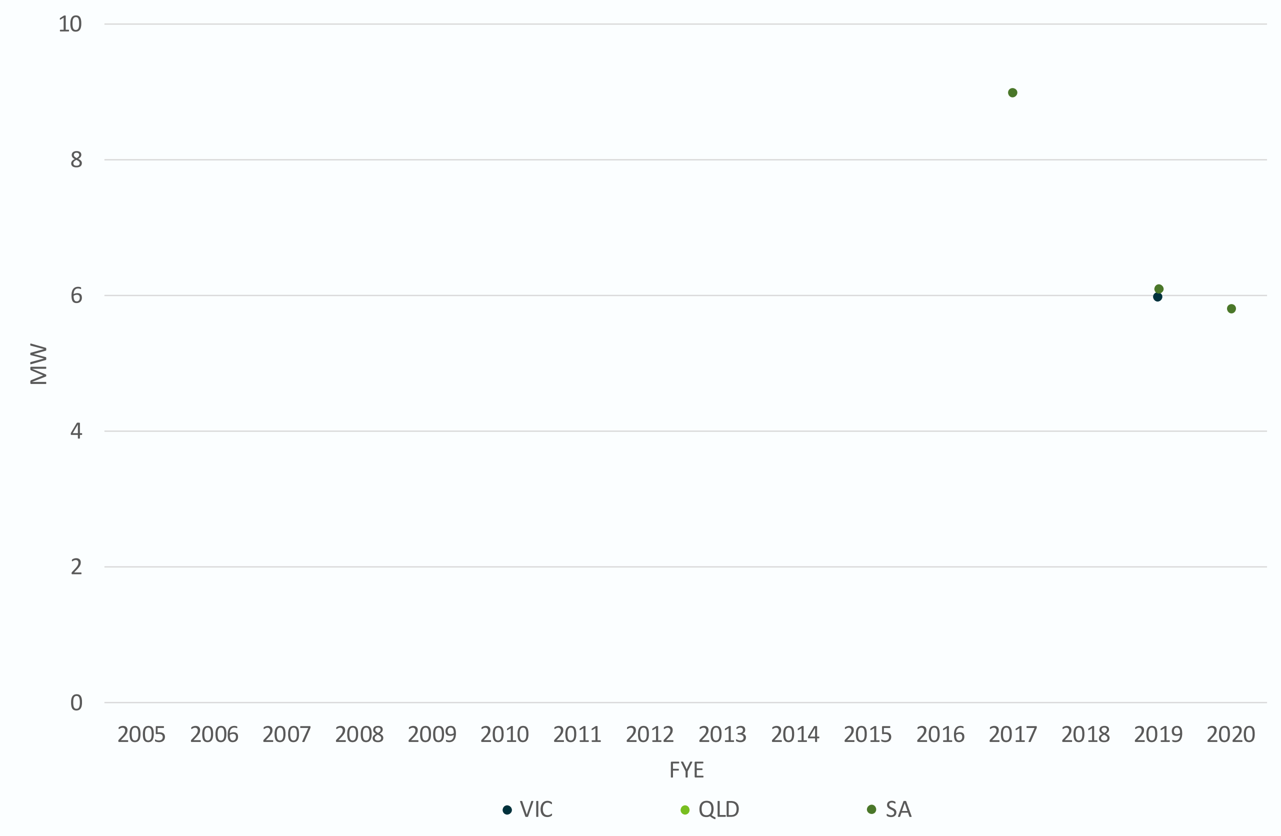

Figure 2-4 Historical deployment by state of solar systems of size 5 to 10 MW

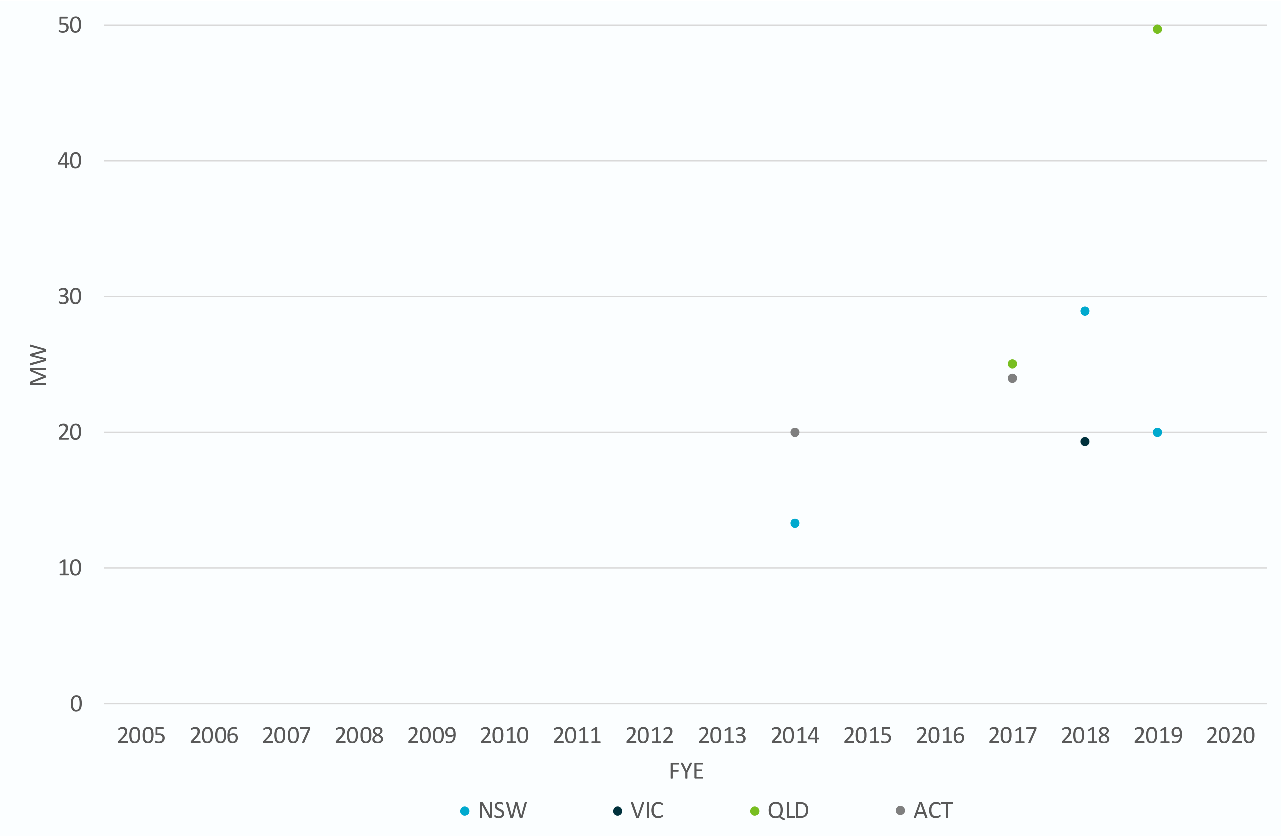

Figure 2-5 Historical deployment by state of solar systems of size 10 to 30 MW

2.1.5 Commercial vehicles

It could be argued that commercial vehicle purchasers would be more weighted to making their decisions on financial grounds only. That is, commercial vehicle sales would rapidly accelerate towards electric vehicles as soon as they offer lower whole of life costs (which also occur sooner than for residential owners because of the longer average driving distances of commercial vehicles). However, we have assumed that infrastructure constraints including the split incentives or landlord-renter problem which can be captured using adoption curves are also relevant for businesses noting that many commercial vehicles park at residential premises. For business parked vehicles, if the business does not own the building, installing charging infrastructure may not be straight-forward. Also, the applicability of vehicle range to a business's needs is just as relevant as whether vehicle range will suit a household's needs.

2.2 Demographic factors and weights

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

2.2.1 Weights and factors for rooftop solar and battery storage

Higgins et al (2014) validated prediction of historical sales for rooftop solar by combining a weighted combination of factors such as income, dwelling density and share of Greens voters. While these factors performed well when the model was calibrated for 2010, given the time that has passed and 2010 being very much an early adopter phase of the market we tested a new set of factors as shown in Table 2-1. We have also chosen our weights based on data that is readily available in the Statistical Area Level 2 format.

Battery storage sales data is not available below the state or territory level. Consequently, it is not possible to calculate a set of historically validated combination of weights and factors. In the absence of such data we assume the same weights apply to battery storage as for rooftop solar.

Table 2-1 Weights and factors for residential rooftop solar and battery storage

Factor	Weight
Average income	0.25
Share of separate dwelling households	1
Share of owned or mortgaged households	0.25

For commercial systems we do not apply any demographic weights since none were found to be highly explanatory. However, the existing location of commercial systems tends to be a strong indicator of future deployment in an SA2 region. This indicates a network effect where awareness of deployment of solar nearby or by neighbours inspires adoption.

2.2.2 Weights and factors for electric vehicles

Previous analysis by Higgins et al (2012) validated several demographic factors and weights for Victoria. We apply a similar combination of factors and weights as shown in Table 2-2. These weighting factors provide a guide for the adoption locations, particularly during the early adoption phase which we currently remain in. However, we allow adoption to considerably grow in all locations over time. It is likely that some of the factors included act as a proxy for other drivers not explicitly included (such as income).

Table 2-2 Weights and factors for electric vehicles

Factors	Weight ranges
Share of ages (in 10-year bands)	0-1 with the 35 to 54 age bands receiving highest scores
Share of number of household residents (1-6+)	0.3-1 increasing with smaller households
Share of educational attainment	0.25-1 for advanced diploma and above, 0 otherwise
Share of mode of transport to place of work	1 for car, 0 otherwise

2.3 Role of economic growth in projection method

Economic growth is a closely tracked indicator of changes in residential and business income and the general health of the economy and as a result we provide an overview of how changes in economic growth impact the projections.

2.3.1 Rooftop solar PV and batteries and economic growth

Income/GDP enters the calculations through the annual calibration of the adoption curve. Economic growth extends the number of locations over time which receive a high demographic score which raises the height (saturation level) of the adoption curve. This is offset by declining scores from assumed reduced home ownership and decrease in separate dwellings (which we discuss later in Section 4). In fact, because these other drivers are stronger or equal to income, the growth in income only serves to reduce the rate of decline in the market saturation point. Income receives only a 16% weight in the demographic score and growth assumptions only operate on a fraction of that weight. The saturation point changes the shape of the adoption curve when it is fitted. The adoption curve shape influences the potential number of installations (but movement along the curve is mostly driven by changes in the payback period).

Overall, changes in economic growth are directly responsible for only small changes in the projections. However, if higher GDP/income means more connections, the projected adoption rate is directly multiplied by connections and so the resulting changes would be directly proportional to changes in connections.

Due to a lack of spatial data on batteries (to teach the model about the most important demographic factors for battery adoption) we use the same weighting as for solar. Therefore, the same relationships apply to economic and customer connections growth.

2.3.2 Electric vehicles and economic growth

Income enters the electric vehicle adoption model only through the size of transport demand. Unlike rooftop solar PV and batteries, economic growth is not included in the demographic score for calibration of the electric vehicle adoption curve. Passenger transport demand is the larger component of transport and is driven by population growth. Demand for light commercial vehicle and truck transport is driven by economic growth. Stronger demand means more vehicle sales. However, growth in demand is the smallest part of vehicle sales. Sales are about 80% replacement of vehicle stock.

In summary, changes in economic growth are only impacting around 20% of the sales of a minority of vehicle types. As such, alternative economic growth assumptions would only have a marginal direct impact on EV projections. Indirectly, if higher economic growth occurred due to higher population growth then that mechanism would broaden the impact of higher economic growth because it would mean the whole of transport demand is experiencing higher demand. In that case the impacts would be approximately 20% of sales increasing in line with increases in GDP and population.

3 Scenario definitions

The projections for small-scale embedded technologies are provided for the five scenarios as shown in Table 3-1: Central, Slow change, Fast change, High DER and Step Change. The AEMO scenario definitions provide useful direction about the differences between the scenarios but require more detail. In this section, to provide greater clarity about what has been assumed in each scenario, we provide an extended scenario definition table based on a deeper consideration of the economic, infrastructure and policy drivers. We then describe each of the financial and non-financial drivers in more detail.

Table 3-1 AEMO scenario definitions

Scenario	Slow Change	Central	Fast Change	High DER	Step Change
Economic growth and population outlook	Low	Moderate	Moderate	Moderate	High
EE improvement	Low	Moderate	Moderate	Moderate	High
Demand Side Participation	Low	Moderate	Moderate	Moderate	High
Rooftop PV	Low	Moderate	Moderate – High	High	High
Battery storage installed capacity	Low	Moderate	Moderate – High	High	High
Battery storage aggregation/Virtual Power Plant (VPP) deployment by 2050	Existing trials do not successfully demonstrate a strong business case for VPP aggregation. Low role for energy storage aggregators and VPPs.	Moderate role for energy storage aggregators and VPPs.	Existing trials demonstrate a business case for VPP aggregation. High role for energy storage aggregators and VPPs.	Existing trials demonstrate a business case for VPP aggregation. High role for energy storage aggregators and VPPs.	Existing trials demonstrate a business case for VPP aggregation. High role for energy storage aggregators and VPPs, faster than all other scenarios.
EV uptake	Low	Moderate	Moderate-High	Moderate-High	High

EV charging times	Delayed adoption of infrastructure and tariffs to enable 'better' charging options.	Moderate adoption of infrastructure and tariffs to enable 'better' charging options.	Faster adoption of infrastructure and tariffs to enable 'better' charging options.	Faster adoption of infrastructure and tariffs to enable 'better' charging options.	Faster adoption of infrastructure and tariffs to enable 'better' charging options.

3.1.1 Extended scenario definitions

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

Table 3-2 Extended scenario definitions

Driver:		Slow change	Central	Fast change	High DER	Step change
Economic						
	Economic growth and population	Low	Moderate	Moderate	Moderate	High
	Cost of solar photovoltaics and battery storage	GenCost 2019-20 Diverse technology scenario	GenCost 2019-20 Central scenario	GenCost 2019-20 High VRE scenario	GenCost 2019-20 High VRE scenario	GenCost 2019-20 High VRE scenario
	Timing of cost[1] parity of short-range electric vehicles with ICE	2035	2030	2025	2025	2025
	Cost of fuel cell vehicles	High	Medium	Low	Low	Low
	NSG solar subsidies available in addition to LGCs	ACCU and VEEC subsidies available and increasing 2% p.a.	ACCU and VEEC subsidies available and increasing 2% p.a.	ACCU and VEEC subsidies available and increasing 2%	ACCU and VEEC subsidies available and increasing 2% p.a.	ACCU and VEEC subsidies available and increasing 3% p.a.

	Rooftop solar schemes (https://www.solar.vic.gov.au/solar-rebates)	Minimum additional uptake of 65,000 p.a. in Victoria to 2029-30	Minimum additional uptake of 65,000 p.a. in Victoria to 2029-30	Minimum additional uptake of 65,000 p.a. in Victoria to 2029-30	Minimum additional uptake of 65,000 p.a. in Victoria to 2029-30	Minimum additional uptake of 65,000 p.a. in Victoria to 2029-30
	Battery storage subsidies	Current state policies in SA, Vic and ACT.	Current state policies in SA, Vic and ACT	Current state policies in SA, Vic and ACT	Current state policies in SA, Vic and ACT extended to national $2000 subsidy	Current state policies in SA, Vic and ACT extended to national $2000 subsidy
Infrastructure						
	Growth in apartment share of dwellings	High	Medium	Low	Low	Low
	Decline in home ownership	High	Medium	Low	Low	Low
	Extent of access to variety of charging options	Low	Medium	High	High	High
Business model						
	Tariff and DER incentive arrangements[2]	No significant change	No significant change	Stronger energy management incentives	Stronger energy management incentives	Stronger energy management incentives
	System architecture changes support greater incentives to DER participation	Low	Medium	High	High	High

Feasibility of ride sharing services	Low	Medium	High	High	High
Feasibility of participation of apartment dwellers and renters in DER	Low	Low	High	High	High
Affordable public charging availability	Low	Medium	High	High	High
Vehicle to home	No	No	No	Yes from 2040	Yes from 2035

1. Upfront sales costs of vehicle, not whole of vehicle running cost. Short range is less than 300km.
2. Time-of-use tariffs are expected to be around 10% of the market by 2030 and these are taken into consideration in addition to more direct control measures such as Virtual Power Plant. See Table 4-3 for details.

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

3.2 Financial and non-financial scenario drivers

3.2.1 Direct economic drivers

Rooftop solar and batteries

Whilst the general buoyancy of the economy is a factor in projecting adoption of small-scale technologies, here we are concerned with the direct financial costs and returns. The key economic drivers which alter the outlook for rooftop solar and battery storage adoption scenarios are shown in Table 3-3.

Table 3-3: Economic drivers of rooftop solar and batteries and approach to including them in scenarios

Driver	Approach to including in scenarios
Any available subsidies or low interest loans	Varied by scenario and outlined in Section 3.2.4 and 3.2.5
Installed cost of rooftop solar and battery storage systems and any additional components such as advanced metering	Varied by scenario and outlined in Section 4.2.1 and 4.2.3
Current and perceived future level of retail electricity prices	Varied by scenario and outlined in Section **Error! Reference source not found.**4.4.1
The level of feed in tariffs (FiTs) which are paid for exports of rooftop solar electricity and wholesale (generation) prices which may influence the future level of FiTs	FiTs varied over time to converge towards generation price which is varied by scenario and outlined in Section 4.4.1
The shape of the customer's load curve	Not varied by scenario but a range of representative customers are included. See Appendix A

Alternative road vehicles

For privately owned electric and fuel cell vehicles the economic drivers and the approach to including them in the scenarios is listed in Table 3-4.

Future hydrogen fuel costs are hard to predict because there is a diversity of possible supply chains, each with their own unique cost structures. Electricity derived hydrogen would probably offer the most flexibility for accessing a low carbon energy source and allowing hydrogen to be generated at either the end-user's location, at fuelling stations or at dedicated centralised facilities.

Table 3-4: Economic drivers of electric and fuel cell vehicles (FCV) and approach to including them in scenarios

Driver	Approach to including in scenarios
The whole cost of driving an electric or fuel cell vehicle including vehicle, retail electricity, the charging terminal (wherever it is installed), hydrogen fuel, insurance, registration and maintenance costs	Vehicle costs vary by scenario and are outlined in Section 4.2.4. Retail electricity prices are varied by scenario and outlined in Section 4.4.1. The remaining factors are held constant.
The whole cost of driving an internal combustion engine (ICE) vehicle as an alternative including vehicle, fuel, insurance, registration and maintenance costs	Not varied by scenario
Perceptions of future changes in petroleum-derived fuel costs including global oil price volatility and any fuel excise changes	Not varied by scenario
The structure of retail electricity prices relating to electric vehicle recharging	Varied by scenario and outlined in 4.9
The perceived vehicle resale value	Not varied by scenario

For autonomous private and ride share vehicles the additional economic drivers compared to electric and fuel cell vehicles and the approach to including them in scenarios is shown in Table 3-5.

Table 3-5: Economic drivers of autonomous private and ride share vehicles and approach to including them in scenarios

Driver	Approach to including in scenarios
The cost of the autonomous driving capability	On-cost of autonomous features not varied by scenario but underlying cost of electric vehicle carried by scenario as outlined in Section 4.2.4
The value of avoided driving time	Not varied by scenario but assumptions discussed in Section 4.2.5
The lower cost of travel from higher utilisation of the ride-share vehicle compared to privately owned vehicles (accounting for some increased trip lengths to join up the routes of multiple passengers)	Not varied by scenario
The avoided cost of wages to the transport company for removing drivers from autonomous trucks	Not varied by scenario but assumptions discussed in Section 4.2.5
Higher utilisation and fuel efficiency associated with autonomous trucks	Not varied by scenario

3.2.2 Infrastructure drivers

Rooftop solar and batteries

One of the key reasons for the already significant adoption of rooftop solar has been its ease of integrating with existing building infrastructure. Battery storage has also been designed to be relatively easily incorporated into existing spaces. However, there are some infrastructure limitations which are relevant over the longer term.

Table 3-6: Infrastructure drivers for rooftop solar and battery systems and approach to including them in scenarios

Driver	Approach to including in scenarios
The quantity of residential or commercial roof space or vacant adjacent land, of varying orientation, ideally free of shading relative to the customer's energy needs (rooftop solar)	Varied by scenario and expressed as maximum market share constraints in Section 4.11
Garage or indoor space, ideally air conditioned, shaded and ventilated (battery storage)	Varied by scenario and expressed as maximum market share constraints in Section 4.11
The quantity of buildings with appropriate roof and indoor space that are owned or mortgaged by the tenant, with an intention to stay at that location (and who therefore would be able to enjoy the benefits of any longer-term payback from solar or integrated solar and storage systems)	Varied by scenario and expressed as maximum market share constraints in Section 4.11
Distribution network constraints imposed on small-scale systems as a result of hosting capacity constraints (e.g. several distribution networks have set rules that new rooftop system sizes may be no larger than 5kW per phase)	Varied by scenario and expressed as maximum rooftop system sizes outlined in Section 4.3
Distribution network constraints relating to connection of solar photovoltaic projects in the 1MW to 30MW range	Not included or varied by scenario due to lack of data
The degree to which the NEM and WEM management of security and reliability begins to place limits on the amount of large- and small-scale variable renewables that can be accepted during peak supply and low demand periods (e.g. to maintain a minimum amount of dispatchable or FCAS serving plant)	Ability to export degrades at a rate of 1% per annum for systems without batteries in all scenarios but each scenario has a unique level of battery uptake
The degree to which solar can be integrated into building structures (flat plate is widely applicable but alternative materials, such as thin film solar, could extend the amount of usable roof space)	Varied by scenario and expressed as maximum market share constraints in Section 4.11

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

Alternative road vehicles

Electric, fuel cell and autonomous ride share vehicles all face the common constraint of a lack of variety of models in the initial phases of supply of those vehicles. While perhaps ride share vehicles can be more generically designed for people moving, purchasers of privately owned vehicles will prefer access to a wider variety of models to meet their needs for the how they use their car (including sport, sedan, SUV, people moving, compact, medium, large, utility, 4WD, towing).

Table 3-7: Infrastructure drivers for electric vehicles and approach to including them in scenarios

Driver	Approach to including in scenarios
Convenient location for a power point or dedicated charging terminal in the home garage or a frequently used daytime parking area for passenger vehicles and at parking or loading areas for business vehicles such as light commercial vehicles, trucks and buses	Varied by scenario and expressed as maximum market share in Section 4.7
Whether the residence or business has ownership or other extended tenancy of the building or site and intention to stay at that location to get a long-term payoff from the upfront costs of installing the charger.	Varied by scenario and expressed as maximum market share in Section 4.7
Convenient access to highway recharging for owners without access to extended range capability (or other options, see below)	Varied by scenario and expressed as maximum market share in Section 4.7
Access to different engine configurations of electric vehicles (e.g. fully electric short range, fully electric long range and plug-in hybrid electric and internal combustion)	Varied by scenario and expressed as maximum market share in Section 4.7
Convenient access to other means of transport such as a second car in the household, ride sharing, train station, airport and hire vehicles for longer range journeys	Varied by scenario and expressed as maximum market share in Section 4.7

Key infrastructure drivers for fuel cell vehicle are varied by scenario as maximum market share assumptions outlined in Section 4.7. The drivers are:

- A mature hydrogen production and distribution supply chain for vehicles. There are many possible production technologies and resources and many ways hydrogen can be distributed with scale being a strong determinant of the most efficient distribution pathway (e.g. trucks at low volumes, pipelines at high volumes).
- The greater availability of fuel cell vehicles for sale.

Sufficient electricity distribution network capacity to meet coincident charging requirements of high electric vehicle share could also be an infrastructure constraint if not well planned for. However, networks are obligated to expand capacity or secure demand management services to meet load where needed and so any such constraints would only be temporary. If hydrogen supply is based on electrolysis this will also mean increased requirements for electricity infrastructure, but its location depends on whether the electrolysis is on site (e.g. at a service station) or centralised (where the location might be a prospective renewable energy zone or fossil fuel resource).

Given the constraints of commute times and cost of land in large cities, we are generally observing a slow trend towards apartments rather than separate dwellings in the capital and large cities where most Australians live. This is expected to result in a lower share of customers with access to their own roof or garage space impacting all types of embedded generation (we define these assumptions later in the report). There has also been recent evidence of a fall in home ownership, especially amongst younger age groups. For electric vehicles these trends might also work towards lower adoption as denser cities tend to encourage greater uptake of non-passenger car transport options and ride sharing services (discussed further in the next section) which result in fewer vehicles sold. Home ownership and separate dwelling share are varied by scenario and outlined in Section 4.6

3.2.3 Disruptive business model drivers

New business models can disrupt economic and infrastructure constraints by changing the conditions under which a customer might consider adopting a technology. Table 3-8 explores some emerging and potential business models which could drive higher adoption. Demand management is an example where there have been trials and rule changes which are the basis of emerging business models which could become more established in the long run. The degree to which these potential business model developments apply by scenario is expressed primarily through their ability to change the maximum market shares for rooftop, solar, batteries and electric, autonomous and fuel cell vehicles as outlined in Sections 4.7, 4.10 and 4.11.

Table 3-8 Emerging or potential disruptive business models to support embedded technology adoption

Name (technology)	Description	Constraint reduced
Building as retailer **(rooftop solar)**	Apartment or shopping centre building body corporate as retailer	Rooftop solar is more suitable for deployment in dwellings which have a separate roof
Peer-to-peer **(rooftop solar)**	Peer-to-peer selling as an alternative to selling to a retailer	Owners may generate more from solar if they could trade directly with a related entity (e.g. landlords and renters, corporation with multiple buildings, families and neighbours) without a retailer distorting price reconciliation
Landlord-tenant intermediary (rooftop solar)	An intermediary (such as the government) sets up an agreement for cost and benefit sharing	Neither the landlord nor tenant are adequately incentivised to adopt solar because neither party can be assured of accessing the full benefits.
Solar exports become a network customer obligation (rooftop solar)	Networks are incentivised through regulatory changes to purchase voltage management services	Network hosting capacity imposes restrictions on rooftop solar uptake through size of connection constraints and financial impact of curtailment (through inverter tripping, even after accounting for improved inverter standards)
Zero upfront solar **(rooftop solar)**	No money down or zero interest loans for rooftop solar	While costs have fallen, rooftop solar still represents a moderately expensive upfront cost for households and businesses with limited cash flow or debt appetite.
Virtual power plant **(battery storage)**	Retailers, networks or an independent market operator reward demand management through direct payments, alternative tariff structures or	Given the predominance of volume-based tariffs, the main value for customers of battery storage is in reducing rooftop solar exports. The appetite for

	direct ownership and operation of battery to reduce costs elsewhere in the system	demand management participation could be more directly targeted than current incentives.
Going off-grid **(Integrated rooftop solar with storage and petroleum fuel generator)**	Standalone power system is delivered at lower cost than new distribution level connections greater than 1km from existing grid	Except for remote area power systems, it is cost effective to connect all other customers to the grid
Going off-grid and green (Integrated rooftop solar with storage and non-petroleum fuel solution)	Energy service companies sell suburban off-grid solar and battery systems plus a non-petroleum back-up system yet to be identified but suitable for suburban areas	Except for remote area power systems, it is cost effective to connect all other customers to the grid
Solar/battery new housing packages **(Integrated rooftop solar with storage)**	New housing developments include integrated solar and batteries on new housing as both a branding tool and to reduce distribution network connection costs	Integrated solar and battery systems represent a discretionary and high upfront cost for new homeowners
Affordable public charging (electric vehicles)	Ubiquitous public charging is provided cost effectively	Low cost access to electric vehicle charging will be primarily at the home or business owner’s premises
Charging into the solar period (electric vehicles and rooftop solar)	Businesses offer daytime parking with low cost-controlled charging and provide voltage control services to the network in high solar uptake areas	Electric vehicle charging will be primarily at home and overnight, poorly matched with solar which receives low FiTs and may be shut off by inverter due to voltage variation in high solar uptake areas
Vehicle battery second life (electric vehicles and battery storage)	Electric vehicle batteries are sold as low-cost home batteries as a second life application	Battery storage represents a high upfront cost and discretionary investment.

Autonomous ride-share vehicles **(electric vehicles)**[1]	Ride sharing services which utilise autonomous vehicles could result in business-led electric vehicle uptake achieving very high vehicle utilisation and lower whole of life transport costs per kilometre	Electric vehicles will be predominantly used for private purposes by the vehicle owner and the return on their investment will be governed by that user's travel patterns.
Vehicle to home **(electric vehicles)**	Electric vehicles are coupled with an in-garage inverter system to provide the role of a stationary battery when at home. This aligns well with public charging during high solar generation periods.	Battery storage represents a high upfront cost and discretionary investment. Using the battery capacity in your electric vehicle for home energy management would be complicated to setup and may void equipment warranties which were designed for isolated operation
Hydrogen economy **(fuel cell vehicles)**	Australia becomes a major hydrogen exporter and this supports some economies of scale in domestic supply of hydrogen for fuel cell vehicles	Fuel cell vehicle distribution infrastructure is not established and will involve a high upfront cost for a business investor.
Collapse of ICE business model	Sales of ICE vehicles fall to a level such that ICE oriented businesses (petroleum fuel supply, vehicle maintenance) lose economies of scale	A "laggard" group of customers choose to continue to preference ICE vehicles so long as they are no too much higher cost to own than electric or fuel cell vehicles.

1 While increasing the kilometres travelled via electric vehicles, this may potentially reduce the number of electric vehicles overall since this business model involves fewer cars but with each car delivering more kilometres per vehicle.

3.2.4 Commonwealth policy drivers

There are a variety of commonwealth policy drivers which impact solar, battery and electric vehicle adoption. We outline how we have chosen to include them in and describe them in further detail below.

Table 3-9: Summary of Commonwealth policies and their inclusion in scenarios

Small-scale renewable energy scheme	Assume to continue as planned to 2030 in all scenarios
Large scale renewable energy target	Assumed to continue as planned with significantly lower prices due to scheme saturation in all scenarios
Emission reduction fund and Climate solutions fund	Price of emission credits grows at 2% per annum in all scenarios except step change where it grows 3% per annum.
New policies (not currently government policy)	It is assumed that a subsidy for batteries becomes available by 2022 of $2000 in High DER and Step change.

Small-scale Renewable Energy Scheme and Large-scale Renewable Energy Target

Rooftop solar currently receives a subsidy under the Small-scale Renewable Energy Scheme whereby rooftop solar is credited with creating small scale technology certificates (STCs) which Renewable Energy Target (RET) liable entities have a legal obligation to buy. Rooftop solar purchases typically surrender their rights to these certificates in return for a lower upfront cost. The amount of STCs accredited is calculated, using a formula that recognises location/climate, based on the renewable electricity generation that will occur over the life of the installation. The amount of STCs accredited to rooftop solar installation will decline over time to reflect the fact that the Renewable Energy Target policy closes in 2030 and therefore renewable electricity generated beyond that time is of no value in the scheme.

STCs can be sold to the Clean Energy Regulator (CER) through the STC Clearing House for $40 each. However, the CER makes no guarantees about how quickly a sale will occur. Consequently, most STCs are sold at a small discount directly to liable entities on the STC open market.

The Large-scale Renewable Energy Target (LRET) is a requirement on retailers to purchase large-scale generation certificates (LGCs). This represents a subsidy for large scale renewable generation but is relevant for any solar system above 100kW as they are not eligible for STCs. In this report we are interested in any solar system up to 30MW, hence the price of LGCs is a relevant driver for adoption. The requirements for the LRET are largely met within existing and under construction plant as the target currently plateaus in 2020 and remains at that level until 2030. Consequently, the LGC price is expected to decline to low levels in the next few years.

Emissions Reduction Fund and Climate Solutions Fund

The Emissions Reduction Fund (ERF) has been extended by the Climate Solutions Fund announced in 2019. The ERF consists of several methods for emission reduction under which projects may be eligible to claim emission reduction and bid for Australian Carbon Credit Units (ACCUs) which are currently awarded via auction at around \$15/tCO_2e. The relevant method in this case is the *Carbon Credits (Carbon Farming Initiative - Industrial Electricity and Fuel Efficiency) Methodology Determination 2015*. As the price of LGCs declines it may become more attractive to seek ACCUs under this method rather than LGC payments. Although we might expect the ACCU price to increase over time, they are not expected to provide as strong a signal as LGC prices have been in the past – more in the order of a \$10/MWh subsidy compared to almost \$90/MWh for LGCs at their peak.

Potential changes to Commonwealth renewable energy and climate policy

While there are currently no announced changes to renewable energy and climate policy, given Australia's nationally determined commitment at the Paris UNFCCC meeting, there may be future adjustments to those policies. At this stage, given the lack of bi-partisan support for price-based policies, any new policies are more likely to take the form of direct actions such as auctions and lower interest finance of renewable and storage capacity. In particular, batteries have a higher payback period and so might be targeted by more subsidies by future governments. To deliver the expected higher deployment of batteries consistent with the High DER and Step change scenarios we have assumed a \$2000 subsidy is available from 2022.

Low emission road vehicles policy

Australia is one of the few developed countries without vehicle greenhouse gas emission or fuel economy standards. Consequently, vehicles sold in Australia are generally 20% less efficient than the same model sold in the UK (CCA 2014). Low emission vehicles such as electric vehicles are expected to be adopted with or without emission standards, but new policies could accelerate their adoption. There is currently no commonwealth fuel excise on electricity or hydrogen used in transport. There is currently a process for developing a national electric vehicle strategy.

3.2.5 State policy drivers

Policies supporting rooftop, larger scale solar and batteries

The policies discussed here are drawn from several state government websites[4]. While we summarise them all for completeness, we do not include each one in the modelling. The approach to including them in the scenarios is outlined in Table 3-10.

Queensland and Victoria have policies that will work in addition to the Commonwealth RET. They are the Victorian Renewable Energy Target (VRET) and Queensland Renewable Energy Target (QRET). Under current auction arrangements, VRET is only open to renewable generators above 10MW which is relevant for some small-scale solar but not rooftop solar. Although technically

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[4] https://energy.nsw.gov.au/renewables/clean-energy-initiatives/empowering-homes

https://www.solar.vic.gov.au/solar-rebates

https://homebatteryscheme.sa.gov.au/

https://www.qld.gov.au/community/cost-of-living-support/concessions/energy-concessions/solar-battery-rebate

https://www.environment.act.gov.au/energy/cleaner-energy/next-generation-renewables eligible, we do not expect either of these schemes to be available in practice to non-scheduled generation below 30MW because they will be less competitive than larger scale solar farms.

The Victorian government is providing a subsidy of half the cost of solar (up to a value of $1,888) to 63,416 homes in 2018-19 including means-tested interest free loans. Another feature is a landlord-tenant agreement whereby renters can also access the scheme. The longer-term target is for 650,000 home solar systems over ten years (Victorian premier, 2018).

Victorian solar projects are also eligible for Victorian Energy Efficiency Certificates (VEECs). These are administratively less complex than applying for ACCUs and the price of VEECs is currently more attractive at around $30/tCO_2e. As with the emissions reduction fund, this potential subsidy source will become attractive only once LGC prices have declined further.

The Queensland government accepted a recommendation to not include any incentives under the QRET for rooftop solar in addition to the Commonwealth Small-scale Renewable Energy Scheme. However, Queensland did provide zero interest loans scheme for rooftop solar and batteries and grants for battery systems. This scheme closed in June 2019.

The NSW policy is to provide interest-free loans of up to $9,000 for a rooftop solar and up to $14,000 for solar plus storage through a 10-year Empowering Homes program that will target up to 300,000 households. Eligible households must be owner-occupiers and have an annual household income of up to $180,000 (NSW government, 2020). The program is being piloted for 12 months in 2020 and so may not be available state-wide until 2021. The NSW government also has an existing scheme providing 3000 3kW solar systems to low income groups already receiving the Low Income Household Rebate.

There are also a few state subsidy schemes directly targeting batteries. The South Australia government has a policy of providing subsidies to 40,000 homes to install batteries. The subsidy will be scaled with the size of the battery and capped at $6000. It is being delivered in collaboration with the CEFC. A set of minimum technical requirements for battery systems has been developed to ensure the batteries are capable of being recruited into virtual power plant (VPP) schemes. The Victorian government's Solar Homes policy also includes battery subsidies for up to 10,000 homes (Victorian premier, 2018). In 2019-20 there are 1000 rebates available of up to $4,838. The ACT government is making available an $825/kW subsidy targeting deployment of 5000 batteries under its Next Generation Energy Storage scheme.

Table 3-10: Summary of state policies supporting solar and batteries and their inclusion in scenarios

	Policy	
NSW	Interest-free loans of up to $9,000 for a rooftop solar and up to $14,000 for solar plus storage through a 10-year Empowering Homes program that will target up to 300,000 households. Eligible households must be owner-occupiers and have an annual household income of up to $180,000	Not included. Assumed that low interest load funds non-additional activity since the benefit of avoided interest is not large enough to be the original motivation
NSW	3000 3kW solar systems to low income groups already receiving the Low Income Household Rebate	Not included. Assumed non-additional design is targeted at customers already receiving bill relief.
VIC	Renewable energy target of 50% by 2030	Not included. These subsidies are not targeted at small scale solar PV.
VIC	650,000 home solar systems over ten years. Policies include a subsidy of half the cost of solar (up to a value of $1,888) to 63,416 homes in 2018-19 including means-tested interest free loans. Another feature is a landlord-tenant agreement whereby renters can also access the scheme.	Minimum addition of 65,000 residential solar systems per year from 2019-20 to 2029-30 applied across all scenarios
VIC	The Solar Homes policy includes battery subsidies for up to 10,000 homes (Victorian premier, 2018). In 2019-20 there are 1000 rebates available of up to $4,838.	Minimum addition of 1,000 residential battery systems per year from 2019-20 to 2029-30 applied across all scenarios
QLD	Renewable energy target of 50% by 2030	Not included. These subsidies are not targeted at small scale solar PV.
SA	Subsidies are to be provided to 40,000 homes to install batteries. The subsidy will be scaled with the size of the battery and capped at $6000.	Minimum addition of 40,000 residential batteries by 2020-21 applied across all scenarios
ACT	The ACT government is making available an $825/kW subsidy targeting deployment of 5000 batteries under it Next Generation Energy Storage scheme.	Minimum addition of 5000 batteries by 2023 applied across all scenarios
All	State feed-in tariffs	Varied over time to converge towards generation price which is varied by scenario and outlined in Section 4.4.1

Low emission vehicles

Victoria provides a $100 discount on annual registration fees for electric vehicles. This represents an ongoing subsidy of electric vehicles relative to other vehicle types. Other states offer similar policies including stamp duty discounts. The Australian Capital Territory's policy offers the greatest financial incentive. Average environmental performance vehicles at or below $45,000 are normally subject to 3% stamp duty. A 5% stamp duty is applicable for each dollar above $45,000. Electric vehicles registered for the first time are exempt from this stamp duty. This application of different stamp duty rates to new vehicles is an approach unique to the Australian Capital Territory. It amounts to an upfront subsidy of $1350 on a $45,000 electric vehicle or $2110 on a $60,000 electric vehicle.

Some states are actively contributing to deployment of more electric vehicle charging infrastructure (e.g. Queensland) while in other cases this is being delivered by non-government parties.

Feed-in tariffs

Feed-in tariffs (FiTs) were historically provided by most state governments to support rooftop solar adoption but have largely been replaced by voluntary retailer set FiTs for new solar customers. These legacy FiTs are in most cases still being received by those customers who took them up when they were available.

The current FiTs set by retailers recognises some combination of the value of the exported solar electricity to the retailer and the value to the retailer of retaining a rooftop solar customer. Retailer set FITs vary mostly in the range of 7-12 c/kWh across most states. While not calculated directly via this formula, this FiT level is close to the average generation price over a year. While there is retail competition in Northern Territory it is worth noting that FiTs are substantially higher in this region, equivalent to the retail price of electricity which is around 25c/kWh to 30c/kWh (depending on customer type).

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

- Queensland: Recognising lower competition, regional Queensland FiTs are set by the state government and were 7.842c/kWh from July 2019.
- Western Australia: Only applicable to residential, non-profit and educational premises the Renewable Energy Buyback Scheme pays a FiT of 7.135c/kWh in the SWIS.
- Victoria: the current minimum feed-in tariff of 12c/kWh is set by the government. It applies to retailers with more than 5000 customers and generation from any renewable energy less than 100kW. A time varying feed-in rate is also available from July 2019 with prices between 9.9 and 14.6c/kWh during off-peak and peak respectively and the daytime feed-in tariff at 11.6c/kWh.
- Tasmania: the feed-in tariff for residential and commercial customers is 9.347c/kWh from July 2019.

While not binding on retailors, the NSW government has called on NSW energy retailers to offer solar customers feed-in tariffs that meet a benchmark set by the Independent Pricing and Regulatory Tribunal (IPART). The benchmark range for the 2019/20 financial year is 8.5 to 10.4 cents per kilowatt hour.

3.2.6 Regulations and standards

Under the current electricity laws the Australian Energy Market Commission (AEMC) can make changes to regulations which are consistent with the goals set out in those laws. There is a general recognition that the electricity market rules were written at a time that did not envisage such a large and competitive role for distributed energy resources. The current customer obligations placed on networks are focussed on reliability of supply and power quality. There is no explicit statement to ensure that customers with rooftop solar can export their excess generation although this does intersect with power quality requirements. If too many embedded solar systems try to export generation relative to local demand, then voltage rises. Inverters are set to trip off solar generation once voltage exceeds the set point. This then reduces the returns to customers from owning rooftop solar.

Improved inverter standards are somewhat reducing the occurrence of voltage issues associated with high rooftop solar exports onto the local distribution network. Currently installed inverters provide reactive power which limits the impact of exports on voltage. However, if rooftop solar penetration is very high (the exact limit depends on the type of feeder), the improved inverters will be unable continually prevent voltage changes that result in inverter trip off. Also, reactive power uses 20% of the available real power and so still represents an impact on rooftop solar customer returns from lack of distribution network capacity.

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

Given the difficulty of predicting the electricity system reform process and subsequent impacts on customers, we have made no assumptions about the degree of lost solar production and exports as a result of distribution network congestion or efforts to manage state loads for stability.

4 Data assumptions

This section outlines the key data assumptions applied to implement the scenarios. Some additional data assumptions which are used in all scenarios are described in Appendix A.

4.1 COVID-19 impacts

Table 4-1: Assumed impact of COVID-19

Scenario	Period	Change in installations/sales relative to trend		Comment/rationale
		Residential	Commercial	
Rooftop solar PV & batteries				
Slow change	Q4 2019-20	-65%	-75%	Most planned installations are cancelled, deposit or not
	Q1 2020-21	-65%	-75%	Lack of interest continues because of persistent bans on economic activity and virus second round
	Remainder to June 2021-22	-10%	-20%	Slow recovery due to persistence of virus and economic impacts
Central, Fast change and High DER	Q4 2019-20	-50%	-60%	Some of planned installations are cancelled, deposit or not
	Q1 2020-21	-40%	-50%	Post-virus peak sees some recovery relative to trend
	Remainder to June 2021-22	-5%	-10%	Slight persistence of economic impacts
Step change	Q4 2019-20	-40%	-50%	Some of planned installations are cancelled, deposit or not
	Q1 2020-21	-30%	-40%	Post-virus peak sees some recovery relative to trend
	Remainder to June 2021-22	0%	0%	No persistence of economic impacts
Electric vehicles				
Slow change	Q4 2019-20	-10%	-15%	Most orders (established up to year earlier) go ahead
	Q1 2020-21	-75%	-85%	Peak of sales impacts, strong decline
	Remainder to June 2021-22	-10%	-20%	Slow recovery due to persistence of virus and economic impacts
Central, Fast change and High DER	Q4 2019-20	-5%	-10%	Marginal impact due to orders delay
	Q1 2020-21	-60%	-50%	Peak of sales impacts, medium-strong decline
	Remainder to June 2021-22	-5%	-10%	Slight persistence of economic impacts
Step change	Q4 2019-20	-5%	-10%	Marginal impact due to orders delay
	Q1 2020-21	-40%	-50%	Peak of sales impacts, medium decline
	Remainder to June 2021-22	0%	5%	Little to no persistence of economic impacts

In the methodology discussion, in Section 2, we outlined several observations about the way in which the COVID-19 pandemic was impacting the economy and employment and the likely impacts on the distributed energy resources market that would flow from those drivers. In Table 4-1 we provide the assumed percentage impact by quarter as a percentage relative to the trend that would otherwise have been projected over the period June 2019-20 to June 2021-22. The data assumptions were based on the following considerations

- The impacts are likely to last for a minimum two quarters: Q4 2019-20 and Q1 2020-21.
- The current quarter, Q4, is probably the deepest impact since the delay in access to government wage or business support schemes will have immediately cancelled plans for non-essential expenditure, unless the persistence of orders created in Q3 sustains deployments.
- Once income support begins in a real material way, there will still be the uncertainty whether normal sources of income will resume and whether that resumption will be smooth or with gaps or reductions. A second wave of virus cases would make Q1 worse. But, alternatively, we could see a sustained improvement. This uncertainty in timing would be appropriate to spread across scenarios.
- Businesses may be impacted more strongly than households since households are notionally more diversified (there will be at least some household with a partner may work in a different industry but notwithstanding a fast shift in business models, some services sectors are 100% exposed). Households also have a better chance of having a larger portion of their lost income replaced by government payments.

4.2 Technology costs

4.2.1 Solar photovoltaic panels and installation

The costs of installed rooftop or small-scale solar installations for each scenario is shown in Figure 4-1 and was sourced from the draft GenCost 2019-20 report by Graham at al. (2019). The Central scenario is assigned the equivalent GenCost Central scenario. The Slow change scenario is assigned a slower cost reduction rate by applying the Diverse Technology GenCost scenario. Finally, the Fast change, High DER and Step change are assigned the fastest cost reduction by applying the High VRE GenCost scenario.

Note that costs shown imply that a 5kW system ought to be advertised for approximately $6000. However, we more commonly see systems advertised in the range of $3600-$4000 installed reflecting that the value of small-scale certificates, which are around $450-550/kW depending on the location. They have been subtracted from the price with the intent that owners will give up their rights to claim them to the installer in return for a discount on the upfront cost.

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

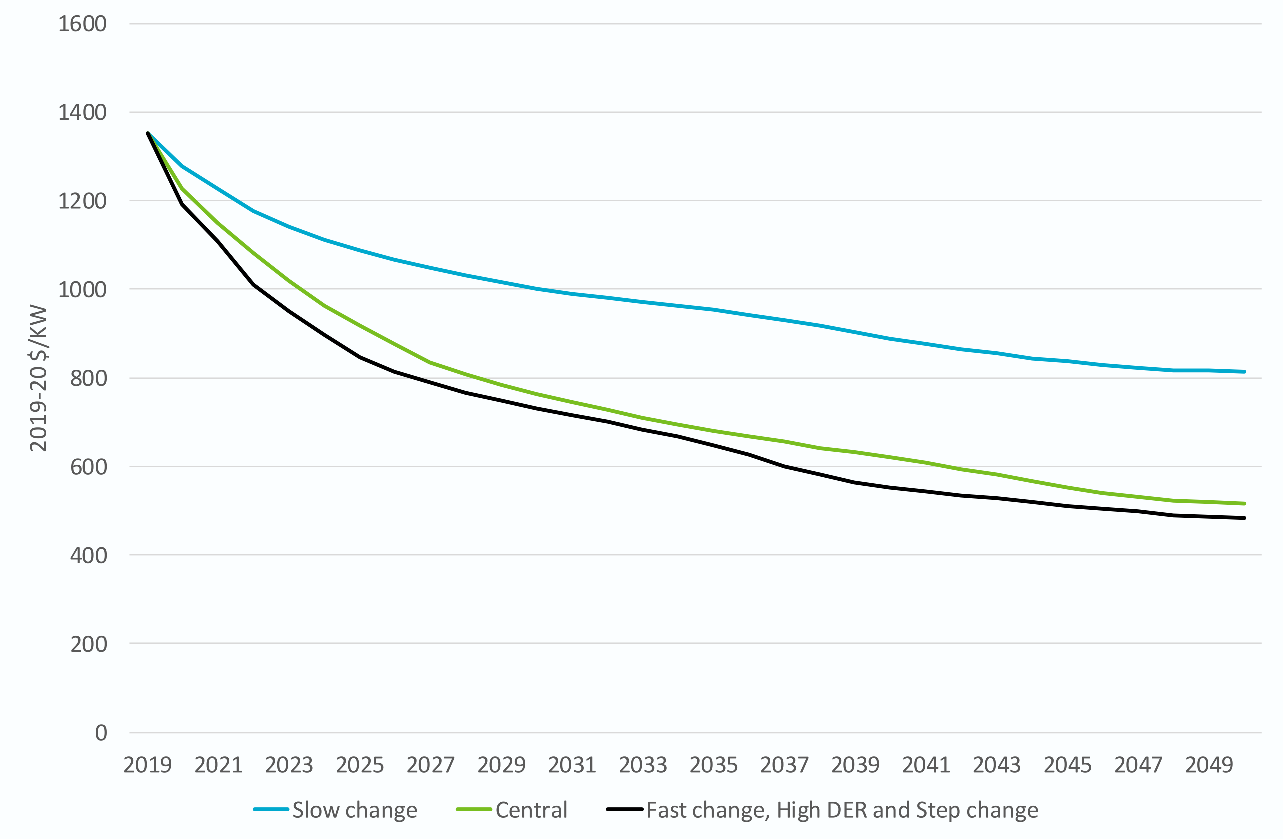


Figure 4-1 Assumed capital costs for rooftop and small-scale solar installations by scenario (excluding STCs or other subsidies)

4.2.2 Small-scale technology certificates (STCs)

STCs reduce the upfront cost of rooftop solar systems beyond that shown in Figure 4-1. While there is the option to sell to the STC Clearing House for $40/MWh, the value of STCs is largely determined on the open market and vary according to demand and supply for certificates. The number of certificates generated depends roughly on the solar capacity factor in different states although this calculation is not spatially detailed (i.e. involves some significant averaging across large areas). Solar generation is calculated over the lifetime, but any life beyond 2030 is not counted as it is beyond the scheme period. Over time the eligible solar generation is declining. Multiplying the eligible rooftop solar generation by the STC price gives the projected STC subsidy by state shown in Figure 4-2. These STC subsidies are assumed to prevail across all scenarios.

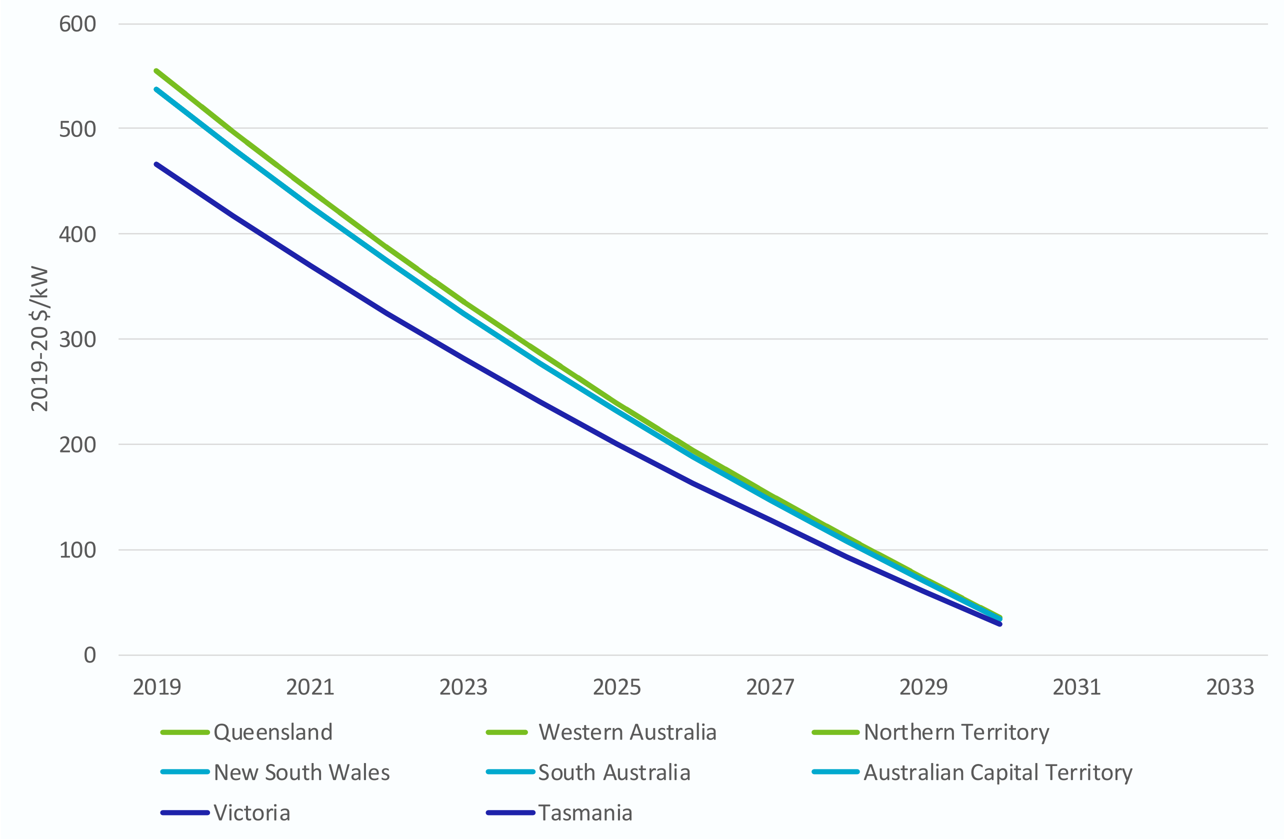


Figure 4-2 Assumed STC subsidy available to rooftop solar and small-scale solar systems by state

4.2.3 Batteries and installation

The Central scenario battery and balance of plant costs are assumed to align with GenCost 2019-20 Central scenario. These are upfront costs and do not take account of degradation or cost of disposal at end of life. End of life and degradation assumptions are included in the modelling and are outlined in Appendix A. King et al. (2018) found that only 2% of lithium-ion batteries were collected for offshore recycling compared to 98% of lead acid batteries. Given the infancy of the waste disposal and recycling systems for lithium-ion we make no assumptions about this topic.

GenCost 2019-20 projects steady cost reductions to 2025 after which cost reductions accelerate with increased global battery production and after 2030 slow to a near flat trend. Inverters are the largest balance of plant cost. Other elements of balance of system are system integration and installation. The Slow change scenario is assumed to be higher cost consistent with the GenCost Diverse technology scenario. For Fast change, High DER and Step Change, battery and balance of plant costs are assumed to be 20% lower than Central are presented in Figure 4-3.

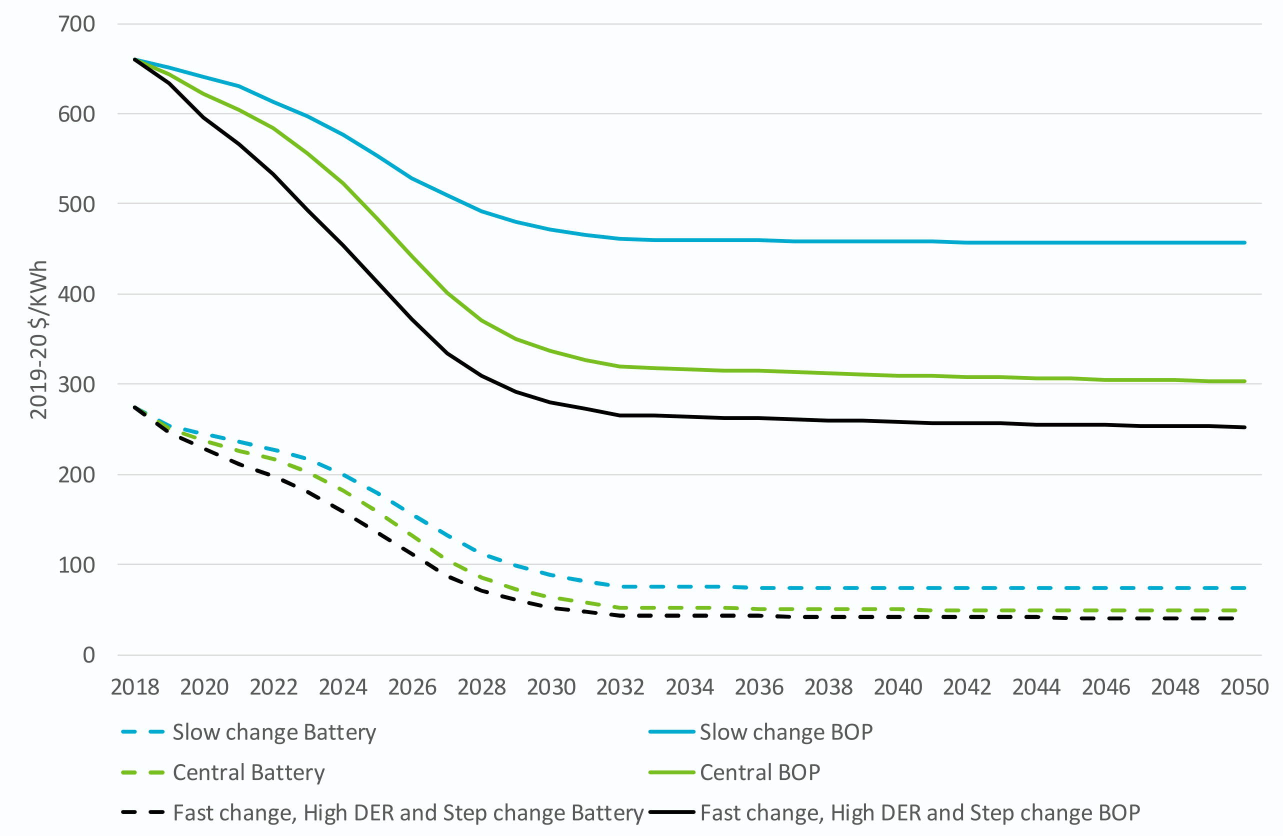


Figure 4-3 Assumed capital costs for battery storage installations by scenario

4.2.4 Electric and fuel cell vehicles

Central scenario short-range electric vehicle (SREV) costs are assumed to reach upfront cost of vehicle parity with internal combustion engine light vehicles in 2030 and remain at that level thereafter (Table 4-2). Heavy SREVS are assumed to reach parity ten years later due to their delayed development relative to light vehicles and higher duty requirements (both load and distance). Parity may be reached earlier in other countries where vehicle emissions standards are expected to increase the cost of internal combustion vehicles over time.

We consider SREV adoption across five vehicle classes: light, medium and large cars, rigid trucks and buses. Long-range electric vehicles (LREVs) also include larger articulated trucks which perform the bulk of long-distance road freight. The costs of LREVs do not reach vehicle cost parity because their extra range adds around $5000 in battery costs to light vehicles (and proportionally more to heavy vehicles). However, from a total cost of driving perspective (i.e. $/km), they are still lower cost than internal combustion vehicles over their life, paying back the additional upfront cost through fuel savings within 2-3 years.

We do not consider applying a plug-in hybrid engine configuration to the small light vehicle class as these vehicles are already efficient so the additional cost would be difficult to pay back with limited additional fuel savings.

The Slow change, Fast change, High DER and Step change scenario assumptions are framed relative to these Central scenario assumptions. In the Slow change scenario, we assume that the cost reductions are delayed by 5 years. In the Fast change, High DER and Step change scenarios we assume the cost reductions are brought forward by 5 years.

Table 4-2 Moderate scenario internal combustion and electric vehicle cost assumptions, real 2019 $'000

	2020	2025	2030	2035	2040	2045	2050
Internal combustion engine							
Light/small car - petrol	15	15	15	15	15	15	15
Medium car - petrol	25	25	25	25	25	25	25
Large/heavy car - petrol	41	41	41	41	41	41	41
Rigid trick - diesel	61	61	61	61	61	61	61
Articulated truck - diesel	300	300	300	300	300	300	300
Bus - diesel	180	180	180	180	180	180	180
Electric vehicle short range							
Light/small	27	21	15	15	15	15	15
Medium	47	36	25	25	25	25	25
Large/heavy	65	53	41	41	41	41	41
Rigid truck	104	92	80	70	61	61	61
Bus	269	246	223	200	180	180	180
Electric vehicle long range							
Light/small	39	28	20	20	20	20	20
Medium	59	42	30	30	30	30	30
Large/heavy	80	61	46	46	46	46	46
Rigid truck	143	125	109	95	83	82	81
Articulated truck	901	694	535	468	410	404	400
Bus	310	279	252	227	204	203	202
Plug-in hybrid electric vehicle							
Medium car - petrol	37	35	33	33	33	33	33
Large/heavy car- petrol	58	53	49	49	49	49	49
Rigid truck – diesel	N.A.	122	81	81	81	81	81
Articulated truck - diesel	N.A.	606	396	396	396	396	396
Fuel cell vehicle							
Light/small	45	35	32	27	24	22	22
Medium	50	41	37	33	30	29	28
Large/heavy	62	51	48	43	40	38	37
Rigid truck	112	96	84	77	71	70	68
Articulated truck	558	479	419	385	357	350	342
Bus	242	221	207	199	192	190	188

Given that fuel cell and electric vehicles have significantly fewer parts than internal combustion engines it could also have been reasonable to consider their costs reaching lower than parity with internal combustion vehicles. However, in the context of the adoption projection methodology applied here, when the upfront price of an electric vehicle equals the upfront price of an equivalent internal combustion vehicle, the payback period is already zero in the sense that there is no additional upfront cost to recover through fuel savings. After this point, adoption is largely driven by non-financial considerations. Also, we considered vehicle manufacturers might continue to offer other value-adding features to the vehicle if this point is reached rather than continue reducing vehicle prices (e.g. luxury, information technology and sport features).

4.2.5 Autonomous vehicle costs and value

BCG (2015) conducted expert and consumer interviews establishing that an autonomous vehicle (AV) would have a premium of around $15,000 and that customers would be willing to pay a premium of around $5000 to own a fully autonomous road passenger vehicle. This last point seems to align well with the concept of valuing people's time saved in transport studies. If commuting via an autonomous vehicle gives back 1 hour of time for other activities per working day and we value that at around $20/hr (slightly more than average earnings), then its value over 235 working days (assuming 5 weeks leave) is $4700 per year.

KPMG (2018) use a value of 20% for the AV cost premium which would be $3,000 to $8,200 for the standard passenger vehicle types used in our modelling. We interpret their costing approach to be focussed on a larger vehicle and longer-term point of view (i.e. not a first of a kind vehicle). This matches the expectation that the autonomous vehicles would initially be targeted towards the larger less-budget conscious end of the market.

Based on these studies, we assume AVs have a premium starting at $10,000 decreasing to $7,500 by 2030 and remaining at that level. Given how consumers value time, significant cost reductions beyond those assumed will not be necessary to support growth in adoption. However, we assume the vehicles will not be available for adoption until the late 2020s.

For freight vehicles, the major value from AVs are fuel consumption savings through platooning, resting drivers so they can complete longer trips without a break or, if technically feasible, completely removing the driver. In removing the driver, the wages costs are avoided which are on average around $75,000 per annum while also increasing truck utilisation. Our assumption is that AV truck premiums will be significantly higher (proportionate to the ratio of truck to passenger car costs) owing to the greater complications of a larger vehicle under load in terms of reaction times for autonomous systems and the requirement of better sensing. However, if these vehicles can achieve full autonomy, the financial incentives are significant.

These assumptions set the economic foundation for AVs which is an important driver for adoption. The adoption of AVs, particularly those with ride share capability in the passenger segment, results in changes in the required size of vehicle fleet and sales which can have secondary impacts on the adoption of all vehicles. These issues are discussed further in Section 4.10.

4.3 Solar system sizes

Assumed new residential and commercial solar panel sizes as shown in Figure 4-4. We impose a trend in the next two years and then impose different assumptions by scenario to 2050. For business customers, while we impose an average, we assume that they match their solar systems to meet their average daily peak load since this strategy would appear to be most financially rewarding. As such we do not expect a large change in commercial system sizes across the scenarios, only a slight increase over time in the Central scenario with the other scenarios varying around that.

Residential rooftop solar systems have been advertised with higher panel to inverter capacity ratios recently. This likely reflects the fact that subsidies are available on rooftop solar capacity. Licensing conditions for installers require that the inverter is no less than 75% capacity of the solar panels. Hence, we commonly see offers for 6.6kW solar with a 5kW inverter[5]. Another limiting factor is that many networks impose a connection limit of 5kW per phase. Many homes have more than one phase, so this is not a hard limit but rather a consideration. Subsidies per watt of solar power capacity are declining (see discussion of STCs in the body of the report) and being replaced with rebates or low interest loans. Based on these drivers, we assume the recent increasing system size trend will continue for several years but ultimately saturate in the long run in the residential sector reflecting limits to the number of households with more than one or two phases and general tightening of network connection limits. Physical roof size is of course another ultimate limit to system size. However, we expect that with lower solar panel costs, acceptance of the use of non-north facing roof areas will continue to grow. We vary this system size saturation level across the scenarios as shown in Figure 4-4.

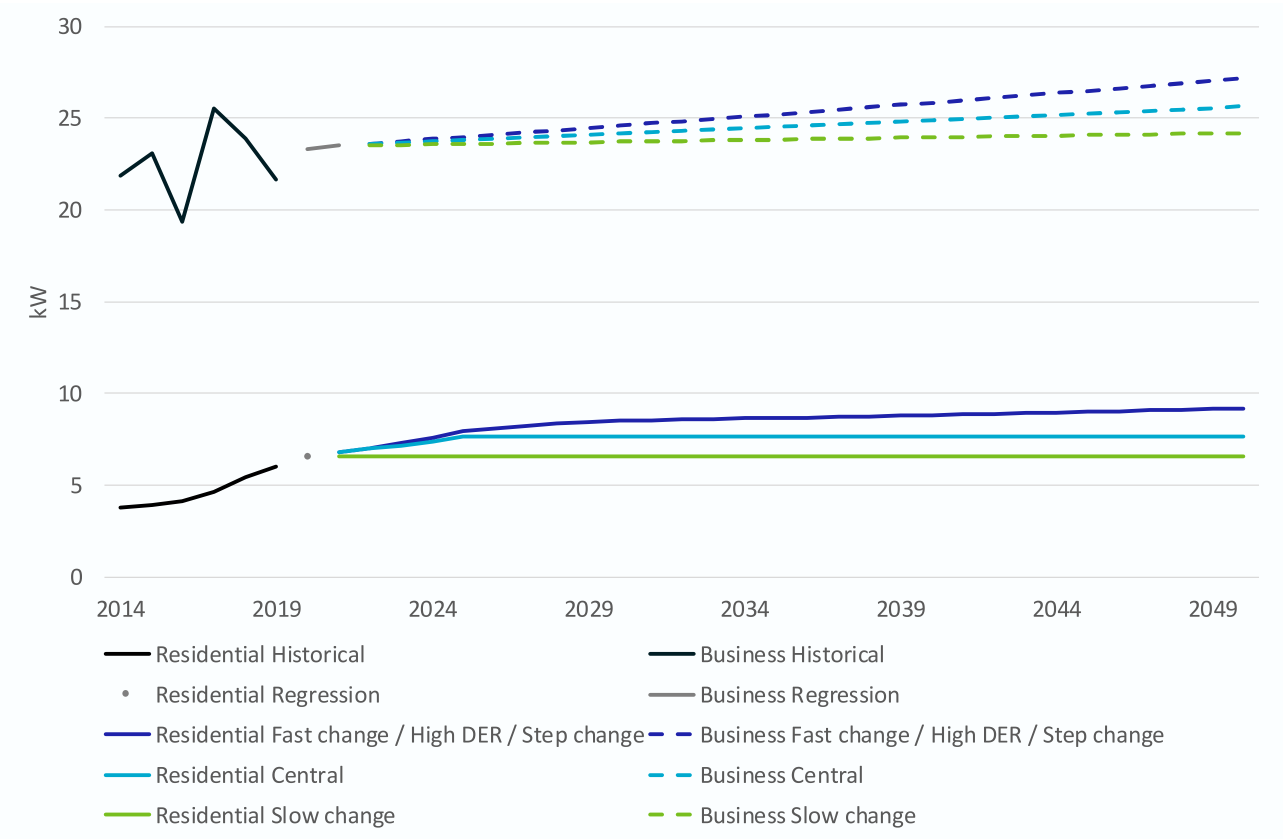


Figure 4-4: Historical and assumed future size of new residential and commercial solar systems

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

4.4 Electricity tariffs, battery management and virtual power plants

4.4.1 Assumed trends in retail and generation prices

Broadly speaking electricity generation prices are expected to fall in the next few years as a major expansion in renewable generation capacity is delivered. However, over the long term, prices are expected to rise again due to retirement of plant with low marginal costs (i.e. sunk capital) and the need to incorporate more balancing technologies such as storage as variable renewable shares approach 50% in several states. Offsetting this is the long-term decline in costs of variable renewables, so price increases are expected to be modest. AEMO provided generation price data which matched these broad drivers and is shown in Figure 4-5 for the Central, High DER and Fast Change scenarios. Generation prices are slightly higher in the Step change scenario and slightly lower in the Slow change scenario but have the same underlying trends.

Assumed changes in residential retail prices under all scenarios also follow this assumed falling and then slightly increasing trend but muted by additional stable elements in the retail price such as distribution and retailing costs. Retail electricity prices in Western Australia and Northern Territory are set by government and are therefore less volatile. Commercial retail prices are assumed to follow residential retail price trends for all scenarios, although under different tariff structures (Table 4-3).

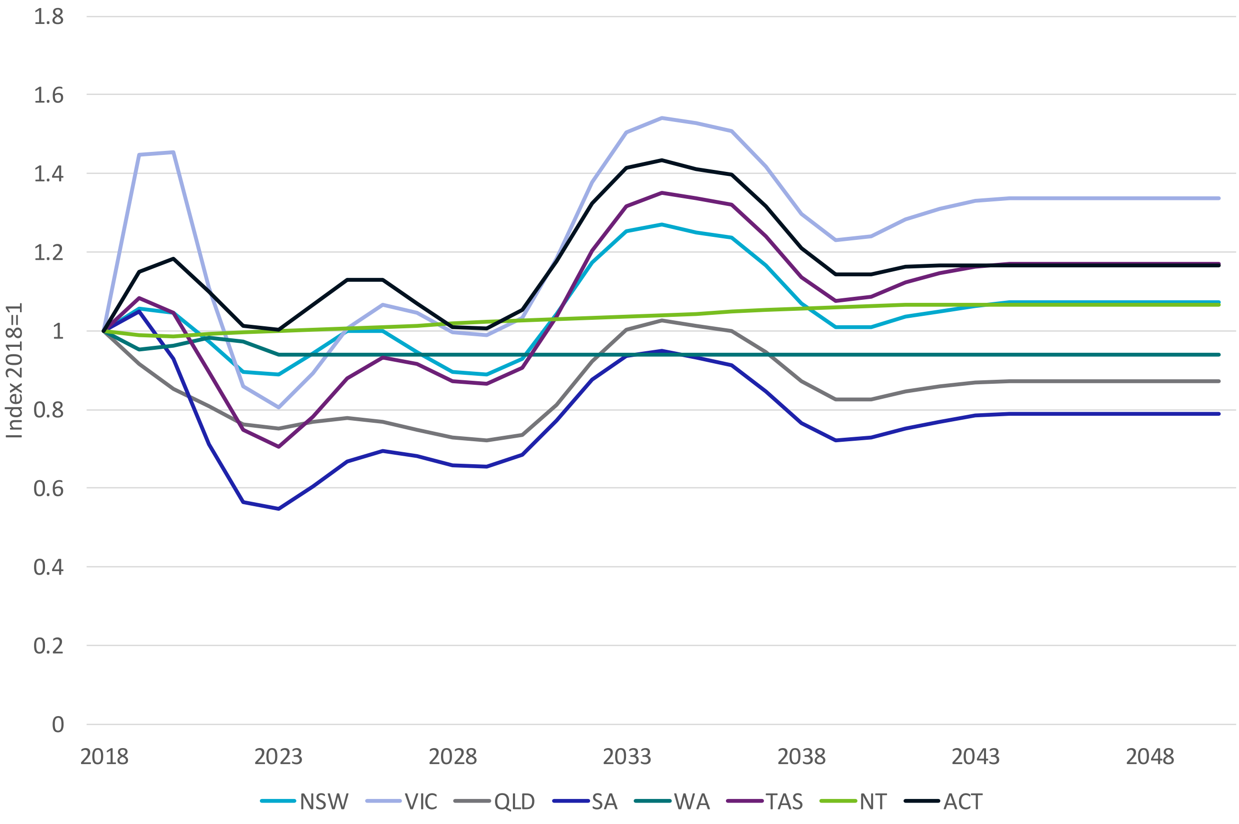


Figure 4-5: Index of regional electricity prices in the Central, Fast change and High DER scenarios, Source: AEMO

4.4.2 Current electricity tariff status

Electricity tariff structures are important in determining the return on investment from customer adoption of small-scale embedded technologies and, perhaps importantly for the electricity system, how they operate those technologies. The vast majority of residential and some small-scale business customers have what is called a 'flat' tariff structure which consists of a daily charge of $0.80 to $1.20 per day and a fee of approximately 20 to 30c for each kWh of electricity consumed regardless of the time of day or season of the year. Customers with rooftop solar will have an additional element which is the feed-in tariff rate for solar exports. Customers in some states have an additional discounted 'controlled load' rate which is typically connected to hot water systems.

Except where flat tariffs are available to smaller businesses, in general, business customers generally face one of two tariff structures: 'time-of-use' (TOU) or 'demand' tariffs. In addition to a daily charge, TOU tariffs specify different per kWh rates for different times of day. Demand tariffs impose a capacity charge in $/kW per day in addition to kWh rates (with the kWh rates usually discounted relative to other tariff structures). Demand tariffs are more common for larger businesses. TOU and demand tariffs may also be combined. Both types of business tariff structures reflect the fact that, at a wholesale level, the time at which electricity is consumed and at what capacity does affect the cost of supply. These tariff structures are not perfectly aligned with daily wholesale market price fluctuations but are a far better approximation than a flat tariff. In that sense, TOU and demand tariffs are also described as being more 'cost reflective' or 'smart' tariffs.

4.4.3 Future developments in DER incentives and management

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

The AEMC has had some success in changing network tariffs charged to retailers to include more TOU and demand elements. Also, some battery and electric vehicle owners currently engage a third party (such as an energy service company or retailer) to control their devices to reduce electricity costs (e.g. optimising battery charging or discharging against a TOU tariff or including electric vehicles in controlled device tariffs usually applied to hot water systems). Our calculations show shifting from a flat tariff to a TOU tariff saves around 7% on a customer's bill with an uncertainty range around that depending on the tariff structure in your network zone. Customers are not given any guarantee that current TOU pricing structures or levels will continue.

There are no current policies which would substantially increase residential customer adoption of alternative tariff structures. As such, given the self-evident lack of uptake of available alternatives, the prospects for greater residential adoption are considered low[6]. Consequently, in the context of understanding DER behaviour, it is appropriate to focus on more direct control measures. Direct

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

control measures are collectively called Virtual Power Plant (VPP) programs since a large aggregation of devices can be equivalent in scale to a large power plant and perform similar functions for the electricity system. Operation of batteries in VPP mode is not demonstrated in this report since it is a function of system needs and is typically estimated by AEMO as part of their electricity market simulations. However, it is important to understand the financial impact of participation in VPP programs for the purposes of projecting battery uptake.

Simulations indicate that, in order to have no increase in their electricity bill, battery owners would need to be compensated an average $15 per year to participate in 10 half hour calls which discharge all available capacity (mainly in the period 6pm to 10pm). This calculation only values their energy, but they could provide other services to the system. AEMO (2020) found in one trial that an energy services company operating a VPP for the purposes of participating in the FCAS market could earn an average $78.52 per month per participating household in South Australia[7]. In a fully commercial project, the proportion of this revenue that might be shared with the owner of the batteries is unknown.

For the purposes of projecting uptake of batteries, our assumption is that, with more refinement of VPP markets, an incentive of around $100 per year in all scenarios is available to residential customers (i.e. implemented as a rebate) and a higher amount for commercial customers proportional to their battery size. We also assume that commercial customers will be moved over to VPP schemes in a less voluntary way than residential customers as the effectiveness of time-based tariff structures for controlling loads with DER devices wanes[8].

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

- If solar exports are detected and the battery is not full, charge
- If electricity imports are detected and the battery is not empty, discharge.

This is a relatively simple onsite algorithm to implement and generally comes as part of the battery manufacturer's standard available settings. The assumed proportion of customers on each tariff contract type and the subsequent battery storage operating mode by scenario is shown in Table 4-3. The tariff assignments reflect the degree of technological success (Fast change scenario), expected political will (step change scenario) or consumer interest (High DER scenario) to implement stronger energy demand management.

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

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

Table 4-3 Assumed proportions of tariffs and subsequent battery storage operating modes by scenario

		Flat tariff (Solar shift mode)		Time-of-use tariff		VPP contract (Aggregated mode)	
		Residential	Commercial	Residential	Commercial	Residential	Commercial
2030	Central	76%	14%	6%	56%	18%	30%
	Slow change	88%	17%	3%	68%	9%	15%
	Fast change	60%	10%	10%	40%	30%	50%
	High DER	52%	8%	12%	32%	36%	60%
	Step Change	48%	7%	13%	28%	39%	65%
2050	Central	68%	12%	2%	48%	30%	40%
	Slow change	84%	16%	1%	64%	15%	20%
	Fast change	44%	6%	4%	24%	53%	70%
	High DER	40%	5%	4%	20%	56%	75%
	Step Change	36%	4%	4%	16%	60%	80%

4.5 Income and customer growth

4.5.1 Gross state product

Gross state product (GSP) assumptions by scenario are presented in Table 4-4 and is sourced from AEMO and their economic consultant. These assumptions are used to project commercial vehicle numbers and are relevant for calibrating adoption functions where income is part of the adoption readiness score. However, in our projection methodology, movement along the adoption curve is largely driven by factors other than economic growth. As such, economic growth assumptions have only a marginal impact on projections (for more discussion see Section 2.3). Given the weak relationship between economic growth and adoption we have used a more direct approach to including COVID-19 impacts described at the beginning of this Section.

Table 4-4 Average annual percentage growth in GSP to 2050 by state and scenario (Pre-COVID-19), source: AEMO and economic consultant

Scenario	New South Wales	Victoria	Queensland	South Australia	Western Australia	Tasmania	Australian Capital Territory	Northern Territory
Slow change	1.8	2.2	2.1	2.1	2.2	1.7	2.4	2.4
Central, Fast change and High DER	2.2	2.5	2.4	2.4	2.4	2.0	2.7	2.7
Step change	2.5	2.8	2.7	2.7	2.7	2.2	2.9	3.0

4.5.2 Customers

Customer growth assumptions by scenario are shown in Table 4-5. These assumptions are relevant for establishing the current market share of solar and battery customers and converting projected adoption shares back to number of installations.

Table 4-5 Average annual percentage rate of growth in customers to 2050 by state and scenario (Pre-COVID-19), source: AEMO and economic consultant

	New South Wales	Victoria	Queensland	South Australia	Western Australia	Tasmania	Australian Capital Territory	Northern Territory
Slow change	0.9	1.1	1.3	0.6	2.0	0.2	1.2	0.5
Central, Fast change & High DER	1.0	1.3	1.5	0.7	2.2	0.3	1.5	0.5
Step change	1.1	1.5	1.7	0.8	2.4	0.4	1.7	0.6

4.6 Separate dwellings and home ownership

4.6.1 Separate dwellings

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

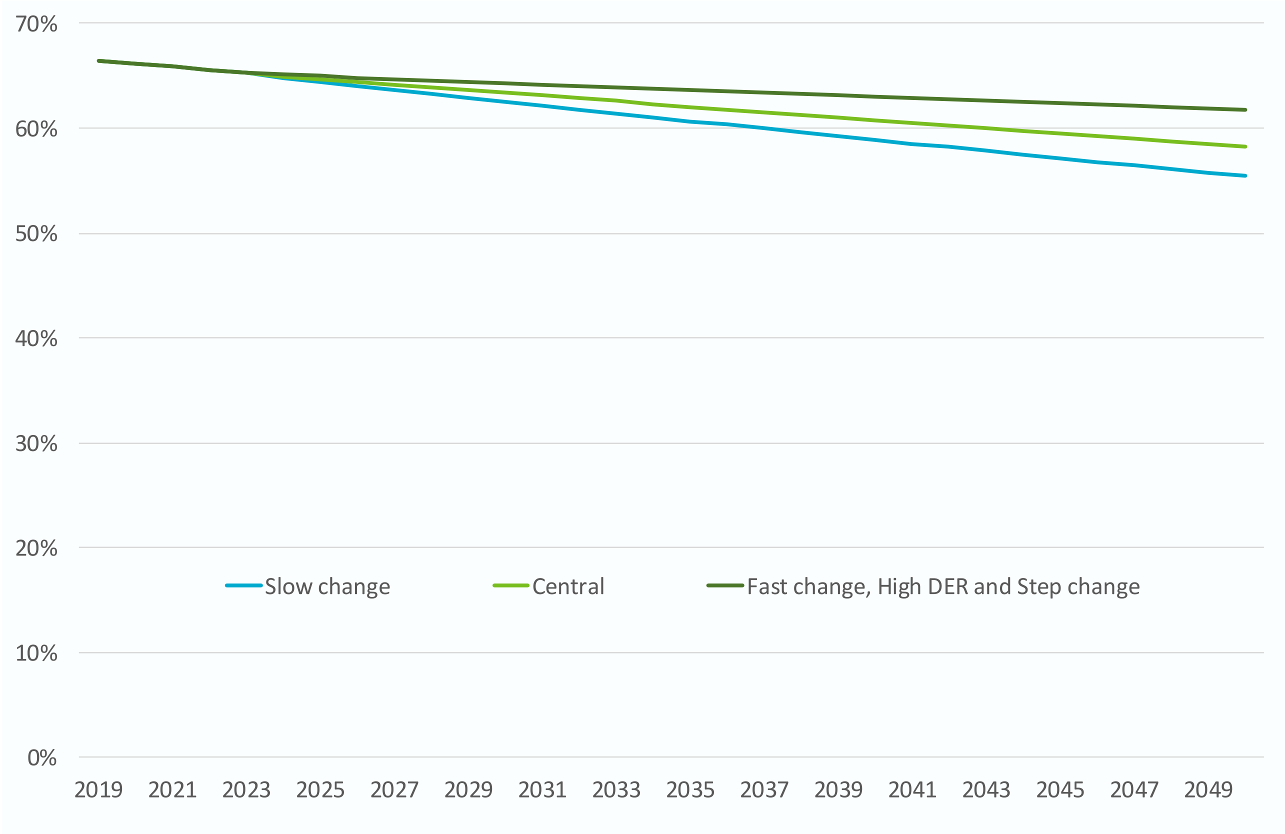


Figure 4-6 Assumed share of separate dwellings in total dwelling stock by scenario

4.6.2 Home ownership

While not a hard constraint, home ownership increases the ability of occupants to modify their house to include small-scale embedded technologies. Home ownership (which includes homes owned outright as well as mortgaged) increased rapidly post-World War II and was steady at around 70% for the remainder of last century. However, in the last 15 years ABS Census data as reported by AIHW (2017) shows that home ownership has been declining and was an average 65.5% in 2016 with the largest declines amongst young people (25 to 34), although all ages below 65 experienced a consistent decline between Censuses.

In the long run, we might expect the housing market to respond by providing more affordable home ownership opportunities. However, we must also acknowledge that 15 years represents a persistent trend. As such, under the Central scenario, we assume the trend continues and we apply the rate of decline in the last 15 years to the year 2050. Under the Slow change scenario, we assume the slightly faster trend of the last 5 years prevails, leading to a slightly faster reduction in home ownership rates relative to the Central scenario. Under the Fast change, High DER and Step change scenarios, consistent with higher DER adoption, we assume a slower rate of decline in home ownership consistent with the trend of the last 25 years representing a slowing in the rate of decline relative to recent history (Figure 4-7).

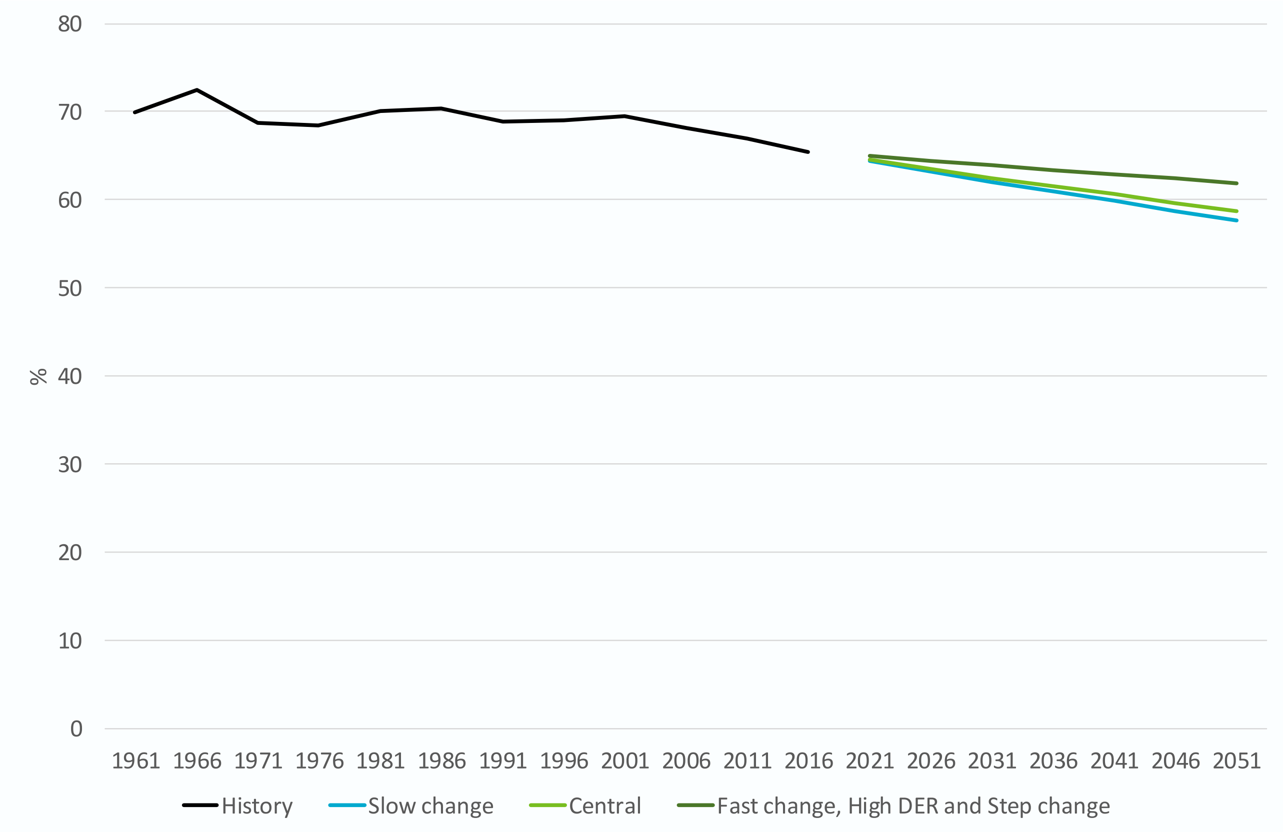


Figure 4-7 Historical (ABS Census) and projected share of homes owned outright or mortgaged, source AIHW (2017)

4.7 Vehicle market segmentation

It is useful to segment the market for electric and fuel cell vehicles in order to determine any constraints to be applied to the maximum market share in the adoption projections and to assign different shares of electric vehicle charging profiles to different segments to understand the diversity of charge behaviour across the fleet.

In Table 4-6 we list eight non-financial factors that might limit the size of a vehicle market segment. These are generally based around limits faced by households because the relevant data for households is easier to access. However, we argue that many of the limitations apply equally to businesses, or, if not there is an equivalent concept (see the last column). Each row describes the share of households in that scenario to which the factor applies and the rationale for that assumption which may be a combination of data sources and scenario assumptions.

The table concludes by calculating the maximum market share for each vehicle category via the formulas shown. The maximum market shares are used to calibrate the consumer technology adoption curve saturation rates such that the indicated rate of sales will apply once the vehicle has reached a low payback period (i.e. once financial constraints are no longer an issue), whenever that may occur. An exception is the Step change scenario where, by design, we force the electric vehicle adoption rate to achieve 100% of the fleet for cars, buses and rigid (smaller) truck by 2050. The electric vehicle adoption rate for articulated (large) trucks by 2050 is 50% with the remainder required to be fuel cell trucks. This complete transformation of the vehicle fleet to zero emission vehicles is consistent with the scenario narrative of greenhouse gas emissions reduction.

In most cases, the market shares across vehicle types adds up to greater than 100%. As such they should be interpreted as the maximum achievable share to be reached independent of competition between vehicles. When applied in the model, the after-competition share is lower. Note that autonomous ride share vehicles are assumed to be a subset of long-range electric vehicles since this is the most natural vehicle type for this service (i.e. lowest fuel cost for high kilometre per year activity). The market share limits are imposed on average. However, the modelling allows individual locations (modelled at the ABS statistical area level 2) to vary significantly from the average according to their demographic characteristics).

Table 4-6 Non-financial limitations on electric and fuel cell vehicle uptake and the calculated maximum market share

		Central	Slow change	Fast change	High DER	Step change	Rationale/formula	Equivalent business constraint
Limiting factors (residential)								
Separate dwelling share of households	A	58%	55%	62%	62%	62%	Based on housing industry forecasts	Businesses located on standalone site
Share of homeowners	B	59%	58%	62%	62%	62%	Based on historical trends	Business not renting their site
Share of landlords who enable (passively or actively) EV charging onsite	C	70%	60%	75%	80%	85%	Data not available. Assumed range of 20-80%	Same
Off-street parking/private charging availability	D	41%	37%	45%	55%	65%	Assume 80% of separate dwellings have off-street parking. Formula=(0.8*A*B)+(0.8*A*(1-B)*C)	Same
Public charging availability	E	30%	25%	45%	50%	55%	Availability here means at your work/regular daytime parking area, apartment carpark or in your street outside your house. Assumptions are based on this type of charging being the least financially viable.	Same
Share of houses that have two or more vehicles	F	60%	58%	62%	65%	65%	Based on historical trends	Share of businesses with two or more fleet vehicles
Share of houses where second vehicle is available for longer range trips	G	70%	67%	72%	75%	75%	Assumed range of 65-75%. There may be a range of reasons why second vehicle is not reliably available for longer trips	Operational availability of fleet vehicles
Share of people who would prefer ICE regardless of EV/FCV costs or features	H	20%	25%	10%	5%	2%	Based on laggards generally being no larger than a third of customers. High DER assumes ICEs suffer a collapse in manufacturing due to systematic loss of supporting infrastructure	Business owner's attitudes and specific vehicle needs

Share of people who prefer private vehicle ownership for all household cars	I	20%	25%	10%	5%	2%	As above with High DER assuming a collapse in private vehicle ownership	Business preference for private ownership
Share of people willing for their second or more cars to be replaced with ride share	J	80%	75%	90%	95%	98%	Assumed that only a laggard proportion would object to this arrangement	Same
Fuel stations with access to hydrogen supply chain	K	13%	5%	20%	15%	15%	Data not available due to uncertainty. Assume range of 5-15%.	Same
Maximum market share								
Short range electric vehicles		15%	12%	19%	27%	33%	Limitations are limited range and charging. Due to range issue, assume SREVS only purchased by two or more car households and 10% of 1 car households. Formula=[(F*G*D)+(0.1*(1-F)*D)]*(1-H)	
Long range electric vehicles		57%	46%	81%	95%	100%	Key limitation is charging and customer who would prefer ICE. Formula=(1-H)*(D+E). Step change: 100% by assumption	
Plug-in hybrid electric vehicles		57%	46%	81%	95%	NA	Same as long range. Step change: excludes all vehicles with an internal combustion engine	
Fuel cell vehicles		10%	4%	18%	14%	50%	Formula=(1-H)*K. Step change: articulated trucks only	
Autonomous ride share vehicles		56%	54%	60%	64%	64%	Formula=J*F+(1-F)*I	

Table 4-7 Shares of different electric vehicle charging behaviours by 2050 based on limiting factor analysis

		Central	Slow change	Fast change	High DER	Step change	Rationale/formula
Limiting factor							
Customers accessing tariffs that support prosumer behaviour and system integration	L	20%	15%	70%	75%	20%	Scenario assumption
Residential vehicles							
Home charging convenience profile		33%	31%	13%	7%	33%	Formula=(1-L)*D or (1-L)*D*(1-E) for High DER and Step change scenarios to account for vehicle to home group
Home charging night/off peak aligned		8%	6%	31%	21%	8%	Formula=L*D or L*D*(1-E) for High DER and Step change scenarios to account for vehicle to home group
Vehicle to home charging pattern (daytime public charge, provide all household consumption while at home)		0%	0%	0%	28%	0%	Vehicle to home is only assumed in High DER and Step change scenarios. Other relevant constraints are public charging and off-street parking to connect to home. Formula=D*E
Public charging highway fast charge		5%	5%	5%	5%	5%	90%+ of driving is within 30km of home
Public charging solar aligned		54%	58%	50%	40%	54%	Residual
Commercial vehicles							
Light commercial							
LCV - Daytime convenience		74%	79%	28%	23%	74%	Non-highway kilometres. Formula=(1-L)*0.95
LCV - Daytime adjusted for solar alignment		19%	14%	65%	69%	19%	Non-highway kilometres. Formula=L*0.95
LCV highway fast charge		8%	8%	8%	8%	8%	Assume similar pattern to residential driving
Trucks & buses morning peak convenience		76%	81%	29%	24%	76%	Non-highway kilometres. Formula=(1-L)*0.95
Trucks & buses solar aligned		19%	14%	67%	71%	19%	Non-highway kilometres. Formula=L*0.95
Trucks & buses highway fast charge		5%	5%	5%	5%	5%	Assume similar pattern to residential driving

4.8 After life electric vehicle batteries and vehicle to home

Once electric vehicles are established, they will represent a large battery storage resource. For example, if long-range electric vehicles are popular, each vehicle will represent around 100kWh of battery storage – some nine times larger than the average 11kWh stationary batteries that are marketed for shifting rooftop solar for households. It is therefore natural to consider whether this battery storage resource could be used either after its life on board a vehicle or during that life.

While possible we have chosen not to focus in using electric vehicle batteries after their on-vehicle life. Our rationale is that we expect electric vehicle batteries will be generally underutilised and therefore not frequently replaced or discarded. The average vehicle in Australia travels 11,000km per year. For a SREV of 200km range the battery size is around 40kWh, the average daily charge cycle will be 6.7kWh which is a depth of charge/discharge of around 17%. Even if a driver were to travel 3 times that distance each year the shelf life of the battery will run out before the cycle life. However, such a driver more than likely has a long-range electric vehicle (due to their higher average kilometres per day) where the daily depth of charge/discharge might be even lower.

Given the expected under-working of electric vehicle batteries it therefore makes more sense to consider how to get more use out of the battery while it is on the vehicle. Household yearly average electricity demand is 6000kWh or 16.4kWh/day. As such, any full charged electric vehicle, short or long range, can cover the required power needs with room to spare for the daily commute. However, the most likely candidate for vehicle to home would be a long-range vehicle with around 100-120kWh battery storage. An LREV could deliver energy to a home and would on average only lose 100km or 20% or less of its 500+km range for the next day's drive.

Vehicle to home would best suit a household that has access to charging via both home off-street parking at their normal place of daytime parking (i.e. at work or in a carpark). Apart from getting better utilisation out of an existing resource (the battery storage capacity in the vehicle), the other financial incentive to this arrangement is the potential that the vehicle can charge up at lower cost. This follows from the general expectation that in the long term, as solar generation capacity increases, the lowest priced period for electricity from the grid will be around midday. The economics would also work well for the charging infrastructure provider. Instead of simply providing electricity for each cars' daily driving needs (around $2/day) they can instead provide their car plus home needs ($6/day).

The process is achievable from a technical point of view with a more specialised connection to the home. At least one current manufacturer has taken this concept forward overseas (the Nissan Leaf).

In the latter half of the projection period to 2050, the modelling approach has not directly reduced growth in stationary battery uptake in favour of vehicle to home in the High DER and Step change scenarios where vehicle to home is assumed to be adopted. However, the rate of growth in adoption of stationary batteries does slow down for other reasons and this additional driver could support that narrative.

4.9 Shares of electric vehicle charging behaviour

Besides informing the technology adoption saturation levels, the maximum market shares identified in Table 4-6 are also used, together with other assumptions, to determine what shares of different electric vehicle charging profiles should be applied by 2050 (Table 4-7). The key additional assumption is to assign the percentage of customers that are participating in tariffs or other incentives for prosumer and electricity system supporting behaviour (which is a scenario assumption).

For residential vehicles we assume a small amount of highway charging consistent with the observation from many trip studies that around 90% of driving is within local areas (see, for example, BITRE 2015). The amount of home charging is calculated from the amount of off-street parking (calculated in Table 4-6). Charging at home is split between convenience and solar aligned charging based on the tariff and other incentives assumptions. The formula for High DER and Step change scenarios is modified to allow for some customers to run their home off their vehicles and charge during the day at their daytime place of parking. This represents the subset of people who have both off-street parking and access to public charging in that scenario.

Commercial charging profiles are already reasonably well aligned to the daytime but could be even more aligned with solar generation to support the electricity system. Current tariffs faced by the commercial sector may also incentivise avoiding peak periods. We assume that signing up to new tariffs or incentives would imply shifting that part of daytime charging which is not aligned with solar generation times into that time.

4.10 Automated vehicles and vehicle fleet size

As part of the modelling phase we have projected the uptake of automated vehicles in both the light and heavy vehicle markets for private use and as ride share vehicles. The main delay in adopting these technologies is achieving full safety and technology feasibility. Otherwise the benefits in terms of time and wages saved from driving appear to be well above the vehicle cost on a whole-of-life basis. The projections assume different market sizes over time across the scenarios based on general uncertainty around this new way of delivering road transport services.

Figure 4-8 shows the projected share of passenger and freight autonomous vehicles by scenario. The total across both vehicle types ranges from 10% to 35% in the scenarios by 2050. Passenger vehicles are disaggregated further into private and ride share vehicles in Figure 4-9. Rideshare vehicles are of interest to this study because they could reduce the number of vehicles required. The share of rideshare vehicles increases from around 1% by 2050 in the Slow change scenario to up to 6% in the Fast change, High DER and Step change scenarios. While these percentages are small, each rideshare vehicle may displace another 2 to 3 vehicles depending on how successful they are in concentrating passengers into the rideshare vehicle.

The impact of these assumptions is that the projected growth in the number of vehicles declines from historical rates after 2030 and increasingly so in the Central, Fast change, High DER and Step change scenarios (Figure 4-10).

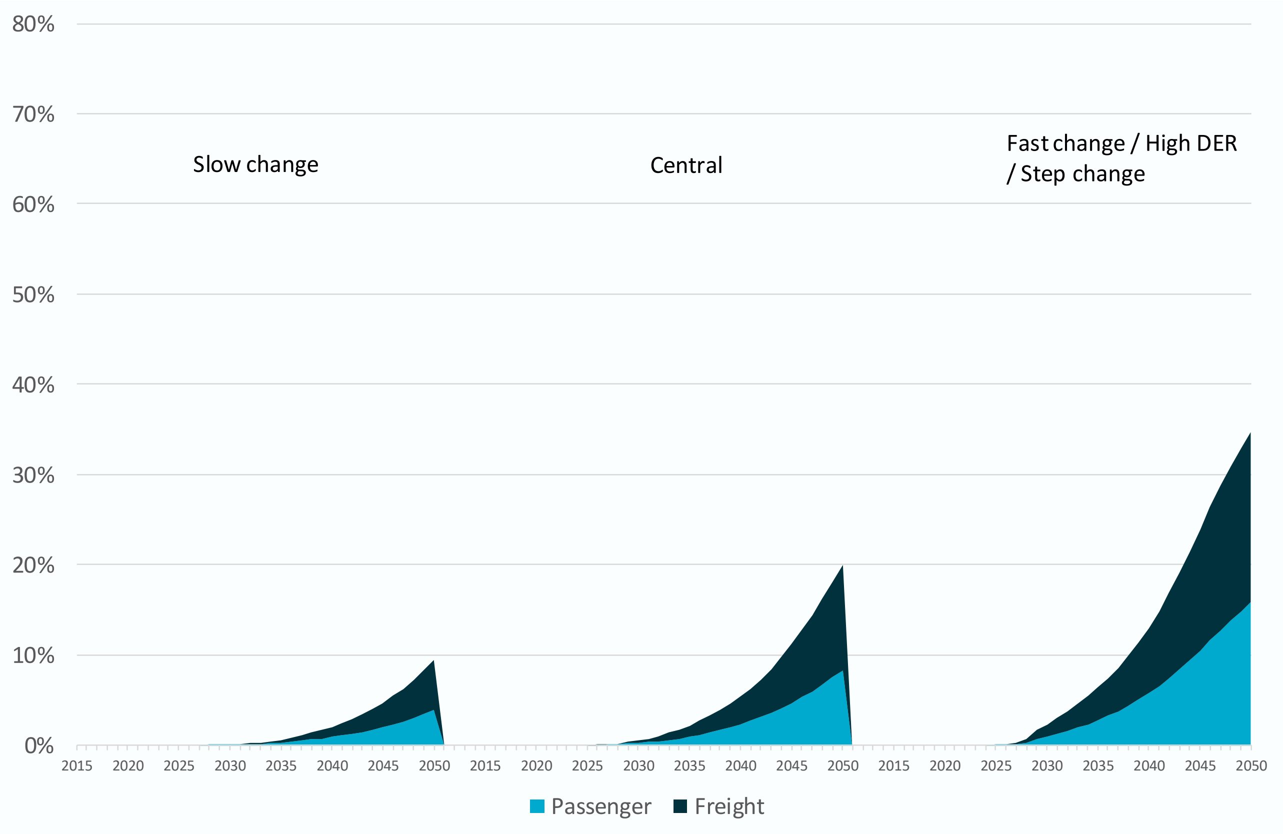


Figure 4-8 Share of passenger and freight autonomous vehicles in the road vehicle fleet by scenario

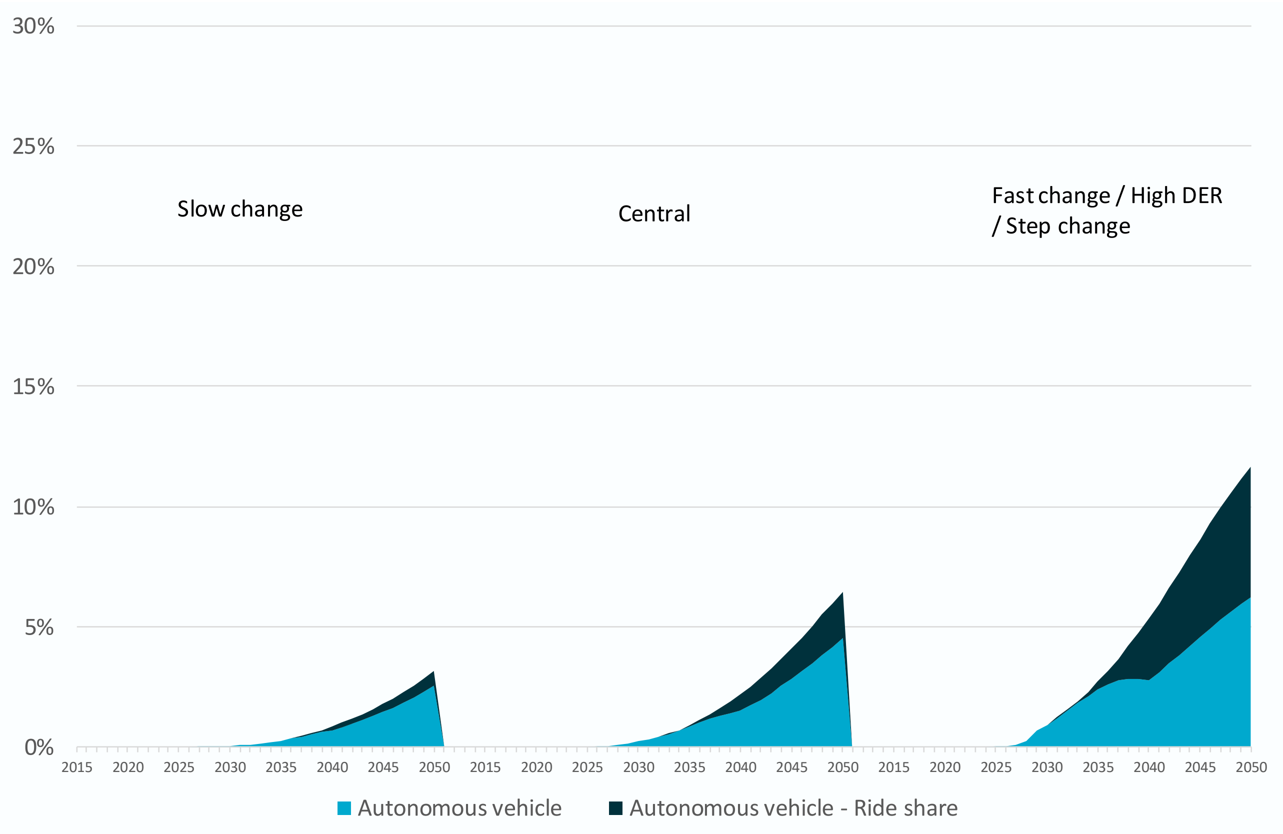


Figure 4-9 Share of passenger autonomous vehicles by private or ride share types by scenario

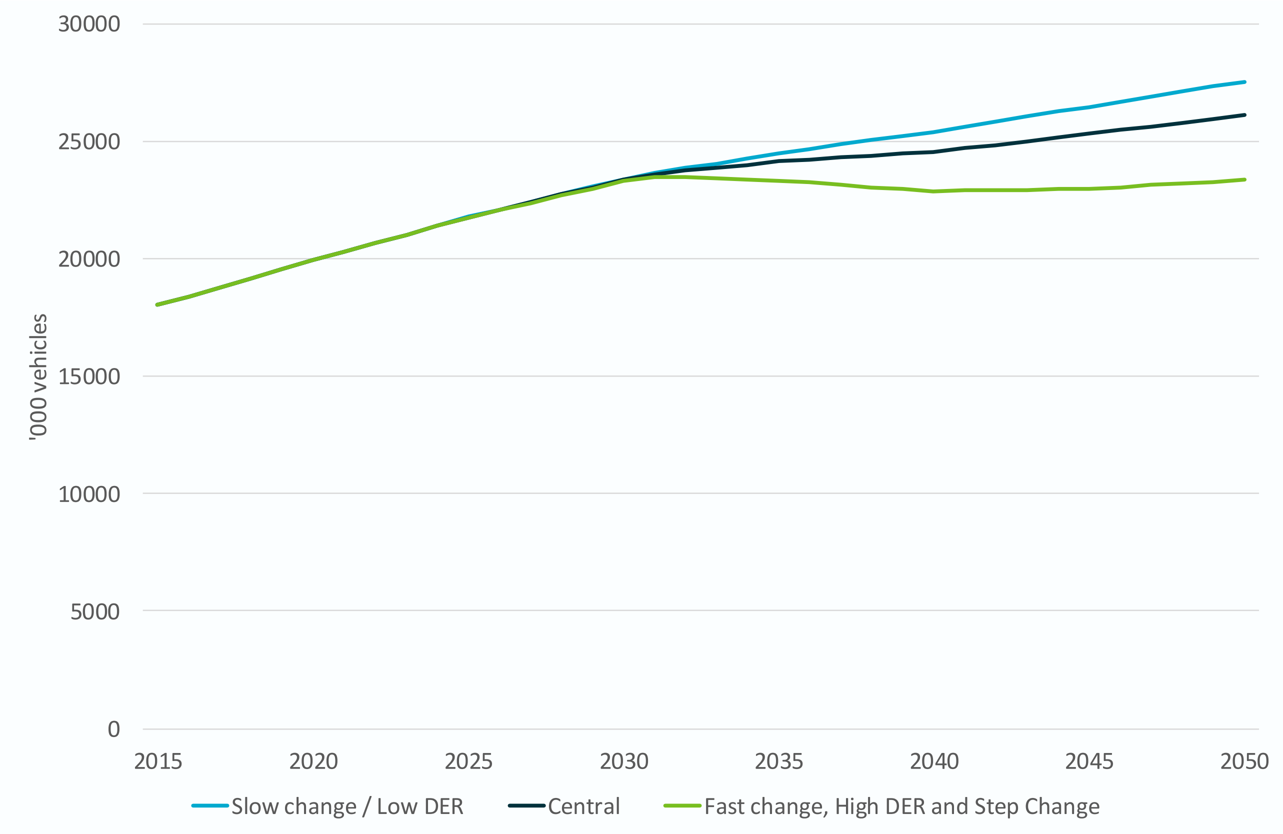


Figure 4-10 Projected national road vehicle fleet by scenario

4.11 Rooftop solar and battery storage market segmentation

For both residential and commercial customers the market that can most easily adopt rooftop solar are those with a separate owner-occupied building. Multi-occupant buildings or those that are not owner-occupied require more complex arrangements (business models) in order to extract and share the value of rooftop solar. This latter group is therefore a smaller market segment. Table 4-8 and Table 4-9 outline how large these market segments are assumed to be in each scenario and their implications for the overall size of the rooftop solar market. The assumptions are based on housing and ownership data discussed elsewhere in this report. The availability of commercial building data is not as good as residential, and consequently there is greater uncertainty in those assumptions.

The market share limits are imposed on average. However, the modelling allows individual locations (modelled at the ABS statistical area level 2) to vary significantly from the average according to their demographic characteristics.

The battery storage market is assumed to be a subset of the rooftop solar market since the main motivation for storage is improving the utilisation and financial returns from rooftop solar. In reality, there may be a small residential and commercial battery only market. For example, commercial customers may use storage to minimise capacity costs, particularly in the South West Interconnected System (SWIS) where capacity market costs are shared out according to customer contribution to demand peaks.

We impose the rooftop solar maximum market shares on the batteries' adoption curves. However, since the payback period for solar with integrated batteries does not reach the same level as for solar alone, in practice, batteries only reach a fraction (typically a third) of the total addressable market (all solar owners) in the projections.

Table 4-8 Non-financial limiting factor and maximum market share for residential rooftop solar

		Central	Slow change	Fast change	High DER	Step change	Rationale/formula
Limiting factors							
Separate dwelling share of households	A	58%	55%	62%	62%	62%	Based on housing industry forecasts
Share of homeowners	B	59%	58%	62%	62%	62%	Based on historical trends
Multi-occupant buildings able to set up internal retailing of solar	C	5%	2%	10%	15%	15%	Scenario assumption
Single occupant building owners able to sell directly to occupant or another peer (virtually)	D	3%	1%	5%	8%	8%	Scenario assumption. Landlords of single occupant buildings have more barriers to retailing
Rooftop solar maximum market share		42%	34%	53%	61%	61%	Formula=(A*B)+C+D

Table 4-9 Non-financial limiting factor and maximum market share for commercial rooftop solar

		Central	Slow change	Fast change	High DER	Step change	Rationale/formula
Limiting factors							
Separate dwelling share of businesses	A	40%	38%	42%	43%	43%	Data limited. Scenario assumption
Share of business building owners	B	24%	23%	27%	27%	27%	Data limited. Scenario assumption
Multi-occupant buildings able to set up internal retailing of solar	C	5%	2%	10%	15%	15%	Scenario assumption
Single occupant building owners able to sell directly to occupant or another peer (virtually)	D	3%	1%	5%	8%	8%	Scenario assumption. Landlords of single occupant buildings have more barriers to retailing
Rooftop solar maximum market share		17%	11%	26%	34%	34%	Formula=(A*B)+C+D

5 Projection results

In this section we provide projections by each of the distributed energy resource technology categories. In some cases, we compare the projections to Graham et al (2019) because those projections are available at a similar level of detail, but that work did not include the Step change scenario and did include a Low DER scenario which is not included in the current scenario set. In other cases, where data is more aggregated, we compare the projections to the Integrated System Plan assumptions (the ISP assumptions workbook released in December 2019) where the scenario set is fully aligned.

5.1 Rooftop solar PV

The projected capacity of residential rooftop solar PV is shown in Figure 5-1 measured in megawatts (MWs) degraded. Degraded MWs means that the capacity has been adjusted for loss of generation effectiveness due to degradation. Since degradation is assumed to be 0.5% per annum, nameplate capacity (the capacity unadjusted for degradation) grows at 0.5% higher than is shown. This is important to note because most public data on solar capacity is nameplate capacity and so should not be compared with the data presented without similar degradation first being applied. The emphasis on degraded capacity reflects that the data will be used by AEMO to inform their electricity demand forecasts. In that context, only effective generation capacity is relevant.

Historical growth in installations of residential rooftop PV was very strong in 2019 and, ordinarily, this trend would have been extrapolated to 2021-22 resulting in projections significantly higher than those published in Graham et al (2019). However, the methodology in 2020 includes a process for adjusting the trend for the impacts of the COVID-19 pandemic. This adjustment significantly slows the rate of new installations to 2022. After 2022, the impact of the COVID-19 pandemic is largely assumed to be complete with the exception that those lost sales installations have a lingering impact on the level of installations for several years (see Section 4.1).

Even with these COVID-19 pandemic impacts in the 2020s and 2030s, the Central and Slow change scenarios are projected to have significantly higher capacity than in the 2019 projections. This reflects a combination of drivers which lift the long-term outlook with Central, Fast change and High DER all exceeding 2019 forecasts in the long run. One driver is confirmation of a substantial long-term solar rebates policy in Victoria which was not included in the 2019 projections. A broader driver for long term growth in all regions is the assumed increase in new residential system sizes. As discussed in Section 4.3, we assume new system sizes continue to grow in all scenarios except Slow change, although this source of growth in the other scenarios weakens over time.

Another important driver is the retail electricity price. In the early 2020s electricity prices are falling. However, there are several stages of price recovery in the mid-2020s, early 2030s and early 2040s. Each of these periods of price increases result in an increase in the rate of growth in capacity over and above other factors (such as falling system costs). Growth rates are lowest during the late 2020s and early 2030s (before electricity prices begin to rise) reflecting the closure of national small-scale renewable target subsidies and end of Victorian government subsidies.

The general price cycle below is less prevalent in the SWIS which is assumed to have relatively stable prices. However, changes in subsidies, system costs and system sizes still result in differences in growth rates over time.

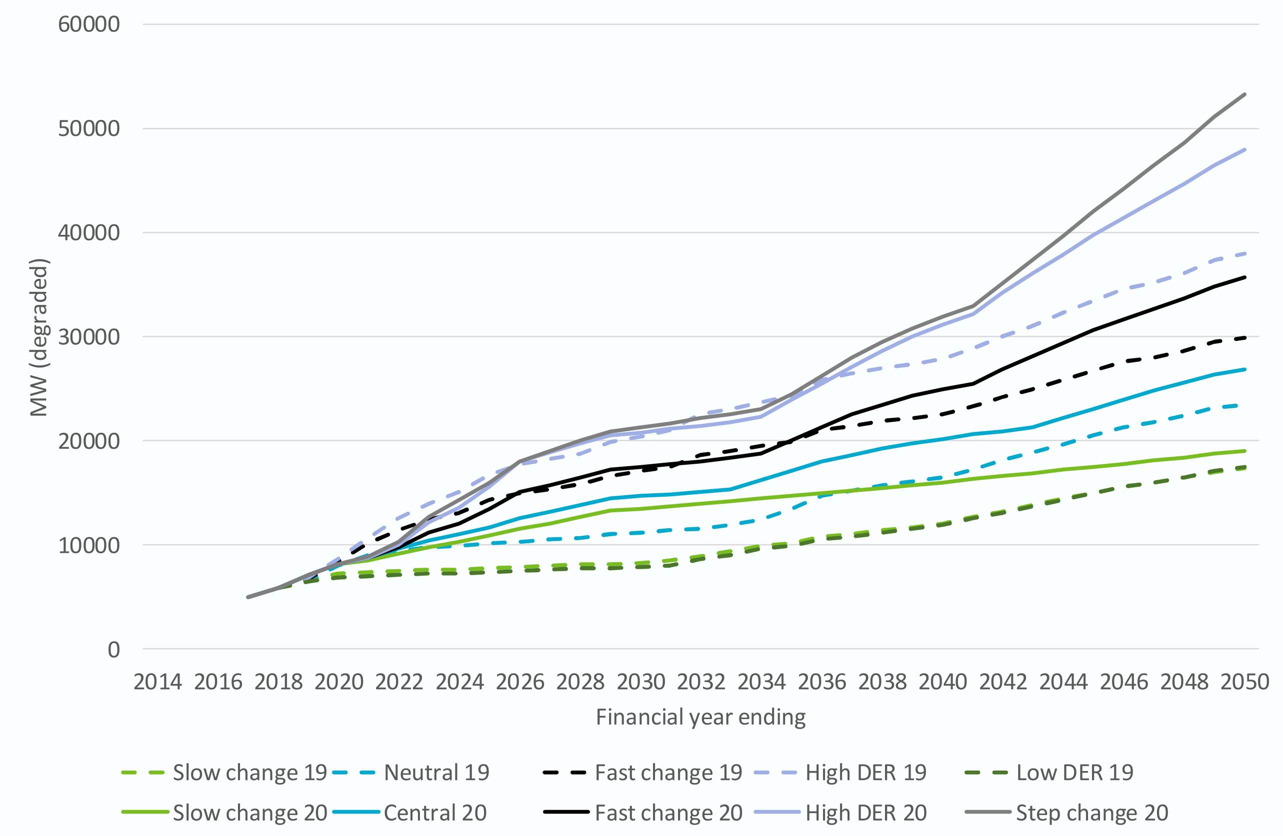


Figure 5-1 Projected national capacity of residential rooftop solar by scenario compared with 2019 projections

Commercial rooftop solar installations tend to have lower payback periods than residential rooftop solar owing to the better match between solar generation and load. Commercial solar generation also partly coincides with higher time-of-use tariffs in the afternoon. Consequently, commercial rooftop solar capacity changes are less sensitive to changes in electricity prices and subsidies (Figure 5-2). As system costs improve, commercial customers in each scenario make a steady progress towards their assumed maximum market share. Across the scenarios, that maximum share is based on factors such as the number of businesses with access to roof space and whether they rent or own that roof space.

Commercial rooftop solar capacity also increases because we have assumed sizes of new commercial installations are growing based on the recent historical trend. This trend is assumed to be strongest in the Step change, High DER and Fast change scenarios.

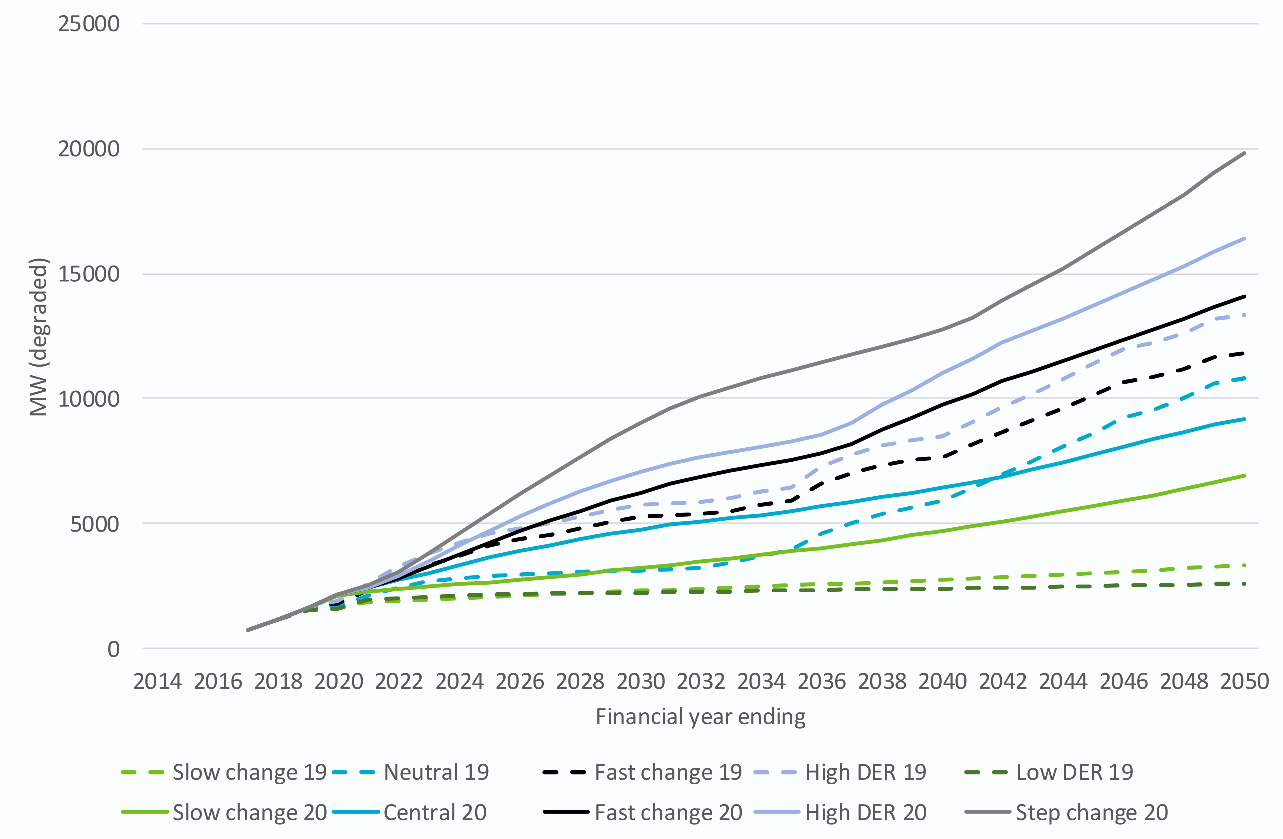


Figure 5-2 Projected capacity of commercial (<100kW) rooftop compared to 2019 projections

In Figure 5-3, projected residential and commercial rooftop solar capacity up to 100kW in size has been added together and compared with the December 2019 ISP assumptions. The COVID-19 impacts mean that the new projections are lower in the period until the early 2020s (except for Slow change). By the late 2020s, nearly all the new projections are above the ISP assumptions. This reflects that, prior to the COVID-19 pandemic, rooftop solar adoption was trending higher than expected and this trend is expected to at least partially reassert itself post-pandemic through a wide range of drivers that have already been discussed.

By 2050, in the Slow change and Central scenarios, the new projections converge towards the ISP capacity levels reflecting that there have not been any major changes in the lower and likely saturation points for rooftop solar adoption in these scenarios. However, the remaining scenarios arrive at a much higher capacity level by 2050. This higher upside risk is reflective of the uncertainty in how large new solar systems may grow which has only grown wider as new system sizes have continued to increase. There is also uncertainty in how well business models will overcome conventional infrastructure constraints like access to roof space and renter-landlord split incentive issues. Another major uncertainty is the degree to which the electricity system will begin to devalue solar generation as both small- and large-scale solar increase in scale. Storage and electric vehicle charging can of course mitigate or make use of daytime solar generation and they are growing as well.

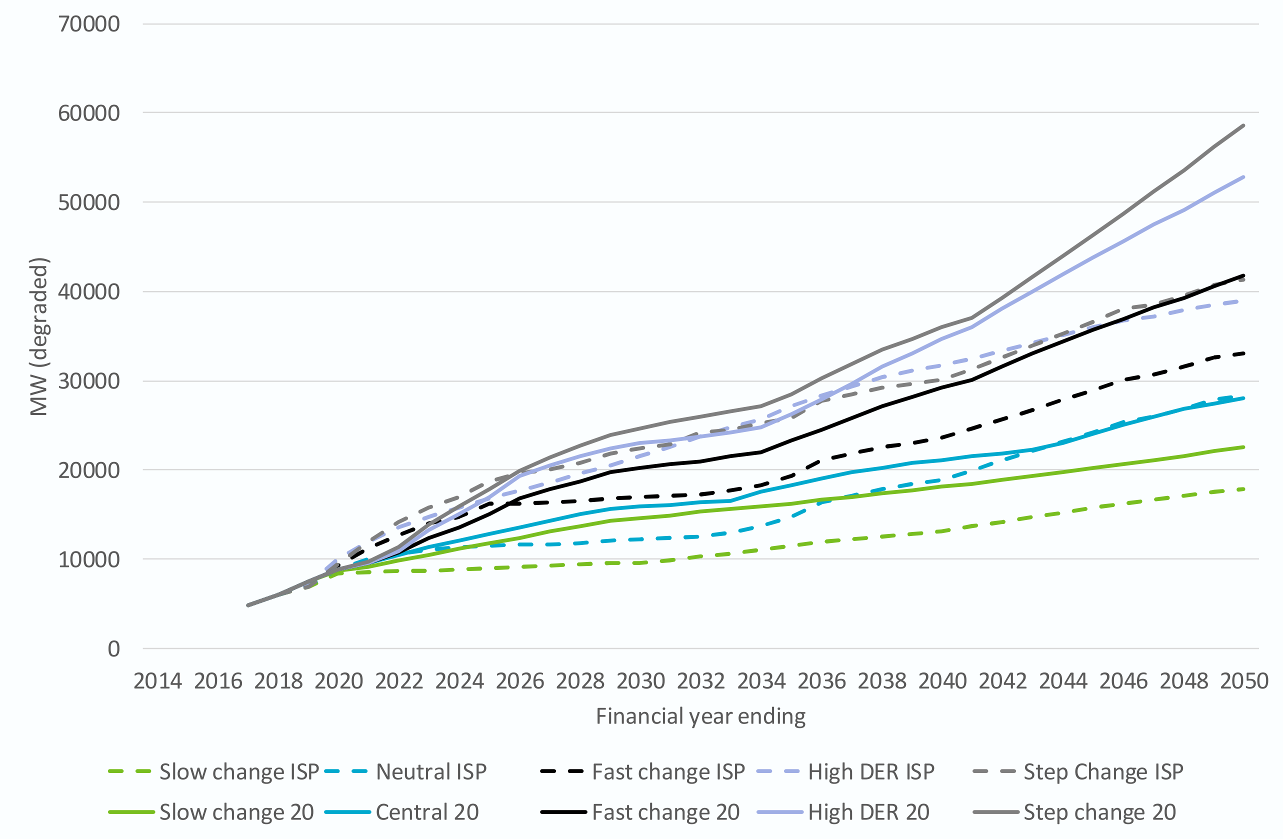


Figure 5-3 Projected NEM capacity of all solar PV less than 100kW compared to December 2019 ISP assumptions

5.2 Non-scheduled generation solar PV (>100kW)

Growth in non-scheduled generation (NSG) solar PV which includes commercial systems larger than 100kW has been strong since 2018 reflecting the culmination of the plans of many individual investors to contribute to the completion of the Large-scale Renewable Energy Target (LRET). Those plans were spurred by subsidies that have since declined indicating either that the subsidies were in excess of what was required or that conditions changed after investments were already committed. Large scale generation certificates (LGCs) under the LRET scheme were priced at nearly $90/MWh in 2017 and remained at around $85/MWh through to the third quarter of 2018 calendar year. Since the fourth quarter of 2018 prices have varied between $30-50/MWh.

The subsidy is now equivalent to that available to small scale solar generation and could fall lower. It is assumed that other national and state emissions reduction funding programs will now provide a floor to the fall in subsidies to larger scale renewables. With this background, the projection for NSG solar shown in Figure 5-4 reflects a delayed weakening in the rate of new deployments during the early 2020s and a recovery at a lower growth rate than that experienced in 2018 to 2020. The growth rate in 2020 to 2022 implicitly assumes that investments remain economically viable even with the reduced subsidy. This is implied only because the projection method for this period is regression analysis which extrapolates the trend rather than performs any financial investment assessment. However, in addition to the trend extrapolation, the projected trend has been adjusted for the impacts of the COVID-19 according the assumptions set out in Section 4.

Financial assessments are made for all increases in capacity beyond 2022 and deployment proceeds at the historical rate per region in each of four size categories: >100kW to 1MW, >1MW to 5MW, >5MW to 10MW and >10MW to 30MW.The larger the size category the impact is has on the total NSG solar capacity – this is the reason for the slight volatility in projected capacity over time.

A major reason for the lower long-term capacity levels in the new projections is that previous projections assumed that NSG solar would be eligible for subsidies available from state renewable electricity targets, particularly in Queensland and Victoria. The new projections do not make this assumption because it was considered that those schemes would target lowest cost generation which would be larger scale. However, we do allow eligibility for national and state emissions reduction schemes. The available subsidy under these schemes is lower than was previously assumed for renewable generation targets. As a result, fewer financial assessments meet the hurdle rate and therefore fewer projects proceed in the updated projections.

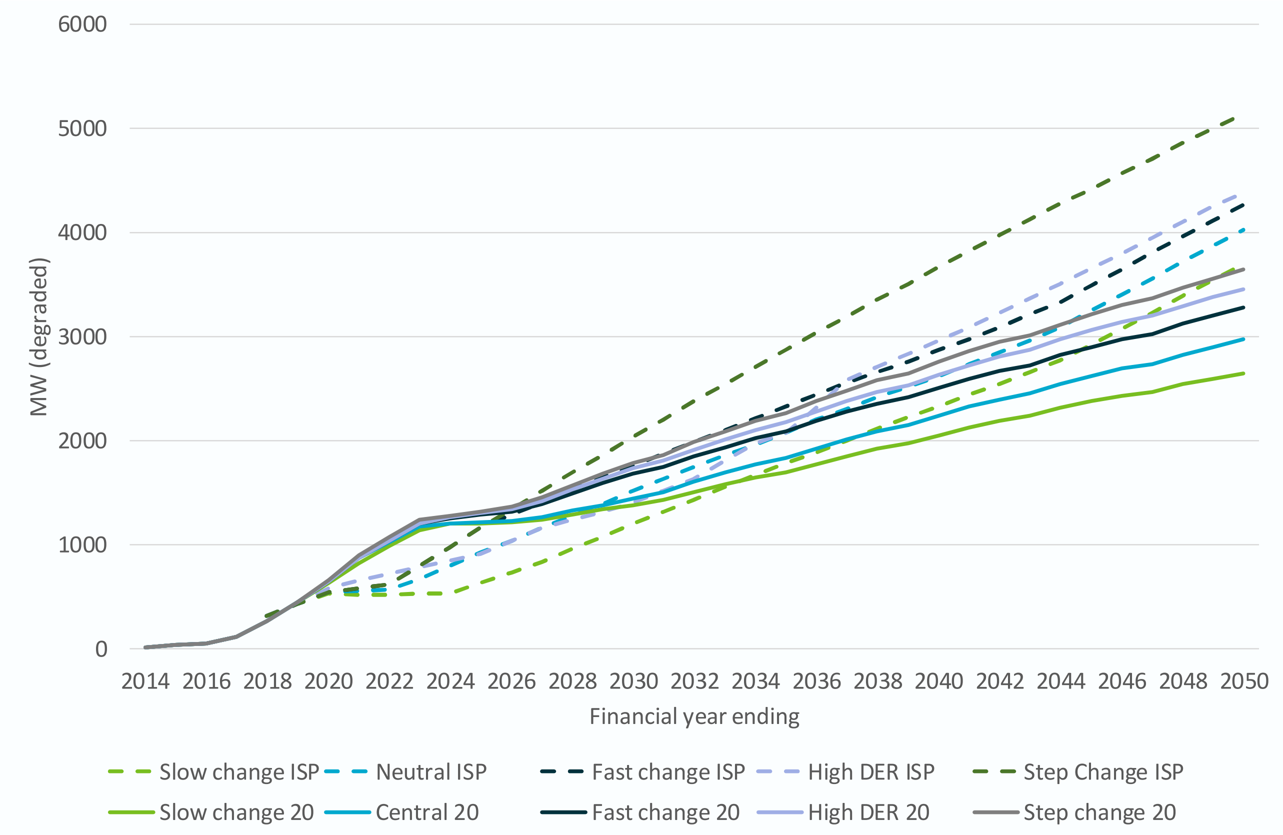


Figure 5-4 Projected NEM capacity of non-scheduled generation solar PV (>100kW) compared to December 2019 ISP

At present, most NSG solar capacity is in the range of 100kW to 1MW or greater than 10MW but less than 30MW (Figure 5-5). These size categories are projected to continue to make up the largest share of capacity. The smaller units (less than 1MW) are easiest to fit into the existing footprint of a commercial facility (ideally on the roof). If a business has the space to build a larger facility, then it is better to build larger to achieve more economies of scale.

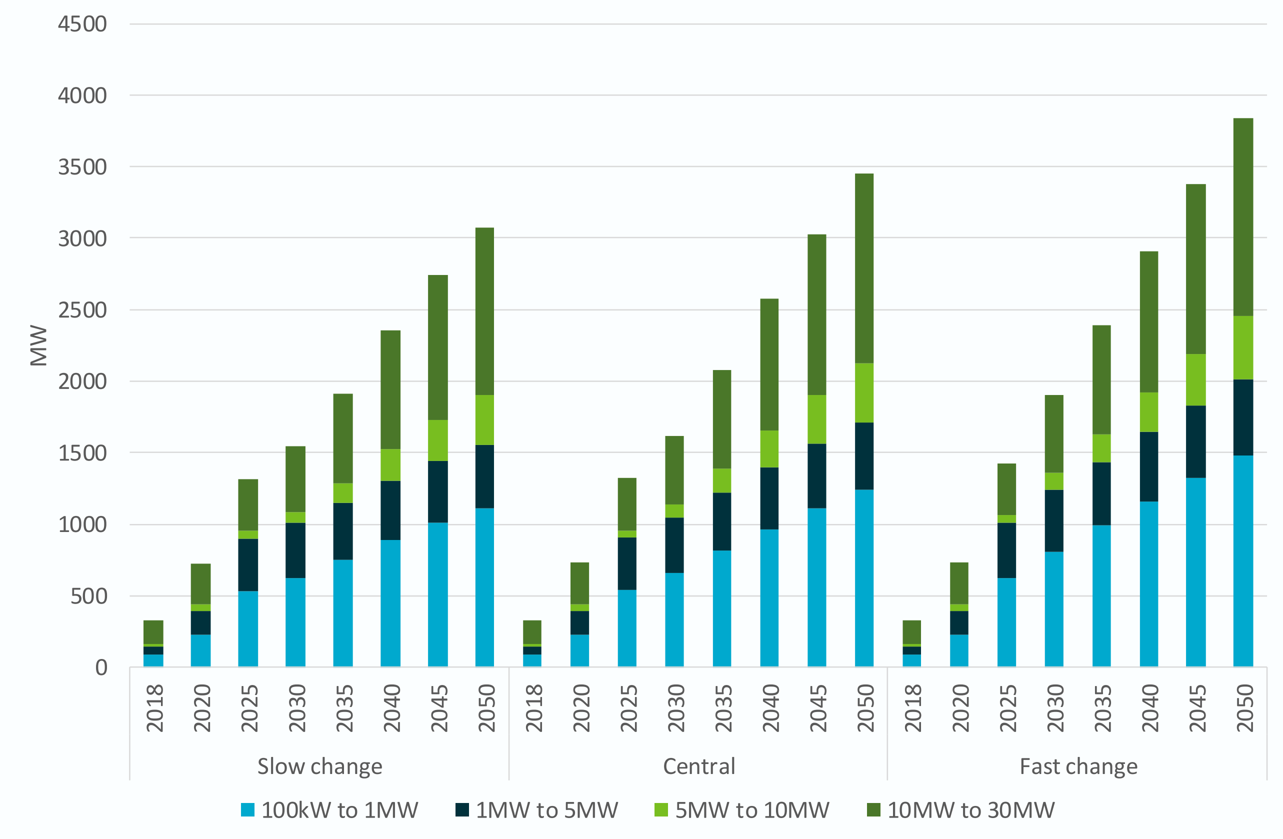


Figure 5-5 Projected national non-scheduled generation solar capacity by size category and scenario

5.3 Batteries

Sunwiz (2020) has estimated that battery sales in 2019 were around 20,000 units which represents no change in sales since 2018. Furthermore, battery sizes are decreasing over time. This indicates a two-dimensional decoupling of battery sales from rooftop solar sales which were very strong in 2019, with increasing system sizes. Accordingly, we have changed our projection approach slightly. In 2019, we restricted growth in battery sales to fall within a range that provided for some consistency with rooftop solar sales. Those restrictions have been removed in the new projections. The outcome is that the new projections are more sensitive to changes in battery financial assumptions (Figure 5-6). Projected capacity of batteries increases strongest in the next decade when decreases in battery costs are the steepest. There are some existing state subsidy schemes, with South Australia's being the largest, which contribute to the growth in the next five years. The immediate two years to 2022 are projected using a combination of trend extrapolation and assumed COVID-19 impacts.

After 2022, the projection model is calculating the system payback period and applying the assumed battery adoption curve to project new installations. Falling battery costs and an increase in electricity prices around the late 2020s and early 2030s see strong growth through those periods. However, from the mid-2030s, when electricity prices ease and battery costs level out, growth in battery capacity slows dramatically due to mostly stagnant payback periods, with capacity only increasing a little in the early 2040s reflecting assumed increasing retail prices during that period.

Apart from these financial factors, the different levels of projected battery capacity by 2050 reflect the assumed maximum market share assumptions (which is used to calibrate the adoption curve). Maximum market share assumptions have not changed significantly since the 2019 projections. As a result, the new projections tend to converge towards the 2019 level of capacity by 2050.

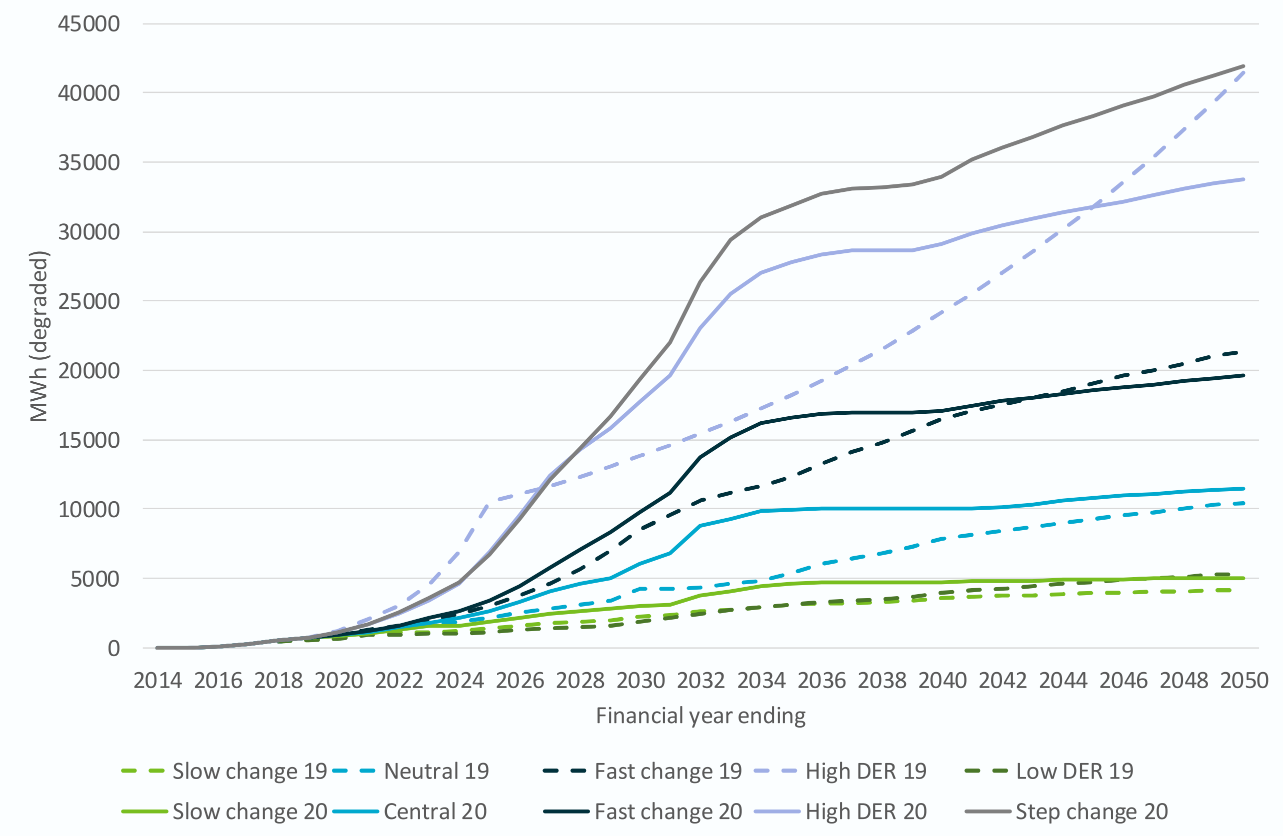


Figure 5-6 Projected capacity of residential batteries compared to 2019 projections

Publicly available data on batteries is not able to provide significant insight on how the commercial sector is performing relative to the residential battery market. However, our financial modelling recognises that a commercial customer will have less excess solar with which to charge their battery due to better alignment between load and solar production and has more price incentives to shift load due to demand and time of use charges. So far, these incentives have led commercial customers to purchase smaller storage duration batteries with a 1 to 1 power to energy storage ratio[9] compared to the residential market where that ratio is around 1 to 2.5.

The inclusion of a 1:1 power to energy ratio is a significant change compared to the 2019 projections and is the cause of the generally lower capacity (in MWhs energy storage capacity) projections by 2050 for most scenarios (Figure 5-7). Apart from this change, the shape of the growth in battery capacity reflects the same path as residential batteries with COVID-19 impacts overlaid over the trend to 2022 and then costs reductions in batteries accelerating uptake in the period to 2030. Flat battery costs slow growth from the mid-2030s.

[9] Unpublished AEMO data.

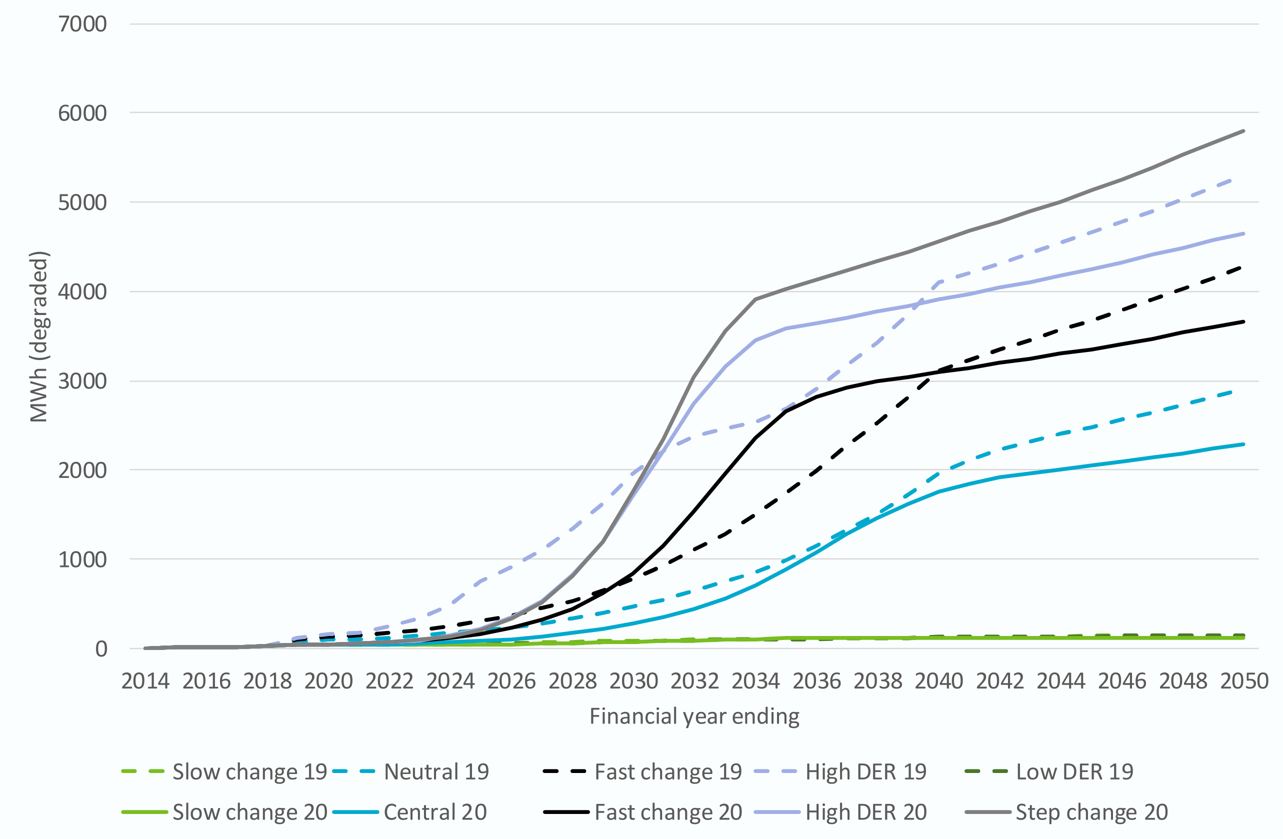


Figure 5-7 Projected capacity of commercial batteries compared to 2019 projections

The sum of both residential and commercial battery capacity is shown in Figure 5-8 and compared with December 2019 ISP assumptions. In the period to 2030, the Slow change, Central and Fast change scenarios are reasonably well aligned with the ISP projections and lower in the case of High DER and Step change. However, this is somewhat accidental as the increase in residential projections to more closely align projections with changes in battery costs has been offset by the assumed lower commercial battery system size. Without this change to commercial system assumption we would have expected to exceed ISP projections during this period in general. The exception is the ISP High DER and Step change which in their early years appear implausible now given a flat sales trend in 2019.

By 2050, the new battery projections are generally below the ISP projections reflecting the impact of the change in commercial battery sizes, common maximum market share assumptions and flat battery prices during the latter part of the projection period. Step change is the only exception with capacity exceeding ISP assumptions. This likely reflects that Step change is the scenario with the highest financial incentives (it includes an assumed future subsidy to support battery deployment under a rapidly decarbonising sector) and the new projections give financial factors more weight than in 2019.

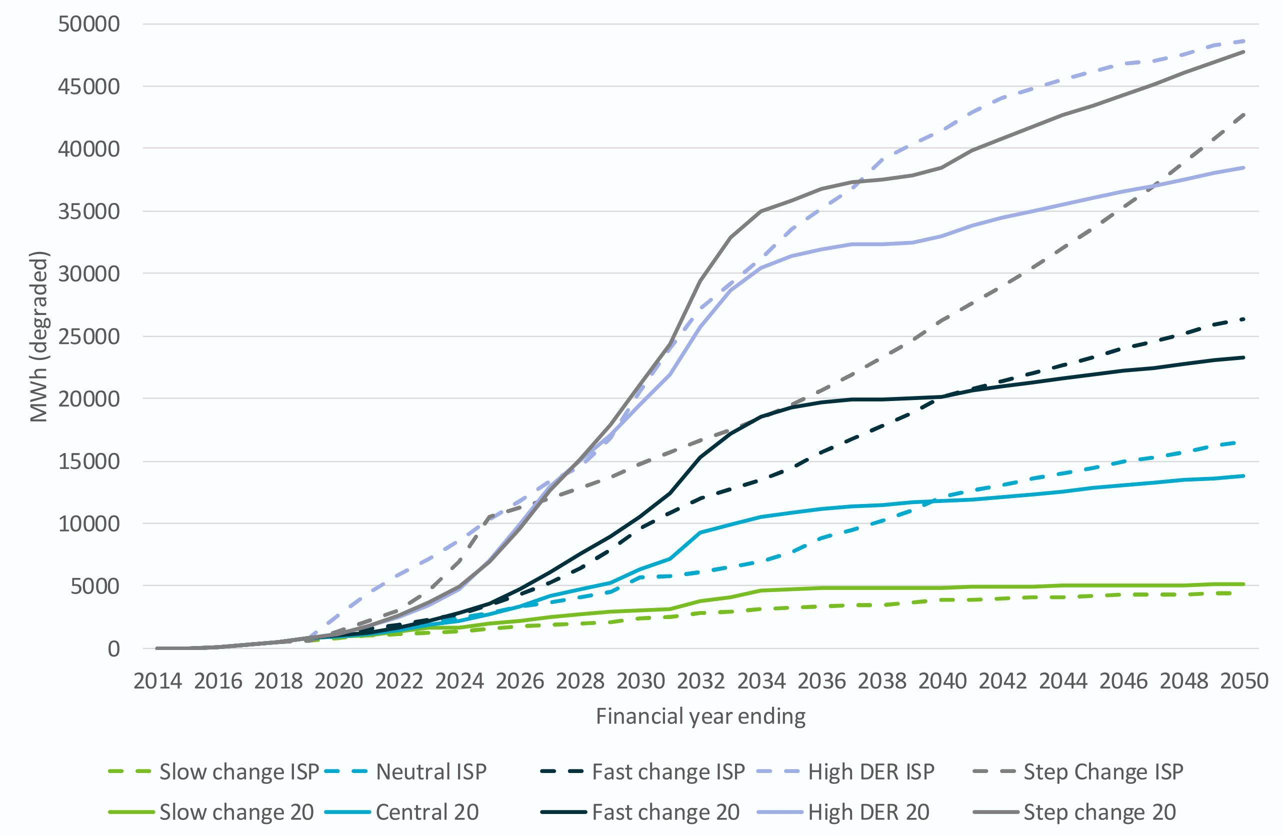


Figure 5-8 Projected capacity of all batteries compared to December 2019 ISP assumptions

Figure 5-9 shows the average share of solar installations that also include batteries across the regions. There is significant diversity within the average. The current share is highest in the Australian Capital Territory (12%) and lowest in Western Australia (2%)[10]. South Australia's share rises the fastest in the next five years reflecting their battery subsidy program. The average residential and commercial profile shows rapid growth in the share of solar installations with batteries to the early 2030s (except for the Slow change scenario) before slowly declining thereafter. This reflects the slowing in battery installations while solar installations continue to grow. The continued growth of solar installations is supported by ongoing costs reductions into the late 2030s and 2040s. However, battery installations slow due to a levelling out in battery costs from the 2030s onwards.

Another feature of the trend is that the shares of commercial solar systems with batteries is lower than the residential sector. This reflects the narrower role for storage in a commercial location where the load can capture a greater share of solar generation.

[10] This is estimated from a combination of SunWiz and Clean Energy Regulator data. There remains some uncertainty about data consistency between sources.

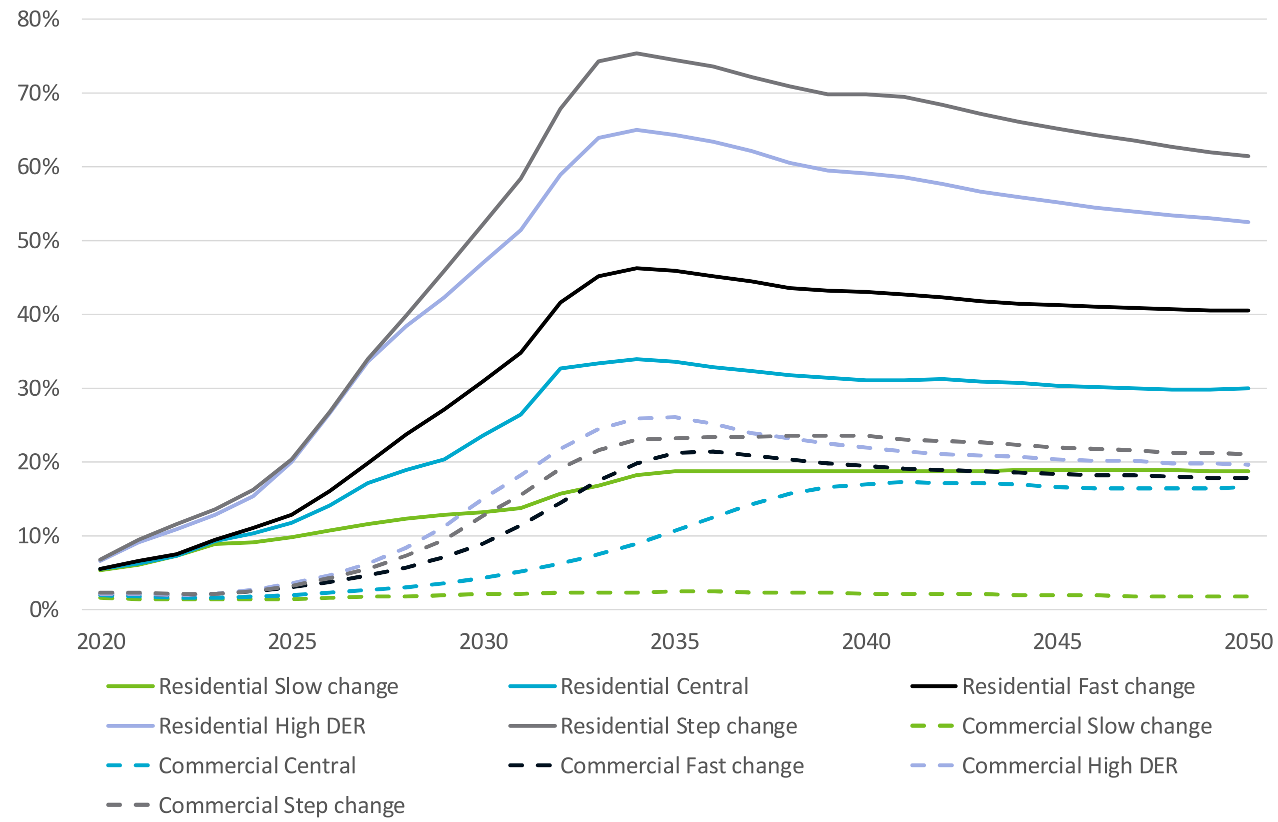
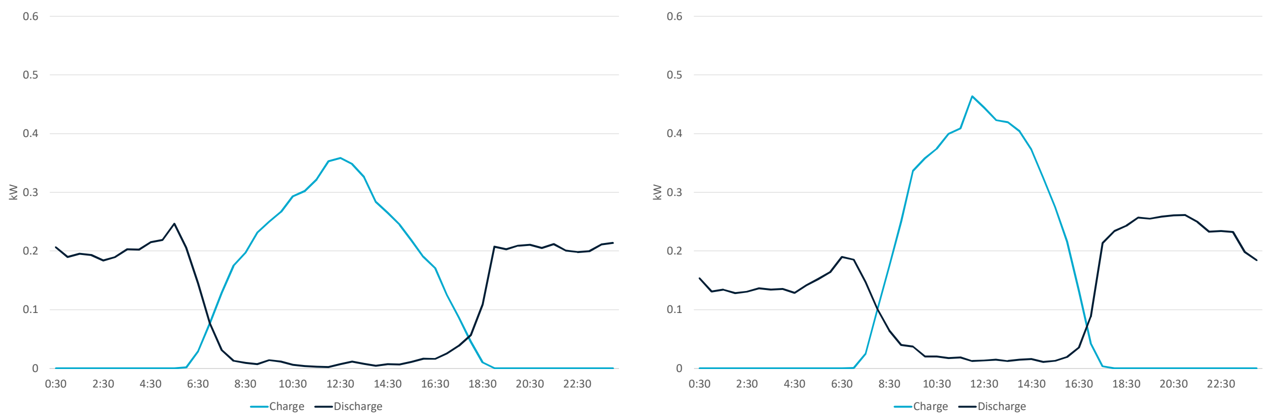


Figure 5-9 Share of solar installations with batteries by customer type

5.4 Battery operation profiles

Battery operation profiles can be used to calculate the impact of that battery capacity on half hourly demand. In Section 4 we provided assumptions about the percentage of customers that would be operating their batteries under either flat tariffs, time-of-use tariffs or under a virtual power plant (VPP) aggregation scheme. We provide after-diversity half hourly battery profiles for several historical solar years by simulating the behaviour of 45 residential and 20 commercial customers in each network zone. The battery profiles are created by using linear programming which minimises electricity bills subject to the physical constraints of the battery, solar production, customer load and the tariff structure faced by the customer.

As an indicator of those profiles, the average battery profile for residential customers on flat tariffs over the summer and winter months is shown in Figure 5-10. In summer, the battery is relatively easy to fill so some customers with low day time load will charge quickly and others later. Discharging ramps up as the sunlight hours fade and can continue all through the night so long as demand persists (including air conditioning demand) and the battery has started this period with a high charge. In winter, the charging profile is narrower and higher to acknowledge that the days are shorter, solar radiation is not as strong and consequently charging is more coincident across households. Evening discharge begins earlier and is higher due to shorter daylight hours (more lights, some extra heating) and can continue if there is demand but will more often be limited by a lack of charge resulting in a lower winter night-time discharge profile.

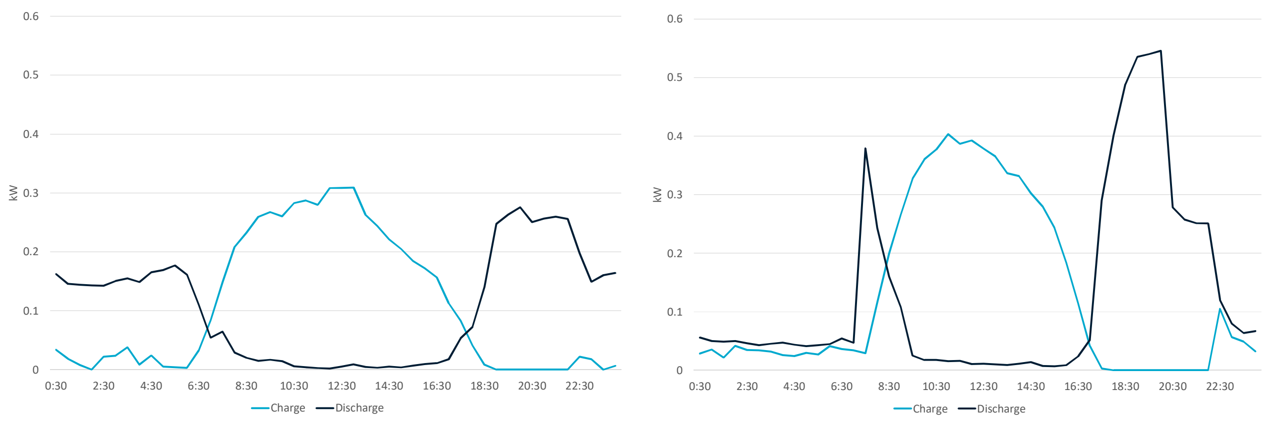


Data is average of activity across 45 customers (i.e. after-diversity) but not normalised. After-diversity profile is significantly lower than individual profiles due to lack of correlation in charging/discharging times. The battery takes longer to charge in winter and as a result charging activity is more coincident between customers

Figure 5-10 Average summer (left) and winter (right) residential battery profiles for a flat tariff in the ACT

The average residential profile for the summer and winter months under a time-of-use tariff is shown in Figure 5-11. In summer, the key goal is to avoid importing electricity during the high-priced evening peak period. Many regions also include a morning peak-price period, and this is also a target for discharging. In summer the average morning discharge is low because of milder temperatures and more natural light. However, in winter the average morning discharge is higher recognising this period can involve higher use of electric air conditioning and lighting. In this case, the battery profile simulation chooses to import electricity after the evening peak discharge (and during the low price-period overnight) to ensure there is enough battery state of charge to meet morning electricity demand during the peak period minimising imports.

We have not sought to adjust time-of-use tariff structures over time to take account of future changes in wholesale prices. Instead, in most scenarios, we phase out the number of customers who are on time-of-use tariffs in favour of aggregated control via VPP which will be more suited to varying charging to match and wholesale price changes without creating sharp coincident charging behaviour.



Data is average of activity across 45 customers (i.e. after-diversity) but not normalised. Bill minimisation in winter includes ensuring battery is able to discharge into the evening and morning peak pricing periods by adding an extra charge from the grid at night. Both charging and discharging is more coincident across customers than in summer. In summer, solar output and battery charge is sufficient to cover both morning and evening peak as well as load through the night on most nights (although pattern indicates night charging on some nights – likely following days when solar outputs was poor)

Figure 5-11 Average summer (left) and winter (right) residential battery profiles for a TOU tariff in the ACT

The average summer and winter battery profiles for commercial customers are shown in Figure 5-12 and Figure 5-13. Compared to residential customers, commercial customers have smaller batteries and less access to solar production for charging (because their load already aligns well with solar production). As a result, under a flat tariff, charging and discharging occurs over a shorter period. The charge is higher in summer because there is a greater frequency of excess solar production and consequently a larger and longer discharge is achieved on average.

Under a time-of-use tariff, in both summer and winter, commercial customers ensure their battery is charged by importing during the night-time low-priced period to ensure they can discharge into the morning high-priced period. Because this period is short the battery can make a large, short discharge to cover the whole period. However, the evening high-priced peak period is much longer, and the battery is less successful in being able to fully avoid imports during this period. As in the residential profile the morning discharge is higher in the winter commercial time-of-use profile because of higher customer load at this time.

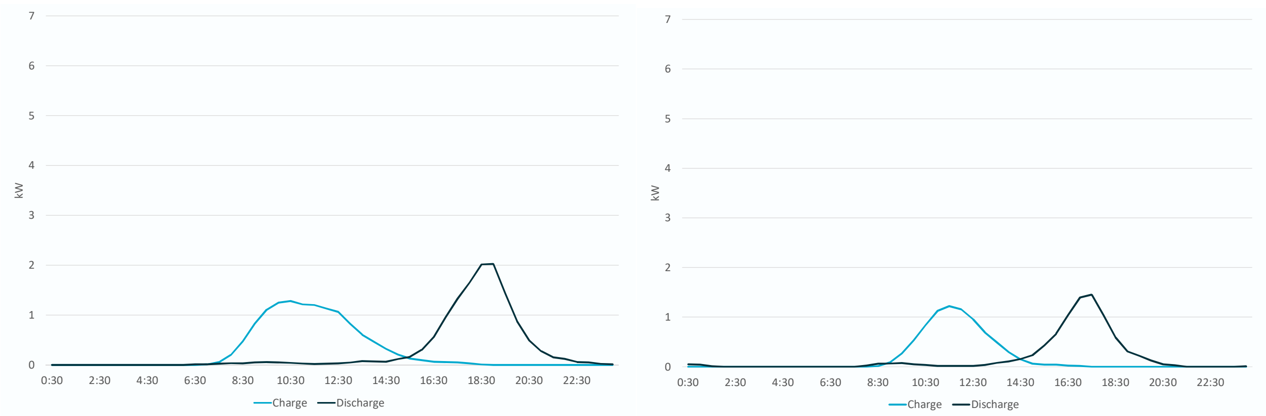


Figure 5-12 Average summer (left) and winter (right) commercial battery profiles for a flat tariff in the ACT

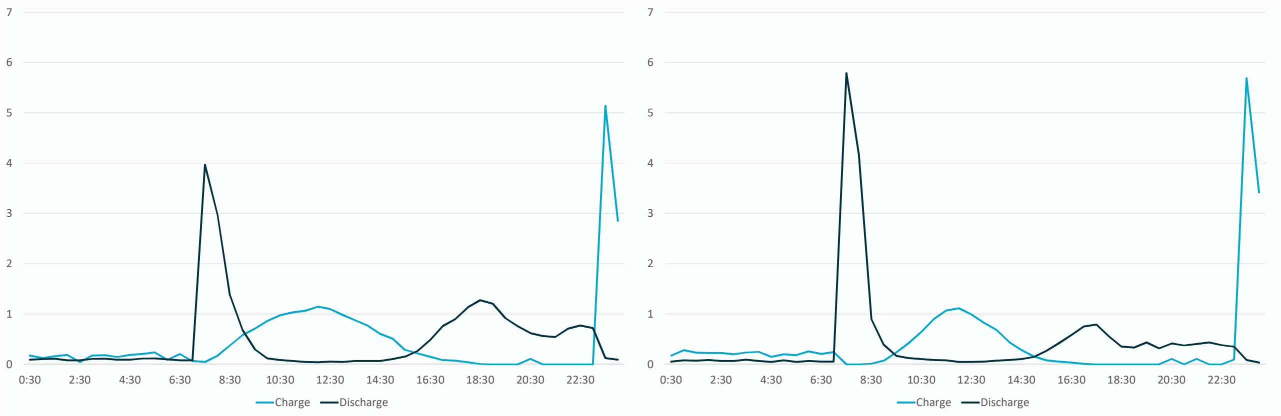


Figure 5-13 Average summer (left) and winter (right) commercial battery profiles for a TOU tariff in the ACT

5.5 Electric and hydrogen fuel cell vehicles

The projections allow for three types of electric vehicles: short- and long-range battery electric vehicles (SREVs and LREVs) and plug-in hybrid electric vehicles (PHEVs). Hydrogen fuel cell vehicles (FCVs) are all assumed to be long range vehicles with hydrogen as the only fuel.

The projected sales share for all electric vehicle types is shown in Figure 5-14. Following the assumption that SREV cost parity begins in 2025 for the Fast change, High DER and Step change scenarios, their sales levels become significant first. Central scenario sales increase to a significant level a few years later (with SREV cost parity assumed in 2030) and significant Slow change sales begin in the late 2020s (SREV cost parity assumed in 2035). Over a period of 10 years, most scenarios see sales shares progress to their assumed maximum market share which is based on several infrastructure and business model constraint assumptions defined Section 4. The exception is the Step change scenario in which, consistent with delivering a zero-emission economy by 2050, we relax all potential constraints and allow the sales share to grow to 100% by 2040 in most vehicle classes. The exception is articulated trucks where we assumed the market is shared between electric and fuel cell vehicles. Reflecting their higher cost, lack of vehicle models and infant fuel supply chain, fuel cell vehicles are projected to capture less than 10% of sales across all scenarios but perform better in the truck mode (particularly articulated trucks which are responsible for long haul road transport).

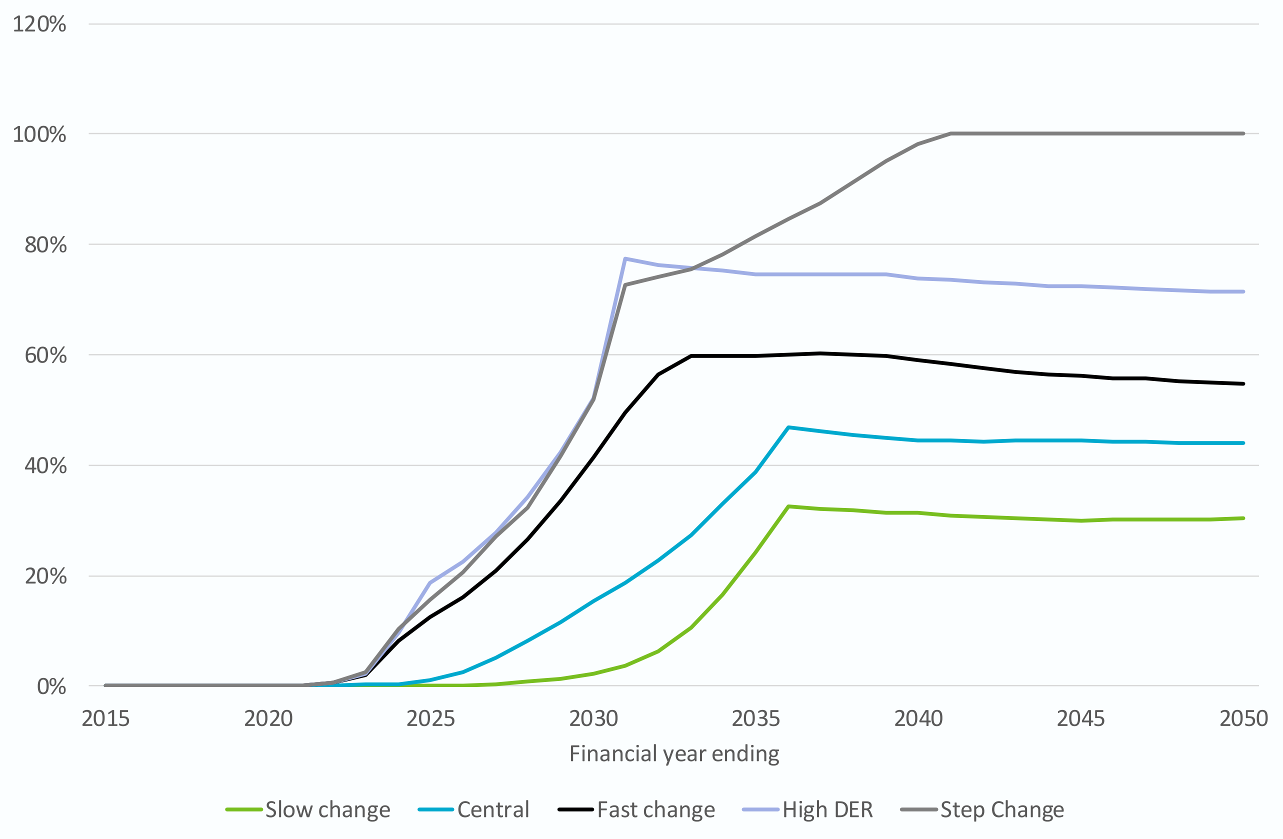


Figure 5-14 Projected sales share of electric vehicles by scenario

On average, Australians tend to keep vehicles on the road for 20 to 30 years depending on the region. This slow turnover of the vehicle stock means it can take more than 20 years for sales to translate into fleet share. In the Central scenario, the fleet share reaches just below 40% by 2050 but could likely reach 45%, the sales share, with more time. The electric vehicle fleet share approaches its sales share over the long run at a declining rate because of two factors. The first is that electric vehicles purchased are also subject to premature scrapping like the rest of the fleet due to accidental damage. The second is that, as discussed in Section 4, we assume ride sharing becomes a larger feature of the fleet in the last 20 years of the projection period and this drives a reduced number of total vehicle sales since fewer vehicles are required to meet passenger demand.

To reach a near 100% fleet share in the Step change scenario it was not sufficient to simply switch to 100% sales at the earliest possible date to achieve this goal. Even if moving to 100% sales within five years was plausible, there would still be a tail end of regions where this is insufficient to see all internal combustion engine vehicles retired from the fleet. Instead we impose a more realistic sales profile and assume that fleet scrapping rates accelerate from the 2030s. The accelerated scrapping rate could be driven by a policy mechanism or it might occur naturally as a product of market incentives and sentiment. Several states have policies to achieve zero net emissions by 2050 and may consider measures to support that in the road transport sector. Market incentives might include a rapidly declining choice of places to refuel and maintain internal combustion vehicles as electric vehicles become dominant. Changes in sentiment might include a shift in views about the economic viability, perceived performance and social acceptability of maintaining internal combustion vehicles. An analogous phenomenon would be the broad scrapping of often still functioning non-flat screen televisions in the last two decades.

Across the scenarios, fuel cell fleet share by 2050 ranges from less than 1% to a maximum of 6%. However, as discussed, they represent 50% of articulated trucks in the Step change scenario.

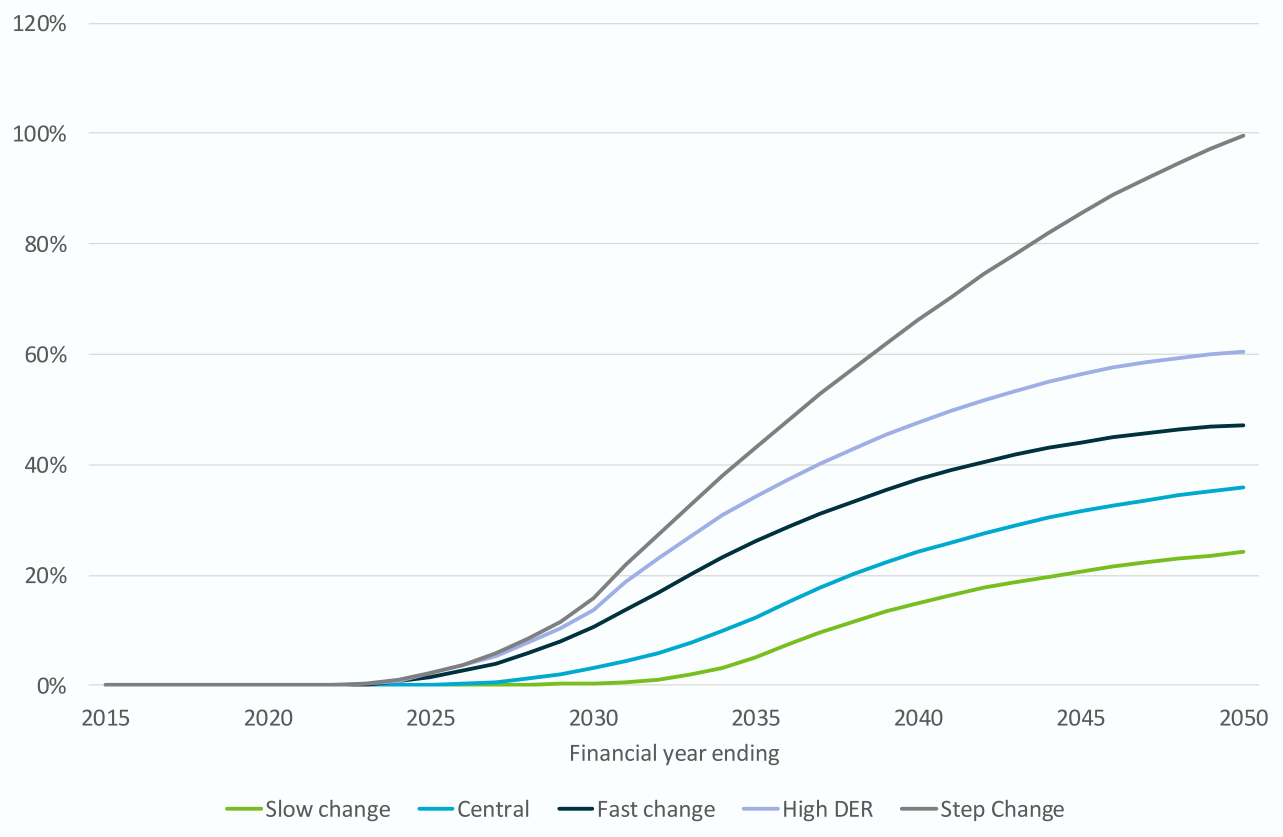


Figure 5-15 Projected electric vehicle shares of fleet

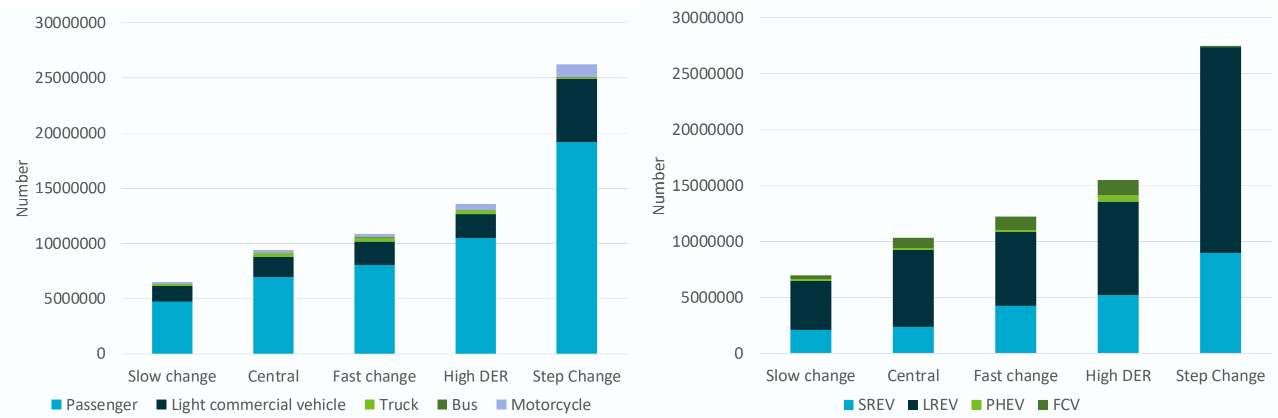


Figure 5-16 Breakdown of project electric and fuel cell vehicles by mode and vehicle type

There are currently around 20 million road vehicles in Australia. Figure 5-16 provides a breakdown of the transport mode (on the left) and type of non-internal combustion engine vehicle (on the right) that is included in the projections. The data shows that passenger vehicles are projected to be the greatest source of electric and fuel cell vehicle numbers followed by light commercial vehicles. The smaller vehicle categories of trucks, buses and motorcycles play a smaller role in terms of vehicle numbers. However, trucks deliver several times the kilometres and load of passenger vehicles so even these small numbers can have a significant impact on electricity and hydrogen demand.

It is projected that SREVs and LREVs will be the dominant non-internal combustion engine vehicle types with PHEVs and FCVs playing a lesser role. These projected outcomes mainly reflect economic circumstances. SREVs will be the cheapest vehicle type due to fewer batteries. However, being limited in range SREVs will only be preferred by a minority of electric vehicle owners who are prepared to make other arrangements when travelling long distance. LREVs are projected to be the most popular future vehicle type providing range similar to current vehicles and, in the long run, cheaper transport than current vehicles.

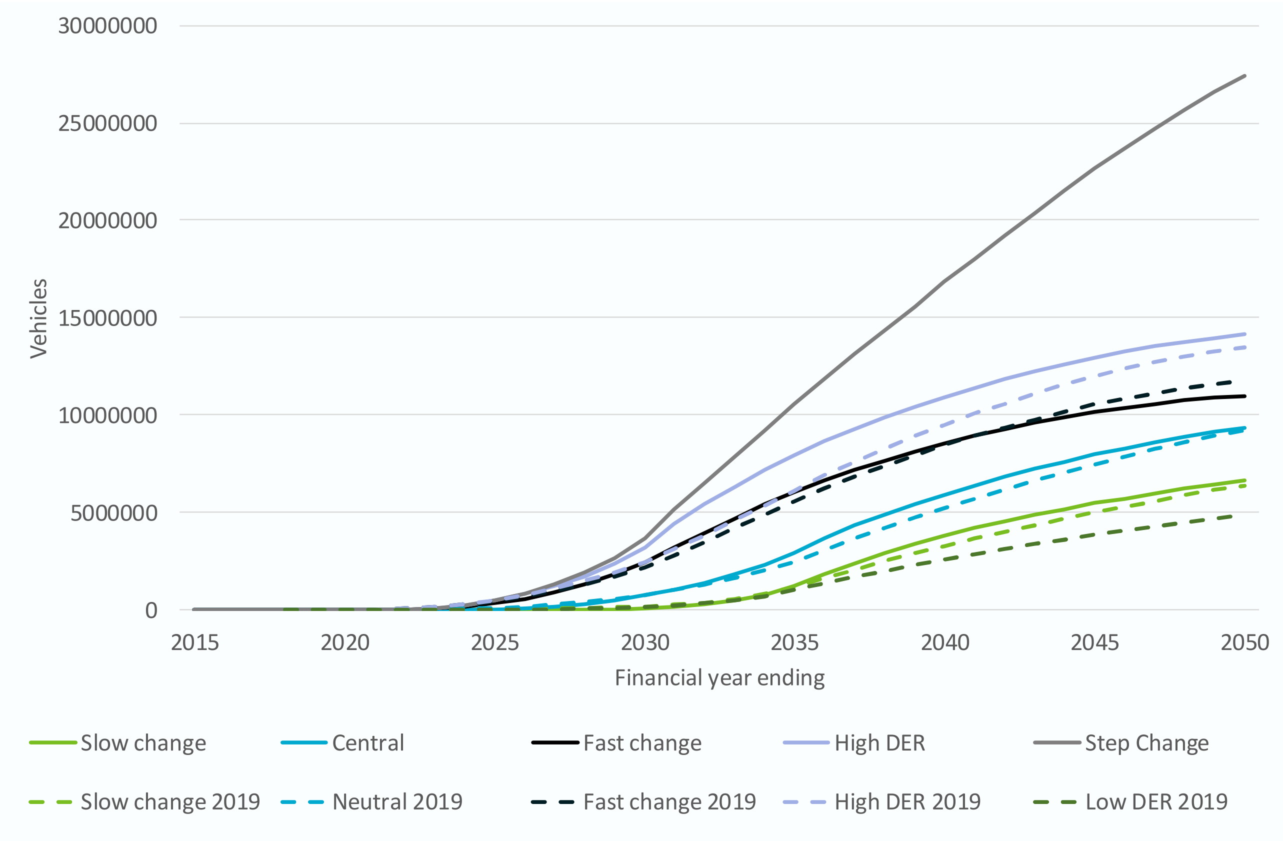


Figure 5-17 Projected number of electric vehicles by scenario compared to 2019 projections

The projected number of electric vehicles by scenario is shown in Figure 5-17 and compared with 2019 projections. Vehicles numbers are higher in Slow change because of a relaxation of maximum market share assumptions due to an upward revision of the share of renters who would be able to negotiate charging facilities in this scenario. Electric vehicle numbers are also slightly higher in other scenarios due to an upward adjustment to maximum imports of electric vehicles. Australia had a relatively strong increase in imports in 2019 and this has provided more confidence that we can accelerate access to global vehicle markets when needed from our relatively low current starting point.

Figure 5-18 shows the projected electricity consumption associated with electric vehicles[11] compared to 2019 projections. In addition to the reasons noted above regarding changes in electric vehicle numbers, all the projections are higher than their equivalent 2019 scenario

[11] The hydrogen that supplies fuel cell vehicles is not included under electricity consumption. Hydrogen could be produced from electricity but also in principle from fossil fuels with or without carbon capture and storage. If the hydrogen were produced from electricity, a general rule is that it requires around twice the electricity per kilometre as an electric vehicle due to losses in the electrolysis and fuel cell stages.

projections because the 2019 projections did not include electricity demand from articulated trucks. While articulated trucks only make up 0.5% of the fleet, each electric articulated truck will require around 50 times the amount of electricity per kilometre. This will be a substantial challenge in terms of charging infrastructure, placement on the vehicle and cost. However, the large portion of fuel costs in whole of vehicle costs means solving those problems has a much bigger pay off than smaller vehicles.

The Step change scenario presents itself as a significant outlier in terms of electricity consumption with almost the entire road transport fleet electrified (except for 50% of articulated trucks being fuel cell vehicles). As such this represents close to an upper bound in terms of what the road sector could contribute to electricity demand. The remaining scenarios are at half this consumption level or lower owing to the general difficulty of transforming the fleet, without a strong drive for zero emissions, when fleet turnover can take 20 to 30 years.

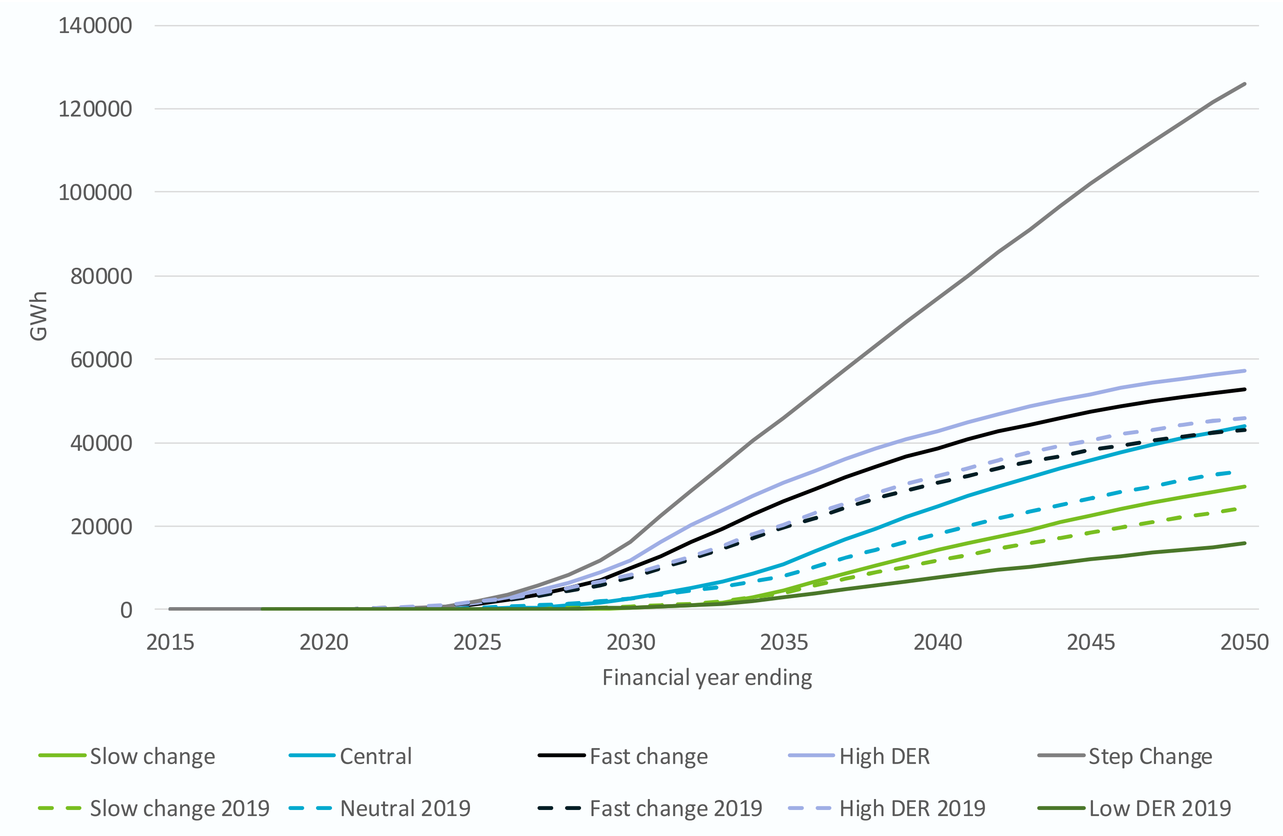


Figure 5-18 Projected electric vehicle electricity consumption

5.6 Electric vehicle charging profiles

Electric vehicle charging profiles are provided for the ten different vehicle types used in our projection modelling which includes motorcycles, 3 sizes of passenger vehicles, 3 sizes of light commercial vehicles, 2 sizes of trucks and buses. Four types of profiles have been created: convenience, night, day and fast charging or highway charging. The convenience profiles have been created from past studies which did not impose any specific constraints on charging (Roberts, 2016; Mader and Bräunl 2013; Victorian Government 2013). Highway charging is based on studies form China where deployment is large enough to see evidence of these outcomes (Chen et al 2016; Wang et al 2016). Day and night charging have been constructed by manually adjusting these observed profiles to account for future incentives structures not yet in place to encourage night charging in the short term and day charging in the longer term when solar generation is expected to strongly reduce daytime load. The night-time profile could be created by simple tariffs and managed individually. However, the daytime profile would need to be achieved through aggregated charging services attached to new infrastructure at the places where vehicles are parked during the day.

The charging profiles for cars and trucks shown in Figure 5-19, Figure 5-20, Figure 5-21 and Figure 5-22 are an average Australian daily profile only. To create an annual time series of charging over several years we make additional adjustments for:

- State differences in kilometres travelled per year
- Weekend and weekday travel
- Monthly differences in travel
- Changes in vehicle fuel efficiency each year
- Time spent travelling using the internal combustion engine in a PHEV.

Given we have identified in Figure 5-16 that passenger vehicles are projected to be the dominant type of electric vehicle, the convenience profile for this vehicle type is obviously a source of concern in regard to its potential contribution to maximum demand. The degree to which other profiles can be incentivised varies across the scenarios (Table 4-7). The inclusion of two truck sizes is new relative to 2019 projections. While we do not vary the shape of the profiles, the scale of charging changes dramatically as we go from rigid to articulated trucks.

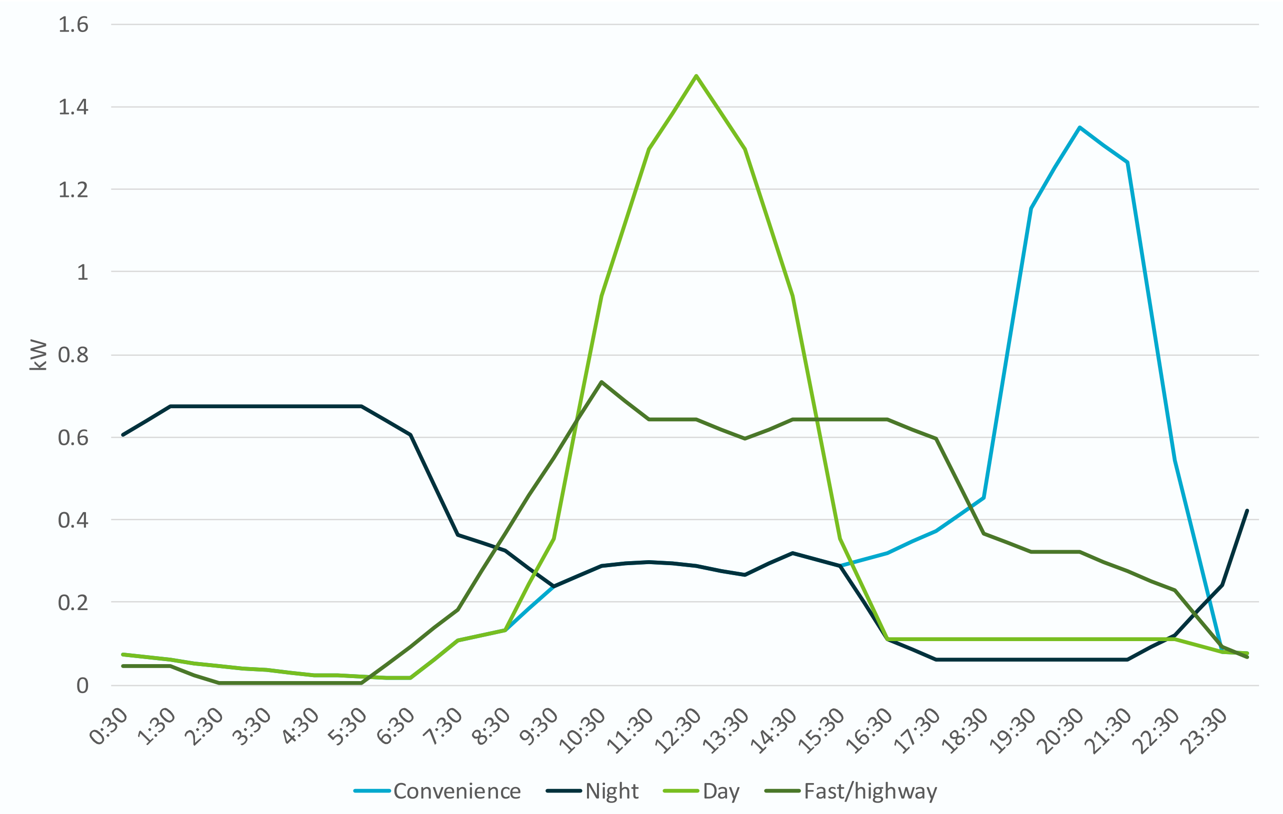


Figure 5-19 Average charging profile for a medium size passenger vehicle

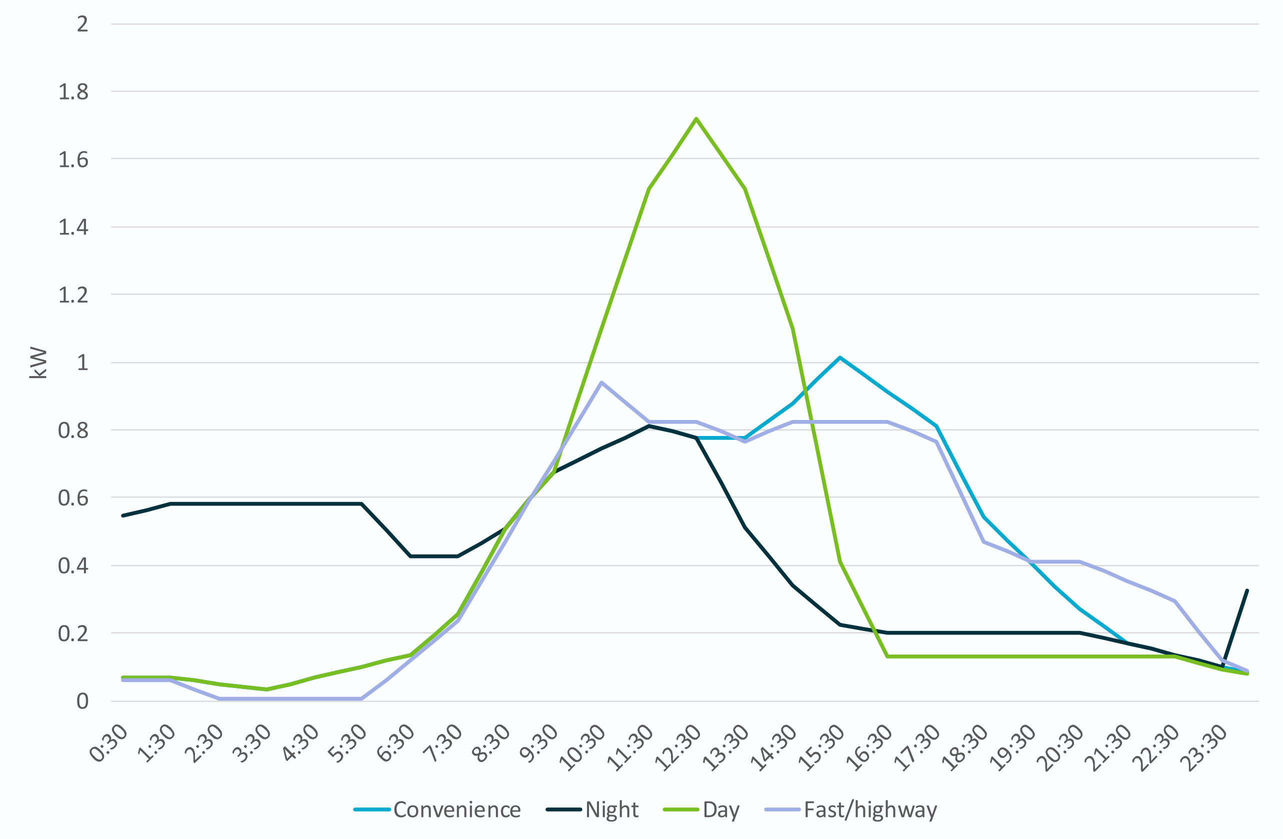


Figure 5-20 Average charging profile for a medium size light commercial vehicle

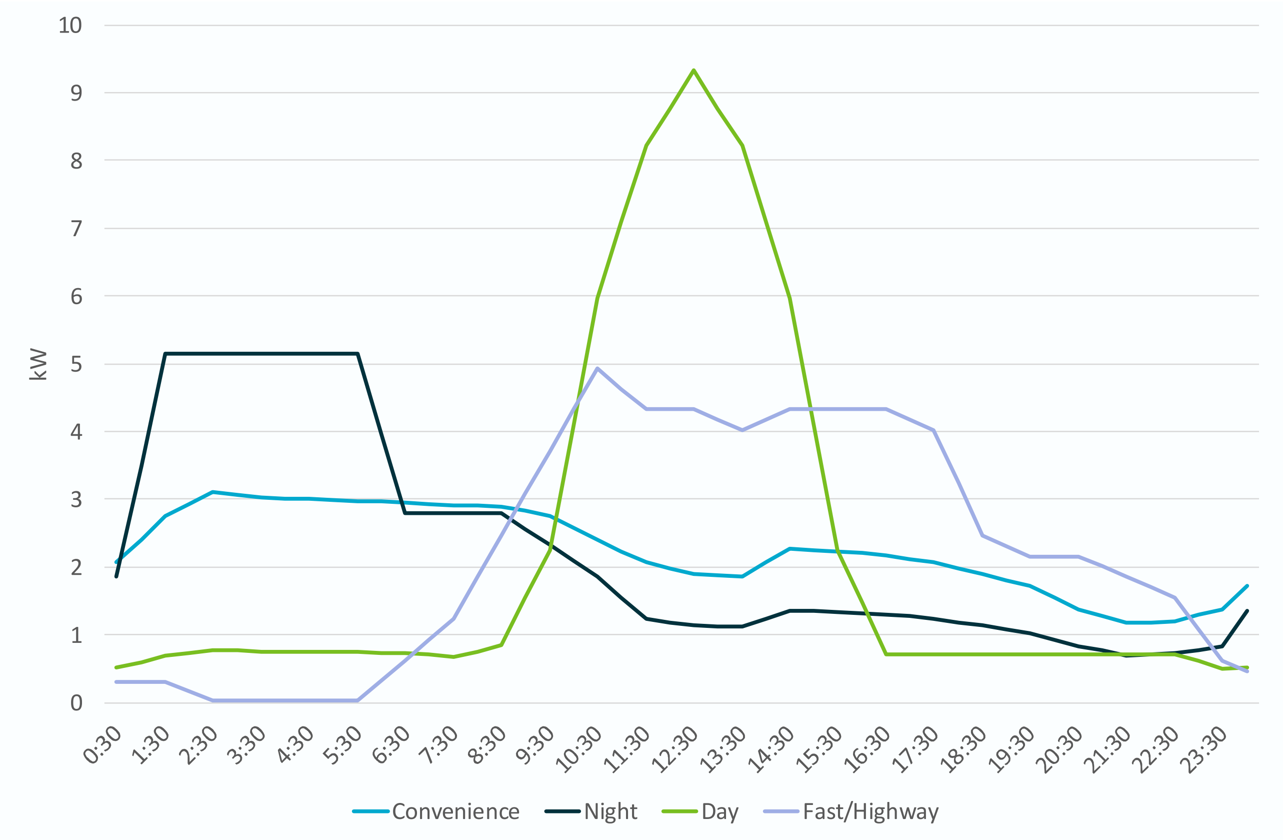


Figure 5-21 Average charging profile for a rigid truck

Figure 5-22: Average charging profile for an articulated truck

Appendix A Additional data assumptions

In this appendix we outline some key additional assumptions that were used to develop the adoption projections in addition to the scenario specific assumptions discussed in the body.

A.1 Technology performance data

Each technology can be described by a small number of performance characteristics with energy efficiency being a common one whilst others are specific to the technology. The following tables outline key performance data for rooftop solar, battery storage and electric vehicles.

A.1.1 Rooftop solar

Rooftop solar generation profiles were sourced from AEMO. Table A.1 shows the average capacity factors from these production profiles.

Apx Table A.1 Rooftop solar average annual capacity factor by state, 2018-19

Apx Table A.1 Rooftop solar average annual capacity factor by state, 2018-19 (to be updated)

	Capacity factor
New South Wales	0.145
Victoria	0.136
Queensland	0.150
South Australia	0.146
Tasmania	0.131
Western Australia (SWIS)	0.159
Northern Territory	0.149

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

Rooftop solar capacity degradation is assumed to be 0.5% per annum based on Jordan and Kurtz (2012). Warranties imply closer to 1% annual degradation but include a margin to be conservative. This is a stock wide assumption and does not preclude better or worse performing product variations.

A.1.2 Battery storage

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

The value of 10kWh for residential customers matches the reported average size in SunWiz (2020) for 2019. It is also reasonably consistent with the average size in the battery operation optimisations which was 9kWh for customers with time-of-use tariffs and 10.9kWh for customers with flat tariffs.

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

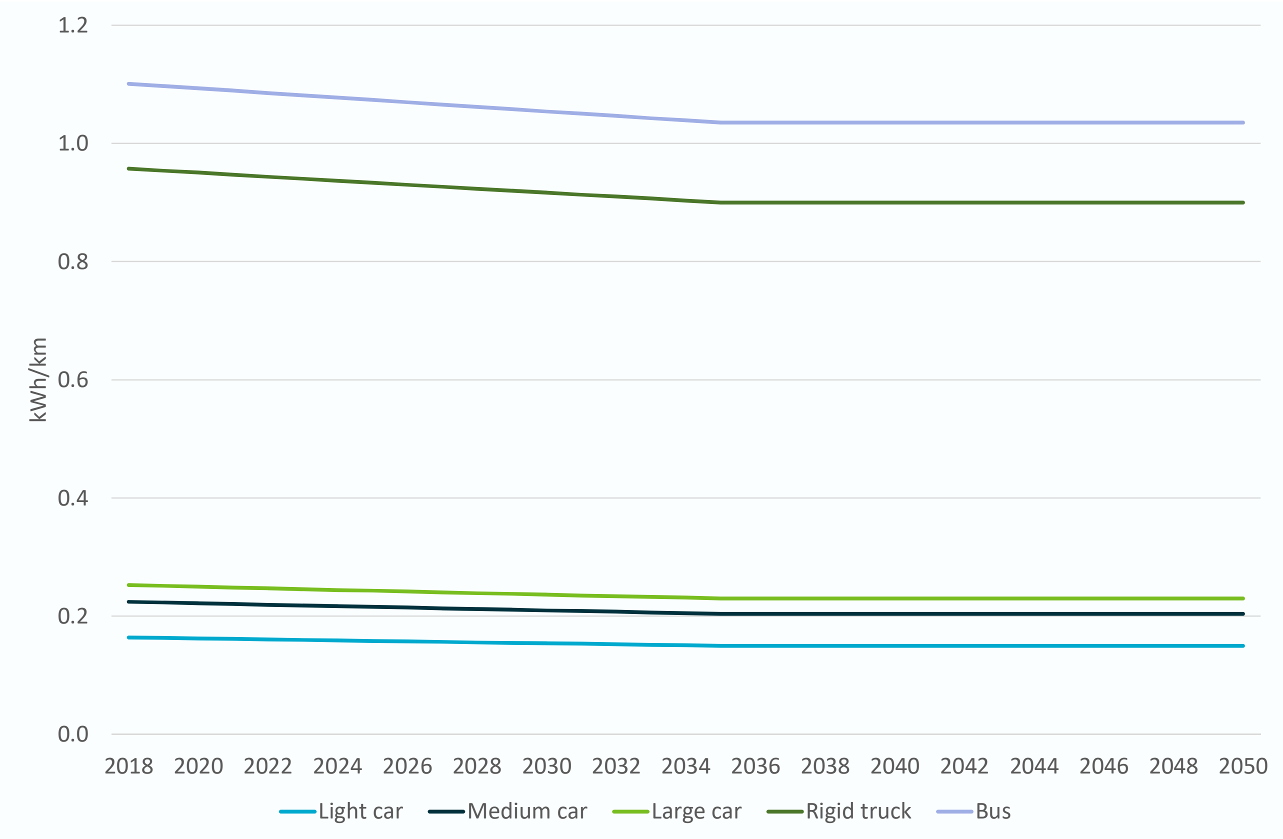
Apx Table A.2 Battery storage performance assumptions

Characteristic	Assumption
Round trip efficiency	85%
Maximum charge or discharge of rated capacity	95%
Rated capacity projections	Residential: 10kWh
	Small commercial: 36kWh Large commercial: 145kWh
Rated capacity operation profiles	Optimised for each residential customer
Maximum power in kW	Residential: Rated capacity divided by 2.6 Commercial: Rated capacity divided by 1.0
Degradation rate	1.6% per annum (on both kW and KWh capacity)
Life	5000 cycles or 10 years

The degradation rate is a function of many factors including temperature, depth of discharge and battery design. There are a wide variety of models for understanding how degradation occurs (Reniers at al., 2019) which can give diverse predictions about degradation rates. We have chosen a rate consistent with loss of 20% battery capacity by the end of a 5000-cycle life which assumes moderate temperatures, the battery is not fully charged or discharged and there is only one cycle per day.

A.1.3 Electric and fuel cell vehicles

The key performance characteristic for electric and plug-in hybrid electric vehicles is their fuel efficiency. Figure A.1 shows the assumed vehicle fuel efficiency per kilometre by mode for electric vehicles.



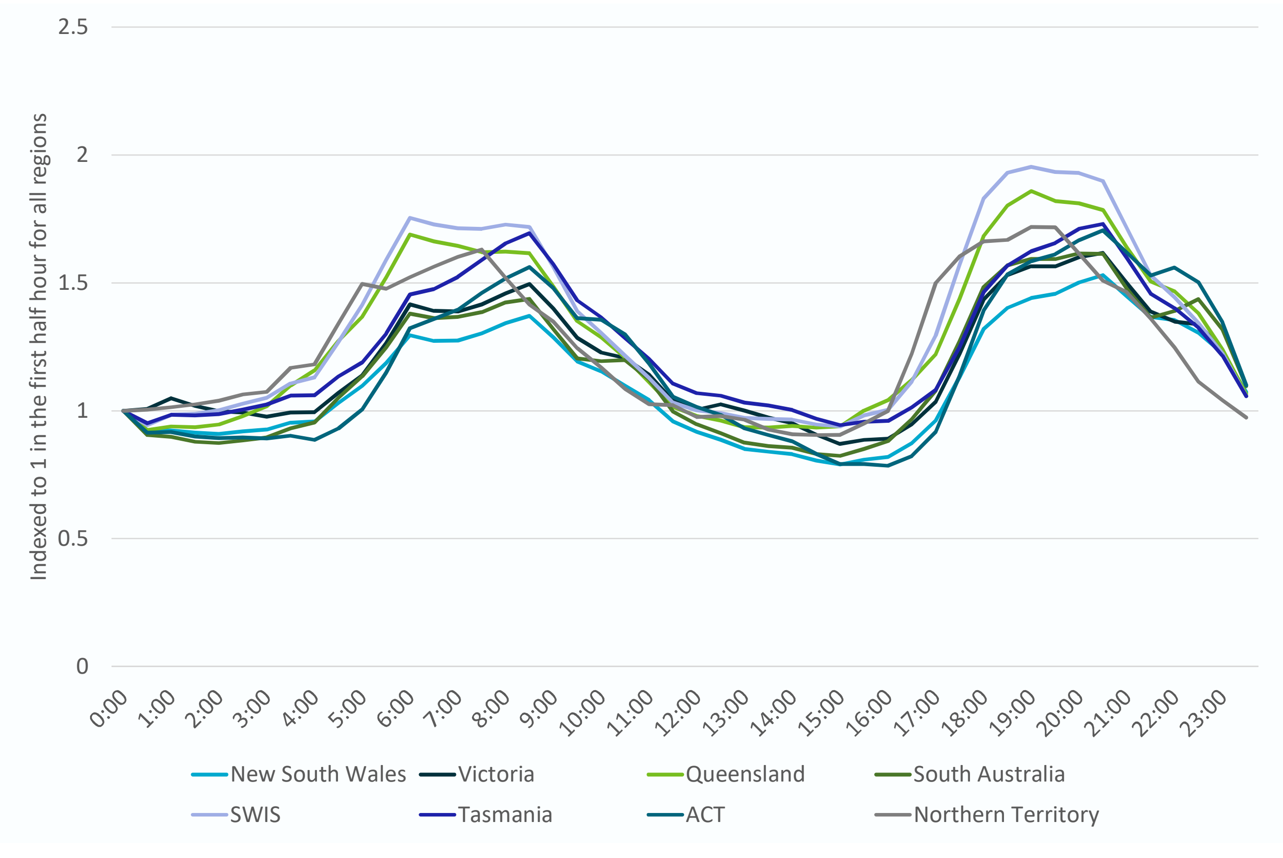
Apx Figure A.1 Electric vehicle fuel efficiency by road mode

The key determinant of fuel efficiency is vehicle weight with the lightest vehicles having the lowest electricity consumption per kilometre. The batteries which store the electricity of course add to total vehicle weight and we assume some improvement in battery energy density over time leads to a steady improvement in fuel efficiency up to around 2035 and plateaus thereafter. Historically, internal combustion engine fuel efficiencies have tended to plateau unless there is significant fuel price pressure. That is further engine efficiency improvements were traded off for better acceleration or more comfort, safety and space. We assume electric vehicles will follow the same trend.

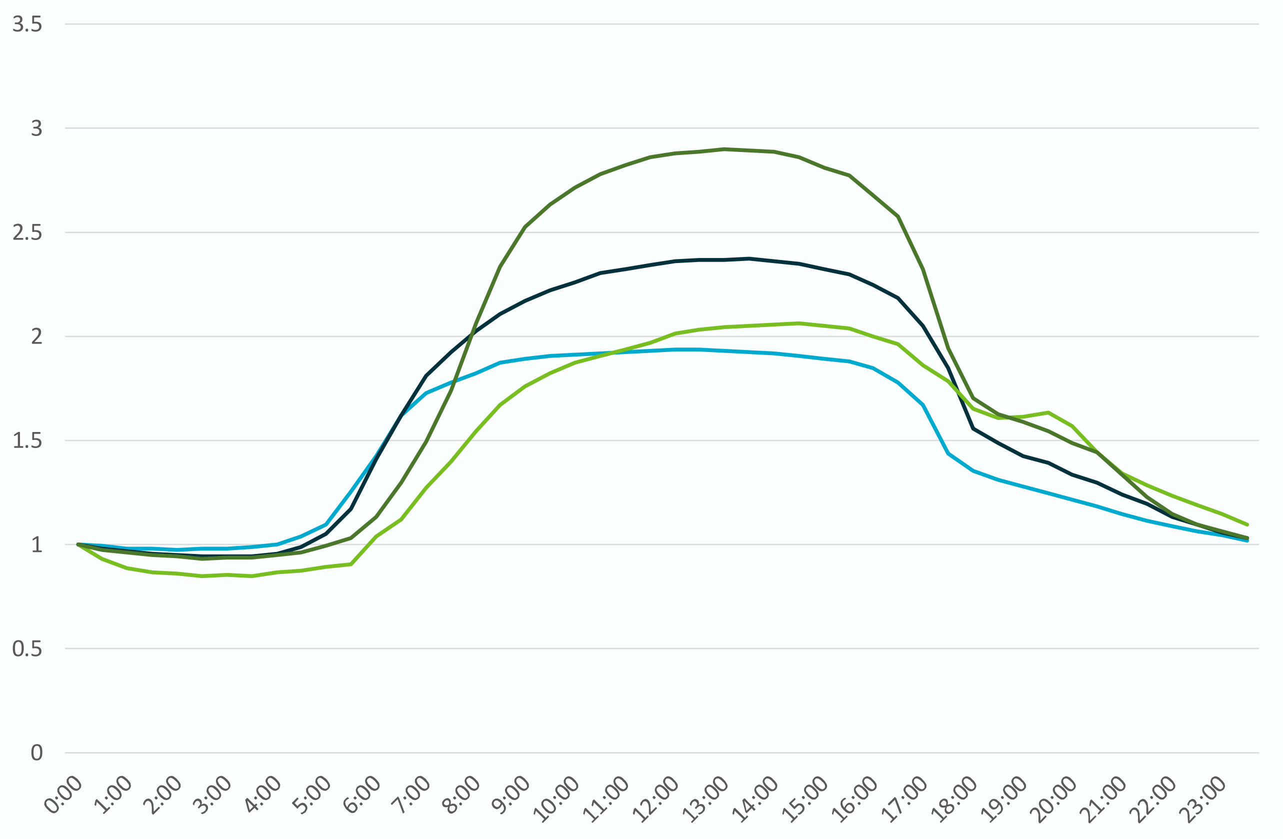
A.2 Customer load profiles

Australia still faces difficulty in accessing public load profiles due to privacy considerations. For that reason, we use a mixture of synthetic and real customer load profiles. For residential data we started with around 5000 New South Wales Ausgrid profiles from the Smart Grid Smart Cities program and found the 5 most representative profiles and their nine nearest neighbours using clustering analysis. We then synthetically created 45 profiles for each other distribution network area by subtracting the difference between the most residential zone substation in each network relative to Ausgrid's most residential zone substation. This process should adjust for differences in timing (daytime hours) and climate but is probably insufficient to account for all differences in gas versus electricity use, for example, between different states. The SGSC data set did include people with and without gas and with and without hot water control but the proportions will not match other states. The average summer profile for each region is shown in Figure A.2. The non-daylight savings regions of the SWIS, Northern Territory and Queensland are evident in the differences in timing of demand. The main difference in load is that New South Wales stands out as the least extreme profile reflecting its relatively milder weather than either the northern or southern states. Otherwise they follow the same double peak/trough trend reflecting daytime activity and sleep cycles. One more notable difference is the timing of controlled hot water at night in South Australia and the Australian Capital Territory.

For commercial load profiles we use a small number from previous work and do not adjust them by region. In using a smaller set our assumption is that commercial profiles vary less than residential between customers and regions (Figure A.3).



Apx Figure A.2 Index of average half hourly residential summer loads by region



Apx Figure A.3 Index of average half hourly summer loads for four commercial customers

Shortened forms

Abbreviation	Meaning
ABS	Australian Bureau of Statistics
ACCU	Australian Carbon Credit Unit
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
APVI	Australian Photovoltaic Institute
AV	Autonomous Vehicle
BOP	Balance of plant
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
EE	Energy Efficiency
ERF	Emissions Reduction Fund
EV	Electric Vehicle
FCAI	Federal Chamber of Automotive Industries
FCAS	Frequency Control Ancillary Services
FCV	Fuel Cell Vehicle
FiT	Feed-in Tariff
GDP	Gross Domestic Product
GSP	Gross State Product
hrs	Hours

ICE	Internal Combustion Engine
IPART	Independent Pricing and Regulatory Tribunal
ISP	Integrated System Plan
kW	Kilowatt
kWh	Kilowatt hour
LCV	Light Commercial Vehicle
LGC	Large-scale Generation Certificates
LRET	Large-scale Renewable Energy Target
LREV	Long-range electric vehicle
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NSG	Non-Scheduled Generation
PHEV	Plug-in hybrid electric vehicle
PV	Photovoltaic
QRET	Queensland Renewable Energy Target
RET	Renewable Energy Target
SA2	Statistical Area Level 2
SGSC	Smart Grid Smart Cities
SREV	Short-range electric vehicle
STC	Small-scale Technology Certificates
SWIS	South-West Interconnected System
TOU	time-of-use
UNFCCC	United Nations Framework Convention on Climate Change

VEEC	Victorian energy Efficiency Certificate
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Target
WEM	Western Electricity Market

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