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Projections for small-scale embedded technologies

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Report for AEMO

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Executive summary

This report provides projections of the number and capacity of small-scale embedded technologies in Australia which include solar photovoltaic systems (solar PV), battery storage and electric vehicles. The projections are for the purpose of assisting AEMO in producing electricity consumption and maximum/minimum demand forecasts for AEMOs 2018 electricity forecasting insights and related documents.

This category of technologies is characterised by a large number of investors, with diverse circumstances and who are likely to include a number of non-price factors in their investment decision making process. Consequently CSIRO applies consumer technology adoption curve theory to the projection methodology. This approach allows for the existence of early adopters, for example, who will invest regardless of long payback periods. The approach also captures factors such as infrastructure constraints which might cause a market to saturate at low market shares, even if the payback period is favourable. As these factors differ by location we are able to provide more granular projections.

The relatively short payback period for rooftop solar PV and recent higher retail prices for electricity have seen continued growth in installations and large system sizes. The projections find that growth is expected to continue in the next few years and then slow through the 2020s. The slower growth in the 2020s reflects an expected weakening in retail prices as new electricity generation capacity enter the wholesale generation market and a decrease in the upfront subsidy available to rooftop solar installations from around $600/kW at present to zero by 2030 with the closure of the Small-scale Renewable Energy Scheme (SRES).

Projections also provided for solar projects that are larger than 100kW (and up to 30MW). Such projects are not eligible for SRES subsidies but can earn renewable generation certificates from the Large-scale Renewable Energy Target (LRET). Data available for 2017 and early 2018 indicates this category of solar is already experiencing strong growth. While the required capacity for the LRET will be complete in 2020, additional state renewable schemes and the continued falling costs of solar PV is expected to support continued growth consistent with historical rates.

For both residential and commercial, the projections for battery storage are for strong growth in the short term. The growth rate is expected to moderate in the 2020s, reflecting slower growth in rooftop solar installations already discussed, but stronger growth is expected to resume from the late 2020s onwards. The payback period for residential integrated solar and battery installations remains high (10 years or greater in most states) and so we would categorise this market as still in the early adopter phase. However, by 2050, 21 to 57% of residential rooftop solar installations are expected to include battery storage. The share is lower for commercial systems because their load and solar generation profiles are better aligned. That is, battery storage has less incremental value compared to residential customers who are in greater need of shifting solar output.

The payback period for electric vehicles is expected to fall to zero, for short range electric vehicles at least, around 2030 for Australia. This may occur earlier in other countries where internal combustion vehicles are higher cost due to the effect of vehicle emission standards policies. As the financial barrier to electric vehicle adoption reduces we expect non-financial issues to be the main driver of adoption. Chief among these is whether prospective owners have access to a second long range vehicle and to off-street parking (or if not, to public charging locally and on major highways). These constraining factors, together with the limited rate of turnover of the vehicle fleet mean that electric vehicles are projected to reach 32% of the fleet by 2050.

Around these central projections which we call the Moderate scenario, we also provide Slow and Fast scenario projections. In considering the Slow and Fast scenarios, a factor common across the categories of small-scale technologies is that business model innovations provide the greatest source of uncertainty in the projections. Business model innovations will define, for example, the potential payments battery owners receive for their demand management capabilities, the amount of public charging infrastructure available to electric vehicle owners, the level of access to solar for apartment dwellers and renters and whether these technologies are predominantly privately or publicly owned. Consequently, these factors lead to significant differences by 2050 between the Slow, Moderate and Fast scenarios. Other significant sources of uncertainty are the rooftop solar hosting capacity constraints of the distribution network, the long term retail price of electricity and the rate at which global vehicle manufacturers can supply electric vehicles during the 2020s in response to growing demand.

1 Introduction

This report was commissioned by AEMO who require projections of small-scale embedded technologies which include solar photovoltaic systems (solar PV), battery storage and electric vehicles. The projections are for the purpose of assisting AEMO in producing electricity consumption and maximum/minimum demand forecasts for AEMOs 2018 electricity forecasting insights and related documents.

The projections are provided for three scenarios: Slow, Moderate and Fast which were developed with AEMO based on agreed scenario parameters. The scenario parameters included input from AEMO on drivers such as customer growth, gross state product and electricity prices. CSIRO also developed other scenario assumptions drawn from a range of other relevant drivers, depending on the technology.

The projections are required at a state level from 2017-18 to 2049-50. For Western Australia and Northern Territory, only the South West Interconnected System (SWIS) and Darwin-Katherine Interconnected System (DKIS) are included. Some projections were also supplied to AEMO at the Australian Bureau of Statistics (ABS) Statistical Area Level 2 (SA2) level. However, this report mostly focusses discussion on state level results.

The solar PV projections are separated by size and market segment as follows: residential, commercial 10 to 100kW, commercial 100kW to 1MW, commercial 1Mw to 10MW and commercial 10MW to 30MW. The first two segments are generally rooftop solar systems and are eligible to receive funding under the Small-scale Renewable energy Scheme (SRES). Battery storage projections are also provided under these two segments.

The last three segments are referred to as Non-scheduled Generation (NSG) and may receive funding under the Large-scale Renewable Energy Target (LRET). We also provide projections for a sixth segment which is standalone power systems (SAPS) or off-grid systems which may include solar PV, battery storage and petroleum based generators. Given SAPS are not connected to the grid they are of less importance in terms of their impact on the profile of grid demand, however their adoption could result in slower net customer growth.

The market segments for electric vehicles include two engine configurations: 100% electric (EV) and plug in hybrid electric (PHEV). The vehicle types include passenger, light commercial vehicles, rigid trucks and buses.

The report describes the projection methodology, scenario drivers and data assumptions and projection results. The appendices also describe additional data assumptions and maps of sub-state results.

2 Methodology

2.1 Adoption projections method overview

CSIRO proposes to use a common projection methodology 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 with a different adoption projection method.

2.1.1 Adoption in “consumer” technology markets

The consumer technology adoption curve posits that technology adoption will be initially led by an early adopter group who, despite high payback periods, are driven to invest by other motivations such as values, autonomy and technological enthusiasm. 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 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 a 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 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, 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. 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.

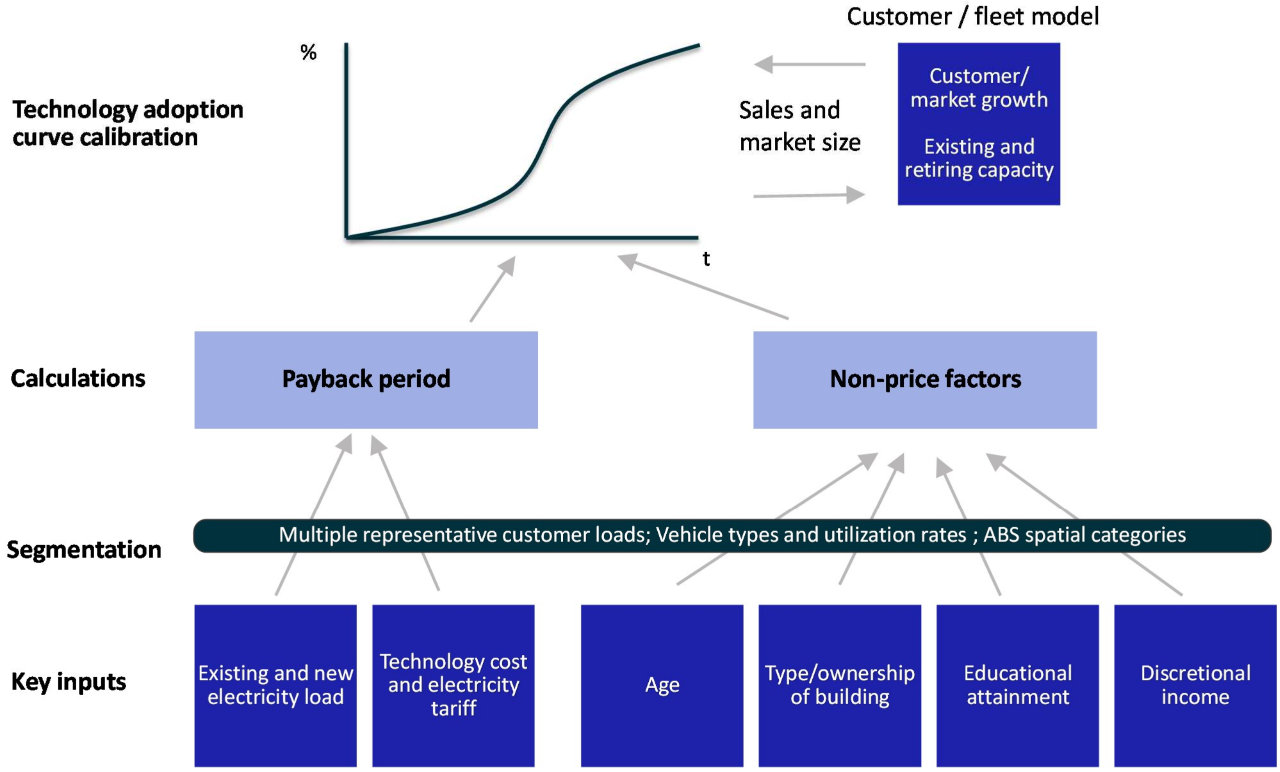


Figure 2-1: Projection methodology overview

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 are influenced by population growth, economic growth and transport mode trends and we discuss the latter further in the scenario assumptions section.

All calculations are carried out at the Australian Bureau of Statistics Statistical Area Level 2 (SA2) as this allows

2.1.2 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 exclusively 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. Electricity prices and any additional available renewable energy credits in each state or territory will therefore be one of the stronger drivers of adoption. Where investment is able to 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 and Figure 2-4 show the historical total deployment in each of solar plants in the 0.1MW to 1MW, 1MW to 10MW and 10MW to 30MW ranges respectively (source from APVI (2018)). 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 plant are less frequent and concentrated only in New South Wales, Western Australia and the Australian Capital Territory.

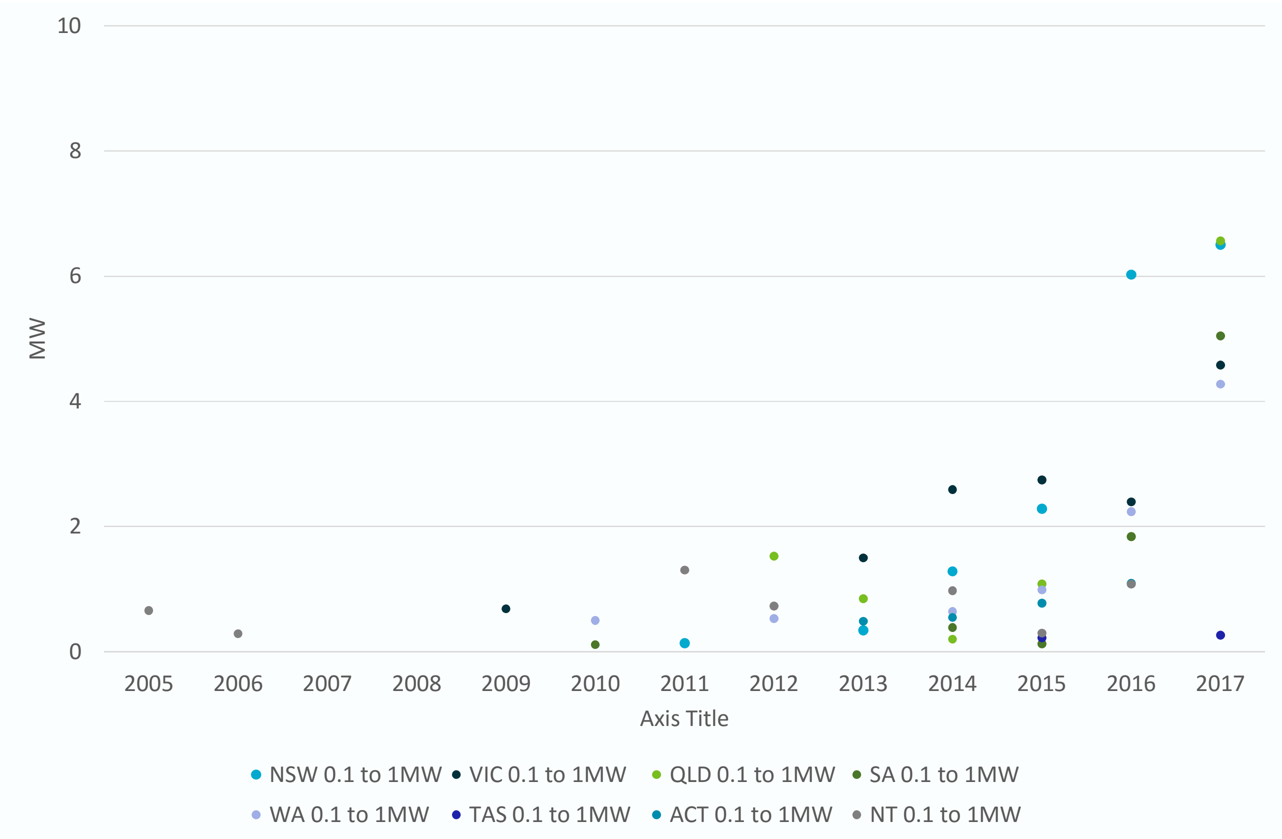


Figure 2-2: Historical deployment by state of solar systems of size 0.1 to 1 MW

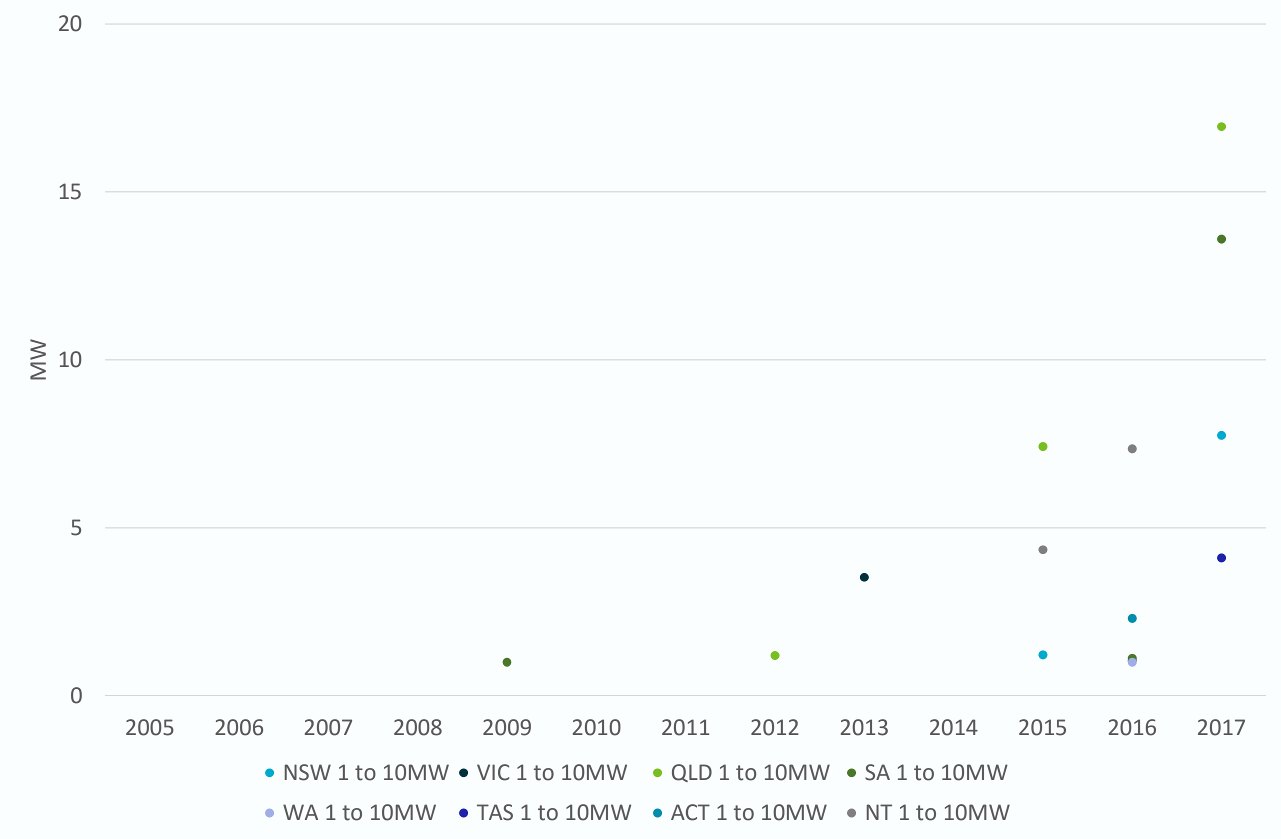


Figure 2-3: Historical deployment by state of solar systems of size 1 to 10 MW

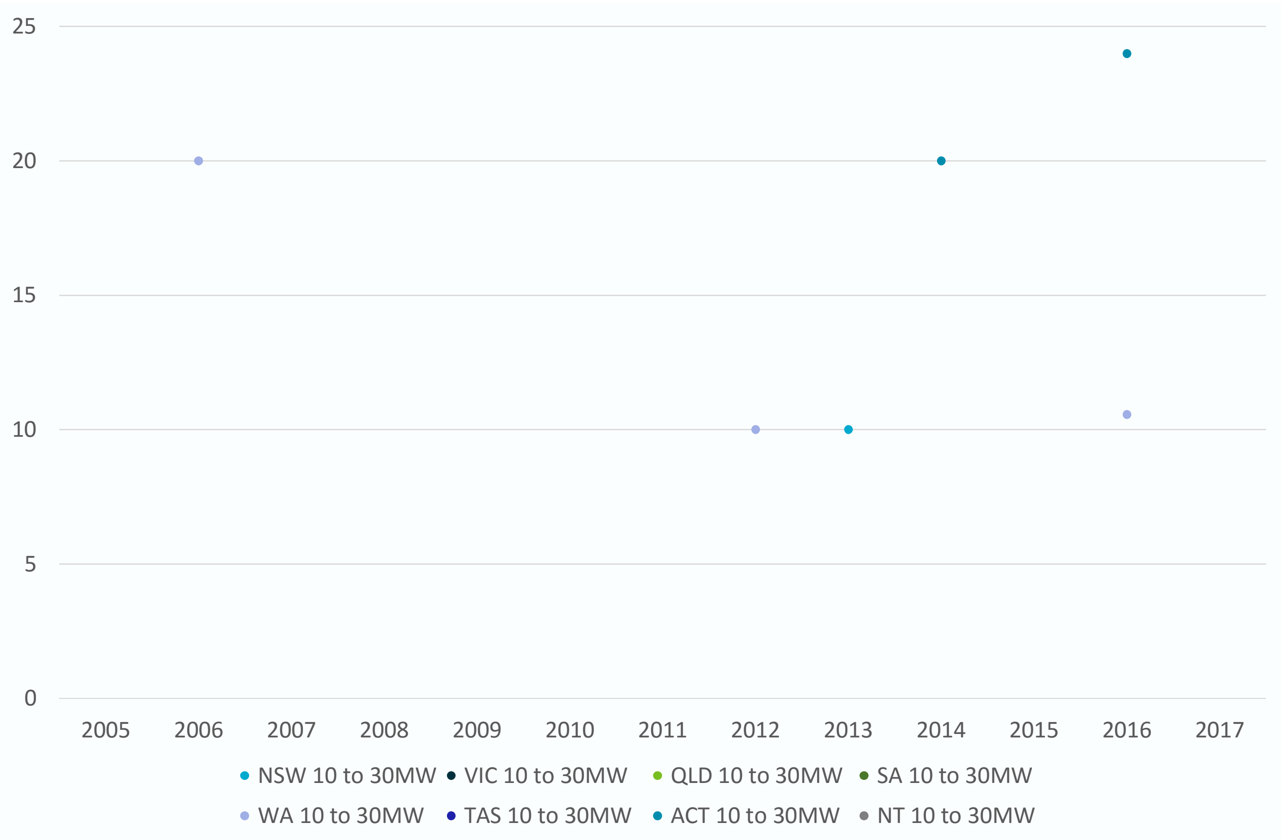


Figure 2-4: Historical deployment by state of solar systems of size 10 to 30 MW

2.2 Demographic factors and weights

The projection methodology includes selecting a set of non-price factors, typically drawn from accessible demographic data to calibrate the consumer technology adoption curve. An optional second step is to assign different weights to each factor to reflect their relative importance. Here we outline the factors and weights chosen for the small-scale technologies 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 the model was calibrated for 2010. Given the time that has passed and 2010 being very a much an early adopter phase of the market we tested a new set of factors. We have also emphasised using data that is readily available in SA2. The weights and factors applied were tested over 2017 sales data and are shown in Table 2-1.

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 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

The current public data is insufficient to locate commercial systems and slightly distorts our understanding of residential solar capacity per spatial region. The spatial data for solar systems below 100kW is not separated by type of owner, only total installations and kilowatts per postcode. Based on other sources, we know the relative share of residential and commercial systems at a state level. We therefore calculate residential and commercials systems as the state share of systems in that postcode.

2.2.2 Weights and factors for electric vehicles

Previous analysis by Higgins et al (2012) validated a number of 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 proxy 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 middle-aged 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

3 Scenario assumptions

The projections for small-scale embedded technologies are provided for three scenarios: Fast, Moderate and Slow. Given the projection methodology encompasses a wide variety of financial and non-financial drivers, there is considerable scope to incorporate a wide range of complex drivers to construct these scenarios.

In developing the scenarios we first define the full range of scenario drivers that could lead to alternative adoption outcomes. Next we combine these drivers into consistent sets of scenario assumptions.

3.1 Scenario drivers

3.1.1 Economic drivers

The key economic drivers which could drive alternative solar and battery storage adoption scenarios are:

- installed cost of rooftop solar and battery storage systems and any additional component such as advanced metering,
- current and perceived future level of retail electricity prices,
- the structure of retail electricity prices available to that residence or business,
- the level of feed in tariffs (FiTs) which are paid for exports of rooftop solar electricity (whilst more normally a retailer set price we discuss this further in policy drivers),
- wholesale (generation) prices which may influence the future level of FiTs
- general buoyancy of economic conditions supporting investment confidence and attitudes to debt (e.g. represented by growth in wages or gross domestic product)

For electric vehicles the economic drivers are:

- the whole cost of driving an electric vehicle including vehicle, retail electricity for charging, the charging terminal (wherever it is installed), insurance, registration and maintenance costs
- the whole cost of driving an internal combustion vehicle as an alternative including vehicle, fuel, insurance, registration and maintenance costs
- perceptions of future changes in petroleum-derived fuel costs including global oil price volatility
- the structure of retail electricity prices relating to electric vehicle recharging
- the perceived vehicle resale value

- general buoyancy of economic conditions supporting investment confidence and attitudes to debt (e.g. represented by growth in wages or gross domestic product)

3.1.2 Infrastructure drivers

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

The key infrastructure drivers for solar and battery systems are:

- The quantity of residential or commercial roof space or vacant adjacent land, ideally free of shading relative to the customer's energy needs (solar)[1]
- Garage or indoor space, ideally air conditioned, shaded and ventilated (battery storage)
- 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)
- Distribution network constraints imposed on small-scale systems as a result of hosting capacity constraints (e.g. new rooftop system sizes may be no larger than 5kW)
- Distribution network constraints relating to connection of solar photovoltaic projects in the 1MW to 30MW range
- The degree to which solar can be integrated into building structures (flat plate is widely applicable but alternative materials could extend the amount of usable roof space)

For electric vehicles the key infrastructure drivers are:

- Convenient location for a 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
- 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 longer term payoff from the upfront costs of installing the charger.
- Convenient access to highway recharging for owners without access to extended range capability (or other options, see below)
- Access to different models of electric vehicles (e.g. fully electric limited range, fully electric long range, plug-in hybrid electric and internal combustion) with different driving ranges to suit diverse customer travel needs

[1] Add footnote here about orientation not being necessarily a big issue

- Convenient access to other means of transport such as a second car, in the household, car/ride sharing, train station, airport and hire vehicles for longer range journeys

Sufficient distribution network capacity to meet coincident charging requirements of high electric vehicle share parts of the network could also be an infrastructure constraint if not well planned for. However, networks are obligated to expand capacity to meet load where needed and so any such constraints would only be temporary.

Given the constraints of commute times and cost of land in large cities, we are generally observing a 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. There has also been recent evidence 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 car/ride sharing services (discussed further in the next section) which result in fewer vehicles.

3.1.3 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 3-1 explores some emerging and potential business models which could drive higher adoption of small-scale embedded technologies.

Table 3-1: Emerging or potential disruptive business models to support small-scale embedded technology adoption

Technology category	Business model	Constraint reduced
Rooftop solar	Apartment building body corporate as retailer	Rooftop solar is more suitable for deployment in dwellings which have a separate roof
Rooftop solar	Peer to peer selling as an alternative to selling to a retailer	Landlords have limited ability to extract value from roof space on their rental properties
Rooftop solar	Networks are incentivised through regulatory changes to purchase voltage control services	Network hosting capacity imposes restrictions on rooftop solar uptake
Rooftop solar	No money down 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.
Battery storage	Retailers and networks reward demand management through direct payments, alternative tariff structures or direct ownership and operation of battery to reduce costs elsewhere in their business	Given the predominance of volume based tariffs, the main value in battery storage is in reducing rooftop solar exports
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
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
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 home owners under high mortgages
Electric vehicles	Some businesses may offer charging as free additional amenity to encourage patronage of their core business	Access to electric vehicle charging will be primarily at the home or business owner's premises
Electric vehicles and rooftop solar	Businesses offer day time parking with low cost controlled charging and provide voltage control services to 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 is frequently shut off by inverter due to voltage variation in high solar uptake areas

Electric vehicles	Electric vehicle batteries are sold as low cost home batteries as a second life application	Battery storage represents a high upfront cost, discretionary investment.
Electric vehicles[1]	Car/ride sharing and vehicle automation could lead to electric vehicle investment being led by businesses which will achieve 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.
Electric vehicles, rooftop solar and battery storage	Home energy management service companies supply and operate integrated electric vehicle, rooftop solar, battery storage, and HVAC and water heating home management packages	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

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.

3.1.4 Policy drivers

Small-scale Renewable Energy Scheme

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 generally 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, 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.

State government renewable energy schemes

While it is possible that other states could implement a variety of new policies the two schemes which are considered in these projections are the Victorian Renewable Energy Target (VRET) and Queensland Renewable Energy Target. Under current auction arrangement VRET is only open to renewable generators above 10MW which is relevant for some small-scale solar but not rooftop solar. The Queensland government accepted a recommendation to not include an incentives in addition to the Commonwealth Small-scale Renewable Energy Scheme.

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 feed-in tariffs 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 6-12 c/kWh across most states with 9c/KWh being a common rate in 2017-18. 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 at around 25c/kWh to 30c/kWh reflecting higher costs of generation.

The exceptions, where state government policy or state owned retailers set the feed-in tariff (and are therefore potentially subject to political influence) are as follows:

- **Queensland:** Recognising lower competition, regional Queensland FiTs are set by the state government and were 10.102c/kWh from July 2017.
- **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 South Western Interconnected system (SWIS) and a variable amount set by Horizon power based on value to the grid for Horizon power customers (similar to the range of retailer prices in other states).
- **Victoria:** the current minimum feed-in tariff of 11.3c/kWh is set by the government. It applies to retailers with more than 5000 customers and generation from any renewable energy less than 100kW.
- **Tasmania:** Aurora energy sets the feed-in tariff for residential and commercial customers at 8.929c/kWh from July 2017.

3.2 Scenario definitions

The scenarios are defined by the sets of assumptions shown in Table 3-2 which have been drawn from the discussion of scenario drivers above. We have not included all drivers as some aspects, particularly relating to new business models, are difficult to define in terms of being able to assign data assumptions. However, the aim has been to include plausible combinations of developments from each of the different scenario driver categories, with a preference towards those factors which are relatively easily parameterised for scenario modelling purposes.

Scenario assumptions are described here in general terms such as “high” or “Low”. Specific scenario data assumptions are outlined in specific terms in the next section.

Table 3-2: Scenario definitions

Driver: / Scenario:		Slow	Moderate	Fast
Economic				
	Technology costs	High	Medium	Low
	Electricity prices	AEMO 'strong'	AEMO 'neutral'	AEMO 'weak'
	Residential customers accessing smart tariffs	10% by 2030, 20% by 2050	25% by 2030, 50% by 2050	50% by 2030, 70% by 2050
	Income growth	Low	Medium	High
Infrastructure				
	Rate of decline in share of customers with own roof or garage space (e.g. city densification)	High	Medium	Slow
	Use of car/ride sharing services	Low	Medium	High
	Network limits on residential rooftop solar size	5kW	6kW	7kW
Business model				
	Degree to which non-traditional customers (apartments, rented properties) can adopt technologies	Low	Medium	High
Policy				
	Feed-in tariffs	Converges towards declining midday generation price in all regions		

4 Data assumptions

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

4.1 Technology costs

4.1.1 Solar photovoltaic panels and installation

The costs of installed rooftop or small scale solar installations for the Moderate scenario is shown in Figure 4-1 and is sourced from the 4 degrees scenario in Hayward and Graham (2017) which is the most recent public Australian technology costs projections report available. The Slow scenario cost assumption is adapted from the *Australia Power Generation Technology* report (EPRI 2015) 550ppm scenario by updating more recent values and following the pathway to 2030 before converging towards the Moderate scenario thereafter. The cost assumptions for the Fast scenario were constructed by following the Hayward and Graham (2017) pathway but arriving at 20% lower costs by 2030 and converging towards the same costs as the moderate scenario by 2050[2].

Note that 2018 costs shown imply that a 5kW system ought to be advertised for approximately $7500. However, we more commonly see systems advertised in the range of $5000 installed reflecting that the value of small scale certificates, which are around $500-600/kW depending on the location 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.

[2] This convergence approach is supported by the 2 degrees cost projection scenario from Hayward and Graham (2017) which projects a negligible difference between the 4 and 2 degree outlooks due to batteries reaching the limit of their assumed learning curve which is not expected to change across the two global climate ambition scenarios.

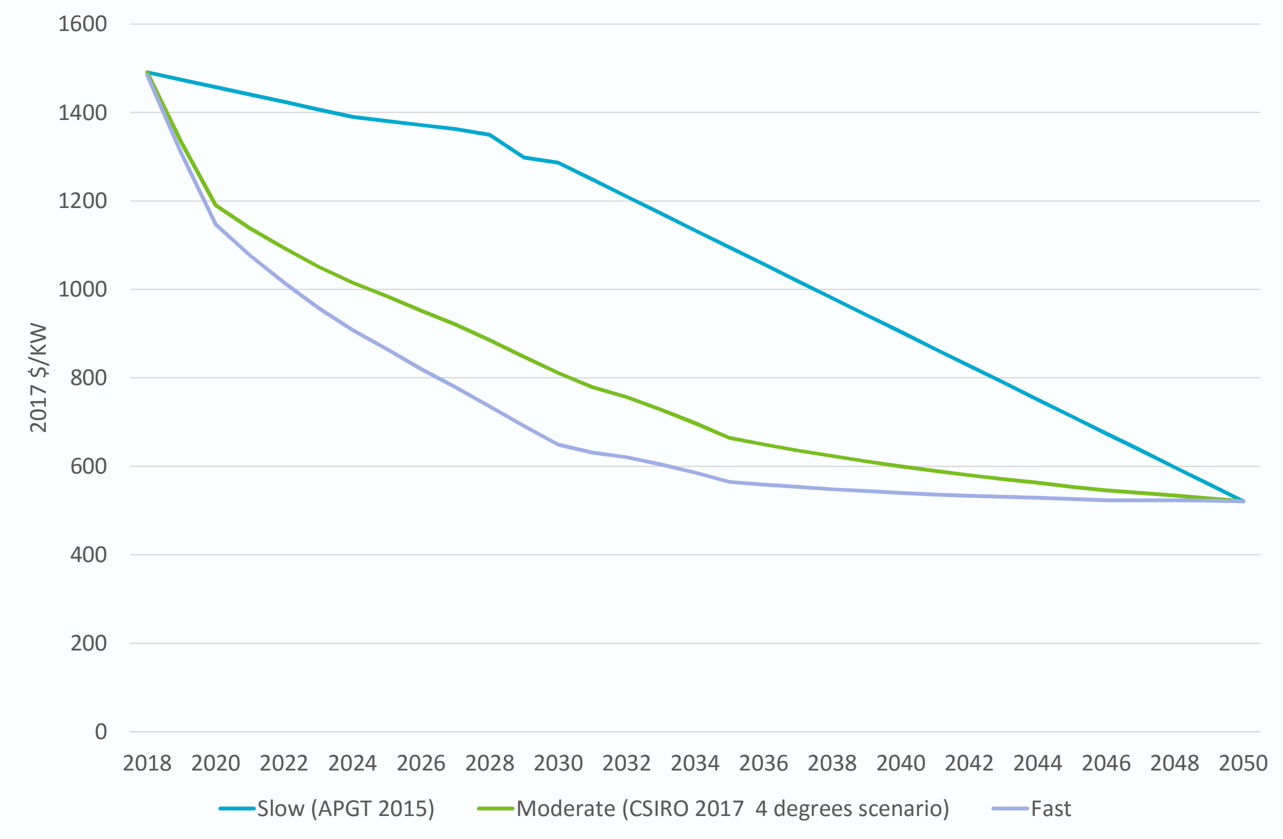


Figure 4-1: Assumed capital costs for rooftop and small-scale solar installations by scenario

4.1.2 Batteries and installation

Moderate scenario battery and balance of plant costs shown in Figure 4-2 are sourced from the projection under the 4 degrees global climate scenario published in Hayward and Graham (2017). It projects a continued non-linear reduction in batteries and a close to linear reduction in balance of plant costs. The battery cost reductions are consistent with historical learning rates and in the immediate future are driven by non-linear growth in electric vehicle manufacturing. With global home battery storage adoption expected to proceed at a slower rate balance of system costs decline at a slower rate.

The Slow scenario battery and balance of plant costs are assumed to follow a slower path which was adapted from the battery cost projections applied in the Electricity Network Transformation Roadmap study (Brinsmead et al 2017). The cost scenario could be interpreted as reflecting slower global battery manufacturing development associated with slower electric vehicle adoption consistent with the Slow scenario. Under the Fast scenario battery and balance of plant costs are assumed to fall at a similar non-linear rate to the Moderate scenario based on Hayward and Graham (2017) but arrive at a 20% lower level by 2030 and converge back to Moderate scenario costs by 2050.

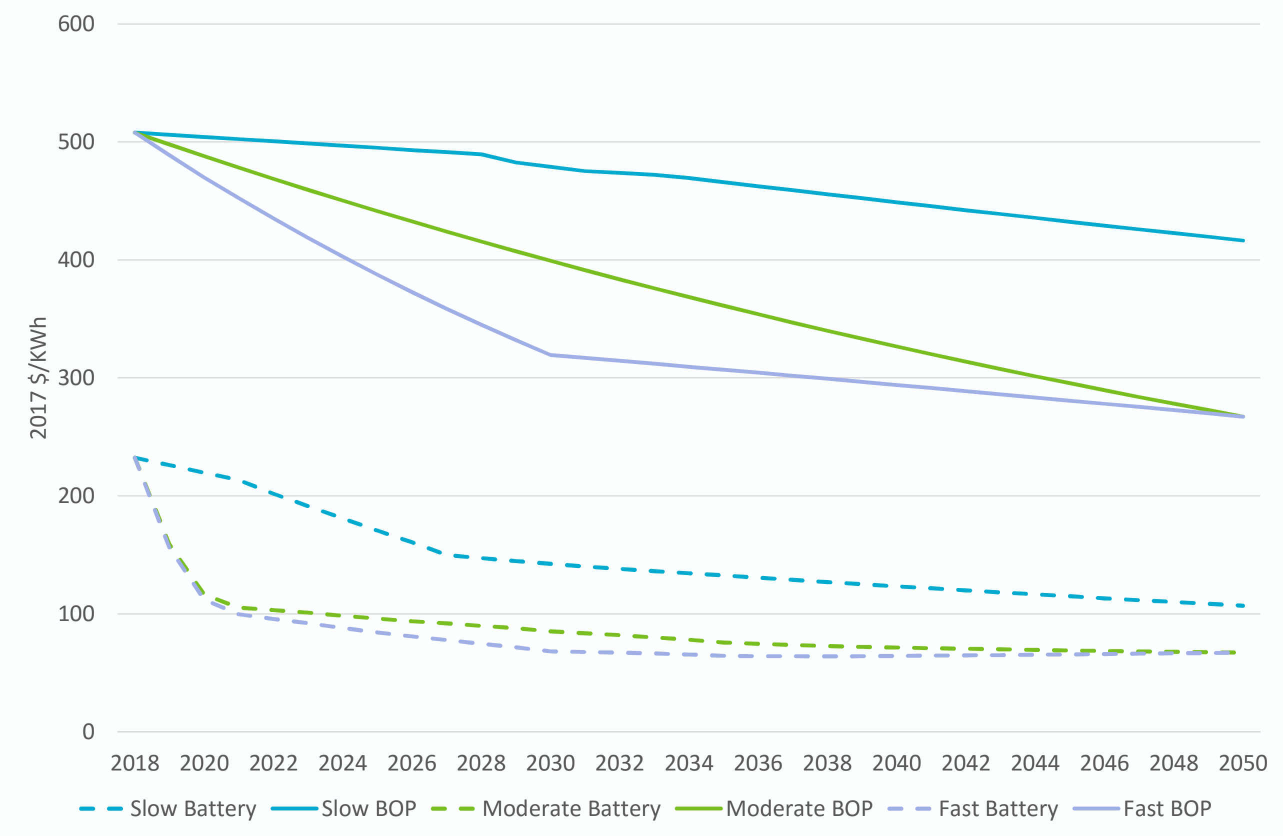


Figure 4-2: Assumed capital costs for battery storage installations by scenario

4.1.3 Electric vehicles

Moderate scenario electric vehicle costs are assumed to reach parity with internal combustion engine vehicles for cars around 2030 and remain at that level thereafter (Table 4-1). Parity may be reached earlier in other countries where vehicle emissions standards are expected to increase the cost of internal combustion vehicles over time[3]. For rigid trucks and buses electric vehicle costs are assumed to converge to within a 15-20% premium by 2050 reflecting their higher duty requirements (both load and distance). We consider electric vehicle adoption across five vehicle classes: light, medium and large cars, rigid trucks and buses. We do not include larger articulated truck because their longer driving range makes electrification prohibitive. We also do not consider applying a plug-in hybrid engine configuration to the small vehicle class size as these vehicles are already efficient so the additional cost would be difficult to pay back with limited additional fuel savings. We have not included plug-in hybrid technologies on trucks or buses as this vehicle configuration has yet to emerge. This may reflect that space is too limited on heavy duty road modes to accommodate two engine and fuel types.

The Slow and Fast scenario assumption are framed relative to these Moderate scenario assumptions. In the Slow scenario we assume that the cost reductions are delayed by 5 years. In the Fast scenario we assume the cost reductions are brought forward by 5 years. Given electric vehicles have significantly less parts than internal combustion engines it could also have been

[3] There is currently a process in Australia to consider policy design options for vehicle emission standards in Australia. However, no firm legislative proposal has emerged as yet. See https://infrastructure.gov.au/vehicles/environment/emission/index.aspx

reasonable to consider electric vehicle costs reaching lower than parity with internal combustion vehicles. However, in the context of the adoption projection methodology applied here, parity already implies zero payback periods 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. more range, more automation, integrated solar electric body materials).

Table 4-1: Moderate scenario internal combustion and electric vehicle cost assumptions, $'000

	2018	2020	2025	2030	2035	2040	2045	2050
Internal combustion engine								
Light/small car - petrol	14	14	14	14	14	14	14	14
Medium car - petrol	25	25	25	25	25	25	25	25
Large/heavy car - petrol	41	41	41	41	41	41	41	41
Rigid truck - diesel	61	61	61	61	61	61	61	61
Bus - diesel	180	180	180	180	180	180	180	180
Plug-in hybrid electric								
Medium car - petrol/electricity	37	37	36	33	33	33	33	33
Large/heavy car - petrol/electricity	59	58	56	49	49	49	49	49
Electric vehicle								
Light/small	30	27	24	14	14	14	14	14
Medium	57	46	35	25	25	25	25	25
Large/heavy	75	63	51	41	41	41	41	41
Rigid truck	105	102	99	80	77	75	73	72
Bus	272	266	260	223	215	211	209	206

4.2 Electricity prices

4.2.1 Retail and generation prices

Broadly speaking electricity 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, there is generally more upside risk, that is, risk of higher prices, than downside risk compared to current electricity prices due to the need to shift towards higher shares of low emission technologies. Intermittent renewables, while low cost at shares of less than 30-40%, begin to increase system costs at higher shares as additional supporting technology investment is required to deliver reliability and also their capacity factors can fall as increasing coincident supply events leads to congestion and curtailment.

Assumed changes in residential retail prices under the Moderate scenario are sourced from the AEMO 'neutral' scenario for NEM states and are shown in Figure 4-3. They reflect this general outlook with falling prices in the next few years followed by a steadily increasing trend (note, we have extrapolated the years 2037-2050). Retail electricity prices in Western Australia and Northern Territory are set by government and are therefore less volatile. The volatility and changes in the retail price index largely reflects changes in the underlying generation price which we also use in the projection modelling, particularly for uptake of larger commercial solar systems (above 100kW).

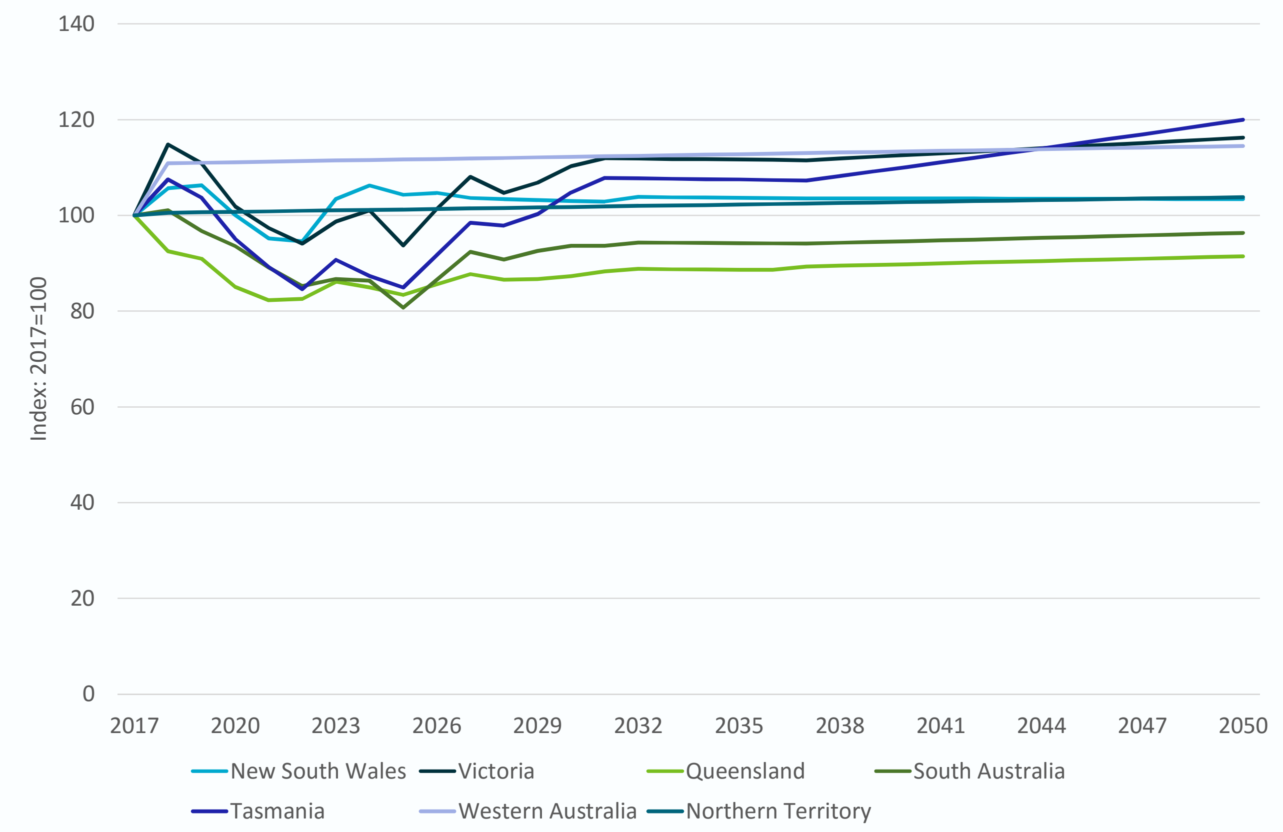


Figure 4-3: Assumed changes in residential retail prices under the Moderate scenario based on the AEMO 'neutral' scenario

Commercial retail prices are assumed to follow residential retail price trends for all scenarios, although under different tariff structures as we discuss below.

4.2.2 Small-scale technology certificates (STCs)

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 that discount to that which varies according to demand and supply for certificates. The amount 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 the 2030 is not counted as it is beyond the scheme period. Therefore over time the eligible solar generation is declining. Multiplying the eligible rooftop solar generation by the STCs price gives the projected STC subsidy by state shown in Figure 4-4.

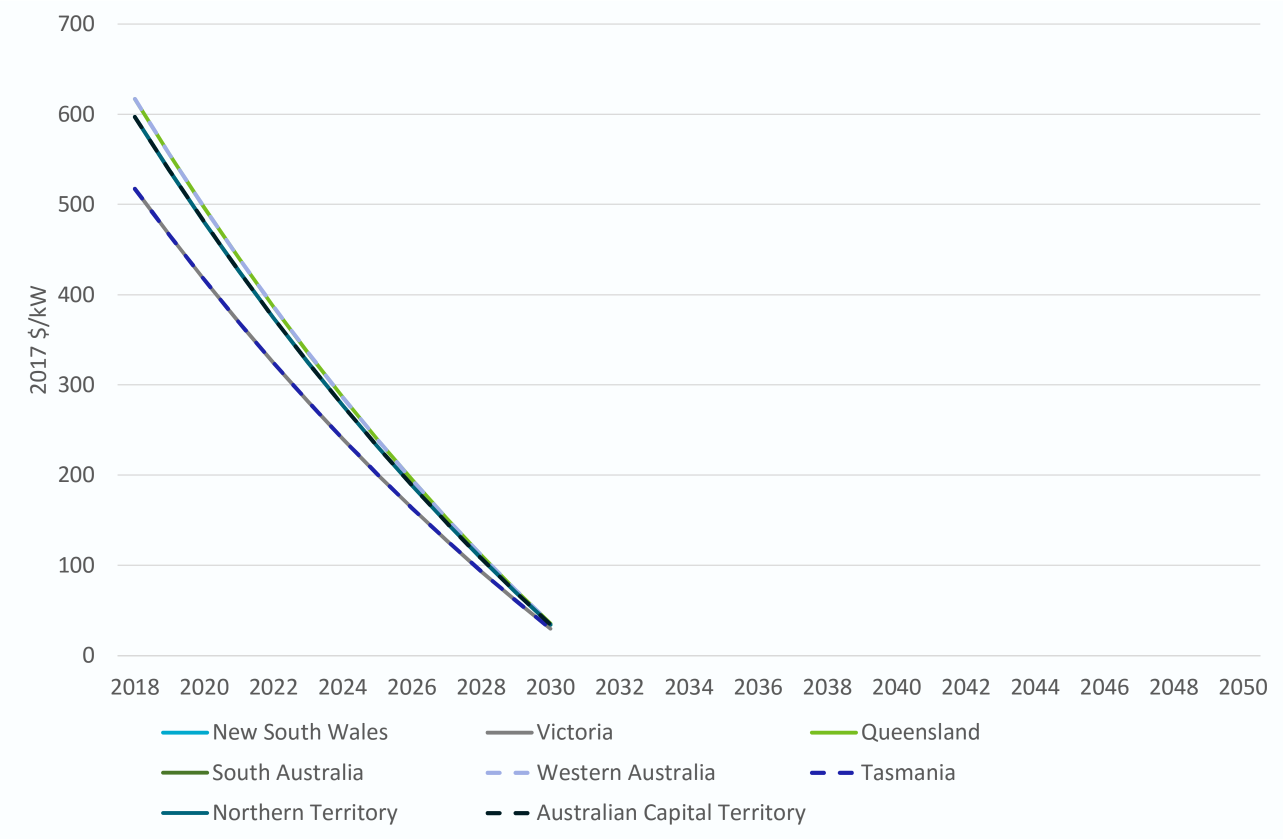


Figure 4-4: Assumed STC subsidy available to rooftop solar and small scale solar systems by state

4.3 Electricity tariff structures

4.3.1 Current 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 we will call 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. Both types of business tariff structures reflect the fact that, at a wholesale level, the time at which electricity is consumed and at what rate does affect its cost of supply. These tariff structures are not perfectly aligned with daily wholesale market price fluctuations but are a far better approximation than a flat tariff. In that sense, TOU and demand tariffs are also described as being more ‘cost reflective’ or ‘smart’ tariffs.

4.3.2 Future developments

While retailers make business-like TOU and demand tariff structures available to residential customers in addition to flat tariffs their adoption is very low. There is a significant body of literature examining why this is the case which we will not review here. 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.

There are no current policies which would force residential customers to do adopt alternative tariff structures and as such one could consider the prospects for greater residential adoption are considered low without a change in policy. Moving to these alternative residential tariff structures inherently requires customers to be more aware and, if concerned, manage on a daily basis their electricity load profile. Battery storage with automated operating instructions could potentially offer customers a way to adopt new tariffs without having to actively manage their daily load. Moreover, new energy service companies already operate businesses which act as a customer’s agent in managing the battery storage operation, minimising their power bill under TOU or demand tariff structures and offering demand management services to the grid.

4.3.3 Assumed tariff structures

These considerations of range of potential developments in residential tariffs are the reasoning behind why we have adopted alternative assumptions for the rate of adoption of smart tariffs in Table 3-2. However to implement these scenarios we need to assume a specific smart tariff structure in each year of the projection period. For TOU tariffs this is a difficult task because the time of day when certain rates might apply will shift with the change in customer behaviour. For example, grater adoption of rooftop solar and electric vehicles could mean low rates for night time power usage are no longer appropriate.

For both TOU and demand tariff structures the large adoption of batteries could create incentives for new peak demand periods just before higher cost periods or at other opportune times to charge the battery, potentially bringing forward the peak or creating new peak periods. When we optimise battery operation using existing tariff structures we see this behaviour in simulations. Figure 4-5 and Figure 4-6 show optimised battery behaviour for a large household customer in the Australian Capital Territory under a TOU tariff and demand tariff respectively. The TOU tariff cause battery charging both early in the morning (off peak) and before the peak rate period to minimise electricity costs. Similarly, the demand tariff creates incentive for charging just before the capacity charge period. These occurrences are more likely in winter months when solar generation is less capable of filling the battery.

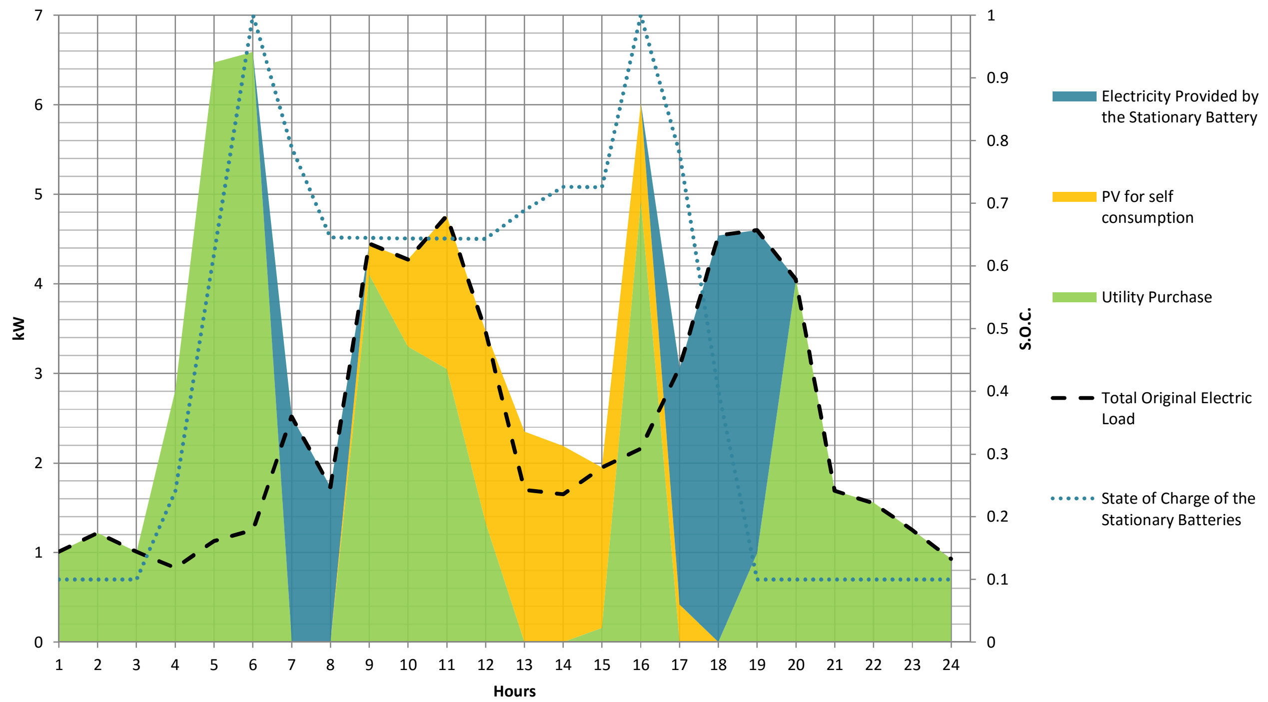


Figure 4-5: Optimised battery charging and discharging, TOU tariff, August, weekday, large ACT customer

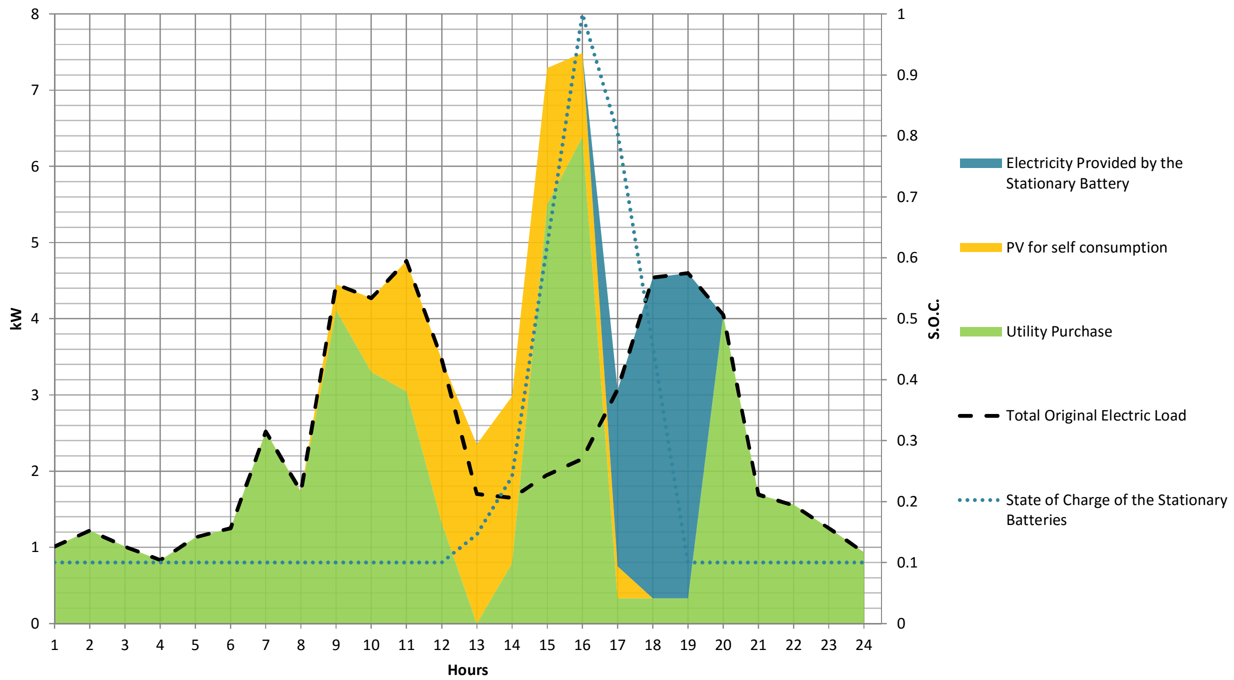


Figure 4-6: Optimised battery charging and discharging, demand tariff, August, weekday, large ACT customer

Given current residential and commercial smart tariff structures may not be appropriate over the longer run, when the scenario requires adoption of a smart tariff we implement a battery operation regime that ensures a preference for discharging to reduce grid electricity demand during the peak time of 5pm to 8pm for which the customer receives an annual rebate equivalent to what they would have saved from adopting TOU or demand tariff structures. The annual rebates were calculated to be in the range of $100-400 per annum depending on the state and customer size.

This approach assumes that an aggregator acts as an agent for a group of customers and is able to make a direct deal with a retailer for the value of demand reduction at peak without the need for a specific tariff structure. Compared to not participating in the aggregator scheme, for a residential customer this battery operation mode in practice means:

- Delaying battery discharge until after 5pm whereas with on a flat tariff a battery owner will normally begin discharging at any time the connection is importing from the grid (resulting in times when the battery has been fully discharged before the peak period has begun or ended)
- Smoother battery operation and longer battery life– discharging and charging at a more modest rate to smooth the load rather than always operating at the maximum power capacity

For commercial customers who were already on smart tariffs, the second dot point mainly applies since they already had an incentive to avoid peaks. Also note that, since commercial load profiles have a closer match to solar output profiles and are more amenable to avoiding peaks, they will have significantly less incentive to take up battery storage.

4.4 Income and customer growth

4.4.1 Gross state product

Gross state product (GSP) assumptions are used to project changes in income. The annual rate of growth in GSP by state is shown in Table 4-2 and is derived from the range of growth exhibited by AEMO’s ‘strong’, ‘neutral’ and ‘weak’ scenarios.

Table 4-2: Annual percentage growth in GSP by state and scenario

	New South Wales	Victoria	Queensland	South Australia	Western Australia	Tasmania	Australian Capital Territory	Northern Territory
Slow	1.3	1.6	2.5	1.5	2.5	1.0	2.1	2.7
Moderate	2.2	2.6	3.3	2.2	3.2	1.8	3.0	3.2
Fast	3.0	3.4	4.0	2.9	3.9	2.5	3.7	3.7

4.4.2 Customers

The annual rate of growth in customer by state is shown in Table 4-3 and is derived from the range of growth exhibited by AEMO’s ‘strong’, ‘neutral’ and ‘weak’ scenarios.

Table 4-3: Annual percentage rate of growth in customers by state and scenario

	New South Wales	Victoria	Queensland	South Australia	Western Australia	Tasmania	Northern Territory	Australian Capital Territory
Slow	0.8	1.1	1.3	0.6	2.0	0.2	0.5	1.2
Moderate	0.9	1.3	1.5	0.7	2.2	0.3	0.5	1.5
Fast	1.1	1.4	1.6	0.8	2.3	0.4	0.6	1.7

4.5 Separate dwellings and home ownership

4.5.1 Separate dwellings

Owing to rising land costs in our large cities where most residential customers live, there has been a trend towards faster building of apartments compared to detached houses (also referred to as separate dwellings in housing statistics). As a result we expect the share of separate dwellings to fall over time in all scenarios. The assumptions for the Moderate scenario were built in extrapolating past trends resulting in spate dwellings occupying a share of just below 60% by 2050, around 6 percentage points lower than today. The Fast and Slow cases were developed around that central projection.

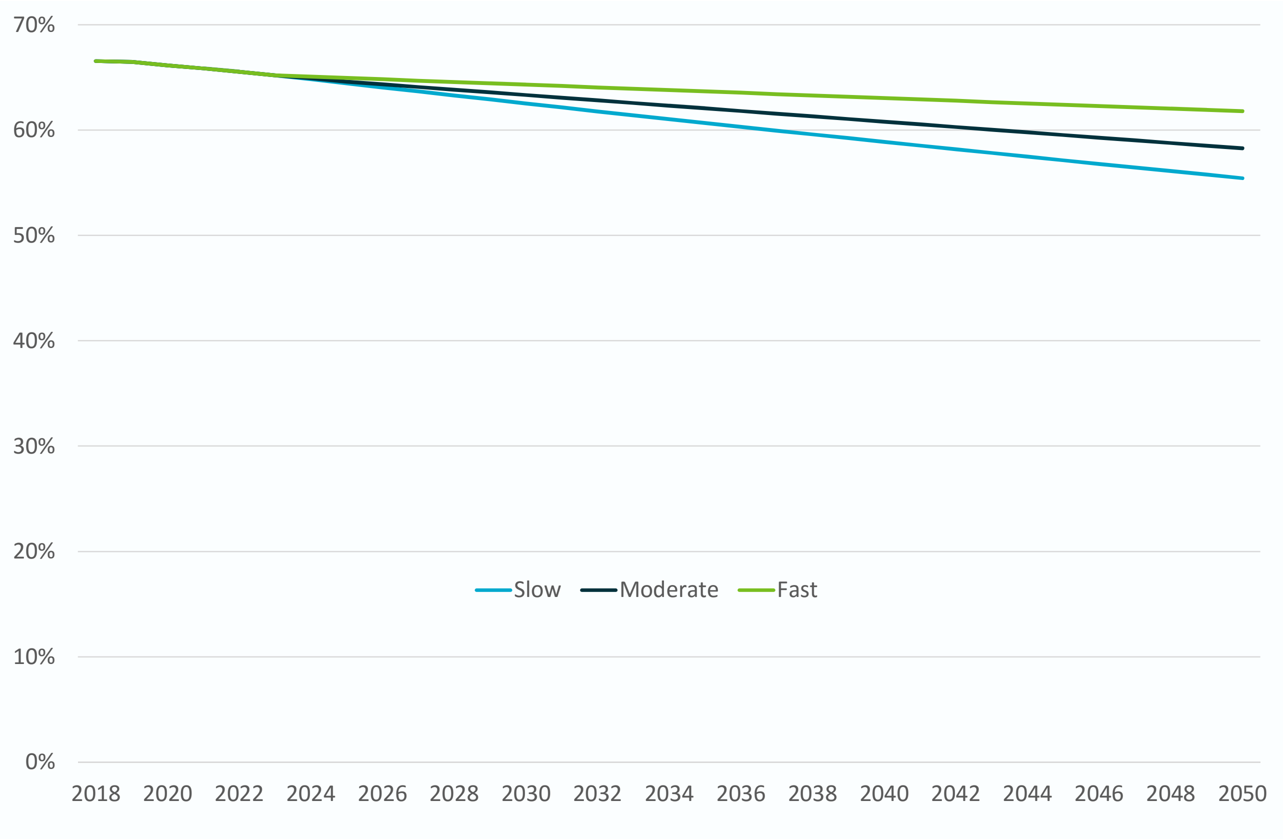


Figure 4-7: Assumed share of separate dwellings in total dwelling stock by scenario

4.5.2 Home ownership

While not a hard constraint, home ownership increases the ability of occupants to modify their house to include small-scale embedded technologies. Home ownership (which includes homes owned outright as well as mortgaged) increased rapidly post-World War II and was steady at around 70 percent 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 expected 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 Moderate 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 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 Moderate scenario. Under the Fast scenario we assumed 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.

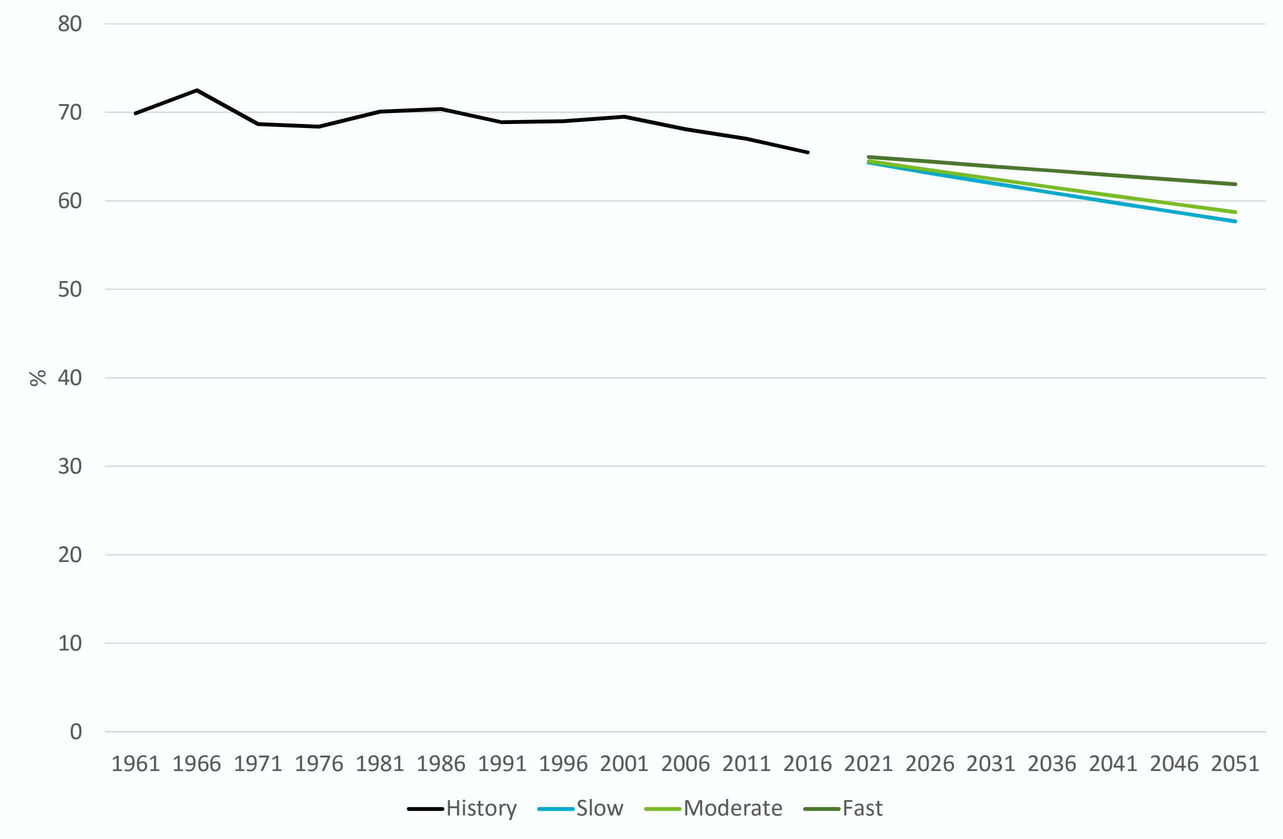


Figure 4-8: Historical (ABS Census) and projected share of homes owned outright or mortgaged, source AIHW (2017)

4.6 Vehicle fleet size

The vehicle fleet size data assumptions are sourced from a recent study by Graham et al (2018) which developed scenarios for growth in vehicle fleet consistent with Commonwealth of Australia (2015) population growth and alternative scenarios for the adoption of car/ride sharing over time.

The assumptions developed in that source for the potential changes in preferences for private versus non-private vehicle services by 2050 have been adapted for use in the Slow, Moderate and Fast scenarios as shown in Table 4-4. The outcome of these assumptions for the size of the vehicle fleet can be sees in Figure 4-9.

Table 4-4: Assumed share of alternative vehicle services by 2050 by scenario (adapted from Graham et al 2018)

	Slow	Moderate	Fast
Private car trips (%)	93	82	55
Car-share trips (%)	5	15	40
Ride-share trips (%)	2	3	5

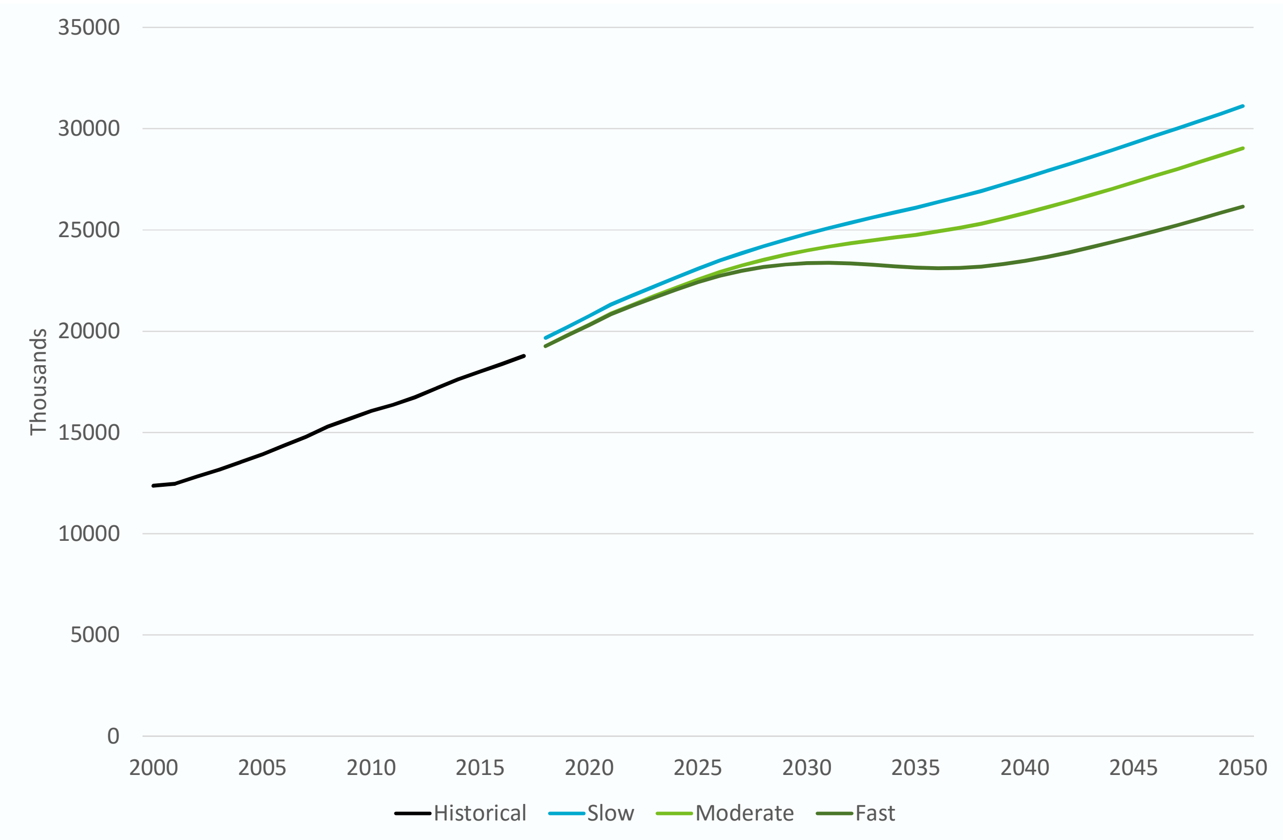


Figure 4-9: Historical and projection national road vehicle fleet by scenario

5 Results

5.1 Residential rooftop solar

The projected capacity of residential rooftop solar is shown in Figure 5-1, where 2015-16 and 2016-17 represent historical data. The data does not directly match public historical sources because it is in terms of effective capacity meaning that the degradation of output from solar systems that occurs as they age has been taken into account. We compare the three scenario projections developed in this report with the Weak, Neutral and Strong scenario projections that were developed in 2017 by Jacobs (2017).

A significant difference in the new projections compared to the 2017 projections is that through most of the projection period (with the exception of 2024 to 2044 in the Slow scenario) the new projections are higher. This primarily reflects that the historical data for 2017 indicates more rapid growth than anticipated in the previous projections.

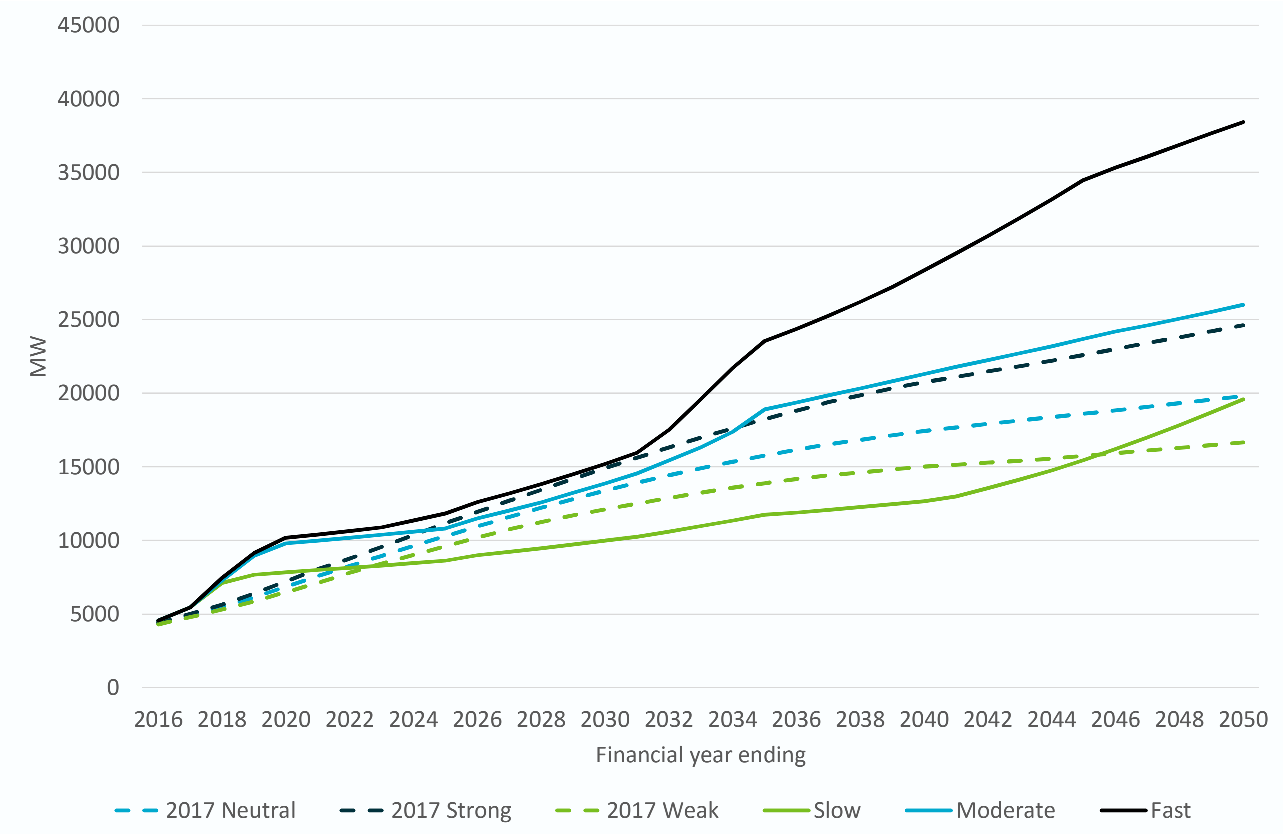


Figure 5-1: Projected effective residential rooftop solar capacity by scenario compared with 2017 scenario projections

The Fast scenario is the most challenging in scale, particularly in the late 2030s and 2040s, but remains plausible. The maximum adoption we allow in residential rooftop projections in any ABS SA2 region is 60% in this scenario. Recall that under the Fast scenario assumptions rooftop solar systems are slightly larger building over time towards a long term average of 7kW and as such this assumption partially accounts for the trend in capacity growth. These larger systems are only useful if the additional energy can be used onsite in the residence or by the grid. The larger deployment and improved orchestration of battery storage and electric vehicles under the Fast scenario supports the utilisation of higher solar PV output.

A second major difference in the new projections is that, rather than increasing steadily like the 2017 projections, residential rooftop solar capacity goes through three distinct phases during the projection period, mainly reflecting changes in financial drivers.

From 2015-16 to 2019-20 there is strong growth in deployment reflecting sustained high retail prices. High retail electricity prices in 2017-18 were a result of the recent increase in generation costs which followed a sustained period of increased distribution prices which began from around 2007-08 depending on the state/territory. A second factor supporting strong growth to 2019-20 is that the small scale technology system (STC) subsidy remains relatively high compared to future years at around $600/kW (see Figure 4-4).

In the period 2020-21 to 2030-31 the projection trend changes to one of slower growth in deployment, particularly before 2025, reflecting residential rooftop solar payback periods stalling due to lower retail prices in most states and STC subsidies falling to zero by 2030 (see previous discussion on this topic). Retail prices are assumed to fall in the early 2020s due to the increased deployment of large scale renewable electricity generation technologies to meet the final stages of the 2020 Renewable Energy Target. This extra capacity is expected to result in lower generation prices due to increased competition and a greater proportion of zero marginal cost generation units. Additional flexible capacity coming into the market in South Australia will also support lower generation prices. Falling rooftop solar system costs are not sufficient to significantly offset these other financial trends.

In the post-2030 period, growth in residential solar deployment recovers indicating that the residential rooftop solar payback period is falling again. It is falling due to assumed rising retail prices that are expected to be driven by higher costs of electricity generation consistent with efforts to deliver greenhouse gas abatement in the electricity sector. Falling payback periods are also driven by the accumulation of further reductions in rooftop solar system costs over time.

We have emphasised the financial drivers in this trend analysis. However, we should also note that other factors supporting growth across the scenarios are larger average rooftop solar system sizes, customer growth and rising incomes. These drivers of growth are partly offset by negative demographic factors such as an assumed falling home ownership and lower share of separate houses in new dwellings.

Figure 5-2 shows the trends in effective residential rooftop solar capacity by state/territory. The difference in the scale and rate of growth in states/territories largely reflects the differences in current population and future customer growth. Customer growth is assumed to be lowest in South Australia, Tasmania and Northern Territory. Tasmania also has the poorest solar capacity factor of all regions. Queensland is expected to remain the state with the highest absolute residential rooftop solar capacity reflecting both higher customer growth and a favourable solar capacity factor. Western Australia is assumed to have the highest customer growth and also experiences the highest rate of growth in effective residential rooftop solar capacity.

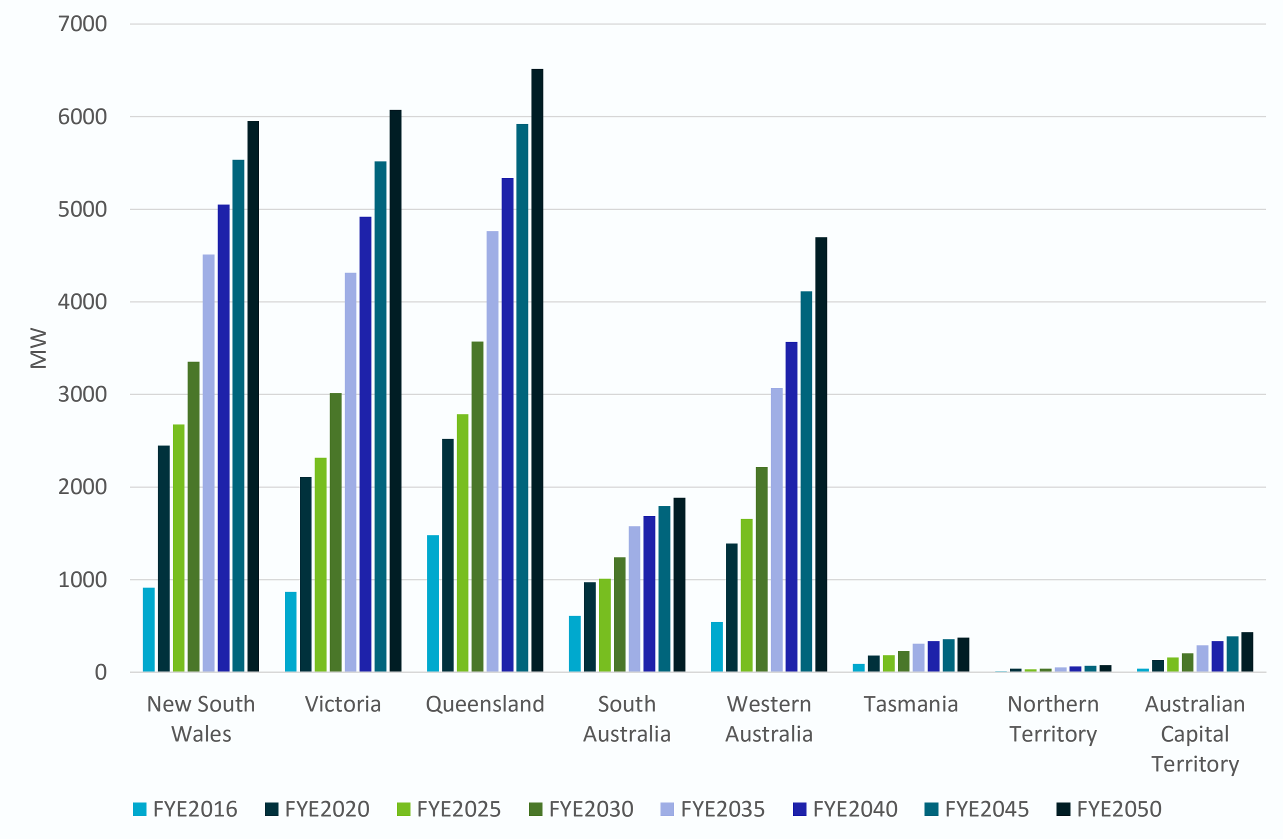


Figure 5-2: Projected effective residential rooftop solar capacity by state under the Moderate scenario

5.2 Commercial rooftop solar, 10kW to 100kW

Like the residential sector, commercial rooftop solar also experienced strong growth in capacity in 2016-17 and projected further strong growth to 2020 reflects similar financial drivers with commercial systems below 100kW also eligible for the STC subsidy and commercial retail prices also at record highs (Figure 5-3). This the main reason for growth above the rate previously expected in Jacobs (2017) in the period to 2020.

In the period 2020 to 2030, the commercial sector is projected to experience lower retail prices and a reduction in STC subsidies to zero resulting in a slower rate of growth in effective commercial rooftop solar capacity. With the resumption of rising retail prices and accumulated reductions in solar system costs, stronger growth resumes in the period 2030 to 2050. However not with as marked a difference in the previous period as residential solar capacity reflecting differences between the two markets

Commercial systems have very low paybacks throughout the projection period owing to strong alignment between solar output and commercial customer load. That is, commercial customers can expect to have fewer exports and therefore receive better average value from their solar output. Despite this more positive financial position, commercial rooftop solar is limited by non-price factors such as building suitability, ownership and competing demands on funds. It is appropriate, therefore to calibrate their adoption curve to a lower market saturation level, limiting their rate of growth.

Relative to the 2017 projections, the projection range is wider. The Moderate and Slow cases are overall more negative in the long run on the prospects for capacity growth. However, the Fast scenario is reasonably aligned with the 2017 Strong scenario up until the 2040s when it grows more strongly.

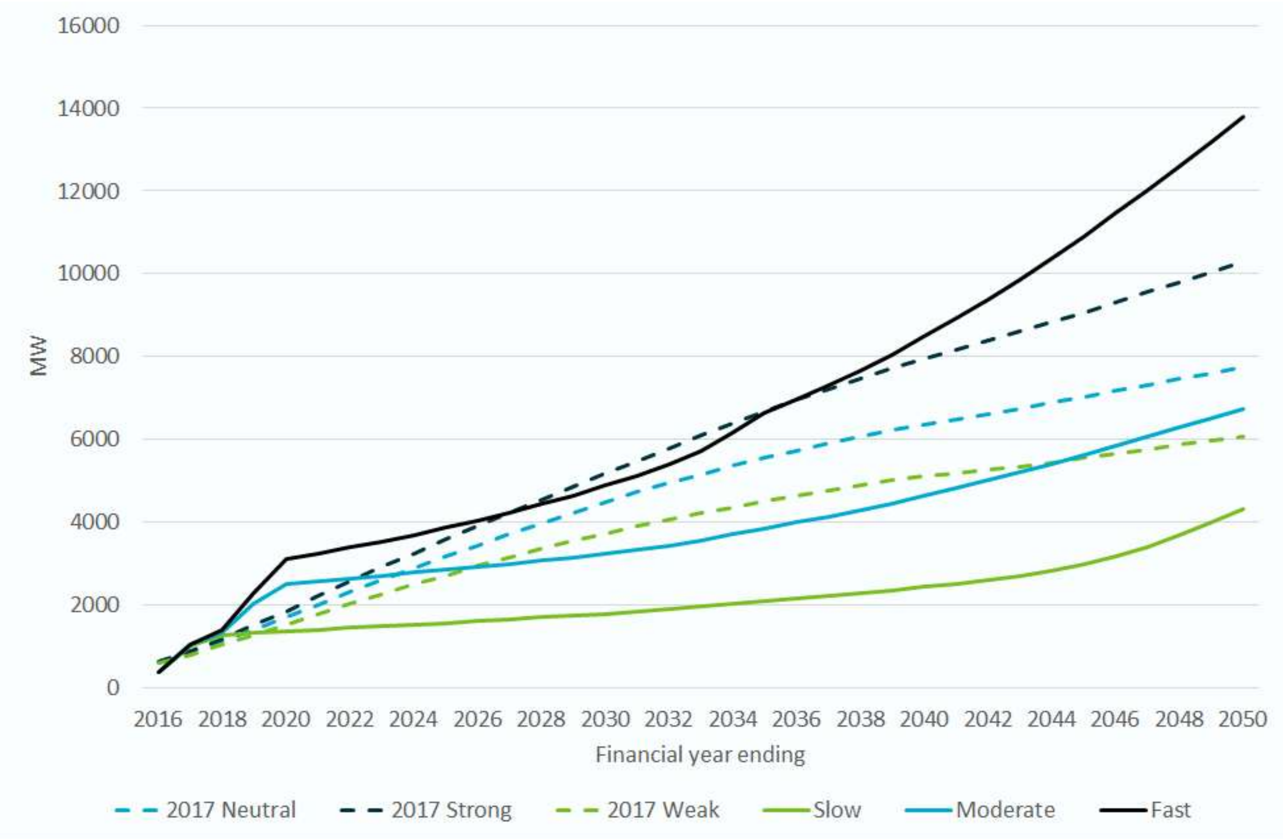


Figure 5-3: Projected effective commercial rooftop solar (10kW to 100kW) capacity by scenario compared with 2017 scenario projections

On a regional basis, New South Wales commences as the region with the largest commercial rooftop solar capacity and is projected to remain so through to 2049-50 (Figure 5-4). However, Western Australia, Victoria and Queensland experience stronger growth (from a lower base) owing to stronger customer growth assumptions. Overall effective commercial rooftop solar capacity is 21% to 29% of residential capacity by 2049-50, depending on the state/territory.

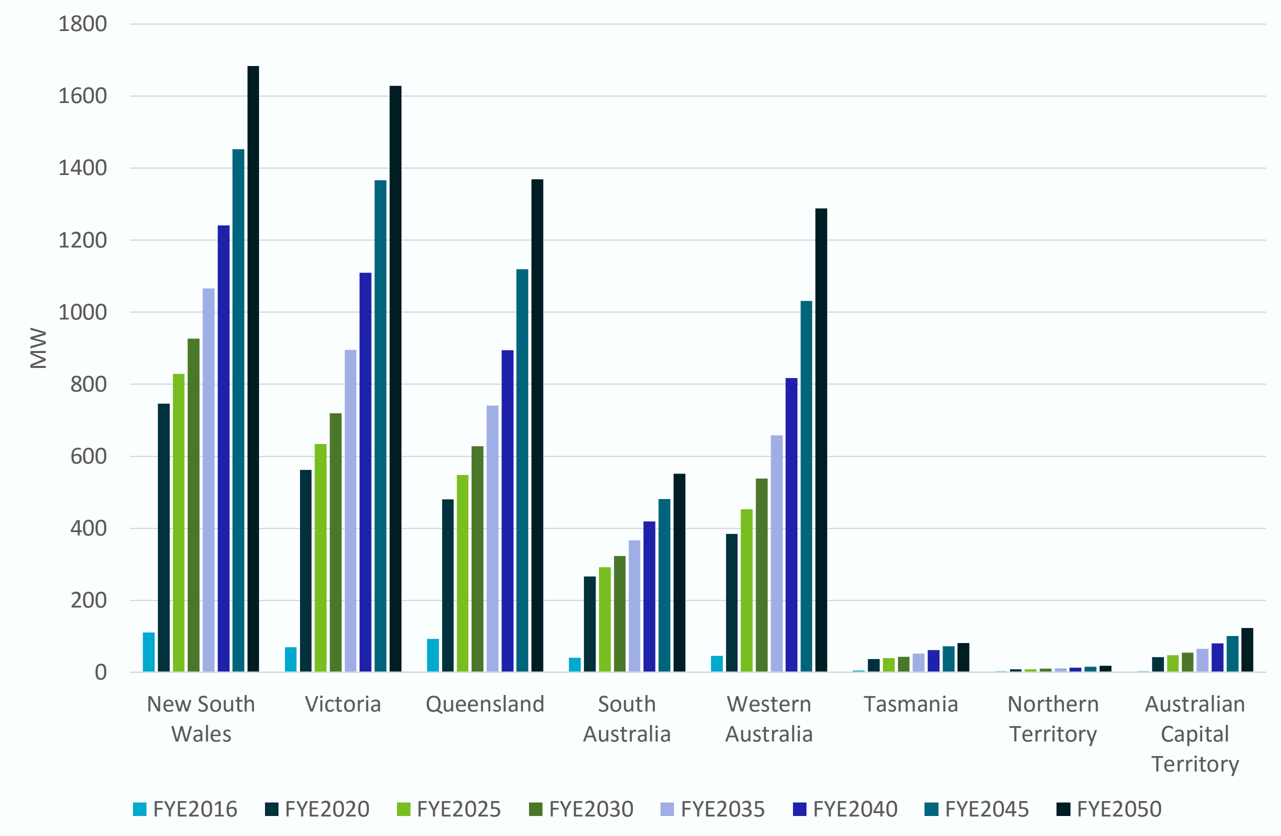


Figure 5-4: Projected effective commercial rooftop solar (10kW to 100kW) capacity by state under the Moderate scenario

5.3 Commercial solar capacity greater than 100kW (non-scheduled generation)

As discussed in the methodology section, commercial solar systems in the 100kW to 30MW size range are subject to different investment decision making than residential and commercial systems below 100kW sizes. They may be, but are less likely to be located on a rooftop. They are not eligible for STCs but can earn LRET certificates. While there may be a significant onsite load, they would be expected to earn a much greater proportion of their revenue directly from sales to the generation market. As such the generation and LRET certificate prices are the key drivers along with the costs of solar PV generation.

Preliminary Clean Energy Regulator data for the first quarter of 2018 suggests that commercial solar systems in the 100kW to 1MW size range systems can be expected to experience a fourfold increase in capacity compared to 2017. The inclusion of this observation alone puts the projections at the high end of the 2017 projections (i.e. the 2017 Strong scenario). Further strong growth in all system sizes is projected on the basis that the LRET certificate and electricity prices are expected to remain high while solar PV costs fall (Figure 5-5).

Where possible, announced projects have been included such as an additional 50MW to be constructed in Western Australia at various projects. Beyond 2020 the main driver for uptake is the fact that the cost of solar electricity generation is expected to remain below the generation price for the foreseeable future (particularly in regions with relatively high capacity factors) and so there will be a continuing incentive to find locations with available sites and connection points.

The projections apportion development of solar across the states/territories according to the relative differences in costs (mainly driven by capacity factors), generation prices and their past rate of developing solar projects across the three size categories examined. The result of this approach is that while there are relatively fewer 10-30MW installations, each incremental installation adds a significant amount of capacity in total (Figure 5-6).

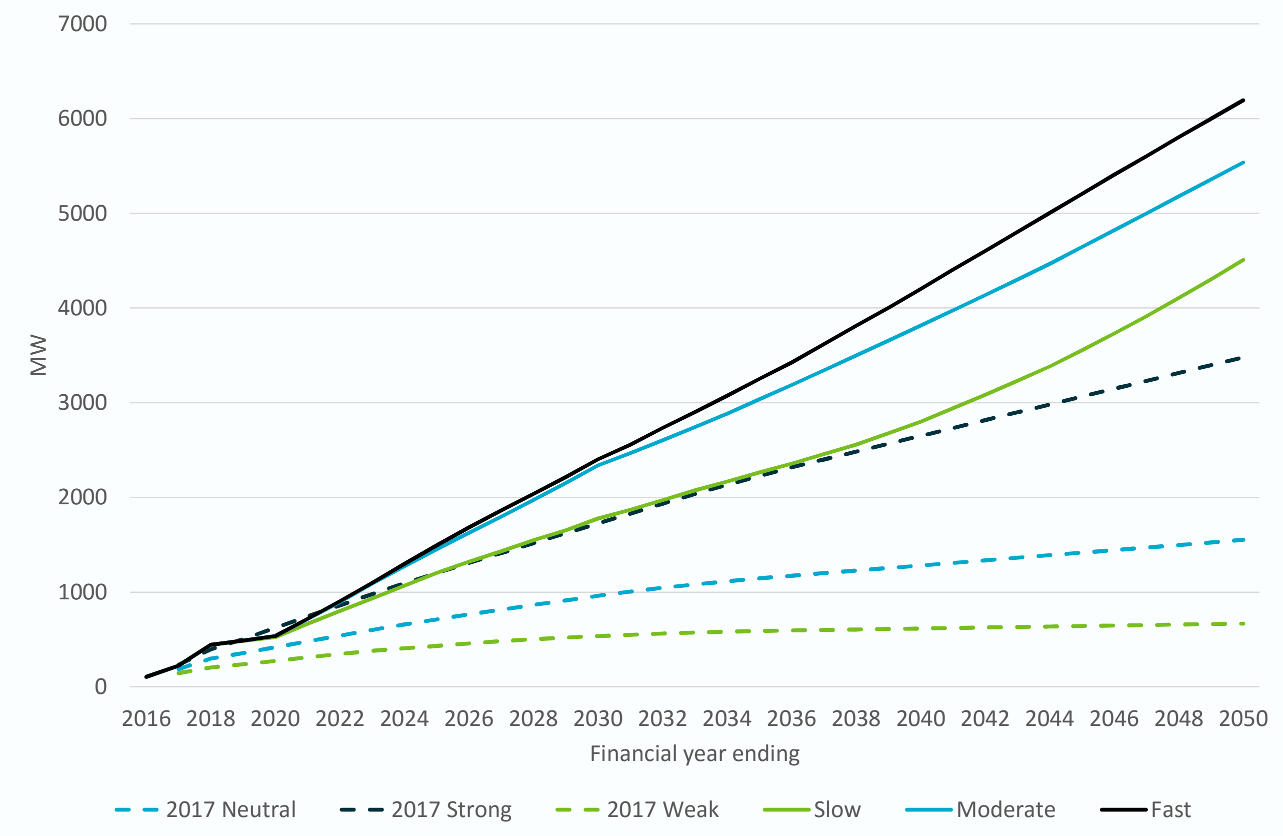


Figure 5-5: Projected effective commercial non-scheduled solar generation capacity (100kW to 30MW) by scenario compared with 2017 scenario projections, NEM states

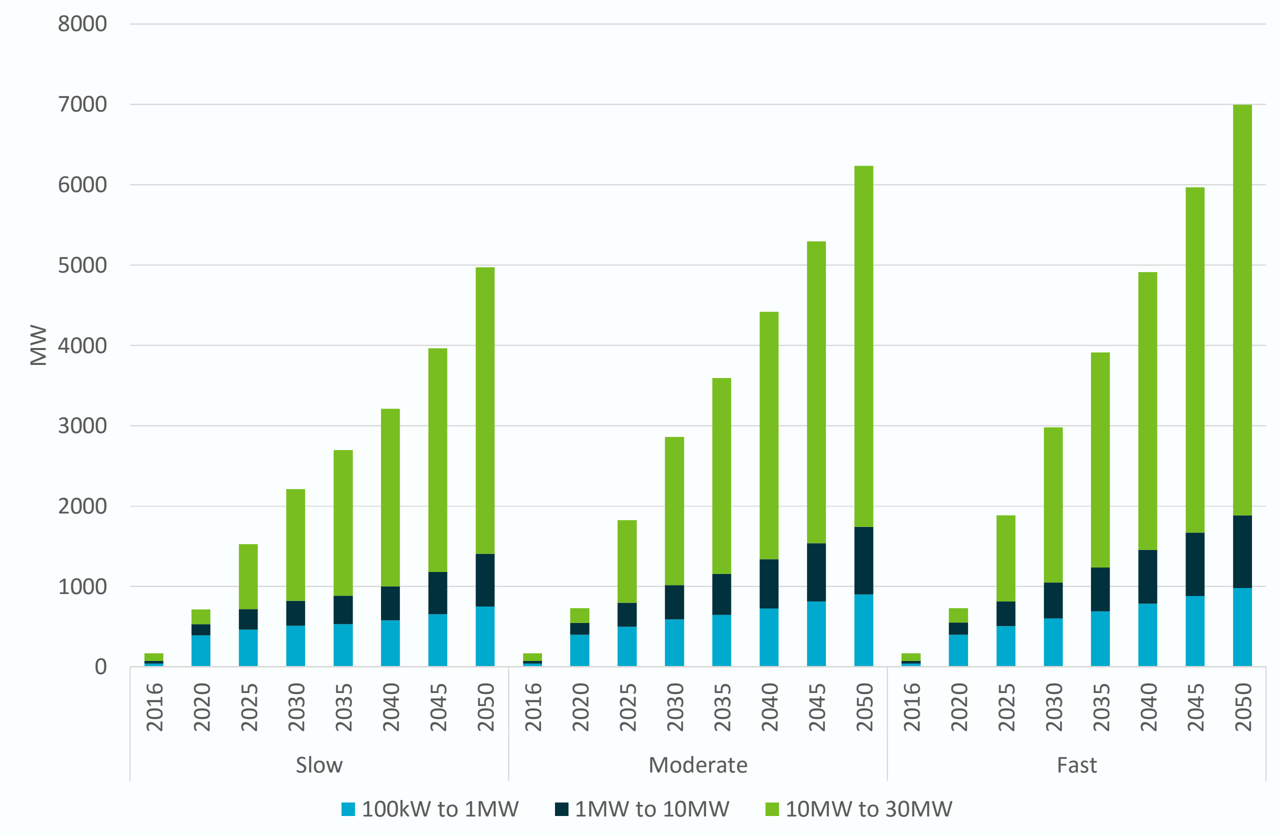


Figure 5-6: Breakdown of projected effective commercial non-scheduled solar generation capacity by capacity size and scenario

We also assumed that additional incentives will available in Victoria and Queensland associated with their respective renewable targets. The result of this assumption is that Victoria, which has a relatively poor capacity factor and smaller past rate of growth preforms on par with other states when otherwise we may have expected a more modest growth (Figure 5-7). Over the long term, Queensland is projected to build around four times the capacity of any other state reflecting high capacity factors, a strong recent rate of solar project development and additional state renewable policy incentives.

The major risk to this outlook is that exports from high adoption of residential and 10 to 100kW commercial solar erodes daytime demand resulting in poor generation prices during the period in which the commercial non-scheduled generation (100kW to 30MW) would be seeking to earn revenue. Given this is a likely outcome, to account for this we assumed a gradual erosion in the generation price received by these projects to around one third of the average price. Ideally the generation price should be estimated from electricity system modelling, however this was out of scope. The Fast and Slow scenarios take alternative views about the extent to which prices received by solar projects are impacted by projects crowding out supply of midday generation.

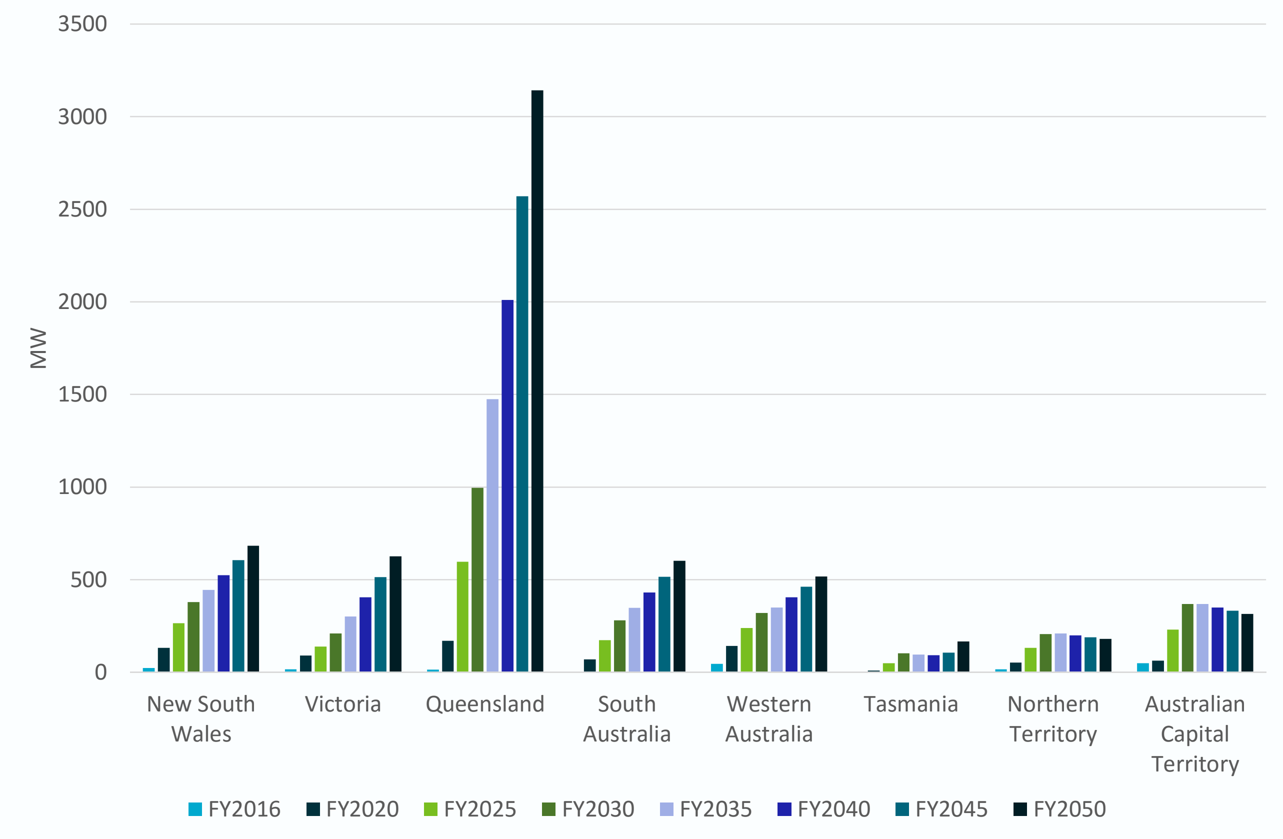


Figure 5-7: Projected effective commercial non-scheduled solar generation capacity (100kW to 30MW) by state under the Moderate scenario

5.4 Residential batteries

While payback periods (the amount of time it takes for electricity bill savings to pay for technology installation costs) for residential and commercial solar are below 5 years, payback periods for integrated solar and battery remain relatively high, estimated at between 10 to 16 years depending on customer load type and state/territory location (where there are differences in the retail electricity price and quality of solar resource available).

The high payback period suggests batteries remain nearer to an early adopter market. On the other hand there are recent signs of broader movement in this market. Sunwiz (2018) report strong growth in integrated solar and battery sales of around 20,000 systems in 2017 compared to the 7,500 in cumulative installations in 2016[4].

Given that the battery and solar systems are integrated in this analysis, the projection trends adopt some of the trends apparent in the solar only residential projections. That is, we see continued growth to 2020, slowing a little in the 2020s and then increasing as the combined effect of changes in the retail price, STC subsidy and technology costs impact the payback period over time against a background of relatively steady growth drivers such as customer numbers, system

[4] These report do not match Clean Energy Regulator (CER) data. However, the CER relies on voluntary reporting which is expected to lead to under reporting. Sunwiz take a direct survey of installers approach and provide reports on results on a commercial basis. Neither source provides public information on installation size. The lack of a reliable and detailed public data source on historical installations adds additional uncertainty to the projections presented here.

sizes and income (Figure 5-8). However, one of the differences in the projection is that the Moderate and Fast scenarios are closer together in the early years and this is because both scenarios have similar battery cost assumptions during this period. Further into the 2020s, battery cost assumptions diverge and so do the projections.

Adoption ranges across the three scenarios are initially lower than the 2017 projection and in the long run higher in the Fast and Moderate scenarios. Overall the long term uncertainty range is significantly wider. The initial lower projection is justified on the basis that, even with recent strong growth in 2017, the capacity remains below the full range of previous forecasts. It is appropriate that the projections should remain slower growing during the 2020s to be consistent with the outlook for solar installations as already discussed.

There are four reasons why we expect stronger growth in the latter part of the projection period and also see a wider uncertainty range emerge. The first is that as the prospects for solar systems improve we should also see more installations of batteries. Secondly, as move into the 2030s, the payback period for integrated battery and solar systems has fallen to closer to 5 years which suggest a period of wider market adoption. Thirdly, batteries will be needed, particularly in high solar uptake scenarios, to support distribution system voltage control and generation system reliability and we would expect some incentives are available to support that (either in a positive sense from aggregators or retailers or in a negative sense from very low solar export prices and frequent inverter trip-off events).

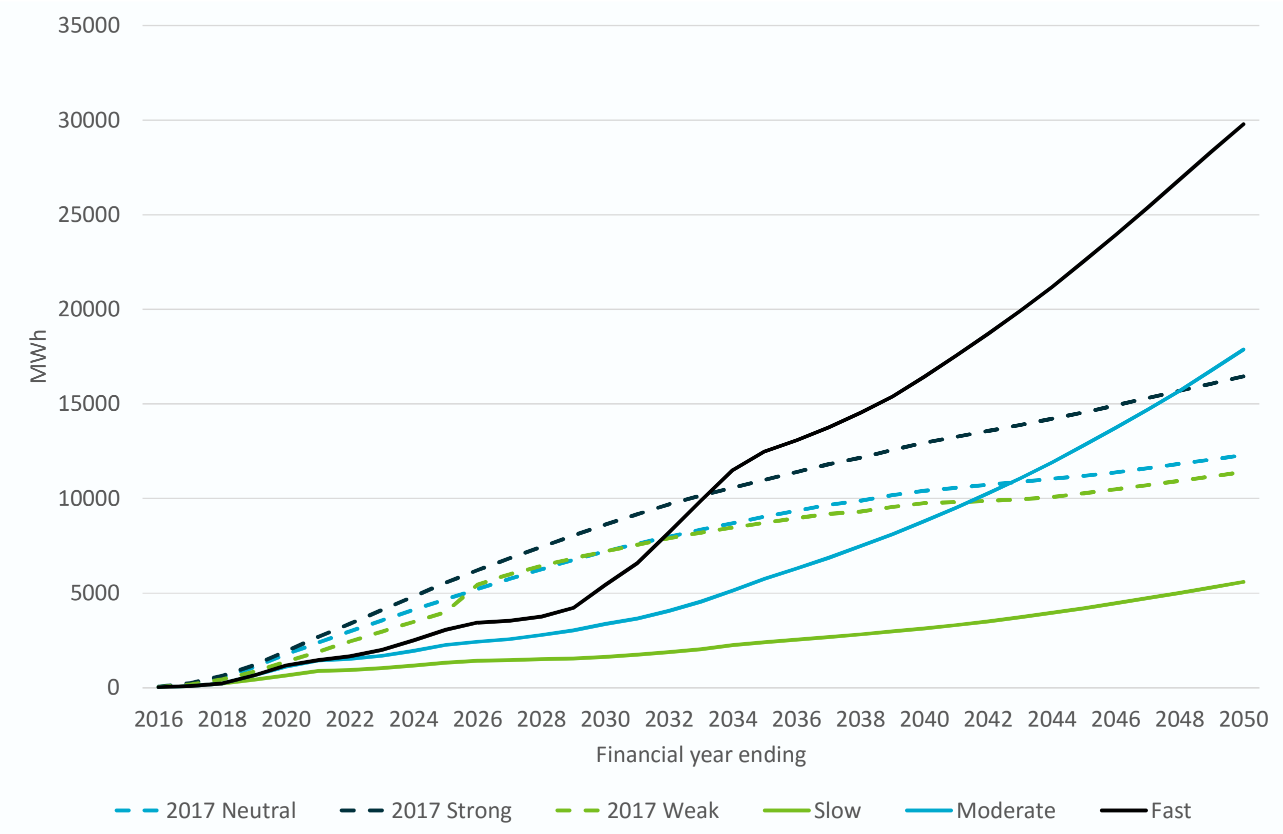


Figure 5-8: Projected residential battery storage capacity by scenario compared with 2017 scenario projections

Finally, while we would expect the services batteries provide will provide rewards for customers and the system in general, how this exchange of value will be priced and communicated over time remains uncertain. At the positive end of scenarios we could envisage battery owners earning multiple streams of value providing services to the customer, distribution system and generation system. At the negative end of scenarios appropriate incentives may be communicated poorly[5] or arrive too late resulting in storage or other load management system investment being duplicated in the generation and distribution sectors leaving customers to focus on operating their battery storage for the sole purpose of minimising their solar exports whilst also paying for the cost of other potentially duplicative grid investments. The scenario assumptions on the implementation of ‘smarter’ tariffs reflect a mix of these opposing worlds.

Consistent with the greater need for batteries to support electricity system operation as solar adoption rises, residential battery capacity as a share of residential solar capacity increase across the scenarios. In the Slow scenario, the battery share of residential solar is 6% to 27% depending on the state or territory. The range is 21%-57% and 25% to 64% for the Moderate and Fast scenarios respectively.

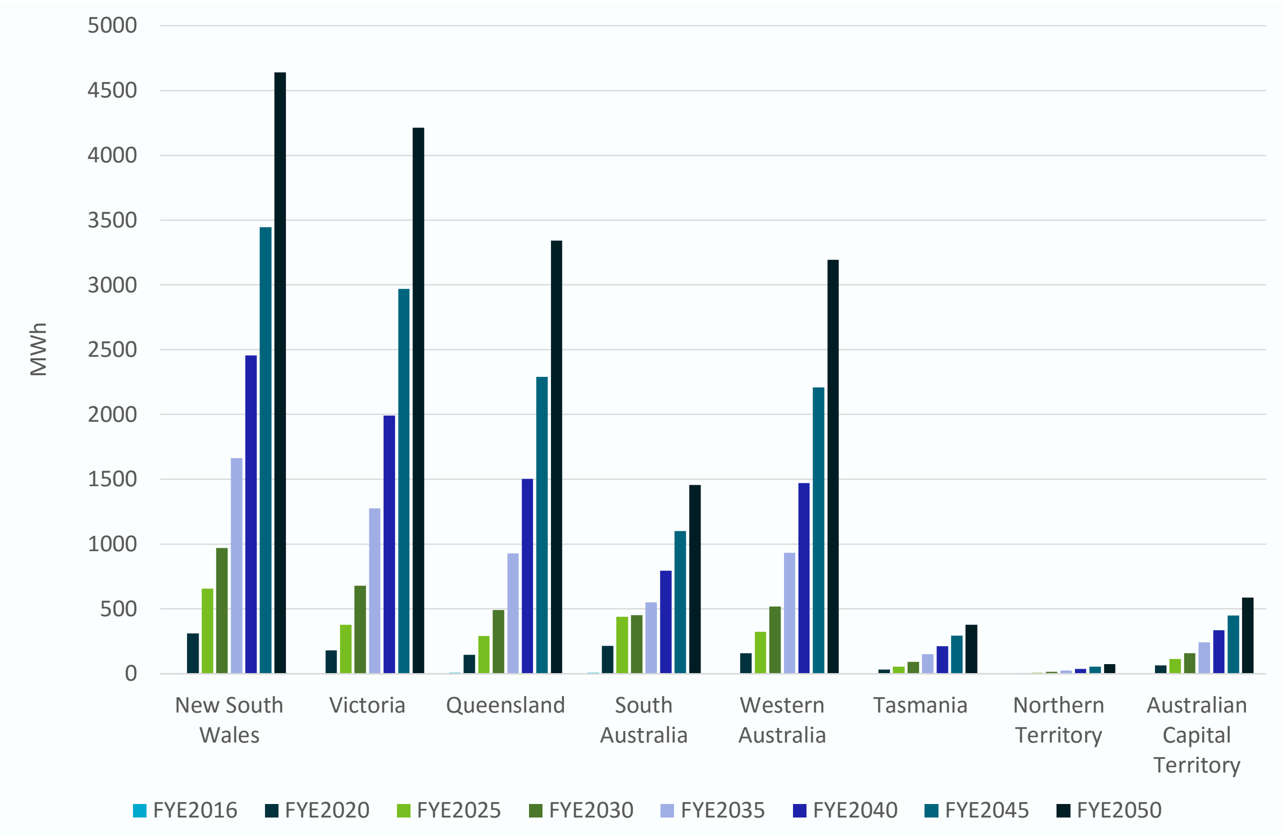


Figure 5-9: Projected residential battery capacity by state under the Moderate scenario

On a state and territory basis, New South Wales is projected to have the largest absolute level of residential battery storage under the Moderate scenario (Figure 5-9). However, other states such as Victoria, Queensland and Western Australia grow at similar annual rates from a lower base. The incoming South Australian government policy of supporting the installation of 40,000 residential

[5] In the scenario assumptions we discuss the potential for current tariff structures to create new peaks rather than reduce peak demand. This is a concern about the accuracy of temporal communication signals. Another issue is the accuracy of spatial communication signals and whether investment will occur where it is most needed. Current electricity pricing structures are applied to entire distribution service provider zones while voltage disturbances are at the suburb and street level.

batteries was included in that state’s projection. The Australian Capital Territory achieves significant growth reflecting its relatively high income per capita.

5.5 Commercial batteries

Commercial battery utilisation, for the purposes of minimising solar exports, is low relative to residential batteries because there are less frequent periods when there is excess solar to store. This is because the optimal sized solar system for a commercial customer, which tends to have a high daytime load, tends to leave less oversupply of solar generation to be stored. This is the opposite circumstance to residential customers who, on average, tend to have lower demand during the day due to household occupants attending to various day time activities away from the house. With the commercial solar system sized to meet average daytime peak demand, summer is likely to be the main period throughout the year where there is significant regular excess solar generation. For the remainder of the year, the battery is under-utilised whereas a residential customer, on average, continues to get regular use of their battery year round.

However, not all behaviour is motivated by financial payback and we cannot be confident all commercial customers will have the typical commercial load profile with relatively high and stable daytime demand. Consequently we allow for some commercial battery adoption at relatively poorer payback periods and the resulting projections are shown in Figure 5-10 and compared with 2017 projections.

Similar to residential batteries, the trend in commercial battery capacity is heavily influenced by the trend in commercial solar capacity growth. This includes a period of strong growth before 2020, slower growth in the 2020s and recovering to accelerating growth in the 2030s. Also similar to residential batteries there is limited difference in the Moderate and Fast scenarios prior to the early 2020s due to minimal differences in battery costs during this period.

Adoption ranges across the three scenarios are significantly wider reflecting the same uncertainties that were discussed in the discussion of residential batteries. The trends in state/territory commercial battery capacity are the same as residential batteries largely by design (Figure 5-11). Since the available data cannot yet disaggregate between residential and commercial battery sales they have been apportioned according to the ratio of rooftop solar capacity between the two market segments.

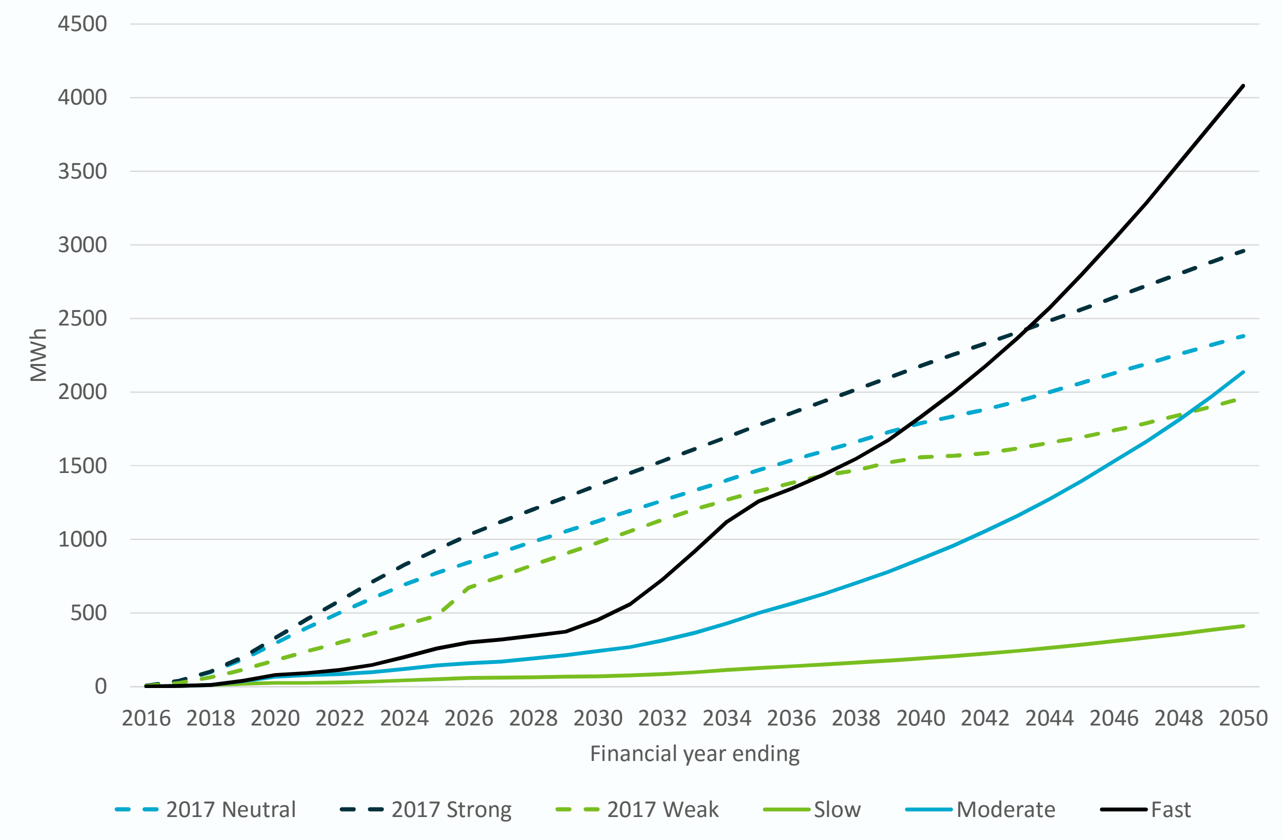


Figure 5-10: Projected commercial battery storage capacity by scenario compared with 2017 scenario projections

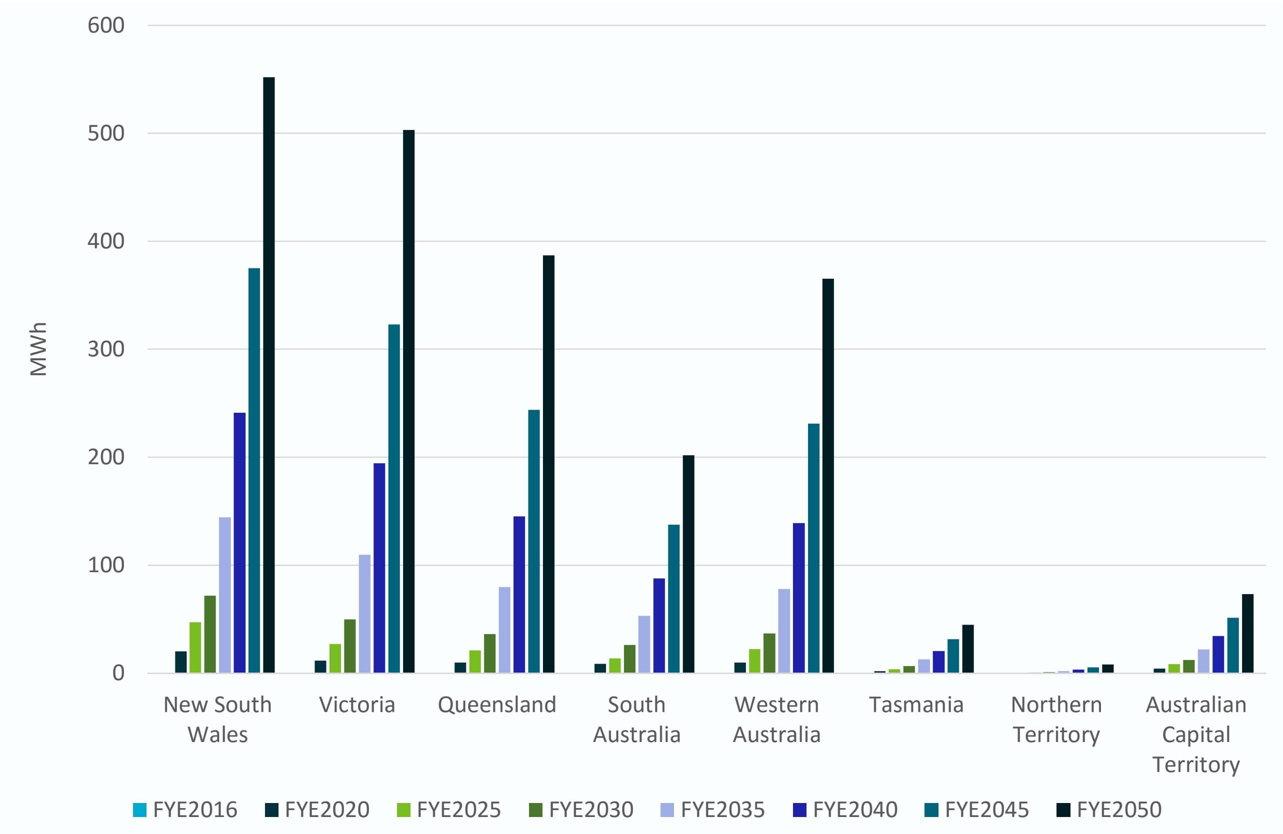


Figure 5-11: Projected commercial battery capacity by state under the Moderate scenario

5.6 Standalone power systems

Existing standalone power systems (SAPS) or off-grid systems are primarily remote area power systems (RAPS) which were installed because the cost of connecting the grid via transmission and distribution lines to some remote areas is prohibitive. However, the falling cost of solar PV and battery storage has potentially broadened the applicability of SAPS. Energeia (2016) examined small towns (500 or less) and farms and found that while costs were prohibitive for small towns, the smallest size farms greater than 1km from the grid would already be financially better off installing SAPS than connecting to the grid. Over time, they projected larger farms could also be able to install SAPS for electricity supply at a similar cost to grid connection, depending on the distance from the existing grid.

In this section we consider a third market segment which is customers who do not have to pay a grid connection cost. In other words, we consider urban customers for whom there is an existing line connection or there would ordinarily be a line constructed as part of a housing development. While RAPs, new farms and semi-remote communities are niche markets, urban SAPS is a large market segment with major implications for the grid if it were to become significant.

At present the payback period on urban SAPS systems is estimated on average to be beyond the life of the equipment (i.e. greater than 20 years) and so it represents an early adopter market in the framework of our projection method (where non-price drivers lead to adoption for a small number of customers). With solar and battery systems costs continuing to fall, however, it would not be unreasonable to expect payback periods to fall – we estimate to around 15 years, on average, in the long run. These payback periods were estimated on the basis of a system comprised of solar PV, battery storage and a petroleum based generator similar to that outlined in Graham et al (2015). Business model innovation could result in alternative products with better payback periods (now and in the future).

The projections for the number of customers that install urban SAPS are shown in Figure 5-12. The projected number of customers in the Moderate scenario who install SAPS represent less than 1% of customers at any time. This reflects that the payback period does not improve enough to build a large market share. The cost of the batteries is major component of the SAPS and so the trend in projected installations borrows somewhat from that of batteries more generally.

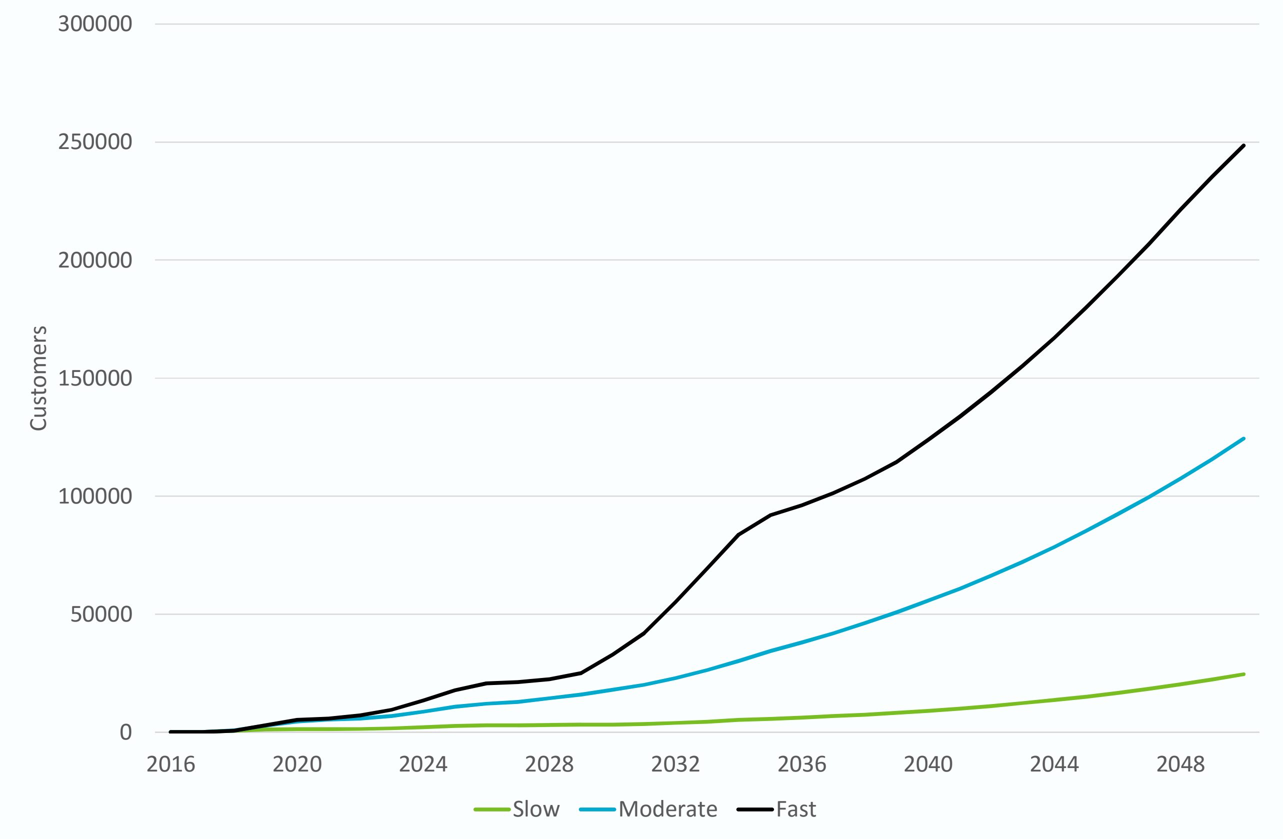


Figure 5-12: Projected number of customer that install urban standalone power systems

The main way in which the payback period can easily be improved is by remaining connected to the grid, reducing both the solar and battery sizes and removing the need for the generator. Others have observed that high fixed charges for grid connection (the daily charge is generally around $1 per day or $365 per year regardless of electricity use) could encourage customers who already have large solar and battery systems to disconnect. Energeia (2016) proposed that retailers and networks could offer customers who would prefer greater grid independence a special 'SAPS tariff' which would include reduced daily charges and the opportunity to gain export revenue and in return SAPS customers reduce their load on the grid to zero at peak times.

Given the small size of the existing market, there is no source which describes the current location of existing urban SAPS installations. The state projections were allocated according to existing population density and are shown in Figure 5-13.

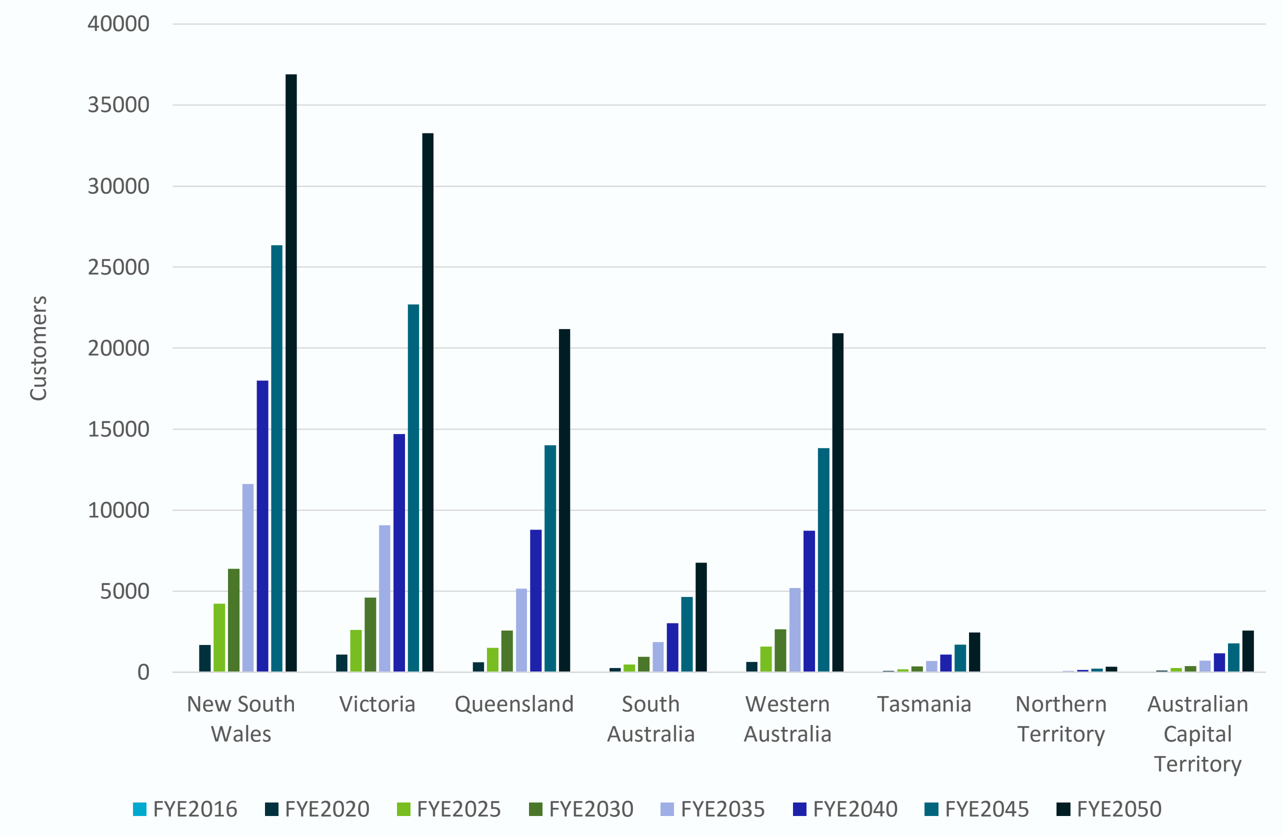


Figure 5-13: Projected number of customers that install urban standalone power systems by state under the Moderate scenario

5.7 Electric vehicles

The Slow, Moderate and Fast scenarios all assume passenger electric vehicles (EVs) reach parity with internal combustion engine vehicles (ICEs) by 2035, 2030 and 2025 respectively. However, trucks and buses which have heavier loads and plug-in hybrid electric vehicles (PHEVs) which have the added complexity of accommodating two drive trains maintain a premium over ICEs throughout the projection period.

For passenger EVs, in the year of reaching parity with ICEs, the payback period is zero and the EV share of total passenger vehicle sales peaks. The Slow, Moderate and Fast scenarios have been designed to saturate at sales rates that, on average, are 38%, 43% and 60% of total vehicle sales (calculated to reflect different levels of access to off-street parking and options for long range driving). However there is significant diversity by location. At individual SA2 levels, we allow that sales rate to vary up to 25 percentage points higher or lower so that under the Fast scenario, for example, we have a maximum sales rate of 85% in some SA2 regions. We also have pockets of very low uptake reflecting demographic differences. The share of sales saturation assumptions are asymmetrical with the Fast scenario higher than the Slow scenario is lower than the Moderate scenario. This is deliberate and reflects the view that there is more upside potential than downside potential.

One of the reasons for having confidence that the plausible range of sales adoption rates would all be above 30% is because around 60% of Australian households have two vehicles. This means that there is a reasonable chance that these households could purchase an electric vehicle without any concern about limited travel range. That is they can access a second vehicle that has extended range when undertaking infrequent longer trips whilst utilising the EV for the high majority of their kilometres. Of course there are alternative solutions for delivering extended range such as larger battery sizes, highway recharging, PHEVs and fuel cell vehicles[6]. Also, there will be a diversity of needs for longer trips amongst customers.

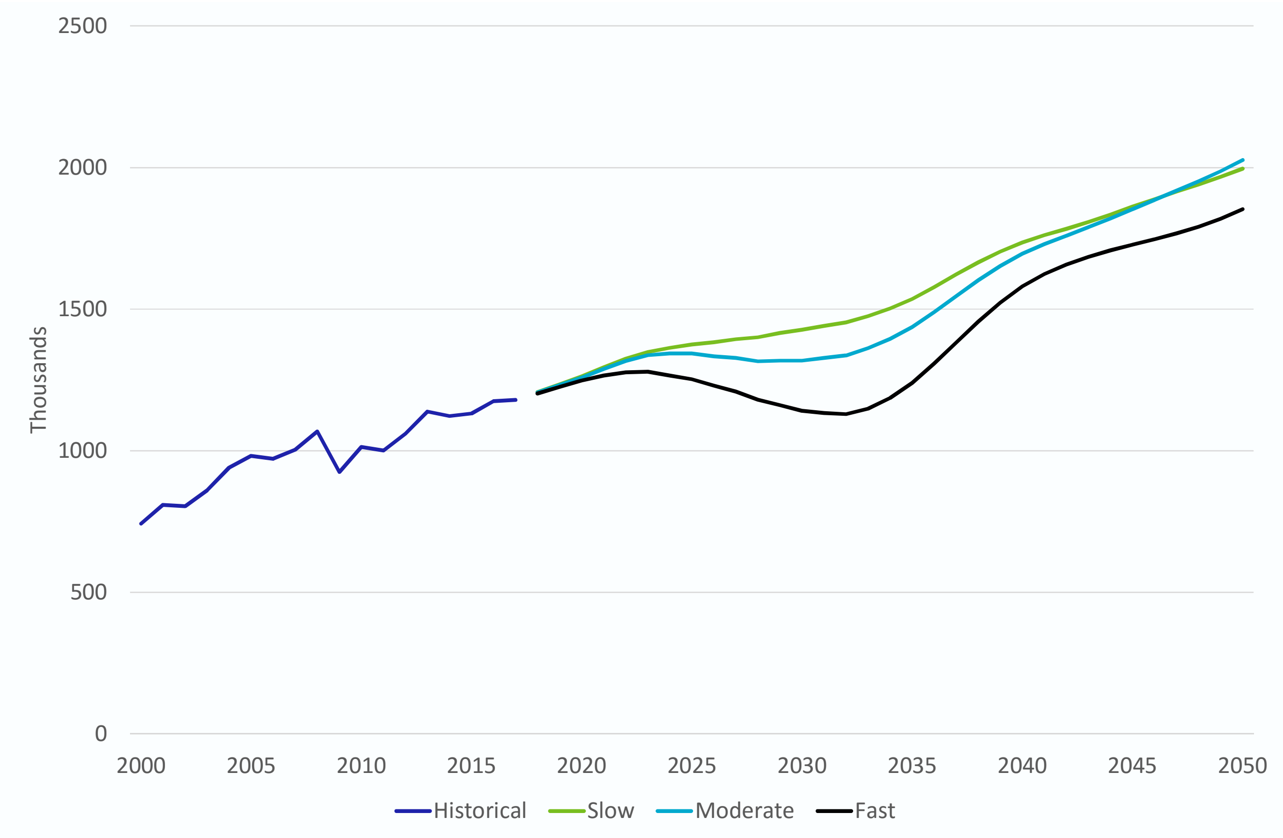


Figure 5-14: Historical and projected total vehicle sales by scenario.

Total vehicle sales differs across the scenarios due to the impact of assumptions about the rate adoption of car ride/sharing (Figure 5-14). All three sales trends include a significant reduction in vehicle sales from the 2020s reflecting greater car ride/sharing adoption which is strongest in the Fast scenario but is also included at lower levels in Moderate and Slow. Increased car/ride sharing reduces the number of vehicles required but leaves total kilometres travelled at a similar level. This means that each vehicle is delivering a larger number of kilometres per year. This development increases the attractiveness of electric vehicle uptake because it means there are greater fuel savings in total for each vehicle with which to payback an additional upfront cost of an EV compared to an ICE vehicle. Whilst these sales trends effect the number of vehicles sold and in the total vehicle fleet, it is the kilometres travelled which determines electricity consumption. As such these trends have almost no impact on the trend in electricity consumption from EVs and PHEVs.

Based on our scenario assumptions, the electric vehicle payback period falls very rapidly to zero or below five years in the period 2025 to 2035, depending on the scenario. This leads to the increases

[6] Fuel cell vehicles and very long range electric vehicles are not modelled explicitly but would have similar costs to PHEVs.

in sales shown in Figure 5-15. Since the payback period is no longer falling, the sales rate slows. The exception is the Fast scenario which experiences a fall in sales owing to the high rate of adoption of car/ride sharing services. However each vehicle under the Fast scenario is travelling further per year. The outcome of these accumulated sales is shown in Figure 5-16 which is total EV and PHEV vehicle numbers accounting for losses due to vehicle scrapping and retirement. Note that any battery replacement during the vehicle life is counted as a maintenance cost rather than new vehicle. Again, we can see the trend that the Fast scenario has a slower rate of growth in vehicles in the latter part of the projection period owing to car/ride sharing adoption.

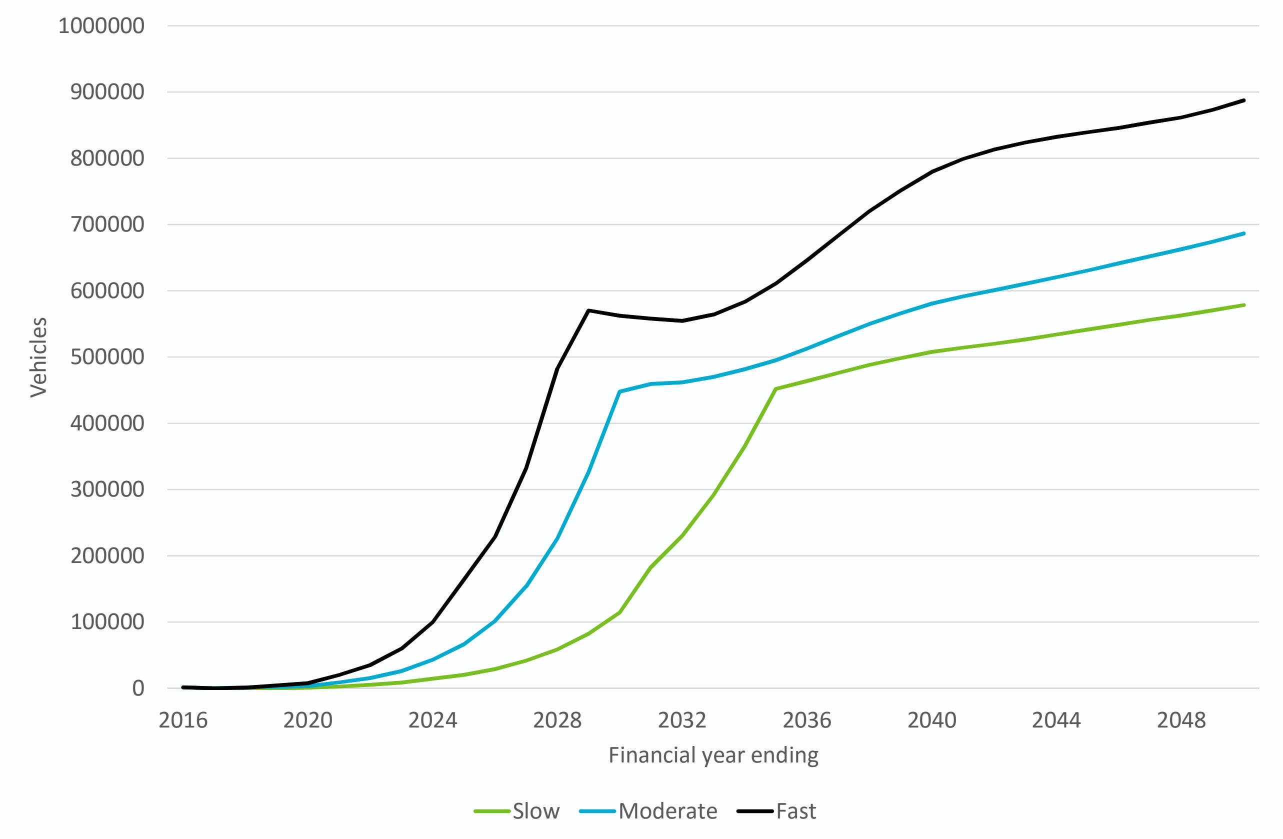


Figure 5-15: Projected electric vehicle (EV and PHEV) annual sales, all road vehicle classes and all states/territories

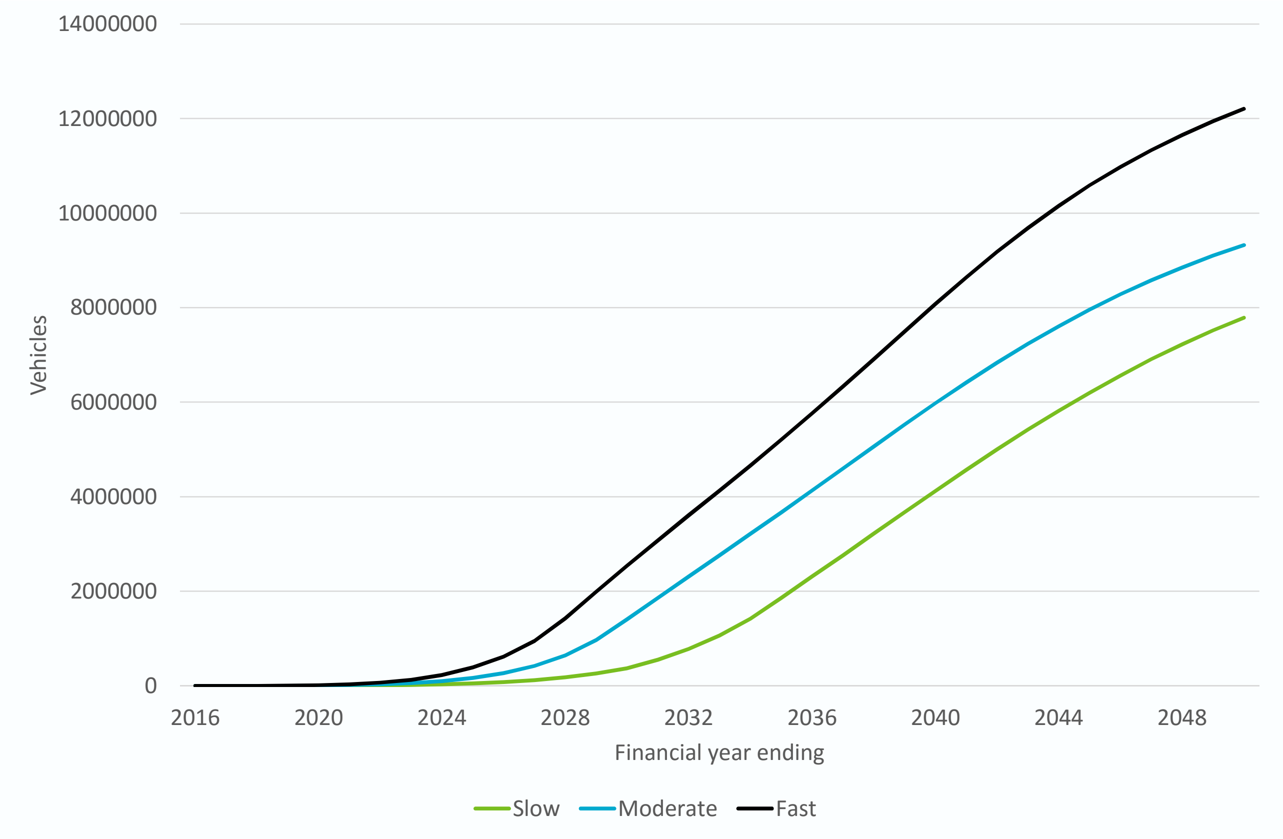


Figure 5-16: Projected total electric vehicle numbers, all vehicle types and all states/territories

Figure 5-17 shows the projected consumption of electricity by the EV and PHEV fleet by scenario compared to previous projections. The differences in projections largely reflect assumptions. The method in Energeia (2017) is similar, including calculation of the payback period, consideration of the timing of when EV cost reach parity with ICE vehicles and constrains growth in the 2020s to reflect delays in the ability of global vehicle manufacturing to deliver EV models to the Australian market. This leads to significant commonality in projections to the mid-2020s.

However after the mid-2020s, differences in assumed market saturation rates place the projections on difference paths. Energeia (2017) assume adoption saturation rates of 80% to 100% which mean that the Neutral and Strong scenarios increase to higher levels than Fast and Moderate. The CSIRO modelled LETR Pathway 2 scenario from Campey et al (2017) and the ENTR scenario from Graham and Brinsmead (2016) both included a similar 80% sales saturation rate for EVs and consequently they sit closer to the projected electricity consumption in the Energeia (2017) Neutral and Strong scenarios in the long run. CSIRO designed these scenarios in previous research to be especially aggressive in the long run as they were undertaken in the context of energy sector wide greenhouse gas abatement including transport playing a significant role and a zero emission electricity sector by 2050. The Slow, Moderate and Fast scenarios assume Australia is reducing emissions consistent with the Paris target and further actions beyond 2030. However, we assume no specific policy framework or target for transport emission abatement.

Another feature of scenario construction which differed was that the DoEE BAU, ENTR and LETR Pathway 2 scenarios all imposed a sales share over time without reference to a specific point in time when EV parity to ICE vehicle costs is reached, making direct comparison more difficult.

The CSIRO (2016) DoEE BAU scenario is closest to the Moderate scenario in assumptions because it included a maximum EV sales share of 46% by 2050 (compared to 43% in the Moderate scenario). Consequently they have very similar EV and PHEV electricity consumption in 2050 with the Moderate scenario having a steeper increase in sales in the earlier years.

The alignment at the lower end of the projections between 2017 Weak and Slow is closer. This perhaps reflects the greater certainty that we'll have at least some EVs and PHEVs in the vehicle fleet. The greater uncertainty is in the upper limits.

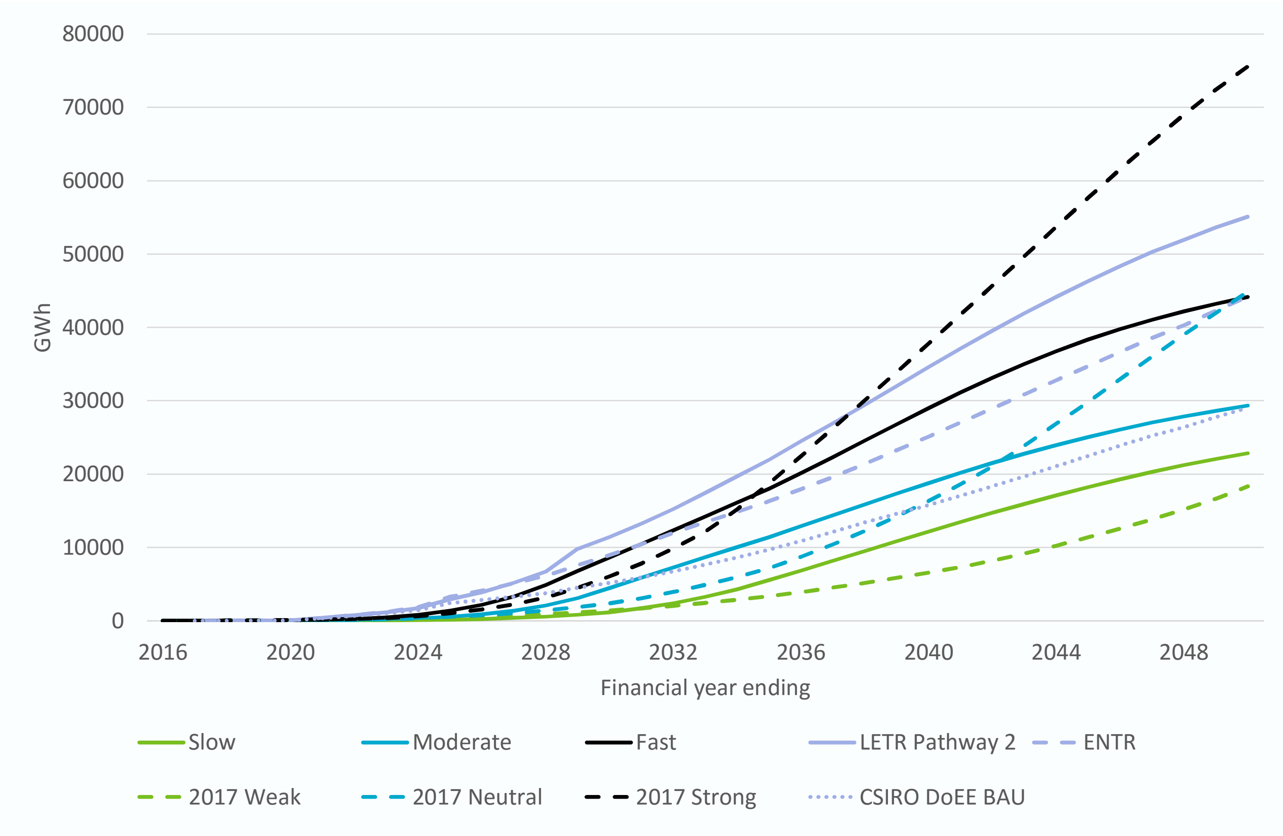


Figure 5-17: Projected electricity consumption by electric vehicles by scenario, all vehicle types and all states/territories

Figure 5-18 shows the projected EV and PHEV electricity consumption by vehicle class under the Moderate scenario. It demonstrates that passenger vehicles are expected to be the leading EV and PHEV vehicle class. This reflects the fact that this is the large vehicle market and because this vehicle class reaches cost parity with ICE. Light commercial vehicles also achieve ICE vehicle cost parity supporting their position as the next most popular EV and PHEV vehicle type but are a smaller vehicle market compared to passenger vehicles.

Electric truck and bus numbers are the next smallest respectively given their costs do not reach parity and they are a smaller portion of the fleet. Across all vehicle classes EVs are favoured over PHEVs at a ratio of 34 to 1 reflecting better EV economics and current purchasing preferences extrapolated in to the future. There is significant uncertainty whether this trend can be reliably extrapolated but is likely appropriate for the sales saturation rates we have applied here. At higher saturation rates such as those in the other comparison studies it would be more appropriate to have a greater number of PHEVs (or other long range electric vehicle variants) to account for the ability of customers to meet the need to undertake infrequent longer range trips.

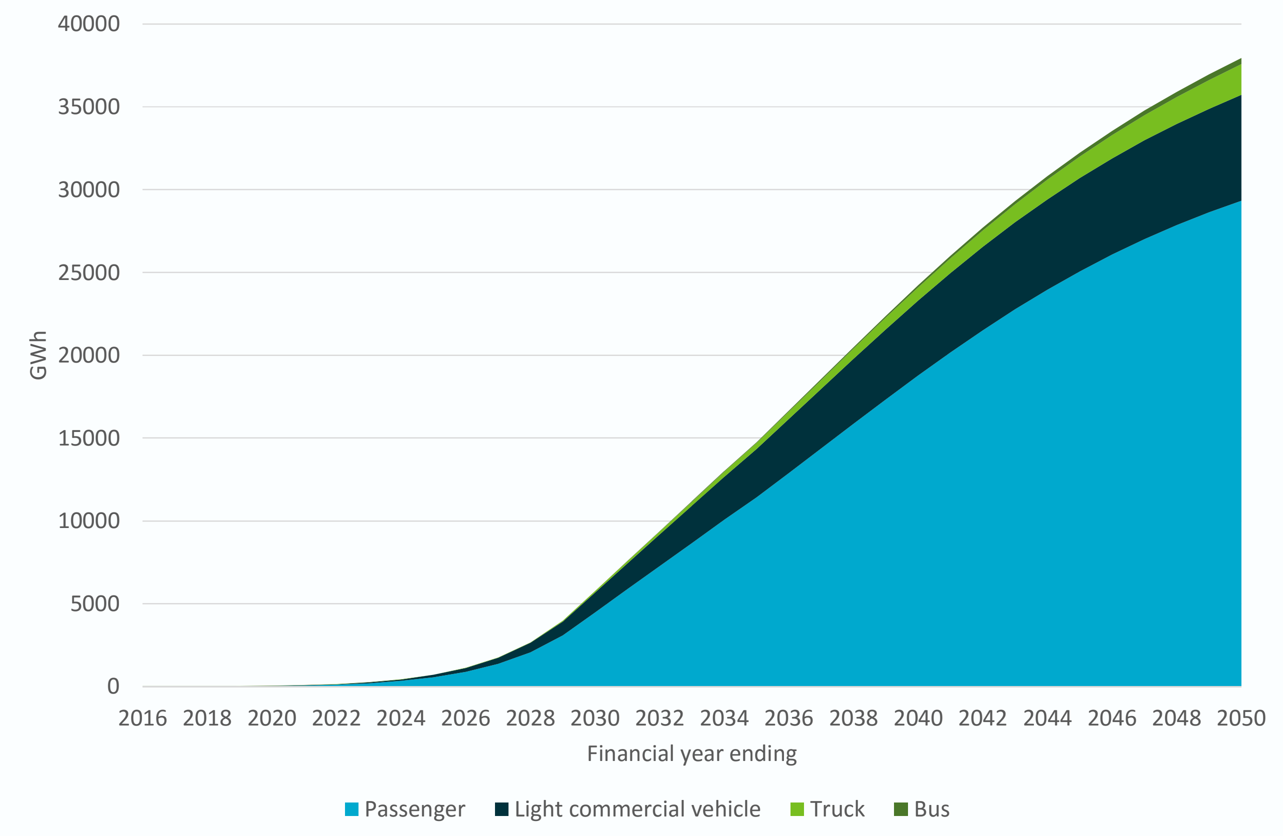


Figure 5-18: Projected electric vehicle consumption by vehicle class under the Moderate scenario

5.8 Electric vehicle load profiles

In order to make it possible to calculate the impact of EV and PHEV electricity consumption on the electricity system the timing of electric vehicle charging is described in half hours in Figure 5-19, Figure 5-20 and Figure 5-21. They are provided as convenience profiles plus two managed profiles. The managed profiles move charging to off peak times. However, owing to solar PV adoption, over time, the off peak period is expected to move from night/early morning to middle of the day. As such we provide two off peak profiles that can be used as the load profile changes over the projection period.

The convenience profiles (where no incentives are offered to influence charging timing) are sourced from Australian and international trials and represent population level rather than individual vehicle profiles (Roberts 2016; Mader and Bräunl 2013; Victorian Government 2013). The key difference to note between vehicle types is that passenger vehicles (without any incentives) are expected to charge mainly in the evening as residents arrive home from day time activities. Given this is the largest EV market segment this is of course a major concern for peak demand. Light commercial vehicles are expected to charge throughout the day (from a population level perspective) because they are located nearer to their charging infrastructure. Trucks and buses tended to be fast charged at the commencement of the day's activities, perhaps reflecting that their owners will have less tolerance to stop for further charges throughout the day due to these vehicles being used for on-time services.

The day and night off-peak scenarios were manually created to access most of their charge in their respective off peak periods. The night charging is flat. However, we allowed for a 'solar-shaped' charging profile in the day to take most advantage of that resource. Demand during the evening peak period was reduced. The changes preserve the same total energy consumption. The data shown represents an average day, however we have used traffic data to create weekday, weekend and monthly differences over a year.

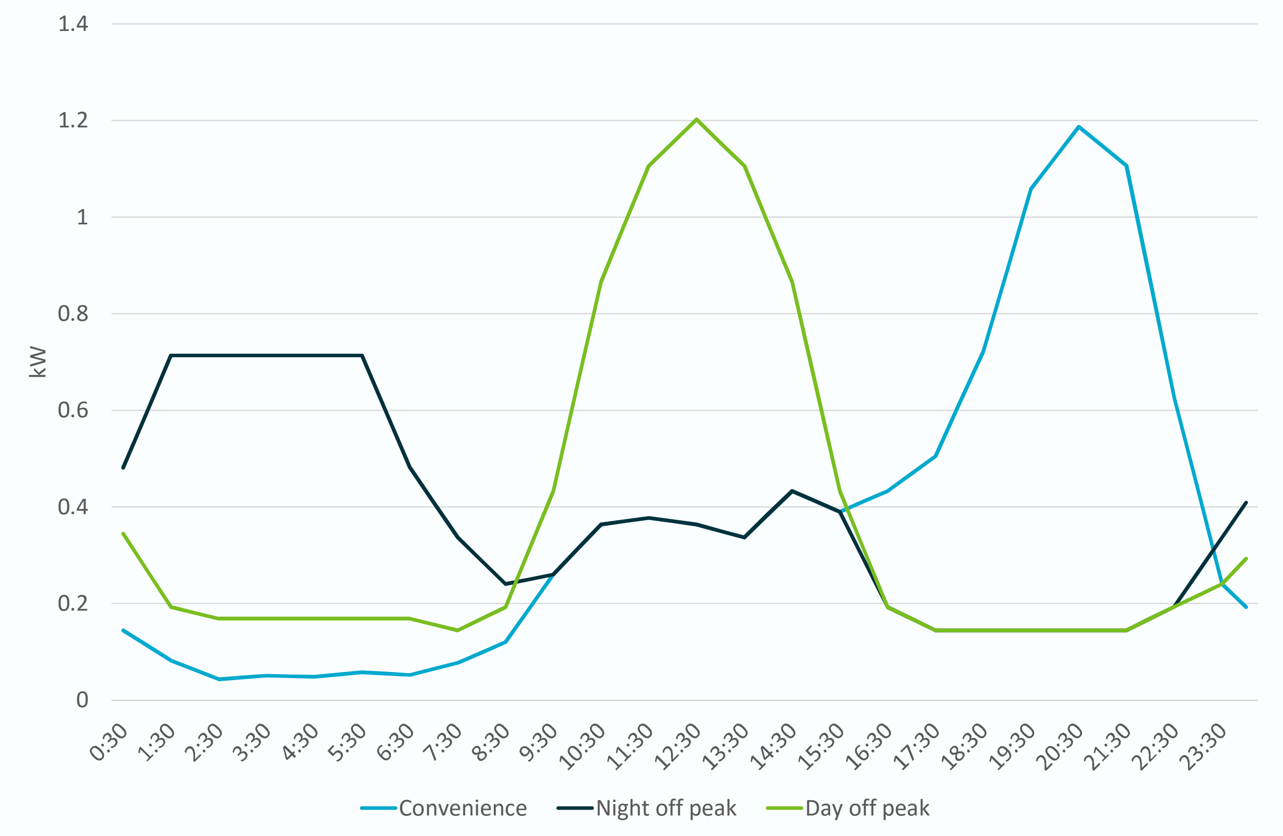


Figure 5-19: Electric vehicle charging profiles for passenger (residential) vehicles

Figure 5-20: Electric vehicle charging profiles for light commercial vehicles

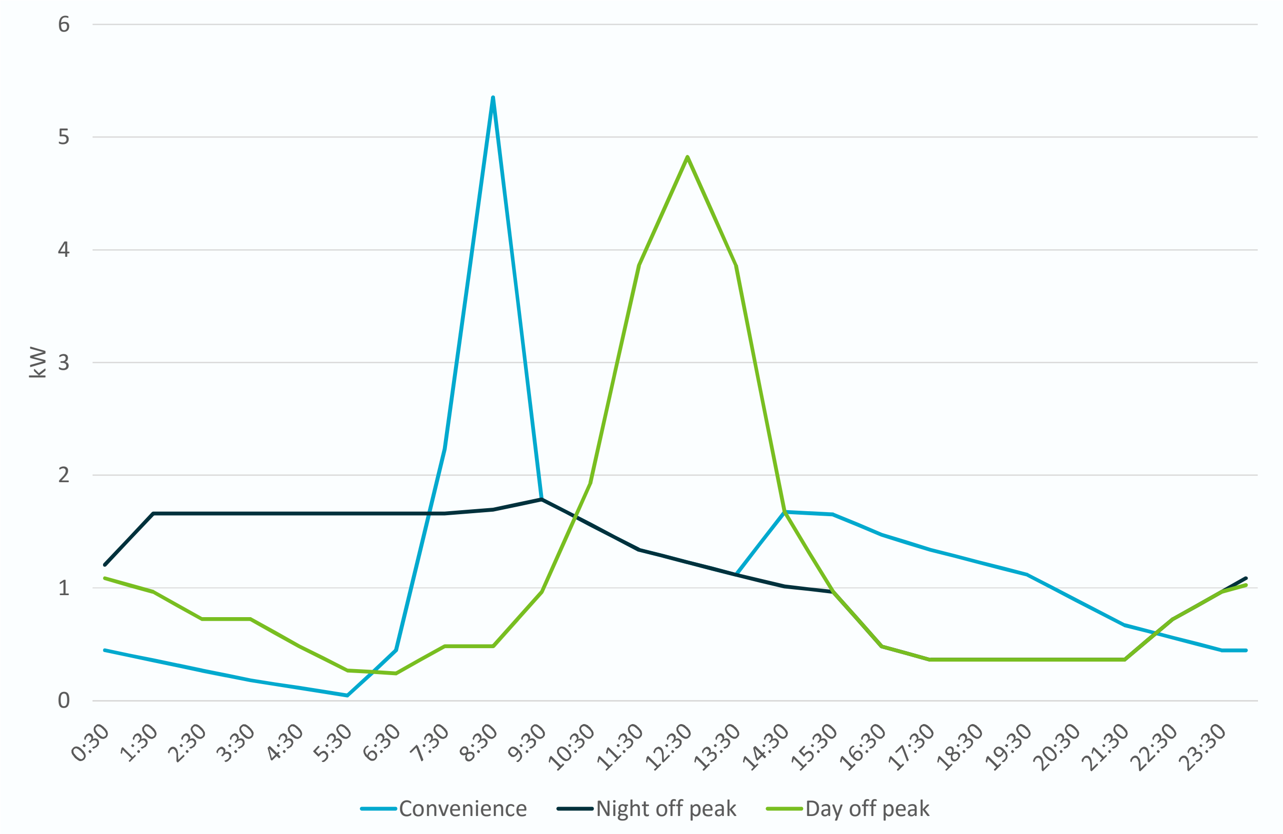


Figure 5-21: Electric vehicle charging profiles for trucks and buses (heavy commercial) vehicles

5.9 Battery storage profiles

As discussed under the section on data assumptions we employ two alternative battery management strategies:

1. Charge if exporting, discharge if importing
2. Same as 1. but also delay any discharge until after 5pm and halve the charge and discharge rates

The first strategy is designed to minimise household/commercial business bills without any concern for whether the aggregate outcome is also optimised for the electricity system costs. The second strategy is designed to reduce system costs by ensuring that batteries are not fully charged before minimum load (i.e. maximum solar PV generation) and increasing the likelihood that battery discharge occurs in the evening peak. Battery storage owners are compensated for providing this service to the grid.

Figure 5-22 shows the resulting residential customer load profile on a sample of winter days for no batteries installed (PV only) and for batteries installed under the two battery management regimes with the first strategy called “PV+Battery” and the second strategy called “PV+Smart Battery”.

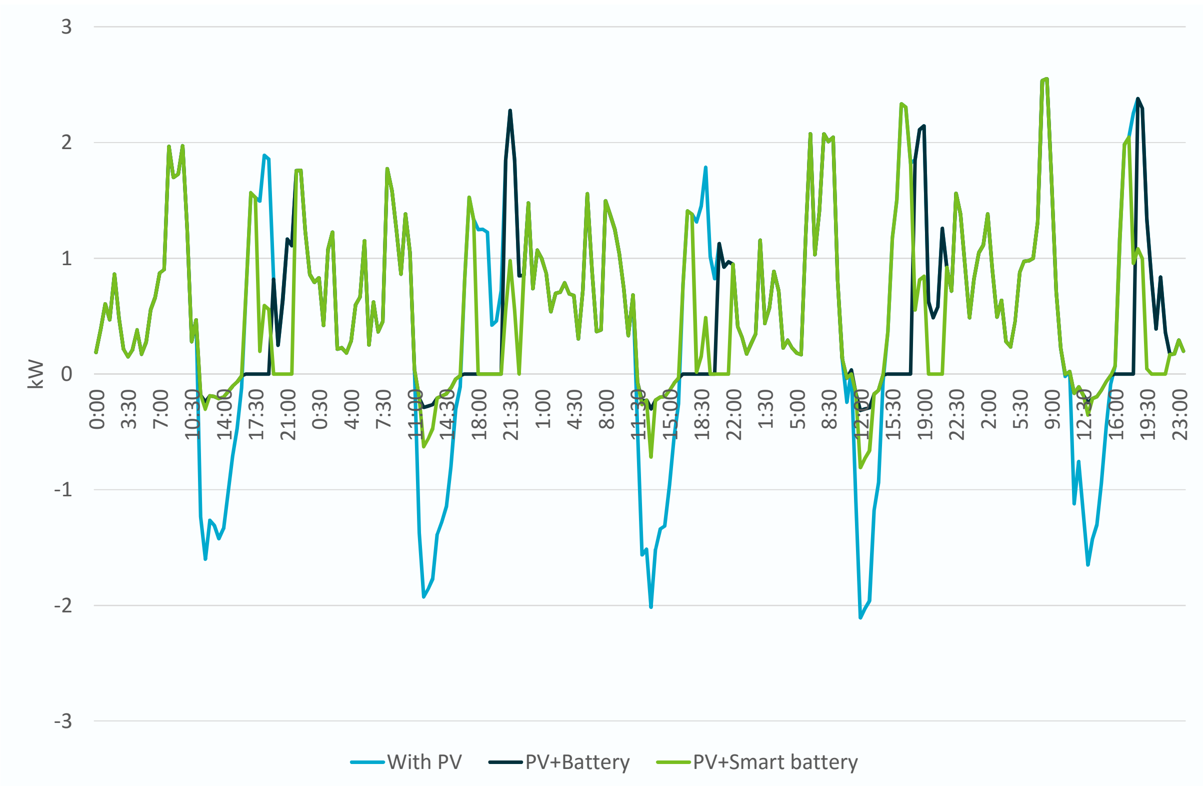


Figure 5-22: Sample of residential load during winter under two battery management regimes

Winter days are shown because it is less likely that battery strategy 2 performs significantly better for the system in summer since the battery will be full more often and can stretch into the evening peak even without a conservation strategy. The sample days show that the second strategy is more effective in reducing the customers evening peak and over many customers this should support a reduced aggregate evening peak. Owing to the season, both battery strategies are effective in reducing minimum load, although the second battery strategy performs slightly worse (as we shall see in the commercial case this turns around in summer).

For commercial customers we show a sample of summer days in Figure 5-23 as during this season a commercial customer is more likely to have excess solar to store and use. Due to their load profile, commercial customers have limited solar to move around in winter. The first battery management strategy results in no reduction in minimum load because the battery has charged to capacity too soon. The slower charging in battery management strategy 2 is better at reducing minimum customer demand. It also performs better at reducing peak demand, whereas the first strategy discharges too quickly, before the peak period has ended.

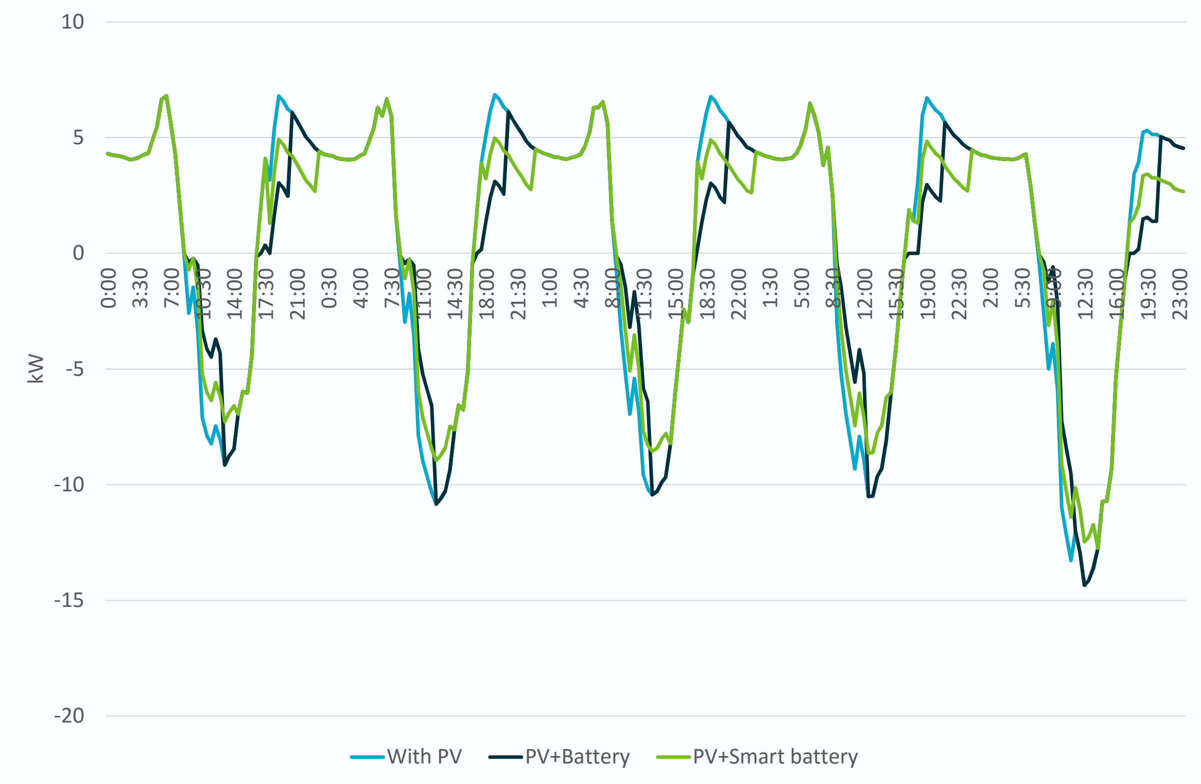


Figure 5-23: Sample of commercial load during summer under two battery management regimes

The strategies that have been explored here are non-optimal relative to what could be implemented by a centralised control system, orchestrating the batteries on behalf of an aggregator or other party responding to real time price signals. However, it was beyond the scope of this report to be able to iterate between system outcomes (e.g. calculated through spot market modelling) and individual customer battery management strategies. Results for net load will also differ depending on customer selection of PV and battery storage system sizes which will vary. For example, the larger the battery the less advantage of strategy 2 over 1 in reducing maximum and minimum load.

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.

Rooftop solar generation profiles were sourced from the AEMO 2016 NTNDP data assumptions for NEM states. Western Australia (the SWIS) and Northern Territory are assumed to have similar profiles to South Australia and Queensland respectively. Table A.1 shows the average capacity factors from these production profiles.

Apx Table A.1 Rooftop solar average annual capacity factor by state

	Capacity factor
New South Wales	0.14
Victoria	0.13
Queensland	0.16
South Australia	0.15
Tasmania	0.12
Western Australia (SWIS)	0.15
Northern Territory	0.16

Residential solar system sizes are set by the scenario assumption at 5 to 7kW reflecting differences in hosting capacity. Given the much better match between commercial customer load profiles and solar output profiles, commercial solar system sizes are assumed to be matched to average daily peak.

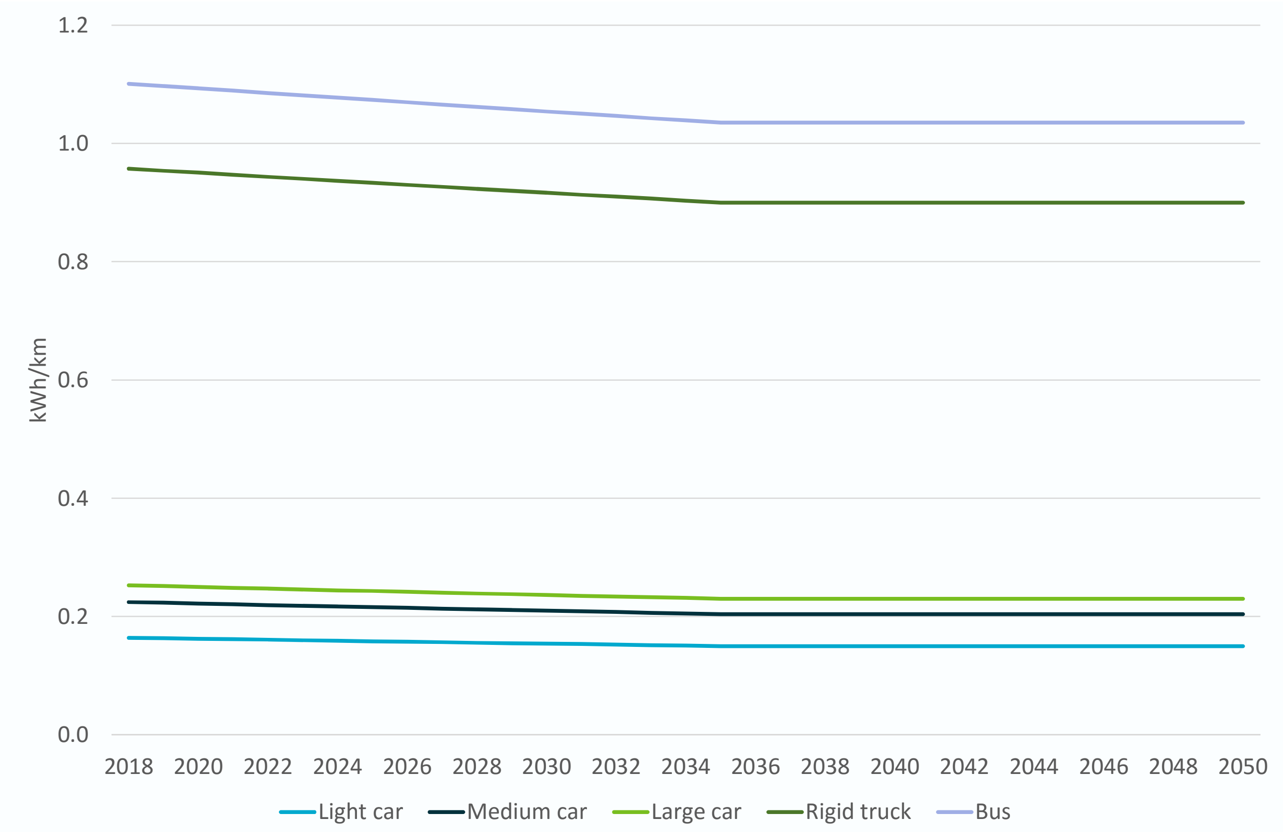
For battery storage sizing we have chosen not to optimise size since the current market tends to only offer limited size ranges. We have looked at popular battery sizes and matched a larger battery to our large customer profiles and a battery around half that size to other customers (see Table A.2). Note that we do not need to explore large batteries because, with a maximum power discharge and charge rate of the battery size in kWh divided by 2.6 for the largest battery can absorb all power from a 5kW solar system. As such there would be little to gain from any larger battery size given rooftop solar size restrictions.

For commercial customers the battery system size in kWh is set proportional to the smaller of the two popular residential system battery to solar ratios. Commercial systems should need a lower storage to solar ratio because their solar is much better matched to the commercial load profile.

Apx Table A.2 Battery storage performance assumptions

Characteristic	Assumption
Round trip efficiency	85%
Maximum charge or discharge or rated capacity	95%
Rated capacity	Large residential: 14kWh, otherwise: 7kWh Commercial: approximately 140% the solar capacity which itself is set at proportional to average daily peak demand
Maximum power in kW	Rated capacity divided by 2.6

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.



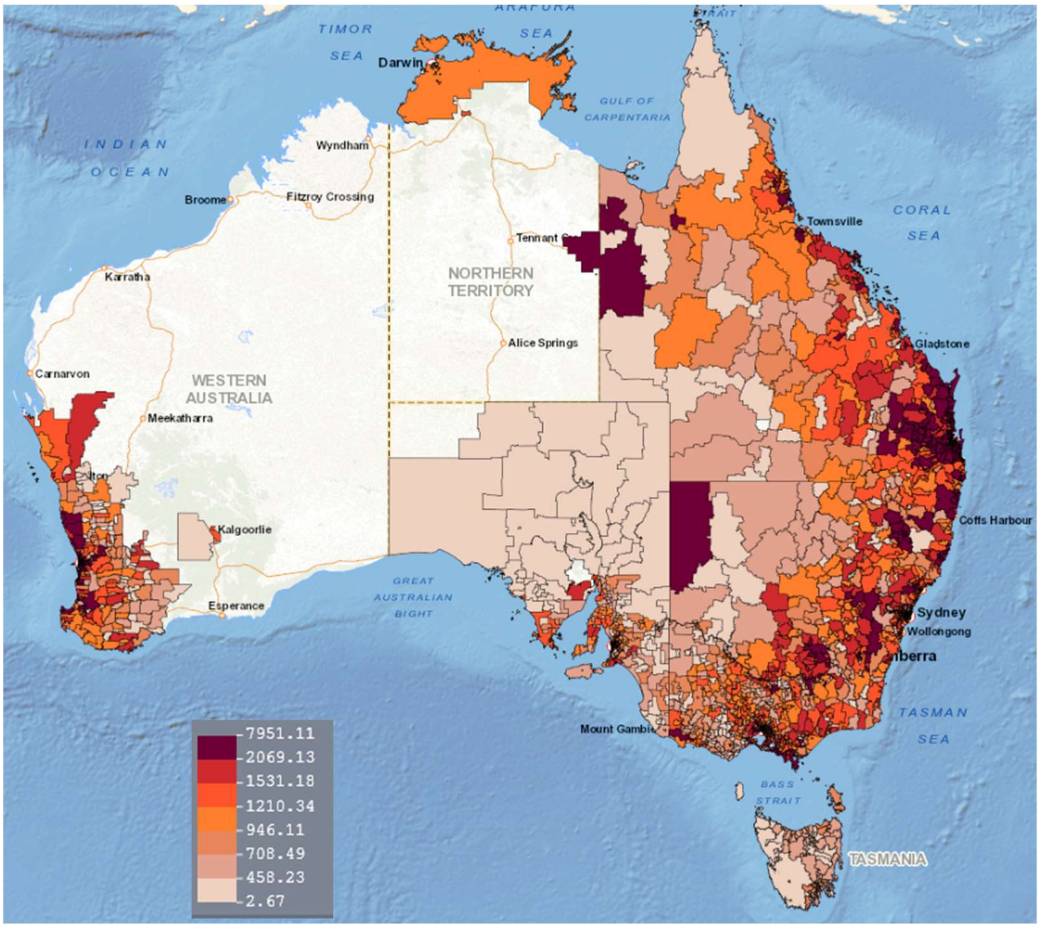
Apx Figure A.1: Electric vehicle fuel efficiency by road mode

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 (with engine improvements traded off for better acceleration or more comfort, safety and space). We assume electric vehicles will follow the same trend.

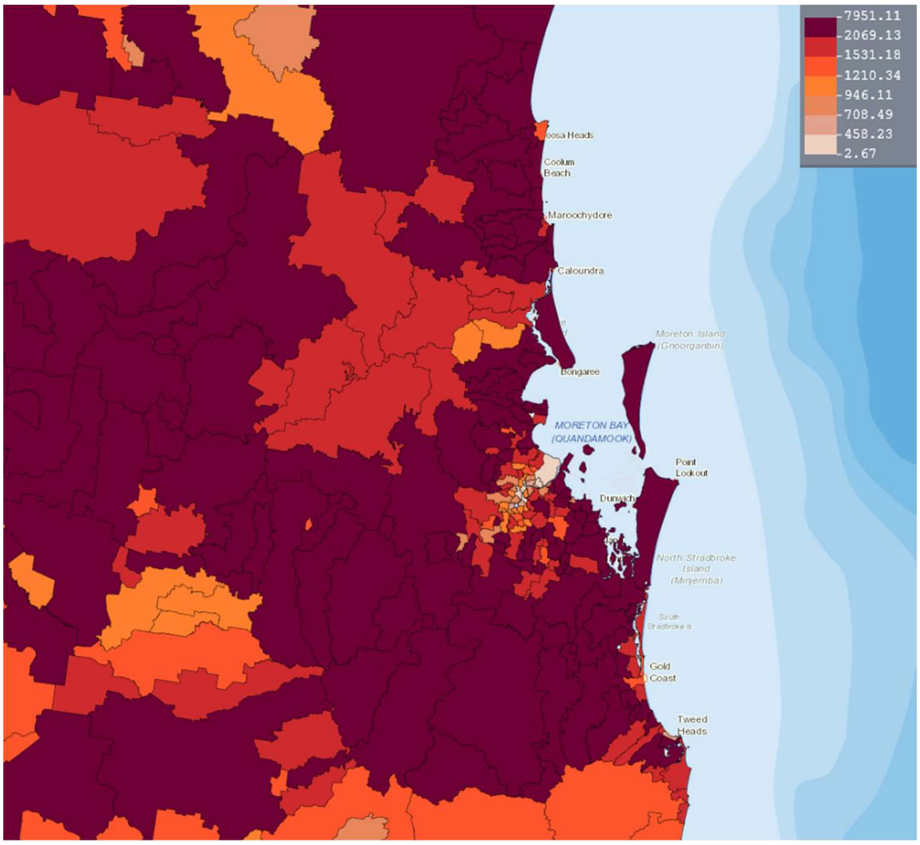
Appendix B Postcode level results

While the focus of this report is state, SWIS and DKIS level results, the projections are calculated at the ABS SA2 level to account for diversity of customers through demographic characteristics. This includes converting Clean Energy Regulator postcode data on solar installations to SA2 regions. When the projections are complete we convert them back to postcode and other spatial formats for reporting and checking purposes. The data is available in annual time steps, consistent with the state data presented in the report body. For brevity, in this appendix we map the year 2030 only and a selection of the reporting data at the Australian level, zooming in on southeast Queensland and central eastern New South Wales for rooftop solar and electric vehicles respectively.

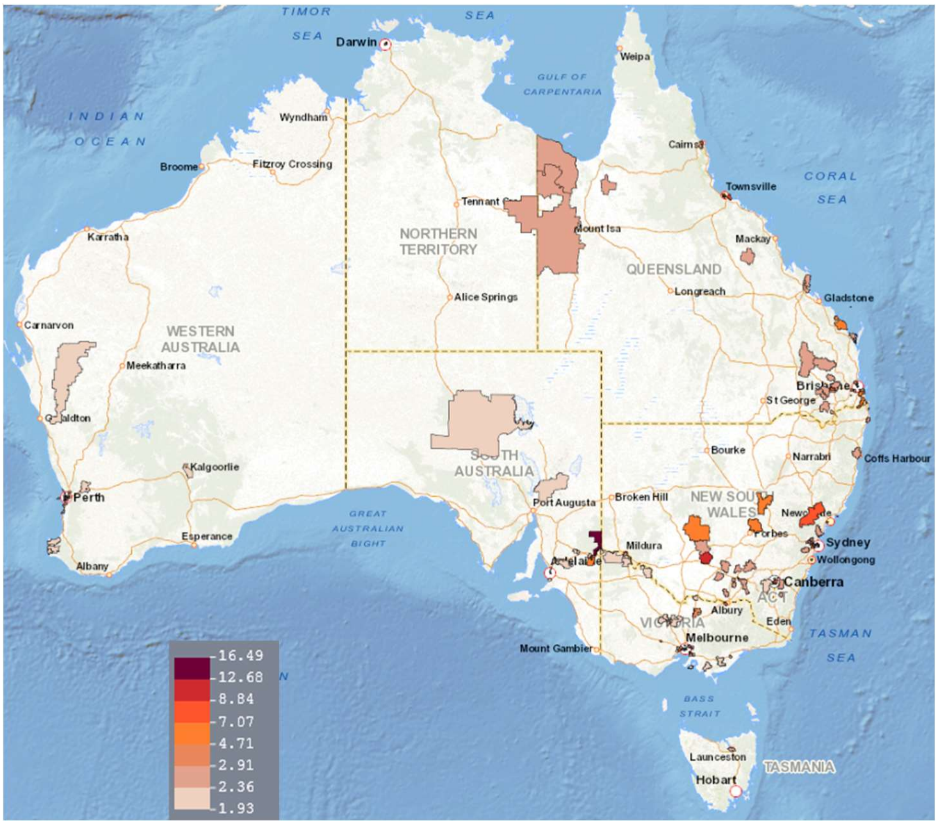
The maps in Figures B.1 to B.5 were created using the Australian Renewable Energy mapping infrastructure which can be found at: http://nationalmap.gov.au/renewables/. Note that postcodes are not necessarily the ideal format for representing the true shape of the SWIS and NKIS electricity consumption zones. Also postcodes are of different sizes. Therefore the colour intensity does not necessarily indicate density across the whole postcode but more likely indicates a high concentration with the large city within that zone (particularly in relation to residential technologies, less so for large commercial solar plant).



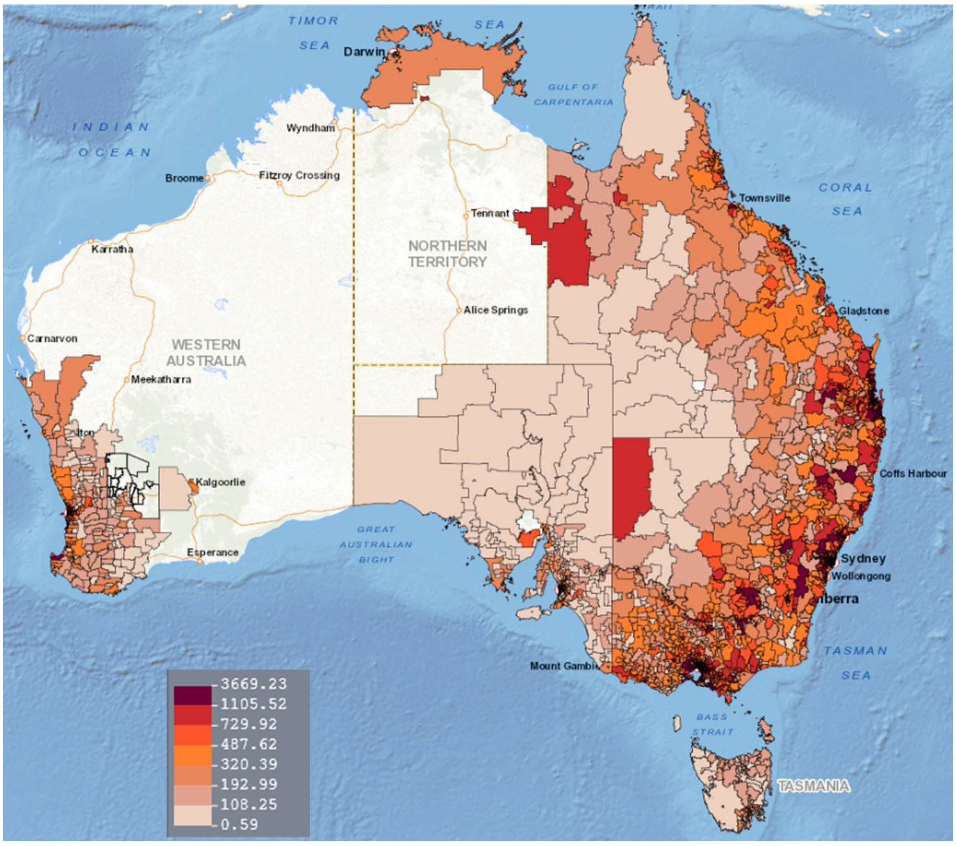
Apx Figure B.1: Australian map of number of projected residential rooftop solar installations in 2030 by postcode



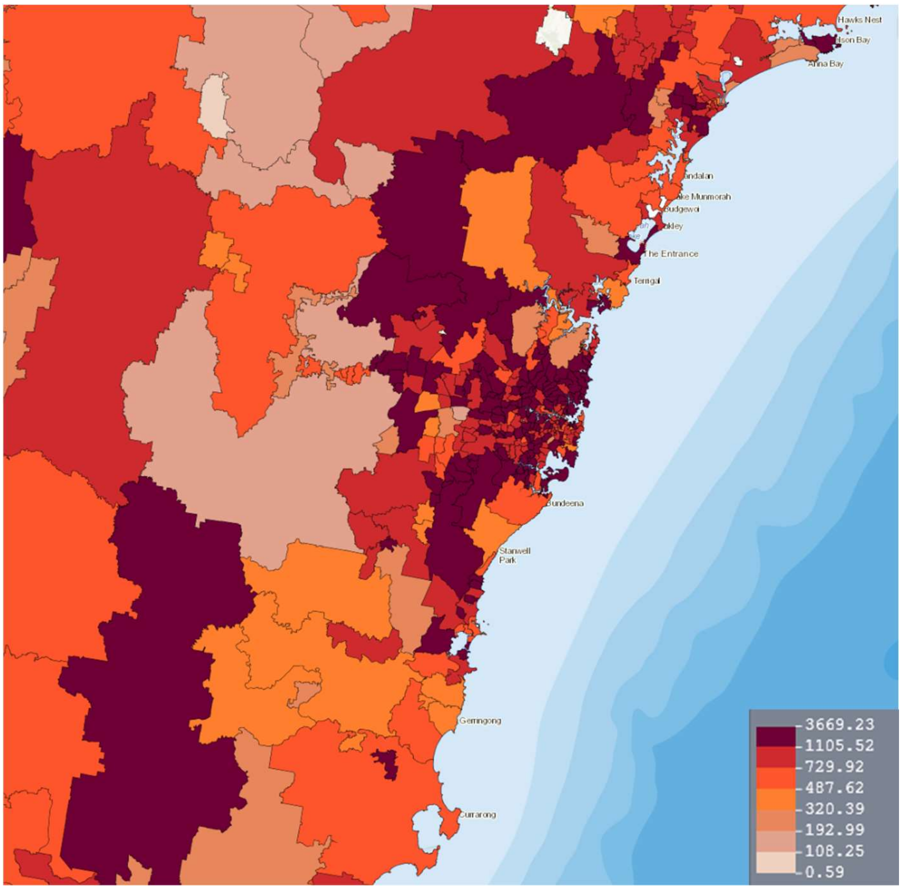
Apx Figure B.2: South East Queensland map of number of projected residential rooftop solar installations in 2030 by postcode



Apx Figure B.3: Australian map of the projected non-scheduled generation solar capacity (MW) in the 100kW to 1 MW range in 2030 by postcode



Apx Figure B.4: Australian map of number of projected residential electric vehicle numbers in 2030 by postcode



Apx Figure B.5: Central New South Wales coast map of number of projected residential electric vehicle numbers in 2030 by postcode

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