Projections of uptake of small-scale systems

Australian Energy Market Operator

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Executive Summary

This report presents PV uptake forecasts prepared by Jacobs for the Australian Energy Market Operator (AEMO). These forecasts will feed into the electricity demand modelling that will be used to produce the 2016 National Electricity Forecasting Report (NEFR).

Three scenarios were explored as part of this modelling exercise: “Neutral”, “Strong” and “Weak” scenarios. This year AEMO has changed its basic approach to formulating the market scenario. Whereas previously AEMO attempted to capture the full range of what may eventuate in the electricity market, they now reflect a narrower range of economic conditions against a most likely future development path. Economic conditions considered include factors such as population growth, the state of the economy and consumer confidence. The neutral scenario reflects a neutral economy with medium population growth and average consumer confidence, the strong scenario reflects a strong economy with high population growth and strong consumer confidence and the weak scenario represents a weak economy with low population growth and weak consumer confidence. For the modelling of PV uptake, different expectations around cost of systems (subject to the different exchange rates adopted in each scenario) ground each scenario.

The modelling of battery storage is challenging because this technology is emerging and rapidly changing. In particular, the future cost, life and technical capacity of batteries is subject to considerable uncertainty and these elements drive the future uptake of PV systems with storage. The report has adopted the base LI-ion battery cost trajectories from CSIRO’s “Future energy storage trends” report that was prepared for the AEMC in September 2015. The forecast uptake of PVs with and without storage is based on Jacobs’ DOGMMA model, an optimisation tool that seeks to minimise total energy supply costs.

The study has found trends in uptake for PV and Integrated PV and Storage Systems (IPSS) in all regions can be explained by trends in financial incentives provided, the declining installation costs of the systems, the changes in retail prices, and assumptions on the transition to a time-of-use tariff structure and steady population growth.

The annual uptake of PV systems in Australia is forecast to be relatively stable up until the time when saturation is reached in some regions. This results in a total uptake of 20,634 MW of capacity in the Neutral scenario. Uptake in the commercial sector is forecast to continue increasing to a penetration of around 28% of total systems installed by 2037. IPSS are projected to have a strong and steady growth in uptake especially after 2020, coinciding with further reduction of their installation costs and the transition to a more cost reflective tariff structure. IPSS capacity is expected to grow to around 4,000 MW of systems being adopted by the end of the forecast period.

In Queensland the strong growth of PV and IPSS uptake in the commercial sector is offsetting a decline in growth in installations in the residential segment expected after 2032. The total capacity of systems at the end of forecast period is 6,552 MW, the highest of all States.

New South Wales is found to have a steady adoption of PV systems in both residential and commercial segments, with IPSS representing almost 25% of annual PV installations after 2020. The total capacity of systems installed in the State is forecast to be 6,036 MW.

Growth in uptake of residential PV systems in South Australia declines because saturation is reached in some regions, with the commercial sector forecast to have a steady growth.

The study forecast a steady adoption of PV systems in Victoria that will continue up until 2033 when saturation is expected to be reached in some regions. The faster transition to a time-of-use tariff structure in this state contributes to rapid penetration of PV systems with battery storage so that 2,500 MWh installed at the end of the modelled horizon is the highest IPSS capacity across all NEM regions.

Growth of PV installations in both the residential and commercial segments is slowest in Tasmania due to lower insolation levels that results in lower financial attractiveness of the systems.

The uptake of systems in the Strong scenario was found to be 18% higher than the Neutral scenario, and the uptake in the Weak scenario was 17% lower than the Neutral scenario. The deviations between the three scenarios are due to the different installation capital costs of the systems and the different population levels assumed in each scenario.

Important note about your report

The sole purpose of this report and the associated services performed by Jacobs is to provide estimates of uptake of PV and storage systems in the residential and commercial sectors across Australia, in accordance with the scope of services set out in the contract between Jacobs and AEMO (the Client). That scope of services, as described in this report, was developed with the Client.

In preparing this report, Jacobs has relied upon, and presumed accurate, information provided by the Client and/or from other sources. Except as otherwise stated in the report, Jacobs has not attempted to verify the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change.

Jacobs derived the data in this report from information sourced from the Client and/or available in the public domain at the time or times outlined in this report. The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project and subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report. Jacobs has prepared this report in accordance with the usual care and thoroughness of the consulting profession, for the sole purpose described above and by reference to applicable standards, guidelines, procedures and practices at the date of issue of this report. For the reasons outlined above, however, no other warranty or guarantee, whether expressed or implied, is made as to the data, observations and findings expressed in this report, to the extent permitted by law.

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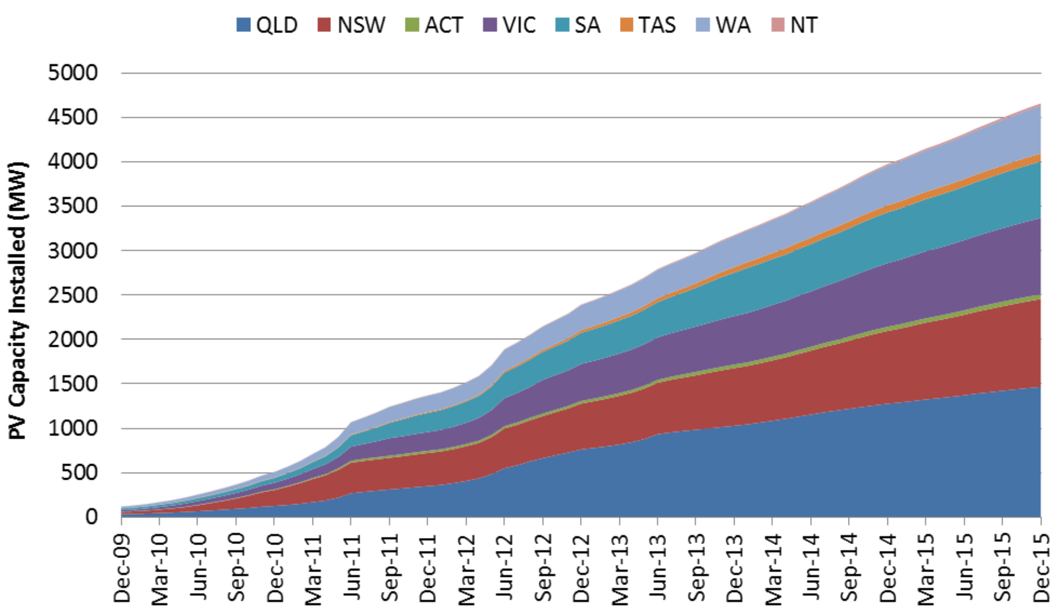
1. Introduction

AEMO is currently preparing forecasts of electricity consumption as part of the 2016 National Electricity Forecasting Report (NEFR). Forecasts of uptake of small-scale electricity generation systems and generation from those systems are required to determine the energy consumption forecasts. Jacobs has been commissioned by AEMO to provide forecasts for solar PV generation and battery storage uptake for each of the NEM States and Territories up to 2036/37. Forecasts are required for three scenarios described as Neutral, Strong and Weak scenarios. The scenario labels refer to the state of the economy, and broadly speaking respectively reflect average, low and high levels of consumer confidence.

2. Historical trends

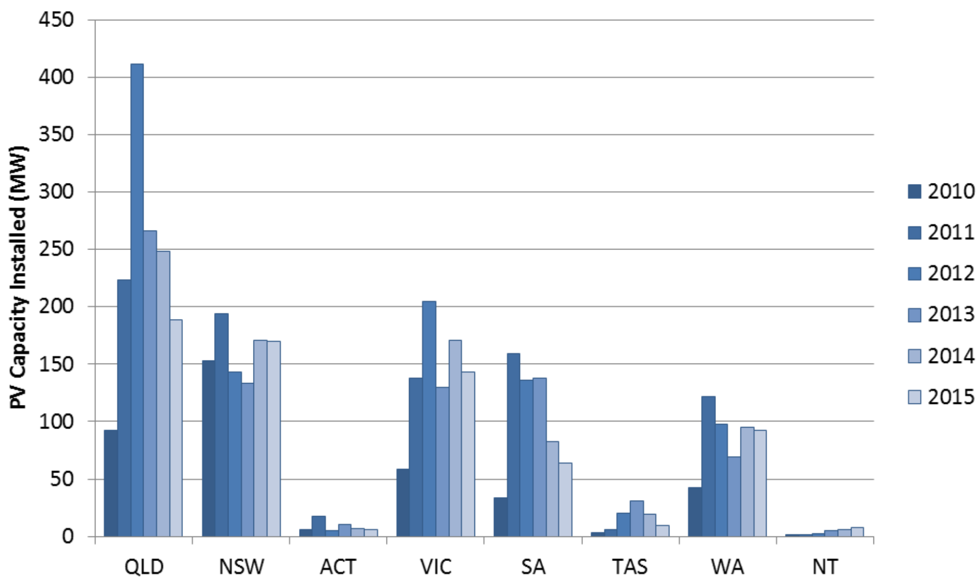
The historical capacity of small scale PV installed from 2009 to the end of 2015 by state and territory is shown in Figure 1. The aggregated small-scale PV capacity was estimated to be around 4,700 MW by the end of 2015 based on the latest CER data. The Australian PV market has grown significantly over that time period with growth rates peaking in 2012 (Figure 6) due to the rapid decline of the PV installation costs, supported by high state-based feed in tariffs and the Solar Credit Multiplier.

Figure 1 Small-scale solar PV capacity by state and territory



Source: Jacobs. Based on postcode data provided by the CER

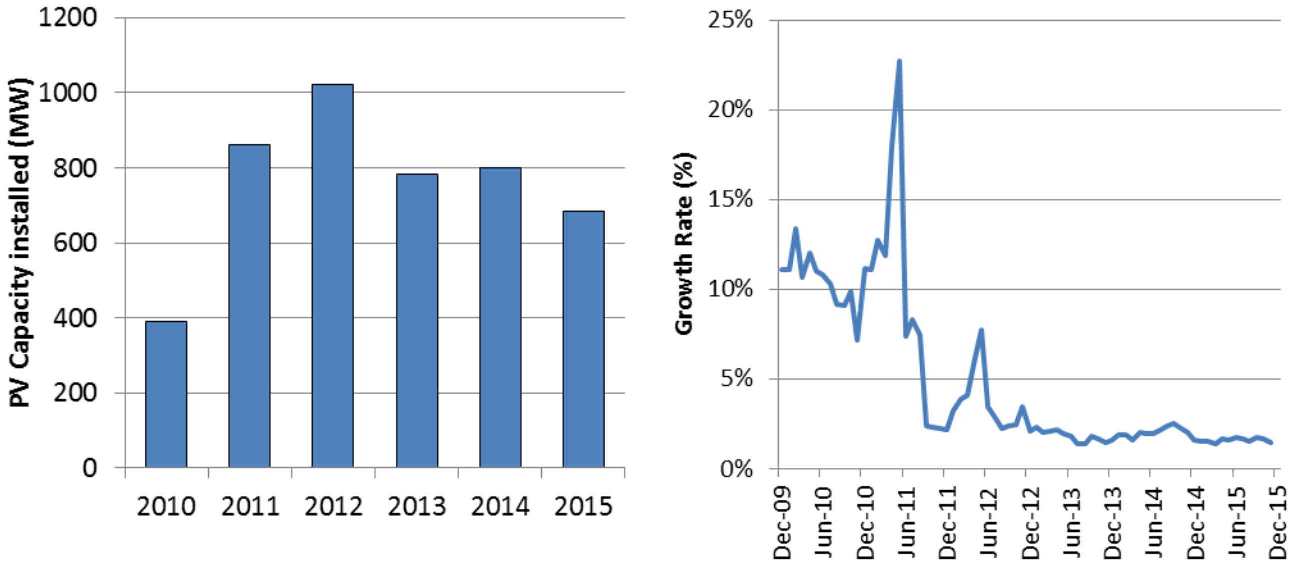
Figure 2 Small-scale solar PV capacity by state and territory



Source: Jacobs. Based on postcode data sourced from the Clean Energy Regulator

Since 2012 annual installed capacity has declined as the support mechanisms have progressively unwound, while the growth rate has remained relative steady at around 2% (Figure 3).

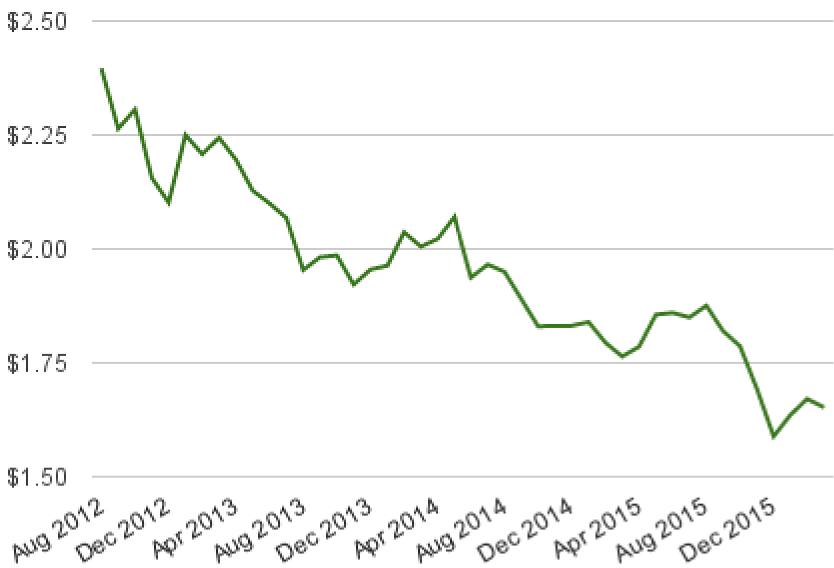
Figure 3 Small-scale solar PV annual capacity installed (left), historical growth rate (right)



Source: Jacobs. Based on postcode data sourced from the Clean Energy Regulator

The main driver for this uptake is the steady decline in PV system costs as shown in Figure 4 below.

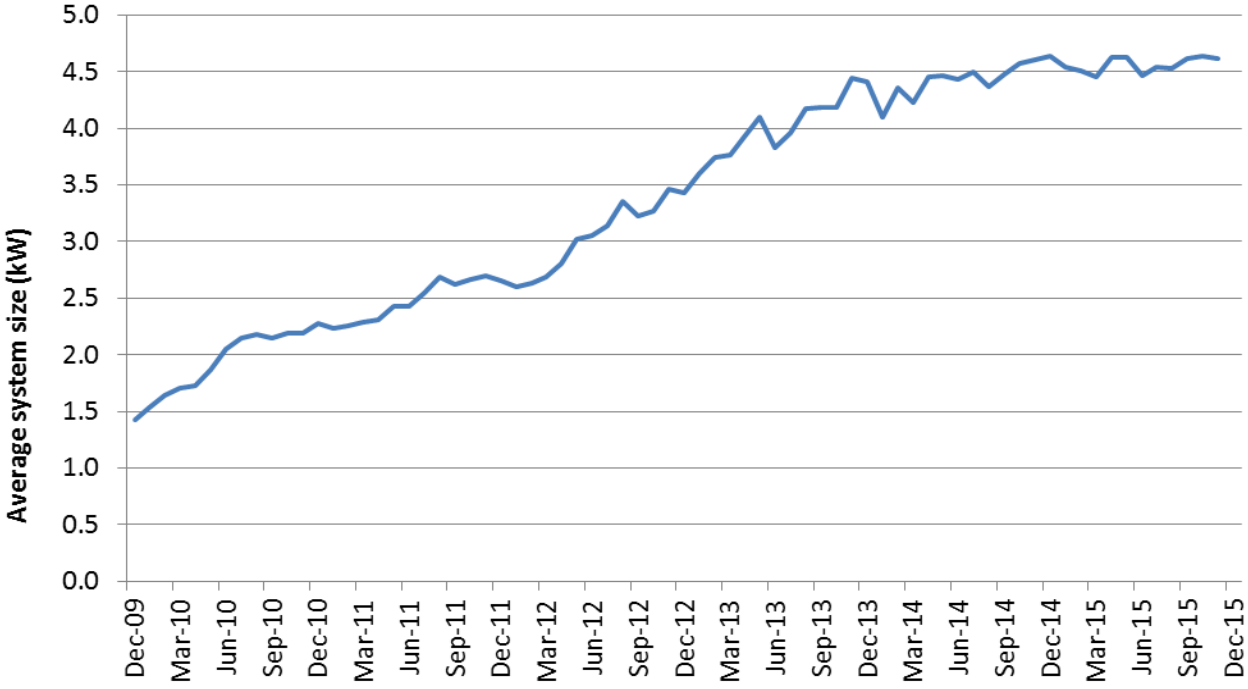
Figure 4 Average $/W for all system sizes



Source: Solar Choice (2016), "Solar PV Power System Prices", March 2016 edition. The data points are the average of average $/W for each system size net of STCs.

At the same time, as shown in Figure 5, the average size of PV systems installed has shown strong growth since 2009 due to significant cost reductions that made larger PV systems more affordable to households.

Figure 5 Average PV system size



Source: Jacobs.

3. Methodology

3.1 Overview

The forecast of small-scale renewable distributed generation has been undertaken using Jacobs' structural model of distributed and embedded generation called *DOGMMA* (Distributed On-site Generation Market Model Australia). The model determines the uptake of small-scale renewable technologies based on comparing the net cost of generation against the net cost of grid delivered power. The model operates on a spatial and market basis, separately providing projections by transmission node and customer class.

The factors considered are as follows:

- Eligible system REC/STC creation for previous years, showing the historical trend in small-scale technology uptake;
- Change in cost of small-scale PV systems and Integrated PV and Storage Systems (IPSS) due to new technological and manufacturing improvements and changes in the cost of system components;
- State and Commonwealth incentive schemes and any expected changes to these schemes over the timeframe, including the impact of potential changes to the State-based feed-in tariffs for generating units;
- Changes to avoidable electricity retail prices, re-introduction of a carbon price mechanism, network regulatory reform (e.g. a number of networks are re-adjusting their tariffs to provide a higher revenue share from fixed rather than variable charges);
- The forecast number of new dwellings;
- PV and IPSS system output and exports;
- Relevant historical legislative changes to the eligibility rules and criteria for small-scale PV systems;
- Global financial conditions, such as changes in currency values, and changes to the cost of raw materials;
- Changes in financial innovation, eg. CEFC loans;
- STC price modelling; and
- Limiting factors for PV and IPSS uptake for households and businesses.

3.2 DOGMMA

DOGMMA determines the uptake of renewable technologies with and without storage based on net cost of generation (after FiT[1] revenue and other subsidies are deducted from costs) versus net cost of grid delivered power.

Revenues from small-scale generation will vary by location because of differing insolation levels which will affect the capacity factor of the units, as well as differing retail charges based on the network area of operation. The model is loaded with estimates of location specific insolation and tariff data enabling it to estimate generation and revenue from newly installed system.

The cost of small scale renewable energy technologies is treated as an annualised cost so that the capital and installation cost of each component of a small scale generation system is annualised over the assumed lifespan of each component, discounted using an appropriate weighted average cost of capital.

[1] Feed-in-tariff

Revenues include sales of electricity to the grid using time weighted electricity prices on the wholesale and retail market (as affected by any emissions reduction policy), avoidance of network costs under any type of tariff structure, including upgrade costs if these can be captured, and the cost of avoided purchases from the grid.

The net cost is determined by deducting revenues from annualised costs. If the net cost is negative, uptake occurs subject to limiting factors.

3.2.1 Optimisation approach

The model selects the level of small-scale generation that minimises electricity supply costs to each region (as defined by transmission node).

The level of uptake of small scale systems increases to the point where any further uptake leads to higher costs of electricity supply than the PV and IPSS systems costs plus a premium for roof-top systems willing to be paid by consumers[2].

The optimisation matches the cost of small scale systems (capital costs and any operating costs) to the avoided grid supplied electricity costs (as would have been experienced by the customer in the absence of the system). The costs of small-scale systems may be reduced by being eligible for a subsidy (for example, the sale of certificates generated under the SRES scheme), or the ability to earn revenue either through sale of surplus electricity generation (surplus to the needs of the householder or commercial business) or from enacted feed-in tariffs.

The optimisation is affected by a number of constraints[3], which are as follows:

- There is a limit to the maximum number of householders and commercial businesses that can install a system:
  - The maximum proportion of residential households that can purchase the system is currently the same for each region and it is set at 55% of all households in the region[4]. This limit was determined by the number of separate dwellings (on the assumption that only separate dwellings would install systems) that are privately owned (on the assumptions that only privately owned dwellings would install systems), and allowing for some limits on installations for heritage or aesthetic reasons.
  - The maximum proportion of commercial businesses that can install a system is 65% of electricity demand. Commercial customers are those in the wholesale and retail trade, schools, hospitals and government offices.
- There are limits on the rate of uptake of each technology in each region. This constraint is designed to ensure there is not a sudden step up in installation rates once a flip point is reached (the point at which the cost of PV and IPSS becomes cheaper than grid supplied electricity) and to account for any logistic constraints. Once the initial simulation is performed, these constraints are progressively relaxed if it appears the constraint is binding uptake unreasonably.
- There are limits on the number of homes and business premises that can accommodate the large sized systems of above 5 kW. We do not have data on the distribution of size of household roof space by region, so this constraint is enforced to limit uptake to around 20% of total households in most regions.

[2] The model allows a premium above grid supply costs for PV systems to account for the purchase behaviour of customers who are willing to pay more for their systems. The premium diminishes to zero as uptake increases on the assumption that only a portion of customers are willing to pay this premium.

[3] In previous modelling studies we were assuming that each household or business can invest either to a solar water heater or a PV system due to space scarcity. This constraint is no longer used

[4] According to the ABS (see ABS (2013), *Household Energy Consumption Survey, Australia: Summary of results, 2012*, Catalogue No. 4670.0, Canberra, September), there are 8.7 million households in 2012 in Australia. Around 89.2% of these households where either separate dwellings or semi-detached dwellings (townhouses, flats). Around 67% of dwellings are privately owned. Assuming that this number is applied to separate dwellings means that around 59.2% of households could install PV systems under our assumptions. We allowed an extra 4% to cater for other constraints on installation.

The technology costs are also adjusted with premiums so that uptake predicted by the model matches historical uptake more closely. The premium reflects the willingness of some consumers to purchase PV systems even if the cost is above grid supply costs. We calculate the premium based on market survey data and other published market data. The premium is assumed to decrease as the rate of uptake increases (reflecting the fact that the willingness to pay will vary among customers).

The costs avoided by small-scale PV systems with or without battery storage comprise wholesale electricity purchase costs (including losses during transmission and distribution), market and other fees, variable network costs, and retail margins.

3.2.2 Model Structure

DOGMMA is characterised by:

- A regional breakdown, where each region is defined by transmission or distribution connection point zones. The number of regions modelled is determined by the availability of energy demand data at a regional level[5] and the availability of data on key determinants. Currently the model comprises 56 regions (see Table 1)
- The handling of different technologies of differing standard sizes including PV systems, solar water heaters, small-scale wind and mini-hydro systems with and without battery storage systems. The sizes depend on typical sized units observed to be purchased in the market. For this study the technologies and systems used include:
  - For the residential sector: solar water heater, 1.0 kW PV system, 1.5 kW PV system, 3 kW PV system, 5 kW PV system, and 3 kW or 5 kW IPSS systems.
  - For the commercial sector: 10, 30 and 100 KW PV systems; 10, 30 and 100 kW IPSS systems.
- Differentiation between the commercial and residential sectors where each sector is characterised by standard system sizes, levels of net exports to the grid, tariffs avoided, funding approaches and payback periods. The assumptions on these used for this study are shown in Table 2.
- The ability to test implications of changing network tariff structures and changes to Government support programs including the proportion of network tariffs that are not 'volume based' (that is, that are independent of average energy use). In practice such tariffs could be fixed supply charges, or linked to peak demand ('capacity charges'). These are not differentiated within Jacobs' model, which assumes that all Victorian customers move away from volume-based network tariffs over the period to 2020 [6]so that by 2020 50% of network tariff charges are derived from fixed charges and the remaining 50% of network tariff charges are derived from a variable component (on average, there are variations across network service providers).

  Other States and Territories move away from volume-based network tariffs in the period to 2030. Capacity and supply charges are assumed to make up 50% of network tariffs by 2030.

Table 1: Number of regions modelled in DOGMMA

State	No of regions
Queensland	10
NSW (including ACT)	5
Victoria	22
South Australia	1
Tasmania	1

[5] For example, regional sub transmission peak demand data published by AEMO. AEMO has recently published more extensive regional demand data which has not been incorporated into the modelling.

[6] According to published data most electricity distributors will have 50% variable charges by 2020 with the exception of Citypower (20%) and Jemena (80%).

State	No of regions
Western Australia	13
Northern Territory	3

Source: Jacobs' analysis based on data provided by AEMO, IMO and ABS

Table 2: System characteristics by customer sector

Sector	% of output exported	Funding approaches	Payback period
Residential	20% for smaller systems to 30% for larger systems	Upfront purchase either by debt financing or outright purchase	10 years
Commercial	20% to 40%	10 year leases	10 years

4. General Assumptions

The following section presents our key modelling assumptions. Capital cost assumptions for small-scale are based on the March 2015 *Solar PV price check* article on the Solar Choice website[7], which is based on price data from 125 solar installation companies across Australia. The battery storage costs are sourced from CSIRO's "Future energy storage trends" report prepared for the Australian Energy Market Commission in September 2015. The population projections are based on the latest Australian Bureau of Statistics data.

4.1 Scenario assumptions

The three market scenarios that were explored for this study were the Neutral, Strong and Weak scenarios. The scenario labels refer to the state of the economy, and broadly speaking respectively reflect average, low and high levels of consumer confidence.

Table 1 summarises the key scenario assumptions in this modelling study.

Table 3 Summary of different scenarios assumptions

	Neutral	Weak	Strong
Economic growth	2015 NEFR[8] **medium** economic growth scenario	Average of 2015 NEFR **medium** and **low** economic growth scenarios	Average of 2015 NEFR **medium** and **high** economic growth scenarios
Population Growth	ABS Series B	ABS Series C	ABS Series A
Carbon price	\$25/t CO_2-e in 2020 escalating to \$50/t CO_2-e in 2030	As per Neutral scenario	As per Neutral scenario
Retail prices	Jacobs' Neutral scenario retail price forecast	Jacobs' Weak scenario retail price forecast	Jacobs' Strong scenario retail price forecast
Exchange rate	1 AUD = 0.75 USD	1 AUD = 0.65 USD	1 AUD = 1.0 USD
Oil price	\$USD 60/bbl	\$USD 30/bbl	\$USD 90/bbl
Gas price	Core Energy Group's **reference** gas price scenario	Core Energy Group's **low** gas price scenario	Core Energy Group's **high** gas price scenario

[7] http://www.solarchoice.net.au/blog/news/solar-pv-system-prices-march-2016-100316
[8] The December 2015 update of the NEFR was used

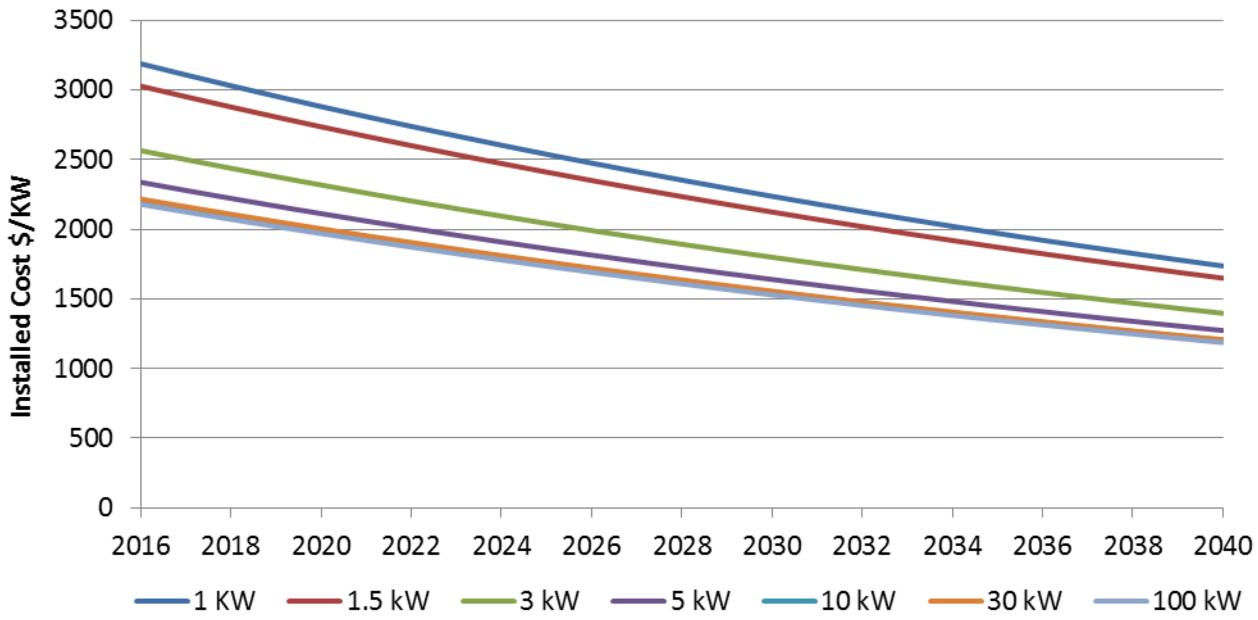
4.2 System assumptions

4.2.1 PV systems costs

Neutral Scenario

PV systems cost assumptions for the Neutral Scenario are shown in Figure 6. The costs in 2016 are sourced from trade data and include balance of system and installation costs while they exclude the STCs rebates. The costs are lower for larger system sizes reflecting economies associated with installing larger systems. The capital costs are projected to decline by 1.5% per annum in real terms based on international and Australian related studies.

Figure 6: Neutral scenario Installed total cost assumptions for PV small scale systems

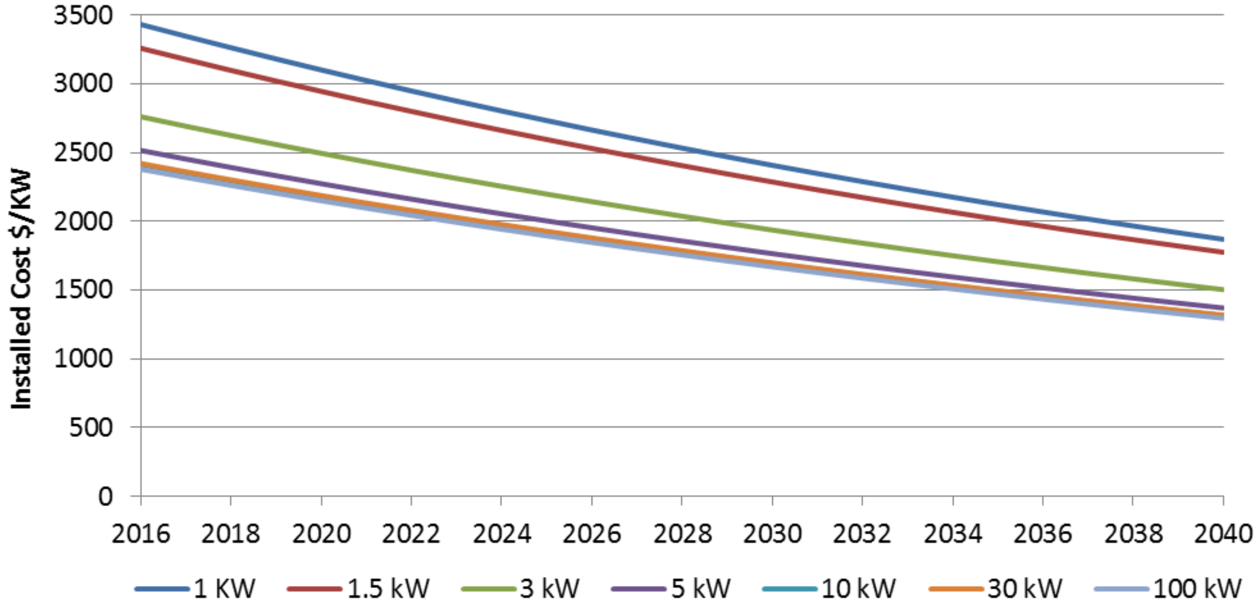


Source: Jacobs analysis based on 2016 data on installed cost supplied in Solar Choice (2016), "Solar PV Power System Prices", March 2016 edition. Installed costs obtained by adding back the rebate obtained from Small-scale Technology Certificates to published data on total system costs, which provide costs to consumers after this rebate has been applied.

Weak Scenario

For the Weak Scenario the lower exchange rate (AUD/USD=0.65 instead of 0.75) impacts the price of the imported components which is higher at the commercial systems (60% imported) than at the residential systems (50% imported). The costs are shown in Figure 6 and include balance of system and installation costs while they exclude the STCs rebates. The annual cost decline remains at 1.5%.

Figure 7: Weak scenario installed total cost assumptions for PV small scale systems

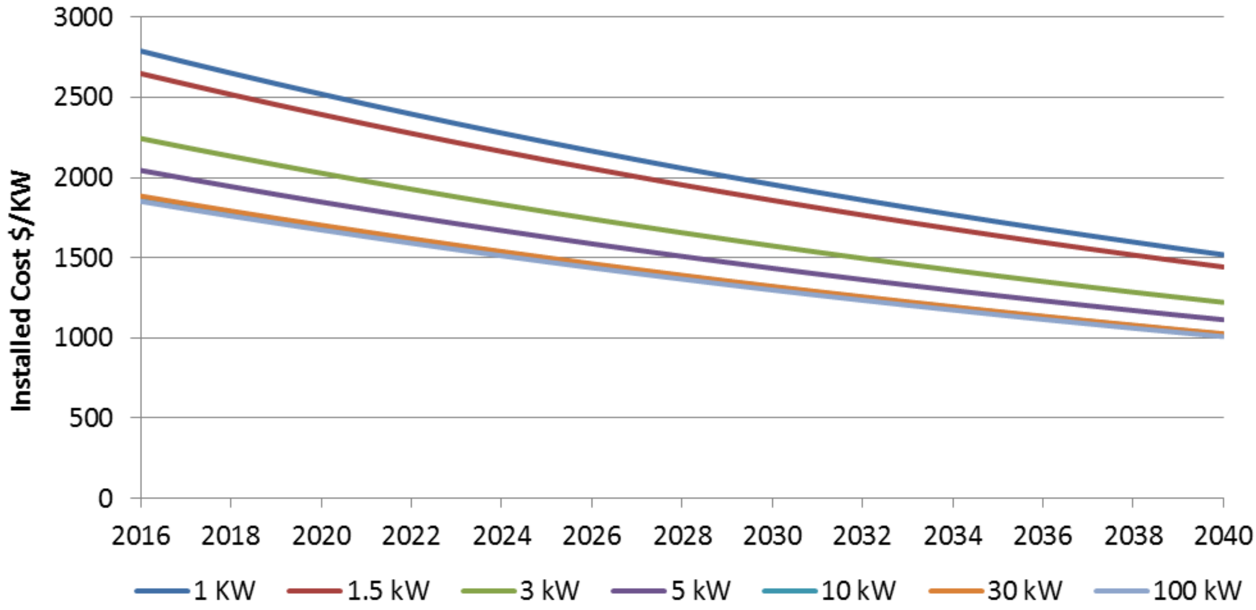


*Source: Jacobs **analysis** based on 2016 data on installed cost supplied in Solar Choice (2016), "Solar PV Power System Prices", March 2016 edition. Installed costs obtained by adding back the rebate obtained from Small-scale Technology Certificates to published data on total system costs, which provide costs to consumers after this rebate has been applied. The costs have also been adjusted for a lower exchange rate.*

Strong Scenario

The Strong Scenario has a higher exchange rate (AUD/USD=1.00 instead of 0.75) therefore lowering the price of the imported components as shown in Figure 8. The annual cost decline remains 1.5%.

Figure 8: Strong scenario installed total cost assumptions for PV small scale systems



Source: Jacobs analysis based on 2016 data on installed cost supplied in Solar Choice (2016), "Solar PV Power System Prices", March 2016 edition. Installed costs obtained by adding back the rebate obtained from Small-scale Technology Certificates to published data on total system costs, which provide costs to consumers after this rebate has been applied. The costs have also been adjusted for a higher exchange rate.

4.2.2 PV capacity factors

By design, the model can vary capacity factors by region, reflecting for example differing insolation levels. However, a lack of regional data means that currently the model applies State wide capacity factors for the selected technology options. The data on capacity factor is obtained from two sources: the capacity factors implied by the zone ratings derived by the Clean Energy Regulator to determine deemed certificates by region[9], and data on metered energy production available from Ausgrid[10].

The average capacity factor over all capacity for each technology in each State diminishes as the level of capacity increases in each region. This is based on the notion that as more systems are installed, they are progressively in less favourable roof spaces (for example, roof spaces facing other than north or due to shading). The parameters of the function determining average capacity factors are varied so that the projected uptake rates for the first year match actual installation data for each region[11].

The initial capacity factors applying in each State are shown in Table 4. PV systems with storage are assumed to have a lower initial capacity factors due to energy losses occurring during charging and discharging cycles.

Table 4: Initial load factors for small-scale PV systems by region

	Victoria	New South Wales (including ACT)	Tasmania	South Australia	Queensland
PV	14.8%	15.8%	13.7%	15.8%	15.8%
IPSS	13.7%	14.6%	12.7%	14.6%	14.6%

Source: Jacobs' analysis based on data provided by CER, Ausgrid and Energex[12].

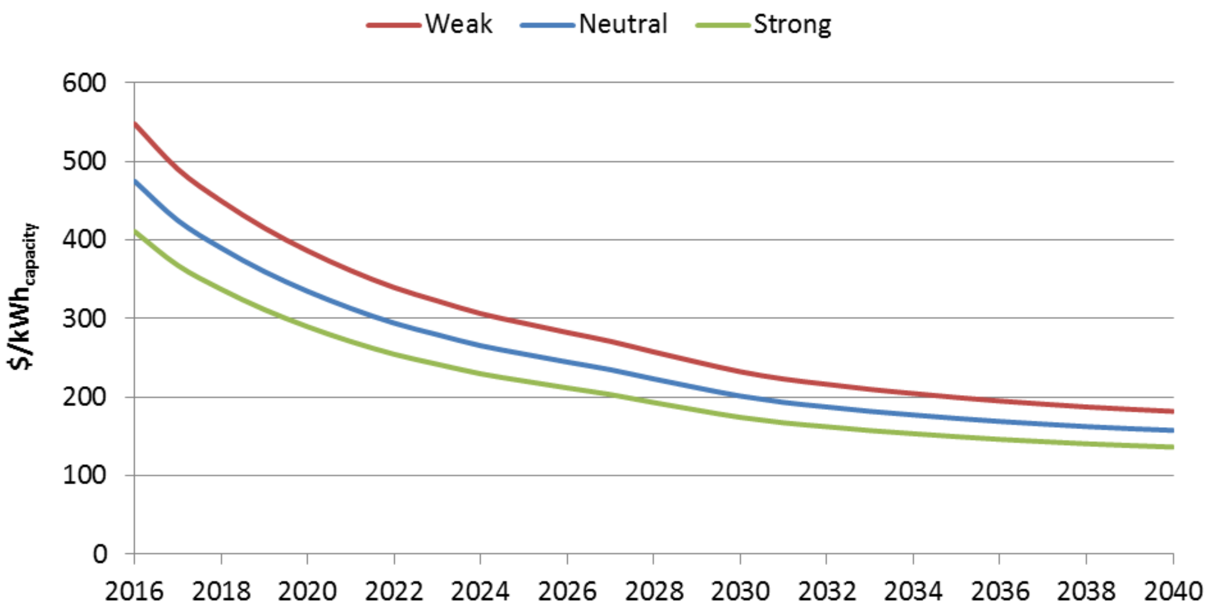
4.2.3 Battery costs

The future of cost of batteries is subject to considerable uncertainty and it is the main driver on the future uptake of PV systems with storage. For the Neutral scenario, this study has adopted the base LI-ion battery cost trajectories from CSIRO's "Future energy storage trends" report that was prepared for the AEMC in September 2015. These costs have been adjusted for the Weak and Strong scenarios based on the exchange rate assumed for each scenario. The cost trajectories for all scenarios are shown in Figure 9. The illustrated costs do not include inverter and installation costs.

The battery performance parameters used for the modelling are given in Appendix A.

[9] The CER divides each State in 4 regions with each zone with a different capacity factor.
[10] Ausgrid (29th May 2013), *Solar Homes Electricity Data*, which contains data on energy production and system capacity for 300 systems;
[11] Postcode data on the number of installations is published by the Clean Energy Regulator.
[12] CER zonal capacity factors, Ausgrid (op. cit.), Energex

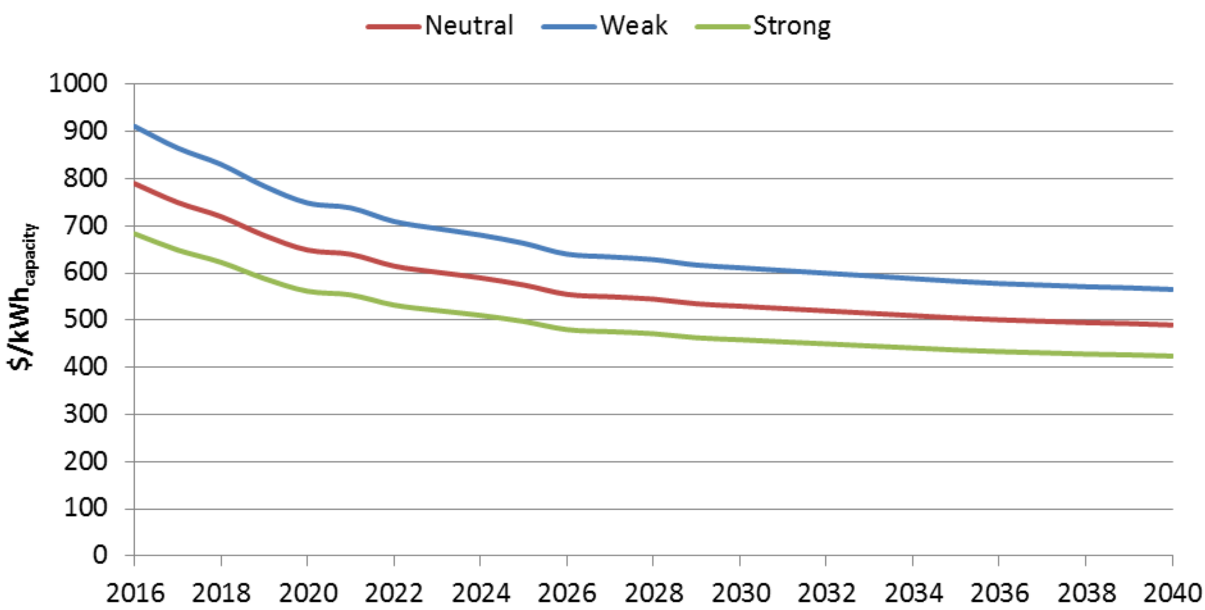
Figure 9 Projected capital cost trajectories of LI-ion batteries for Neutral, Weak and Strong scenarios



Source: Jacobs' analysis based on CSIRO's ""Future energy storage trends"

The inverters for battery storage can both transmit and receive electricity (inverter- chargers) and are therefore more complex than the most common PV inverters. In the DOGMMA model, when an already installed PV system adds a battery system (retrofitting) it is assumed that a new inverter will also need to be installed to accommodate the new system[13]. The battery inverter cost assumed is the average cost used in the same CSIRO report for the Neutral scenario, and adjusted for the change exchange rates for the Strong and Weak scenarios.

Figure 10 Projected inverter cost trajectories for Neutral, Weak and Strong scenarios



Source: *Jacobs' analysis based on CSIRO's ""Future energy storage trends"*

[13] CSIRO (September 2015), *" Future energy storage trends"*, Report prepared for the Australian Energy market Commission

4.2.4 Feed in tariffs

Feed-in tariffs are equivalent to payments for exported electricity. Feed-in tariff schemes have been scaled back in most jurisdictions so that the value of exported energy does not provide a significant incentive to increase uptake of solar PV systems.

Between 2008 and 2012, state governments in most states mandated feed-in tariff payments to be made by distributors to owners of generation systems (usually solar PV). A list of such schemes is provided in Table 5. Following a commitment by the Council of Australian Governments in 2012 to phase out feed-in tariffs that are in excess of the fair and reasonable value of exported electricity, most of these schemes are now discontinued and have been replaced with feed-in tariff schemes with much lower rates.

However, the costs of paying feed-in tariffs from those schemes to customers must still be recouped as eligible systems continue to receive payments over a period that could be as long as twenty years. Network service providers provide credits to customers who are eligible to receive feed-in payments, and recover the cost through a jurisdictional scheme component of network tariffs. Networks are able to estimate the required payments each year and include these amounts in their tariff determinations adjusting estimated future tariffs for over and underpayments annually as needed. Where this has occurred, it would be reasonable to assume that cost recovery components are included in the distribution tariffs under 'jurisdictional' charges, so no additional amounts are included in the Jacobs' estimates of retail price. In all cases where distributors are responsible for providing feed-in tariff payments, the distributors would have been aware of the feed-in tariffs prior to the latest tariff determination, so it is reasonably safe to assume inclusion.

Retailers may also offer market feed-in tariffs, and the amount is set and paid by retailers. Where such an amount has been mandated, the value has been set to represent the benefit the retailer receives from avoided wholesale costs including losses, so theoretically no subsidy is required from government or other electricity customers. , The tariff rates are set using Jacobs wholesale price projections, which are based on a post-scheme generation profile.

Table 5 Summary of mandated feed-in tariff arrangements since 2008

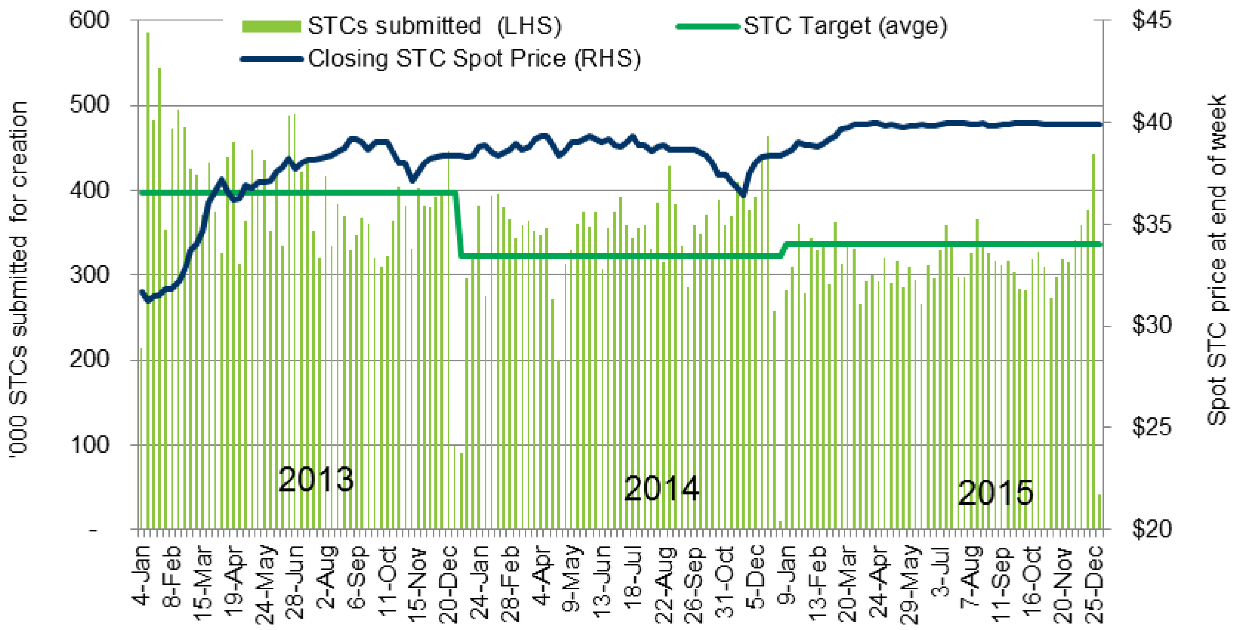
State or territory	Feed-in tariff	Cost recovery
Queensland	*Queensland solar bonus scheme (legacy)* The Queensland solar bonus scheme provides a 44 c/kWh feed-in tariff for customers who applied before 10 July 2012 and maintain their eligibility. The scheme was replaced with an 8 c/kWh feed-in tariff which applied to 30 June 2014. The scheme is now closed to new solar customers. The tariff provided to existing solar customers is recovered through an impost in the network tariffs of Ergon Energy, Energex and Essential Energy. These networks must apply annually to the AER for a pass through of these costs which are expected to diminish over time.	Network tariffs include provision for legacy payments
	Regional mandated feed-in tariffs From 1 July 2014, retailers in regional Queensland are mandated to offer market feed-in tariffs that represent the benefit the retailer receives from exporting solar energy, ensuring that no subsidy is required from government or other electricity customers. The feed-in tariff is paid by Ergon Energy and Origin Energy for customers in the Essential Energy network in south west Queensland. The amount set in 2015/16 is 6.348 c/kWh.	Assume 6.348 c/kWh over projection period.
NSW	*NSW Solar Bonus scheme* This scheme began in 2009 offering payment of 60 c/kWh on a gross basis, reduced to 20 c/kWh after October 2010. These rates are now no longer open to new customers, and legacy payments are made by distributors and are recovered through network tariffs. Retailers contribute 5.2 c/kWh from November 2015, based on the subsidy-free value to retailers of the electricity exported to the grid. IPART now regulates a fair and reasonable rate range for new customers who are not part of the SBS, where the minimum rates in 2011/12 were 5.2 c/kWh, 6.6 c/kWh for 2013/14, 5.1	Network tariffs include some provision for legacy payments which is topped up by retailer contribution. Assume 4.7 c/kWh over projection

State or territory	Feed-in tariff	Cost recovery
	c/kWh for 2014/15, and 4.7 c/kWh from November 2015. However offering the minimum rate is optional.	period to cover retailer benefit.
ACT	*ACT feed-in tariff (large scale)* ACT feed-in tariff (large scale) supports the development of up to 210 MW of large-scale renewable energy generation capacity for the ACT. This scheme has been declared to be a jurisdictional scheme under the National Electricity Rules, and is therefore recovered in network charges. *ACT feed-in tariff (small scale, legacy)* ACT feed-in tariff (small scale), is already declared to be a jurisdictional scheme under the National Electricity Rules, and is therefore recovered in network charges. In July 2008 the feed-in tariff was 50.05 c/kWh for systems up to 10 kW in capacity for 20 years, and 45.7 c/kWh for systems up to 30 kW in capacity for 20 years. The feed-in tariff scheme closed on 13 July 2011.	Network tariffs include provision for feed-in tariffs. Assume 4.7 c/kWh over projection period to cover retailer benefit (based on NSW estimates)
Victoria	*Premium and transitional feed-in tariff scheme (legacy)* The Victorian Government introduced the premium feed-in tariff of 60 c/kWh in 2009 and closed it to new applicants in 2011. Consumers eligible for the premium rate are able to continue benefiting from the rates until 2024 if they remain eligible to do so. The Transitional Feed-in Tariff was then introduced with a feed-in rate of 25 cents/kWh. The transitional and premium feed-in tariffs are cost recovered through distribution network tariffs.	Network tariffs include provision for feed-in tariffs
	Minimum feed-in tariffs The Essential Services Commission (ESC) in Victoria is required to determine the minimum electricity feed-in tariff that is paid to small renewable energy generators for electricity they produce and feed back into the grid. The minimum feed-in tariff is determined by considering wholesale electricity market prices and distribution and transmission losses avoided through the supply of distributed energy. These payments are made by retailers and applied on a calendar year basis. The ESC has determined that the minimum energy value of feed-in electricity for 2016 is 5 c/kWh, compared with a 2015 value of 6.2 c/kWh and a 2014 and 2013 value of 8 c/kWh.	Assume a feed-in tariff of 5 c/kWh, to recover likely retailer rates
South Australia	*Premium feed-in tariff scheme (legacy)* In July 2008 the South Australian government introduced a feed-in tariff scheme providing 44 c/kWh for 20 years until 2028. In 2011, this amount was reduced to 16 c/kWh for 5 years until 2016. This scheme was closed to new customers in September 2013.	Network tariffs include provision for feed-in tariffs
	Premium feed-in tariff bonus A retailer contribution is also available, as set by the SA regulator (Essential Service Commission of South Australia or ESCOSA), where the minimum tariff is set to 6.8 c/kWh in 2016.	Assume a feed-in tariff of 6.8c/kWh over the projection period
Tasmania	*Metering buyback scheme (legacy)* In Tasmania, Aurora offered a feed-in tariff which offered customers a one for one fit at the regulated light and power tariff for residential customers or general supply tariff for small business customers for their net exported electricity. This program was closed to new customers in August 2013 and replaced with a transitional feed-in tariff of 20 c/kWh for residential customers and a similar blocked feed-in tariff for commercial customers.	Network tariffs include provision for feed-in tariffs
	Post reform The Tasmanian regulator has now stipulated smaller rates which are now 5.5 c/kWh for 2015/16, compared with 5.55 c/kWh in 2014/15 and 8.28 c/kWh for the first half of 2014. These rates are now a component of standing offer tariffs provided by retailers.	Assume a retailer tariff of 5.5 c/kWh to recover retailer costs

4.2.5 Small-scale Technology Certificates (STCs)

The value of STCs as shown in Figure 11 has been stable over the last two years with a spot price plateauing just below $40/ STC.

Figure 11 STC value



Source: Green Energy Markets

The assumed STC price in DOGMMA is $39.50 in 2016 and remains stable in real terms until 2030. Between 2017 and 2030 the SRES will follow a declining deeming rate by one year in each year. That means that systems installed in 2017 will create certificates for 14 years of output while systems created in 2030 are deemed to create certificates for only one year of output.

4.2.6 Retail electricity prices

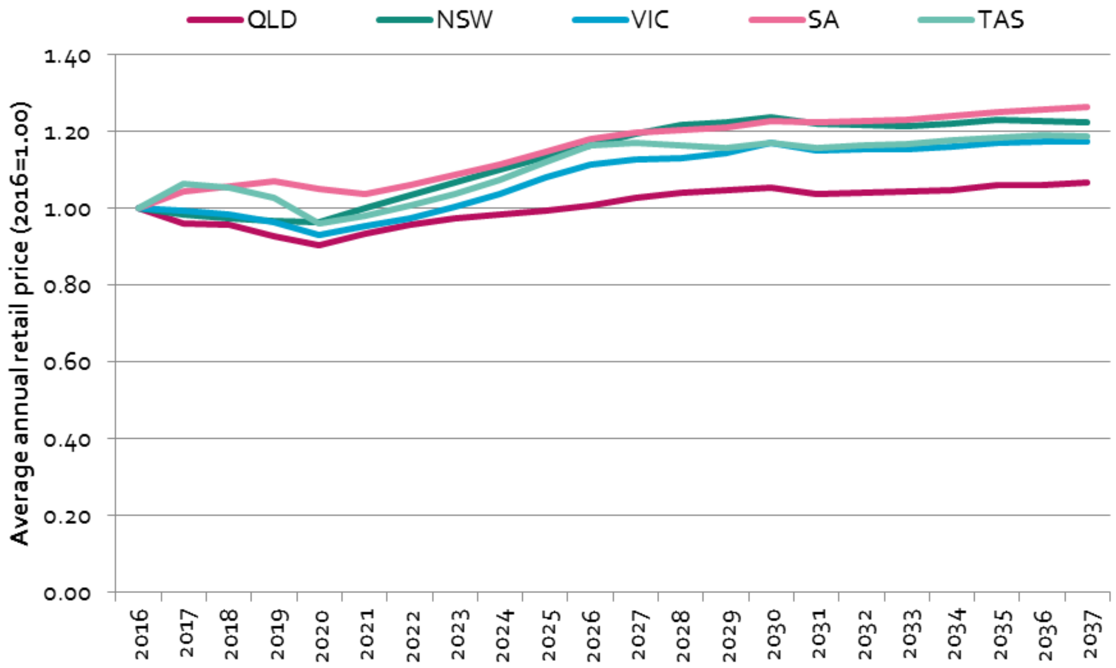
The retail electricity prices are an important component to the calculations in DOGMMA since every kWh of output from a PV system that is consumed by the owner is an avoided cost. The electricity retail prices adopted for this study are the resulted outcomes from Jacobs' "Retail electricity price history and projections" report for AEMO, since the scenarios and the underlying assumptions have remained unchanged in both studies. The electricity retail prices, expressed as a real index, are given in Figure 12 for the Neutral scenario, in Figure 13 for the Weak scenario and in Figure 14 for the Strong scenario. All retail prices shown in the figures below have been indexed using 2015/16 as the base year (2015/16 = 1.00)

For the estimation of these retail prices two policy measures were used so as to achieve the 28% reduction in emissions at the wholesale market level:

i. The introduction of a carbon price in 2020 commencing at $25/t CO_2-e and escalating in a linear manner to $50/t CO_2-e by 2030, remaining flat thereafter; and

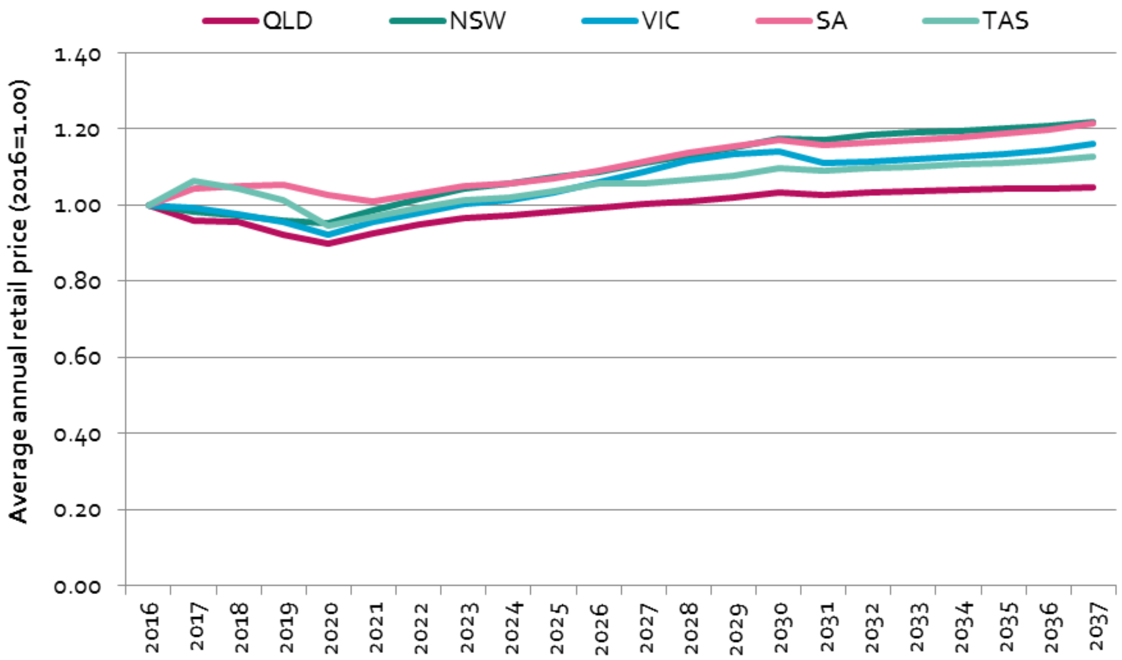
ii. Assumed coal-fired retirements, where coal-fired power stations are assumed to be mandated to retire their capacity in a given year with the objective of achieving the 2030 emission reduction target.

Figure 12 Average annual residential indexed retail prices in the Neutral scenario (2016 = 1.00)



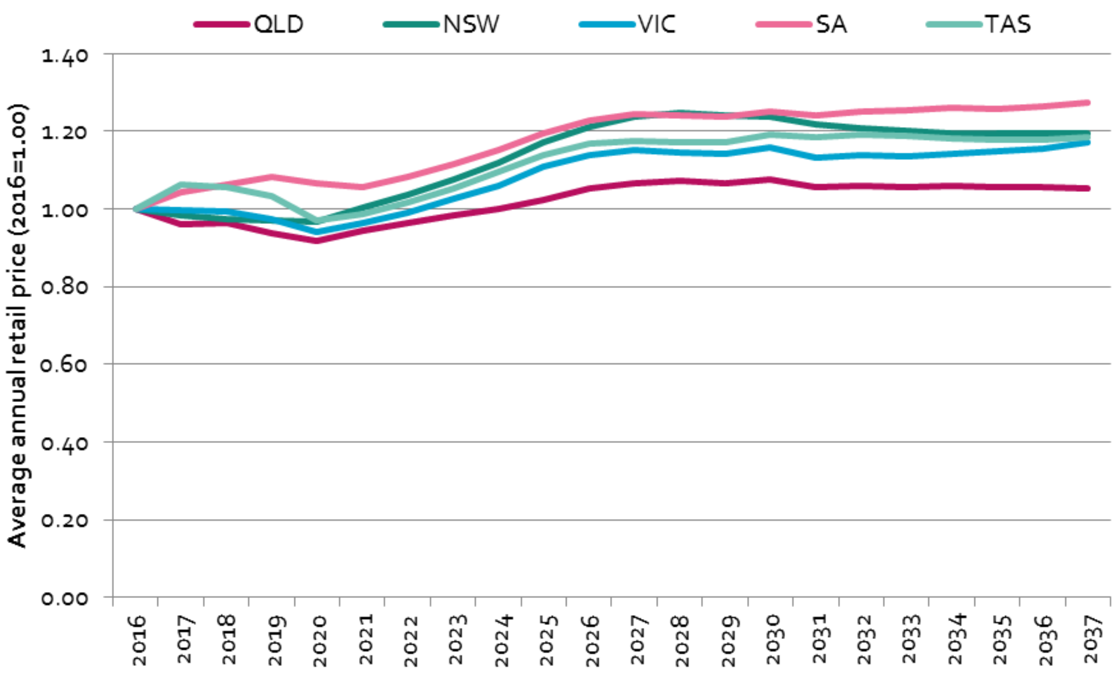
Source: Jacobs' analysis

Figure 13 Average annual residential indexed retail prices in the Weak scenario (2016 = 1.00)



Source: Jacobs' analysis

Figure 14 Average annual residential indexed retail prices for the Strong scenario (2016 = 1.00)



Source: Jacobs' analysis

4.2.7 Net cost

The net cost of the PV systems is a key variable in explaining the uptake of these systems in the DOGMMA model, which is a forward looking optimisation model that seeks to minimise total energy supply costs from the consumer's viewpoint

The net cost is defined as follows:

- Sum of capital cost including installation
- Less
  - Value of any available government rebates
  - Revenue from the sale of RECs and/or STCs
  - Net present value of future feed-in tariff payments and/or retailer payments for export to the grid
  - Net present value of the avoided cost of electricity

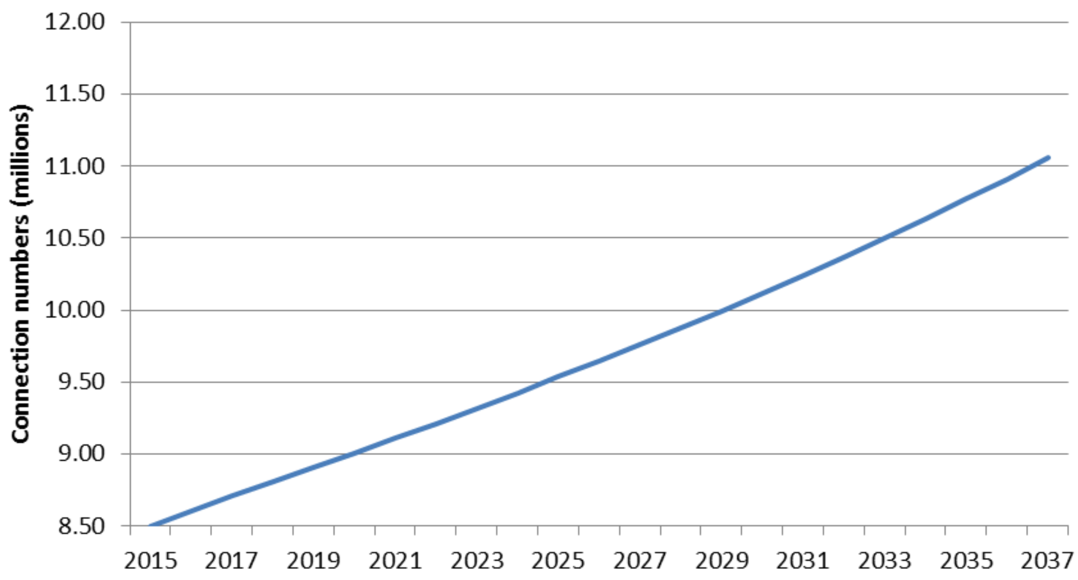
Costs avoided by customers are in one of two ways:

- Avoided retail tariffs on electricity produced by the PV system and used in the premise.
- Revenue earned from exports of electricity that is not used on the premises. This price for exported electricity is equal to the wholesale price weighted to the hourly profile of PV generation plus network losses. This revenue acts a negative cost in the model.

4.2.8 Population growth

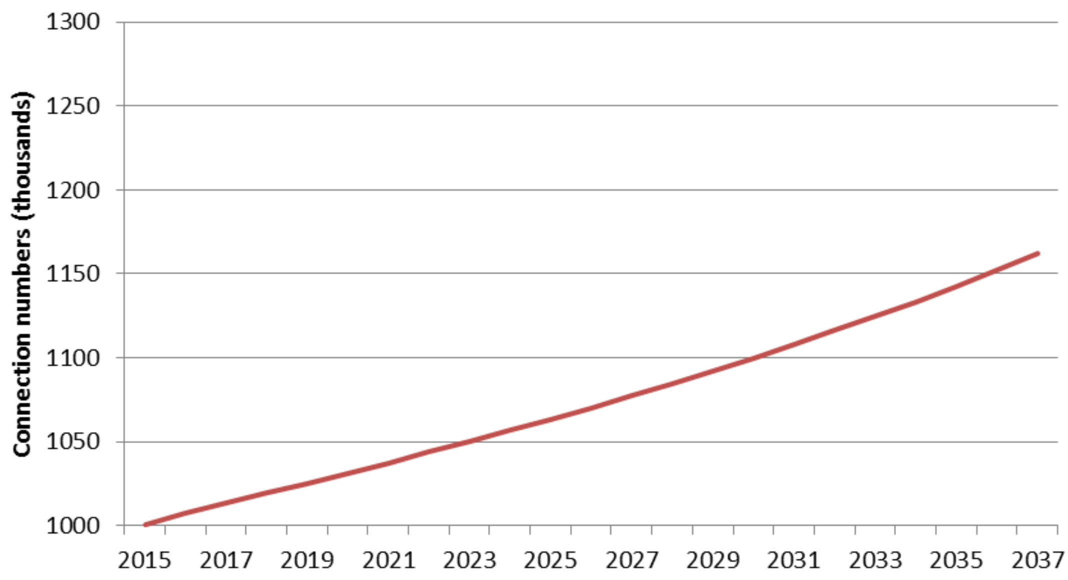
The population growth is a key input to DOGMMA, since the maximum uptake of PV systems is constrained by the total population in each region. The assumed population growth used for the Neutral, Weak and Strong scenarios is taken from the three main series (A, B and C) of ABS population. The Neutral scenario is using Series B projection and follows a medium growth largely reflecting current trends in fertility, life expectancy at birth and NOM, whereas high (series A) and low (series C) are based on high and low assumptions for each of these variables respectively. The projected population is converted to new connections and allocated to residential and commercial connections as shown in Figure 15 and Figure 16 for the Neutral scenario.

Figure 15 Projected residential connections in the NEM



Source: AEMO

Figure 16 Projected commercial connections in the NEM



Source: AEMO

The detailed projected connections per state and territory for all three scenarios are given in Appendix A.

4.3 Behavioural change due to solar PV generation and uptake of battery storage

There are two behavioural assumptions modelled:

- A willingness to pay premium which represent the amount above avoided grid supply costs that consumers are prepared to tolerate in choosing a PV system. This premium reduces to zero with increasing uptake levels. For standalone PV systems, the premium is now assumed to be zero, and choice is purely based on the comparison of economic cost of PV systems versus supply from the grid.

- For PV systems with storage it is assumed PV generation excess to internal load is not exported but instead charges up the battery (to its capacity limit). This stored electricity is used to displace internal energy use in the peak evening period.

4.4 Modelling uncertainties, limitations and exclusions

Some of the main uncertainties regarding this modelling are:

- There is a great uncertainty regarding the trajectory of PV installation costs. While there is a general consensus that internationally the costs will continue to decline, Australia's differentiating dynamics (high wages, low barriers to entry, high amount of Tier 2 or Tier 3 products) is making it more difficult to forecast this cost trajectory.

- The future financial incentives for PV systems such as the FiTs and its terms of payment are considered uncertain.

- In the commercial sector there are a lot of uncertainties regarding the potential size of the market. Among the factors that are difficult to determine is the number of businesses that own the commercial facilities and also the roof space that they have to install a large (>10 kW) system. Furthermore, there is a great uncertainty regarding the number of businesses that consume enough electricity during daylight hours so as to make it financially attractive to invest to PV system.

- Battery storage is an emerging technology in its infancy with no existing patterns and no recording mechanism at the moment. The future of energy storage technologies is subject to considerable uncertainty although it is generally expected to have a sharp decline of costs over the next five years.

- The financial attractiveness of PV systems and IPSS systems is heavily dependent on the future tariff structure in the NEM that is still undetermined. As part of a general drive towards cost-reflective pricing it is expected that the structure will move to time-of-use pricing over time.

- Future policies impacting the uptake of PVs and storage are still uncertain. The historical rapid uptake of rooftop PV during the implementation of generous financial incentives set by the Federal and State governments is a good example of how significant these are for determining the future uptake of the systems.

Furthermore, there are some further issues that will affect the future of PV uptake and battery storage that have not been considered in this study. Some of them are:

- The upgrades, expansions and replacement of residential PVs. Many existing rooftop PV owners have small systems (less than 3 kW) and some of them will consider expanding these systems in response to higher electricity costs and lower PV installation costs. Furthermore, there is the possibility that the transition to a time-of use tariff structure will incentivise the installation of west-facing panels so as to cut peak demand.

- No change in battery performance over time has been considered.

- Behavioural drivers have not been modelled (i.e. early adopters, business preference to invest in core activities instead of PVs etc.)

- No system optimisation based on individual customers' load profiles has been explored. Especially in the commercial sector, it is expected that the systems will be optimised increasing the financial attractiveness of PVs with and without battery storage.

- In the model the average demand profile of households and commercial businesses has been assumed instead of individual ones, something that potentially underestimates the cost savings caused by sharper load spikes.

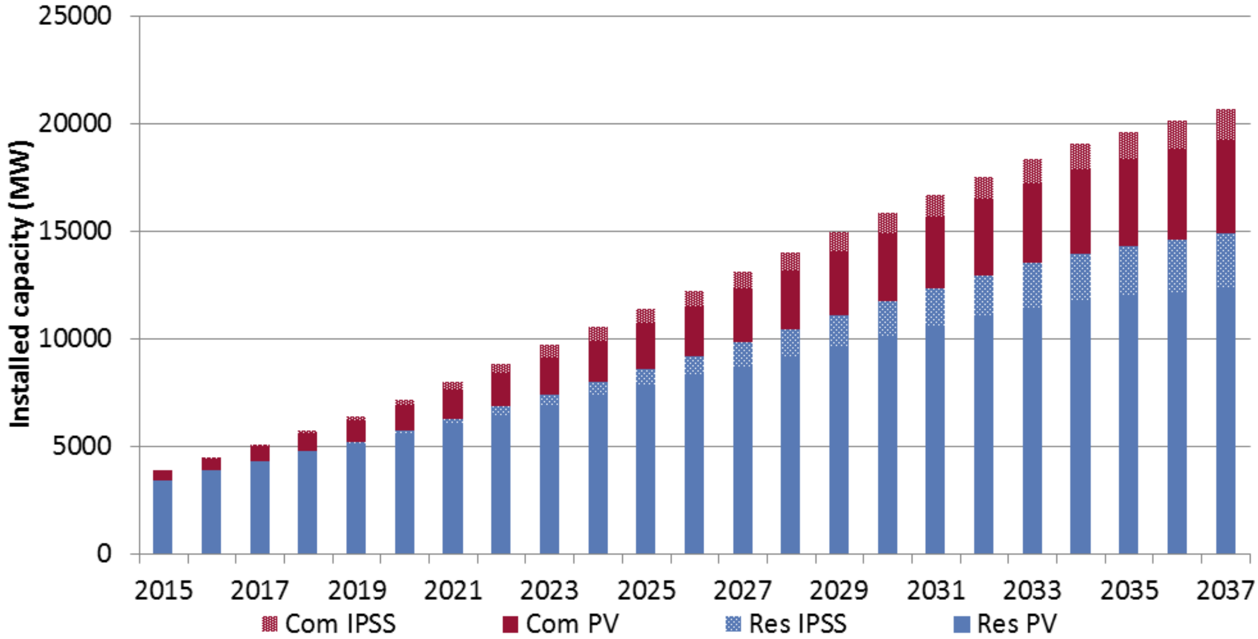
5. Rooftop PV and Battery Storage Forecasts

5.1 National Electricity Market Forecasts

The PV uptake in the NEM remains relatively stable in the short term with the falling installation costs of PV systems offsetting the gradual fade out of the SRES incentive starting from 2017. The increased electricity prices after 2020 and the transition to a time-of-use tariff structure are driving some additional growth to the sector for next 10 years. From the early 2030s, some decline to the annual installations numbers is observed in the NEM due to saturation in some regions.

Figure 17 shows the forecasted total installed capacity of rooftop PV in the NEM, and the proportion of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS.

Figure 17 Total installed capacity of rooftop PV and IPSS in the NEM

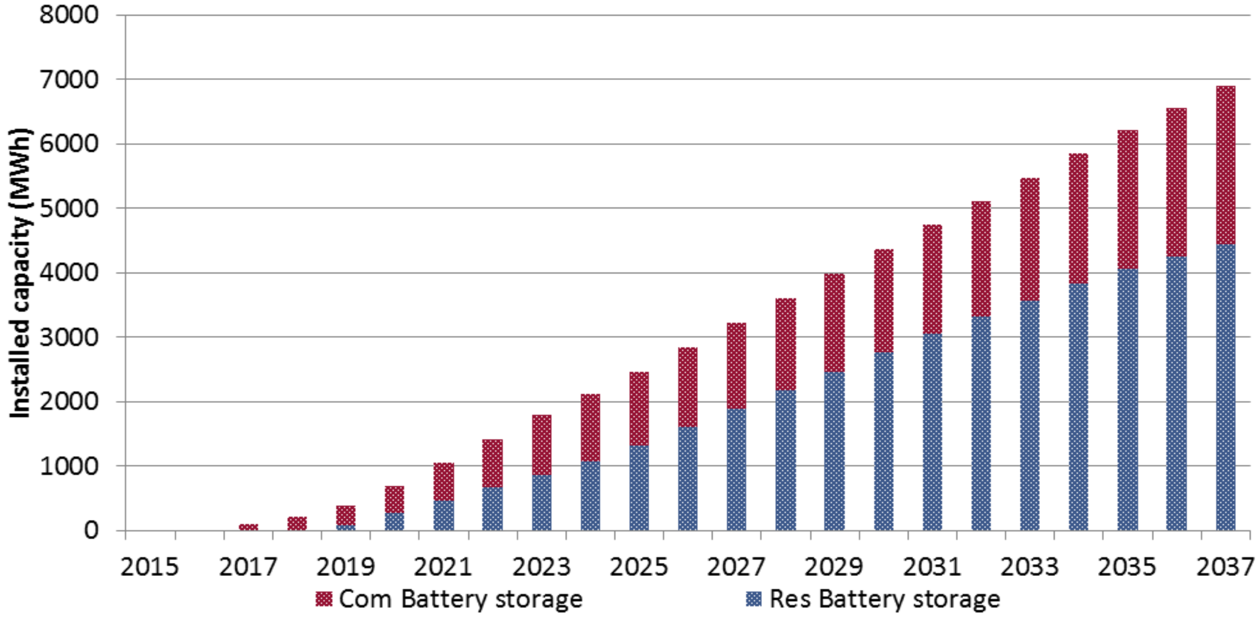


The residential annual PV uptake in the NEM is projected to be stable but slightly lower than the previous years until 2032/33 when saturations levels are reached in some regions. The total capacity of PV and IPSS systems at the end of the period is 20,634 MW. A strong growth of PV system uptake is projected in the commercial sector for the entire modelled horizon, reaching around 5,757 MW in 2040 and accounting for 28% of total installations.

IPSS system uptake starts slowly and picks up especially after 2020 in both the residential and the commercial sectors, resulting to around 4,000 MW installed at the end of the horizon. The penetration of IPSS systems is not uniform in all states. A reason for that is the high installed capacity of residential PVs in some states that prevents a higher penetration of battery storage since no retrofitting of batteries to existing systems has been considered in the model.

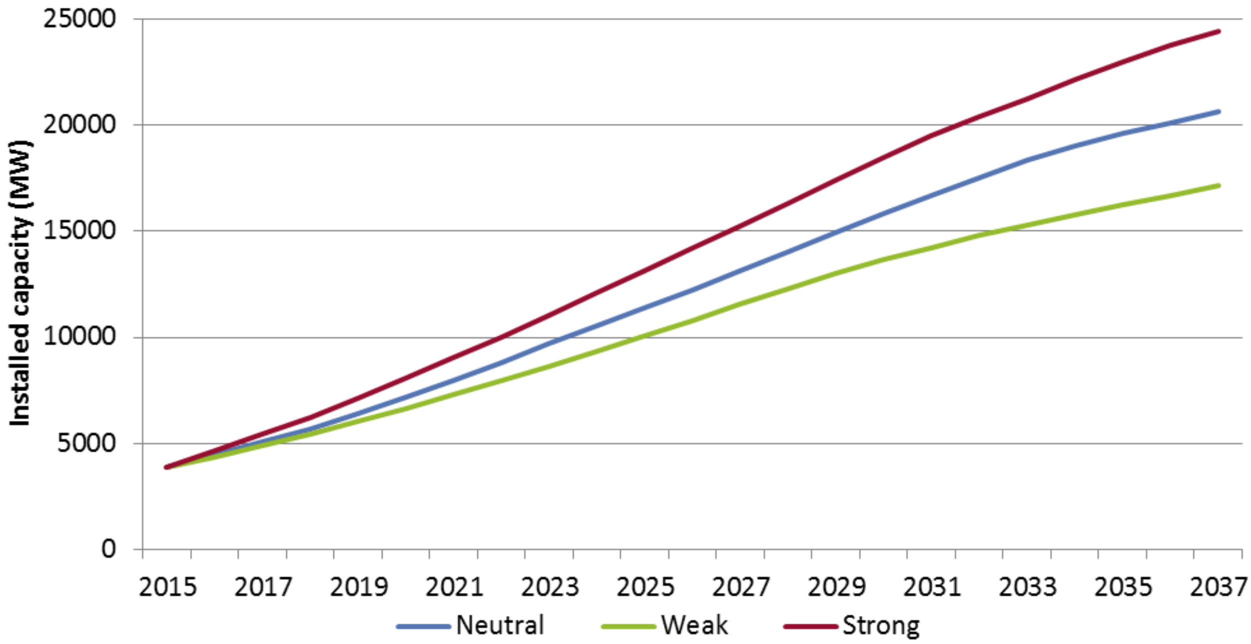
Figure 18 shows the total battery storage capacity installed in the NEM for the neutral scenario. During the first 5 years it is mostly commercial battery storage that is found economically viable to be installed but as capital costs quickly decline and there is transition to a time-of-use tariff structure, more residential battery storage is forecasted to be adopted resulting to a total of 6,920 MWh of battery storage in both the sectors at the end of 2037.

Figure 18 Total installed battery storage capacity in the NEM



The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in the NEM are given in Figure 19. The main drivers for the deviating results in the Strong and Weak scenarios are the different capital costs of PV and IPSS systems resulting from different applied exchange rates. At the end of the forecast period in the Strong scenario the NEM has around 24,400 MW of PV and IPSS systems installed (18% higher than the Neutral scenario), while in the Weak case around 17,130 MW is installed (17% lower than the Neutral scenario).

Figure 19 NEM rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

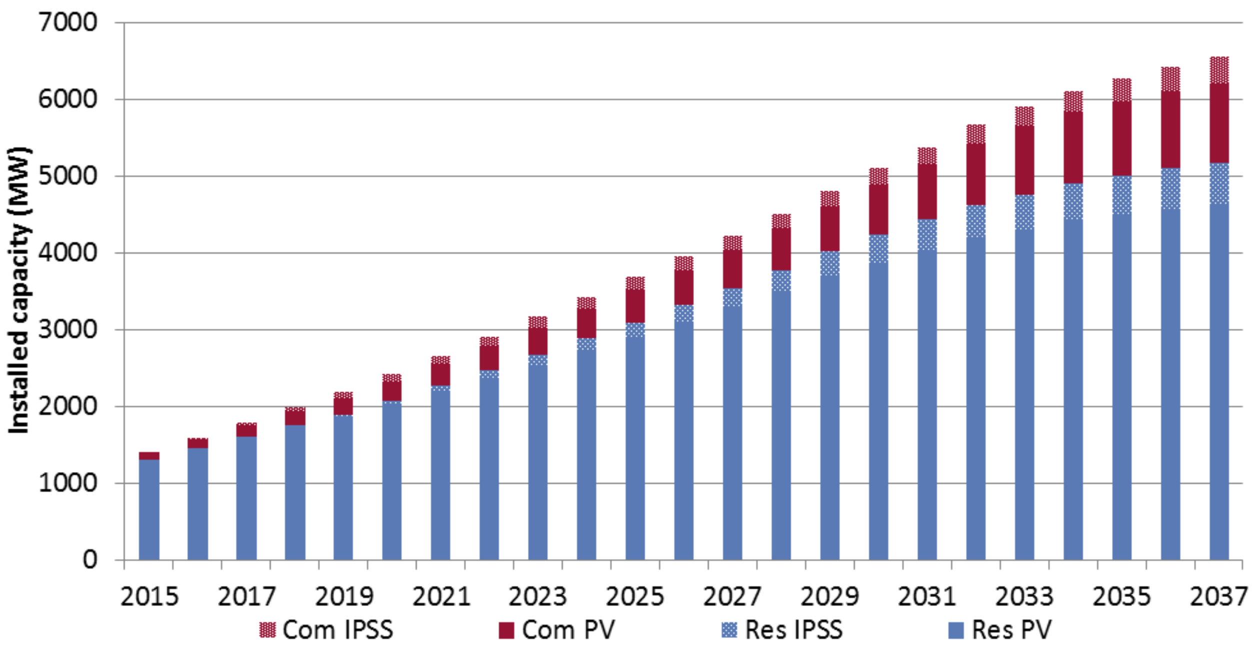


5.2 Queensland forecasts

In the short term, the main drivers for PV and IPSS uptake in both the residential and commercial segments are the existing financial incentives for these systems (STCs and FiTs). As the SRES is gradually fading out from 2017 onwards, the falling system installation costs and the increase of retail prices are becoming the key determinants for PV and IPSS installations.

Figure 20 shows the forecast total installed capacity of rooftop PV in Queensland, and the proportion of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS.

Figure 20 Total installed capacity of rooftop PV and IPSS in Queensland

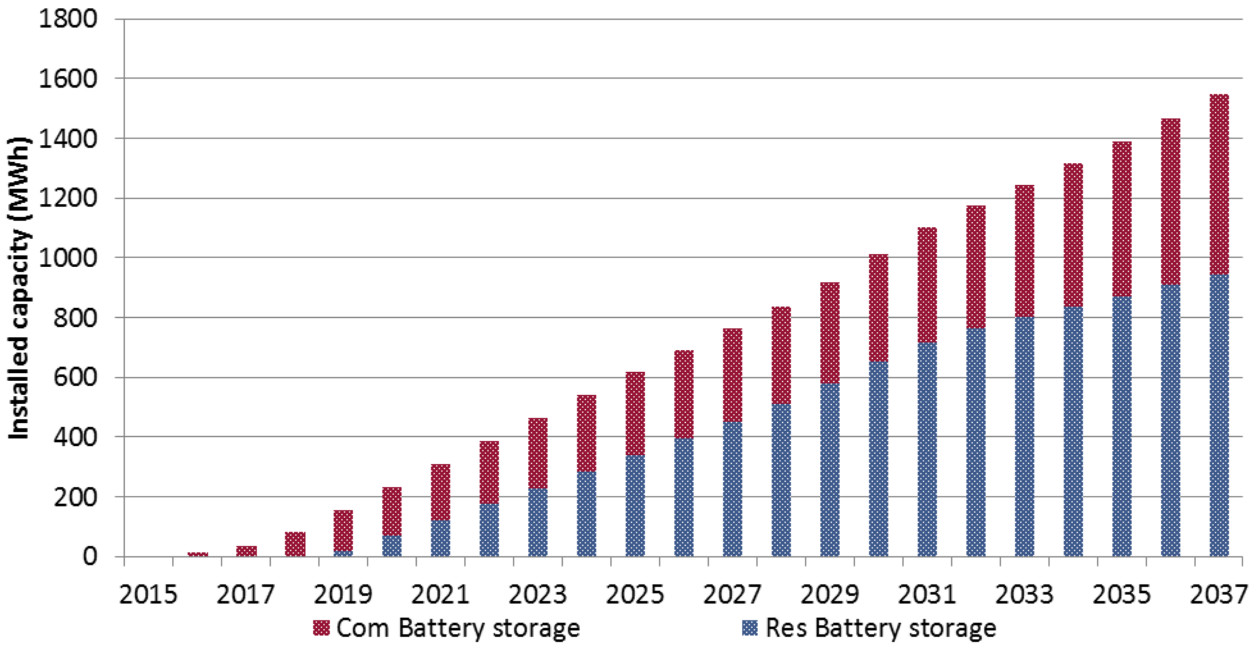


Although Queensland has already a high level of PV penetration in the residential segment, with around 23% of total dwellings having installed a PV system, the residential rooftop PV in the state continues to have a steady uptake of installations until the early 2030s when it reaches saturation in many regions. This effect is partially offset by a continuous growth in the commercial sector for the entire forecast period. The total forecast residential PV and IPSS capacity in 2036/37 is around 5,162 MW while the commercial is 1,390 MW accounting for 21% of total installations.

IPSS system uptake starts slowly during the first three years and continues with a steady growth after that accounting for around 14% of total annual installations in the forecast period. The fact that Queensland has already high installed capacity of residential PVs prevents a high penetration of battery storage since no retrofitting of batteries to existing systems has been considered in the model (due to such retrofitting likely being uneconomic).

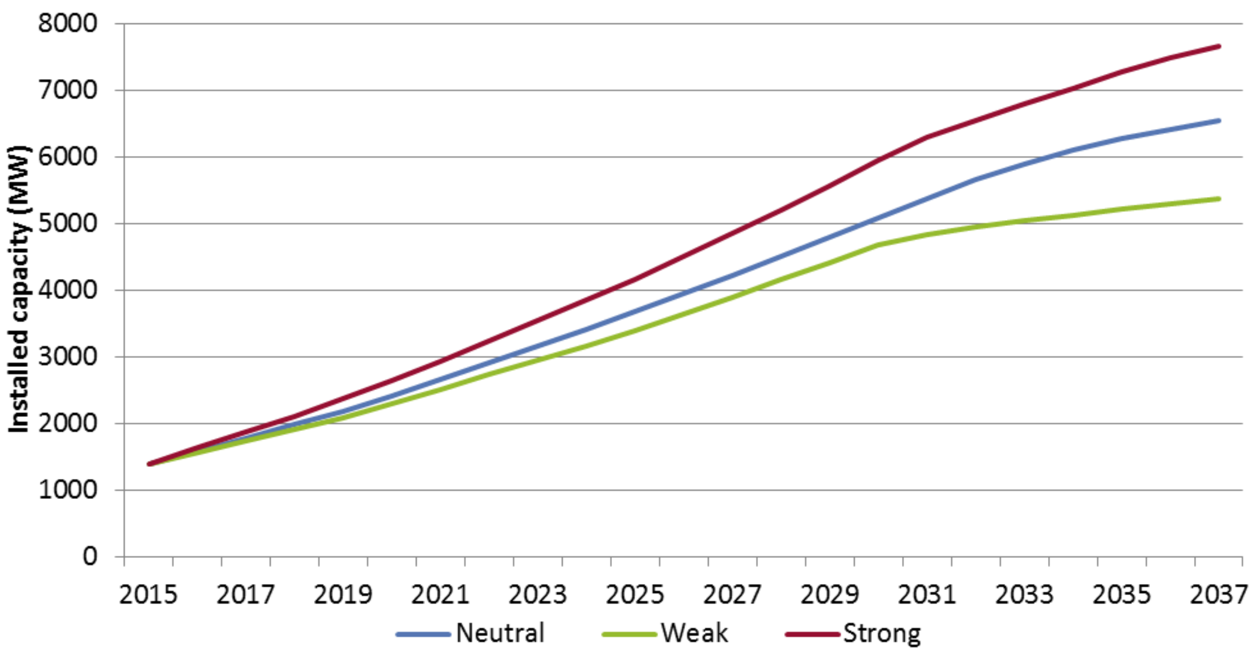
Figure 21 shows the total battery storage capacity installed in Queensland. Initially it is predominantly commercial battery storage that is being installed, but as the IPSS system costs continue to decline, residential uptake becomes prevalent and the total battery storage at the end of the modelled horizon reaches 1,551 MWh.

Figure 21 Total installed battery storage capacity in Queensland



The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in Queensland are given in Figure 22. Since the population growth and the retail prices have relatively small differences in all scenarios, the main drivers for the deviating results in the Strong and Weak scenarios are the different capital costs of PV and IPSS systems resulting from different exchange rates. At the end of the forecast period in the Strong scenario Queensland has around 7,660 MW capacity of PV and IPSS systems installed (17% higher than the Neutral scenario), while in the Weak case around 5,380 MW capacity is installed (18% lower than the Neutral scenario).

Figure 22 Queensland rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

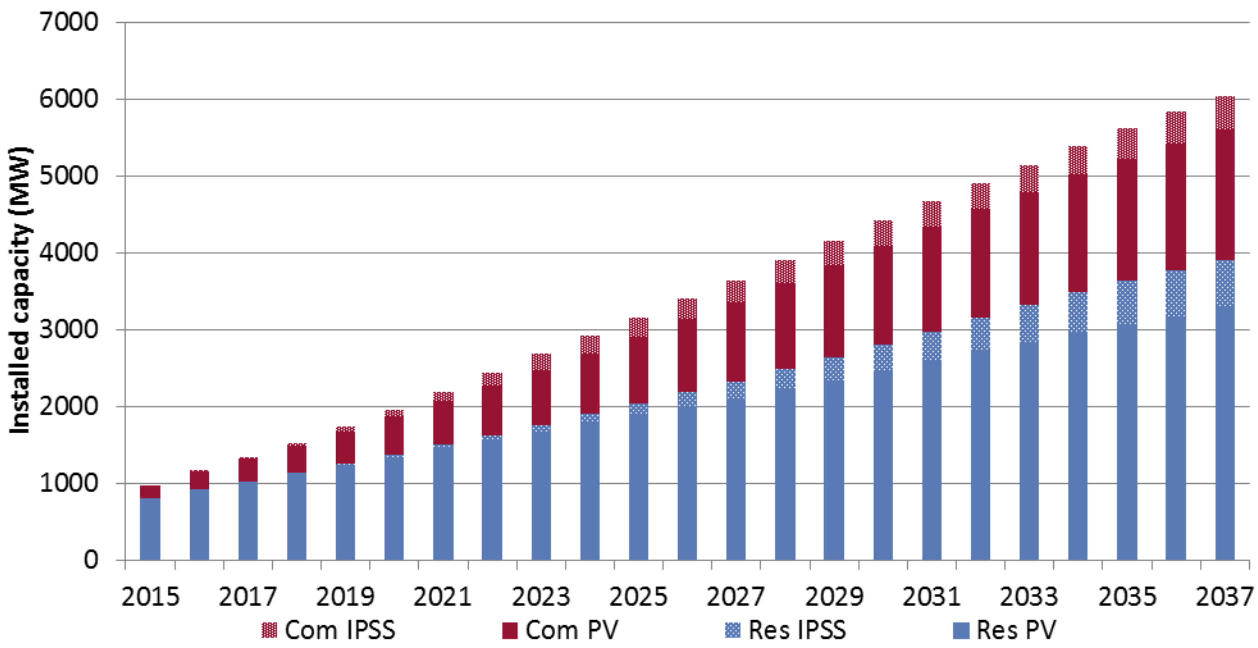


5.3 New South Wales[14] forecasts

The installations of PV and IPSS systems in New South Wales are predominantly driven by the existing financial incentives that increase the economic viability of these systems. As these incentives gradually decline the falling capital costs of the PVs and IPSS and the increasing retail prices are becoming the main reasons for a steady PV and IPSS uptake.

Figure 23 shows the forecasted total installed capacity of rooftop PV in New South Wales, and the fraction of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS.

Figure 23 Total installed capacity of rooftop PV and IPSS in New South Wales



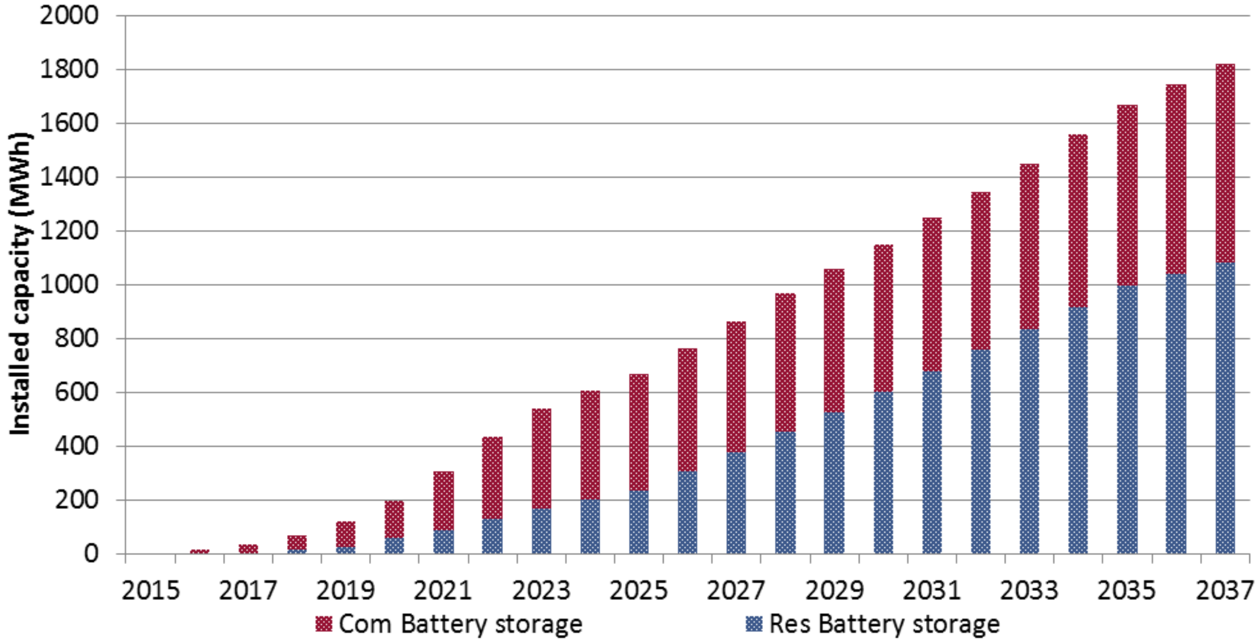
In New South Wales the installations of PV in both the residential and the commercial sector continue to grow steadily reaching a total cumulative capacity of around 4,990 MW in 2036/37. A third of that capacity (or 1,713 MW) is installed in the commercial sector. A reason for this continuous uptake is the current low saturation levels in that state.

The commercial segment is also the first that starts investing in IPSS systems, having stronger financial incentives to do so, especially after the increase of retail prices in the early 2020s. It ends up with around 430 MW installed by the end of the forecast horizon. Households have a moderate growth of IPSS installations in the early 2020s with stronger growth after 2025/26 resulting in 620 MW installed. On average, around 24% of total annual installations after 2020/21 are IPSS systems. The total capacity of PV systems with storage in both sectors in 2036/37 is around 1,050 MW.

Figure 24 shows the total battery storage capacity installed in New South Wales. Although most storage is initially adopted by the commercial sector, the declining IPSS system costs and the rising retail prices drive a strong residential uptake after 2025/26. At the end of the modelled period NSW is forecast to have installed around 1,820 MWh of battery storage with 60% of that in being installed in the residential sector.

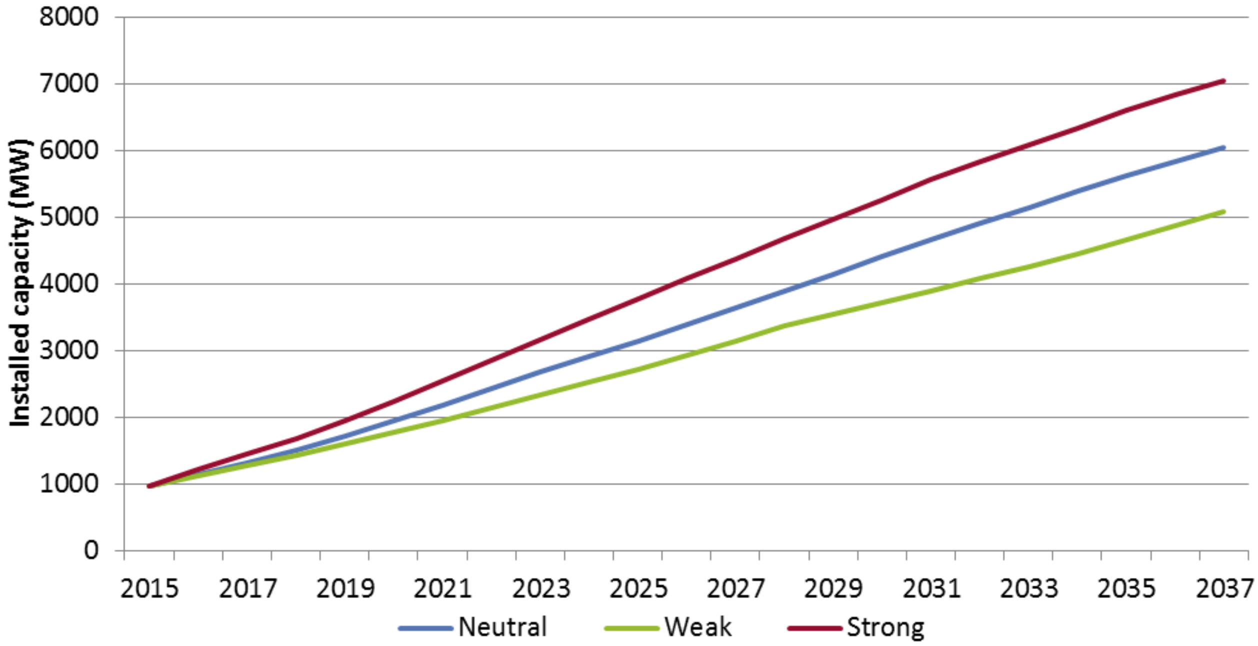
[14] The uptake of PV and IPSS systems in ACT is incorporated in the New South Wales results.

Figure 24 Total installed battery storage capacity in New South Wales



The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in New South Wales are given in Figure 25. The main drivers of the differences are the PV and IPSS capital costs chosen in each scenario. In 2036/37, the total installed capacity of PV and IPSS for the Strong scenario is around 7,050 MW (17% higher than the Neutral case), while for the Weak scenario it is 5,080 MW (which is 17% lower than the Neutral scenario).

Figure 25 New South Wales rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

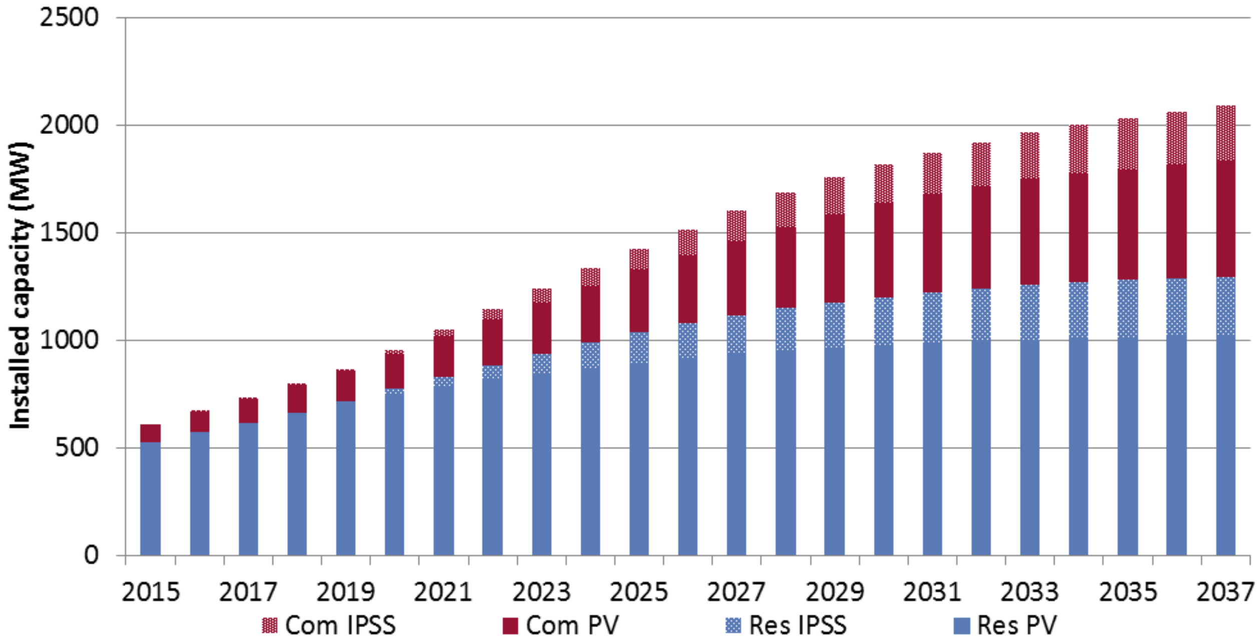


5.4 South Australia forecasts

South Australia currently has the highest penetration of residential PVs in Australia and that along with the falling STC incentives is leading to a moderate decline in the growth of households' installations. Conversely, there is a rise of PV uptake in the commercial sector mainly driven by the fallen PV installation costs and the projected higher retail prices in the state.

The forecast total installed capacity of rooftop PV in South Australia, and the proportion of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS is shown in Figure 26.

Figure 26 Total installed capacity of rooftop PV and IPSS in South Australia

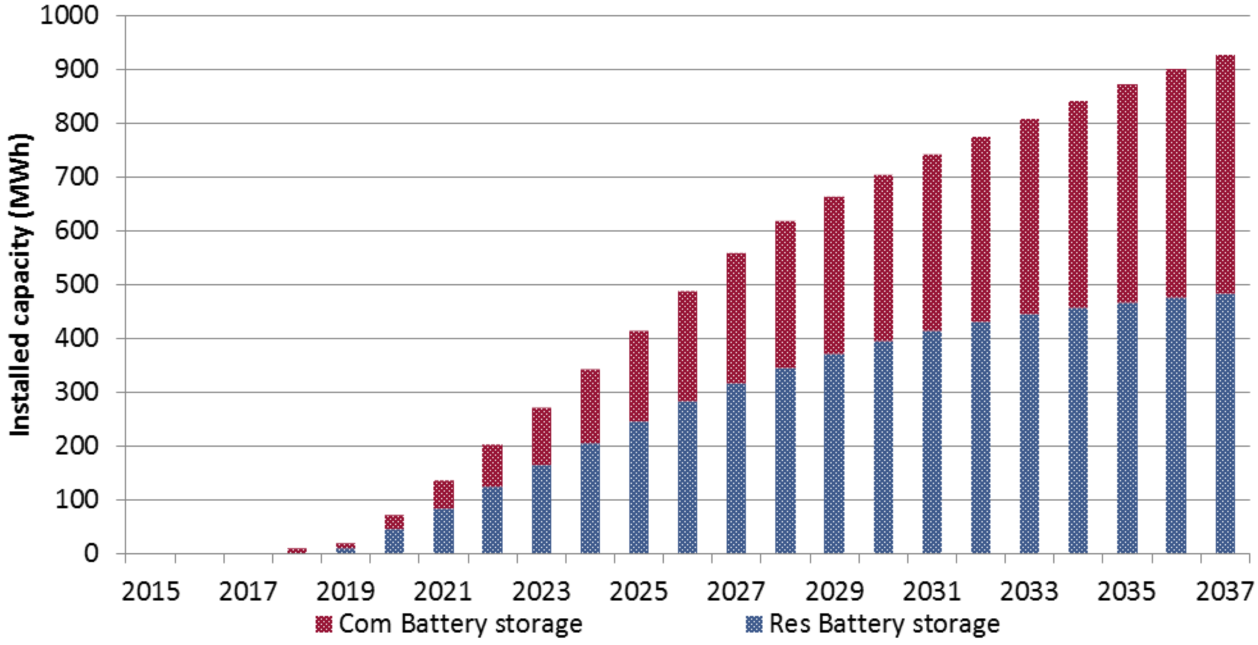


The residential PV uptake shows a continuous decline in the modelled horizon reaching a total installed capacity of around 1,022 MW in 2036/37. This is offset by the rapid increase of PV installations in the commercial sector that reach saturation in some regions in the early 2030s. At the end of the forecasted period commercial PV capacity is around 536 MW accounting for 34% of total PV installed.

IPSS system uptake becomes significant after 2019/20 in both the residential and commercial sectors, mainly driven by the falling system costs but also by the rapidly increasing retail prices. The already high penetration levels of household PVs constraints the IPSS installations after the early 2030s when saturation is reached. The total IPSS capacity installed at the end of the modelled period is around 533 MW accounting for slightly more than 25% of total installed capacity.

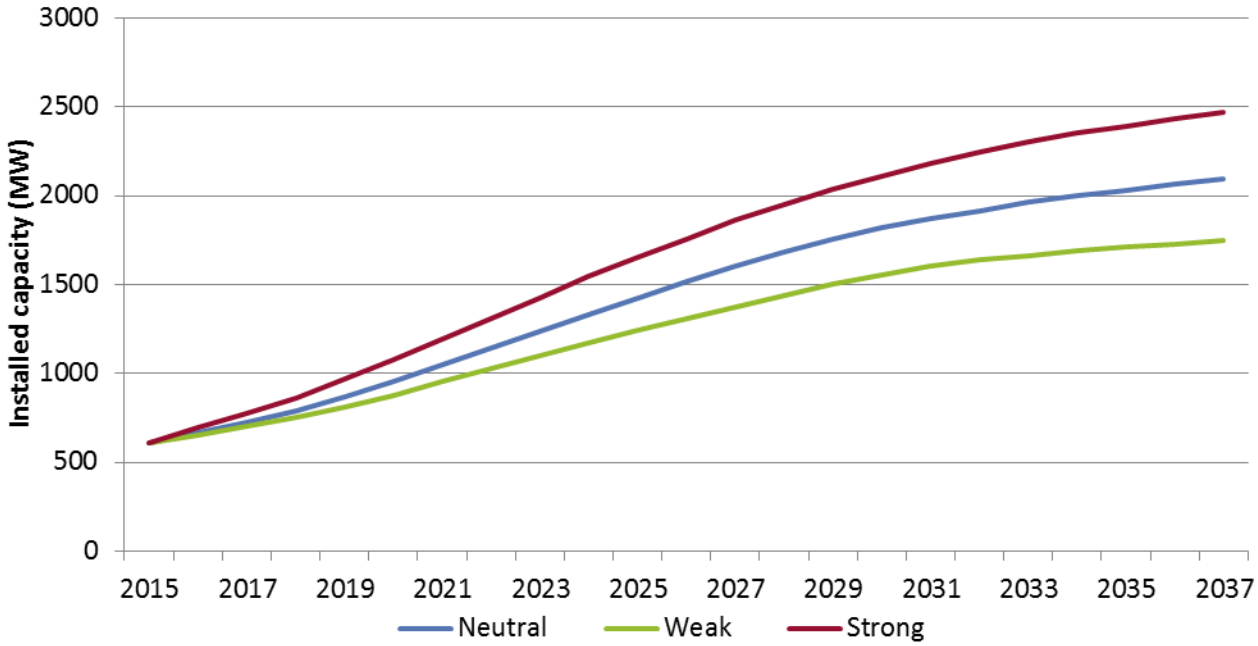
The cumulative installed battery storage capacity in South Australia is shown in Figure 27. The total storage installed in 2036/37 is 929 MWh with 48% of that being installed in the commercial sector.

Figure 27 Total installed battery storage capacity in South Australia



The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in South Australia are given in Figure 28. As in the previous states, the main drivers of the differences are the PV and IPSS capital costs chosen in each scenario. In 2036/37, the total installed capacity of PV and IPSS for the Strong scenario is around 2,470 MW (18% higher than the Neutral case), while for the Weak scenario it is 1,745 MW (which is 17% lower than the Neutral scenario).

Figure 28 South Australia rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

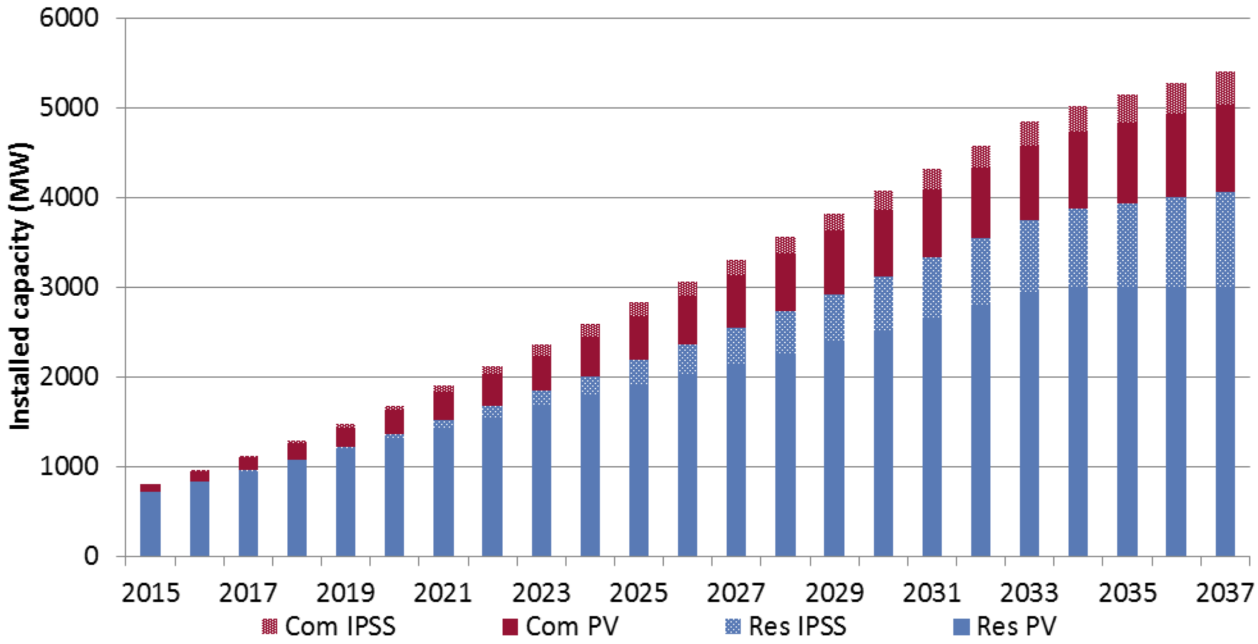


5.5 Victoria forecasts

The main drivers for PV and IPSS systems installations in Victoria are the financial incentives (STCs and FiTs) in the short term, and the declining capital costs and rise of retail prices in the long term. In the residential sector, the growth of systems uptake is strong until 2033/34 when saturation is reached in some regions of the state. On the other hand, the installations in the commercial sector remain steady throughout the forecast period with no signs of decline. The faster transition to a time-of-use tariff structure relative to the other states, leads to a high penetration of IPSS systems.

Figure 29 shows the forecasted total installed capacity of rooftop PV in Victoria, and the fraction of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS.

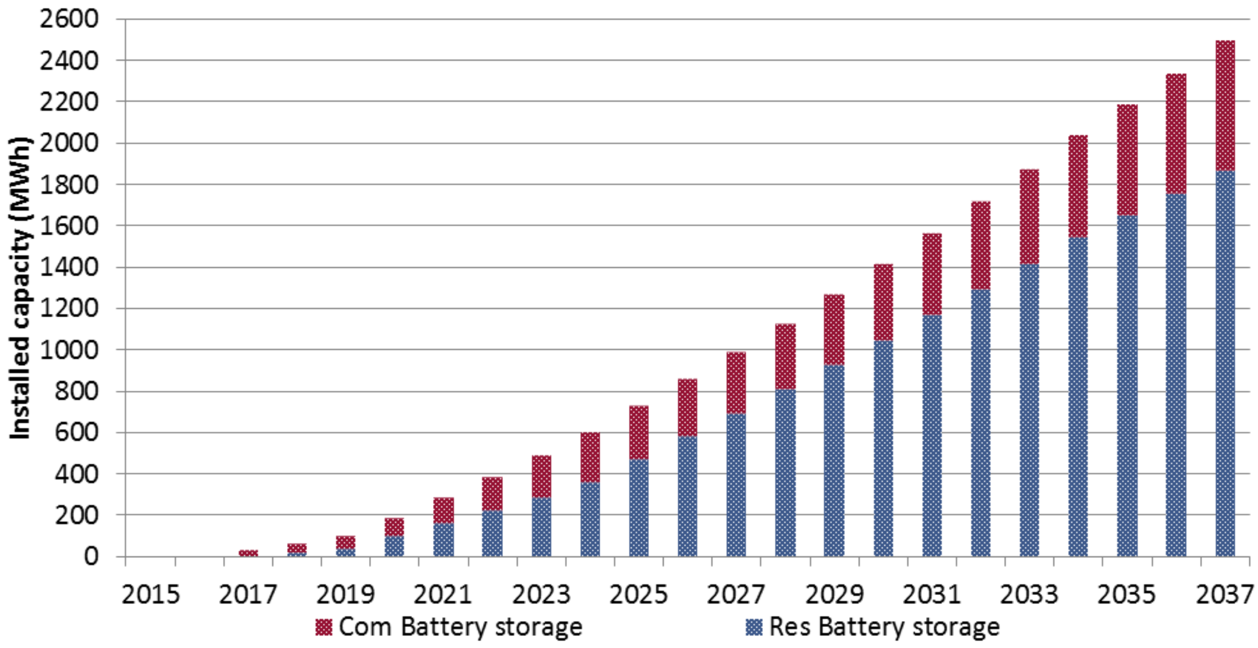
Figure 29 Total installed capacity of rooftop PV and IPSS in Victoria



As the figure shows, the uptake of PV systems in Victoria continues to grow in both the residential and the commercial segments. The household installations reach saturation levels after 2033/34, with the commercial sector remaining strong throughout the whole period. At the end of the modelled horizon the total installed PV capacity in the state is 3,960 MW with 25% of that being installed in businesses.

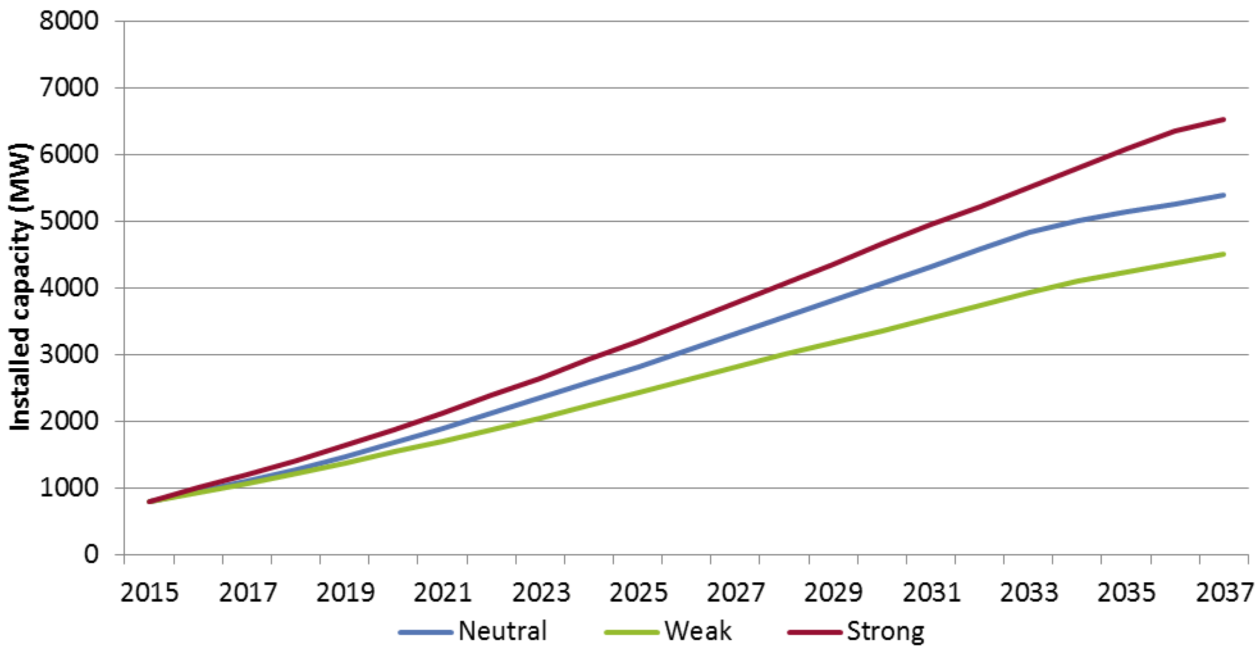
Regarding the uptake of IPSS systems, it starts slowly in both sectors during the first 4 years and continuous strongly after that accounting for around 30% of total annual installations during the 2020s and 50% during the 2030s. The total installed IPSS capacity in 2036/37 is around 1,440 MW with 1,070 MW of those installations taking place in households. At the end of the forecast period, the percentage of IPSS capacity is 27 % of total capacity. Figure 30 shows the total battery storage capacity installed in Victoria. Both the residential and the commercial sectors have a steady growth of IPSS systems throughout the forecasted period leading to a total uptake of 2,500 MWh of battery storage with 25% of that being installed in businesses.

Figure 30 Total installed battery storage capacity in Victoria



The forecasts of total PV and IPSS capacity installed in Victoria for the all three modelled scenarios (Neutral, Weak and Strong) are given in Figure 31. The main drivers for the differences between the scenarios remain the different capital costs of PV and IPSS systems resulting from different applied exchange rates. At the end of the forecast period in the Strong scenario Victoria has around 6,530 MW capacity of PV and IPSS systems installed (20% higher than the Neutral scenario), while in the Weak case around 4,510 MW capacity is installed (16% lower than the Neutral scenario).

Figure 31 Victoria rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios

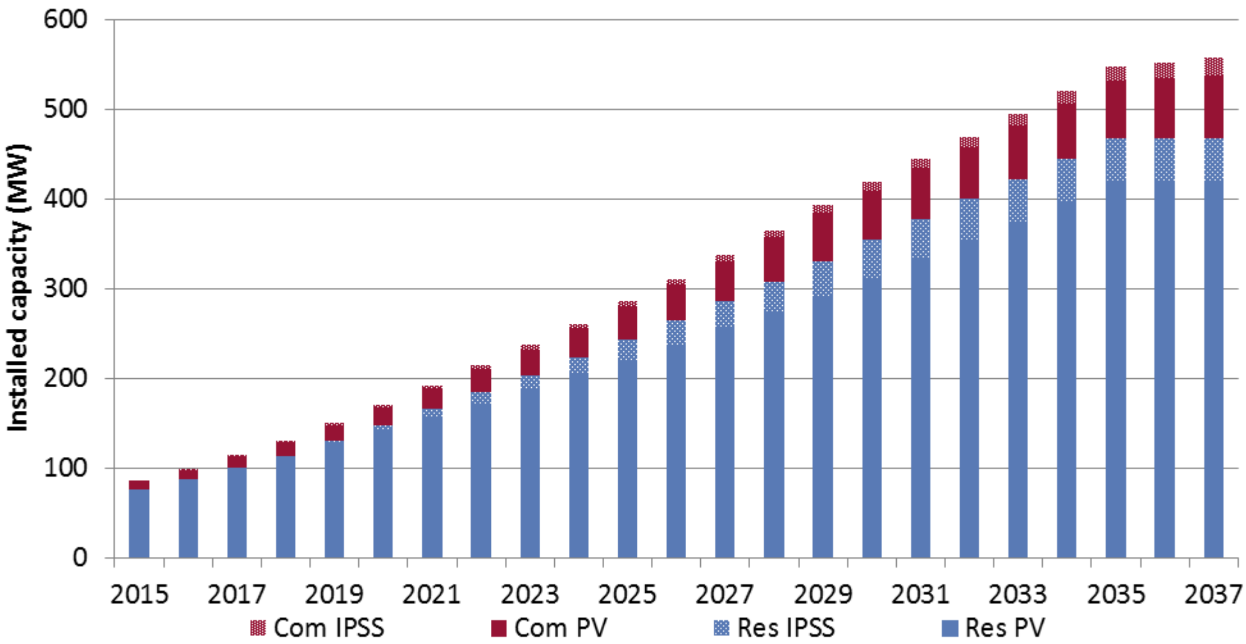


5.6 Tasmania forecasts

The PV and IPSS systems in Tasmania have a steady uptake up until 2035/36 when saturation is reached in the residential segment. The main drivers for this uptake are the STCs and FiT incentives initially, with lower installation costs and higher electricity prices stimulating the installations especially after the mid-2020s.

The forecasted total installed capacity of rooftop PV in Tasmania, and the proportion of residential rooftop PV, residential IPSS, commercial PV and commercial IPSS is shown in Figure 32.

Figure 32 Total installed capacity of rooftop PV and IPSS in Tasmania

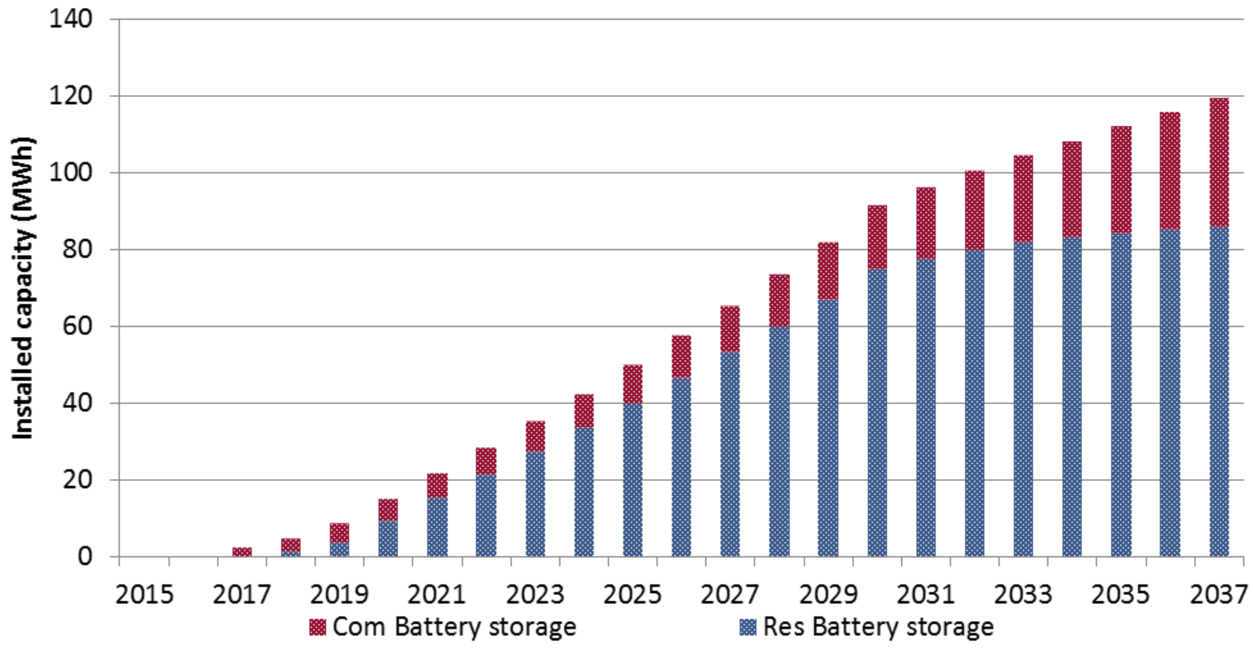


Both the residential and commercial sectors show a steady uptake of PVs, with the total installed capacity in households and businesses reaching 418 MW and 69 MW respectively in 2036/37.

The uptake of IPSS systems is weak in Tasmania since the state has the lowest solar resource. The total installed capacity in 2036/37 is 69 MW with 29% of that being adopted by commercial businesses.

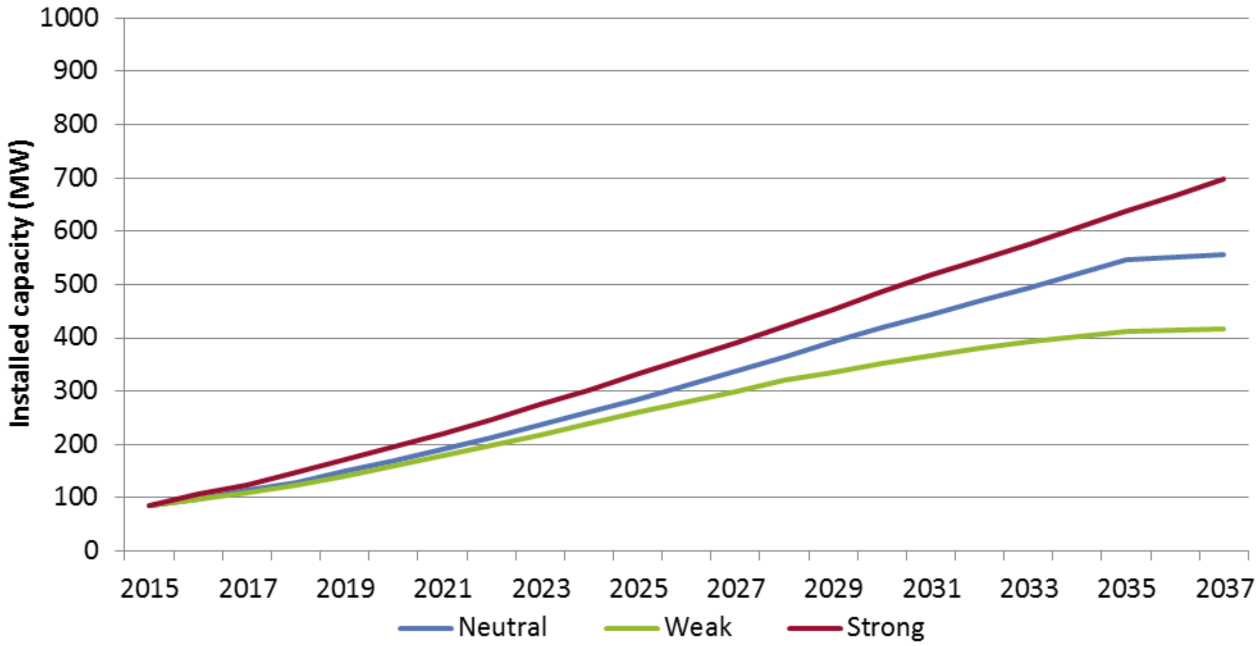
The cumulative installed battery storage capacity in Tasmania is shown in Figure 33. The total storage installed at the end of the forecast period is 120 MWh with 28% of that being commercial battery storage.

Figure 33 Total installed battery storage capacity in Tasmania



The forecasts of total PV and IPSS capacity installed for the Neutral, Weak and Strong scenarios in Tasmania are given in Figure 34. As in the other States, the main drivers of the differences are the PV and IPSS capital costs chosen in each scenario. In 2036/37, the total installed capacity of PV and IPSS for the Strong scenario is around 697 MW (25% higher than the Neutral case), while for the Weak scenario it is 418 MW (which is 25% lower than the Neutral scenario).

Figure 34 Tasmania rooftop total PV and IPSS capacity forecasts for Neutral, Weak and Strong scenarios



6. Comparison to NEFR 2015 – Emerging Technologies Paper

Table 6 provides a comparison between this papers' forecast uptake of PV and IPSS systems and the projections in the NEFR 2015 – Emerging Technologies Paper. Jacobs did not develop the model that was used for the NEFR 2015 forecast and therefore the comparison is restricted to a review of model outputs.

Table 6 Comparison of PV and IPSS uptake projections to NEFR 2015

	Res PV (MW)		Res IPSS (MW)		Com PV (MW)		Com IPSS (MW)	
	NEFR 2015	Jacobs	NEFR 2015	Jacobs	NEFR 2015	Jacobs	NEFR 2015	Jacobs
2017-18	6734	4705	306	26	1149	870	0	104
2024-25	9060	7816	1978	760	2942	2114	0	672
2034-35	10784	11978	4563	2334	5808	4030	0	1256

The table reveals that the new projection is forecasting a lower growth of uptake of PV and IPSS systems during the first decade. After 2024-25 the uptake remains relatively stable when compared to the previous projections reaching saturation in some regions during the 2030s. Fewer residential IPSS are projected to be adopted but this result is offset by additional commercial IPSS systems. Overall, the NEFR 2015 – Emerging Technologies Paper was forecasting a total uptake of 21,155 MW of photovoltaic systems with 4,563 MW being IPSS, while the new forecast is for a total uptake of 19,598 MW of systems with 3,590 MW being IPSS.

7. Key insights

The main drivers of PV uptake in all regions are the following:

- The financial incentives provided for the systems (STCs and FiTs)
- The declining installation costs of PVs and PV with storage. For PV systems in the short term, it is predominantly a decline of the “soft costs”[15] that include marketing and customer acquisition, system design, installation labour, permitting and inspection costs, and installer margins. In the longer term better system efficiencies and improvements from research and development are expected to reduce the installation costs. For the battery component, economies of scale and increased competition are considered to be the main causes of the downward pressure on costs.
- The increase in retail electricity tariffs from 2020 and onwards, as caused by the introduction of a carbon price commencing at $25/t CO2-e and escalating in a linear manner to $50/t CO2-e by 2030 and as a result of a reduced levels of excess capacity in the grid.
- A steady population growth across Australia, allowing for more PV systems to be adopted before saturation is reached.
- The transition to a time-of-use tariff structure that enables consumers to gain greater value from IPSS. Appropriate tariff structures that provide cost-reflective pricing enables charging during low cost time periods and discharge during the high cost time periods.

The phase out of STCs, starting from 2017, is gradually offset by the declining cost of PV installations, and the increase of retail tariffs (especially after 2020).

Over the modelled period, South Australia and Queensland residences are the first to reach saturation levels for some areas by around 2030. This is followed by Victoria 3 years later and Tasmania at the end of the forecast period.

Battery storage has a steady uptake after 2021 in both the residential and the commercial sectors. This is driven by higher retail electricity prices, rapid decline of battery costs and the transition to a time-of-use tariff structure.

Some of the key messages resulting from this modelling study are:

- PV uptake in the NEM remains relatively stable in the short term since the falling installation costs of PV systems is offset by the gradual fade out of the SRES incentive. Increased electricity prices after 2020 drive some additional growth to the sector for the next 10 years. After that, some decline in new annual installations numbers is observed since in some regions saturations levels are reached.
- The level of commercial PV installations is expected to increase and remain strong over the modelled horizon, due to the decline of installation costs and the projected increase in electricity prices.
- PVs with storage are forecasted to slowly emerge over the next few years as the cost of batteries is forecast to sharply reduce as a result of economies of scale and increased competition. IPSS are projected to reach a penetration level of around 11% in 2023 in the NEM and around 20% of total cumulative PV installations by 2037. The cumulative battery storage installed by 2037 is around 6,900 MWh.
- Queensland continues to have a steady uptake of installations until 2032 with additional growth in the commercial sector offsetting saturation reached in some residential areas. After 2032 a rapid decline in annual installations is evident with saturation reached in most regions. The fact that Queensland has

[15] Soft costs refer to non-hardware balance-of-system costs

already high installed capacity of residential PVs prevents a high penetration of battery storage since no retrofitting of batteries to existing systems has been considered to be economic.

- In New South Wales both residential and commercial uptake of PVs continues to grow across the entire forecasted period with installations reaching saturation only in some regions at the end of the horizon. There is also a strong growth of PVs coupled with battery storage in the state especially after 2020 accounting for almost 25% of the total annual PV installations. The main drivers for this being the decline battery costs and the transition to a time-of-use tariff structure.

- South Australia currently has the highest penetration of residential PVs of all the NEM regions, and sees a decline of new rooftop PV installations throughout the modelled period due to (i) phasing out of the SRES incentive, and (ii) saturation reached in some regions after the early 2030s. Some of the decline in new installations is offset by a higher uptake of commercial PVs which is driven by a steady increase in electricity prices. Residential prices also boost PV with battery storage installations in both the residential and the commercial sectors.

- Residential PV uptake in Victoria has a steady growth until 2033 that reaches saturation in some regions. Uptake in the commercial sector remains strong across the entire forecasted period and the installation of systems with battery storage is driven by a faster transition to a time-of-use tariff structure than in other states. This leads to high penetration of PV systems with battery storage reaching around 2,500 MWh installed battery capacity, the highest across the NEM regions.

- Tasmania continues to have slower growth of PV installations in both the residential and commercial segments when compared to the other states, due to lower insolation levels and consequently lower financial attractiveness of the systems. The PV and IPSS uptake in the state reaches saturation levels in the residential sector at the end of the forecasted period.

- At the end of the modelled horizon, the uptake of PVs and IPSS is forecasted to be 18% higher in the Strong scenario than in the Neutral scenario and 17% lower in the Weak scenario than in the Neutral scenario. These differences arise from the differences in the scenarios including different installation capital costs of the systems and different population levels.

Appendix A. Assumptions in the model

Table 7 Performance characteristics of batteries modelled

Technology	Lithium-ion
DoD (%)	90
Cycle life (No.cycles)	4000
Lifetime (years)	10
Round-trip efficiency (%)	90

Note: The DoD refers to the amount of energy that is actually usable in a battery. The value of the cycle life represents the number of cycles of complete discharge (down to the DoD) that a battery can go through before its performance degrades substantially. Therefore, it is assumed that once a battery has reached its cycle life it would be replaced The lifetime has a similar purpose to the cycle life, in that it represents the number of years for which a battery's performance is warranted. Although a battery may last beyond its lifetime, its performance will be degraded. Therefore, we assumed that once a battery has reached its lifetime it would be replaced. The round-trip efficiency is the percentage of energy a battery releases, relative to the energy provided. The round-trip efficiency is used in the modelling to represent loss of energy of ES.

Table 8 2016 NEFR's projected residential connections by state and territory for Neutral scenario

Residential Connections							
FY	QLD	NSW	VIC	SA	TAS	ACT	NEM
2015	1,863,005	3,086,654	2,403,864	749,494	234,528	161,443	8,498,988
2016	1,891,863	3,119,768	2,434,574	756,682	238,086	165,589	8,606,562
2017	1,927,291	3,148,646	2,464,583	761,644	240,434	167,977	8,710,575
2018	1,958,431	3,179,025	2,492,200	767,836	242,328	171,640	8,811,460
2019	1,986,004	3,207,500	2,520,768	774,114	244,210	175,344	8,907,941
2020	2,013,390	3,235,562	2,551,960	781,188	246,173	178,994	9,007,266
2021	2,041,342	3,264,056	2,583,456	788,680	248,173	182,735	9,108,442
2022	2,070,089	3,292,921	2,615,923	796,420	250,205	186,587	9,212,145
2023	2,099,463	3,322,358	2,649,024	804,156	252,250	190,503	9,317,755
2024	2,129,248	3,352,167	2,682,778	811,772	254,302	194,503	9,424,770
2025	2,159,756	3,382,311	2,717,334	819,344	256,377	198,609	9,533,730
2026	2,190,786	3,412,698	2,752,208	827,129	258,494	202,785	9,644,099
2027	2,222,785	3,443,636	2,788,058	835,039	260,636	207,107	9,757,260
2028	2,255,778	3,475,133	2,824,907	843,076	262,801	211,581	9,873,277
2029	2,289,796	3,507,197	2,862,779	851,240	264,992	216,213	9,992,217
2030	2,324,866	3,539,836	2,901,698	859,534	267,206	221,007	10,114,147
2031	2,361,020	3,573,055	2,941,690	867,959	269,444	225,971	10,239,139
2032	2,398,289	3,606,863	2,982,779	876,514	271,706	231,110	10,367,263
2033	2,436,706	3,641,268	3,024,991	885,201	273,992	236,432	10,498,590
2034	2,476,303	3,676,276	3,068,353	894,022	276,300	241,943	10,633,197
2035	2,517,114	3,711,895	3,112,892	902,977	278,631	247,649	10,771,159
2036	2,559,177	3,748,132	3,158,637	912,068	280,986	253,559	10,912,559
2037	2,602,530	3,784,997	3,205,618	921,295	283,363	259,681	11,057,482

Source: AEMO

Table 9 2016 NEFR's projected commercial connections by state and territory for Neutral scenario

Commercial Connections							
FY	QLD	NSW	VIC	SA	TAS	ACT	NEM
2015	224,174	333,360	298,107	94,568	36,832	13,621	1,000,662
2016	228,705	330,687	303,618	94,040	36,880	13,351	1,007,281
2017	231,801	329,665	308,441	93,266	36,883	13,290	1,013,346
2018	235,477	328,239	313,426	92,517	36,780	13,156	1,019,595
2019	238,723	326,543	318,566	91,760	36,670	13,009	1,025,270
2020	241,944	324,736	324,076	91,076	36,566	12,841	1,031,240
2021	245,231	322,903	329,665	90,418	36,463	12,665	1,037,345
2022	248,612	321,036	335,419	89,764	36,360	12,479	1,043,670
2023	252,066	319,155	341,296	89,086	36,253	12,281	1,050,136
2024	255,567	317,236	347,301	88,369	36,141	12,072	1,056,686
2025	259,152	315,276	353,454	87,624	36,027	11,851	1,063,385
2026	262,799	313,265	359,692	86,878	35,914	11,617	1,070,166
2027	266,559	311,231	366,104	86,121	35,798	11,374	1,077,188
2028	270,437	309,172	372,694	85,352	35,681	11,120	1,084,455
2029	274,434	307,086	379,467	84,571	35,560	10,855	1,091,973
2030	278,556	304,971	386,429	83,777	35,437	10,579	1,099,749
2031	282,805	302,828	393,584	82,969	35,312	10,290	1,107,788
2032	287,185	300,654	400,939	82,148	35,184	9,989	1,116,097
2033	291,699	298,447	408,499	81,313	35,052	9,673	1,124,683
2034	296,352	296,206	416,269	80,463	34,918	9,342	1,133,550
2035	301,148	293,929	424,256	79,598	34,781	8,996	1,142,707
2036	306,091	291,615	432,466	78,717	34,640	8,633	1,152,162
2037	311,184	289,261	440,905	77,820	34,496	8,252	1,161,920

Source: AEMO

Table 10 2016 NEFR's projected residential connections by state and territory for Weak scenario

	Residential Connections						
FY	QLD	NSW	VIC	SA	TAS	ACT	NEM
2015	1,863,005	3,086,654	2,403,864	749,494	234,528	161,443	8,498,988
2016	1,891,863	3,119,768	2,434,574	756,682	238,086	165,589	8,606,562
2017	1,926,628	3,148,494	2,464,014	761,592	240,343	167,898	8,708,970
2018	1,957,702	3,178,845	2,491,543	767,762	242,232	171,555	8,809,639
2019	1,985,208	3,207,338	2,520,022	774,018	244,108	175,254	8,905,949
2020	2,010,011	3,235,007	2,548,701	780,732	245,745	178,621	8,998,817
2021	2,037,652	3,263,035	2,579,783	788,119	247,720	182,339	9,098,648
2022	2,066,168	3,291,547	2,611,947	795,781	249,731	186,172	9,201,347
2023	2,095,436	3,320,820	2,644,905	803,478	251,759	190,078	9,306,476
2024	2,125,111	3,350,465	2,678,519	811,053	253,792	194,067	9,413,007
2025	2,155,509	3,380,432	2,712,940	818,586	255,850	198,161	9,521,479
2026	2,186,428	3,410,646	2,747,675	826,333	257,950	202,325	9,631,358
2027	2,218,316	3,441,414	2,783,382	834,204	260,074	206,636	9,744,027
2028	2,251,253	3,472,816	2,820,153	842,219	262,228	211,102	9,859,771
2029	2,285,267	3,504,865	2,858,008	850,379	264,411	215,731	9,978,661
2030	2,320,332	3,537,486	2,896,909	858,667	266,617	220,522	10,100,535
2031	2,356,478	3,570,687	2,936,880	867,085	268,848	225,482	10,225,462
2032	2,393,736	3,604,475	2,977,948	875,633	271,104	230,618	10,353,514
2033	2,432,137	3,638,857	3,020,134	884,313	273,381	235,935	10,484,756
2034	2,471,714	3,673,838	3,063,467	893,124	275,680	241,441	10,619,264
2035	2,512,500	3,709,430	3,107,973	902,070	278,002	247,143	10,757,117
2036	2,554,533	3,745,635	3,153,681	911,149	280,346	253,047	10,898,391
2037	2,597,849	3,782,465	3,200,621	920,364	282,712	259,162	11,043,174

Source: AEMO

Table 11 2016 NEFR's projected commercial connections by state and territory for Weak scenario

Commercial Connections							
FY	QLD	NSW	VIC	SA	TAS	ACT	NEM
2015	224,174	333,360	298,107	94,568	36,832	13,621	1,000,662
2016	228,705	330,687	303,618	94,040	36,880	13,351	1,007,281
2017	231,138	329,514	307,873	93,214	36,792	13,211	1,011,742
2018	234,748	328,060	312,768	92,444	36,683	13,071	1,017,775
2019	237,926	326,382	317,819	91,665	36,568	12,919	1,023,279
2020	238,565	324,181	320,817	90,620	36,139	12,469	1,022,791
2021	241,541	321,882	325,992	89,858	36,011	12,268	1,027,552
2022	244,690	319,663	331,443	89,126	35,885	12,064	1,032,873
2023	248,038	317,616	337,178	88,408	35,761	11,856	1,038,857
2024	251,430	315,533	343,042	87,651	35,631	11,635	1,044,922
2025	254,906	313,398	349,059	86,867	35,501	11,403	1,051,134
2026	258,441	311,214	355,159	86,083	35,370	11,158	1,057,425
2027	262,091	309,009	361,428	85,286	35,237	10,903	1,063,954
2028	265,911	306,854	367,940	84,495	35,107	10,642	1,070,948
2029	269,905	304,753	374,696	83,709	34,979	10,374	1,078,417
2030	274,022	302,622	381,640	82,909	34,849	10,095	1,086,137
2031	278,263	300,460	388,775	82,096	34,716	9,802	1,094,112
2032	282,631	298,265	396,108	81,268	34,581	9,496	1,102,349
2033	287,130	296,035	403,641	80,425	34,441	9,176	1,110,848
2034	291,763	293,767	411,383	79,566	34,298	8,840	1,119,618
2035	296,534	291,463	419,336	78,692	34,151	8,490	1,128,666
2036	301,446	289,117	427,510	77,799	34,000	8,121	1,137,993
2037	306,504	286,730	435,909	76,890	33,846	7,734	1,147,612

Source: AEMO

Table 12 2016 NEFR's projected residential connections by state and territory for Strong scenario

	Residential Connections						
FY	QLD	NSW	VIC	SA	TAS	ACT	NEM
2015	1,863,005	3,086,654	2,403,864	749,494	234,528	161,443	8,498,988
2016	1,891,863	3,119,768	2,434,574	756,682	238,086	165,589	8,606,562
2017	1,927,284	3,148,646	2,464,579	761,644	240,433	167,975	8,710,560
2018	1,958,428	3,178,976	2,492,204	767,839	242,328	171,638	8,811,413
2019	1,986,004	3,207,496	2,520,777	774,120	244,211	175,342	8,907,950
2020	2,013,434	3,235,751	2,552,070	781,237	246,178	178,988	9,007,658
2021	2,041,299	3,264,172	2,583,467	788,711	248,177	182,724	9,108,550
2022	2,070,080	3,293,132	2,616,010	796,472	250,212	186,578	9,212,484
2023	2,099,494	3,322,666	2,649,160	804,231	252,265	190,496	9,318,311
2024	2,129,312	3,352,567	2,682,965	811,869	254,321	194,496	9,425,528
2025	2,159,851	3,382,781	2,717,577	819,462	256,402	198,603	9,534,676
2026	2,190,908	3,413,243	2,752,497	827,269	258,526	202,780	9,645,223
2027	2,222,934	3,444,252	2,788,388	835,198	260,672	207,103	9,758,546
2028	2,255,990	3,475,874	2,825,325	843,268	262,848	211,580	9,874,885
2029	2,290,061	3,508,062	2,863,279	851,466	265,047	216,213	9,994,129
2030	2,325,183	3,540,822	2,902,275	859,790	267,269	221,012	10,116,351
2031	2,361,383	3,574,153	2,942,336	868,243	269,516	225,978	10,241,609
2032	2,398,695	3,608,064	2,983,494	876,826	271,786	231,119	10,369,984
2033	2,437,195	3,642,644	3,025,830	885,561	274,086	236,446	10,501,762
2034	2,476,869	3,677,813	3,069,308	894,425	276,408	241,961	10,636,783
2035	2,517,755	3,713,579	3,113,950	903,420	278,750	247,674	10,775,126
2036	2,559,883	3,749,952	3,159,792	912,546	281,114	253,588	10,916,875
2037	2,603,297	3,786,943	3,206,862	921,807	283,501	259,712	11,062,121

Source: AEMO

Table 13 2016 NEFR's projected commercial connections by state and territory for Strong scenario

	Commercial Connections						
FY	QLD	NSW	VIC	SA	TAS	ACT	NEM
2015	224,174	333,360	298,107	94,568	36,832	13,621	1,000,662
2016	228,705	330,687	303,618	94,040	36,880	13,351	1,007,281
2017	233,119	329,968	309,574	93,369	37,063	13,447	1,016,542
2018	236,933	328,550	314,743	92,668	36,972	13,323	1,023,190
2019	240,315	326,862	320,068	91,958	36,874	13,187	1,029,263
2020	248,745	326,035	330,704	92,038	37,427	13,581	1,048,530
2021	252,569	325,062	337,021	91,570	37,373	13,446	1,057,040
2022	256,445	323,994	343,457	91,093	37,316	13,299	1,065,605
2023	260,150	322,539	349,669	90,516	37,250	13,124	1,073,250
2024	263,904	321,040	356,006	89,903	37,180	12,938	1,080,971
2025	267,740	319,503	362,486	89,257	37,106	12,741	1,088,833
2026	271,636	317,914	369,048	88,610	37,033	12,531	1,096,772
2027	275,646	316,290	375,786	87,950	36,958	12,312	1,104,941
2028	279,700	314,546	382,620	87,258	36,875	12,076	1,113,076
2029	283,757	312,615	389,509	86,519	36,777	11,820	1,120,998
2030	287,940	310,657	396,583	85,767	36,678	11,553	1,129,177
2031	292,251	308,662	403,849	85,001	36,575	11,274	1,137,612
2032	296,697	306,631	411,316	84,221	36,469	10,982	1,146,316
2033	301,325	304,646	419,052	83,449	36,369	10,681	1,155,523
2034	306,097	302,618	426,996	82,661	36,265	10,364	1,165,001
2035	311,017	300,544	435,153	81,855	36,158	10,033	1,174,758
2036	316,085	298,429	443,533	81,033	36,048	9,685	1,184,813
2037	321,312	296,272	452,143	80,194	35,936	9,320	1,195,176

Source: AEMO