EMERGING TECHNOLOGIES INFORMATION PAPER

NATIONAL ELECTRICITY FORECASTING REPORT

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this information paper to explore the potential impacts of emerging technologies and trends on operational consumption and maximum demand in the National Electricity Market, over a 20-year outlook period, as modelled using data and assumptions at the date of publication.

Disclaimer

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EXECUTIVE SUMMARY

About this paper

This paper forecasts potential impacts of battery storage, electric vehicles and fuel switching in the 20-year outlook period, among consumers in the residential sector in the National Electricity Market (NEM).[1]

AEMO considers that these emerging technologies have the potential to impact operational consumption and maximum demand from the national electricity grid, and has produced this information paper to continually monitor and assess any potential impacts to reliability or security of supply. These findings were not included in the 2015 National Electricity Forecasting Report (NEFR).

Although it is challenging to forecast the potential impacts of these technologies and trends, given current limitations in scope, methodology and available data, AEMO has produced this information paper as a first step.

The assumptions AEMO has used in these forecasts, and the current limitations on the modelling, are clearly identified throughout this paper. AEMO continues to work with industry and stakeholders to address limitations and improve its methodologies, and will revise its forecasts accordingly.

Emerging technologies

The energy industry is being transformed by technological advancements which are changing the generation mix and creating opportunities for increased consumer engagement when it comes to choice and energy supply solutions.

AEMO observes that battery storage and electric vehicles continue to gather momentum internationally and in Australia, with industry and consumers keen to explore the opportunities and challenges presented by these new technologies.

Using the example of rooftop photovoltaic (PV) systems uptake in Australia and its subsequent impact on forecasting and the National Electricity Market (NEM) since 2008–2009, AEMO recognises:

- Large scale penetration of new technologies can occur over a short period of time.
- Early monitoring is critical to understanding the potential impact and implications of emerging technologies and trends on annual operational consumption and maximum demand from the national electricity grid.
- Modelling future uptake is challenging, and is greatly assisted by appropriate frameworks for collecting data about the adoption of emerging technologies and trends.

Modelling battery storage

Modelling battery storage is challenging because, unlike rooftop PV, the market is in its infancy and there currently is no mechanism for tracking the number of installations in Australia.

AEMO has developed the first step of its economic model to estimate the uptake of battery storage systems by residential consumers, and used this estimate to determine the impact on 2015 NEFR maximum demand forecasts.

This work has not modelled behavioural drivers, but has focused on residential installation of batteries as part of a new installation of rooftop PV and battery storage together, with the view to providing the

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[1] These emerging technologies and trends, notably fuel switching and storage, have the potential to impact operational consumption and maximum demand in the commercial and industrial sectors, and AEMO will consider these sectors in due course.

economic benefit to the individual household. The economics of retrofitting battery storage to existing rooftop PV has also not been considered for this paper.

The structure of distribution tariffs is critical to any assessment of the economics of alternative supply solutions and the sensitivity to several options has been assessed in this work.

The payback period (average time to recover the investment costs of installing a rooftop PV system with battery storage) varies between NEM regions, because it relies on individual household demand, available tariffs, and solar resources, all of which vary broadly across the NEM.

The payback period also varies according to different household types, which are categorised, according to their average daily consumption, as either small, medium or large. AEMO's assessment found that larger consumers benefited more from installation of rooftop PV with battery storage compared to their counterparts, so they have the shortest payback period.

Forecast uptake of battery storage capacity

The uptake in each region is affected by the current installed capacity of rooftop PV. As this study did not consider the economics of retrofitting battery storage, the market for new rooftop PV plus battery systems is more limited in some regions.

Table 1 Forecast installed capacity of battery storage (MWh)

	Queensland	New South Wales	South Australia	Victoria	Tasmania	NEM
2017–18	129	201	2	188	9	529
2024–25	982	1,043	206	1,131	83	3445
2034–35	2,046	2,482	484	2,774	196	7982

Queensland

There is already a relatively high installed capacity of residential rooftop PV in Queensland. Despite 2,046 MWh of battery storage capacity being installed with new rooftop PV over the forecast period, this represents a relatively small percentage of total installed rooftop PV capacity.

New South Wales

The combination of the tariff structure and average household daily demand profile gives consumers in New South Wales economic incentive to install rooftop PV and battery storage. By the end of the forecast period, New South Wales has the largest percentage of installed rooftop PV (72%) that is integrated with battery storage.

This results in a sizeable reduction in the 10% Probability of Exceedance (POE)[2] summer and winter maximum demand forecasts, as seen in Table 2.

South Australia

As outlined in the 2015 NEFR, South Australia currently has the highest penetration of rooftop PV of all the NEM regions.

As in this paper AEMO has only considered uptake of battery storage with new installations of rooftop PV, this reduces the size of the market being modelled in South Australia. In addition, the installation of rooftop PV in South Australia already has a short payback period. The forecasts show that the

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[2] A probability of exceedance (POE) refers to the likelihood that a maximum demand forecast will be met or exceeded. A 10% POE maximum demand projection is expected to be exceeded, on average, one year in 10 years.

additional benefits of installing battery storage compared with rooftop PV alone were limited in South Australia, compared to other NEM regions.

Victoria

Victoria currently has a time-of-use tariff structure that incentivises the uptake of battery storage, as households are able to use electricity from the battery during peak times. Victoria has the highest installed battery capacity (2,774 MWh) by the end of the forecast period, and this results in a sizeable reduction in the 10% POE summer and winter maximum demand forecasts, as seen in Table 2.

Tasmania

As Tasmania historically has the least amount of solar resource, the payback period is the longest of all NEM regions. However, the percentage of total installed rooftop PV that is integrated with a battery storage system is the third highest of the NEM regions across the forecast period. Despite this uptake, given Tasmania's maximum demand peak occurs in winter, there is only a small reduction in the 10% POE maximum demand forecasts.

Forecast impacts of battery storage capacity on maximum demand

Table 2 summarises the forecast impacts of battery storage capacity on maximum demand in the 10% POE, for each NEM region.

The table shows the potential impact that the combination of battery storage and rooftop PV could have on the grid as the solar-charged battery generally discharges at peak demand times.

Table 2 Forecast reduction in the 10% PoE maximum demand (MW)

	Queensland		New South Wales		South Australia		Victoria		Tasmania[a]	
	Summer	%	Summer	%	Summer	%	Summer	%	Winter	%
2017–18	41.4	0.5	54	0.4	0.4	0.0	47	0.5	0	0.0
2024–25	187.9	2.0	210	1.4	33.9	1.0	280	2.7	1.9	0.1
2034–35	225.3	2.1	414	2.4	76.1	2.2	720	6.2	5.3	0.3

[a] The maximum demand occurs in winter for Tasmania.

The above table highlights significant reductions in 10% POE maximum demand in Victoria and New South Wales. The proportionately lower impacts for Queensland and South Australia in this forecast are affected by the existing level of solar PV installed.

Electric vehicles

Based on initial assumptions and current market conditions, AEMO anticipates there will be negligible impact on the daily load profiles in each NEM region in the 20-year outlook period based on the estimated uptake of electric vehicles.[3]

In the NEM, only 1,909 electric vehicles were sold to 30 April 2015. In 2014, electric vehicles represented 0.1% of new vehicle sales.[4] Based on this current level of uptake and the absence of any policy incentives, AEMO assumes the uptake of electric vehicles to continue to be small, with a projected 165,734 electric vehicles across the NEM in 2024–25, increasing to 524,775 in 2034–35.

The expected impact of this level of uptake on the 2015 NEFR residential and commercial consumption forecasts is a 0.20% increase in 2024–25 and a 0.54% increase in 2034–35.

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[3] Electric vehicles in this paper are passenger vehicles propelled by one or more electric motors, powered by rechargeable battery packs. It does not include "hybrid" vehicles, or heavy transport.

[4] Federal Chamber of Automotive Industries

Fuel switching

Fuel switching refers to the replacement of gas with electric appliances in existing households and the development of new households which are solely powered by electricity.

The proportion of households which can switch varies across NEM regions, and also involves a behavioural element that AEMO has not considered. Based on initial assumptions, AEMO expects the impact of fuel switching in the residential sector to be low across the NEM during the outlook period.

Using an assessment of the economic viability of switching from gas to electricity appliances, AEMO estimates that, in 2024–25, fuel switching may contribute an additional 815 GWh (0.4%) to forecast operational consumption, increasing to 2,552 GWh (1.2%) in 2034–35.

As the gas market is small relative to the NEM, the impact of fuel switching may be more apparent in this sector. AEMO will continue assessing the impact of fuel switching in the 2015 National Gas Forecasting Report.

Importance of forecasting the impact of emerging technologies

Network forecasting is imperative to maintaining secure, reliable and efficient markets. The information in this paper complements the recently released 2015 NEFR, highlighting a likely scale and impact of emerging technologies.

Stakeholder feedback welcome

AEMO welcomes feedback from this inaugural information paper, and would like to hear your thoughts on this initial data. Please contact Louis Tirpcou at louis.tirpcou@aemo.com.au.

AEMO will be exploring the implications of battery storage and emerging technologies in upcoming South Australian Electricity reports and the upcoming National Transmission Network Development Plan (NTNDP) to be released later this year.

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CHAPTER 1. INTRODUCTION

Modelling and forecasting emerging technologies is challenging, because:

- There are limited existing patterns in the market to draw on.
- Predicting future uptake involves uncertain assumptions about what drives the adoption of emerging technologies, and how important an influence these drivers are on consumer behaviour.
- Large scale penetration can occur over a short period of time, driven by shifts in policy and/or economics. This was demonstrated by the uptake of rooftop photovoltaic (PV) systems in Australia, which increased from 17.8 MW in 2008 to an estimated 4,200 MW by 30 June 2015.

This information paper assesses the potential impact on annual operational consumption and maximum demand in the NEM, in the residential sector, of:

- Two emerging technologies, battery storage and electric vehicles.
- One emerging trend, fuel switching (consumers changing from dual fuel – gas and electricity – to primarily powering households with electricity).

This paper is a first step in forecasting and assessing the potential implications of these emerging technologies and trends. AEMO has initially focused only on the residential sector, as households are expected to be the first adopters. However, fuel switching and storage in particular have the potential to impact operational consumption and maximum demand in the commercial and industrial sectors.

For each emerging technology or trend, this paper covers:

- Defining the technology or trend, and understanding the Australian context.
- Modelling and assumptions.
- Likely uptake and potential impacts on the 20-year 2015 NEFR forecasts (medium scenario) across the NEM and for each region.

Key definitions

AEMO forecasts are reported as:

Annual operational consumption: electricity used by residential, commercial, and large industrial consumers drawn from the electricity grid, including transmission losses.[5] It is measured in gigawatt hours (GWh) and the forecasts are presented on a “sent-out”[6] basis.

Operational maximum (minimum) demand: the highest (lowest) level of electricity drawn from the transmission grid at any one time in a year measured on a daily basis, averaged over a 30 minute period. It is measured in megawatts (MW) and the forecasts are presented “as generated”.[7]

Probability of exceedance (POE): refers to the likelihood that a maximum demand or minimum demand forecast will be met or exceeded. The various probabilities (generally 90%, 50% and 10%) provide a range of alternatives for analysts to determine a realistic range of power system and market outcomes. A 10% POE maximum demand forecast is expected to be exceeded, on average, one year in 10.

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[5] Supplied by scheduled, semi-scheduled and significant non-scheduled generating units. Refer to AEMO’s definitions here.

[6] Measured at the connection point between the generating system and the network.

[7] Measured at the terminals of a generating system.

CHAPTER 2. RESIDENTIAL BATTERY STORAGE

This chapter presents the inputs and methodology AEMO used to develop its first residential battery storage uptake model. It provides a detailed overview of the projected uptake for each NEM region, and the estimated impact of residential battery storage on the 2015 NEFR forecasts of maximum demand for each region, and minimum demand in South Australia.

The results presented in this section are intended to complement the 2015 NEFR medium scenario. Where applicable, the inputs are consistent with those used in the 2015 NEFR and are referenced.

This is the first step for AEMO in developing forecasts for the uptake of storage technologies and the implications on the network. The current modelling is subject to a number of assumptions and limitations to the modelling, outlined in the following sections, and AEMO plans to work with industry and stakeholders to advance its modelling in this space. Table 3 shows the scope of AEMO's battery storage modelling in this paper, for each NEM region. The checks (✓) indicate what has been included, and the crosses (✗) indicate what has not been considered at this stage. The asterisks (✶) are the areas AEMO has not considered in this paper, but intends to explore next.

Table 3 Summary of scope and next steps

	Queensland	New South Wales	South Australia	Victoria	Tasmania
Market sector					
Residential – new installations of rooftop PV and battery storage	✓	✓	✓	✓	✓
Residential – retrofit of battery storage on existing rooftop PV installations	✶	✶	✶	✶	✶
Commercial storage	✗	✗	✗	✗	✗
Tariffs assessed[a]					
Flat	✓	✓	✓	✓	✓
Time-of-use	✓	✓	✗	✓	✓
Capacity	✗	✗	✓	✓	✗
Inclining block	✗	✓	✓	✗	✗
Financial models					
Upfront household purchase, battery optimised to benefit household	✓	✓	✓	✓	✓
Retail aggregated through finance packages	✗	✗	✗	✗	✗
Network aggregated and controlled	✗	✗	✗	✗	✗
Impact on network					
Impact on forecast maximum demand	✓	✓	✓	✓	✓
Impact on forecast minimum demand	✶	✶	✓	✶	✶
Policies					
Government incentive schemes	✗	✗	✗	✗	✗
Technical or regulatory restrictions					
Zero export limit on inverters	✗	✗	✗	✗	✗
Behavioural factors	✗	✗	✗	✗	✗

[a] AEMO is limited to forecasting only the tariffs currently available in each region at the time this paper was produced.

The assumptions and limitations are discussed further in the methodology overview (see Sections 2.2 to 2.5) and are summarised in Section 2.6.

2.1 Introduction

Battery storage, especially in the residential sector, has recently received extensive media attention, particularly with the high-profile launch of Tesla Motors' PowerWall[8], followed by energy storage packages offered by major retailers.

There are a range of estimates in the market currently as to the cost and projected uptake of the technology, but as the number of companies producing competitive and accessible battery storage solutions increases, mainstream adoption of battery storage is likely to occur more quickly.

Similar to the uptake of rooftop PV, which surged after 2009 due to a combination of state and federal government incentives, and, as noted in the 2015 NEFR, is impacting annual operational consumption and maximum and minimum demand, any rapid adoption of battery storage is expected to have an impact on the NEM.

It is widely expected that residential and commercial battery storage will encourage greater self-consumption of rooftop PV, and thereby reduce consumer demand from the grid, but the quantitative impact to the grid cannot yet be assessed.

Given the limited uptake of battery storage to date, AEMO has restricted its assessment to new installations of residential battery storage only, and will consider commercial scale storage in future work.

2.1.1 Battery technologies

For many decades, lead acid batteries dominated the market, and they are still popular, as they are among the cheapest type of battery and have a proven track record of performance.

In recent years, various lithium-ion chemistries have largely replaced lead acid in consumer electronics, due to their superior performance characteristics for certain applications. Lithium-ion batteries typically have a higher energy density, greater depth of discharge, and lower loss of charge when not in use, than lead acid batteries. These qualities also make them the preferred technology for electric vehicles.

Although lead acid batteries are still used for residential storage applications, many multinational battery manufacturers (including Panasonic, Samsung, LG, and Tesla Motors) use lithium-ion technology in their residential storage systems. It is no coincidence that these manufacturers also produce batteries for electric vehicles, and the growing manufacturing capacity for these batteries is driving significant cost reductions.

For these reasons, this paper focuses on the most cost-effective lithium-ion residential storage system that has been announced in the market to date. Although other battery chemistries may become more successful over the 20-year horizon of this paper, AEMO has assumed that lithium-ion batteries will dominate this industry for the foreseeable future.

2.1.2 The Australian market

Electricity storage solutions have been implemented in remote and off-grid regions in Australia for some time, as more favourable economics see these systems displacing expensive diesel generation.

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[8] http://www.teslamotors.com/en_AU/presskit

For grid-connected residential systems, however, the economics have been largely prohibitive. Up to 31 December 2014, approximately 500 systems have been installed across Australia, according to the Clean Energy Council (CEC)[9], with very little known data on size and performance.

In its rooftop PV modelling, AEMO is able to forecast future installations based on the relationship between historical installations and the consumer payback rate. This is facilitated by the extensive historical data maintained by the Clean Energy Regulator (CER), which enables analysis of household purchasing behaviour. There is currently no similar mechanism for tracking residential battery storage installations.

Given the lack of historical battery storage data on which to base a similar uptake model, and the absence of similar policy incentive schemes, AEMO has had to impose a number of assumptions in modelling what will drive the residential battery storage market in Australia.

In Australia, factors that could drive the uptake of storage include:

- High retail electricity prices (average prices rose 70% in real terms from 2007 to 2013).[10]
- Declining solar feed-in tariffs (FiT)[11], which reduce the export value of excess solar generation.
- A decline in battery storage costs, which is expected as the market matures.
- Excellent solar resources.
- Availability of innovative electricity tariff structures.
- A desire by some households to be more independent from the grid.

At present, there are no existing or announced policies in Australia to incentivise the uptake of residential battery storage.

There are two clear market segments for the uptake of residential battery storage:

- New installations, where households install both rooftop PV and a battery system.
- Retrofits, where households that already have rooftop PV decide to also install a battery system.

By the end of 2014–15, 3.7 gigawatts (GW) of residential PV capacity is expected to be installed across the NEM. Some of these households are on premium feed-in tariffs, which pay up to about 66 cents per kilowatt hour (c/kWh) for excess rooftop PV generation exported to the grid. Many of these state-based feed-in tariffs are not contracted to expire until after 2025–26, which impacts the economics of retrofitting battery storage before then. After the end of the feed-in tariffs, the economics of retrofitting will be more favourable, but not necessarily sufficient to incentivise large scale uptake.

At this stage, AEMO has not considered the retrofit market, but is planning to extend its modelling to capture the economics of uptake in this segment, particularly in New South Wales where feed-in tariffs are due to expire in December 2016, and for current installations that are not on premium feed-in tariffs.

All installations referred to in this report correspond to new installations of both rooftop PV and battery storage, referred to as Integrated PV and Storage Systems (IPSS).

2.2 Overview of methodology

Similar to AEMO’s rooftop PV forecasts, the uptake of IPSS has been estimated via an economic model, based on estimated payback periods for the residential household. Although the Australian storage market is in its infancy, there are many business models emerging to support the uptake of

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[9] https://www.cleanenergycouncil.org.au/dam/cec/policy-and-advocacy/reports/2015/150429-Australia-storage-industry-roadmap-FINAL/150429%20Australia%20energy%20storage%20roadmap%20FINAL.pdf

[10] Productivity Commission. Electricity Network Regulatory Framework. 2013. Available: http://www.pc.gov.au/inquiries/completed/electricity/report. Viewed: 15 June 2015

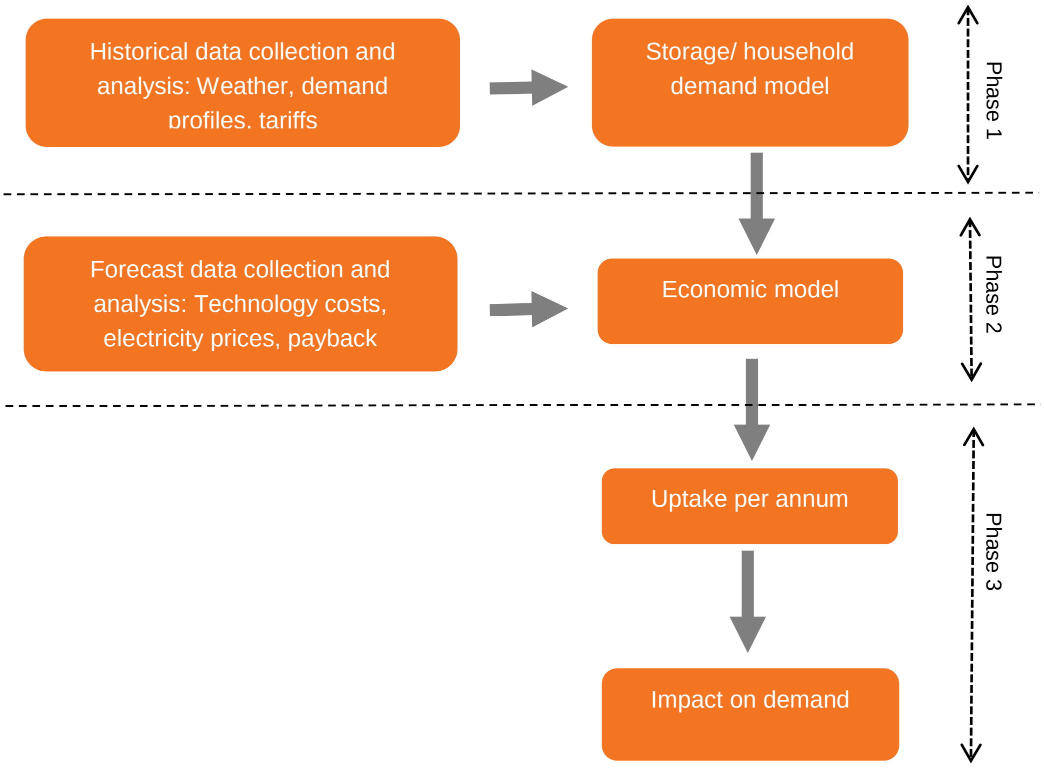
[11] The feed-in tariff (FiT) is the amount the household is paid in cents per kilowatt hour (c/kWh) for excess PV generation exported to the grid.

battery storage. Some are specific finance packages, while others explore the stackable benefits to the local network of aggregated storage systems.

For the first stage of its modelling in this space, AEMO has adopted a purely financial approach which analyses the value to a household of purchasing an IPSS upfront. These forecasts do not explicitly account for individual consumer behaviour or potential advantages, but model uptake based on optimising the economic benefit to individual households. AEMO intends to consider and model sensitivities around different finance structures and business models in 2015–16.

The battery storage uptake model was separated into three phases, as shown in Figure 1 and described below. Each NEM region has been modelled separately.

Figure 1 Overview of methodology



- Phase 1 evaluated the technology, weather and electricity prices to determine the management of the battery system for the local demand profile. Annual savings could then be calculated given the assumed tariff structure and the imports and exports between the grid and household.
- Phase 2 calculated the payback of the system for each year of the forecast period.
- Phase 3 estimated IPSS uptake and imposed relevant saturation rates. This uptake, and the demand profile determined in Phase 1, were used to estimate the impact on maximum (or minimum) demand for the region.

As AEMO has modelled the uptake of residential battery storage as a supplementary to the 2015 NEFR, an adjustment was made to the rooftop PV forecasts in the NEFR to account for the estimated uptake of IPSS. The 2015 NEFR forecasts were revised downwards to determine the capacity of standalone rooftop PV.

2.3 Phase 1 – forecasting local demand profile and potential savings

This section describes the methodology AEMO used to develop the local demand profile and savings once an IPSS is installed. These were then used as inputs into the payback model.

To develop the predicted savings for each NEM region and household size, AEMO:

- Collected historical weather and household demand data by region, as well as existing tariff structures and technical specifications of available technology.
- Derived a model to determine rooftop PV generation with available hourly weather data.
- Developed a mathematical model that optimised the operation of the battery system to procure electricity from both the IPSS and the grid at the least cost to the individual household.
- Applied the grid imports and exports produced by the model against applicable tariffs to determine the annual savings of the IPSS to the equivalent base case (with no rooftop PV and battery).

Key components of each step are described in more detail in the sections below.

2.3.1 Data inputs and assumptions

At this initial stage, only new installations have been considered (see Section 2.1.2). It was also assumed that all systems are grid-connected and can freely import and export from the national electricity grid.

Actual data inputs and a number of assumptions were used in order to estimate the impact of an IPSS on the household's daily load profile.

Weather and solar generation model

A solar generation model was used to calculate the amount of electricity that a rooftop PV system can generate under certain weather parameters. The weather input data comprised satellite-estimated three-hourly (interpolated to hourly) measurements from the European Centre for Medium-Range Weather Forecasts (ECMWF). The data was selected for regions across Sydney, Melbourne, Adelaide, Brisbane, and Hobart, for the 2014 calendar year.[12]

The solar inputs included hourly global irradiance (direct and diffuse) and zenith angle. These measurements were used in conjunction with geometric data on the position of the sun to calculate the available energy from sunshine for each given hour and location. Parameters on the size, orientation and tilt angle of the rooftop PV panels were then used to calculate the expected solar generation of the system in kilowatts for each hour throughout the year.

Household demand profiles

To assess typical household demand, a random sample of available smart meter profiles from each NEM region was obtained for the full 2014 calendar year on a half-hourly resolution (aggregated up to the hour). Incomplete profiles, and customers on solar tariffs, were removed from the sample to make sure the smart meter readings were a true indication of the baseline household consumption.

For New South Wales (including the ACT), South Australia and Victoria, the distribution of the remaining profiles was then segmented, based on their average daily electricity consumption:

- Large consumers – households with consumption above the 75th percentile.
- Medium consumers – households with consumption between the 25th and 75th percentiles.

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[12] The capital cities were chosen to match big population centres as a first approximation. For some regions, particularly Queensland, this not necessarily ideal. See Section 2.6 for more details.

- Small consumers – households with consumption below the 25th percentile.

Queensland and Tasmania were treated separately, due to the limited smart meter data available in these regions:

- In Queensland, only demand profiles for large consumers were obtained from smart meters. Small and medium consumers were assumed to follow the same profile, but their total consumption was scaled down accordingly.
- There is very limited smart meter data in Tasmania. Hence, the net system load profile was used to represent the demand profiles for all consumers. Total consumption was assumed to vary with the type of consumers.

The household data assumptions are summarised in Table 4 and are expressed in kilowatt hours (kWh).

Table 4 Household data assumptions

	Number of smart meters sampled	Average annual consumption (kWh)		
		High demand	Medium demand	Low demand
Queensland	300	10,400	4,400	1,700
New South Wales	1000	11,400	4,900	1,900
South Australia	1000	9,700	4,900	2,300
Victoria	1000	8,200	3,800	1,700
Tasmania	N/A	10,000	4,500	1,900

The segmentation of each region into the respective demand categories was based on absolute consumption, and so differs across regions. This should be taken into consideration when making comparisons between the regions. AEMO intends to undertake a sensitivity in future work to normalise all demand profiles.

Technical specifications

There is an extensive range of both PV and battery technologies available in the market. AEMO has considered the cost and technical specifications of the PV and the battery systems separately, as there are few combined systems in the market, and selected an appropriate IPSS for three housing sizes (large, medium and small) by consumption.

For rooftop PV, AEMO obtained pricing and technical specifications, from average aggregated CER data, of the fully-installed, out of pocket expense for each system. Projected costs were dependent on forecast exchange rates and system cost reductions. Also, electricity generated from a rooftop PV system was calibrated using the monthly energy distribution profiles used in the 2015 NEFR. For more detail on rooftop PV pricing and output, see the 2015 NEFR Forecasting Methodology Information Paper. Specifications of the PV systems used in AEMO's modelling are summarised in Table 5.

Table 5 Rooftop PV system specifications

Demand Category	Small	Medium	Large
Capacity (kW)	1.5	3.0	4.0

For batteries, consumers can purchase a fully-integrated battery storage system that incorporates batteries, inverter, controller, and a battery management system, or buy these components separately.

Although it may be cheaper to “build the system”, AEMO has assumed that most consumers will select an off-the-shelf fully integrated system.

AEMO has selected the most cost-effective battery storage system currently expected to become available in the market in the foreseeable future, for the large consumer. From this, AEMO determined the systems for small and medium consumers, assuming a similar dollar per watt hour ($/Wh) ratio. In the absence of enough relevant installation data, the total installed cost is assumed to be the same for all regions. Table 6 summarises the battery specifications.

Table 6 Battery system specifications

Demand category	Small	Medium	Large
Capacity (kWh)	3	5	7
Max power (kW)	1.5	2.5	3.3
Round-trip DC efficiency (%)	92	92	92
Depth of discharge (%)	90	90	90
Inverter max power (kW)	3	5	7
Inverter efficiency (%)	97	97	97
Total cost ($AUD)	3,699	6,165	8,631

AEMO has assumed that the battery storage system is a sealed unit which requires minimal maintenance, so has applied a relatively low maintenance cost of $300 every five years. The lifetime of a battery system was assumed to be 15 years, although this is expected to continue to improve in the future as the technology matures.

Tariff structures

The economic viability of IPSS is heavily dependent on electricity prices, and specifically the tariff structure the household has contracted. This is because the final cost of grid-consumed electricity, and therefore the potential savings, is the product of imports from the grid and the retail tariff. Retailer offers differ in the level of fixed daily connection fee and the variable energy component.

It is difficult to predict what tariff structures will be made available in the future, and how, or if, they will complement the uptake of IPSS. AEMO has only considered the different types of tariffs currently available in the retail market in each NEM region as at May 2015.

These are the tariff structures considered:

- Flat tariffs, or single rate tariffs, are the most common type, with the customer charged the same amount for electricity consumption (in kWh) no matter what time of day it is consumed.
- Inclining block tariffs consist of a series of tariff blocks that charge a different rate based on the amount of electricity consumed (in kWh). The first block is charged at one rate for electricity usage up to a certain kWh threshold. Once this threshold is reached, the second block is applicable at a higher charge. Any electricity used above the second block level is then charged at the higher third block level, and so on.
- Time of use (TOU) tariffs charge different rates depending on what days and/or time of the day electricity is consumed (in kWh). There are generally up to three time periods, peak, off-peak and shoulder, with the peak charge the highest, and off-peak the lowest.
- Capacity tariffs, also referred to as demand tariffs, are based on electricity demand (in kW) rather than on consumption (kWh), where demand is a measure of the maximum power used during a time interval. The tariff is based on what proportion of the network’s capacity the customer uses, with higher tariffs applying if demand exceeds certain thresholds.

The advantage of battery systems is the ability to store power during off-peak times, which can then be used during peak times, reducing the cost of electricity use. Flat tariffs do not enable households to capitalise on this, and therefore a time-of-use tariff or a capacity tariff generally provide greater savings and give the household the best economic benefit.

Because AEMO has considered new installations only, it assumed the majority of customers would be on a flat tariff and, after investing in an IPSS, would then adopt the most cost-effective tariff available for their region for the lifetime of the system.

2.3.2 Modelling household demand and battery management

AEMO developed a mixed integer linear program[13] to determine the operation of the IPSS for the typical household demand profile. The model optimised the best utilisation of the IPSS to minimise the overall cost to the consumer, based on their daily load profile, rooftop PV generation, and tariff structure.

The model included a number of limitations for the battery:

- Electricity stored in the battery could only be exported to the household, not to the grid. That is, there was no arbitrage functionality considered in the IPSS. The only exports to the grid from the household were from excess rooftop PV generation.
- The battery could be charged from either rooftop PV generation or electricity drawn from the grid.
- Battery charging and discharging could not occur at the same time as any imports or exports to or from the grid.
- The battery system would be constrained by the size, performance and efficiencies in the manufacturer specifications.

See Appendix A for a summary of the linear program equations applied.

It is important to note that the optimisation model operated on the basis that the battery would have perfect monthly foresight of weather and household demand. Current systems do not yet have software sophisticated enough to provide perfect foresight, and a penalty for this was considered in the economic model (see Section 2.4).

Table 7 shows three scenarios modelled for each demand profile – base case, with rooftop PV, and with an IPSS installed.

Table 7 Modelling scenarios

Scenario	Description
Base case	Ongoing annual cost of electricity without rooftop PV or battery system.
Rooftop PV	Total annual cost of electricity with a rooftop PV system installed.
IPSS	Total annual cost of electricity with both rooftop PV and battery system installed.

For the scenarios, the annual electricity costs were determined by multiplying the tariff by the amount of electricity produced or supplied to the grid only. Electricity supplied to the household via the battery system was not considered to have an annual operating cost (maintenance costs were treated as a periodic capital cost):

$$Debit = Grid\ Imports\ \times Electricity\ Tariff + Fixed\ charges$$

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[13] This is an optimisation program where the variables to be solved are constrained to integers.

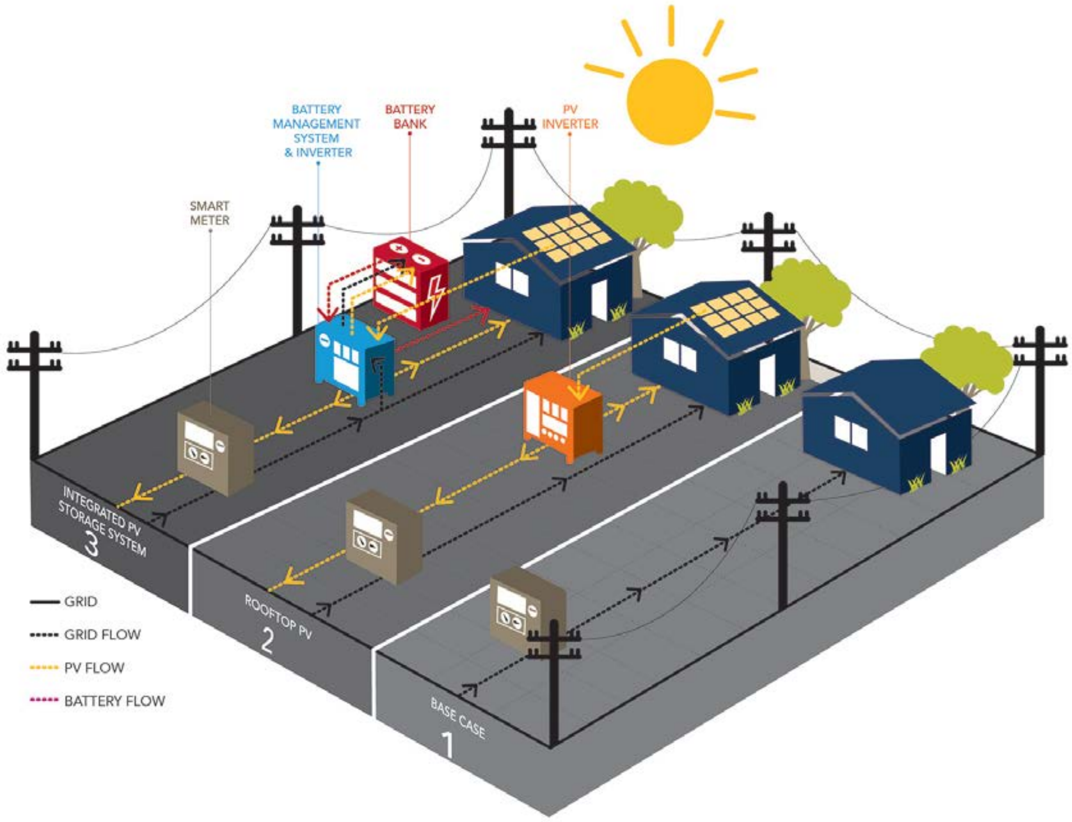
$$Credit = \ Grid\ Exports\ \times Feed\ in\ Tariff$$

The feed-in tariffs vary in each state, and ranged in the scenarios from 5.5 to 8.0 c/kWh (see Appendix B).

The annual savings were defined to be the difference in annual electricity costs of the rooftop PV and IPSS scenario relative to the base case.

Figure 2 represents the IPSS model and the three cases that have been assessed.

Figure 2 Residential IPSS system flow diagram



For the IPSS, in each hour, the difference between household demand, rooftop PV generation and the battery represents one of the following electricity states:

- Charge – electricity drawn from the grid or rooftop PV to charge the battery storage system.
- Discharge – electricity drawn from the battery to meet household demand in excess of solar generation.
- Export – further excess solar generation fed into the electricity grid.
- Import – electricity drawn from grid to meet further excess household demand or to charge the battery.

As only new installations are considered in this paper, Figure 2 represents an integrated system with a single inverter. This is the more efficient scenario, whereby the battery can be charged directly from the rooftop PV, removing any potential loss in efficiency.

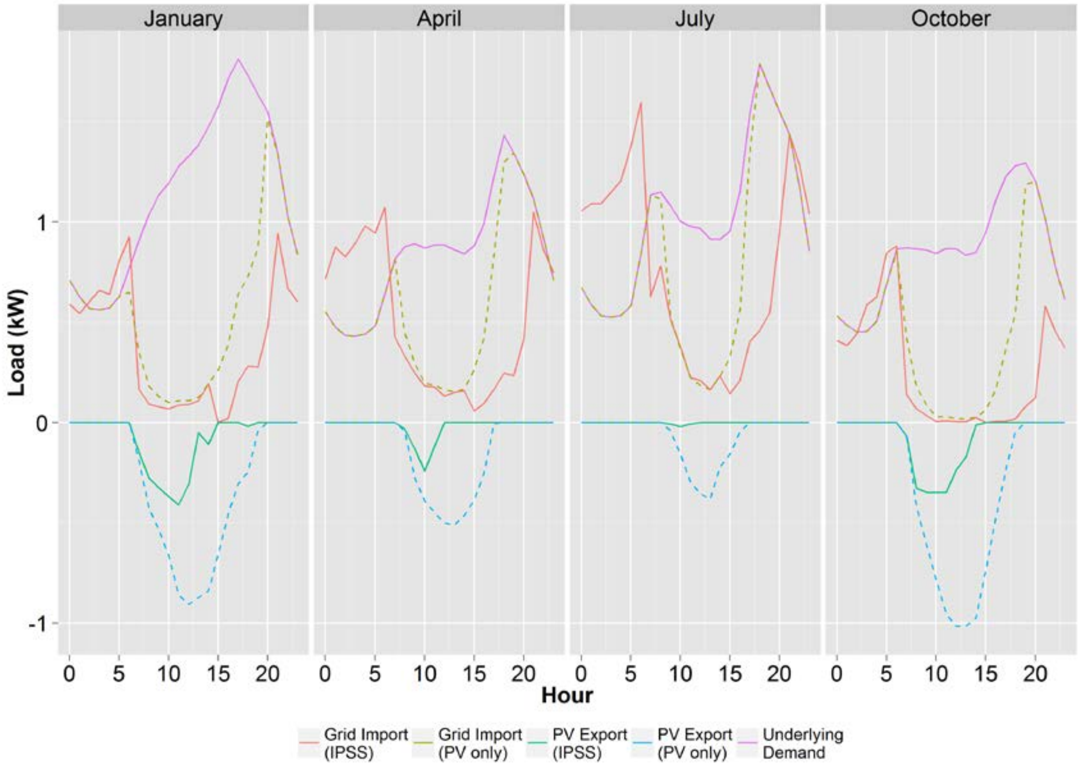
As previously noted, battery systems can be retrofitted to existing rooftop PV systems. This, however, would mean that solar generated electricity fed into a battery would need to convert from DC (PV) to AC and back to DC (battery), so either the PV inverter would need to be upgraded or a second inverter installed.

2.3.3 The impact of IPSS on household demand and electricity costs

Average household daily profile

As an example, Figure 3 below shows the average daily profile of a diversified large consumer household in Victoria for the months of January, April, July and October, and the impact of rooftop PV and IPSS on that profile. They are presented at an hourly resolution, and are averaged over the month. The average daily profiles for the other NEM regions are in Appendix C.

Figure 3 Average daily profile of a Victorian large consuming household



The purple line shows the household’s underlying demand across the day. The evening peak is evident, and is highest in January and July due to household cooling/heating loads respectively. In the base case, electricity to meet this demand is imported entirely from the grid.

The gold dashed line shows how the profile of grid imports changes if the household has a rooftop PV system. In summer, the solar generation from the rooftop PV system delays the time of the peak slightly, as well as reducing it to an extent. In the milder months, rooftop PV alone does not reduce peak demand. The blue dashed line indicates the solar generation in excess of household demand that gets exported to the grid from a rooftop PV system.

If an IPSS is installed, the household daily demand from the grid is reduced substantially, and the time and size of peak demand changes depending on the season. The red line shows the net demand drawn from the electricity grid, and the green line represents the excess solar generation that is exported to the grid. In the warmer months, the IPSS is able to meet much of the household demand and lowers the size of the peak substantially. Rooftop PV generation is sufficient to both meet the household demand and charge the battery, with a small amount of excess generation still exported to the grid.

In the colder months, there is little export of rooftop PV generation to the grid, with most used to meet household demand and charge the battery. Overall, there is a sizable reduction in the volume of rooftop PV generation exported to the grid with an IPSS, compared with the rooftop PV only scenario.

The increase in consumption drawn from the grid in off-peak times (late evening/early morning) occurs because the battery is charging from the grid. In the colder months, grid imports during these times are greater, as there is less PV generation available to charge the battery.

This indicates how IPSS can both:

- Delay and reduce evening household demand peaks.
- Reduce the level of rooftop PV generation that is exported to the grid.

It is also important to note that batteries charging from the grid during winter mornings could create an unexpected morning peak, if many systems in a concentrated residential area operate using the same charging parameters or price signals. Battery management software could alleviate this issue by extended charging at a lower rate during these early morning hours.[14]

Annual electricity costs

The three scenarios (see Table 7) were modelled for each NEM region, and each available tariff structure was applied for the 2014 calendar year. Within each category of tariffs, the ones that resulted in the least annual electricity costs were considered (and these are listed in Appendix B). Figure 4 summarises the annual electricity costs for each consumer type across the regions for each scenario.

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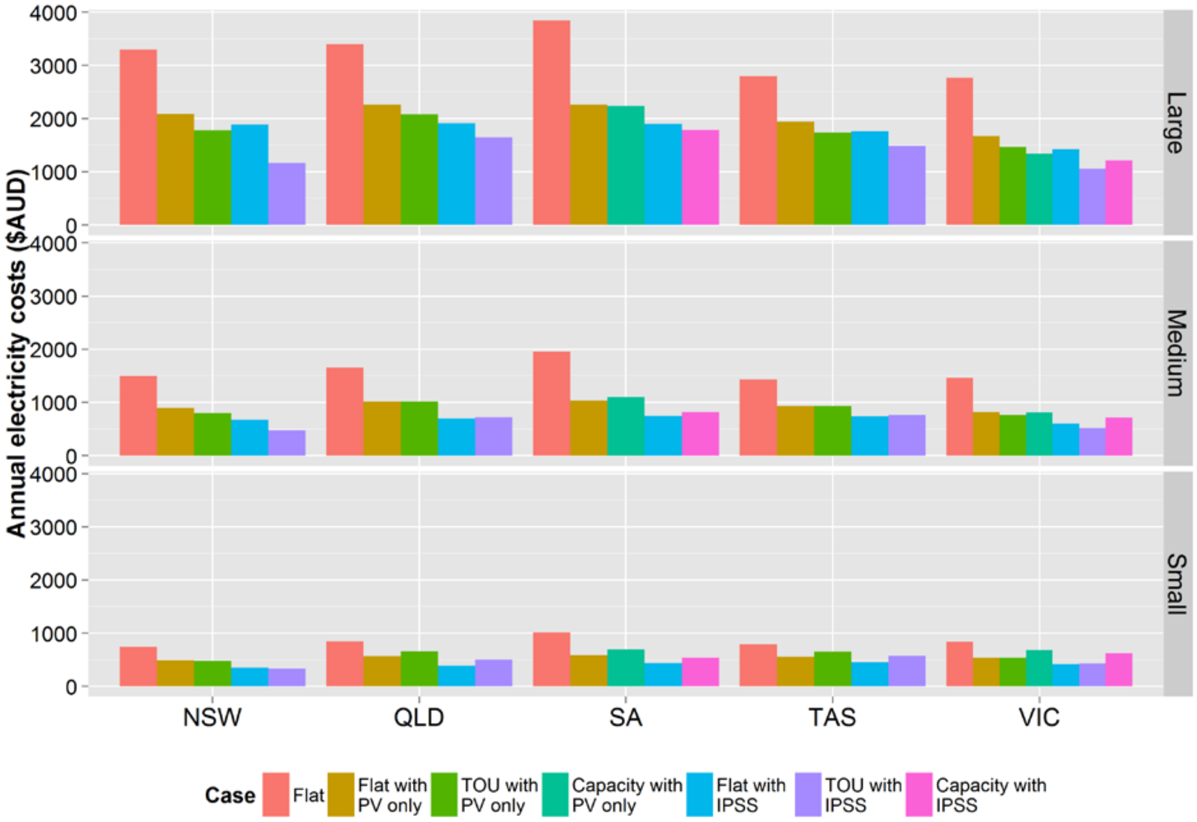
[14] This again highlights the importance of data collection so the potential emergence of these issues can be monitored.

Figure 4 Annual electricity costs for each type of consumer by tariff



The regional differences arise from the different household demand profiles, the specifics of tariff pricings and time of applicability.

It can be seen in this model that:

- The base case (flat tariff with no rooftop PV or battery system) is the most expensive annual cost across all the regions and customer types. As expected, large consumers achieve the greatest savings (which are the difference between the flat tariff and the other tariffs) through installing either PV or IPSS.
- For large consumers, IPSS combined with either a TOU or capacity tariff provide the greatest potential savings compared to the base case in all regions.
- For medium consumers, the benefits of some scenarios over others are reduced compared to large consumers and this is more obvious with the small consumers. Much of this reduction comes from the reduced percentage of variable charge relative to the fixed component.
- Overall, not all capacity tariffs are cheaper than TOU depending on region. For small consumers, remaining on the flat tariff after installation of IPSS is more economical than shifting tariffs, except in New South Wales.
- The incremental annual savings from installing IPSS, over installing rooftop PV alone, are lower for small consumers, so it can be expected that these households would be more inclined to install rooftop PV alone rather than an IPSS.

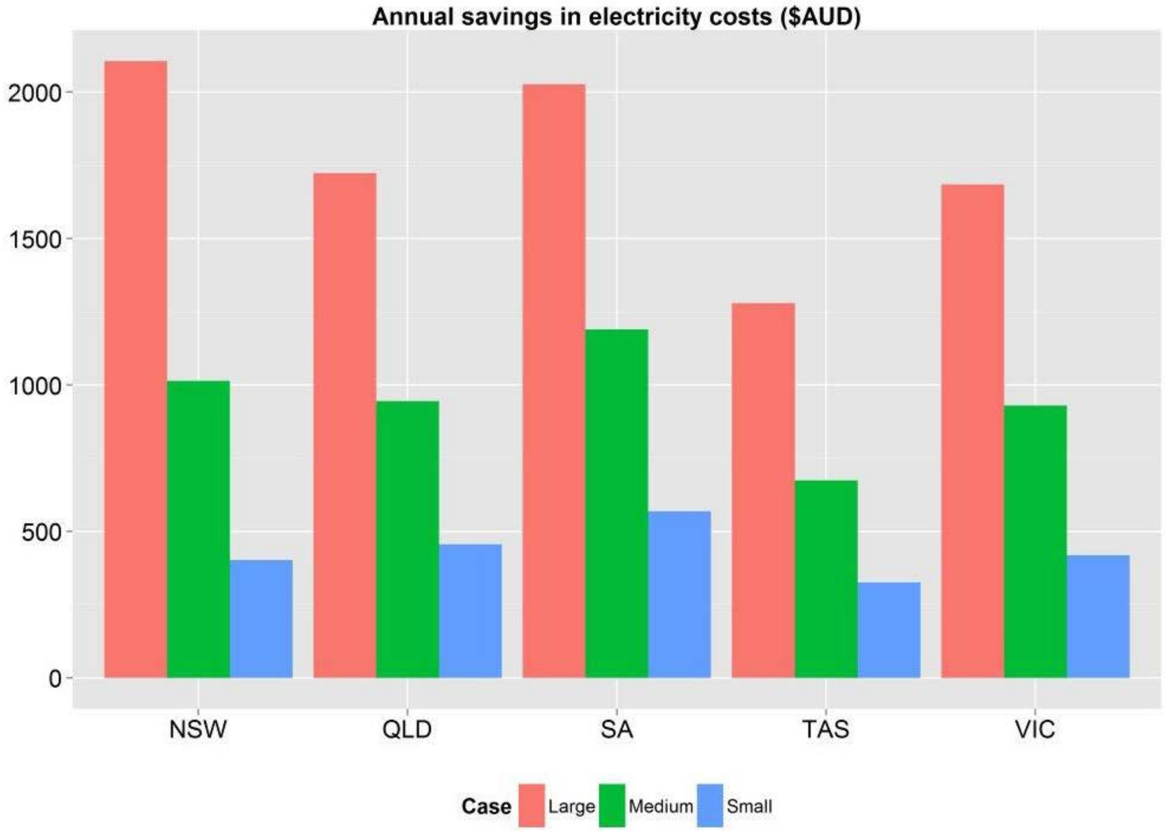
From Figure 4 it is clear that, for consumers who decide to invest in IPSS, there is a particular tariff that will provide them with the greatest savings in annual electricity costs, and it is assumed that each consumer adopts the available tariff that is most viable for them. These are summarised in Table 8.

Table 8 Tariff structure selected for each consumption household type

Household consumption type	Queensland	New South Wales	South Australia	Victoria	Tasmania
Large	TOU	TOU	Capacity	TOU	TOU
Medium	Flat	TOU	Flat	TOU	Flat
Small	Flat	TOU	Flat	Flat	Flat

Figure 5 shows the annual savings in electricity costs, compared to the base case, for the selected tariffs shown in Table 8 for each customer type and region.

Figure 5 Annual electricity savings by consumer



The differences in savings between the regions depend on a combination of the tariffs available, weather, and daily demand profiles, all of which vary broadly.

The annual savings and daily household demand profile for each customer type and NEM region were then fed into the economic model to determine the payback period for installing an IPSS over the 20-year forecast horizon.

2.4 Calculating the payback for IPSS

This section details the model AEMO used to determine the payback over time on which uptake forecasts are based. The model forecast the number of years required to recoup the initial IPSS capital cost, assuming also a periodical maintenance cost. The payback calculation was similar to that used for rooftop PV, however, AEMO assumed a discount rate as outlined below.

2.4.1 Data inputs and assumptions

Economic variables

At this initial stage, it was assumed that consumers invested the capital cost upfront coupled to their mortgage, rather than adopting a third-party finance arrangement. AEMO has assumed a discount factor of 5%, which is closely related to the mortgage rate, to reflect the opportunity cost of reducing their liability.

AEMO has used the electricity price forecasts developed for the 2015 NEFR by Frontier Economics.[15] Estimates of future annual savings in electricity costs were indexed to these forecasts.

System costs

AEMO used the forecast residential rooftop PV costs in the 2015 NEFR as an input for the IPSS payback model.

This model takes into account a number of assumptions on subsidies received through the Small-scale Renewable Energy Scheme (SRES), namely the receipt of Small-scale Technology Certificates (STC). The system costs account for the STC rebate, with a 15-year deeming period ending in 2030. For further detail on PV costs and assumptions, see the 2015 Forecasting Methodology Information Paper.

For the battery system component, AEMO has determined its own technology cost curve based on available information. It is assumed that the Tesla Powerwall system would be the indicative starting cost of the system, as it is currently the most cost-effective technology that has been announced to the market.[16] The complete system cost, including installation, was based on the recent announcement by SolarCity[17] in the US, converted to Australian dollars and including GST.

This value is the system cost for 2015–16, and the system cost curve assumes:

- An initial decline in costs of 8% in the first year.
- An annual decline of 12% thereafter.

These parameters were based on expected cost reductions in the components, as discussed below.

Figure 6 displays the projected cost curve across the 20-year outlook period, and provides a comparison with the cost curve from Bloomberg New Energy Finance (BNEF).[18]

The BNEF projections were developed before Tesla's announcement, and so do not include the lower cost compared to other products on the market. This is clear in the significant difference ($0.90/Wh) in the initial technology costs.

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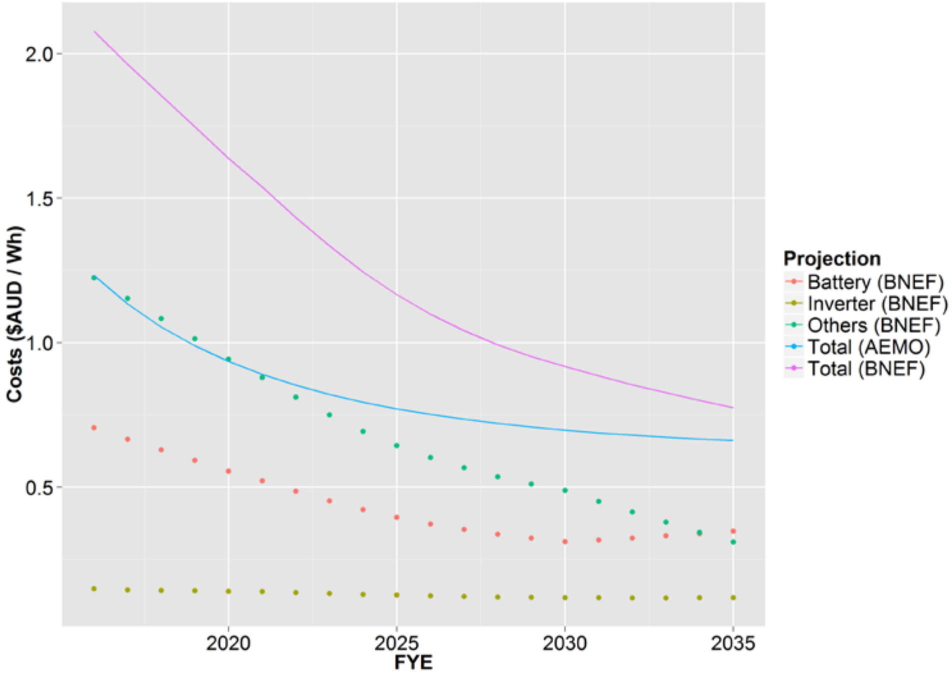
[15] Frontier Economics, Electricity Market Forecasts: 2015, April 2015.

[16] This is true as at 31 May 2015.

[17] http://www.bloomberg.com/news/articles/2015-05-01/solarcity-taking-orders-for-tesla-batteries-starting-at-5-000

[18] Bloomberg New Energy Finance, Now or Never?: The Economics of Residential PV and Storage in Australia, 10 April 2015. Bloomberg's projections have been converted to Australian dollars.

Figure 6 **Battery system forecast technology costs by component**



Given the differences in the entry price point of Tesla compared to BNEF's cost curve, it was assumed that Tesla's price already factors in cost savings achieved through mass production. Based on this, it is difficult to determine how much greater the initial cost reduction in technology costs could be. AEMO has adopted a conservative view, expecting the cost curve to decline at a much slower rate than initially predicted by BNEF. AEMO's projected cost curve was based upon the component costs illustrated above, with manufacturing and technology costs continuing to decrease over time, but at this slower rate.

As Tesla's battery storage product represents the lowest system cost currently announced, this has been used as the base for the economic modelling.

Based on discussions with companies intending to distribute the product, it was assumed that it will be available in the Australian market from November to December 2015.

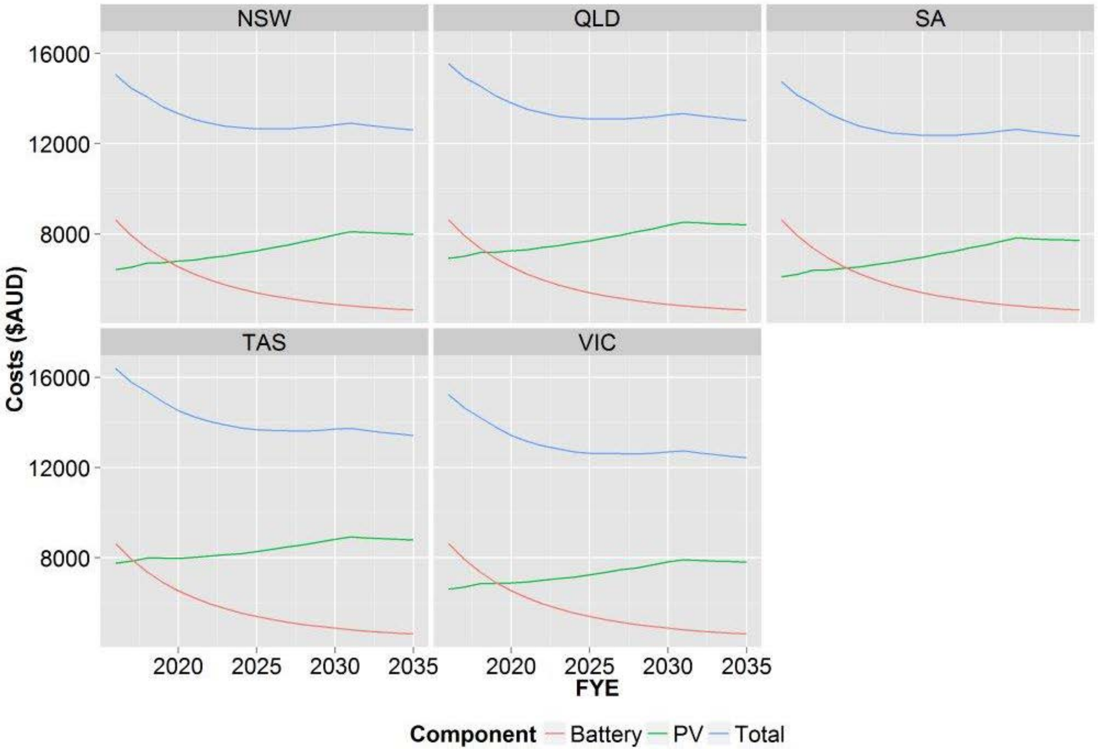
The combined system cost was determined based on the above assumptions and those in Tables 5 and 6, and also assuming only a single inverter is installed.

Figure 7 shows the total forecast system cost for an IPSS with a 7 kWh battery and 4 kW rooftop PV system.

The rooftop PV cost component represents the total out-of-pocket expense to the customer. This is forecast to increase slightly in the short and medium term, because the reduction in the STC subsidy is expected to outpace the fall in gross system costs. Rooftop PV costs then resume a slow decline from 2030–31, at which point the STC subsidy is assumed to end.

From about 2026–27, the increase in out-of-pocket PV expenses outpaces the decline in battery costs, resulting in a small uplift in combined system costs until 2030–31.

Figure 7 IPSS projected costs

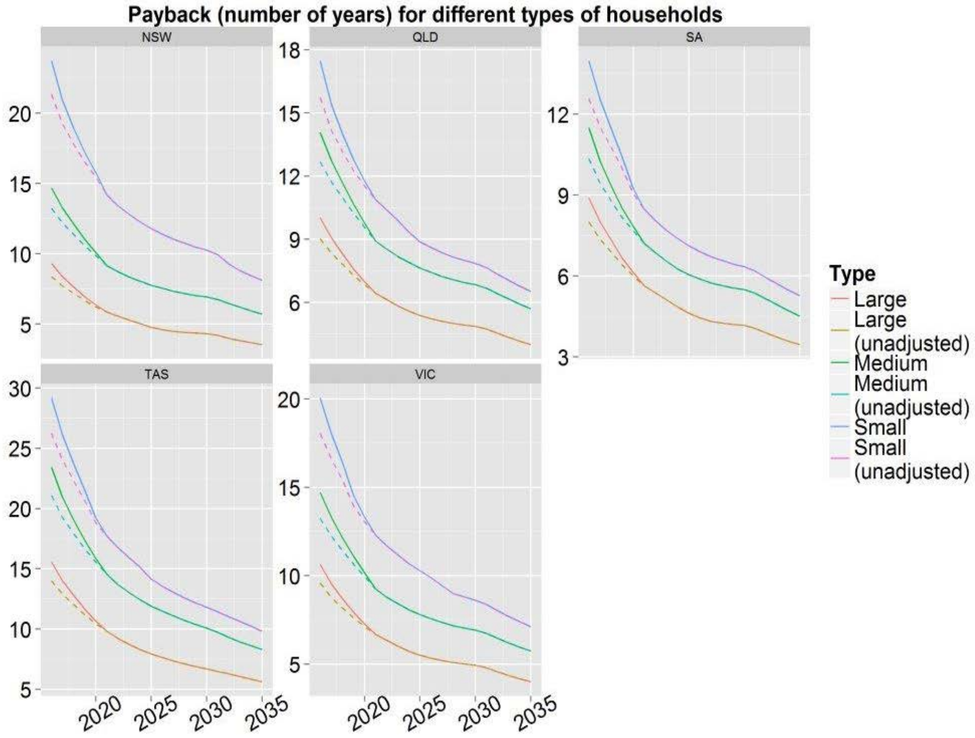


2.4.2 Payback results

Figure 8 shows the estimated payback for IPSS for all NEM regions and customer types.

The dashed lines indicate the payback if it is assumed the battery management system has perfect foresight, meaning that it has knowledge of the next month's weather and PV generation. Because system software does not yet have this capability, AEMO has applied a penalty over five years, to account for software development in the management systems to increasingly enable the system to have as close to perfect foresight as possible. The penalty was initially set at 10% and was reduced by 2% per annum for five years. As Figure 8 shows, this increases the payback period in the first five years, and is expected to dampen uptake.

Figure 8 Payback for each customer type by region



As expected, the payback period is much shorter for large consumers, compared to small and medium consumers. The differences are attributable to the different demand profiles and tariff structures which are less favourable for small consumers wanting to install IPSS (see Figure 4). Small consumers pay a larger proportion of their annual electricity bill in fixed charges compared to large consumers, which reduces the annual savings that an IPSS could provide.

Table 9 shows that this significantly shorter payback period for large consumers applies across all NEM regions.

It also shows that South Australia is projected to have the fastest payback of all the NEM regions, due to its high solar resource and relatively more expensive electricity prices. When comparing payback between regions, it is important to remember that the demand categories represent absolute values of consumption, and so are defined differently for each region.

Table 9 2015–16 estimated payback periods for IPSS

	IPSS Payback (years)			Rooftop PV payback (years)
	Small	Medium	Large	4 kW system
Queensland	18	14	10	6.9
New South Wales	24	15	9	8.1
South Australia	14	11.5	9	6.1
Victoria	20	15	11	7.0
Tasmania	29	23	16	10.2

2.4.3 Comparison to other payback models

In the weeks following Tesla's announcement of its residential battery, a variety of reports were published estimating likely payback periods for a fully installed 7 kWh Tesla Powerwall in Australia. See Table 10 for examples.

When comparing different analytical reports, it is important to consider what differences in assumptions or methodology led to different conclusions. The primary difference in these studies appears to be the assumed cost of a fully installed Tesla Powerwall in Australia, which remains uncertain because product pricing has only been announced for the Unites States.

Another distinction is that some analysts, like SunWiz, sought to calculate the annual savings that an IPSS can provide to a household by building a cost optimisation model on an hourly resolution over a full year. Other reports have used summary calculations that assume the storage system continually operates to its nameplate capacity.

AEMO's more detailed approach, using actual demand data, enables a more comprehensive analysis of how an IPSS is likely to be used by consumers. Models that use more aggregated inputs in calculations are likely to deliver less reliable conclusions.

This is particularly true when analysing storage, due to the variability of inputs such as household demand, weather, electricity tariffs, and technology costs.

Table 10 Comparison of other studies

Assumptions	UBS[a]	Morgan Stanley[b]	SunWiz[c]
NSW payback - years	6	12 (SA-7.7, QLD-8.6)	9.8
Installed AUD cost of Tesla 7kWh + inverter	5175	4179	8901
Paired with solar system	unclear	3 kW	3 kW
Daily energy supplied kWh	7	7	7
Cycles	4000	3650	3650
Efficiency	89%	92%	92%
Electricity prices	Peak - 51c, FIT - 6c	Unclear	Peak: 51c, shoulder: 19.8, off-peak: 11.1

[a] http://reneweconomy.com.au/2015/ubs-tesla-powerwall-can-deliver-6-year-payback-in-australia-63386
[b] http://www.businessspectator.com.au/article/2015/5/20/energy-markets/morgan-stanley-downgrades-origin-and-agl-due-tesla-powerwall
[c] http://www.sunwiz.com.au/warwick/Solar2015-WarwickJohnston-BatteryStorageDesignforGridConnectedSystems.pdf

Using comparable models, AEMO's estimated payback for a large consumer in New South Wales (9.3 years) is similar to that reported by SunWiz (9.8 years).

2.5 Forecasting battery storage uptake

AEMO used the payback periods, determined using the assumptions and model above, to forecast IPSS uptake. The following sections provide an overview of the approach, then present:

- The forecast uptake for each NEM region.
- The projected impact on the 2015 NEFR maximum demand forecasts.
- The projected impact on the 2015 NEFR operational minimum demand forecast for South Australia.

2.5.1 Methodology and assumptions

As mentioned earlier, there is little information available about current installations, or at what price signal households will decide to invest in IPSS.

In forecasting the uptake of rooftop PV, AEMO is able to use historical installation data provided by the CER. There is no such database for battery storage systems, and even if there were, the limited number of installations to date would make it difficult to demonstrate a consistent pattern of consumer behaviour.

The uptake of rooftop PV provides the closest indicator of potential storage uptake behaviour. AEMO has assumed that a similar historical relationship between payback and the number of installations is valid, and applied this forwards to project future uptake. For further detail on how this relationship is determined for rooftop PV, refer to the 2015 Forecasting Methodology Information Paper.

Additionally, the 2014 (calendar year) monthly uptake rate of rooftop PV was assumed to be the long-term average growth rate, as it represents uptake in the absence of past incentives additional to STCs, such as premium feed-in tariffs offered by state governments. This was applied as an upper threshold on the long-term average growth of IPSS.

There is a linear relationship between payback and the number of rooftop PV installations. While this is valid for mature technologies, the uptake of emerging technologies follows a more exponential curve, with few early adopters in the initial years. For this reason, the payback/installation relationship was modified slightly to account for the immaturity of IPSS relative to rooftop PV. Specifically, a penalty factor was applied to the uptake of IPSS, in the case where its estimated payback period is greater than what was observed in historical PV installations. A linear relationship is still assumed, where the IPSS payback becomes similar to the historical PV payback.

AEMO also applied a further reduction of 50% to the forecast uptake for 2015–16, based on an assumption around when the technology is first introduced into the market. After this point it will become available to the larger population and uptake will increase.

It is also assumed that the potential market for IPSS is made up evenly by large, medium and small consumers, although differences in the payback periods will drive different uptake rates for each category of consumers.

Once uptake was estimated, a saturation level was applied, following the same ratio as the 2015 NEFR rooftop PV model. This model relates the saturation rate of rooftop PV to the number of detachable residential dwellings on which they can be installed.

The 2015 NEFR rooftop PV forecasts were then adjusted to account for the level of uptake of IPSS.

While this saturation represents the upper limit on rooftop PV installations, it does not represent the true saturation level for IPSS. Battery systems can be retrofitted in households with existing rooftop PV, so this saturation only applies for new installations, which are the focus of this initial modelling.

2.6 Summary of assumptions and limitations

As outlined in the sections above, there are a number of limitations and assumptions that have been applied. AEMO’s intention is to provide a first step to understanding the impact residential battery storage could have on operational consumption and maximum or minimum demand in the NEM.

Table 11 provides a summary of these and their potential impact on the forecasts.

Table 11 Summary of assumptions and limitations

Assumption	Description and implications	Potential impact on forecast uptake
Market Scope		
Residential market	At this initial stage, AEMO has only considered the uptake of new installations of rooftop PV integrated with a battery system. This results in limitations on modelled uptake in some regions where there is already a high penetration of rooftop PV as saturation limits are imposed (South Australia and Queensland in particular). There is a market for retrofitting storage systems with existing rooftop PV – not addressed in this paper – for customers who: • Installed systems after the end of premium FiT schemes and so receive only around 6 c/kWh of PV generation exported to the grid. • Are on generous FiTs that are due to expire. (In New South Wales, this is from 31 December 2016, while the other regions continue for much longer). In the retrofit case, the base cost of electricity for consumers in this analysis would be the annual cost with rooftop PV coupled with the new (lower) FiT. As the base case is already at a lower annual cost than for new installations, the payback for retrofit is not necessarily shorter than that of new installations of IPSS. **Next Steps** – AEMO will estimate the uptake of battery storage in the retrofit market in each region.	Underestimation of potential uptake.
Commercial market	The commercial market for battery storage has not yet been considered. Many businesses are already subject to demand tariffs and so this may potentially incentivise uptake but the economics have not yet been explored. **Next Steps** – AEMO will assess the economics of commercial energy storage.	None on residential uptake.
Modelling assumptions		
Demand Profiles	The projection of uptake across the NEM was developed based on average consumer profiles. The limitation of using an average profile from a large sample of consumers is that the 'needle peaks' associated with individual demand profiles are lost. A potential benefit of battery storage is the ability to reduce household peak demand charges. This value is not fully captured when using average demand profiles, so the uptake is potentially underestimated in regions where there are demand tariffs (South Australia and Victoria). **Next Steps** – AEMO will work with stakeholders to develop demand profiles that better reflect individual households.	Underestimation of potential uptake.
Financial model	At this initial stage, AEMO has only considered the value of IPSS to the individual household. It does not take account of different value streams or business models that retailers and/or network service providers may promote, for example: • Aggregated control of many storage systems for demand management and/or network support services. • Leasing or finance packages whereby retailers provide customers with a bundled package of installation and services on a long-term contract. **Next Steps** – AEMO will work with stakeholders to develop its modelling of the benefits of storage from these perspectives.	Unclear
Financial model	AEMO has only considered the financial merits of an IPSS for typical households across the NEM. It does not consider behavioural factors like a desire for independence from the electricity grid, or a desire to maximise self-consumption of rooftop PV generation. **Next Steps** – AEMO will seek to monitor the uptake of battery storage based on behavioural factors.	Unclear
Tariff structures	Analysis was based on tariffs that currently exist in the market as of May 2015, and assumes the same tariff structure is applied across the 20-year outlook period. It is inevitable that new tariffs structures will emerge, with tariff changes already scheduled to occur in 2017–18 in some regions. **Next Steps** – AEMO cannot make assumptions on what tariffs will be available in the market in the future but will continue to monitor this space and update its forecasts as new tariffs emerge.	Unclear
Hourly resolution model	The model described in this paper is calibrated to operate on an hourly resolution, where in reality smart meters record data on a half-hourly basis. Aggregating the demand profiles up to the hour can reduce the individual peaks that may be present in half-hourly time intervals. As a result, the model may underestimate the actual costs associated with tariff charges based on demand peaks.	Unclear

Assumption	Description and implications	Potential impact on forecast uptake
Weather	The original weather data was from ECMWF which includes 3-hourly satellite estimated data, interpolated to hourly measurements. It would be preferable to use actual measurements from the Bureau of Meteorology weather stations, but there are not sufficient stations to cover the entire NEM. **Next Steps** – This will be monitored for future analysis.	Unclear
Technology Specifications		
Degradation	The degradation over time of both rooftop PV and battery storage systems is not included in the model. Deteriorating performance of these technologies would provide a marginal difference to the forecast paybacks and uptake of battery storage, but this is difficult to project given the lack of performance track record for these systems. **Next Steps** – AEMO will monitor the performance of battery systems as installations increase.	Potential overestimation of uptake
Product sizing	AEMO has only assumed a single configuration for each of the three different housing sizes. The interaction of the battery with the PV, and therefore the grid, would change if either the PV or the battery were oversized in comparison to the other. This model has only assumed a standard system size. **Next Steps** – Other configurations that retailers may provide could be considered in further work.	Potential underestimation of uptake
Prices	AEMO has assumed that the Tesla Powerwall will be available in the Australian market late 2015 and at a certain price. **Next Steps** – AEMO will monitor the products and their prices available on the Australian market and uptake its assumptions as needed. AEMO is also looking to work with stakeholders such as AEMC and CSIRO to assist in developing the technology cost curves.	Potential overestimation of uptake
Technical, regulatory or policy		
Export restrictions	Uptake of battery systems could be influenced by operational restrictions that may be imposed by network service providers, for example, if a distribution network applied a zero export restriction on rooftop PV in certain areas. Conceptually this should incentivise uptake for IPSS systems, as consumers seek to maximise self-consumption of their rooftop PV generation. **Next Steps** – AEMO will consider export restrictions as a sensitivity in future modelling.	Potential underestimation of uptake
Zero FiTs	Similar to export restrictions, if the FiT were reduced to zero, this would impact on the economics of installing IPSS over rooftop PV alone. **Next Steps** – AEMO will consider zero FiTs as a sensitivity in future modelling.	Potential underestimation of uptake
No policies	At this stage there are no policies to incentivise the uptake of battery storage. AEMO will continue to monitor this space, and uptake its forecasts if any policies are announced.	N/A

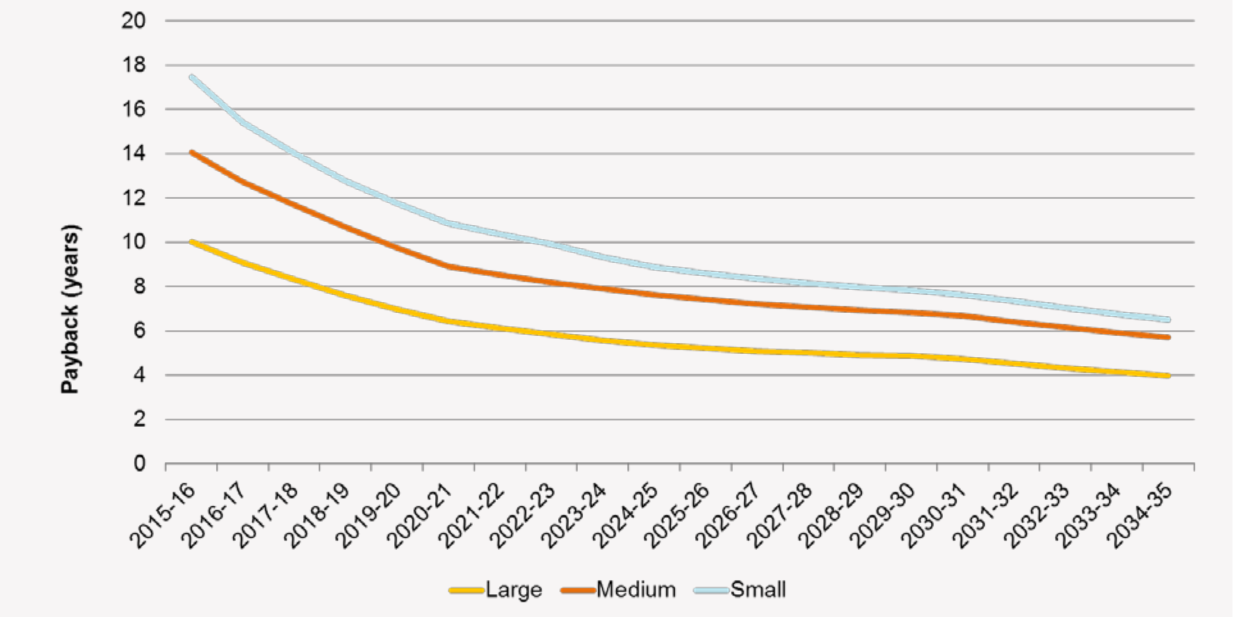
2.7 Queensland forecasts

2.7.1 Uptake

Figure 9 shows the payback period for new installations of IPSS in Queensland for each customer type. For large consumers, payback is estimated to start at around 10 years, and reduce to around five and a half years in 2024–25. These consumers are on a TOU tariff and have a higher daily demand.

As expected, payback periods are longer for medium and small customers, and are not projected to fall below ten years until 2019–20 and 2022–23 respectively. They are assumed to remain on a flat tariff after installing IPSS.

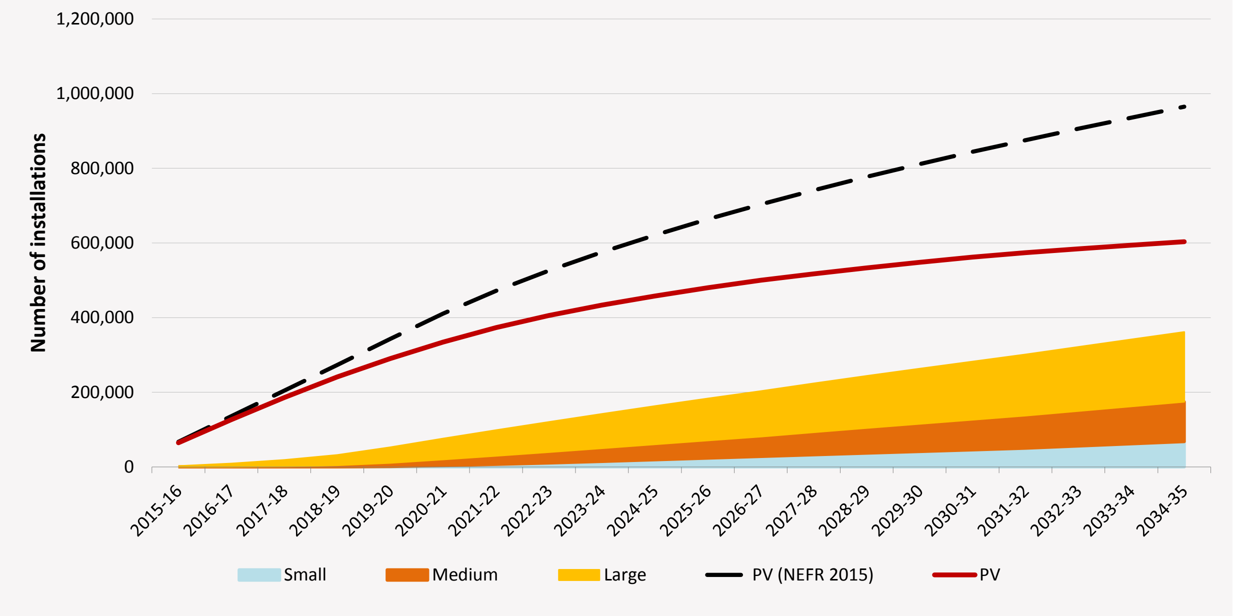
Figure 9 Estimated payback periods for IPSS in Queensland



As Figure 10 shows, the payback relationships result in forecast uptake being dominated by large consumers. It shows cumulative new installations of IPSS over the 20-year outlook period from 2014–15. The black line indicates the uptake of new rooftop PV systems forecast in the 2015 NEFR (additional to the current 474,343 rooftop PV installations in Queensland) when storage is not considered, while the red line indicates the cumulative number of new rooftop PV installations that do not include storage.

Comparatively, the estimated payback for a 4 kW rooftop PV system alone is 6.5, 5.6 and 4.8 years in 2017–18, 2024–25 and 2034–35 respectively.

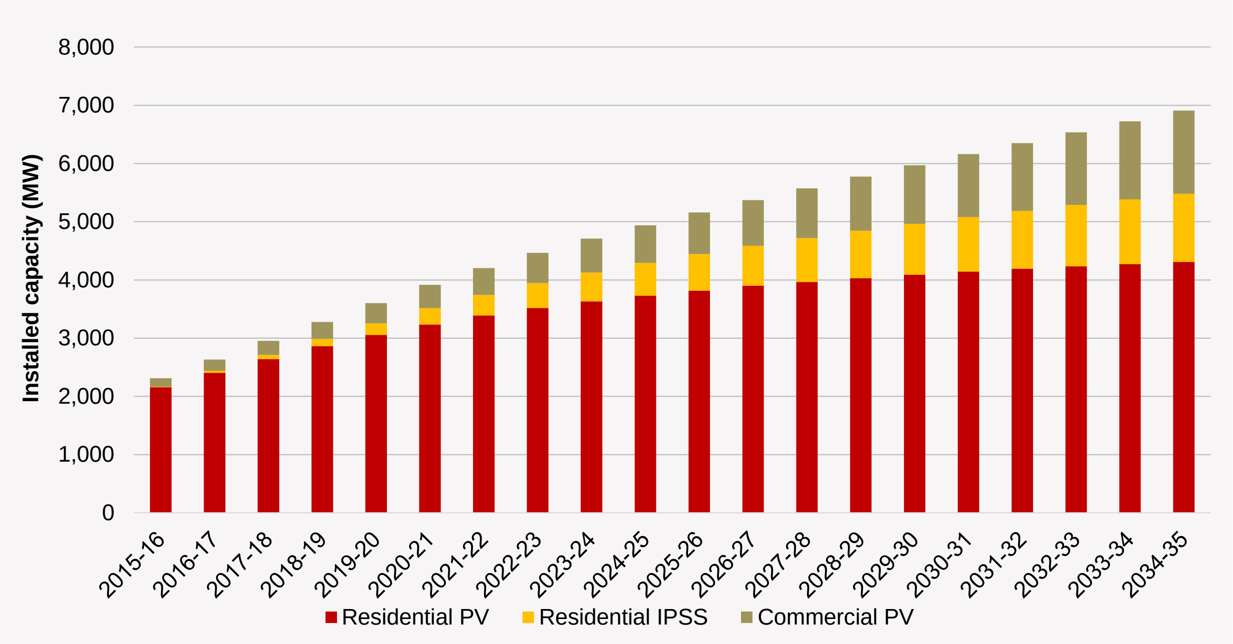
Figure 10 Cumulative new installations of IPSS forecast from 2015–16 in Queensland



Uptake of IPSS is initially only by large consumers, and this sector represents over half of the total storage installations at the end of the forecast period.

Figure 11 shows the forecast total installed capacity of rooftop PV in Queensland, and the proportion of standalone residential rooftop PV, residential IPSS and commercial PV. As can be seen by the curve in installations, saturation begins to occur from 2020–21.

Figure 11 Total installed capacity of rooftop PV and IPSS in Queensland



Although IPSS is forecast to make up 9% of new installations in 2017–18 and 26% by 2024–25, they represent only 3% and 15% of total households that have rooftop PV installed respectively. At the end of the forecast period, it is estimated that a total of 25% of residential rooftop PV installations will also have battery storage, but this constitutes only 17% of total rooftop PV installed capacity. Table 12 summarises the forecast installed capacity in Queensland.

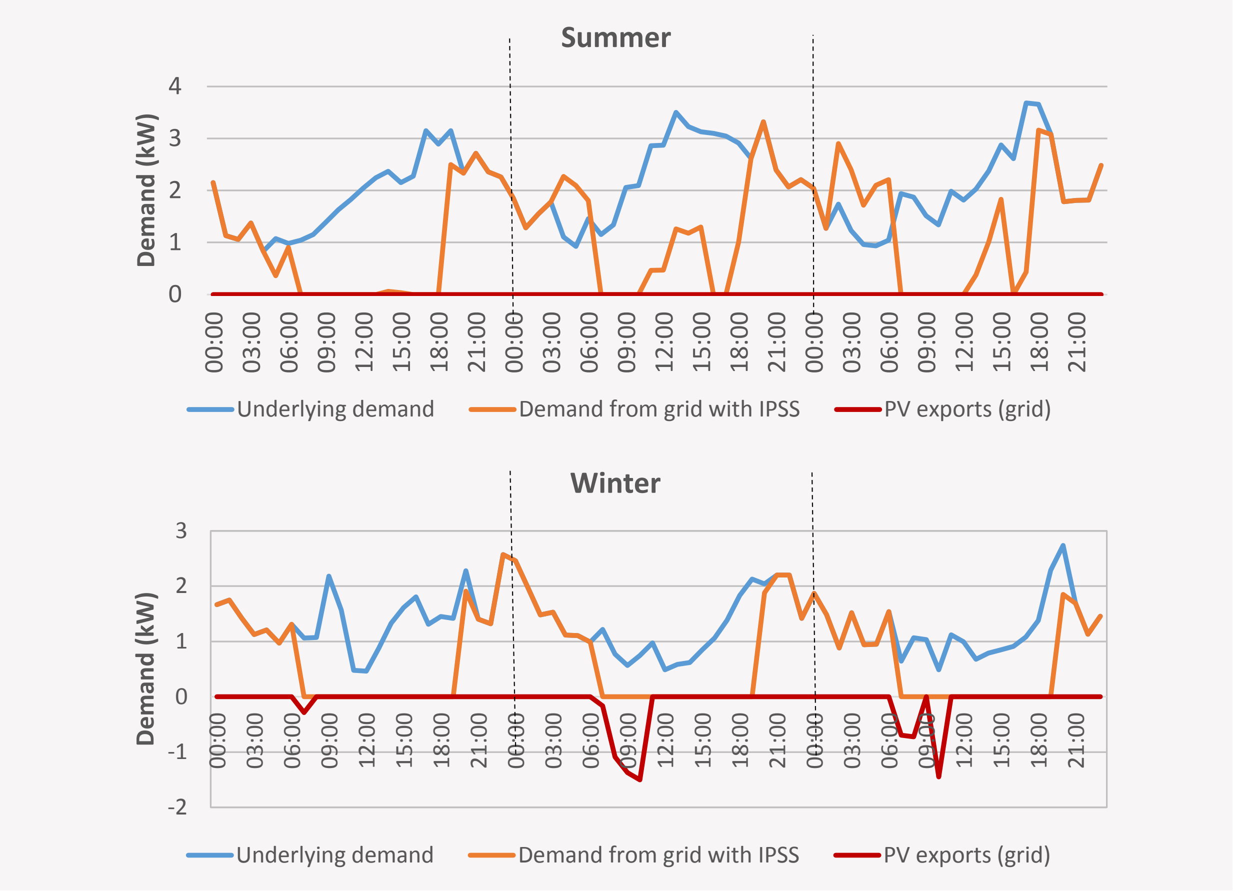
Table 12 Forecast installed capacity of PV and IPSS in Queensland

	Residential rooftop PV only (MW)	Installed capacity of IPSS		Commercial PV (MW)	Percentage IPSS of total capacity (%)
		PV (MW)	Battery (MWh)		
2017–18	2,640	74	129	241	2%
2024–25	3,730	563	982	647	11%
2034-–35	4,310	1,170	2,046	1,430	17%

2.7.2 Impact on daily household demand

The daily load profile of a large consumer household with IPSS, across three summer days and three winter days around times of regional maximum demand in 2014, is shown in Figure 12. This is a simplified profile, which shows the underlying household demand with no IPSS, and the modified demand from the grid after IPSS is installed. More detailed profiles showing the charge and discharge profile of the battery, as well as the PV generation, for each of the three types of consumer households, are in Appendix D.

Figure 12 Forecast impact of IPSS on daily load profile for a large consumer in Queensland around times of regional maximum demand



The underlying demand clearly shows the evening peak, particularly in summer when cooling loads are high. In summer, the IPSS reduces the size of the peak and delays it to later in the evening, although such impact is constrained by the storage capacity. Once storage energy is depleted, the household demand will be met using the grid only, as illustrated by the rapid increases in grid demand in the early evening during these high-demand days.

The red line indicates the excess PV generation that is exported to the grid. In summer there are no exports over these three high-demand days. On most normal days, however, there would still be exports, but this would be reduced with the IPSS. In winter, some excess PV generation is exported to the grid during the mornings.

2.7.3 Impact on operational maximum demand

Since battery storage systems are assumed to operate to minimise household energy costs, these systems would discharge at times of high tariffs, which typically coincide with peak network demand times. As a result, the increased penetration of storage systems has the potential to shift load from peak demand periods.

Assuming that households who install IPSS do not change their underlying electricity consumption patterns, the overall electricity they consume over the day will remain unchanged, but their requirements for grid-supplied electricity will change as seen above.

Therefore, the net impact of IPSS on the national electricity grid will be downward pressure on operational maximum demand. The extent of this impact on the daily load profile, however, would be highly influenced by the tariff structures, which can vary widely depending on the region.

Figure 13 shows the 10% POE summer and winter maximum demand forecasts for Queensland, with and without storage. The solid lines show the 2015 NEFR forecast, and the dashed lines show the adjusted maximum demand forecast based on the projected uptake of storage.

The impact of storage on maximum demand is forecast to be small in the short term. By 2034–35, storage would reduce the summer and winter maximum demand by 2.1% and 3.4% respectively. It is interesting to note that the smaller reduction of summer maximum demand is a result of storage further shifting the time of summer maximum demand to later in the day (see Table 13), when there is little storage energy left to impact maximum demand.

Figure 13 Queensland summer and winter 10% POE maximum demand forecasts with and without IPSS

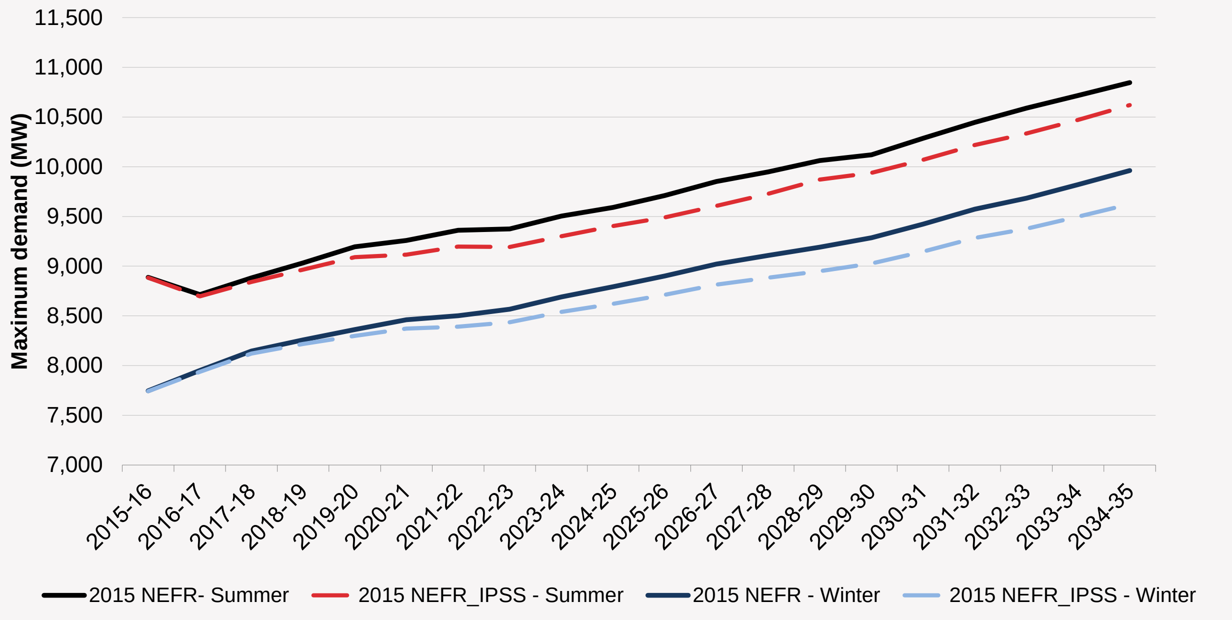


Table 13 shows the impact of IPSS on maximum demand in summer and winter by the end of the short, medium and long term outlook periods.

Table 13 Impact of IPSS on summer and winter 10% POE maximum demand forecasts in Queensland

	Summer			Winter		
	MW	%	Time of maximum demand	MW	%	Time of maximum demand
2017–18	41.4	0.5%	No change	25.0	0.3%	No change
2024–25	187.9	2.0%	Delayed to 20:00	171.1	1.9%	No change
2034–35	225.3	2.1%	Delayed to 20:00	338.1	3.4%	No change

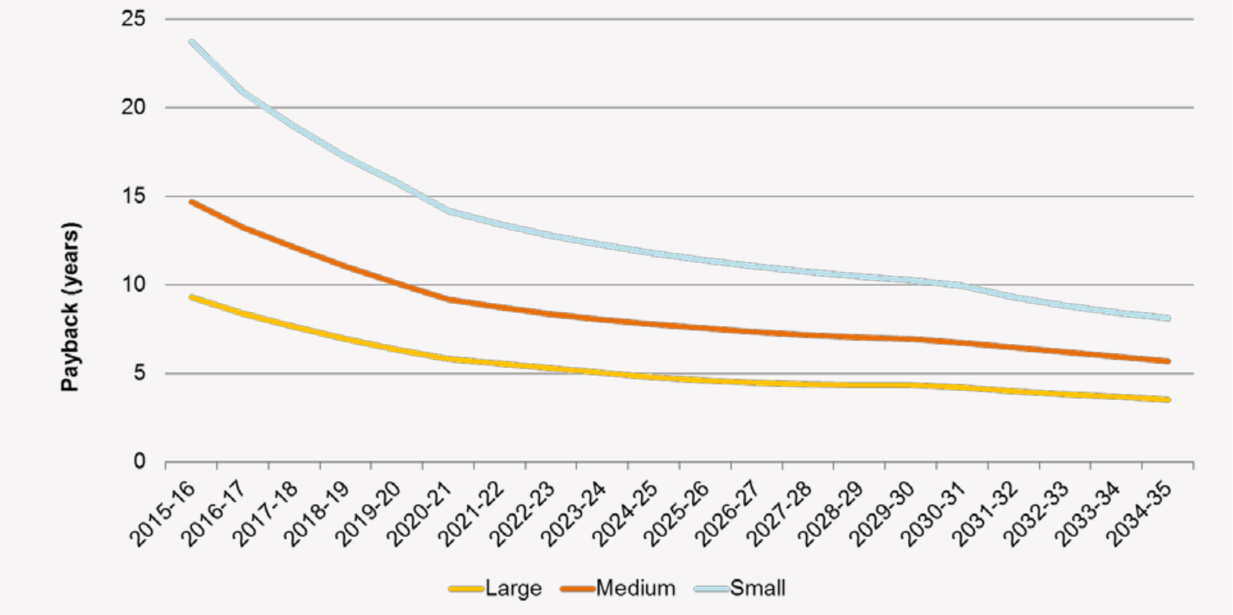
2.8 New South Wales forecasts

2.8.1 Uptake

Figure 14 shows the payback period for new installations of IPSS in New South Wales for each customer type. For large consumers, payback is estimated to start at around nine years and reduces to around five years in 2024–25. As expected, payback periods are longer for medium and small customers, and are not projected to fall below ten years until 2020–21 and 2030–31 respectively.

As Figure 5 showed, the annual savings for small and medium customers in New South Wales are much smaller than in other states, so longer paybacks are forecast.

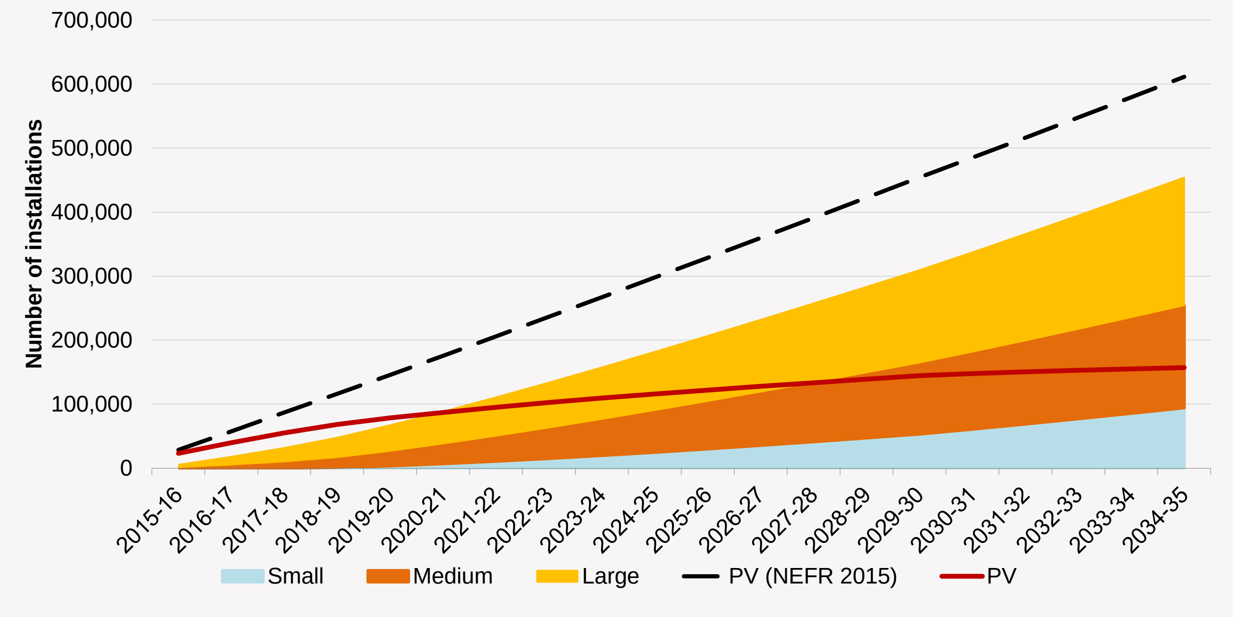
Figure 14 Estimated payback periods for IPSS in New South Wales



As Figure 15 shows, the payback relationships result in forecast uptake being dominated by large consumers. It shows cumulative new installations of IPSS over the 20-year outlook period from 2014–15. The black line indicates the uptake of new rooftop PV systems forecast in the 2015 NEFR (additional to the current 334,591 residential rooftop PV installations in New South Wales) when storage is not considered, while the red line indicates the cumulative number of new PV installations that do not include storage.

Comparatively, the estimated payback for a 4 kW rooftop PV system is 7.7, 6.6 and 5.7 years in 2017–18, 2024-25 and 2034-35 respectively.

Figure 15 Cumulative new installations of IPSS forecast from 2015-16 in New South Wales



Uptake of IPSS is initially only by large consumers, and this sector represents over half of the total storage installations at the end of the forecast period.

New South Wales has the highest forecast penetration rate of IPSS of all the NEM regions, with 37% and 61% of IPSS in 2017–18 and 2024–25 respectively. Although IPSS constitutes a large proportion of new installations in 2017–18 and 2024–25, they represent only 8% and 29% of total households that have PV installed respectively. At the end of the forecast period, up to 48% of total residential installations could also have battery storage.

One of the reasons for the high penetration rate in New South Wales is the fact that saturation is not reached in the forecast period, as Figure 15 shows. The black line corresponding to the 2015 NEFR PV forecasts continues to increase, indicating that saturation based on the number of residential detachable dwellings is not reached, so the market for new installations is greater.

Figure 16 shows the total installed capacity of rooftop PV in New South Wales, and the proportion of standalone residential PV, residential IPSS and commercial PV. As commercial PV constitutes a large proportion of the rooftop PV market in New South Wales, the penetration of IPSS with respect to total installed capacity of rooftop PV is smaller, as shown in Table 15.

Figure 16 Total installed capacity of rooftop PV and IPSS in New South Wales

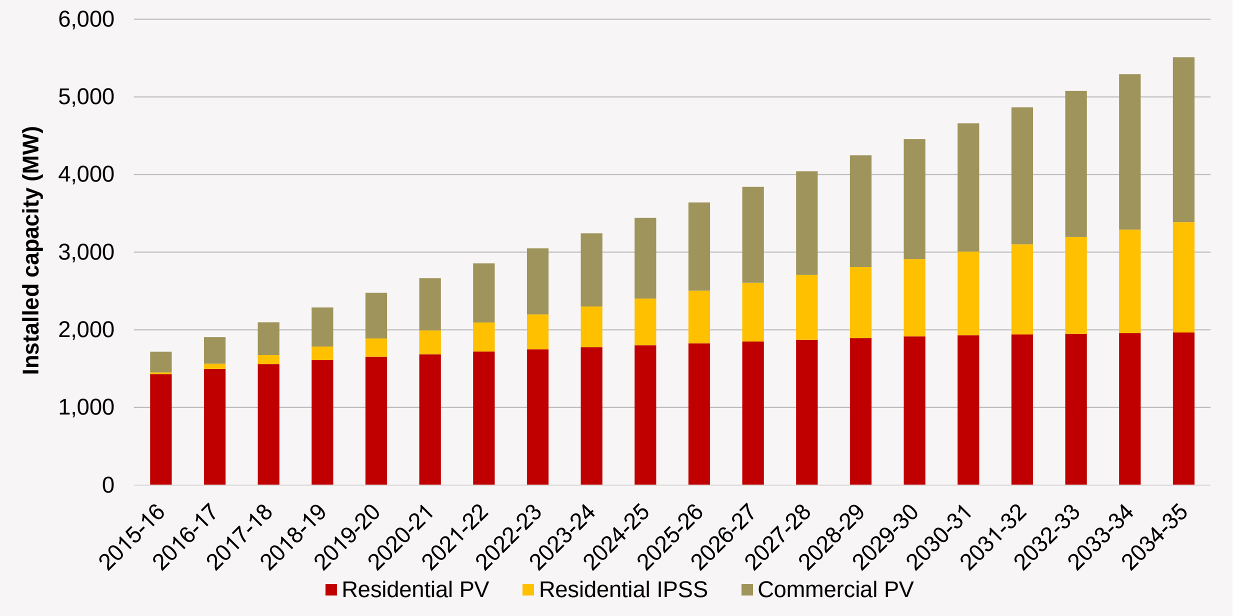


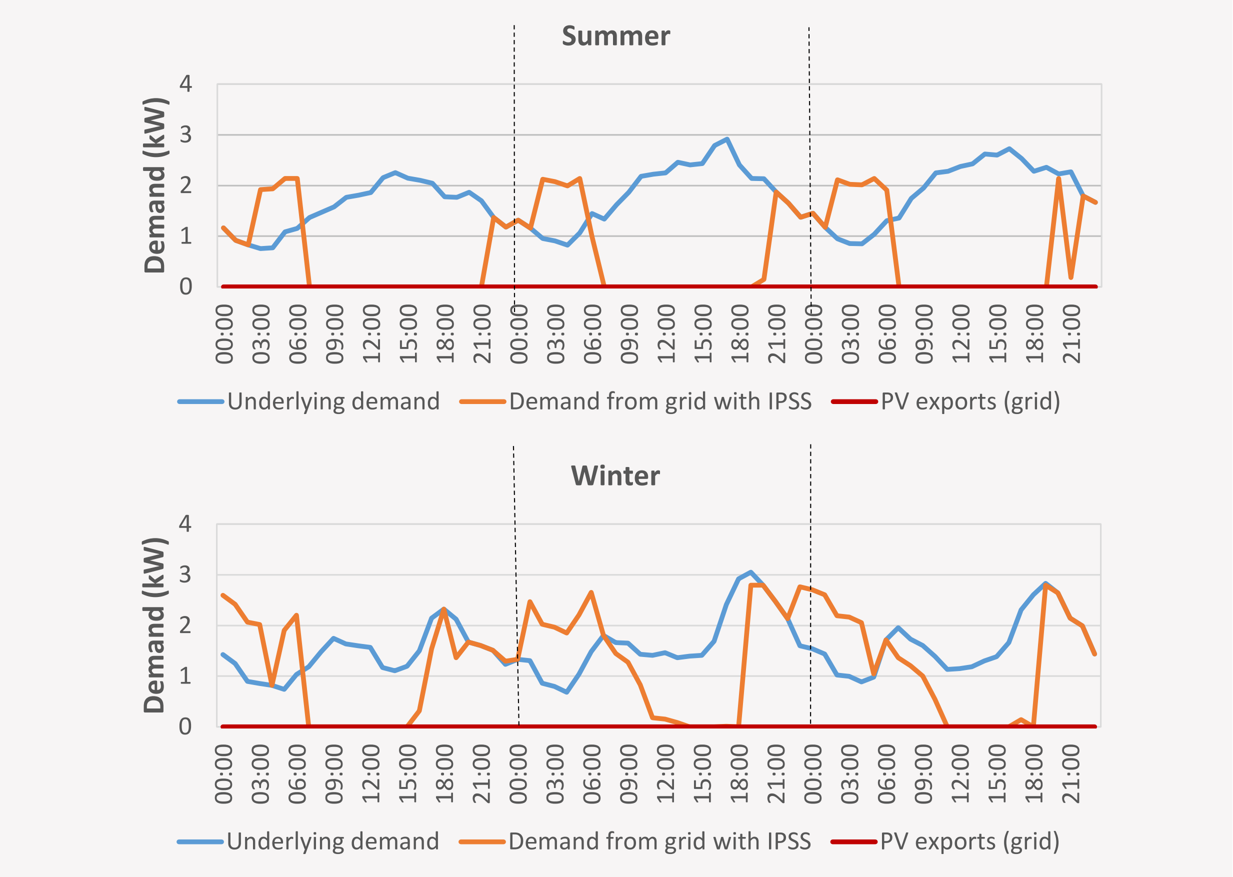
Table 14 Forecast installed capacity of PV and IPSS in New South Wales

	Residential PV (MW)	Residential IPSS		Commercial PV (MW)	Percentage IPSS of total capacity (%)
		PV (MW)	Battery (MWh)		
2017–18	1,559	117	201	422	6%
2024–25	1,802	600	1043	1,039	17%
2034–35	1,967	1,421	2,482	2,123	26%

2.8.2 Impact on daily household demand

The daily load profile of a large consumer household with IPSS, across three summer days and three winter days around times of regional maximum demand in 2014, is shown in Figure 17. This is a simplified profile, which shows the underlying household demand with no IPSS, and the modified demand from the grid after IPSS is installed. More detailed profiles showing the charge and discharge profile of the battery, as well as the PV generation, for each of the three types of consumer households, are in Appendix D.

Figure 17 Forecast impact of IPSS on daily load of a large consumer in New South Wales around times of regional maximum demand



The underlying demand clearly shows the afternoon peak, in both summer and winter, due to heating and cooling loads. In summer, the IPSS shifts the household peak and delays it to the early mornings when the battery draws from the electricity grid.

In winter, the IPSS does not shift the evening peak or provide much reduction in the household demand peak, although the peak does not last as long. As in summer, a new peak occurs in the early morning as the battery charges from the grid.

The red line indicates that there is no excess rooftop PV generation exported to the grid across these high-demand days, in either summer or winter. On most normal days, however, there would still be exports, but this would be reduced with the IPSS.

2.8.3 Impact on operational maximum demand

Since battery storage systems are assumed to operate to minimise household energy costs, these systems would discharge at times of high tariff charges, which typically coincide with peak network demand times. As a result, the increased penetration of storage systems has the potential to shift load from peak demand periods.

Assuming that households who install IPSS do not change their electricity consumption patterns, the overall electricity they consume over the day will remain unchanged, but their requirements for grid-supplied electricity will change, as seen above.

Therefore, the net impact of IPSS on the national electricity grid will be downward pressure on operational maximum demand. The extent of this impact on the daily load profile, however, would be highly influenced by the tariff structures, which can vary widely depending on the region.

Figure 18 shows the 10% POE summer and winter maximum demand forecasts for New South Wales, with and without storage. The solid lines show the 2015 NEFR forecast, and the dashed lines show the adjusted maximum demand forecast based on the projected uptake of storage.

The impact of storage on maximum demand is forecast to be small in the short term. By 2034–35, storage would reduce the summer and winter maximum demand by 2.4% and 4.2% respectively. The difference arises from the different expected times of maximum demand in summer (around 4.00–5.00 pm) and winter (around 7.00–8.00pm). In summer, there is still considerable rooftop PV generation which offsets the maximum demand, and hence reduces the impact of storage. In winter, on the other hand, there is less rooftop PV generation in the early evening so storage is expected to have a larger impact on maximum demand.

Figure 18 New South Wales summer and winter 10% POE maximum demand forecasts with and without IPSS

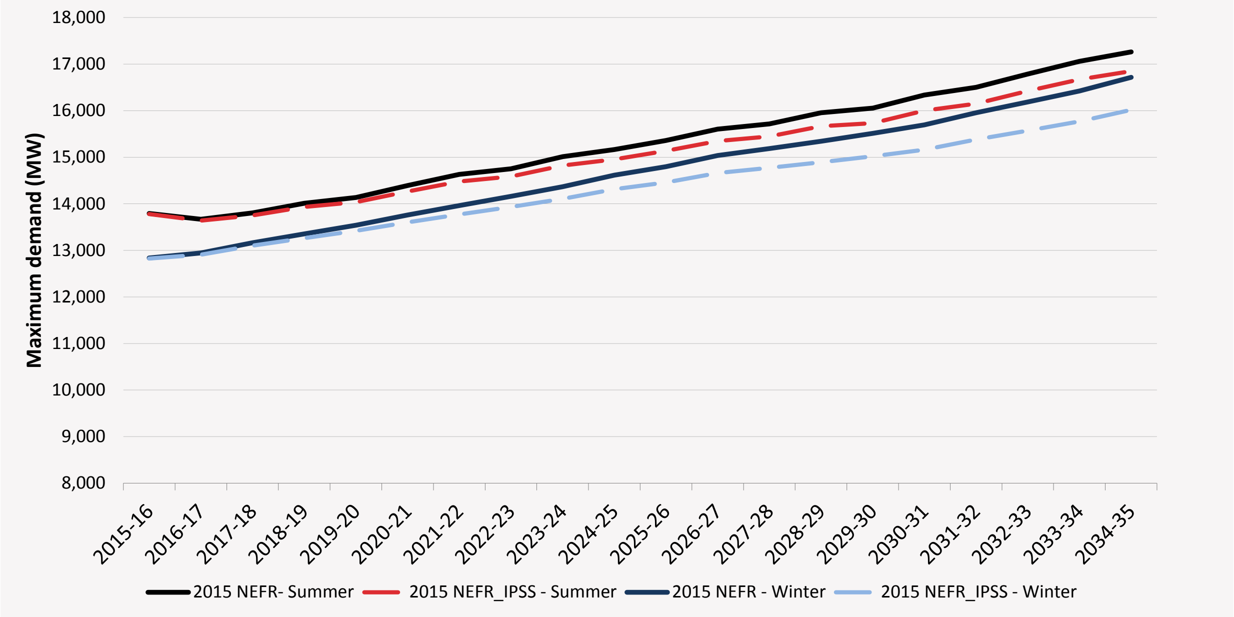


Table 15 shows the impact of IPSS on maximum demand in summer and winter by the end of the short, medium and long term outlook periods.

Table 15 Impact of IPSS uptake on 10% POE summer and winter maximum demand in New South Wales

	Summer			Winter		
	MW	%	Time of maximum demand	MW	%	Time of maximum demand
2017–18	54.4	0.4%	No change	61.4	0.5%	No change
2024–25	209.6	1.4%	No change	300.5	2.1%	No change
2034–35	414.0	2.4%	No change	696.9	4.2%	No change

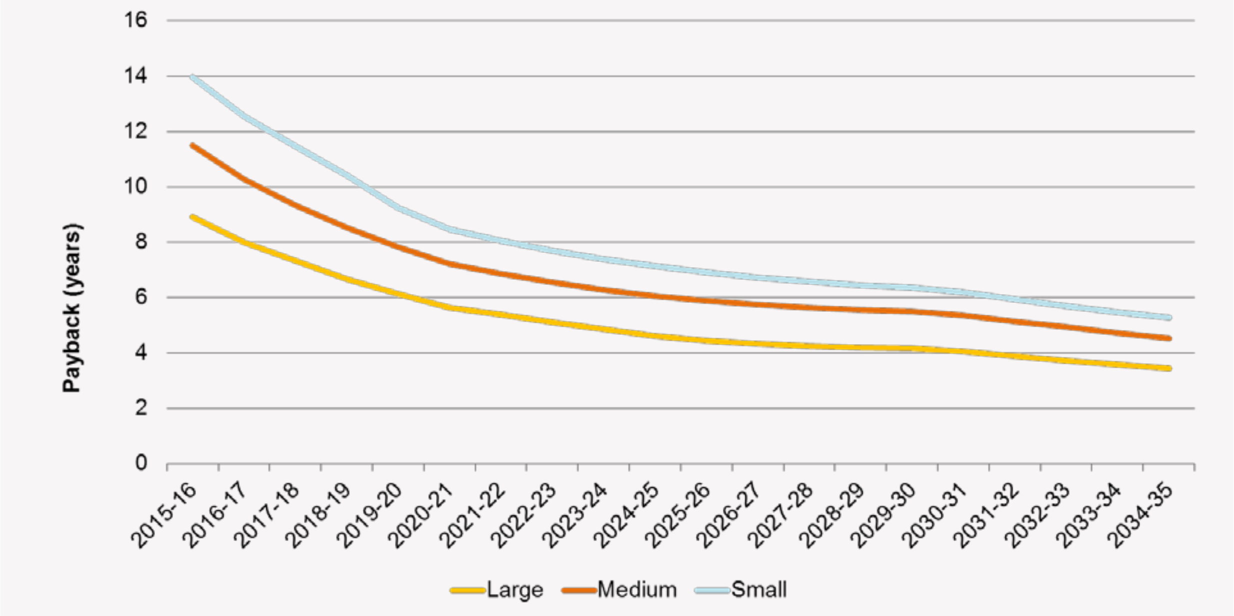
2.9 South Australia forecasts

2.9.1 Uptake

Figure 19 shows the payback period for new installations of IPSS in South Australia for each customer type. South Australia is estimated to have the shortest payback period at the beginning of the forecast for all three household sizes, due to a combination of high electricity prices, high solar resource and favourable tariff structure. The smallest customers experience the longest payback period. The payback period for large households is expected to be just under nine years, and will drop by half over the subsequent ten years, similar to the trend forecast for New South Wales. South Australian medium and small customers are expected to be the first to see a payback period of less than 10 years, in 2017–18 and 2019–20 respectively.

It is important to note that these payback periods were estimated using the average demand profile for each customer type. An average demand profile may not necessarily reflect the actual demand profile of individual households, which are likely to have sharper load spikes. As such, current modelling results may underestimate the cost savings from installing IPSS for customers who are on the capacity tariff in South Australia (and Victoria) where the tariff exists. AEMO will continue to investigate the impact of this in future modelling.

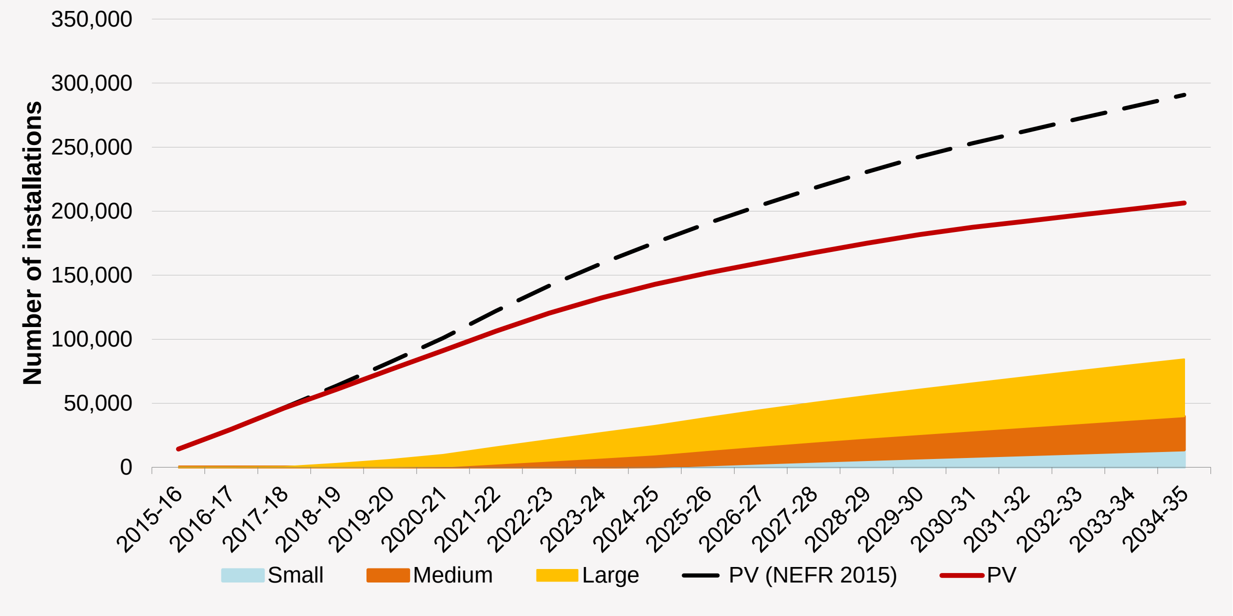
Figure 19 Estimated payback periods for IPSS in South Australia



As Figure 20 shows, the payback relationships result in forecast uptake being dominated by large consumers. It shows cumulative new installations over the 20-year outlook period from 2014–15. The black line indicates the uptake of new rooftop PV systems forecast in the 2015 NEFR (additional to the current 195,240 rooftop PV installations in South Australia) when storage is not considered, while the red line indicates the cumulative number of new rooftop PV installations that do not include storage.

Comparatively, the installation of a 4 kW rooftop PV system alone has an estimated payback of 5.7, 5, and 4.3 years in 2017–18, 2024–25 and 2034–35 respectively.

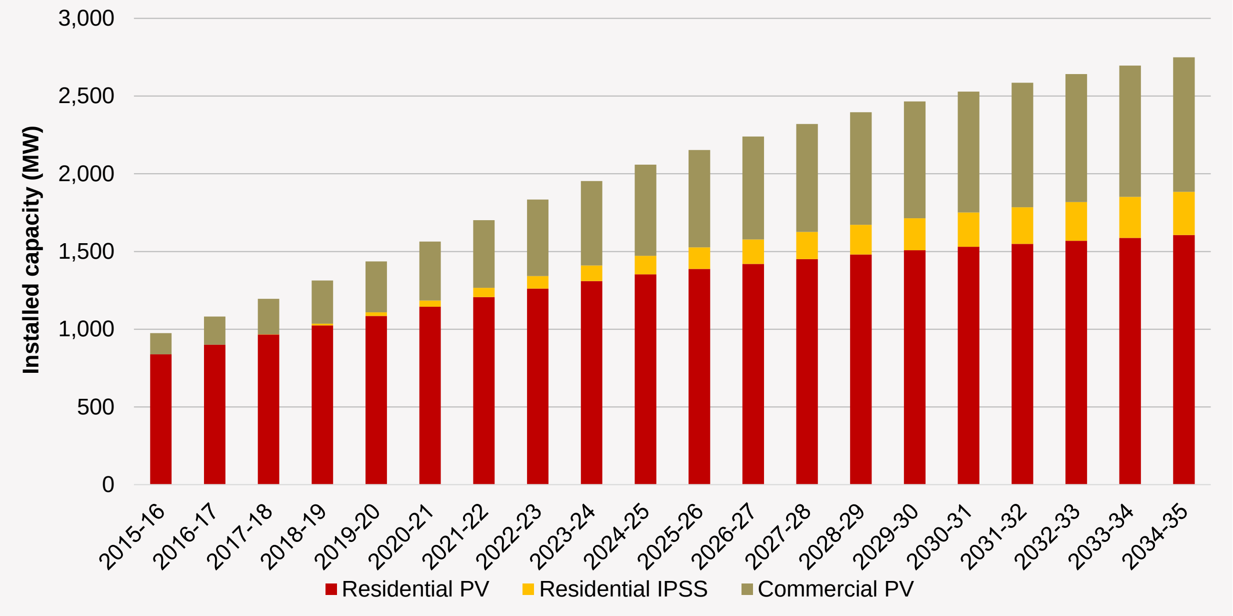
Figure 20 Cumulative new installations of PV and storage forecast from 2015–16 in South Australia



Uptake of IPSS for the first five years is only by large consumers. By the end of the forecast period, the large consumer sector represents about half the total storage installations.

Figure 21 shows the forecast total installed capacity of rooftop PV in South Australia, and the proportion of standalone residential PV, residential IPSS and commercial PV. IPSS constitutes 0.6% of new installations in 2017–18, and 18.5% by 2024–25, representing only 0.1% and 8.8% respectively of total households that have PV installed.

Figure 21 Total installed capacity of rooftop PV and IPSS installations in South Australia



At the end of the forecast period it is estimated that a total of 17.4% of residential rooftop PV installations will also have battery storage.

As can be seen by the curve in installations, saturation begins to occur from 2023–24, due to the high number of currently installed rooftop PV systems, and this results in a slower uptake of IPSS in the longer term.

Despite South Australia having relatively short payback periods for IPSS, as shown in Figure 19, the incremental benefits of installing IPSS over rooftop PV alone are smaller than in other regions, so the relative forecast uptake of IPSS is lower (see Figure 4).

It is important to also note that there is potential for uptake of IPSS in the retrofit market. This is not considered in the current model but will be investigated in further work.

Table 16 summarises the installed capacity forecast in South Australia.

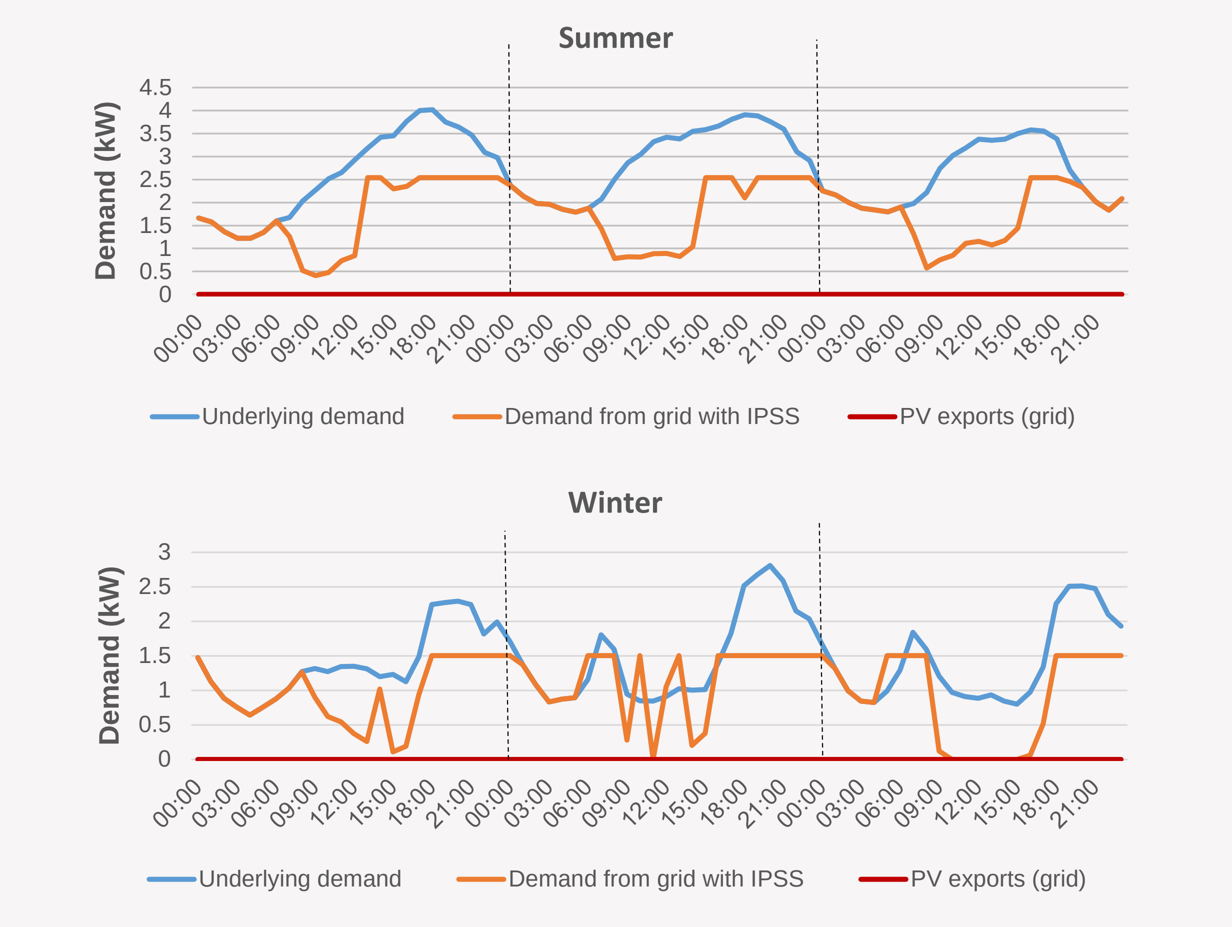
Table 16 Forecast installed capacity of PV and IPSS in South Australia

	Residential PV (MW)	Residential IPSS		Commercial PV (MW)	Percentage IPSS of total capacity (%)
		PV (MW)	Battery (MWh)		
2017-18	966	1	2	228	0%
2024-25	1,353	119	206	587	6%
2034-35	1,606	277	484	866	10%

2.9.2 Impact on daily household demand

The daily load profile of a large consumer household with IPSS, across three summer days and three winter days around times of regional maximum demand in 2014, is shown in Figure 22. This is a simplified profile, which shows the underlying household demand with no IPSS and the modified demand from the grid after IPSS is installed. More detailed profiles showing the charge and discharge profile of the battery, as well as the PV generation, for each of the three types of consumer households, are in Appendix D.

Figure 22 Forecast impact of IPSS on daily load profile of a large consumer in South Australia around times of regional maximum demand



The underlying demand clearly shows the evening peak, in both summer and winter, due to heating and cooling loads.

In both summer and winter, the IPSS reduces the household peak. The IPSS system optimises to the capacity tariff capping imports from the grid to just below 2.5 kW in summer and 1.5 kW in winter. These are the demand points at which the household incurs additional charges for demand over this threshold.

The red line indicates that there is no excess rooftop PV generation exported to the grid across these high-demand days, in either summer or winter. On most normal days, however, there would still be exports, but this would be reduced with the IPSS.

2.9.3 Impact on operational maximum demand

Since battery storage systems are assumed to operate to minimise household energy costs, these systems would discharge at times of high tariff charges, which typically coincide with peak network demand times. As a result, the increased penetration of storage systems has the potential to shift load from peak demand periods.

Assuming that households who install IPSS do not change their electricity consumption patterns, the overall electricity they consume over the day will remain unchanged, but their requirements for grid-supplied electricity will change as seen above.

Therefore, the net impact of IPSS on the national electricity grid will be downward pressure on operational maximum demand. The extent of this impact on the daily load profile, however, would be highly influenced by the tariff structures, which can vary widely depending on the region.

Figure 23 shows the 10% POE summer and winter maximum demand forecasts for South Australia, with and without storage. The solid lines show the 2015 NEFR forecast and the dashed lines show the adjusted maximum demand forecast based on the projected uptake of storage.

While the impact of storage on maximum demand is forecast to be negligible in the short term, storage would reduce the summer and winter maximum demand by 76 MW (2.2%) and 72 MW (2.6%) respectively by 2034–35. No further shift of the times of maximum demand is expected. This storage impact is modelled based on the uptake of IPSS only. Including the retrofit market would further reduce the summer and winter maximum demand.

Figure 23 **South Australia summer and winter 10% POE maximum demand forecasts with and without IPSS**

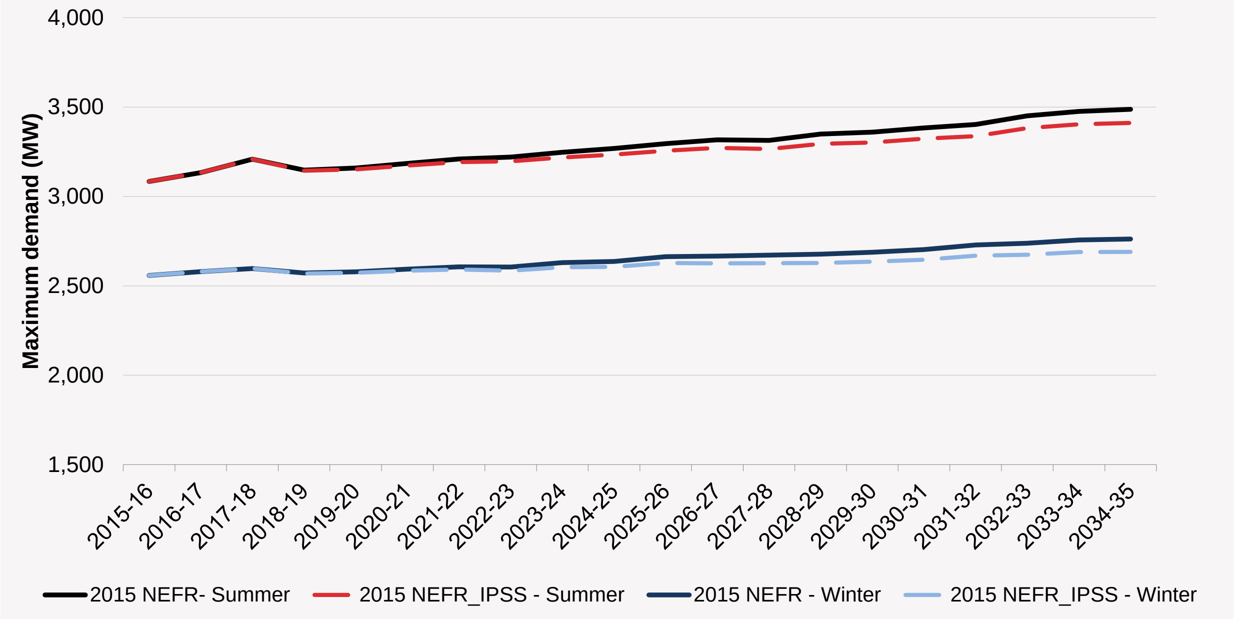


Table 17 shows the impact of IPSS on maximum demand in summer and winter by the end of the short, medium and long term outlook periods.

Table 17 **Forecast impact of IPSS on 10% POE summer and winter demand in South Australia**

	Summer			**Winter**		
	MW	%	**Time of maximum demand**	MW	%	**Time of maximum demand**
2017–18	0.4	0.0%	No change	0.3	0.0%	No change
2024–25	33.9	1.0%	No change	30.1	1.1%	No change
2034–35	76.1	2.2%	No change	71.6	2.6%	No change

2.9.4 Impact on operational minimum demand

The 2015 NEFR explored the potential implications of increasing penetration of rooftop PV on the electricity grid. In South Australia, existing rooftop PV systems are already a significant source of electricity supply on a clear day, and this can meet larger proportions of consumer demand during minimum demand times. For example, rooftop PV supplied 445 MW at 1.30 pm on 26 December 2014 resulting in a grid demand of just 790 MW, which is the lowest experienced in the last ten years.

The 2015 NEFR forecast that, by around 2023–24, minimum demand from the grid would fall to 0 MW, meaning rooftop PV alone would be sufficient to meet all customer demand at times of minimum demand. This forecast did not consider the potential impact of battery storage. This section therefore attempts to:

- Assess the potential impact of residential storage on grid demand during times of minimum demand.
- Discuss any implications that may arise.

Impact of storage on PV exports

On a household level, installing a rooftop PV system reduces grid demand by:

- Reducing the household electricity demand from the grid.
- Exporting any surplus generation to the grid, reducing the energy required to supply others from centrally-dispatched generators.

Consequently, grid demand could potentially fall to zero during the middle of the day when enough rooftop PV systems are installed. This may cause network stability and operational issues.

Battery storage has the potential for alleviating this issue. As shown above, installing battery storage reduces the export of excess PV generation to the grid, as it is instead first used to charge the battery.

Impact of storage on minimum demand

Increasing penetration of IPSS could potentially help alleviate low grid demand issues where penetration of rooftop PV is high. Using the uptake of IPSS forecast above, AEMO estimated the impact this would have on the network during times of minimum demand.

Figure 24 shows the profile of an IPSS system and its effect on a large consuming household in South Australia on the minimum demand day in 2014. From 12.00 pm, the generation from the rooftop PV system is used to meet household demand, but also to charge the battery, so it would not be exported to the grid at 1.30 pm, the time of minimum grid demand.

The impact of the projected uptake of IPSS on the 90% POE summer minimum demand forecasts developed in the 2015 NEFR is shown in Figure 24.

Note that these minimum demand forecasts were derived from half-hourly demand profiles, and are different from the yearly minimum demand forecasts published in the 2015 NEFR[19]. The differences are due to several factors, including:

- Demand profiles in the yearly forecasts are not adjusted for energy efficiency, as half-hourly data is not available for this component of the forecasts.
- Demand profiles are based on the probability distributions for each half-hour period. Annual minimum demand forecasts are based on the probability distribution of entire days.

Figure 25 shows that uptake of IPSS in South Australia increases demand from the grid during these minimum demand times based on the half-hourly NEFR forecasts, but only delays, by one year, the time when rooftop PV is projected to offset 100% of demand generated from the grid. Exports from rooftop PV could fall by around 150 MW in 2035 due to storage, but will still meet 100% of demand at minimum demand times.

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[19] The NEFR includes an annual maximum/minimum demand forecast and half-hourly forecasts for maximum and minimum demand. This paper considers only half-hourly forecasts.

Figure 24 Average daily load profile, and estimated PV and storage energy profiles for large households in South Australia during Boxing Day (i.e. minimum demand day) in 2014

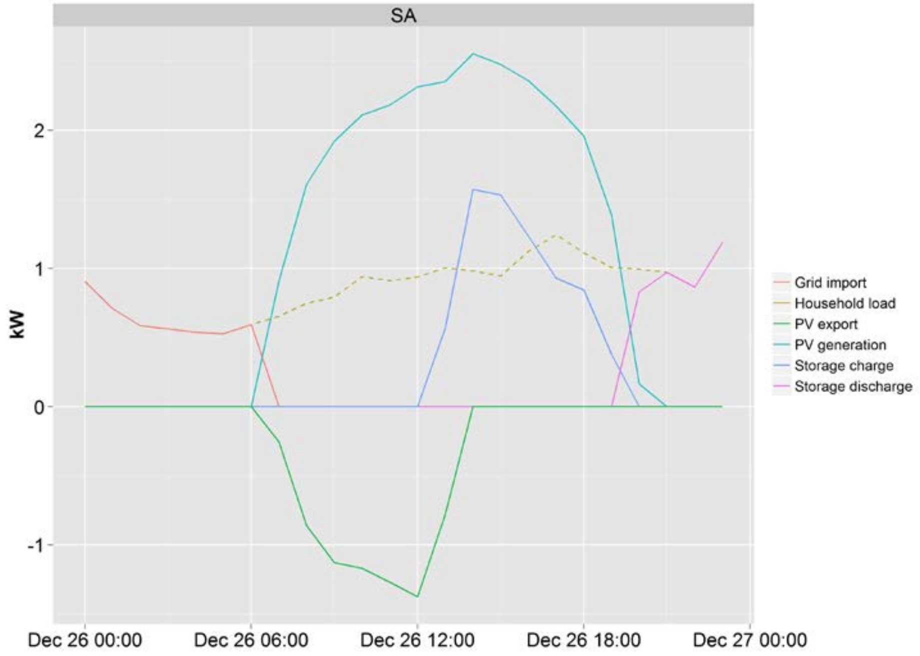
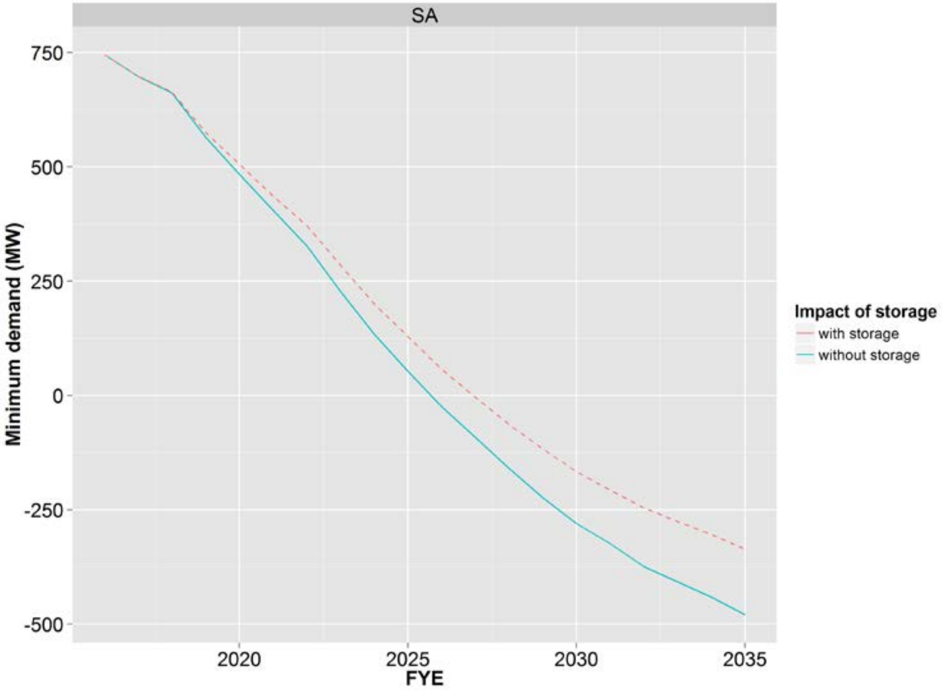


Figure 25 Impact of storage on minimum demand in SA during summer

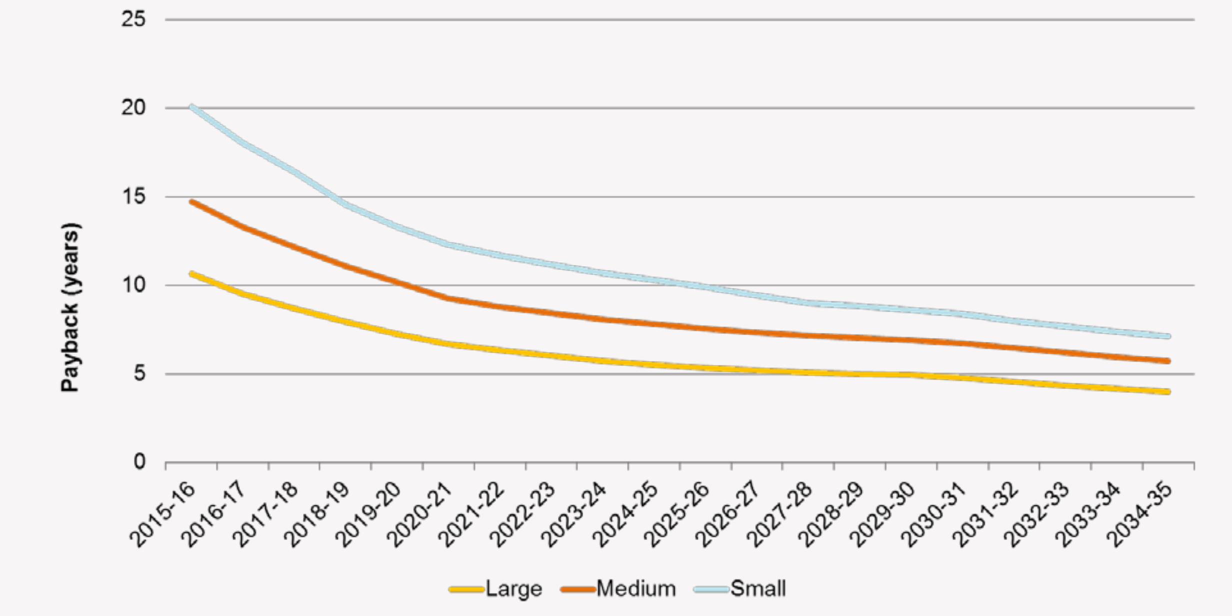


2.10 Victoria forecasts

2.10.1 Uptake

Figure 26 shows the payback period for new installations of IPSS in Victoria for each customer type. For large consumers, payback is estimated to start at around 11 years, and reduce to around six years in 2024–25. As expected, payback periods are longer for medium and small customers, and are not projected to fall below ten years until 2020–21 and 2025–26 respectively.

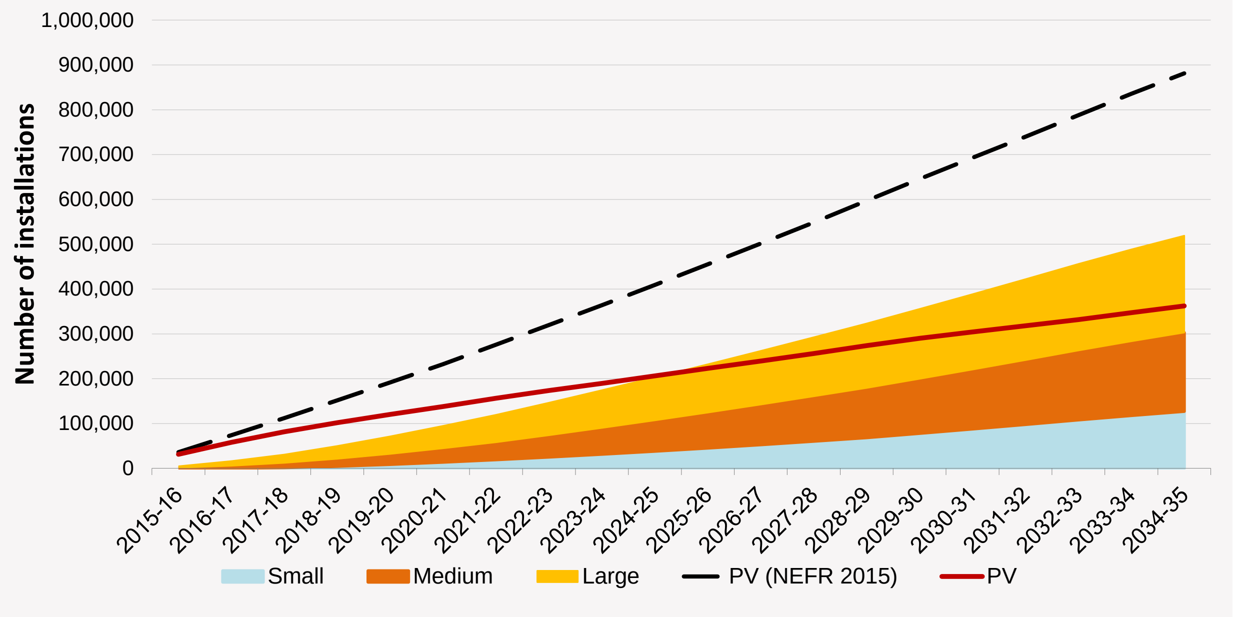
Figure 26 Estimated payback periods for IPSS in Victoria



As Figure 27 shows, the payback relationships result in forecast uptake being dominated by large consumers. It shows the cumulative new installations of IPSS over the 20-year outlook period from 2014–15. The black line indicates the uptake of new rooftop PV systems forecast in the 2015 NEFR (additional to the current 272,783 rooftop PV installations in Victoria) when storage is not considered, while the red line indicates the cumulative number of new rooftop PV installations that do not include storage.

Comparatively, installation of a 4 kW rooftop PV system has an estimated payback of 6.7, 5.6 and 4.8 years in 2017–18, 2024–25 and 2034–35 respectively.

Figure 27 Cumulative new installations of PV and IPSS from 2015–16

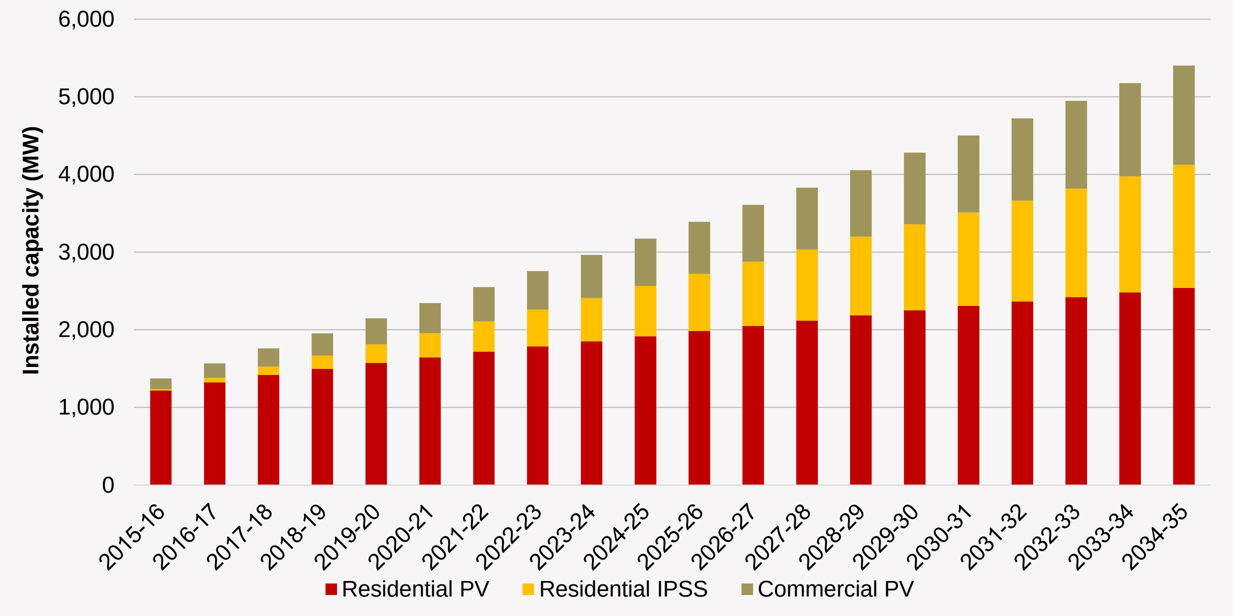


Uptake of IPSS for the first four years is only by large and medium consumers. By the end of the forecast period, the large sector represents about half of the total storage installations.

As the black line shows, saturation does not occur during the forecast period.

Figure 28 shows the forecast total capacity of rooftop PV in Victoria, and the proportion of standalone residential PV, residential IPSS and commercial rooftop PV.

Figure 28 Forecast total capacity of PV and IPSS installations in Victoria



Although IPSS is forecast to make up 27% of new installations in 2017–18, and 50% by 2024–25, they represent only 8% and 30% of total households that have rooftop PV installed respectively. At the end of the forecast period it is estimated that a total of 45% of residential rooftop installations will also have battery storage, representing only 29% of total rooftop PV installed capacity. Table 18 summarises the installed capacity forecast in Victoria.

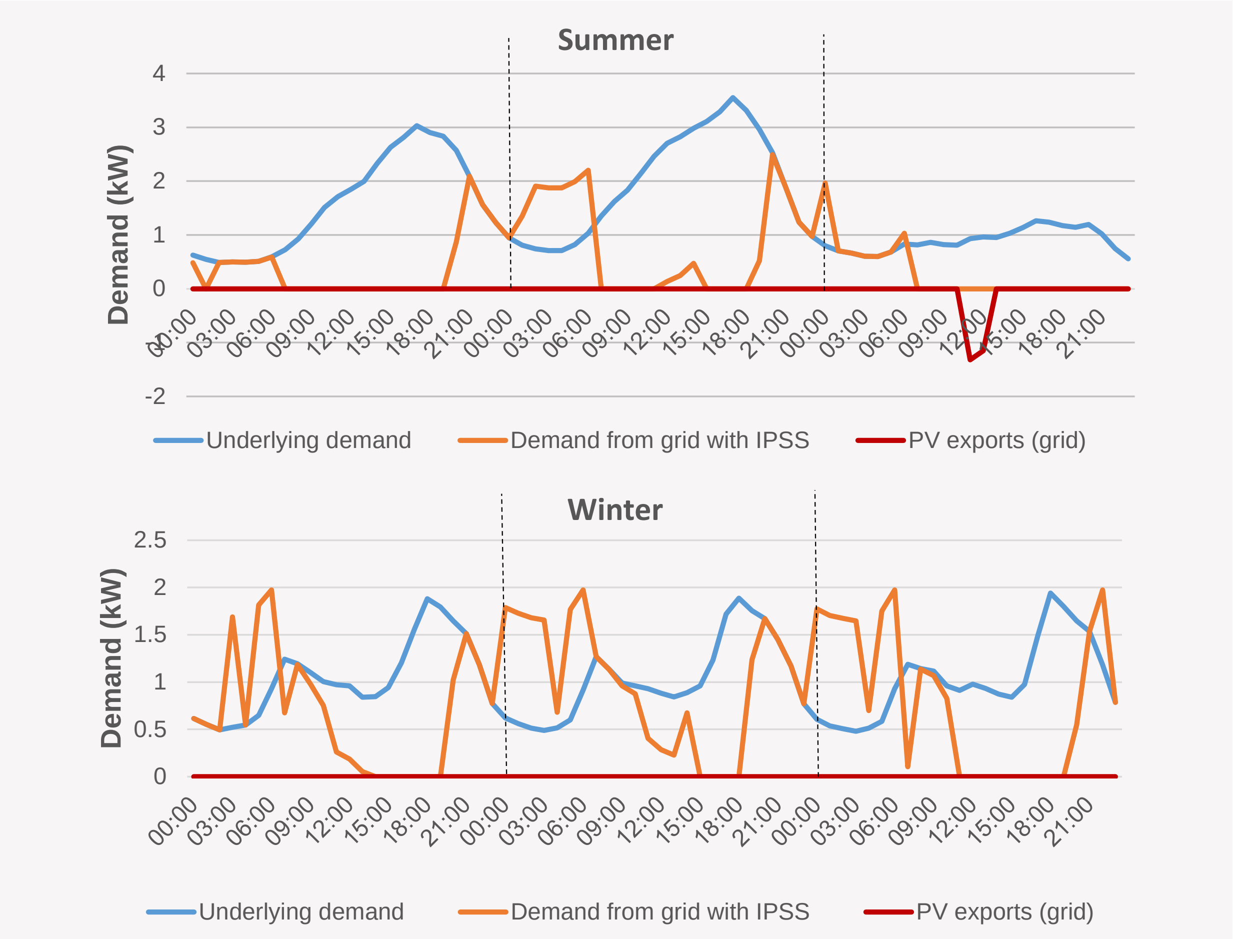
Table 18 Forecast installed capacity of PV and IPSS in Victoria

	Residential PV (MW)	Residential IPSS		Commercial PV (MW)	Percentage IPSS of total capacity (%)
		PV (MW)	Battery (MWh)		
2017-18	1,418	109	188	234	6%
2024-25	1,916	648	1,131	611	20%
2034-35	2,540	1,583	2,774	1,278	29%

2.10.2 Impact on household demand

The daily load profile of a large consumer household with IPSS, across three summer days and three winter days around times of maximum demand in 2014, is shown in Figure 29. This is a simplified profile, which shows the underlying household demand with no IPSS, and the modified demand from the grid after IPSS is installed. More detailed profiles showing the charge and discharge profile of the battery as well as the PV generation, for each of the three types of consumer households, are in Appendix D.

Figure 29 Forecast impact of IPSS on daily load profile for a large consumer in Victoria around times of regional maximum demand



The underlying demand clearly shows the afternoon peak in both summer and winter. In summer, the IPSS shifts the household peak and delays it to the early mornings, when the battery draws from the electricity grid. Of the three summer days shown, the first two days were both peak days falling on the Australia Day holiday, and the third day was a relatively low household demand day.

In summer, the IPSS both reduces and delays the peak demand of the household, and doesn't create a new early morning peak as it is charged sufficiently from the PV generation.

In winter, the IPSS shifts the evening peak but does not necessarily provide much reduction, with the household demand peak not lasting as long. A new peak occurs in the early morning as the battery charges from the grid.

The red line indicates that no excess rooftop PV generation is exported to the grid in either summer or winter, except on low household demand days.

2.10.3 Impact on operational maximum demand

Since battery storage systems are assumed to operate to minimise household energy costs, these systems would discharge at times of high tariff charges, which typically coincide with peak network demand times. As a result, the increased penetration of storage systems has the potential to shift load from peak demand periods.

Assuming that households who install battery storage do not change their electricity consumption patterns, the overall electricity they consume over the day will remain unchanged, but their requirements for grid-supplied electricity will change as seen above.

Therefore, the net impact of battery storage on the national electricity grid will be downward pressure on operational maximum demand. The extent of this impact on the daily load profile, however, would be highly influenced by the tariff structures, which can vary widely depending on the region.

Figure 30 shows the 10% POE summer and winter maximum demand forecasts for Victoria, with and without storage. The solid lines show the 2015 NEFR forecast, and the dashed lines show the adjusted maximum demand forecast based on the projected uptake of storage.

The impact of storage on maximum demand is forecast to be small in the short term. By 2034–35, storage would reduce the summer and winter maximum demand by 720 MW and 582 MW respectively. Of all regions, the storage impact on maximum demand would be the largest in Victoria, which is forecast to have the highest uptake of IPSS.

Figure 30 Victoria summer and winter 10% POE maximum demand forecasts with and without IPSS

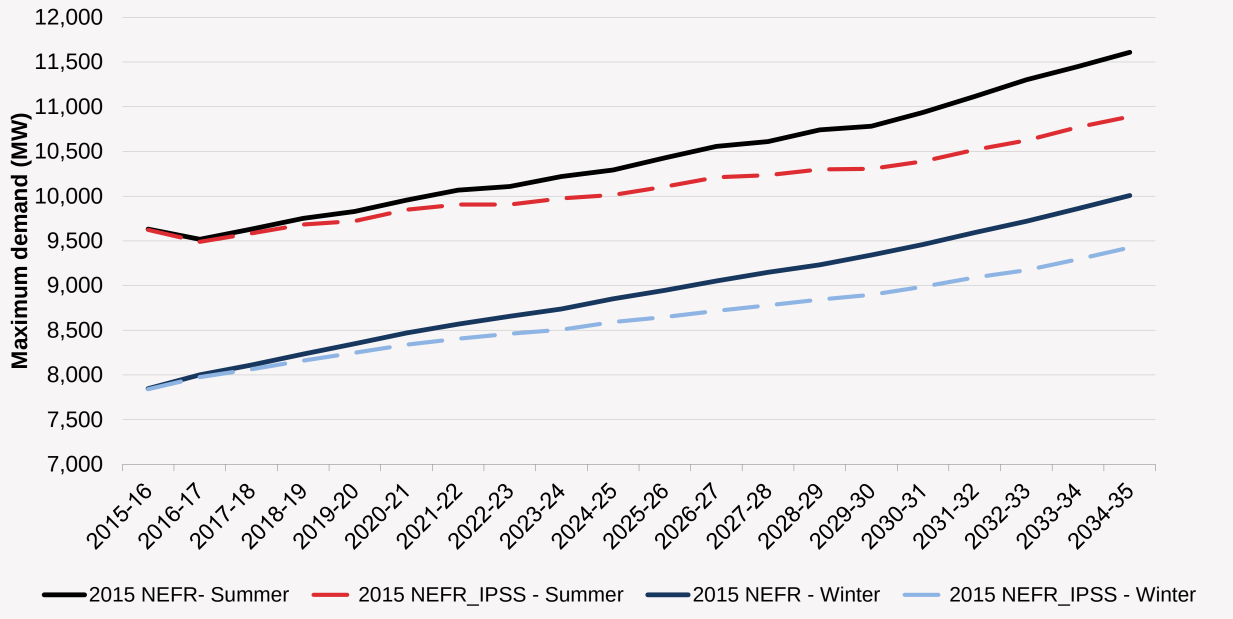


Table 19 shows the impact of IPSS on maximum demand in summer and winter by the end of the short, medium and long term outlook periods.

Table 19 Forecast impact of IPSS on 10% POE summer and winter maximum demand in Victoria

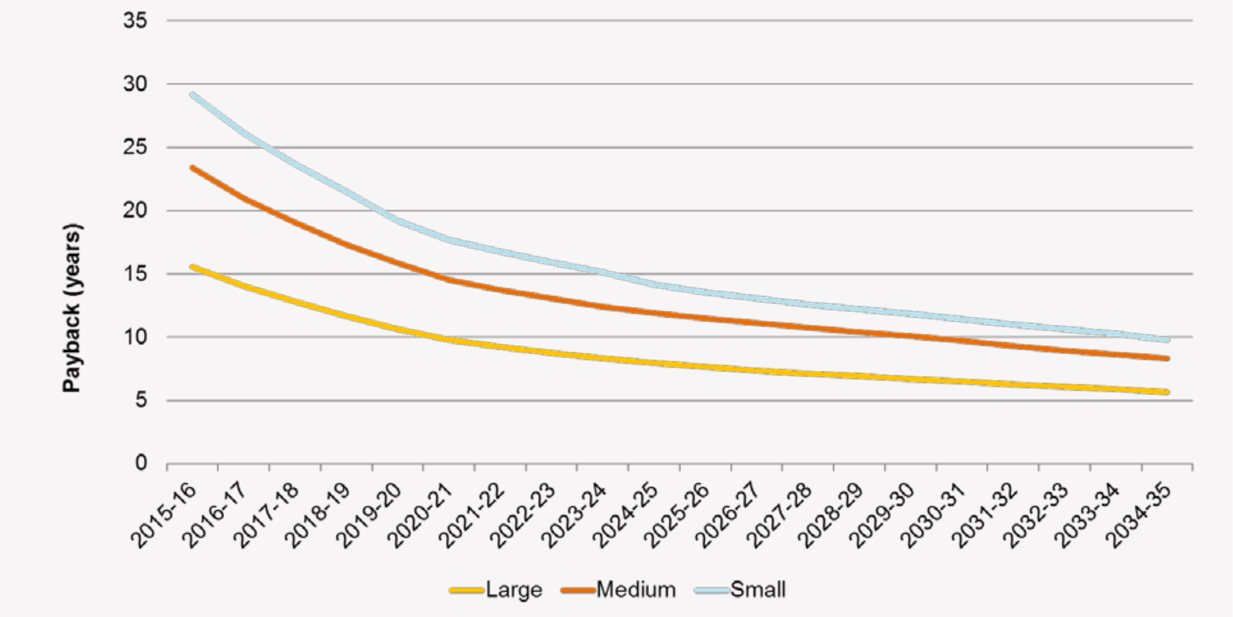
	Summer			Winter		
	MW	%	**Time of maximum demand**	MW	%	**Time of maximum demand**
2017–18	47.4	0.5%	No change	46.9	0.6%	No change
2024–25	280.2	2.7%	No change	258.7	2.9%	No change
2034–35	719.9	6.2%	No change	582.2	5.8%	No change

2.11 Tasmania forecasts

2.11.1 Uptake

Figure 31 shows the payback period for new installations of IPSS in Tasmania for each customer type. Tasmania is estimated to have the longest payback period at the beginning of the forecast, for all three household segments, with the smallest customers experiencing the longest payback period of the forecast, of 29 years. The payback period for large households is expected to be about 15.6 years, and will drop by half over the subsequent ten years. Payback periods are not projected to fall below ten years for medium and small customers until 2030–31 and 2034–35, respectively.

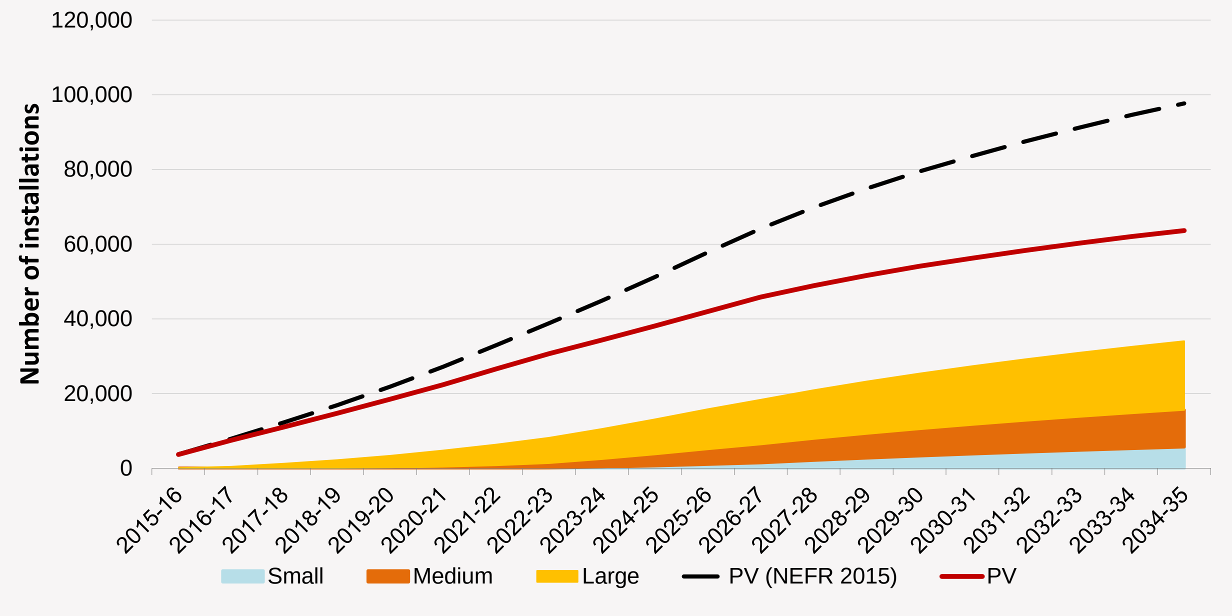
Figure 31 Estimated payback periods for IPSS in Tasmania



As Figure 32 shows, the payback relationships result in forecast uptake being dominated by large consumers. It shows cumulative new installations of IPSS over the 20-year outlook period from 2014–15. The black line indicates the uptake of new rooftop PV systems forecast in the 2015 NEFR (additional to the current 26,694 rooftop PV installations in Tasmania) when storage is not considered, while the red line indicates the cumulative number of new rooftop PV installations that do not include storage.

Comparatively, the payback for the installation of a 4 kW rooftop PV system is 9.6, 7.7 and 6.3 years, in 2017–18, 2024–25 and 2034–35 respectively.

Figure 32   Forecast new installations of PV and IPSS from 2015–16



Uptake of IPSS for the first four years is only by large consumers. By the end of the forecast period, this sector represents about half of the total storage installations.

As can be seen by the curve in installations, saturation begins to occur from 2025–26.

While IPSS constitutes 10% of new installations in 2017–18 and 26% by 2024–25, this represents only 3% and 17% of total households that have PV installed respectively. At the end of the forecast period, a total of 27% of residential rooftop installations could also have battery storage.

Figure 33 shows the forecast total installed capacity of rooftop PV in Tasmania, and the proportion of standalone residential PV, residential IPSS and commercial PV, while Table 20 summarises the installed capacity.

At the end of the forecast period it is estimated that a total of 35% of residential rooftop PV installations will have battery storage also, but this constitutes only 27% of total rooftop PV installed capacity.

Figure 33   Total installed capacity of rooftop PV and IPSS in Tasmania

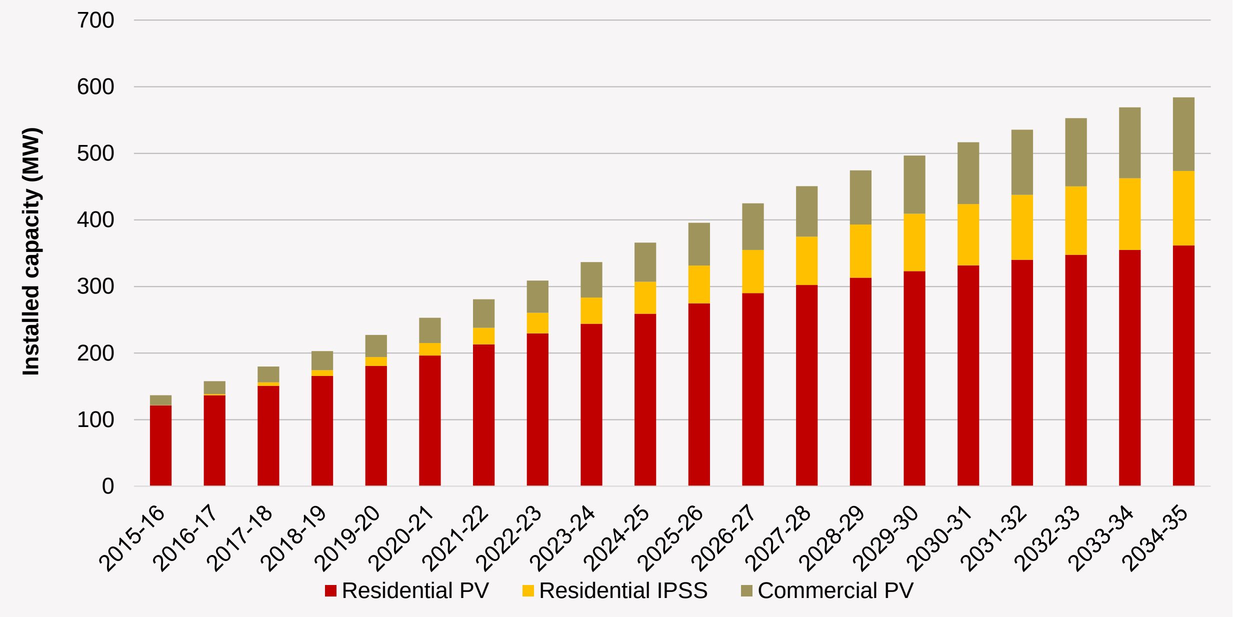


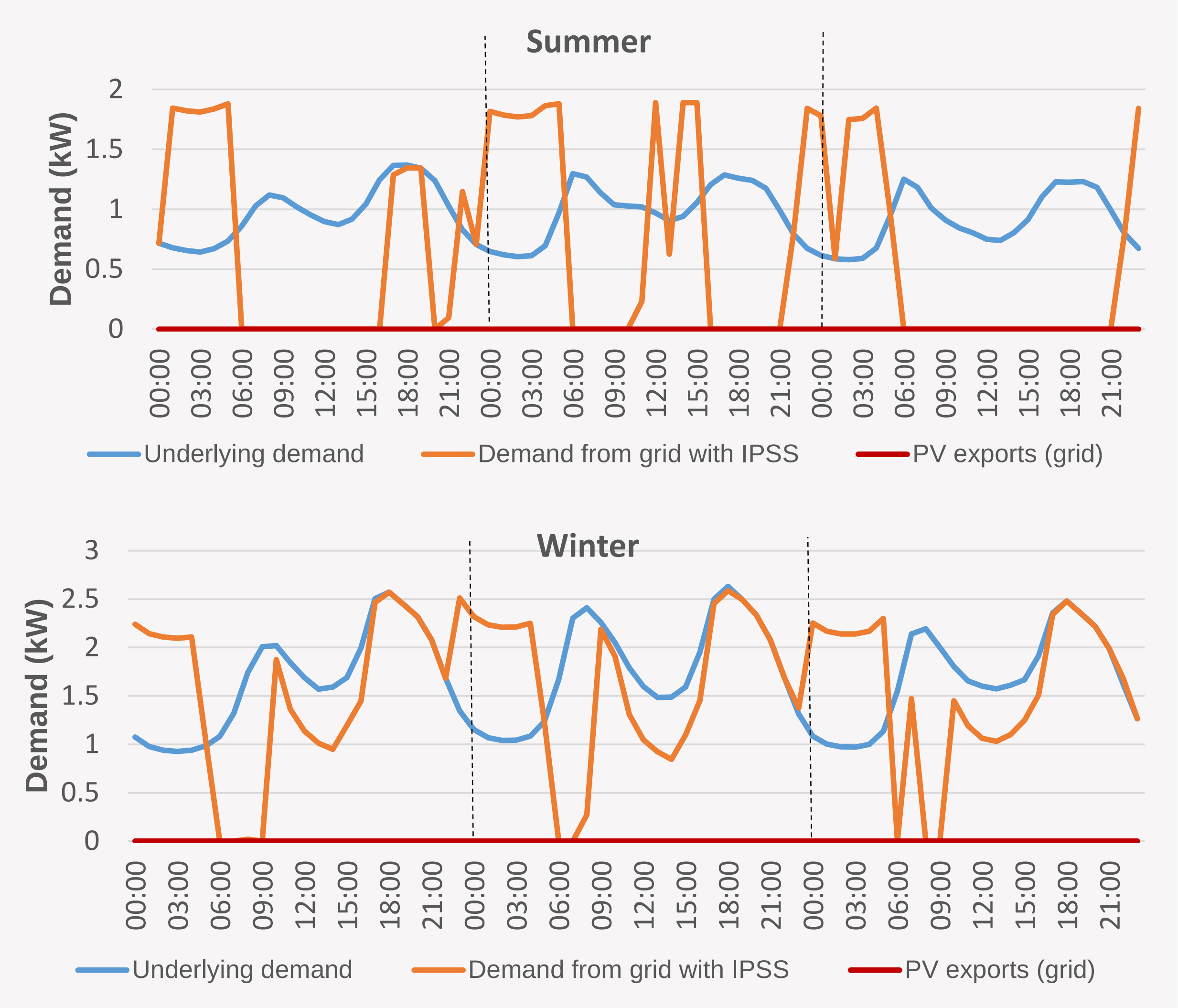
Table 20   Installed capacity of PV and IPSS in Tasmania

	Residential PV (MW)	Residential IPSS		Commercial PV (MW)	Percentage IPSS of total PV capacity (%)
		PV (MW)	Battery (MWh)		
2017–18	151	5	9	24	3%
2024–25	259	48	83	59	13%
2034–35	361	112	196	111	19%

2.11.2 Impact on household demand

The daily load profile of a large consumer household with IPSS, across three summer days and three winter days around times of regional maximum demand in 2014, is shown in Figure 34. This is a simplified profile, which shows the underlying household demand with no IPSS, and the modified demand from the grid after IPSS is installed. More detailed profiles showing the charge and discharge profile of the battery, as well as the PV generation, for each of the three types of consumer households, are in Appendix D.

Figure 34 Forecast impact of IPSS on daily load profile of large consumer in Tasmania around times of regional maximum demand



The underlying demand clearly shows the evening peak, in both summer and winter, due to heating and cooling loads.

The IPSS operates to minimise grid imports during times of peak charges under the current TOU tariff. These peak charges are applicable during 6:00 to 10:00, and 16:00 to 22:00 (see Appendix B).

In summer, the IPSS shifts the morning and evening household peaks to off-peak hours. This means the storage system is charged from the grid during off-peak hours, resulting in a higher peak than what would be observed without the IPSS. The size of the IPSS can be critical.

In winter, the IPSS shifts only the morning household peak to off-peak hours. There is minimal impact on the evening peak, at which point the storage system is almost fully depleted, due to lower PV generation in winter.

The red line indicates that no excess rooftop PV generation is exported to the grid across these high-demand days, in either summer or winter. On most normal days, however, there would still be exports, but this would be reduced with the IPSS (see Appendix C).

2.11.3 Impact on operational maximum demand

Since battery storage systems are assumed to operate to minimise household energy costs, these systems would discharge at times of high tariff charges, which typically coincide with peak network demand times. As a result, the increased penetration of storage systems has the potential to shift load from peak demand periods.

Assuming that households who install battery storage do not change their electricity consumption patterns, the overall electricity they consume over the day will remain unchanged, but their requirements for grid-supplied electricity will change as seen above.

Therefore, the net impact of battery storage on the national electricity grid will be downward pressure on operational maximum demand. The extent of this impact on the daily load profile, however, would be highly influenced by the tariff structures, which can vary widely depending on the region.

Figure 35 shows the 10% POE summer and winter maximum demand forecasts for Tasmania, with and without storage. The solid lines show the 2015 NEFR forecast and the dashed lines show the adjusted maximum demand forecast based on the projected uptake of storage.

The impact of storage on maximum demand is forecast to be small in the short term. By 2034–35, storage would reduce the summer and winter maximum demand by 18 MW and 5 MW respectively. It is interesting to note that maximum demand is expected to occur in the morning in summer, and early evening in winter. Of all regions, Tasmania is forecast to have the lowest uptake of IPSS and hence experience the smallest impact on maximum demand.

Figure 35 Tasmania summer and winter 10% POE maximum demand forecasts with and without IPSS

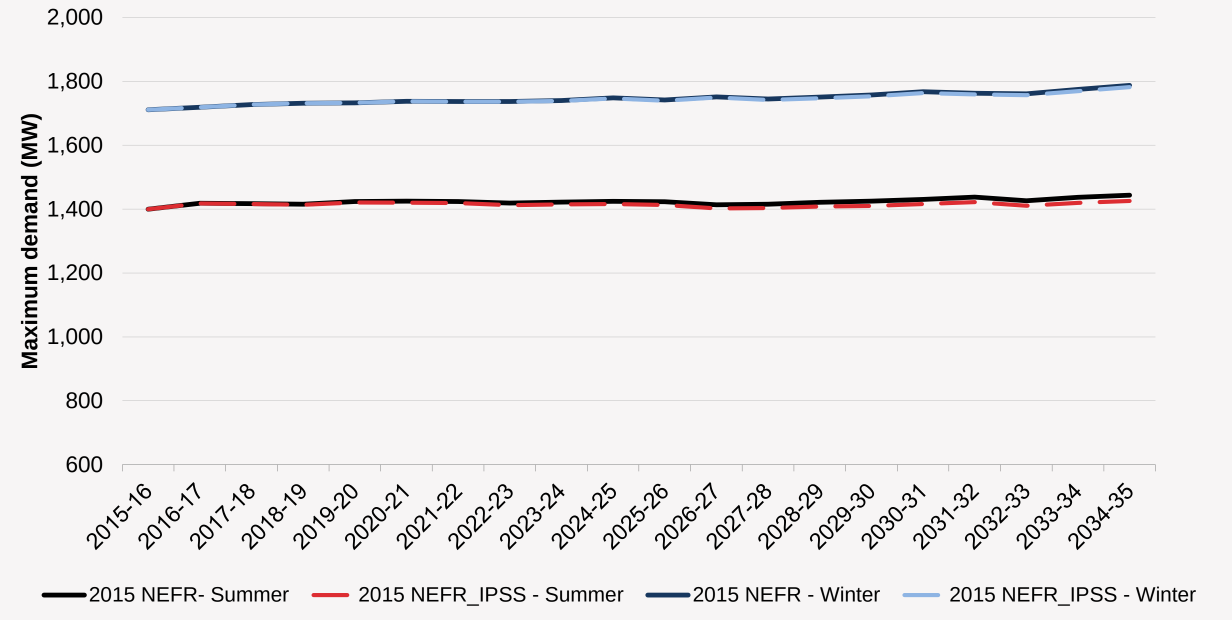


Table 21 shows the impact of IPSS on maximum demand in summer and winter by the end of the short, medium and long term outlook periods.

Table 21 Forecast impact of IPSS on 10% POE summer and winter maximum demand for Tasmania

	Summer			Winter		
	MW	**%**	**Time of maximum demand**	**MW**	**%**	**Time of maximum demand**
2017–18	1.3	0.1%	No change	0.0	0.0%	No change
2024–25	8.5	0.6%	No change	1.9	0.1%	No change
2034–35	18.3	1.3%	No change	5.3	0.3%	No change

CHAPTER 3. ELECTRIC VEHICLES

3.1 Introduction

Electric Vehicles

Recently there has been interest around the potential of electric vehicles (EVs), and more models have become available on the global market over the last two years. While costs remain high compared to conventional vehicles, EVs may become cost-competitive over the NEFR’s 20-year forecasting horizon. Internationally, government incentives have already seen an increase in uptake that has resulted in a decrease in EV battery costs, and manufacturers continue to develop new models.

In this paper, AEMO is addressing EVs (consumer passenger vehicles propelled by one or more electric motors, powered by rechargeable battery packs), and the potential impact of uptake on the NEM. The paper does not address:

- “Hybrid” electric vehicles (see below).
- Heavy transport or light commercial vehicles propelled by electric motors.
- Other fuel-powered vehicle technologies, such as hydrogen and fuel cells.

3.1.1 Technologies

These are the two main categories of battery rechargeable electric vehicles considered in this paper.

Vehicle	Description
Plug-in Hybrid Electric Vehicle (PHEV)	PHEVs are powered by an internal combustion engine and electric motor which can be recharged from the grid. This combination allows the vehicle to drive on electricity alone using battery energy, and, after the battery is discharged, continue driving using petrol much like a hybrid vehicle.
Battery Electric Vehicle (BEV)	Battery electric vehicles are powered by an electric motor and battery alone. Battery electric vehicles can travel farther on electricity alone than plug-in hybrids, but their range is limited by the size of their batteries. As battery technology develops, the expected range of the vehicles will increase.

Hybrid electric vehicles are popular vehicles that are powered by an internal combustion engine assisted by a battery and electric motor or motors. However, the batteries cannot be recharged with electricity drawn from the grid. Instead, they use technologies that turn off the petrol engine at a stop and use regenerative braking, which captures braking energy and stores it in the battery for use during acceleration. As their operation does not impact the national grid, they are not considered in this paper.

EVs can use three levels of charging infrastructure:

- Level 1 (nominal) charging requires only the standard 240V/10A sockets, power 2.4 kW.
- Level 2 (fast) charging requires installation of a unit capable of 240V/30A, power 7.2 kW.
- Level 3 (superfast) commercial and public charging stations are capable of 125A, 400-600V DC, power > 50-75 kW.

Depending on the battery and type of charging, it can take from one to eight hours to recharge an EV.

3.1.2 Australian context

A limited number of EVs have been available in Australia since 2010, and uptake has been minimal. Only 1,909 EVs were purchased in the NEM from 1 January 2010 to 30 April 2015. In 2014, a total of 1.1 million vehicles were sold in Australia, of which 228 were BEV (0.02%) and 953 were PHEV

(0.09%).[20] Table 22 shows the total number of electric vehicles purchased in each NEM region up to 30 April 2015.

Table 22 Total number of electric vehicles sold by region to 30 April 2015

	Qld	NSW & ACT	SA	Vic	Tas	NEM
PHEVs	204	296	376	306	15	1,197
BEVs	90	170	171	268	13	712

3.2 Forecasting the uptake of electric vehicles

3.2.1 Overview

AEMO does not expect large penetration of EVs in the short or long term, because:

- There are no significant policy incentives for consumers to purchase electric vehicles.
- Capital costs are currently prohibitive.
- There are key consumer barriers such as range anxiety, and lack of public infrastructure and awareness.

Previous studies estimating the uptake of EVs in Australia were developed in the context of clean transport policy scenarios, so cannot be directly translated to the current market.[21] However, these studies demonstrate how policy can drive uptake.

An EV uptake model would need to be based on both economic and behavioural decisions that influence purchasing.

Unlike other consumer behaviour, EV uptake is not based on binary decision-making (that is, consumers don’t face a yes–no choice, as they have a range of models and options to choose from), and would be impacted by other factors outside the model, such as availability of public infrastructure.

As this is an emerging market, there is very little data available to inform modelling. AEMO decided not to explicitly model the predicted uptake of EVs in the NEM, but instead developed an EV User Tool[22] to demonstrate the impact on operational consumption and daily demand of an assumed percentage uptake of PHEVs and BEVs. This paper presents AEMO’s view of a medium scenario.

The EV User Tool can be used to create alternative scenarios to that presented here. It shows the impact to the 2015 NEFR operational consumption and maximum demand forecasts.

AEMO will continue to monitor developments in the market and implement improvements in its modelling approach over time. This may include the development of an economic uptake model.

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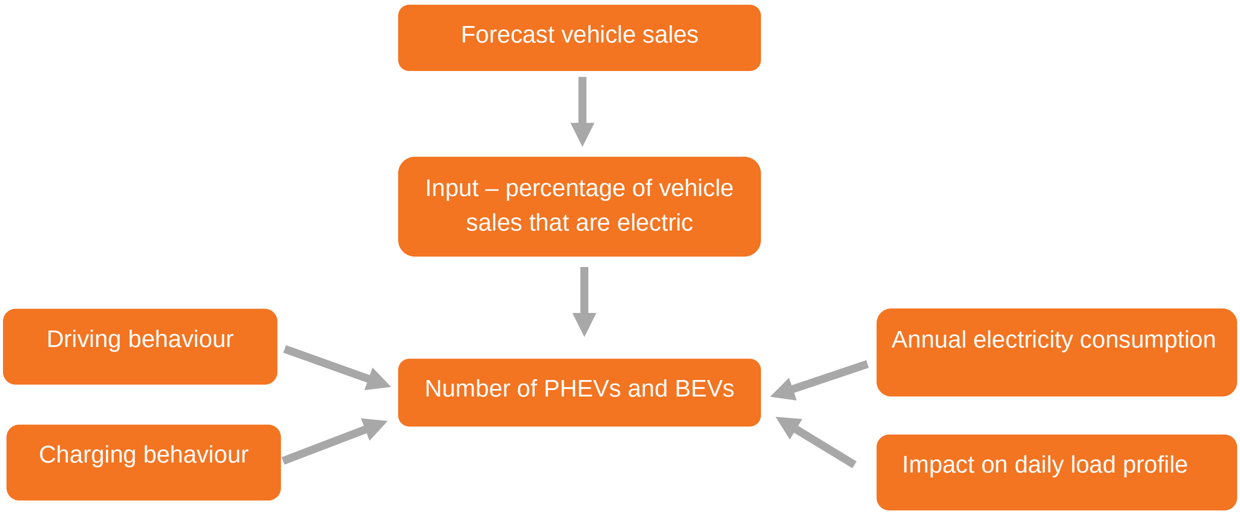
[20] Federal Chamber of Automotive Industries, http://www.fcai.com.au/ provided 5 May 2015.

[21] AECOM, Impact of Electric Vehicles and Natural Gas Vehicles on the Energy Markets, May 2012. CSIRO, Road transport sector modelling: supplementary report on Clean Energy Future and Government Policy scenarios, September 2011.

[22] Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information

Figure 36 Overview of methodology



3.2.2 Assumptions

To estimate the impact of EVs on operational consumption and the daily load profile, assumptions need to be made on the mix of vehicle models, technology specifications, vehicle sales, driving behaviour, and charging behaviour.

Vehicle models and specifications

Only vehicle models currently available in the Australian market are considered (excluding the Mitsubishi i-MiEV, which has been discontinued beyond clearing current stock). Although many car manufacturers have released new models and plans to develop new EVs, many have publicly stated that unless Australia has strong government incentives to facilitate uptake, they will not be sold here.[23]

AEMO applied a weighted average of the 2014 sales by model, and this was assumed to remain true across the forecast period. Table 23 summaries the key assumptions for both vehicle classes.

Table 23 Vehicle assumptions

Vehicle Class	Fuel efficiency (Wh/km)	Fuel efficiency annual improvement (%)[24]
PHEV	134[25]	0.45
BEV	170	0.45

This paper also only considers the passenger vehicle market, as it is the largest sector. There are a limited number of electric vehicle models in the light commercial segment, but there have been few sales in Australia and they are not considered in AEMO's methodology.

It is also assumed that PHEVs drive on electricity 90% of the time (this allows for the electric motor to recharge by regenerative braking).

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[23] See for example http://www.news.com.au/technology/innovation/the-30000-electric-car-designed-by-holden-in-australia-that-will-never-be-sold-here/story-fnjwucvh-1227182770578

[24] AECOM, Forecast Uptake and Economic Evaluation of Electric Vehicles in Victoria, 2011

[25] This is based on the Mitsubishi Outlander which has dominated recent sales in the PHEV market. There has been speculation about the future of the Holden Volt in the Australian market due to declining sales. See for example http://www.drive.com.au/motor-news/holden-volt-could-face-axe-20150106-12io19.html

Vehicle sales

Total vehicle sales are forecast based on historical data from the Australian Bureau of Statistics (ABS) for each region.[26] Table 24 shows the number of sales assumed to be EVs.[27] A linear growth rate is assumed from the current sales percentage to 2019–20 and 2029–30, slowing after 2029–30.

Table 24 Assumed percentage of new vehicle sales that are electric

	Percentage sales in 2019–20	Percentage sales in 2029–30
Electric vehicles	2%	5%

These forecasts represent the aggregate percentage of EV sales for the NEM. To determine an estimated proportion of sales within each region, AEMO applied the current market breakdown, adjusted to remove fleet purchases as part of some state government trials.

EVs are assumed to have a life of 10 years, which is the average lifetime of Australian cars. Based on this, the assumed number of EVs N_t in use in any given year t is:

$$N_t = N_{t-1} + P_t \times S_t - N_{t-10}$$

where P_t is the percentage of sales that are electric, and S_t is the total number of new vehicle sales.

AEMO has taken a conservative approach in estimating the uptake of EVs given the current market and policy landscape. The purpose of the EV User Tool is to allow other uptake scenarios to be explored.

Driving behaviour

The annual electricity consumption due to EVs will depend on the total mileage. Average annual driving distances for passenger vehicles were taken from a 2013 ABS survey and are displayed for each region in Table 25.

Table 25 Average annual distance driven (km)[a]

NEM	NSW & ACT	Vic	Qld	SA	Tas
13,740 km	13,060 km	13,700 km	15,400 km	12,600 km	12,000 km

[a] Australian Bureau of Statistics, Survey of Motor Vehicle Use, Australia (9208.0), 2013

Driving behaviour is likely to differ for EVs, compared with conventional cars, due to range anxiety.[28] Rather than using transport surveys to determine the average daily distance driven, AEMO derived assumptions on EV driving patterns using data from an EV trial run by AusGrid as part of their Smart Grid, Smart City program.[29] The average daily distance travelled was 48 km, and this assumption is applied across all regions of the NEM.

Charging behaviour

The impact of EVs on the daily load profile and maximum demand depends on how and when they are charged. Charging is likely to be influenced by the availability of public infrastructure, tariff structures, any energy management systems, and the driver's routine.

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[26] Australian Bureau of Statistics, Sales of New Motor Vehicles, Australia (9314.0), Dec 2014

[27] AGL, Electric Vehicles in the NEM: energy market and policy implications, October 2011.

[28] Range anxiety refers to driver concern about the distance an electric vehicle can travel without recharging. This distance is a lot less than the distance conventional vehicles can achieve on a full tank of fuel.

[29] Data from AusGrid's EV trial as part of Smart Grid, Smart City, http://www.smartgridsmartcity.com.au/Ausgrid-trial/Network-customer-trials/Electric-cars.aspx

The impact of EVs on daily demand also depends on the number of cars charging on any given day. This number is determined for each region based on the average daily distance travelled and the annual average distance.

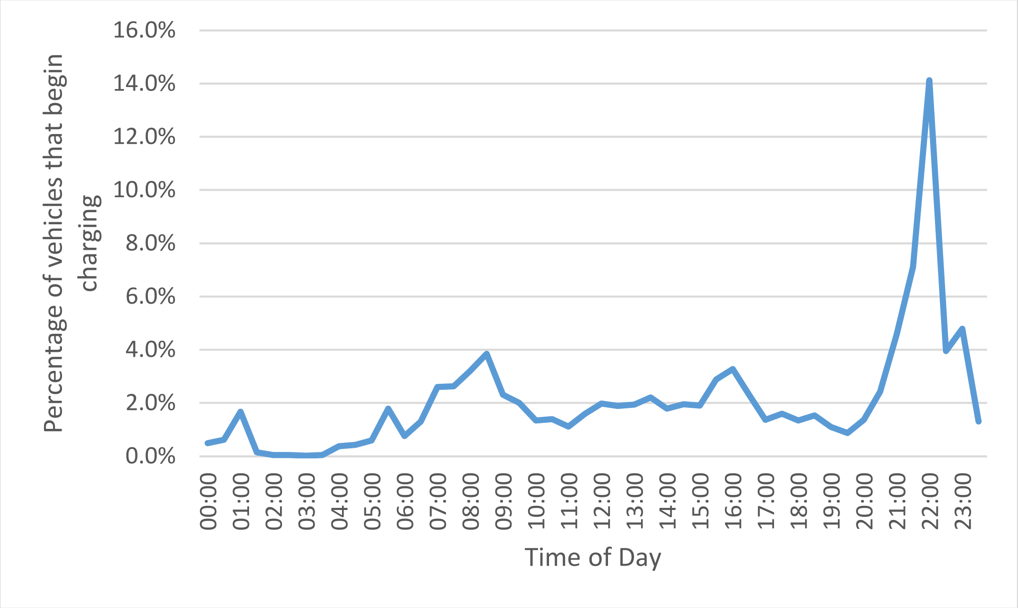
AEMO applied the following assumptions:

- Owners charge their battery at the end of each daily journey (48km), so only partial charging is required.
- Nominal charging for all vehicles.
- The battery does not export any electricity to the grid.
- Charging times are random, and based on the average charging start times by participants in the Smart Grid, Smart City trial. This profile is shown in Figure 37.

Based on the average annual distance travelled, AEMO determined the number of vehicles that would be charging on any given day.

The EV User Tool also calculates the impact under different charging assumptions and allows for a customised charging profile.

Figure 37 Percentage of electric vehicles that commence charging during the day



3.3 Forecast impact of EVs in NEM regions

3.3.1 Operational consumption

Table 26 shows the contribution to annual operational consumption of EVs for each NEM region, while Table 27 shows the consumption of EVs as a percentage of the residential and commercial consumption in each region.

Overall, with this projected uptake of EVs, their impact on annual consumption forecasts in the 2015 NEFR is small in the short term and grows only slightly over the long term.

Table 26 Summary of projected number of EVs and the annual consumption for each NEM region

		2017–18	2024–25	2034–35
Queensland	Number of EVs	1,927	26,963	85,323
	Consumption (GWh)	4	52	158
New South Wales	Number of EVs	2,531	37,495	118,728
	Consumption (GWh)	4	61	186
South Australia	Number of EVs	2,959	52,281	167,045
	Consumption (GWh)	4	78	239
Victoria	Number of EVs	3,521	46,877	146,999
	Consumption (GWh)	7	85	255
Tasmania	Number of EVs	154	2118	6,680
	Consumption (GWh)	0	3	10
NEM	Number of EVs	**11,092**	**165,734**	**524,775**
	Consumption (GWh)	**19**	**279**	**848**

Table 27 Percentage contribution of EVs to residential and commercial consumption in each NEM region

	Queensland	New South Wales	South Australia	Victoria	Tasmania	NEM
2017–18	0.01%	0.01%	0.05%	0.02%	0.01%	**0.01%**
2024–25	0.16%	0.11%	0.89%	0.22%	0.10%	**0.20%**
2034–35	0.44%	0.28%	2.69%	0.60%	0.28%	**0.54%**

3.3.2 Impact on demand

The impact of EV charging on the transmission grid is negligible, based on this small uptake. If there were a significant uptake of EVs within the same region, then they would be some expected impact on the local level and AEMO is currently investigating this.

Queensland

The average typical daily load[30] in 2014–15 in Queensland varies from 4,860 MW to 7,114 MW. Figure 38 below shows the contribution from EVs.

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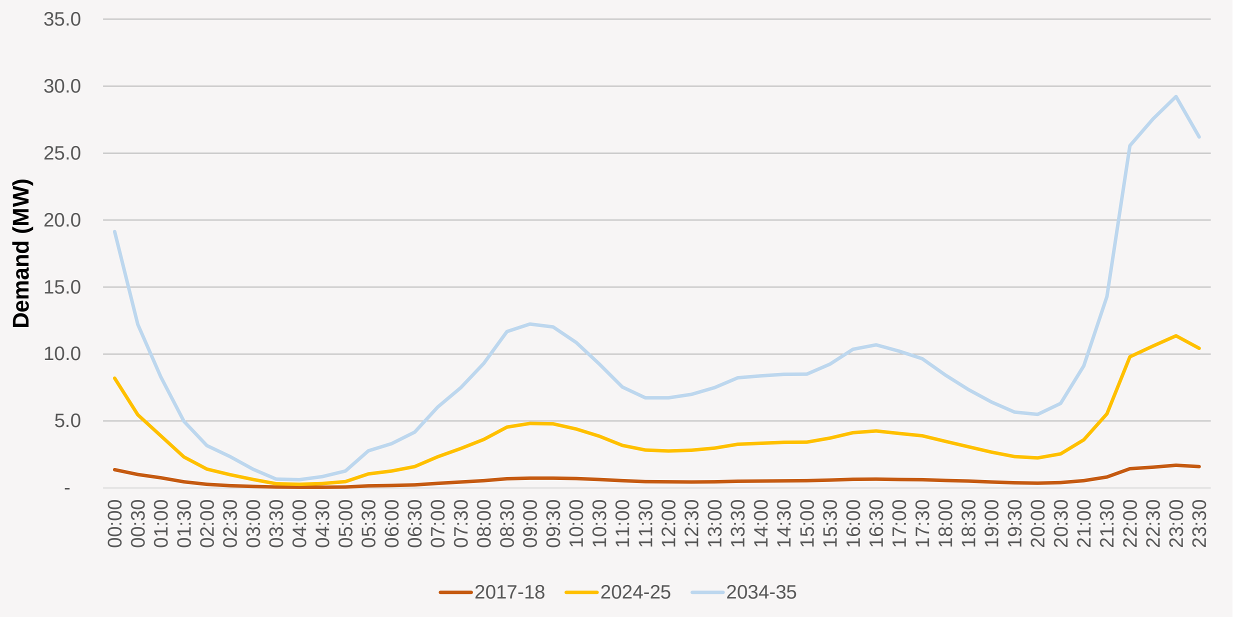
[30] Based on the 50% POE.

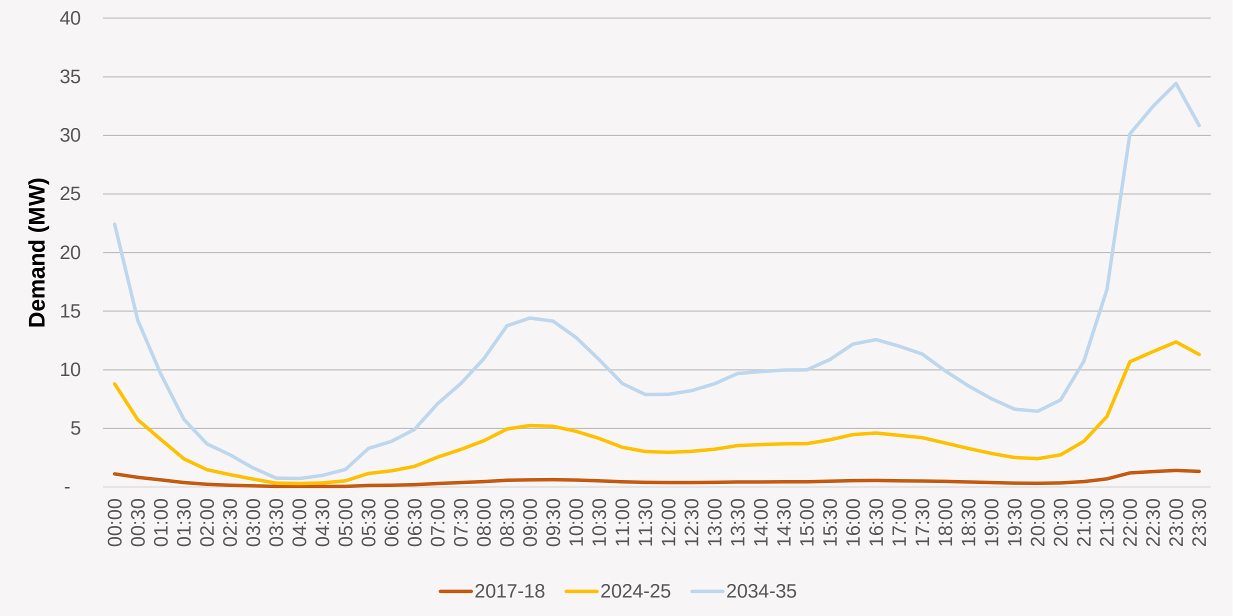
Figure 38 Contribution to daily load profile in Queensland



New South Wales

The average typical daily load in 2014–15 in New South Wales varies from 6,096 MW to 9,181 MW. Figure 39 below shows the contribution from EVs.

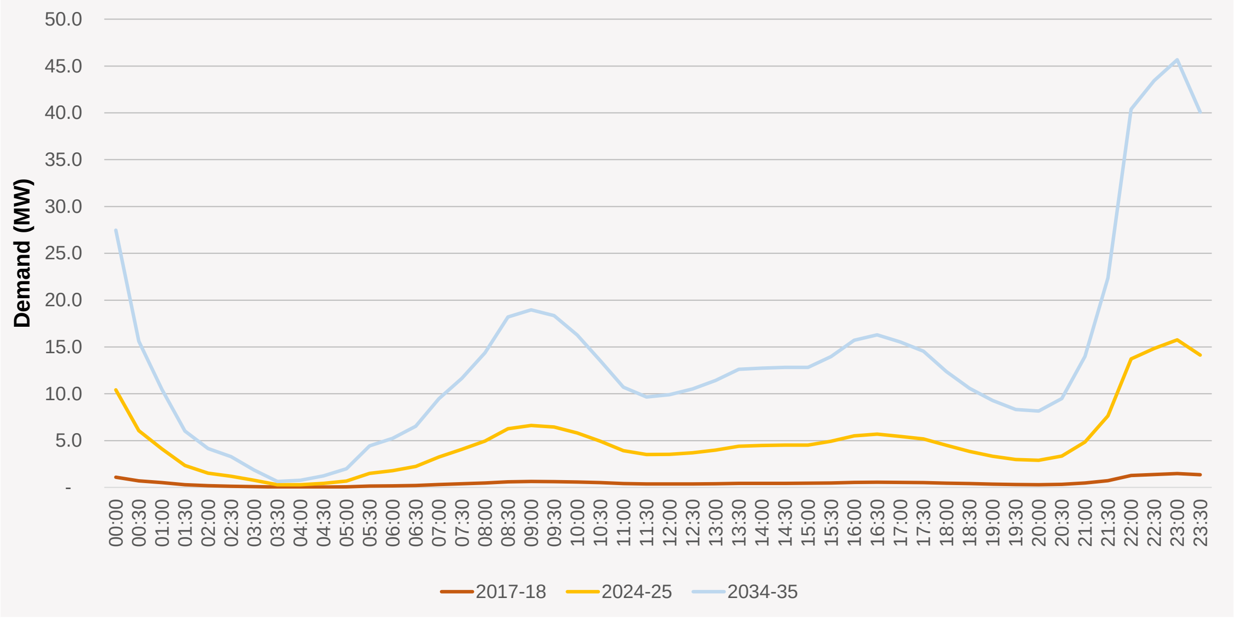
Figure 39 Contribution to daily load profile in New South Wales



South Australia

The average typical daily load in 2014–15 in South Australia varies from 1,241 MW to 1,669 MW. Figure 40 below shows the contribution from EVs.

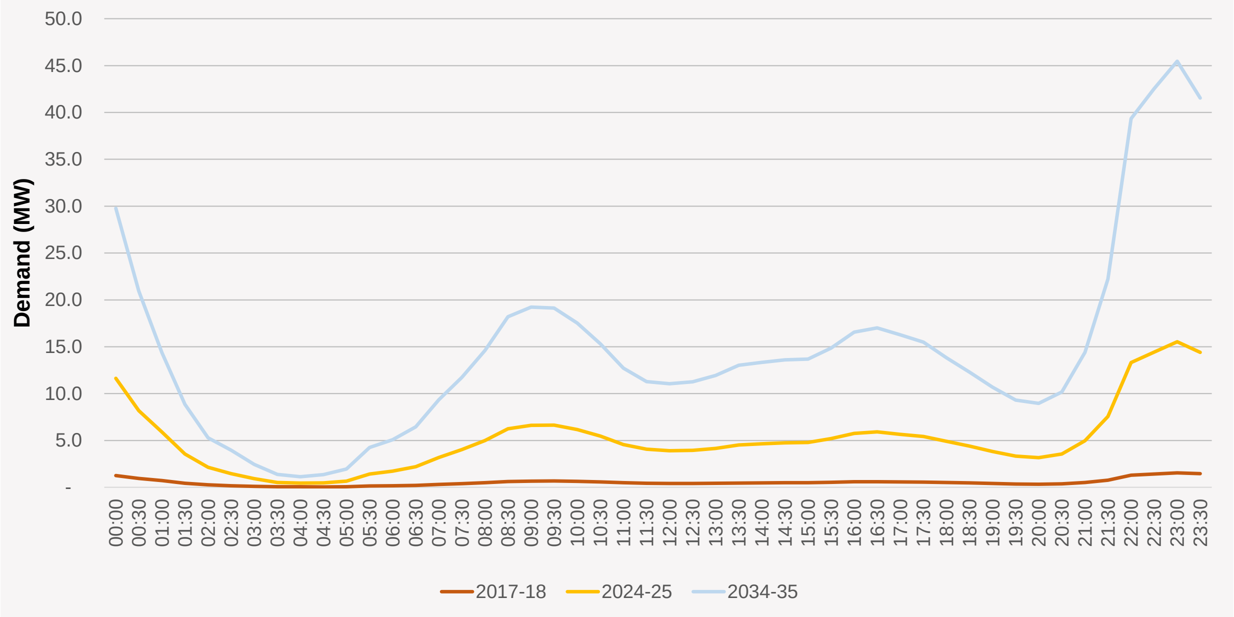
Figure 40 Contribution to daily load profile in South Australia



Victoria

The average typical daily load in 2014–15 in Victoria varies from 4,304 MW to 5,610 MW. Figure 41 below shows the contribution from EVs.

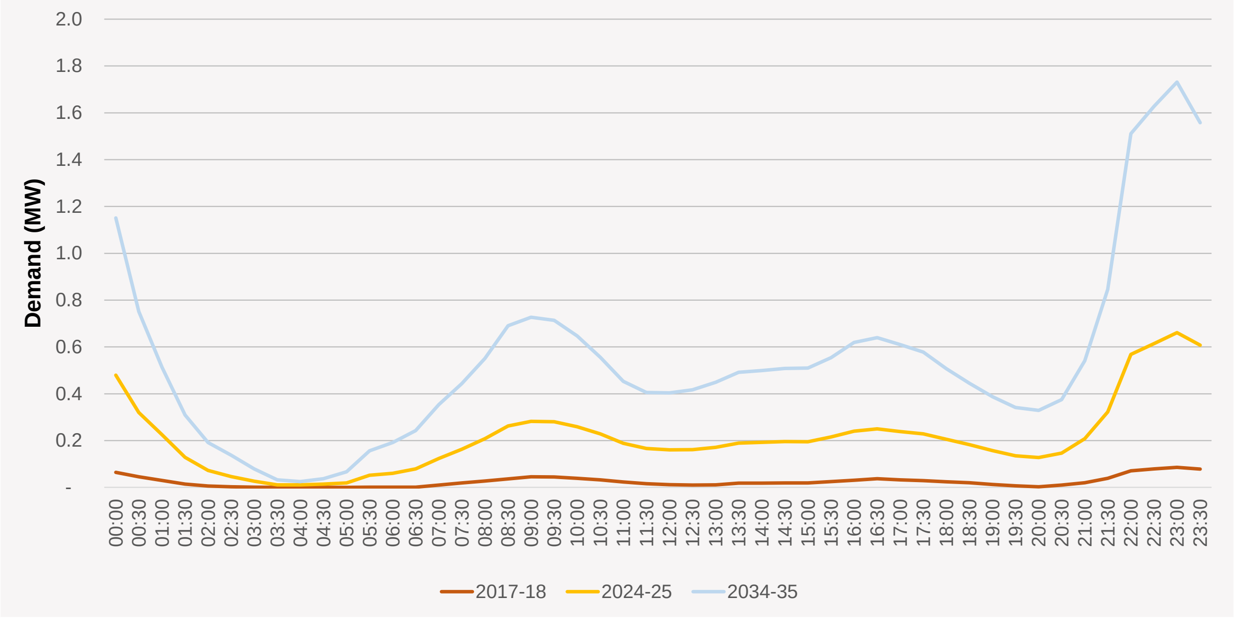
Figure 41 Contribution to daily load profile in Victoria



Tasmania

The average typical daily load in 2014–15 in Tasmania varies from 1,011 MW to 1,190 MW. Figure 42 below shows the contribution from EVs.

Figure 42 Contribution to daily load profile in Tasmania



CHAPTER 4. RESIDENTIAL FUEL SWITCHING

4.1 Introduction

Residential Fuel Switching

Expected retail gas price rises across Australia can affect the affordability of using residential gas appliances for space heating, water heating and cooking. Consumers may choose to reduce gas usage or replace gas appliances with electric appliances when the gas-electricity price ratio is high.

Using an assessment of the economic viability of switching from gas to electricity appliances, AEMO currently expects the impact of fuel switching to be low across the National Electricity Market (NEM) during the 2015 NEFR forecast period.

Although fuel switching is already viable in some NEM regions, and higher gas prices will make it more viable between 2015–16 and 2035–36, the low proportion of households eligible to switch, and the high upfront cost of efficient electric appliances relative to annual energy cost savings, limits its impact on the NEM.

AEMO will continue to monitor gas and electricity price forecasts, further develop the residential switching analysis and incorporate commercial and industrial consumers in its analysis.

4.1.1 What is fuel switching?

For residential consumers, fuel switching involves replacing gas-powered appliances with electric-powered ones for space heating, water heating and cooking. Consumers may choose to switch fully to electricity for all three thermal needs, or switch partially to meet one or two of those needs.

The consumer’s decision rests on a range of factors. They include gas and electricity prices, appliance types and lifespans, capital costs, installation costs and how the appliances fit particular lifestyles.

There is also a behavioural component related to personal choice. Some households may prefer ducted gas heating or gas cooking, even though they may not be better economically. Gas water heaters are often replaced only when they have reached the end of their useful life, regardless of the longer-term economics of switching to efficient electric water heaters. As changing fuel prices and advances in technologies such as induction cooking emerge, economics may become more dominant over behavioural preferences.

This paper focuses on residential fuel switching, building on recent research by the Alternative Technology Association (ATA) in this area.[31] AEMO plans to extend the analysis to commercial and industrial consumers as data on their energy use breakdowns becomes available.

4.1.2 The Australian context

Overseas demand for Australia’s liquefied natural gas (LNG) exports, coupled with higher prices internationally, are expected to drive higher retail gas prices in Australia over time. Fuel switching becomes more favourable in this light, where retail gas prices are forecast to rise while at the same time retail electricity prices remain stable, or decline.

Forecast annualised retail electricity and gas price for residential consumers are shown in Table 28.[32,33]

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[31] ATA, 2014, ‘Are we still Cooking with Gas?’, http://www.ata.org.au/wp-content/projects/CAP_Gas_Research_Final_Report_251114_v2.0.pdf

[32] Electricity price forecasts available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/~/media/Files/Electricity/Planning/Reports/NEFR/2015/150420%20AEMO%202015%20Electricity%20price%20forecasts%20%20Final%20External%20STC.ashx

[33] Gas price forecasts available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/~/media/Files/Other/planning/NEFR/2014/2014%20Supplementary/IE_Economic_Forecast_2014_FINAL.ashx

Table 28 Residential fuel prices annualised growth (2014–15 to 2044–45)

Prices	Queensland	New South Wales	South Australia	Victoria	Tasmania
Electricity price growth	0.9%	0.5%	0.7%	0.8%	1.0%
Gas price growth	0.8%	0.9%	1.2%	2.1%	0.9%

Residential consumer diversity is a key factor underlying the dynamics of fuel switching. Households have different thermal energy needs depending on dwelling size and the region in which they live, and the proportion of households with gas-powered appliances varies considerably between NEM regions. For example, the penetration of gas-powered space heating (GSH), based on Australian Bureau of Statistics (ABS) data, is as low as 2% in Queensland and as high as 64% in Victoria (see Table 29). [34].

Table 29 Households with gas-powered space heating (GSH) in NEM regions

Households	Queensland	New South Wales	South Australia	Victoria	Tasmania
GSH	41,700	775,700	170,700	1,443,500	8,600
Total	1,828,100	2,995,700	691,400	2,243,900	210,600
%	2%	26%	25%	64%	4%

4.2 Forecast impact of fuel switching in NEM regions

AEMO undertook an economic assessment of residential fuel switching for each NEM region. The model assumes that households would fuel switch when economically viable, and ignores behavioural preferences. The change in electricity consumption per dwelling, and the impact on operational consumption, was calculated.

AEMO expects the impact of residential fuel switching on operational consumption to be low. This is due to the small proportion of households able to switch and the high upfront cost of efficient electric appliances relative to annual energy cost savings.

Table 30 shows the cumulative impact on operational consumption, in the short-term (2014–15 to 2017–18), medium-term (2017–18 to 2024–25), and long-term (2024–25 to 2034–35) outlook periods.

New South Wales contributes the largest initial impact, as switching is economical for households in this region at current retail gas and electricity prices. Victoria is the last region for which switching is economical, but it contributes the largest impact overall in the long term, due to the large number of households with gas space heating in this region.

Table 30 Forecast Impact on Operational Consumption (GWh)

Year	NEM	Queensland	New South Wales	South Australia	Victoria	Tasmania
2017–18	31.5	1	23	7	-	0.5
2024–25	815	32	502	153	120	8
2034–35	2,552	38	608	182	1,715	9

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[34] ABS, 2014, '4602.0.55.001 - Environmental Issues: Energy Use and Conservation', http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/4602.0.55.001Mar%202014

APPENDIX A. LINEAR PROGRAM ALGORITHMS

Inequality Constraints

1. PV exports: -PV inverter outflow ≤ Exports
2. Max imports: Imports ≤ Max imports
3. Integer charge: -Storage charge – 100 (integer) ≤ 0
4. Integer discharge: Storage discharge + 100 (integer) ≤ 100
5. Integer imports: Imports – 100 (integer) ≤ 0
6. Integer exports: -Exports + 100 (integer) ≤ 100

Inequality Constraints

1. PV exports: -PV inverter outflow ≤ Exports
2. Max imports: Imports ≤ Max imports
3. Integer charge: -Storage charge – 100 (integer) ≤ 0
4. Integer discharge: Storage discharge + 100 (integer) ≤ 100
5. Integer imports: Imports – 100 (integer) ≤ 0
6. Integer exports: -Exports + 100 (integer) ≤ 100

Equality Constraints

1. Supply: Supply = Solar PV generation
2. Demand: Demand = Demand values from smart meter profiles
3. AC balance: Demand = (Imports – Exports) + (Storage inverter outflow – Storage inverter inflow) + PV inverter outflow
4. Solar PV balance: PV inverter outflow = (PV × efficiency) – (PV dump × efficiency)
5. Battery Balance: Storage end = storage start + (Charge × Efficiency) – Discharge
6. Battery Inflow: Storage charge = Storage inverter inflow × Efficiency
7. Battery Outflow: Storage inverter outflow = Discharge × Efficiency

Lower and Upper Bounds

1. Solar PV: 0 ≤ PV ≤ PV max power
2. PV dump: 0 ≤ PV dump ≤ Infinity
3. PV inverter outflow: 0 ≤ PV inverter outflow ≤ PV inverter max power
4. Storage start: Max capacity × Depth of Discharge ≤ Storage Start ≤ Max Capacity
5. Storage end: Max capacity × Depth of Discharge ≤ Storage End ≤ Max Capacity
6. Storage charge: - Max Power ≤ Storage Charge ≤ 0
7. Storage discharge: 0 ≤ Storage Discharge ≤ Max Power
8. Storage inv. Inflow: - Storage inverter max power ≤ Storage inverter inflow ≤ 0
9. Storage inv. Outflow: 0 ≤ Storage inverter outflow ≤ Storage inverter max power

10. Demand: - Infinity ≤ Demand ≤ 0
11. Max imports: Minimum capacity charge ≤ Max Imports ≤ Infinity
12. Imports: 0 ≤ Imports ≤ Infinity
13. Exports: - Infinity ≤ Exports ≤ 0
14. Integer battery: 0 ≤ Integer Battery ≤ 1
15. Integer charge: 0 ≤ Integer Charge ≤ 1

APPENDIX B. RETAIL ELECTRICITY TARIFFS

The below tariffs are the tariff within each of the category of available tariff structures in each region which gave the most economically favourable results to the household.

Tariffs offered by all retailers were considered in Phase 1 of the analysis but the ones listed below were then used for the other components of the modelling. These were true as at 31 May 2015.

Queensland Tariffs

State	Retailer	Distributor	Energy Rate incl. GST (cents/kWh)	Connection incl. GST (cents/day)
Flat	Click	Energex	29.312	96.344
Time-of-Use	Click	Energex	Peak (4pm to 8pm; Mon to Fri): 35.741 Shoulder (7am to 4pm and 8pm to 10pm; Mon to Fri. 7am to 10pm Sat and Sun): 24.201 Off Peak (all other times): 20.163	134.683
Feed-in Tariff	Click	Energex	6.0	

New South Wales Tariffs

State	Retailer	Distributor	Rate incl. GST (cents/kWh)	Connection incl. GST (cents/day)
Inclining Block	Lumo	Ausgrid	First 10.96 kWh/day: 24.651 Next 10.96 kWh/day: 26.279 Remaining: 28.59	76.461
Time-of-Use	Lumo	Ausgrid	Peak (2pm to 8pm; Mon to Fri): 49.808 Shoulder (7am to 2pm and 8pm to 10pm; Mon to Fri. 7am to 10pm Sat and Sun): 19.107 Off Peak (all other times): 10.428	85.349
Feed-in tariff	Lumo	Ausgrid	5.5	

South Australia Tariffs

State	Retailer	Distributor	Rate incl. GST (cents/kWh)	Connection incl. GST (cents/day)
Inclining Block	AGL	SA Power Networks	First 3.2877 kWh/day: 31.79 Next 7.6712 kWh/day: 32.406 Remaining: 38.335	70.169
Capacity	AGL	SA Power Networks	29.271 Summer 4pm to 8pm Capacity rate:1800 Minimum rate: 1.5 Winter 4pm to 8pm Capacity rate: 900 Minimum rate: 1.5	40.392
Feed-in tariff	AGL	SA Power Networks	8.0	

Victoria Tariffs

State	Retailer	Distributor	Energy Rate incl. GST (cents/kWh)	Connection incl. GST (cents/day)
Flat	Dodo	United Energy	29.568	91.2
Time-of-Use	Dodo	United Energy	Peak (3pm to 9pm; Mon to Fri): 42.812 Shoulder (7am to 3pm; Mon to Fri): 29.568 Off Peak (all other times): 15.686	109.989
Time-of-Use	AGL	United Energy	Peak (3pm to 11pm; Mon to Fri): 33.484 Off Peak (all other times): 15.422	124.179
Feed-in Tariff	Dodo/AGL	United Energy	8.0	

Tasmania Tariffs

State	Retailer	Distributor	Energy Rate incl. GST (cents/kWh)	Connection incl. GST (cents/day)
Flat	Aurora		24.717	87.677
Time-of-Use	Aurora		Summer Peak (6am to 11am and 4pm to 10pm; Mon to Fri): 25.86 Shoulder (11am to 4pm; Mon to Fri and 6am to 10pm Sat and Sun): 20.13 Off Peak (all other times): 11.74 Winter Peak (6am to 11am; Mon to Fri): 25.90 Shoulder (11am to 8pm; Mon to Fri and 6am to 8pm Sat and Sun): 20.80 Off Peak (all other times): 16.43	132.4
Feed-in Tariff	Aurora		5.6	

APPENDIX C. AVERAGE DAILY LOAD PROFILES WITH IPSS

Figure 43 Average daily profile of a Queensland large consuming household

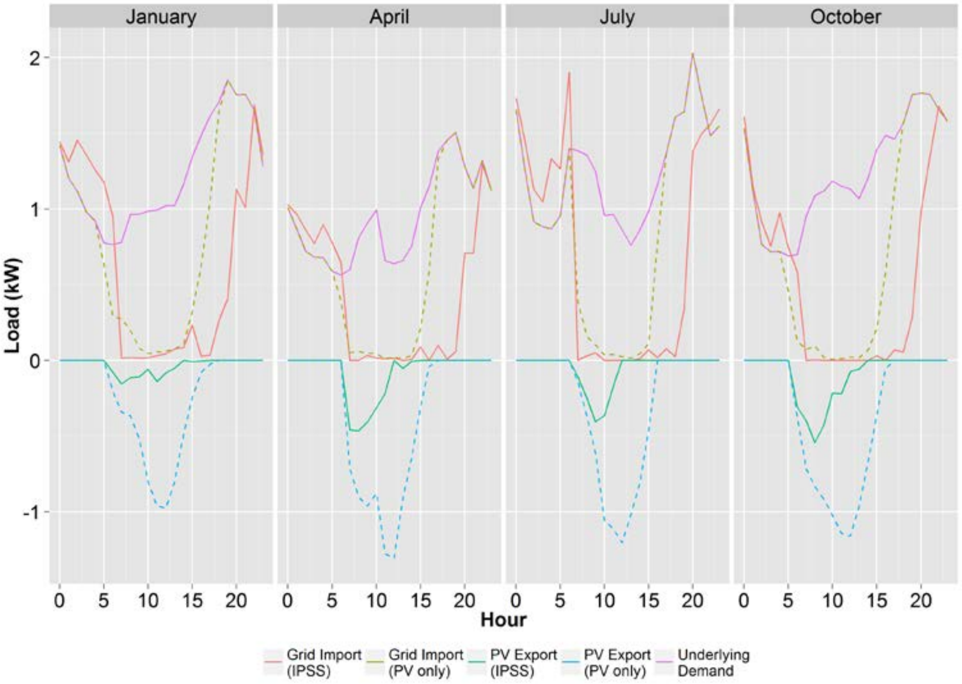


Figure 44 Average daily profile of a New South Wales large consuming household

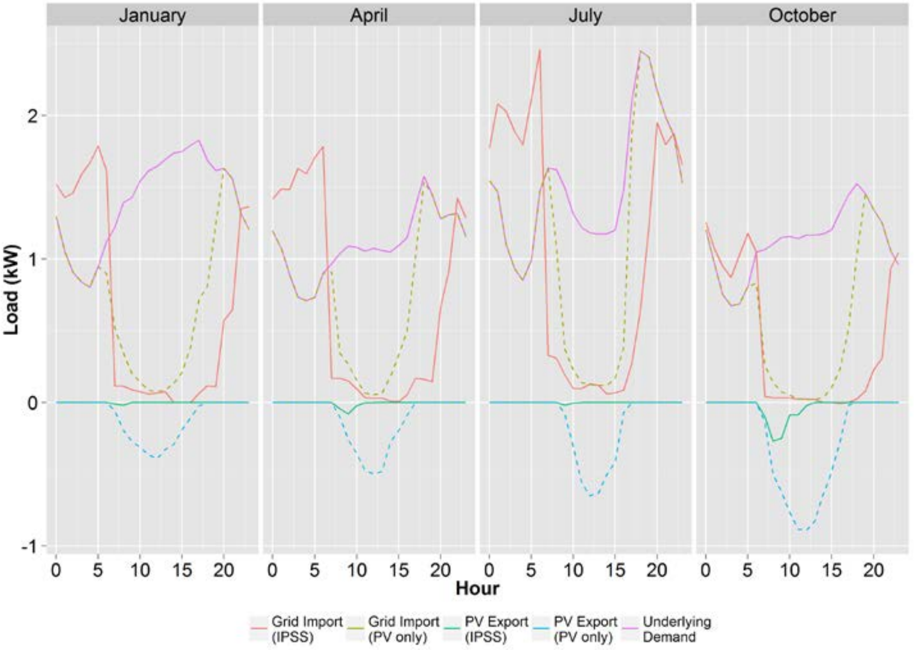


Figure 45 Average daily profile of a South Australia large consuming household

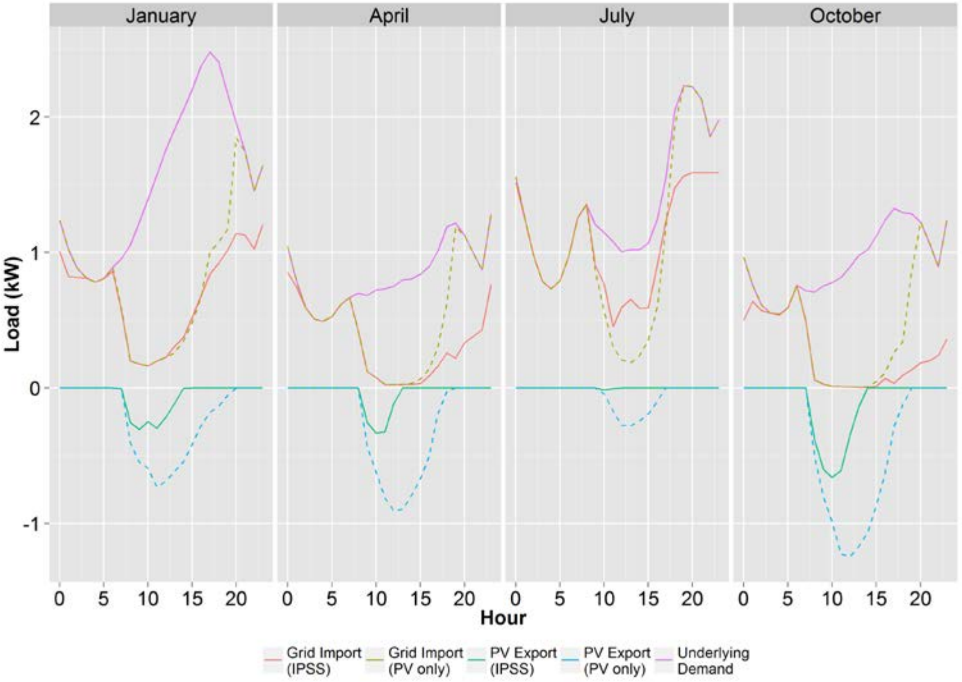


Figure 46 Average daily profile of a Victoria large consuming household

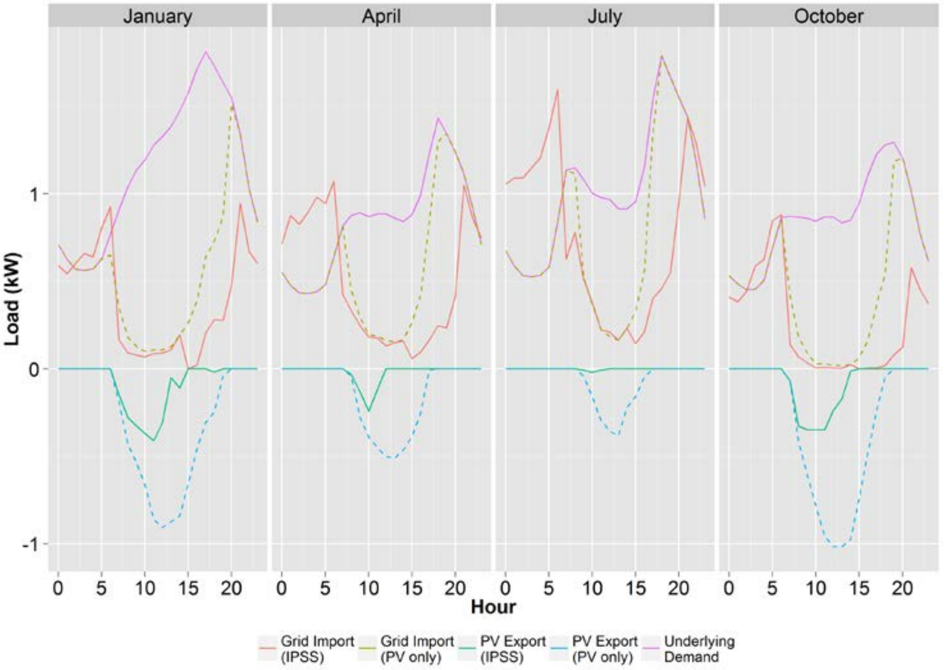
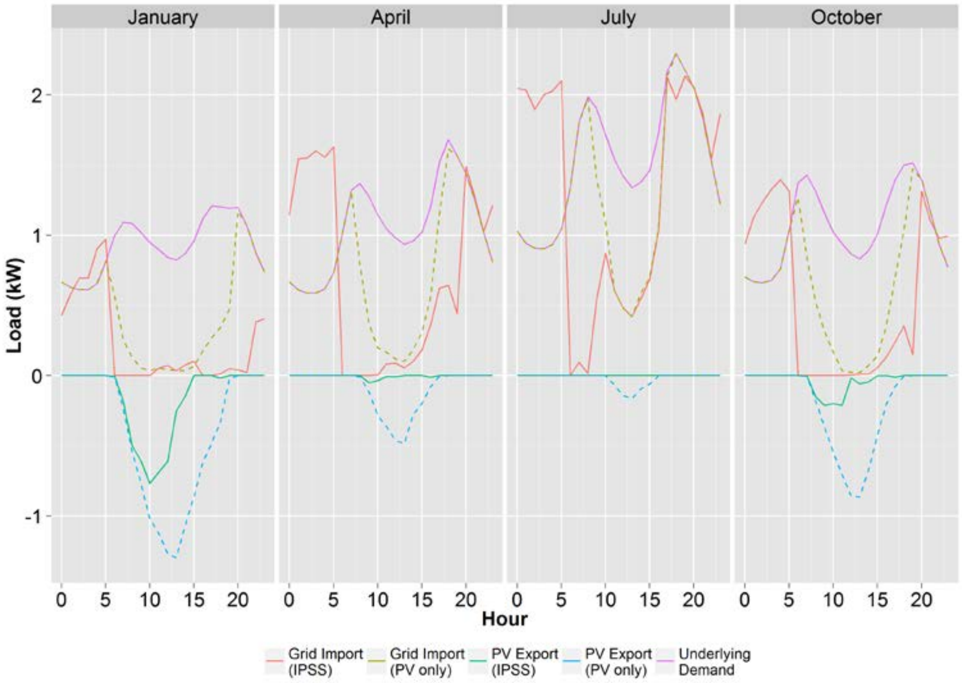


Figure 47 Average daily profile of a Tasmania large consuming household



APPENDIX D. DAILY HOUSEHOLD LOAD PROFILES

D.1 Queensland

Figure 48 Summer daily household load profile for Queensland around times of maximum demand

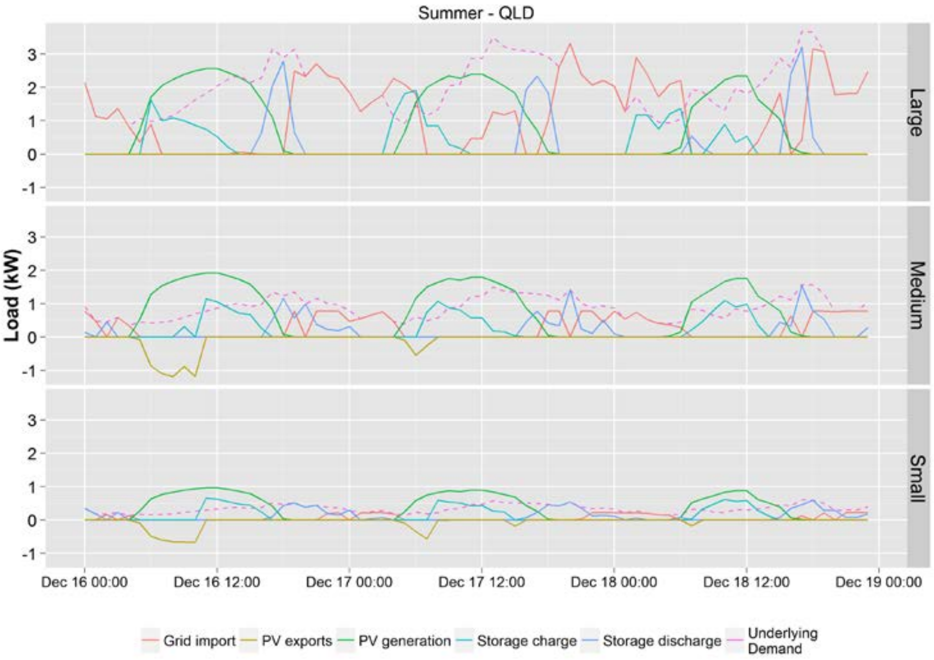
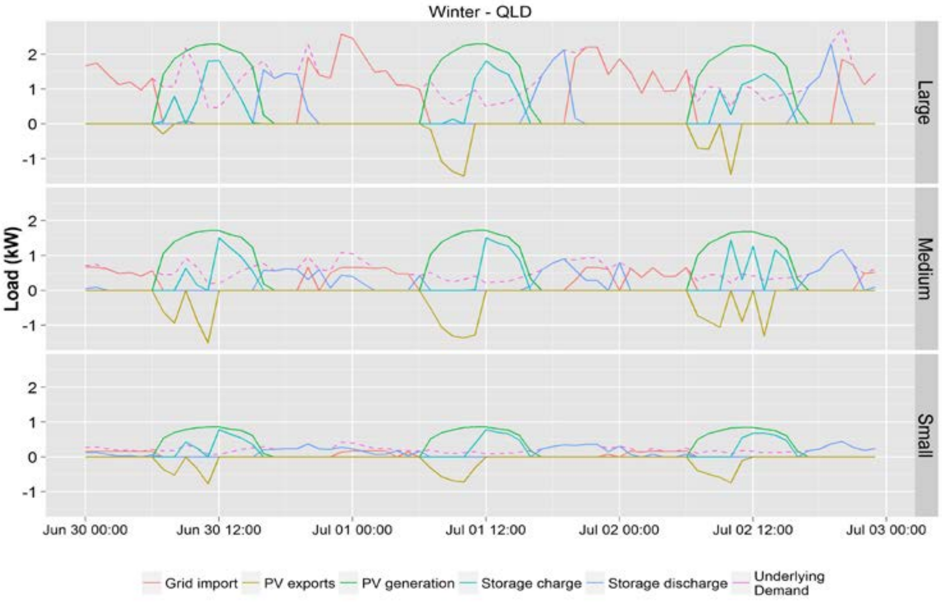


Figure 49 Winter daily household load profile for Queensland around times of maximum demand



D.2 New South Wales

Figure 50 Summer daily household load profile for New South Wales around times of maximum demand

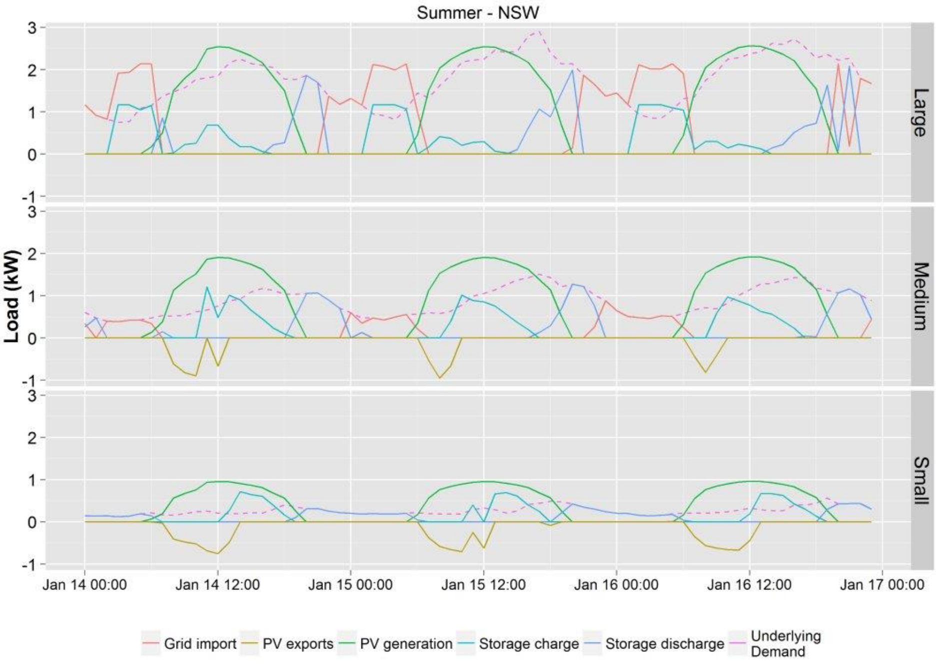
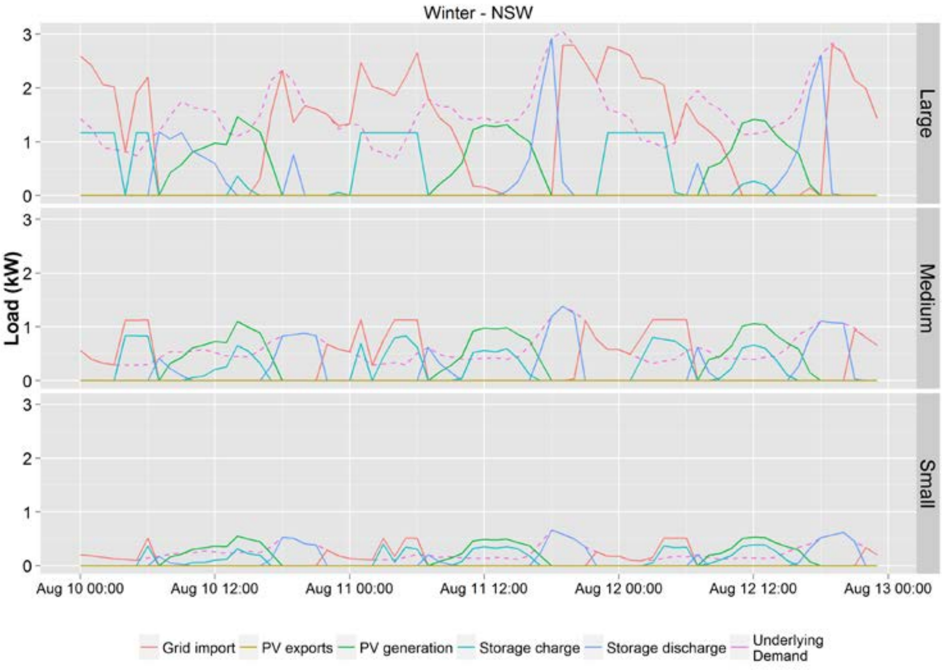


Figure 51 Winter daily household load profile for New South Wales around times of maximum demand



D.3 South Australia

Figure 52 Summer daily household load profile for South Australia around times of maximum demand

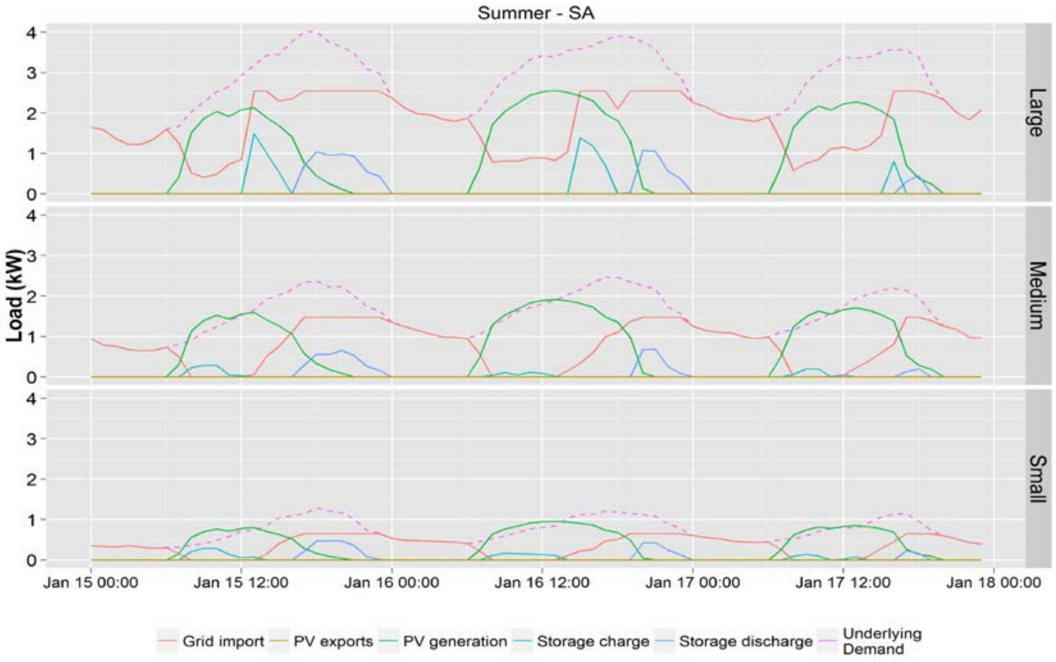
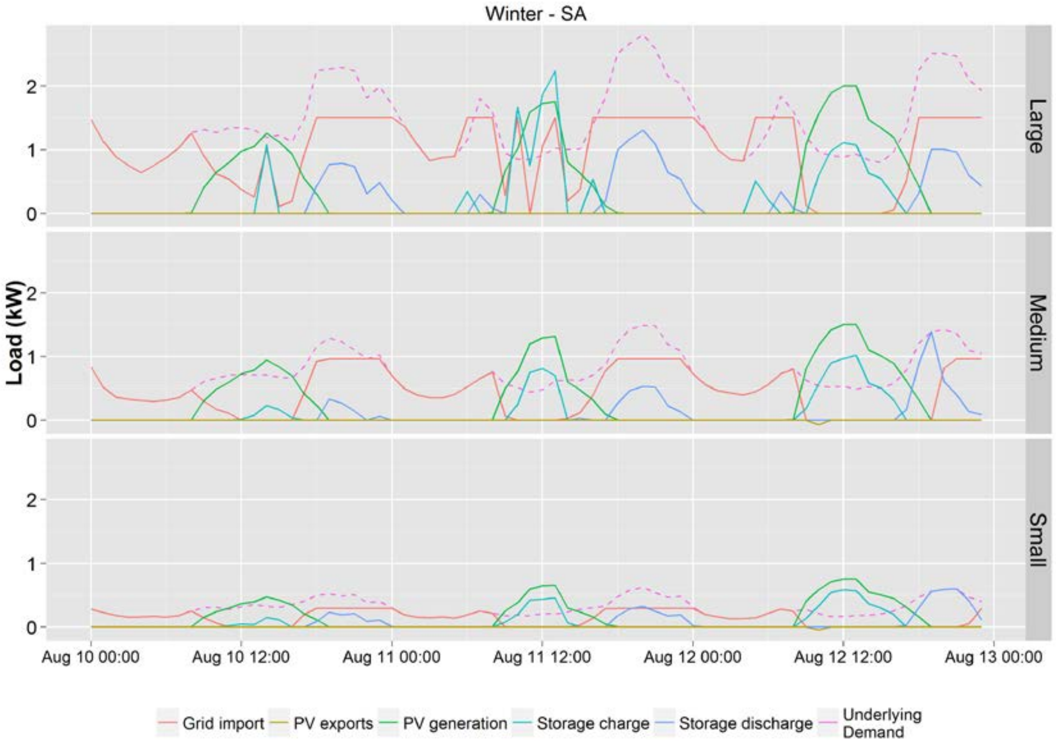


Figure 53 Winter daily household load profile for South Australia around times of maximum demand



D.4 Victoria

Figure 54 Summer daily household load profile for Victoria around times of maximum demand

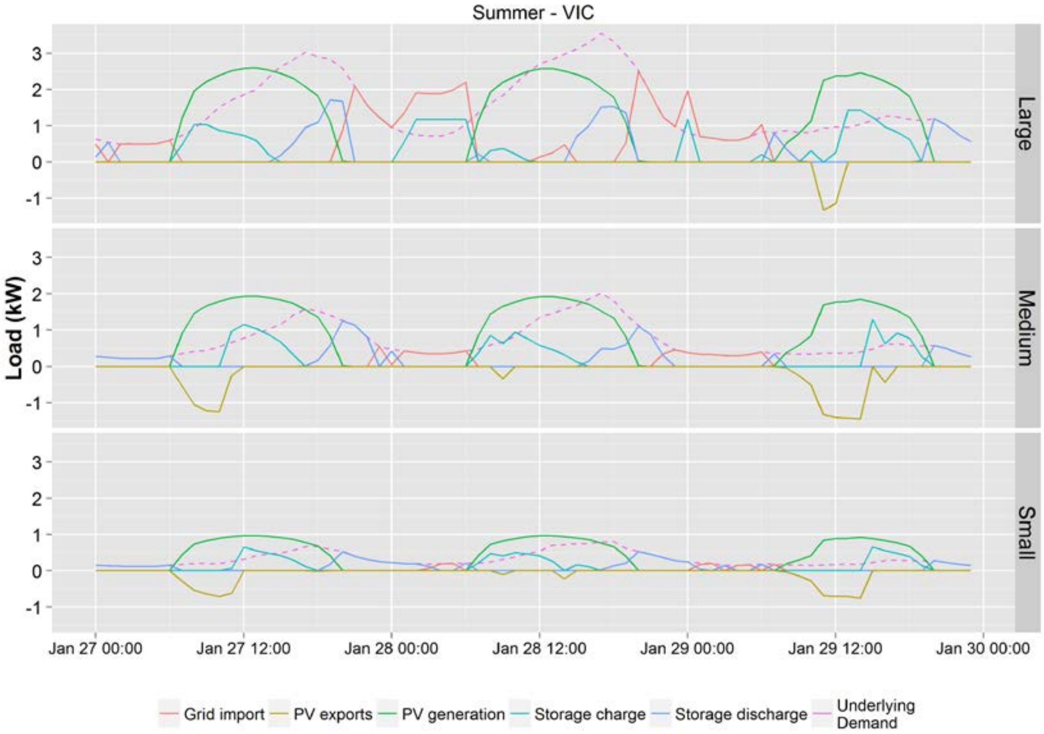
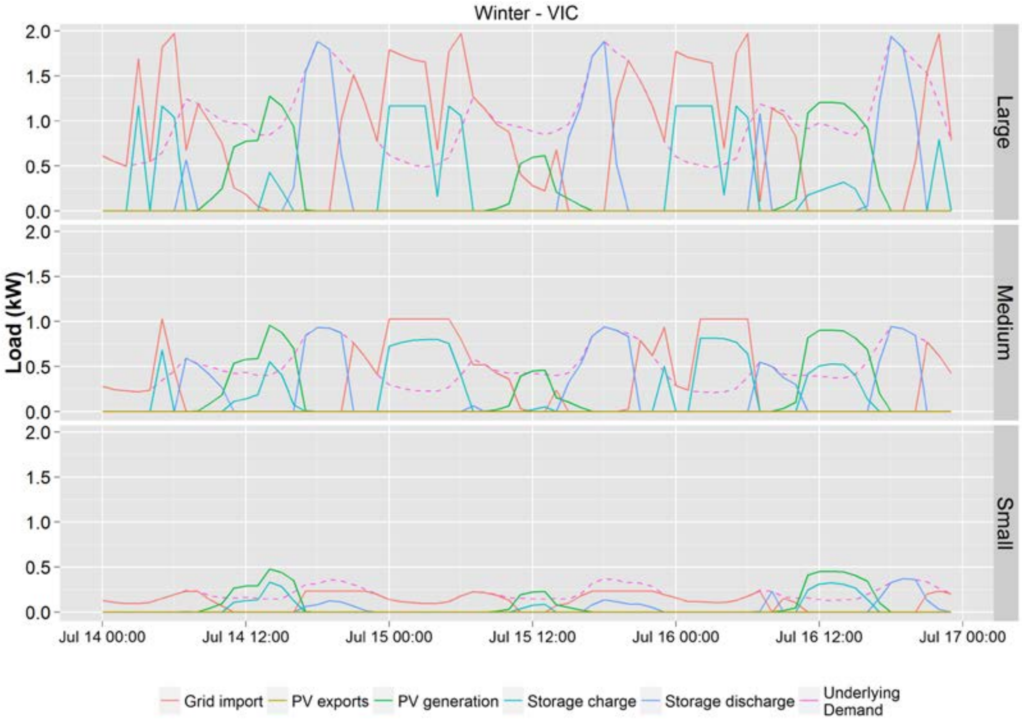


Figure 55 Winter daily household load profile for Victoria around times of maximum demand



D.5 Tasmania

Figure 56 Summer daily household load profile for Tasmania around times of maximum demand

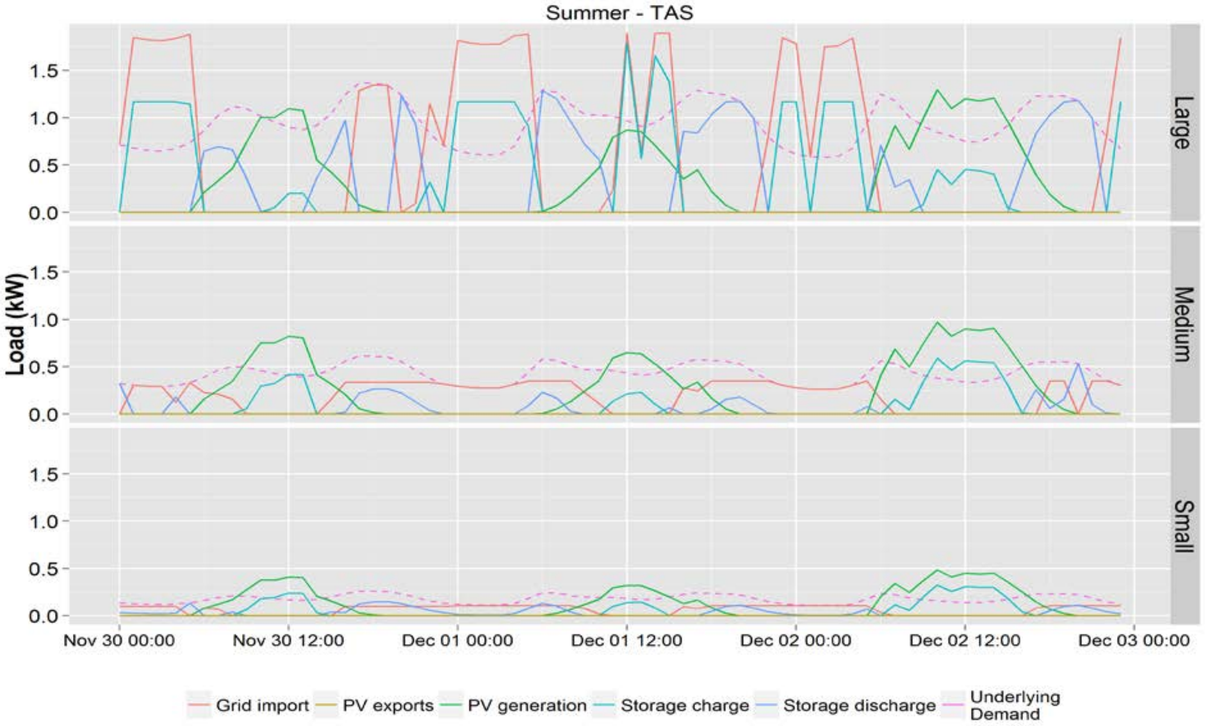


Figure 57 Winter daily household load profile for Tasmania around times of maximum demand

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
A	Amperes
GWh	Gigawatt hours
HDD	Heating degree days
kV	Kilovolts
kW	Kilowatt
kWh	Kilowatt hours
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
V	Volts
$	Australian dollars
$/kWh	Australian dollars per kilowatt hour
$/MWh	Australian dollars per megawatt hour

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AC	Alternating current
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
ATA	Alternative Technology Association
BEV	Battery Electric Vehicle
BOM	Bureau of Meteorology
CEC	Clean Energy Council
CER	Clean Energy Regulator
DC	Direct current
DNSP	Distribution network service provider
ECMWF	European Centre for Medium-Range Weather Forecasts
EE	Energy efficiency
EV	Electric Vehicle
GPG	Gas-powered generation
GSH	Gas-powered space heating
GSP	Gross state product
HEV	Hybrid Electric Vehicle
IPSS	Integrated Photovoltaic Storage System
LNG	Liquefied Natural Gas
MD	Maximum demand
NEM	National Electricity Market

Abbreviation	Expanded name
NERF	National Electricity Repository for Forecasting
NPV	Net Present Value
NSW	New South Wales
PHEV	Plug in Hybrid Electric Vehicle
POE	Probability of exceedance
PV	Photovoltaic
QLD	Queensland
RBS	Residential Battery Storage
RET	Renewable Energy Target - national Renewable Energy Target scheme
RCAC	Reverse Cycle Air-conditioner
Rooftop PV	Rooftop photovoltaic
SA	South Australia
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificates
TAS	Tasmania
TNSP	Transmission network service provider
TOU	Time of use
VIC	Victoria

GLOSSARY

Definitions

Terms not already defined in the 2015 National Electricity Forecasting Report (NEFR) glossary are listed below.

Term	Definition
battery charge	Any electricity taken from the grid or PV system to charge the battery.
battery discharge	Any electricity consumed by the household, directly from the battery,
battery electric vehicle	Battery electric vehicles are powered by an electric motor and battery alone. Battery electric vehicles can travel farther on electricity alone than plug-in hybrids, but their range is limited by the size of their batteries. As battery technology develops, the expected range of the vehicles will increase.
battery management system (BMS)	An electronic system that controls the operation of the battery and by default the grid imports and exports.
capacity tariff (or demand tariff)	Tariff structure based on electricity demand (in kW) rather than on consumption (kWh), where demand is a measure of the maximum power used during a time interval. The tariff is based on what proportion of the network's capacity the customer uses, with higher tariffs applying if demand exceeds certain thresholds.
charge	Electricity drawn from the grid or rooftop PV to charge the battery storage system.
contribution factor	The rooftop PV power generation (in MW) as a percentage of the total rooftop PV (MW) installed capacity.
declining block	Tariff structure that consists of a series of tariff blocks that charge a different rate based on the electricity consumed (in kWh) within a time period (such as within a day, month or quarter). The first block is charged at one rate for electricity usage up to a certain kWh threshold. Once this threshold is reached, the second block is applicable at a lower charge. Any electricity used above the second block is applicable at a higher third block level, and so on.
discharge	Electricity drawn from the battery to meet household demand in excess of solar generation.
export	Excess solar generation that is fed into the electricity grid.
feed-in tariff	A tariff paid to consumers for electrical energy they export to the network, such as rooftop PV output that exceeds the consumers' load.
flat tariff	Tariff structure where the customer is charged a single electricity rate (c/kWh) regardless of time of day.
fuel switching	Refer to replacing traditional gas appliances to electric equivalents, the three appliances observed are: Space heating Water heating Cooking (stove cooktop and oven)
hybrid electric vehicle	HEVs are powered by an internal combustion engine assisted by a battery and electric motor or motors. They use technologies that turn off the petrol engine at a stop and use regenerative braking, which captures braking energy and stores it in the battery for use during acceleration. Despite the electric motor, they do not draw any energy from the electricity grid and so are not considered here.
imports	Electricity drawn from the grid to meet excess household demand or to charge the battery.
inclining block	Tariff structure that consists of a series of tariff blocks that charge a different rate based on the electricity consumed (in kWh) within a time period (such as within a day, month or quarter). The first block is charged at one rate for electricity usage up to a certain kWh threshold. Once this threshold is reached, the second block is applicable at a higher charge. Any electricity used above the second block is applicable at a higher third block level, and so on.
local demand profile	The household's hourly electricity demand profile throughout the year.
maximum demand (MD)	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.

Term	Definition
network service provider (transmission – TNSP; distribution – DNSP)	A person who engages in the activity of owning, controlling, or operating a transmission or distribution system.
payback period	The time required for the return on an investment to equal the original investment amount.
Perfect foresight	The battery management system, whereby the control system has knowledge of the future solar and demand profile. This means that the system provides the optimal control to a household energy system, to charge or discharge the battery, or to import or export to the grid.
Plug-in hybrid electric vehicle	PHEVs are powered by an internal combustion engine and electric motor which can be recharged from the grid. This combination allows the vehicle to drive on electricity alone using battery energy, and after the battery is discharged, continue driving using petrol much like a hybrid vehicle.
Power purchase agreement (PPA)	A legal binding agreement between the retailer and consumer, in this case, of an IPSS system. Whereby the price of electricity is locked in for the consumer over the lifetime of the system.
probability of exceedance (POE) maximum demand	The probability, as a percentage, that a maximum demand (MD) level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, for a 10% POE MD for any given season, there is a 10% probability that the corresponding 10% POE projected MD level will be met or exceeded. This means that 10% POE projected MD levels for a given season are expected to be met or exceeded, on average, 1 year in 10.
Range	Refers to the distance that an electric vehicle can travel on a single battery charge.
Regenerative breaking	An energy recovery mechanism which slows down a vehicle by converting its kinetic energy into another form, or storing it.
residential and commercial load (annual energy or maximum demand)	The annual energy or maximum demand relating to all consumers except large industrial load. Mass market load is the load on the network, after savings from energy efficiency and rooftop PV output have been taken into account. Includes light industrial load.
retail electricity price	The price paid by consumers to retailers for supplying them with electricity.
rooftop photovoltaic (PV) systems	A system comprising one or more photovoltaic panels, installed on a residential or commercial building rooftop to convert sunlight into electricity.
saturation level	The estimated maximum rooftop PV capacity, reflecting the number of households, rooftop areas, and other siting factors.
sent-out	A measure of demand or energy (in megawatts (MW) or megawatt hours (MWh), respectively) at the connection point between the generating system and the network. This measure includes consumer load and transmission and distribution losses.
smart meter	An electricity meter that records electricity usage for discrete time intervals (such as for each 30-minute period) and automatically sends this data to the electricity supplier. Some smart meters have additional communications and load control functions.
summer	Unless otherwise specified, refers to the period 1 November–31 March (for all regions except Tasmania), and 1 December–28 February (for Tasmania only).
time-of-use (TOU) tariff	Tariff structure that charges different rates depending on the time of day, day of the week, and occasionally the season. These are generally divided into three time periods; peak, shoulder and off peak.
transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission network.
winter	Unless otherwise specified, refers to the period 1 June–31 August (for all regions).