Clean Energy Regulator
Stage 1: Small-scale Technology Certificate Projections

Final Report

Clean Energy Regulator
IS501000

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Executive summary

The Clean Energy Regulator (CER) is responsible for administering Australian Government schemes for measuring, managing and reducing or offsetting Australia's carbon emissions. One of these schemes is the Small-scale Renewable Energy Scheme (SRES).

The SRES creates a financial incentive for individuals and small businesses to install eligible small-scale renewable energy systems. It does this through the creation of small-scale technology certificates (STCs), which Renewable Energy Target (RET) liable entities have a legal obligation to acquire and surrender to the CER on a quarterly basis.

Participants can trade STCs on the open market, which enables the option of a varied STC price reflective of the market's supply and demand. Alternatively, scheme participants have the option of trading small-scale technology certificates (STCs) at a fixed price of $40 per certificate through the STC clearing house which is maintained by the CER. Up until the end of 2016, each installed system could create certificates equivalent to 15 years of expected generation for small generation units (SGU) and equivalent to 10 years for a solar or air source heat pump water heater. From 2017, the number of STCs per unit is calculated over a deeming period one year less than the previous year, with the intention being that the number of STCs created per eligible installation reduces to 2030, when the scheme ends.

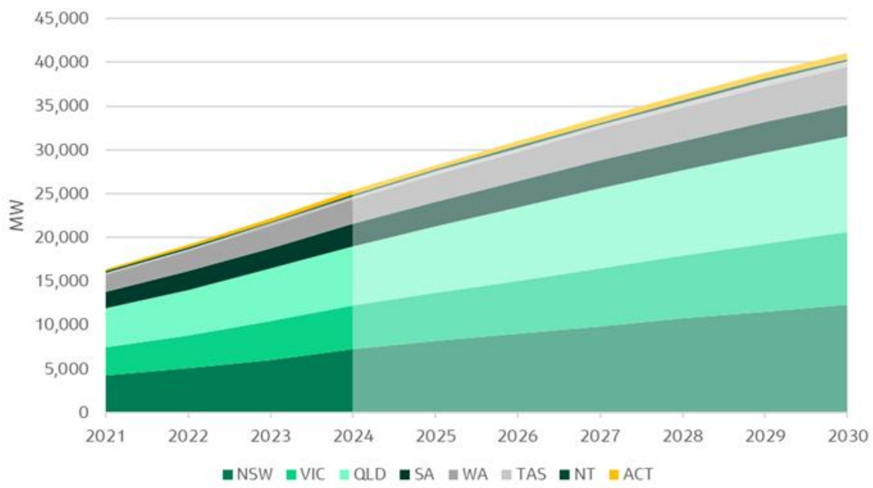
Jacobs has been engaged by the CER to forecast the number of STCs and the installed capacity of small-scale solar PV systems in the calendar years of 2024 to 2030, inclusive.

Forecasting the installation of distributed energy resources (DER) is complex, and uptake occurs at different rates in residential and commercial sectors of the market. To project the uptake of DER in both sectors, Jacobs has employed an in-house agent-based model. Agent-based modelling is a bottom-up approach that models unique agents at the micro-level to simulate customer level decision making. The agents represent Australian households and businesses that are autonomous, have internal behaviours and characteristics, and make decisions in response to exogenous and endogenous factors.

To forecast the creation of STCs for solar water heaters (SWH) and air source heat pumps (ASHP) Jacobs has used a time-series autoregressive integrated moving average (ARIMA) model.

As illustrated in Figure ES 1, the projected cumulative installed rooftop PV capacity increases over the forecast period, rising from 25,354 MW at the end of 2024 to 41,045 MW by the end of 2030.

Figure ES 1: Small-scale PV state forecasts, cumulative installed capacity



Annual installed small-scale rooftop solar PV capacity is displayed in Table ES 1 for each state, territory, and sector.

Table ES 1: Annual installed small-scale rooftop solar PV capacity (MW)

	2024	2025	2026	2027	2028	2029	2030
RESIDENTIAL							
Australian Capital Territory	38	36	38	30	33	40	28
New South Wales	1,013	784	749	723	741	673	685
Northern Territory	8	15	12	10	13	12	10
Queensland	652	713	649	658	575	532	453
South Australia	196	182	144	159	121	129	108
Tasmania	50	47	29	35	39	47	27
Victoria	495	403	403	471	454	469	429
Western Australia	213	247	232	212	203	212	192
Total Residential	**2,664**	**2,427**	**2,255**	**2,298**	**2,177**	**2,114**	**1,932**
COMMERCIAL							
Australian Capital Territory	7	7	4	6	4	5	4
New South Wales	157	142	138	128	121	120	108
Northern Territory	4	4	3	4	3	4	3
Queensland	114	125	124	103	92	71	70
South Australia	31	28	38	35	30	29	30
Tasmania	4	4	4	4	5	4	4
Victoria	100	107	103	113	111	109	106
Western Australia	42	41	42	40	37	37	38
Total Commercial	**458**	**458**	**456**	**432**	**402**	**379**	**363**
Total Capacity	3,123	2,885	2,711	2,730	2,579	2,493	2,294

Across the east coast of Australia, the National Electricity Market (NEM) had experienced prolonged periods of high wholesale electricity prices. This was largely a result of the undersupplied global gas market, ultimately caused by the economic sanctions imposed on Russia. These sustained prices in the wholesale market have flowed through to retail electricity prices from the second half of 2023 and has re-incentivised a new wave in rooftop PV installations. Whilst 2022 was the first year that marked a slowdown in annual uptake following several years of consecutive record growth, annual installed capacity rebounded in 2023 with similar trends expected by the end of 2024. Across Australia, 3,123[1] MW of capacity is expected by end of 2024 compared to 3,096 estimated for 2023.

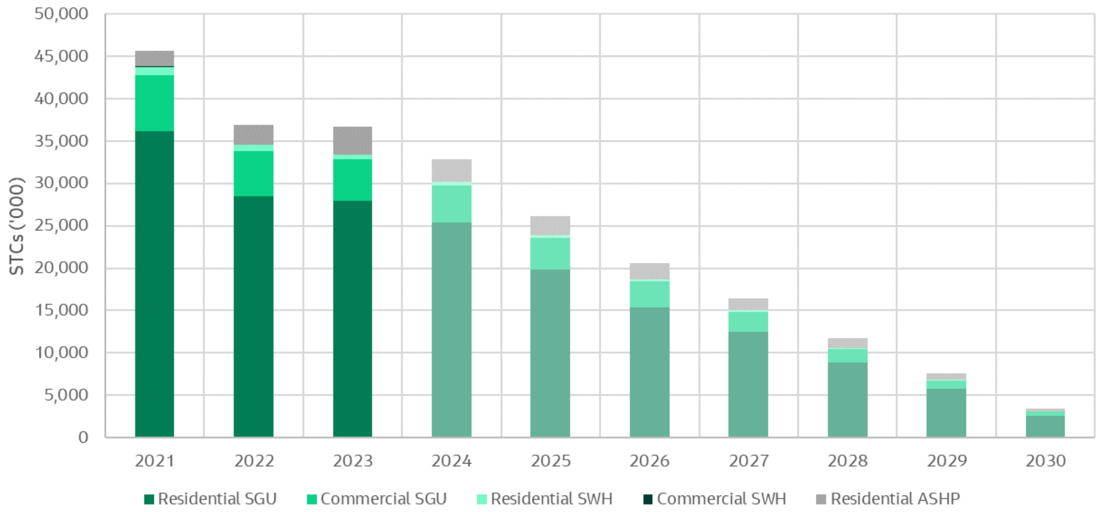
Due to electricity retailer hedging, the NEM's wholesale price recovery in 2023 (down from record high prices in 2022) will eventually flow through to the retail electricity market from 2025, lowering retail prices in this year. As a result, lower electricity prices reduce the net financial benefit of PV systems leading to an expected 8% decline in annual installed capacity to 2,885 MW. Despite the diminishing STC subsidy, net system costs are still projected to fall slightly in 2025 which partially offsets the reduced benefits from lower retail electricity prices.

[1] 2023 and 2024 capacities are estimates including 12-month creation estimates.

However, from 2026 the cost reduction rate of rooftop PV costs has slowed to the point of being outpaced by the reducing STC discount. At this point, system costs are still recovering from inflationary pressure caused by increased global uptake of utility and small-scale solar, and the STC subsidy is diminishing at a greater rate as the deeming period decreases by another year. In addition, the feed-in tariffs of a few states continue to fall in line with the increasing solar supply which diminishes the value of daytime solar generation. Whilst the trend of system costs will have now stagnated (the diminished deeming period of STCs has fully outpaced any cost decline from technological innovation), the fall of retail electricity prices and feed-in tariffs are the primary drivers for creating comparatively less attractive payback periods throughout the late 2020s. As a result, installed annual capacity is expected to continue declining with 2,711 MW of annual installed rooftop PV capacity in 2026, declining to 2,294 MW by 2030.

Figure ES 2 illustrates the STC creation projections by sector, including STCs created from installations of solar PV and hot water systems (wind and hydro STCs make up a negligible portion). In 2024, it's projected that a total of 33.0 million STCs will be created, which despite having an increase in small generation unit capacity, is slightly less than 2023.

Figure ES 2: Total STC annual projections



Overall trends in STC forecasts are largely linked to residential rooftop PV installations, which comprise the largest portion of STCs created. Commercially sized SWH units are expected to maintain their relatively low level of uptake and are not expected to have considerable influence on STC creation across the forecasting period. It is expected that STC creation from domestic SWH systems will continue to decline, with the uptake of ASHP systems is expected to continue to be relatively constant for the remainder of the forecast horizon, with its STCs falling only with the deeming period.

Contents

Appendices

Tables and figures

Acronyms and abbreviations

ABS	Australian Bureau of Statistics
ABM	Agent based model
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARIMA	Autoregressive integrated moving average
ASHP	Air source heat pump
BESS	Battery energy storage systems
CER	Clean Energy Regulator
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DLF	Distribution loss factor
ERA	Economic Regulation Authority (Western Australia)
ESC	Essential Services Commission (Victoria)
ESC	Energy Savings Certificate
ESS	Energy Saving Scheme (NSW)
FiT	Feed-in tariff
FY	Financial year
IPART	Independent Pricing and Regulatory Tribunal
kW	Kilowatt
kWh	Kilowatt-hour
LRET	Large scale renewable energy target
LV	Low voltage
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NSW	New South Wales

NT	Northern Territory
OTTER	Office of the Tasmanian Economic Regulator
PA	Per annum
PDRS	Peak Demand Reduction Scheme
PV	Photo-voltaic
PWC	Power and Water Corporation
QCA	Queensland Competition Authority
QLD	Queensland
RET	Renewable energy target
SA	South Australia
SA3	Statistical Area Level 3
SGU	Small generation unit
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale technology certificate
SWH	Solar water heaters
TAS	Tasmania
TLF	Transmission loss factor
VEU	Victorian Energy Upgrades program
VIC	Victoria
VPP	Virtual power plant
WA	Western Australia
WEM	Wholesale Electricity Market

1. Introduction

The Clean Energy Regulator (CER) is responsible for administering Australian Government schemes for measuring, managing, and reducing or offsetting Australia's carbon emissions. One of these schemes is the Small-scale Renewable Energy Scheme (SRES).

The SRES is designed to achieve the following objectives:

- Generation of electricity from renewable energy sources.
- Reduced emissions of greenhouse gases in the electricity sector.
- Ensuring renewable energy sources are ecologically sustainable.

The SRES creates a financial incentive for individuals and small businesses to install eligible small-scale renewable energy systems. It does this through the creation of small-scale technology certificates (STCs), which Renewable Energy Target (RET) liable entities have a legal obligation to acquire and surrender to the CER.

Participants can trade STCs on the open market, which enables the option of a varied certificate price reflective of the market's supply and demand. Alternatively, scheme participants have the option of trading certificates at a fixed price of $40 per certificate through the STC clearing house which is maintained by the CER.

Whilst there is a limit on the number of certificates created for each eligible installation, there is no cap on the total number that can be created within the scheme. STC creation is based on an estimate of the amount of electricity that will be generated or displaced by the renewable energy sources over an assumed lifetime. Because of this, the number of certificates created is influenced by the geographical location of the asset.

Up until the end of 2016, each installed system could create certificates equivalent to 15 years of expected generation for small generation units and equivalent to 10 years for a solar or air source heat pump water heater. From 2017, the number of STCs per unit is calculated over a deeming period one year less than the previous year, with the intention being that the number of STCs created per eligible installation reduces to 2030, when the scheme ends.

The purpose of this report is to provide forecasts of the number of STCs that will be generated in the calendar years 2024 to 2030, inclusive. In developing this report, Jacobs has executed following tasks:

- Modelled expected small-scale technology installations (≤100 kW) and provided updated SRES forecasts for 2024-2030.
- Identified key factors affecting the type, number, and size of small-scale system installations and the trends in STC creation for various categories of systems, including residential and commercial uptake across Australian states and territories.
- Reviewed and updated previously developed models and methodologies to improve the accuracy of projections. Jacobs has identified and analysed changes to circumstances and trend breaks, and/or including alternative estimators. An in-house approach founded on agent-based modelling is utilised in this study, designed to better capture the impact of structural changes in the STC market.

All analysis and forecasts in this study are based on STCs created in the month of installation, including an estimate of additional STCs for that month to be created over the next 12 months. This report commences in Section 2 with an analysis of trends in the uptake of small-scale systems, followed in Section 3 by a description of current government incentives and solar PV policies. Section 4 describes the method of forecasting STCs, and the assumptions used are described in Section 5. Section 6 presents the results.

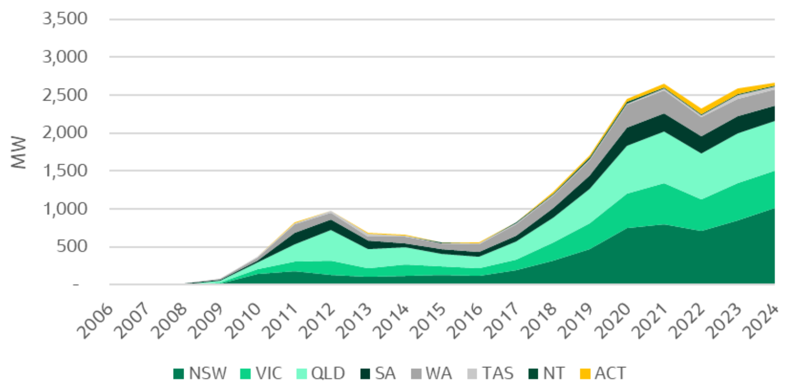
2. Trends in uptake

This section provides commentary on trends in the uptake of small-scale PV systems, which comprise the main element of STC creation.

2.1 Small-scale PV Systems

Figure 2-1 illustrates historical annual installed capacity of residential rooftop PV from (calendar year) 2006 to 2024, inclusive.

Figure 2-1: Installed residential capacity



***Source**: Jacobs' analysis of CER data, 2024 estimate*

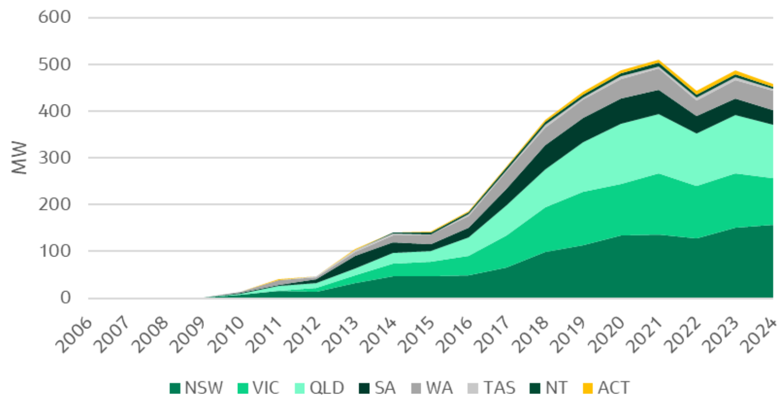
For the six years from 2016 to 2021, there was an increase each year in annual small-scale PV uptake, including over 2020-2021, defying disruptions from the COVID-19 pandemic. However, 2022 saw a reduction in installed PV capacity, likely the result of a range of transient factors, including:

- Stagnant capital costs.
- Lower feed-in tariff (FiT) rates.
- Wetter than average weather.
- Increased consumer uncertainty and cost of living pressures.
- Scarcity of available installers and tradespeople and supply chain constraints (creating upwards pressure on system costs).

However, installed residential rooftop PV capacity has rebounded from 2023. Wholesale electricity prices across the east coast of Australia reached unprecedented highs towards the end of 2022, largely because of record high coal and gas prices (globally, and domestically). In addition to feed-in tariffs subsequently increasing for some states (e.g., NSW, Tasmania), the widespread anticipation of a similar increase in retail electricity prices was likely a key influencing factor in the rebound of rooftop PV uptake. This trend is expected to continue into 2024 as retail electricity prices have now increased in line with the wholesale trends in 2022.

Figure 2-2 illustrates the recent trends in installed PV capacity by schools and businesses. As with residential installations, strong growth in uptake has occurred since 2016. A distinct seasonal trend has emerged as businesses hasten to commit to installations prior to annual steps down in rebates applied to small scale technology. The COVID-19 pandemic also appeared not to affect the trend in commercial PV installations, despite the temporary closure of many small-medium sized enterprises. This may be attributable to government incentives that incentivised solar PV installations (such as the instant tax write-off) and growth in businesses that have benefitted from the transformation of the digital work and life environment post-COVID-19. However, as with the residential data, there was a slowdown in the rate of growth of commercial solar installations in 2022 but uptake is expected to rebound in 2023 for similar reasons to those for the residential sector. For 2024, commercial solar PV uptake is expected to stagnate, decreasing slightly to 458 MW (compared to 486 MW in 2023).

Figure 2-2: Annual installed commercial capacity

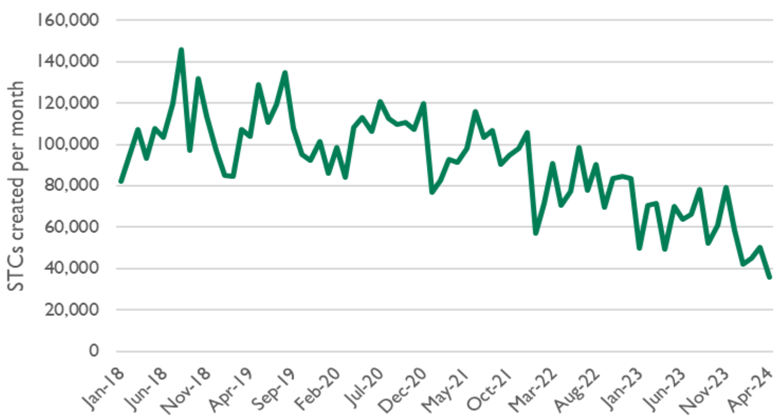


Source: Jacobs' analysis of CER data, 2024 estimate

2.2 Solar water heaters

Figure 2-3 shows the historical trend in the creation of STCs from installations of residential solar water heaters from January 2018 to April 2024. Since 2022, the STC deeming period for SWH has begun decreasing which reduces the number of certificates created per SWH every year. However, structurally there has been a decline since 2018 which coincides with the acceleration of air-sourced heat pumps (see section 2.3).

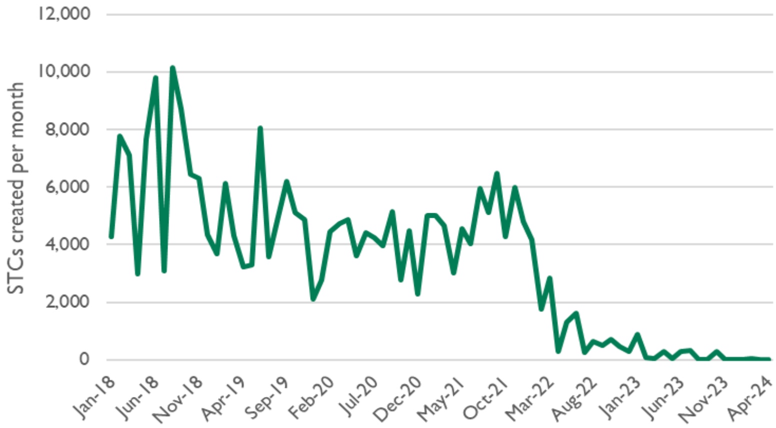
Figure 2-3: Monthly trend in STC creation from residential SHW



Source: Jacobs' analysis of CER data

STC creation from commercially sized units continues to decline with an annual decrease of 29% in 2019 and a 14% reduction in 2020, and a further decrease of around 80% in 2022, as can be seen in Figure 2-4. Monthly STCs dropped to a 20-year lows in 2023 and 2024, down to zero monthly certificates created for some months. Similar to the residential sector, this is most likely due to air-sourced heat pumps gaining popularity within the commercial sector. Since the introduction of the NSW Peak Reduction Certificates (PRCs) in November 2022, businesses can receive additional incentives on top of energy savings certificates which has attributed a rise in commercial ASHP installations. However, this incentive will conclude from 1 August 2024.

Figure 2-4: Monthly trend in STC creation from commercial SHW



Source: Jacobs' analysis of CER data

2.3 Air source heat pumps

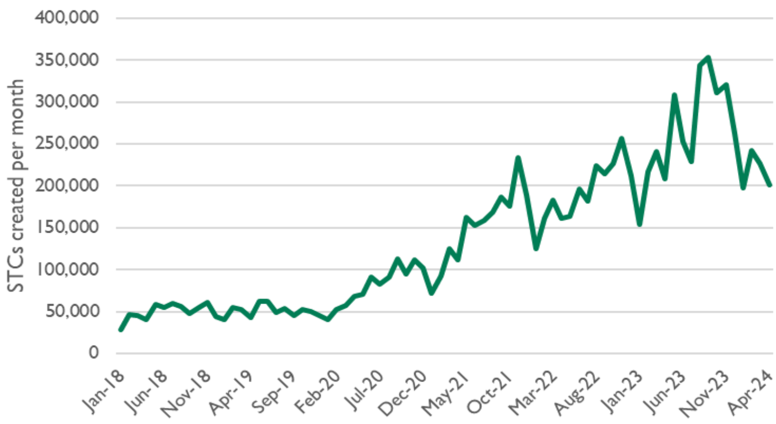
Figure 2-5 shows the monthly trend in uptake of residential ASHP. Uptake has been trending up since 2014, but a rapid acceleration has occurred since mid-2020. A distinct seasonal pattern has occurred in the last few years with monthly STC creation peaking each November before the year-end. The uptake of ASHP has continued to accelerate throughout 2022 and 2023, with September 2023 being the highest month on record for STC creation from this technology.

Drivers for the uptake of ASHP appear to be:

- A growing acceptance of electric based ASHP, particularly in new housing estates.
- Additional support from some state governments, particularly the Peak Demand Reduction Scheme in NSW.
- That they do not take up roof space, allowing households to install both solar panels and low emission water heaters. This fits in with the trend towards larger PV sizes, allowing households to reserve roof space for solar panels.

The recent decline in 2024 is consistent with the distinct historical monthly pattern where installations peak at the end of the year (to lock in the STC benefit before it reduces in January), before slumping at the commencement of the new year.

Figure 2-5: Monthly trend in STC creation from residential ASHP



Source: Jacobs' analysis of CER data

3. State government incentives and policies

The number of STCs created is dependent on uptake of eligible technologies by households and businesses, which is in turn influenced by financial incentives and regulations such as federal and state rebates, state-based FiT schemes, and building standards. The energy efficiency building standards impact the choice of water heaters installed in new houses. The forecasts provided by Jacobs account for government policies and programs explicitly or implicitly.

3.1 Government policies

The state-wide blackout in South Australia during September 2016 resulted in the South Australian Government shifting from providing energy saving incentives based on renewable generation to ones based on energy storage, such as the residential BESS program. South Australia has also given the Australian Energy Market Operator (AEMO) authority to curtail rooftop solar when necessary for the benefit of the power system. New inverter standards for new rooftop solar installations have been enforced to enable AEMO more visibility and control of rooftop systems. However, it is expected that curtailment of rooftop solar will only occur under extreme circumstances, and therefore it is likely these rules will not have considerable impact on the uptake of PV in South Australia.

Western Australia and the Northern Territory have significantly reduced their standard FiT rates. This reduces the incentives for exports of solar generated power from rooftop systems, due to concerns of the impact of high PV penetration on grid stability.

From 1 January 2024, Victoria has banned gas connections to new dwellings requiring planning approvals. With over 50,000 new homes built in Victoria each year, the government estimates that this policy will prevent around 40,000 new gas connections annually. The shift to all-electric homes will increase demand for alternative appliances for cooking and heating purposes. This includes increased uptake of SWH and ASHPs.

3.2 Government programs

Some jurisdictions in Australia have in place at least one scheme to encourage the uptake of DER (including rooftop solar PV and household batteries), and solar water heaters. These state-based schemes are summarised below.

3.2.1 Victorian Solar Homes Program

In August 2018, the Victorian Labor Government announced a rebate scheme for the installation of rooftop solar PV on eligible dwellings. The rebate is means tested to households of combined taxable income less than $210,000. Based on the 2021 Australian Bureau of Statistics (ABS) Census, more than 98% of Victorian households would be eligible for the program. The scheme was expected to fund the installation of rooftop PV systems on 720,000 homes over a 10-year period.

Since July 2021, the offer has been open to Victorian households and small businesses who may receive a rebate to cover half the cost of a solar PV system up to a maximum of $1,400 for households and $3,500 for small businesses. Eligible Victorian residents have also been able to receive an interest free loan for a period of four years to finance the remainder of the cost of installation up to the value of their rebate.

Rebates of up to $1,000 are also being offered to install a SWH or ASHP unit, in eligible dwellings that have not previously received a Solar Homes rebate.

In addition, the Victorian Government has pledged to support uptake of rooftop solar on rental properties. This component involves an additional $82 million package of 50,000 rebates to be delivered over a 10-year period to eligible tenants and landlords that agree to share the remaining costs of the system. As of October 2023, the rebate value is $1,400.

3.2.2 Victorian Energy Upgrades Program

The Victorian Energy Upgrades (VEU) program was established by the Victorian Energy Efficiency Target (VEET) Act which originally commenced on 1 January 2009, and provides for the VEU program to operate until the end of 2030. The main objectives of the VEET Act are to reduce greenhouse emissions, encourage the efficient use of electricity and gas, and to incentivise investment and technology development in industries which reduce the use of electricity and gas by consumers.

The program provides financial incentives for the replacement of inefficient electric and gas water heaters with either an electric boosted solar water heater or an air source heat pump water heater.

The VEU program specifically establishes minimum energy efficiency requirements for eligible prescribed activities, and the methods needed to establish the amount of greenhouse gas equivalent emissions reduced by each activity.

Targets of 2.7 Mt CO_2-e per annum applied between 2009 and 2011 and were doubled to 5.4 Mt CO_2-e per annum between 2012 and 2016. Targets ramped up from 5.9 Mt CO_2-e in 2017 to 6.9 Mt CO_2-e in 2023. The set targets for 2024 and 2025 are 7.1 and 7.3 Mt CO_2-e, respectively. Targets beyond 2025 are not yet defined.

3.2.3 NSW Energy Security Safeguard

Under the Energy Security Safeguard, the NSW Energy Saving Scheme (ESS) was established in 2009 to incentivise NSW households and business to reduce electricity consumption by investing in energy saving projects. Under the ESS, SWH and ASHP which replace electric water heaters are eligible to receive rebates through the creation of Energy Savings Certificates (ESC). One ESC represents 1 MWh of energy saved, with a typical ASHP (replacing an electric hot water system) historically generating around 40 certificates. At the current spot price of $18.60, this equates to around $784 in savings. Initially, a minimum co-payment of $30 (exclusive of GST) was required by the end user to receive these benefits. As of 19 June 2024, this co-payment was increased to $200 (plus GST). Under the same rule change, the certificate creation methodology was revised potentially decreasing the number of ESCs created per installation.

Also under the Energy Security Safeguard, the Peak Demand Reduction Scheme (PDRS) was created in 2022 to reduce peak electricity demand in NSW. The scheme provides financial incentives to households and businesses to reduce electricity consumption during peak demand hours through the adoption of eligible technologies. Originally, small commercial ASHP were eligible under the PDRS, in addition to the ESS and SRES. The permitted stacking of multiple scheme benefits created very attractive financial incentives which was a key driver in NSW ASHP uptake in the last two years. However, from 1 August 2024, eligible ASHP under the PDRS will be limited to large units that cannot receive SRES benefits (minimum volumetric capacity of 425 litres).

Under the same rule change, new incentives under the PDRS will be extended to behind-the-meter batteries. While the batteries themselves will not contribute to STC creation, it is expected that the increase in benefit to households via load shifting may encourage the installation of rooftop PV and battery packages. However, based on our analysis the payback period of a combined solar and battery system is not likely to be more attractive than a standalone rooftop solar PV system within the forecast period, so is not considered to impact the solar PV forecasts.

3.2.4 Australian Capital Territory – Home Energy Support program

In March 2022, the Australian Capital Territory (ACT) Government launched its Home Energy Support Program, which commits $50 million over four years. Eligible households can receive a rebate of up to $2,500 for the installation of a rooftop PV system and the option to finance the remaining costs with an interest-free loan. The second phase of the program offers an additional $2,500 rebate for heating and cooling systems, hot water heat pumps, and other energy efficiency products. Eligible homes must be valued up to $750,000 for detached dwellings based on the property's 2022 (or later) unimproved land value. Multi-story apartments must have an unimproved value of up to $300,000. In addition, eligible homeowners must hold either an Australian Government Pensioner Concession Card, Department of Veterans' Affairs Gold Card, or an Australian Government Health Care Card.

4. Methodology

Forecasting uptake of small-scale systems is complex, and its uptake occurs at different rates, in different locations, and across different customer segments. Subject to exogenous constraints such as technical limits, technology choice, and environmental and regulatory factors, uptake is based on a combination of economic and non-economic behavioural factors.

Economic return depends on a range of price and cost factors such as income, underlying energy demand, electricity tariffs, and the cost of the systems (both upfront capital and ongoing operation and maintenance), which together produce an accepted payback period for uptake.

The non-economic factors that can accelerate or decelerate an investment decision are largely behavioural and societal, such as additional value placed by an individual or a business on 'doing the right thing' for the environment, becoming energy independent or 'being seen to be contributing' to better community outcomes. In some cases, particularly for established technology, these influences are captured in historical data on decision making. In other cases, and particularly for newer technologies, these influences need to be assumed.

Overlaying this, some factors may have more permanent effects and others may be temporary or change over time. For example, the impact of COVID-19 has resulted in some persistent work-from-home trends that have the impact of increasing residential electricity use while mostly reducing commercial use. But recessionary impacts or those that relate to consumer confidence are generally temporary.

To account for all these factors, a bespoke agent-based model was employed to represent the households in each State across Australia to project their uptake of solar PV systems. However, for the projection of solar water heaters, and air source heat pumps, a secondary time-series ARIMA model is utilised. Both models are partly based on expected payback periods from installing new systems, as the main driver of uptake, with the payback periods influenced by projected trends in the cost of systems, level of government subsidy and expectations around future revenue streams, namely retail and feed-in tariffs. Transient or temporary drivers observed recently are reflected in trends on installation costs (with a return to long term trends projected), and an assumption that current shortfall in labour material dissipate over a two-year period. In the ARIMA model the impact of transient factors are captured through the residuals. And to the extent these have been changing it will be observed in changes in the residuals over time.

Under the SRES scheme, small generation units cover rooftop PV, wind, and hydro systems up to 100 kW in capacity. However, small-scale wind and hydro units have historically represented a negligible proportion of STCs (less than 0.02%), so only the future uptake of rooftop PV systems are considered in this study.

4.1 Agent based modelling

Agent-based modelling is a bottom-up approach, which models unique agents at the micro-level to simulate customer level decision making. Agents are autonomous, have internal behaviours and characteristics, and make appropriate decisions (in terms of their assumed decision criteria) in response to both exogenous and endogenous factors.

Unlike traditional modelling approaches, agent-based modelling creates heterogeneity between agents, and may enable interaction among agents to influence behaviour and outcomes. This approach is especially suitable for modelling intricate, non-linear, and interrelated parameters in unstable and complex environments.

In the context of Australia's energy market and rooftop PV uptake, agent-based modelling can allow agents representing Australian households, businesses, and schools, to respond to price signals, such as electricity price increases and falling technology costs, and macro-economic, technological, policy, and electricity-related variables to simulate the magnitude of installations over the next six years.

There are several steps to creating an agent-based model, as are described in the following sections, starting with setting up, or initialising, the agents in the model.

4.2 Agent initialisation

Agents are split into two broad groups – residential and commercial. Basic attributes are assigned to agents to proportionately reflect the real world, such as whether they are a renter or an owner-occupier. These exogenous variables are held fixed across the modelling time horizon for existing agents. However, the proportion of these variables may change over time. Therefore, new agents that are created as population grows may be assigned attributes in differing proportions to those assigned to the initial set of agents.

4.2.1 Residential agents

Residential agents are initialised with the following parameters:

- Location.
- Dwelling type (e.g., detached house, townhouse, apartment).
- Tenure type (e.g., owner-occupier, renter).
- Solar PV penetration status.

Parameters are initialised using available local information and/or ABS data and are allocated to agents based on cumulative probability distributions. Heterogenous location assignment is important because it allows agents from different regions to have different behaviours and characteristics. Within a region, it is assumed all agents share the same characteristics.

The dwelling and tenure type probability distributions are unique to each region. That is, each region has a dwelling and tenure type profile that is particular to that area.

In terms of rooftop suitability, this can be determined in different ways and depends on the circumstances of the environment being modelled. In some cases, there is publicly available satellite data to inform the proportion of rooftops and types of dwellings that have the potential to take rooftop solar panels. In most cases, an assumption is made based on which dwelling types can take solar, and upper saturation limits are applied. A common assumption is that only homeowners living in a detached dwelling (i.e., house, townhouse) are likely to adopt a rooftop solar PV system, with renters and/or those living in apartments, flats, caravans, and so forth assumed to not purchase these systems.

To account for current penetration levels, the appropriate number of agents is assigned a rooftop PV system at the commencement of the model.

4.2.2 Commercial agents

Unlike residential households, businesses do not have the same degree of behavioural variation across regions. Rather, it is the size and electricity consumption of a business that presents a better point of differentiation. Therefore, while commercial agents are initialised with a region in the model, they are also assigned to an ‘underlying demand segment’ and are assumed to make decisions relating to their electricity consumption.

Within commercial agents, businesses are separated into schools, small businesses, and large businesses, depending on the availability of data. These groups of agents are modelled separately to each other because they are associated with different levels of demand, DER capacity, and retail tariffs, and sometimes subject to different regulation.

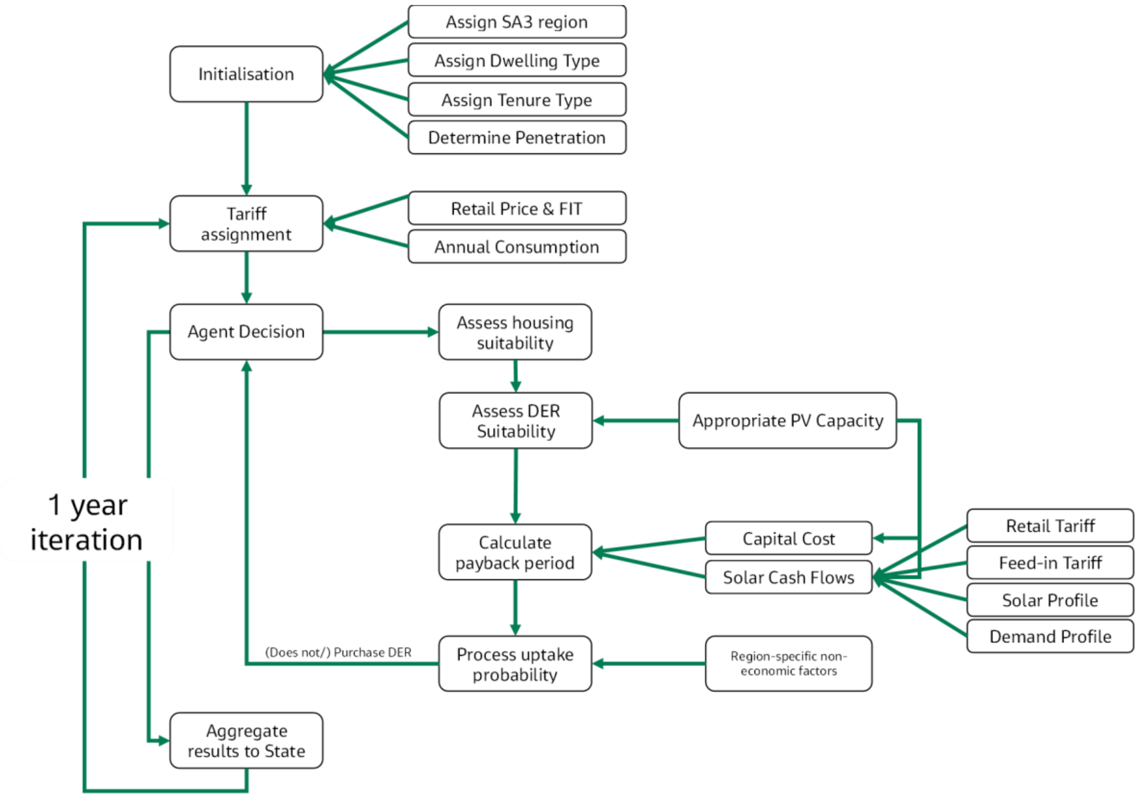
Like residential agents, the current penetration level for commercial agents is assigned at the commencement of the model based on available data.

Businesses tend to act in a more economically rational way relative to households. Therefore, it is assumed that commercial rooftop PV systems are optimised to their electricity consumption and are not oversized. Under this assumption, every commercial customer is assigned a system capacity based on their individual electricity consumption, not on their region's historical average capacity.

4.3 Economic agent decisions

Once agents are initialised, electricity tariffs are assigned, including retail prices for grid consumption and FiTs for electricity exports to the grid (from solar PV). Subsequently, a range of other price and non-price factors affecting an agent's decision of whether to take up solar systems are incorporated in the model, such that each agent follows a defined set of decisions. This set of decisions is illustrated in Figure 4-1 for a residential agent, and a commercial agent follows a similar path.

Figure 4-1: Residential agent framework



After an agent has been initialised, if it does not currently own a rooftop solar PV and/or battery system and is eligible to take one up, it is assigned the following data at the commencement of each year:

- Retail tariff.
- Feed-in tariff.
- Annual consumption.
- Hypothetical PV system capacity.
- Hypothetical BESS capacity.

- Associated capital costs.
- Operational and maintenance costs (which are generally assumed to be zero).

In each year that an agent is deciding, using the assigned values they calculate the average net cashflow that its system will provide over its assumed life, accounting for factors such as PV degradation. In these calculations, the retail tariffs and FiTs that reflect the customers' current situation are used. However, agents may also consider how these tariffs are anticipated to change in subsequent years. This is discussed in further detail in Section 4.4.

The equation to calculate the cash flow earned in year, n for a PV system is:

$$CF_{pv,n} = (Deg_{PV})^{n-1} \times \left[\left(\sum_{i=1}^{17520}(PVo_i - PVs_i)\right)(T_r) + \left(\sum_{i=1}^{17520} PVs_i\right)(T_{fi})\right]$$

All equation variables and constants are summarised in Table 4-1 and Table 4-2, respectively.

Table 4-1: Cash flow equation variables

Variable	Description	Unit
$CF_{pv,n}$	The cash flow earned in year, n for a rooftop PV system	$
T_r	Retail tariff	$/kWh
T_{fi}	Feed-in tariff	$/kWh
PVo_i	PV output during 30-min interval, i	kWh
PVs_i	PV surplus during 30-min interval, i	kWh

Table 4-2: Cash flow equation constants

Constant	Description	Value
Deg_{PV}	PV degradation factor	0.993

Using these cash flow values, each agent then calculates the corresponding payback period of the nominated system for the respective year across the system's assumed 20-year life. This is represented by the following equation, with the variables described in Table 4-3:

$$PB_n = \frac{C_s(1+r)}{\frac{1}{20}\sum_{i=1}^{20} CF_i}$$

Table 4-3: Payback period equation variables

Variable	Description	Unit
PB_n	The payback period of a system for year, n	Years
C_s	The total capital cost of a system	$
r	The discount rate	%

4.4 Uptake functions

Hundreds of thousands of households and businesses may calculate the same payback period for rooftop solar PV, yet they do not all make the same purchasing decisions. Despite sharing similar economics, people make different investment decisions due to factors like socioeconomic conditions, neighbourhood influence, beliefs, or different levels of awareness and understanding of the technology.

An uptake function is created and used to calculate the probability of uptake based on key economic parameters (e.g., payback period) to account for these real-world behavioural differences.

A solar uptake function analyses the historical rooftop PV uptake of eligible households and businesses in each region and plots the corresponding historical payback periods during each historical year. Various regressions are conducted to model different behaviours using a mix of linear and exponential equations. These behaviours include responsiveness to a certain level of DER economics or capturing the 'fear of missing out' (FOMO) effect from reducing feed-in tariffs and solar cash flows. With every timestep in the model, each agent calculates the payback period for a solar PV system. These metrics become an input to the relevant uptake function to calculate the probability of solar PV uptake.

4.5 Time-series modelling

A time series is a sequence of data points measured at different points in time, and its analysis comprises methods for extracting meaningful characteristics of the data (e.g., trend, seasonality, autocorrelation). Forecasting using time series techniques involves predicting future events based on a model of the data built upon known past events. Unlike other types of statistical regression analysis, a time series model accounts for the natural order of the observations and will reflect the fact that observations close together in time will generally be more closely related than observations further apart.

The water heater data were modelled by the number of installations. The original water heater time series were non-stationary, showing both a changing mean and changing variance over time. However, the logarithm of the original time series was found to be stationary after the trend was removed.

In summary, the time series analysis of the data for the water heaters was carried out by fitting univariate ARIMA models to the logarithm of the monthly number of registered installations by water heaters, split into domestic and commercial categories for Australia. The projection also considers deeming reductions in future years.

5. Inputs and assumptions

This section discusses the key assumptions used in the agent-based forecasting model. The model was built to forecast solar uptake for Australia's 336 SA3 regions, which are then aggregated to the state level. A range of de-identified rooftop PV data was supplied by CER, which informed historical, and future rooftop PV uptake.

5.1 Initialisation assumptions

As discussed in Section 4.2, agents are segmented into residential or commercial customers. The initialisation assumptions for each group are described in the following sub-sections, and Table 5-1 provides a summary of the data sources.

Table 5-1: Customer initialisation data sources

Category	Assumption	Source	Granularity
Residential demographics	Residential customer numbers and location	ABS Census 2021	SA3
	Dwelling type and tenure type	ABS Census 2021 microdata	
	Existing solar PV penetration	CER 2024	
Commercial demographics	Network system business customer numbers	AER, ESC, ERA, PWC	State
	Existing solar PV penetration	CER 2024	
School demographics	Existing solar PV penetration	CER 2024	
	Number of schools and location	ABS	
Historical residential energy characteristics	Energy consumption	AER, ESC, AusGrid, Essential Energy, Energex, Ergon Energy	SA3, Climate Zone
	Retail tariff	AER, ERAWA, ESC	State
	Feed-in tariff	IPART, ESC, QCA, Synergy, OTTER, NT Gov	
	Average retail bill	AER, IPART, ESCOSA	
	Solar profile	AEMO NemWeb	
	Capital costs	SolarChoice	
	Demand profile	CSIRO	National

5.1.1 Residential demographics

Information on residential customer numbers, location, dwelling type, and tenure type were sourced from the latest 2021 ABS census.

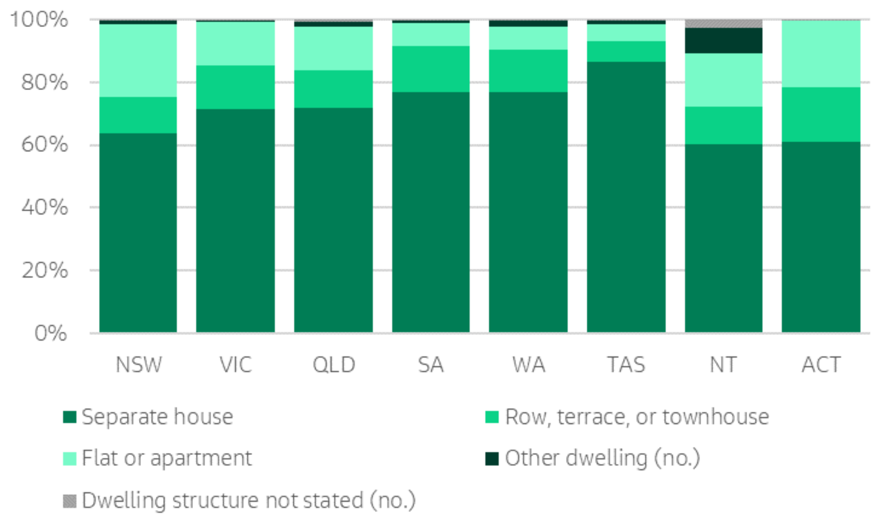
5.1.1.1 Residential dwelling type and tenure type

The ABS census details the proportion of dwelling type for each SA3 region, and tenure type. Only dwellings characterised as a separate house, or a semi-detached dwelling (terrace house, townhouse) are assumed eligible to adopt a rooftop solar PV system. Similarly, it is assumed only owner-occupiers can uptake a system due to constraints on renters' ability to modify their home.

Although households have different dwelling characteristics and electricity consumption behaviours, the trends in a region's average installed capacity are relatively homogenous. It is therefore acceptable to assign residential agents with their region's average capacity size because the standard deviation is small.

The state aggregated proportions of each dwelling type are illustrated in Figure 5-1. Out of the mainland states, New South Wales has the lowest proportion of detached dwellings, and the highest proportion of residents living in apartments or flats. Northern Territory, and the Australian Capital Territory also have a low proportion of detached dwellings. Tasmania has the highest share of houses and other detached dwellings.

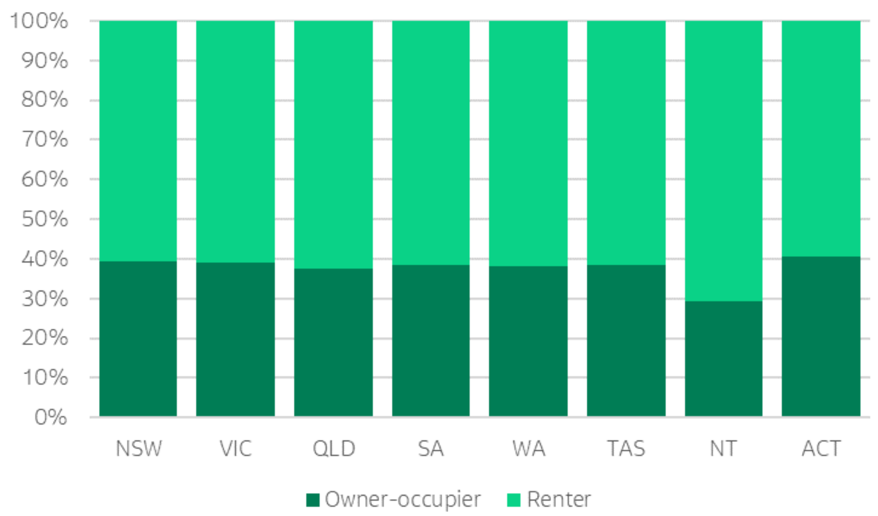
Figure 5-1: State dwelling proportions



Source: Jacobs' analysis of ABS Census 2021 data

The state aggregated proportions of each tenure type for detached dwellings are illustrated in Figure 5-2. All states have similar home ownership rates, except for the Northern Territory which is lower.

Figure 5-2: Detached dwelling tenure proportions per state/territory



Source: Jacobs' analysis of ABS Census 2021 data

5.1.2 Commercial demographics

Information on commercial customer numbers and location were sourced from various sources, depending on the state.

5.1.2.1 Commercial customer numbers and classification

Commercial agents are assigned to a state or territory based on the number of business customers for each region. Small and large business customer numbers were sourced from the Australian Energy Regulator (AER) for New South Wales, Queensland, South Australia, Tasmania, and the ACT, Essential Services Commission (ESC) for Victoria, and Economic Regulation Authority (ERA) for Western Australia and used for all regions except the Northern Territory. 'Low Voltage' non-residential customer numbers were sourced from Power and Water Corporation and used for NT.

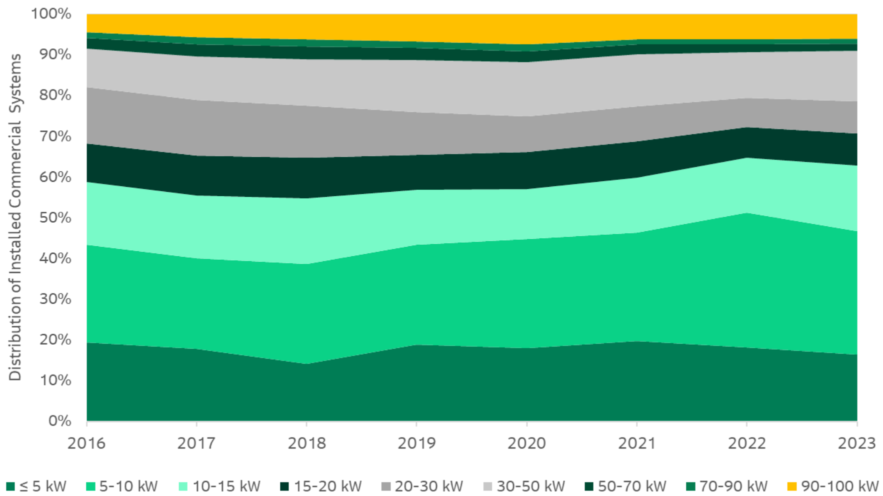
However, each state has a different definition of the customer classifications as outlined in Table 5-2.

Table 5-2: Business customer definitions

Business customer	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
Small	≤ 100 MWh pa	≤ 100 MWh pa	≤ 100 MWh pa	≤ 160 MWh pa	≤ 150 MWh pa	≤ 150 MWh pa	-	≤ 100 MWh pa
Large	> 100 MWh pa	> 100 MWh pa	> 100 MWh pa	> 160 MWh pa	> 150 MWh pa	> 150 MWh pa	-	> 100 MWh pa
Low Voltage	-	-	-	-	-	-	≤ 750 MWh pa	-

An analysis of historical commercial installations (excluding schools) indicates a consistent distribution of installed capacity sizes over the years, as shown in Figure 5-3, which is assumed to remain constant throughout the forecast period. It is assumed that commercial rooftop PV systems are optimised to the electricity consumption of the business and are not oversized.

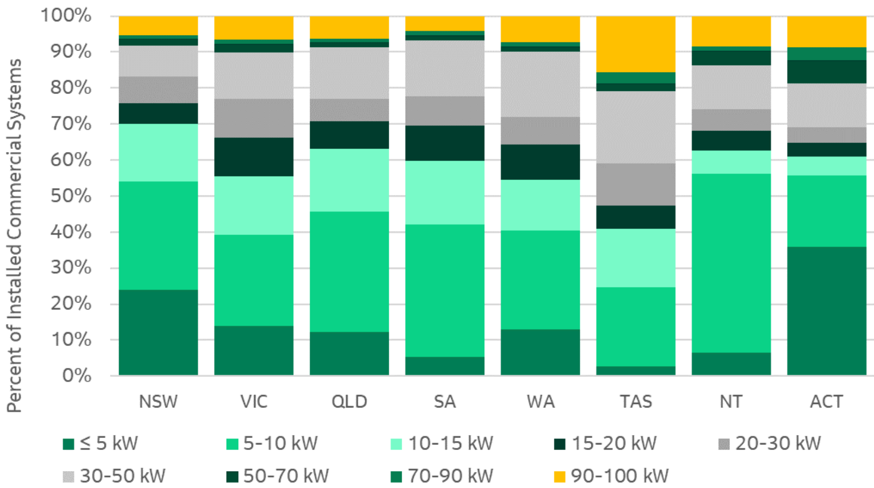
Figure 5-3: Historical distribution of commercial capacity segments, Australia



***Source**: Jacobs' analysis of CER data*

Under these assumptions, systems within the same capacity segment, as displayed in Figure 5-4 and Figure 5-5, belong to businesses with similar electricity consumption to each other.

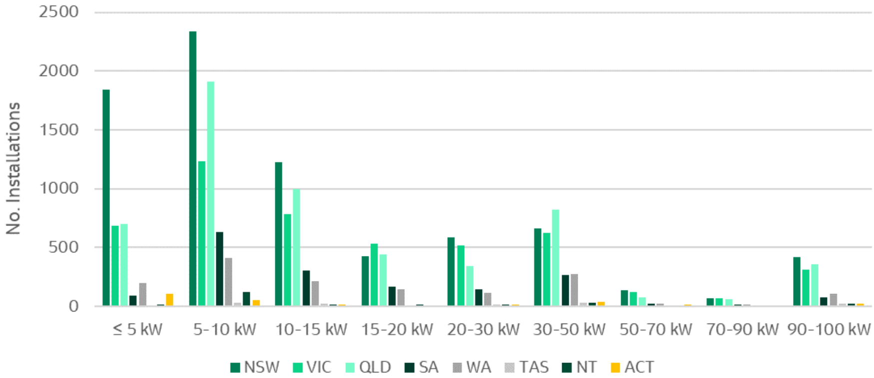
Figure 5-4: Commercial capacity segment distribution, 2023



***Source**: Jacobs' analysis of CER data*

While residential agents are assigned proportionately to SA3 regions, commercial agents are assigned to a system capacity segment (representing business consumption and size), based on their business customer type.

Figure 5-5: Number of installations by capacity segment, 2023



***Source**: Jacobs' analysis of CER data*

This segmentation is outlined in Table 5-3.

Table 5-3: Business customer segmentation

<table>
<tr><th>Capacity segment</th><th>NSW</th><th>VIC</th><th>QLD</th><th>SA</th><th>WA</th><th>TAS</th><th>NT</th><th>ACT</th></tr>
<tr><td>≤ 5 kW</td><td rowspan="5">Small</td><td rowspan="5">Small</td><td rowspan="5">Small</td><td rowspan="6">Small</td><td rowspan="6">Small</td><td rowspan="6">Small</td><td rowspan="9">LV</td><td rowspan="5">Small</td></tr>
<tr><td>5-10 kW</td></tr>
<tr><td>10-15 kW</td></tr>
<tr><td>15-20 kW</td></tr>
<tr><td>20-30 kW</td></tr>
<tr><td>30-50 kW</td><td rowspan="4">Large</td><td rowspan="4">Large</td><td rowspan="4">Large</td><td rowspan="4">Large</td></tr>
<tr><td>50-70 kW</td><td rowspan="3">Large</td><td rowspan="3">Large</td><td rowspan="3">Large</td></tr>
<tr><td>70-90 kW</td></tr>
<tr><td>90-100 kW</td></tr>
</table>

School agents are assigned to a state or territory based on school numbers from the ABS. The current penetration level for commercial and school agents are initialised using CER historical postcode data. Both agents subsequently follow a decision process like that illustrated in Figure 4-1.

5.1.3 Historical energy characteristics

As well as current data on customer demographics, a range of historical data was used to inform forward projections of underlying demand and solar and battery uptake, including:

- Energy consumption.
- Retail tariffs.
- Feed-in tariffs.
- Average retail bills.
- Demand profiles.
- Solar generation profiles.
- Capital costs (provided by SolarChoice[2]).
- Installed rooftop PV capacity.

5.1.3.1 Underlying electricity consumption

Energy consumption is a critical component of calculating the potential savings for households and businesses of investing in rooftop solar PV. The underlying electricity consumption (i.e., without a behind-the-meter system) was assumed for each SA3 region, using historical local government area (LGA) energy consumption data provided by various regional DNSPs (including self-consumed rooftop solar PV generation). In regions where their respective DNSP has not provided this data, an annual electricity consumption value was assigned depending on the SA3 region's climate zone, as published by the AER[3]. The state average underlying electricity consumption per year is shown in Figure 5-6.

Figure 5-6: Average residential underlying electricity consumption per annum

Source: *Jacobs' analysis of DNSP and AER data*

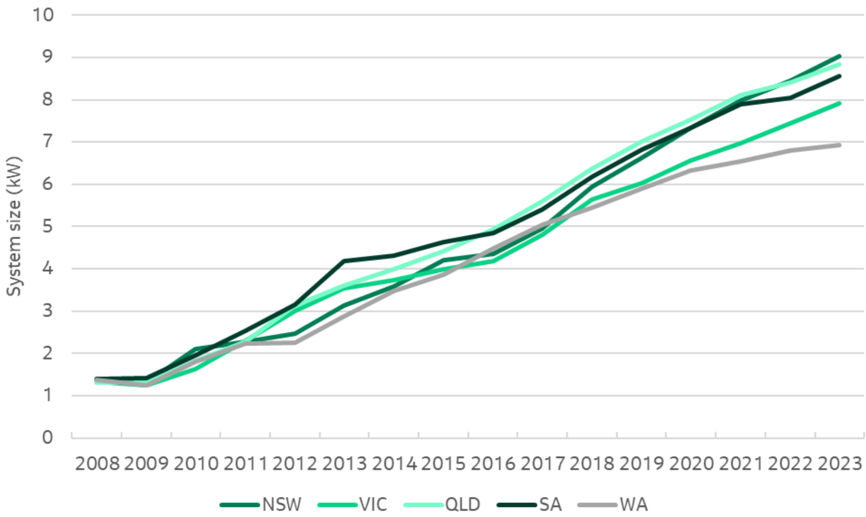
[2] See https://www.solarchoice.net.au/solar-panels/solar-power-system-prices/

[3] See https://www.aer.gov.au/industry/registers/resources/guidelines/electricity-and-gas-consumption-benchmarks-residential-customers-2020

5.1.3.2 Rooftop PV system sizes

Figure 5-7 shows the trends in average PV system sizes being installed since January 2008. The graph indicates that average system size has continued to grow at a steady rate over the last six months, consistent with growth patterns since mid-2016.

Figure 5-7: Trend of average residential PV solar system size, selected states



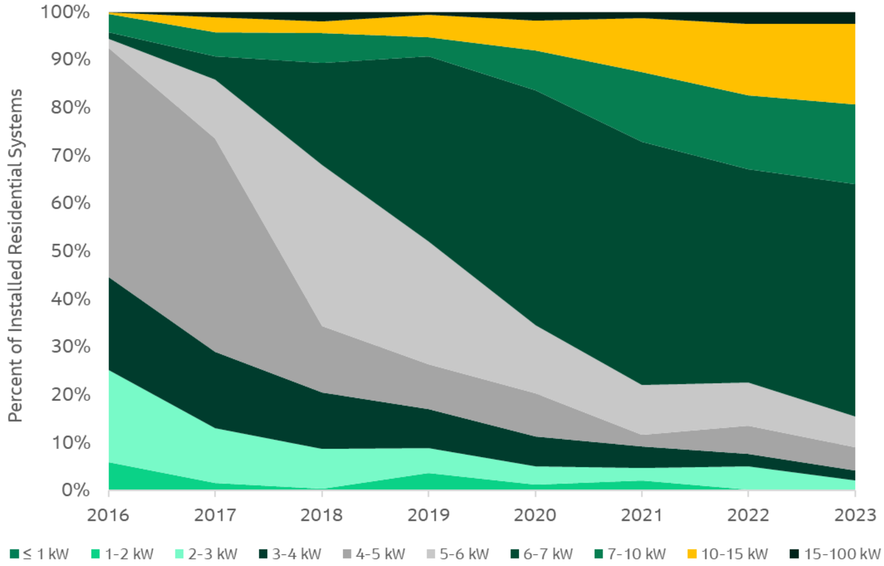
***Source**: Jacobs' analysis of CER data*

Consumers have continued to install larger PV systems. This results in the average household that consumes about 15 kWh/day to export approximately 70% of energy produced from their solar system to the grid. For illustrative purposes, Figure 5-8 shows the historical capacity distribution in the Latrobe Valley (for illustration purposes), which indicates a strong emergence in systems of between 6-7 kW in recent years, and an increasing uptake in larger systems of between 7-15 kW.

The tendency to oversize could be driven by several reasons including:

- Generous FiTs offered by retailers.
- Residents hedging against future electricity price increases.
- Residents hedging against future demand increases such as electrification of appliances and vehicles.
- Increasing environmental awareness and consumers wishing to contribute to the grid.
- Utilising battery systems to shift excess electricity.
- Economies of scale offered by installers for larger systems.
- Continued improvement in the capture efficiency of PV panels.

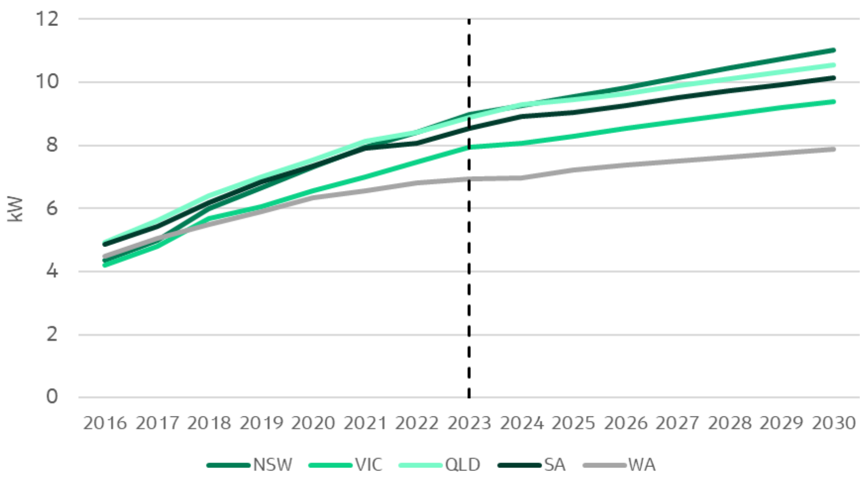
Figure 5-8: Historical residential system capacity distribution, Latrobe Valley



Source: Jacobs' analysis of CER data

Average system sizes will not likely continue to grow at the observed linear rate. Residential system sizes will become constrained by available roof space, and most states have a restricted inverter capacity of 5 kW_{ac} for residential phase 1 systems, which limits residential PV systems to a capacity of about 6.6 kW. This restriction combined with limited roof space, is expected to eventually curtail the average system size for residential properties. However, as observed in Figure 5-8, installations between 7-15 kW have been steadily increasing in the last four years. This can be attributed to households with three-phase connections which have higher inverter export limits, as well as households opting for larger systems for self-consumption despite the 5 kW inverter export limit. Power curves have been fitted in each SA3 region to reflect these changes in system size (Figure 5-9).

Figure 5-9: Weighted average rooftop PV residential system size forecast, select States



Source: Jacobs' analysis

At the end of 2023, NSW has the largest average residential system size (8.97 kW) out of the mainland states, closely followed by Queensland (8.87 kW). Western Australia has the smallest average residential system size in Australia (6.94 kW). From February 2022, all new solar systems in Western Australia with an inverter capacity higher than 5 kW will have an export limit of the greater between 1.5 kW and 5% of the inverter capacity; this has therefore greatly disincentivised any system above 6.6 kW. This regional spread in average system capacity is expected to persist throughout the forecast period, although NSW is projected to have a slightly higher growth rate (due to higher uptake in sub-regions with larger system sizes). Mostly consistent with historical trends, the increase in projected average system capacity for all regions is largely driven by three-phase connection households, and households opting for larger systems for self-consumption despite prescribed export limits. By 2030, the average residential system size for NSW is 11.0 kW, and 7.87 kW for Western Australia.

5.1.4 Time lag to registration

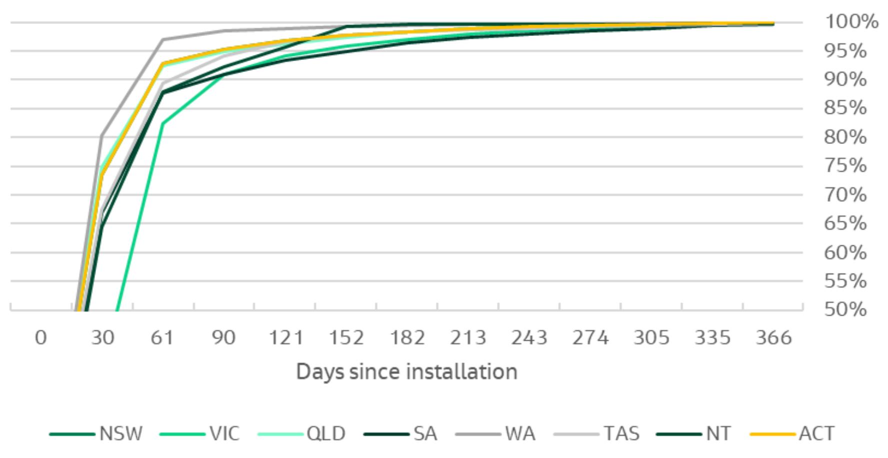
As there is a 12-month window from the date of installation in which to register eligible systems, the most recent registrations database will be missing records of systems that have already been installed, but which have not yet been registered. If not corrected, this will lead to an underestimate in the number of systems installed in recent months. This is especially important for the time-series forecasting, which is sensitive to recent data points.

The average duration between system installation, and the date of STC registration was examined. The data provided by the CER includes both the date of system installation and of the STC creation, so it is possible to calculate how many systems are registered one, two, three, or more months after the system was installed.

Residential and commercial data were analysed between May 2022 to April 2023 which was selected to reflect recent trends. Installations from the previous 12 months were not incorporated due to the bias that would occur in favouring the population of customers who install early rather than later, resulting in an underestimate of time taken to register PV systems.

Figure 5-10 shows the typical delay in registration for residential system installations by state.

Figure 5-10: Cumulative delay in STC creation from date of installation, residential SGUs (May 22 – Apr 23)



Source: Jacobs' analysis of CER data

From May 2023 through to April 2024, the residential installed capacity was divided by the percentage of registered installations to create an expected percentage of installations for the respective month, as shown in Table 7.

Table 5-4: Percentage of installed capacity used in modelling for residential solar PV systems

	ACT	NSW	NT	QLD	SA	TAS	VIC	WA
1/05/2023	100%	100%	100%	100%	100%	100%	100%	100%
1/06/2023	100%	100%	100%	100%	99%	100%	100%	100%
1/07/2023	100%	100%	100%	100%	99%	99%	99%	100%

	ACT	NSW	NT	QLD	SA	TAS	VIC	WA
1/08/2023	100%	100%	100%	100%	99%	99%	99%	100%
1/09/2023	99%	99%	100%	99%	98%	99%	99%	100%
1/10/2023	99%	99%	100%	99%	97%	99%	98%	100%
1/11/2023	99%	98%	100%	98%	96%	98%	97%	99%
1/12/2023	98%	98%	99%	97%	95%	98%	96%	99%
1/01/2024	97%	97%	96%	96%	93%	97%	94%	99%
1/02/2024	96%	95%	92%	95%	91%	94%	91%	98%
1/03/2024	94%	93%	88%	93%	88%	89%	82%	97%
1/04/2024	71%	73%	64%	75%	67%	67%	39%	80%

5.1.5 Solar PV uptake function

In reality, thousands of households may calculate the same payback period for a rooftop solar PV system, yet they do not all make the same purchasing decisions. Despite sharing similar economics, people respond differently due to factors like socioeconomic conditions, neighbourhood influence, beliefs, or different levels of awareness and understanding of the technology. An uptake function is used to calculate the probability of uptake based on a given payback period to account for these real-world behavioural differences. For residential agents, this function is unique to each SA3 region. For commercial agents, it is unique for each state/territory capacity segment.

The uptake function analyses the historical rooftop PV uptake of eligible households in each region and plots the corresponding historical payback periods during each historical year. A power regression is conducted for all data sets to provide a power equation. If the relationship's R^2 value is greater than 0.70, the agent inputs their calculated payback period to calculate the probability of uptake. However, the payback/uptake relationship is not necessarily perfect for every region. For this reason, multiple regression equations are computed for each SA3 region, and the uptake function chooses which one to use based on the R^2 value, and the resultant probability.

The following relationships are used in the uptake function:

- Payback period versus historical uptake.
- Retail electricity price versus historical uptake.
- Capital cost versus historical uptake.

5.2 Uptake assumptions

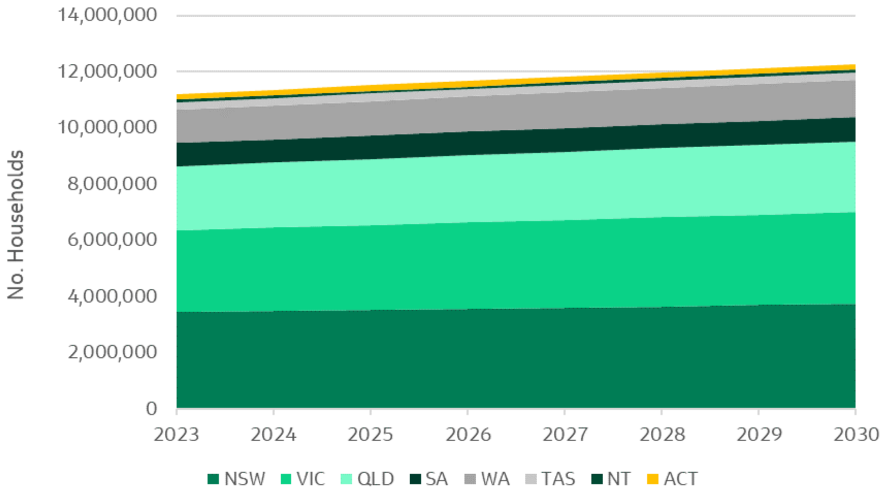
This section describes the assumptions that underpin the uptake forecasts for solar PV. While some of these measures have been discussed in the initialisation assumptions described in Section 5.1, they differ in the fact that in the previous section they referred to historical data used to set up and initialise agents, whereas in this section they refer to data used in forecasts of future years. Further, the assumptions in this section are the key economic and financial drivers that influence payback calculations used by customers to decide whether to take up rooftop solar systems, as well as the assumptions used to forecast changes in population.

5.2.1 Household growth

Household growth was indexed to the SA3 population or household growth forecasts from the respective state and territory governments (except Tasmania and Northern Territory). Using SA3 household numbers from the latest ABS 2021 Census, household growth followed the trend of its corresponding SA3 household/population forecast using its state government's central case. Where an SA3 region experiences negative growth during a given year, zero growth is assumed. This is due to the uncertainty in attributing outflows of agents in one location to inflows of agents in another.

The total household growth forecast is shown in Figure 5-11. Within the agent-based model, the appropriate number of agents are introduced every year to account for household growth. These new agents are initialised using the initial assumptions discussed in section 4.2.1, and subsequently follow the same decision process. Due to accounting for only 3% of Australian households, the number of dwellings in Tasmania and Northern Territory are assumed constant.

Figure 5-11: Household growth forecast



5.2.2 Solar PV system capital costs

Solar PV system costs have risen over the last few years, as the global oversupply on PV module manufacturing capacity diminished during COVID-19. From late 2020 until the end of 2022 there had been a shortage on manufacturing capacity (due to greater than anticipated global demand for solar PV systems), which have also been coupled with higher costs of module raw materials and higher costs of freight. The impact of raw material costs is being ameliorated by an increase in demand for alternative module materials. This volatility challenged logistic supply chains, and as a result freight costs had increased by a factor of 3-4 for shipments from China. Delivery times were also stretched, which placed upward pressure on system prices.. However, increased manufacturing capacity has led to an amelioration of price pressures with downward pressure on price seen recently. Over the past year, average year on year capital costs for solar systems has had limited reductions.

Capital cost assumptions for PVs in 2024 are based on the Solar Choice website's[4] monthly unit pricing overview, which is based on price data from 125 solar installation companies across Australia. These were converted into real dollars using historical CPI data.

For residential systems, the price per system per kW for capacity sizes of 5 to 10 kW was trended over time, and forecasts for each State were performed by utilising the expected learning curve extrapolated from CSIRO's 2023-24 GenCost[5] forecasts for rooftop PV (Global NZE post-2050 scenario), illustrated in Figure 5-12. These cost projections only account for single inverter systems; uptake of microinverters were not considered in this

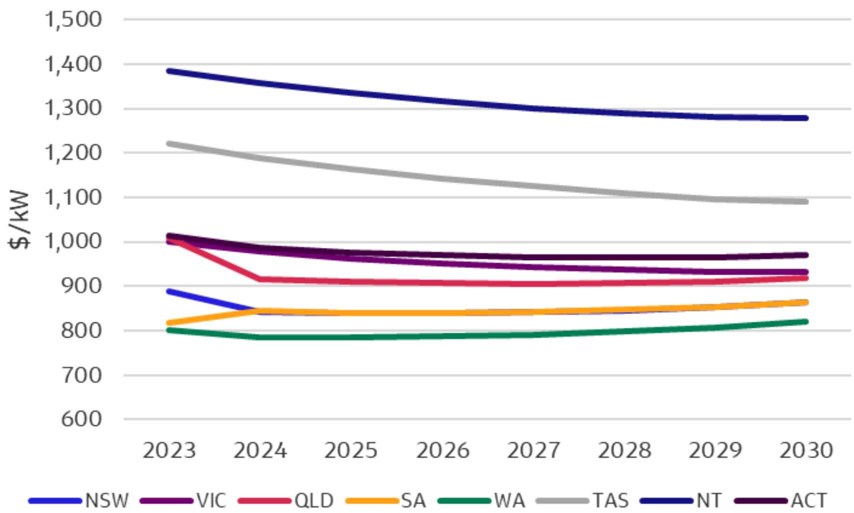
[4] https://www.solarchoice.net.au/solar-panels/solar-power-system-prices/

[5] https://data.csiro.au/collection/csiro:44228

study. Current global inflationary pressures are expected to remain higher for longer from faster technological deployment to meet stronger climate policies. This is expected to slow the rate of decline. The diminishing STC discount largely offsets the yearly cost reductions throughout the forecast period.

The NT is expected to have the highest system prices starting at $1,358/kW in 2024 to $1,278/kW in 2030. All other States and Territories besides Tasmania are projected to have capital costs roughly between $800/kW to $1,100/kW over the projection period.

Figure 5-12: Net capital costs, residential solar PV systems ($/kW 2023)

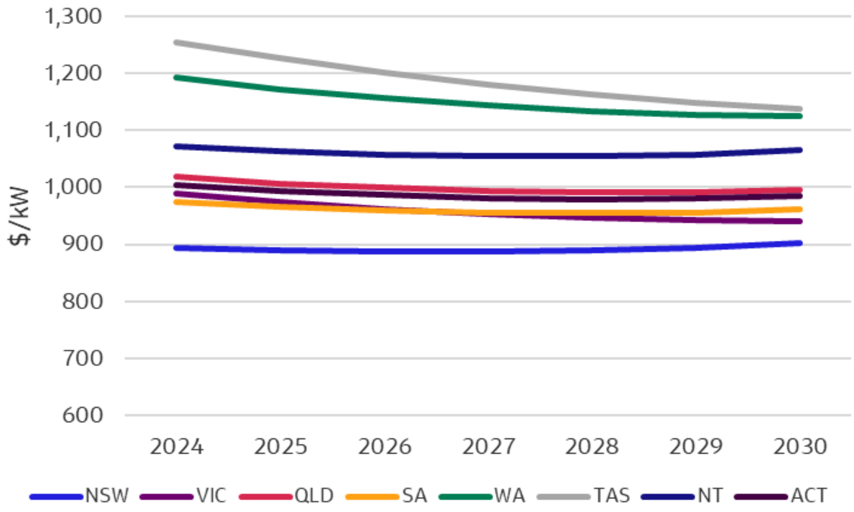


Source: Jacobs' market analysis, Solar Choice, CSIRO GenCost

A similar method was applied to costs of commercial systems, by utilising the data for systems between 10 kW and 100 kW. The average cost was plotted for all states, and the CSIRO's rate of decline was applied from 2024 to 2030.

The economies of scale were less apparent in commercial systems, with little difference between cost per kilowatt for a 10-kW system versus a 100-kW system. Therefore, a ratio for economies of scale was not applied and the cost per unit was assumed to be constant. Figure 5-13 shows the forecasted costs assumed for commercial systems.

Figure 5-13: Net capital costs, commercial solar PV systems ($/kW 2023)



Source: Jacobs' market analysis, Solar Choice, CSIRO GenCost

5.2.3 Retail electricity tariffs

Jacobs' in-house wholesale electricity price forecasts were used as the basis for estimating retail electricity prices, which in turn were used in calculating future electricity savings and/or revenues for solar generation units (SGUs).

Jacobs has prepared the retail price projections using a bottom-up book build approach. This approach involves developing projections for each cost component of the retail tariff and adding up the components to formulate an overall retail price forecast. These cost components include network charges, wholesale charges, environmental scheme costs, market operator charges, and retailer charges and margins. The cost breakdown of the current retail price is used as a measure to calibrate the various components of the retail price.

5.2.3.1 Wholesale costs

The wholesale market costs faced by retailers include:

- Spot energy cost as paid to AEMO adjusted by the applicable transmission and distribution loss factors.
- Hedging costs around the spot energy price consisting of swaps, caps and floor contracts.

Retailers must formulate a contracting strategy that enables them to manage trading risk according to their own risk profile. Generally, contracts are available at a premium to spot market prices to reflect the protection against volatile prices.

Our analysis of the wholesale market[6] determined an allowance of 30% was added to wholesale market costs to account for both price risk and forecasting risk for smaller customer markets (i.e., residential and SME markets). For larger customers, Jacobs considered that the ability to forecast loads and the presence of temperature sensitivity in the loads may be lower for larger customers and reduced the risk premium to 13% for large commercial customers and to 10% for industrial customers.

[6] See "Analysis of electricity retail prices and retail margins", May 2013, SKM-MMA (note this is a previous trading name of Jacobs), available at https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-market-performance-and-reporting/electricity-retail-prices-and-margins-reporting-2013

There is also a strong relationship between this margin and the average price, with the margins being lower when the average price is lower (on the basis that lower average prices indicates an excess of supply or lowering of demand and hence the less likelihood of price spikes). Hence, we used a regression model that will map the uplift rates to projected average price, based on historical margins (on spot forward prices) against average prices.

Allowances for losses occuring across power lines in transmission and distribution are accounted for by applying transmission loss factors (TLFs) and distribution loss factors (DLFs).

The annual retail prices are built from quarterly wholesale price forecasts adjusted for seasonality based on regional monthly demand. The wholesale prices (real $/MWh) are based on Jacobs' market forecasts. More detail on the market modelling assumptions and methodology is provided in Appendix A: Annual System Installations.

5.2.3.2 Network charges

Network charges are the costs associated with transmission and distribution of electricity for the retailers. These costs are set by network service providers who own the transmission infrastructure. The network charges are found on the AEMC website in their electricity prices and trends report where the base year values are actuals. Network determinations are set every five years. The current network determination period with published network charges ranges from 2024 to 2029.

As large interconnector upgrades for transmission systems are expected in the NEM in the medium term, Jacobs has estimated additional charges expected to be passed onto customers.

The costs have been annualised over a 50-year period utilising a weighted average cost of capital (WACC) of 7.4%. This WACC is also utilised for renewables build-out in Jacobs' wholesale price modelling. The first year in which the annualised cost is applied is 1 year prior to assumed construction commencement date of the interconnector upgrades. The annual costs are then divided by the forecasted regional demand to present a cost per MWh of electricity usage.

5.2.3.3 Other charges

Large-scale renewable energy target (LRET) – The LRET provides a financial incentive to establish or expand renewable energy power stations by legislating the creation of Large-scale Generation Certificates (LGCs), where one LGC is equivalent to one MWh of eligible renewable electricity produced by an accredited power station. LGCs are sold to liable entities (mostly electricity retailers who must purchase a percentage of electricity from renewable sources each year) who must surrender them annually to the CER.

LGCs were introduced as a mechanism to achieve the Federal Government's target of 33,000 GWh of electricity from eligible large-scale renewable sources in the NEM by 2020. The annual target increased each year until 2020 and is now constant at 33,000 GWh per year to 2030, when the scheme ends.

The LGC price is anticipated to decline through to 2030 because the supply of LGCs should increase as more accredited renewable energy is established in the electricity market but demand for LGCs from liable entities should remain at about the same level, in line with the steady target. However, recent forward prices have retained significant value. In the future, additional demand from voluntary cancellations to meet private sector decarbonisation goals is expected to continue rapidly increasing, being the primary driver for retaining value of LGCs.

The LGC projections are adjusted using the DLF and TLF applying to the generator.

Small-scale renewable energy scheme – Electricity retailers are liable entities under the SRES who surrender STCs to the CER to meet their SRES obligations. This imposed cost to electricity retailers are passed on to consumers through the retail electricity tariff.

Feed-in-tariffs – This is built up by calculating the proportion of solar generation in relation to operational demand and multiplying by the relevant state or territory FiT rate.

5.2.3.4 Market charges

Market fees are regulated to recover the costs of operating the wholesale market, the allocation of customer meters to retailers, and settlement of energy purchases. These fees, charged by the AEMO to retailers, are applicable to wholesale black energy purchases and are $0.57/MWh in FY2024 according to the AEMO 2023-24 Budget and Fees. AEMO has forecast an increase of 4.5% in NEM fees from FY2023 to FY2025. For the years beyond FY2025, Jacobs has assumed a continuation of the previous growth per year (approximately 2% for NEM fees) up to FY2030.

In addition to these fees, AEMO also recovers the costs for Full Retail Contestability ($0.094/MWh in FY2023) and Energy Consumers Australia (ECA), a body which promotes the long-term interests of small energy consumers (approximately $0.04/MWh for residential and SME customers, annualised). The NEM 5 Minute and Global Settlements (5MS) charge and NEM Distributed Energy Resources (DER) program charges are now $0.24/MWh and $0.0296/MWh respectively.

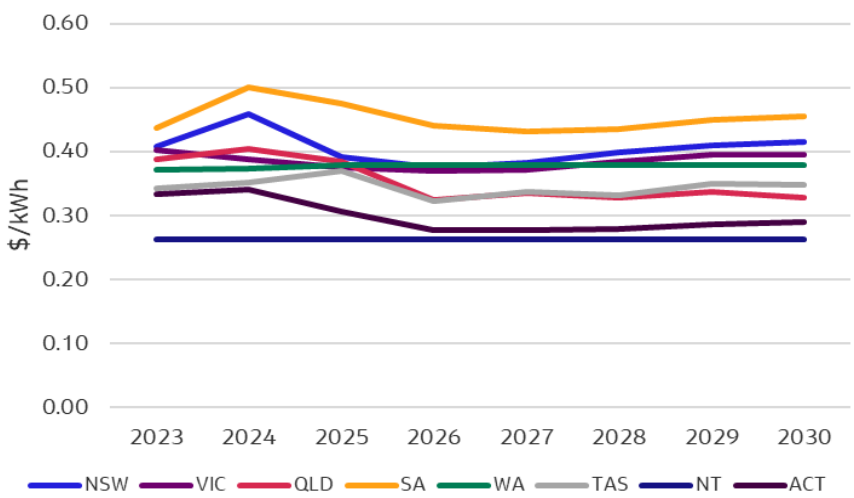
5.2.3.5 Retailer costs and margin

The retail margin is estimated from historical data from the AEMC. The proportion of the total retail tariff that encompass retailer costs and margins is given in its electricity price trends report. This is assumed to remain constant over the forecasting period.

5.2.3.6 Retail electricity tariff

Figure 5-14 shows the retail electricity prices for each state used in the forecasts. Northern Territory and Western Australian prices are regulated by the state government, and it is assumed these will remain constant.

Figure 5-14: Residential retail electricity tariff forecasts



Source: Jacobs' market modelling

5.2.4 Feed-in tariffs

Feed-in tariffs in Australia for small-scale renewable energy generation are offered by retailers and, in some instances, they have an obligation imposed by the relevant state government to offer a minimum tariff for exports of electricity to the grid. Where the required data for FiTs and customers per retailer were available, a price based on the weighted average retail offer of the three largest retailers and a combination of remaining retailers was assumed in the modelling.

The Northern Territory and Western Australian governments have reduced their FiTs to reduce incentives to export rooftop solar power because of the impact of high penetration of solar on grid stability. In April 2020, the Northern Territory standard FiT was reduced from 26.05c/kWh to 8.3c/kWh, applied to all new installations.

In Western Australia, the standard FiT rate of 7.135 c/kWh was lowered to 2.25c/kWh for exports prior to 3pm and 10c/kWh for exports between 3-9pm. This is a move to encourage the installation of west facing solar panels and BESS to shift exports to during the evening peak period. This change is in place for all new systems installed from September 2020.

In New South Wales, the benchmarked FIT has recently been revised downwards in response to the recovered wholesale electricity prices, and further diminished value of solar generation from low daytime demand (from high rooftop PV penetration), and high daytime supply (from utility solar). The FY2025 benchmarked FiT has lowered from 7.7-9.4 c/kWh in FY2024 to 4.9-6.3 c/kWh. Similarly in Victoria, the minimum flat feed-in tariff has been reduced to 3.3 c/kWh in 2025, from 4.9 c/kWh in 2024.

5.2.5 STC prices

Figure 5-15 shows the historical STC prices for the period January 2018 to June 2024. During this period the STC prices hovered below $40, indicating that a surplus of STCs was being generated in the market. While $40 is in effect a ceiling price, and in the short-term prices may fluctuate beneath that level, it is assumed that prices converge and maintain at that level as annual targets are matched to projected levels of uptake.

Figure 5-15: Monthly historical STC price (nominal)

Source: Jacobs' analysis of Demand Manager data

5.2.5.1 STC zoning

The CER divides Australia into four regional zones based on the estimate of renewable energy that can be generated by a solar panel in each area, so installations in areas with high insolation[7] will create more certificates per kilowatt than rooftop installations based in areas in the south of the country. Zones are defined by postcodes. To convert the capacity of solar panels installed to the number of STCs produced, the average STC per kilowatt of installed capacity was calculated for the years 2013 to 2016 for each state and territory, which is the period when STC generation was not affected by multipliers or reduced deeming periods. Table 5-5 shows the effective multiplier for each state and territory used for conversion of the forecast capacity into STCs. From 2017, the deeming period reduces by an additional year every year; therefore, systems installed in 2024 will have a maximum deeming period of 7 years. As a result, the number of STCs created per kW reduces by a greater rate each year.

Table 5-5: Average STCs generated per kW of PV installed

Region	Pre-2017[8]	2024	2025	2026	2027	2028	2029	2030
New South Wales	20.7	9.8	8.4	7.0	5.6	4.2	2.8	1.4
Victoria	17.8	8.8	7.5	6.3	5.0	3.8	2.5	1.3
Queensland	20.6	9.7	8.3	6.9	5.5	4.1	2.8	1.4
South Australia	20.5	9.6	8.3	6.9	5.5	4.1	2.8	1.4
Western Australia	20.6	9.7	8.3	6.9	5.5	4.1	2.8	1.4
Tasmania	17.6	8.2	7.1	5.9	4.7	3.5	2.4	1.2
Northern Territory	23.2	10.8	9.2	7.7	6.1	4.6	3.1	1.5
Australia Capital	20.6	9.6	8.3	6.9	5.5	4.1	2.8	1.4

[7] Insolation is the amount of solar radiation received on a given surface in each period.

[8] For a 15-year deeming period

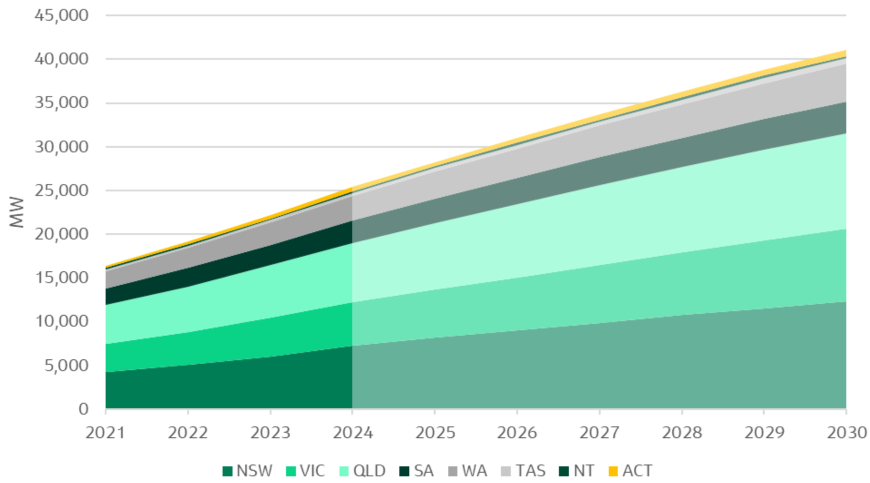
6. Results

This section presents the main projections from the agent-based and ARIMA time-series modelling undertaken by Jacobs. All results are provided in calendar years, and historical numbers from (at least) 2021 are given for context.

6.1 Rooftop PV capacity

The cumulative installed rooftop PV capacity increases over the forecast period, rising from 25,354 MW at the end of 2024, to 41,045 MW by the end of 2030, as shown in Figure 6-1.

Figure 6-1: Small-scale PV state forecasts, cumulative installed capacity



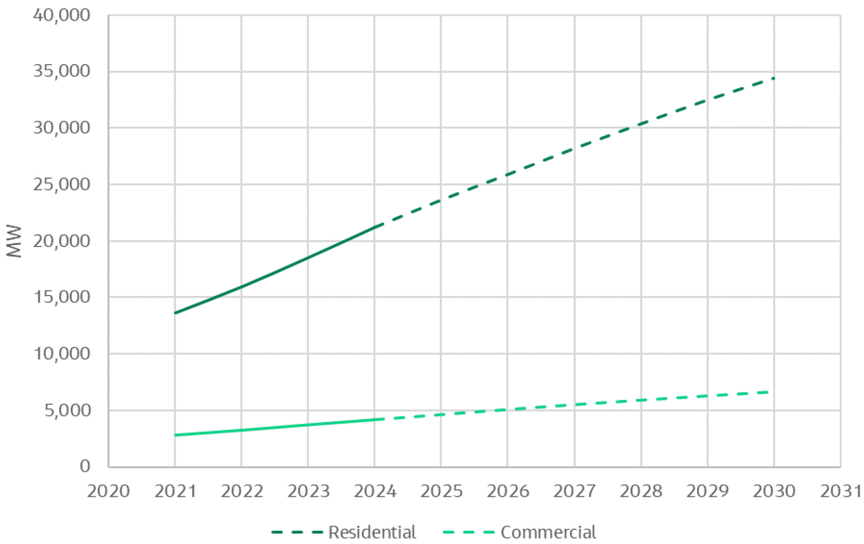
Across the east coast of Australia, the National Electricity Market (NEM) had experienced prolonged periods of high wholesale electricity prices. This was largely a result of the undersupplied global gas market, ultimately caused by the economic sanctions imposed on Russia. These sustained prices in the wholesale market have flowed through to retail electricity prices from the second half of 2023 and has re-incentivised a new wave in rooftop PV installations. Whilst 2022 was the first year that marked a slowdown in annual uptake following several years of consecutive record growth, annual installed capacity rebounded in 2023 with similar trends expected by the end of 2024. Across Australia, 3,123 MW of capacity is expected by end of 2024 compared to 3,096 MW estimated for 2023.

Due to electricity retailer hedging, the NEM's wholesale price recovery in 2023 (down from record high prices in 2022) will eventually flow through to the retail electricity market from 2025, lowering retail prices in this year. As a result, lower electricity prices reduce the net financial benefit of PV systems leading to an expected 8% decline in annual installed capacity to 2,885 MW. Despite the diminishing STC subsidy, net system costs are still projected to fall slightly in 2025 which partially offsets the reduced benefits from lower retail electricity prices.

However, from 2026 the cost reduction rate of rooftop PV costs has slowed to the point of being outpaced by the reducing STC discount. At this point, system costs are still recovering from inflationary pressure caused by increased global uptake of utility and small-scale solar, and the STC subsidy is diminishing at a greater rate as the deeming period decreases by another year. In addition, the feed-in tariffs of a few states continue to fall in line with the increasing solar supply which diminishes the value of daytime solar generation. Whilst the trend of system costs will have stagnated (the diminished deeming period of STCs has fully outpaced any cost decline from technological innovation), the fall of retail electricity prices and feed-in tariffs are the primary drivers for creating comparatively less attractive payback periods throughout the late 2020s. As a result, installed annual capacity is expected to continue declining with 2,711 MW of annual installed rooftop PV capacity in 2026, declining to 2,294 MW by 2030.

Figure 6-2 shows the forecasts of cumulative installed small-scall PV capacity, across the residential and commercial sectors.

Figure 6-2: Small-scale PV sector forecasts, cumulative capacity



In 2023, residential cumulative capacity comprises 83.3% of total solar PV capacity in Australia, increasing slightly to 83.8% by 2030. At the end of 2024, the residential and commercial sectors have 21,180 MW and 4,173 MW of installed PV capacity, respectively. By the end of 2030, there is 34,383 MW and 6,662 MW of cumulative capacity in the residential and commercial sectors, respectively.

Throughout the forecast period, residential installations convey more volatility than commercial uptake. A reason is that residential customers are more sensitive to changing FiT rates, as they are more dependent on solar export revenue from their relatively oversized PV systems than commercial customers. Conversely, commercial PV systems tend to be sized to meet their electricity grid consumption and are less responsive to changing FiTs. Table 6-1 displays the annual installed rooftop PV capacity for each state/territory and sector. Annual installations per region are tabulated in Appendix A: Annual System Installations.

Table 6-1: Annual installed rooftop PV capacity (MW)

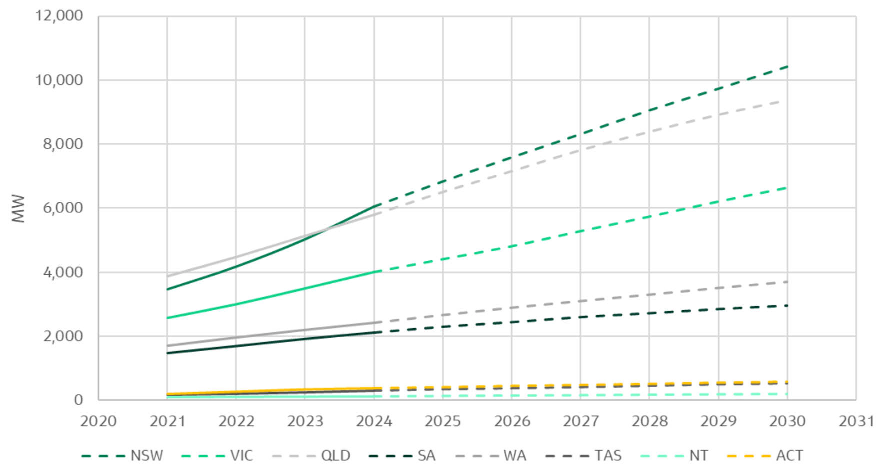
	2024	2025	2026	2027	2028	2029	2030
RESIDENTIAL							
Australian Capital Territory	38	36	38	30	33	40	28
New South Wales	1,013	784	749	723	741	673	685
Northern Territory	8	15	12	10	13	12	10
Queensland	652	713	649	658	575	532	453
South Australia	196	182	144	159	121	129	108
Tasmania	50	47	29	35	39	47	27
Victoria	495	403	403	471	454	469	429
Western Australia	213	247	232	212	203	212	192
Total Residential	**2,664**	**2,427**	**2,255**	**2,298**	**2,177**	**2,114**	**1,932**

	2024	2025	2026	2027	2028	2029	2030
COMMERCIAL							
Australian Capital Territory	7	7	4	6	4	5	4
New South Wales	157	142	138	128	121	120	108
Northern Territory	4	4	3	4	3	4	3
Queensland	114	125	124	103	92	71	70
South Australia	31	28	38	35	30	29	30
Tasmania	4	4	4	4	5	4	4
Victoria	100	107	103	113	111	109	106
Western Australia	42	41	42	40	37	37	38
Total Commercial	**458**	**458**	**456**	**432**	**402**	**379**	**363**
Total Capacity	3,123	2,885	2,711	2,730	2,579	2,493	2,294

6.1.1 State residential PV projections

The cumulative residential solar PV capacity forecasts of each state are shown in Figure 6-3.

Figure 6-3: State residential small-scale PV projections, cumulative capacity



By the end of 2024, most regions comprising the NEM have similar or higher annual installed PV capacity to the levels in 2023. Although retail prices had not officially increased until mid-2023, the strong anticipation of these price hikes and prevalent coverage of the global energy crisis in mainstream forums was likely to have played a role in influencing installations from 2023, carrying into 2024 as the retail prices officially reflected expectations. Western Australia and Northern Territory are expected to see a decline in installed capacity in 2024 - both these regions have regulated retail electricity prices and were not affected to the same extent as households along the east coast. NSW is expected to have the largest increase in uptake for 2024, installing 1,103 MW. This is an 18.6% increase from 2023 (estimated to be 854 MW) and enough to surpass Queensland with the highest cumulative installed residential capacity. This is primarily driven by the increase in the state's retail electricity price which had among the highest annual uplift in the country.

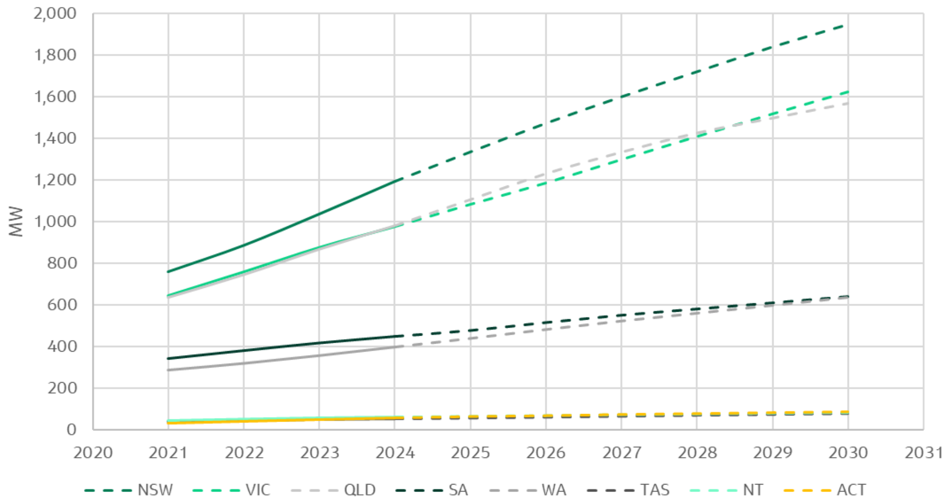
Stagnated capital costs and falling retail electricity and feed-in tariffs from 2025 onwards is projected to decrease annual growth for all regions for the remainder of the forecast period. However, particularly in Queensland, historically high installations have resulted in a small proportion of eligible dwellings remaining yet to install solar PV. As Queensland reaches near its saturation limit, annual uptake for new installations decreases every year. However, a material proportion of the state's installations are attributed to households replacing older, smaller systems. Currently, around 25% of all Queensland installations are from replacements which is expected to steadily increase throughout the forecast period. Other regions adopt a similar trend, with many households who installed during the early 2010-2011 peak installation period are projected to replace those systems during the late 2020s which were typically under 2-3 kW and would have significantly degraded[9]. The assumed replacement capacity is aligned with the projected average system sizes shown in Figure 5-9.

In 2030, NSW is forecast to install 685 MW of annual capacity in the residential sector. Queensland and Victoria are expected to install 453 MW and 429 MW capacity in 2030, respectively.

6.1.2 State commercial PV projections

Figure 6-4 shows the cumulative installed commercial small-scale PV capacity forecasts. Except for NSW, most regions are expected to have marginally lower annual installed capacity by the end of 2024, compared to 2023. New South Wales, Victoria, and Queensland are projected to install 157 MW, 100 MW, and 114 MW by the end of 2024, respectively. However, unlike residential customers, commercial customers are not as reactive to changing FiTs since their systems are typically more efficiently sized to their electricity consumption and are not as reliant on solar export revenue.

Figure 6-4: State commercial small-scale PV projections, cumulative capacity



6.2 Water heater STCs

The ARIMA time series model forecasted the monthly installations of residential and commercial SWH and residential ASHP. Annual multipliers were applied to the forecasted installations to project the resultant number of STCs.

6.2.1 Solar water heaters

Figure 6-5 shows the historical and forecasted installations for residential SWH across Australia. Historical installations have been declining since late 2018, which has coincided with the rise in residential air source heat pumps. This mild downtrend is expected to continue across the forecast period as ASHP continue to rise in popularity amongst households and gradually replace its market share. Forecasted installations are tabulated in Appendix A: Annual System Installations.

[9] A system installed in 2010 will have degraded by ~10.6% by 2026, assuming a 0.7% annual degradation rate

Figure 6-5: Residential SWH installations, monthly (≤40 STCs per installation)

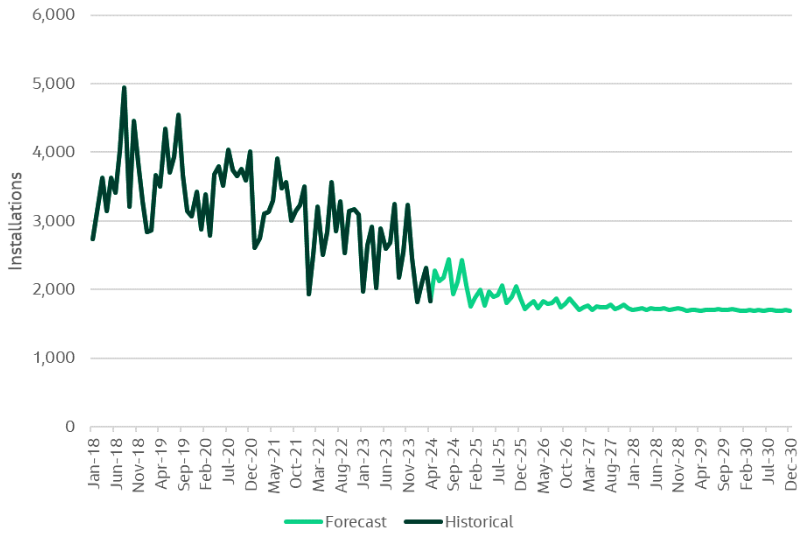
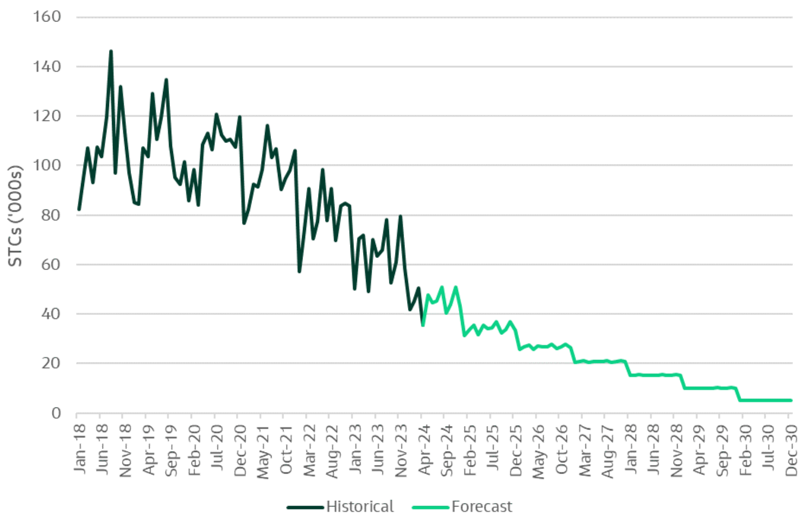


Figure 6-6 shows the historical and projected creation of STCs for residential SWH installations. Since 2021, the deeming period for SWH STC creation has been reducing. Installations in 2024 are only eligible for 70% of the number of STCs created under a full 10 year deeming period. By 2030, the number of STCs reduces to only 10%.

Figure 6-6: Residential STCs for SWH, monthly (Australia)



Historical and forecasted installations for commercial SWH are shown in Figure 6-7. Since early 2022, the number of commercial installations has dropped significantly, decreasing to less than 200 installations per year across Australia. Like residential SWH, the slump in commercial installations is likely attributed to air source heat pumps which have also gained popularity in the commercial sector. In the future, it is projected that only a handful of commercial SWH will be installed every year, whilst businesses opt instead for the energy efficient ASHP.

Figure 6-7: Commercial SWH Installations, monthly (Australia)

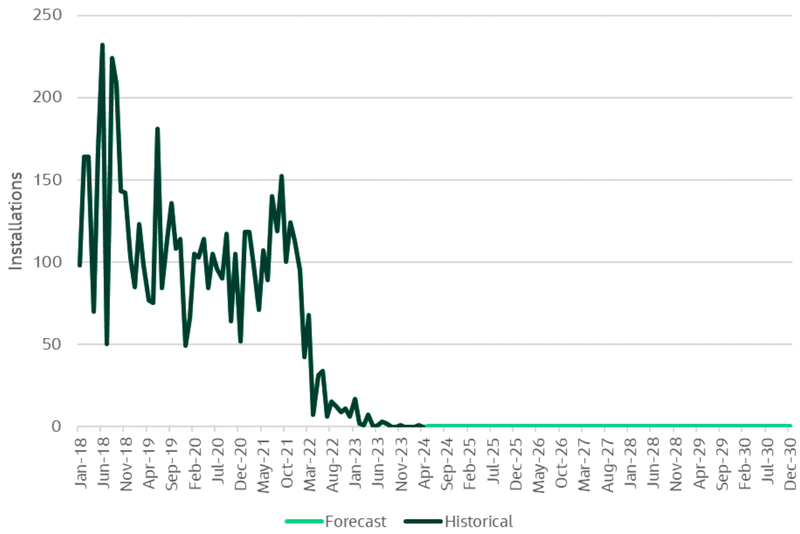
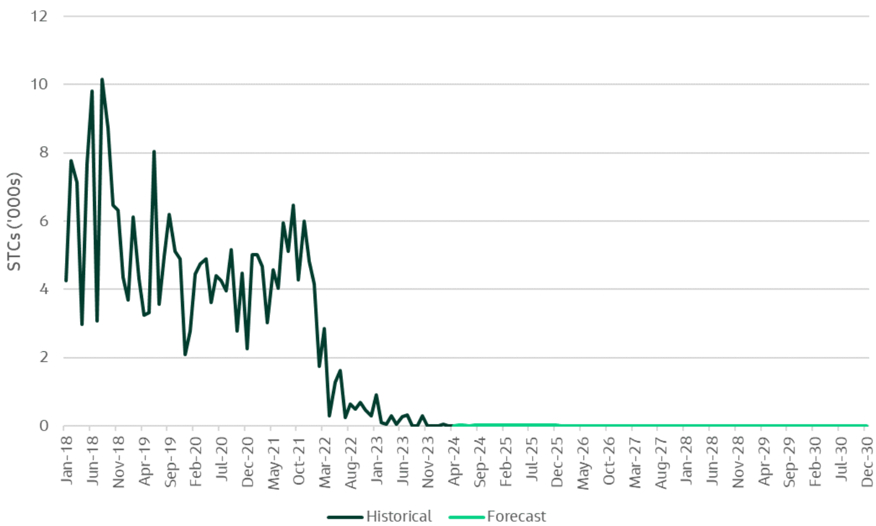


Figure 6-8 shows the historical and projected creation of STCs for SWH classified as commercial sized units. Due to both the drop in installations, and diminishing STC deeming period, STC creation is expected to decline to negligible levels by 2030.

Figure 6-8: Commercial STCs for SWH, monthly (Australia)



6.2.2 Air source heat pump water heaters

Historical and forecast installations for residential ASHP are shown in Figure 6-9. Prior to 2022, the majority of ASHP installations were attributed solely to Victoria which provided financial incentives through its VEU program. From late 2022, the commencement of NSW's Peak Demand Reduction Scheme (PDRS) provided attractive incentives in addition to those from the ESS and SRES. This caused a significant spike in ASHP installations in NSW, peaking in September 2023. However, from 1 August 2024 ASHP eligible under the SRES will be excluded from the PDRS, decreasing the financial incentives available to it. Conversely, Victoria and ACT have banned gas connections to new home builds which will increase demand for residential ASHP in these regions. In the short to medium term, ASHP installations are projected to continue at its current rate of uptake as rising installations in Victoria are offset by the slightly falling rate of uptake in NSW. In the long-term, all regions are projected to install at a steady rate. The forecasted installations for each state and territory are tabulated in Appendix A: Annual System Installations

Figure 6-9: Residential installations for ASHP, monthly (Australia)

Figure 6-10 shows the historical and forecasted creation for STCs from ASHP. Because installations are projected to be steady, the reducing STC deeming period progressively diminishes the total number of STCs created every year.

Figure 6-10: Residential STCs for ASHP, monthly

6.3 STC Projections

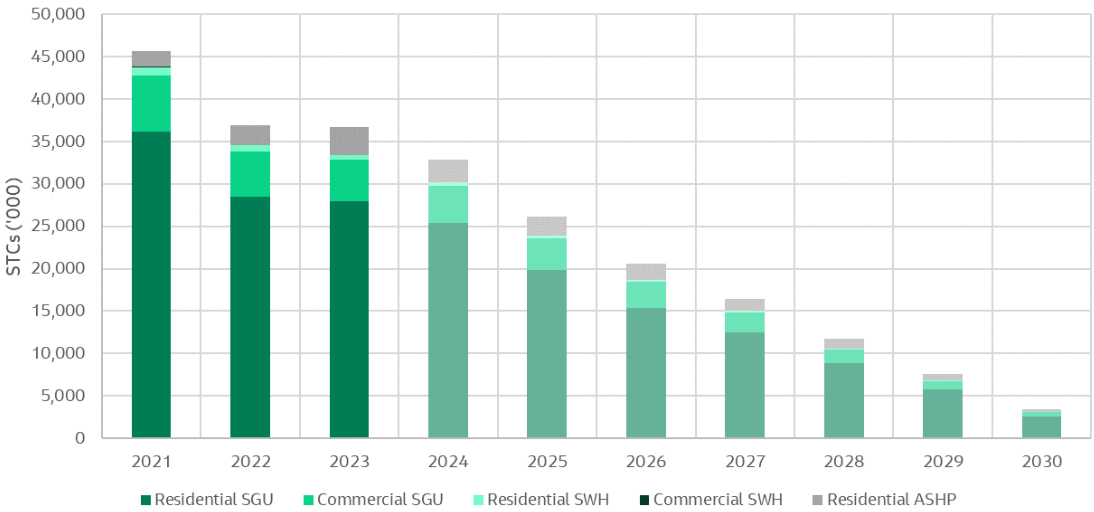
The projections for STCs created are shown in Table 6-2. These projections include STCs created through the installation of solar PV and hot water systems (wind and hydro STCs make up a negligible portion). In 2024, a total of 33.0 million STCs is projected to be generated. Despite having an increase in SGU capacity, this is 10.4% lower than 2023 due to the scheme's deeming period declining by another year, compared to the previous year.

Table 6-2: Small-scale technology certification (STC) creation projections ('000s)

	2024	2025	2026	2027	2028	2029	2030
RESIDENTIAL							
Australian Capital Territory	363	296	261	167	134	109	38
New South Wales	9,925	6,584	5,239	4,049	3,110	1,883	958
Northern Territory	82	139	94	59	58	37	16
Queensland	6,304	5,908	4,481	3,632	2,380	1,469	626
South Australia	1,885	1,503	988	873	498	356	149
Tasmania	408	334	169	167	139	111	32
Victoria	4,358	3,039	2,532	2,370	1,711	1,179	539
Western Australia	2,057	2,039	1,600	1,167	839	586	264
Total Residential	25,383	19,843	15,364	12,483	8,869	5,730	2,622
COMMERCIAL							
Australian Capital Territory	66	57	29	34	17	14	6
New South Wales	1,536	1,194	964	715	507	335	151
Northern Territory	42	36	26	22	15	12	4
Queensland	1,102	1,034	853	570	380	197	97
South Australia	302	233	263	192	123	80	41
Tasmania	29	26	21	19	16	9	5
Victoria	877	804	645	566	417	273	133
Western Australia	407	341	291	221	153	102	52
Total Commercial	4,362	3,726	3,092	2,338	1,628	1,022	489
TOTAL SOLAR PV STCs	29,745	23,568	18,456	14,820	10,498	6,752	3,111
Residential Solar Hot Water	540	410	322	250	185	122	61
Commercial Solar Hot Water	0.142	0.108	0.090	0.072	0.054	0.036	0.018
Residential Air-sourced Heat Pump	2,728	2,250	1,860	1,482	1,109	738	369
ALL STCs	33,013	26,229	20,638	16,552	11,791	7,612	3,540

Figure 6-11 illustrates the STC creation projections by sector. STC trends are largely linked to residential rooftop PV installations which comprise the largest portion of STCs created. The decline in total STCs in 2024 is attributed to the diminishing deeming period as it continues reducing by an additional year in each subsequent year. However, the fall in STCs between 2025 to 2030 is a result of both fewer STCs generated per kW of small-scale solar, and the decline in annual installed SGU capacity.

Figure 6-11: Total STC annual projections



Commercially sized SWH units are expected to maintain their relatively low level of uptake and are not expected to have considerable influence on STC creation across the forecasting period. It is expected that domestic SWH systems will continue a modest decline, and the uptake of ASHP systems is expected to continue for the remainder of the forecast horizon, with its STCs falling only with the deeming period.

Appendix A: Annual System Installations

Small-scale PV

Table A-1 shows the total projected annual installations of small-scale PV systems for each Australian state and territory. Installations for 2023 and 2024 are estimates from historical data accounting for registration lag.

Table A-1: Total projected annual small-scale PV installations

	2023	2024	2025	2026	2027	2028	2029	2030
Australian Capital Territory	8,344	4,417	3,889	4,045	3,321	3,416	4,060	2,790
New South Wales	102,354	116,209	93,962	87,645	82,252	82,191	74,305	73,479
Northern Territory	1,310	946	2,056	1,702	1,459	1,733	1,656	1,483
Queensland	80,203	75,414	88,842	81,663	81,536	71,389	65,947	56,271
South Australia	27,840	23,252	23,624	19,978	21,010	16,309	17,106	15,433
Tasmania	5,592	6,182	5,939	3,776	4,475	4,803	5,449	3,295
Victoria	66,560	65,930	53,885	53,216	60,377	56,807	57,551	53,496
Western Australia	34,762	32,147	37,365	35,554	32,681	30,835	32,183	30,598
Total Installations	**326,964**	**324,497**	**309,563**	**287,580**	**287,110**	**267,483**	**258,258**	**236,846**

Solar Water Heaters

Table A-2 shows the total projected annual installations of SWH across Australia.

Table A-2: Total projected annual SWH installations

	2024	2025	2026	2027	2028	2029	2030
Residential SWH	25,607	22,871	21,548	20,908	20,598	20,449	20,376
Commercial SWH	4	4	4	4	4	4	4
Total Installations	25,611	22,875	21,552	20,912	20,602	20,453	20,380

Air Source Heat Pumps

Table A-3 shows the total projected annual installations of ASHP for each state and territory in Australia.

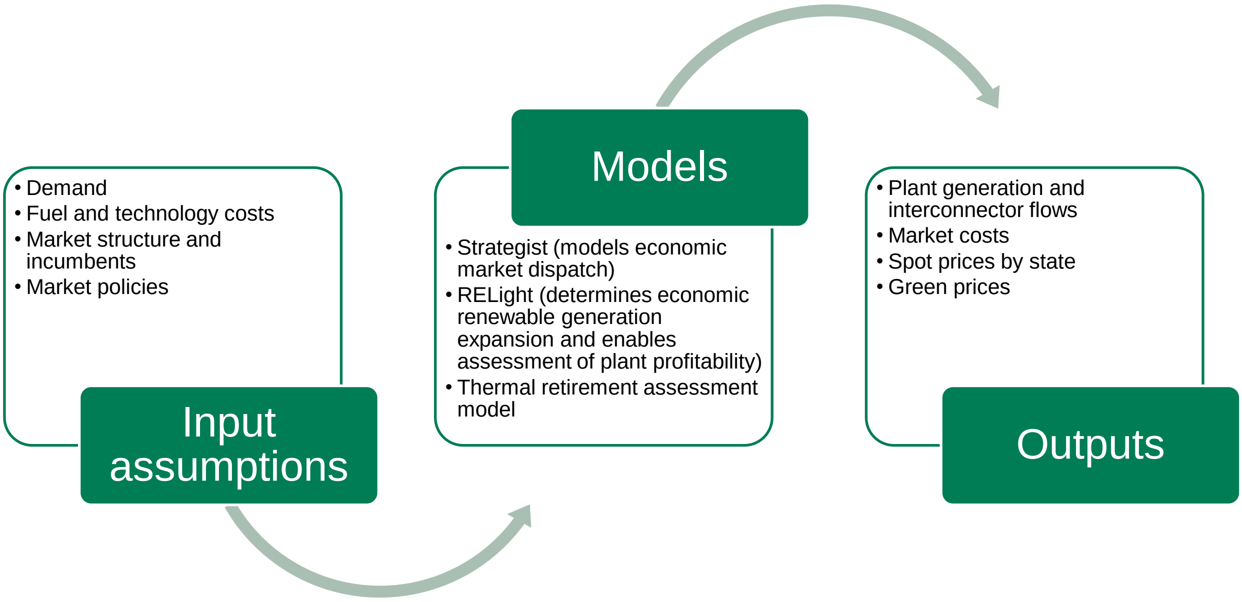
Table A-3: Total projected annual ASHP installations

	2024	2025	2026	2027	2028	2029	2030
Australian Capital Territory	1,588	1,475	1,477	1,477	1,477	1,477	1,477
New South Wales	58,209	50,325	46,253	44,151	43,065	42,504	42,215
Northern Territory	64	83	84	84	84	84	84
Queensland	10,532	11,229	11,512	11,627	11,674	11,693	11,700
South Australia	4,341	4,407	4,437	4,451	4,457	4,460	4,462
Tasmania	1,091	1,003	952	936	931	930	929
Victoria	45,975	51,905	54,938	56,488	57,281	57,687	57,894
Western Australia	6,253	6,296	6,299	6,299	6,299	6,299	6,299
Total installations	128,052	126,724	125,952	125,513	125,268	125,134	125,060

Appendix B: NEM modelling method and assumptions

Overview

Market models have been developed to determine a least cost market development plan and the likely outcome with respect to each scenario's underlying assumptions. Market models create the foundation for the wholesale price projections. An overview of the approach is displayed below with additional detail to be provided in later sections of this report.



The market forecasts consider regional demand forecasts, generating plant performance, timing of new generation including embedded generation, existing interconnection limits, and the potential for interconnection development. Jacobs used its Strategist and RELight models to develop long-term time weighted prices to the year 2030. Strategist models the NEM, whilst RELight models the details of the renewable energy market.

The dynamic programming method in Strategist selects new capacity on a least-cost basis. In Jacobs' experience the model has been generally accurate in the prediction of the future generation mix, with the main deviations from predicted investment the result of:

- Economies of scale.
- Pre-emptive new entry.
- Fuel supply arrangements.
- Interconnection upgrades included in the Strategist modelling as development options in competition with new generation capacity.

Future wholesale electricity prices and related market outcomes are driven by the supply and demand balance, with long-term prices being effectively capped at the cost of new entry on the assumption that prices above this level provide economic signals for new generation to enter the market. Consequently, assumptions on the fuel costs, unit efficiencies, and capital costs of new plant and emissions intensity threshold will have a noticeable impact on long-term price forecasts.

Year-to-year prices will deviate from the new entry cost level based on the timing of new entry. In periods when new entry is not required, the market prices reflect the cost of generation to meet regional loads, and the bidding behaviour of the market participants as affected by market power.

Negative price period prices are limited in the modelling for the following reasons:

- We model hourly demand profiles for typical weeks in each month of the projection period.
- The modelling is optimised over average weather conditions (50% probability of exceedance) so does not model outcomes for when we have warmer than normal days in winter or hotter than normal days in summer.
- Modelling includes transmission and interconnector upgrades, which will relieve network constraints and remove bottlenecks on interconnectors.
- Significant uptake of storage and EV charging (in the long-term) which means that middle of day demand is boosted.
- Continuing uptake of solar PV in our models is limited by the level of profitable entry. If we have too many zero or negative price periods, then prospective new plants may not earn enough revenue to recover capital and investment costs, and hence they do not enter the market. Similarly, if there are too many zero price periods, then eventually some incumbent thermal plants become unprofitable and are retired.
- We have included an emission penalty, which does increase dispatch prices for thermal plant in middle of the day.

Key assumptions used in the modelling include:

- Capacity is installed to meet the target reserve margin in each region. Some of this peaking capacity may represent demand side response rather than physical generation assets. It is assumed that this is already included in the demand forecasts provided by AEMO.
- Wind generation is based on observed wind power generation profiles for each region in 2019.
- Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This is a conservative assumption as there have been periods when prices have exceeded new entry costs when averaged over 12 months.
- Infrequently used peaking resources are bid near the market price cap or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.
- The LRET target is for 33,000 GWh of renewable generation by 2020. Additional renewable energy is included for expected GreenPower sales and desalination purposes.

Assumptions

The base scenario assumptions are summarised in the Table below.

Table B-1: Key electricity market price modelling assumptions

Parameter	Base Scenario
Commonwealth Emissions Policy	State Government targets and the Capacity Investment Scheme drive emissions reductions to 2030. The inclusion of the amended Safeguard Mechanism commences from 2024, however the electricity sector is included from 2031 creating an implied shadow carbon price. Emissions reductions target of 43% over 2005 levels by 2030 is included.

Demand growth	AEMO ESOO 2023 Central Scenario
EV growth	AEMO ESOO 2023 Central Scenario
Rooftop PV and PVNSG	AEMO ESOO 2023 Central Scenario
State policies	VRET/Vic Solar Homes Program are included. 1st Stage of VRET 2nd Stage of VRET: 40% renewables by 2025 65% renewables by 2030, 95% by 2035 An offshore wind target for Victoria has been added of 2 GW by 2032, 4 GW by 2035 and 9 GW by 2040. QRET included: 50% renewables by 2030 70% renewables by 2032, 95% by 2035 Implementation of New South Wales Energy Roadmap. New South Wales 50% emissions reduction by 2030. SA net 100% renewable energy by 2030.
Gas Price	Short term prices linked to Chief Economist's Resources & Energy Quarterly March 2024 LNG export prices. Converges to GSOO 2024 Step Change by 2030.
Coal Price	Short term prices linked to Chief Economist's Resources & Energy Quarterly March 2024 thermal coal global contract prices for non-mine mouth coal plants. Converges to ISP 2022 Step Change scenario (same as ISP 2024) by 2030.
Renewable Technology Costs	Wind, solar and battery updated to CSIRO GenCost 2023-24 (Global Post-2050 NZE Scenario)
Renewable generation inclusion	Updated to include recently committed plant, fully energised projects, and relevant project delays.