ACIL ALLEN

# Mid-scale PV projections

## 2024-2030

15 August 2024

## About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

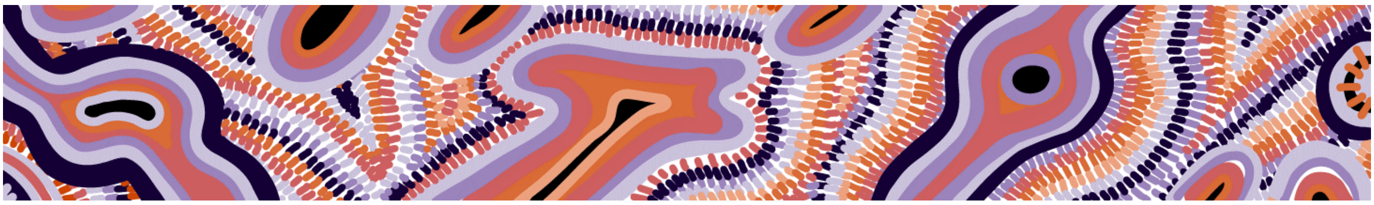
Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

## Report to:

### Clean Energy Regulator



ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

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# Contents



## Figures



## Tables

# Executive Summary

*ACIL Allen has been engaged by the Clean Energy Regulator (CER) to undertake projections of mid-scale photovoltaic (PV) systems in Australia for the period 2024 to 2030. The projections cover behind-the-meter, front-of-meter, and off-grid systems.*

## Mid-scale projections

We have used econometric modelling techniques to model the uptake of mid-scale systems using historical data in the period from January 2015 to 30 April 2024.

Behind-the-meter projections are largely a function of the payback period of installing a PV system. We have used our in-house econometric model of PV system[1] uptake to develop projections of mid-scale BTM system installations for each region for calendar years 2024 to 2030 and for the following size thresholds:

— Threshold 1: >100 kW to <=1 MW

— Threshold 2: >1 MW to <=5 MW

For the mid-scale BTM PV systems in threshold 3 (>5 MW to <=30 MW), we have used a simpler approach for projecting future system new builds based on payback periods. This is because the number of data points are too low for regression analysis even at the national level.

Front-of-meter projections are a function of the performance indicator of a new entrant grid-scale PV system. The performance indicator is a measure of how well a new grid-scale PV system would be able to cover their fixed costs with projected revenue from the wholesale electricity market.

Off-grid systems projections are a function of the levelised cost of energy (LCOE) of solar PV.

In each category, we have included committed off-grid systems in the near term (2024 and 2025).

Table shows historical (to 30 April 2024) and projected PV systems for each category and regions (where applicable). There is insufficient data to split the front-of-meter analysis by capacity range, and the off-grid analysis by region or capacity range.

Table ES 1 Historical and projected annual mid-scale solar PV systems (MW)

| Category | Capacity range | State/ territory | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| Behind the meter | 100kW to ≤ 1MW | ACT | 0.9 | 1.4 | 1.2 | 1.0 | 0.7 | 0.6 | 0.6 |
| Behind the meter | 100kW to ≤ 1MW | NSW | 46.9 | 38.9 | 17.4 | 4.1 | 1.1 | 0.7 | 0.7 |
| Behind the meter | 100kW to ≤ 1MW | NT | 3.1 | 3.7 | 3.1 | 2.6 | 2.6 | 2.9 | 2.8 |
| Behind the meter | 100kW to ≤ 1MW | QLD | 33.7 | 24.5 | 9.6 | 2.1 | 0.1 | 0.1 | 0.1 |
| Behind the meter | 100kW to ≤ 1MW | SA | 8.0 | 4.4 | 0.8 | 0.2 | 0.0 | 0.0 | 0.0 |
| Behind the meter | 100kW to ≤ 1MW | TAS | 0.6 | 0.6 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Behind the meter | 100kW to ≤ 1MW | VIC | 17.7 | 10.1 | 2.3 | 0.6 | 0.5 | 0.6 | 0.6 |
| Behind the meter | 100kW to ≤ 1MW | WA | 5.3 | 4.3 | 4.4 | 4.5 | 4.6 | 4.7 | 4.8 |

[1] This is the same modelling framework used for our projections of small-scale solar PV installations.

| Category | Capacity range | State/ territory | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| Behind the meter | 1MW to ≤ 5MW | ACT | 0.8 | 0.6 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 |
| Behind the meter | 1MW to ≤ 5MW | NSW | 24.1 | 13.7 | 2.2 | 0.2 | 0.0 | 0.0 | 0.0 |
| Behind the meter | 1MW to ≤ 5MW | NT | 0.6 | 0.8 | 0.7 | 0.5 | 0.6 | 0.7 | 0.7 |
| Behind the meter | 1MW to ≤ 5MW | QLD | 12.8 | 7.9 | 2.5 | 0.1 | 0.0 | 0.0 | 0.0 |
| Behind the meter | 1MW to ≤ 5MW | SA | 12.8 | 10.5 | 4.9 | 1.2 | 0.2 | 0.2 | 0.2 |
| Behind the meter | 1MW to ≤ 5MW | TAS | 0.7 | 0.5 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 |
| Behind the meter | 1MW to ≤ 5MW | VIC | 9.8 | 5.6 | 1.8 | 0.9 | 0.8 | 0.8 | 0.8 |
| Behind the meter | 1MW to ≤ 5MW | WA | 2.9 | 4.5 | 2.6 | 0.6 | 0.2 | 0.1 | 0.1 |
| Behind the meter | 5MW to ≤ 30MW | ACT | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Behind the meter | 5MW to ≤ 30MW | NSW | 5.7 | 2.5 | 1.0 | 0.3 | 0.2 | 0.2 | 0.2 |
| Behind the meter | 5MW to ≤ 30MW | NT | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Behind the meter | 5MW to ≤ 30MW | QLD | 1.4 | 1.3 | 0.5 | 0.2 | 0.1 | 0.1 | 0.1 |
| Behind the meter | 5MW to ≤ 30MW | SA | 7.5 | 7.4 | 2.9 | 0.9 | 0.6 | 0.5 | 0.6 |
| Behind the meter | 5MW to ≤ 30MW | TAS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Behind the meter | 5MW to ≤ 30MW | VIC | 6.8 | 6.7 | 2.6 | 0.8 | 0.5 | 0.5 | 0.5 |
| Behind the meter | 5MW to ≤ 30MW | WA | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| In front of meter | 100kW to ≤ 30MW | ACT | 0.0 | 0.0 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 |
| In front of meter | 100kW to ≤ 30MW | NSW | 22.9 | 57.8 | 25.1 | 25.4 | 20.9 | 21.7 | 19.5 |
| In front of meter | 100kW to ≤ 30MW | NT | 0.0 | 0.0 | 3.9 | 4.1 | 0.0 | 0.2 | 0.0 |
| In front of meter | 100kW to ≤ 30MW | QLD | 15.0 | 15.0 | 5.4 | 5.4 | 5.3 | 5.3 | 5.3 |
| In front of meter | 100kW to ≤ 30MW | SA | 36.5 | 30.0 | 32.6 | 33.0 | 24.1 | 25.6 | 21.3 |
| In front of meter | 100kW to ≤ 30MW | TAS | 0.0 | 0.0 | 1.0 | 1.0 | 0.6 | 0.6 | 0.4 |
| In front of meter | 100kW to ≤ 30MW | VIC | 4.0 | 5.0 | 32.1 | 31.8 | 38.2 | 37.1 | 40.2 |
| In front of meter | 100kW to ≤ 30MW | WA | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Off-grid | 100kW to ≤ 30MW | All | 81.7 | 68.8 | 51.8 | 55.4 | 58.9 | 62.4 | 65.7 |

Note: Historical data up to 30 April 2024.

*Source: ACIL Allen*

# 1 Introduction

*The Clean Energy Regulator (CER) administers the Large-scale Renewable Energy Target (LRET) that creates financial incentives for investment in renewable energy power stations and a market for creating and selling large-scale generation certificates (LGCs). LRET eligible photovoltaic (PV) systems must be greater than 100 kW and generate more than 25 MWh per year. Mid-scale solar PV systems, which include behind-the-meter, off-grid and smaller grid connected systems with capacities from 100 kW up to 30 MW, are eligible to create LGCs under the LRET. The growth in installations in this sector is primarily due to increasing demand from small and large businesses and industrial facilities to either reduce their energy procurement costs or demonstrate their green credentials.*

## 1.1 The brief

The CER has engaged ACIL Allen to undertake projections of:

- The capacity of mid-scale PV systems for the following size thresholds:
  - >100 kW to <=1 MW
  - >1 MW to <=5 MW
  - >5 MW to <=30 MW

The projections cover calendar years 2024 to 2030 for the following categories:

- Behind-the-meter
- Front-of-meter
- Off-grid

The projections are provided for each region in Australia.

# 2 Methodology

*Our approach to modelling mid-scale PV systems by category and size threshold is outlined in the sections below:*

## 2.1 Behind-the-meter (BTM)

Mid-scale BTM PV systems are generally rooftop arrays that are installed by a large commercial or industrial user for own use.

### Thresholds 1&2

We have used our in-house econometric model of PV system[2] uptake to develop projections of mid-scale BTM system installations for each region for calendar years 2024 to 2030 and for the following size thresholds:

— Threshold 1: >100 kW to <=1 MW

— Threshold 2: >1 MW to <=5 MW

The projections of BTM PV systems for these size thresholds are largely a function of the payback period of PV systems. The model uses historical data in the period January 2015 to April 2024 and for each state/territory and size threshold separately. We have also undertaken desktop research to develop a projection of committed systems under these size thresholds and have included the committed systems in the projections.

The model uses a logistic function to determine the probability of a new PV system build based on statistically significant factors drawn from a suite of potential factors such as payback period, interest rates, etc. The projected probabilities are applied to remaining eligible commercial rooftop space in MW to find the projected new systems in MW terms.[3]

To get the number of new systems for threshold 1 systems, we divide the projected MW of new systems by an assumed average system size, which is based on recent historical average system size of 300 kW. For threshold 2, we have avoided converting projected MW installations into number of installations because of the skewed distribution of system sizes in this category. That is, the range of sizes is too wide for us to assume one average size. For this threshold 2 systems, the median system size is 1.5 MW while the average system size is 1.8 MW.

Key inputs for the model consist of system size, system costs, system performance (output) by region, regional retail electricity prices and avoided retail tariffs, regional daily consumption profiles and solar exports, feed-in-tariffs, upfront subsidies, LGC revenue, state and territory and commonwealth schemes, and an assumed lag between the timing of these factors and the decision by a business to install a system.

Retail electricity price projections are developed using our in-house retail price model, which includes as inputs, projected wholesale electricity prices from our PowerMark wholesale electricity market simulator which has been developed over the past 30 years in parallel with the development of the NEM and WEM, projected renewable energy policy costs, network costs, retailer operating and prudential costs, and retail margin. ACIL Allen uses its retail model extensively in simulations and sensitivity analyses conducted on behalf of industry and regulator clients. The retail model also considers tariff reform. As well as projected

[2] This is the same modelling framework used for our projections of small-scale solar PV installations.

[3] Eligible commercial roof space is characterized by kW available due to the large range of roof space sizes in this market segment.

retail prices, two outputs from the retail model are the costs a business avoids if installing BTM PV, and the solar feed in tariff for surplus energy exported to the grid.

A detailed table of assumptions used in this analysis is presented in Appendix A.

### Threshold 3

For the mid-scale BTM PV systems in threshold 3 (>5 MW to <=30 MW), we have used a simpler approach for projecting future system new builds. This is because the number of data points are too low for regression analysis even at the national level.

To project new threshold 3 systems, we have used the average of historical annual new build capacity in 2020-2023 in each region and applied an annual factor that is consistent with payback periods over the projection period. For example, the annual factor will be smaller with higher projected payback periods, or in other words, a 20% increase in payback periods results in 20% decline in installations. This is broadly consistent with history, noting that the number of data points are low.

For threshold 3, we have avoided converting projected MW installations into number of installations because of the skewed distribution of system sizes in this category. That is, the range of sizes is too wide for us to assume one average size. For this category of PV, the median system size is 6.5 MW while the average system size is 7.5 MW.

We have undertaken desktop research to develop a projection of committed systems in this size threshold and have included these committed projects in the projections.

## 2.2 Front-of-meter

Mid-scale front-of-meter PV systems are grid-connected solar farms that generate power directly into the wholesale electricity market.

We have used performance indicators of representative new entrant PV projects for front-of-meter solar PV from our PowerMark wholesale electricity market simulator to develop projections of new front-of-meter PV systems.

In any given year, the PowerMark new entrant performance indicators show whether projected earnings from the energy and LGC markets for a front-of-meter PV system meets or exceeds its annualised fixed costs (amortised capital plus fixed operating and maintenance costs).

We have used a 1-year lagged historical relationship between new entrant PV performance and actual capacity of mid-scale front-of-meter PV systems to develop projected capacity (in MW) of PV systems.

The front-of-meter projections in MW-terms are not converted into number of installations because of the large range of sizes per systems in this category (ranging from 110 kW to 30 MW). For this category of PV, the median system size is 550 kW while the average system size is 3.5 MW.

In the near term (2024 to 2025), rather than relying solely on a regression model, we have undertaken desktop research to develop a projection of committed front-of-meter systems, utilising sources such as AEMO, ARENA and developers Green Gold Energy, MPower, and Bison Energy. The committed projects are included in the projections.

## 2.3 Off-grid

Off-grid systems are PV systems that are not connected to the major electricity grids in Australia (National Electricity Market (NEM), South West Interconnected System (SWIS), North West Interconnected System

(NWIS) and Darwin to Katherine Interconnected System (DKIS)). These systems typically include systems built to supply a remote mine or town.

We have used the relationship between historical off-grid capacity and the levelised cost of energy (LCOE) of solar PV to develop projections of off-grid PV capacity. The LCOE is used for off-grid rather than the approach for front-of-meter (new entrant performance indicator), because the off-grid systems do not face a grid energy price (which is part of the new entrant indicator).

As with the other categories, we have undertaken desktop research to develop a projection of committed off-grid systems in the near term, utilising sources such as off-grid developers Zenith Energy, Horizon Power, AGL Energy, Pacific Energy, and Rio Tinto. The committed projects are included in the projections.

The off-grid projections in MW-terms are not converted into number of installations because of the large range of sizes per systems in this category (ranging from 110 kW to 30 MW). For this category of PV, the median system size is 375 kW while the average system size is 3 MW.

## 2.4 Base case

We have modelled a Base case scenario which is consistent with the 2023 ESOO Central scenario narrative – that is, the Draft 2024 ISP Step Change scenario. The Final 2024 ISP, with relatively minor changes compared to the Draft 2024 ISP, was published after finalising the modelling for this report and could not be incorporated due to timing.

# 3 Results

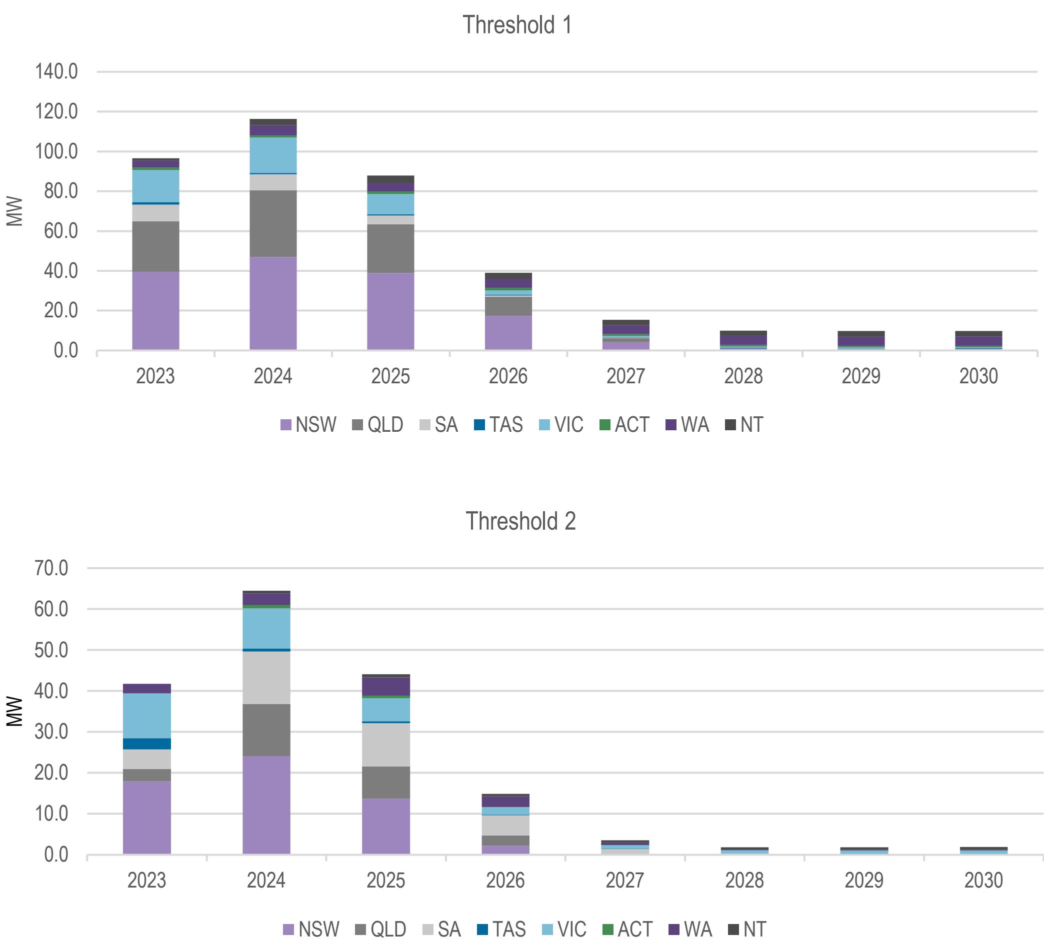
*This chapter presents historical and projected mid-scale PV system installations by category and size threshold.*

## 3.1 Behind-the-meter (BTM)

### Thresholds 1&2

Figure 3.1 shows historical and projected annual solar PV systems in MW-terms by region for threshold 1 (>100 kW to <=1 MW) (upper panel) and threshold 2 (>1 MW to <=5 MW) (lower panel). The values are presented on a calendar year basis. This data is also shown for threshold 1 and threshold 2 in Table 3.1 and Table 3.2, respectively.

Figure 3.1 Historical and projected annual threshold 1 BTM (upper panel) and threshold 2 BTM (lower panel) solar PV systems (MW) by region – 2023-2030




Note: Historical data up to 30 April 2024.

*Source: ACIL Allen analysis using CER data*

Table 3.1 Historical and projected annual BTM solar PV systems (MW), by region – Threshold 1

| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| NSW | 39.5 | 46.9 | 38.9 | 17.4 | 4.1 | 1.1 | 0.7 | 0.7 |
| QLD | 25.4 | 33.7 | 24.5 | 9.6 | 2.1 | 0.1 | 0.1 | 0.1 |
| SA | 8.5 | 8.0 | 4.4 | 0.8 | 0.2 | 0.0 | 0.0 | 0.0 |
| TAS | 1.2 | 0.6 | 0.6 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| VIC | 16.1 | 17.7 | 10.1 | 2.3 | 0.6 | 0.5 | 0.6 | 0.6 |
| ACT | 1.3 | 0.9 | 1.4 | 1.2 | 1.0 | 0.7 | 0.6 | 0.6 |
| WA | 3.4 | 5.3 | 4.3 | 4.4 | 4.5 | 4.6 | 4.7 | 4.8 |
| NT | 1.1 | 3.1 | 3.7 | 3.1 | 2.6 | 2.6 | 2.9 | 2.8 |
| Total Threshold 1 | **96.5** | **116.3** | **87.9** | **39.0** | **15.3** | **9.9** | **9.8** | **9.8** |

Note: Historical data up to 30 April 2024.

*Source: ACIL Allen*

New system threshold 1 and threshold 2 installations increased in 2023 to 96.5 MW and 41.8 MW, respectively, and are projected to increase again in 2024 to 116.3 MW and 64.5 MW, respectively, because of falling payback periods due to higher retail electricity tariffs and higher LGC and VEEC (where applicable) prices.

Threshold 1 and threshold 2 PV system installations are projected to decline slightly in 2025 to 87.9 MW and 44.1 MW, respectively, and then sharply decline because of rising payback periods to 9.8 MW and 1.9 MW, respectively, by 2030. This is due to a projected decline in retail electricity tariffs driven by the implementation of State-based schemes such as the New South Wales Electricity Infrastructure Roadmap and Queensland Energy and Jobs Plan, and national-schemes such as the expanded Capacity Investment Scheme (CIS) encouraging a strong rollout in utility scale renewable energy and storage projects reducing wholesale electricity prices across these regions and interconnected regions.

LGC and VEEC prices are projected to decline during this period which also contributes to the rising payback periods. Avoided retail tariffs decline quite sharply over this period due to large commercial and industrial customers being on a demand-based tariffs structure.

Table 3.2 Historical and projected annual BTM solar PV systems (MW), by region – Threshold 2

| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| NSW | 18.0 | 24.1 | 13.7 | 2.2 | 0.2 | 0.0 | 0.0 | 0.0 |
| QLD | 3.0 | 12.8 | 7.9 | 2.5 | 0.1 | 0.0 | 0.0 | 0.0 |
| SA | 4.8 | 12.8 | 10.5 | 4.9 | 1.2 | 0.2 | 0.2 | 0.2 |
| TAS | 2.7 | 0.7 | 0.5 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 |
| VIC | 11.0 | 9.8 | 5.6 | 1.8 | 0.9 | 0.8 | 0.8 | 0.8 |
| ACT | 0.0 | 0.8 | 0.6 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 |
| WA | 2.3 | 2.9 | 4.5 | 2.6 | 0.6 | 0.2 | 0.1 | 0.1 |
| NT | 0.0 | 0.6 | 0.8 | 0.7 | 0.5 | 0.6 | 0.7 | 0.7 |
| Total Threshold 2 | **41.8** | **64.5** | **44.1** | **14.9** | **3.6** | **1.8** | **1.9** | **1.9** |

Note: Historical data up to 30 April 2024.

*Source: ACIL Allen*

Installation numbers for threshold 1 (Table 3.3) have been estimated by dividing projected MW of new systems by the average system size of 300 kW, based on recent history. We have avoided converting threshold 2 projected MW installations, due to the skewed distribution of system sizes in this category.

Table 3.3 Historical and projected number of BTM solar PV systems, by region – Threshold 1

| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| NSW | 130 | 149 | 124 | 55 | 13 | 3 | 2 | 2 |
| QLD | 84 | 107 | 78 | 30 | 7 | 0 | 0 | 0 |
| SA | 28 | 26 | 14 | 2 | 0 | 0 | 0 | 0 |
| TAS | 4 | 2 | 2 | 1 | 1 | 1 | 1 | 1 |
| VIC | 53 | 56 | 32 | 7 | 2 | 2 | 2 | 2 |
| ACT | 4 | 3 | 4 | 4 | 3 | 2 | 2 | 2 |
| WA | 11 | 17 | 14 | 14 | 14 | 14 | 14 | 14 |
| NT | 4 | 10 | 12 | 10 | 8 | 8 | 9 | 9 |
| Total Threshold 1 | **318** | **370** | **280** | **123** | **48** | **31** | **30** | **30** |

Note: Historical data up to 30 April 2024.

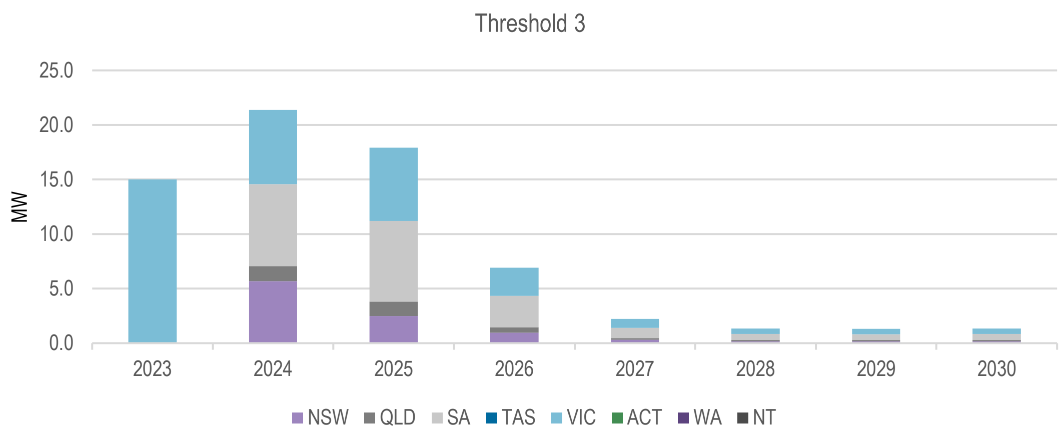
*Source: ACIL Allen*

## Threshold 3

Figure 3.2 and Table 3.4 show historical and projected annual solar PV systems by region for threshold 3 (>5 MW to <=30 MW). The values are presented on a calendar year basis.

In recent years, threshold 3 systems have been installed in one region, for a single off taker or developer, for example various sites owned by SA Water in South Australia in 2022 or Greentech sites in Victoria in 2023.

Figure 3.2 Historical and projected annual threshold 3 BTM solar PV systems (MW) by region – 2023-2030




Note: Historical data up to 30 April 2024.

*Source: ACIL Allen analysis using CER data*

Table 3.4 Historical and projected annual BTM solar PV systems (MW), by region – Threshold 3

| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| NSW | 0.0 | 5.7 | 2.5 | 1.0 | 0.3 | 0.2 | 0.2 | 0.2 |
| QLD | 0.0 | 1.4 | 1.3 | 0.5 | 0.2 | 0.1 | 0.1 | 0.1 |
| SA | 0.0 | 7.5 | 7.4 | 2.9 | 0.9 | 0.6 | 0.5 | 0.6 |
| TAS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| VIC | 15.0 | 6.8 | 6.7 | 2.6 | 0.8 | 0.5 | 0.5 | 0.5 |
| ACT | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| WA | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NT | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Threshold 3 | **15.0** | **21.4** | **17.9** | **6.9** | **2.2** | **1.3** | **1.3** | **1.3** |

Note: Historical data up to 30 April 2024.

*Source: ACIL Allen*

For the mid-scale BTM PV systems in threshold 3 we have used a simpler approach for projecting future system new builds due to fewer historical data points to use in the analysis.

To project new threshold 3 systems, we have used the average of historical annual new build capacity in 2020-2023 in each region and applied an annual factor that is consistent with movement in payback periods over the projection period. For example, as payback periods increase on average by 20%, installed capacity declines by 20% on average.

Threshold 3 systems increase to 15 MW and 21.4 MW in 2023 and 2024, respectively, with falling payback periods due to higher retail electricity tariffs and higher LGC and VEEC prices. Payback periods for threshold 3 increase rapidly from 2026, which is reflected in the lower projections falling to 1.3 MW by 2030.

We have avoided converting threshold 3 projected MW installations, due to the skewed distribution of system sizes in this category.

## 3.2 Front-of-meter

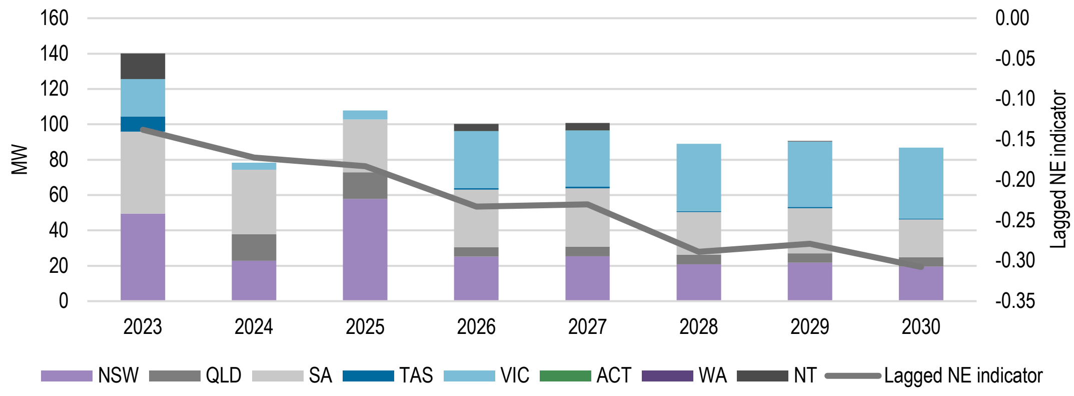
Figure 3.3 shows historical and projected annual front-of-meter solar PV systems by region. The values are presented on a calendar year basis. Historical data is shown up to 30 April 2024, with committed projects in 2024 and 2025.

We have used new entrant performance indicators for front-of-meter solar PV from our PowerMark wholesale electricity market simulator to develop projections of new front-of-meter PV systems.

In any given year, the PowerMark new entrant performance indicators show whether projected earnings from the wholesale electricity and LGC markets for a front-of-meter PV system meets or exceeds its annualised fixed costs (amortised capital plus fixed operating and maintenance costs). The lower the indicator, the less profitable is the new entrant.

We have used a 1-year lagged historical relationship between new entrant PV performance and actual capacity of mid-scale front-of-meter PV systems to develop projected capacity (in MW) of PV systems.

Figure 3.3 Historical and projected annual mid-scale front-of-meter solar PV systems (MW) by region (primary axis) and lagged NE indicator (secondary axis)– 2023-2030




Note: Historical data up to 30 April 2024; committed projects in 2024 and 2025; projected from 2026.

*Source: ACIL Allen*

Table 3.5 Historical and projected annual front-of-meter solar PV systems (MW), by region

| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| NSW | 49.5 | 22.9 | 57.8 | 25.1 | 25.4 | 20.9 | 21.7 | 19.5 |
| QLD | 0.0 | 15.0 | 15.0 | 5.4 | 5.4 | 5.3 | 5.3 | 5.3 |
| SA | 46.3 | 36.5 | 30.0 | 32.6 | 33.0 | 24.1 | 25.6 | 21.3 |
| TAS | 8.5 | 0.0 | 0.0 | 1.0 | 1.0 | 0.6 | 0.6 | 0.4 |
| VIC | 21.2 | 4.0 | 5.0 | 32.1 | 31.8 | 38.2 | 37.1 | 40.2 |
| ACT | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 |
| WA | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NT | 14.5 | 0.0 | 0.0 | 3.9 | 4.1 | 0.0 | 0.2 | 0.0 |
| Total Front-of-meter | **140.0** | **78.3** | **107.8** | **100.1** | **100.7** | **89.1** | **90.6** | **86.7** |

Note: Historical data up to 30 April 2024; committed projects in 2024 and 2025; projected from 2026.

*Source: ACIL Allen*

The decision by market participants to install front-of-meter PV systems will be driven largely by commercial incentives. Unlike large scale PV projects, which may be able to secure additional revenue or contracts in the various state-based government incentive programs (e.g., NSW Roadmap, Victorian Renewable Energy Target VRET, Queensland Renewable Energy Target QRET, etc.), mid-scale projects are unlikely to be viewed as attractive by governments when awarding the various scheme contracts. Therefore, mid-scale PV projects will be subject to the value that off-takers ascribe to the projects' energy based on wholesale market outcomes. As the rollout of the federal (CIS) and state-based programs (NSW Roadmap, VRET, QRET, TRET, etc.) ramps up over the next five years, wholesale prices, particularly during daylight hours, will decline substantially due to the large amount of incentivised new PV investment occurring in the NEM. Setting aside committed projects that come online between 2024 and 2027, the reducing value of solar energy in the wholesale market results in installations declining to around 90 MW between 2028 and 2030.

Historical and committed projects sizes range from 101 kW to 30 MW. This range is too wide to calculate an average size for which to estimate the number of systems.

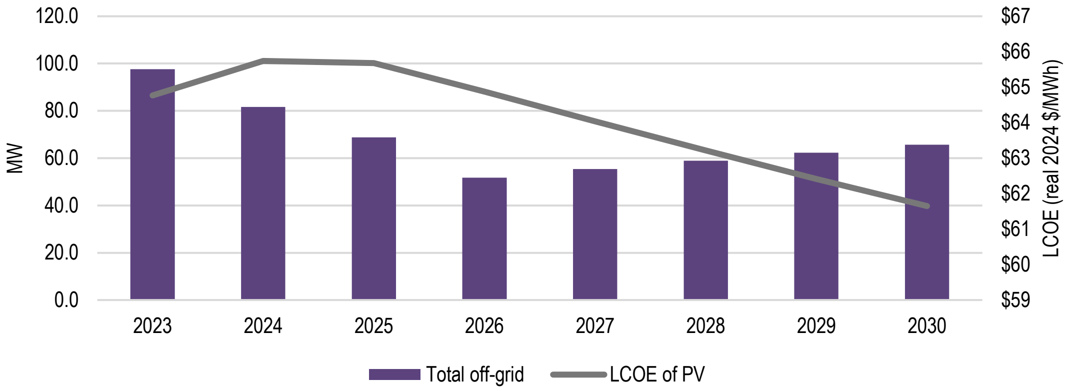
## 3.3 Off-grid

Figure 3.4 shows historical and projected annual off-grid solar PV systems by region (primary axis) and the LCOE of solar PV (secondary axis). The values are presented on a calendar year basis.

Most off-grid PV systems are in remote regions in Western Australia (86%), the Northern Territory (9%), Queensland (4%) and South Australia (1%), to satisfy a local load such as a mine or small town.

Off-grid PV installations increased in 2019 to 2023 (primarily in Western Australia) with a decline in the LCOE of PV. Installations in 2024 and 2025 are committed projects.

Figure 3.4 Historical and projected annual mid-scale off-grid solar PV systems (MW) (primary axis) and LCOE of solar PV (real 2024 $/MWh) (secondary axis) – 2023-2030




Note: Historical data up to 30 April 2024; committed projects in 2024 and 2025; projected from 2026.

*Source: ACIL Allen*

Projections from 2026 onwards are based on the historical relationship between installations and the LCOE of solar.There are insufficient historical data points to undertake the analysis by region or capacity threshold. However, we would expect most of the projected growth to occur in Western Australia which reflects the extent of remote mining activity in that state. Although the same could be expected in Queensland, we assume the commencement of CopperString 2032 in 2029 which links up Queensland's North-West Minerals Province with the NEM, reduces the incentive for installing mid-scale PV systems given access to lower cost grid supplied electricity.

Historical and committed projects sizes range from 120 kW to 26 MW. This range is too wide to calculate an average size for which to estimate the number of systems.

Table 3.6 Historical and projected annual off-grid solar PV systems (MW)

| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| Total off-grid | 97.7 | 81.7 | 68.8 | 51.8 | 55.4 | 58.9 | 62.4 | 65.7 |

Note: Historical data up to 30 April 2024; committed projects in 2024 and 2025; projected from 2026.

*Source: ACIL Allen*

# Appendices

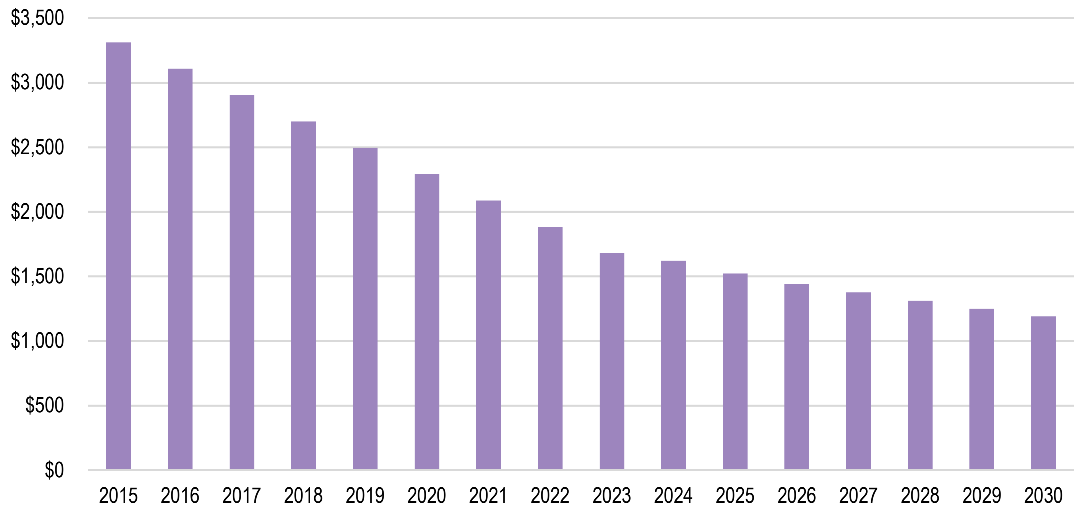
# A Assumptions

*The key assumptions underpinning the projections are outlined in this Appendix A..*

## A.1 Installation costs

Historical installation costs are sourced the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and International Renewable Energy Agency (IRENA). We assume installation costs decline in real terms over the projection period due to technology improvements.

Figure A.1 Solar system cost (Real 2024 $/kW)




*Source: ACIL Allen analysis using CSIRO and IRENA data*

## A.2 Electricity prices

Retail tariffs include wholesale, network, environmental, and retailing costs. Wholesale electricity costs are modelled using our in-house PowerMark market simulator.

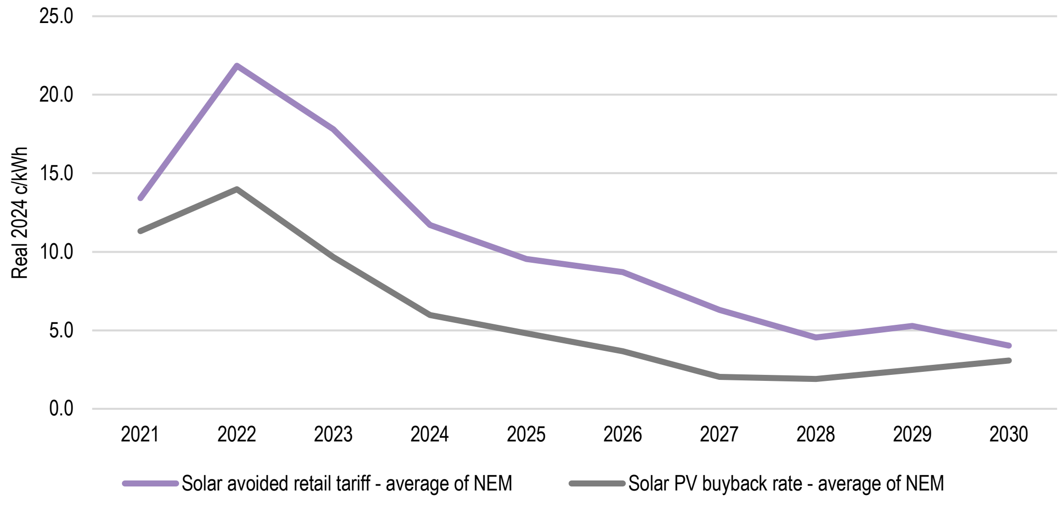
Network, environmental and retailing costs are based on data from publicly available sources such as the AER determinations regulator determinations and AEMO.

Projected prices decline over the period because of assumed build out of significant renewable and storage capacity, incentivised by state-based schemes such as the NSW Roadmap and the Queensland Energy and Jobs Plan and Australia-wide schemes such as the expanded Capacity Investment Scheme (CIS). Solar avoided tariffs (or retail tariffs) include the variable network component only.

Solar buyback rate (or the solar feed-in tariff) reflects the projected generation-weighted price of solar PV. This is projected to decline over time because of assumed build out of significant renewable capacity. After 2028, the solar buyback rate is projected to increase with the expected closure of large amounts of steam turbine capacity (coal-fired and gas-fired).

Avoided retail tariffs decline quite sharply over this period due to large commercial and industrial customers being on a demand-based tariffs structure.

Figure A.2 Solar avoided retail tariffs and solar buyback rate in the NEM (real 2024 c/kWh)

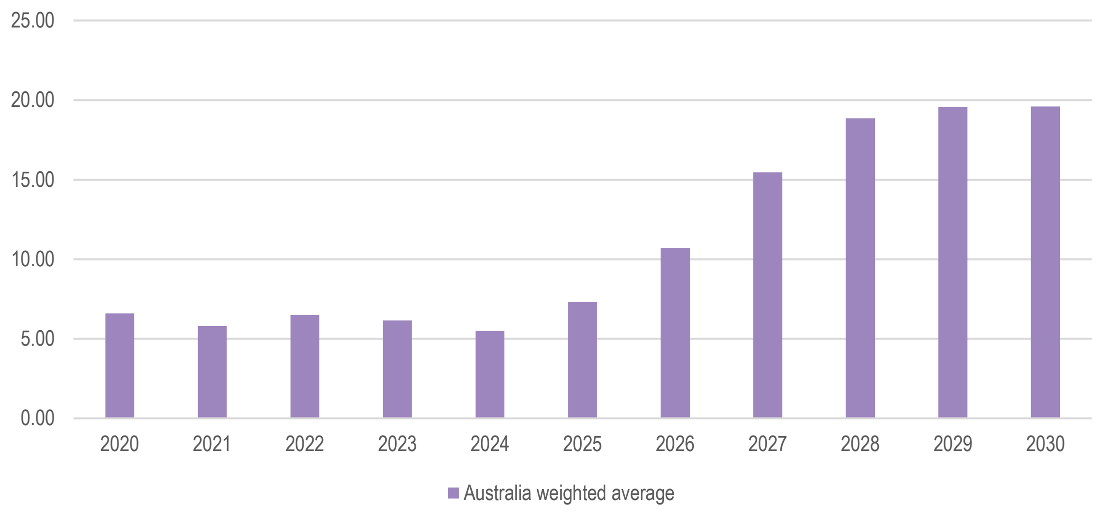



*Source: ACIL Allen*

## A.3 Payback periods

Average payback periods for small-scale solar installations are a function of the upfront installation cost, and the future value of avoided electricity expenditure and the revenue received from PV exports and environmental certificates (LGCs or VEECs). The model takes account a lagged impact of electricity prices on installation rates and is already considered in the payback periods shown below. The projected increase in payback periods is driven by the projected decline in retail electricity tariffs and solar feed-in-tariffs, which offsets the impact of declining installation costs. The levelling in payback periods for PV in 2029 and 2030 is due to the projected increase in the solar buy back rate, as discussed earlier.

Figure A.3 Average payback periods (years) for BTM solar PV




*Source: ACIL Allen*

## A.4 LGC prices

Mid-scale PV installations are eligible to produce LGCs under the LRET. Our in-house model of LGC prices is based on a regression analysis of the historical relationship between the level of voluntary surrender (a key driver going forward now that the mandated target is met), cumulative oversupply of LGCs[4], and the LGC spot price. We assume the annual level of voluntary demand increases from 10 million LGCs in 2024 to over 26 million LGCs in 2030.

ACIL Allen's wholesale market simulator model *PowerMark* is used to project creation of LGCs under the Base case. We also consider the development of Renewable Energy Guarantees of Origin (REGOs) and its influence on LGC spot prices to date.

ACIL Allen's projected LGC spot prices keep their value out to 2027 due to increasing demand from voluntary surrenders. However, LGC spot prices are projected to fall more rapidly after 2027 due to the strongly increasing cumulative oversupply of LGCs resulting from the large-scale investment required to fulfill the expanded CIS and state-based schemes – almost doubling renewable capacity in the NEM by 2030.

While ACIL Allen's modelling indicates a rapid decline in LGC prices there are several reasons why some level of value is maintained in the forward curve:

- Voluntary surrenders increase substantially driven by either increased volumes of GreenPower sales or corporate entities seeking to offset electricity-based emissions
- Withholding of LGCs by large market players with spot LGC exposure
- Legislative changes to the scheme itself
- Greater reliance on the scheme within tightened baselines under the Safeguard Mechanism.

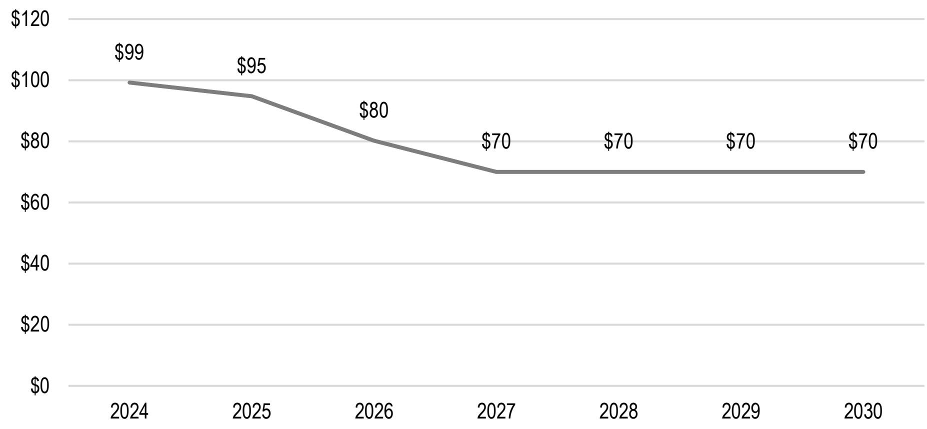
Due to lower spot prices, and the scheme ending in 2030, LGCs will likely be a smaller component of the revenue stream for PV systems commissioned in 2028 or later.

[4] Oversupply of LGCs is equal to total annual supply of LGCs minus total annual demand of LGCs.

## A.5 VEEC prices

We assume that mid-scale PV systems in Victoria are eligible to produce either Victorian Energy Efficiency Certificates (VEECs) or LGCs but not both. We assume projects can earn 0.8 VEEC per MWh of PV output and they choose the more lucrative scheme in the year of commissioning. Currently, VEEC spot prices are around $100. We assume this declines to around $70 for the remainder of the projection period. Under these assumptions, all projected new projects in Victoria opt to generate VEECs rather than LGCs.

Figure A.4 Assumed VEEC prices (real 2024 $/VEEC)




*Source: ACIL Allen*

## A.6 PowerMark wholesale electricity market modelling assumptions

ACIL Allen maintains a Reference case projection of the National Electricity Market (NEM), which it updates each quarter in response to supply changes announced in the market in terms of new investment, retirements, fuel costs, and plant availability.

Projected electricity prices used in this analysis are based on our March quarter 2024 Reference case projection settings which, in the short term, are closely aligned with AEMO's Integrated System Plan (ISP) and ESOO. Table A.1 summarises the key assumptions adopted in the Reference case that are pertinent to the period to 2030.

Table A.1 Overview of National Electricity Market Reference case assumptions

<table>
<tr><th>Assumptions</th><th colspan="4">Details</th></tr>
<tr><td>Macro-economic variables</td><td colspan="4">– Exchange rate of AUD to USD converging to 0.75 AUD/USD.<br>– Inflation of 2.5 per cent per annum in the long-run.<br>– The brent crude oil price is assumed to converge from current levels to USD65/barrel by the mid-2020s and remain at this level in the long-run.<br>– International thermal coal prices are assumed to converge from current elevated levels of about USD$130/t to USD$80/t by 2030.</td></tr>
<tr><td>Electricity demand</td><td colspan="4">The demand forecast used in the wholesale electricity market modelling is based on the AEMO Draft 2024 ISP Step Change scenario (energy and POE50 peak demand).<br>Projected uptake of rooftop solar PV, home battery systems and electric vehicles are based on outputs from ACIL Allen’s modelling.</td></tr>
<tr><td>Federal greenhouse gas emission policies</td><td colspan="4">– Economy-wide 43% reduction in GHG emissions below 2005 levels by 2030 and a net zero emissions target by 2050.<br>– National target of 82% renewable energy generation by 2033 (see note on Capacity Investment Scheme below).</td></tr>
<tr><td rowspan="2">State based schemes</td><td>NSW<br>NSW Roadmap capacity of:<br>– 12 GW renewables by 2032 within designated Renewable Energy Zone (REZ)<br>– 2 GW long-duration storage by 2030</td><td>QLD<br>Powering Queensland Plan:<br>– CleanCo has been mandated to contract for a total capacity of 1 GW<br>Queensland Energy and Jobs Plan (QEJP):<br>– QRET target of 50 per cent renewable energy generation by 2030<br>–</td><td>TAS<br>TRET target of 15,750 GWh (150 per cent) of renewable energy by 2030</td><td>VIC<br>VRET targets of 40 per cent by 2025, 50 per cent by 2030.<br><br>Victoria energy storage targets:<br>– At least 2.6 GW storage capacity by 2030<br>Offshore wind capacity target:<br>– 2 GW of offshore wind capacity by 2032</td></tr>
<tr><td colspan="4">SA</td></tr>
</table>

| Assumptions | Details |
|---|---|
| | The government has indicated a 100 per cent net renewable energy ambition by 2030. The SA government announced its Hydrogen Jobs plan in December 2022. It includes the development of a 250 MW electrolyser, a 200MW hydrogen-fuelled power generator and a hydrogen storage facility by the end of 2025. |
| | All NEM states: Economy-wide net zero emissions by 2050; interim targets of 50 per cent reductions by 2030. |
| Capacity Investment Scheme (CIS) | The Capacity Investment Scheme (CIS) aims to:<br>– deliver 32 GW of new capacity nationally, made up of 23 GW of renewable capacity and 9 GW of clean dispatchable capacity; the Reference case assumes about 17 GW renewable and 6 GW of dispatchable capacity is developed in the NEM (with the remaining capacity allocated to non-NEM grids)<br>– fill expected reliability gaps in the energy network as ageing coal-fired power stations exit<br>– deliver the Australian Government's 82% renewable electricity by 2030, however the Reference case stretches out the rollout of the scheme by three years, meaning that the 82% target is met by 2033, reflecting a more realistic/achievable timetable of investment. |
| Electricity supply (beyond new supply driven by state-based schemes) | Committed projects<br>– Named new entrant projects are included in the modelling where there is a high degree of certainty that these will go ahead (i.e., project has reached financial close)<br>– Includes the Federal Government's Snowy 2.0 by 2030.<br><br>Assumed new entry and closures<br>– 200 MW of corporate PPAs across New South Wales and Victoria entering from mid-2026 to reflect the continued appetite by larger corporates to demonstrate their green credentials as well as reduce electricity costs ahead of the rollout of the various state-based schemes<br>– Committed or likely committed generator closures included where the closure has been announced by the participant (Torrens Island B in 2026, Yallourn in 2028, Eraring in 2029, Bayswater and Stanwell in 2033, Tarong and Tarong North in 2034, Loy Yang A and Kogan Creek by 2035).<br><br>Projected new entry and closures<br>– Beyond committed and assumed projects, only commercial generic new entrants are introduced within the modelling.<br>– Closure of existing generators where the generator is projected to be unprofitable over an extended period of time or the generator's expected closure year as indicated to AEMO – whichever is earlier. |
| Gas prices into gas-fired power stations | — The East Coast Gas Market (ECGM) is modelled by ACIL Allen's GasMark model, which produces projections of seasonal gas prices delivered into the NEM's gas fired generators.<br>— Gas prices for mid merit CCGTs are projected to:<br>  — commence the projection at around \$9-\$15/GJ (summer – winter) |

<table>
<tr><th>Assumptions</th><th colspan="6">Details</th></tr>
<tr><td></td><td colspan="6">– gradually increase to about $13-25/GJ by the mid-2030s when demand for GPG peaks with the closure of coal plant<br>— Gas prices for peaking OCGTs are assumed to:<br>– commence the projection at around $16-$26/GJ (summer – winter)<br>– gradually increase to between $15-$40/GJ by the 2030s</td></tr>
<tr><td rowspan="2">Coal prices into coal-fired power stations</td><td colspan="6">ACIL Allen's in-house understanding of the cost of thermal coal to the NEM's coal-fired power stations, based on existing contracts with domestic mines and the plant's exposure to the international export market. However, between 2023 and 2027, export coal prices are capped at AUD$125/t as part of the Government's response to high electricity prices.</td></tr>
<tr><td colspan="2">New South Wales<br>The delivered marginal coal prices in NSW are assumed to be linked to export parity and therefore follow the assumed movement in export coal prices. However, from FY24 coal prices are capped at AUD$125/t.<br>Marginal coal prices decline from $9/GJ in 2023 to $5/GJ by 2025 under the coal price cap, to about $4/GJ by 2030 with the assumed decline in export coal prices.</td><td colspan="2">Queensland<br>There are four types of coal supply arrangements across the Queensland fleet, with most generator's fuel supply not linked to export pricing.<br>Marginal coal prices range from $1.10 to $3.70/GJ for the entire projection period.</td><td colspan="2">Victoria<br>Coal mined for power generation in Victoria is unsuitable for export and hence not affected by fluctuations in export prices.<br>Marginal coal prices range from $0.28 to $0.78/GJ, representing marginal mining costs.</td></tr>
<tr><td>Coal & gas price caps</td><td colspan="6">A gas price cap of AUD$12/GJ and a coal price cap of AUD$125/t have been introduced. This Reference case applies the gas and coal price caps starting from 2023. The caps are expected to end when market prices for export coal and gas fall below cap levels. Based on our assumptions, the coal price cap is in place until 2027, whereas the gas price cap is binding until mid-2025.</td></tr>
<tr><td>Interconnectors</td><td colspan="3">Existing interconnection<br>Assumed transfer capabilities updated to reflect recent history and known constraints (e.g., related to planned outages as part of upgrade works).</td><td colspan="3">ISP committed and actionable projects included:<br>– QNI minor (July 2023); QNI connect (Jul 2029)<br>– EnergyConnect (Jul 2026)<br>– Heywood upgrade (Jul 2026)<br>– VNI Minor (Sep 2022)<br>– VNI West (Apr 2029)<br>– Marinus Link (750 MW) (Jul 2029)</td></tr>
<tr><td>Marginal loss factors</td><td colspan="6">ACIL Allen's projections of average annual marginal loss factors (MLF) by generator DUID, developed using commercial power flow software. Our latest calibration with AEMO's forecast has shown over 95 per cent of connection point values deviating by no more than 0.02 from the latest AEMO values for 2023-24.</td></tr>
</table>

| Assumptions | Details |
| --- | --- |
| Constraints | – Thermal constraints which impact renewable energy zones in Western Victoria, South West New South Wales and Central New South Wales and result in generator curtailment greater than five 5 per cent are included in the Reference case modelling. Stability limit constraints which have a material impact on QLD-NSW and VIC-NSW flows and regional prices during peak periods are also included.<br>– Certain constraints are disabled once upgrades are installed. . |

*[a] ACIL Allen's modelling considers battery storage technologies of varying duration – the eight-hour batteries are the most prevalent duration option in our modelling results.*

*Note: Unless stated otherwise, all dollar values in this table are presented in real 2024 AUD.*

*Source: ACIL Allen*

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