ACIL ALLEN

Mid-scale PV projections

2026-2035

18 July 2025

About ACIL Allen

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

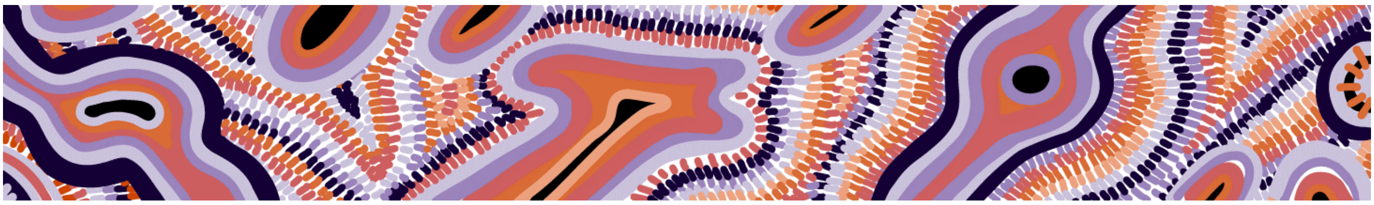
Our purpose is to help clients make informed decisions about complex economic and public policy issues.

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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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 2026 to 2035. 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 2025.

Behind-the-meter (BTM) 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 2026 to 2035 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 operating costs and amortised return-of and -on capital 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.

We have included committed off-grid systems in the near term (2025 and 2026).

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

Table ES 1 Projected annual mid-scale solar PV systems (MW)

Category	Capacity range	State/ territory	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Behind the meter	100kW to ≤ 1MW	ACT	1.4	1.6	2.0	2.3	2.3	2.3	2.3	2.4	2.4	2.4
		NSW	14.4	9.5	1.7	0.4	0.4	0.4	0.5	0.5	0.5	0.5
		NT	2.1	1.8	1.8	2.1	2.4	2.8	2.7	2.3	2.6	3.0
		QLD	11.8	10.2	4.4	1.0	0.3	0.3	0.3	0.3	0.3	0.3
		SA	3.7	3.1	1.1	0.3	0.1	0.1	0.1	0.1	0.1	0.1
		TAS	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
		VIC	2.9	2.8	2.1	2.1	2.1	2.2	2.2	2.3	2.3	2.4
		WA	3.5	3.5	3.6	3.6	3.7	3.8	3.9	3.9	4.0	4.1
		Total	40.0	32.8	16.9	12.2	11.6	12.1	12.2	12.0	12.5	13.0

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

Category	Capacity range	State/ territory	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Behind the meter	1MW to ≤ 5MW	ACT	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		NSW	0.42	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		NT	0.04	0.02	0.02	0.04	0.09	0.20	0.21	0.10	0.21	0.47
		QLD	6.58	5.72	2.24	0.46	0.18	0.19	0.19	0.19	0.20	0.20
		SA	1.91	1.95	0.38	0.03	0.01	0.01	0.01	0.01	0.01	0.01
		TAS	0.17	0.17	0.13	0.14	0.14	0.14	0.14	0.15	0.15	0.15
		VIC	1.86	1.90	1.46	1.49	1.52	1.55	1.59	1.62	1.65	1.68
		WA	1.98	1.24	0.61	0.34	0.27	0.40	0.46	0.32	0.42	0.62
		Total	13.0	11.0	4.8	2.5	2.2	2.5	2.6	2.4	2.6	3.1
Behind the meter	5MW to ≤ 30MW	ACT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		NSW	1.04	1.01	0.60	0.32	0.29	0.32	0.34	0.32	0.34	0.39
		NT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		QLD	0.44	0.42	0.25	0.14	0.12	0.14	0.14	0.14	0.14	0.16
		SA	3.38	3.27	1.95	1.05	0.94	1.05	1.10	1.05	1.10	1.26
		TAS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		VIC	2.94	2.84	1.69	0.91	0.82	0.91	0.96	0.91	0.96	1.10
		WA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total	7.8	7.5	4.5	2.4	2.2	2.4	2.5	2.4	2.5	2.9
In front of meter	100kW to ≤ 30MW	All	81	78	59	58	53	53	57	61	75	90
Off-grid	100kW to ≤ 30MW	All	52	46	50	54	58	62	66	71	75	78

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:
  - Threshold 1: >100 kW to <=1 MW
  - Threshold 2: >1 MW to <=5 MW
  - Threshold 3: >5 MW to <=30 MW

The projections cover calendar years 2026 to 2035 for the following categories:

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

The projections are provided for each region in Australia (where there is sufficient regional data available).

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

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 2026 to 2035 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 2025 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.

[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.

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 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 operating costs and amortised return-of and -on capital costs The performance indicator includes a commercial rate of return to equity.

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 (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). The LCOE projections have been estimated using the 2025 Draft IASR build costs.

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, Ark Energy, etc) and large Australian mining companies that have renewable projects in remote areas (BHP, Rio Tinto, Fortescue, etc). 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 assumptions shared with us and adopted by DCCEEW in their latest emissions projections work. Key assumptions include 2024 ESOO for grid demand, population projections from the Centre for Population, fuel costs from AEMO 2025 Draft IASR, and federal government policy of reaching 82% renewables by 2030.

3 Results

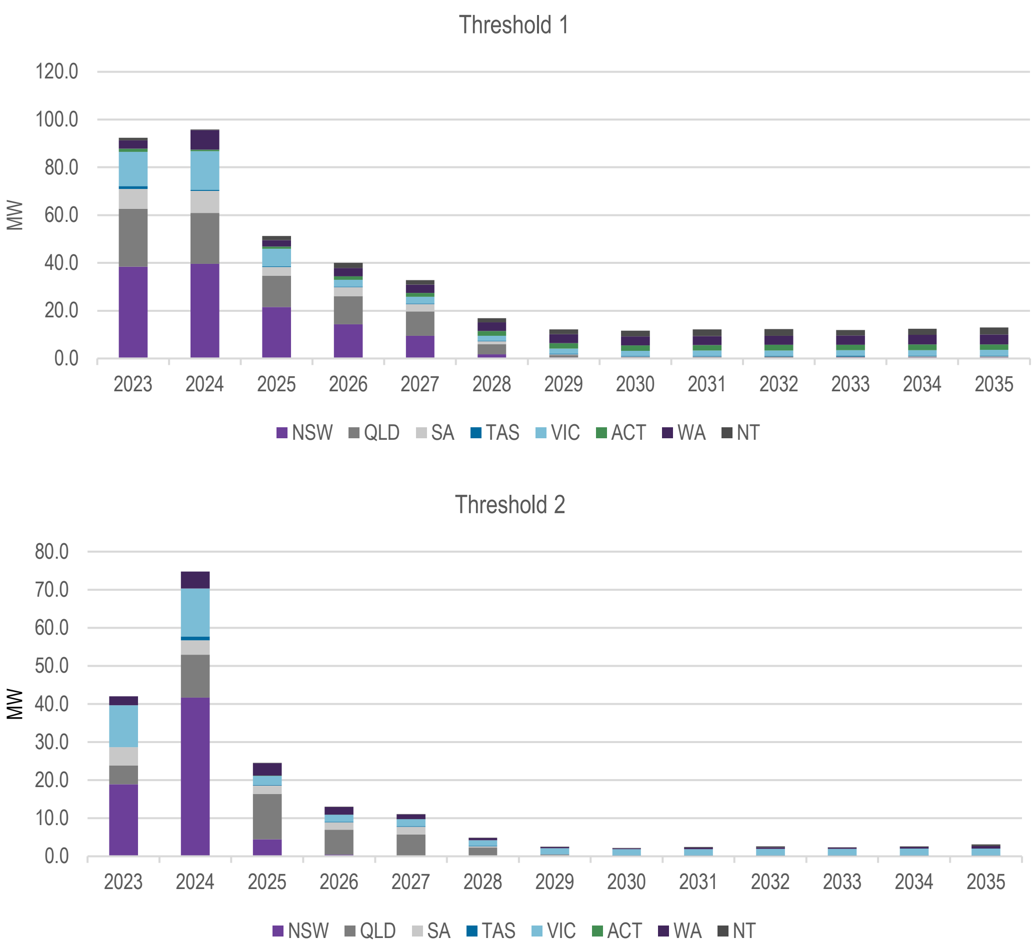
This chapter presents historical and projected mid-scale PV system installations by category and size threshold.

3.1 Behind-the-meter

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 – 2024-2035



Note: Historical data up to 30 April 2025, using capacity based on accreditation start date.

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	2031	2032	2033	2034	2035
NSW	38.4	39.6	21.5	14.4	9.5	1.7	0.4	0.4	0.4	0.5	0.5	0.5	0.5
QLD	24.2	21.2	13.2	11.8	10.2	4.4	1.0	0.3	0.3	0.3	0.3	0.3	0.3
SA	8.3	9.3	3.7	3.7	3.1	1.1	0.3	0.1	0.1	0.1	0.1	0.1	0.1
TAS	1.2	0.4	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
VIC	14.4	16.3	7.4	2.9	2.8	2.1	2.1	2.1	2.2	2.2	2.3	2.3	2.4
ACT	1.3	0.7	0.9	1.4	1.6	2.0	2.3	2.3	2.3	2.3	2.4	2.4	2.4
WA	3.4	8.1	2.7	3.5	3.5	3.6	3.6	3.7	3.8	3.9	3.9	4.0	4.1
NT	1.1	0.3	1.6	2.1	1.8	1.8	2.1	2.4	2.8	2.7	2.3	2.6	3.0
Total Threshold 1	**92.4**	**95.9**	**51.2**	**40.0**	**32.8**	**16.9**	**12.2**	**11.6**	**12.1**	**12.2**	**12.0**	**12.5**	**13.0**

Note: Historical data up to 30 April 2025, using capacity based on accreditation start date.

Source: ACIL Allen

New system threshold 1 and threshold 2 installations in 2023 and 2024 are high historically, due to lower payback periods driven by elevated avoided tariffs and high LGC and VEEC (where applicable) prices. The model takes account a 2-year lagged impact of electricity prices on installation rates.

Threshold 1 and threshold 2 PV system installations are projected to decline from 2025 due to rising payback periods, which are driven by a fall in revenue from LGC and VEEC (where applicable) and softening of avoided tariffs. Avoided tariffs, which are based on variable network charges, decline quite sharply over this period due to large commercial and industrial customers being on a demand-based tariff structure, which contains a higher proportion of fixed network costs (which are not avoided when installing PV).

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

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSW	18.9	41.6	4.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
QLD	4.9	11.3	12.0	6.6	5.7	2.2	0.5	0.2	0.2	0.2	0.2	0.2	0.2
SA	4.8	3.8	2.1	1.9	1.9	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TAS	0.0	1.0	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
VIC	11.0	12.6	2.3	1.9	1.9	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.7
ACT	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WA	2.3	4.5	3.3	2.0	1.2	0.6	0.3	0.3	0.4	0.5	0.3	0.4	0.6
NT	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.1	0.2	0.5
Total Threshold 2	**42.0**	**74.8**	**24.5**	**13.0**	**11.0**	**4.8**	**2.5**	**2.2**	**2.5**	**2.6**	**2.4**	**2.6**	**3.1**

Note: Historical data up to 30 April 2025, using capacity based on accreditation start date.

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	2031	2032	2033	2034	2035
NSW	125	122	68	45	30	5	1	1	1	1	1	1	1
QLD	79	65	42	37	32	13	3	1	1	1	1	1	1
SA	27	28	12	12	10	4	1	0	0	0	0	0	0
TAS	4	1	1	1	1	1	1	1	1	1	1	1	1
VIC	47	50	24	9	9	6	6	7	7	7	7	7	7
ACT	4	2	3	5	5	6	7	7	7	7	7	7	7
WA	11	25	9	11	11	11	11	11	12	12	12	12	12
NT	4	1	5	7	6	5	6	7	8	8	7	8	9
Total Threshold 1	**301**	**294**	**163**	**126**	**102**	**52**	**37**	**35**	**37**	**37**	**37**	**38**	**40**

Note: Historical data up to 30 April 2025, using capacity based on accreditation start date.

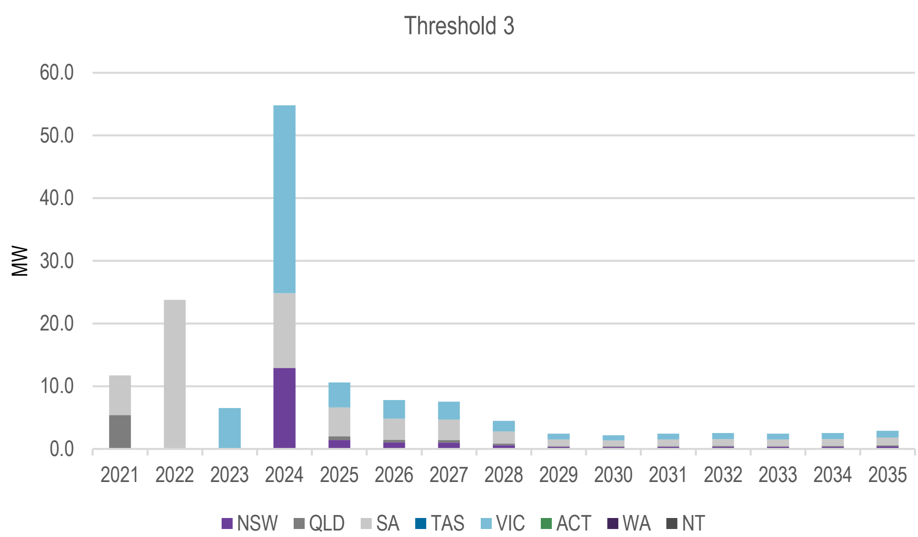
Source: ACIL Allen

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 in Victoria in 2024.

Figure 3.2 Historical and projected annual threshold 3 BTM solar PV systems (MW) by region – 2021-2035



Note: Historical data up to 30 April 2025, using capacity based on accreditation start date.

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	2031	2032	2033	2034	2035
NSW	0.0	12.9	1.4	1.0	1.0	0.6	0.3	0.3	0.3	0.3	0.3	0.3	0.4
QLD	0.0	0.0	0.6	0.4	0.4	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.2
SA	0.0	11.9	4.6	3.4	3.3	1.9	1.0	0.9	1.0	1.1	1.0	1.1	1.3
TAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VIC	6.5	30.0	4.0	2.9	2.8	1.7	0.9	0.8	0.9	1.0	0.9	1.0	1.1
ACT	0.0	0.0	0.0	0.0	0.0	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	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	0.0	0.0	0.0	0.0	0.0
Total Threshold 3	**6.5**	**54.8**	**10.6**	**7.8**	**7.5**	**4.5**	**2.4**	**2.2**	**2.4**	**2.5**	**2.4**	**2.5**	**2.9**

Note: Historical data up to 30 April 2025, using capacity based on accreditation start date.

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 forward new threshold 3 systems, we have used the average of historical annual new build capacity in 2021-2024 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 increased to around 55 WM in 2024, with falling payback periods due to elevated avoided tariffs and high LGC and VEEC prices. Payback periods for threshold 3 increase from 2025, which is reflected in the projections falling to around 10 MW in 2025 and then to 2.9 MW by 2035. Higher payback periods from 2025 are driven by falling avoided tariffs and rapidly declining revenue from LGC and VECC (where applicable). Avoided tariffs, which are based on variable network charges, decline quite sharply over this period due to large commercial and industrial customers being on a demand-based tariff structure.

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

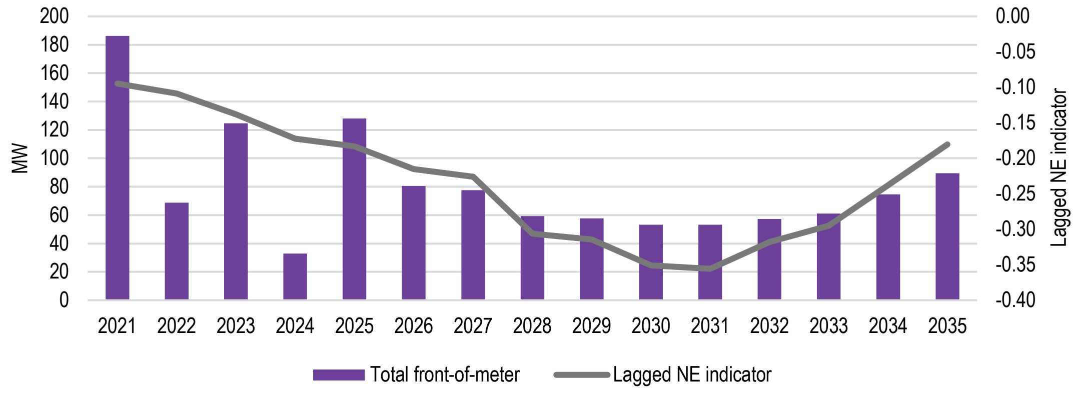
Figure 3.3 shows historical and projected annual front-of-meter solar PV systems by region. The values are presented on a calendar year basis. Historical data is shown up to 30 April 2025, with committed projects in 2025.

We have used new entrant (NE) 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 energy and LGC markets for a front-of-meter PV system meets or exceeds its amortised investment cost (return of and on capital) and operating 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.

Figure 3.3 Historical and projected annual mid-scale front-of-meter solar PV systems (MW) by region (primary axis) and lagged new entrant (NE) indicator (secondary axis)–2023-2035



Note: Historical data up to 30 April 2025, using capacity based on accreditation start date; committed projects in 2025; projected from 2026.

Source: ACIL Allen

Table 3.5 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 2025, with committed projects in 2025. There are insufficient historical data points to undertake the analysis by region or capacity threshold.

Table 3.5 Historical and projected annual mid-scale front-of-meter solar PV systems (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total front-of-meter	125	33	128	81	78	59	58	53	53	57	61	75	90

Note: Historical data up to 30 April 2025, using capacity based on accreditation start date; committed projects in 2025; projected from 2026.

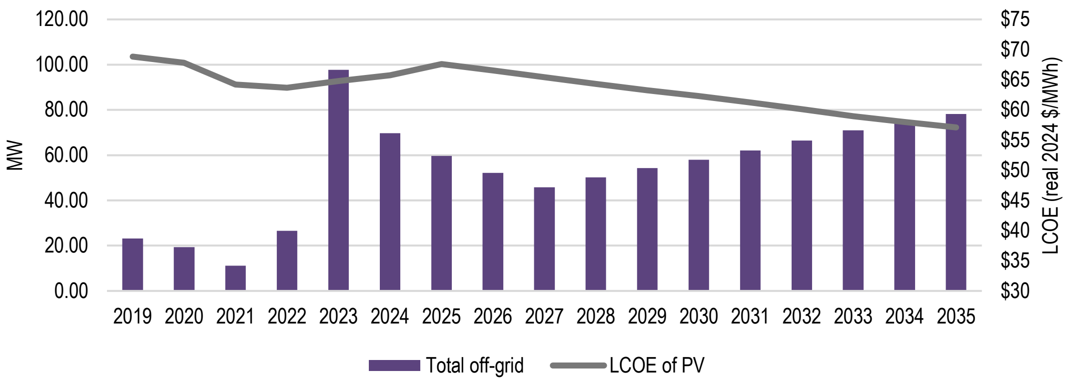
Source: ACIL Allen

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., Capacity Investment Scheme (CIS), NSW Roadmap, 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, 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 in 2025, the reducing value of solar energy in the wholesale market results in installations declining to around 55 MW between 2028 and 2033, before ramping up to approximately 90 MW by 2035, as wholesale prices increase again with the winding up of the federal and state schemes and expected coal closures. 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 (85%), the Northern Territory (10%), Queensland (3%), and South Australia (1%) to satisfy a local load such as a mine or small town. Off-grid PV installations increased significantly in 2023 and 2024 in Western Australia and Queensland (supplying remote mines) in response to a decline in the LCOE of PV in 2020, 2021 and 2022. Installations in 2025 are committed projects supplying Western Australia and the Northern Territory mining activity.

Figure 3.4 Historical and projected annual mid-scale off-grid solar PV systems (MW) (primary axis) and LCOE of solar PV (real 2025 $/MWh) (secondary axis) – 2019-2035



Note: Historical data up to 30 April 2025, using capacity based on accreditation start date; committed projects in 2025; projected from 2026.

Source: ACIL Allen

Projections from 2026 onwards are based on the historical relationship between installations and the LCOE of solar PV. 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, Queensland and the Northern Territory, which reflects the extent of remote mining activity in those regions. 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	2031	2032	2033	2034	2035
Total off-grid	98	70	60	52	46	50	54	58	62	66	71	75	78

Note: Historical data up to 30 April 2025, using capacity based on accreditation start date; committed projects in 2025; projected from 2026.

Source: ACIL Allen

Appendices

A Assumptions

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

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 experience a decline based on learning rates from CSIRO's GenCost report provided as an input to AEMO's 2025 Draft IASR.

Figure A.1 Solar system cost (Real 2025 $/kW)

Source: ACIL Allen analysis using historical CSIRO and IRENA data and GenCost projections

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.

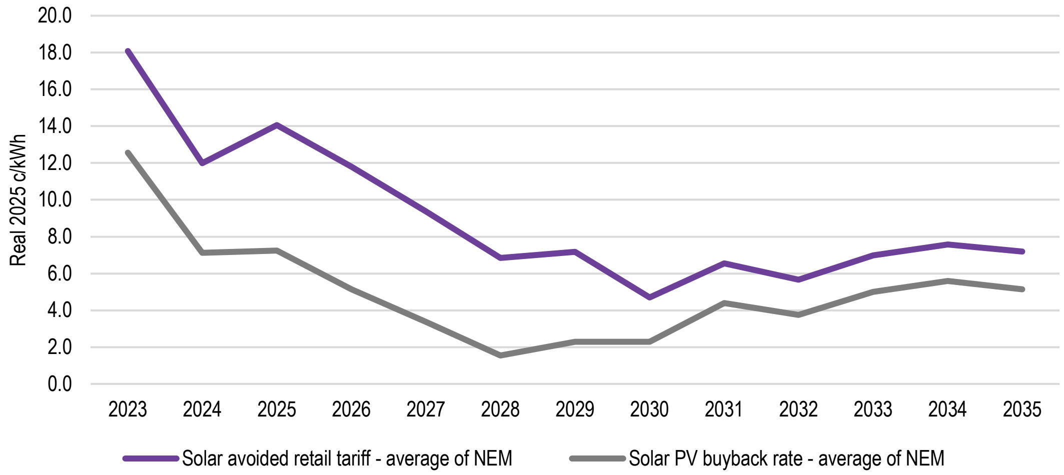
Network, environmental and retailing costs are based on data from publicly available sources such as the AER determinations regulator determinations and AEMO.

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 Australia-wide schemes such as the expanded Capacity Investment Scheme (CIS). Solar avoided tariffs (or retail tariffs) include the variable network component only.

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

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 2030, the solar buyback rate is projected to increase with the expected closure of large amounts of steam turbine capacity (coal-fired and gas-fired).

Figure A.2 Solar avoided retail tariffs and solar buyback rate in the NEM (real 2025 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 from 2025 is driven by the projected decline in LGC and VEEC prices combined with the decline in avoided tariffs and solar feed-in-tariffs, which offsets the impact of declining installation costs.

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 introduction of Renewable Energy Guarantees of Origin (REGOs) from mid-2025 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. By 2030, the assumed value of LGCs falls to zero.

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.

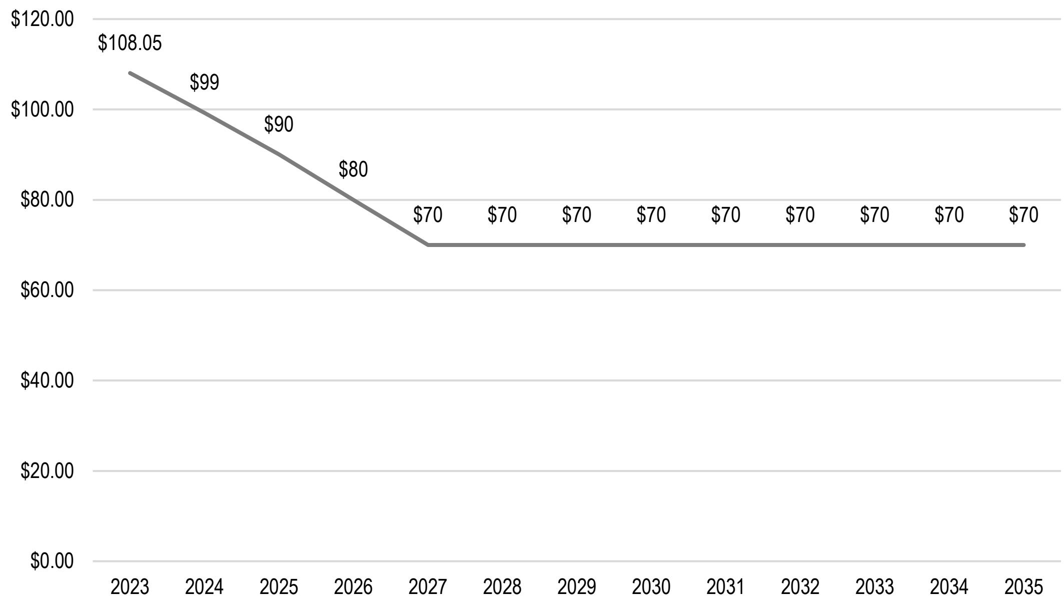
Additionally, due to the policy of 82% renewable energy by 2030, the value of REGOs after 2030 are likely to be low.

[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 2025 $/VEEC)



Source: ACIL Allen

A.6 PowerMark wholesale electricity market modelling assumptions

Projected electricity prices used in this analysis are based on a Base case projection of the NEM using assumptions aligned with the DCCEEW Emissions Projections modelling. Table A 1 summarises the key assumptions adopted in the Base case that are pertinent to the period to 2035.

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

<table>
<tr><th>Assumptions</th><th colspan="4">Details</th></tr>
<tr><td>Electricity demand</td><td colspan="4">AEMO 2024 Electricity Statement of Opportunities (ESOO) Step Change scenario</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.
– National target of 82% renewable energy generation by 2030 (see note on Capacity Investment Scheme below).</td></tr>
<tr><td rowspan="3">State based schemes</td><td>NSW
NSW Roadmap capacity of:
– 12 GW renewables by 2032 within designated Renewable Energy Zone (REZ)
– 2 GW long-duration storage by 2030
– 3.5 GW long-duration storage by 2034</td><td>QLD
– Queensland’s new government has committed to keep its coal generators online for longer and shown support for smaller pumped hydro projects as part of broader efforts to transition to renewable energy and ensure energy reliability in the state. The Reference case assumes four small pumped hydro plants (500 MW/ 4,000 MWh each) coming online between 2035 and 2038.</td><td>TAS
TRET targets of 15,750 GWh (150%) of renewable energy by 2030 and 21,000 GWh (200%) by 2040.</td><td>VIC
VRET targets of 40% by 2025, 65% by 2030 and 95% by 2035.
Victoria energy storage targets:
– At least 2.6 GW storage capacity by 2030
– At least 6.3 GW storage capacity by 2035

Offshore wind capacity target:
– 2 GW of offshore wind capacity by 2032</td></tr>
<tr><td colspan="4">SA
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.</td></tr>
<tr><td colspan="4">All NEM states: Economy-wide net zero emissions by 2050; interim targets of 50 per cent reductions by 2030.</td></tr>
<tr><td>Capacity Investment Scheme (CIS)</td><td colspan="4">The Capacity Investment Scheme (CIS) aims to:
– 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)</td></tr>
</table>

<table>
<tr><th>Assumptions</th><th colspan="3">Details</th></tr>
<tr><td></td><td colspan="3">– fill expected reliability gaps in the energy network as ageing coal-fired power stations exit
– deliver the Australian Government's 82% renewable electricity by 2030.</td></tr>
<tr><td>Electricity supply (beyond new supply driven by state-based schemes)</td><td>Committed projects
– 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)
– Includes the Federal Government's Snowy 2.0 by 2030.</td><td>Assumed new entry and closures
– 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
– 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 2027, Bayswater in 2033, Loy Yang A and Kogan Creek by 2035, Stanwell, Tarong and Tarong North in 2036).</td><td>Projected new entry and closures
– Beyond committed and assumed projects, only commercial generic new entrants are introduced within the modelling.
– 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.</td></tr>
<tr><td>Gas prices into gas-fired and coal-fired power stations</td><td colspan="3">AEMO 2025 Draft IASR Step Change scenario</td></tr>
<tr><td>Interconnectors</td><td>Existing interconnection
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="2">AEMO 2025 Draft Stage 2 IASR and the latest Transmission Augmentation Information.
IASR committed and actionable projects included:
– QNI minor (July 2023); QNI connect (Jul 2029), QNI medium (Jul 2033)
– EnergyConnect (Jul 2027)
– Heywood upgrade (Jul 2027)
– VNI Minor (Sep 2022)
– VNI West (Jan 2030)
– Marinus Link (750 MW) (Jul 2030)</td></tr>
</table>

Source: ACIL Allen

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