Mid-scale solar outlook 2020 to 2025
Systems above 100kW to 30MW

Report to the Clean Energy Regulator

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Green Energy Markets
G.02 109 Burwood Road Hawthorn VIC 3122
T: 03 9805 0777
admin@greenmarkets.com.au
www.greenmarkets.com.au

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1. Executive Summary

Green Energy Markets has been commissioned by the Clean Energy Regulator to provide a projection of levels of mid-scale solar capacity installed by year for the period of 2021 to 2025. Mid-Scale capacity is defined as solar systems above 100 kilowatts and up to 30 megawatts[1]. The projection covers:

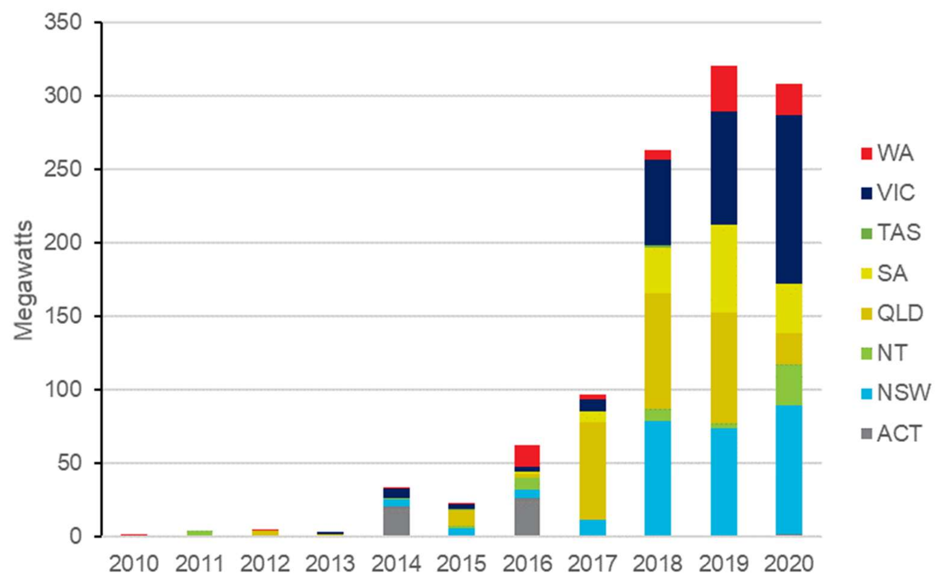
- Systems installed on electricity consumers' premises in a behind the meter configuration (where the generation can be self-consumed to offset the need to purchase power from the grid at the retail-delivered price of electricity)
- Systems installed as power plants in front of the meter which are dependent on revenue tied to the value of the wholesale electricity market; and
- Systems installed in remote or off-grid power systems where their primary benefit is to reduce gas and diesel fuel use to supply power.

All charts and figures provided in this report only detail numbers for systems registering for Large Scale Generating Certificates or LGCs which are assumed to be above 100kW in capacity (they exclude systems registered under the Small Scale Renewable Energy Scheme).

Projecting uptake within this narrow sub-sector of the solar market is subject to considerable uncertainty because the market is highly immature and still undergoing rapid development and change.

The market has only really emerged at any noticeable level since 2017 as a result of significant reductions in system costs, and a dramatic increase in the wholesale price of electricity in the east-coast National Electricity Market.

Figure 1-1 Capacity of solar systems up to 30MW by year of accreditation



Complicating matters in projecting uptake is that the underlying supply-demand balance for electricity is changing rapidly due to a large influx of solar and wind capacity within a short period of time. This capacity has already acted to substantially depress the wholesale market value of electricity during daytime periods. In the states of Queensland, South Australia and Western Australia wholesale market prices reach

[1] In practice there is a very small amount of capacity captured in this analysis involving some systems that are below 100kW in scale but have elected to register under the Large-Scale Renewable Energy Target to create Large-Scale Generation Certificates rather than STCs. In 2019 these systems represented 0.03% of total capacity accredited for LGCs involving systems of 30MW or less capacity. For modelling convenience and given their insignificance they were not specifically excluded from the historical dataset.

record lows over daytime periods and this is now also becoming a feature in other states (with the exception of NT which does not yet have an effective functioning wholesale market). This will noticeably reduce the revenue gain (or avoided electricity cost) solar systems provide.

In addition, measures to contain the COVID19 virus pandemic may have had a short-term impact on the market for solar systems over 2020 which complicate the ability to make firm conclusions about how the solar market is responding to what is likely to be a long-term fall in daytime electricity prices.

This report's projections of solar uptake are based on a combination of:

- interviews with a range of solar industry participants that have experience in the mid-scale segment of the solar market. The selection of interviewees seeks to draw together a small group of experienced industry participants that once combined provides a good overview of conditions in the market from both a qualitative and quantitative perspective who have enough experience in the industry to evaluate market behaviour and changes in an historical context. It involved two specialist commercial-sector solar retailers, one mass market solar retailer (with a significant commercial market component), an energy management consultant, a major solar equipment vendor, the largest commercial solar LGC creator (Green Energy Trading), three specialists in small solar farm development, two firms focussed on off-grid systems, and two solar sales and marketing firms;
- bottom-up research identifying near-term, significant solar roll-out plans by large organisations such as supermarkets, shopping centre operators, airports, water companies, and government entities.
- financial modelling of the payback periods for investing in solar systems across different states. Uptake in 2021 to 2025 is calibrated against uptake and payback periods for three reference years – 2019, 2020 and 2015. Given expected large falls in the wholesale market value of electricity, it is expected paybacks will deteriorate (become longer) relative to 2019 electricity prices. Therefore the amount of solar capacity installed would be expected to decline. The extent of the decline is guided against how much paybacks deteriorate relative to what they were in 2015, which provides a type of bottom-end guidepost. However, the financial modelling provides a baseline of indicative projected installations over the period to 2025 but these are then adjusted to take into account the information gathered via interviews and the bottom-up research.

In addition, to cater for the fact the uptake of solar PV is subject to significant uncertainty, we have developed two scenarios for how the market might unfold:

- a **Base Case** which reflects uptake based on what we think is the most likely trajectory for system costs and an expectation that market uptake will be reasonably sensitive to declining financial attractiveness as a result of falling wholesale energy costs; and
- a **High DER Case** which caters for the possibility that:
    - system costs decline faster; and
    - the high level of consumer concern about electricity prices and interest in installing solar remains high even as power prices decline.

Table 1-1 provides the resulting nation-wide estimates of capacity installed over the outlook period for the Base Case.

Table 1-1 Base Case - projected mid-scale total megawatts accredited/installed

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	127	55	47	50	62
NT	46.8	1.0	0.8	0.9	0.9
QLD	30	24	26	33	39
SA	188	49	15	19	28
TAS	1.2	0.3	0.3	0.3	5.4
VIC	60	26	27	30	48
WA	15	7	37	9	10
Off Grid - all states	14.5	32	15	30	30
TOTAL	**482**	**194**	**168**	**173**	**223**

Table 1-2 below meanwhile provides estimates of capacity over the same period under the High DER Case.

Table 1-2 High DER Case - projected mid-scale total megawatts accredited/installed

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	141	84	68	97	150
NT	47	1	6	11	11
QLD	45	36	35	57	75
SA	198	66	21	38	44
TAS	2	0	0	6	11
VIC	75	51	36	59	94
WA	18	11	71	20	26
Off Grid - all states	15	40	30	50	50
TOTAL	**541**	**289**	**268**	**338**	**461**

The average amount of annual LGC production each year's installed capacity would create is detailed in Table 1-3 for the Base Case and in Table 1-4 for the High DER Case. Please note that these numbers from 2022 onwards are well below the installed systems' likely power generation because our analysis indicates that owners of behind the meter systems would be financially better off registering their systems to create either Victorian Energy Efficiency Certificates when located in Victoria from 2022 onwards or Australian Carbon Credit Units in other states from 2024 onwards.

Table 1-3 Annual ongoing LGCs by year of plants' accreditation – Base Case

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	236,835	80,151	65,750	0	21,024
NT	90,648	1,478	1,263	0	0
QLD	39,420	31,906	33,556	0	0
SA	283,513	91,546	19,798	0	10,512
TAS	1,419	329	346	0	9,198
VIC	78,209	9,636	9,636	0	19,272
WA	19,815	9,258	50,471	0	0
Off Grid - all states	21,593	47,654	22,338	44,676	44,676
TOTAL	**771,452**	**271,959**	**203,157**	**44,676**	**104,682**

Table 1-4 Annual ongoing LGCs by year of plants' accreditation – High DER Case

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	259,533	133,447	93,545	139,715	105,120
NT	91,489	1,792	12,885	23,979	21,900
QLD	59,130	47,605	45,701	82,381	21,024
SA	299,592	122,695	26,963	57,225	21,024
TAS	2,201	556	492	9,843	18,396
VIC	99,864	28,908	9,636	19,272	57,816
WA	24,440	14,410	119,306	31,085	21,024
Off Grid - all states	22,338	59,568	44,676	74,460	74,460
TOTAL	**858,588**	**408,981**	**353,204**	**437,961**	**340,764**

2. Overview of the Market

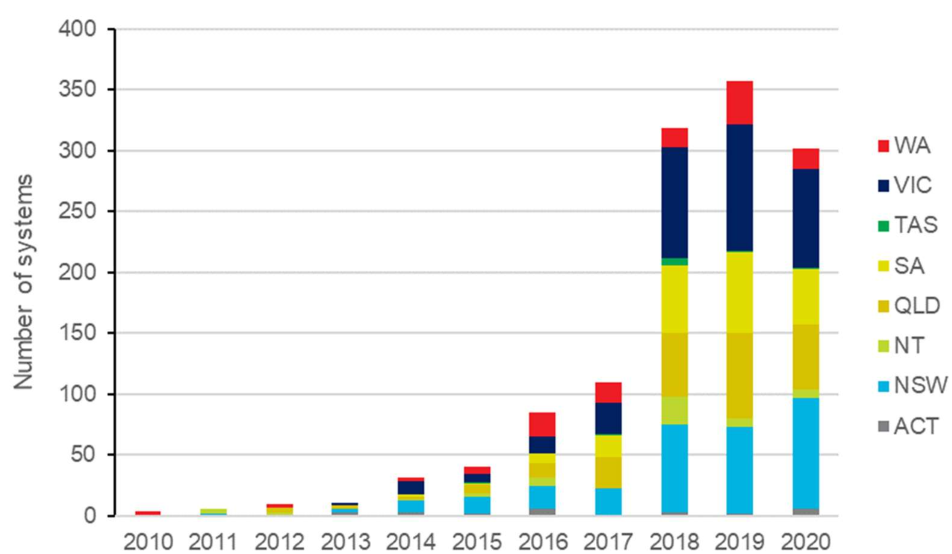
The mid-scale solar market continues to experience rapid change and is subject to significant uncertainty

Assessing the likely trajectory of installations for mid-scale solar systems (defined as those 100 kilowatts and up to 30 megawatts in capacity) is subject to considerable uncertainty.

Factors making it difficult to predict future installations include the fact that the market is in reality highly immature and still undergoing rapid development and change. Prior to 2016 solar systems larger than 100kW were not really a commercial proposition to electricity customers where a large proportion of network charges are recovered via demand-based tariffs[2]. In addition, while solar was a more viable financial option for use in remote applications for displacing diesel fuel, it's widespread use was limited due to other factors such as unfamiliarity with the technology, concerns around maintaining power system reliability, and the fact that energy costs are often a relatively minor driver of financial performance in mining activities. Lastly, solar was substantially more expensive than wind power and so uncompetitive for provision of LGCs and electricity for the wholesale market.

As shown in Figure 2-1, the number of systems installed in Australia prior to 2016 was very small, with just 42 systems accredited in 2015, 31 in 2014 and an average of just 8 per annum from 2010 to 2013. The most installed in any single state was just 15 prior to 2016. This very small sample set over a short period of time makes it difficult to draw confident inferences about how the market responds to different factors likely to influence uptake. Although with the fall in system installs in 2020 there are now at least tentative signs that the market may have passed its rapid growth phase, but one also needs to be wary of the possible short-term impact of COVID-19 restrictions.

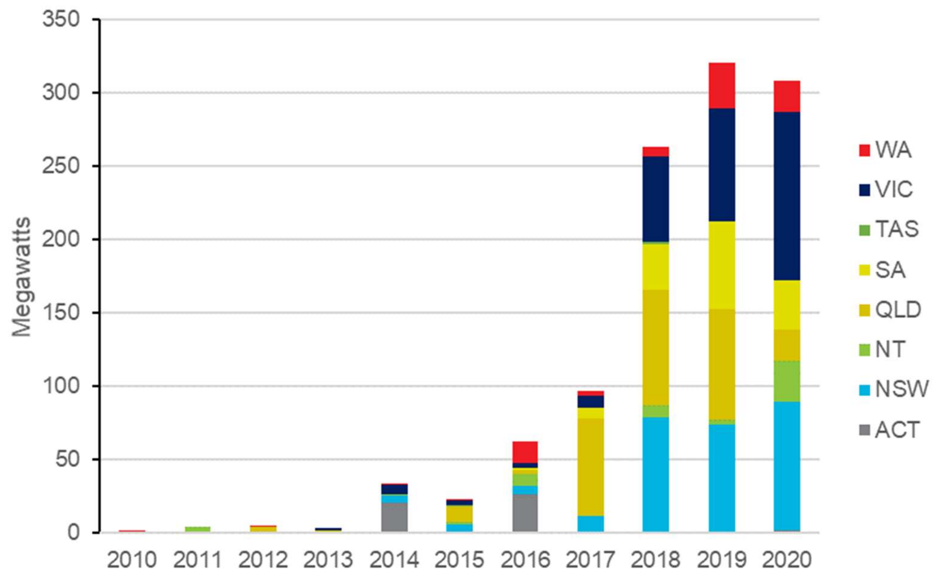
Figure 2-1 Number of mid-scale solar systems by year of accreditation (up to 30MW)



[2] This is where a customer is charged by the power network provider on the basis of their maximum kilovolt-amp or kVA demand drawn from the network across any individual 30 minute interval over the measured period, rather than their overall consumption of kilowatt-hours on the network.

Megawatts of generating capacity, shown in Figure 2-2, have followed a similar trajectory to the number of systems.

Figure 2-2 Capacity of mid-scale solar systems by year of accreditation (up to 30MW)



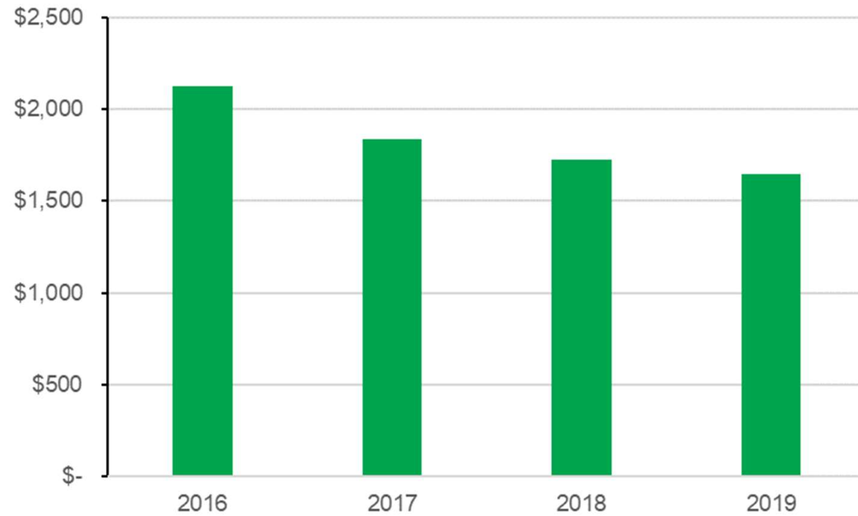
The small numbers of installations until just recently means there is a scarcity of historical data with which to assess statistical relationships between uptake and possible causes of increased uptake that might facilitate precise quantitative analysis. However the fact that numbers of systems and capacity fell slightly in 2020 at the same time that electricity prices fell and prospective paybacks for systems deteriorated gives us a an important new piece of information that reinforces our view that financial attractiveness is the overwhelming driver of customer uptake of mid-scale solar and that the recent historical trend of rapid growth is now likely to reverse.

Rapid growth in mid-scale has been spurred by a dramatic improvement in solar system financial attractiveness

Even though the limited sample set constrains the ability to develop a precise and confident relationship between uptake and plausible variables that influence uptake, what is clear is that the market's rapid growth since 2016 was predominately a function of improving financial attractiveness of solar systems relative to end consumers buying power from the grid.

Based on the sample set provided by the Clean Energy Regulator, system cost per kilowatt declined by around 25 percent between 2016 and 2019.

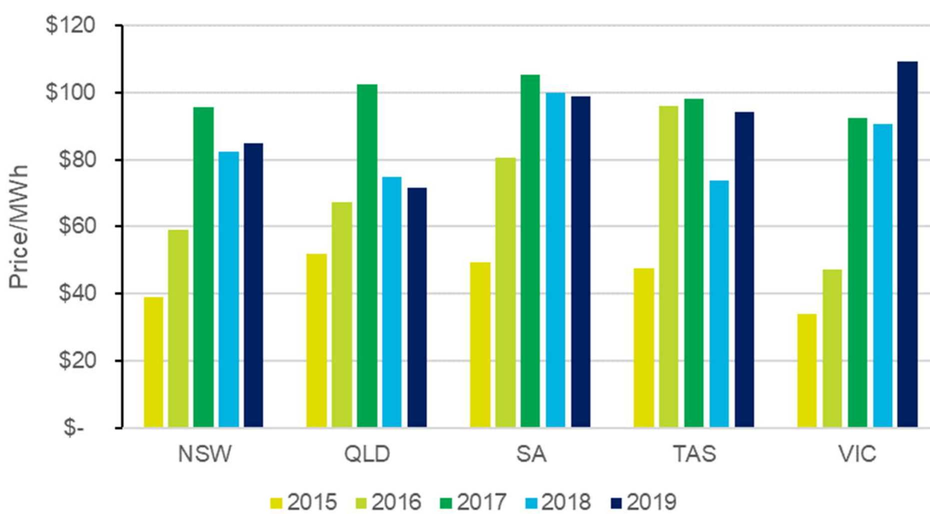
Figure 2-3 Cited installed cost of mid-scale systems per kilowatt by year (excluding off-grid/remote grid systems)



Note: Off-grid or remote grid systems have been excluded because these usually involve substantial additional costs not faced by mains grid-connected systems which then act to skew the cost data upwards in years in which off-grid systems were accredited.

Meanwhile, over the same period we saw a dramatic rise in wholesale electricity prices in the East-Coast National Electricity Market as shown in Figure 2-4. The jump in prices began in 2016 but was greatest in 2017 for NSW, QLD and Victoria.

Figure 2-4 Average time-weighted wholesale electricity spot price by state



For customer sites potentially suitable for behind the meter systems larger than 100kW, changes in wholesale market energy prices have a far greater impact on kilowatt-hour charges than for smaller customers such as the residential market (whose network charges are recovered based on consumption of kilowatt-hours). And of course these prices are the predominant driver of revenue for in-front of the meter power station installations.

The final factor that helped drive a dramatic improvement in the financial attractiveness of 100kW+ solar systems around 2016 was a significant rise in the LGC spot price which increased from around $30 over 2014 to above $80 in 2016 and 2017. One LGC is awarded to a solar system for each megawatt-hour of electricity it generated so the revenue gain in LGCs almost the same as that captured by the rise in wholesale electricity markets.

Combining the decline in system costs with the increase in revenue from higher wholesale prices and higher LGCs prices, we estimate the payback period on solar systems roughly halved for a range of customer sites likely to be suitable for 100kW+ behind the meter systems.

Suppliers also became more capable in marketing and installing 100kW+ solar systems and consumers more confident in these systems

It is important to recognise that Australia's solar industry has traditionally been dominated by selling and installing small, generic solar systems to residential households. Selling and installing such residential systems is usually much simpler than what's required for large commercial systems. Commercial clients have more varied tariff types, need a more tailored approach to system design, take a more involved and sophisticated approach in evaluating whether to purchase solar, are more prone to landlord-tenant split incentives, and the technical requirements of such systems are more difficult, in particular the grid connection process. Another factor that has been more important in the commercial sector than residential has been the provision of financing that avoids the need for clients to commit their own upfront capital to purchasing the system.

As the financial attractiveness of large commercial solar systems has improved and the levels of interest in installing solar has grown, the solar industry has gained much greater experience in the sale and installation of these larger systems. This has allowed them to become better at presenting and explaining the investment proposition for solar to clients involving multiple decision makers and detailed evaluation processes. In addition, they have become more adept at dealing with the needs and concerns of electricity networks, and likewise electricity networks have gained greater comfort and understanding in having 100kW+ solar systems operating within their network. Also financing products have been developed with more attractive terms such as lower interest rates, longer repayment periods, and repayments tied to consumption of electricity from the solar system otherwise known as power purchase agreements. These have helped to at least somewhat mitigate tenant-landlord split incentives, and the often myopic approach businesses take to allocating capital to non-core elements of their business (a problem of bounded rationality which is a well understood factor behind sub-optimal levels of investment in energy efficiency).

Feedback from industry interviews indicates that more technically sophisticated and experienced commercial sector solar firms have found themselves facing increasing levels of competition and difficulty maintaining margins as they find more firms capable of selling and installing systems above 100kW in scale. One interviewee colourfully reflected last year, "systems bigger than 100kW used to be confined to technically savvy outfits. But now any old monkey can install up to a 300kW system, with 600kW where they get out of their depth."

The improved capability and greater spread of capability in installing 100kW+ solar systems has meant customers see not just a lower purchase price for solar systems, but also find the purchase decision making process easier and more compelling. In many cases the decision to purchase solar is not an over-riding priority for a business. Given this, the ability of the solar supplier to develop customer confidence about solar can make a decisive difference.

In addition to this improvement in the supply side push, business consumers understanding and appreciation for how solar can help them reduce electricity costs has improved significantly. This is partly a product of the fact that a large proportion of the Australian population now have a solar system and this naturally filters through to understanding within the business community. In addition, a large installed base of several gigawatts of systems has now been operating in Australia for several years.

This provides a large sample set of in-field operating performance data that large business buyers will often need before they can be prepared to sign-off on a purchase. Also the fact these business consumers can now see other businesses, often in the same industry as themselves, installing solar helps to also generate interest in purchasing a system. So in combination there is an enhanced demand-pull for solar in the large rooftop sector.

It is important to recognise that while falling electricity prices will act to dampen uptake, we expect ongoing improvement in how both supply push and demand pull aspects of the large behind the meter solar market. This will act to some degree to counteract the dampening impact of on uptake of deteriorating payback.

We should also note that improving supplier capability and customer understanding and confidence are also increasingly evident and incredibly important in the remote or off-grid power market. For this market the installation of a solar system represents a more complicated proposition because it often requires modifications in how the overall power supply system is managed and controlled to maintain reliability. In this context suppliers need to take into account how the solar system will work as part of an integrated system with the conventional gas and diesel generators that have constraints to how much they can ramp power output up and down. If this isn't achieved the consequences are complete loss of power supply, which in say a mine operation could lead to loss of all production until power is restored which incurs financial losses that can soon exceed any saving a solar system may provide in displaced diesel or gas use.

The role of lags and customer foresight

An important feature to keep in mind in assessing how changes in system cost and electricity prices flow through to solar uptake is that there can be significant lags involved in customers responding to changes in the economics of mid-scale solar PV by installing and then accrediting these systems.

Firstly, large electricity customers tend to procure electricity via 2 to 3 year contracts. This means that it can take several years before customers experience the impact of changes in wholesale market costs. Secondly the purchasing evaluation and supplier selection process for solar, particularly in large organisations that are often the target market for mid-scale solar, can take many months. Lastly the actual scheduling and then ultimate installation can take several months plus there can be further lags until the system is ultimately accredited with the Clean Energy Regulator. There are several examples of accredited mid-scale projects where this whole process took over 12 months, even though installation may have only taken a month or two.

These lags mean that even though power prices surged over 2016 and 2017 while system costs declined, and both have since largely stabilised, the impact in terms of increased solar system accreditations only came through in earnest in 2018. Furthermore, our interviews suggest that systems coming through accreditation now are likely to still be a function of customer responses to elevated power prices over 2017 to 2019.

These lags mean that solar uptake in each year will tend to reflect the economic conditions of a solar system for 12 to 24 months previously. Interestingly interviews suggested that customers evaluating whether to purchase solar in the last few months, are for the most part basing this on current and recent historical electricity prices, rather than seeking to anticipate likely future supply and demand conditions affecting electricity prices. This is especially important given both the National Electricity Market and the Western Australian South-West Interconnected System (SWIS) have only recently begun experiencing noticeably depressed power prices over daytime periods. Unless there are further major coal generator retirements, wholesale electricity prices are going to remain at record low levels over periods when solar system output is high. This myopic approach to evaluating whether to purchase solar, along with lags in customer response, mean that when we evaluate likely customer uptake, it is informed by a customer perception of paybacks based on an assumption that they will evaluate the financials based heavily on electricity prices from the prior year and the current year, rather than a detailed outlook over the life of the solar system.

3. Market conditions and modelling assumptions

Solar system costs anticipated to continue decline steadily

We assume a solar system cost for mid-scale behind the meter, grid connected solar dropped to $1,330 per kilowatt in 2020 (ex-GST). The cost assumed for 2020 is lower than the data provided from the Clean Energy Regulator's extract of registry data and is heavily informed by interviews with industry participants and also data obtained from other sources.

For future costs we assume the installed cost of a large commercial rooftop system will reach around $1000 per kilowatt (2021 dollars) in 2025 in our Base Case scenario. For the High DER Case Scenario they fall more quickly to reach close to $880 per kilowatt (2021 dollars) in 2025.

Ongoing cost reductions in the mid-scale sector are expected to be driven by ongoing declines in module prices, but mainly savings in labour and balance of system equipment costs per watt installed through gains in solar module conversion efficiency. This gain in module conversion efficiency allows for more watts to be installed for a given number of modules, with the number of modules installed being a key driver of labour and balance of system costs. The potential to exploit productivity gains remains significant in the mid-scale solar segment where installations can take several days to be completed and sometimes roof space can be a constraining factor.

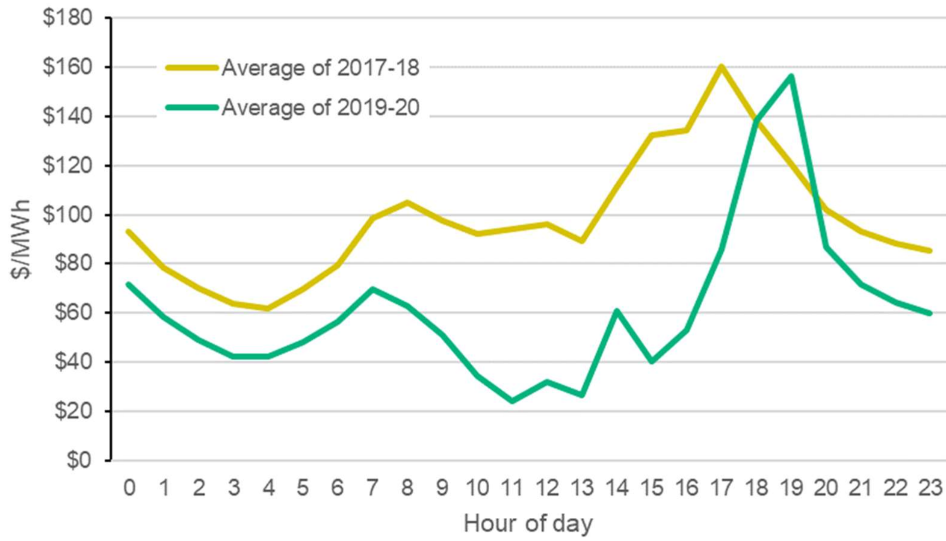
Wholesale electricity market prices are dropping significantly during sunlight hours

The amount of solar generating capacity that has been added to the National Electricity Market and Western Australia's SWIS since 2017 now represents a large proportion of average demand. In addition, further gigawatts of capacity are likely to come over the next two years from both behind the meter rooftop installations and solar farms which are already under construction. We can now see this is having a significantly depressive impact on wholesale power prices during daylight periods relative to what was experienced in the past. This is most obvious in Queensland and South Australia which have the highest penetration of rooftop solar capacity in Australia, but other states should not be far behind given they are also installing significant amounts of solar capacity.

Wholesale power prices in the NEM in recent years have been highly elevated because the price of gas increased considerably, and the closure of Northern and Hazelwood Power Stations provided greater scope for the remaining coal generators to price their output relative to the cost of gas generation. Given the substantial additional supply from solar and wind generators coming on stream, during sunny periods it is likely coal generators will increasingly need to price their output relative to the operating cost of other coal generators, rather than gas plant, in order to be dispatched.

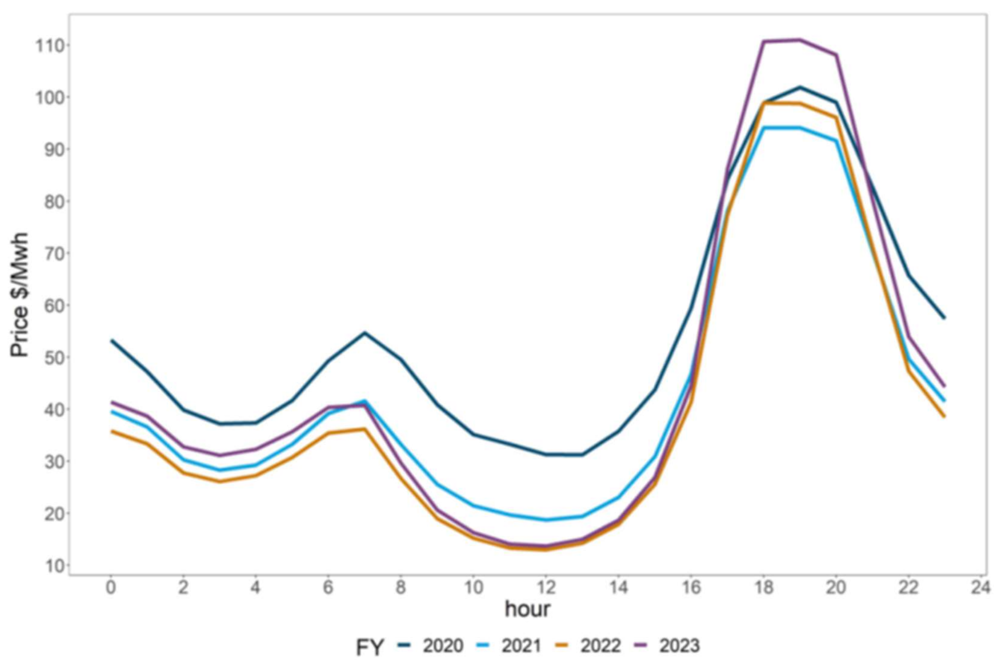
Figure 3-1 illustrates the depressive impact on wholesale prices from solar in SA. It shows the average wholesale power price in SA by hour of the day for 2017-18 (yellow line) and then for the most recent financial year of 2019-20 (green line). While prices are generally down across all hours of the day for 2019-20 (likely due to much lower gas prices), the difference in prices becomes substantially greater in the hours of highest solar output. Over 10am to 1pm when solar generation is likely to be at its greatest prices are stuck below $40/MWh.

Figure 3-1 Average SA wholesale prices by hour – 2017-18 vs 2019-20



Looking forward the AEMC in their 2020 Residential Price Trends report forecasts that this daytime price depression is expected to become even more pronounced and also to spread across all states. Figure 3-2, taken from the AEMC report, illustrates the noticeable depression in prices in the middle of the day for Queensland, and how they expect the daytime price to get lower over time such that it is noticeably lower than even the 2am to 4am period when consumption of electricity is at its lowest. The AEMC projects similar outcomes in other states, albeit with a lag for NSW and Victoria relative to Qld and SA. Our analysis of Western Australian Energy Market balance prices shows a similar daytime depression impact from solar.

Figure 3-2 AEMC forecast of QLD wholesale power prices by hour of day- 2020 to 2023



Source: AEMC (2020) Residential Electricity Price Trends 2020

For evaluating the financial attractiveness of mid-scale behind the meter solar systems we assume that customers are on a demand-based network tariff structure. This involves most of the network-related charges being levied on customers based on a peak in their site's demand for power capacity during a 30 minute interval with a much smaller proportion of the costs based on kilowatt-hours of consumption.

Wholesale energy costs are assumed to be recovered from NEM customers based upon three-part time-of-use structure involving the following:

- Peak period between 3pm to 10pm on weekdays;
- A daylight solar period between 9am to 3pm every day; and
- Off-peak which is all remaining times.

The daylight solar period prices are structured to reflect what we are now seeing in the wholesale markets of SA, Queensland and illustrated in Figure 3-1 and Figure 3-2. Our analysis indicates WA's SWIS already experiences similar patterns and, as the AEMC projects, other NEM states will soon follow in the footsteps of QLD and SA given Victoria and NSW are experiencing rapid growth in solar capacity and Tasmania's prices will be heavily influenced by those in Victoria.

For the NEM states wholesale prices until 2023 are derived from the AEMC's projections detailed in the 2020 Residential Price trends report. Prices remain at similar levels to 2023 until 2025. This involves the solar period wholesale price falling to around 2.5c to 3.3c/kWh by 2023 and remaining around this level to 2025. On top of the analysis prepared by the AEMC which partially incorporates the closure of Liddell Power Station in 2023, these low daytime prices are expected to persist based on electricity market supply-demand analysis prepared by Green Energy Markets and the Institute of Energy Economics and Financial Analysis detailed in the report, *Fast Erosion of Coal Plant Profits in the National Electricity Market*[3]. The persistence of low wholesale prices in spite of the closure of Liddell over 2022 and 2023 is supported by current wholesale electricity forward contract prices which are currently trading at prices for the 2024 year that are lower than 2023 for all regions that are traded (South Australia, Victoria, NSW and Queensland)[4].

NT and WA customers on the other hand are assumed to be charged for energy based on charges that are more smeared across peak and non-peak periods and so see much higher energy charges during the daytime period. WA customers are assumed to pay around 11c/kWh during the daylight period, while NT customers pay 20c/kWh. Smearing is assumed to begin to slowly unwind between 2023 and 2030 such that over the solar daytime period they decline down to the long run marginal cost of a new entrant solar farm by 2030.

LGC prices

LGC prices used for our assessment of paybacks are based on averaged forward prices via reported broker trades over February covering the years of 2021 to 2025 as follows:

- 2021 – $37
- 2022 - $28
- 2023 - $22
- 2024 - $11
- 2025 - $8

For the years 2025 until 2030, where there are no forward trades from which to draw a value, a price of $5 per LGC was assumed.

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[3] See this weblink for the report: http://greenmarkets.com.au/images/uploads/Coal-Plant-Profitability-Is-Eroding_February-2021.pdf

[4] This is based on ASX baseload calendar contracts obtained from https://www.asxenergy.com.au/ on 9 July 2021. Prices per MWh were SA: 2023-$48.64/2024-$48.17. NSW: 2023-$61.77/2024-$59.51. VIC: 2023-$44.15/2024-$43.53. QLD: 2023-$51/2024-$48.78

Victorian Energy Efficiency Certificate price assumptions

Behind the meter solar systems installed in Victoria can be eligible to create Victorian Energy Efficiency Certificates under the Victorian Energy Upgrades Scheme. The number of certificates a solar system is eligible to create are a function of the estimated greenhouse gas emissions that would be avoided by the solar system's generation displacing the need for electricity that would have otherwise been imported from the grid. The Victorian Energy Upgrades Scheme, similar to the Renewable Energy Target, imposes a legal obligation on electricity retailers to achieve emission abatement targets which are satisfied through surrendering Victorian Energy Efficiency Certificates. While solar systems have to date elected to create LGCs, with the price of them expected to decline significantly over the next few years, creating VEECs from solar is expected to become more financially attractive than LGCs. We assume that all solar systems installed in Victoria from 2022 onwards will elect to create VEECs instead of LGCs. While it is theoretically possible for solar systems to create VEECs now, the industry is still in the process of developing the systems and processes to satisfy the scheme's requirements for creation of VEECs from solar systems.

Our analysis assumes a VEEC price of $60 in 2021 based on averages of brokered prices in the last few months and $65 in 2022 based on forward market trades. However, from 2023 onwards $49.42 is assumed which was the estimated cost of certificates within the regulatory impact statement that evaluated the impacts of the ultimately implemented expansion of the Victorian Energy Efficiency Target.

Australian Carbon Credit Unit (ACCU) price assumptions

Solar systems installed behind the meter act to abate carbon emissions by reducing the need for fossil fuel generated electricity from the grid, in a similar fashion as measures that improve electrical energy efficiency or measures which substitute a carbon intensive fuel with a less carbon intensive fuel. Consequently, we assume that behind the meter solar systems would be a valid and eligible means of creating Australian Carbon Credit Units under the Industrial Electricity and Fuel Efficiency Method. Similar to the situation with VEECs, with LGCs expected to decline in value over time and the duration over which they can be created shortens, it is conceivable that it becomes financially more rewarding for new solar systems register to create ACCUs instead of being accredited to create LGCs.

We assume that such systems would only be eligible for ACCU's for generation which was self-consumed and not exported.

At present the framework around the Emission Reduction Fund lacks clear guidance around how many ACCUs it will seek to acquire over a specific defined timeframe, therefore the future price of ACCUs is difficult to predict. We have made a simplifying assumption that the ACCU price begins at 17.50 in 2021 (which is roughly in line with average prices traded in the brokered market over the past year) and ascends by a dollar each year to 2025.

Batteries not yet economically viable but should become viable within next few years.

Batteries have the potential to greatly enhance the value proposition of solar by addressing the following issues:

- Improving the probability of lowering customers' network demand charges by firming-up the solar generation;
- A solar system's economics rapidly deteriorate once they reach a size where they exceed on-site demand due to the lower value available for exported generation or even the inability to export at all (due to network connection controls). A battery can soak up this excess generation for the site to use at a later time when solar output has fallen below the load of the site.

- that solar generation is now increasingly likely to co-incide with periods of low wholesale market prices, yet much higher prices will prevail within just a few hours of solar generation subsiding.

Similar to what we have done in prior years' projection exercises for the CER, we have engaged with several large commercial solar suppliers to learn their experiences with battery costs and their value to energy consumers. Costs have declined but they still tend to be attractive to customers in rare circumstances. Our modelling now suggests that by around 2023 to 2024 the paybacks on battery coupled solar system will become shorter than that of a solar system alone and so they help enhance the expected level of solar uptake. This is around a year or two earlier than what we had modelled last year, which is partly a function of faster cost reductions but also in NSW the effect of their Peak Demand Reduction scheme. NSW's scheme involves obligating electricity retailers to procure peak demand reduction certificates which will be created by the roll-out of technologies and services which act to reduce demand in the electricity demand peak period (late afternoon and early evening when weather is either quite hot or cold). Batteries are expected to be one of the technologies that will be eligible to create these peak demand reduction certificates.

4. Payback periods and modelling approach - behind the meter systems

As noted earlier, the lack of a suitably large and representative sample set of solar system installations, stretching back over several years, prevents the development of a robust quantitative evaluation of how solar system uptake is likely to change in response to changes in the financial attractiveness of solar systems. Nonetheless changes in payback periods provide a useful benchmark or guidepost to inform how future mid-scale solar uptake might unfold.

We have attempted to evaluate how uptake of behind the meter solar is likely to change by assessing payback periods on solar systems in 2021 to 2025 relative to a baseline of the 2019 and 2020 years. Given the noticeable lags affecting the mid-scale solar market we believe 2019 and 2020 installation levels are a reasonable reflection of the likely sustained customer solar uptake in response to the large electricity price and system cost changes that unfolded over 2016 to 2018.

Capacity of solar systems accredited in 2019 and 2020 by state are used as our reference or benchmark for evaluating how changes in payback relative to these years will change uptake of LGC registered behind the meter solar capacity.

We expect that paybacks over the next few years will be longer than they were in 2019-2020 for most states across most of the outlook period. To provide a lower bound guidepost as to how much capacity accredited could fall as paybacks deteriorate (become longer), we've used 2016 installation levels as a benchmark which we assume were a product of payback periods based on 2015 market prices. While it varies between states and customer-types, payback periods based on 2015 market conditions were roughly twice as long as what they were in 2019 (in Victoria and NSW it was about 2.5 times as long, in Queensland and WA it was closer to 1.5 times longer than 2019 levels). Mid-scale behind the meter solar capacity accredited in 2016 (excluding remote or off-grid power) was 22MW or 15% of the capacity we expect to be accredited in 2019.

With these two reference points we have constructed an uptake curve that estimates how the capacity of behind-the-meter solar installs are assumed to change as paybacks lengthen. Both uptake and paybacks are referenced relative to 2019 and 2020 levels. So, if the payback period in a future year was the same as this time (a value of 1) then the capacity accredited would be the same, or 100%, of what it was in 2019 or 2020. If the payback period is twice as long as what it was in 2019-2020 then uptake is assumed to drop down, although not quite as low as what it was in 2016.

However, on top of the payback evaluation we also overlay an underlying growth factor to account for the fact discussed in section 2 that:

- the solar industry is expected to become more capable and competitive in the sale and installation of solar systems; and
- customers have growing understanding and confidence with solar systems' ability to reduce electricity costs.

This growth factor steadily increases the baseline capacity that will be induced by given payback. In the Base Case scenario the growth factor is set at 10% in 2021 and then increases by 6% per annum. In the High DER Case the growth factor is set at 15% in 2021 and increases by 10% per annum.

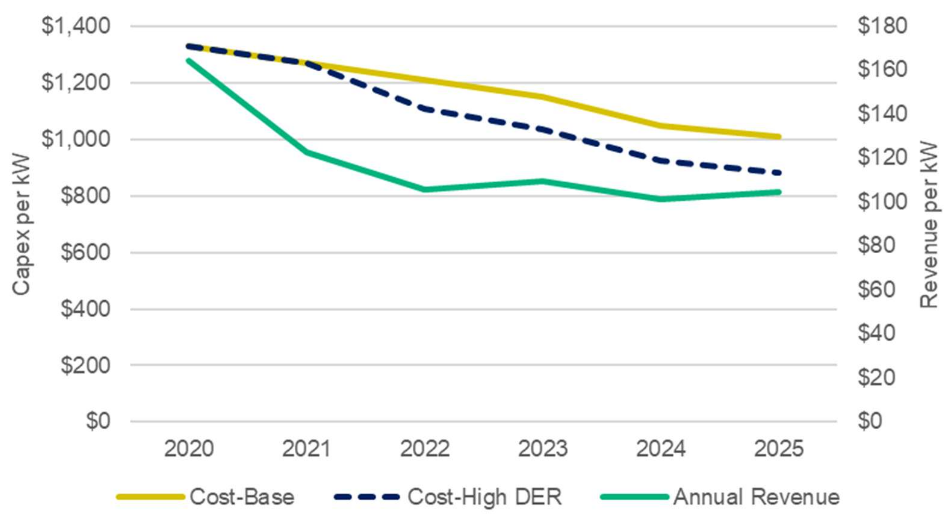
The uptake curve is structured in such a way that once paybacks lengthen beyond 1.5 times 2019 levels, then uptake becomes less sensitive to lengthening payback. This is based on feedback from industry participants and observations of the market that suggest there is an underlying level of demand for solar installations that is heavily driven by non-financial motivations. This source of demand is much less sensitive to payback periods. But as payback shortens from 1.5 times 2019 levels then uptake accelerates, which is consistent with the rapid growth the market experienced from

2016 to 2018. Unfortunately, we do not have any experience to draw from to understand how uptake might respond if paybacks were to noticeably improve/shorten relative to 2019 levels. Our current hypothesis is that uptake would accelerate noticeably as payback moved towards a halving from 2019 levels. This is because at such a point solar would provide such a rapid payback that most businesses would find it attractive to install. However as noted earlier, given the lack of historical experience and the small sample of systems installed to date our estimates of uptake responsiveness are highly uncertain.

Payback periods expected to initially lengthen due to drops in daytime wholesale market prices but then shorten as system costs decline

In the figure below we have detailed how capital cost and revenue per kilowatt of solar capacity unfold over the projection period. Capital cost is detailed for both the Base Case (yellow line) and the High DER Case (dashed blue line).

Figure 4-1 Capital cost and revenue per kilowatt for NSW

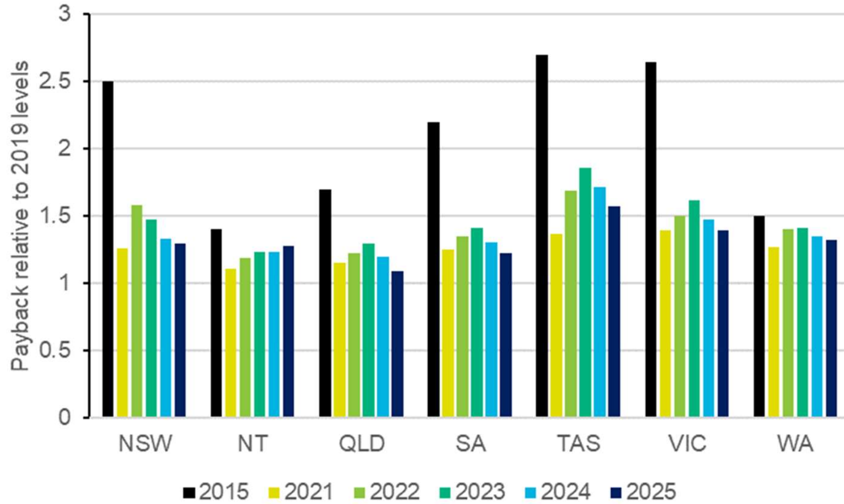


As shown in the green line, revenue (or electricity costs saved) for a solar system is expected to fall rapidly from $170 per annum per kilowatt to just above $100 per kilowatt. Similar patterns occur for the other states. While capital cost also declines it is outpaced by the revenue falls and so paybacks deteriorate.

Figure 4-2 details how estimated customer-perceived payback periods in 2020 to 2025 compare relative to what they were in 2019 based on our modelling assumptions. Note that the scale is not the payback period in years but rather the length of the payback relative to or divided by what it was in 2019. So if the value is exactly 1 it means the payback period has remained the same as it was in 2019 in that state and that customer usage/tariff profile. If the value is 2 then it means the payback period is twice as long as what it was in 2019. As explained earlier to provide a reference point of possible lower-bound uptake we've also analysed likely paybacks under 2015 market conditions relative to 2019 which are also illustrated in Figure 4-2.

Note that these paybacks below are not the actual payback but rather the payback as we expect a customer will perceive it based on the myopic purchasing decisions explained in section 2. This means they evaluate payback based on prices prevailing only in the current year and the prior year rather than a forecast of future power prices over the life of the solar system.

Figure 4-2 Changes in payback period by state and site type relative to 2019 level
2019 payback period assigned value of 1



For the NEM-based states payback periods noticeably deteriorate (become longer) in 2021 relative to 2019 levels due to our assumption that the cost of a kWh of electricity consumed during the daytime solar tariff period drops significantly as do feed-in tariff. Another important factor increasing the length of payback is the assumed fall in the LGC price and the declining time period over which LGCs can be created. Paybacks then tend to steadily improve after 2023 for most states which is largely a function of assumed declines in system costs and the impact of lower cost batteries.

5. Uptake projections

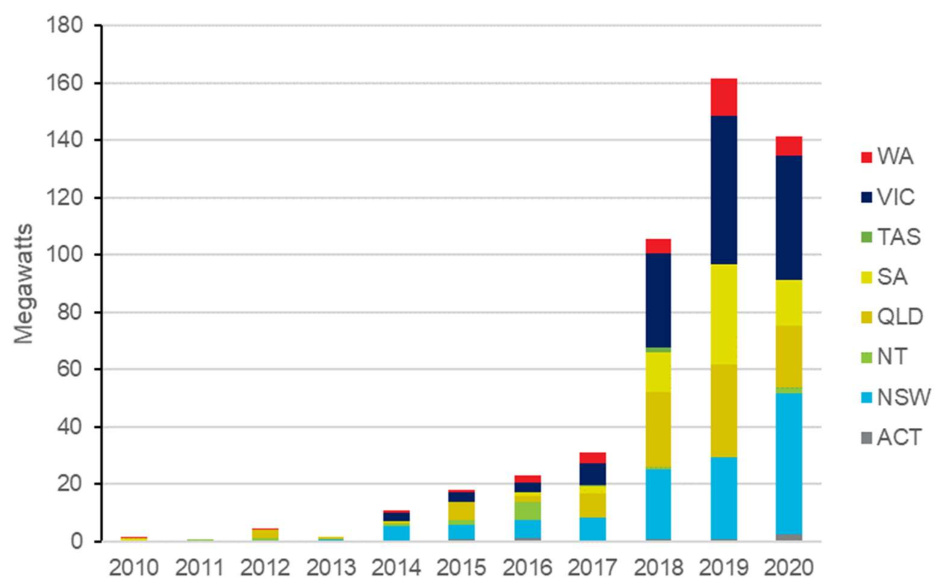
Uptake in megawatts of capacity have been developed for mid-scale solar according to three separate segments which each involve a different set of analysis to estimate uptake:

1. Systems installed on electricity consumers' premises in a behind the meter configuration (where the generation can be self-consumed to offset the need to purchase power from the grid at the retail-delivered price of electricity)
2. Systems installed as power plants in front of the meter which are dependent on revenue tied to the value of the wholesale electricity market; and
3. Systems installed in remote or off-grid power systems where their primary benefit is to reduce gas and diesel fuel use to supply power.

Behind the meter solar systems

Figure 5-1 details the history of megawatts installed in behind the meter applications that were registered to create LGCs.

Figure 5-1 Capacity of behind-the-meter systems by year of accreditation



The projected future capacity of behind the meter systems is estimated based predominantly on changes in payback periods relative to 2019 levels as explained in section 4 of this report with adjustment for an industry and customer capability growth factor. However, we then apply a second pass to the projected numbers to account for significant solar roll-out initiatives that have been publicly disclosed (e.g. SA Water Corporation) and larger systems that we are aware of that are in the process of being constructed or tendered.

Megawatts expected to be installed behind the meter in the base case are detailed in Table 5-1 below.

Table 5-1 Base Case projected megawatts registered – Behind the meter

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	38	45	42	50	52
NT	16.8	1.0	0.8	0.9	0.9
QLD	30	24	26	33	39
SA	143	14	15	19	23
TAS	1.2	0.3	0.3	0.3	0.4
VIC	50	21	22	30	38
WA	15	7	37	9	10
TOTAL	**293**	**113**	**143**	**143**	**163**

Table 5-2 provides the results for the alternative High DER Case scenario.

Table 5-2 High DER Case projected megawatts registered – Behind the meter

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	46	54	63	82	100
NT	17.3	1.2	1.3	1.4	1.3
QLD	45	36	35	47	65
SA	148	21	21	28	34
TAS	1.9	0.5	0.4	0.5	0.8
VIC	60	36	31	49	64
WA	18	11	41	15	16
TOTAL	**336**	**159**	**193**	**223**	**281**

A number of adjustments have been made to these numbers to reflect information about specific organisations' solar initiatives.

The most significant is SA Water Corporation's Project Zero initiative to roll-out 154 megawatts of solar across a large number of its sites which is predominantly made up of systems above 100kW in size. We expect almost of all the planned systems will be accredited in 2021, which is the reason why South Australia's accredited capacity blows out to such a large amount in that year before then collapsing to a much lower amount in 2022.

WA jumps up suddenly in 2023 due to an assumption that the Homestead Mine Site Solar Farm or Kalgoorlie Power Hub proceeds to construction and is accredited at this point.

NSW's numbers are also adjusted upwards across 2021 to 2024 to take into account a boost in installation levels as a result of the NSW Government's initiative to install 18MW of solar across government sites by the end of 2021 and 40MW by 2024.

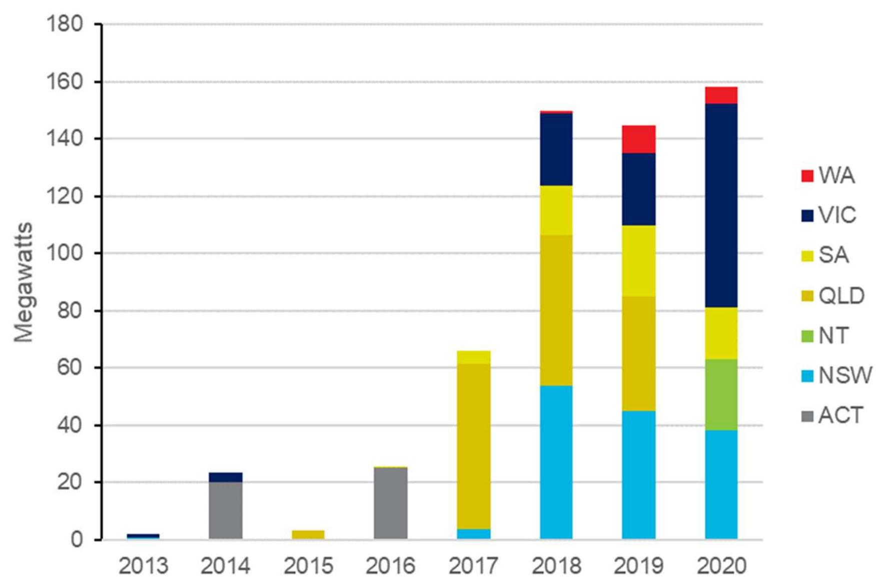
Lastly NT's anomalously higher capacity installed in 2021 relative to subsequent years (and prior years) is a function of 2 large solar projects rolled across NT's military bases which we expect to be accredited this year.

In front of the meter power plants

In front of the meter power plants are solely dependent on the wholesale market for electricity market revenue and tend to be much larger in scale while smaller in aggregate number. Consequently, we have used a bottom-up approach to estimating their future uptake, solely dependent on feedback from industry participants.

Since solar became an economically competitive option for deployment in front of the meter, developers have favoured quite large plants, typically 50MW or larger in scale. This has been partly a function of lower construction costs, but the major reasons were financier preferences for larger transaction sizes to minimise due diligence effort, and maximising returns for developer effort. Figure 5-2 details annual capacity installations for power stations below 30MW back to 2013.

Figure 5-2 Capacity of sub-30MW power stations by year of accreditation



So far this segment has been a relatively minor portion of overall solar farm power station solar capacity additions (but is a significant part of the mid-scale solar market). Power stations smaller than 5MW have been particularly uncommon and most have been developed by a single company – Yates Electrical Services. However, due to the increasing difficulty and cost involved in obtaining grid connection for solar power plants 30MW in scale or greater, several developers switched their attention towards smaller-scale plant, particularly those 5MW or smaller in size which are not subject to a range of system management and grid connection obligations.

Our evaluation of the economics of these plants - based on an expectation of large falls in wholesale power prices during daylight hours - suggests they are not financially viable, or at least would rationally be delayed until wholesale market prices reflate or batteries drop considerably in cost. Therefore, one should logically expect installation levels to fall to zero.

However, in the base case scenario we expect a small number of projects each of 5MW in scale to proceed in the next few years. These are a function of community-based ownership projects or supported by offtake agreements with corporate electricity customers that are willing to sign long-term offtake agreements for these projects at prices noticeably above wholesale market rates in order to provide a tangible demonstration of their contribution towards carbon emission reductions.

Table 5-3 details the amount of megawatts that feedback from developers and solar equipment suppliers suggests is reasonably likely in the sub-30 megawatt range.

Feedback suggests that these plants are unlikely to exceed 5MW (AC rated capacity). It is important to note that there is large room for error in these estimates. This is because projects can come in sizable lots of 5 MW per project, so it doesn't take much of a change in the number of projects proceeding for there to be a large change in the megawatts of capacity accredited. Also, there may be developers that are well progressed with projects that we are unaware of because projects of this scale do not need to pass through state government level approval processes, and can escape media attention. On the downside, there are plenty of hurdles that might stall or halt projects that industry participants fail to anticipate and mean ultimate accreditations fall short of the estimates below.

Table 5-3 Base Case projected megawatts registered – Power stations (AC-rated)

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	89	10	5	0	10
NT	30	0	0	0	0
QLD	0	0	0	0	0
SA	46	35	0	0	5
TAS	0	0	0	0	5
VIC	10	5	5	0	10
WA	0	0	0	0	0
TOTAL	**174**	**50**	**10**	**0**	**30**

The capacity levels in 2021 are largely a function of projects where the investment decision was made a year or more ago and are a product of investors that we believe failed to appreciate the impact of large amounts of rooftop solar capacity on the wholesale electricity market. However, the impact has since become far better understood given the actual outcomes in wholesale markets over the past 12 months. Consequently we expect a collapse in power station registrations after this year.

In the High DER Case we still expect a dramatic drop in power station projects, but levels remain noticeably higher. These higher levels of installations are conceivable in the event that a coal closure (beyond Liddell) date came forward by several years, or potentially as a result of support from state government support programs.

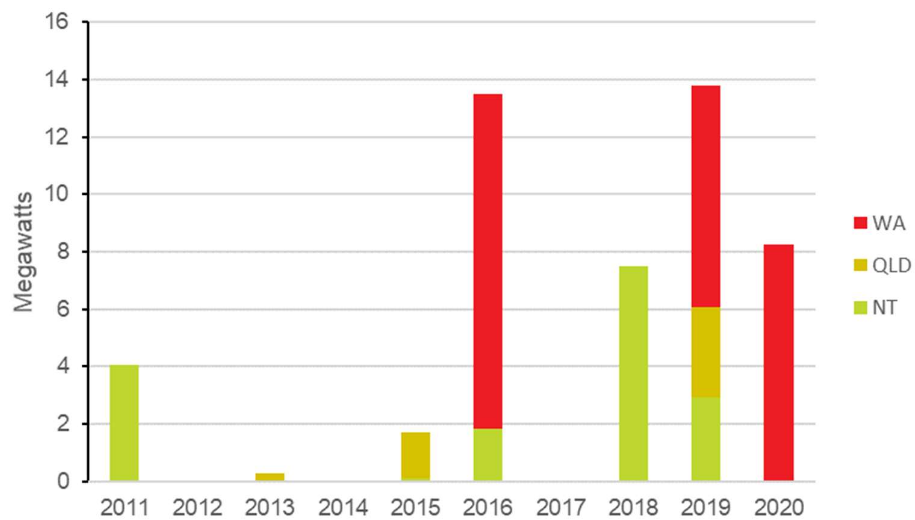
Table 5-4 High DER Case projected megawatts registered – Power stations (AC-rated)

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	95	30	5	15	50
NT	30	0	5	10	10
QLD	0	0	0	10	10
SA	50	45	0	10	10
TAS	0	0	0	5	10
VIC	15	15	5	10	30
WA	0	0	30	5	10
TOTAL	**190**	**90**	**45**	**65**	**130**

Remote/Off-grid power systems

While the economics of solar displacing diesel in remote power applications have appeared to be attractive for many years, to date the capacity of mid-scale solar systems accredited for LGCs in remote power applications has been modest.

Figure 5-3 Capacity of remote/off-grid solar systems by year of accreditation



However, as noted in our report last year and which has been reinforced by further remote-power project announcements since, solar has reached a critical inflection point where its economics and demonstrated technical performance suggest installations could rise significantly relative to the past.

However, it is critical to note that viability is conditional on the customer for the power being able to make a 10 year commitment to purchase the power in order to justify the significant upfront investment involved in deploying solar. For many mine sites a ten-year commitment is difficult because of either volatile prices for their mined product, or because the economically recoverable resource may be exhausted within that timeframe. Also, some sites may have contracts in place with several years until expiry that potentially limit the flexibility or incentive for solar to be deployed. This means that even though solar has been economically attractive, its speed of adoption is constrained.

Last year we scaled-back our projections of installations in the remote/off-grid market due to a significant drop in the oil price as a result of the COVID 19 induced downturn in oil demand. However, oil prices have since substantially recovered and in addition resource commodity prices have also been buoyant supporting new mining activity. Furthermore it also appears that miners are facing pressure from large institutional investors to reduce their carbon emissions intensity. This, in conjunction with new mining project announcements has led us to lift the amount of capacity we are projecting to the installed in the off-grid/remote power market.

Table 5-5 details our estimates of megawatts by accreditation year for the Base Case. These are partially informed by announced system roll-outs by Horizon Power, BHP, EDL, Roy Hill Mine and Pacific Energy. Outside of these known initiatives our estimates of future capacity are highly speculative given they are a function not just of solar system economics but also future mining activity. Given the uncertainties afflicting this sector it was not possible to break-this down to state level estimates, although we'd expect the bulk of capacity to be installed in WA, followed by NT and QLD.

Table 5-5 Base Case projected off-grid/remote system megawatts registered nationally

2021	2022	2023	2024	2025
14.5	32	15	30	30

Table 5-6 provides higher estimates of installations which are informed by an assessment of the total size of the remote power market in Australia and views from some industry participants about what was considered an optimistic outcome for the level of solar installations.

Table 5-6 High DER Case projected off-grid/remote system megawatts registered nationally

2021	2022	2023	2024	2025
15	40	30	50	50

6. LGC Creation

The tables below provide estimates of projected annual LGC creation for the plant accredited in each year of the projection by each market category. These are not projections of LGC creation in the year indicated but rather the ongoing annual LGCs the capacity accredited in each year indicated can be expected to produce over a full year of operation.

Behind the meter

Table 6-1 details estimated ongoing annual LGC creation from solar systems installed in a behind the meter configuration for the Base Case, while Table 6-2 provides LGC estimates under the High DER case. Please note that we anticipate that new behind the meter systems are likely to elect to not register to create LGCs from 2024 onwards and instead opt to register to create ACCUs across all states except Victoria. New Victorian systems would instead be better off from 2022 onwards registering to create VEECs instead of LGCs.

Table 6-1 Annual ongoing LGCs by year of plants' accreditation - Base Case

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	49,932	59,127	55,238	ACCUs	ACCUs
NT	24,948	1,478	1,263	ACCUs	ACCUs
QLD	39,420	31,906	33,556	ACCUs	ACCUs
SA	187,785	18,824	19,798	ACCUs	ACCUs
TAS	1,419	329	346	ACCUs	ACCUs
VIC	59,130	VEECs	VEECs	VEECs	VEECs
WA	19,815	9,258	50,471	ACCUs	ACCUs
TOTAL	**382,449**	**120,922**	**160,671**	**0**	**0**

Note this is intended as an approximate average of annual LGC creation, panel degradation means in reality output and therefore LGCs will decline slowly over time as systems age.

Table 6-2 Annual ongoing LGCs by year of plants' accreditation - High DER Case

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	59,805	70,375	83,033	ACCUs	ACCUs
NT	25,789	1,792	1,935	ACCUs	ACCUs
QLD	59,130	47,605	45,701	ACCUs	ACCUs
SA	194,472	28,087	26,963	ACCUs	ACCUs
TAS	2,201	556	492	ACCUs	ACCUs
VIC	70,956	VEECs	VEECs	VEECs	VEECs
WA	24,440	14,410	56,297	ACCUs	ACCUs
TOTAL	**436,794**	**162,825**	**214,422**	**0**	**0**

In front of the meter power stations

In front of the meter power stations are understood to be unable to create either ACCUs or VEECs based on the existing available methodologies for certificate creation and so new systems continue to register to create LGCs. Table 6-3 details expected annual average LGC creation from capacity installed under the Base Case while Table 6-4 provides this for capacity projected under the High DER case.

Table 6-3 Annual ongoing LGCs by year of plants' accreditation – Base Case

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	186,903	21,024	10,512	0	21,024
NT	65,700	0	0	0	0
QLD	0	0	0	0	0
SA	95,728	72,722	0	0	10,512
TAS	0	0	0	0	9,198
VIC	19,079	9,636	9,636	0	19,272
WA	0	0	0	0	0
TOTAL	**367,410**	**103,382**	**20,148**	**0**	**60,006**

Note this is intended as an approximate average of annual LGC creation, panel degradation means in reality output and therefore LGCs will decline slowly over time as systems age.

Table 6-4 Annual ongoing LGCs by year of plants' accreditation – High DER Case

State/Territory	2021	2022	2023	2024	2025
ACT&NSW	199,728	63,072	10,512	31,536	105,120
NT	65,700	0	10,950	21,900	21,900
QLD	0	0	0	21,024	21,024
SA	105,120	94,608	0	21,024	21,024
TAS	0	0	0	9,198	18,396
VIC	28,908	28,908	9,636	19,272	57,816
WA	0	0	63,009	10,512	21,024
TOTAL	**399,456**	**186,588**	**94,107**	**134,466**	**266,304**

Note this is intended as an approximate average of annual LGC creation, panel degradation means in reality output and therefore LGCs will decline slowly over time as systems age.

Remote/Off-grid power systems

Remote/Off-grid power systems are assumed to be treated as equivalent to power stations and are therefore interpreted to be ineligible to create ACCUs based on the existing available methodologies and so new systems continue to register to create LGCs.

Table 6-5 details expected annual average LGC creation from capacity installed under the Base Case while Table 6-6 provides this for capacity projected under the High DER case.

Table 6-5 Annual ongoing LGCs by year of plants' accreditation – Base Case

2021	2022	2023	2024	2025
21,593	47,654	22,338	44,676	44,676

Note this is intended as an approximate average of annual LGC creation, panel degradation means in reality output and therefore LGCs will decline slowly over time as systems age.

Table 6-6 Annual ongoing LGCs by year of plants' accreditation – High DER Case

2021	2022	2023	2024	2025
22,338	59,568	44,676	74,460	74,460

Note this is intended as an approximate average of annual LGC creation, panel degradation means in reality output and therefore LGCs will decline slowly over time as systems age.