Response to Question F

Prepared for the South Australian Productivity Commission

June 2022

Table of Contents

Table of Figures

1 Introduction

1.1 Terms of reference

We are asked to provide a high-level assessment of whether the current NEM market rules around pricing are likely to lead to an optimal combination of renewable generation and storage in a completely decarbonised grid. Two specific question are asked:

- Will the existing NEM rules support financial sustainability of renewable generators in a decarbonised grid?

- Will the answer to question 1 (i.e. financial sustainability of renewable generation in a decarbonised grid) be different if the optimal grid is a 'significantly overbuilt generation capacity/low storage' grid compared to a grid that has less overbuilding of generation and more storage?

1.2 Approach and layout

We seek first to accurately describe how energy is priced in the NEM in both wholesale markets and also when produced behind-the-meter, which is now the dominant form of electricity production in South Australia. We have then developed data-based analysis of supply, demand and prices in South Australia. This forms of the basis of further analysis in course of our responds to the two questions, as set out in the last two sections.

2 How is electricity priced in the NEM ?

The NEM is a mandatory centrally-settled energy-only market. It is one of only a few mandatory markers; one of a few that are centrally-settled and one of only a few that only compensate for produced electricity i.e. "energy-only". The closest market to the NEM is the New Zealand market, a hydro-dominated energy market (where hydro electricity is priced at the opportunity cost of a fossil-fuel alternative).

The NEM is the only mandatory energy-only market in a thermal system. When it was first implemented the NEM was most similar to the electricity market (known as "the Pool") in England and Wales. The E&W market has since evolved to a non-mandatory balancing spot market, a model common in European electricity markets.

In the NEM, prices are determined in 5-minute auctions and the market is now settled each 5 minutes. In each 5-minute there is a price floor of -$1000/MWh and a price ceiling of $15,500/MWh (from 1 July 2022). There is also a Cumulative Price Threshold (CPT) of $1,359,100 (from 1 July 2022). The CPT is the maximum price that applies for any 7 day contiguous period (it can be otherwise stated as $674/MWh).

The spot markets are regional and they determine the dispatch of all grid-connected generators that are in bigger than 30 MW. Unless directed to the contrary by AEMO, all generators whose most expensive offer is less than or equal to the market-clearing price, will be dispatched. In addition to AEMO directions, some retailers have mandatory "reliability" obligations developed pursuant to the "National Energy Guarantee". These arrangements are not at all clear and have not yet been invoked and so their effect on prices is not known.

Only a very small amount of electricity is actually transacted with customers at the spot price. The vast majority is hedged either through ownership (generators and retailers are owned together and so neither the generator-retailer nor the customer is directly exposed to spot prices in the short term) or through financial market contracts. However spot prices are nonetheless significant – a generator-retailer which is not able to produce electricity more cheaply than the spot price faces the risk that, over time, their customers will defect in due course to cheaper suppliers.[1]

Even retailers that do not own generators can (and do) largely hedge their exposure to spot prices by swapping their exposure to spot prices in favour of fixed prices (swap futures contracts) or by buying insurance (cap contracts).

The most commonly-traded swaps are quarterly “base load” and “peak load” swaps. Base load swaps are specified as 1 MW for every hour and peak load swaps are specified as 1 MW for every hour from 7am to 10pm on weekdays excluding public holidays. The contract market in SA is not nearly as heavily traded as that in NSW or VIC and so retailers (and generators) in SA have limited ability to hedge their exposure for more than one year ahead.

The description of pricing in the NEM to this point only covers supply from grid-connected centrally dispatched (typically bigger than 30 MW) generators. However in South Australia in 2021, 21% of all grid-supplied electricity came from rooftop solar. Counting just the hours from 10am to 4pm, 86% of all electricity came from rooftop solar (the highest in the NEM by far – Queensland the next highest at 32%). This is also by far the highest penetration of rooftop solar in any sophisticated electricity market globally.

Rooftop solar avoids grid purchases and so the opportunity cost of its self-consumption is the variable price of electricity (for households in South Australia, typically around 33 cents per kWh) or for larger commercial/industrial (C&I) customers typically around 15-20 cents per kWh. Exports to the grid are now typically priced at around 3-8 cents per kWh for households and much lower (often zero) for solar exports by C&I producers.[2]

---

[1] If spot prices are consistently low, this will feed into contract prices. The spot market is, by implication, the reference market against which producers competitiveness is assessed, in the long term.

[2] It should be stressed that these estimates are before the recent surge in wholesale prices, which we expect will be reflected in potentially significantly higher retail prices.

The typical South Australian household with 6.6 kW PV panel capacity, 5 kW inverter capacity might expect to self-consume around one-third of the production from their rooftop solar system, with the remainder exported to the system.

As households increasingly install batteries, the opportunity cost of exports to the grid rise to the avoided cost of later purchasing from the grid (i.e. typically at least 30 cents per kWh).

3 Contemporary demand, supply and prices in South Australia

Here we provide charts to describe relevant details on supply, demand and prices in SA by way of context to the question I am asked whose answers follow in the next two sections.

Figure 1 shows the median hourly price, Residual Demand (RD) and rooftop-solar production in South Australia in 2021. Price is shown on the left-hand axis and all other values are shown on the right hand axis. RD is the Operational Demand (the demand on the electrical grid in SA as measured by AEMO) less variable renewable energy (VRE) (i.e. wind and solar) generation fed into the grid.[3]

All data in the charts that follow is obtained from AEMO and the Australian PV Institute and is processed on VEPC's data dashboard: http://vepc-data.appspot.com/

RD is a measure of the amount of the demand that needs to be supplied from resources other than VRE in South Australia. In a fully decarbonised grid it might be expected that the majority of the RD will be supplied by some form of battery or other storage charged from surplus VRE. At present it is mostly supplied in SA by gas-fired generators and to a lesser extent chemical batteries.

The chart shows an almost perfect correlation of price and RD. It also shows that from 9.30am to 5pm, RD was negative. In other words, solar (exported rooftop and grid scale, and to a lesser extent wind) typically produced more electricity than was demanded from the grid from around 9.30am to 5pm. One reason for the surplus supply is the extent to which solar homes and business are able to meet their demand from their own generation, reducing Operational Demand in the NEM, and exporting surplus generation to the NEM.

---

[3] AEMO's measurement of Operational Demand, and therefore the estimated Residual Demand, excludes generation and consumption that occurs behind the meter such as a household or business consuming electricity it generated with its own solar panels.

Figure 1. Median hourly prices, Residual Demand and roof-top solar production in South Australia in 2021

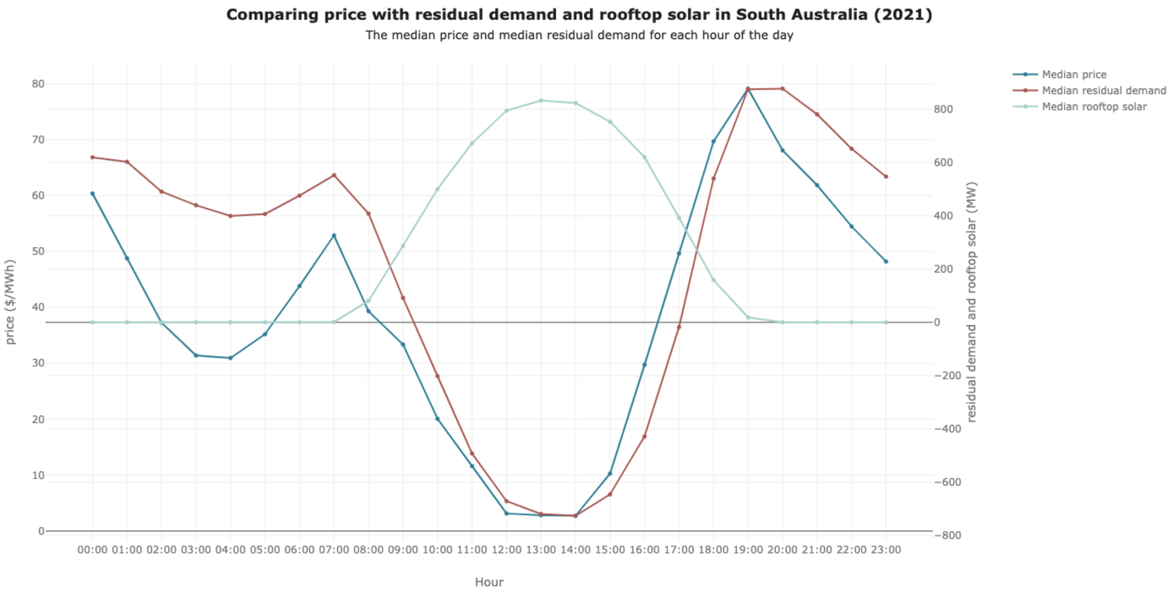


Figure 2shows the median and maximum hourly RD in 2016 and 2021. The chart shows the very big change – when measured at the median – between 2016 and 2021, accounted for largely by the expansion of solar generation which both increases supply into the NEM and reduces Operating Demand at times of peak solar production.

The maximum RD is largely unchanged between 2016 and 2021 from 10am to 6pm. The highest RD (in the early evening) is very similar in 2016 and 2021. These values – around 2,200 MW - are an estimate of the storage that will be required in a full decarbonised grid (assuming no consistent reliance on imports at the time of the evening peak).

When RD is negative, most of this represents energy that is exported to Victoria and energy that is stored in batteries for later use (at the moment just a very small part of the RD).

Figure 2. Median and maximum Residual Demand in 2016 and 2021

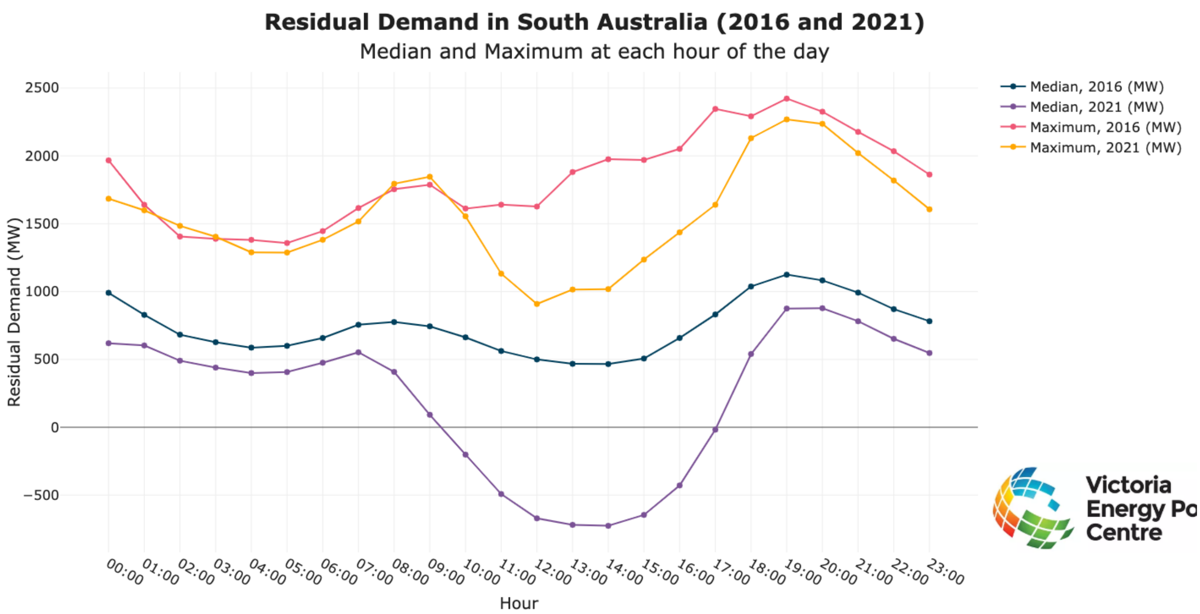
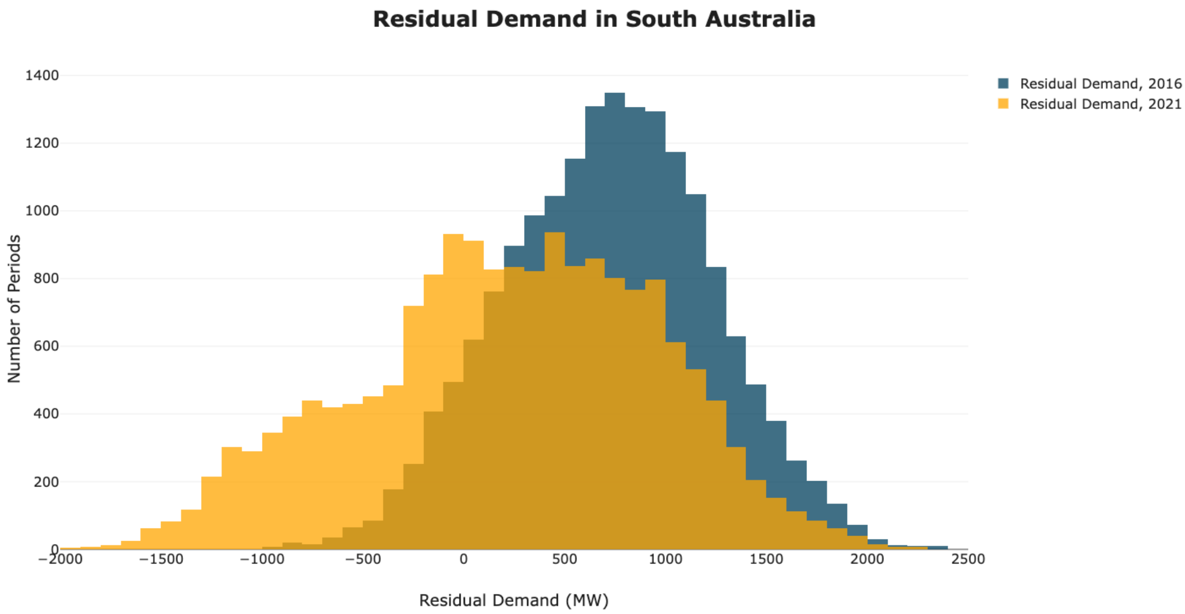


Figure 3 digs deeper to show the change in the RD between 2016 and 2021 through the use of histograms of the hourly RD in 2016 and 2021. Again at the top of the distribution we see similar totals in 2016 and 2021. However not far below that we start to see quite a sharp leftward shift. The median hourly RD is still greater than zero in 2021, but soon will not be, as solar and wind generation expands.

Figure 3. Histograms of Residual Demand in 2016 and 2021[4]



To understand how much dispatchable generation is needed in South Australia after taking account of the effect of transfers over the interconnectors we need to adjust RD to for these transfers. Exports to Victoria will increase the RD in SA (electricity produced in SA is being consumed in Victoria). Conversely, imports from Victoria will reduce the RD in SA (less generation is needed to meet SA demand because supplies are being imported from Victoria). Therefore to take account of the effect of interconnector transfers on RD in SA, we need to add the electricity that is exported and deduct the electricity that is imported. This Adjusted (for interconnector flows) Residual Demand (ARD) can be stated mathematically as follows:

[4] The large negative Residual Demands will be in part exported, in part consumed behind the premises and in part spilled. The measurement of VRE behind the meter (i.e. rooftop production is estimated based on solar capacity and solar insolation information, it is not directly metered). Some part of that rooftop solar is likely to be effectively spilled if aggregate production exceeds aggregate demand plus export. It may also be spilled through inverter control or substation voltage control.

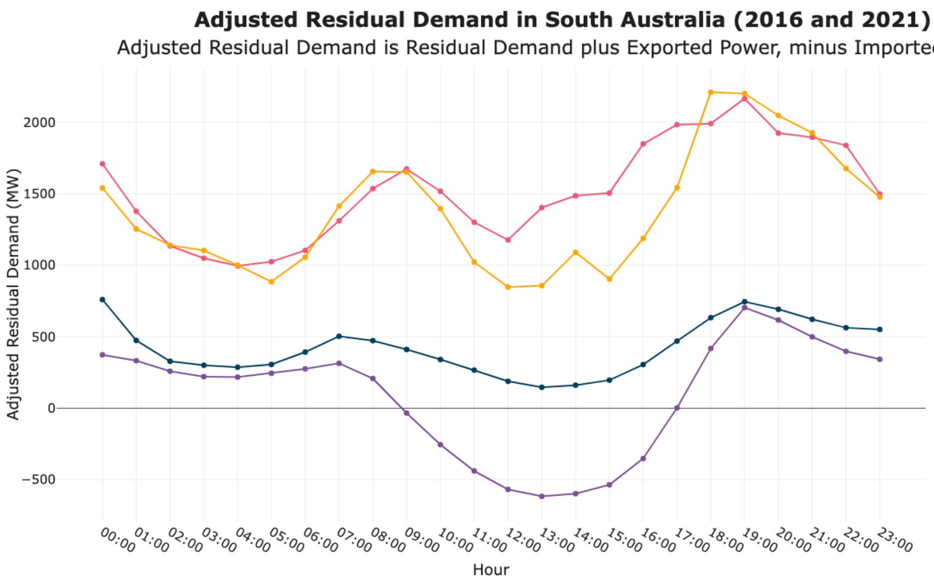
$ARD_i = RD_i + Export_i - Import_i$

Where:

RD_i = Operating $Demand_i$ – VRE_i
$Export_i$ = energy exported to Victoria over the interconnectors in hour i
$Import_i$ = energy imported from Victoria over the interconnectors in hour i
VRE_i = Total variable renewable electricity generation in South Australia in hour i
Operating $Demand_i$ = total grid-supplied electricity to customers in South Australia in hour i

Figure 4 shows the ARD in 2016 and 2021. Comparing the hourly median ARD in Figure 4 with the RD in Figure 2 shows a reasonably significant difference between RD and ARD when measured at the median at time of the evening peak (from around 1,100 MW RD to 750 MW ARD). In other words, after accounting for imported capacity at the time of the SA evening peak, it is clear that about 350 MW (1,100-750) of the dispatchable generation that is *typically* (i.e. median) needed to meet SA demand at the time of the 7pm evening peak, is imported. But it is also notable that the maximum ARD is not much less than the maximum RD at the time of the evening peak (2 211 MW versus 2 268 MW). In other words, imported generation over the interconnector does not play a big role in meeting the peak RD in SA. Or, to put it differently, little reliance can be placed on imported energy in meeting the peak gird demands in SA. Policy makers intent on ensuring reliable supply in SA can be expected to place little reliance on interconnector capacity.

Figure 4. Adjusted Residual Demand in 2016 and 2021



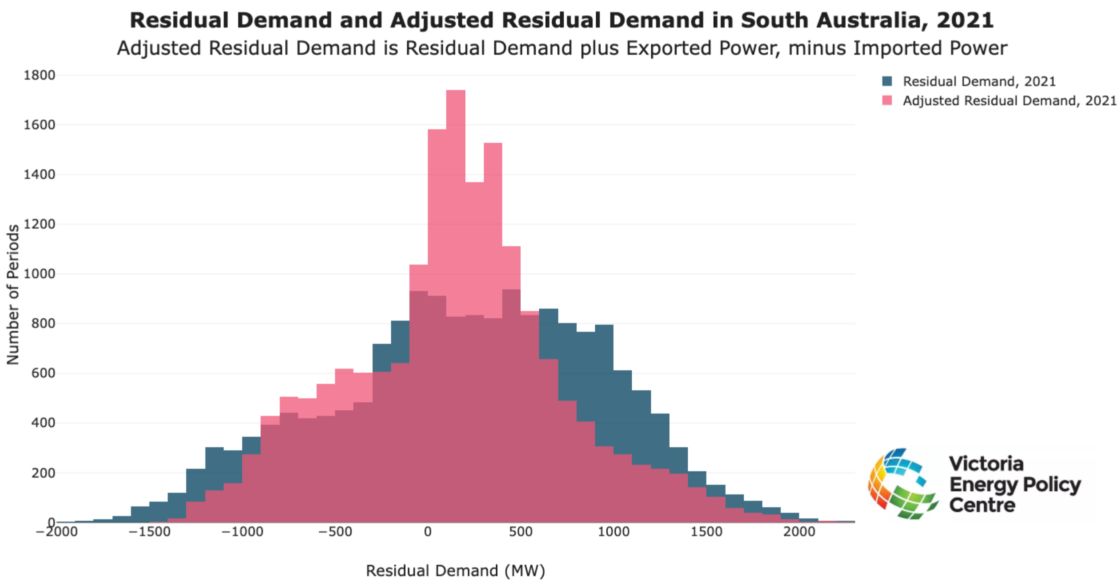
To dig a little deeper into the difference between ARD and RD in SA in 2021,

Figure 5 presents a histogram of hourly values. It shows, consistent with what we see in the maximum hourly values in the line charts in Figure 4, that ARD and RD are quite similar when considering the maximum values of the distribution. In other words, the interconnector does not make a big difference in supply in those moments in SA when dispatchable generation is most needed (i.e. RD is the highest).

The main effect of the inter-regional trade is to shift the frequency of RD in the range from 500 to 1500 MW to the range from 0 to 500 MW.

In summary, it is evident that the interconnectors reduce the utilisation of dispatchable generation in SA but do not meaningfully reduce the total quantity of dispatchable generation needed in SA to ensure reliable supply in SA. Policy makers intent on ensuring reliable supply in SA can be expected to place little reliance on interconnector capacity.

Figure 5. Histograms of Adjusted Residual Demand and Residual Demand in 2021



4 Will the current NEM market rules lead to an optimal combination of renewable generation and storage?

The pursuit of "optimality" is a policy goal in many sectors of the economy, on the basis that the pursuit of optimality reflects the pursuit of the public interest. However what it is that constitutes "optimality" is contentious. For example, it might be argued that economies of scale in electricity generation should lead to the construction of large-scale wind and solar farms, rather than decentralised small scale rooftop supply. Similarly, arguments can be made for large-scale storage, rather than small-scale storage along the same lines. On this premise, optimality is judged by the amount of large production/storage relative to small scale production/storage.

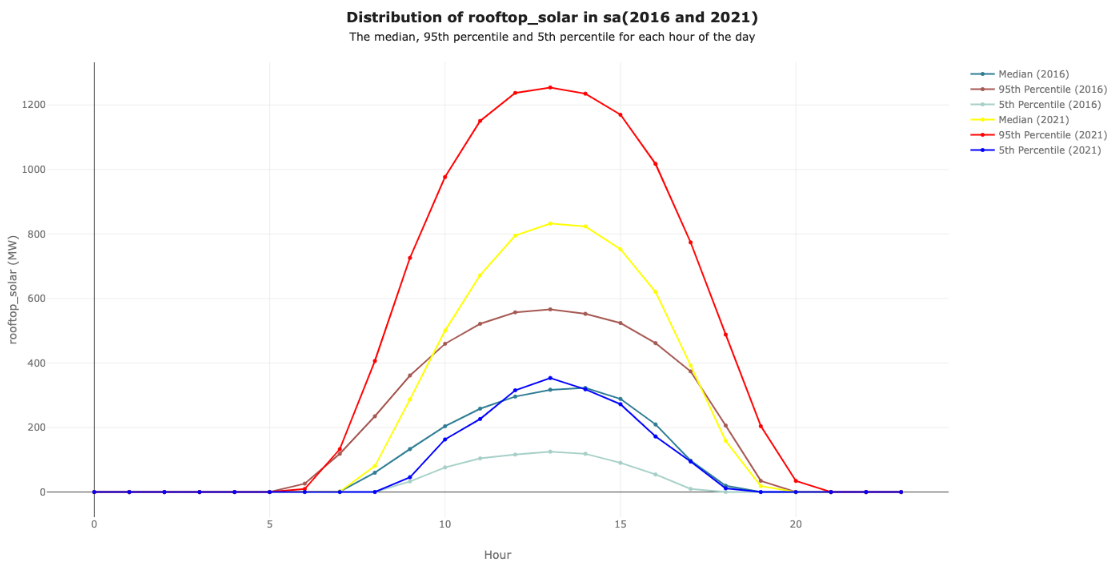
On the other hand, the claim of economies of scale in VRE production are contentious, and economists differ on the appropriate way to think about potentially stranded shared infrastructure (poles and wires mainly but also shared generation and retail infrastructure) that results when consumers increasingly self-supply.

Thus, even if we could know ex-ante how VRE and storage technology might evolve in future, the combination of these that constitutes optimality will remain contentious. Therefore we think the question posed is not capable of an objective answer.

Instead of pursuing an unattainable objective response, in the rest of this section we speculate on how we think the electrical system will develop in South Australia under the current market rules, and excluding the possibility of any additional policy support for either VRE, new fossil fuel generation or any form of storage in SA (i.e. a "purer" market than that which actually obtains currently and almost certainly will obtain also in future).

Figure 6 shows the aggregate hourly rooftop solar generation in South Australia measured at the 5th, 50th and 95th percentiles in 2016 and 2018. It shows that rooftop solar generation is normally distributed around 12pm with the tails terminating at around 6am and 8pm. The charts show that the median production roughly tripled over the period from 2016 to 2021. We noted in the previous section that distributed (behind-the-meter) solar is likely to continue to be financially attractive even if the 70% of its production that is typically exported receives little compensation. For this reason, and taking account of the likelihood of further growth in behind-the-meter battery storage, and the large number of un-electrified roofs we imagine that rooftop solar will continued to expand in SA even if not at the same rate that it has expanded in the past[5].

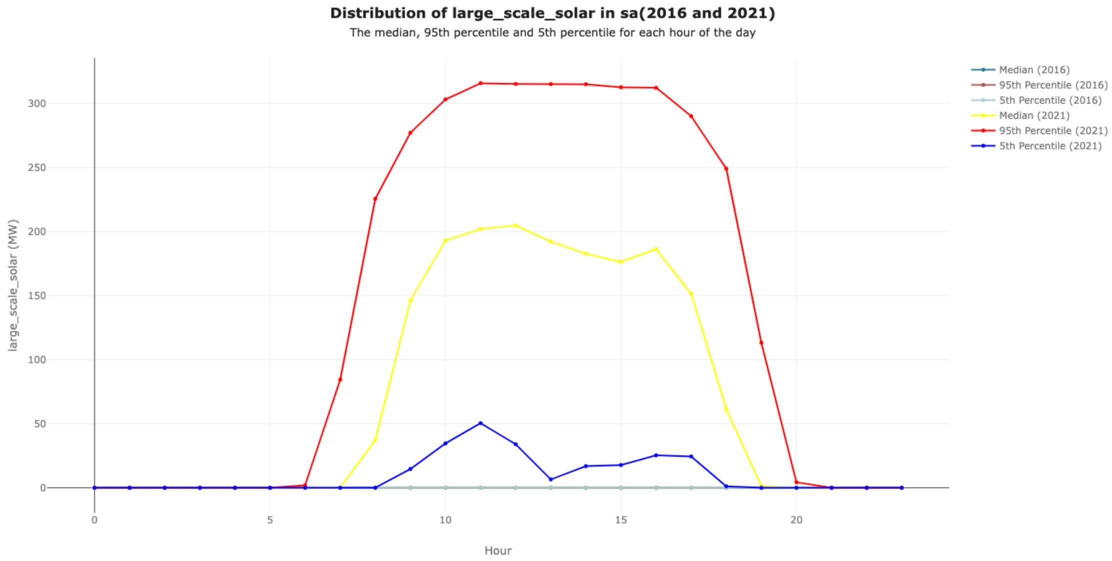
Figure 6. Rooftop solar generation in South Australia in 2016 and 2021



What about large-scale solar electricity generation? Figure 7 below shows the same measures as in Figure 6 but for large scale solar generation in South Australia. The flatter profile of large-scale solar production – likely explained by some combination of dual-axis tracking (i.e. that tracks the sun over the day), oversized DC panel capacity to AC inverter capacity (hence lopped production at peak but higher production outside peak), and voluntary curtailment (when spot prices become more negative than LGC prices) is evident.

[5] Solar on rented or multiple occupancy homes are much less likely.

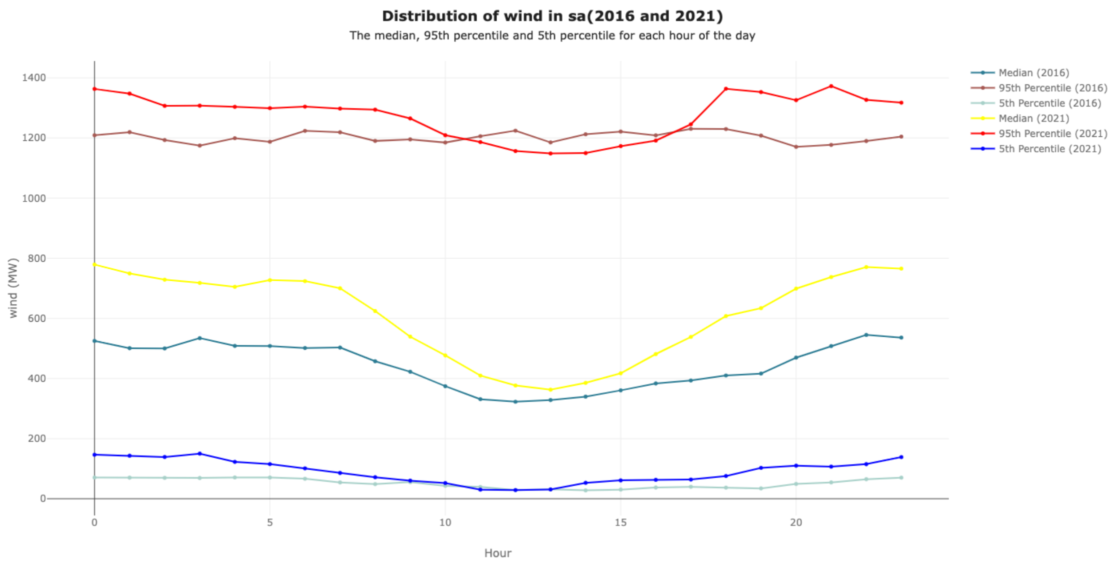
Figure 7. Large scale solar generation in South Australia in 2016 and 2021



What about large-scale wind generation?

Figure 8 shows large scale wind generation in SA, using the same measures as in Figure 7. The chart shows at all measures a reasonable degree of anti-correlation of wind generation relative to solar, when measured across the hours of a day. Wind generation has not grown as much as solar between 2016 and 2021 but the anti-correlation has grown wider. This is likely to reflect curtailment during hours of production when spot prices are more negative that the price of Large Scale Generation certificates.

Figure 8. Large scale solar generation in South Australia in 2016 and 2021



Recalling the hourly price data shown in Figure 1, we expect that the incentive for continued expansion of large scale solar and wind generation in South Australia is likely to be weak if investors expect those prices to be sustained in future. However two factors (leaving aside policy responses) are likely to affect this:

1. The vertically integrated generator-retailer companies that dominate the market in SA are likely to have regard to the average prices that they expect their customers will accept, in deciding their future investment decisions. As such they may be inclined to continue to expand wind and solar investment, with onsite storage, even if spot market prices do not seem favourable.
2. The commissioning of Project Energy Connect is likely to significantly expand export capacity from South Australia to New South Wales, and possibly also to Victoria pending future network developments. This will increase demand for South Australian grid-supplied electricity and thus increase South Australian spot prices from what they otherwise would be.

Bringing these strands together we speculate that continued expansion of distributed and large-scale solar, and large-scale wind generation, is likely in South Australia under the existing NEM rules. We also expect continued market-driven investment in storage, although we think it is unlikely that such market-driven investment will be sufficient to meet the requirement to fully decarbonise electricity supply.

In addition, although the economics of electricity storage are not well known and the sector is characterised by very rapid innovation, it is widely recognised that storage is essential for the transition to renewable electricity. We therefore expect that policy makers will be receptive to supporting the expansion of storage through policy even if there is reasonable confidence that storage investment will arise without policy support.

5 Will renewable generation be financially sustainable (in a decarbonised grid) if there was significantly overbuilt generation/low storage ?

In answering this question, it is useful to clarify what is meant by "significantly overbuilt generation/low storage". The existing SA market may be characterised in this way. In particular, the price pattern (and Residual Demand) shown in Figure 1 may be argued to be consistent with a market characterised by significantly overbuilt generation and also low storage. As we set out earlier, behind-the-meter solar is likely to be financially sustainable at current prices. And, in respect of large-scale wind and solar, for those vertically integrated suppliers, spot prices are of secondary significance in assessing financial sustainability. In other words, the existing overbuilt generation/low storage market is likely to be financially sustainable.

Extending the question, might it be possible that further wind and solar over-building would be financially sustainable? In short, following our response in the previous section, we imagine that further expansion – even assuming current prices in future – is likely considering the expected effect of Project Energy Connect. Noting also from Figure 8 that the 5th and 95th percentile values of wind generation when the sun is not shining in SA are around 100 MW and 1200 MW respectively, it is inconceivable that SA will have reliable electricity supply without significant investment in storage – only an inconceivably high level of overbuilding of wind generation would be able to produce enough electricity to meet night-time demands in SA, with a high level of confidence. Such a level of over-building would result in very large price disparity between moments of high wind/sun and moments of low wind/sun. While wind and (and to a more limited extent) solar generation can substitute for storage, in most cases it is a poor substitute and while the wind and sun can produce a kWh less expensively than a discharged kWh from a storage device, significant overbuilding of wind/solar generation is likely to be very much more expensive than a moderate over-building of wind/solar generation.

My answer to the question is therefore that, leaving to one side the effect of Project Energy Connect (PEC), the focus of future investment in SA is likely to increasingly turn to storage.

PEC is likely to expand the supply of VRE, even without storage in SA. However as VRE expands in NSW and VIC, we are sceptical that the additional VRE in SA that may be built in anticipation of the export market that PEC purports to offer, will prove to be sustainable.