Avoided generation capacity investment report

2025-2030 Regulatory Proposal

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SA Power Networks

Empowering South Australia

Estimating the avoided generation capacity investment costs of alleviating export constraints

A report for SA Power Networks

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Executive summary

As part of its evaluation of its distributed energy resource (DER) integration strategy, SA Power Networks (SAPN) has asked HoustonKemp to estimate the avoided generation capacity investment that can be expected from the anticipated alleviation of small-scale solar export curtailment.

Our approach involved modelling the wholesale National Electricity Market (NEM) under two cases, namely:

- the factual (with) case in which DER export curtailment in South Australia is alleviated with the quantity and timing of alleviation characterised by SAPN's forecast alleviation profile; and
- a counterfactual (without) case in which there is no change to the baseline level of DER export curtailment alleviation in South Australia.

We were provided with three distinct forecast alleviation profiles representing different scenarios for future investment in DER integration by SAPN. These future DER integration investment scenarios are:

- the central scenario, reflecting an investment profile intended to deliver positive market benefits when using the Australian Energy Regulator's (AER's) customer export curtailment value (CECV) estimates;
- an upper-bound scenario reflecting an investment profile that completely alleviates curtailment; and
- a lower-bound scenario reflecting an investment profile that alleviates a lower total volume of curtailment than the central scenario but seeks to maintain a minimum level of service during daylight hours.

The results of the upper- and lower-bound scenarios are presented to reflect the range of outcomes possible under the different alleviation profiles that could be achieved through variations to SAPN's DER integration investment profile.

We find that the anticipated alleviation of export curtailment in the central scenario is sufficient to result in $9.3 million ($2022, PV) of avoided generation capacity investment in the NEM between 2025-26 and 2049-50.

The benefits result from two effects as additional solar exports are made available in South Australia, ie:

- a reduction in the need to invest in utility-scale solar generation capacity in South Australia as additional distributed energy being exported due to alleviation contributes to meeting electricity demand in South Australia and so reduces operational demand; and
- a change in the need to invest in new generation capacity in other NEM regions due to the different level of excess utility-scale solar generation output available for export from South Australia.

The results highlight the direct trade-off obtained through alleviating small-scale solar export curtailment to avoid investment in new utility-scale renewable generation investment that is expected as part of the energy transition occurring in the NEM. Based on SAPN's forecast alleviation profile in the central scenario, we estimated that 31 MW of utility-scale renewable generation investment can be avoided across the modelling horizon in South Australia.

We also consider how the value of avoided generation capacity investment changes based on the size and shape of the anticipated profile of avoided alleviation. Given the differences in the value of avoided generation capacity investment across alleviation profiles that vary in magnitude and shape, we find a non-linear relationship between alleviated curtailment and avoided generation capacity investment costs. The upper-bound scenario forecasts around five times the total volume of alleviated curtailment than the central scenario, with the value of avoided generation capacity investment almost 5.5 times as large. Similarly, the lower-bound scenario has over 10 per cent lower alleviated curtailment yet the value of avoided generation capacity investment decreases by only 7.5 per cent, relative to the central scenario.

In particular the lower-bound scenario, which explicitly targets alleviated curtailment during daylight hours, results in more avoided utility-scale generation capacity investment, relative to total alleviation, than the central scenario. This reflects the need for utility-scale solar generation capacity in the counterfactual to satisfy renewable energy needs under the energy transition. It follows that the quantum of benefits depends on both the size of the alleviated curtailment and also the timing of when this alleviation takes place, ie, consistently during daylight hours across the year.

Finally, we estimate the value of avoided generation capacity investment costs in the central scenario as being equal to $25.94 per megawatt hour of alleviated curtailment in South Australia. This value increases to $27.90 per megawatt hour in the lower-bound scenario and increases to $29.18 per megawatt hour in the upper-bound scenario.

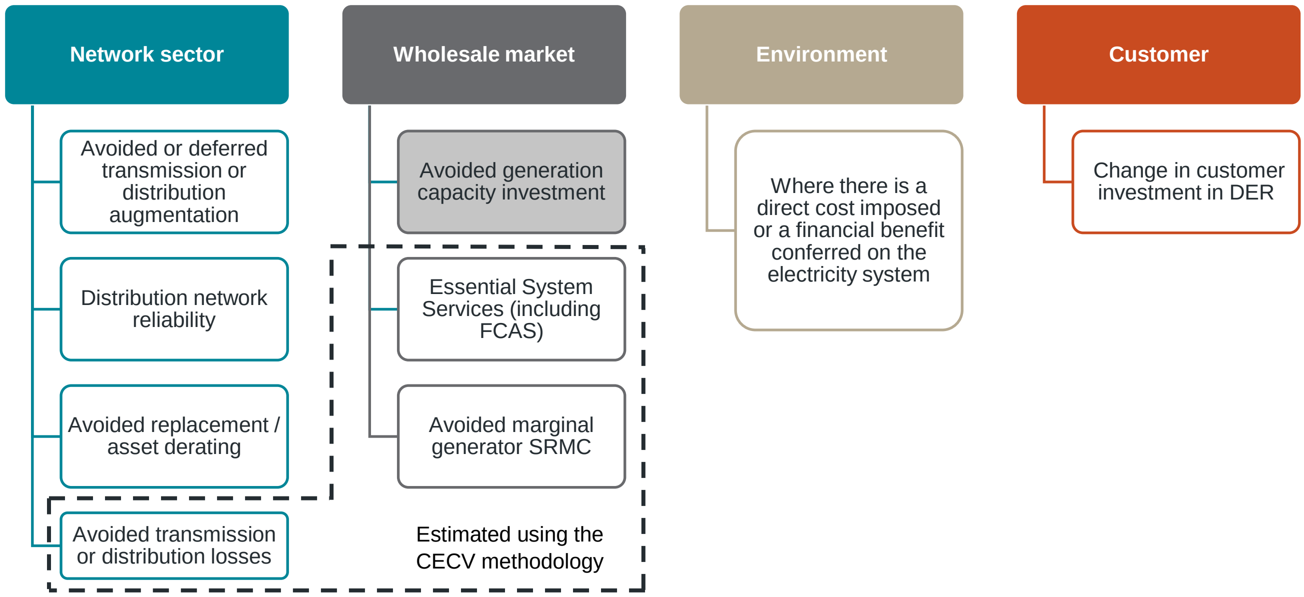
The relatively higher per unit benefits in the alternate scenarios reflects the alignment of these alleviation profiles with the profile of utility-scale solar generation, which allows for a greater quantum of this installed utility-scale capacity to be avoided or deferred. In this sense, the alleviated curtailment in the central scenario, which is aligned with periods of higher network benefits, is less effective at avoiding wholesale renewable generation capacity investment that is being driven by Australia's emissions targets than alleviated curtailment in the alternate scenarios. We find that higher alleviated curtailment during daylight hours is more effective at avoiding renewable generation capacity investment.

Our modelling shows that these avoided generation capacity investments can be considered a material benefit stream, over the range of forecast alleviation we have modelled, and so should be taken into account with the AER's estimated customer export curtailment value, when evaluating SAPN's DER integration strategy.

1. Introduction

SA Power Networks (SAPN) is developing its distributed energy resource (DER) integration strategy, which requires consideration of the expected benefits resulting from increased DER hosting capacity. The Australian Energy Regulator (AER) has set out several relevant DER value streams for the evaluation of network investment to increase DER hosting capacity – figure 1.1.

Figure 1.1: DER value streams provided by AER guidance



Source: AER, Final CECV methodology, Explanatory statement, June 2022, p 8.

To simplify the evaluation process, the regulatory framework requires the AER to estimate the customer export curtailment value (CECV). The AER's methodology for estimating the CECV captures most of the anticipated wholesale market benefits from increased DER hosting capacity (as outlined by the dotted box in figure 1.1). However, the CECV does not include any value that might result from avoided generation capacity investment as a consequence of increased DER hosting capacity. The AER notes that distribution network service providers can separately consider this value as part of evaluating their DER integration strategy.[1]

HoustonKemp has been asked by SAPN to quantify the avoided generation capacity investment value stream associated with its DER integration strategy. Our analysis indicates that the high penetration of rooftop PV in South Australia allows SAPN to alleviate sufficient export curtailment through its integration strategy to change generation capacity investment decisions across the NEM, and so deliver benefits.

The remainder of this report proceeds as follows:

- we discuss the motivation for this engagement and describe the methodology for quantifying these benefits in section 2; and
- we present the results of our analysis in section 3.

[1] AER, *DER integration expenditure guidance note*, June 2022, p 19.

2. Motivation and methodology

Estimating the amount of avoided generation capacity investment that might result from increased alleviation of export curtailment is important to promote efficient investment trade-offs between unlocking access to small-scale renewable generation sources and investing in utility-scale renewable generation. Ultimately, facilitating this efficient investment trade-off is important for promoting least cost delivery of power during the transition to lower emission generation.

A key determinant in this decision-making process is the ability for a distribution network service provider (DNSP) to alleviate a volume of curtailed exports that is sufficient to defer or avoid some investment in utility-scale generation capacity.

In this section, we explain the rationale for including avoided generation capacity investment as a benefit when evaluating a DER integration strategy, before providing a brief explanation of our approach to estimating these benefits.

2.1 Rationale for including avoided generation capacity investment

In this section, we highlight that the CECV should not be the only value stream attributed to the wholesale market benefits of network investment that improves DER hosting capacity. In particular, SAPN's network has sufficient underutilised rooftop PV capacity that can be harnessed to influence generation capacity investment decisions in the NEM.

2.1.1 Excluding avoided generation capacity investment may lead to inefficient outcomes

The AER excluded avoided generation capacity investment costs from the CECV methodology under the premise that the quantum of alleviated export curtailment is likely to be insufficient to yield significant benefits in this value stream.[2] However, if there are avoided generation capacity investment costs then omitting this value stream from the economic assessment of network investment will lead to less than efficient network investment to alleviate DER export curtailment, increasing energy costs for consumers.

In essence, there will be less benefits attributed to this network investment during the evaluation process, resulting in underinvestment in DER integration expenditure and overinvestment in centralised generation capacity expenditure in the wholesale market. These missing benefits will harm end-users of electricity across the NEM, since they will have to pay higher electricity prices in the long run.

The AER allows for DNSPs to evaluate whether the anticipated alleviation in curtailment of distributed generation, as a result of its DER integration strategy, is sufficient to result in avoided generation capacity investment costs. Our analysis shows that network investment by SAPN to alleviate DER curtailment can avoid a non-trivial amount of utility-scale generation capacity investment in South Australia. These avoided costs should therefore be taken into consideration by SAPN in developing its DER integration investment plan. This will ensure that the transition to lower emission generation is efficient, resulting in lower bills for consumers.

[2] AER, *Final CECV methodology*, Explanatory statement, June 2022, p 13.

2.1.2 A suitable alleviation profile is key to quantifying the potential for avoided generation capacity investment costs

The AER's reasons for excluding avoided generation capacity investment as a benefit stream within the CECV include:[3]

- limited network curtailment, even within networks of significant PV penetration; and
- insignificant impact of tripping and curtailment for most energy users, ie, less than one per cent of total generation curtailed.

However, the AER also noted that:[4]

> As potential alleviation across networks grows, it could lead to market benefits associated with avoiding grid-scale investment over time.

It follows that the potential alleviation profile is fundamental to the quantification of potential avoided wholesale generation capacity investment costs.

While currently excluded from the CECV methodology, the AER states that the avoided generation capacity investment value stream may be included in the CECV methodology in the future when more reliable data regarding the timing and magnitude of export curtailment is available.[5]

The AER does not expect all DNSPs to be able to currently alleviate sufficient curtailment of distributed generation to influence the investment decisions in the wholesale market.[6] Specifically, the AER states that:[7]

> It is likely that several years of sustained PV growth in low penetration networks could slowly increase export curtailment and accompanying potential for alleviation of that curtailment.

In light of the AER's expectation that avoided wholesale generation capacity investment will only occur under suitable network-specific conditions, it is important for DNSPs to evaluate whether its forecast alleviation profile is sufficient to avoid investment in wholesale generation capacity. The answer to this question is likely to differ between DNSPs given the specific characteristics of each network, in particular the varying penetration of distributed generation on each network.

Relevantly, South Australia is far more advanced in its adoption of small-scale generation technology than other parts of the NEM.[8] During periods of low demand and high solar output, South Australia now experiences widespread and significant reverse flows across the distribution network. Further, AEMO suggests that South Australia may experience negative operational demand[9] in the 2023-24 financial year.[10]

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[3] AER, *Final CECV methodology*, Explanatory statement, June 2022, p 13.

[4] AER, *Final CECV methodology*, Explanatory statement, June 2022, p 13.

[5] AER, *Final CECV methodology*, June 2022, pp 10-11.

[6] AER, *Final CECV methodology*, Explanatory statement, June 2022, p 13.

[7] AER, *Final CECV methodology*, Explanatory statement, June 2022, p 13.

[8] AEMO, *2022 South Australian Electricity Report*, November 2022, p 18.

[9] Operational demand is defined by the Australian Energy Market Operator (AEMO) as demand in a region that is met by local scheduled generating units, semi-scheduled generating units, and non-scheduled intermittent generating units of aggregate capacity greater than 30MW, and by generation imports to the region and wholesale demand response. See: AEMO, available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/operational-demand-data, accessed 9 December 2022.

[10] AEMO, *2022 South Australian Electricity Report*, November 2022, p 31.

The high level of generation from DER assets in South Australia relative to underlying network demand suggests that there could be potential for alleviated curtailment in the distribution network to avoid wholesale generation capacity investment in the state. Importantly, the AER's guidance does not restrict DNSPs from quantifying the avoided generation capacity investment value stream,[11] with the AER recommending DNSPs to:[12]

> …use electricity market modelling to estimate avoided generation capacity investment costs.

In section 2.2 we explain how we use a wholesale market modelling framework to quantify this potential benefit stream.

2.1.3 SAPN is able to alleviate a substantial volume of exports that would otherwise be curtailed

An incremental change in DER export curtailment in SAPN's network contributes to meeting electricity demand in South Australia. This reduces the level of operational demand, ie, demand seen by the wider network, against which total generated supply must balance. This decreased reliance on supply during times of high alleviation reduces the need to invest in utility-scale generation capacity that would be generating at this time.

Additional DER exports in South Australia may:

- reduce the need for additional utility-scale generation capacity in South Australia, particularly renewable generation to satisfy the net zero target; and
- facilitate increased exports from South Australia to other jurisdictions, with an associated reduction in the required generation capacity investment in these other jurisdictions to satisfy the net zero target.[13]

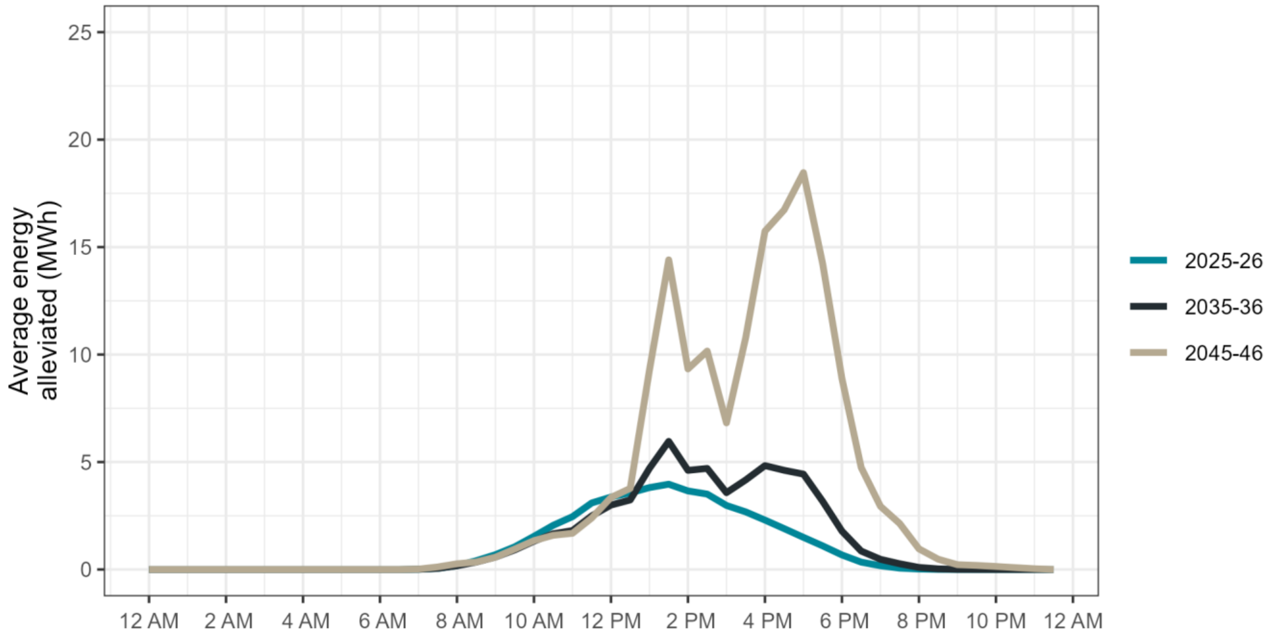
SAPN's proposed DER integration investment plan achieves significant alleviation in both the near-term, ie, over 4 MWh of alleviated curtailment on average each day at its peak in 2025-26, and the long-term, ie, around 18 MWh of alleviated curtailment on average each day at its peak in 2045-46. We present a summary of the daily average alleviation profile for 2025-26, 2035-36 and 2045-46 in figure 2.1, anticipated from its planned DER integration strategy.

[11] AER, *Final CECV methodology*, Explanatory statement, June 2022, p 11.

[12] AER, *DER integration expenditure guidance note*, June 2022, p 20.

[13] We note that in an interconnected system like the NEM, there may be circumstances when other regions require an offsetting increase in installed generation capacity. We therefore analyse the total change in generation capacity investment across all regions.

Figure 2.1: Average alleviated DER generation by time of day – 2025-26, 2035-36 and 2045-46



Source: alleviation profile for the central scenario provided by SAPN.

In developing guidelines for the CECV methodology, Oakley Greenwood (the AER's consultant) expected avoided generation capacity investment to be small due, in part, to the small amount of DER curtailment relative to system generation.[14] In this context, system generation is similar to operational demand, ie, the level of generation required to balance demand across the network.

Our expectation is that in South Australia, the high penetration of DER assets gives rise to a profile of alleviated DER export curtailment that materially impacts the generation requirement of the network.

2.1.4 Sufficient alleviated export curtailment will likely avoid utility scale renewable generation investment needed as part of the energy transition

We note that Oakley Greenwood states that:[15]

> The periods in which additional generation capacity is needed are often after dark where curtailment of most of the DER currently and expected to be in place is unlikely.

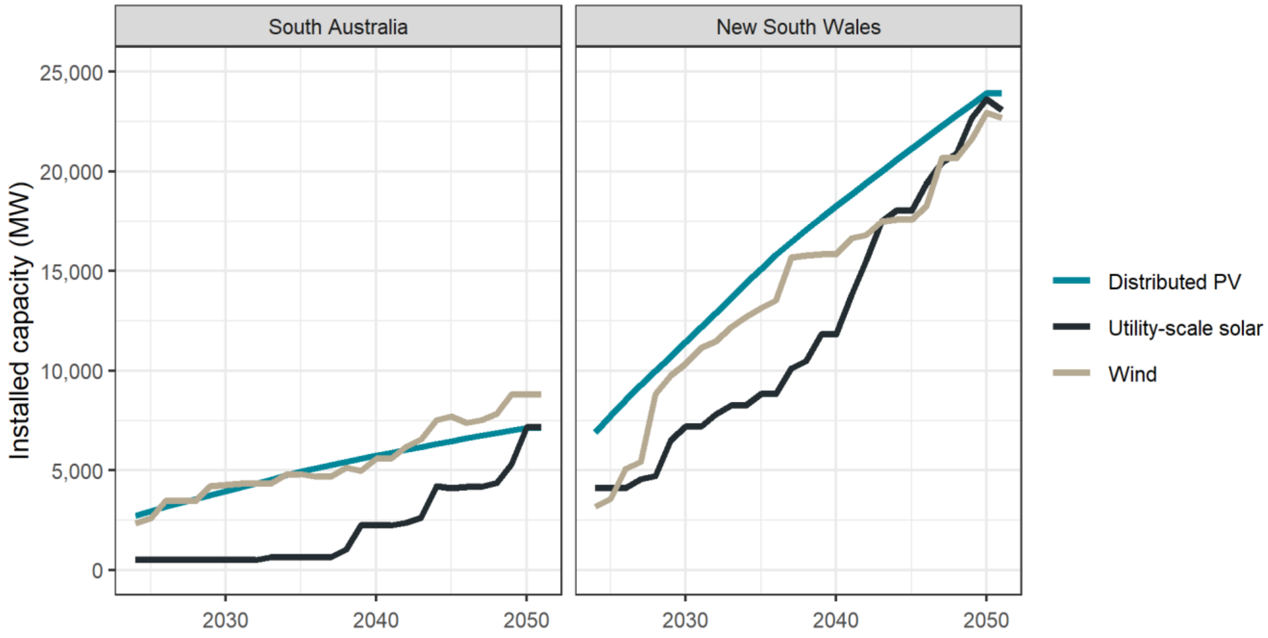
We agree that, while alleviated curtailment can reduce total energy consumed, it is unlikely to impact maximum network demand. For this reason, avoided generation capacity investment is unlikely to come from dispatchable generation that would be used during peak periods.

However, the NEM is undergoing a period of transformative change with regards to the generation mix, with new renewable generation displacing existing thermal generation. Figure 2.2 presents the forecast increase in utility-scale and distributed solar generation capacity, as well as wind generation capacity in both South Australia and New South Wales for the step change scenario in the 2022 Integrated System Plan (ISP) published by the Australian Energy Market Operator (AEMO).

[14] Oakley Greenwood, *CECV Methodology*, Final report, June 2022, p 15.

[15] Oakley Greenwood, *CECV Methodology*, Final report, June 2022, p 15.

Figure 2.2: Forecast generation capacity in South Australia and New South Wales – ISP step change scenario



Source: AEMO, 2022 Integrated system plan, June 2022, Generation outlook, '2022 Final ISP results workbook – Step Change – Updated Inputs' file, 'Capacity by year' series for South Australia and New South Wales.

We see that distributed solar capacity in both South Australia and New South Wales is forecast to grow steadily to 2050, with significant new investment in utility-scale solar and wind generation capacity over this period. Due to the high correlation between the generation output of distributed and utility-scale solar generators, it follows that increased utilisation of existing distributed capacity can remove the need for utility-scale renewable generation capacity.

In addition, the commencement of a new interconnector between South Australia and New South Wales in 2026, ie, Project EnergyConnect, will facilitate additional distributed exports in South Australia to potentially reduce the need for utility-scale investment in New South Wales.

Further, Oakley Greenwood's critique of the proposed inclusion of avoided generation capacity investment benefits is the:[16]

> Failure to consider the fact that wholesale marginal generation cost is likely to be well below average (and not infrequently zero) under the conditions in which rooftop PV export curtailment is most likely to occur.

While it is true that alleviation will likely occur during periods of low, or negative, wholesale electricity prices, this is only relevant for the calculation of avoided marginal generator short run marginal cost (SRMC), which is captured in the CECV methodology. What is relevant for the investment decision of utility-scale generation in this context is whether there is a need for that generator in terms of expected operational demand. In fact, additional distributed generation is likely to drive the wholesale electricity price down as only lower-cost generators are dispatched in this lower grid-sourced demand case. This may place further pressure on the economics of utility-scale generators and may lead to less incentives for these generators to enter or remain in the market.

[16] Oakley Greenwood, *CECV Methodology*, Final report, June 2022, p 71.

2.2 Methodology for quantifying avoided generation capacity investment

Consistent with the AER's guidance,[17] we use HoustonKemp's bespoke wholesale electricity market model of the NEM, 'ElectricBlue', to estimate potential avoided generation capacity investment resulting from the alleviation of export curtailment. A detailed description of this model is presented in section 2.2.1.

As stated by the AER, quantifying this value stream requires a comparison of outcomes 'with' and 'without' the alleviated curtailment.[18] We estimate the quantum of avoided generation capacity investment value by undertaking a 'with/without' analysis. Further details of this modelling process are presented in section 2.2.2.

2.2.1 HoustonKemp's wholesale electricity market model

We use HoustonKemp's proprietary market modelling suite, 'ElectricBlue', to quantify the avoided generation capacity investment costs. The model uses the Gurobi optimisation language and the Python programming language to create a flexible system for simulating outcomes in wholesale electricity markets. The model has been applied in a number of similar contexts, including to support RIT-T assessments.

To quantify the avoided generation capacity investment in response to export curtailment alleviation, 'ElectricBlue' applies optimisation techniques to develop a 'least-cost' plan for the development of the NEM from 2025-26 to 2049-50, ie, a 25 year period. A least-cost plan involves projections of the generation, storage and generation capacity required to meet demand over the modelling horizon at minimum cost, while satisfying policy, technical and system security constraints.

The model simultaneously optimises the short-term dispatch of generation and storage and the long-term investment in new generation, storage and transmission capacity.[19]

The modelling for this project uses our long-term planning model. This model simulates market outcomes over a timeframe in which capacity decisions are relevant, in this case to 2049-50. Similar to AEMO's ISP, the model adopts a 'social planner' framework to estimate the least-cost generation options for meeting demand in each year subject to a range of technical, operation and policy constraints. The model incorporates legislated renewable energy targets and emissions policies, both state and federal, to ensure that the profile of investment complies with these policy objectives.

More specifically, inputs to the long-term planning model include:

- forecasts of energy demand and maximum demand;
- technical parameters for existing and new entrant generators/storage, eg, capacities, heat rates, emissions intensity factors, auxiliaries and losses;
- emissions and/or an emissions limit and state renewable energy targets;
- interconnector limits and losses and any future interconnector upgrades;
- wind and solar traces for existing and new entrant generators;
- fuel prices;
- new entrant capital costs;
- hydro storages and inflows; and
- Renewable Energy Zone (REZ) resource limits, transmission constraints and costs for transmission augmentations.

[17] AER, *DER integration expenditure guidance note*, June 2022, p 20.

[18] AER, *DER integration expenditure guidance note*, June 2022, p 20.

[19] The approach is equivalent to the capacity outlook modelling applied by AEMO in the analysis underpinning its ISP 2022. See: AEMO, *ISP methodology*, August 2021.

To make the model computationally tractable, yet still capture the key relationships between demand, solar PV and wind, the model applies a load block or 'slicing' approach to identify representative daily profiles that cover the range of system conditions. This involves applying a statistical technique known as 'clustering'. This approach ensures that the variability in wind and solar PV and the daily operating profile of battery storage are incorporated into the long-term projection of investments.

Our analysis has been undertaken based on the step change scenario,[20] which is considered the 'most likely' scenario in the ISP.[21] The step change scenario is characterised by:[22]

- rapid consumer-led transformation of the energy sector and coordinated economy-wide action;
- fulfilment of Australia's net zero policy commitments to limit global temperature rise to below 2 degrees;
- consistently fast-paced transition from fossil fuel to renewable energy in the NEM; and
- a step change in global policy commitments, supported by rapidly falling costs of energy production, including consumer devices.

It follows that the avoided generation capacity investment costs are consistent with the projected impact of alleviated curtailment on renewable investment needs to satisfy the step change scenario.

2.2.2 We perform a 'with/without' analysis to quantify the economic benefits

In this context, a 'with/without' analysis compares:

- the factual (with) case in which an amount of DER export curtailment in South Australia is alleviated with the quantity and timing of alleviation characterised by SAPN's forecast alleviation profile; and
- a counterfactual (without) case in which there is no change to the baseline level of DER export curtailment alleviation in South Australia.

Operational demand is a key determinant of the required generation mix in the NEM as it sets the level of supply that is necessary to ensure whole of system reliability, ie, electricity is available for use when end-users want it. By alleviating export curtailment in South Australia, SAPN is able to reduce the amount of electricity that needs to be transported onto its network to supply its customers.

It follows that by varying the level of operational demand in South Australia between the with and without cases, our long-term planning model for the NEM is free to choose two different whole of system generation capacity investment profiles to best suit the demand characteristics of that scenario. This is the key characteristic of the 'with/without' analysis.

The modelling framework and assumptions applied to the 'with/without' analysis are consistent with the step change scenario in AEMO's 2022 ISP. The without case, as the 'status-quo' case, is entirely consistent with the step change scenario in AEMO's 2022 ISP. The with case uses all the same assumptions as the step change scenario in AEMO's 2022 ISP, with the exception of forecast operational demand in South Australia.

[20] We include assumptions regarding Project EnergyConnect and the Victoria to NSW Interconnector West which reflect the updates to these projects since the publication of the most recent inputs and assumptions for the ISP.

[21] AEMO, *2022 Integrated System Plan*, June 2022, p 33.

[22] AEMO, *2022 Integrated System Plan*, June 2022, p 31.

3. Estimates of avoided generation capacity investment costs

This section sets out the results for the avoided generation capacity investment costs achieved from SAPN's forecast alleviation profile. We also present estimates of avoided generation capacity investment costs per unit of alleviated curtailment, ie, $/MWh, to allow for integration with the AER's CECV estimates, which are also measured in $/MWh. This approach effectively spreads the total value evenly over the total alleviation that achieved this benefit.

We focus our results over the period of SAPN's next regulatory control period between the 2025-26 and 2029-30 financial years.

3.1 Total avoided generation capacity investment costs

Our wholesale market modelling of SAPN's forecast alleviation profile in the central scenario results in total incremental generation investment benefits in the NEM of $9.3 million ($2022,[23] PV[24]) between 2025-26 and 2049-50.

The avoided generation investment costs are primarily driven by two dynamics as additional distributed solar exports are made available in South Australia:

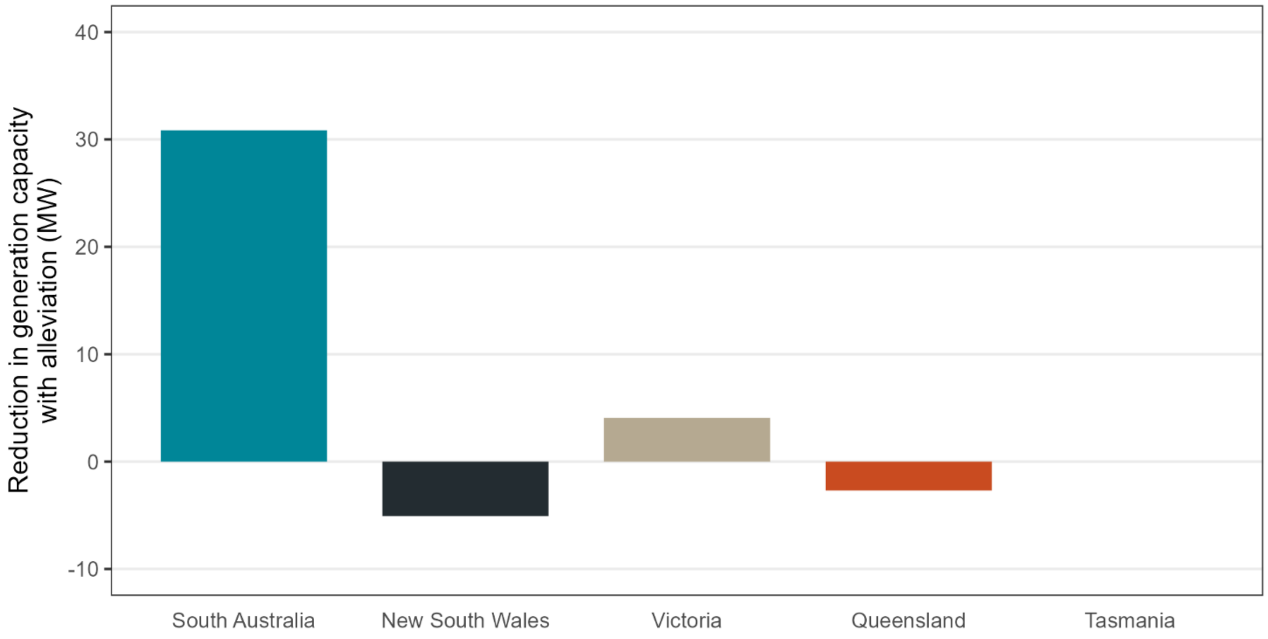
- a reduction in the need to invest in utility-scale solar generation plants in South Australia as additional distributed energy being exported due to alleviation contributes to meeting electricity demand in South Australia and so reduces operational demand; and
- a change in the need to invest in new generation capacity in other NEM regions due to the different level of excess utility-scale solar generation output available for export from South Australia.

The estimated size of the reduction can be observed in figure 3.1, which presents the avoided generation investment capacity across the NEM at the end of the modelling horizon in 2049-50.

[23] The 2022 ISP uses input values in real dollar terms as at 30 June 2021. We update these values in our modelling to real dollar terms as at 30 June 2022 using a 6.1 per cent inflation rate. See: AEMO, *2022 Forecasting Assumptions Workbook*, August 2022, 'Assumptions Summary' worksheet, cell B4; and ABS, 6401.0 Consumer Price Index, Australia, Series A2325847F '*Percentage Change from Corresponding Quarter of Previous Year; All groups CPI; Australia*', June 2022 value.

[24] Consistent with the 2022 ISP, we use a 5.5 per cent discount rate. See: AEMO, *2022 Integrated System Plan*, June 2022, p 91.

Figure 3.1: Avoided wholesale generation capacity with alleviation of DER export – 2049-50



Source: HoustonKemp analysis using the central scenario provided by SAPN.

We note that the forecast alleviation profile results in approximately 31 MW of generation capacity being avoided in South Australia by the end of the 2049-50 financial year. This is a result of approximately 910 GWh of otherwise curtailed DER exports displacing generation from the wholesale market between 2025-26 and 2049-50 financial years.

In an interconnected system such as the NEM, changes in one region have flow-on effects in another. Our modelling shows that the alleviation of previously curtailed DER exports in South Australia also leads to changes in the required generation capacity in both New South Wales and Victoria, which are both directly connected to South Australia, and Queensland.

Our modelling shows that lower installed utility-scale generation capacity in South Australia will require an increase in wholesale generation capacity in New South Wales and Queensland alongside a reduction in wholesale generation capacity in Victoria. This dynamic is primarily driven by the losses that generated electricity incurs within regional networks and across interconnectors.

Alleviated curtailment of generation that occurs on the distribution network can avoid the ‘upstream’ losses that would otherwise arise if this electricity had been generated by utility-scale generators. In general, alleviated curtailment can more efficiently meet demand located on the South Australian distribution network than generation from the wholesale market.

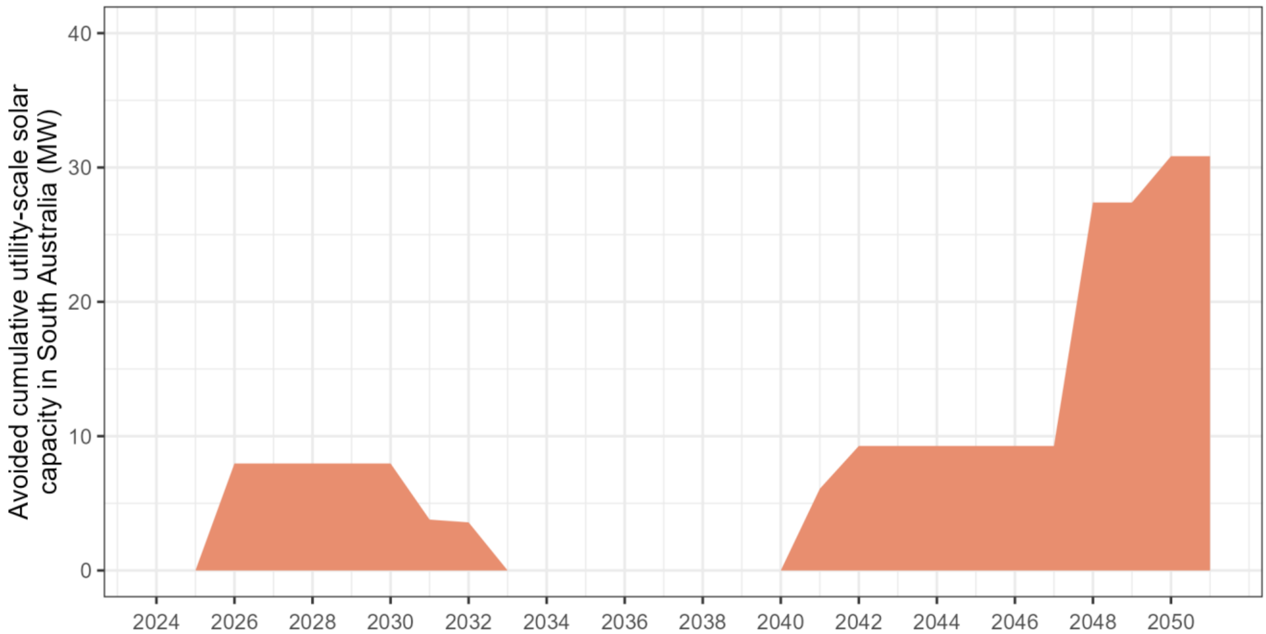
However, the lower utility-scale generation capacity in South Australia impacts on neighbouring regions being able to import electricity from South Australia. To offset the lower installed capacity of South Australian generation for export purposes in this scenario, neighbouring regions may require an increase in installed wholesale generation capacity. Our modelling shows that the alleviated curtailment of DER exports in South Australia can result in a reallocation of utility-scale generation capacity across NEM regions, with this reallocation influenced by the losses incurred over interconnectors as electricity is transferred between regions. This explains the different generation investment outcomes across other regions in the NEM.

Importantly, the total generation investment benefits of $9.3 million ($2022, PV) between 2025-26 and 2049-50 captures:[25]

- a reduction in the amount of utility-scale renewable investments that are needed in South Australia over the modelling horizon;
- the deferral of some generation investments in South Australia within the modelling horizon; and
- any corresponding changes, both increases and decreases, that are required in other regions of the NEM.[26]

We present the outcome for South Australia in figure 3.2, which indicates that the difference in total installed utility-scale solar generation capacity in South Australia between the with and without scenarios fluctuates over the modelling horizon. This variation typifies deferral, rather than avoidance, of investment. However, the increase in avoided capacity from 2040 onwards shows that some avoidance is also occurring alongside this deferral.[27]

Figure 3.2: Total avoided installed utility-scale solar generation capacity in South Australia with alleviation



Source: AEMO, 2022 Integrated system plan, June 2022, Generation outlook, '2022 Final ISP results workbook - Step Change – Updated Inputs' file, 'Capacity by year' series for South Australia; and HoustonKemp analysis using the central scenario provided by SAPN.

[25] All committed future projects, as presented in the step change scenario in AEMO's 2022 ISP, are assumed to occur at the time stated by AEMO in the ISP and are not able to be deferred or avoided in our modelling.

[26] By calculating benefits across the entire NEM, we do not exclude any offsetting actions required in neighbouring regions that would reduce total net benefits.

[27] We note that the profile of avoided wind generation capacity in South Australia indicates deferral of new investment in the late 2020s and early 2030s, with no avoided or deferred wind for the remainder of the modelling horizon.

The reduction in utility-scale solar generation capacity in South Australia due to alleviated curtailment is 0.4 per cent of total installed utility-scale solar generation capacity in the 2049-50 financial year in the without case.[28]

AEMO's 2022 ISP assumes a steady reduction in the build costs for utility-scale solar generators in the step change scenario from:[29]

- $1.250 million per MW of installed capacity in 2025-26 ($2021); to
- $0.541 million per MW of installed capacity in 2049-50 ($2021).

This provides some context for the magnitude of the avoided generation capacity investment costs, in which the total build cost of the 31 MW of avoided utility-scale solar PV in South Australia is equal to $16.7 million ($2021) using the lowest possible capital cost over the modelling horizon. Our estimated benefits of $9.3 million ($2022, PV) deviates from this estimate due to:

- inflating build costs from 2021 dollars to 2022 dollars;
- using the build cost value for the relevant year in which the avoided investment occurred, which differ from the build cost values for 2025-26 and 2049-50;
- calculating the present value of this avoided investment stream using AEMO's 5.5 per cent discount rate; and
- the offsetting effect of increased generation capacity investment, in aggregate, across New South Wales, Victoria and Queensland.

3.2 Representing avoided costs per unit of alleviation

The results in section 3.1 present the total value of avoided generation capacity investment costs over the modelling horizon between the 2025-26 and 2049-50 financial years. These total avoided costs can be translated into the generation investment capacity benefits associated with alleviating one MWh[30] of curtailed DER export at any point in time over any year. This measure represents the value from avoided generation capacity investment resulting from the alleviation of DER export curtailment by one MWh irrespectively of the time of day the alleviation occurs. This approach allows for this DER value stream to be added to the AER's CECV estimates.

We translate total avoided generation capacity investment costs into a per unit of alleviated curtailment measure by allocating total benefits evenly across each unit of alleviated curtailment over the modelling horizon, which results in a single value for each MWh of alleviated curtailment in each year.

In principle, multiplying the half-hourly alleviated curtailment by the applicable per MWh measure and summing across all years will yield the total avoided generation investment benefits over the modelling horizon in present value terms. Avoided generation capacity investment costs are higher in later years as the quantum of alleviated curtailment increases each year.

[28] AEMO model 7,161 MW of installed utility-scale solar generation capacity in South Australia in 2049-50 in the step change scenario of the 2022 ISP.

[29] AEMO, *Forecasting Assumptions Update Workbook*, August 2022, 'Build costs' worksheet, 'Build costs - Global NZE post 2050' series for large scale solar PV.

[30] The conversion from MW to MWh is to account for the fact that the AER's CECV estimates are expressed in $ per MWh.

3.3 Scenario analysis

SAPN provided three distinct forecast alleviation profiles representing different scenarios for future investment in DER integration by SAPN. These future DER integration investment scenarios are:

- the central scenario, reflecting an investment profile intended to deliver positive market benefits when using the Australian Energy Regulator's (AER's) customer export curtailment value (CECV) estimates;
- an upper-bound scenario reflecting an investment profile that completely alleviates curtailment; and
- a lower-bound scenario reflecting an investment profile that alleviates a lower total volume of curtailment than the central scenario but seeks to maintain a minimum level of service during daylight hours.

The above analysis in sections 3.1 and 3.2, is performed on the specific alleviation profile for the central scenario.

In this section, we perform the same analysis as above with the specific alleviation profiles for the upper- and lower-bound scenarios. This analysis demonstrates that the avoided generation capacity investment cost value stream, per MWh of alleviated curtailment, is relatively insensitive to the input assumptions within a reasonable range.

Moreover, any differences between these value streams, on a per MWh of alleviated curtailment basis, can be intuitively explained by differences in the underlying characteristics of the scenarios.

A comparison of the avoided generation investment costs across the scenarios is provided in table 3.1.

Table 3.1: Comparison of avoided generation capacity investment costs across scenarios

	Lower-bound	Central scenario	Upper-bound
		Alleviated curtailment	
Total alleviation between 2025-26 and 2049-50	*815 GWh*	*910 GWh*	*5,529 GWh*
Difference relative to central scenario	*-10.4%*	-	*507.5%*
		Avoided generation investment costs	
Total avoided generation capacity investment costs ($2022, present value)	*$8.6 million*	*$9.3 million*	*$60.4 million*
Difference relative to central scenario	*-8.1%*	-	*548.6%*
		Avoided generation investment costs per unit of alleviated curtailment	
Avoided generation capacity investment costs per unit of alleviated curtailment ($2022)	*$27.90/MWh*	*$25.94/MWh*	*$29.18/MWh*
Difference relative to central scenario	*7.5%*	-	*12.5%*

Source: HoustonKemp analysis using alleviation profiles provided by SAPN.

In general, the results show that value of alleviated curtailment expressed on a dollar per MWh basis is relatively insensitive to the total volume of alleviated curtailment, due to:

- the higher avoided investment costs that are obtained from increased alleviated curtailment being offset by this higher volume of alleviated curtailment when converting this total benefit to a per MWh measure; and
- the lower avoided investment costs that are obtained from decreased alleviated curtailment being offset by this lower volume of alleviated curtailment when converting this total benefit to a per MWh measure.

However, the results also show that total alleviated curtailment is not the only determinant of total benefits. In addition to the quantum of alleviated curtailment, the timing of this alleviation, within the day and over the year, also influences the estimated benefits. This is shown by the relatively higher value of avoided generation capacity investment costs per MWh for both the upper- and lower-bound scenarios.

These two alternate scenarios both represent an improved service standard relative to the central scenario with respect to alleviated curtailment during daylight hours. The upper-bound scenario alleviates all curtailment during daylight hours, ie, represents a 100 per cent level of service, while the lower-bound scenario ensures that no customer's rooftop PV system is constrained for more than five per cent of daylight hours across the year.

These alternate scenarios explicitly target alleviated curtailment during daylight hours which can directly displace generation that otherwise would have been provided by utility-scale solar plants. In this sense, the upper- and lower-bound scenarios are able to alleviate curtailment at the time of the day and year when the value of doing so is highest, from the perspective of avoided generation capacity investment costs. In contrast to the central scenario, the lower-bound scenario alleviates curtailment at a time when its value is higher on a per unit basis.

This highlights the misalignment in the timing of the benefits associated with the CECV and avoided generation capacity investment. The alleviation profile for the central scenario is achieved from a profile of DER integration investment that maximises benefits to the network and to customers, as calculated by the CECV. The alleviation profile in the central scenario therefore alleviates more curtailment during periods of network constraints and higher wholesale prices, which often occur outside of daylight hours during the evening. As such, the central scenario does not align alleviated curtailment with periods in which the potential for avoiding wholesale generation capacity investment is largest.

3.4 Sensitivity analysis of the central scenario

To test the robustness of our results to the underlying alleviation profile we test high and low sensitivity cases in which the alleviation profile for the central scenario is adjusted in each period and each year by 20 per cent upwards, for the upper-bound, and downwards, for the lower-bound.

A comparison of the avoided generation investment costs of the high and low sensitivities with the central scenario is provided in table 3.2. As seen in the results of the scenario analysis, avoided generation capacity investment costs, per MWh of alleviated curtailment, is relatively insensitive to the total quantum of alleviated curtailment.

Table 3.2: Comparison of avoided generation capacity investment costs across high and low sensitivities

	Low sensitivity	Central scenario	High sensitivity
		Alleviated curtailment	
Total alleviation between 2025-26 and 2049-50	*728 GWh*	*910 GWh*	*1,092 GWh*
Difference relative to central scenario	*-20.0%*	-	*20.0%*
		Avoided generation investment costs	
Total avoided generation capacity investment costs ($2022, present value)	*$7.3 million*	*$9.3 million*	*$11.3 million*
Difference relative to central scenario	*-21.7%*	-	*21.6%*
		Avoided generation investment costs per unit of alleviated curtailment	
Avoided generation capacity investment costs per unit of alleviated curtailment ($2022)	*$25.38/MWh*	*$25.94/MWh*	*$26.28/MWh*
Difference relative to central scenario	*-2.2%*	-	*1.3%*

Source: HoustonKemp analysis using alleviation profiles provided by SAPN.

We note that both the high and low sensitivities result in a similar measure of avoided generation investment costs per unit of alleviated curtailment as the central scenario. This is due to relatively similar movements in total avoided generation capacity investment costs and total alleviated curtailment relative to the central scenario, ie:

- a 20 per cent reduction in alleviated curtailment reduces avoided generation capacity investment costs by 21.7 per cent; and
- a 20 per cent increase in alleviated curtailment increases avoided generation capacity investment costs by 21.6 per cent.

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Memo

To	Bryn Williams, Network Strategy Manager, SA Power Networks
From	Adrian Kemp, Sam Pfeiffer
Subject	Implications of updates to the customer export curtailment value (CECV) for estimated avoided generation capacity investment from alleviated curtailment of distributed generation
Date	20 December 2023

Throughout the 2022-23 financial year, HoustonKemp assisted SA Power Networks by valuing the utility-scale generation capacity investment that can be expected to be avoided through network investments that alleviate consumer energy resource (CER)[1] export curtailment. We provided a report to SA Power Networks in April 2023 detailing the methodology applied to this analysis and the resulting estimate of avoided generation capacity investment.

In June 2023, the Australian Energy Regulator (AER) updated the CECV estimates for use by SA Power Networks in its regulatory proposal.[2] This note presents a brief summary of the implications for the estimated avoided generation capacity investment from alleviated CER export curtailment from this update to the CECV.

In this note we present:

- a brief description of the update to the CECV; and
- consideration of this update on our estimated avoided utility-scale generation capacity from alleviated small-scale curtailment.

1. Summary of CECV update

The CECV was updated by Oakley Greenwood, the AER's consultant, in June 2023 and is based on the step change scenario from the 2023 update to the Inputs, Assumptions and Scenarios Report (IASR) by the Australian Energy Market Operator (AEMO).[3] The 2023 IASR was used to develop the draft 2024 Integrated System Plan (ISP).[4]

When compared to the inputs used in the previous IASR from 2021, which was used for AEMO's modelling for the 2022 ISP, Oakley Greenwood note, amongst other factors, that capital costs for:[5]

- utility-scale solar generation capacity and battery energy storage system (BESS) capacity are relatively higher in the 2023 IASR; and
- wind generation capacity are relatively higher in the near term and relatively lower in the long term in the 2023 IASR.

As a consequence of the changes in solar, wind and BESS capital costs, Oakley Greenwood state that the 'the long-term generation mix will have less solar but more wind' for the projected future state-of-the-world in which the updated CECV was estimated.[6]

[1] We note that our April 2023 report refers to distributed energy resources (DER), which are now more frequently referred to as consumer energy resources (CER) in this context.

[2] AER, *Customer export curtailment value methodology | Update | 30 June 2023*, available at https://www.aer.gov.au/industry/registers/resources/guidelines/customer-export-curtailment-value-methodology/update, accessed 20 December 2023.

[3] Oakley Greenwood, *Summary Note of Key Drivers of Changes from 2022 | 2023 CECV Update*, 29 June 2023, p 3.

[4] AEMO, *Draft 2024 Integrated System Plan for the National Electricity Market*, 15 December 2023, p 39.

[5] Oakley Greenwood, *Summary Note of Key Drivers of Changes from 2022 | 2023 CECV Update*, 29 June 2023, p 5.

2. Implications for CECV update on our analysis

The analysis presented in our report from April 2023 was undertaken using inputs and assumptions aligned with those used in the 2022 ISP, ie, the 2021 IASR. As such, the estimates of avoided utility-scale generation capacity investment in our report do not reflect the same set of underlying inputs and assumptions as the modelling used to determine the most recent CECV estimates.

As a result, SA Power Networks will be using two metrics to estimate the economic value of alleviated CER export curtailment in its regulatory proposal that are based on different sets of assumptions, ie:

- the CECV, to estimate the avoided short-run dispatch costs associated with increased distributed generation, which is based on the 2023 IASR; and
- an estimated uplift to the CECV, representing the avoided long-run investment costs associated with increased distributed generation, which is based on the 2021 IASR.

As noted above, the 2023 IASR – used for the CECV estimate – assumes significantly higher utility-scale solar capital costs than the 2021 IASR – used in our modelling.

The results of our modelling show that the avoided utility-scale generation capacity investment costs from alleviated CER export curtailment are primarily driven by avoided solar generation capacity, as a significant volume of alleviated curtailment aligns with the output of utility-scale solar generation.[7] Further, almost all of the total avoided utility-scale generation capacity that is avoided through alleviated CER export curtailment is located in South Australia, with all of this avoided utility-scale generation capacity in South Australia being from solar plants.[8]

It follows that with higher assumed capital costs for new utility-scale solar generation capacity that the value of this avoided investment will be higher using the updated 2023 IASR relative to the previous 2021 IASR.

Further, we model a reduction in total South Australian utility-scale solar generation capacity of less than 0.5 per cent in the 2049-50 financial year.[9] As such:

- while the long-term generation mix under the 2023 IASR will likely result in less solar;
- our results are driven by avoiding a relatively small portion of total utility-scale solar capacity; that
- this changing future generation mix is unlikely to reduce the quantum of avoided utility-scale solar generation in response to alleviated CER export curtailment by SA Power Networks.

In our opinion, it is likely that the value of avoided utility-scale generation capacity investment will increase if our analysis were to be updated using the same assumptions as the most recent CECV estimates, ie, the 2023 IASR. Therefore, while using the results of our previous analysis raises an internal inconsistency with the use of the updated CECV, SA Power Networks is choosing an approach that is likely to conservatively under-estimate the avoided utility-scale generation capacity investment that can be expected from the anticipated alleviation of CER export curtailment.

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[6] Oakley Greenwood, *Summary Note of Key Drivers of Changes from 2022 | 2023 CECV Update*, 29 June 2023, p 5.

[7] HoustonKemp, *Estimating the avoided generation capacity investment costs of alleviating export constraints*, April 2023, p 16.

[8] HoustonKemp, *Estimating the avoided generation capacity investment costs of alleviating export constraints*, April 2023, pp 11-14.

[9] HoustonKemp, *Estimating the avoided generation capacity investment costs of alleviating export constraints*, April 2023, p 14.