6 May 2022

Dr Kris Funston
Executive General Manager, Networks Regulation
Australian Energy Regulator

Sent via email

AER Customer Export Curtailment Value – Draft Methodology

Dear Dr. Funston,

Energy Networks Australia (**ENA**) appreciates the opportunity to make a submission to the Australian Energy Regulator's (**AER**) draft customer export curtailment value (**CECV**) methodology[1], developed following the Australian Energy Market Commission's (**AEMC**) *access, pricing and incentive arrangements for distributed energy resources* (**DER**) final rule.[2]

ENA is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

CECVs are meant to capture the detriment to customers and the market when DER exports are curtailed and should help guide efficient levels of investment for export services. Over or under estimation of the CECV will lead to inefficient trade-offs between investments in networks and electricity generation, ultimately leading to higher electricity costs for consumers that is not consistent with their long-term interests.

ENA engaged HoustonKemp to provide an independent assessment of the methodology proposed by the AER and its consultants, which can be found in the public memorandum **attached.** In their review, HoustonKemp found several material limitations that are strongly recommended to be addressed in the development of the final methodology, namely:

» the methodology produces a granular and sophisticated estimation of only a portion of the benefits and excludes a material component, i.e., the benefits arising from avoiding generation capacity investment – or 'investment benefits' – thereby risking materially underestimating the CECV,

[1] On 8 April 2022, the AER published its draft Customer export curtailment value (CECV) methodology, explanatory statement, consultant report and workbook containing draft CECVs.

[2] AEMC, Access, pricing and incentive arrangements for distributed energy resources, Rule determination, 12 August 2021.

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- the CECVs estimated using the consultant's methodology are not consistent with the levels of investment in solar PV expected under the Australian Energy Market Operator's Integrated System Plan modelling; and
- the AER consultant's modelling of CECVs makes assumptions that lead to a downward bias in the estimates.

HoustonKemp finds that the proposed methodology results in CECVs that are materially below the wholesale market costs that can be expected to be avoided by alleviating curtailment, highlighting that this can then be expected to lead to inefficient investment to facilitate the energy transition, to the detriment of consumers who, if this occurs, will inevitably pay more in future energy costs.

We therefore strongly encourage the AER to consider the results of this analysis, and work collaboratively to develop a pathway forward to address industry's concerns. CECVs will be a critical input in guiding efficient investment decisions for export services, and networks have a significant role to play in supporting the energy transition in an efficient and timely manner that reflects the expectations of customers.

If you wish to discuss any of the matters raised in this letter further, please contact Lucy Moon, Head of Regulation, on [redacted]

Yours sincerely,

[redacted]

Garth Crawford
General Manager, Regulation

HOUSTONKEMP Economists

Memo

Observations on the Australian Energy Regulator's proposed customer export curtailment value methodology

Summary of observations

- The purpose of the customer export curtailment value (CECV) is to provide a value for energy that would be made available to the electricity market through network investment that alleviates curtailment of distributed energy resources (DER), ie, rooftop PV and battery storage.
- Over or under estimation of the CECV will lead to inefficient trade-offs between investments in networks and electricity generation, ultimately leading to higher electricity costs for consumers that is not consistent with their long-term interests.
- The draft CECV methodology proposed by the Australian Energy Regulator (AER) has several shortcomings that in our opinion need to be addressed, namely:
  - the methodology produces a granular and sophisticated estimation of only a portion of the benefits and excludes a material component, ie, the benefits arising from avoiding generation capacity investment – or 'investment benefits' - thereby risking materially underestimating the CECV;
  - the CECVs estimated using the consultant's methodology are not consistent with the levels of investment in solar PV expected under the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) modelling; and
  - the AER consultant's modelling of CECVs makes assumptions that lead to a downward bias in the estimates.
- In our opinion the AER's proposed CECV methodology results in CECVs that are materially below the wholesale market costs that can be expected to be avoided by alleviating curtailment. This can be expected to lead to inefficient investment to facilitate the energy transition, to the detriment of consumers who will inevitably pay more in future energy costs. This cannot be in the long-term interests of consumers.
- Using a 'with and without' market modelling approach with indicative profiles and cost benchmarks based on information readily available from AEMO, would be more consistent with the aim of the CECV, and would also allow the AER to capture *all* the wholesale market benefits in the CECV, including the investment benefits, and we strongly recommend that the AER undertakes this. We present benchmarks and modelling results that support this conclusion.
- We further acknowledge that the AER is required to publish CECVs by 1 July 2022, which means there is limited time within which it could develop these refined CECV estimates. As a practical way forward, we recommend that the AER's June 2022 release:
  - acknowledge the importance of investment benefits in the value of customer export curtailment in its final (interim) CECV methodology, given inconsistencies with the level of investment implied in the ISP and comparisons with benchmark values and modelling results;
  - provide guidance to DNSPs on how to best incorporate investment benefits, in an interim way, when examining benefits of network investments to alleviate curtailment, which could involve making pragmatic use of cost information provided by AEMO on generator, storage and transmission capital costs to establish initial benchmark values, or the use of with/without market modelling;
  - commit to undertaking a formal review of its CECV methodology and interim CECVs in the remainder of 2022-23 given that investment benefits are currently material, so that its 2023-24 values of CECV include these avoided costs;[1] and
  - review and refine the CECV methodology for estimating dispatch and benefits to address methodological issues we have identified.

This memorandum sets out our opinions on the draft methodology for the estimation of the CECV proposed by the AER, and the AER's consultant, Oakley Greenwood (OGW). The memorandum is structured as follows:

- in section one, we set out the relevant context for the setting of the CECV;
- in section two, we provide a set of high-level observations on the consistency of the draft CECV estimates and the investment requirements implied in AEMO's draft Integrated System Plan (ISP);
- in section three, we highlight some additional methodological points that appear to lead to a downward bias in the CECV estimates and in our opinion require refinement; and
- in section four, we make recommendations for a way forward to address our observations.

1. The CECV aims to ensure that appropriate trade-offs are made to promote an efficient energy transition in the long-term interests of consumers

The Australian Energy Market Commission (AEMC) introduced the concept of a CECV as part of its rule on access, pricing and incentive arrangements for DER.[2]

The rule requires the AER to develop a methodology for estimating CECVs, and to publish annually values of customer export curtailment.[3]

As the AEMC explains, values of customer export curtailment will:[4]

> … help guide the efficient levels of network expenditure for the provision of export services and serve as an input into network planning, investment and incentive arrangements for export services.

This is achieved by the CECV representing the benefits that could be achieved by avoiding the curtailment of exports from DER. In the context of the wholesale electricity market, the AER appropriately recognises that these values represent the detriment to all customers from the curtailment of DER exports, and include:[5]

- avoided generation capacity investment;
- essential system services (including frequency control ancillary services);
- avoided marginal generator short run marginal cost (SRMC); and
- avoided transmission or distribution losses.

Most relevantly, by requiring the AER to publish these values rather than requiring each DNSP to develop its own, the AEMC contemplated administrative cost efficiencies and the use by DNSPs of a consistent methodology when conducting business cases. Specifically:[6]

> having a single body responsible for establishing these values would provide consistency and transparency of estimates and avoid unnecessary duplication and administrative costs

[1] The AER has indicated that it will conduct a review of the CECV methodology prior to the five-yearly review if there is new information to support the inclusion of new wholesale market value streams. See AER, *Draft CECV methodology*, Explanatory statement, April 2022, p 23.

[2] AEMC, *Access, pricing and incentive arrangements for distributed energy resources*, Rule determination, 12 August 2021.

[3] Part J, Chapter 8, National Electricity Rules.

[4] AEMC, *Access, pricing and incentive arrangements for distributed energy resources*, Rule determination, 12 August 2021, p ix.

[5] AER, *Draft CECV methodology*, April 2022, pp 5-6.

[6] AEMC, *Access, pricing and incentive arrangements for distributed energy resources*, Rule determination, 12 August 2021, p 62.

It follows that the CECVs methodology and values should represent a close-as-possible approximation of the wholesale market benefits that could be expected to result from an alleviation of DER export curtailment. In this way, it is intended to have a similar role in the regulatory framework as the Value of Customer Reliability (VCR), which provides a common basis and value for understanding the benefits from reducing unserved energy in the market.

The emphasis in the CECV methodology should be on ensuring that the value includes all material wholesale market benefits that can be expected by alleviating DER export curtailment. This is to promote an efficient energy transition where appropriate trade-offs are made between investment in unlocking electricity supply through reducing constraints on DER, and investment in new large-scale generation capacity and associated network infrastructure.

A CECV that does not include all material benefits and so is excessively low will lead to inefficiently high investment in new sources of large-scale generation and so increase the cost of the energy transition. Equally, a CECV that is excessively high will lead to inefficiently high investment in network capacity to accommodate DER, and so also increase the cost of the energy transition. It follows that it is important to balance the risks arising from inaccurate estimation of the CECV against the inefficiencies that might be expected from under or overestimating the value.

The AER's draft methodology for the CECV expressly excludes wholesale market benefits that arise from avoided costs of generation investment, ie, generation investment benefits. This is justified by the AER on the basis of OGW's belief that the generation investment impact of avoided curtailment is small and that the required information for estimating this impact is not available. We note that OGW does not provide any analysis to support these conclusions. We discuss these further in section 3 below.

In our opinion, the risk is that by not including material investment benefits within the CECV, consumers will inevitable pay more in future energy costs, thereby increasing the cost of the energy transition compared to what it might have otherwise been. This cannot be in the long-term interests of consumers.

2. The AER's draft CECVs are inconsistent with projected investments in the Integrated System Plan

The wholesale electricity market dispatch modelling undertaken by OGW to estimate the CECV focuses on the short run marginal costs of electricity supply during each period. This modelling does not consider the potential effects of alleviating export curtailment on generation investment costs.[7] In that way, the modelling does not consider 'avoided generation capacity investment' benefits, which is one of the benefit categories identified (but not quantified) in the AER's draft methodology.[8]

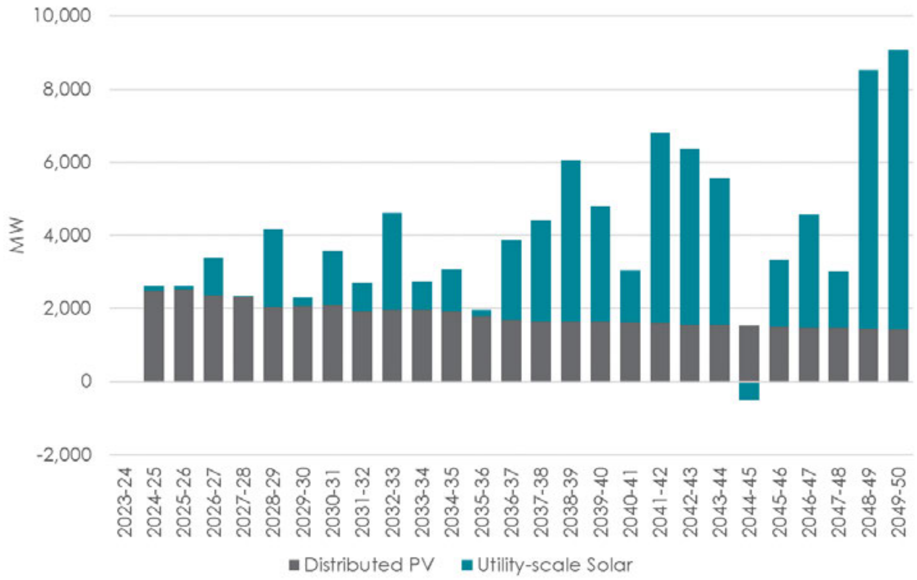
When considering the appropriateness of the modelling outcomes, the value streams estimated and the underpinning assumptions, an important reference point is whether the overall modelling outcomes are consistent with the economic conditions that would drive investment in new generation capacity, as projected in AEMO's ISP.

Figure 1 below shows the level of new utility-scale solar PV and rooftop PV projected in AEMO's ISP Step Change scenario and assumed within the modelling conducted by OGW. By way of example, the capacity projection assumptions shown in the figure include over 3,000 MW of new utility-scale solar PV and over 1,500 MW of new rooftop PV entering the market in 2039-40.

[7] We adopt the term 'generation investment' to refer to investment in generation and storage capacity, as well as any associated transmission capacity required to support the connection of the assets, eg, in Renewable Energy Zones.

[8] AER, Draft customer export curtailment value methodology, April 2022, p 6.

Figure 1: Project level of investment in utility-scale and rooftop solar PV – AEMO draft ISP Step Change scenario (DP2)



Source: AEMO Draft 2022 ISP generation outlook

In this same year of 2039-40, the AER's draft CECV estimates for a solar PV profile are approximately $5 to $15 per MWh, depending on the National Electricity Market (NEM) region.[9] Our analysis of AEMO's new entrant capital cost data indicates that the levelised cost of large-scale solar PV in the AEMO Step Change case is approximately $35 to $40 per MWh in 2039-40, with some variation depending on the geographic location of the generation investment.[10]

This suggests that under current levels of export curtailment, market participants in the wholesale sector are willing to incur costs to construct a large quantity of new solar PV capacity that are materially higher than the AER would allow DNSPs to incur to increase supply by the same quantity under the current CECV values. However, network investment to alleviate export curtailment can be considered an approximate substitute for incremental investment in utility-scale solar and so the willingness to pay for these forms of supply should be comparable. As a matter of economic principle, adopting the AER's draft CECV values would inefficiently bias investment towards utility-scale solar as compared to investment in networks to unlock curtailed rooftop solar.

Further to the above point, the new solar PV generation capacity installed in 2039-40 is being installed after some 20GW of large-scale solar PV will have previously been installed since 2022, based on AEMO's projections. By implication, this capacity will likely be installed in higher cost locations that require augmentations to the transmission network to facilitate connection to the National Electricity Market, eg, as part of Renewable Energy Zones. These costs of transmission augmentation will also be avoided if significant quantities of otherwise curtailed rooftop PV capacity is made available through network investments. We note that the AER's draft methodology acknowledges (but does not quantify) the benefits of avoided curtailment arising from avoided costs of network investment and the impact on these costs is

[9] Oakley Greenwood, CECV Methodology – Interim Report, 6 April 2022, p 25.

[10] AEMO, 2021 Inputs and assumptions workbook, 12 December 2021. The analysis assumes a build cost and connection cost for a 'Large scale solar PV', an economic life of 25 years, a capacity factor of 25% and a discount rate of 5.5%.

typically considered as part of investment benefits in modelling considered by the AER in other similar contexts.

The magnitude of these avoided transmission augmentation costs is likely to be material. By way of example, AEMO estimates that new network capacity for the Central-West Orana REZ in excess of 5,400MW will attract a cost of $1.36 million per MW, a value that is nearly double the capital cost for the same megawatts of solar PV generation in 2040.[11] Simplistically, if transmission capacity is built out to support 80 per cent of the capacity of solar plant, we estimate that this is equivalent to a further cost of approximately $30 per MWh.[12] Again, an implication of the AEMO ISP modelling is that market participants must be willing to incur these costs to construct these large-scale renewable generators – costs that are far greater than the allowed costs for an equivalent source of supply under the AER's CECV values.

It follows that in our opinion, the investment benefits arising from avoided generation costs, inclusive of REZ augmentation transmission costs, are likely to be material and so should be expressly included in the AER's CECV.

In summary, the CECVs estimated by OGW do not appear to reconcile with the level of new solar PV capacity projected to be built under the ISP and the cost of this investment. This suggests a material underestimation of the avoided costs from alleviating curtailment of DER in the CECV and that applying these values would lead to an inefficiently low level of investment in network capacity than is not in the long-term interests of consumers.

3. The AER's proposed CECV methodology underestimates benefits of avoided curtailment

The observations above around the inconsistency of the CECV estimates with the ISP investment outcomes arise due to a number of assumptions adopted by OGW that are inherently conservative. Our principal concerns with the proposed methodology can be summarised as:

- the exclusion of the investment benefits either risks materially underestimating the CECV or requires DNSPs to individually calculate values for investment benefits; and
- the approach appears to make modelling methodological assumptions that underestimate the CECV.

We elaborate on these points below.

3.1.1 Explicit exclusion of investment benefits in the CECV risks materially underestimating the value of avoided curtailment

The transition of the energy sector at the lowest cost to consumers requires efficient investment across both distributed and large-scale resources.

An investment in the distribution network to reduce curtailment of DER is effectively equivalent to investment in a new generation or storage source with the same time-based profile of output (or load in the case of storage charging) at the same location within the network. It follows that the avoided system costs resulting from alleviated export curtailment can be approximated by the costs that would be required to produce this profile from the lowest cost alternative. This is the premise behind the draft methodology proposed by the AER.

We discuss in section 2, that the estimated CECVs are not consistent with the level of implied investment projected in AEMO's ISP Step Change scenario and that the modelling does not take account of benefits

[11] AEMO, 2021 Inputs and assumptions workbook.

[12] Estimated on the basis of a discount rate of 5.5 per cent and an asset life of transmission assets of 50 years.

arising from avoided generation investment costs. OGW state that the proposed methodology does not take account of these investment benefits because:[13]

- Between now and the medium term, DER curtailment mostly occurs when there is an abundance of system generation and/or low system demand (i.e., high solar output period). 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.

- The amount of DER curtailment is small relative to the system generation

In our opinion, this reasoning is flawed.

OGW's reasoning fails to recognise that the market is continuing to invest in material quantities of new solar PV capacity - as illustrated in Figure 1. While curtailment does typically occur at times of high solar output the more relevant trade-off question is whether alleviated curtailment can substitute for utility-scale solar PV, which likely has a similar generation profile.

This suggests that there is demand for electricity capacity that supplies electricity at times other than the evening peak, albeit with complementary storage to shift the output to times of relative scarcity of supply.[14] It follows that there are significant future costs in large-scale renewable generation investment that in principle might be delayed or avoided as a consequence of alleviating DER export curtailment. Most importantly these investment benefits are likely to be material.

We also note that while these generation investment benefits have not to date been included in DNSP submissions on the benefits of network investments to increase export hosting capacity, we believe these benefits are increasingly relevant as the energy transition accelerates and the expectations around the quantities of future investment required increase. We note that the previous values produced by DNSPs were principally developed prior to the AEMC's rule change and so prior to an export service being included in the National Electricity Rules (NER) as a service provided by DNSPs.

Further, the observation that the level of DER curtailment is expected to be small does not appear to be well-founded. Distribution networks are experiencing constraints within their networks currently, hence the requirement for the development of the CECV. The capacity projections underpinning the modelling by OGW assume that at least a further 30GW of distributed solar PV will be installed to 2040, which is going to give rise to a material amount of curtailed energy without significant investment in network capacity.

Irrespective, in our view, the methodology should not be set at this initial stage on the presumption that the scale of curtailment is expected to be small, when the purpose of the CECV is to determine the extent of curtailment that is efficient.

In this context, the key question then becomes to what extent might alleviated DER export curtailment be sufficient to delay or avoid some of the future large-scale renewable generation investment needed to achieve net-zero by 2050? Given the ongoing and anticipated investment in DER, and the potential constraints anticipated over the next five to ten years, in our opinion there is significant opportunity for alleviated export curtailment to defer or delay large-scale generation investment.

Finally, the AER suggests that:[15]

[13] AER, *Draft CECV methodology*, Explanatory statement, April 2022, p 11, and Oakley Greenwood, *CECV Methodology*, Interim report, 6 April 2022.

[14] We note that while storage is required to shift avoided curtailment during periods of solar PV, an equivalent level of storage would be required in the counterfactual where the electricity is supplied form large-scale sources.

[15] AER, *Draft CECV methodology*, Explanatory statement, April 2022, p 33.

> Estimating the avoided generation capacity investment component is complex and would require further assumptions about the alleviation profiles provided by DNSP investments. Since we do not have this information we consider it sensible to exclude this component from the methodology.

We believe that there are approaches that could be adopted to approximate the value of the market benefits, including investment benefits, through the use of representative profiles. While we agree that modelling this component has a degree of complexity, this should not preclude its inclusion in the values of customer export curtailment.

To illustrate the practicality of undertaking 'with and without' modelling to estimate a long-run marginal cost (LRMC)-based CECV, and to illustrate the materiality of the inclusion of investment benefits within the CECV, we have undertaken illustrative modelling of the total avoided costs, including avoided generation investment costs, associated with a set of indicative alleviated curtailment profiles. This modelling gives rise to an estimate of market benefits that is inclusive of both dispatch and investment benefits.

This modelling involved applying a least-cost, long term planning model of the NEM both with and without potential alleviation profiles. We note that similar models are routinely applied across the NEM to assess transmission network investments. The modelling involved:

1. developing least-cost pathways for the development of the NEM under the ISP Step Change and Progressive Change scenarios by applying all relevant assumptions applied in the draft 2022 ISP, eg, fuel and operating costs for generators, capital costs of new generation and storage, REZ transmission augmentations costs, projections of demand and DER uptake and demand response;
2. developing alternative least-cost pathways for the NEM by including an additional form of zero-cost supply with intra-day profiles that reflect different potential alleviation profiles and magnitudes of curtailment;
3. estimating the change in the total costs of supplying electricity between the pathways developed in steps 1 and 2 for each case; and
4. estimating the avoided long run marginal cost by dividing the net present value of the change in total costs by the net present value of the energy in the alleviation profile – this value is equivalent to an estimate of the full market benefits, including both dispatch and investment benefits, from the alleviation profile.

We recognise that this modelling exercise produces a range of values depending on the shape and magnitude of the alleviation profile on an intra-day, seasonal and yearly basis and on the scenario adopted. It follows that some regulatory judgement is required to arrive at a single set of values using this information but than in principle this modelling can be informative in illustrating the market benefits that would arise from likely potential alleviation profiles. Our modelling indicated that as storage is increasingly prevalent in the market, sensitivity of the modelling results to the specific intra-day shape of alleviation starts to diminish.

By way of example, our modelling indicates that for a uniform block of incremental curtailment alleviation between 11am and 2pm each day commencing from 2022 onwards, wholesale market total costs reduce by on average approximately $75 per MWh (in 2022 real terms) across the Step Change and Progressive Change scenarios. This is broadly consistent with the aggregation of the levelised solar PV generation costs and REZ transmission augmentation cost values as considered above, adjusted for losses. This value is driven by:

- avoidance of investment in generation capacity, particularly utility-scale solar PV capacity;
- avoidance of investment in REZ augmentation costs – we note that this type of modelling captures the avoided cost of the highest cost electricity supply options, which practically means the avoidance of renewable investment in areas of relatively lower quality resources and in areas of the network requiring relatively high-cost network augmentations; and

- avoided of dispatch costs, both fuel and operations and maintenance - a profile with alleviation during periods of solar PV output can still support some avoidance of costs during periods with dispatch of higher cost generation through utilisation of existing battery storage capacity.

Relevantly, our estimated average value of $75 per MWh is significantly higher than the AER's draft CECVs of between approximately $5 and $25 per MWh over the same 20-year time horizon. This comparison further highlights the materiality of not including generation investment benefits in the CECV.

It follows that we disagree with the AER's conclusion that estimating avoided generation investment capacity is sufficiently complex that it cannot be included in the AER's CECVs. Given the materiality of the avoided costs, we believe that further investigation should be undertaken as to how best to include avoided generation investment capacity in the AER's value of customer export curtailment.

3.1.2 The CECV estimation approach involves methodological assumptions that tend to underestimate the CECV

We have identified three additional methodological factors that appear to be driving the conservative and low estimates of the CECV within the modelling undertaken by OGW.

To provide context for the estimation of marginal dispatch costs, our experience undertaking similar modelling suggests there are several factors that will go towards supporting investment in the quantity of solar PV projected by AEMO. These factors principally increase wholesale market demand during periods of solar PV output, and so increase the frequency with which solar PV is dispatched at times when higher cost supply options are also generating. These factors can include:

- the modelling methodology for large-scale battery storage; and
- the treatment of uptake of electric vehicles, which will have a strong incentive to charge during periods of high DER generation.

Each of these represent sources of load that will effectively compete for the energy supplied by solar PV, and so help to support demand during periods of high solar PV generation.

A complexity with modelling dispatch arises because we expect storage will be the marginal source of supply during a large number of periods, and the marginal costs of storage are essentially zero. As discussed below, the methodology used to capture the opportunity cost of storage will be material in estimating avoided marginal cost and so need to be carefully considered in the overall dispatch modelling methodology.

Our observations on the various elements of the methodology that should be refined illustrate the complexity in undertaking such a modelling exercise and the scope for discretion to be applied in the methodologies adopted. This supports our opinion that a more pragmatic CECV estimation methodology (eg, using a with or without analysis of the market), that seeks to estimate all dimensions of market benefits, is likely to result in CECVs that are more aligned with its intended purpose.

Approach to the estimation of opportunity cost

It appears from the AER's explanatory statement that the modelling undertaken by OGW does not take account of any intra-day foresight in estimating the opportunity cost of bidding of storage and hydro. The modelling assumes that storage 'takes the value of the alternative generation' when bidding into the market.[16]

Further, OGW state with regards to their approach to the modelling of batteries:

[16] Oakley Greenwood, CECV Methodology – Interim Report, 6 April 2022, p 25.

> The SRMC for batteries requires some additional clarification given they are the main assets that manage energy supply after coal closure. Once installed, they have close to zero running costs each cycle apart from the energy loss associated with their round-trip efficiency. However, this does not mean the opportunity cost of battery cycling is zero (excluding energy loss).
>
> Batteries do have a limited number of cycles over their asset life, which means one cycle today comes at the cost of one less cycle (and benefiting from energy arbitrage) at some point in the future. Therefore, we have applied an opportunity cost for cycling of batteries in our model, based on the shadow price of their life-time cycle limits.

This approach correctly recognises the importance of the concept of opportunity cost for the marginal costs of storage and some of the implications of this concept for modelling avoided dispatch costs. However, based on this description, it appears that OGW's modelling only considers the alternative generation in each period in isolation, rather than the highest cost alternative across a foresight period, eg, a day. In this circumstance the number of cycles does not necessarily change.

The AER's approach will lead to a lower estimate of avoided dispatch costs. To address this methodological issue, we suggest that OGW consider the application of dispatch modelling that captures the full opportunity cost of storage and hydro dispatch in each period.[17]

Consistency of dispatch outcomes with emissions trajectories

The ISP modelling includes 'emissions budget' constraints that act to limit the output from emissions-producing sources of generation when projecting investment in new capacity. These limits are a major driver of the timing of the retirement of coal fired generation and the corresponding entry of new renewable generation and storage into the market. These emissions budgets are also the method by which net zero emission targets adopted by the Commonwealth and State governments are captured within the ISP's long-term modelling.

In practical terms, these limits restrict the aggregate level of, principally coal, output until it is uneconomic for a generating unit to run. Broadly, at the point at which a unit is no longer economic to run, the unit will be retired, and the utilisation of the remaining plants will tend to increase. This process leads to periods of time where the output from coal plants is restricted to a level that is below the level that it would otherwise output if being dispatched purely on a cost-basis.[18]

Based on the description provided, it appears that the approach adopted by OGW to the dispatch modelling involves adopting the capacity values for coal plants and then dispatching the market on the basis of short run marginal costs. This approach will lead to a scenario where the output from coal plants is higher than would otherwise occur in the presence of emissions constraints and where the level of emissions will be inconsistent between AEMO's ISP modelling to project capacity investment and the dispatch modelling conducted by OGW.

All else equal, OGW's approach will tend to reduce the output of lower-emissions technologies, such as gas-fired generation and storage and lead to lower estimates for the CECV estimated using the OGW's methodology. In contrast, an approach that ensures consistency of the modelling with the long-term emissions outcomes incorporated into AEMO's modelling will tend to increase estimates of the CECV, and we recommend that the AER explore this as a refinement to the final methodology.

[17] Such an approach may involve a model that dispatches all periods within a day, or set of days, in a single optimisation problem, thereby capturing the intra-day battery dynamics within the shadow price, or marginal dispatch cost value, in each period.

[18] This assumes no explicit price on carbon that internalises carbon costs.

Application of average outage factors

OGW apply an averaged outage rate across all periods, rather than use a sequence of projected outage status values. The later approach is adopted in the modelling undertaken in AEMO's Electricity Statement of Opportunities, albeit with numerous simulation runs.[19]

The adoption of an average outage factor will tend to lead to:

- modestly higher average prices during periods with no material outages; but
- potentially substantially higher prices in periods with material outages.

This is due to the typically convex shape of the electricity supply curve. On average, we expect that OGW's approach will generally tend to lower the estimated avoided marginal cost estimate. We accept that this approach is reasonable when seeking to adopt a pragmatic approach that only considers a single model run.

This approach likely adds to the degree of conservatism on the modelling approach adopted by OGW. It follows that the modelling would likely benefit from further sensitivity testing of this assumption to ascertain the extent of conservatism in this approach. If this sensitivity analysis indicates that the results are sensitive to this assumption, then we recommend the AER considers adjusting its approach.

4. Recommendations for a way forward

In summary, in our opinion the AER's proposed CECV methodology results in CECVs that are materially below the wholesale market costs that can be expected to be avoided by alleviating curtailment. This can be expected to lead to inefficient investment to facilitate the energy transition, to the detriment of consumers into the future.

To address these concerns, we believe that AER should include in its CECV methodology, and so the resulting CECV estimates, avoided costs of generation, storage and transmission investment arising from avoided curtailment.

We acknowledge the challenges that have been highlighted by OGW in estimating these investment costs. However, benchmark values and our own modelling highlights that these avoided generation investment costs are likely to material. It follows that the detriment to consumers of not including these values in the CECV mean that the AER should look to address these challenges in its CECV methodology as a matter of priority.

Importantly, our own modelling demonstrates that avoided generation investment costs can be readily modelled using representative curtailment profiles, albeit with a pragmatic approach that may involve some simplifying assumptions. This suggests a potential pathway forward for the AER in developing these estimates, which could then be readily used by DNSPs when evaluating proposed network investments.

While DNSPs could undertake this analysis themselves, this is inconsistent with the rationale for the AER having responsibility for estimating CECVs as required in the NER. By not including investment benefits in the CECV, the AER is contributing to significant uncertainty about the CECVs relevance in network investment evaluations.

We further acknowledge that the AER is required to publish CECVs by 1 July 2022, which means there is limited time within which it could develop these refined CECV estimates. As a practical way forward, we recommend that the AER's June 2022 release:

[19] AEMO, ESOO Reliability Forecast Methodology Document, August 2021, p 9.

- acknowledge the importance of investment benefits in the value of customer export curtailment in its final (interim) CECV methodology, given inconsistencies with the level of investment implied in the ISP and comparisons with benchmark values and modelling results;
- provide guidance to DNSPs as to how best in an interim way to incorporate investment benefits when examining benefits of network investments to alleviate curtailment, which could involve making pragmatic use of cost information provided by AEMO on generator, storage and transmission capital costs to establish initial benchmark values, or the use of with/without market modelling;
- commit to undertaking a formal review of its CECV methodology and interim CECVs in the remainder of 2022-23 given that investment benefits are currently material, so that its 2023-24 values of CECV include these avoided costs;[20] and
- review and refine the CECV methodology for estimating dispatch benefits to address the matters we raise above.

As we have indicated throughout this memorandum, while using 'with and without' modelling involves a degree of complexity, in our opinion, the complexities are comparable to the current dispatch modelling approach used by the AER. We believe that a pragmatic modelling approach that provides a reasonable estimate of the full market benefits would be more consistent with the regulatory purpose of the CECV within the NER, and will more importantly, deliver network investment outcomes that are more aligned with the long-term interests of consumers.

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[20] The AER has indicated that it will conduct a review of the CECV methodology prior to the five-yearly review if there is new information to support the inclusion of new wholesale market value streams. See AER, *Draft CECV methodology*, Explanatory statement, April 2022, p 23.