Jemena Electricity Networks (Vic) Ltd

Submission on the AER's customer export curtailment value (CECV) methodology issues paper

Jemena
bringing energy to life

An appropriate citation for this paper is:

Submission on the AER's customer export curtailment value (CECV) methodology issues paper

Contact Person

Matthew Serpell
Electricity Regulation Manager
Ph: Ph: [redacted]
[redacted]

Jemena Electricity Networks (Vic) Ltd

ABN 82 064 651 083
Level 16, 567 Collins Street
Melbourne VIC 3000

Postal Address

PO Box 16182
Melbourne VIC 3000
Ph: (03) 9713 7000
Fax: (03) 9173 7516

Table of Contents

Abbreviations

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BAU	business-as-usual
CECV	customer export curtailment value
DER	distributed energy resources
DNSPs	distribution network service providers
JEN	Jemena Electricity Networks
NER	National Electricity Rules

1. Response to the issues paper

Jemena Electricity Networks (**JEN**) welcomes the opportunity to respond to the Australian Energy Regulator's (**AER**) customer export curtailment value (**CECV**) methodology issues paper (**issues paper**). We strongly support the AER's continued engagement and consultation on issues related to distributed energy resources (**DER**). Refining expenditure assessment methodologies and tools in consultation with stakeholders will ensure that the AER is well placed to make expenditure assessment decisions that are in the long-term interests of consumers and also give certainty to businesses, including JEN, on how the AER will assess regulatory proposals.

JEN supports a principles-based approach to DER integration expenditure investments rather than an overly prescriptive approach. This also applies to the CECV methodology. DER-related investment proposals, which will likely include underlying CECV methodologies and calculations, should be fit-for-purpose and undertaken on a case-by-case basis. Better business case methodologies can and will be developed over time and therefore any guidance should be flexible enough to account for changing best practice approaches. Below we outline our response to the AER's issues paper and its consultation questions.

1.1 DER definition

JEN supports the AER's inclusion of a DER definition in its issues paper. To date, stakeholders and regulators have had many discussions on 'DER' but have not had a clear framing of what DER encompasses. For stakeholders to continue to engage effectively on this topic and ensure that they speak the same language, a clear definition of DER must be outlined. In our submission to the AER's draft DER integration expenditure guidance note (**guidance note**), we highlighted that the AER had not explicitly defined what DER is in the context of expenditure assessments.[1] Below we suggest several minor changes to the AER's proposed DER definition and we explain these suggestions in the subsequent dot points.

> **DER definition**
>
> Distributed energy resources (DER) are ~~resources~~ <u>apparatuses</u> connected to the <u>electricity</u> distribution network that can produce electricity or manage ~~demand~~ <u>*system limitations*</u> by responding to price or control signals. ~~It~~ <u>DER</u> includes, <u>but is not limited to</u>, rooftop solar, batteries, electric vehicles and energy management systems. These resources are often located on the ~~consumer's~~ <u>*distribution service end-user's*</u> side of the electricity meter.~~, rather than as a centralised generation source, and are growing in Australia as consumers become more active in the power system.~~

- Defining a resource as a "resource" is redundant. We recommend using "apparatus", which is consistent with language used in the National Electricity Rules (**NER**).
- DER can be used to manage broader system limitations[2] and therefore "manage demand" is too narrow.
- For the avoidance of doubt, the types of DER technology should not be limited to rooftop solar, batteries, electric vehicles and energy management systems, as other technologies may be developed and integrated into the energy system over time.
- Any references to "consumers" should be updated to "distribution service end-users". This is to reflect that end-users with DER are both energy consumers and producers, and is consistent with the changes made to the NER in the Australian Energy Market Commission's (**AEMC**) access, pricing & incentive arrangements for DER final rule change.[3]
- We recommend deleting "rather than as a centralised generation source", as future development will see DER being dispatched and therefore become centralised.

1 JEN, *Submission on the AER's draft DER integration expenditure guidance note,* August 2021, p. 1.

2 As defined in NER, cl. 5.13.1(d)(2).

3 AEMC, *Access, pricing & incentive arrangements for DER final rule change*, August 2021.

- The growth rate of DER is not relevant to its definition. Therefore, we recommend deleting "and are growing in Australia as consumers become more active in the power system".

1.2 Link to broader DER program

We seek clarity from the AER on how the CECV methodology interacts with other components of its ongoing DER work program, including:

- the VaDER methodology study that the AER commissioned from the CSIRO and CutlerMerz
- the DER integration expenditure guidance note
- the development of a future DER incentive scheme, as discussed in the AEMC's access, pricing & incentive arrangements for DER final rule change.[4]

All of these elements are interrelated but have not been presented as such in the issues paper. These different components will need to align with each other otherwise inefficiencies and incentive mismatches may occur.

1.3 Updating the CECV methodology

The issues paper states that the AER is required to review the CECV methodology every five years.[5] However, the AER will be required to review the CECV methodology *at least once* every five years.[6] This review frequency is an important distinction due to the infancy of the CECV methodology and this mechanism could be used to effectively address emerging issues. We elaborate on this below.

- Given that the industry is still in the very early stages of the DER integration 'S-curve', there will likely be a rapid development in learnings, new data will become available and changes in direction may be required over the next few years. These learnings will reveal opportunities and risks embedded in the first release of the CECVs.
- Recognising that the CECVs will be used to inform business case approvals, any 'error' in the CECV could have unintended consequences, including approving (or not approving) business cases. In these situations, *distribution service end-users'* needs may not be met.

We recommend that the AER considers revising the CECV methodology sooner than in five years. Undertaking more frequent reviews of the CECV methodology will mitigate against the issues identified above.

In addition, wider less prescriptive guide rails should be adopted when considering business cases that rely on CECVs given the infancy of this process and the modelling methodology. There are significant risks if the prescribed methodology is inaccurate, including potential under or over-investment in both distribution networks and the wholesale generation market, which would not be in the long-term interests of end-users. As a result, the AER's CECV methodology should not be considered as the only measure to assess business cases and greater discretion should be provided to distribution network service providers (**DNSPs**) and other stakeholders.

1.4 Using CECVs to plan for DER integration

The issues paper highlights that valuing export curtailments or valuing CECVs is relevant to justifying and assessing proposed expenditure for DER integration.[7] It outlines the view that CECVs will capture the wholesale market costs and benefits to customers, as measured by changes in generator dispatch costs. We agree with this statement but consider that the CECVs should also capture the economic value of line losses that would be

4 AEMC, *Access, pricing & incentive arrangements for DER final rule change*, August 2021.

5 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 8.

6 NER, cl. 8.13(f).

7 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 12.

avoided by relying on DER generation rather than more traditional forms of centralised wholesale generation. We discuss DER value streams in more detail below in section 1.6.

1.5 Interpreting export curtailment

Section 2.2 of the issues paper states that DER export curtailment can occur when local network voltages exceed statutory limits and avoiding this may require stopping or reducing the output of the DER generation to allow the distribution network to continue operating within technical limits.[8] While we agree with this statement, this interpretation of export curtailment is too narrow, as export constraints are broader than just voltage issues.

For example, system security and minimum demand concerns could cause DNSPs to curtail customer exports. Ignoring these network features could potentially understate the total volume of expected constrained exports, which would weaken the DER integration investment case. Therefore, DNSPs should have the flexibility to include other operational issues that may contribute to export curtailment in their DER integration business cases.

Section 2.2 also outlines the AER's initial view that to calculate CECVs, the AER does not necessarily need to identify instances of curtailment and estimate the impacts on specific customers, but rather it could assume that curtailment is a scenario where a lower level of DER export occurs relative to an expected level.[9] We have several concerns with this approach.

Firstly, we agree that it would not be the AER's role to identify instances of curtailment. DNSPs would be required to forecast expected volumes of constrained exports over a forecast regulatory control period and these volumes would be used in an investment proposal. We also agree that instances of curtailment would not need to be estimated for specific end-users.

Secondly, we are concerned that this statement means the AER expects DNSPs to aggregate the total volume of curtailed exports over an investment period and multiply this by an average expected price to calculate the total detriment to end-users. If this is the case, the value of the curtailed exports would be averaged out and not reflect the true temporal benefits associated with removing export constraints at different times of the day.

For example, it may be economic to constrain exports in the middle of the day when wholesale prices are low due to excess solar and wind generation; in these instances, the CECVs could be negative. In contrast, there could be significant value in relieving export constraints during times of peak network demand; in these cases, the CECVs would be quite high. Overall, DNSPs would need to match the level of granularity for the volume of expected export constraints (e.g. in kWh) to the level of granularity that the AER determines for the CECV price (e.g. in c/kWh). The case study below outlines the importance of more granular CECVs that vary temporally rather than relying on average CECVs. Section 1.10 discusses the temporal nature of costs in more detail.

Case study – Weighted average vs simple average

Parameter	Morning	Middle of the day	Network peak	Average
Exports constrained (kWh)	3	5	1	3
CECV (c/kWh)	5	-2	9	4
Value of constraints	$0.15	-$0.10	$0.09	$0.12

[8] AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 13.

[9] AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 14.

> **Note:** these numbers are indicative only.
>
> The total value of the constrained exports in this scenario is $0.14. However, if a simple average is used, the total value of the constrained exports is $0.12. In this case, using a simple average understates the total value. In addition, if this simple average CECV price (12 c/kWh) is used to value export constraints in the middle of the day, a positive investment case could be made, when in reality it would be economic to continue constraining end-users from exporting at this time.

Section 2.2 also states that defining these scenarios and setting the expected level of DER exports would be a key element of the CECV methodology.[10] We request the AER provide more clarity on these scenarios and what it means by "the expected level of DER exports". Our submission to the AER's guidance note highlighted the need for a clearer definition of the base case in investment proposals. A clear base case definition would help define these scenarios and the expected levels of DER export referenced by the AER. Our submission noted a clear base case definition could be:

> *What are the expected export constraints assuming the network continues to operate under business-as-usual (**BAU**) conditions over the forecast regulatory control period?*[11]

This is a clear counterfactual that would also apply to other DER technologies, including batteries and EVs. It is also consistent with other investment approaches, including replacement and augmentation expenditure.

1.6 Interpreting value

Table 2 of the issues paper outlines a range of DER benefit types and value streams that could be captured in the CECV methodology.[12] As highlighted in section 1.4, we agree that CECVs should capture the wholesale market costs and benefits to end-users, as measured by changes in generator dispatch costs. CECVs should also capture the economic value of line losses at a DNSP level that would be avoided by relying on DER generation rather than more traditional forms of centralised wholesale generation (outlined in row 7 of table 2). This strikes the right balance between administrative costs and an appropriate level of granularity.

Some of the other network sector benefits will be very challenging to include in a general CECV methodology. For example, the issues paper states that increased DER exports can reduce load and peak demand, leading to avoided or deferred network augmentation.[13] As highlighted in our submission to the AER's guidance note, this may be true in some isolated instances and specific areas of the network (e.g. commercial and industrial areas). However, in general, increased solar PV would generate more exported energy during the middle of the day, while network peaks are increasingly occurring later into the early evening when solar resources are lower.

Nevertheless, DNSPs should have the flexibility to include other benefit streams, including but not limited to the benefit streams outlined in table 2, if they materially affect the investment case and can be justified. In these cases, DNSPs could 'value stack' the additional benefits onto the AER's established baseline CECV price. Importantly, we would consult on these additional benefits extensively with our end-users, and other stakeholders including the AER, as part of our price reset and in preparing DER integration business cases. This broad-based stakeholder support would be critical in developing and justifying DER integration investment proposals.

As outlined in both our submission to the AER's guidance note and above in section 0, better business case methodologies can and will be developed over time. Therefore, any methodology or guidance should be flexible enough to account for changing best practice approaches, which may include additional benefit streams or changes to existing benefit streams.

10 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 14.

11 JEN, *Submission on the AER's draft DER integration expenditure guidance note,* August 2021, p. 1.

12 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 15.

13 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 15.

1.7 Relationship between CECVs and export tariffs

Section 2.4 of the issues paper outlines that CECVs and two-way pricing have an indirect relationship.[14] It highlights that export charges and rebates (two-way pricing) will, where justified, signal to DER exporters the cost of network investment to host exported power. For example, when energy is exported at times when the network is already hosting large volumes of exports, such as in the middle of the day, exporting end-users will face export charges to reflect the potential costs that minimum demand issues can cause.

For the wholesale market benefit component of the CECV, we agree that CECVs and export charges or two-way pricing do not have a direct or causal relationship. However, we do consider that the CECVs and export charges could be highly correlated at particular times of the day. This relationship will be further strengthened if network sector benefits are included in the CECV methodology. Table 1–1 below outlines the link between the detriment to end-users from having their exports curtailed and the network costs associated with facilitating a greater level of export (the basis for export charges), as well as highlighting the likely relationship at different times of the day.

Table 1–1: Comparing cost and benefit value streams

Time of day	Detriment to all end-users from having their exports curtailed (CECV)	Network costs associated with facilitating a greater level of export	Relationship between CECV and export charge
Middle of the day	In the middle of the day, constrained DER exports may displace cheaper centrally-dispatched generation. As a result, all end-users would benefit by exporters having their exports curtailed at this time. Therefore, the CECV would be negative as there is value, not detriment, to all end-users.	Facilitating more exports in the middle of the day could cause minimum demand issues, which will need to be addressed by network expenditure. Exporters would be charged to reflect the long-run marginal costs that will be incurred to address these minimum demand issues.	Strong inverse correlation, i.e. a negative CECV would correspond to a positive export charge.
Evening peak	During the evening peak, constrained DER exports would likely have displaced more expensive centrally-dispatched generation in the wholesale market. Therefore, the CECV at this time would be positive, because there is a detriment to all end-users from exporters having their exports curtailed.	Facilitating more exports during the evening peak could be cheaper than having to augment the network to allow for more consumption during times of peak network demand. To encourage greater exports at this time, and to reflect the most efficient long-run marginal costs, DNSPs could adopt a negative export tariff.	Strong inverse correlation, i.e. a positive CECV would correspond to a negative export charge.
All other times	CECVs could be positive or negative depending on the wholesale generation market characteristics.	The long-run marginal costs of facilitating greater levels of export during other times of the day will vary (positively or negatively).	Variable

1.8 Distribution of costs

Section 3.1 of the issues paper outlines the AER's initial interpretation that CECVs will represent the detriment to all customers from the curtailment of exports and not particular customer groups.[17] We agree with this characterisation and agree that there should be one set of CECVs for all end-users. The wholesale market benefits associated with displaced generation (where applicable) accrue to all network end-users, regardless of whether

[14] AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 20.

[15] Based on the marginal change in dispatch costs in the wholesale generation market.

[16] And therefore the basis of DNSPs' export charges (two-way prices).

[17] AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 24.

they own DER systems or export energy back onto the network or not. However, section 3.1 also states that CECVs specific to DER customers may be more useful for the purpose of developing export tariffs.[18] This draws a direct link between CECVs and export tariffs, which is inconsistent with the AER's previous statement outlining that CECVs and two-way pricing would have an indirect link.[19]

As noted above in section 1.7, export tariffs would be linked to the long-run marginal network costs associated with exporting back onto the grid at particular times of the day, whereas the CECVs would be based on the detriment all end-users would face from exporters having their DER exports curtailed at different times. As highlighted in Table 1–1, the relationship between CECVs and export tariffs may be highly correlated at certain times of day (e.g. in the middle of the day or during network peaks). However, for the most part, this highly correlated relationship would not be causal.[20]

1.9 Locational nature of costs

Section 3.2 of the issues paper outlines the AER's view that CECVs should be estimated by NEM region, as this would be a simple approach and would reflect the nature of operations in the NEM.[21] As highlighted in section 1.4, CECVs should also capture the economic value of line losses (at an individual DNSP level) that would be avoided by relying on DER generation rather than more traditional forms of centralised wholesale generation. Including this benefit stream would result in the CECVs being more granular than values at a jurisdictional NEM level. This approach provides a balance between administrative costs and an appropriate level of granularity.

1.10 Temporal nature of costs

Section 3.3 states that while it is theoretically possible for DNSPs to forecast changes in dispatch costs over short timespans such as hours, days and weeks, this approach is not practical.[22] The AER considers that, in general, DNSPs will forecast these values on an annual basis and weight them according to an assumption about the time of day when solar PV generation displaces centralised generation. As highlighted in section 1.5, we are concerned that this approach would not provide the necessary granularity required to accurately capture the value of CECVs at different times of the day (refer to the case study in section 1.5). In addition, our interpretation was that the AER, not DNSPs, would forecast these values (over an appropriate period). DNSPs would forecast the expected volume of export constraints over the equivalent period. Multiplying these two inputs together would then produce the expected value of the constrained exports, which would be used in investment proposals.

The AER highlighted that an issue to consider in developing the CECV methodology is whether CECVs will be forecast into the future, and if so, how far it is possible to credibly forecast CECVs.[23] We agree that CECVs will need to be forecast into the future. If the AER does not publish these long-term values as part of its CECV methodology, then DNSPs will be required to forecast or extrapolate these values in investment proposals. IPART noted that the ASX futures market provides useful information on future wholesale market prices.[24] We agree and highlight that relying on wholesale futures prices would be consistent with the Victorian Essential Service Commission's (**ESC**) approach for establishing minimum feed-in tariffs in Victoria.[25]

18 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 24.

19 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 20.

20 The relationship may become increasingly causal as network sector benefits (i.e. reduced network augmentation etc) increase to a larger proportion of the total CECV amount.

21 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 25.

22 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 26.

23 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 27.

24 AER, *Customer export curtailment value methodology issues paper,* October 2021, p. 27.

25 ESC, *Minimum feed-in tariff review 2022-23,* December 2021.

2. Response to consultation questions

2.1 Interpreting export curtailment

Question 1

Do you agree with our interpretation of export curtailment in the context of calculating CECVs?

As highlighted in section 1.5, the AER's interpretation of export curtailment is too narrow. Export constraints are broader than just voltage issues. System security and minimum demand concerns could cause DNSPs to curtail customer exports. Ignoring these network features could potentially understate the total volume of expected constrained exports, which would weaken DER integration investment cases.

2.2 Interpreting value

Question 2

Which value streams should be captured in the CECVs?

As outlined in section 1.6, we agree that CECVs should capture the wholesale market costs and benefits to end-users, as measured by changes in generator dispatch costs. CECVs should also capture the economic value of line losses that would be avoided by relying on DER generation rather than more traditional forms of centralised wholesale generation. Other network sector benefits will be very challenging to include in a general CECV methodology. Nevertheless, DNSPs should have the flexibility to include other benefit streams if they materially affect the investment case and can be justified.

Question 3

Should CECVs reflect the detriment to all customers from the curtailment of DER exports or particular types of customers?

As discussed in section 1.8, we agree that CECVs should represent the detriment to all end-users from the curtailment of exports.

Question 4

How should CECVs be expressed?

We agree that CECVs could be expressed as a dollar per MWh or cents per kWh value. DNSPs would forecast the expected volume of export constraints over an appropriate analysis period, and multiplying these two inputs together would produce the expected value of the constrained exports, which would be used in investment proposals. Using a dollar per MWh or cents per kWh value would be consistent with other approaches to value DER exports, including the Victorian ESC's approach to establishing minimum feed-in tariffs in Victoria.[26]

[26] ESC, *Minimum feed-in tariff review 2022-23,* December 2021.

Question 5

Do you agree with our overall interpretation of CECV?

Broadly, noting the overall concerns discussed in section 0 and our response to the consultation questions above.

2.3 Relationship between CECVs and export tariffs

Question 6

Should there be a more explicit link between CECVs and export tariffs?

Please refer to our discussion on the relationship between CECVs and export tariffs in section 1.5.

2.4 Distribution of costs

Question 7

How could we estimate CECVs across different customer groups?

We agree that CECVs should represent the detriment to all end-users from the curtailment of exports and not particular customer groups. The wholesale market benefits associated with displaced generation will accrue to all network end-users, regardless of if they own DER systems or export energy back onto the network.

2.5 Locational nature of costs

Question 8

Should CECVs be estimated by NEM region?

As highlighted in section 1.4, CECVs should also capture the economic value of line losses that would be avoided by relying on DER generation rather than more traditional forms of centralised wholesale generation.

Question 9

Should CECVs for a particular NEM region reflect the impact of DER export curtailment that occurs in other NEM regions?

Yes, CECVs for a particular region will inherently reflect the impact of DER export curtailment in other NEM regions, because the constraints would already be factored into the wholesale price of each region.

2.6 Temporal nature of costs

> **Question 10**
>
> What is the appropriate temporal aggregation for estimating CECVs?

As highlighted in sections 1.5 and 1.10, we are concerned that the AER's proposed approach would not provide the necessary granularity required to accurately capture the value of CECVs at different times of the day. Overall, at a minimum CECVs should be broken down into three periods throughout the day, including during the middle of the day, the network peak period and other times. This is broadly consistent with the Victorian ESC's approach for establishing minimum feed-in tariffs in Victoria.

> **Question 11**
>
> Should we also estimate CECVs into the future or allow DNSPs to forecast changes in CECVs over time?

Yes, the AER should forecast CECVs into the future to assist DNSPs prepare investment proposals. This would ensure that DNSPs use a consistent approach, which was sought by many stakeholders including consumer groups during the 2021-26 price resets for the Victorian DNSPs. Alternatively, the AER should provide guidance to DNSPs on acceptable approaches for forecasting changes in CECVs over time.

2.7 Modelling issues

> **Question 12**
>
> Do shorthand approaches provide sufficient forecasting ability or is electricity market modelling necessary for calculating CECVs?

The AER should test both shorthand and longhand methods when calculating CECVs, including conducting scenario modelling and sensitivity analysis on both approaches. As highlighted in section 0, any approach should be flexible and fit-for-purpose.

> **Question 13**
>
> How should generator bidding behaviour be modelled?

It is not clear how the generator bidding behaviour feeds into the AER's proposed CECV methodology, noting that we consider the NEM regional pricing already captures generator bidding behaviour.

> **Question 14**
>
> How should interconnector behaviour be modelled to determine regional CECVs?

It is not clear how the interconnector behaviour feeds into the AER's proposed CECV methodology, noting that we consider the NEM regional pricing already captures interconnector behaviour.