CLEAN ENERGY COUNCIL

Monday, 3 February 2025

Scott Hall
AER

Sent via email to: transmissionSTPISreview@aer.gov.au

Dear Mr Hall

CEC submission on AER's proposed amendments to the STPIS Scheme

The Clean Energy Council (CEC) is the peak body for the clean energy industry in Australia, representing nearly 1,000 of the leading businesses operating in renewable energy, energy storage, and renewable hydrogen. The CEC is committed to accelerating the decarbonisation of Australia's energy system as rapidly as possible while maintaining a secure and reliable supply of electricity for customers.

We welcome the opportunity to provide feedback on the AER's proposed amendments to the Market Impact Component (**MIC**) and Network Capability Component (**NCC**) of the Service Target Performance Incentive Scheme (**STPIS**). This submission reflects the views of our developer and investor industry members only and does not reflect the views of TNSPs.

Overview

CEC does not support suspending the MIC without a replacement mechanism that incentivizes the effective management of network outages to minimise market impacts.

We consider that the MIC should be replaced as soon as possible with the incentive scheme proposed in section 2.3 below. The purpose of this scheme is to improve outage management by incentivising TNSPs inputting data in the NOS at least 4 months ahead of time.

The CEC broadly supports the AER's proposals in relation to the NCC. However, we consider there could be improvements to the proposed NCC scheme as outlined in section 5 below. These improvements aim to increase transparency in the decision making concerning the inclusion and removal of priority projects and permit increased stakeholder engagement in identifying and proposing priority projects under the NCC scheme for the TNSP's consideration.

We recommend that each TNSP is required to appoint an independent expert to audit line ratings of their network, and to examine how specified alternative transmission technologies could improve network capability (indicating by how much), within 6-12 months of the commencement of the new NCC scheme. TNSPs should be required to publish this study. We recommend that that TNSPs should be able to recoup the cost of this study as part of the NCC scheme.

Market impact component

1. MIC needs to be replaced without delay

CEC acknowledges that the MIC is currently not working as intended. However, we do not support suspending the MIC without a replacement mechanism that incentivises the effective management of network outages to minimise market impacts.

We are concerned that the AER has given no clear commitment or timeframe for re-instating the MIC – only once a suitable metric can be worked out, if this can even be achieved. This could be after 2030 when the bulk of the energy transition would be over, or not at all.

Improved network outage management is needed as soon as possible, and certainly before TNSP's next regulatory period, to minimise market impacts during the energy transition when there will be works to connect new projects to the grid and significant network augmentations.

The AER in its latest report into high price outcomes (for the July to September 2024)[1] also recognises the immediate need for improved network outage management, and notes, in particular, that scheduling of multiple network outages impacting different network flow paths at the same time should be minimised.

2. Proposed New Incentive Scheme to replace the MIC

We need improvements to the amount of advance notice given by TNSPs of planned network outages. We have set out below in section 2.3 a scheme to immediately replace the MIC to address the need for adequate advanced notice of planned outages to minimise market impacts.

2.1 Need for adequate advanced notice of planned outages to minimise market impacts

Adequate advance notice of planned outages is needed for TNSPs, AEMO and Registered Participants to minimise market impacts of planned outages. TNSPs are required to submit their current intentions on planned network outages for the next thirteen months[2] and they input this information into the Network Outage Schedule (**NOS**). However, the data, and tables, in the Outage Statistics section of the AEMO's Annual Constraints Report 2023 show that between 80 to 100 per cent of planned network outages are inputted into the NOS by TNSPs less than 3 months before starting[3].

The amount of advance notice given by TNSPs has not improved despite AEMO reporting annually on how each TNSP has performed. For this reason, CEC does not consider that the AER's proposal to report annually on each TNSP's outage performance will provide a reputational incentive on TNSPs to improve. Instead, we consider that an incentive scheme based on financial rewards/penalties is needed to replace the MIC to incentivize effective network outage management practices.

2.2 Need to give at at least 4 months' notice of planned outages to minimise market impacts

It is the CEC's view that TNSPs need to give at least 4 months' notice of planned outages in the NOS for market impacts to be minimised. This would permit:

[1] AER - Electricity prices above $5,000MWh - July to September 2024 | Australian Energy Regulator (AER) pages 3 and 7
[2] Rule 3.7A of the NER incorporating the requirements of clause 11.30.2(b) of the NER
[3] Relevant tables and data has been extracted in CEC's presentation on the AER's proposed amendments to the STPIS

- retailers to adopt risk mitigation measures to minimise impacts on consumer prices (via hedging)
- generators to schedule their own maintenance work to align with the network outage
- better coordination to minimise consecutive network outages which impacts generators on borders and market pricing outcomes
- AEMO and TNSPs to work collaboratively to move planned outages during the planning stages to reduce market impacts
- AEMO, TNSPs and generators to collaborate to minimise impacts of planned network outages through the NEM Maintenance Forum. This ACCC authorised forum was set up to manage reliability risks associated with System Works and it uses NOS data.

We also note that with adequate notice, AEMO can use its powers to minimise impacts eg through the Systems Integrity Protection Scheme (SIPs).

2.3 New Incentive Scheme to replace the MIC

We recommend that the MIC be replaced at least with a scheme which incentivises TNSPs to give **at least 4 months' notice of planned outages in the NOS** through rewards and penalties**.** Under the proposed scheme:

- TNSPs would sustain an incentive payment if they provide at least 4 months' notice of planned outages in the NOS
- TNSPs' incentive payment would be reduced if they provide less than 4 months' notice for each planned outage in the NOS, with penalty levels increasing as the notice period in the NOS decreases ie
  - the lowest penalty would be payable where 3-4 months' notice of an outage is given
  - the penalty would gradually increase as the notice period in the NOS decreases – eg increasing if less than 3 months, 2 months and 1 month notice is given
  - the highest penalty will be associated with outages for which less than 2 weeks notice is provided.
- There would be no penalty where the planned outages is moved at AEMO's request, required to be taken for an unforeseeable emergency or for unforecastable forced outages.

We suggest the AER consult with industry, AEMO and TNSPs on what planned outages should be included in the incentive scheme. However, we consider that the scheme should at least include:

- planned outages outlined in 3.2.2 of AEMO's Congestion Information Resource (**CIR**) guidelines; and

- planned outages based on the following two quantitative measures:

  - 10-15% expected impact on a network flow path's transfer capability

  This would, for example, capture outages of transmission lines in any of the Yass to Marulan/Bannaby or Canberra – Kangaroo Valley – Dapto – Sydney South flow paths (ie lines 4 and 5 in NSW in the southern to central NSW flow path). These are currently not classified as high impact outages under 3.2.2 of AEMO's Congestion Information Resource guideline, even though an outage on these lines would reduce transfer capability between Southern and Central NSW by approximately one third.

  - 10-15% expected impact on a generator(s) output capability

  We note that a TNSP should be able to predict whether a generator's output would be impacted if a transmission line is taken out. As noted above, it is important that a generator is given at least four months' notice of such a planned outage so that the generator would be in a position to organise maintenance work to occur at the same time.

These two quantitative measures are intended to capture planned outages which are likely to have a material effect on transfer capability or materially affect network constraints in relation to a transmission system. We have recommended in our submission to AEMO as part of its 2024 review of the CIR Guidelines that the definition of Planned Network Outage in paragraph 2 of Section 3.2.2 of the CIR Guideline be expanded to include these two quantitative measures in order to:

- capture those planned network outages which are not currently categorised as high impact network outages within section 3.2.2 of the CIR guidelines, but which have a material impact on the market, generator output and interconnector flows

- limit the opportunity for the qualitative criteria in section 3.2.2 to be interpreted narrowly, with the result that less network outages are notified via the NOS at least 4 months in advance of their commencement and in accordance with the requirements of rule 3.7A of the NER. This will result in TNSPs providing more network outage information earlier via the NOS, which will support the CIR objective and the National Electricity Objectives.

2.4 Benefits of the New Incentive Scheme

The proposed incentive scheme:

- has a clear, simple and easy to monitor metric
- provides TNSP's with clear incentive to implement improved network outage planning processes
- is not onerous as TNSP's already are required to input network outages in the NOS under the NER and AEMO's CIR guidelines
- will provide the opportunity for market impacts of planned outages to be minimised through the promotion of improved risk management by TNSPs and participants.

2.5 There could be more than one incentive scheme to replace the MIC

We have suggested one incentive scheme to improve outage management by incentivising TNSPs inputting data in the NOS at least 4 months ahead of time – which should be implemented as soon as possible (and at least by the next regulatory period for each TNSP).

Without holding up the implementation of the incentive scheme proposed in section 2.3 above, we consider that there could be more than one incentive scheme to replace the MIC and each incentive scheme could be based on a different metric. It is open to the AER to continue to engage with industry as to a suitable metric for an additional incentive scheme to replace the MIC (to be added to the scheme proposed in section 2.3) and this could be implemented later once a suitable metric for the additional incentive scheme is worked out (ie after the implementation of the scheme in section 2.3).

We acknowledge that finding a suitable metric for a workable and tested additional incentive scheme could be difficult and take time, and this should not be used as a reason not to immediately implement the incentive scheme proposed in section 2.3 above.

In developing a second additional scheme to replace the MIC, we recommend that the AER gathers information on:

- spot price impacts at the time of the outage as well as following the outage (if a battery cannot charge during the outage, they cannot discharge later when demand is high so there may be price impacts after an outage)

- revenue impacts on generation and batteries on energy and non-energy markets
  The AER should adopt a broad interpretation of 'market impacts" to also include revenue impacts on generation and storage. Revenue certainty will support the investment in renewables needed to maintain reliability as well as lower consumer prices.

- outages using the statistics in AEMO's network outage statistics report and their Annual Constraint Reports

- Impacts on radial lines – noting impacts will become greater as more generation, hybrid (generation/battery) projects and standalone batteries are connected to them.

We suggest that the AER work with AEMO to assess whether short notice of outages contribute to high price events - continuing the AER's analytical work so far, for example, in Figure 5 on page 21 of the AER's Explanatory Statement.

The AER should also collect information on the notice period given of the outage to determine if there has been compliance with the incentive scheme which we have proposed to replace the MIC in section 2.3 above. Please note that AEMO may be able to provide this information as part of its reporting under the CIR guidelines.

3. Industry guidance on NOS obligations

We need improvements to the advance notice given by TNSPs of planned network outages as soon as possible. We believe there is scope to do so under the current rules.

AER should issue guidance to clarify when an outage is likely to have a "material effect" on network constraints on transfer capabilities under the NER rules[4] so that more outages are inputted into the NOS with more than 4 months' notice on a consistent basis. For example, in order to achieve the National Electricity Objectives and the Congestion Information Resource Objective, we recommend that the AER issues industry guidance to clarify that an outage is likely to have a "material effect" on network constraints and transfer capabilities when it will have an expected impact of more than 10 - 15% of network flow path's transfer capability or an expected impact of more than 10 - 15% of generation output capability. We note that where more than one interpretation of the National Electricity Rules is possible, the National Electricity Law states that the interpretation of the NER that will best achieve the purpose or object of the NEL is to be preferred to any other interpretation[5].

4. Passing on penalties could undermine the MIC

We consider that any STPIS incentive scheme could be undermined if the TNSP can pass on penalties under the scheme to a Proponent[6]

[4] See NER 3.7A(b)(1) and NER 11.30.2(b)(5)

[5] Clause 7(1) of Schedule 2 to the NEL

[6] As an example one of the TNSP's standard form Generator Network Connection Agreement provides that the Customer is required to compensate the TNSP for any loss incurred or revenue foregone by the TNSP under AER's service target performance incentive scheme or any replacement, amended or other similar scheme (a "Performance Scheme") that is attributable to or caused by: (a) any outages needed to undertake the Connection Work (as defined in the Project Agreement)

We recommend that the AER write to industry to make clear that penalties under the MIC should not be passed on to Proponents, or the AER prohibits this specifically under the revised MIC scheme.

Network capability component

CEC welcomes the decision by the AER to retain the NCC scheme and link it with the TAPR. and considers that these changes will reduce the administrative burden on the TNSPs to identify and change NCC projects. However, we consider that the NCC scheme could be further improved as identified below.

5.1 Greater role of NCC

The AEMC considers that there should be a greater role for the NCC scheme in the future. The AEMC in its Final Report on the Transmission Access Reform:

- recommended that "the AER work with stakeholders, including through its review of the NCC component of the STPIS, to improve processes and incentives to identify and progress efficient, low-cost transmission augmentation projects that could alleviate local congestion": see recommendation 5.
- "considers that improvements to the NCC would be valuable in incentivising efficient, low-cost transmission investment to alleviate impactful congestion issues as they arise".
- noted that "the rationale of providing incentives to pursue low-cost solutions to improve the capability of the existing network, rather than high-cost capital augmentations, is likely to be of even greater benefit than when the scheme was introduced in 2012. Increasing connections of new generation to lower network capacity locations potentially creates new congestion. Improving capability of the existing infrastructure in a cost-effective way through this scheme will assist in delivering required investment to transition the power system": paragraph 3.2.3.

The AER has also noted in their 2022 report on network resilience:

> if weather events are becoming more volatile and result in more adverse outcomes, through a partial feedback loop, the STPIS is likely to gradually incorporate the effect of these events.

5.2 Greater role of all stakeholders

The AEMC considers that all *stakeholders* (which is broader than TNSPs and includes AEMO, participants, developers and innovators) should have a role in improving processes to identify and progress efficient, low-cost projects which would alleviate local congestion through the NCC and otherwise.

Consistent with the AEMC's recommendations:

- we consider that stakeholders (including developers, participants and AEMO) should be able to propose NCC projects to the TNSP and there should be a positive obligation on TNSPs to consider those projects. This contrasts to the current framework which gives the TNSP wide discretion as to whether to identify and progress any NCC projects.

In the Annexure, we have provided an example of a NCC project identified by participants around 2019 to address an emerging congestion risk, which if implemented prior to the closure of Liddell Power Station, could have avoided the significant subsequent curtailment of northward flows on the QNI. However, this did not occur as there is no formal process for participants to submit a NCC project to a TNSP for review.

- there should be transparency for all stakeholders in relation to the identification and progression of NCC projects (which the current framework lacks). In particular:

    - if the TNSP does not include a NCC project proposed by a stakeholder as a priority project in the TAPR, the TNSP should be required in their annual STPIS compliance review report to outline those NCC projects that were proposed and their identified benefits, and to give reasons for not including them as a priority project. The same information should be reported in the TAPR (unless the NCC project relates to a renewable project that has not been announced).

    - The TNSP should demonstrate how they have considered other NCC projects identified as being of low cost but high value in the study proposed in section 5.3 below, and the reasons for not including them.

    - Information on the progress of approved projects, including costs, and information about the removal of approved projects or addition of new projects, which the TNSP is required to report to the AER should also be made available to stakeholders on a timely basis.

We do not agree with the AER that “the TAPR process itself provides opportunities for market participants to provide input on connection point limitations” on page 36 of the Explanatory Statement. There is no formal consultation process to the TAPR, and our members have never seen a request to participate in a consultation concerning priority projects to be included in the TAPR. For this reason, CEC considers that there is a need for the NCC scheme to be improved to permit market participants to identify and recommend projects to TNSPs, as proposed in our submission on the Issues Paper.

Given the regulatory regime still provides incentives for TNSPs to dedicate their resources to the implementation of projects above the RIT-T threshold, and there is no obligation on the TNSPs to identify and progress projects under the NCC scheme, it is important that all stakeholders are able to propose NCC projects to the TNSP and there is more transparency around the TNSP’s consideration of priority projects under the NCC scheme, to ensure that low cost but high value NCC projects continue to be undertaken.

5.3 Independent studies of line ratings

Within 6-12 months of the commencement of the new NCC scheme, the TNSPs should be required to appoint an independent expert to undertake a study which:

- audits of line ratings of their network.
- examines how specified alternative transmission technologies could improve network capability (and by how much) at different locations where there is already high congestion, or where there is likely to be high congestion in the near future.
- recommends technologies and locations for low cost but high value projects.

TNSPs should be required to publish this study.

The independent expert, and the scope of the study, should be submitted to the AER for approval.

We recommend that that TNSPs should be able to recoup the cost of this study as part of the NCC scheme, for example, such studies could be deemed to be priority projects or included in the updated definition of “priority projects”. However, the TNSP should not receive any incentive payment in respect of the study.

The AER should have power to direct the TNSPs to update the studies/undertake new studies as required (for example, to take into account new and emerging technologies and changes in the network). It is recommended that the AER take into account any recommendations made by AEMO as to when to do so.

These studies will be invaluable as:

- it will permit AER to make informed decisions when reviewing the priority NCC projects in the TAPR and their ranking
- it can be used by the AER, AEMO, participants and developers to identify new projects under the NCC scheme
- it will facilitate better locational decision making for new projects
- incentivise the development of new and innovative solutions to identified system needs
- AEMO could include the findings of the studies in their Enhanced Locational Information Reports.

5.4 AEMO’s role in relation to NCC projects

We agree with the proposal to remove AEMO’s formal consultative role under the current framework, subject to the following qualifications:

- as noted in section 5.1, AEMO (like other stakeholders) should be able to propose NCC priority projects to the TNSP which the TNSP must consider.
- we recommend that the TNSPs should be required to consult with AEMO in relation AEMO’s Annual and Monthly Constraint Reports to determine the potential for viable projects, within a reasonable timeframe before submitting its annual STPIS compliance report.

5.6 Definition of priority project needs clarification

We consider that the proposed definition of priority project could be clarified to make clear it includes any low-cost project which could improve network capability (eg weather monitoring for dynamic line ratings).

We suggest that the definition of priority project is amended to read:

> each proposed augmentation to the network or proposed replacement of network assets ***or any other project that has the capability to improve network capability*** which is:
>
> (a) identified in the most recent Transmission Annual Planning Report published by a TNSP in accordance with clause 5.12.2(a) of the NER;
>
> (b) is likely to result in a material benefit to customers or wholesale market outcomes; and

(c) estimated to incur a capital cost less than the cost threshold for the proposed transmission investment to be subject to the regulatory investment test for transmission in Chapter 5 of the NER; or

any study undertaken by an independent expert to audit line ratings and/or to identify projects which could improve network capacity by utilising alternative transmission technologies.

The CEC welcomes further engagement with the AER on the amendments to the Service Target Performance Incentive Scheme. Further queries can be directed to [redacted]

Kind regards

Christiaan Zuur

Director
Market, Operations and Grid

Annexure

NCC Project identified by Participants to address emerging congestion risks

Background to emerging congestion risk

The Liddell Power Station TransGrid switchyard located in the Hunter Valley of NSW has always been, and remains, a key switchyard as it is the:

- primary network connection point for supply of consumer load in NSW ie north of Tamworth and Port Macquarie, and
- connection point for the Queensland to NSW Interconnector (QNI) to the core of the NSW shared network.

The Liddell switchyard is connected to the Bayswater switchyard by two routinely highly loaded 330 kV transmission lines. Historically tidal flows between these connection points occurred dependent on generation output at Liddell Power Station.

The Liddell switchyard is also connected to two additional 330 kV transmission lines, Liddell to Newcastle and Liddell to Tomago, which service significant consumer demand from the Newcastle and Tomago switchyards. These two additional transmission lines to Newcastle and Tomago take a similar geographical route from Liddell as the Bayswater to Liddell transmission lines traversing close to the Bayswater switchyard.

Historically, at times of low output from Liddell Power Station, exports limits from NSW to Qld would be severely constrained requiring forced imports from Qld to manage network loading across the two Bayswater to Liddell transmission lines.

Participants recognised that the announced closure of Liddell Power station which was confirmed in 2019 for April 2023 would result in the risk of significant curtailment of northward flows on QNI.

Potential NCC Project

There is a potential NCC project identified by participants in 2019 to address this emerging congestion risk – and which should have been progressed and completed prior to the closure of Liddell Power Station. Unfortunately, however, there is no formal process for participants to submit a NCC project to a TNSP for review.

The project would involve the turn in of one or both of the Liddell to Tomago/Newcastle 330 kV transmission lines to form an additional 330 kV transmission line between Bayswater and Liddell. This would double, for one line, or triple, for two lines, the transfer capability between Bayswater and Liddell without negatively impacting the transfer capability between Liddell and Tomago/Newcastle. It is unlikely that the standalone cost of this relatively minor project would have exceeded the RIT-T threshold.

The project would not require the construction of new 330 kV switchyard bays at the Bayswater switchyard as conversion of the two 330 kV transmission lines from Bayswater to Mt Piper to 500 kV operation and the retermination of these transmission lines to the new 500 kV switchyard at Bayswater released the respective 330 kV switchyard bays at Bayswater for alternative use.

Participants are now being told by the TNSP that it is necessary to wait for completion of the Central West/Orana REZ network project before this small network augmentation can be implemented.

Impact of failure to implement NCC project

Data from the period 1/5/23 to 23/1/25 indicates significant periods of binding of the constraint for managing flows on the Bayswater to Liddell flow path under system normal conditions.

Number of dispatch intervals each constraint was binding and spot prices while the constraint was binding

Constraint

Search from Monday , 1 May 2023

Search to Thursday , 23 January 2025

FCAS

Ramping

Search

Details

Live Chart

Constraint ID	Binding Events	Avg Marginal	Region	Avg Spot Price	Cap Payoff	Max Spot Price
N>BWLD33_BWLD34	243	-584.44	NSW	138.63	109.33	9520.98

There are also additional periods of binding constraints during periods of network outages on the Eraring to Newcastle and Vales Point to Newcastle 330 kV transmission lines which result in increased flows from Liddell to Tomago/Newcastle which further lower the northward limit on QNI.

The significant market costs of this congestion risk could have been fully avoided by early implementation of one of the Liddell to Tomago/Newcastle 330 kV transmission lines as a NCC project. Given the early announcement of the closure of Liddell Power Station, this work could, and should have been completed, prior to the closure of Liddell.