Electricity transmission network service providers

Service Target Performance Incentive Scheme

Proposed amendments

Explanatory Statement

November 2024

AUSTRALIAN ENERGY REGULATOR

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Invitation for submissions

Stakeholder engagement is a valuable input to our review of the STPIS. When we receive stakeholder submissions that articulate consumer preferences, address issues raised, and provide evidence and analysis, our decision-making process is strengthened.

You can contribute to our review by:

- making a written submission on proposed amendments to the STPIS to TransmissionSTPISReview@aer.gov.au with subject line “Submission to Transmission STPIS Proposed Amendments” by 3 February 2025
- joining us at an online public forum in December 2024.

Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. We will treat submissions as public documents unless otherwise requested.

Parties wishing to submit confidential information should:

1. Clearly identify the information that is the subject of the confidential claim.
2. Provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be published on our website. For further information on the AER’s use and disclosure of information provided to it, see the ACCC/AER Information Policy, June 2014.

Executive summary

The National Electricity Market (NEM) has undergone a significant transition since the service target performance incentive scheme (STPIS) for electricity transmission network service providers (TNSPs) was introduced in 2007. At that time, electricity generation in the NEM was almost entirely powered by fossil fuel sources. Over 40% of scheduled generation capacity used black coal as its fuel source, with brown coal comprising just under 20% and gas making up around 15%. Hydro accounted for just under 20% and wind generation accounted for only around 1% of capacity.[1] Rooftop PV capacity across the NEM was around 20 MW.[2]

The STPIS was introduced to maintain or improve TNSPs' service standards. It also provides countervailing incentives to those that arise from the efficiency benefit sharing scheme (EBSS) and the capital expenditure sharing scheme (CESS), which incentivise TNSPs to reduce expenditure. Without the STPIS, there is a risk that in response to the EBSS and CESS TNSPs will reduce their expenditure at the expense of service standards.

Fast forward to now and the generation landscape has changed dramatically. Our 2023 State of the Energy Market Report shows significant growth in renewable generation. Wind and solar output in the NEM accounted for 27% per cent of total generation, more than double its share in 2018. Renewable generation now makes up 60% of total generation capacity, with rooftop solar alone accounting for just over 18000 MW or 23% of generation capacity. Rooftop solar now accounts for more generation capacity than black coal. While gas use as a fuel source has remained stable, brown coal has fallen to around 6% of capacity with the closure of brown coal generators.[3]

This move from more centrally located thermal generation to more geographically dispersed and weather dependent fuel sources creates new demands on the transmission network and therefore has implications for how TNSPs manage their assets. This raises questions about whether the STPIS still provides appropriate incentives for TNSPs to maintain and improve service standards.

In April 2023, we completed a review of the incentive schemes that we apply to network service providers. During this review, stakeholders raised concerns about whether the market impact component (MIC) and the network capability component (NCC) of the STPIS remain fit for purpose, given the significant changes in generation across the NEM. More recently, TNSPs have also raised concerns with the approach to setting the performance target for the service component (SC) of the STPIS.

We consider the STPIS remains an important regulatory tool to ensure TNSPs are operating their networks in the best interest of market participants and consumers. However, we agree with concerns raised by networks and other stakeholders that in its current form elements of the STPIS are no longer working as intended.

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1 AER, State of the Energy Market, 2008, p 59.

2 AER, State of the Energy Market 2012, p 33.

3 AER, State of the Energy Market 2023, pp 54-55.

Market Impact Component

In monitoring market outcomes after the STPIS was introduced, we observed that planned outages were at times scheduled during periods of high demand and resulted in a substantial market impact. In response we amended the STPIS to introduce the MIC in 2008. The MIC provided TNSPs with financial incentives to schedule planned outages at times of least disruption.

Initially, the incentives provided by the MIC seemed to work well. The number of MIC events decreased materially. However, there is a general consensus that the MIC is no longer working as intended. High investment in renewables, increased congestion on radial lines, and more outages associated with high transmission investment, has contributed to a significant increase in the number of MIC events over the past five years. Now most TNSPs face maximum penalties regardless of their actions. For these reasons, we propose to suspend the MIC.

However, the original intent of the MIC, to minimise the market impact of planned outages, remains as important as ever. Maximising the capacity and performance of the existing transmission infrastructure will contribute to the energy transition and limit price pressures on consumers. Given that it appears that the MIC in its current form is not working as intended, we need to consider alternative options.

We propose to increase our monitoring of how TNSPs conduct themselves in planning outages, to assess how much of a problem this is for consumers. We will do this by exercising our information gathering powers to require TNSPs to provide more detailed information about their outages and by assessing existing data collected by the Australian Energy Market Operator (AEMO). We will report on this information annually.

Our reports will, among other things, show wholesale market price outcomes at the time planned outages are scheduled, show when outages coincide with high prices, and provide our assessment of the impact of the planned outage when prices are above $5000/MWh. These reports will also assess a TNSP's reasons for scheduling and rescheduling, how they have taken demand and supply forecasts into account, and to the extent possible, provide an overall assessment of the TNSPs' performance.

Through our monitoring and reporting, we may decide to reinstate the MIC, (or a variant thereof), should we identify a better metric that could be applied as an incentive mechanism.

We could also propose a conduct obligation in the National Electricity Rules (NER). Such an obligation would aim to encourage TNSPs to plan outages at times that are not detrimental to the market. We seek stakeholder views on the merits of a conduct obligation and suggestions on what form such an obligation could take. We also seek views on the timing of when we should introduce a conduct obligation (were we to do so). Specifically, whether we should propose a conduct obligation as soon as practicable or propose it only if our reports reveal material and systemic problems with TNSP outage management planning.

Network Capability Component

The NCC provides incentives for TNSPs to undertake low-cost solutions to address existing transmission constraints. This is consistent with the objective of the STPIS to maintain or improve the reliability of the transmission system.[4] Since the NCC was introduced, consumers have funded around $180m in expenditure across the TNSPs, which equates to $270m in directly funded costs through the NCC. The NCC so far has delivered around 100 projects that have improved network capability by over 8000 MW.

The NCC currently requires TNSPs to submit a network capability incentive parameter action plan (NCIPAP) as part of their revenue proposals. For each regulatory year, a TNSP will receive an annual network capability incentive allowance equal to 1.5 times the estimated cost of the priority projects identified. The incentive allowance is capped at one per cent of a TNSP's proposed average annual maximum allowed revenue (MAR). In addition, any capital expenditure that is incurred is rolled into the regulatory asset base (RAB). Revenue reductions may apply if a project exceeds its predicted costs, or a material change in assumptions used to estimate benefits results in the project no longer having a material benefit.

Increasing connections of new wind and solar generation potentially creates new congestion making the NCC as relevant as ever. However, the NCC, and the NCIPAP, are administratively complex. The identification of projects included in a NCIPAP is done well in advance of their likely delivery, and any variations during a regulatory control period must be reviewed by AEMO and approved by us. Further, we also need to review annual compliance and assess whether any revenue reductions are necessary at the end of the regulatory control period.

To streamline the process, we propose to require a TNSP to identify those projects in its annual Transmission Annual Planning Report (TAPR) that should be a priority project for the purposes of the NCC. There is an existing level of duplication between the information that a TNSP is required to provide in a TAPR, and in a NCIPAP. If we implemented this proposal, the NCIPAP would no longer be required.

Each year, a TNSP would submit an application to us that identifies the projects in its TAPR that the NCC should apply to. We would assess that application and publish our decision on which projects we have approved in annual NCC reports. We would also require TNSPs to report annually to the AER on progress towards reaching the priority project improvement target for each project. This would provide transparency and inform our decision whether to apply any reductions to the incentive allowance (for example, if there are delays or cost over-runs). This information could also be published in our annual NCC reports.

The NCC currently requires AEMO to review the TNSPs' proposed priority projects and AEMO may also propose projects that have not been identified by a TNSP. We welcome stakeholder views on whether AEMO still needs to be involved in assessing proposed priority projects.

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4 NER, cl 6A.7.4(1).

We also propose to simplify any adjustments to incentive allowances. Under the current NCC, revenue reductions can be up to 3.5 per cent of TNSPs' average annual MAR if improvement targets are not achieved. We propose to cap reductions in the incentive allowance to 1.5 times a project's actual costs. For capital expenditure projects the revenue reduction would be the same as the initial incentive payment provided that the project's estimated costs are the same as the actual costs. Where this is the case, TNSPs will be no worse off by proposing projects under the NCC, even if an incentive allowance reduction is applied because a project has not achieved the project improvement target.

Service Component

The SC provides incentives for TNSPs to reduce the number and duration of outages. For the most part the incentives have worked well with significant improvements in performance over time.

TNSPs urged us to review the loss of supply event frequency parameter in the SC. This parameter provides incentives for TNSPs to restore services quickly when an outage occurs. TNSPs raised concerns that the scheme can result in unreasonable performance targets. In setting a target we currently round the annual average number of events to the nearest whole number. This means that targets can be zero even if there were loss of supply events in the previous regulatory period. For example, if a TNSP experiences two loss of supply events over a five-year regulatory control period, the average annual number of events is 0.4. This is then rounded down to zero. Powerlink and Transgrid have been penalised by rounding.

We propose to amend the SC to remove rounding. Rounding was originally intended to simplify the administration of the SC. At the time, loss of supply event targets were much higher than now and the possibility of zero targets was not envisaged. Since then, TNSPs have improved outage response times substantially, creating the zero-target problem now experienced by some TNSPs.

By removing rounding, we would set targets as a fraction of events. For example, if a TNSP had 2 loss of supply events in the previous five-year regulatory period, the annual target would be 0.4. If the TNSP then has no events in a year they receive a financial reward, but if they have one or more events, they incur a penalty.

Timing of applying an amended STPIS

Under the NER, there is no ability for us to apply an amended STPIS to a TNSP during its current regulatory control period. We can only specify that an amended STPIS apply to a TNSP when making the revenue determination for a TNSP's next regulatory control period. As such, an amended STPIS can only start to apply to a TNSP at the commencement of its next regulatory control period. The earliest we could apply an amended STPIS is to Directlink from 1 July 2025 and the latest is to TasNetworks, from 1 July 2029.

To apply an amended STPIS to a TNSP in advance of its next regulatory control period would require a rule change. The purpose of proposing any such rule change would be to allow us to apply a new version of the STPIS during a TNSP's current regulatory control period.

Next steps

Our proposed amendments to the STPIS follow an extensive consultation process. We received 13 submissions in response to an Issues Paper we released in December 2023, as well as feedback from a public forum we held in March 2024 and focus groups that we held with TNSPs in June and July 2024.[5]

This review is being undertaken at the same time as other reviews that could affect the regulation of transmission networks. These include the Australian Energy Market Commission's (AEMC) final recommendations for Transmission Access Reform, the AEMC investigation into system strength frameworks in the NEM, and more generally the implementation of actionable projects under AEMO's integrated system plan. Our proposals are consistent with the objectives of these reviews to improve transmission capacity, improve system strength and improve efficiency.

We seek submissions in response to our proposed amendments to the STPIS by 3 February 2025 and invite stakeholders to participate in a public forum in December 2024. We plan to publish our final amendments to the STPIS by 24 April 2025.

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5 We received submissions from AEMO, TNSPs (APA, AusNet, ElectraNet, Powerlink, Transgrid), Energy Networks Australia (representing TNSPs), generators/retailers (Energy Australia, ENGIE), the Clean Energy Council, Tilt Energy, and user/consumer representatives including the Energy Users' Association of Australia and the Justice and Equity Centre (formerly the Public Interest Advocacy Centre). All submissions are available on our website.

1 Introduction

In May 2023, we completed a review of the incentive schemes that we apply to regulated Network Service Providers (NSPs), which included the Service Target Performance Incentive Scheme (STPIS).[6] In relation to the transmission STPIS, the final decision was to:

- review the market impact component (MIC), which provides an incentive to TNSPs to minimise the impact of transmission outages on wholesale markets
- review the network capability component (NCC), which provides incentive payments to TNSPs to undertake small, high net benefits projects, and
- retain the service component (SC), which provides a reward or penalty based on the number of unplanned network outages and how quickly the TNSP restores them, as is.

Our review of incentive schemes identified shortcomings with the MIC and NCC. Data revealed that the MIC initially worked as intended, but this is no longer be the case. Similarly, whilst the NCC has encouraged Transmission Network Service Providers (TNSP) to explore low-cost solutions to increase transmission capability, it is administratively intensive and is under-utilised.

In December 2023, we published an Issues Paper on the MIC and NCC. In response to the Issues Paper, among other things, the TNSPs suggested that we review the loss of supply event frequency parameter in the SC. The scheme sets performance targets based on past performance. However, at times the targets understate historic outcomes and TNSPs have been set a target of zero loss of supply events. This is a legitimate issue and we have now included it in this review. This Explanatory Statement and the proposed amendments to the STPIS follow submissions in response to the Issues Paper. We plan to publish the final amendments to the STPIS in April 2025.

1.1 What is the STPIS?

1.1.1 Incentive regulation

We regulate transmission network service providers (TNSP) by setting revenue caps over a regulatory period (typically five years). The revenue caps reflect forecast expenditure requirements.

The regulatory framework set out in Chapter 6A of the National Electricity Rules (NER) provides incentives for TNSPs to spend less than the expenditure forecasts that we set in our revenue determinations. These incentives are further strengthened by applying the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS). Generally, TNSPs receive financial rewards when they spend less than forecast. However, incentives provided by the EBSS and CESS to reduce expenditure run the risk of compromising service standards. This risk is addressed by providing countervailing incentives to maintain service standards. These incentives

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6 AER, *Review of incentive schemes for networks, Final Decision*, May 2023.

complement minimum standards established by state based licencing requirements (such as N-1 redundancy requirements).

Service standard incentives for TNSPs were first introduced in 2003 by the Australian Competition and Consumer Commission (ACCC) in a guideline that formed part of the Statement of Principles for the Regulation of Transmission Revenues.[7] The guideline applied rewards and penalties for the number and duration of outages and formed the basis for the first version of the STPIS that we published in 2007.

In monitoring market outcomes after service standard incentives were introduced, we observed that planned outages scheduled during peak periods (for example in summer) could constrain off generators, forcing AEMO to dispatch more expensive alternatives. The market impact was often substantial. We were concerned that the increase in spot market prices would flow through to contract prices and ultimately retail prices paid by households and businesses.

In response, we analysed metrics of the market impact of transmission congestion and developed the MIC incentive scheme. We amended the STPIS to introduce the MIC in 2008. This provided TNSPs with financial rewards for scheduling planned outages at times of least disruption. In 2015, we further amended the STPIS to include penalties as well.

In 2012, we introduced the NCC. The NCC provides incentives for TNSPs to undertake opex and minor capex that results in improving the capability of:

- those parts of the transmission system most important to determining spot prices, or
- the transmission system at times when users place greatest value on the reliability of the transmission system.

The scheme is based on business case analysis and outcomes are generally considered project by project. The NCC encourages cost effective improvements in transmission capacity.

1.2 Stakeholder consultation

This Explanatory Statement sets out our reasons for our proposed amendments to the STPIS. It follows the submissions we received in response to our Issues Paper released in December 2023,[8] the public forum we held in March 2024, and the focus groups that we held with TNSPs (on 14 June 2024), generators (on 26 June 2024) and consumer groups (on 5 July 2024).

The main views expressed by stakeholders are:

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7 ACCC, Statement of principles for the regulation of transmission revenues: Service standards guidelines, 12 November 2003.

8 We received submissions from AEMO, TNSPs (APA, AusNet, ElectraNet, Powerlink, Transgrid), Energy Networks Australia (representing TNSPs), generators/retailers (Energy Australia, ENGIE), the Clean Energy Council, Tilt Energy, and user/consumer representatives including the Energy Users' Association of Australia and the Justice and Equity Centre (formerly the Public Interest Advocacy Centre). All submissions are available on our website.

Market Impact Component

- Stakeholders agree that the MIC is not working as intended, and do not support retaining the status quo.
- However, views differ on a preferable alternative. TNSPs generally support suspending or ceasing the application of the MIC. Generators and consumer groups generally support amending the MIC in response to changing energy market conditions.
- Renewable generators do not support options we proposed to improve the scheme, primarily on the basis that the proposals focus too much on scheduled rather than semi-scheduled generation. Their preference is to link the MIC more directly to the revenue impact of outages on generators.
- Consumer groups consider suspension of the scheme is reasonable if combined with annual reporting of outage management outcomes.
- AEMO emphasised its focus on reliability and noted that scheduling planned outages has become more difficult because of the impact of renewables.

Network Capability Component

- Most stakeholders support retaining an amended form of the NCC that encourages TNSPs to undertake more projects.
- The Department of Climate Change, Energy, the Environment and Water (DCCEEW) and the AEMC were primarily interested in how the NCC can reduce transmission constraints and help with the energy transition.

Service Component

- TNSPs and the Clean Energy Council (CEC) support us reviewing the SC.

Attachment A provides a summary of submissions.

The transmission consultation procedures in the NER provide us with 80 business days from publishing our proposed amendments to publish our final decision on the amendments.[9] We have extended this time given the complexity of the issues involved.[10]

Indicative key dates for our review process are set out in Table 1.

9 NER, rule 6A.20.

10 NER, cl 6A.20(g).

Table 1: Indicative key dates for the review of the STPIS

Milestone	Date
AER public forum on proposed amendments to STPIS	December 2024
Submissions on proposed amendments to STPIS	3 February 2025
AER publishes final decision on the amendments to STPIS	24 April 2025

Note: Timelines are indicative and could be subject to change.

2 Market Impact Component (MIC)

2.1 About the MIC

The STPIS provides NSPs with incentives to maintain and improve network performance. It does so by rewarding and penalising NSPs that respectively outperform and underperform against service performance targets. The focus of the SC is the frequency and duration of interruptions to supply to consumers. For TNSPs, the SC parameters are:

- unplanned circuit outage event rate
- loss of supply event frequency
- average outage duration.

For the SC, reliability targets are typically based on the level of reliability achieved by a TNSP over the five years of its previous regulatory control period. The rewards and penalties are up to one per cent of the TNSP's MAR for the relevant year.

While the SC provides incentives to reduce the number and duration of interruptions to supply, it does not account for the market impact of outages. When transmission outages constrain off generators at times of peak demand, the impact on wholesale prices can be substantial.

Among other things, the principles of the STPIS are that it should provide incentives for TNSPs to:

> *(i) provide greater reliability of the transmission system that is owned, controlled or operated by it at all times when Transmission Network Users place greatest value on the reliability of the transmission system; and*
>
> *(ii) improve and maintain the reliability of those elements of the transmission system that are most important to determining spot prices*[11]

Accordingly, the MIC aims to provide incentives for TNSPs to schedule planned outages at times such as to minimise the impact on market outcomes than would otherwise have been the case. For example, to encourage TNSPs to schedule longer planned outages when seasonal demand is low (typically spring and autumn), shorter planned outages at times of the week and day when demand is low (such as weekends or overnight), or to alter practices where possible to allow for rapid return to service of equipment if market circumstances change.

The MIC works by identifying outages that require a network constraint to be invoked in AEMO's NEM Dispatch Engine (NEMDE).[12] Available AEMO data does not quantify the impact of constraints on regional wholesale prices. As a proxy for the impact, the MIC utilises published data on the marginal impact of network constraints.

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11 NER, cl 6A.7.4(b)(1).

12 The NEM dispatch engine (NEMDE) is the software developed and used by AEMO to ensure the central dispatch process maximises value of trade subject to the various constraints.

The marginal impact of a constraint is calculated by considering the impact of relieving a constraint by a fraction of a MW. This constraint reduction allows the constrained off generators to be dispatched for that additional amount.

To measure the impact of constrained off generators, NEMDE calculates the change in the cost of dispatch, which in simple terms usually equates to the difference between the price bid in by the constrained off generators and the regional price (the marginal generator’s bid). If, for example, generators behind the constraint bid -$1,000/MWh when the regional price is $100/MWh, then the marginal impact of the constraint is measured as $1,100/MWh.

The MIC identifies all the constraints that cause a marginal impact of $10/MWh or more in a dispatch interval. The AER sets a comparison point based on performance over the previous seven years. TNSPs receive financial incentives of up to one per cent of their MAR if there are fewer $10/MWh events in a year than the comparison point, and are penalised by up to one per cent of the MAR if there are more $10/MWh events than the comparison point.

TNSPs can propose to us to exclude events from the performance results. There are 13 possible reasons for exclusions listed in the STPIS, including force majeure events and events which are caused by a fault or event on a non-prescribed third-party asset.

2.2 A new approach to outage management is needed

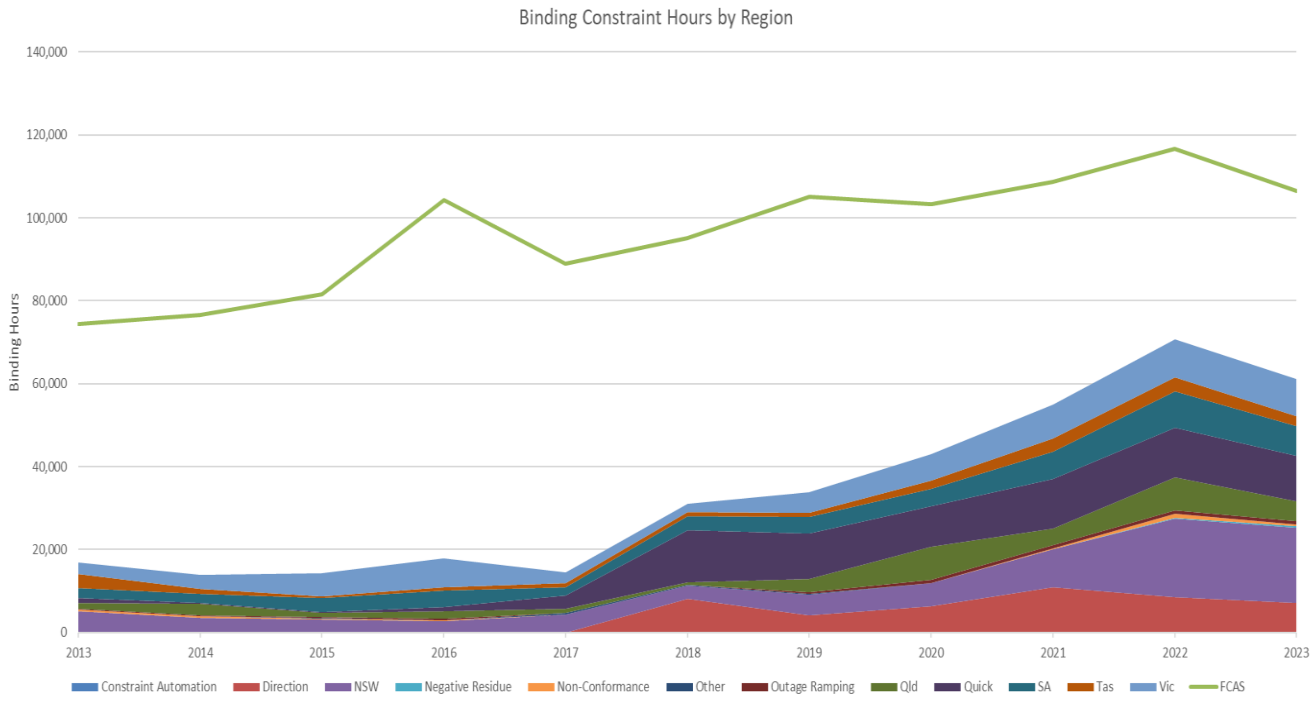
We consider that the MIC no longer works as intended because the energy transition is driving a fundamental shift in generation and the transmission network. Nevertheless, the original objective of the MIC remains as valid today as when it was introduced in 2008. We have considered some options and propose an approach to achieve good outage management practices in sections 2.3 and 2.4.

The energy transition is putting more pressure on transmission networks

The high investment in renewable energy generation has created widespread congestion, increasing network constraints above historical averages. As shown in Figure 1, binding constraints[13] on transmission networks have increased significantly.

[13] For network constraint equations, a binding constraint indicates the power system is being operated near or at a design limit (e.g. thermal, voltage stability or transient stability).

Figure 1: Binding constraint hours by region and constraint type



Source: [Annual NEM Constraint Reports]

The increase in binding constraints has contributed to a substantial increase in the number of $10/MWh events experienced by TNSPs. Specifically, the number of $10/MWh events for:

- Powerlink, increased from under 1,000 per annum in 2018 to over 13,000 per annum in 2019 and remains high.
- ElectraNet, increased from 96 events in 2014 to over 10,000 in 2015, then fell in 2017 but increased again in 2018, 2021 and 2022 to reach the highest level recorded in 2022 at 15,742.
- Transgrid, increased from 1,252 in 2019 to over 14,000 in 2020.
- AusNet Services, has fluctuated, but stepped up in 2021 to 3,756 and 2022 to 6,355.

Only TasNetworks has experienced relative stability in the number of $10/MWh events.

Since performance targets are based on historic performance, TNSPs submit that they are being penalised for changes in the generation mix instead of their management of outages.

The outcome is consistent with a step change in renewable generation. In the past, most generation was coal fired and located at a limited number of sites, for example, brown coal generation in the LaTrobe Valley in Victoria. Radial lines serviced load in the regions, but rarely generation. This meant that outages on these radial lines usually did not affect generation dispatch or spot market prices.

This changed with increased investment in renewables. Many new solar and wind farms are more locationally dispersed and connected to radial lines servicing regional areas. Outages on these lines, combined with the new requirement for system strength to allow stable operation of wind and solar farms, has led to a significant increase in the constraining off of these generators. In turn, these outages often cause $10/MWh events.

Other factors have also contributed to the increase in $10/MWh events:

- More planned outages are required with increased investment in new transmission lines, upgrades to existing transmission infrastructure, and connection of new generators. For example, the number of planned outages scheduled by Powerlink and ElectraNet increased four-fold and three-fold respectively between 2016 and 2023.[14]
- Scheduling outages is more challenging. Historically, TNSPs could rely on low demand and prices in Spring and Autumn to schedule substantial outages. As shown in Figures 2 and 3, we now see higher prices during these periods, especially during evening peak periods.
- Average Regional Reference Prices (RRP)[15] prices increased from 2021 onwards and were particularly high in 2022. This means that any given scheduled outage is more likely to coincide with high prices.

[14] AEMO, NEM Constraint Report 2023 summary data, April 2024.

[15] Regional reference price provides a reference from which the spot prices are determined within each region.

Figure 2: Regional reference price (RRP) average daily trends (Spring)

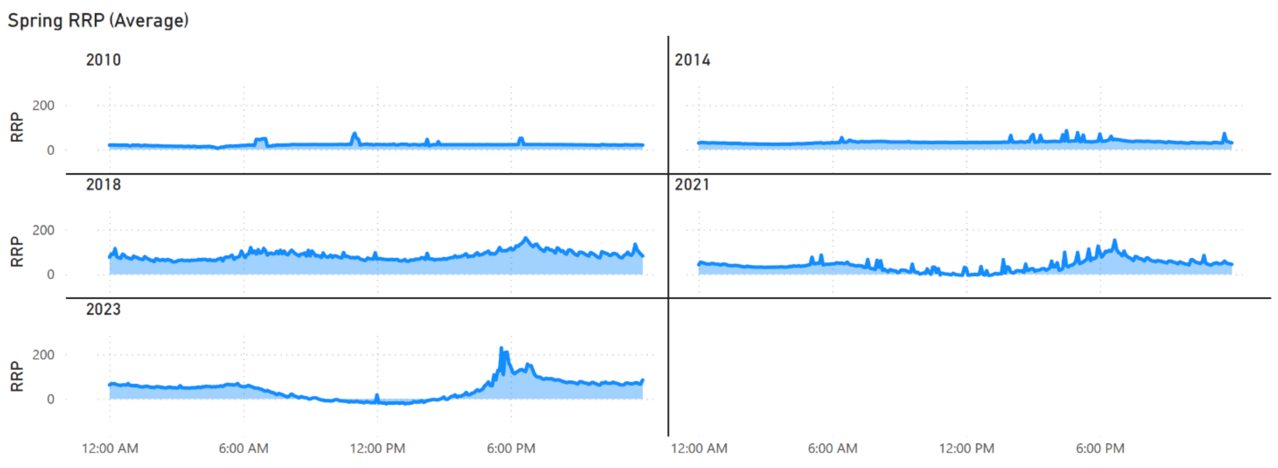
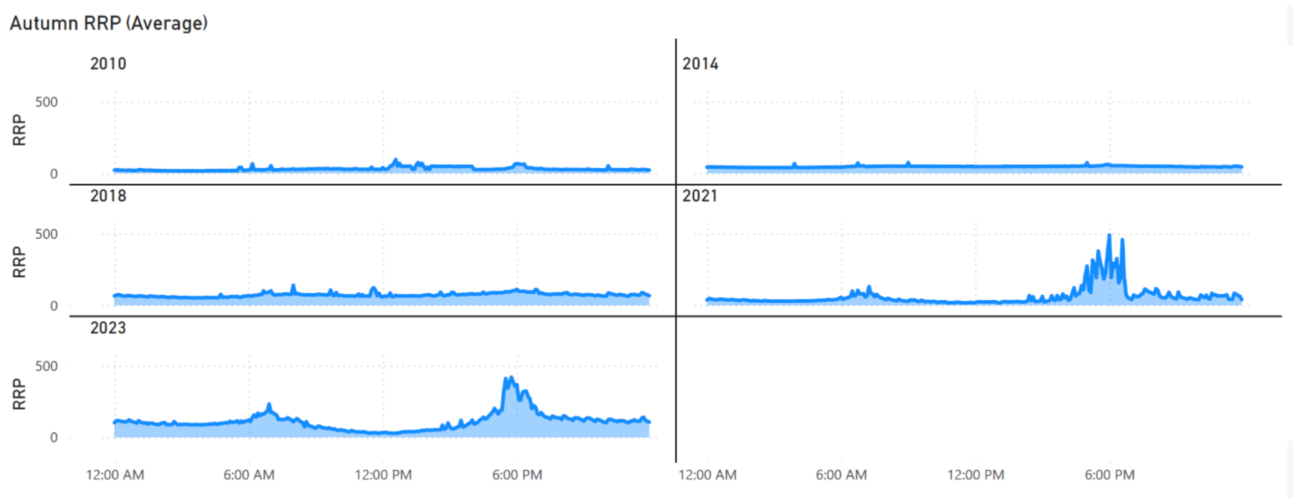


Figure 3: Regional reference price (RRP) average daily trends (Autumn)



The MIC no longer works as intended

Early in the MIC's operation, all TNSPs received rewards for improving performance. This was most marked for Powerlink with rewards averaging around one per cent of MAR between 2013 and 2018.

For some TNSPs, however, the number of $10/MWh events at times exceeded the performance target from 2015. Under version 4 of the STPIS (introduced in 2012) the TNSPs were not penalised, but often received no rewards. For example, ElectraNet did not receive a reward between 2015 and 2018. Nor did Transgrid, between 2015 and 2017.

Version 5 of the STPIS (introduced progressively between 2017 and 2019 at the start of each TNSP's new regulatory control period) allowed for penalties of up to one per cent of MAR. Increases in $10/MWh events resulted in MIC penalties, with all TNSPs except for TasNetworks eventually incurring maximum penalties:

- AusNet Services incurred maximum MIC penalties in 2021 and 2022.

- ElectraNet has incurred penalties since version 5 of the STPIS was introduced and maximum penalties from 2020 until 2022.
- Powerlink incurred maximum penalties from 2019 to 2022.
- Transgrid incurred maximum penalties from 2020 until 2022.

Factors outside the control of TNSPs have driven the substantial increase in the number of $10/MWh events and the penalties that the TNSPs consequentially face. If a TNSP knows it is likely to incur maximum penalties under the MIC irrespective of what it does, the incentive to better manage outages is significantly diminished. This appears to be the case for AusNet, ElectraNet, Powerlink and Transgrid. A new approach is required.

2.3 Market Impact Component options

Our Issues Paper canvassed the following three options for the MIC:

1. Retain the status quo.
2. Remove penalties and rewards by:
    - discontinuing the MIC
    - making it a transparency only scheme, or
    - replacing financial incentives with a conduct obligation.
3. Better target rewards and penalties by:
    - only including $10/MWh events on trunk lines
    - excluding semi-scheduled generation, or
    - only capturing MIC events that have a significant impact on wholesale prices.

This section discusses the options for improving outage management, and the reasons for our proposed approach.

Status quo

The rewards and penalties of the MIC are based on past performance and are revised every five years as part of a TNSP's revenue determination process. This means that an increase in $10/MWh events will eventually be captured in a future MIC target. Arguably, therefore, a future MIC target would reflect the impact of increased investment in renewables and $10/MWh events. This could provide a TNSP with the prospect of being rewarded under the MIC for improving the management, and reducing the market impact, of outages.

However, as we stated in our Issues Paper, we do not propose to retain the status quo. The impact of the energy transition is substantial, and it is likely to continue for an extended period. High investment in renewable generation will continue, both in response to government carbon emission targets and reductions in renewable energy costs. Historic outage performance measures are therefore likely to be a poor basis for predicting future performance for years or even decades to come. No stakeholders support retaining the status quo either. For example, Energy Networks Australia (ENA) stated:

> The transition brings with it many new constraints that were not there only a few years ago as the generation mix and their locations on the transmission network alter. Existing constraints are also binding more frequently. This makes setting an effective incentive framework for elements like the MIC extremely difficult.

Similarly, the Energy Users Association of Australia (EUAA) stated:

> EUAA is opposed to the current situation that unintentionally penalises TNSPs due to an outdated process that uses historical averages when the network was significantly different and less congested. In effect, the MIC has become a congestion tax on TNSPs.[16]

Better target rewards and penalties

When an outage constrains off a large generator (for example, a coal plant), the impact on spot prices can be substantial. By contrast, constraints on many radial lines only affect a small amount of generation with limited implications for spot prices. The current MIC is unable to distinguish between these types of events.

The objective of better targeting MIC events is to only reward or penalise TNSPs for events that have a material impact on spot prices. For consumers, this would improve the effectiveness of incentives to improve outage management.

In the Issues Paper we suggested three ways rewards and penalties could be better targeted:

- Exclude semi-scheduled generation. This would exclude $10/MWh events caused by constraints which only affect semi-scheduled generation such as wind and solar farms. The basis for this approach is that constraining off semi-scheduled generation is unlikely to have a material effect on spot prices.
- Limit the MIC to outages on trunk lines. This option removes outages on rural radial lines that typically have little impact on the regional price.
- Combine the $10/MWh threshold with a wholesale market price target. As noted above, much of the time constraining off generation doesn’t have a significant effect on regional spot prices, even if the marginal value of a constraint is measured at over $10/MWh. This option would only include $10/MWh events that occur at a time of high wholesale prices, for example more than $200/MW/h.

Taking into account stakeholder submissions and further data analysis we are now of the view that these options are unlikely to be effective for two reasons:

- Over time wind, solar and batteries will become more significant in the generation mix and therefore semi-scheduled generation should not be excluded. All the options identified in the Issues Paper exclude some or all semi-scheduled plant.

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16 ENA, EUAA submissions, AER Transmission STPIS Review, 5 April 2024.

- They are unlikely to work in practice.

The Justice and Equity Centre (JEC), the EUAA and generators expressed concern about options that exclude semi-scheduled generation. For example, Tilt Renewables stated:

> Tilt Renewables does not support limiting the MIC to trunk lines or scheduled generation. The future of generation in the NEM is more semi-scheduled generation on trunk and other transmission lines; therefore, it makes little sense to have the MIC only apply to generation technologies with ever declining market shares.[17]

Stakeholders also expressed reservations about limiting the MIC to trunk lines. For example, the ENA expressed concerns about practical implementation:

> …limiting the scheme to trunk lines vs radial may be problematic to agree and this can also change over time impacting the validity of the scheme.[18]

Generators argue that the MIC should focus on the impact of outages on their revenues, and that excluding radial lines is inconsistent with this focus. Excluding radial lines would affect many wind and solar farms, reducing their revenues and affecting investment. The generators submit that higher revenues and profits support higher investments in generation, and therefore, their interests are aligned with those of consumers.

In our view, excluding semi-scheduled generation from the MIC is not an effective long-term solution particularly as semi-scheduled generation is likely to become the dominant source of generation. Similarly, excluding radial lines has its limitations. This would exclude significant amounts of semi-scheduled generation and administering it would be arbitrary given there is no objective or agreed delineation between trunk and radial lines, as the ENA has pointed out.[19] Further, the boundary between trunk and radial lines may change over time as investments are made to upgrade and extend the transmission network.

In the Issues Paper, we expressed a preference for linking the $10/MWh threshold to a wholesale market price target. We observed that many, perhaps most, of the $10/MWh events used to determine rewards and penalties for TNSPs do not affect market prices and therefore do not directly affect consumer outcomes. The aim of this option was to filter out the $10/MWh events that do not have a material effect on prices and to provide a more stable data set for purposes of establishing incentive rewards and penalties.

The JEC and the EUAA supported exploring this option. However, generators and TNSPs expressed reservations. Generators are concerned that linking the MIC to a price threshold will exclude the impact of outages on many renewable generation and battery operators. The CEC stated:

> The CEC recommends the AER pursue a fundamental redesign of the MIC, to reflect its impact on renewable generation and storage revenues and investment more

17 Tilt Renewables submission. AER Transmission STPIS Review, 5 April 2024.

18 ENA submission, AER Transmission STPIS Review, 5 April 2024.

19 ENA submission, AER Transmission STPIS Review, 5 April 2024.

> broadly. Spot price effects are no longer the best indicator of long run market impact and consumer costs. Instead, we consider that generator revenue impacts, and consequential impacts on investment efficiency, should form the basis of the MIC.[20]

TNSPs submitted that the MIC is no longer fit for purpose even if the options for better targeting the MIC are introduced. For example, Powerlink submitted:

> The current and medium-term future state of the power system differs markedly from the power system operating environment when the MIC was first established. The current design of the STPIS largely reflects a previous paradigm. It was predicated on a transmission business' ability to reasonably forecast when transmission network capacity is of most value to network users and to plan network outages around these times, with some capability to respond to short notice variability.
>
> Power flows on our network are now heavily influenced by weather-dependent variable renewable energy output, both grid-connected and on customer rooftops. The rapid change in the mix and location of generation is not directly within our control. It is clear that the paradigm has shifted rapidly, and the scheme is no longer fit-for-purpose.[21]

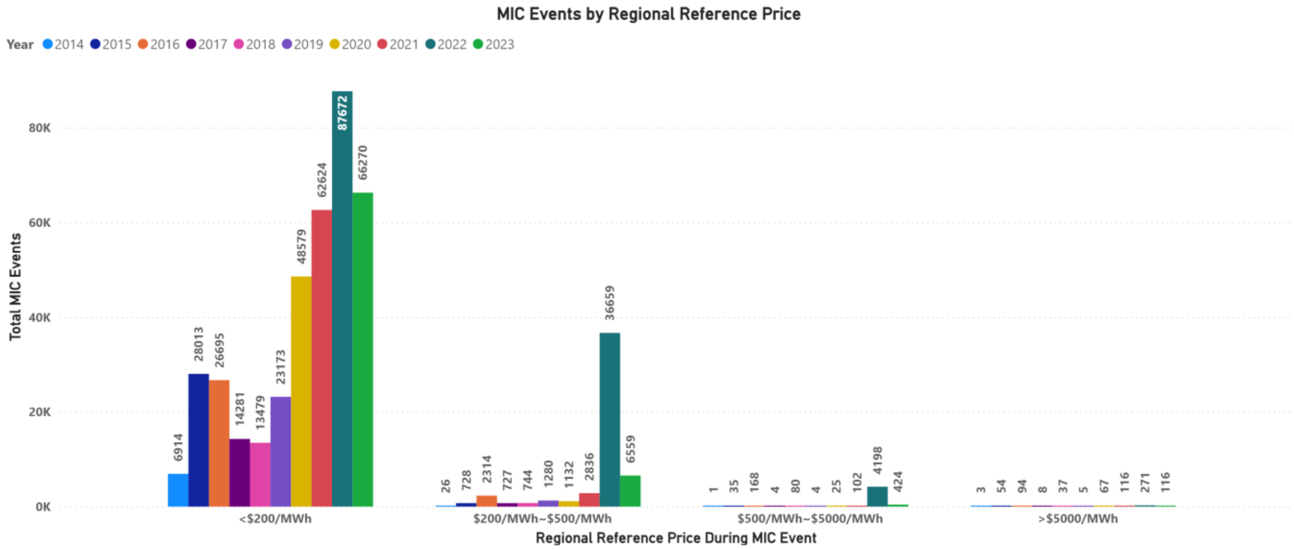
Since releasing the Issues Paper, we have assessed the data further. The reason to link $10/MWh events to wholesale prices was to filter out the impact of outages on radial lines, thereby providing a more stable pattern of $10/MWh events over time. Figure 4 provides a summary of results.

As a starting point, we only counted $10/MWh events that occurred in excess of a moderately high price point, namely, when the relevant RRP exceeded $200/MWh. As can be seen from Figure 4, this excluded many $10/MWh events. The question is whether excluding these events would provide a stable basis for forecasting MIC targets. While there was a significant uplift in $10/MWh events at lower price bands (less than $200/MWh), there was also an uplift in $10/MWh events in higher price bands. In the $200/MWh to $500/MWh price band, there was a significant upward trend in $10/MWh events from 2018 onwards. For higher price bands the data set is less stable but there are increases in the number of $10/MWh events over time.

[20] CEC submission, AER Transmission STPIS Review, 5 April 2024.

[21] Powerlink submission, AER Transmission STPIS Review, 5 April 2024.

Figure 4: Number of MIC events by RRP price band



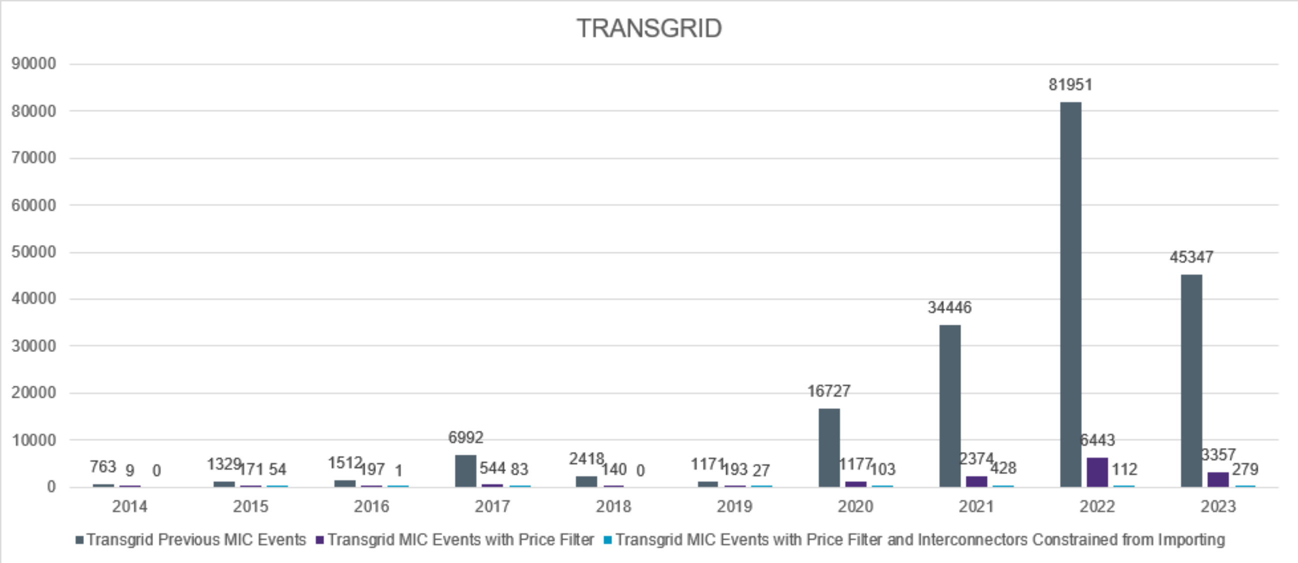
Source: AER analysis

Notably, the average RRP has fluctuated considerably since 2020. When the average RRP is higher, more $10/MWh events are captured in higher price bands. To control for this, we filtered the data by excluding $10/MWh events which occurred below twice the average annual price. The results for NSW (Transgrid) are shown in Figure 5 (noting the other regions show similar results). The total count of $10/MWh events is the grey column. The purple column is a count of events that occur when the regional price is twice the average, in other words when the market impact of an outage is likely to be material. This is a much smaller data set than the unfiltered count of all events.

As a further control, we took into account the impact of constrained interconnectors, that is to only include events where the region is also constrained away from neighbouring regions (the blue column). Being constrained away means no more imports are available from neighbouring regions and the market impact of the network outage is likely to be greater because the outage is likely to be involved in a material way in impacting the availability of supply to a region (either from within the region and/or from other regions). This is an even smaller data set of events.

Overall, the data reveals that few events occur when market prices are at twice average levels, and even fewer when a region is also priced away from other regions.

Figure 5: Number of Transgrid MIC events above normalised price and when region is constrained



Source: AER analysis

As stated earlier, most TNSPs currently face maximum penalties, which means that the incentive scheme (with the current MIC metrics) no longer works as intended. It is unclear whether if there was an improved metric, TNSPs would be able to better manage the much smaller number of network outages that have a material impact on the market.

The MIC was introduced after careful analysis of different indicators of the market impact of transmission congestion and several annual reports on those indicators.[22] Any new metric would need to be carefully designed and tested before being introduced as an incentive mechanism.

The conclusion that setting effective targets for a financial incentive scheme using current metrics is not workable, in the current environment, is consistent with our focus group discussion with user groups (JEC, ECA and EUAA) and submissions from TNSPs.

A revised approach: transparency and potential conduct obligation

For the reasons set out above, the MIC no longer works as intended. Nevertheless, the original intent of the MIC, to minimise the market impact of outages, remains as valid today as when it was introduced in 2008. Investing in large scale transmission capacity to connect new solar, wind and hydro generation capacity is crucial to implementing the current energy transition. Maximising the capacity and performance of existing transmission infrastructure will similarly contribute to the energy transition and limit price pressures on consumers.

Given the limitations of the existing MIC and the lack of workable alternative metrics at this point, we propose to suspend the application of the MIC. Instead of applying the MIC now, we propose to collect new data, introduce new metrics to measure the impact of transmission outages, and to

22 https://www.aer.gov.au/documents/market-impact-transmission-congestion-report

report annually. This will allow us to reinstate the MIC (or a variant thereof) should we identify a better metric that could be applied as an incentive mechanism.

We propose to introduce new annual reports on the TNSPs’ planned outage performance. Our reports will show wholesale market price outcomes at the time planned outages are scheduled, and which planned outages are scheduled when demand and supply conditions are tight. For example, we could provide a list of planned outages scheduled when the RRP was at a high level (say over $500/MWh or twice the annual average RRP). Where the wholesale price exceeds $5000/MWh, we can augment this information by drawing on relevant $5000/MWh reports.

The annual reports will:

- provide stakeholders with information about the TNSPs’ outage management performance
- to the extent possible, provide an overall assessment of the TNSPs’ outage management performance
- provide data and analysis that could pave the way for a revised MIC
- provide reputational incentives for TNSPs to maintain or improve outage management practices.

In order to enhance transparency, we propose exercising our information gathering powers to collect new data on reasons for planned outage scheduling and rescheduling decisions. When scheduling outages TNSPs should have regard to demand and supply forecasts and avoid scheduling an outage that could lead to high wholesale prices. Further, TNSPs should have regard to subsequent changes in demand and supply forecasts and consider rescheduling planned outages where the subsequent changes are likely to result in high wholesale prices. We propose to require TNSPs to explain how they have taken the demand and supply forecasts into account in making their scheduling and rescheduling decisions. Subject to confidentiality claims, we will make this information available in our annual reports.

We could also propose a conduct obligation in the National Electricity Rules. The intent of such a conduct obligation would be to, where possible, require TNSPs to avoid taking planned outages which could contribute to high wholesale market prices. We are mindful that any such conduct obligation should not have the effect of directing when a TNSP must take an outage. TNSPs remain best placed to determine timing of outages given the unique circumstances facing each TNSP, the complexity of their networks, and the need to retain the flexibility for them to respond to market conditions.

The Office of Gas and Electricity Markets (Ofgem) previously had an incentive scheme based on transmission capacity outcomes. This was more broadly based than the MIC but was similar in that it provided financial incentives based on defined metrics. Ofgem changed its approach in 2018 on the basis that outage management targets are unpredictable and hard to forecast. It stopped setting incentive payments based on quantitative targets, and instead adopted a scheme weighted toward qualitative assessments. As part of the (new) assessment process, it established a panel of independent experts to evaluate outage management performance, and initially provided financial rewards and penalties informed by the panel’s assessment. More recently, Ofgem discontinued the incentive payments.

2.4 Proposed amendments - MIC

We propose to suspend applying the MIC.[23]

Instead, we propose to exercise our information gathering powers to collect new data, introduce new metrics to measure the impact of transmission outages, and to report annually. This will allow us to reinstate the MIC (or a variant thereof) should we identify a better metric that could be applied as an incentive mechanism.

We could also propose a conduct obligation in the National Electricity Rules. Introducing a conduct obligation would require a rule change. We seek stakeholder views on the merits of a conduct obligation and suggestions on what form such an obligation could take. We also seek views on the timing of when we should introduce a conduct obligation (were we to do so). Specifically, whether we should propose a conduct obligation as soon as practicable or propose it only if our reports reveal material and systemic problems with TNSP outage management planning.

Amendments to the STPIS can only be applied at the commencement of each TNSP’s next regulatory control period. As such, the MIC financial incentives would only cease to apply at the commencement of each TNSP’s next regulatory control period.

[23] We have suspended the MIC by removing section 4 of the STPIS and ceasing its application to TNSPs. We can lift this suspension, or reinstate the MIC, by again amending the STPIS in accordance with the transmission consultation procedures.

3 Network Capability Component (NCC)

3.1 About the NCC

In 2012 the STPIS was amended to introduce the NCC.[24]

The NCC is designed to fund and provide incentives to increase the efficient capability of existing assets in the network when most valued, while maintaining reliability. The NCC provides an incentive to a TNSP to reveal the capability of parts of its existing network and to identify and implement measures that would provide greater value to generators and consumers. Specifically:

- *Generators* benefit from increased network capability as they are less likely to be constrained from dispatching generation by network limits, leading to more efficient generator dispatch in the market.
- *Consumers* benefit from the resulting lower wholesale costs and efficient improvements in network capability to meet increases in peak demand.

The NCC was originally intended to provide incentives for TNSPs to undertake low-cost solutions and operating expenditure to reveal the location of network limitations and to address constraints, to ultimately improve the reliability of the transmission system. This was consistent with the objective of the STPIS to maintain or improve the reliability of the transmission system.[25] At that time, this was also consistent with the revenue and pricing principles, in so far as providing an incentive to TNSPs to address constraints in this way was effective in promoting economic efficiency.[26] That is, the intention of the NCC was to encourage the undertaking of incremental or small improvements to the existing network rather than pursuing additional large augmentations and expansions of the network. When we established the NCC we considered that:[27]

> The network capability incentive would encourage TNSPs to identify whether incremental or small improvements can be implemented to resolve limitations or emerging constraints on the network. This would not be a heavy additional regulatory burden on TNSPs, but rather an extension of the existing obligations on TNSPs to identify known and emerging limitations in annual planning reports. TNSPs would now be incentivised to deliver a more service-oriented focus by determining whether incremental or small improvements could be implemented to improve network capability.

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24 AER, *Final Decision – Electricity TNSP Service Target Performance Incentive Scheme (STPIS) version 4*, 19 December 2012.

25 NER, cl 6A.7.4(b)(1).

26 NEL, s 7A.

27 AER, Explanatory statement, Electricity transmission network service providers, Draft Service Target Performance Incentive Scheme, September 2012, p.19

Under the NCC, a TNSP is required to consult with AEMO and submit a network capability incentive parameter action plan (NCIPAP) as part of the STPIS component of its revenue proposal. In summary, in a NCIPAP, a TNSP is required to:

- identify and outline the key network capability limitations on each transmission circuit or load injection point on its network
- include a list of priority projects it proposes to improve, through operational and/or minor capital expenditure, the network capability for some of the circuits or injection points
- for each proposed priority project, specify a priority project improvement target
- rank the priority projects based on the likely benefit of the projects on customers or wholesale market outcomes in descending order
- ensure the total annual incentive allowance does not exceed one per cent of the average annual MAR proposed by the TNSP in its revenue proposal.

For each regulatory year, a TNSP will receive an annual network capability incentive allowance equal to 1.5 times the average annual cost of the priority projects that we have approved, up to a maximum of 1.5 per cent of the average annual MAR of the TNSP over the regulatory control period.

If a TNSP does not achieve the targets for each approved priority project, then they may incur a revenue reduction of up to 3.5 per cent of the average annual MAR as a once-off adjustment that is determined in the final year of the regulatory control period. The target may not be achieved when the project exceeds its predicted costs, or a material change in assumptions used to estimate benefits results in the project no longer having a material benefit. To determine if a revenue reduction should be applied in these circumstances, we must consider, amongst other things, whether the project is still likely to provide a material benefit.

3.2 The utility of the NCC

Since the NCC was introduced, consumers have funded around $180 million in expenditure across the TNSPs, which equates to $270 million in directly funded costs through the NCC (refer to Figure 6). The NCC so far has delivered around 100 projects that have improved network capability by an estimated 8000 MW. The 8000 MW is calculated by summing the minimum increase in capacity for each project.[28] The increase in capacity is cost effective compared to major upgrades and greenfield projects. For example, the 8000 MW increase in capacity compares to just 190 MW of additional capacity into NSW and 460 MW of additional capacity into Queensland provided by the QNI upgrade but at a similar cost.[29] Greenfield projects, such as Project Energy Connect, cost more again. Project Energy Connect will deliver an 800 MW increase in capacity at a cost of approximately $3 billion.

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28 The increase in capacity differs for the time of year and the direction of power flow.

29 The QNI upgrade cost $236m.

Box 1 provides an example of the benefits provided by NCC projects and the type of projects that have been approved under the NCC.

Box 1: Example of the benefits of a priority improvement project

One priority project, to illustrate the value of these projects, was from Transgrid to upgrade the ‘Terminal Equipment’ for the 67 and 68 Murray – Dederang lines. The priority project identified that the 67 and 68 lines were being limited by equipment at the Murray Switching Station. This priority project replaced the disconnectors and wave traps and changed the current transformer ratios and protection settings to increase the rating of the terminal equipment by 311 MVA for each line. In their revenue proposal, Transgrid estimated the annual market benefit of this to be $0.477 million for a total project cost of $0.360 million.

There were a range of NCC project types, including:

- upgrading capability by replacing low-cost equipment
- dynamic line ratings (by installing weather stations to measure actual conditions)
- increasing operating temperature of lines by increasing ground clearances
- improving transformer cooling and monitoring transformer loading; and
- reactive power support for system stability and increased power flows during peak demand conditions.

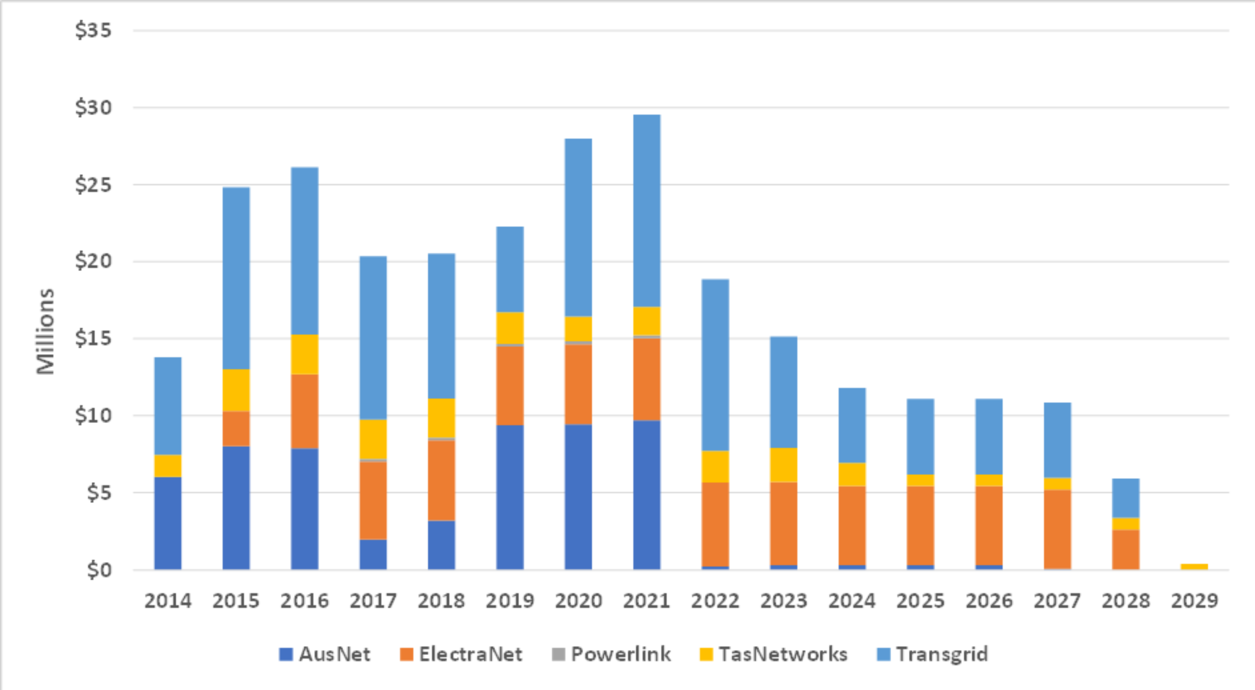
While this demonstrates there is value with the scheme, there is a question about whether the NCC is continuing to provide optimum incentives to maintain or improve the reliability of the transmission system, and, if so, whether this is promoting economic efficiency.

Declining use of the NCC

The total estimated cost of priority projects being undertaken across all TNSPs is around $35 million in the period 2025–29 (refer to Figure 6). Both the estimated expenditure and number of projects has declined in recent years. Specifically:

- total expenditure in the current regulatory control period is around 50 per cent lower than in previous regulatory control periods
- there are 15 projects in the current regulatory control period across the TNSPs, compared to 42 and 43 in previous regulatory control periods.

Figure 6: Scale and scope of NCC expenditure

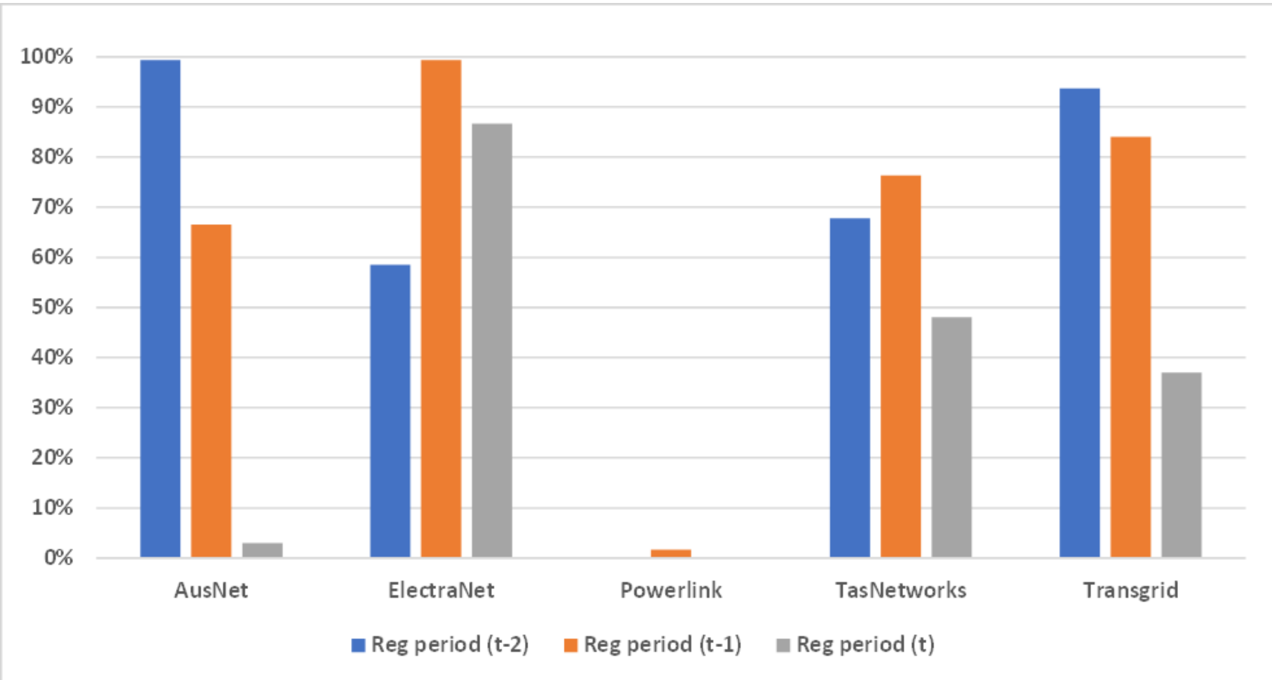


Source: AER analysis

Note: Expenditure reflects forecast expenditure over the period 2023-29

The NCC has been applied for at least two regulatory cycles for each TNSP. The use of the NCC varies between TNSPs but use of the NCC has been reducing over time (refer to Figure 7).

Figure 7: TNSP utilisation of the NCC



Source: AER analysis

Note: Utilisation is measured as the cost of the proposed NCIPAP projects relative to the NCIPAP cap which is 1 per cent of proposed MAR.

The underlying rationale of providing incentives to encourage TNSPs to maximise the capability of the existing network through low-cost solutions, rather than high-cost capital augmentations, remains applicable today just as in 2012. In observing this decline in the usage of the NCC, our Issues Paper sought stakeholder feedback on how important the NCC is in light of the scale and scope of the network augmentations under consideration today to transition to renewable energy sources.

3.3 Network Capability Component options

In the Issues Paper, we identified three options. Namely:

- continue to apply the current version of the NCC
- amend the NCC, to reduce its complexity and make its application and administration less burdensome; and
- discontinue the NCC.

In response to the Issues Paper, stakeholders did not support continuing to apply and administer the current version of the NCC. However, most stakeholders support amending the NCC to allow for more projects to become eligible and to reduce its administrative burden.[30] In particular, the generators are of the view that they (and consumers) benefit from the NCC as it encourages TNSPs to undertake low-cost solutions to reduce constraints on the network.

The exceptions are ElectraNet, who consider that its original intention has been satisfied so it is now appropriate to consider whether the NCC should continue, and Powerlink who prefer to use the standard revenue reset capex/opex process to fund these projects.[31] JEC and EUAA have queried whether the NCC was ever fit for purpose given its limited uptake.[32]

The amendments to the NCC proposed by stakeholders who supported it, include:

- balancing rewards and penalties with project value rather than MAR[33]
- making the application of the NCC optional[34]
- broadening the definition and project cost threshold so there are more eligible projects[35]
- fast tracking particularly beneficial projects[36]; and

30 ENGIE, Tilt Renewables, ENA, ElectraNet, Powerlink, Transgrid, AusNet, CEC, Energy Australia, EUAA, PIAC.

31 ElectraNet, Powerlink submissions, AER Transmission STPIS Review, 5 April 2024.

32 JEC, EUAA submissions, AER Transmission STPIS Review, 5 April 2024.

33 ENA, ElectraNet, Powerlink, Transgrid, CEC submissions AER Transmission STPIS Review, 5 April 2024.

34 ENA, ElectraNet, Powerlink, Transgrid submission, AER Transmission STPIS Review, 5 April 2024.

35 ElectraNet, Transgrid, CEC, Energy Australia, Tilt Renewables ENA and AusNet Services submissions, AER Transmission STPIS Review, 5 April 2024.

36 Tilt Renewables submission. AER Transmission STPIS Review, 5 April 2024.

- allowing collaboration with market participants.[37]

3.4 Proposed approach

Having considered stakeholder submissions, we propose to amend the NCC to improve its effectiveness to facilitate the take up of minor projects that improve network capability. In the context of the energy transition, the NCC continues to have an important role to play given there are likely to be opportunities to address pockets of congestion on the network from the entry of new generation on the fringes of the network and increases in demand from the economy.

The NCC therefore remains just as relevant today in seeking to incentivise TNSPs to deliver low-cost high value projects that can be quickly delivered alongside the delivery of large augmentations with longer lead times to deliver additional capacity. Most submissions supported retaining the NCC but consider the NCC needs to be revised given the focus on building large transmission projects to augment existing capacity to facilitate the energy transition.

Relevantly, the ENA submitted:[38]

> The AER's discussion paper correctly identifies that project numbers have been decreasing. We do not consider that this is an indication that the scheme is no longer effective or that it should be removed. When the scheme was first introduced, TNSPs were able to identify a larger number of projects. Projects are becoming harder to identify as 'low hanging' fruit has largely been picked.
>
> Augmentation of the network to facilitate the transition to renewable energy will remain a key focus for at least the next decade, if not longer. However, this does not mean that low cost, high benefit projects that increase the capability of existing assets do not have an important role to play. Incentivising the identification and delivery of these projects, when the focus is on larger augmentation, may be increasingly necessary. Although project numbers are decreasing, the scheme may have an increasing role to play in the future as assets age or capability of limitations of newer assets emerge or become apparent.

Similarly, the EUAA submitted:[39]

> The EUAA is of the firm belief that the NCC should be retained, but needs a significant revision in order to function as intended, and probably needs to account for the current massive infrastructure spend TNSPs are currently undertaking with ISP projects and the transition of the NEM to net zero.

The JEC submitted:

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37 CEC submission, AER Transmission STPIS Review, 5 April 2024.

38 ENA submission, AER Transmission STPIS Review, 5 April 2024.

39 EUAA submission, AER Transmission STPIS Review, 5 April 2024.

> The increases in costs and time needed to complete large scale transmission projects in recent years add weight to the position that small scale augmentations are likely to be value adding. It is not clear to PIAC (now JEC) which provisions in Chapter 6A of the NER the review paper is referring to. We consider that if discontinuing the NCC is likely to result in fewer priority projects being undertaken, this is not likely to be in consumers' interests.

However, ElectraNet submitted: [40]

> When the Network Capability Component was introduced, the AER said that it intended that it be in place for one regulatory cycle, with a review at that point. This reflected the general view that there was some 'low hanging fruit' in the form of small projects that would increase transfer capability and that a temporary intervention would enable these to be addressed.
>
> The Network Capability Component has now been in place for the regulatory cycle initially planned. As the issues paper shows, it seems to have met its original purpose. Numerous projects have been pursued, but the number of projects identified as the second regulatory cycle begins now seems to have reduced.
>
> In ElectraNet's view the AER is right to consider now whether the Network Capability Component should now be wound up. This is an opportune time to consider whether the challenge facing the transmission network today is seeking out small improvements in transfer capacity on the existing network or whether TNSPs and AEMO should be focussed on planning and building the transmission network necessary to facilitate Australia's transition to a low carbon future.

We agree with most submissions that in the context of the energy transition, the NCC continues to have an important role to play. This is especially so given there is likely to be opportunities to address pockets of congestion on the network from the entry of new generation on the fringes of the network and increased demand from the electrification of the NEM and the wider economy.

Some stakeholders have suggested that we consider amending the NCC to increase the scale and scope of eligible projects. In particular, by increasing the capital cost threshold cap for including a project in the NCIPAP (which currently must be less than the RIT-T threshold of $7 million).[41] However, we do not agree with this suggestion. Increasing the threshold cap is inconsistent with the intent of the NCC to provide incentives for TNSPs to implement low cost, high value projects. Further, the regulatory regime already provides incentives for TNSPs to implement projects of an estimated cost in excess of the RIT-T threshold. For projects above the RIT-T threshold, there is likely to be more scope for non-network solutions which may not be implemented if higher value

40 ElectraNet submission, AER Transmission STPIS Review, 5 April 2024.

41 We are required to review the RIT-T threshold every three years with our next scheduled review to be completed in 2024. On 3 September 2024, we released our draft decision proposing to increase the RIT-T threshold to $8 million.

projects were subject to the scheme and the RIT-T process may identify more efficient solutions to address a network constraint.

We are currently reviewing the RIT-T threshold and our draft decision on the RIT-T thresholds proposes to increase the RIT-T threshold to $8 million.[42] To the extent that the costs of delivering minor projects have increased, this proposed increase to the RIT-T threshold has had regard to the increased costs associated with transmission projects.

To improve the effectiveness of the NCC, our proposed amendments are to:

- link the NCC to a TNSP's Transmission Annual Planning Report, and remove the NCIPAP; and
- better align incentive payments with revenue reductions for not achieving priority project improvement targets.

Link the NCC to the Transmission Annual Planning Report (TAPR)

To streamline the operation of the NCC, we propose to link the TAPR to the NCC. Instead of requiring a TNSP to submit a NCIPAP as part of the STPIS component of its revenue proposal, we now propose that a TNSP should instead identify, each year, the projects in its TAPR that should be the subject of the NCC, for our approval.

The TNSPs are required to publish a TAPR, annually, that sets out information required by clause 5.12.2(c) of the NER and is consistent with the AER's TAPR Guidelines[43], which were introduced in 2018. A TAPR provides a 10-year outlook on network constraints and limitations and projects to address these. This includes:

- actual and forecast network limitations on transmission segments and connection points
- information on specific emerging limitations targeted at where the limitation will occur at a connection point or on a transmission line
- information about actual and forecast constraints, including their cause, location, economic cost (e.g., cost of load curtailment or wholesale market impact); and
- how the constraint is to be addressed (augmentation, replacement or operational investment).

It follows that all the information on network limitations, and the projects to address those limitations, that are relevant to the NCC should already be identified in the TAPR.

Specifically, we propose that a TNSP makes an application to us, each year, for approval of which projects identified in the TAPR should be subject to the NCC. We expect such an application to include:

- which projects identified in the TAPR should be considered a priority project for the purposes of the NCC, and the reasons why

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[42] AER, Cost thresholds review for the Regulatory Investment Test, Draft determination, 3 September 2024.

[43] NER, cl 5.12.2. AER, Transmission Information Guidelines, 2018.

- the estimated project costs and the proposed improvement targets, for all lines and injection points as outlined in their current TAPR
- the estimated net benefits of each priority project
- the ranking of these priority projects based on the estimated payback period for each project.

The annual incentive allowance for all priority projects is capped for a regulatory year and must not exceed 1 per cent of the TNSP's proposed average annual MAR.

We would assess the TNSP's application and publish our decision on which projects we have approved in annual NCC reports. We would also require TNSPs to report annually to the AER on progress towards reaching the priority project improvement target for each project. This would provide transparency and inform our decision whether to apply adjustments to the incentive allowance (for example, if there are delays or cost over-runs). This information could also be published in our annual NCC reports.

The NCC currently requires AEMO to review the TNSPs' proposed priority projects and AEMO may also propose projects that have not been identified by a TNSP. Given our proposal for the TNSPs to identify priority projects from their TAPR, there is a question about whether AEMO still needs to be involved. We welcome views from stakeholders on the extent to which the process leading up to the publication of a TAPR can be relied on, and whether AEMO as the independent planner should continue to review priority projects that are identified from a TAPR.

Incentive arrangements

The NCC applies an incentive allowance of 1.5 times the estimated cost of the project. The AER may also apply a reduction in revenue in the final year of a regulatory control period of up of to 3.5 per cent of a TNSP's average annual maximum allowed revenue in circumstances where the network capability improvement target has not been achieved. The NCC outlines the considerations that we must take into account in deciding whether to apply a reduction in revenue – noting that in total there have been only 2 projects where revenue reductions have been applied.

In the event a revenue reduction is applied, the magnitude of this reduction will depend on:

- the ranking of the project (projects are ranked in order of their estimated payback period, with projects that are ranked highly subject to a larger revenue reduction for non-delivery)
- the number of approved NCIPAP projects.[44]

The TNSPs submitted that revenue reductions for not achieving priority improvement targets should be based on project value.[45] We agree that the revenue reductions should be more closely aligned

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44 For projects ranked in the top 50th percentile, the revenue reduction is calculated as 2.5% of average annual MAR divided by the number of projects in the top 50th percentile. For projects ranked in the bottom 50th percentile, the revenue reduction is calculated as 1% of average annual MAR divided by the number of projects in the bottom 50th percentile.

45 ENA, ElectraNet, Powerlink, Transgrid and CEC, submissions, AER Transmission STPIS Review, 5 April 2024.

with the rewards as this may facilitate improved take up of the NCC. In particular, this should ensure the revenue reductions are not disproportionate to the rewards.

However, there is a question about whether reductions in incentive allowances should apply to estimated or actual costs of a project. Using estimated project costs is consistent with the incentive allowance under the current NCC. On the other hand, using actual costs avoids potential incentives for TNSPs to inflate project costs. We seek stakeholder views on this issue.

We recognise that the current reduction in revenue based on a percentage of MAR is not aligned with the incentive allowance, which is based on approved project costs. We propose to amend the NCC in response to submissions and to simplify the incentive structure. Specifically, we propose the reduction in incentive allowance is set at 1.5 times the actual cost of the project that materially did not achieve the improvement target as defined in the NCC. This would better align reductions in the incentive allowance to the initial rewards. This proposal would also simplify the incentive scheme by setting a single incentive allowance reduction rate, rather than the two incentive rates in the current NCC.

We also propose the incentive allowance applies when the priority project is expected to commence and, if necessary, to apply a reduction in the incentive allowance when the project is completed, where:

- the incentive allowances are provided on an annual basis for projects that are expected to commence in the next regulatory year; and
- where relevant, the reduction in the incentive allowance is applied on an annual basis for a completed project.

This differs from the current version of the NCC, where the incentive allowance is provided upfront and only adjusted where necessary during the regulatory control period as a result of the removal or addition of priority projects in the NCIPAP. In addition, our proposal would apply incentive allowances and incentive allowance reductions on an annual basis. By contrast, in the current NCC revenue reductions are applied in the last year of the regulatory control period.

The impact of the proposed incentives on a hypothetical priority project described below is illustrated in Table 2.

The priority project installs power flow technology that will increase overall capacity by increasing power flows on lines with surplus capacity. The estimated cost of the project is $4 million. The TNSP receives an incentive allowance of 1.5 times estimated priority project expenditure in the year the project is undertaken. This amounts to $6 million. Table 2 shows incentive payments under three scenarios:

- Scenario 1 shows the NCC rewards to the TNSP if the actual cost of the project is higher than estimated at $5 million. It shows that the TNSP receives $11 million for the project (comprising the incentive allowance and value of the RAB roll in), incurs $5 million in costs (the actual cost of the project), therefore receiving a reward of $6 million. This amounts to 120% of the actual cost of the project.
- Scenario 2 shows the outcome if the actual cost of the project is lower than estimated. In this this case the TNSP receives $9 million for the project, incurs $3 million in costs, and receives a reward of $6 million or 200% of the actual cost of the project.

- In some cases adjustments to the incentive allowance may apply, for example if the project does not achieve the improvement target. In scenario 3 we show the impact on the TNSP if a reduction in the incentive of 150% of the project's actual costs is applied and the actual cost of the project is higher than estimated.

Table 2: NCC incentives: hypothetical priority project*

	Scenario 1 - overspend	Scenario 2 - underspend	Scenario 3 -project target not achieved
Description	• Estimated cost $4m • Actual cost $5m • Project target achieved	• Estimated cost $4m • Actual cost $3m • Project target achieved	• Estimated cost $4m • Actual cost $5m • Revenue reduction of 1.5 times actual costs
Incentive allowance to TNSP**	$6m	$6m	$6m
RAB roll in (actual cost of project)	$5m	$3m	$5m
Revenue reduction	$0	$0	-$7.5m
Total amount received by TNSP	$11m	$9m	$3.5m
NCC incentive payment $***	$6m	$6m	-$1.5m
NCC incentive payment as per cent of actual cost***	120%	200%	-30%

*For simplicity this example does not include the impact of the CESS. There is a CESS impact on NCC incentives, however this is immaterial given the small size of the projects in the NCC.
**This example assumes incentive allowances are based on estimated costs not actual costs. As discussed above, we seek stakeholder views on whether estimated or actual costs should be used to set incentive allowances.
***NCC incentive payments are not expressed in present value terms and do not reflect adjustments for the time value of money for the timing differences between the provision of the incentive allowance and any incentive allowance reductions.

Other issues raised

Additional amendments proposed by TNSPs that we have we have not accepted are discussed below.

Making the application of the NCC optional

The ENA, and some TNSPs supported applying the NCC on an opt-in opt-out basis at the time of each revenue proposal. However, these submissions provided limited reasoning in support of their view that the application of the NCC should be optional. It is also important to recognise that the STPIS would need to be amended to allow the disapplication of components of the STPIS to be determined in a revenue determination and these submissions did not propose amendments be made to the STPIS.

We do not propose to make the NCC optional. As outlined above, we consider that the NCC is an important tool to improve existing network capability and our proposed amendments seek to encourage the use of the NCC.

Broadening the definition of priority projects

AusNet supported including projects that:

- enhance operating capability of the network (not just physical capability)
- enhance system security and network availability for credible and non-credible contingencies; and
- raise total network capacity or remove network limitations.

We consider that the current definition of the NCC remains appropriate in terms of identifying specific projects with specific capability improvement targets that can be simply assessed, to address network limitations. Operational capability improvements, on the other hand, are challenging to evidence. The scheme already provides the TNSPs with flexibility to amend the projects included in the NCIPAP during the regulatory control period and so we do not consider that the capability of the network is assessed at a given point in time.

Similarly, we consider that projects required to address system security requirements for credible contingencies are difficult to quantify. We also do not consider it is appropriate to incentivise a TNSP to implement projects to address non-credible contingencies given these relate to low probability events.

We maintain that the NCC should identify specific network limitations rather than total network capacity as this is necessary to identify the materiality of the benefits of projects to address these limitations and whether the specific capability improvement target was achieved.

CEC recommended expanding to include more low-cost/high-value projects (such as non-network solutions and emerging technologies).[46]

The NCC allows TNSPs to propose minor capex and operational expenditure to improve the network capability of existing assets. In circumstances where a project enhances the operating capability by addressing a circuit or connection point limitation to meet reliability requirements, this project would provide market benefits and be consistent with the NCC. The proposed amendments to the NCC which would require that priority projects be drawn from the TAPR may provide some opportunity for non-network solutions to be identified.

Allowing collaboration with market participants

CEC considered that other market participants should be able to identify and recommend projects to TNSPs as they could have better visibility over certain constraints. They should be able to submit a

46 CEC submission, AER Transmission STPIS Review, 5 April 2024

joint proposal with the TNSP to the AER. The CEC submitted that this could be proposed ahead of the TNSP's regulatory control period, but the NCC could also allow for projects to be identified during the regulatory control period.[47]

The NCC provides specifically for TNSPs to propose joint priority improvement projects. However, we recognise that there may be limited incentives for TNSPs to seek views from market participants on network constraints.

Our proposed amendments propose that priority projects that form the NCC be drawn from the TAPR, and the TAPR process itself provides opportunities for market participants to provide input on connection point limitations.

3.5 Proposed amendments - NCC

We propose to amend the NCC to implement the following:

1. Require a TNSP to propose, on an annual basis, which projects identified in its TAPR have the purpose of maintaining or improving existing network capability to achieve the objectives of the NCC and should accordingly be subject to the incentives provided by the NCC.
2. Provide for the AER to assess these proposals.
3. Require TNSPs to provide information on progress of approved projects, including costs.
4. Continue the existing incentive of 1.5 times the project's proposed costs and amend the incentive regime to better align the incentive allowance to any revenue reductions for not achieving priority project improvement targets, with a revenue reduction of up to 1.5 times a project's actual costs where targets are not met.
5. Provide the incentive allowance annually for AER approved priority projects expected to be commenced in the next regulatory year. Where relevant, apply any incentive payment adjustments annually to completed projects.

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[47] CEC submission, AER Transmission STPIS Review, 5 April 2024

4 Service Component (SC)

4.1 About the Service Component

The SC provides incentives to a TNSP to maintain the reliability of its network. It does this by providing a reward or penalty of $\pm$1.25% of MAR, based on the number of unplanned network outages and how quickly these outages are restored. The parameters used for the SC are either determined within the STPIS or are proposed by a TNSP in a revenue proposal.[48]

Four parameters comprise the SC:

- Unplanned outage circuit event rate.
- Loss of supply event frequency.
- Average outage duration.
- Proper operation of equipment.

TNSPs have expressed concern about application of the loss of supply event frequency parameter. This parameter measures the impact of unplanned outages on consumers and provides incentives for TNSPs to improve their response times when unplanned outages occur. This parameter accounts for 30 per cent of the SC of the STPIS.

For context, the loss of supply event frequency parameter measures the number of unplanned outages per year that take longer to rectify than system minute thresholds set out in the STPIS. System minutes are calculated as follows:

$$System\ minute = \frac{\sum(Energy\ not\ supplied\ (MWh) \times 60)}{Peak\ demand\ (MW)}$$

where:

- energy not supplied is the estimated load profile over the disconnection period from the NEM metering and substation load data
- peak demand is the network's peak demand in the previous periods.

The system minute thresholds specified in the STPIS represent reasonable times for a TNSP to respond to outages, which have been set using historical data and stakeholder feedback. We have updated these with each version of the STPIS. The system minute thresholds have reduced over time.

The TNSP's performance over a five-year period is used to set the target number of unplanned outage events. TNSPs receive financial rewards if they outperform, and penalties if they underperform, against their target.

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[48] Page 5, STPIS version 5 (corrected)

The current targets for the current and previous regulatory period are shown in Table 3. The targets are split into two components:

- Moderate loss of supply events (also called X parameter events). Table 3 shows the target number of events per year. The target is the five-year average number of events that could not be addressed within the timeframe specified in the STPIS.
- Large loss of supply events (also called Y parameter events). These outages have larger customer impact and generally take longer to rectify. TNSPs are given more time to respond to large loss of supply events than moderate loss of supply events. Again, Table 3 shows the target number of events per annum for each TNSP.

Table 3 shows that the target number of events varies across TNSPs, ranging from 1 to 4 per year for moderate loss of supply events, and 0 to 1 for large loss of supply events.

Table 3: Loss of supply targets

	Current Regulatory Period		
	Target		Period
	Moderate loss of supply events	Large loss of supply events	
ElectraNet	2	1	2023-28
Powerlink	2	0	2022-27
AusNet Services	1	1	2022-27
Transgrid	1	0	2023-28
TasNetworks	4	1	2024-29

4.2 Incentives are asymmetric at times

In our 2023 review of incentive schemes, we decided to retain the SC as is.[49] Accordingly, the Issues Paper did not cover the SC. However, in response to the Issues Paper, TNSPs urged us to review the SC to address alleged shortcomings with the loss of supply event frequency parameter.

While TNSPs support the retention of the loss of supply event frequency parameter, they are concerned that the scheme can result in a target of zero even if a TNSP experienced loss of supply events in the previous regulatory period. In administering the scheme, we:

49 Page 7, Review of incentive scheme for networks – final decision

- count the total number of loss of supply events over the previous regulatory period
- derive an annual average number of events (by dividing the total number of events in the previous regulatory period by the number of years in the regulatory period)
- round the annual average number of events to the nearest whole number.

The last step has resulted in zero targets. For example, if a TNSP experiences two loss of supply events in five years, the average annual number of events is 0.4. This is then rounded down to zero.

TNSPs are also concerned that the incentive scheme is asymmetric when the target is zero. As can be seen from Table 3, this is currently the case for Transgrid and Powerlink. When the target is zero, any loss of supply event incurs a penalty, but rewards are not possible. The best a TNSP can do is to avoid penalty payments.

Submissions couched the issue in terms of the threshold that is used to set the target. For example, Powerlink stated:

> We also consider that inflexible system minute thresholds for the loss of supply frequency measures can result in a TNSP target of zero. This approach raises concerns for the following key reasons:
>
> - A zero target indicates the best possible performance. As a result, the incentive to continue to *improve* performance is removed and the scheme becomes a penalty-only arrangement.
> - A target of zero is not in the interests of customers. The costs to maintain a performance level to meet a zero target would be higher compared to a lower target. These are costs which are ultimately borne by customers.[50]

We recognise that the SC can operate asymmetrically, and that this is inconsistent with the original objective of the STPIS. We have proposed amendments to the STPIS to address these shortcomings.

4.3 Service Component options

There are two options to address the shortcomings of the SC. We can amend the STPIS to:

- allow system minute thresholds (the time that TNSPs have to respond to an outage before it is counted as an event) to be changed, or
- remove rounding of targets to the nearest whole number.

TNSPs proposed amendments to allow the system minute thresholds to be changed. For example, the ENA submitted:

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50 Powerlink, AER Transmission STPIS Review, 5 April 2024.

> ENA proposes that X and Y should be removed from the STPIS instrument and set as part of a TNSP's Revenue Determination process.
>
> This is a 'no regrets' change from the AER's perspective. Shifting 'X' and 'Y' to the Revenue Determination process will not require the AER to change the levels, though in some cases ENA considers that they should be changed. The change proposed here merely gives the AER the ability to change them if it considers this appropriate. This allows improved flexibility for consideration at the time of each Regulatory Proposal and better reflects the agility needed for a transition to renewables. It is also consistent with the scheme's objectives, that is the need to promote transparency and efficient setting of expenditure allowances to maintain reliability throughout the transition.

Providing flexibility for TNSPs to amend thresholds allows TNSPs to choose thresholds which result in non-zero targets. If a TNSP takes longer to rectify an outage than specified by the X and Y system minute thresholds, the event is included as a loss of supply event for purposes of the SC. Lower thresholds mean that a TNSP has less time to respond to an outage before it is included as an event for purposes of the incentive scheme. This is likely to result in more events and higher targets over a given period.[51]

We do not agree with amending the SC in this way, because the thresholds have been reviewed several times and are fit for purpose. Allowing TNSPs to propose thresholds at each revenue determination process will also create additional complexity that is unwarranted.

Rounding was intended to simplify the administration of the SC. At the time loss of service event targets were much higher than now and the possibility of zero targets was not envisaged. Since then, TNSPs have improved outage response times substantially creating the zero target problem now experienced by Powerlink and Transgrid.

By removing rounding, we would set targets as a fraction of events. For example, if a TNSP had 2 loss of supply events in the previous five-year regulatory period, the annual target would be 0.4. If the TNSP then has no events in a year they receive a financial reward, but if they have one or more events, they incur a penalty.

In our view, removing the rounding is therefore a simpler and more effective way of addressing the asymmetry problem.

4.4 Proposed amendments – SC

We propose to amend the loss of supply frequence parameter of the SC to remove rounding so that targets can be fractions of an event.

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51 Our targets are set using historic performance. A lower threshold is likely to result in more loss of service events over the previous five-year regulatory period.

5 Timing of applying an amended STPIS

The AER makes a revenue determination for a TNSP prior to the commencement of its next regulatory control period. One matter that a revenue determination for a TNSP specifies for a regulatory control period is the STPIS that applies to the TNSP in respect of the regulatory control period.

We cannot amend a TNSP's revenue determination to allow an amended STPIS to apply during a TNSP's current regulatory control period. We can only specify that an amended STPIS apply to a TNSP when making a revenue determination for the TNSP's next regulatory control period. As such, an amended STPIS can only start to apply to a TNSP at the commencement of its next regulatory control period.

The commencement date of the next regulatory control period for each TNSP is set out in Table 4 below.

Table 4: Commencement date of the next regulatory control period for each TNSP

TNSP	Commencement of next regulatory control period
Powerlink	1 July 2027
Transgrid	1 July 2028
AusNet	1 April 2027
TasNetworks	1 July 2029
ElectraNet	1 July 2028
Directlink	1 July 2025
Murraylink	1 July 2028

Table 4 highlights that the earliest we could apply an amended STPIS is to Directlink, from 1 July 2025 and the latest is to TasNetworks, from 1 July 2029. A rule change is required in order to apply an amended STPIS to a TNSP in advance of its next regulatory control period.

Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CEC	Clean Energy Council
CESS	capital expenditure sharing scheme
DCCEEW	Department of Climate Change, Energy, the Environment and Water
EBSS	efficiency benefit sharing scheme
ENA	Energy Networks Australia
EUAA	Energy Users Association of Australia
JEC	Justice and Equity Centre (formerly PIAC)
MIC	market impact component
NCC	network capability component
NCIPAP	network capability incentive parameter action plan
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
Ofgem	The Office of Gas and Electricity Markets
opex	operating expenditure
PIAC	Public Interest Advocacy Centre (now JEC)
SC	service component
STPIS	service target performance incentive scheme
TNSP	Transmission Network Service Provider

Appendix A – Stakeholder submissions

This attachment summarises and responds to input that stakeholders provided on the following components of the STPIS:

- Market Impact Component
- Network Capability Component
- Service Component.

Table A1: Market Impact Component

Issue	Stakeholder submissions	AER response
Target setting and incentives	ENA, ElectraNet, AusNet and Powerlink submitted that TNSPs cannot respond meaningfully to MIC incentives as outage windows are becoming narrower as outage times are now dependent on the weather, and they can be rejected on short notice by AEMO if they issue an LOR2 notice.	Agree that the MIC is no longer fit for purpose. Propose suspension of MIC combined with consideration of new compliance obligations.
	ENA, Ausnet, ElectraNet, Powerlink and Transgrid stated that TNSPs are receiving maximum penalties.	
	ENA, ElectraNet, Transgrid and AusNet stated that the MIC is not focused on price impacts as many MIC events now do not have a material impact on spot market prices at the regional reference node (i.e., are intraregional constraints or constrain generators that are 'price-takers').	
	AusNet and ElectraNet submitted that the MIC relies on a measurement approach that is becoming less reliable as a proxy for real-world price impact, in an energy system that will be progressively more dependent on highly variable and decentralised renewables generation.	
	ENA, AusNet, ElectraNet, Powerlink and Transgrid submitted that the MIC target is not meaningful; it sets an unrealistic historical 'baseline' to project future expected TNSP performance. Changes in generation have resulted in substantial increases in the frequency of binding constraints for the same outage today compared to several years ago, therefore, there is no reasonable performance target that can be set.	

	AusNet stated that in Victoria, the MIC applies to a set of planned AEMO-initiated works beyond AusNet's reasonable control that results in unnecessary cost for Victorians.	
	Powerlink submitted that the application of the MIC means they are being penalised for factors outside their control.	
	ENA and ElectraNet considered that the $10/MWh threshold has no meaning and isn't linked to customer benefit.	
	Powerlink stated that amendments might make the scheme even more complicated	
	AusNet submitted that the MIC is unreasonably administratively burdensome to operate.	
	EnergyAustralia submitted that the AER's reliance on bid data rather than the "true" marginal cost of constrained resources reflects data limitations and the need for administrative simplicity in applying incentives.	Agree with data limitations for a complex issue such as the MIC.
	EnergyAustralia and CEC stated that we can expect to see greater market impacts of planned and unplanned transmission outages due to the energy transition, which, if not managed appropriately, will increase risk for investors and will impact costs, which will be paid for by consumers.	Agreed, hence our compliance and transparency proposals.
	Engie submitted that the MIC is not currently incentivising TNSPs to minimise disruptions during times of peak demand due to the maximum penalty being achieved annually.	
	Tilt Renewables and CEC commented that scheduled outages can result in 100% generator curtailment. Displacement of capacity does not only have "limited implications" for spot prices and generators.	
	Tilt Renewables commented that only about 10% of TNSP outages were put in 13 months' ahead of time as required by the NER, and only about 33% were lodged more than 3 months ahead of time. Further, short notice of planned network outages results in fewer opportunities to coordinate outages, which increases wholesale electricity prices.	Agreed but MIC not intended for commercial reasons and AEMO and AEMC are actively addressing this.

	CEC considered that spot prices are no longer the best indicator of long-run market impact and consumer costs. Instead, generator revenue impacts, and consequential impacts on investment efficiency, should form the basis of the MIC.	Agreed, being addressed by AEMO and AEMC.
	The CEC submitted that spot prices represent a narrow metric that does not consider the long-term impact of generators being constrained off due to outages.	The intent of the MIC is to focus on the reliability of assets that affect spot prices. Unclear what objective data is available on this as TNSPs still need to conduct outages.
	AEMO expressed concern that the MIC could have unintended consequence of delaying connections of new generation. Similarly, timely delivery of network augmentations that are in long-term consumer interest can be impacted if TNSPs are not willing to take outages in certain periods due to short-term disincentive.	STPIS objective relates to the reliability of assets that affect the spot price under the NER.
	AEMO commented that STPIS payments to TNSPs are allocated to consumers through Transmission Use of Service charges	Agreed.
	ENA, AusNet, ElectraNet, Powerlink, Transgrid support monitoring and reporting of TNSP outages but only if an appropriate measure can be established	
Proposed amendments to the MIC	CEC and Tilt Renewables support financial incentives but support a guideline or conduct obligations.	We are proposing a conduct obligation.
	CEC recommends that the MIC focuses on long-term investment impacts, which are primarily impacted by issues concerning revenue certainty for renewable generation and storage development, rather than short-term spot market outcomes. Tilt Renewables think it's worth considering shortening the 7-year period to 3-5 years of historical data. Energy Australia recommends:	We consider that the MIC is not fit for purpose in its current form. Many of the proposals from user groups and generators would improve the scheme but are not always implementable, for example use of trunk lines or re-running NEMDE.

	• Increasing the $10/MWh price threshold, noting this has not increased since its introduction in 2008. • Considering the inclusion of system normal constraints not just outages. • Introducing performance targets that capture the depth or volume of lost energy, not just the frequency of material price events during outages. • Introducing price bands that provide escalating incentives in line with events of higher market value. • Reconsideration of the total revenue at risk for TNSPs. The marginal incentive for TNSPs relating to an outage should be set equal to the value of the associated loss to the market, while also accounting for any costs incurred by the TNSP of selecting (or shortening) particular outage windows. EUAA supports only after rigorous modelling which is adjusted annually and advertised at least a year in advance.	
	PIAC supports better targeting of rewards and penalties by only applying $10MWh events to trunk lines, if the additional cost doesn't outweigh the benefits.	
	EUAA supports combining a price threshold with a target wholesale market price, to ensure that the MIC has maximum impact to TNSP outage scheduling during high demand periods where curtailment of generation due to the outage has the maximum impact to wholesale prices.	
	ENA and ElectraNet considered that rerunning the NEMDE would likely achieve the desired outcome but would likely add to AEMO's costs to an extent likely to outweigh the scheme's consumer benefit and it might work ex-post but cannot signal the cost of TNSP behaviour in advance.	
Alternative approaches	EUAA expressed a preference is for the AER to identify each line as having "low impact" or "high impact" to regional wholesale prices to allow TNSPs to manage outages with minimal impact to NEM wholesale prices in each region.	

Table A2: Network capability Component

Issue	Stakeholder submissions	AER response
Objectives of the NCC	ENA and CEC considered that incentivising the identification and delivery of low-cost projects may become more necessary as the network undergoes significant augmentation. Future assets will age, and the capability limitations of newer assets will be identified.	We agree that the NCC has an important role to play in incentivising the delivery of high value projects to optimise the existing capacity of the networks.
	Transgrid supports the NCC on the basis that it offers significant consumer benefits with short payback period. It encourages TNSPs to be proactive in finding innovative solutions to unlock capacity of existing assets.	We agree that an important aspect of the NCC is to encourage innovative solutions to improve the existing capability of the network.
	ENA, ElectraNet, CEC submitted that focusing on the number of projects is not an effective measure of the scheme. The AER should focus on the value add of each project. When the scheme was introduced TNSPs had a backlog of projects now they are doing more business as usual, which reflects the normal level of projects.	We have reviewed the trends in both the number and expenditure on priority projects. These trends evidence that there has been a recent decline in the usage of the scheme by TNSPs. We acknowledge the view that TNSPs may have had a back log of projects and now projects reflect business as usual opportunities. However, going forward we expect that there may be further opportunities as a result of the changing nature of the generation mix and projected increases in system demand.
	CEC considered that without the NCC, the TNSPs would not be incentivised to implement efficiencies.	We consider that the rationale for introducing the NCC remains just as relevant today and it has an important role in encouraging TNSPs to implement low-cost high value projects and consumers given the focus on large scale upgrades to network capacity to facilitate the energy transition.
	ENGIE stated that removal of the NCC may signal that TNSPs should shift focus to maximise remuneration through investment programs rather than maintaining service levels of existing assets.	The NCC is intended to provide incentives for the TNSPs to focus on service levels of existing assets. We have proposed amendments to the NCC that are intended to improve the effectiveness of the scheme in meeting the objectives of the NCC.

	Tilt Renewables commented that large projects are being delayed and it could be 3-5 years before the next major transmission project is completed. Therefore, TNSPs and AEMO should be working together to maximise the capability of the existing network.	We consider that optimisation of the network to meet the intent and objectives of the NCC remains an important feature of the regulatory regime. We have proposed that the NCC be linked to the TNSPs Transmission Annual Planning Reports (TAPR).
	Tilt Renewables proposed that the forecast and actual benefits to customers should be documented to demonstrate its importance.	The existing NCC requires us to undertake an assessment of whether a priority improvement target has been achieved in the last year of the regulatory control period. This includes a consideration of actual expenditure and if the project no longer provides estimated material benefits. The scheme requires the review of expected benefits of completed projects. To date we have considered that around 2 priority improvement projects have not achieved the priority improvements. The scheme has also provided improved capability of 8000 MW of existing capacity. We propose to assess applications for NCC projects and publish our decisions on which projects we have approved in annual NCC reports. We also propose that the TNSPs report annually on progress with identified projects. This would provide transparency to stakeholders.
	The CEC considered that other market participants should be able to identify and recommend projects to TNSPs as they could have better visibility over certain constraints. They should be able to submit a joint proposal with the TNSP to the AER.	The TNSPs consult on their NCIPAP proposals as part of their revenue proposals. We propose amendments to the NCC to require TNSPs to identify projects for the purposes of the NCC from their TAPRs on an annual basis. We encourage market participants to engage with the TNSP to inform the development of a TNSP's annual TAPR.
	EUAA considered that the AER should do further investigation on why the TNSPs are not fully utilising the scheme based on the facts not economic based analysis.	We have proposed amendments to the NCC that are aimed at encouraging take up of the NCC by the TNSPs.
	PIAC submitted that the changing network has led to even more generator curtailment and transmission access issues therefore the need to maximise capacity of existing assets has risen and will continue to rise.	We recognise that the changing market in terms of generator locations means that the NCC plays an important role in optimising the capacity of the existing network and have streamlined the NCC to encourage the implementation of high

		value low-cost projects to address network limitations.
	PIAC expressed concern that if discontinuing the NCC will lead to less priority projects it is not in consumer's interest.	We propose to retain the NCC subject to amendments on the basis that the NCC will continue to deliver high value projects to the market and consumers.
	PIAC submitted that the costs and time needed to complete large scale transmission projects in recent years increases the value add of small-scale projects.	We consider that the NCC is important to optimise the capacity of existing network and note that the NCC is designed to deliver projects that can be implemented quickly.
	PIAC submitted that there are alternatives to positive incentive schemes.	We are of the view that incentive arrangements are likely to promote the delivery of high value low-cost projects.
	ElectraNet submitted the AER is right to consider whether it should be discontinued as the number of identified projects has decreased. Additionally, the intention was to only operate for one regulatory period which it has done.	We propose to retain the NCC subject to the proposed amendments given the importance of providing incentive for TNSPs to deliver high value low-cost projects to address network limitations.
Balancing incentives	ENA, ElectraNet, Powerlink, Transgrid, CEC proposed that the penalty payments be based on project value not MAR.	We consider that adjustments to incentive allowances should be based on the actual cost of a priority project. This better aligns with the rewards given the incentive payment is based on proposed costs of the priority project, rather than project value.
	Powerlink stated that the NCC has disproportionate penalties.	We agree there is the potential for revenue reductions to be substantially higher than the rewards. We have proposed amendments to better align incentive allowances and revenue reductions.
	EUAA submitted that a project multiplier may be more effective to increase the incentive	We have maintained the incentive allowance of 1.5 times the proposed cost of a project.
Make the scheme optional for TNSPs	ENA, ElectraNet, Powerlink, Transgrid supported an opt-in opt-out arrangement at the time of each revenue proposal.	We do not propose that the application of the NCC be made optional noting limited reasoning was provided in support of their view that the NCC be optional.

Broaden the definition of projects	AusNet recommends including projects that: • Enhancing operating capability of the network (not just physical capability) • Enhancing system security and network availability for credible and non-credible contingencies • Raising total network capacity or remove network limitations. CEC recommend expanding to include more low-cost/high-value projects (such as non-network solutions and emerging technologies).	The scheme allows TNSPs to propose minor capex and operational expenditure to improve the network capability of existing assets. Operational capability improvements, on the other hand, are challenging to evidence. Similarly, we consider that projects required to address system security requirements for credible contingencies are difficult to quantify. We also do not consider it is appropriate to incentivise a TNSP to implement projects to address non-credible contingencies given these relate to low probability events. We maintain that the NCC should identify specific network limitations rather than total network capacity as this is necessary to identify the materiality of the benefits of projects to address these limitations and whether the specific capability improvement target was achieved. The proposed amendments to the NCC which would require that priority projects be drawn from the TAPR may provide some opportunity for non-network solutions to be identified.
Increase project size threshold from the RIT-T threshold	ElectraNet, Transgrid, CEC, Energy Australia, Tilt Renewables and ENA proposed increasing project size threshold from the RIT-T threshold, Tilt Renewables, ENA ElectraNet proposes an increase to $30 million and indexed.	The NCC includes minor capex and opex to improve the network capability of existing assets. Minor capex is defined as estimated capex that is less than the RIT-T threshold. This is consistent with the objectives and intent of the scheme which is to provide incentives for TNSPs to implement low cost, high value projects. We do not consider it is consistent with the objectives and intent of the scheme to allow higher cost projects above the RIT-T threshold to be included in the scheme. Specifically, we consider that the standard incentives in the regulatory regime should be sufficient to incentivise TNSPs to implement these projects. Further, for higher cost projects above the RIT-T threshold, there is likely to be more scope for non-network solutions which may not be implemented if higher value projects were subject to the scheme and the RIT-T process may identify more efficient solutions to address a network constraint.

Fast track certain projects	Tilt Renewables proposed that particularly beneficial projects should be fast tracked. Qualitative evaluation by experts could result in some NCIPAPs being determined to provide obvious benefits well above their costs and these could be quickly approved while the final analysis is completed.	We do not consider this is necessary as the NCIPAP is established at each revenue reset and can be varied on an annual basis throughout the regulatory control period. We propose that priority projects be identified and approved on an annual basis. If a project has a significant net benefit, the value of the project is likely to be highly ranked, and the TNSP would be expected to prioritise the most highly ranked projects.
Promote project benefits	Tilt Renewables advocated that public display and communication of the successful NCC projects in mitigating constraints on generation and reducing wholesale prices would be useful information to communicate to stakeholders and customers.	The NCC requires us to undertake an assessment as to whether projects have achieved the priority improvement target in the final year of the regulatory control period. To date there are only a few instances where we have applied a revenue reduction in circumstances where the target has not been achieved. We estimate that the NCC has improved network capability by 8000 MW.
Collaborate with market participants	CEC considered that other market participants should be able to identify and recommend projects to TNSPs as they could have better visibility over certain constraints. They should be able to submit a joint proposal with the TNSP to the AER. This could be proposed ahead of the regulatory period, but the NCC could also allow for projects to be identified during the revenue period.	The NCC provides specifically for TNSPs to propose joint priority improvement projects. However, we recognise that there may be limited incentives for TNSPs to seek views from market participants on network constraints. We encourage market participants to engage with TNSPs. The existing NCC also already provides the TNSPs with the flexibility to take into account new information by amending their approved NCIPAP during the regulatory control period.
	EnergyAustralia supported TNSP efforts could be reduced by socialising information on priority NCIPAP projects. This in turn could help facilitate collaboration.	We encourage market participants to engage with TNSPs to inform the development of their annual TAPR and to provide TNSPs with information on connections and emerging network limitations.
Replace NCIPAP	CEC suggested that TNSPs could flag minor capex projects as part of their Transmission Annual Planning Report.	In response to the AEMC's transmission connection and planning arrangements rule determination, we published Transmission Information Guidelines in 2018 and the TAPRs include: • actual and forecast network limitations on transmission segments and connection points; and

		• information on emerging limitations be specific and targeted at where the limitation will occur at a connection point or on a transmission line. We have proposed linking the TAPR for the purposes of identifying priority projects for the NCC.
Administrative burden	AusNet submitted that the scheme does not create unnecessary administrative burden.	We acknowledge AusNet's view that the NCC may not provide an administrative burden. However, we also recognise that the NCC is complex to administer, and we propose streamlining the NCC by relaying on the TAPR to identify projects.
	Powerlink considered that the NCC has a high administrative burden.	We propose to streamline the NCC as noted above.
	EUAA considered that it appears that the administrative burden for NCC projects outweighs the benefits for consumers	We consider that the NCC has provided material benefits to consumers and we have proposed amendments to streamline the NCC as outlined above.

Table A3: Service Component

Issue	Stakeholder submissions	AER response
Target setting	ENA, AusNet, Transgrid and Powerlink expressed concern that the current process could create a penalty only scheme as the inflexible system minutes can result in a TNSP target of zero.	Agree
	Powerlink stated that the AER review should consider the interactions between all components in its review.	Agree
	ENA, AusNet, Transgrid and Powerlink proposed that the 'X' and 'Y' system minute threshold be removed from the scheme and instead set them in a revenue determination.	Approach proposed is to remove rounding of targets.