Issues Paper

Transmission STPIS Review: MIC and NCC

December 2023

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Tel: 1300 585 165

AER reference: 15970779

Amendment record

Version	Date	Pages
1	8 December 2023	25

Contents

1 Executive summary

The priorities and challenges facing transmission network service providers (TNSPs) are very different to those which they faced over the last two decades. The scale and scope of the network augmentations under consideration today, to facilitate the transition to renewable energy sources, has changed how transmission networks operate and invest, and how the AER should regulate them.

This means that we need to assess whether the regulatory frameworks and tools that we apply remain fit for purpose and will facilitate the transition to renewable energy sources in the long-term interests of consumers.

In April 2023, the AER completed a review of the incentive schemes that we apply to network service providers. During this review, all transmission network service providers (TNSPs) raised concerns about the market impact component (MIC) of the service target performance incentive scheme (STPIS). The TNSPs questioned whether the performance targets associated with the MIC, which are set on past data, continue to be appropriate considering the substantial changes in mix and location of new generators across the National Electricity Market (NEM). We identified similar questions about whether the network capability component (NCC) of the STPIS remains fit for purpose.

Several other related reviews that could affect the regulation of transmission networks are currently underway. These include the Energy Advisory Panel's (EAP's) proposals for Transmission Access Reform, the Australian Energy Market Commission's (AEMC's) investigation into system strength frameworks in the NEM, and more generally the implementation of actionable projects under the Australian Energy Market Operator's (AEMO's) integrated system plan.

We consider it prudent to review the MIC and NCC in light of the energy transition and transmission reviews currently underway.

As part of their maintenance and expansion programs, TNSPs undertake planned outages. The MIC provides incentives for TNSPs to minimise disruption by undertaking planned outages at times when they will have little impact on wholesale market outcomes. This paper reviews the available data, concluding that MIC does not appear to be currently working as intended.

- Most TNSPs (Ausnet, ElectraNet, Powerlink and Transgrid) are incurring the maximum MIC penalty year after year. When a TNSP incurs the maximum penalty irrespective of its outage management actions, there are no financial rewards for good outage management, and the incentive properties of the MIC do not work as intended.
- The increased prevalence of solar and wind farms on radial lines has contributed to a large jump in MIC penalties. Outages on these radial lines are the main reason for increased MIC penalties. However, outages on radial lines often have little impact on the wholesale electricity market. Typically, the amount of generation capacity displaced is small with limited implications for spot prices and consumers.

There is a case to amend the MIC to address these problems.

The rationale for the NCC was to provide incentives to encourage TNSPs to maximise the capability of the existing network through low-cost options, rather than large capital augmentations. But how important this is, in light of the scale and scope of network augmentations under consideration to transition to renewable energy sources, is a question that needs to be addressed. The complexity of administering and applying the NCC is also a relevant factor in considering its future.

Further, AEMO plays an important role in ensuring the efficacy of the scheme. AEMO now focuses on large network projects and is more fully occupied with the Integrated System Plan. AEMO and TNSPs also now work more closely together on transmission planning including in developing options and undertaking cost-benefit assessments.

This Issues Paper is the first step in our review of the MIC and NCC. It discusses how these schemes work, how well they work, and outlines possible options to address identified shortcomings. We plan to finalise this review by the end of 2024.

2 Introduction

In April 2023, the AER completed a review of the incentive schemes that we apply to regulated Network Service Providers (NSPs).[1] This review focused on the Efficiency Benefit Sharing Scheme (EBSS), the Capital Expenditure Sharing Scheme (CESS) and the Service Target Performance Incentives Scheme (STPIS).

In relation to the STPIS, the final decision was to:

- retain the distribution STPIS as is
- retain the service component of the transmission STPIS as is
- review the market impact component (MIC) and the network capability component and the associated network capability incentive parameter action plan (NCIPAP) of the STPIS, in late 2023.

This Issues Paper is the first step in our review of the MIC and Network Capability Component (NCC) of the STPIS (the NCIPAP is the instrument which a TNSP must include as part of the STPIS component of its revenue proposal). We will release a draft decision in July 2024 and finalise the review by the end of 2024.

2.1 Why are we reviewing the transmission STPIS?

Our incentives review committed to review the MIC, commencing in late 2023. As part of the review we will consider whether the MIC is still fit for purpose given the transition to renewable energy, whether it should be retained, and whether it can be improved.

Data reveals that the MIC initially worked as intended. However, multiple submissions in response to our review of incentives schemes expressed concern about the operation of the MIC more recently. With high investment in renewables (often located where there is less network capacity than is the case for traditional generation) TNSPs are finding it difficult to schedule planned outages that do not have a wholesale market impact. TNSPs consider that they are being penalised for events that are outside their control.

The review also concluded that there is also a case to review the NCC. While the scheme has generated many projects and encouraged TNSPs to explore low-cost solutions to increase transmission capability, circumstances have changed. AEMO plays a key role in the scheme. TNSPs propose projects to address network limitations, then AEMO assesses the benefits of the proposed projects, and may even propose additional projects. AEMO now focuses on large network projects needed to support the transition to renewable energy and is more fully occupied with the Integrated System Plan. AEMO and TNSPs also now work more closely together on transmission planning including in developing options and undertaking cost-benefit assessments. This then raises the question about whether the NCC is still required, particularly in light of the energy transition and the administrative complexity and resource intensity of the NCC.

---

[1] AER, Review of incentive schemes for networks, Final Decision, May 2023.

2.2 Review process

This Issues Paper provides information about how the MIC and NCC schemes work, explains TNSP concerns, reviews data on the schemes' performance, and outlines possible options for addressing shortcomings. It is a first step in the review process and will inform the draft revised scheme we will release in mid-2024.

Indicative key dates for our review process are set out in Table 1. We are working towards having the review completed before the next round of resets begin.[2]

In accordance with the transmission consultation procedures, we have 80 business days from publishing the draft revised scheme to publish our final decision.[3] We may extend this time if the consultation involves issues of unusual complexity or difficulty or because of circumstances beyond our control.

Table 1: Indicative key dates for the Review of the MIC and NCC

Milestone	Date
AER publishes issues paper	8 December 2023
AER public forum on issues paper	Early March 2023
Submissions on issues paper due	5 April 2024
AER publishes draft revised scheme	July 2024
AER public forum on draft revised scheme	August 2024
Submission on draft decision due	September 2024
AER publishes final decision	November 2024
Revised scheme takes effect	December 2024

Note: Timelines are indicative and subject to change.

2.3 How can you get involved?

Stakeholder engagement is a valuable input to our review of the MIC and NICIPAP. 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 our Issues Paper to TransmissionSTPISReview@aer.gov.au by 5 April 2024
- joining us at an online public forum in March 2023.

2 AusNet is the next TNSP to commence the reset process. Its Regulatory Proposal is due to be lodged in October 2025.

3 NER, rule 6A.20.

3 The STPIS

3.1 Service standard incentives for electricity transmission networks

We regulate TNSPs by setting revenue caps over a regulatory period (typically five years). The revenue caps reflect forecast expenditure requirements.

In forecasting revenue requirements, we draw on past outcomes. For operating expenditure, we typically use a 'base year' as our starting point with adjustments for inflation, productivity gains and step-changes (such as new regulatory obligations). Similar for capex we consider past unit rates (for example the cost of each pole replacement) along with the past asset replacement activity.

Incentives are integral to this 'revealed cost' approach to regulation. The regulatory framework set out in Chapter 6A of the National Electricity Rules (NER) provides incentives for TNSPs to beat the expenditure forecasts that we set in our revenue determinations. These incentives are further strengthened by applying the EBSS and the CESS. Generally, TNSPs receive financial rewards when they spend less than forecast.

Electricity consumers benefit from efficiency gains that are realised because of our incentive schemes. The efficiencies are reflected in future expenditure forecasts and contribute to reductions in real prices over time. Our incentive review found that TNSPs have significantly reduced operating expenditure and capital expenditure since 2013 when the CESS and the current version of the EBSS were introduced. This has contributed to reductions in network charges.[4]

However, incentives provided by the EBSS and CESS to reduce expenditure run the risk of compromising service standards. This risk is addressed by also providing incentives to TNSPs to maintain service standards.

3.2 Transmission STPIS

Service standard incentives for transmission networks are set out in the transmission STPIS. The transmission STPIS comprises three components:

- **Service component (SC) -** provides a reward or penalty based on the number of unplanned network outages and how quickly the TNSP restores them.
- **Network capacity component (NCC) -** provides incentive payments to TNSPs to undertake small, high net benefits projects.
- **Market impact component (MIC)** - provides an incentive to TNSPs to minimise the impact of transmission outages on wholesale market outcomes.

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

---

4 See pages 11 and 12, Position Paper: Capital Expenditure Sharing Scheme, August 2022.

Statement of Principles for the Regulation of Transmission Revenues.[5] 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 taken 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 amended the STPIS to introduce the MIC in 2008. This provided TNSPs with financial rewards for undertaking planned outages at times of least disruption, which limits the price impact of outages on consumers. 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. It reduces the need for large scale investment projects along with their impact on transmission charges and consumer prices.

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

4 Market Impact Component of the STPIS

4.1 About the Service Component of the STPIS

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

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

Reliability targets are typically based on the level of reliability achieved by a TNSP over the five years of the previous regulatory period. The rewards and penalties are up to one per cent of the TNSP's maximum allowed revenue (MAR) for the relevant year.

Our review of incentives schemes retained the service component of the STPIS as is. Based on submissions, and our review of transmission service standard outcomes, we concluded that the Service Component of the STPIS remains fit for purpose. Performance standards for TNSPs are high and have improved since the current scheme was introduced in 2007.[6]

4.2 About the MIC

While the service component of the STPIS provides incentives to reduce the number and duration of outages, 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.

As part of their maintenance and expansion programs, TNSPs undertake planned outages. The MIC provides incentives for TNSPs to minimise disruption by taking the planned outages at times when they will have little impact on market outcomes. In practice this means taking longer planned outages when seasonal demand is low (typically spring and autumn), and similarly shorter outages at times of the week and day when demand is low (such as weekends or overnight).

The MIC also provides incentives for TNSPs to minimise the impact of unplanned network outages. The incentive in this instance is to return the equipment to service as quickly as possible when there is a market impact.

The MIC works by identifying outages that require a network constraint to be invoked, which allows NEMDE (AEMO's NEM Dispatch Engine) to factor in the impact of the constraint on dispatch options. Available AEMO data does not quantify the impact of constraints on

[6] For example, in 2021 the NEM experienced 5 loss of supply events due to transmission failures, the fewest events in any year dating back to at least 2006. See the AER's State of the Energy Market 2023, chapter 4.

regional wholesale prices. As a proxy for this impact, the MIC utilises published data on the marginal impact of network constraints.

The marginal impact of a constraint is calculated by considering the impact of reducing a constraint by 1MW. A constraint reduction would notionally allow the constrained off generators to be dispatched for that 1 MW rather than the generator dispatched by NEMDE.

To measure the impact of dispatching constrained off generators, AEMO compares the price bid by the constrained off generators to the regional price. 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. A $10/MWh event occurs when the difference between the bids of constrained off generators and the regional prices is equal to or greater than $10/MWh.

The MIC then provides incentives for TNSPs to improve performance over time. The AER sets a comparison point to measure improvement as follows:

- It identifies the number of planned outage events which have a market impact of more than $10/MWh for each of the previous seven years.
- It adds unplanned outage events which have a market impact of more than $10/ MWh. The number of unplanned events in any year is capped at 17% of total events.
- It removes the two outlier years (the highest and lowest years), and then calculates an annual average of the number of $10/MWh events (for the remaining five years)[7].

Unplanned events are capped so that the focus of the MIC is on planned rather than unplanned events.

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 maximum allowable revenue if there are more $10/MWh events than the comparison point.

TNSPs can propose to the AER to exclude events from the performance results. There are 13 possible exclusions that are 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.
Details of the MIC are provided in version 5 of the STPIS.[8]

4.3 How well does the MIC work?

We collect data on the number of $10/MWh events by TNSP by year. We also collect data on MIC rewards and penalties for each TNSP including how often the maximum reward or penalty is reached. This section discusses TNSP views, the data and what it reveals about the effectiveness of the MIC.

---

7 Details of the scheme are in appendix F of the Service Target Performance Incentive Scheme, version 5.

8 AER, Final Decision - TNSP Service Target Performance Incentive Scheme, version 5, September 2015.

4.3.1 TNSP views

Most TNSPs[9] raised the STPIS in their submissions to our 2022-23 review of incentive schemes. In particular, they focused on the MIC, saying that it is no longer working as intended.

The submissions noted that high investment in renewable energy generation is creating more widespread congestion, significantly increasing network constraints above historical averages. Since performance targets are based on historic performance, the TNSPs consider that they are being penalised for changes in the generation mix rather than their management of outages.

The TNSPs proposed an urgent review of the transmission STPIS on the basis that the method for setting performance targets is no longer fit for purpose. In a joint letter dated 11 March 2022 the TNSPs stated[10]:

> The current design of the transmission STPIS is no longer fit-for-purpose. It reflects an earlier industry paradigm, where relatively slow change in the usage of the transmission network allowed transmission businesses to reasonably forecast when transmission capacity was of most value to network users and to plan network outages around these times.
>
> In contrast, the rapid pace of the energy transition will see almost the entire fleet of pre-2020 generators retire within the next 20 years to be replaced largely by Variable Renewable Energy (VRE) sources. This rapid turnover is increasing the operational complexity of the power system and is resulting in greater, and more widespread, congestion across the transmission network.
>
> The target setting arrangements under the MIC use seven years of historical data to set performance targets that apply for each year of the relevant five-year regulatory period. In our experience the historical data used to set future targets now bears no relationship to the current state of the power system, much less the needs over the next five years.
>
> ……There is therefore a risk that the incentive scheme will not drive behaviours to deliver outcomes that align with customers' expectations. Given the rapid and large-scale changes that have occurred on the power system, and that are expected to continue to occur over the medium to long-term, a backward-looking target setting approach no longer meets the current needs much less those of the future. The current scheme design is no longer valid and should not be maintained.

4.3.2 Data on the MIC

Figures 1 to 5 show how TNSPs have performed against targets over the last 10 years:

- the green bars show the number of $10/MWh events (see left axis)
- the grey bars show the target number of events (based on past performance)

---

9 AusNet, ElectraNet, Powerlink, Transgrid and TasNetworks provided submissions. Directlink and Murraylink did not.

10 The letter is on our website at aer.gov.au. See submissions in response to our discussion paper, AER – Review of expenditure incentive schemes – Discussion paper, December 2021.

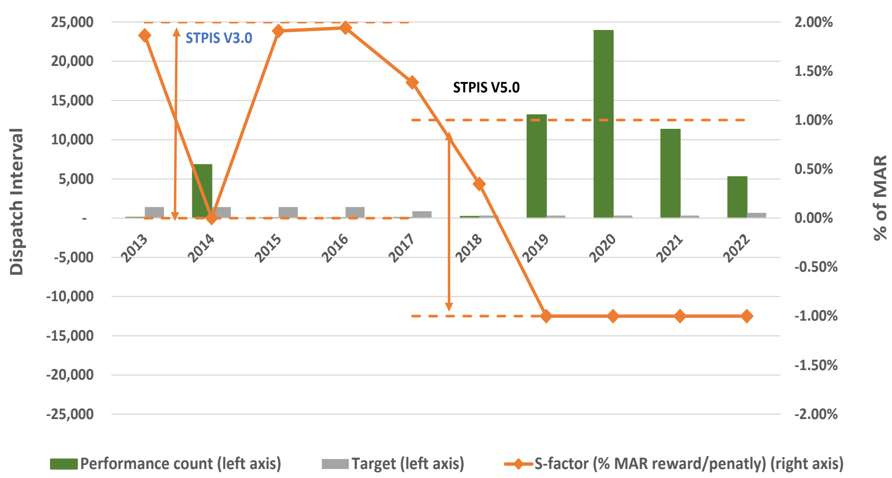
- the orange solid line shows the TNSP's reward or penalty as a percentage of the MAR (see right axis)
- the orange dashed lines show reward and penalty boundaries, also measured in % of the MAR.

To interpret how a TNSP has performed, if the number of $10/MWh events (green bar) was below the target (grey bar) a TNSP was rewarded[11]. If the number of $10/MWh events was above the target, from 2015 the TNSP was penalised.

Note the scheme has changed over time. Initially the scheme rewarded TNSPs (up to 2% of MAR) with no penalties.[12] In 2015 we amended the STPIS to allow for both rewards and penalties (+/- 1% of MAR).[13]

Overall, the data reveals that there has been a significant increase in $10/MWh events over time and that most TNSPs are incurring the maximum possible MIC penalty. Our findings are set out below.

Figure 1: Powerlink MIC results



[11] In a couple of instances there are rewards where the green bar is higher than the grey (and visa versa) when we changed from financial to calendar years.

[12] See versions 3, 4, and 4.1 of the STPIS.

[13] See version 5 of the STPIS.

Figure 2: ElectraNet MIC results

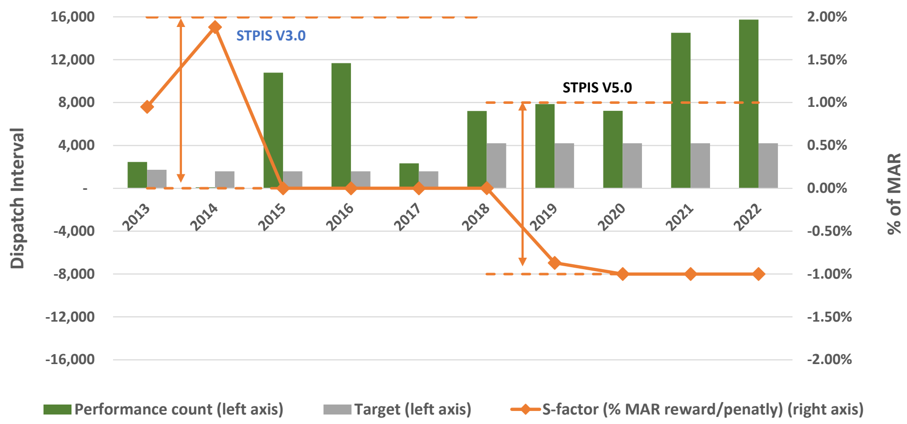


Figure 3: AusNet MIC results

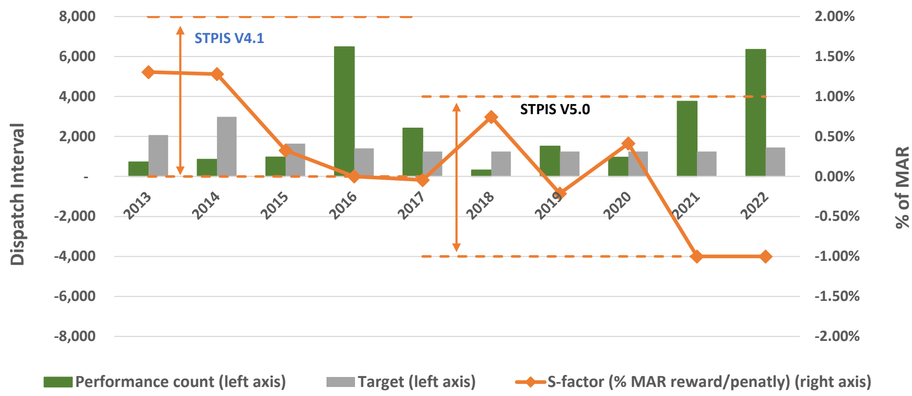


Figure 4: Transgrid MIC results

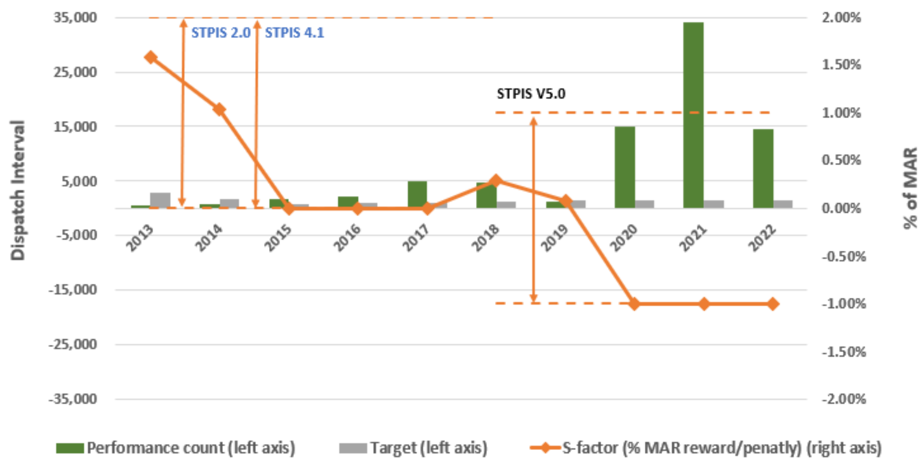
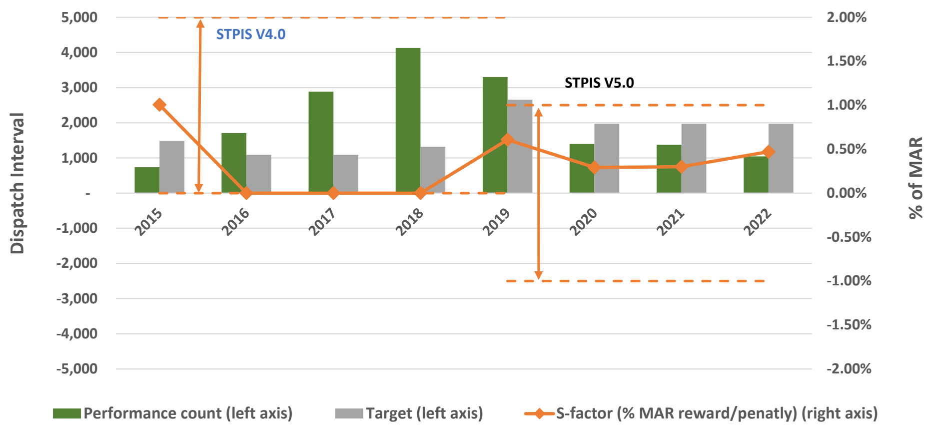


Figure 5: TasNetworks MIC results



4.3.3 What does the data tell us about the MIC?

The data set out above reveals some limitations with the MIC's operation. This section discusses the issues along with their implications.

The number of $10/MWh events has increased substantially

Except for TasNetworks, the number of $10/MWh events has increased substantially over time:

- 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 has stayed high since.
- ElectraNet experienced a large increase in $10/MWh events in 2015 (up from 96 event in 2014 to over 10,000 in 2015). The number of events then fell in 2017 but increased again in 2018, 2021 and 2022 (reaching the highest level recorded in 2022).
- A significant step up in events for Transgrid occurred in 2020 when the number of $10/MWh events increased from 1,252 in 2019 to over 14,000 in 2020.
- For AusNet Services, the number of $10/MWh events has fluctuated, but stepped up in 2021 and 2022.

For TasNetworks, the number of $10/MWh events was highest between 2017 and 2019 and has since decreased.

Most TNSPs are incurring maximum penalties

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 STPIS version 4 (introduced in 2012) the TNSPs were not penalised, but often received no rewards. For example, ElectraNet received no reward between 2015 and 2018, and Transgrid no reward between 2015 and 2017.

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

- 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.

Increased renewables on radial lines are driving the change

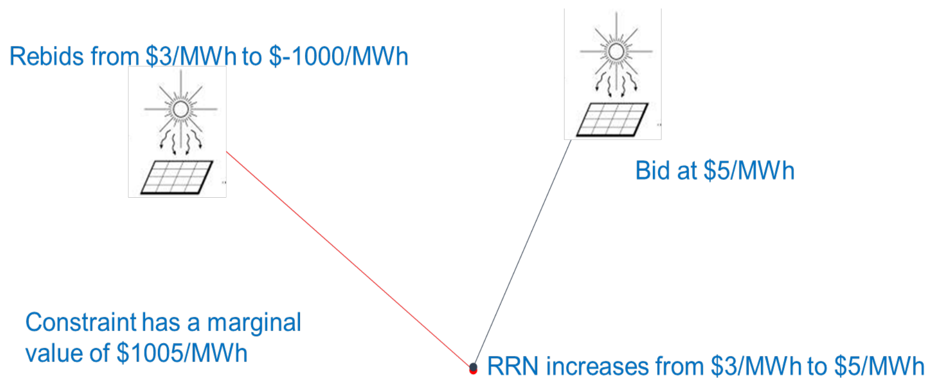
While our data does not provide reasons for the step up in events, the outcomes are consistent with substantial increases in renewable generation.

In the past most generation was coal fired and located at a limited number of sites, for example, 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 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 now often constrain off generators. In turn, these outages often cause $10/MWh events. Figure 6 shows how this can happen.

In this example, a network outage by a transmission provider on a radial link reduces the ability for a solar farm to sell into the market. The solar farm responds by rebidding from $3/MWh to $-1000/MWh in an attempt to minimise the impact of the constraint (shown in red) on its dispatch. The constraint requires higher output from a separate solar farm priced at $5/MWh. The impact on the market is an increase of $2/MWh at the Regional Reference Node (RRN), but the TNSP is penalised because the marginal value is $1005/MWh.

Figure 6: Stylised example – constraint leads to rebidding to price floor



Implications for the MIC

The intent of the MIC is to incentivise TNSPs to improve outage management to minimise the impact of outages on wholesale electricity prices. In our view, the objective of the MIC remains as relevant today as when the MIC was introduced.

However, the data reveals that the MIC is not providing incentives as intended. There are two main problems.

First, most TNSPs (Ausnet, ElectraNet, Powerlink and Transgrid) are incurring the maximum penalty year after year. When a TNSP incurs the maximum penalty irrespective of its outage management actions there are no financial rewards, and the incentive properties of the MIC do not work as intended.

Second, and as shown in the stylised example in Figure 6, many $10 events now do not have a material impact on spot market prices at the regional reference node. The increased prevalence of solar and wind farms on radial lines means outages on those lines often result in $10 events, contributing to MIC penalties. Often though, the amount of generation capacity displaced is small with limited implications for spot prices and therefore generators and consumers.

There is a strong case to amend the MIC to address these problems, whilst still retaining the intended incentive properties.

4.4 MIC options

This section discusses options to address the limitations of the current MIC. The options fall into four categories:

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 conduct obligations
3. revise the performance targets
4. better target rewards and penalties by:
    - only including $10 events on trunk lines;
    - excluding semi-scheduled generation; or
    - only capturing MIC events that have a significant impact on wholesale prices.

A case can be made that regardless of which option is chosen, it is worth considering simplifying the MIC by limiting it to planned outages and to larger TNSPs (i.e. excluding Murraylink and Directlink). Each of the options is discussed further below.

4.4.1 Status quo

MIC penalties and rewards are based on past performance and are revised every five years as part of a TNSPs revenue reset process. If there has been a step up in $10 events this will eventually be captured in the MIC target.

On this basis there could be a case to maintain the current MIC and let the MIC target catch up with the impact of renewable generation. The idea is that the new targets, once implemented, will again provide TNSPs with the prospect of MIC rewards. For consumers this should improve management, and reduce the market impact, of outages.

In practice this may not be effective for two reasons. First, there is a lag before the target is revised with a period where TNSPs continue to incur maximum penalties. Second, investment in solar and wind generation remains high and it is possible that the upwards trend in $10 events will continue.

4.4.2 Remove penalties and rewards

Discontinuing the MIC is an option given its limitations. For consumers, there is no benefit in retaining the MIC if it does not improve outage management.

However, in our view the original intent of the MIC, namely to minimise the market impact of outages, remains valid and would not be addressed. A variant on discontinuing the MIC is to retain the MIC as a transparency measure. This option would remove financial rewards and penalties. Transparency provides reputational incentives to improve performance. The question with this option is whether reputational incentives are enough to achieve the intended outcomes.

A further variant is to remove financial incentives and replace them with compliance obligations. This approach could establish directives which tell TNSPs when they can and can't undertake outages. For example, that extended outages must be undertaken in spring or autumn, and that short duration outages must be undertaken on weekends or at night.

The question with compliance obligations is how feasible they are to implement. The 'right' time to undertake outages is likely to depend on circumstances specific to the outage. Further, obligations may become redundant as circumstances in the market change over time.

4.4.3 Revise performance targets

Performance targets for STPIS are set based on historical performance of the TNSPs. The large increase in MIC events since 2015 has effectively made these targets redundant. An option is to revise the targets upwards, either by increasing the target number of $10 events or by increasing the $10 threshold (for example to $100).

The primary question with this option is on what basis should we set revised targets. Given the rapid transition away from fossil fuel generators to renewable energy, it is unlikely that past performance will be a good basis to measure future performance against. If we don't use past performance we are open to alternatives.

4.4.4 Better target rewards and penalties

As illustrated in Figure 6, many MIC events have little impact on prices to consumers. 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 affects a small amount of generation with limited implications for spot prices.

The option of better targeting MIC events would only reward or penalise TNSPs for events that have a material impact on spot prices. For consumers, improved targeting of MIC events would again incentivise effective outage management and reduce the market impact of outage events.

In theory the MIC could be better targeted through NEMDE, by running NEMDE with and without the outage in question. Rewards or penalties would only apply where NEMDE showed outage events have a material impact on spot prices.

However, AEMO does not do this now and we understand that the change would be difficult and costly to implement.

Alternative ways of better targeting MIC events include:

- Exclude semi-scheduled generation. This would exclude $10 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 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. This option would only include $10 events that occur at a time of high wholesale prices, for example more than $200 per MW/h.

Excluding semi-scheduled generation would go a long way to addressing the limitations of the MIC in the short to medium term. However, longer term the approach does not work well as renewables are likely to become the dominant source of generation. Excluding semi-scheduled generation may also be administratively complex for some TNSPs.

Limiting the MIC to outages to trunk lines has administrative advantages over excluding semi-scheduled generation. It is also more flexible in the long term as it can incorporate transmission lines servicing large amounts of semi-scheduled generation, for example transmission lines servicing as Renewable Energy Zones (REZs).

Combining the $10 threshold with a wholesale market price target is a more direct way to filter out MIC events that do not materially impact spot prices. The approach should be clear and easy to administer, though the choice of the regional reference price trigger point may be arbitrary.

Questions about the MIC

1. Is the MIC still fit for purpose given the experience to date and the energy transition underway?
2. What have the benefits of the MIC been for consumers?
3. Should the MIC be retained as is, discontinued or amended?

4. Are there any other options that this Issues Paper does not identify that we should consider?
5. If the MIC is amended, which option will best promote the National Electricity Objective (NEO)?

5 Network Capability Component

5.1 About the NCC and the NCIPAP

In 2012, the STPIS was amended to introduce the NCC.[14]

The NCC is designed to fund and provide incentives to increase the efficient capability of existing assets in the network when most needed, while maintaining adequate levels of reliability.

The NCC provides an incentive to a TNSP to reveal the capability of parts of its existing network and to identify measures that would provide greater value to generators and customers. Generators benefit from increased network capability as they are less likely to be constrained from dispatching generation by network limits, leading to more efficient dispatch. Customers benefit from the resulting lower wholesale costs and efficient improvements in network capability to meet increases in peak demand. Overall, the NCC encourages low-cost solutions to address limitations in the transmission network which may otherwise unnecessarily restrict energy flows. It also avoids large capex investments that would otherwise achieve the same object but at greater cost to consumers.

The operative element of the NCC is the network capability incentive parameter action plan (NCIPAP) which a TNSP is required to consult with AEMO and submit to us as part of the STPIS component of its revenue proposal. In short, in a NCIPAP, a TNSP is required to identify the low-cost solutions it can undertake to address limitations in the transmission network in the forthcoming regulatory control period. Specifically, in a NCIPAP, a TNSP is required to:

- 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 average expenditure of the proposed priority projects does not exceed 1.5 per cent of the average maximum allowed revenue (MAR) proposed by the TNSP in its revenue proposal.

For each regulatory year, a TNSP will receive an ex ante annual network capability incentive allowance equal to 1.5 times the average annual proposed cost of the priority projects that

---

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

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.

Rationale for the NCC

The rationale for the NCC is to provide incentives to encourage TNSPs to exploit or maximise the capability of the existing network through low-cost solutions, rather than high-cost capital augmentations, where possible. In our submission to the Transmission Frameworks Review, we stated:

> In the AER's conception of an ideal transmission framework, a significant proportion of a TNSPs' remuneration would be based on the level of service they provide rather than the size of their investment programs. … TNSPs would have incentives to operate, maintain and upgrade their network in a manner that delivers an appropriate level of network capability for least sustainable cost.

Similarly, in the explanatory statement in which we first conceived of the NCC (and the NCIPAP), we stated:[15]

> The AER considers that the introduction of the MIC has not only focussed network outage scheduling on the market consequences of those outages, but has also brought greater focus on network capability. Since the MIC was introduced, there has for example been increased focus by TNSPs on the safety margins used in constraint equations by AEMO, as the magnitude of these margins can now have financial impacts for TNSPs. This has incentivised TNSPs to work with AEMO to formulate the most efficient constraints.
>
> However, the MIC only focuses on network outages. As a result system normal constraints have not been the subject of the same degree of focus. The AER considers there may be an opportunity to introduce incentives to improve TNSPs' processes to enable more efficient use of the network under all conditions, not just under network outage conditions.
>
> …
>
> However, the AER notes that despite the benefits of TNSPs undertaking such measures to improve network capability to the benefit of users of the network, the current regulatory arrangements do not promote such behaviour. Rather, they promote major capital investment to meet minimum reliability standards. TNSPs are not incentivised or allocated expenditure to identify limitations that could be addressed or improved through increasing the network capability of existing transmission assets as part of their business as usual practices. The current framework also provides limited incentives for interaction between the operating and asset management units of a TNSP's business. As highlighted above, prior to the MIC there was little focus by TNSPs on the impact their asset management decisions had on wholesale market pricing outcomes. Thus, the absence of an adequate incentive has meant that attempts to increase network capability by TNSPs other than through major capital expenditure have been sporadic.
>
> The AER considers it is appropriate to introduce a capability incentive to deliver efficient levels of network capability from existing assets when it is most needed. 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

15 AER, Explanatory Statement, Electricity transmission network service providers, Draft Service Target Performance Incentive Scheme, September 2012, pp. 52 and 53.

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. However 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.

5.2 How well does the NCC work?

NCIPAP projects undertaken to date

Since its introduction, the NCC has encouraged TNSPs to explore undertaking smaller and lower cost projects to address transmission capability across their networks. We have approved several of these projects (which we refer to as priority projects). The number and scale of the projects undertaken, over the current regulatory control period, and the two preceding periods, is summarised in Tables 3, 4 and 5 below.

Table 3: NCC projects by TNSP – current regulatory control period (t)

TNSP	Number of projects	Total cost ($m)	1.5% of MAR ($m)	Total MAR ($m)	Regulatory period
TransGrid	5	13.9	66.7	4,446	2023-28
AusNet Services	2	1.6	42.8	2,854	2022-27
ElectraNet	4	14.8	30.4	2,029	2023-28
TasNetworks	3	5.7	10.3	685	2019-24
Powerlink	0	0	52.7	3,515	2022-27
Total	**14**	**36**	**202.9**	**13,529**	

Table 4: NCC projects by TNSP – previous regulatory control period (t–1)

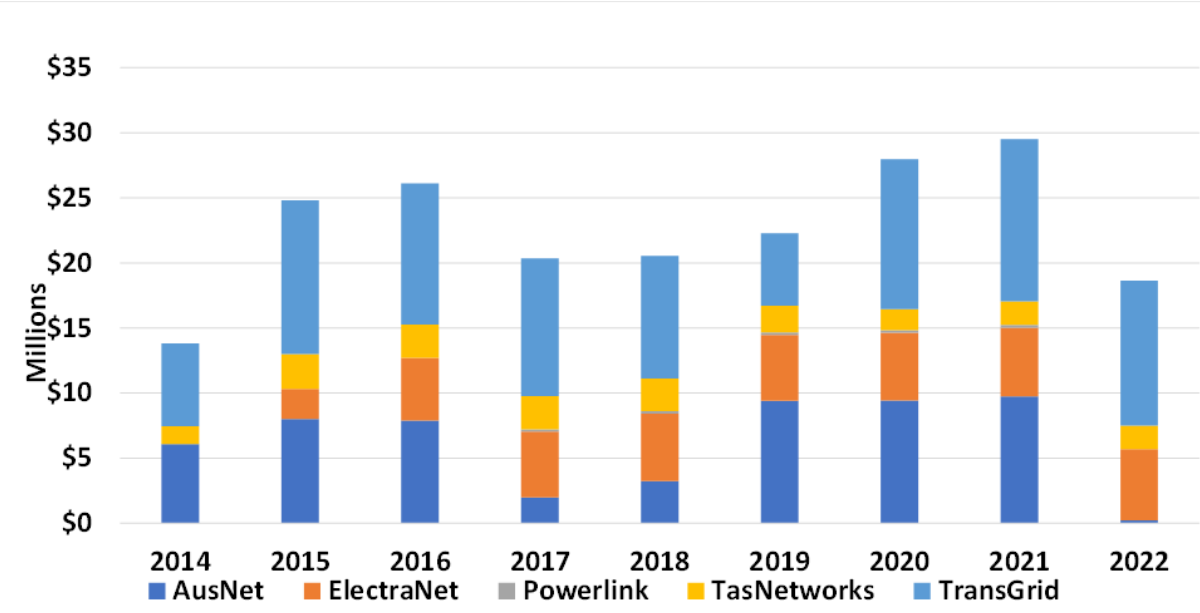
TNSP	Number of projects	Total cost ($m)	1.5% of MAR ($m)	Total MAR ($m)	Regulatory period
TransGrid	12	33.4	55.9	3,728	2018-23
AusNet Services	7	19.6	38.3	2,553	2017-22
ElectraNet	7	16.3	22.8	1,518	2018-23
TasNetworks	15	6.6	12.3	822	2014-19
Powerlink	1	0.6	54.7	3,648	2017-22
Total	**42**	**76.5**	**184**	**12,269**	

Table 5: NCC projects by TNSP – previous regulatory control period (t–2)

TNSP	Number of projects	Total cost ($m)	1.5% of MAR ($m)	Total MAR ($m)	Regulatory period
TransGrid	28	36.3	43.0	2,868	2014-18
AusNet Services	10	15.9	24.0	1,600	2014-17
ElectraNet	5	10.1	23.7	1,578	2013-18
TasNetworks	0	0	14.5	966	2009-14
Powerlink	0	0	70,2	4,679	2012-17
Total	**43**	**62.3**	**105.2**	**11,691**	

Figure 7 below summarises the scale of the expenditure involved in the NCC projects that have been completed to date.

Figure 7: Scale of NCC project expenditure



Based on the data above, several observations can be made.

1. Compared to the total MAR of the TNSPs, and the applicable 1.5 per cent of MAR threshold, the total quantum of the priority projects undertaken to date is small. . For example, the total cost of priority projects being undertaken in the current regulatory control periods across all TNSPs is $36 million. This approximates to 0.026 per cent of the combined MARs of all TNSPs (see Table 3 above).

2. Given the scale of the transmission networks, the total number of priority projects undertaken across all TNSPs, being 14 in the current regulatory control period, and 42 and 43 in the preceding two regulatory control periods respectively (see Table 4 above), is relatively small.

3. Powerlink did not undertake any priority projects in the 2012-17 and 2009-14 regulatory control periods, and TasNetworks did not undertake any in the 2009-14 regulatory control period (see Tables 3 and 5 above). This raises a question about the effectiveness of the incentives created by the NCC.

Change in circumstances

The priorities and challenges facing TNSPs today are very different to that when we introduced the NCC in 2012. In particular, the network augmentations under consideration today to facilitate the change to renewable energy sources was not a matter that we considered when we introduced the NCC. AEMO now focuses on large network projects and is more fully occupied with the Integrated System Plan. AEMO and TNSPs also now work more closely together on transmission planning including in developing options and undertaking cost-benefit assessments.

Administrative complexity

The NCC is administratively complex to apply. This is because of the discrete nature of the projects that are included in a NCIPAP, and the level of detail required to identify and articulate what may or may not be necessary to relieve or improve the existing capability at a given point in a transmission network. Engaging in this level of detail is also at odds with our role of setting overall forecast operating and capital expenditure allowances, and the MAR. This is why AEMO has had a key role in the scheme.

5.3 NCC options

The rationale of providing incentives to encourage TNSPs to exploit or maximise the capability of the existing network by undertaking low-cost solutions, rather than high-cost capital augmentations, remains applicable today just as it was in 2012.

But how important is this considering the scale and scope of the network augmentations under consideration today to transition to renewable energy sources? This is a question that we need to address.

We seek the views of stakeholders on the NCC. Responding to this is likely to raise several considerations, including the following:

- the strength or efficacy of the incentives created by the NCC which has resulted in TNSPs undertaking almost 100 projects
- whether the administrative resources required to apply the NCC outweigh the benefits of the NCC
- given the change in circumstances, whether the importance of encouraging TNSPs to continue to exploit or maximise the capability of the existing network through low-cost solutions should be reconsidered, considering the overall incentive framework established by Chapter 6A of the NER.

Further, we also seek views on whether to:

- continue to apply and administer the NCC as is

- discontinue the NCC, or
- amend the NCC, to perhaps make its application and administration less administratively burdensome.

Questions about the NCC

6. Is the NCC still fit for purpose given the experience to date and the energy transition underway?
7. How can the data collected by the TNSPs to date be best evaluated to demonstrate the benefits consumers may have realised from the undertaking of NCC projects? Have those benefits for consumers outweighed the costs?
8. Should the NCC be retained as is, discontinued or amended?
9. Are there any other options that this Issues Paper does not identify that we should consider?
10. If the NCC is amended, which option will best promote the NEO?

6 Summary of questions

Number	Question
MIC	
1.	Is the MIC still fit for purpose given the experience to date and the energy transition underway?
2.	What have been the benefits of the MIC for consumers?
3.	Should the MIC be retained as is, discontinued or amended?
4.	Are there any other options that this Issues Paper does not identify that we should consider?
5.	If the MIC is amended, which option will best promote the NEO?
NCC	
6.	Is the NCC still fit for purpose given the experience to date and the energy transition underway?
7.	How can the data collected by the TNSPs to date be best evaluated to demonstrate the benefits consumers may have realised from the undertaking of NCC projects? Have those benefits for consumers outweighed the costs?
8.	Should the NCC be retained as is, discontinued or amended?
9.	Are there any other options that this Issues Paper does not identify that we should consider?
10.	If the NCC is amended, which option will best promote the NEO?

Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
DNSP	Distribution Network Service Provider
EBSS	efficiency benefit sharing scheme
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
opex	operating expenditure
STPIS	service target performance incentive scheme
TNSP	Transmission Network Service Provider