15. Service Target Performance Incentive Scheme

15.1 Introduction

This chapter outlines Powerlink's performance under the Service Target Performance Incentive Scheme (STPIS) in the current 2018-22 regulatory period, as well as our proposed STPIS values and targets for the 2023-27 regulatory period.

The three components to the STPIS are the Service Component (SC), Market Impact Component (MIC) and Network Capability Component (NCC).

Key highlights:

- Our STPIS performance for the SC and NCC for the current 2018-22 regulatory period demonstrates improved network performance.
- Changes in power flows and the emergence of system strength constraints have impacted our MIC performance. This is expected to continue into the 2023-27 regulatory period.
- We propose an alternative target of one in lieu of zero for the large loss of supply event sub-parameter of the SC.
- We do not propose any Network Capability Incentive Parameter Action Plan (NCIPAP) projects in our Revenue Proposal. We will consider potential NCIPAP projects further and may propose projects to the Australian Energy Regulator (AER) within the 2023-27 regulatory period.
- We have proposed SC and MIC targets consistent with the AER's historical data ranges[1] and our alternative proposed data range, which incorporates the most recent calendar year. This is to ensure our 2023-27 target incorporates the impact of significant changes in our operating environment.
- We engaged WSP to independently assess the robustness of our methodology to determine the best fit statistical distributions for the SC. WSP concluded our approach is robust.

15.2 Regulatory requirements

The National Electricity Rules (the Rules)[2] require the AER to develop and publish a STPIS that complies with specified principles. We are required to include proposed values for the STPIS parameters as part of our Revenue Proposal[3].

We are currently subject to the AER's 2015 STPIS (Version 5) and our Revenue Proposal complies with Version 5. In its Final Framework and Approach paper for Powerlink[4], the AER confirmed that it will apply this version of the scheme for the 2023-27 regulatory period.

15.3 STPIS in the current environment

There have been some significant changes in our operating environment as Australia's energy market transitions to a low carbon future (refer Chapter 2 Business and Operating Environment). These changes, which have occurred since the AER's 2015 STPIS was published, have presented a number of challenges in the management of our network performance. Given the intent and scope of the STPIS, the changes of particular importance here are:

- ***Changes in power flows***: with over 1,000MW of new wind and solar generation connected to our transmission network in Central and North Queensland since 2017, there has been a significant increase in north-south intra-regional power flows along our transmission network. This has created a situation where system normal constraints are binding more often, which can severely restrict outage windows despite efforts to plan outside these periods.
- ***The emergence of system strength constraints***: system strength is a characteristic of an electrical power system that relates to the size of the change in voltage following a fault or disturbance on the power system[5]. It has emerged as a prominent challenge in Queensland (particularly in North Queensland) as well as other parts of the National Electricity Market (NEM), which is discussed further below.

1 Reset Regulatory Information Notice (RIN): clauses 11.1 and 11.2, Australian Energy Regulator, October 2020.
2 National Electricity Rules, clause 6A.7.4.
3 National Electricity Rules, schedule 6A.1, clause S6A.1.3(2).
4 Final Framework and Approach: Powerlink, Australian Energy Regulator, July 2020.
5 Managing Power System Fault Levels Rule Determination, Australian Energy Market Commission, September 2017, page 3.

In May 2019, the Australian Energy Market Operator's (AEMO's) National Electricity Market Dispatch Engine (NEMDE) was updated to recognise system strength constraints in Queensland. AEMO formally declared a fault level shortfall in North Queensland in April 2020[6]. The fault level shortfall occurred due to the significant number of Inverter-Based Resources (IBR) that connected to the North Queensland transmission network. These constraints only became apparent in Queensland in 2019 and are therefore not reflected in the historical constraint data before 2019.

The main driver of the increase in constraints is the rapid change in the mix and location of generation, which is not directly within our control. North Queensland now has the third highest proportion of solar and wind generation in the world, only slightly behind Denmark and South Australia[7]. With limited base load synchronous generation in North Queensland and large distances between the synchronous generators in Central and Southern Queensland, this creates low system strength conditions in North Queensland.

We continue to respond to these challenges to ensure that the needs of our customers are met and that we continue to meet our network security and reliability obligations. This involves alignment of activities and executing work in a way that has the least practicable impact to customers, such as working coincident with customer outages, live work on transmission lines and substations, consolidation of outages and the use of shoulder periods.

These changes have impacted our MIC performance in the 2018-22 regulatory period and will influence our MIC targets for the 2023-27 regulatory period. This is discussed further in Section 15.5 and Appendix 15.01 Setting STPIS Values.

15.3.1 Review of STPIS

In October 2019, we raised concerns with the AER about whether the STPIS is still fit-for-purpose as part of our Framework and Approach (F&A) initiation, in light of the rapid changes that have occurred within the energy market post-2015[8].

Following further discussion, the AER responded to us in November 2019 to advise it did not consider a STPIS review appropriate at the present time. We provided further information in January 2020 to support a review, which also had support from our Revenue Proposal Reference Group (RPRG)[9]. Other Transmission Network Service Providers (TNSPs), via Energy Networks Australia (ENA), called for a review of the STPIS in February 2020 (refer to Appendix 15.02) and noted this issue was particularly pressing for Powerlink, given the timing of our revenue determination process. In May 2020, at the request of the AER we provided further evidence to support a review.

In the AER's July 2020 Final F&A Paper, the AER concluded that the STPIS is operating appropriately[10]. We received a formal response from the AER in August 2020 that there was no immediate need for a review. The AER advised that a review will be required in the future to respond to NEM changes resulting from the expected implementation of the Coordination of Generation and Transmission Investment (COGATI) reforms, the Australian Energy Market Commission's (AEMC's) investigation into system strength frameworks in the NEM and the Energy Security Board's (ESB's) Post-2025 Market Design Review.

We remain firmly of the view that the 2015 STPIS should be reviewed as a matter of urgency, and that the current arrangements to apply to Powerlink for the 2023-27 regulatory period are not fit-for-purpose. More broadly, the current arrangements do not appear to promote the long-term interests of customers and are inconsistent with the principles upon which the incentive schemes have been established by the AER under the Rules – to provide genuine financial incentives for improvements in market performance.

Our view is that all elements of the regulatory framework, and regulatory bodies, should adapt to significant changes in the energy market and operating environment.

15.4 Historical performance in the 2018-22 regulatory period

Our performance for the SC, MIC and NCC components of the scheme over the current 2018-22 regulatory period are summarised in Table 15.1. Overall, our STPIS performance demonstrates continued improvement, with the exception of MIC performance due to the reasons outlined in Section 15.3.

6 Notice of Queensland System Strength Requirements and Ross Fault Level Shortfall: A Report for the National Electricity Market, Australian Energy Market Operator, April 2020.
7 World Energy Outlook 2018, IEA, 2018.
8 Framework and Approach initiation, Powerlink, October 2019.
9 Meeting Minutes of January 2020 RPRG, Powerlink, https://www.powerlink.com.au/2023-2027-regulatory-period.
10 Framework and Approach: Powerlink, Australian Energy Regulator, July 2020, page 12.

STPIS operates and data is reported to the AER on a calendar year basis. As our current regulatory period commenced on 1 July 2017, the information below reflects performance for the second half of that year. The AER's 2015 STPIS requires that a two-year rolling average is used to report the SC performance of the unplanned outage circuit event rate and average outage duration.

Table 15.1: Historical STPIS annual compliance performance 2017 2H to 2020

Parameter	Unit of Measure	2018-22 Target	Calendar year			
			2017 2H	2018	2019	2020
Service Component						
Unplanned outage circuit event rate[1]						
Lines event Rate – Fault	Rate	20.88	17.43	21.61	20.62	12.86
Transformer event rate – Fault	Rate	18.91	17.21	22.81	19.01	12.54
Reactive plant event rate – Fault	Rate	29.85	26.84	27.67	26.02	23.59
Lines event rate – Forced	Rate	20.39	17.26	17.24	16.24	18.39
Transformer event rate – Forced	Rate	19.17	16.62	14.62	11.11	15.15
Reactive plant event rate – Forced	Rate	24.23	22.06	21.40	20.82	20.97
Loss of supply events frequency						
Loss of supply events > 0.05 (x) system minutes	Count	3	2	2	0	0
Loss of supply events > 0.40 (y) system minutes	Count	1	0	1	0	0
Average outage duration[1]						
Average outage duration	Minutes	94	29	32	26	36
Proper operation of equipment[2]						
Failure of protection system	Number	N/A	21	38	15	21
Material failure of Supervisory Control and Data Acquisition (SCADA) system	Number	N/A	0	2	0	0
Incorrect operational isolation of primary or secondary equipment	Number	N/A	2	2	5	9
Market Impact Component						
MIC	Number of Dispatch Intervals (DI)	333	9	217	13,152[3]	23,909[4]
Network Capability Component						
NCIPAP	The priority project 'Increase design temperature of two 275kV transmission lines' was completed and achieved its target limit value.					

(1) Two-year rolling average performance is reported as required by the AER's 2015 STPIS.

(2) Report only parameter with no weighting.

(3) In March 2020, the AER advised us that AEMO made manual changes to its Marginal Constraint Cost (MCC) data after we lodged our annual STPIS report for the 2019 regulatory period to the AER. We re-ran the data and identified that the updated dataset would have added on an extra 532 DIs to our original 2019 result of 12,620 DIs. AEMO's additional DIs have been included in the calendar year figure in the table.

(4) The calendar year 2020 MIC performance result that Powerlink reports in the 2023-27 Reset RIN Return (7.9 STPIS Alternative) and in our annual 2021 STPIS submission is our estimate based on the MCC data which was made available by AEMO on 15 January 2021. We will update the AER on any changes to the 2020 MCC as part of the AER's review of our Revenue Proposal prior to its September 2020 Draft Decision. We will also update data in our Revised Revenue Proposal to be submitted in December 2021.

The following sections outline our historical performance for each parameter in the current regulatory period, which informs our caps, floors and targets for the 2023-27 regulatory period. The targets outlined in Table 15.3 have been calculated using the year ranges indicated in Figures 15.1 to 15.10. We have also provided 2020 calendar year data for information.

15.4.1 Service Component performance

Our overall performance under the SC consistently exceeded the AER's target in this regulatory period. Positive performance under the SC minimises the impact of unplanned outages and loss of supply on customers. We have responded to the AER's 2015 STPIS and have modified our approach to non-urgent plant issues which in the past would have resulted in forced outages with less than 24 hours notice to our customers. Where possible, we have delayed our response to non-urgent plant issues, for example low gas alarms from circuit breakers, and as a result, provide more time for our customers to better plan and prepare their operations prior to an outage. From a broader perspective, in the current regulatory period, we have on average experienced fewer climatic related impacts to our network.

The combination of our ongoing asset management practices and fewer climatic events has resulted in us performing well against the large (y) loss of supply events frequency sub-parameter. Only one loss of supply event exceeded the threshold of 0.40 system minutes in the past five years, which has resulted in near-ceiling performance for this measure. The implications of this for our target for the 2023-27 regulatory period are discussed in Section 15.5.4.

We detail our performance against the three SC parameters – unplanned outage circuit event rate, loss of supply events frequency and average outage duration – in the following sections.

Service Component performance – unplanned circuit outage event rate

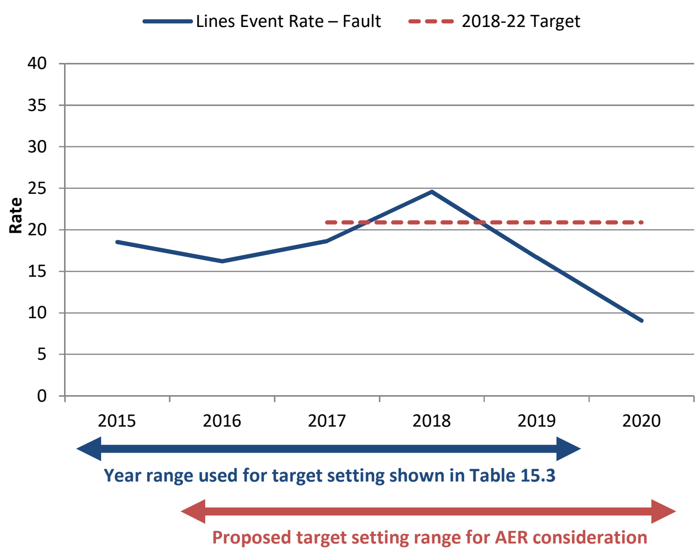
Unplanned outage circuit event rate – Fault

A fault outage is any element outage that occurred as a result of an element being switched off (such as a transformer) unexpectedly, i.e. it did not occur as a result of intentional manual operation of switching devices. The fault outage circuit event rate parameter measures network reliability based on an aggregate number of fault outages per annum for each of the transmission element types: lines, transformers and reactive plant.

To minimise the impact on our customers and the market, we rapidly respond to and restore fault outages on our network. Deterioration in asset condition can contribute to fault outage events. Where prudent and efficient, we refurbish our deteriorating assets. This can restore asset performance, reduce fault level outage occurrences and improve the overall reliability of our assets.

The historical performance of our fault outage circuit rates since 2015 for transmission lines, transformers and reactive plant is shown in Figures 15.1, 15.2 and 15.3.

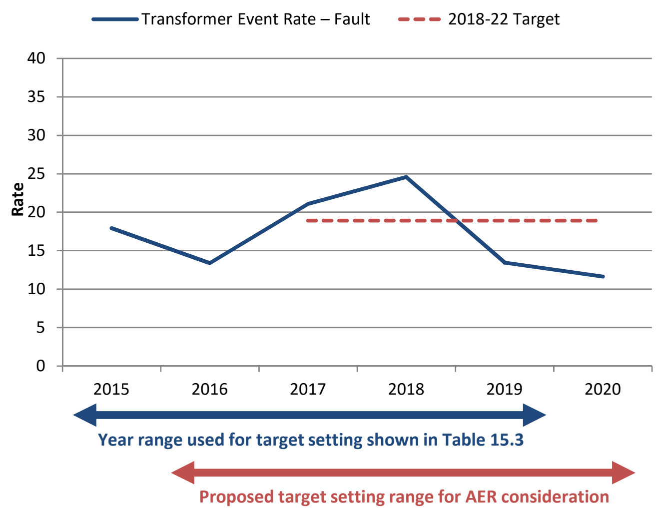
Figure 15.1: Lines event rate – Fault 2015-2020



The lines fault event rate sub-parameter performed better than the target, except for 2018 when a higher than average number of busbar trips impacted transmission lines. These occurred, for example, due to lightning and abnormal age-related deterioration and a loose wiring connection.

In 2019 and 2020, less than the average number of weather events impacted the network. As a result, the lines fault event rate decreased and returned to a performance level better than the target.

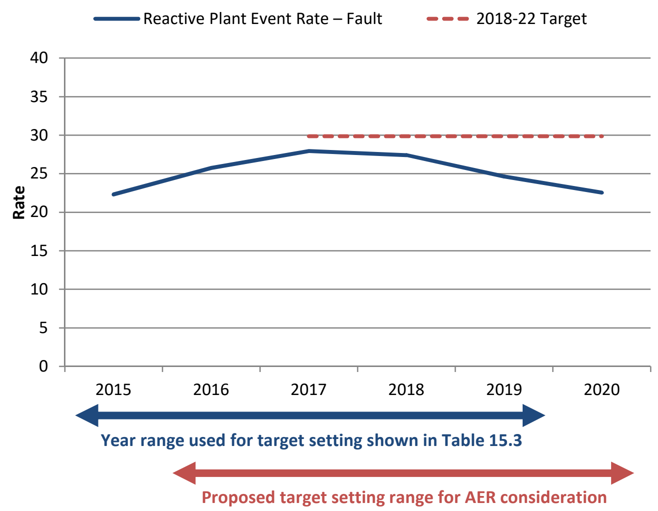
Figure 15.2: Transformer event rate – Fault 2015-2020



The transformer fault event rate did not meet the target in 2017[11] and 2018. This was due to a higher than average number of transformer circuit breaker issues and a higher than average number of faults on transformer ended feeders. These occurred, for example, due to water ingress into circuitry, lightning faults and pollution build-up on line insulators.

In 2019 and 2020, the sub-parameter performed better than the target due to a return to normal of the number of connection equipment related issues.

Figure 15.3: Reactive plant event rate – Fault 2015-2020



The reactive plant fault event rate sub-parameter performed consistently better than the target due to less than average number of storm and lightning-related fault impacts, static var compensator (SVC) transformer and reactive plant component issues.

Unplanned outage circuit event rate - Forced

A forced outage is any element outage that occurred as a result of intentional manual operation of switching devices based on the requirement to undertake urgent and unplanned corrective activity, where less than 24 hours notice was given to the affected customer(s) and/or AEMO.

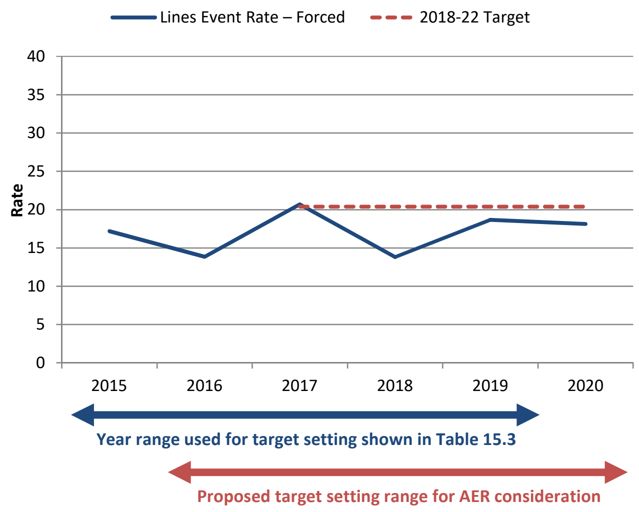
Similar to the fault outage rate, the forced outage circuit event rate parameter measures network reliability based on an aggregate number of forced outages per annum for each of the transmission element types (lines, transformers and reactive plant).

In 2018, we revised our approach by delaying our response to non-urgent conditions of high voltage plant where it was safe to do so, which provided more time for our customers to better plan and prepare their operations prior to an outage. This has reduced the number of occurrences of forced outage circuit rates across all categories.

The historical performance of our forced outage circuit rates since 2015 for transmission lines, transformers and reactive plant is shown in Figures 15.4, 15.5 and 15.6.

[11] For the first half of the 2017 calendar year (the end of our previous regulatory period) we were subject to the AER's 2011 STPIS (Version 3). For the second half of the 2017 calendar year (the start of the 2018-22 regulatory period), we were subject to the AER's 2015 STPIS (Version 5). We met our target for this sub-parameter for the second half of the 2017 calendar year.

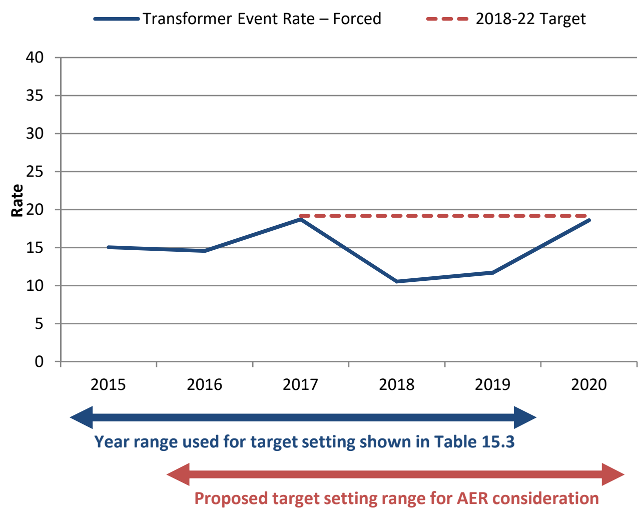
Figure 15.4: Lines event rate – Forced 2015-2020



The lines forced event rate performed better than the target, except for 2017, which was on target.

The number of specific issues requiring an outage with less than 24 hours notice to market participants was slightly below average. This includes issues such as marginal trees impacting line clearances and connection equipment issues such as a circuit breaker low gas condition.

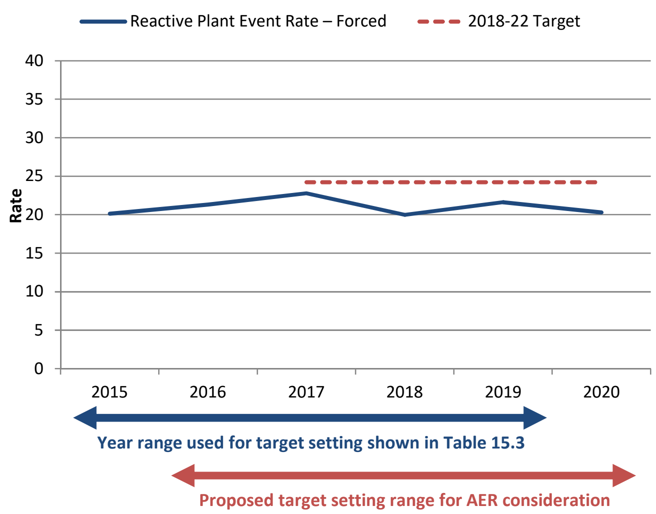
Figure 15.5: Transformer event rate – Forced 2015-2020



The transformer forced event rate sub-parameter performed consistently better than the target.

The number of specific issues requiring an outage with less than 24 hours notice to market participants was below average. This includes low oil level transformer related issues and connection equipment issues such as a circuit breaker low gas condition.

Figure 15.6: Reactive plant event rate – Forced 2015-2020



The reactive plant forced event rate performed well against the target.

The number of specific issues requiring an outage with less than 24 hours notice to market participants was slightly below average. This includes reactive element component related issues such as a capacitor bank out of balance condition or occurrence of SVC low cooling water condition and connection equipment issues such as a circuit breaker low gas condition.

Service Component performance – loss of supply event frequency

We report performance against two loss of supply event targets based on the thresholds specified in the AER's 2015 STPIS:

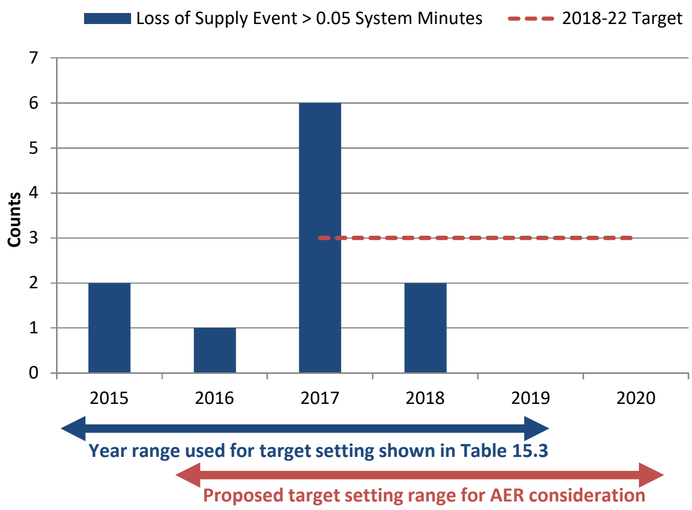
- the moderate event (x) threshold is a loss of supply event greater than 0.05 system minutes; and
- the large event (y) threshold is a loss of supply event greater than 0.40 system minutes.

For the 2023-27 regulatory period we remain subject to the same two sets of targets for loss of supply events as they can only be adjusted through a review and amendment of the STPIS. As outlined in Section 15.5.4, we have actively worked to minimise the impact of loss of supply events on our network. This has resulted in performance above the target for both moderate and large event thresholds.

Loss of supply event frequency greater than 0.05 system minutes (x)

Our historical performance for this parameter is shown in Figure 15.7.

Figure 15.7: Loss of supply event frequency greater than 0.05 system minutes (x) 2015-2020



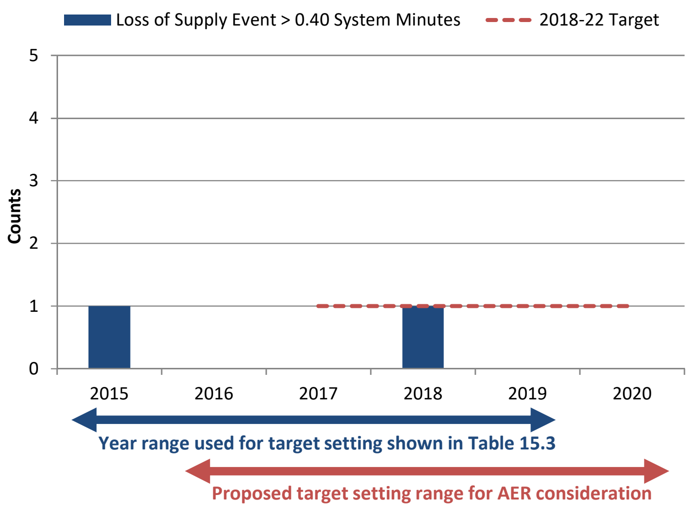
Overall we performed better than the target for the loss of supply event frequency sub-parameter under the moderate (x) threshold. This is a result of improvements to our established incident response processes such as targeted incident response training and simulation exercises, to minimise the impact of loss of supply on customers.

2017 was an outlier year where there was a higher than average number of events greater than 0.05 system minutes associated with outages and equipment faults.

Loss of supply event frequency greater than 0.40 system minutes (y)

Our historical performance for this parameter is shown in Figure 15.8.

Figure 15.8: Loss of supply event frequency greater than 0.40 system minutes (y) 2015-2020



We performed better than the target for the loss of supply event frequency sub-parameter under the large (y) threshold.

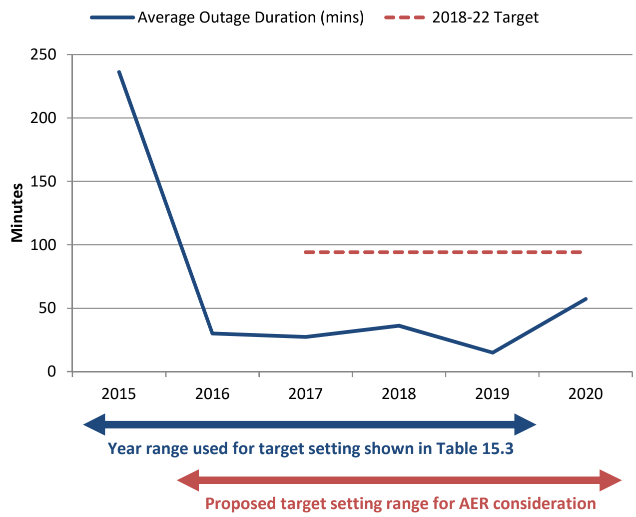
Since 2016, we experienced only one loss of supply event exceeding 0.40 system minutes. The one event occurred in 2018 and was a loss of both Chalumbin to Woree feeders due to lightning impact, which resulted in the loss of supply to Cairns and surrounding areas.

Service Component performance – average outage duration

The average outage duration parameter measures the average time to restore loss of supply events. It is calculated by the division of the total duration of loss of supply events in a year by the number of loss of supply events in that year.

Our historical performance for this parameter is shown in Figure 15.9.

Figure 15.9: Average outage duration 2015-2020



We performed better than the target for the average outage duration of loss of supply event parameter, due to a reduction in extended duration outages and outages associated with bulk supply points where supply could not be restored from alternative locations.

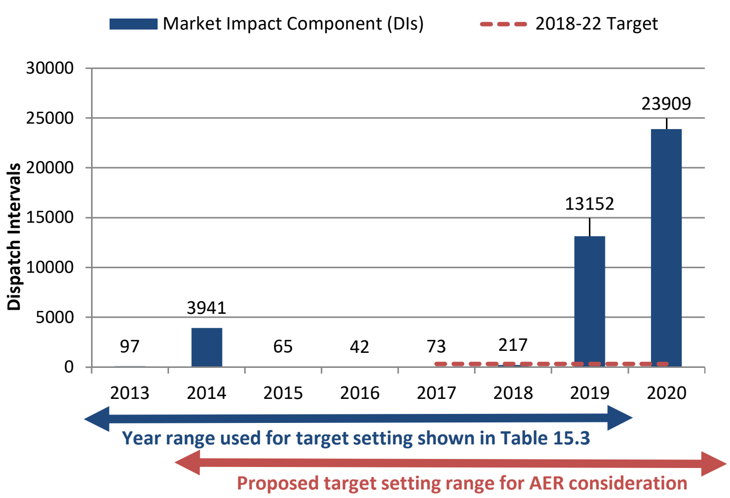
In 2015, a loss of supply event occurred which impacted a single directly-connected customer for an abnormally long duration.

15.4.2 Market Impact Component performance

The MIC measures the number of DIs where an outage on our network results in a network outage constraint with a marginal value greater than $10/MWh. Our MIC performance target for the 2018-22 regulatory period is 333 DIs per year.

As outlined in Section 15.3, our ability to manage network availability in the 2018-22 regulatory period has been challenged by significant changes to power flows and the generation mix, which have impacted system utilisation and constraints. This impact is evident from our historical MIC performance as shown in Figure 15.10.

Figure 15.10: Historical MIC performance 2013-2020



We performed well against the AER's target for the MIC up to the second quarter of 2019, as we consistently applied our established processes to minimise the impact of outage events.

In 2019, an unprecedented increase in DI counts was recorded for our network due to reductions in system strength, changes to generation topology and an increased penetration of non-synchronous generators. This trend has continued into 2020 despite our consistent application of enhanced processes to minimise the impact of outage events on market participants.

We continue to work closely with customers to plan and coordinate network outages at times least likely to result in a market constraint. We also take real-time action to reschedule works to reduce the impact of binding constraints on the market.

15.4.3 Network Capability Component performance

Under the NCC, we successfully completed our NCIPAP project at the end of 2018. This project was delivered at a cost of $0.4m.

The focus of our NCIPAP project was the Bouldercombe to Raglan and Larcom Creek to Calliope River 275kV circuits. These circuits form part of a transmission corridor that enables power flows between Central West Queensland and Gladstone.

Network constraints on this corridor were forecast to increase in the medium term[12]. We undertook works to increase ground clearances on 14 spans, which increased the design temperature of two 275kV transmission lines and ultimately enabled additional flexibility of dispatch to the NEM.

15.5 STPIS target setting for the 2023-27 regulatory period

This section sets out our proposed STPIS values and the approach we used to set our targets for the 2023-27 regulatory period. This is based on the Rules[13], the AER's 2015 STPIS and the AER's Final Framework and Approach for Powerlink[14].

15.5.1 Historical values for target setting

The AER's Reset RIN[15] stipulates the historical calendar years to be used to calculate our STPIS values for the 2023-27 regulatory period to be submitted in our Revenue Proposal and Revised Revenue Proposal. The AER's stipulated date ranges are:

- for the SC – 2015-19 (Revenue Proposal) and 2016-20 (Revised Revenue Proposal); and
- for the MIC – 2013-19 (Revenue Proposal) and 2014-20 (Revised Revenue Proposal).

We have urged the AER to reconsider these historical ranges as they do not reflect the latest historical year data i.e. it does not include the 2020 calendar year data, which is the most recent year data available for our Revenue Proposal, or the 2021 calendar year data for consideration as part of the AER's Final Decision in April 2022.

Our view is that the most recent historical data range ensures our STPIS targets more closely reflect the recent operating environment of the energy market, and enables the business to more meaningfully respond to the incentive and deliver benefits to our customers. This aligns with the AER's 2015 STPIS, which specifies that performance history over the most recent five years for the SC[16] and the most recent seven years for the MIC[17] be used to calculate the performance target.

Use of the most recent historical data to derive targets is particularly important for the MIC, due to the significant changes in our operating environment set out in sections 15.3 and 15.5.5. This is also demonstrated in Table 15.2, which compares the MIC target for the 2023-27 regulatory period without the most recent year data (the Reset RIN required 2013-2019 year range), and the MIC target with the most recent year data (the 2014-2020 year range). The comparison shows a significant difference that reflects the rapid changes in our operating environment.

Table 15.2: MIC target comparison

	2013-2019 Year Range			2014-2020 Year Range		
MIC Parameter	Performance Target	Unplanned Outage Event Limit	Dollar per Dispatch Interval Incentive	Performance Target	Unplanned Outage Event Limit	Dollar per Dispatch Interval Incentive
MIC	879	149	$7,673	3490	593	$1,933

The calendar year 2020 MIC performance result that Powerlink has provided in its 2023-27 Reset RIN Return (7.9 STPIS Alternative) and in our annual 2021 STPIS report submission is our estimate based on the Marginal Constraint Cost (MCC) data which was made available by AEMO on 15 January 2021. We will update the AER on any changes to the 2020 MCC as part of the AER's review of our Revenue Proposal prior to its Draft Decision. We will also update data in our Revised Revenue Proposal to be submitted in December 2021.

12 NEM Constraint Report 2014 Supplementary Data, Australian Energy Market Operator, April 2015.
13 National Electricity Rules, schedule S6A.1, clause S6A.1.3(2).
14 Final Framework and Approach Paper for Powerlink, Australian Energy Regulator, July 2020.
15 Reset RIN: Powerlink - clauses 11.1 and 11.2, Australian Energy Regulator, October 2020.
16 2015 STPIS, clause 3.2 (f).
17 2015 STPIS, Appendix F.

15.5.2 Proposed 2023-27 STPIS values

To ensure our Revenue Proposal complies with our Reset RIN, we have provided our STPIS values for the 2023-27 regulatory period based on the historical date ranges required by the AER in Table 15.3.

We have also provided the AER with two sets of data to inform its assessment:

- targets consistent with our Reset RIN; and
- targets based on our most recent historical data.

To inform the AER's assessment and its Final Decision, we will provide the AER with actual data for full calendar year 2021 in early 2022, including updated targets.

Table 15.3: STPIS values

SC Parameter (±1.25% Maximum Allowed Revenue (MAR))	Floor	Target	Cap	Distribution
Unplanned Outage Circuit Event Rate (±0.75% MAR)				
Lines event rate – Fault	23.85	18.92	14.85	Pearson5
Transformer event rate – Fault	25.09	18.07	10.44	Weibull
Reactive plant event rate – Fault	29.16	25.60	22.34	LogNormal
Lines event rate – Forced	21.00	16.83	11.85	Weibull
Transformer event rate – Forced	19.07	14.10	9.78	Gamma
Reactive plant event rate – Forced	22.80	21.18	18.92	Weibull
Loss of Supply Event Frequency (±0.30% MAR)				
Greater than 0.05 system minutes (x)	7	2	0	Geometric
Greater than 0.40 system minutes (y)	2(1)	1(1)	0	N/A
Average Outage Duration (±0.20% MAR)				
Average outage duration	147.17	69.00	7.91	LogLogistic

MIC Parameter (1.0% MAR)	Performance Target	Unplanned Outage Event Limit	Dollar per Dispatch Interval Incentive
MIC	879	149	$7,673
NCC Parameter(2)			
NCIPAP	No priority projects proposed, $0		

(1) The values derived from an alternative target methodology – refer Section 15.5.4.

(2) Pro-rata based allowance up to 1% MAR each year, with incentive of 1.5 times average annual project cost. Penalty of up to 3.5% final year MAR.

15.5.3 Proposed Service Component values

We have proposed targets, caps and floors for the relevant parameters and sub-parameters related to the SC based on Section 3.2 of the AER's 2015 STPIS.

The caps and floors were calculated on the basis of a best fit statistical distribution to the previous five years' performance data for each of the parameters and sub-parameters. The caps and floors reflect the 5th and 95th percentiles of each of the chosen statistical distributions. The methodology we applied to determine the statistical distributions for each parameter and sub-parameter is provided as Appendix 15.01 Setting STPIS Values.

The proper operation of equipment parameter is report only and therefore no values are required. We do not address this further in our Revenue Proposal.

We have also proposed an alternative approach to set our target for the large (y) loss of supply (greater than 0.4 system minutes) sub-parameter, consistent with Section 3.2(i) of the AER's 2015 STPIS. Our reasons for this are explained further in Section 15.5.4.

We engaged WSP to review our methodology for setting floors and caps. WSP confirmed that we have used a robust methodology to determine the best fit statistical distributions. WSP also verified the actual statistical output from our statistical modelling and confirmed that the dataset meets the Version 5 requirements, as set out below:

> *In WSP's view this (Powerlink's) approach is robust, and does not seem to be sensitive to the choice of distribution function because the results were either close to the next best fit distributions or confirmed through close analysis of the underlying data. The approach is also consistent with the Australian Energy Regulator's previous regulatory decisions to use a curve of best fit approach*[18].

WSP's full report is included in Appendix 15.03.

15.5.4 Alternative Target Setting - Porposed large loss of supply event frequency

Under its 2015 STPIS[19], the AER can approve a performance target based on an alternative methodology proposed by the TNSP. We have proposed an alternative target setting approach for the large loss of supply event frequency. The following sections explain our reasons for this proposed alternative approach and why this alternative target meets the relevant NER requirements.

WSP considered that setting a target value based on a symmetric maximum revenue increment and decrement would be most consistent with the requirements of the Rules[20] and the AER's 2015 STPIS. Consistent with this, an adjustment of the system minutes threshold for this parameter would have been the most appropriate action.

In its report, WSP noted the AER's decision to not undertake a STPIS review at this time and, given this circumstance, WSP considered that the application of an alternative methodology as allowed for by the STPIS, would be appropriate[21].

Standard target setting approach for the large loss of supply event frequency

The large loss of supply event frequency floor and target is based on historical performance over the 2015-2020 period. Our event counts for the large loss of supply events measure is shown in Table 15.4.

Table 15.4: Event counts: loss of supply events 2015-2020

	2015	2016	2017	2018	2019	2020
Loss of Supply Event >0.4 System Minutes	1	0	0	1	0	0

The table shows that we experienced only one large loss of supply event in the most recent five years from 2016 to 2020. This strong performance means that the average of the most recent five years performance is anticipated to be 0.2. The five year average from the AER's required historical data range of 2015 to 2019 is 0.4.

The AER's 2015 STPIS[22] requires that targets are rounded to the nearest integer. This means that as a consequence of the improvements we have made over the 2018-22 regulatory period, there is potential for the threshold target for the large loss of supply event frequency measure to be set at zero events for the 2023-27 regulatory period.

One of the principles for the design of the STPIS is that it should provide incentives to maintain and improve the reliability of transmission network elements. We consider that a target of zero events does not support this principle.

We initially raised this issue with the AER in October 2019 as part of our request that it review and amend our Framework and Approach for the STPIS (SC and MIC). In its November 2019 response, the AER set out reasons why it considered a zero target is reasonable and invited us to submit an alternative target. As permitted under the AER's 2015 STPIS, we have therefore proposed an alternative target that we consider will better reflect the intent and design principles of the scheme.

On the issue of the zero target, our independent consultant WSP noted:

> *WSP does not consider that setting the target and cap to zero for the 'Large' loss of supply event frequency parameter is consistent with the requirements of the NER and STPIS as it does not provide incentive to improve reliability as set out by NER clause 6A.7.4(b)(1), nor does it enable the scheme to provide a maximum revenue increment of 1.25% MAR as required by STPIS clause 3.3(a).*

18 Statistical Validation of STPIS Service Component, WSP, January 2021, page 17.
19 2015 STPIS, clause 3.1(i).
20 National Electricity Rules, clause 6A.7.4(b).
21 Statistical Validation of STPIS Service Component, WSP, January 2021, pages 19-20.
22 2015 STPIS, Australian Energy Regulator, October 2015, clause 3.2(k).

> *Further, setting both the cap and target to zero reduces the maximum revenue increment that Powerlink may earn against the parameters and values to below the value of 1.25% MAR that is specified by the STPIS:*
>
> - *Clause 3.3(a) of the STPIS version 5 (Corrected) specifies that the maximum revenue increment or decrement a TNSP may earn against its parameters under the service component is 1.25% of MAR; and*
> - *Clause 3.4(b) Table 3-1 of the STPIS sets the weighting for the large loss of supply parameter at 0.15% MAR.*
>
> *If zero incentive applies to the large loss of supply parameter, the maximum revenue increment provided for by the STPIS under this scenario is 1.1% of MAR and the maximum revenue decrement is 1.25%. This may not comply with the requirements of the STPIS, hence the cap, floor and target are not considered appropriate*[23]*.*

We agree with WSP.

Our proposed alternative target

We propose that the performance target for the large loss of supply event frequency parameter be the average performance over the relevant five year period rounded to the nearest non-zero integer. This alternative methodology results in a target of one.

A comparison of the incentive payments under a target of zero against our proposed alternative target of one is contained in Table 15.5.

Table 15.5: Comparison of large loss of supply event incentive targets

Incentive target	Number of events		
	Zero	1	2
Zero	$0	Penalty of -0.15% of MAR (floor)	Penalty of -0.15% of MAR (floor)
1	Bonus of +0.15% of MAR (cap)	$0	Penalty of -0.15% of MAR (floor)

We consider that our proposed alternative target minimises the economic harm caused by large loss of supply events at an appropriate cost to customers. It sets an incentive for us to maintain a high standard of performance, maintains a symmetrical incentive and is consistent with the intent of the scheme.

We further explain the reasons why an alternative target is proposed below and show how this meets the requirements of the AER's 2015 STPIS.

Reasons for an alternative target

The STPIS is designed to provide incentives for service-level improvement and the delivery of benefits to customers. A zero target does not support this intent and the design principles of the scheme for the following reasons.

- It is not in the best interests of customers. The costs to maintain a performance level that is aimed to meet a zero target, which are ultimately borne by customers, would be higher compared to a lower target.
- A target of zero (i.e. the best possible performance level) undermines the incentive for a TNSP to continue to improve performance across all parameters in the scheme. The reason for this is that if a zero target is achieved, a TNSP would then be subject to a penalty-only incentive (or disincentive) for the relevant parameter/s in the future.
- The SC has applied symmetrically since the inception of the scheme. A target of zero would make the scheme asymmetric, as there is no scope for us to perform better than the target. We would only be exposed to downside risk as we would be penalised for any possible loss of supply events (above the floor). Effectively, it becomes a penalty only scheme. This would undermine the intent and purpose of the scheme, which is to incentivise TNSPs to improve and maintain reliability[24].

[23] Statistical Validation of STPIS Service Component, WSP, January 2021, page 19.
[24] National Electricity Rules, clause 6A.7.4(b).

The AER has previously noted that the S-factor (or service factor) is symmetrical, i.e. penalties are incurred at the same rate as rewards[25]. In its development of the 2017 STPIS (Version 2) for electricity distribution, the AER confirmed that the STPIS is a symmetrical scheme that provides a direct link between a Distribution Network Service Provider's (DNSP's) revenue and the standard of service provided[26].

This was also supported by stakeholders. While these statements have been made in the context of distribution they are equally applicable to TNSPs and the AER's 2015 STPIS[27].

This is shown by the S-curve (reverse) charts below. They compare our proposed target of one, which retains a symmetrical rate of incentive payments (refer to Figure 15.11) against the scenario where the performance target is set at zero (refer to Figure 15.12).

Figure 15.11: Symmetrical scheme - target set at one

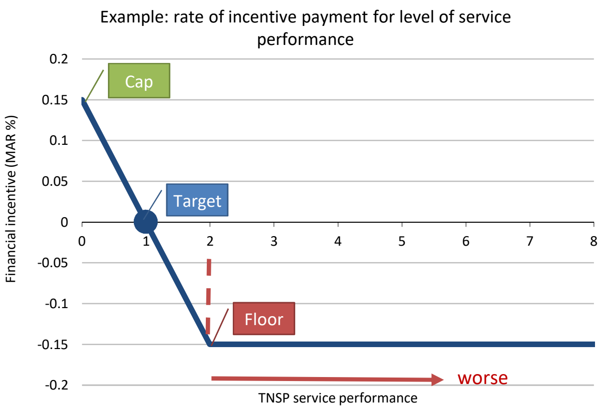
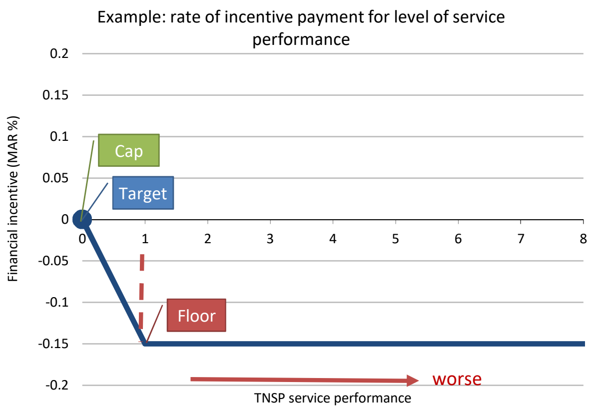


Figure 15.12: Asymmetrical scheme - target set at zero



Consideration of the 2015 STPIS requirements

We summarise how our alternative methodology meets the requirements of Section 3.2(i)(1) to (5) of the AER's 2015 STPIS in Table 15.6.

In addition to our assessment below, WSP undertook an independent evaluation of our proposed alternative target setting methodology against the requirements of the AER's 2015 STPIS and the Rules. For ease of reference, WSP's assessment from its report is also included in the table[28].

25 Explanatory Statement and Discussion Paper: Proposed Electricity Distribution Network Service Providers Service Target Performance Incentive Scheme, Australian Energy Regulator, April 2008, pages 14-15.

26 Explanatory Statement: Service Target Performance Incentive Scheme, Australian Energy Regulator, December 2017, page 25.

27 The 2015 STPIS defines the S-factor as 'the percentage revenue increment or decrement that the maximum allowed revenue is adjusted by in each regulatory year based on a TNSP's performance in the previous calendar year.'

28 Statistical Validation of STPIS Service Component, WSP, January 2021, pages 21-23.

Table 15.6: Assessment of alternative target against the AER's 2015 STPIS

Consideration	Powerlink position	WSP assessment
The methodology is reasonable.	The standard methodology to set targets under the AER's 2015 STPIS is to use the average of five years of history. For the loss of supply event frequency parameters the performance target is rounded to the nearest integer. Our proposed methodology retains this design feature, and ensures that a symmetrical scheme is maintained at high levels of performance. This maintains the incentive properties of the scheme. We consider this is reasonable and consistent with the intent of the STPIS.	WSP considers that the methodology is reasonable as it targets the specific issue and will only affect the outcome in the situation where the average of the past performance is less than 0.5 events per year. In any other case, rounding to the nearest integer (the standard calculation) and rounding to the nearest non-zero integer will result in the same outcome.
The TNSP's performance as measured by the relevant parameter has been consistently very high over every calendar year of the previous five years.	As shown in Table 15.4, we have performed at a consistently high level and only experienced one large loss of supply event over the last five years.	Powerlink has performed highly during the past five calendar years, exceeding their target in three years and meeting the target in two. Hence this clause is satisfied.
It is unlikely that the TNSP will be able to improve its performance during the next regulatory control period (or any potential improvement would be marginal), or any further improvements are likely to compromise the TNSP's other regulatory obligations.	If the target is set at zero, this is the highest possible performance level. In actual terms, compared to the one large event experienced over the most recent five calendar years, the only improvement we could make is to have zero large events in every year of the 2023-27 regulatory period. The achievement of this outcome would require expenditure that outweighs the benefits to customers.	It is unlikely that Powerlink would be able to improve its performance significantly, and cannot improve it beyond the target that would be set by the standard calculation methodology, hence the lack of incentive described in the sections above.
Where applicable, the TNSP's proposed performance targets are not a lower threshold than the performance targets that applied to an identical parameter in the previous regulatory control period.	The alternative target proposed is no lower than the performance targets that have previously been set for this parameter.	The performance target in the current regulatory control period is one with a cap of zero and a floor of two. Hence, the proposed values are the same as for the current period and are not lower.
The proposed methodology is consistent with the objectives in clause 1.4 of the scheme.	To support the National Electricity Objective (NEO), it is important that the methodology results in incentives to maintain efficient operation in the long-term interests of consumers. The proposed methodology is also consistent with the objectives set out in clause 6A.7.4(b) of the Rules, which are that the STPIS provide incentives to improve and maintain the reliability of network elements.	The proposed methodology ensures: There is a cost neutral position over the long-term to allow for natural variation around the average, hence promoting prudent and efficient expenditure decisions and consistency with STPIS clause 1.4(a)(1) and STPIS clause 1.4(b)(3). There is incentive to improve performance and therefore is consistent with STPIS clause 1.4(a)(2). There is a transparent calculation approach and is therefore consistent with STPIS clause 1.4(b)(1) and (2). *Note: WSP also undertook a more detailed assessment of consistency under clause 6A.7.4, which is included in its report* (1).

(1) Statistical Validation of STPIS Service Component, WSP, January 2021, pages 21-23.

15.5.5 Proposed Market Impact Component target values

We have proposed our performance target, unplanned outage event limit and dollar per dispatch interval incentive for the MIC based on the AER's 2015 STPIS[29]. Our approach is consistent with the AER's methodology in Appendices C and F of its 2015 STPIS. Appendix 15.01 Setting STPIS Values includes detailed information on the calculations for this parameter.

[29] 2015 STPIS, Section 4.2.

We have also based our target values for the MIC on historical performance for the 2013-2019 period, shown in Section 15.4.2. As noted in Section 15.5.1, we have urged the AER to use data to 2020 as the proposed target setting range.

The changes we have observed to power flows and the generation mix in the current regulatory period, which have been experienced across the NEM, was the key reason for our request to the AER to review the STPIS (refer Section 15.3.1). This proposal was supported in principle by our customers, noting that adequate consultation would need to occur as part of the review[30].

We remain concerned about the AER's continued use of our historical performance to set our future MIC targets, and the use of data that does not capture the most recent year's performance. In our correspondence to the AER[31] we explained that if our actual/forecast performance for the MIC between 2015 and 2021 is used to set the target for the 2023-27 regulatory period, we would likely exceed the maximum penalty for that entire period. This reflects the impact of the growth in DI counts that only emerged in 2019, as shown in Figure 15.10.

In response to a request from the AER, we provided more detailed analysis of why the MIC counts increased in 2019. We also provided analysis to support our expectation that this MIC count will increase in future, which we attribute to three main drivers:

- Central Queensland–Southern Queensland (CQ-SQ) intra-regional flows: this will increase periods of constraint;
- system strength constraints: an outcome of the increased asynchronous generation built across the network, which was not initially designed for this outcome; and
- localised generation constraints: this is manifest through the locations of new renewable generation.

The AER has advised that it considers that the MIC operates appropriately under the AER's 2015 STPIS[32]. Unlike the SC, the AER's 2015 STPIS does not allow us to propose an alternative methodology to set the performance target for the MIC.

While the use of historical performance data to set our MIC target remains a concern for us, we have calculated our target for the 2023-27 regulatory period consistent with the methodology in Appendices C and F of the AER's 2015 STPIS[33].

15.5.6 Proposed Network Capability Component projects

The NCC is intended to facilitate improvements in the capability of transmission assets through operational expenditure and minor capital expenditure. Under the AER's 2015 STPIS, we may submit a Network Capability Incentive Parameter Action Plan (NCIPAP)[34] to facilitate these improvements.

Our approach to NCIPAP is to only propose projects that provide genuine customer and market benefits, which meet the objectives and criteria of the NCC[35]. To determine whether there are any potential projects that meet this criteria to be put forward in our Revenue Proposal, we carried out an internal process to identify, review, validate and rank a broad range of potential candidate priority projects. We initially identified 12 potential projects for review and shortlisted three credible candidate priority projects.

Broadly, the three shortlisted projects would potentially result in increased operating limits on selected transmission lines, assist with the provision of operational data and increase grid transfer capacity. We then undertook a more detailed internal review and validation of customer benefits, which included consultation with AEMO. This review resulted in the identification of a range of technical issues associated with each project that may impact their potential market/customer benefits.

As a result, we consider that these issues need to be better understood and require more analysis and timing/technology alignment prior to the progression of a NCIPAP. We have therefore decided not to include any NCIPAP projects in our Revenue Proposal.

We may pursue potential projects within the 2023-27 regulatory period if they become viable, based on the AER's 2015 STPIS. To facilitate this, in we have amended our annual asset management processes to include routine potential NCIPAP project reviews to ensure we consider, and where appropriate propose, NCIPAP projects for implementation.

30 Meeting minutes of January and February 2020 Revenue Proposal Reference Group (RPRG), Powerlink, https://www.powerlink.com.au/2023-2027-regulatory-period.
31 Proposed STPIS review, Powerlink, Australian Energy Regulator, January 2020.
32 Framework and Approach: Powerlink, Australian Energy Regulator, July 2020, page 12.
33 2015 STPIS, Appendix C Market Impact Component – Definition, Appendix F Market Impact Component - Application.
34 2015 STPIS, Section 5.2(b).
35 2015 STPIS, Section 5.2.

We will make a request to the AER as part of our annual STPIS reports during the 2023-27 regulatory period[36], if we consider that any of the three shortlisted projects or any other NCIPAP project would meet the STPIS requirements and provide benefit to customers. This will involve consultation with AEMO, the AER and our customers and stakeholders.

15.6 Summary

Our STPIS performance for the 2018-22 regulatory period demonstrates the improvements that we have made to deliver safe and reliable network services to meet the needs of our customers.

Over this period the impact of changes in our operating environment and energy market has become more evident. This includes the challenges that have arisen from the constraints experienced as a result of the rapid change in the mix and location of generation. This has particularly impacted the MIC.

As provided for under the AER's 2015 STPIS, we have proposed an alternative target for our large loss of supply event frequency parameter. Our proposed alternative target better reflects the intent and design principles of the scheme, and targets a higher level of performance than our 2018-22 target for this parameter.

We have provided the AER with two sets of data to inform its assessment of our Revenue Proposal and its Draft Decision:

- targets consistent with our Reset RIN; and
- targets based on our most recent historical data.

To inform the AER's assessment and its Final Decision, we will provide the AER with actual data for full calendar year 2021 in early 2022, including updated targets.

[36] Consistent with the AER's 2015 STPIS, clause 5.4 (b).