Jemena Electricity Networks (Vic) Ltd

2021-26 Electricity Distribution Price Review Regulatory Proposal

Attachment 07-05

Incentive mechanisms

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Glossary

Current regulatory period	The regulatory control period covering 1 Jan 2016 to 31 Dec 2020
Intervening period	The six months between the end of the current regulatory period and beginning of the next regulatory period covering 1 Jan 2021 to 30 Jun 2021
Next regulatory period	The regulatory control period covering 1 Jul 2021 to 30 Jun 2026
RIN Response	Our response to the Regulatory Information Notice issued to JEN by the AER on 4 October 2019 to allow the AER to make a distribution determination for the period 1 July 2021 to 30 June 2026

Abbreviations

AER	Australian Energy Regulator
AEMO	Australian Energy Market Operator
Capex	Capital Expenditure
CESS	Capital Expenditure Sharing Scheme
CY	Calendar Year
DMIA	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EDPR	Electricity Distribution Price Review
ESC	Essential Services Commission of Victoria
ESV	Energy Safe Victoria
F&A	Framework and Approach
FY	Financial Year
GSL	Guaranteed Service Level
HY	Half Year
MAIFIe	Momentary Average Interruption Frequency Index event
MED	Major Event Day
NEL	National Electricity Law
NER	National Electricity Rules
Opex	Operating expenditure
RAB	Regulated Asset Base
RIN	Regulatory Information Notice
R&D	Research and development
STPIS	Service Target Performance Incentive Scheme
VCR	Value of Customer Reliability

Overview

An important element of the regulatory framework under the National Electricity Law (**NEL**) and National Electricity Rules (**NER**) is the application of various incentive schemes. The purpose of these schemes is to balance the incentives a Distribution Network Service Provider (**DNSP**) has to incur efficient operating and capital expenditure across a regulatory control period while also maintaining appropriate levels of reliability and customer service, as well as considering demand management options.

Incentive schemes give DNSPs temporary rewards to pass the benefits of improved efficiency to customers over time. In this way, incentive schemes are an effective mechanism for promoting the long-term interests of customers.

The AER is required to publish its proposed approach to incentive schemes in its Framework and Approach paper.[1] The AER published its final Framework and Approach paper for the 2021-25 regulatory control period (**F&A**) in January 2019. We have applied the AER's approach to incentive schemes in preparing this proposal for the regulatory control period control period covering 1 July 2021 to 30 June 2026 (**next regulatory period**).

This document sets out an overview of the outcome of certain incentives schemes which apply in the regulatory control period control period covering 1 January 2016 to 31 December 2020 (**current regulatory period**) as well as explains our approach on the application of the incentive schemes in the next regulatory period. The relevant schemes include the:

- Efficiency Benefit Sharing Scheme (**EBSS**)
- Capital Expenditure Sharing Scheme (**CESS**)
- Service Target Performance Incentive Scheme (**STPIS**)
- Demand management incentive scheme (**DMIS**) and demand management innovation allowance mechanism (**DMIAM**).

As outlined in this attachment, we do not propose a small scale incentive scheme.

State-based incentive schemes also apply during the next regulatory period. These include:

- F-Factor scheme
- Low-reliability payment scheme.

We consider the above schemes will contribute to outcomes which are in the long term interests of JEN's customers and will facilitate us in delivering a safe and reliable service at an affordable price consistent with our customers' expectations.

1 NER, cl 6.8.1(b)(2)(iii)-(vii).

1. Efficiency Benefit Sharing Scheme

1.1 Overview

The EBSS provides an incentive for us to pursue efficiency improvements in operating expenditure and provides for the sharing of savings with our customers. Depending on our actual performance, we receive either a reward or penalty in our revenue requirement, which is taken into account in the following regulatory period.

This section outlines:

- the outcomes of applying EBSS during the current regulatory period
- how JEN proposes to apply the EBSS during the next regulatory period.

1.2 Outcome of EBSS in the current regulatory period

The building blocks used to calculate the annual revenue requirements for each year of a regulatory control period must include any revenue increments or decrements for the relevant regulatory year where an EBSS applies.[2] As the EBSS applied to JEN in the current regulatory period,[3] our performance in the current regulatory period impacts the amount of revenue we receive in the next regulatory period.

We have estimated the EBSS carryover revenue for the next regulatory period. We are forecasting additional revenue of $24M ($ June 2021) under the EBSS reflecting our share of operating expenditure efficiency improvements made in the current regulatory period, as shown in Table 1–1. Our strong performance results in customers realising benefits in the next regulatory period through network bill savings.

Table 1–1: EBSS ($ June 2021, millions)

Incentive schemes	FY22	FY23	FY24	FY25	FY26	Total
Efficiency Benefit Sharing Scheme	8.1	6.5	4.9	2.1	2.1	**23.6**

Our calculation of the EBSS carryover amount relating to the current regulatory period reflects the AER's approach to the EBSS in its 2016-20 EDPR decision,[4] as well as an expected continuation of the scheme over the **intervening period**—that is, the period in between the current regulatory period and next regulatory period.[5] We have adopted the AER's Workbook 5 in our RIN Response to estimate the carryover revenue for the next regulatory period.[6] These EBSS calculations are set out in Attachment 07-19 *EBSS model*.

In Attachment 07-19 *EBSS mode*l, there are two additional true-ups to be applied in the carryover revenue to account for the incentive payments for the intervening period. These two true-ups require the actual operating expenditure of the calendar year (**CY**) 2020 and half year (**HY**) 2021, which will not be available by the time the AER makes its final decision. Hence these two true-ups are likely to be applied as part of the FY27-31 price reset process.

2 NER, cl 6.4.3(a)(5).

3 NER, cl 6.5.8. AER, *Final Decision, Jemena distribution determination 2016-20, Attachment 9–Efficiency benefit sharing scheme*, 2016.

4 NER, cl 6.5.8. AER, *Final Decision, Jemena distribution determination 2016-20, Attachment 9–Efficiency benefit sharing scheme*, 2016.

5 Refer to JEN's regulatory proposal for setting distribution prices for the period 10 January 21 to 30 June 2012 for details on how the EBSS will apply in the intervening period.

6 RIN Response - Workbook 5 - EBSS.

1.3 EBSS in the next regulatory period

1.3.1 Continued application of EBSS

In its F&A, the AER stated that it intends to continue to apply the EBSS if the AER is satisfied that the scheme will fairly share efficiency gains and losses between JEN and consumers.

JEN has adopted AER's revealed cost approach for setting operating expenditure allowance for the next regulatory period and proposes that the EBSS continue to apply in the next regulatory period.[7] Specifically, we consider that the incentives delivered by the scheme are in the long term interests of our customers, delivering reduced operating expenditure over time. We also consider that we meet the criteria that the AER developed in the F&A for deciding whether to apply an EBSS, namely:[8]

- we use a revealed cost approach to forecasting operating expenditure
- we have demonstrated how our operating expenditure is efficient (see section 1.3.1.1) below[9]
- we propose that a CESS apply (see section 2), to balance the operating expenditure and capital expenditure incentives, and also the DMIS to encourage non-network alternatives to network planning (see section 4).

The continued application of the EBSS is also consistent with customer feedback.[10] Specifically, our customers told us that energy affordability is a critical issue they face and challenge us to address. Continuing the EBSS for the next regulatory period is consistent with the feedback from our customers, and in their long-term interests, as it will incentivise us to actively pursue efficiency improvements in operating expenditure, with consumers benefiting through lower network charges.

1.3.1.1 Our operating expenditure is efficient

We have nominated the CY18 regulatory year as our base year.[11] We consider this reflects the best estimate of efficient operating expenditure to develop an operating expenditure forecast for the next regulatory period because:

- this is the most recent regulatory year for which expenditures are audited and is representative of normal business activities
- the alternative most recent regulatory year, CY19, incorporates one-off expenditure relating to a substantial transformation program,[12] making it difficult for the AER to assess the extent of our efficiency in that period (either negatively or positively).

Further information about our operating expenditure forecast for the next regulatory period is set out in Attachment 06-01 *Operating expenditure*.

7 NER, cl S6.1.3(3).

8 AER, *Final framework and approach, AusNet Services, Citipower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January 2019, section 3.2

9 Attachment 06-01 *Operating expenditure*.

10 Attachment 02-01 *Overview of our customer and stakeholder engagement program*.

11 We note that in discussion with the AER regarding the change in regulatory years that there is a general agreement that a CY base year is preferred over a FY base year.

12 Within the current regulatory period we have undertaken a significant efficiency program to reduce costs, the potential benefits will only be realised towards the latter years of the next regulatory period. More details are outlined in Attachment 06-01 *Operating expenditure*.

1.3.2 Proposed adjustments and excluded cost categories

The current version of the AER's EBSS specifies the adjustments to be made to each regulatory year of forecast and actual expenditure.[13] The EBSS permits exclusions of cost categories where the AER does not use a single year revealed cost forecasting approach for those categories of operating expenditure. Excluding certain costs from the EBSS is intended to better share the benefits of efficiency improvements between consumers and DNSPs and prevent windfall gains or losses arising. JEN agrees that these adjustments should be made in applying the EBSS during the next regulatory period.

In addition, we nominate the same cost exclusions approved by the AER in our 2016-20 EDPR final decision—namely, debt raising costs and GSL payments.[14] We also nominate two additional cost categories related to the Energy Safe Victoria (**ESV**) levy[15] and cost pass-through costs to the extent that an application for pass-through is made in accordance with the NER[16] and in the current regulatory period or next regulatory period.

The rationale for each of these proposed excluded costs categories is set out in Table 1–2.

Table 1–2: Proposed cost category exclusions from the EBSS

Cost category	Reason for exclusion
Debt raising costs	Not forecasted using a single year revealed cost approach. Previously approved to be excluded by the AER.
GSL payments	Not forecasted using a single year revealed cost approach, and subject to jurisdictional GSL scheme. Previously approved to be excluded by the AER.
ESV levy	This levy is paid to fund the safety-related activities undertaken by the ESV in accordance with a Ministerial determination under section 8 of the *Electricity Safety Act 1998* (Vic). We are proposing this exclusion as the costs represent a specific forecast, for which we have no opportunity to seek more efficient solutions to minimising this cost; the levy is prescribed, and we must pay it.
Cost pass-throughs and other approved adjustments	Costs of uncontrollable events that would qualify for a pass through event and contingent project.

13 AER, *Efficiency Benefit Sharing Scheme*, 29 November 2013, section 1.4.

14 AER, *Final decision, Jemena distribution determination 2016 to 2020, Attachment 9 – Efficiency benefit sharing scheme*, May 2016. Table 9.2. For the current regulatory period the following costs were excluded from the EBSS: (i) debt raising costs and (ii) Guaranteed Service Levy (**GSL**) payments.

15 We outline the nature of this expenditure item in Attachment 06-01 *Operating expenditure*.

16 NER cl. 6.6.1.

2. Capital Expenditure Sharing Scheme

2.1 Overview

The CESS incentivises DNSPs to only undertake efficient capital expenditure during a regulatory control period through a system of rewarding efficiency gains and penalising efficiency losses.[17] Consumers benefit from the improved efficiency via lower network prices in the future associated with a lower regulated asset base (**RAB**) value. When CESS is applied in conjunction with other incentive schemes such as EBSS and STPIS, we are incentivised to balance operating expenditure, capital expenditure and service performance objectives which supports outcomes aligned to our customers' long-term interests.

This section outlines:

- the outcomes of applying CESS during the current regulatory period
- how we propose to apply CESS during the next regulatory period.

We are proposing to apply the CESS as outlined in the F&A, without modification.

2.2 The outcome of CESS in the current regulatory period

2.2.1 CESS Revenue

The building blocks used to calculate the annual revenue requirements for each year of the regulatory control period must include revenue increments or decrements for the relevant regulatory year arising from any CESS.[18] We are currently subject to a CESS[19] and have applied forecast depreciation to roll-forward the RAB consistent with the AER's guidance.[20]

The CESS revenue adjustment from the current regulatory period, to be applied within the next regulatory period building block model, is calculated at $26M (as shown in Table 2–1). This amount is determined with reference to our relative capital expenditure performance, in accordance with the CESS set out in the AER's distribution determination for JEN's 2016-20 regulatory period.

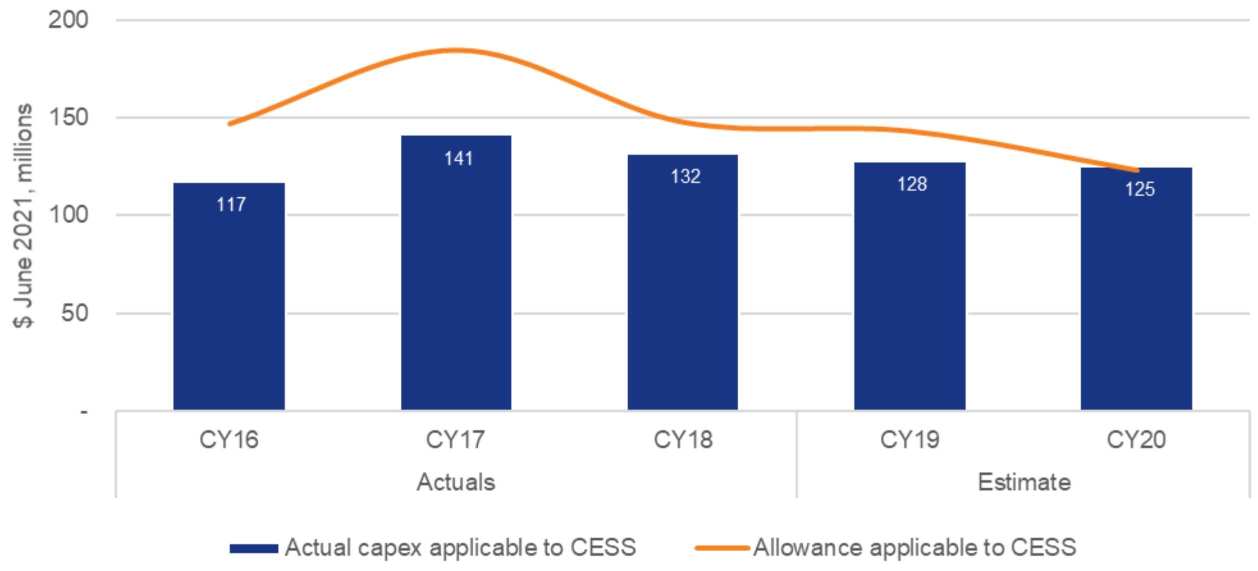
[17] NER, cl 6.5.8A. AER, *Capital expenditure incentive guideline*, November 2013.

[18] NER, cl 6.4.3(a)(5).

[19] AER, *Final decision, Jemena distribution determination, 2016 to 2020, Attachment 10 – Capital expenditure sharing scheme*, May 2016.

[20] AER, *Better Regulation: Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, section 3.3.

Figure 2–1: Comparison of actual and allowance capex ($ June 2021, millions)(1)



(1) Excluding contributions, equity raising costs and disposals.

When calculating the CESS payments, adjustments have been made for deferrals of capital expenditure. These are detailed in section 2.2.2.

Table 2–1: CESS rewards/penalties ($ June 2021, millions)

CESS	FY22	FY23	FY24	FY25	FY26	Total
Reward (+) / Penalty (-)	5.1	5.1	5.1	5.1	5.1	**25.6**

We have adopted the AER's Workbook 6 of RIN Response for estimating the CESS revenue for the next regulatory period.[21] This is set out in Attachment 07-20 *CESS model*.

2.2.2 Deferral expenditure adjustment

Some of the savings that we expect to make during the current regulatory period are attributable to changes in the timing of these investments—known as capital expenditure deferrals. To ensure that our customers do not bear the cost of a CESS reward for the deferral of these projects, we have removed the CESS benefits attributable to these projects from our CESS revenue adjustment, consistent with the AER's guidance.[22]

To make this adjustment, we identified material projects included in our forecast capital expenditure for the current regulatory period, which we do not expect to undertake during the current regulatory period and which form part of our proposed capital expenditure for the next regulatory period.

We then calculated the total deferral adjustment amount using the forecast capital expenditure for these projects in the current regulatory period, profiled to match the proposed timing of the corresponding capital expenditure in the next regulatory period. We consider this approach is consistent with the adjustment methodology outlined in the AER's *Capital Expenditure Incentive Guideline*,[23] as it ensures our customers share in the benefits of efficient capital expenditure deferrals between the current and next regulatory periods.

21 RIN Response – *Workbook 6*.

22 AER, *Better Regulation: Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p. 9.

23 AER, *Better Regulation: Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p. 9.

The projects and amounts reflected in our deferral adjustment, shown in nominal dollars,[24] are set out in Table 2–2.

Table 2–2: CESS deferral adjustment – by project ($ nominal, millions)

Project	FY22	FY23	FY24	FY25	FY26	Total
Replacement of relays at Footscray West zone substation	5.82	0.00	0.00	0.00	0.00	**5.82**
Replacement of switchgear at Footscray East zone substation	5.84	0.00	0.00	0.00	0.00	**5.84**
Replacement of switchgear at Footscray West zone substation	5.78	0.00	0.00	0.00	0.00	**5.78**
Replacement of transformers at Heidelberg zone substation	6.02	0.00	0.00	0.00	0.00	**6.02**
Total	**23.46**	**0.00**	**0.00**	**0.00**	**0.00**	**23.46**

We have been able to defer the Footscray West and Footscray East replacement projects as the condition of the individual assets had not degraded as much as expected when developing our capital expenditure forecast for the current regulatory period, allowing us to manage the risk of asset failure for an extended period.

The deferral of the Heidelberg zone substation transformer replacement project is due to complexities associated with underground assets located within the zone substation site discovered during detailed design work, meaning this project must now be undertaken in stages and expenditure will be incurred later than originally forecast. Further information about our capital expenditure during the current regulatory period is outlined in Attachment 05-02.

2.3 CESS for the next regulatory period

The AER stated in its F&A that it intends to apply the CESS to the Victorian DNSPs in the next regulatory period.[25] Consistent with this approach, we propose to apply the AER's approach as set out in the F&A with no variation or departure.[26] We also propose to adopt forecast regulatory deprecation, consistent with the default position[27] (see Attachment 07-04 *Regulatory asset base*).

24 Workbook 6 of the Reset Regulatory Information Notice issued by the AER to JEN requires that capital expenditure deferred and re-proposed be provided in nominal dollars.

25 NER, cl 6.3.2(a)(3).

26 NER, cl S6.1.3(3A).

27 AER, Better Regulation, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, section 3.3.

3. Service Target Performance Incentive Scheme

3.1 Overview

The Service Target Performance Incentive Scheme (**STPIS**) is designed to provide a financial incentive for DNSPs to maintain and improve their service performance.[28] It provides a counterbalance to the EBSS and CESS which reward DNSPs for lowering expenditure by ensuring that rewards under these schemes are not achieved at the expense of deteriorating service quality for customers. Specifically:

- The STPIS counterbalances the incentive to reduce operating costs that the EBSS provides by discouraging cost efficiencies at the expense of service outcomes for customers
- The performance targets under the STPIS reflect planned reliability improvements and therefore, any incentive to reduce capital expenditure under the CESS at the expense of performance outcomes will be curtailed by the STPIS penalty.

The STPIS operates as part of the building block determination, but unlike the EBSS and CESS, STPIS-based financial rewards (or penalties) over a regulatory period are added to (or subtracted from) the DNSP's annual revenue requirement, lagged by two years. The STPIS comprises the following two mechanisms:[29]

- a service factor (**S-factor**) adjustment to annual revenue allowances, rewarding/penalising DNSPs for better/worse performance compared with historical targets for supply reliability and customer service
- a GSL component whereby individual customers receive a fixed amount if they experience service below a predetermined level.

JEN proposes to apply the most recent version of the AER's STPIS in the next regulatory period,[30, 31] however, rather than applying the GSL component, we seek to apply the GSL payments as outlined in the Electricity Distribution Code.[32] This variation is consistent with the approach adopted by JEN, and approved by the AER, in the current regulatory period.[33] We outline how we apply the low-reliability payment scheme in Attachment 06-01 *Operating expenditure*.

The sections below outline how JEN propose to apply the STPIS during the next regulatory period.[34]

3.2 STPIS for the next regulatory period

The AER stated in its F&A for the Victorian DNSPs that it intends to continue applying the STPIS for the next regulatory control period on the basis that it interacts with other expenditure and demand management incentive schemes.[35] The AER proposed to:

- set revenue at risk for each DNSP within a range of ±5 per cent
- segment the network according to the four STPIS feeder categories (CBD, urban, short rural and long rural as appropriate for each DNSP)

[28] NER, cl 6.6.2.

[29] AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018.

[30] NER, cl 6.3.2(a)(3).

[31] AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018.

[32] ESC, *Electricity Distribution Code, Version 9A,* August 2018, cl 6.3.

[33] AER, *Final decision, Jemena distribution determination, 2016 to 2020, Attachment 11 – Service target performance incentive scheme*, May 2016.

[34] NER, cl S6.1.3(4).

[35] AER, *Final framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January2019, p. 80.

- apply the system average interruption duration index (**SAIDI**), system average interruption frequency index or (**SAIFI**), momentary interruption frequency index event or (**MAIFIe**) and customer service (telephone answering) parameters
- set performance targets based on the DNSP’s average performance over the past five regulatory years
- apply the method in the STPIS for excluding specific events from the calculation of annual performance and performance targets
- apply the method and value of customer reliability (**VCR**) values as indicated in Australian Energy Market Operator’s (**AEMO**) 2014 Value of Customer Reliability Review final report, unless a more up-to-date value is available. [36] We note that the AER is developing a new VCR; however, at the time of submitting this proposal, the revised methodology and VCR values have not been determined.

We propose to adopt the elements of the STPIS scheme as outlined in the F&A.

Application of the STPIS performance targets

The actual STPIS outcomes for the next regulatory period will be applied to the annual pricing proposal in FY23 to FY28, noting the two years lag for when rewards and penalties apply. However, for the development of our FY23 standard control services (**SCS**) network tariffs, the STPIS outcomes over the intervening period will also apply.[37] That is, two successive STPIS outcomes will be applied to determine the SCS network tariff for FY23.

3.3 STPIS performance targets

The STPIS requires that reliability performance targets must not deteriorate over the regulatory control period and must be based on average performance over the past five regulatory years.[38]

For the next regulatory period, we propose to:

- set the supply reliability performance targets based on a consistent method of averaging performance over the past five years (i.e. our average performance over the years FY16 to FY20)
- maintain the following performance measures:[39]
  - Unplanned SAIDI – urban and short rural
  - Unplanned SAIFI – urban and short rural
  - MAIFIe – urban and short rural
- apply the exclusions as defined in clause 3.3 of the STPIS[40]
- maintain the Telephone Answering customer service parameter (see section 3.4 below).

Consistent with clause 2.5(a) of the STPIS, we propose to cap the revenue at risk at plus or minus 5 per cent.[41]

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36 AER, *Final framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January2019, p. 76.

37 Refer to JEN’s regulatory proposal for setting distribution prices for the period 10 January 21 to 30 June 2012 for details on how the STPIS will apply in the intervening period.

38 AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018, s 3.2.1.

39 AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018, s 3.1.

40 AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018, s 3.3.

41 NER cl S6.1.3(4).

3.3.1 Reliability performance outcomes

This section sets out our reliability performance outcomes over the current regulatory period and resulting reliability performance targets we propose to apply for the next regulatory period.

We use historical data for establishing the reliability parameters as outlined in Appendix A, Table A1 of the STPIS.[42] Back-casting is necessary to account for the new MAIFIe definition.

Table 3–1 shows our reliability STPIS outcomes over the FY16 to FY19 period segmented into urban and short rural feeder types. The outcomes are based on actual reliability performance data available over the period. The reliability outcomes have been calculated consistent with the AER's most recent version of the STPIS using the unplanned SAIDI, unplanned SAIFI and MAIFIe supply reliability parameters.[43]

The changes in the calculation of SAIDI, SAIFI and MAIFIe targets in the next regulatory period are:

- a change of the momentary interruption definition from 1 minutes or less to 3 minutes or less
- the reclassification of the feeders by feeder type based on the definition of an urban feeder as one that is not a CBD feeder, has a 3-year average maximum demand over the 3-year average feeder route length greater than 0.3 MVA/km (being FY16 to FY18). Accordingly, our network is segmented into urban and short rural feeder types.

Table 3–1: Reliability performance outcomes over FY16 to FY19

Reliability parameter	FY16	FY17	FY18	FY19
Unplanned SAIDI	**39.716**	**40.626**	**52.928**	**34.647**
Urban	38.787	38.736	50.582	37.325
Short rural	48.029	57.241	72.956	11.397
Unplanned SAIFI	**0.682**	**0.683**	**0.913**	**0.513**
Urban	0.680	0.651	0.869	0.564
Short rural	0.704	0.962	1.293	0.073
MAIFIe	**1.060**	**0.695**	**1.151**	**1.151**
Urban	0.975	0.675	1.063	1.126
Short rural	1.816	0.872	1.898	1.366

(2) The three parameters (highlighted in blue) are calculated as the weighted average of the relevant outcomes for (a) urban and (b) short rural customers. The weights are assigned taking account of feeder types.

(3) The STPIS outcomes are based on reliability performance that is adjusted for the exclusion events.

(4) The data for FY16 to FY18 has been audited through our annual RIN submission process, and the data for FY19 is unaudited.

Excluded events

The STPIS allows certain events to be excluded from the calculation of the S-factor revenue adjustment. These exclusions include events that are beyond the control of JEN, such as the effects of transmission network outages and other upstream events. They also exclude the effects of extreme weather events that have the potential to affect JEN's STPIS performance significantly.

Over the FY16 to FY19 period, there were:

- one load shedding event at the direction of the AEMO on 25 January 2019

[42] AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018, s 3.3.

[43] AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018, Appendix A, Table A1.

- two major event days (**MED**) on 9 October 2016 and 6 February 2019.

The reliability performance outcomes and the proposed indicative reliability targets in Table 3–1 and Table 3–3 respectively reflect the exclusion of the load shedding event and the two MEDs.

The MED thresholds have been calculated using the 2.5 beta method in accordance with Appendix D of the STPIS.[44] The thresholds are based on the daily unplanned SAIDI data. Only those days where an unplanned SAIDI per day value greater than zero are considered. The MEDs are based on unplanned daily SAIDI data for five sequential financial years. Table 3–2 shows the MED thresholds over the FY16 to FY19 period.

Table 3–2: MED thresholds over FY16 to FY19

	FY16	FY17	FY18	FY19
MED threshold	4.251	3.989	3.884	4.194

3.3.2 Application of the STPIS targets in the next regulatory period

The reliability performance targets to apply during any regulatory control period must be based on average performance over the past five regulatory years.[45] For our proposed reliability targets in the next regulatory period, we have based our targets on the actual performance over FY16 to FY19—being the most recent four years where actual data is available. We will update the targets over five financial years when the FY20 performance is known in our revised regulatory proposal.

The input data for setting the STPIS performance targets for the next regulatory period are set out in RIN Workbook 9. The calculation of the above SAIDI and SAIFI and MAIFIe reliability performance targets are consistent with the methodology in the AER's current STPIS and the approach in Distribution Reliability Measures Guideline.[46]

Our proposed indicative reliability targets in the next regulatory period are set out in Table 3–3.

[44] AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018, Appendix D.

[45] AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018, clause 3.2.1.

[46] AER, *Distribution Reliability Measures Guideline, Version 1*, November 2018.

Table 3–3: Proposed indicative reliability targets in the next regulatory period

Reliability parameter	Value
Unplanned SAIDI	
Urban	41.358
Short rural	47.406
Unplanned SAIFI	
Urban	0.691
Short rural	0.758
MAIFIe	
Urban	0.960
Short rural	1.488

3.3.3 STPIS Incentive rates

The incentive rates we propose to apply over the next regulatory period are calculated in accordance with STPIS.[47] The STPIS incentive rate to apply to each parameter is calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and Appendix B of the STPIS and the values of customer reliability are applied in accordance with clause 3.2.2(b) and Appendix B of the STPIS.

The VCR value applied is $41,331/MWh (in 2019 dollars) adjusted for CPI to 2021/22 dollars by 6.12%.

Table 3–4 shows the proposed incentive rates (expressed as a percentage for each 0.01 interruption away from the performance target) for each of the reliability parameters.

Table 3–4: Proposed incentive rates in the next regulatory period

Reliability parameter	Value
Unplanned SAIDI	
Urban	0.0800%
Short rural	0.0073%
Unplanned SAIFI	
Urban	3.1911%
Short rural	0.3027%
MAIFIe	
Urban	0.2553%
Short rural	0.0242%

3.4 Telephone answering targets

This section sets out the telephone answering performance achieved over FY15 to FY19 regulatory years, and our proposed telephone answering performance targets for the next regulatory period.

47 AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018, section 3.2.2.

Table 3–5 sets out our telephone answering performance outcomes over FY16 to FY19. The performance outcomes in this table have been calculated consistent with the definition of telephone answering in the STPIS.[48]

Table 3–5: Telephone answering service outcomes over FY16 to FY19

Customer service parameter	FY16	FY17	FY18	FY19
Telephone answering	67.333%	68.273%	76.031%	79.927%

The STPIS requires that customer service performance targets must be based on the average actual performance over the past five regulatory years—that is, the average performance over FY16 to FY20 regulatory period.[49] Therefore, based on the data over the period FY16 to FY19 (being the latest four years where actual data is available), our proposed customer service performance target over the next regulatory period is 72.626%. In our revised regulatory proposal, we will update the customer service performance target.

In accordance with clause 5.2(b) of the STPIS, we propose to cap the revenue at risk at plus or minus 0.5% for the customer service parameter, namely telephone answering.

3.5 Guaranteed service levels

In the AER's final F&A it states that it will not apply the GSL component of the STPIS over the next regulatory period given that Victorian DNSPs are subject to a jurisdictional GSL scheme.[50] We agree with the AER's proposed approach for the GSL component of the STPIS, which is consistent with the approach to applying GSL in the current regulatory period.

[48] AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018, Appendix A.

[49] AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0,* November 2018, section 5.3.

[50] AER, *Final framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January 2019, p 76.

4. Demand management incentive scheme and demand management innovation allowance

4.1 Overview

In December 2017, the AER developed a new DMIS and DMIAM.[51,52]

The DMIS incentivises DNSPs to identify lower-cost alternatives and undertake efficient expenditure on non-network options relating to demand management.

The DMIAM relates to research and development (**R&D**) fund supporting DNSPs to explore and trial new demand management solutions to keep costs down for electricity consumers in the future. This will fund innovative projects that have the potential to deliver ongoing reductions in demand or peak demand. Potential solutions include, but are not limited to tariff offerings, demand response, embedded generation, energy storage solutions and energy efficiency incentive programs. The DMIAM complements the DMIS, increasing the likelihood of DNSPs investing in projects that pursue the objectives of the scheme.

Both the DMIS and DMIAM are designed to put downward pressure on network prices for electricity consumers in the future.

4.2 Use of DMIA in the current regulatory period

In our efforts to be leaders in network innovation, we have been active users of the DMIA in the current regulatory period, to facilitate exploring new opportunities to realise benefits for our customers. Some of the initiatives we have explored are described in Table 4–1.

Table 4–1: Summary of DMIA projects undertaken in the current regulatory period

Project	Summary/Benefits
In 2016, we undertook four initiatives: 1. Commercial and industrial customer demand management response trial on 22kV Feeder BD-13 (Phase 1). 2. Feasibility study on Grid Battery Energy Storage System to better understand battery technology. 3. Demand management constraint analysis to facilitate non-network option planning. 4. Commercial and industrial solar PV and battery storage systems and residential demand response.	All the four initiatives listed for 2016 were exploratory in nature, setting foundations and enabling non-network option trials in the subsequent years.

51 AER, *Demand Management Incentive Scheme, Electricity distribution network service providers*, December 2017.

52 NER, cl 6.6.3 and cl 6.6.3A.

Project	Summary/Benefits
In 2017, we commenced a residential demand response trial (publicly branded as 'Power Changers') to understand the customer behaviours and the potential role they can play in reducing emerging capacity constraints on the network and enable deferral or avoidance of augmentation capital expenditure in predominantly residential areas. The trial ran during the 2017-18 summer in constrained areas of our network (Fairfield, Alphington, Ivanhoe, East Ivanhoe, Eaglemont and Craigieburn) and targeted the recruitment of at least 600 households. The trial was designed to test the hypotheses that if customers are provided with easily actionable tips to reduce energy consumption, especially during times of network constraint, a fundamental shift in customer behaviour can be achieved to the benefit the network.	This residential demand response trial was supported by the Victorian Government (namely the Department of Energy Land Water and Planning). The project explored the potential benefit of deferral or avoidance of network augmentation capital expenditure and of mitigating supply risks on constrained feeders in our network. This trial established the feasibility of customer-led behavioural demand response to support the networks and electricity markets.
In 2018, we completed our residential demand response trial.	The field component of the trial ran from 1 December 2017 to 31 March 2018. Rigorous analysis of customer responses followed, and learning was reported. A total of 613 residential customers registered their interest through the demand response portal (mobile app and web link). We called six demand response challenges (events) including one on Sunday, 28 January 2018, when an extreme heatwave was experienced across the state.

The AER stated in its F&A for the Victorian DNSPs that it intends to apply the new DMIS and DMIAM in the 2021−26 regulatory control period.[53] Consistent with the AER's stated approach, we also propose to adopt the new DMIS and DMIAM in the next regulatory period without any variation or departure.[54]

The forecast demand management innovation allowance for the next regulatory period is set out in Attachment 07-15 *SCS PTRM FY22-26*.

[53] NER, cl 6.3.2(3).

[54] NER, cl S6.1.3(5).

5. Small scale incentive scheme

In our draft Proposal, we outlined our preference to incorporate a customer service incentive scheme via the small scale incentive scheme mechanism available under the NER in the next regulatory period.[55]

We asked our People's Panel for their views on a proposed customer service incentive scheme. Only 46 per cent of the members supported the proposed scheme. The majority of the People's Panel considered that good customer service is just expected. This feedback was consistent with our customer's views on continuous customer engagement, in particular, through new technologies and simpler administrative processes.[56]

We note that the AER has commenced consultation on a possible customer engagement incentive mechanism similar to that which we proposed to our People's Panel.[57] However, the AER has not specified any small scale incentive scheme in the F&A.

While we are supportive of this kind of incentive scheme, we do not consider it appropriate to propose a customer service incentive scheme for the next regulatory proposal given the response received from our customers during the consultation process. We are, however, committed to improving our customer service and will seek to find better ways to delivering this outcome over the next regulatory period, and will continue to collect customer service performance data so that if an opportunity arises to develop a scheme, we have the information available.

55 NER, cl 6.6.4; JEN, *Jemena Electricity Networks, Draft 2021-25 Plan*, January 2019, p 66.

56 Attachment 02-02 – Capire Community Consultation Report, p 44. Our customers indicated in the forum held on 21 July, 2018 that JEN should improve their channels of customer service by increasing their services to include mobile apps and using simpler processes.

57 AER, *Draft, Customer Service Incentive Scheme,* December 2019.

6. F-factor scheme

The F-factor scheme is designed to encourage DNSPs to minimise the number of fire starts caused by distribution network assets. The scheme does this through a system of rewards and penalties, with greater incentives applying in bushfire-prone areas and at times of high fire danger.

On 22 December 2016, the Victorian Government published the "F-factor scheme order 2016" (**2016 Order**). The 2016 Order replaces the previous F-factor scheme that commenced on 23 June 2011, and pursuant to it, the AER made an F-factor scheme determination in June 2017.[58] This scheme establishes an incentive mechanism to reduce fire ignitions that pose the greatest risk of harm through the use of ignition risk units (**IRU**). The IRU represents a blended measure for tracking DNSP performance which takes into account the relevant fire danger rating and the location of each fire start.

Under the AER's F-factor determination, the AER set JEN a benchmark target of 9.7 IRUs for the current regulatory period. As outlined in the F&A,[59] the AER considers that maintaining this current IRU target for the next regulatory period is appropriate. We support this view, and therefore we propose a target of 9.7 IRUs applies in the next regulatory period.

58 AER, *Final determinations and Explanatory statement Electricity f-factor scheme 2016–2020 For Victorian electricity distribution network service providers*, June 2017. The AER's 2017 f-factor decision supersedes the AER's 2016-20 F-factor scheme determination.

59 AER, *Final framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January 2019, section 3.5.1.