Jemena Electricity Networks (Vic) Ltd

2026-31 Electricity Distribution Price Review Regulatory Proposal

Attachment 07-01

Incentive mechanisms

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Abbreviations

AER	Australian Energy Regulator
ARENA	an Australian Renewable Energy Agency
CESS	Capital Expenditure Sharing Scheme
CSIS	Customer Service Incentive Scheme
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
EBSS	Efficiency Benefit Sharing Scheme
EDCoP	Electricity Distribution Code of Practice
ERG	Energy Reference Group
ESIS	Export Service Incentive Scheme
ESV	Energy Safe Victoria
EV	Electric Vehicle
F&A	Framework and Approach Paper
FCAS	Frequency Control Ancillary Services
GSL	Guarantee Service Level
IRU	Ignition Risk Units
JEN	Jemena Electricity Networks (Vic) Ltd.
MAIFIe	Momentary Interruption Frequency Index Event
NBI	Neighbourhood Battery Initiative
NEL	National Electricity Law
NER	National Electricity Rules
R&D	Research and Development
RAB	Regulated Asset Base
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
STPIS	Service Target Performance Incentive Scheme
VCR	Value of Customer Reliability
VEBM	Victorian Emergency Backstop Mechanism

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 Australian Energy Regulator (**AER**) is required to publish its proposed approach to incentive schemes in its Framework and Approach paper (NER, cl. 6.8.1(b)(2)). The AER published its final Framework and Approach paper **(F&A**) for the 2026-31 regulatory control period in July 2024. For the most part, we have applied the AER's approach to incentive schemes in preparing this proposal for the regulatory control period covering 1 July 2026 to 30 June 2031 (**next regulatory period**). However, we are proposing a deviation from the AER's proposed Capital Expenditure Sharing scheme by not including connection capital expenditure in the incentive scheme.

This document sets out an overview of the outcome of certain incentive schemes that apply in the regulatory control period covering 1 July 2021 to 30 June 2026 (**current regulatory period**), as well as explains our approach to 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**).
- Small Scale Incentives Scheme – Customer Service Incentive Scheme (**CSIS**).

As outlined in this attachment, we do not propose an export incentive scheme.

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

- Low-reliability payment scheme
- F-Factor scheme

We consider the above schemes will contribute to outcomes that are in the long-term interests of Jemena Electricity Networks (Vic) Ltd. (**JEN's**) customers and will facilitate our delivery of a safe and reliable service at an affordable price consistent with our customers' expectations

1. Efficiency Benefit Sharing Scheme

1.1 Overview

The AER's EBSS is designed to encourage networks to seek out efficiencies in their operating expenditure. The scheme allows the cost savings from these efficiencies to be shared between customers and DNSPs while also ensuring DNSPs face a penalty if they spend above their AER-approved operating expenditure allowance. Consumers benefit from improved efficiencies through lower operating expenditure allowances in subsequent regulatory periods.

This section outlines:

- JEN's EBSS outcomes in 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 revenue requirement for the next regulatory control period includes any revenue increments or decrements as a result of EBSS outcome (carryover amount) from our operating expenditure performance in the current regulatory period.

In calculating the EBSS outcome, we relied on operating expenditure allowances, including the approved cost passthrough on the Victorian Emergency Backstop Mechanism (**VEBM**).[1] It ensures that the additional costs of complying with new regulations are included in both the regulatory allowances and our reported costs. We are forecasting a positive EBSS carryover amount reflecting the operating expenditure efficiency improvements we made in the current regulatory period, as shown in Table 1-1. Our operating expenditure efficiency performance results in customers realising network bill savings in the next regulatory period through lower forecast operating expenditure.

Table 1-1: EBSS ($ June 2026, millions)

Incentive schemes	FY27	FY28	FY29	FY30	FY31	Total
EBSS carryover amount	4.60	3.82	6.68	5.86	-	20.96

Our calculation of the EBSS carryover amount relating to the current regulatory period reflects the AER's standard approach[2] and the calculations are set out in *Attachment 08-09 EBSS model*.

1.3 EBSS in the next regulatory period

1.3.1 JEN proposes to continue to apply the EBSS

In April 2023, the AER published its final decision on its review of incentive schemes, including the EBSS. The review found that the EBSS, in its current form, continues to deliver efficiency benefits to customers, and the current sharing ratios remain appropriate.[3] In light of this, the AER stated its intention to continue applying the EBSS in its F&A paper for the coming period.[4]

1 AER, *Determination, Jemena, Victorian Emergency Backstop Mechanism Cost Pass Through*, September 2024.

2 NER, cl 6.5.8. AER, *Final Decision, Jemena distribution determination 2021-26, Attachment 9–Efficiency benefit sharing scheme*, 2021.

3 AER, Final Decision, *Review of incentive schemes for networks*, April 2023.

4 AER, *Final Framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026–31*, 31 July 2024, section 4.1.

In 2026-31 Proposal, JEN has adopted the AER's revealed cost approach for setting the operating expenditure allowance for the next regulatory period and proposes that the EBSS continue to apply.[5] 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.

1.3.2 Proposed adjustments and excluded cost categories

The EBSS allows network service providers to exclude certain cost categories which are not forecast using single year revealed cost from both forecast and actual expenditure[6]. As the cost of these categories can vary dramatically from year to year, excluding these costs from calculations ensures EBSS rewards/penalties reflect actual efficiencies and prevents windfall gains or losses.

The current version of the EBSS scheme excludes both Guarantee Service Level (**GSL**) payments and debt raising costs from EBSS calculations on this basis. In the current regulatory period the AER has approved additional exclusions for:

- Energy Safe Victoria (**ESV**) levies
- Cost pass-throughs and contingent projects
- DMIAM operating expenditure.

We do not propose to exclude ESV levies from EBSS calculations in the next regulatory period as these costs are treated as Jurisdictional Scheme amounts[7] and are no longer part of our SCS operating expenditure. However, for DMIAM amounts, we propose continuing to exclude these from the EBSS calculations in the next regulatory period. For contingent projects and cost passthrough events, we propose to add the approved operating expenditure to the EBSS calculations so that the regulatory allowances and costs we incur are treated on the same basis, consistent with the AER's recent decisions[8]. In addition to retaining these adjustments for the next regulatory period, we propose to also exclude any operating expenditure approved as part of our proposed Innovation Fund.[9]

The rationale for these proposed adjustments is outlined in Table 1-2.

Table 1-2: Proposed cost category adjustments for the EBSS

Cost Category	Rationale for Adjustment
Debt raising costs	Based on the current version of EBSS, forecasts based on benchmarking rather than single-year revealed costs should be excluded.
GSL payments	Forecast based five year historical average, rather than single year revealed costs, should be excluded based on the current version of EBSS.
Cost pass-throughs and contingent projects	The costs of uncontrollable and unforeseen/uncertain events which are not included in our baseline allowance. These costs are not forecast based on single year revealed costs and their efficiency is assessed by the AER at the time of cost pass-through application. The approved costs are to be added to the operating expenditure allowances in the EBSS assessment.
DMIAM	Approved on a 'use it or lose it' basis, should be excluded based on current version of EBSS.
Innovation Fund	As discussed in Attachment 03-02, we propose the Innovation Fund be approved on a 'use it or lose it' basis, which should be excluded from the EBSS assessment. As such we don't believe it would be appropriate to earn a reward if we underspend this allowance.

5 NER, cl S6.1.3(3).

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

7 AER, *Jurisdictional scheme determination, Licence fees under Electricity Industry Act 2000 (Vic)*, July 2024.

8 AER, *Draft Decision Attachment 8 - Efficiency benefit sharing scheme - Energex - 2025-30 Distribution revenue proposal - September 2024,* Pg. 4-5.

9 Please see Attachment 03-02 for further details on our proposed Innovation Fund.

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.[10] 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, networks 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 modify the CESS as outlined in our response to the F&A consultation[11] and consistent with the changes we proposed in JEN's Draft Plan[12] to exclude connection capital expenditure from the CESS calculations.

2.2 Outcome of CESS in the current regulatory period

2.2.1 CESS Revenue

The revenue requirement for the next regulatory control period includes revenue increments or decrements arising from the application of CESS in the current regulatory period.[13]

In the current regulatory period, we anticipate exceeding the AER's approved capital expenditure allowance due to unprecedented growth in the number of data centres and other large customers seeking to connect to our network. The volume and size of large customer connections were unforeseen and were not included in our capital expenditure allowance for the current regulatory period. Subsequently, we have applied to reopen JEN's current period determination to account for this unforeseen and material increase in expenditure. At the time of submitting this proposal, the AER is assessing our reopener application.

For the purposes of calculating CESS rewards or penalties for the current regulatory period capital expenditure, we relied on allowances that incorporated the approved cost pass through application for VEBM and assumed that JEN's reopener application is approved as submitted to the AER. As a result, we are projecting a CESS payment of $3M. If the capital expenditure allowance for CESS purposes excludes JEN's reopener application, we would incur a CESS penalty of approximately $36M. A summary of our proposed CESS outcome is provided in Table 2-1.

Table 2-1: Proposed CESS outcomes for the next regulatory period ($ June 2026, millions)

CESS	FY27	FY28	FY29	FY30	FY31	Total
Reward (+) / Penalty (-)	0.6	0.6	0.6	0.6	0.6	3.1

10 NER, cl 6.5.8A. AER, *Capital expenditure incentive guideline*, November 2013.

11 JEN, *Jemena's response to the draft 2026-31 Framework and Approach decision*, 15 May 2024.

12 JEN, *Draft Proposal – Incentive Schemes*, August 2024.

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

When calculating the CESS payments, adjustments have been made for material capital expenditure deferred from the current regulatory period and re-proposed in the next regulatory period. These are detailed in section 2.2.2.

Details of the CESS adjustments for the next regulatory period are set out in *Attachment 08-10M 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 projects that were deferred and re-proposed in the following period, we have removed the CESS benefits attributable to these projects from our CESS calculation, consistent with the AER's guidance.[14]

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 lower amount between the forecast capital expenditure for these projects in the current regulatory period and the re-proposed amount in the next regulatory period, net of any capital contributions.

The projects and amounts reflected in our deferral adjustment are set out in Table 2-2.

Table 2-2: Project deferral ($ June 2026, millions)

Project Name (per 2021-26 Allowance)	Net capital expenditure – deferred projects		
	2021-26 allowance	2026-31 proposal	Deferral adjustment
Augment BTS-NS 22kV loop	13.8	2.5	2.5
Augment steel section - SBY24	1.5	1.3	1.3
EP Conversion Stage 8	10.4	19.7	10.4
New feeder - TMA15	2.9	1.9	1.9
Replace 22kV Switchgear - BLTS	1.0	7.1	1.0
Replace 22kV Switchgear - CN	7.3	47.6	7.3
Replace Aged Relays - CS	9.2	18.0	9.2
Total	**46.1**	**98.0**	**33.6**

Note: The deferral amount in nominal terms are presented in *JEN – Att 08-10M CESS model.*

2.2.3 Capital contributions on an as-incurred basis

JEN has historically reported capital contributions on an 'as commissioned' basis,[15] consistent with the statutory auditing standards[16,17] required under the Regulatory Information Notice (**RIN**). In contrast, the forecast capital contribution in regulatory allowances are provided on an 'as incurred' basis.[18] This creates a timing misalignment between regulatory allowances and reported capital expenditure, potentially leading to misestimation of CESS outcomes. In normal circumstances, the timing issue is generally immaterial, as the customer connection projects

14 AER, *Final Decision Review of Incentive Schemes for Networks*, April 2023.

15 This means recognising the contribution amounts in the regulatory reporting at the time the contribution is recognised in the statutory revenues.

16 *ASA 805 Special Considerations — Audits of Single Financial Statements and Specific Elements, Accounts or Items of a Financial Statement.*

17 *ASRE 2405 Review of Historical Financial Information Other than a Financial Report.*

18 This means recognising the contributions amounts in the regulatory reporting at the same time as and in proportion to the capital expenditure incurred on the project.

are completed in a continuous pipeline where the timing of capital contributions and capital expenditure broadly offset each other across the portfolio of connection projects giving the *appearance* of an 'as incurred' basis for recognising capital contributions at a total level. However, in the current regulatory period, JEN is experiencing unprecedented growth in large connection infrastructure projects spanning multiple years[19] which has skewed the portfolio, exacerbating the impacts of the timing misalignment.

In November 2024, the AER issued a guidance note clarifying the timing of recognising capital contributions (contributions guidance).[20] It requires cash contributions for connection projects exceeding $200,000 and spanning more than 12 months to be individually reported on an 'as incurred' basis.[21]

While JEN had projects meeting these criteria in FY22 to FY24, they were reported on an 'as commissioned' basis in the annual RINs as this was the requirement under the auditing standards at the time of reporting against the RIN requirements. Given the timing of receiving the contributions guidance, JEN is unable to undertake the detailed review of all our projects in FY22 to FY24 and restate the RINs before submitting our 2026-31 regulatory proposal. Therefore, JEN proposes the following approach for each regulatory year to ensure that the total capital contributions are recognised on an 'as incurred' basis for the current regulatory period:

- FY22-FY24: Actual capital contributions will remain on an 'as commissioned' basis, consistent with JEN's audited Annual RINs.
- FY25-FY26: Forecast capital contributions will be reported on an 'as incurred' basis, calculated as a percentage of the forecast capital expenditure.
- Catch-up adjustment in FY25: An adjustment to account for any FY22-FY24 projects that should have been recognised on an 'as incurred' basis but were not.

We propose auditing the FY22-FY24 catch-up adjustment alongside FY25 capital contributions as part of the FY25 annual RIN reporting process and prior to submitting our revised proposal. This approach provides additional time to review historical projects and implement system changes to ensure capital contributions are reported on an 'as incurred' basis from FY25 onwards. It also ensures the adjustment complies with the AER's guidance note and provides external assurance of its accuracy.

Table 2-3 illustrates our proposed approach and the corresponding capital contributions.

Table 2-3: Transitional approach to reporting capital contributions on 'as incurred' basis ($ June 2026, millions)

Capital contributions	Audited actuals			Estimates	
	FY22	FY23	FY24	FY25	FY26
As commissioned	48.2	74.1	96.2		
'Catch-up' adjustment for FY22-24 on as incurred basis				49.1	
As incurred				113.7	180.6
Total capital contributions	**48.2**	**74.1**	**96.2**	**162.8**	**180.6**

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, as amended by the 2023 Incentive Review, in the next regulatory period.[22] While JEN agrees the CESS should apply in the next regulatory period, we propose that new connections should be excluded from the scheme. This will account for non-

[19] See Attachment: *Att 05-01 Capital expenditure*.

[20] AER, *Reporting capital contributions AER Guidance Note for electricity distributors*, November, 2024.

[21] meaning qualifying connection projects are to recognise capital contributions in proportion to the connection project capital expenditure spent

[22] AER, *Final Framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026–31*, 31 July 2024, section 4.1.

controllable factors that JEN is exposed to, ensure consistency with the remaining elements of the regulatory framework, and result in a more symmetrical incentive scheme.

Additionally, and for clarity, we will calculate net capital expenditure using capital contributions stated as incurred, consistent with the AER's expectations.[23]

2.3.1 Rationale for excluding new connections from CESS

In Victoria, DNSPs are required to undertake market-based testing of works related to connection services made by a connection applicant.[24] This requirement means that the most efficient price will be incorporated into JEN's capital expenditure forecasts for the 2026-31 period, meaning the opportunity to find further efficiencies does not exist.

Under the NER, DNSPs must provide customer connection services.[25] In preparing for this proposal, JEN has forecasted the volume of connection services that will need to be provided; however, this forecast was developed on a best-efforts basis, and the actual volume of connections required may vary dramatically due to a range of factors outside of JEN's control, including; housing developments within JEN's distribution area, emerging technology and industry trends[26] and other market forces. This means JEN is developing these forecasts with incomplete information and must incur capital expenditure related to providing these connection services, such as investment in distribution infrastructure, over which we have no control.

Additionally, to calculate the CESS, deferred capital expenditure is excluded; however, the CESS is not adjusted where JEN necessarily incurs additional capital expenditure (unforeseen at the time of the distribution determination) on projects arising out of the energy transition driven by a change in government policy or due to new connections. We consider that this results in unintended outcomes for the CESS because of the lack of symmetry.

The overarching objective of the CESS is to set incentives for DNSPs—such as JEN—to undertake efficient capital expenditures during a regulatory control period.[27] Within this objective, we view that the CESS should only apply to the part of JEN's capital expenditure program that is within JEN's control. We should exclude parts of our capital expenditure program that are outside of our control from the CESS.

Our proposal to exclude new connections from CESS is also supported by the Energy Reference Group (**ERG**)[28]. In its submission, the ERG raised concerns about including forecast connection costs beyond the network's control in CESS, which may distort the scheme's goal of promoting efficiency. It noted that our proposal helps to ensure that the CESS outcome reflects efficiency rather than factors beyond a distributor's control.

[23] AER, *Reporting capital contributions AER Guidance Note for electricity distributors*, November, 2024.

[24] Essential Services Commission of Victoria, *Electricity Distribution Code of Practice, version 2*, 1 May 2023, s5.2.1(a).

[25] NER, Chapter 5A, Part C.

[26] The growth of data centres is a clear example here.

[27] AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, April 2023.

[28] JEN, *JEN - Att 02-23 Energy Reference Group Report.*

3. Service Target Performance Incentive Scheme

3.1 Overview

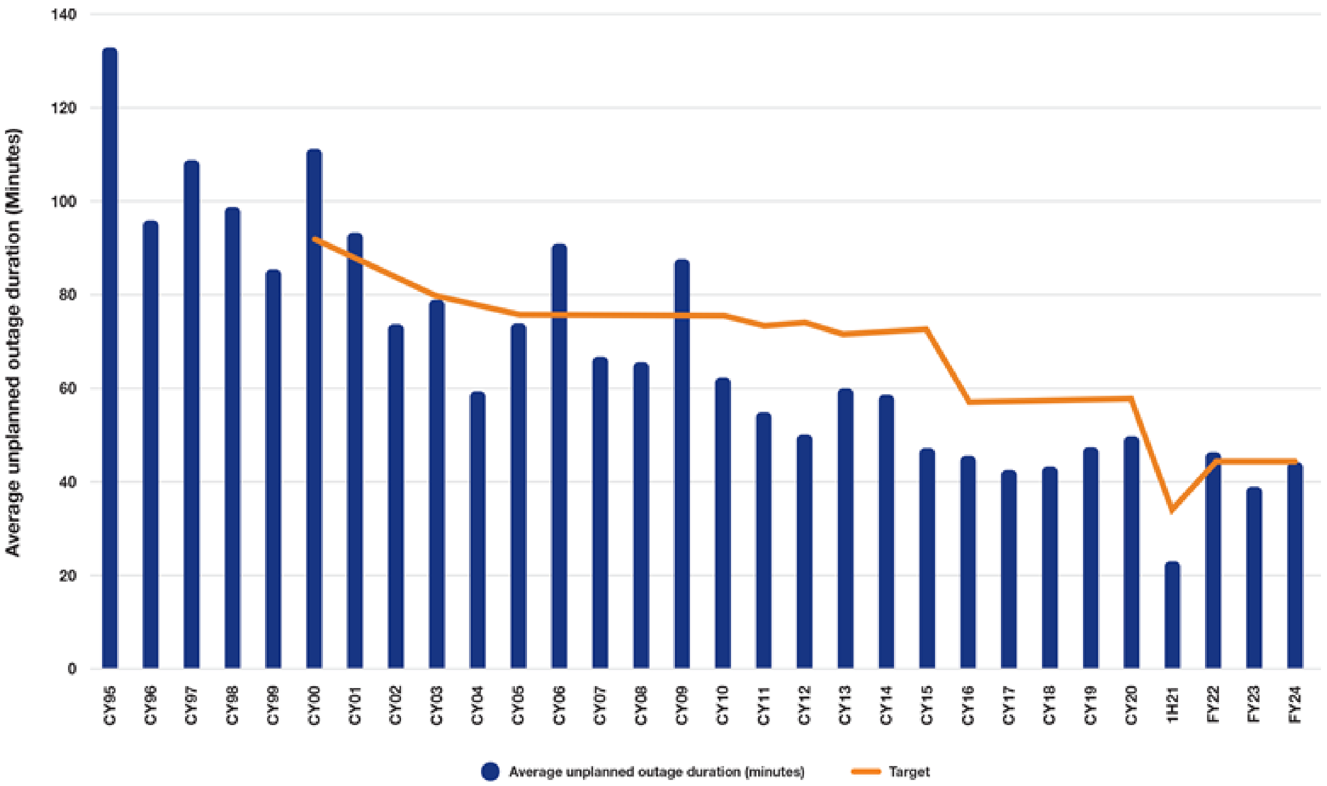
The STPIS is designed to provide DNSPs with a financial incentive to maintain and improve their service performance, up to the level which customers are willing to pay for.[29] The amount of reward and penalty each year is tied to the network's performance in delivering a reliable electricity supply to its customers.

Network Performance

Several key performance indicators measure the service performance of an electricity distribution business. These include the system average interruption duration index (**SAIDI**) and the system average interruption frequency index (**SAIFI**). SAIDI and SAIFI measure how long an average outage takes and the number (or frequency) of outages in a particular regulatory year.

JEN has performed well on both of these measures, as demonstrated in Figure 3-1 and Figure 3-2 where the length and number of outages, included under the STPIS have steadily decreased over the long term. Our customers have enjoyed the benefits of the operation of the STPIS (or its predecessor schemes) that have been applied over the previous regulatory control periods. From time to time, extreme events occur that are beyond the reasonable control of the network business—such as extreme weather events—that adversely impact large parts of the electricity network for extended periods of time.[30] These events are excluded from the performance measures.

Figure 3-1: JEN's SAIDI outcomes CY95 – FY24

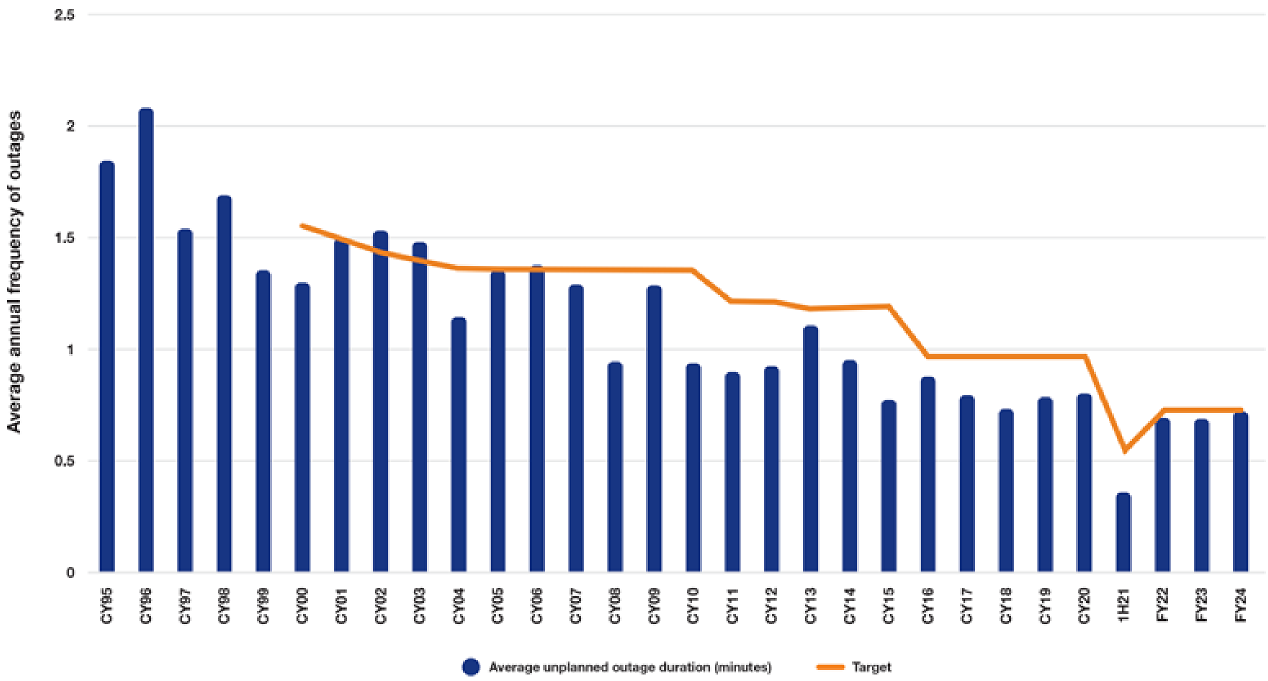


Note: The chart does not include excluded events

29 NER, cl 6.6.2.

30 Chapter 3 of JEN's Regulatory Proposal gives an overview of our strategy for addressing the increasing frequency of these extreme weather events.

Figure 3-2: JEN's SAIFI outcomes CY95 – FY24



Note: The chart does not include excluded events.

The Service Target Performance Incentive Scheme

The STPIS is designed to provide DNSPs with a financial incentive to maintain and improve their service performance, up to the level which customers are willing to pay for.[31] It provides a counter-balance 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 counter-balances 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-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.[32]

- 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 elements of the most recent version of the AER's STPIS in the next regulatory period,[33,34] Below, we outline the elements we propose adopting and those we seek to exclude.

31 NER, cl 6.6.2.

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

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

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

3.1.1 Reliability performance outcomes

JEN's reliability performance outcomes in the current regulatory period inform our STPIS targets for the next regulatory period. Table 3-1 below shows these outcomes segmented by urban and short rural feeders.[35]

Table 3-1: reliability performance outcomes – exclusions removed (FY21 – FY24)

Reliability parameter	Current period target	FY21	FY22	FY23	FY24
Unplanned SAIDI		**46.710**	**46.404**	**39.119**	**44.779**
Urban	43.914	47.356	50.272	38.640	44.467
Short rural	48.440	38.660	19.530	42.540	47.149
Unplanned SAIFI		**0.710**	**0.701**	**0.684**	**0.727**
Urban	0.728	0.738	0.748	0.672	0.738
Short rural	0.952	0.498	0.376	0.772	0.640
MAIFIe[36]		**0.854**	**0.887**	**0.948**	**1.144**
Urban	0.952	0.877	0.859	0.921	1.177
Short rural	1.416	0.302	10.84	1.141	0.894

Source: Response to Annual Regulatory Information Notices.

3.2 STPIS for the next regulatory period – Framework and approach

The final F&A paper for the next regulatory period states the AER's intention to continue to apply the STPIS to the Victorian DNSPs, as it acts as a countervailing measure to the EBSS and CESS, ensuring the efficiencies incentivised by these schemes do not come at the expense of service quality.[37] As per the F&A, the AER intends 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)
- apply the SAIDI, SAIFI, MAIFIe and customer service (telephone answering) parameters[38]
- 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 latest AER published value of customer reliability (**VCR**) at the time it makes its final decision to set the incentive rates for SAIDI and SAIFI.

[35] JEN's network does not include any feeders that meet the AER's 'CBD' or 'Long Rural' definitions.

[36] Momentary interruption frequency index event.

[37] AER, *Final Framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026–31*, 31 July 2024, section 4.2.

[38] Per the Final F&A, if the DNSP chooses to adopt a CSIS, the customer service metric will not apply.

3.3 STPIS for the next regulatory period – Our proposal[39]

For the next regulatory period, we propose to:

- segment the network according to the four STPIS feeder categories
- maintain the following performance measures:[40]
  - Unplanned SAIDI – urban and short rural
  - Unplanned SAIFI – urban and short rural
  - MAIFIe – urban and short rural
- 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 FY21 to FY25)[41]
- apply the exclusions as defined in clause 3.3 of the STPIS[42]
- apply the latest AER published VCR at the time it makes its final decision to set the incentive rates for SAIDI and SAIFI.

However, we propose the following departures from the approach outlined in the F&A:

- exclude the telephone answering customer service parameter in favour of our proposed CSIS (see section 5).
- amend the revenue at risk cap downwards from +/-5% to +/-4.5% to recognise the transfer of the +/-0.5% revenue at risk from the customer service component to the CSIS
- removing the GSL component. Instead, we propose applying the low-reliability payments as outlined in the Victorian Electricity Distribution Code of Practice. We elaborate on this in section 3.4 below.

The AER completed a review of each of these departures in the Final F&A and provided a path forward for their implementation.

3.3.1 STPIS performance targets

At the time of submitting this JEN 2026-31 Proposal, the FY25 year is not yet complete, and therefore, we are unable to finalise the data set on which to set performance targets for the STPIS for the next regulatory period. As part of our revised 2026-31 regulatory proposal, we will provide updated targets which reflect JEN's FY25 performance. Placeholder performance targets, based on FY21 – FY24 data have been included in Table 3-2 below.

Table 3-2: Placeholder STPIS performance targets for 206-31 regulatory control period

Feeder Type	SAIDI	SAIFI
Urban	45.518	0.713
Rural Short	37.355	0.566

Source: JEN 2026-31 Regulatory Information Notice (17 Oct 2024) Response.

39 NER cl S6.1.3(4).

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

41 Ibid, s 3.2.1.

42 Ibid, s.3.3.

A comparison of these targets against the current and previous periods is included in Figure 3-3, Figure 3-4 Figure 3-5 and Figure 3-6. With each regulatory control period, the targets move closer to the actuals, meaning customers benefit through better service and yet not having to pay STPIS regards beyond each regulatory control period

Figure 3-3: SAIDI Urban Feeders - outcomes, targets and period average 2011 - 2031

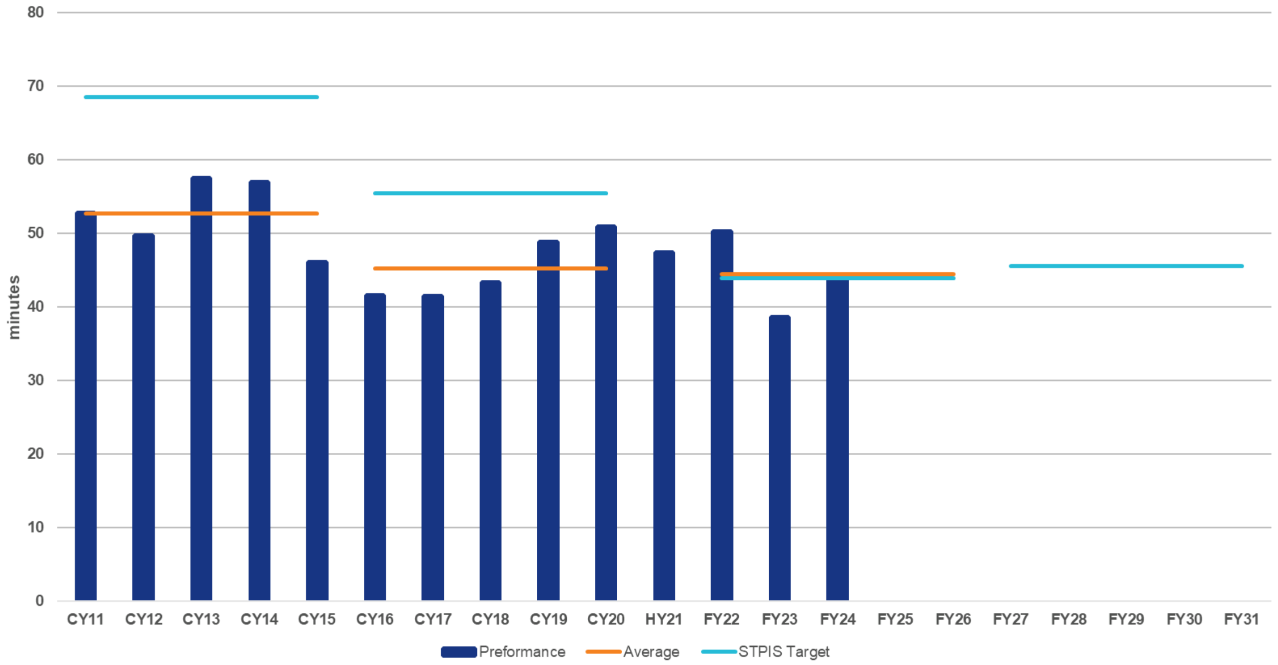


Figure 3-4: SAIDI Rural Short Feeders - outcomes, targets and period average 2011 - 2031

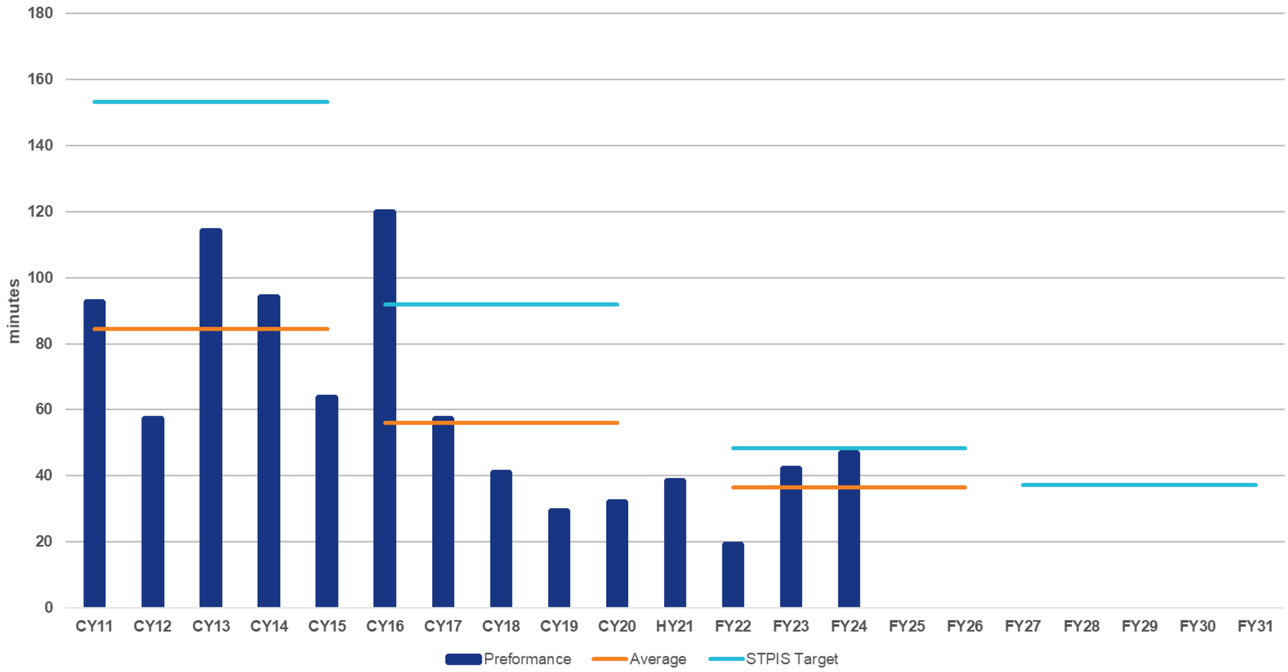


Figure 3-5: SAIFI Urban Feeders - outcomes, targets and period average 2011 - 2031

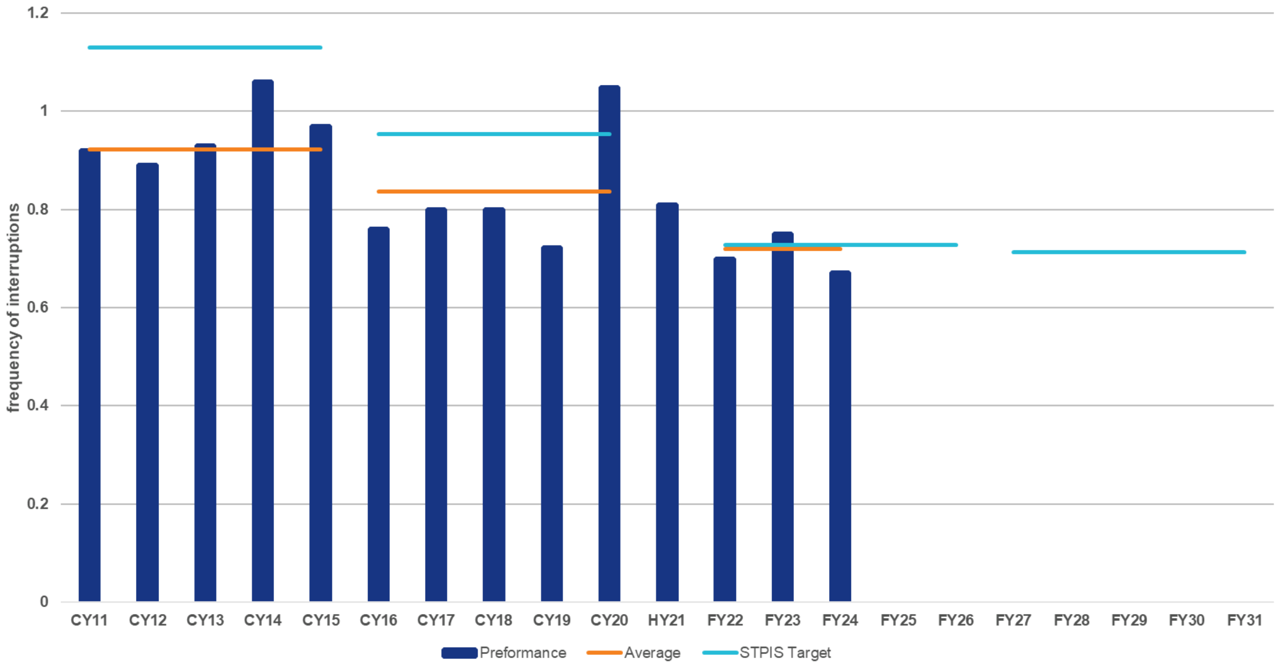
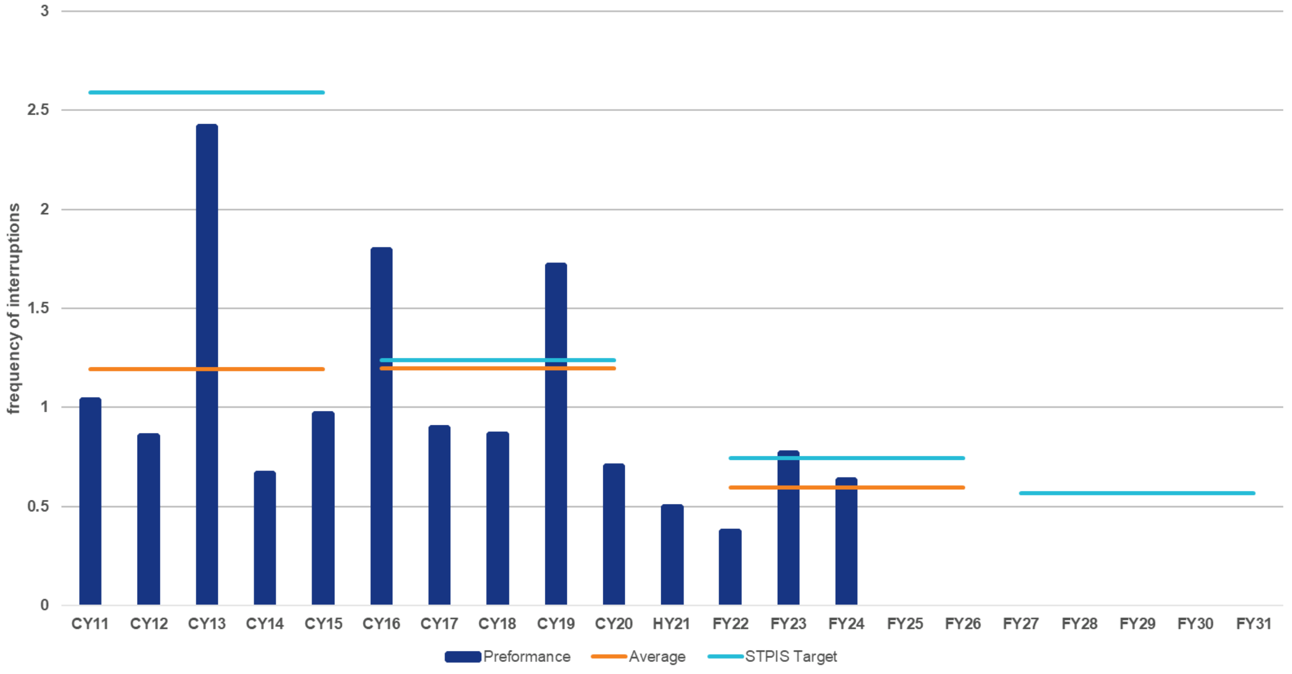


Figure 3-6: SAIFI: Rural Short Feeders - outcomes, targets and period average 2011 - 2031



Amendments to JEN's STPIS targets in the next regulatory period

JEN has had several instances in the current regulatory period that resulted in reliable events being excluded from the performance calculation under clause 3.3 and appendix D of the STPIS. We propose to make adjustments to the reliability targets to take these events into account.[43]

Other considerations in regard to setting JEN's STPIS targets in the next regulatory period

We are not proposing any other adjustments to the STPIS reliability targets, noting:

- We are not proposing any projects that seek to improve the reliability of the electricity network as a part of our JEN 2026-31 Proposal.[44]
- We have not had any STPIS payment that exceeds the current revenue at risk parameters and, therefore, do not need a further adjustment.[45]
- We have 5 years of data for all performance measures, and therefore, there is no need to adjust the target for short data periods.[46]
- We are not aware of any other material factors that warrant adjustments to the targets.[47] However, if the AER chooses to adjust for the 2021 half-year performance (that is, the interregnum determination to account for changing the regulatory year from calendar year to financial year) as part of the averaging process, then some further adjustments to targets may be required.

3.3.2 Incentive rates

We propose to develop incentive rates once the final VCR rates have been determined[48] as per the approach outlined in the Final F&A. We note that the AER released an updated VCR report on 18 December 2024.[49] However, this has not afforded us sufficient time to develop incentive rates before the required timing to submit this JEN 2026-31 Proposal. We will, therefore, update the incentive rates in our revised proposal.

3.3.3 Applying the STPIS in the next regulatory period

Once performance targets are set, we will compare these to our actual performance to determine the out-performance, or underperformance, achieved. We will then multiply these by the incentivise rates that will be determined once the final VCR rates are completed. Finally, we will aggregate this outcome and apply it to prices in our annual price reset process.[50] These activities will be undertaken in accordance with the methodology outlined in the STPIS.[51]

3.4 Guaranteed service levels[52]

In the AER's final F&A it states that the determination 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 that serves a similar purpose. We agree with this approach, noting that we will apply the "Supply restoration and low reliability

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43 AER, *Electricity distribution network service providers, Service target performance incentive scheme*, Version 2.0, November 2018, s. 3.2.1(a)(1).

44 Ibid, s. 3.2.1(a)(1A).

45 Ibid, s. 3.2.1(a)(1B).

46 Ibid, s. 3.2.1(c).

47 Ibid, s. 3.2.1(a)(2).

48 Ibid, s. 3.2.2(b)(3).

49 AER, *Values of customer reliability, Final report on VCR values*, December 2024.

50 AER, *Electricity distribution network service providers, Service target performance incentive scheme*, Version 2.0, November 2018, s2.1(a).

51 Ibid.

52 Known as the *supply restoration and low reliability payments*, per section 14.5 of the EDCoP in Victoria.

payments" as outlined in the Electricity Distribution Code of Practice (**EDCoP**). This variation is consistent with the approach applied in the current regulatory period[53] and as required by the EDCoP. We outline how we account for the GSL payment as an operating expenditure category specific forecast in *Attachment 06-01 Operating expenditure*.

[53] AER, *FINAL DECISION, Jemena Distribution Determination 2021 to 2026, Attachment 10 - Service target performance incentive scheme*, April 2021.

4. Demand management incentive scheme and demand management innovation allowance mechanism

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**) funds 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
- 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 DMIAM & DMIS in the current regulatory period

4.2.1 DMIS

JEN has not identified any projects suitable for inclusion under the DMIS in the current regulatory period. Despite this, we seek to have access to the DMIS in the next regulatory period as opportunities may arise, which we could leverage.

4.2.2 DMIAM

In the current period, JEN has used the DMIAM to participate in collaborative trials to develop our own and the wider industry's understanding of the changing relationship between our network and the customers we serve. Given the nature of innovation, the majority of this expenditure will be incurred in the latter half of the current regulatory period.

4.2.2.1 Dynamic electric vehicle (EV) charging trial

JEN is leading an Australian Renewable Energy Agency (**ARENA**) partially funded collaboration between five DNSPs (comprising JEN, AusNet Services, United Energy, TasNetworks and EvoEnergy) and a leading EV charging installer (JET Charge) to understand the impacts of EVs on the electricity system, consumer willingness for third party control and to demonstrate how DNSPs can play a direct role in EV charge management.

The trial involved dynamically managing EV charging load by sending a dynamic operating envelope (**DOE**) to the charging infrastructure, with a real-time assessment of available network capacity, to accommodate more EVs without network augmentation. A small number of EVs per DNSP were included in the trial. Incentives were offered to customers to install smart EV chargers and to participate in EV charge management events referred to as solar soak and demand response events.

As a result of this trial, DNSPs have advanced their preparedness for the expected impacts of EVs on the electricity network. The project also has the potential to improve the efficiency of JEN's future network investments through the deferral or avoidance of network augmentation capex and to mitigate supply risks on capacity-constrained feeders.[54]

4.2.2.2 Victorian Government Neighbourhood Battery Initiative (**NBI**)[55] and Australian Government Community Batteries for Household Solar Program[56]

JEN has used a portion of our DMIAM allowance, in conjunction with funding secured under NBI, to develop a business case for the deployment of network-owned neighbourhood batteries in residential and mixed-use greenfield developments. Examining how neighbourhood/community batteries may be integrated into the network design of a new development is a particularly novel aspect of this study.

JEN has also been successful in obtaining co-funding from the Australian Government's Community Batteries for Household Solar Program. This funding, in conjunction with a portion of JEN's DMIAM allowance will be used to install community batteries in Alphington, Bellfield, Coburg and Flemington. This will enable solar soak and peak load shaving, while also facilitating an aggregator or retail partner to leverage market benefits associated with wholesale market arbitrage and the Frequency Control Ancillary Services (**FCAS**) market.

These projects will demonstrate demand management capabilities as a primary network benefit, enabling solar soak during peak solar minimum demand periods and peak shaving during peak demand periods. Other benefits and use cases investigated are emissions reductions, enable more solar connections and third party access to leverage market benefits associated with wholesale market arbitrage and FCAS markets.

These projects will investigate the feasibility to reduce long term network costs by utilising technology to avoid and defer traditional network augmentation. They also explore a solution that is an alternative to traditional behind the meter storage providing access to customers who are unable to invest in storage at home.

4.2.3 Total expenditure in the current period

Table 4-1: DMIAM Expenditure 2021 - 26 (26$)

	Audited Actuals			Forecast Estimates – *based on allowance*		
DMIAM Expenditure (26$)	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**Total**
Capital Expenditure	0	0	162,602	TBA	TBA	TBA
Operating Expenditure	283,281	189,365	247,712	TBA	TBA	TBA
Total	**283,281**	**189,365**	**410,314**	**337,315**	**335,364**	**1,555,639**

4.3 DMIAM & DMIS in the coming regulatory period

The AER stated in the F&A its intention to apply the DMIS and DMIAM to JEN.[57] Consistent with the AER's stated approach, we also propose to adopt the DMIS and DMIAM in the next regulatory period without any variation or departure.

54 Further information about this project can be found in: *Jemena - DMIAM annual compliance report - 2021-22.pdf s.7, 2022.*

55 Further details on this program can be found here: Neighbourhood Battery Initiative

56 Further details on this program can be found here: Community Batteries for Household Solar Program - Delivery of Election Commitments Stream 1 | business.gov.au

57 AER, *Final Framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026–31*, 31 July 2024, section 4.2.

4.3.1 Interaction between DMIAM & DMIS and JEN's proposed Innovation Fund

JEN is proposing to establish an Innovation Fund in the coming regulatory period.[58] The objective of this fund is to support nationwide future network innovation and capability development, while also supporting energy equity within JEN's customer base. JEN recognises there is some intersection between the objectives of this fund and demand management activities incentivised and financed through DMIAM and DMIS and has designed the fund to exist separately as a compliment to DMIAM and DMIS.

Projects will first be assessed to see if they are suitable for DMIAM funding before using JEN's Innovation Fund. The fund would then be used to finance projects which would not enable demand management activities or *may* enable demand management activities as a secondary benefit without stretching the definition or diluting the intention of the DMIAM and DMIS. Like the DMIAM, if suitable projects are not identified, Innovation Fund expenditure will be returned to customers.

Further information on JEN's proposed Innovation Fund is included in *Att 03 – 02 Innovation Fund Proposal.*

58 See '*JEN – Att – 03 – 02 Innovation Fund Proposal'* for further details.

5. Customer Service Incentive Scheme

Following consultation with our customers, JEN is proposing to introduce a CSIS

In the next regulatory period, JEN proposes to introduce a CSIS to encourage greater alignment between us and our customers when it comes to providing customer service. The decision to apply this scheme, and the proposed measures used to assess our performance were developed through a multi-faceted engagement approach with both our Customer Voice Groups, Peoples' Panel and Small/Medium Business Customer Engagement, and JEN's ERG.

JEN's proposed metrics reflect key moments in the customer journey

Our proposed CSIS focuses on improving customer outcomes and moves us from a scheme focusing on only one metric, telephony answering, to a broad-based approach of four customer service metrics, including;

- **Fault-line telephone answering:** This measure is currently captured under the STPIS. JEN is proposing to include this metric under the CSIS. It will continue to reward or penalise JEN based on the number of calls to our fault-line which are answered within 30 seconds.
- **SMS unplanned outage notification:** Number of minutes between the start of an unplanned outage and the customer receiving an SMS message advising them of the outage.
- **Planned outages:** Measuring customers' satisfaction with their planned outage experience. This metric reflects overall satisfaction with JEN's management of the planned outage, including the timeliness and quality of information provided across all notification channels, the duration of the outage, and our ability to meet the forecasted restoration time.
- **New connections**: Measuring customers' satisfaction with their connection journey. This metric reflects overall satisfaction with the end-to-end process, including; the ease of application, the quality and timeliness of communications, the quality of the work completed, and the total time taken to complete the connection.

Further information on JEN's proposed CSIS can be found in *Attachment 07-03*.

6. Export service incentive scheme

The AER made the Final Decision on its proposed Export Service Incentive Scheme (**ESIS**) in June 2023.[59]

JEN is not proposing to apply the incentive scheme in the next regulatory period. Although we and our customers can see value in solar export services, JEN does not currently have the data necessary to create a meaningful benchmark measuring current performance. This is due to the infancy of the service being provided. Developing a scheme without a proper baseline could result in windfall gains or losses, and we do not believe this is in customers' long-term interests.

In the next regulatory period, JEN intends to formalise our data collection around customer exports. This will allow us to engage with our customers on the development of and potential implementation of an ESIS for the 2031 – 2036 regulatory period.

59 AER, *Export Services Incentive Scheme Final Decision*, June 2023.

7. F-Factor scheme

The F-factor scheme is designed to encourage DNSPs to minimise the number of fire starts caused by distribution network assets. 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, with greater incentives applying in bushfire-prone areas and at times of high fire danger.[60]

JEN will continue to apply the Victorian f-factor scheme during the next regulatory period in accordance with jurisdictional obligations.

[60] 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.