Jemena Electricity Networks (Vic) Ltd

Response to the Annual Information Order 5 April 2024 for the 2024-25 regulatory year

Jemena
bringing energy to life

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Glossary

AER	Australian Energy Regulator
ACS	Alternative Control Service
AIO	Annual Information Order
CAM	Cost Allocation Methodology
CB	Community Batteries
DEECA	Department of Energy, Environment and Climate Action
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DOE	Dynamic Operating Envelope
ELC	Electric Line Clearance
ESV	Energy Safe Victoria
FCAS	Frequency Control Ancillary Services
HBRA	Hazardous Bushfire Risk Area
JEN	Jemena Electricity Networks (Vic) Ltd
MAIFI	Momentary Average Interruption Frequency Index
MED	Maximum Event Day
NBI	Neighbourhood Battery Initiative
NEL	National Electricity (Victoria) Law
NER	National Electricity Rules
ORP	Other Responsible Person
PTRM	Post Tax Revenue Model
PV	Photovoltaic
RIT-D	Regulatory Information Test- Distributors
RTU	Remote Terminal Unit
SCS	Standard Control Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
STPIS	Service Target Performance Incentive Scheme
VBRC	Victorian Bushfires Royal Commission

Introduction

Submission purpose

This submission is the Jemena Electricity Networks (Vic) Ltd (**JEN**) response to the Annual Information Order (**AIO**) that the Australian Energy Regulator (**AER**) issued to JEN on **4 November 2024** under Division 4 of Part 3 of the National Electricity (Victoria) Law (**NEL**) (**Order**).

This response document covers the 2024-25 regulatory year ending on 30 June 2025 (the **relevant regulatory year**). Unless otherwise indicated, all numbers are expressed in nominal 2024-25 dollars. This AIO response provides:

- the information required in the regulatory template as attachment 2
- a basis of preparation for all information provided in the regulatory template as attachment 6
- a copy of the signed statutory declaration by JEN's authorised representative as attachment 7
- a copy of the audit report for financial information as attachment 9
- a copy of the review report for non-financial information as attachment 10

Submission structure

This document provides JEN's responses to the information requested under Section 4 of the Order for the relevant regulatory year. Each numbered section of this document corresponds to a sub-section in Section 4 of the Order. This document is structured as follows:

- Section 4.1 – Requirement to provide information under this Order
- Section 4.2 – Policies and procedures
- Section 4.3 – Regulatory adjustments
- Section 4.4 – Discretionary row descriptors
- Section 4.5 – Allocation of revenue and expenditures to distribution services
- Section 4.6 – Allocation of revenus and expenditures to service segments
- Section 4.7 – Material differences
- Section 4.8 – Compliance
- Section 4.9 – Demand management incentive scheme
- Section 4.10 – Demand management innovation allowance mechanism
- Section 4.11 – Tax standard asset lives
- Section 4.12 – Tax reporting – immediate expensing
- Section 4.13 – Regulatory investment test expenditure
- Section 4.14 – Related party information
- Section 4.15 – Reporting of fines and penalties
- Section 4.16 – Tariff variations
- Section 4.1.7 – Vegetation management
- Section 4.1.8 – Reconciliation of expenditure

- Section 4.19 – Benchmarking asset base
- Section 4.20 – Taxable income adjustments
- Section 4.21 – Interest expenditure
- Section 4.22 – Small scale incentive schemes
- Section 4.23 – Large projects
- Section 4.24 – Circuit capacity

4. Supporting information requirements

4.1 Requirement to provide supporting information under this Order

This section sets out JEN's response to Section 4.1 of the Order.

4.1.1 Regulatory templates

Section 4.1.1 of the Order requires JEN to prepare and provide the AER with the information set out in sections 4, 5 and 6 of this Order.

This information for sections 5 and 6 are provided as attachments 6 and 11 respectively.

4.1.2 Summary of responses to Section 4 and list of documents for submission

Section 4.1.2 of the order requires JEN to provide the following information to assist the AER in identifying the information:

a) a table that identifies each response to this section 4 and where it is provided in the annual information submission;

b) a table that references each file (workbook, document or other) provided, where each file listed in the table must be given a name in the form:

[Electricity distributor name] – Annual Order – [reporting period] – [title] –[public/confidential]

where:

i) [Title] provides a meaningful description of the content of document, with limited reliance on acronyms or cross references,

ii) [Public/confidential] identifies if the file in its entirety can be published (public); or if it contains any information that is the subject of a claim for confidentiality in accordance with this Order (confidential).

Each response to section 4 is provided in the sub-sections in this document and the table below references each file provided for JEN's response to the Order.

Attachment	Title
Attachment 2	Jemena Networks - Annual Order - 2024-25 - Data submission workbook-Nov2025 - Consolidated - Confidential
Attachment 2a	Jemena Networks - Annual Order - 2024-25 - Data submission workbook-Nov2025 - Consolidated - Public
Attachment 2b(i)	Jemena Networks - Annual Order - 2024-25 - Data submission workbook-Nov2025 - Actual - Public
Attachment 2b(ii)	Jemena Networks - Annual Order - 2024-25 - Data submission workbook-Nov2025 - Actual - Confidential
Attachment 2c(i)	Jemena Networks - Annual Order - 2024-25 - Data submission workbook -Nov2025 – Estimated - Public
Attachment 2c(ii)	Jemena Networks - Annual Order - 2024-25 - Data submission workbook -Nov2025 – Estimated - Confidential

Attachment	Title
Attachment 3	Jemena Networks - Annual Order - 2024-25 -Reconciliation between statutory and regulatory accounts - Public
Attachment 4	Jemena Networks - Annual Order - 2024-25 -Regulatory accounting principles and policies - Public
Attachment 6	Jemena Networks - Annual Order - 2024-25 -Basis of preparation-Nov2025 - Public
Attachment 7	Jemena Networks - Annual Order - Statutory declaration-Confidential
Attachment 8	Jemena Networks - Annual Order - DMIAM statutory declaration - Confidential
Attachment 9	Jemena Networks - Annual Order - EY audit report- Confidential
Attachment 10	Jemena Networks - Annual Order - EY review report - Confidential
Attachment 11	Jemena Networks - Annual Order - EY assurance report - Confidential

4.2 Policies and procedures

This section sets out JEN's response to Section 4.2 of the Order.

4.2.1 Policies and procedures

Section 4.2.1 of the Order requires JEN to provide its policies and procedures, encompassing:

a) regulatory accounting principles and policies,

b) capitalisation policy,

c) policy/procedures for the allocation of overheads, in accordance with the approved cost allocation method.

Item a) is provided in attachment 4.

For items b) and c), for the regulatory year there are no changes to JEN's capitalisation policy and policy for determining the allocation of overheads in accordance with the approved cost allocation method.

4.2.2 Changes to regulatory accounting principles and policies

Section 4.2.2 of the Order requires JEN to identify any changes to the policies and procedure listed at 4.2.1 that have occurred in the reporting period, and describe:

a) the reason for the change

b) the impact of the change on the information being reported.

As its underlying principle, JEN prepares its trial balance for purposes of RIO compliant with the Australian Accounting Standards and the Statement of Significant Accounting Policies in the notes to the accounts and only varies from these Standards and Policies where specifically required or permitted by the RIO.

For item a), Type 1 Capital Contributions have been calculated on an 'As Incurred' basis in accordance with AER Guidance Note issued in November 2024 for electricity distributors for reporting Capital Contributions, whereas Capital Contributions as per Audited Trial Balance is on an a 'As Commissioned' basis in accordance with Australian Accounting Standards Board (AASB) 15 - Revenue from Contracts with Customers.

For item b), a reconciliation between the two Capital Contribution calculations is provided under 8.2.5 - CAPITAL CONTRIBUTIONS BY ASSET CLASS for Standard Control Services Capital Contribution and under 8.2.5(B) - CAPITAL CONTRIBUTIONS BY TYPE for Alternative Control Services capital contribution in the basis of preparation.

Table 4–1: Reconciliation of SCS capital contribution between Audited Trial Balance and Capital Contribution

	FY25		
	Type 1 SCS	Type 2 SCS	Total
As per audited balance	66,545,127	15,421,782	81,966,908
Adjustment to recognise capital contribution on a "As incurred' basis	2,885,321	-	2,885,321
Reported in this table	**69,430,448**	**15,421,782**	**84,852,230**

Table 4–2: Reconciliation of ACS capital contribution between Audited Trial Balance and Capital Contribution

	FY25		
	Type 1 ACS	Type 2 ACS	Total
As per the audited balance	1,666,559	2,895,155	4,561,714
Adjustment to recognise capital contribution on a "As incurred' basis			
Reported in this table	**1,666,559**	**2,895,155**	**4,561,714**

4.2.3 Previous submission date for policies and procedures

Section 4.2.3 of the Order requires that if the policies and procedures required at 4.2.1 have previously been submitted to the AER and have not been amended since that submission, JEN must report the previous submission date and does not have to provide the policies and procedures again.

Given JEN's response to 4.2.2, this section is not applicable to JEN.

4.3 Regulatory adjustments

This section sets out JEN's response to Section 4.3 of the Order.

4.3.1 Regulatory adjustments

For regulatory adjustments specified in the data workbooks (Workbook 06 – Operating expenditure, Workbook 09 – Revenue and financial statements) section 4.3.1 of the Order requires JEN to provide information that reconciles and explains all adjustments between the audited statutory accounts and the Distribution business, set out in a regulatory adjustment reconciliation report.

The Regulatory adjustments must be submitted in the Data submission workbook table 8.1.1 Income Statement and tables 8.4.1 Operating & Maintenance Expenditure by purpose (and 8.4.2 Operating & Maintenance Expenditure by purpose – margins only)

This information is provided in attachment 3.

4.3.2 Details of regulatory adjustments

According to Section 4.3.2 of the Order for each regulatory adjustments specified in the data workbooks (Workbook 06 – Operating expenditure, Workbook 09 – Revenue and financial statements) the regulatory adjustment reconciliation report is required to include:

a) a detailed explanation for the underlying reason for the regulatory adjustment

b) methodology and assumptions used to quantify the regulatory adjustment

c) details of relevant debits and credits associated with the regulatory adjustment.

This information is provided in attachment 3.

4.3.3 Previous regulatory adjustments journal

According to Section 4.3.2 of the Order, if JEN has previously provided the AER with a regulatory adjustments journal in response to annual reporting obligations in place for the 2022-23 reporting year, then the regulatory adjustment reconciliation report must continue to be in the form of a regulatory adjustments journal.

This section is not applicable to JEN. JEN has not previously provided the AER with a regulatory adjustments journal in response to annual reporting obligations in place for the 2022-23 reporting year.

4.4 Discretionary row descriptors

This section sets out JEN's response to Section 4.4 of the Order.

4.4.1 Keeping inputs to meet the information order requirements

According to Section 4.4.1 of the Order, JEN should keep discretionary row descriptors (inputs) used to meet the information requirements in the data workbooks at Appendix A the same in each reporting period.

JEN keeps discretionary row descriptors (inputs) used to meet the information requirements in the data workbooks at Appendix A the same in each reporting period.

4.4.2 Varying the row descriptors (input)

According to Section 4.4.2 of the Order, if JEN has varied the row descriptors (input) compared to those used in the previous reporting period or regulatory year, JEN is required to provide:

a) an explanation of the relationship between the current row descriptors, and those used previously

b) an explanation of why the change was made

c) supporting material (or references to supporting material) driving the change (including for example policies, guidelines, or accounting standards).

Any row descriptors (input) that JEN has varied compared to those used in the previous reporting period or regulatory year is explained in detail in the relevant basis of preparation (BoP).

4.5 Allocation of revenues and expenditures to distribution services

This section sets out JEN's response to Section 4.5 of the Order.

4.5.1 Revenue and expenditure reported on a causal allocation basis to distribution services

According to Section 4.5.1 of the Order, for each item of revenue or expenditure that is not directly attributable and is reported on a causal allocation basis to distribution services, JEN is required to provide:

a) a description of the causal basis of allocation

b) the numeric quantity of the allocator

c) an explanation of why the allocator was selected

JEN has applied its AER-approved CAM in all relevant circumstances. The AER approved JEN's revised CAM effective from 01 Jan 2021 in May 2019. JEN has previously provided these documents to the AER.

The items allocated to JEN have been identified and are listed in Table 4-3. Each of these items has been allocated on a causation basis, and thus, there are no items allocated in the category identified in section 4.5.2 of the AIO.

Table 4–3: Directly attributable and allocated on a causation basis

Item	Directly attributable ($)	Allocated ($)
8.1.1.1 - REVENUE		
Distribution revenue	346,115,755	-
Cross-boundary revenue	11,838,752	-
Contributions	-	-
Interest income	402,198	-
Shared asset revenue	3,406,129	
Jurisdictional scheme amounts	5,250,915	-
Profit from sale of fixed assets	28,765	-
TUOS revenue	99,630,519	-
Pass through revenue (F-factor)	-	-
Recoverable works	-	-
Other revenue	42,007,229	-
Total revenue	**508,680,263**	**-**
8.1.1.2 - EXPENDITURE		
TUOS expenditure	96,765,531	-
Cross-boundary expenditure	6,742,041	-
Depreciation	84,083,782	-
Finance charges	-	-
Impairment losses	-	-
Jurisdictional scheme amounts	4,970,824	-
Loss from sale of fixed assets	12,947,987	-
Maintenance expenditure	36,097,303	
Operating expenditure excluding maintenance expenditure	84,069,424	37,489,843
Other	-	
Total expenditure	**325,676,832**	**37,489,843**

For each item of revenue or expenditure that is not directly attributable and is reported on a causal allocation basis to distribution services, the description (4.5.1(a)), numeric quantity of the allocator (4.5.1(b)) and explanation of why the allocator was selected (4.5.1 (c)) are set out in Table 4-4 below:

Table 4–4: Shared cost allocation

Cost Item (Section 4.5.1(a))	Amount ($) (Section 4.5.1(b))	Method of allocation and reason for basis (Section 4.5.1(c)))	Allocator (%)
Digital Provision and management of IT infrastructure and services. Costs include residual labour costs and non-labour costs	18,602,872	**Method:** Management and support staff time effort and associated costs survey-based driver. **Reason:** Digital costs support the delivery of Jemena's capital and operating programs, including those of JEN. Costs are attributed to specific Digital activities based on time writing and goods and services receipting. Residual costs are allocated to Digital activities using SAP assessment cycles[1] on residual cost centre costs based on feedback from the latest survey of management and support staff time effort and associated costs.	23%
Finance Provision and management of commercial, financial shared services, management & external reporting, treasury & fundraising, risk & insurance and taxation services. Costs include residual labour costs and non-labour costs.	10,867,752	**Method:** Management and support staff time, effort, and associated costs survey-based driver. **Reason:** Finance costs support the delivery of Jemena's finance operations & stewardship activities, including those of JEN. Costs are allocated to Finance activities using SAP assessment cycles on cost centre costs based on feedback from the latest survey on management and support staff time, effort, and associated costs.	19%

[1] Assessment cycles are used in SAP to allocate costs between different elements.

Cost Item (Section 4.5.1(a))	Amount ($) (Section 4.5.1(b))	Method of allocation and reason for basis (Section 4.5.1(c)))	Allocator (%)
People, Safety & Legal Management of recruitment and remuneration benefit services, health and services training, performance, quality and adverse impact on the environment, advice on economic regulation, environmental law, employment law, property law, and company law, including the role of company secretary. Costs include salaries, employee-related expenses, recruitment agent fees, training, court and tribunal costs and procurement of external advice and licence fees.	8,019,220	**Method:** Management and support staff time effort and associated costs survey-based driver. **Reason:** People Safety & Legal supports Jemena's people, HSE and legal strategy, operations & compliance activities, including those of JEN. Costs are allocated to People Safety & Legal activities using SAP assessment cycles on cost centre costs based on the latest survey on management and support staff time, effort, and associated costs.	19%

4.5.2 Revenue and expenditure reported on a non-causal allocation basis to distribution services

According to Section 4.5.2 of the Order, for each item of revenue or expenditure that is not directly attributable and is reported on a non-causal allocation basis to distribution services, JEN is required to provide:

a) a description of the non-causal basis of allocation

b) the numeric quantity of the allocator

c) an explanation of why the allocator was preferred over other possible allocators

d) an explanation of why no causal basis of allocation could be established

e) documents showing any approval previously granted by the AER to use the allocator.

As outlined above, the causation basis of each cost item is shared, causal and operating in nature, so there are therefore no items for JEN that have been identified in response to paragraph 4.5.2. Sections 4.5.2(a) to (e) are therefore not applicable to JEN.

4.6 Allocation of revenues and expenditures to service segments

This section sets out JEN's response to Section 4.6 of the Order.

Note: The service segment refers to direct control services (either standard control services or alternative control services), negotiated distribution services, unregulated distribution services and non-distribution services.

4.6.1 Revenue and expenditure reported on a causal allocation basis to service segments

According to Section 4.6.1 of the Order, for each item of revenue or expenditure reported on a causal allocation basis from distribution services to a service segment, JEN is required to provide:

a) a description of the causal basis of allocation

b) the numeric quantity of the allocator

c) an explanation of why the allocator was selected

For each item of revenue or expenditure that is not directly attributable and is reported on a causal allocation basis to distribution services, the description (4.6.1(a)), numeric quantity of the allocator (4.6.1(b)) and explanation of why the allocator was selected (4.6.1 (c)) are set out in Table 4-5 below:

Table 4–5: Cost allocation to service segments

Cost Item (Section 4.61(a))	Total amount ($)	Direct ($)	Allocated ($) (Section 4.6.1(b))	Method of allocation and reason for Basis (Section 4.6.1(c))	Allocator %
OPEX- SCS - Vegetation management	5,977,705	5,977,705	-	Directly charged.	-
OPEX- SCS - Maintenance	8,120,665	8,120,665	-	Directly charged.	-
OPEX- SCS - Emergency response	5,373,500	5,373,500	-	Directly charged.	-
OPEX- SCS - Non-network	26,835,437	4,365,818	22,469,619	JEN allocates non-network costs to these expense activities in accordance with its internal policies and the AER-approved CAM. The non-network costs include an allocation of residual Digital and Property costs.	75%
OPEX- SCS – Network Overheads	24,222,187	21,966,499	2,255,687	JEN allocates Network overheads to these expense activities based on its internal policies and in accordance with the AER-approved CAM. The overheads include an allocation of residual Asset Management costs.	83%
OPEX- SCS – Corporate Overheads	22,469,733	4,338,188	18,131,545	JEN allocates corporate overheads to these expense activities based on its internal policies and in accordance with the AER-approved CAM. The overheads include an allocation of residual corporate costs.	80%
OPEX- SCS - Export Services	990,813				
OPEX- SCS – SaaS costs	1,747,467	1,747,467	-	Directly charged.	
OPEX- ACS - Metering	5,805,317	5,805,317	-	Directly charged.	-

Cost Item (Section 4.61(a))	Total amount ($)	Direct ($)	Allocated ($) (Section 4.6.1(b))	Method of allocation and reason for Basis (Section 4.6.1(c))	Allocator %
OPEX- ACS - Public Lighting	2,431,847	2,431,847	-	Directly charged.	-
OPEX- ACS - Fee and Quoted	5,815,162	5,815,162	-	Directly charged.	-
OPEX- ACS - Network Overheads	2,203,317	22,033	2,181,284	JEN allocates Network overheads to these expense activities based on its internal policies and in accordance with the AER-approved CAM. The overheads include an allocation of residual Asset Management and Property costs.	18%
OPEX- ACS - Corporate Overheads	8,151,605	163,032	7,988,573	JEN allocates Corporate overheads to these expense activities based on its internal policies and in accordance with the AER-approved CAM. The overheads include an allocation of residual Digital and Corporate costs.	19%
CAPEX – SCS – Replacement Expenditure	96,116,245	96,116,245	-	Directly charged.	-
CAPEX – SCS – Connections	113,215,441	113,215,441	-	Directly charged.	-
CAPEX – SCS – Augmentation Expenditure	48,844,636	48,844,636	-	Directly charged.	-
CAPEX – SCS – Non-Network	26,255,214	26,255,214	-	Directly charged.	-
CAPEX – SCS - Export Services	13,138,982	13,138,982	-	Directly charged.	
CAPEX – SCS - Capitalised Network Overheads	40,246,176	40,246,176	-	Directly charged.	-
CAPEX – ACS - Capitalised Network Overheads	2,555,642	2,555,642	-	Directly charged.	-
CAPEX – ACS – Public Lighting	9,620,207	9,620,207	-	Directly charged.	-

Cost Item (Section 4.61(a))	Total amount ($)	Direct ($)	Allocated ($) (Section 4.6.1(b))	Method of allocation and reason for Basis (Section 4.6.1(c))	Allocator %
CAPEX – ACS – Connection Services	7,841,093	7,841,093	-	Directly charged.	-
CAPEX – ACS – Metering Services	1,611,132	1,611,132	-	Directly charged.	-
CAPEX – ACS – Ancillary Network Services	109,524	109,524	-	Directly charged.	-

4.6.2 Revenue and expenditure reported on a non-causal allocation basis to service segments

According to Section 4.6.2 of the Order, for each item of revenue or expenditure reported on a non-causal allocation basis from distribution services to a service segment, JEN is required to provide:

a) a description of the non-causal basis of allocation

b) the numeric quantity of the allocator

c) an explanation of why the allocator was preferred over other possible allocators

d) an explanation why no causal basis of allocation could be established

e) documents showing any approval previously granted by the AER to use the allocator.

This requirement is not applicable as there are no instances in JEN's response where operating, maintenance and capex costs were not allocated to an activity area in part on a directly attributable basis or a causation basis (or both) to a service segment. All costs were allocated in a way that is consistent with JEN's approved CAM.

4.7 Material differences

This section sets out JEN's response to Section 4.7 of the Order.

4.7.1 Material differences in service performance

Section 4.7.1 of the Order requires JEN to identify each difference (where the difference is equal to or greater than ± 10 per cent) between the target performance measure specified in the service target performance incentive scheme and actual performance outcomes calculated using the data reported in the Data submission workbook table 6.3.1 Sustained interruptions to supply.

The performance measures used in assessing STPIS reliability are as follows:

- urban unplanned average sustained interruptions (System Average Interruption Frequency Index) (**SAIFI**)
- urban unplanned average minutes off supply (System Average Interruption Duration Index) (**SAIDI**)

- urban unplanned average momentary interruptions (Momentary Average Interruption Frequency Index) (**MAIFI**)
- rural unplanned SAIFI
- rural unplanned SAIDI
- rural unplanned MAIFI.

The comparison between JEN's actual and target STPIS reliability measures, after accounting for major event days (**MEDs**), is set out in Table 4-6.

Table 4–6: STPIS reliability

	Performance Measure	FY25 Actual	FY25 Target	Variance
Urban (after removing excluded events MEDs)	Unplanned SAIDI	40.439	43.914	-7.9%
	Unplanned SAIFI	0.586	0.728	-19.6%
	Unplanned MAIFI	1.217	0.952	27.9%
Rural (after removing excluded events and MEDs)	Unplanned SAIDI	66.514	48.440	37.3%
	Unplanned SAIFI	0.992	0.743	33.5%
	Unplanned MAIFI	1.266	1.416	-10.6%

The performance measure used in assessing STPIS customer service is call centre performance (telephone answering). The comparison between JEN's actual and target STPIS customer service measures is set out in Table 4-7. An explanation for the variance is outlined in section 4.7.1- Reasons for material difference in service performance.

Table 4–7: STPIS customer service

Performance Measure	FY25 Actual	FY25 Target	Variance
Telephone answering	81.376%	73.263%	11%

4.7.2 Material difference in operating expenditure

Section 4.7.2 of the Order requires JEN to identify each difference (where the difference is equal to or greater than ± 10 per cent) between the AER's forecast operating expenditure and actual operating expenditure specified in the Data submission workbook table 8.4.1 Operating & Maintenance Expenditure – by purpose.

The comparison is set out in Table 4-8 below

Table 4–8: Operating and maintenance expenditure by purpose

Category	FY25 Forecast	FY25 Actual	Variance	Explanation (Section 4.7.4)	% Variance
SCS - Vegetation management	5,136,573	5,977,705	(841,132)	The increase is mainly due to higher activity and escalated costs.	-16%

Category	FY25 Forecast	FY25 Actual	Variance	Explanation (Section 4.7.4)	% Variance
SCS - Maintenance	8,797,513	8,120,665	676,848		8%
SCS - Emergency response	6,752,582	5,373,500	1,379,083	Lower than expected Premise Faults, ST/HV & HV Feeder Faults and Underground Cable Faults.	20%
SCS - Non-network	43,175,071	26,835,437	16,339,634	Lower Non-Network costs are mainly due to lower IT cost base due to various initiatives & efficiencies and lower Property costs.	38%
SCS - Network overheads	32,490,067	24,222,187	8,267,880	Lower Network Overheads are mainly due to net benefits derived from transformation programs introduced from 2019 onwards.	25%
SCS - Corporate overheads	30,277,789	22,469,733	7,808,056	Lower Corporate Overhead costs are mainly due to net benefits derived from transformation programs introduced from 2019 onwards.	26%
SCS - Debt raising cost	-	-	-	Financing costs are held at Jemena's Corporate entity and not transferred to JEN.	
SCS - Export Services	-	990,813		New RIO category from FY25 onwards which didn't have an allowance for current period.	

Category	FY25 Forecast	FY25 Actual	Variance	Explanation (Section 4.7.4)	% Variance
SCS - SaaS costs	-	1,747,467	(1,747,467)	Allowance for SaaS costs is in Capex.	
	126,629,596	**95,737,507**	**31,882,903**	**As above**	**25%**

4.7.3 Material differences in capital expenditure

Section 4.7.3 of the Order requires JEN to identify each difference (where the difference is equal to or greater than ± 10 per cent) between the AER's forecast capital expenditure by purpose and actual capital expenditure by purpose specified in the Data submission workbook table 8.2.1 Capex by Purpose – Standard Control Services – Including Total Capital Contributions.

The comparison is set out in Table 4-9 below.

Table 4–9: Capital expenditure by purpose (including total capital contributions)

Category	FY25 Forecast	FY25 Actual	Variance	Explanation (Section 4.7.4)	% Variance
SCS – Replacement expenditure	47,306,655	96,116,245	(48,809,590)	Higher volume of condition based replacement mainly in poles (+$19.3M), zone substation transformers and switchgear (+$14.6M), business supply projects carried out for customers where costs are recoverable (+$8.9M), distribution transformers (+$4.6M), underground cables (+$3.5M), pole reinforcement (+$2.1M) and overhead conductor (+$1.4M). The overspend was partly offset by lower than expected spend on services (-$2.5M), zone substation protection relays (-$1.5M), pole tops (-$1.3M) and SCADA & RTS systems (-$0.3M).	-51%

Category	FY25 Forecast	FY25 Actual	Variance	Explanation (Section 4.7.4)	% Variance
SCS - Connections	52,118,931	113,215,441	(61,096,511)	JEN offers and provides connection services to customers in accordance with its Electricity Distribution Licence. In FY25, the volume of customer initiated connection works was significantly higher than expected, mainly due to new or additional works to HV commercial & industrial customers (+$45.0M), installation of new kiosk or indoor substations (+$6.2M), underground supplies to new medium density housing (+$4.2M), installation of pole mounted substations (+$3.0M), extension of LV mains (+$2.9M) and sub-transmission connection works (+$2.7M). The difference was partly offset by lower than expected volume in provision of additional supply points to existing residential customers (dual and multiple occupancy) (-$3.4M).	
SCS – Augmentation expenditure	20,902,219	48,844,636	(27,942,417)	The difference in augmentation expenditure is driven by higher expenditure in zone substations (+$24.9M), remote monitoring and control schemes (+$2.4M), subtransmission lines (+$1.6M) and distribution substations (+$0.6M). The difference was partly offset by lower than expected expenditure on high voltage and low voltage network augmentation (-$1.5M).	-57%
SCS - Non-network	30,833,813	26,255,214	(4,578,599)	The difference in Non-network is driven by lower than expected expenditure on IT applications (-$5.8M), property (-$1.3M) and equipment (-$0.5M). The difference was partly offset by higher than expected fleet (+$1.5M) and IT infrastructure (+$1.4M) expenditure.	**-15%**

4.7.4 Reasons for material differences

Section 4.7.4 of the Order requires JEN to explain the reasons for each difference identified in the response to section 4.7.1, 4.7.2 and 4.7.3.

Reasons for the material difference in service performance in 4.7.1

Five of the six STPIS performance measures in Table 4-6 show a variance of greater than 10 per cent.

Urban Unplanned SAIFI and Rural Unplanned MAIFI both performed better than the target levels. The main factors contributing to the favourable performance are:

- JEN's more stringent vegetation management practices arising from legislative changes to the Electricity Safety (Electric Line Clearance) Regulations in 2010 and JEN's effective condition-based asset replacement, prudent network augmentation and maintenance of current network performance standards

Urban Unplanned MAIFI, Rural Unplanned SAIDI, and Rural Unplanned SAIFI performed worse than the target. The unfavourable performance was primarily due to more severe weather, particularly storms, which occurred more frequently and with greater intensity during this regulatory year compared to the last few years.

The STPIS Customer Service performance measure outcome in Table 4–7 shows a variance of 11 per cent to JEN's target. This favourable variance is a result of responding to customer feedback and expectations of call centre performance of similar organisations.

Reasons for the material difference in operating expenditure by purpose in 4.7.2

An explanation for the variance is outlined in Table 4-8 -Operating and maintenance expenditure by purpose.

Reasons for material difference in capital expenditure by purpose in 4.7.3

An explanation for the variance is outlined in Table 4-9 - Capital expenditure by purpose.

4.8 Compliance

This section sets out JEN's response to Section 4.8 of the Order.

4.8.1 Service classification

Section 4.8.1 of the Order requires JEN to explain the procedures and processes used to ensure the distribution services have been classified in accordance with JEN's current determination.

JEN's regulatory team monitors changes in service classification as part of its business-as-usual activities. Leading up to price reset review determinations – when service classifications are reviewed – JEN's regulatory team consults directly with the AER on its approach to service classification.

JEN's staff have reviewed and updated the activity codes for all of JEN's services and activities within JEN's SAP system to reflect changes to service classification resulting from the 2021-26 electricity distribution price review determination. This approach ensures that the services JEN provide are correctly classified throughout the regulatory control period.

4.8.2 Negotiated service

Section 4.8.2 of the Order requires JEN to explain the procedures and processes used to ensure the negotiated service criteria, as set out in JEN's current distribution determination, have been applied.

JEN's staff regularly review the activity codes for all of JEN's services and activities within JEN's SAP system to ensure that its service classifications—including negotiated services—are mapped to the correct activity codes. This approach ensures that JEN's negotiated services (new public lighting services, alteration and relocation of distribution network service provider (DNSP) public lighting assets, and construction of reserve feeders) are correctly classified throughout the regulatory control period and comply with the negotiated service criteria set out in the 2022-26 distribution determination.

4.8.3 Negative change event

Section 4.8.3 of the Order requires JEN to describe the process JEN has in place to identify a negative change event under clause 6.6.1(f) of the NER and the materiality threshold applied to these events.

JEN staff monitor legislative and regulatory changes, as well as updates to technical and service standards within JEN, as part of their business-as-usual responsibilities. Where a negative change event that may have a material cost impact on JEN occurs, the regulation and legal teams assess whether a pass-through event has occurred and (if necessary) prepare the required cost pass-through application.

4.9 Demand management incentive scheme

This section sets out JEN's response to Section 4.9 of the Order.

4.9.1 Eligible Project Initiatives

Section 4.9.1 of the Order requires JEN to identify each demand management incentive scheme (DMIS) eligible project and committed project for which the electricity distributor seeks approval.

JEN does not seek approval for any projects in relation to this DMIS. Therefore, JEN does not provide any further information in response to section 4.9.1 of the Order.

4.9.2 Project Criteria

According to Section 4.9.2 of the Order, for each DMIS eligible project identified in the response to section 4.9.1, JEN is required to:

a) explain how it complies with the AER's RIT-D or the minimum project evaluation requirements detailed at section 2.2.1 of the DMIS;

b) submit a demand management compliance report in accordance with section 2.4 of the DMIS.

JEN does not seek approval for any projects in relation to this DMIS. Therefore, JEN does not provide any further information in response to section 4.9.2 of the Order.

4.9.3 Project Compliance Reporting

According to Section 4.9.3, for each committed project identified in the response to section 4.9.1 ,JEM is required to:

a) explain how it complies with committed project requirements as detailed in section 2.2.2 of the DMIS;

b) calculate the project incentive that each committed project can receive, in accordance with section 2.3 of the DMIS;

c) calculate total financial incentive that a distributor can accrue across all committed projects for the reporting period in accordance with section 2.5 of the DMIS;

d) submit a demand management compliance report in accordance with section 2.4 of the DMIS.

JEN does not seek approval for any projects in relation to this DMIS. Therefore, JEN does not provide any further information in response to section 4.9.3 of the Order.

4.9.4 Project Developments and Results

According to Section 4.9.4 of the Order, JEN is required to provide an overview of developments related to projects or programs completed in previous years of the current regulatory control period, as well as any results to date.

JEN does not seek approval for any projects in relation to this DMIS. Therefore, JEN does not provide any further information in response to section 4.9.4 of the Order.

4.9.5 Other required information

According to Section 4.9.5 of the Order, JEN is required to provide any other required information as specified by the DMIS.

JEN does not seek approval for any projects in relation to this DMIS. Therefore, JEN does not provide any further information in response to section 4.9.5 of the Order.

4.10 Demand management innovation allowance mechanism

This section sets out JEN's response to Section 4.10 of the Order.

4.10.1 Eligible Project Initiatives

According to Section 4.10 of the Order, JEN is required to identify each demand management innovation allowance mechanism (DMIAM) eligible project for which the electricity distributor seeks approval.

According to Section 4.10 of the Order, JEN is required to identify each demand management innovation allowance mechanism (DMIAM) eligible project for which the electricity distributor seeks approval.

JEN seeks approval for six projects for the relevant regulatory year, which are outlined below. Section 2.3(3)(f) of the demand management innovation allowance mechanism (**DMIAM**)[2] requires a statutory declaration signed by an officer of JEN.

- Victorian Government Neighbourhood Battery Initiative (NBI)
- Australian Government Community Batteries (CB) for Household Solar Program
    - Flemington Community Battery
    - Coburg Community Battery
    - Bellfield Community Battery
    - Alphington Community Battery
- Broadmeadows BESS

These projects span multiple financial year periods. The costs reported for this Order reflect costs from FY24-25 and consider any external funding that has been received over the life of the project. There is no cost duplication across all regulatory years.

4.10.1.1 Project Criteria

Section 4.10.2(a) of the Order requires JEN to explain how JEN's initiatives comply with the project criteria detailed in Section 2.2.1 of the DMIAM.

JEN's eligibility is outlined below.

Victorian Government Neighbourhood Battery Initiative (NBI)

JEN were successful in attaining Round 3, Stream 1 funding for the delivery and development of a business case related to works for one or more neighbourhood batteries located behind or in front of the meter as part of the Victorian Government's Neighbourhood Battery Initiative (NBI), administered by the Department of Energy, Environment and Climate Action (DEECA).

The scope of this project delivered a business case to consider the installation of network-owned Neighbourhood Batteries in two or more new Underground Residential Distribution (URD) developments in JEN, including

[2] AER, *Demand Management Innovation Allowance Mechanism, Electricity distribution network service providers*, December 2017.

project scope, project costs, project benefits and project economics. The business case project encompassed a number of desktop assessments: Engineering, Financial, Regulatory, Commercial & Legal, and Community.

Australian Government's Community Batteries (CB) for Household Solar Program [Flemington, Coburg, Bellfield, Alphington]

JEN were successful in attaining Stream 1 funding for the design, delivery and maintenance of four Community Batteries installed in-front of the meter in different suburbs as part of the Australian Government's Community Batteries for Household Solar programs, run by the Department of Climate Change, Energy, the Environment and Water (DCCEEW) and administered through the Department of Industry, Science and Resources.

The scope of this project involved the installation of a Community Battery in Alphington, Bellfield, Coburg and Flemington, enabling solar soak, peak load shaving, as well as facilitating an aggregator or retail partner to leverage market benefits associated with wholesale market arbitrage and the Frequency Control Ancillary Services (FCAS) market.

Broadmeadows BESS

JEN plans to relocate a BESS used in a previous trial and install it at its Broadmeadows Depot as a Behind-the-Meter (BTM) BESS. The primary purposes of this initiative are: Local Consumption Optimisation, Dynamic Operating Envelope (DOE) Adherence, and Scheduling and Dispatch.

4.10.1.2 Eligibility

JEN considers that works undertaken in the relevant regulatory year for the projects in Section 4.10.1 comply with the DMIAM criteria in the following ways:

- 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 and third-party access to leverage market benefits associated with wholesale market arbitrage and FCAS markets.
- These projects are innovative as they explore how an in-front of the meter Community Battery (and BTM BESS) can be integrated into the electricity market. This has not been investigated in detail by JEN and the projects explore the feasibility and approach to meeting network needs by using a non-network community storage (and BTM BESS) solution to address the interests of networks, markets and customers whilst navigating the regulatory, commercial, customer and engineering considerations within the framework of the National Electricity Market and the National Electricity Rules.
- These projects investigate the feasibility to reduce long term network costs by utilising technology to avoid and defer traditional network augmentation. In the case of Community Battery, 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.
- The costs recovered under the DMIAM are not recoverable under any other jurisdictional incentive scheme.

4.10.2 Project Compliance Reporting

According to Section 4.10.2 of the Order for each DMIAM eligible project identified in the response to section 4.10.1 JEN is required to:

a) Explain how it complies with project criteria detailed at section 2.2.1 of the DMIAM;

b) submit a compliance report in accordance with section 2.3 of the DMIAM.

Section 4.10.2(b) of the Order requires JEN to submit a compliance report in accordance with Section 2.3 of the demand management innovation allowance mechanism.

JEN's compliance report is outlined in Table 4-10 below:

Table 4–10: Compliance report

Section 4.10.2 (b) Compliance reporting	Relevant Section
(1) For each regulatory year, a distributor must submit a compliance report to the AER no later than 4 months after the end of the regulatory year to which the compliance report relates.	4.10.2
(2) The distributor must submit each compliance report in a form suitable for publication.	4.10.2
(3) Each compliance report must include, for the regulatory year to which the compliance report relates:	
(a) the amount of the allowance spent by the distributor	4.10.2.6
(b) a list and description of each eligible project on which the allowance was spent	4.10.2.1
(c) a summary of how and why each eligible project complies with the project criteria	4.10.2.3
(d) For each eligible project on which the allowance was spent, and in a form that is capable of being published separately for each individual eligible project, a project specific report that identifies and describes:	
(i) The nature and scope of the eligible project;	4.10.2.1
(ii) The aims and expectations of the eligible project;	4.10.2.2
(iii) How and why the eligible project complies with the project criteria;	4.10.2.3
(iv) The distributor's implementation approach for the eligible project;	4.10.2.4
(v) The distributor's outcome measurement and evaluation approach for the eligible project;	4.10.2.5
(vi) The costs of the eligible project: a. incurred by the distributor to date as at the end of that regulatory year; b. incurred by the distributor in that regulatory year; and c. expected to be incurred by the distributor in total over the duration of the eligible project.	4.10.2.6
(vii) For ongoing eligible projects: a. a summary of project activity to date;	4.10.2.7 & 4.10.2.8

Section 4.10.2 (b) Compliance reporting	Relevant Section
b. an update of any material changes to the project in that regulatory year; and c. reporting of collected results (where available).	
(viii) for eligible projects completed in that regulatory year a. reporting of the quantitative results of the project; b. an analysis of the results; and c. description of how the results of the eligible project will inform future demand management projects, including any lessons learnt about what demand management projects or techniques (either generally or in specific circumstances) are unlikely to form technically or economically viable non-network options.	4.10.2.8
(ix) any other information required to enable an informed reader to understand, evaluate, and potentially reproduce the demand management approach of the eligible project.	N/A
(e) Where an eligible project has extended across more than one regulatory year of the regulatory control period, details of the actual expenditure on each such project or program in each regulatory year of the regulatory control period to date.	4.10.4
(f) A statutory declaration signed by an officer of the distributor delegated by the chief executive officer of the distributor, certifying that the costs being claimed for each demand management project: a. are not recoverable under any other jurisdictional incentive scheme; b. are not to be recoverable under any state or Australian Government scheme; and c. are not otherwise included in forecast capital expenditure or operating expenditure approved in the AER's distribution determination for the regulatory control period under which the mechanism applies, or under any other incentive scheme in that distribution determination.	Attachment 8
(4) The confidentiality guidelines apply to the information contained in compliance reports. If the distributor's compliance report contains confidential information, the distributor must also provide a non-confidential version of the report in a form suitable for publication. The AER may publish the compliance report (or the non-confidential version of the compliance report, if applicable) on its website, including by publishing a separate report for each eligible project as contemplated by clause 2.3.3(d) above.	N/A
(5) For avoidance of doubt, to the extent that a distributor's compliance reporting requirements can be more effectively and economically achieved by, or in collaboration with, another party or parties, the mechanism does not preclude distributors from doing this.	No response required.

4.10.2.1 Nature and scope of projects

See section 4.10.1.1.

4.10.2.2 Aims and expectations of the projects

Victorian Government Neighbourhood Battery Initiative (NBI)

The project delivered a business case to install a network-owned Community Battery in two or more new URD developments in JEN, including project scope, project costs, project benefits and project economics. The business case project encompassed a number of desktop assessments: Engineering, Financial, Regulatory, Commercial & Legal, and Community.

Australian Government's Community Batteries (CB) for Household Solar Program [Flemington, Coburg, Bellfield, Alphington]

The scope of this project resulted in the installation of a Community Battery in Alphington, Bellfield, Coburg and Flemington, enabling solar soak, peak load shaving, as well as facilitating an aggregator or retail partner to leverage market benefits associated with wholesale market arbitrage and the FCAS market.

Broadmeadows BESS

The scope of this project will relocate a BESS used for a previous trial and install it at JEN Broadmeadows Depot as a Behind-the-Meter (BTM) BESS. The primary purposes of this initiative are:

- Local Consumption Optimisation - Increase utilisation of the energy produced by the 80kW solar panels installed at Broadmeadows to offset load consumption;
- DOE Adherence – Through an offline paper trial, demonstrate opportunistic use of BESS to buy and sell electricity from/into the spot market to maximise market benefit while adhering to the maximum import and export limits in the Dynamic Operating Envelopes (DOEs) issued by SCADA for the site;
- Scheduling and Dispatch - Demonstrate scheduling and dispatch of the BESS from JEN's RTU and SCADA system.

4.10.2.3 Compliance with the project criteria

See section 4.10.12.

4.10.2.4 Project Implementation

Victorian Government Neighbourhood Battery Initiative (NBI)

This project has been delivered in key milestones as below:

- Project commencement
  - Tender documentation, evaluation, assessment and consultant service award.
- Engineering assessment
  - Engineering assessment report
  - Community research and engagement
- Financial, regulatory and commercial assessment reports
- Draft business case
- Final business case and project close out

Australian Government's Community Batteries (CB) for Household Solar Program [Flemington, Coburg, Bellfield, Alphington]

This project is being delivered in key milestones as below:

- Procurement
    - Tender documentation, evaluation, assessment, manufacturer agreement and order, retail partner agreement
- Lease agreement and installation contract
    - Site assessment, stakeholder engagement and lease agreement
- Battery installed and operational
    - Delivery of battery to site, civil and underground works, connection to infrastructure
    - Commissioning
- Battery operation and demonstration of developed use cases
    - Solar soak, peak load shaving, leveraging market benefits.

Broadmeadows BESS

This project will be delivered in key milestones as below:

- Site feasibility assessments (fire risk, noise modelling, environmental/planning, geotechnical)
- Decommission and removal of BESS from the existing location
- Installation and commissioning of BESS at the new location
- Establish communication from JEN SCADA to the local BESS Remote Terminal Unit (RTU)
- Battery operation and demonstration of developed use cases
    - Local consumption optimisation
    - DOE adherence
    - Schedule and dispatch

4.10.2.5 Project outcome measurement and evaluation approach

Victorian Government Neighbourhood Battery Initiative (NBI)

This project has been completed with reports covering the areas of engineering assessment, financial assessment, regulatory assessment and commercial assessment. The final outcome of this project is the delivery of a project plan and business case for a number of URD developments.

The outcomes from the overall assessments and business case have provided JEN with knowledge on the benefits of Community Batteries, comparing the investment to the traditional network augmentation for URD developments.

Australian Government's Community Batteries (CB) for Household Solar Program [Flemington, Coburg, Bellfield, Alphington]

This project has delivered:

- A specification and tender documentation for the procurement of the battery
- Lease agreement for the site and contract award for the installation of the battery
- Installation design, site preparation, site survey, civil and underground works
- Battery installation and connection to infrastructure
- Battery commissioning

The outcomes will enable JEN to develop equipment specifications and standards that can be used for future battery initiatives.

Broadmeadows BESS

This project will deliver:

- Feasibility assessments, installation design, site preparation, site survey, civil and underground works
- Battery installation and connection to infrastructure
- Battery commissioning
- Operational guidelines

The outcomes will enable JEN to develop equipment specifications, standards, and operational guidelines that can be used for future battery initiatives.

4.10.2.6 Project costs

The actual expenditure for all projects, including any external funding received from State and Federal Government grants in the relevant regulatory year is $2,282,076 and reflects the following:

Table 4–11: Project costs

Project	Direct Costs	External Funding	Total DMIAM
VIC Government Neighbourhood Battery Initiative (NBI)	$100,342	$181,818	-$81,476
Australian Government Community Battery (CB) Initiative – Flemington	$664,838	$440,000	$224,838
Australian Government Community Battery (CB) Initiative – Coburg	$1,170,592	$440,000	$730,592
Australian Government Community Battery (CB) Initiative – Bellfield	$1,296,032	$440,000	$856,032
Australian Government Community Battery (CB) Initiative – Alphington	$914,787	$440,000	$474,787
Broadmeadows BESS	$77,303	N/A	$77,303
Total	**$4,223,894**	**$1,941,818**	**$2,282,076**

The forecasted cost of the eligible projects to completion is approximately $2,095,000.

The associated **$2,282,076** costs we have claimed under DMIAM for the project this regulatory year have not been:

- recovered under any other jurisdictional incentive scheme;
- recovered under any other Commonwealth or State Government scheme or funding; or
- included in the forecast capital or operating expenditure approved in the 2021-26 distribution determination or recovered under any other incentive scheme in that determination.

4.10.2.7 Ongoing project activity

Victorian Government Neighbourhood Battery Initiative (NBI)

This project has delivered the following milestones:

- Engineering assessment

- Financial, regulatory and commercial assessment reports
- Draft business case
- Final business case and project close out

Australian Government's Community Batteries (CB) for Household Solar Program (Flemington, Coburg, Bellfield, Alphington)

This project has delivered the following milestones:

- Procurement
- Lease agreement and installation contract
- Cybersecurity and digital design
- Communications and SCADA design
- Factory Acceptance Testing and inspection of unit prior to delivery
- Install and commissioning of BESS at Coburg and Bellfield
- Site Acceptance Testing
- Metering, connection to network, energisation and commissioning
- Engagement with retailer; and
- Operations and maintenance manual development

Broadmeadows BESS

This project has delivered the following milestones:

- Site feasibility assessments (fire risk, noise modelling, environmental/planning, geotechnical)

4.10.2.8 Results of the project

The business case assessment report was built upon previous assessments conducted on the deployment of Neighbourhood Batteries (NBs) in residential and mixed-use greenfield developments. Its primary purpose was to answer the question: Are there sufficient benefits for JEN to invest in NBs as a regulated Distribution Network Service Provider (DNSP)?

The analysis showed that there is a benefit to invest in NBs as a DNSP; however, at the current costs and value stack available, there are currently commercial challenges with the widescale rollout of NBs within greenfield developments compared to traditional network augmentation.

The assessments have found that there are significant network benefits that NBs can provide for Underground Residential Distribution (URD) developments in the northern growth corridor of JEN This area has seen an increase in electricity consumption and rooftop photovoltaic (PV) installations, creating reliability risks and export curtailment on the high-voltage distribution network. NBs can also reduce the number of distribution substations that need to be installed on the URD site, providing a benefit to the URD developers. In addition, co-locating the NB with distribution substation infrastructure on the URD site addresses a key issue of NB – finding suitable land to locate the NB that is acceptable to nearby residents and businesses.

Although the NBs are primarily there to support the network and new URD developments, possible revenue streams from leasing the NBs to Market Participants for energy market-related services are important to maximise the benefits that the NBs bring. In the benefit modelling, nominal values of energy arbitrage and Frequency Control Ancillary Service (FCAS) were included.

It was found that the business case for NB deployment in the two URD use cases is contingent on the availability of the network reliability benefits for at least five years. Currently, JEN addresses network reliability risks and export curtailment through implementing network augmentation projects. Two network augmentation projects have already been approved to increase the capacity of the high voltage feeders supplying into the two URD developments. Network reliability and PV export curtailment benefits will no longer exist once these projects are completed.

Due to the current high costs of NBs, it is unlikely that NBs can assume the role of network augmentation projects in addressing network risks in the short to medium term. The hypothesis that a sufficient number of NBs can be installed to mitigate network risks, thereby deferring network augmentation, while also providing local and market-related benefits, was tested. JEN undertook the financial assessment of deferring the planned network augmentation projects by two or five years using NBs and compared the change in the project Net Present Value (NPV) against the planned network augmentation projects occurring in 2024.

The assessment also explored pathways where costs can be reduced and benefits improved. As NB benefits are spread among various industry players, a collaborative effort among stakeholders will be required to advance the cause of NBs and expedite the development of a sustainable model for deployment.

Australian Government's Community Batteries (CB) for Household Solar Program [Flemington, Coburg, Bellfield, Alphington]

JEN has installed and commissioned two of the Community Batteries in Bellfield and Coburg. Two more community batteries are planned to be installed in Flemington and Alphington in 2025.

The projects have enabled additional hosting capacity in areas of JEN. The benefit of this is that more solar can be exported to the grid, supporting more solar and other CER connections to occur in the community. There are also network benefits from the reduction of peak demands, which will accumulate over time, allowing network upgrades to be deferred. The project has enabled a greater energy awareness within the community, and it is believed that this impact will extend beyond the project.

The batteries are expected to continue delivering benefits beyond 10 years, and the modular nature of them means that they may be upgraded or replaced rather than removed.

JEN have acquired learnings and capabilities in the following key areas:

- Development of equipment technical specification
- Evaluation of tender proposals
- Network studies and site determination
- Community and stakeholder engagement plans
- Safety and risk assessment
- Development of commercial, legal and land agreement requirements
- Risk assessment and field technical change process
- Cybersecurity and digital design
- Communications and SCADA design
- Factory and Site Acceptance testing
- Metering, connection to network, energisation and commissioning
- Engagement with retailer
- Operations and maintenance manual development.

Broadmeadows BESS

JEN has completed various feasibility assessments to determine the suitability of the BESS location and have identified key recommendations to proceed with the project. The following feasibility assessments have been completed with key recommendations:

- Fire Risk Assessment
    - Fire hazards are well mitigated with layered safety systems; ongoing maintenance and emergency planning required.
- Noise Modelling Assessment
    - Predicted levels marginally compliant with EPA limits; monitoring at Broadmeadows recommended to confirm compliance.

    - Mitigation options identified including: acoustic treatment of vents, acoustic barriers and positioning the ventilation to reduce reflections.
- Environmental / Planning due diligence
    - No permits or vegetation removal required; relocation can proceed within current zoning provisions.
    - Review of existing parking conditions is recommended.
- Geotechnical & Footprint design
    - Subsurface conditions suitable for engineered slab and pier design; further testing of fill is advised before construction.

4.10.3 Project Developments and Results

Section 4.10.3 of the Order requires JEN to provide an overview of developments in relation to projects or programs completed in previous years of the current regulatory control period, and of any results to date.

The project developments and results to date are outlined in Section 4.10.2.8.

4.10.4 Total amount of DMIAM

Section 4.10.4 of the Order requires JEN to provide any other required information as specified by the DMIAM.

Section 2.3(3)(a) of the demand management innovation allowance mechanism requires JEN to state the total amount of DMIAM spent in the relevant regulatory period. The total amount of DMIAM spent in this regulatory year is **$2,282,076** and excludes any funds that will be recovered from external bodies.

The total DMIAM allocation for the regulatory period is summarised in Table 4-12 below:

Table 4–12: DMIAM allocation

Project	FY21-22	FY22-23	FY23-24	FY24-25	FY25-26	Total
Dynamic EV Charging Trial	$240,105	$165,408				$405,513
VIC Government Neighbourhood Battery Initiative (NBI)			$152,460	-$81,476		$70,984
Australian Government Community Battery (CB) Initiative – Flemington			$61,943	$224,838		$286,781
Australian Government Community Battery (CB) Initiative – Coburg			$59,107	$730,592		$789,699
Australian Government Community Battery (CB) Initiative – Bellfield			$56,125	$856,032		$912,156
Australian Government Community Battery (CB) Initiative – Alphington			$55,087	$474,787		$529,874

Project	FY21-22	FY22-23	FY23-24	FY24-25	FY25-26	Total
Broadmeadows BESS				$77,303		$77,303
Total	**$240,105**	**$165,408**	**$384,722**	**$2,282,076**		**$3,072,311**

4.11 Tax standard asset lives

This section sets out JEN's response to Section 4.11 of the Order.

4.11.1 Reconciliation of tax standard asset lives

Section 4.11.1 of the Order requires JEN to identify all tax standard asset lives applied to asset classes that differ from those contained in the AER approved Post Tax Revenue Model for the reporting period.

We confirm that all tax standard asset lives reconcile with those contained in the AER approved Post Tax Revenue Model for the reporting period.

4.11.2 Reasons for difference in reconciliation of tax standard asset lives

Section 4.11.2 of the Order requires JEN to explain the reasons for each difference identified in section 4.11.1 including reasons for any departure from the Australian Tax Office's most recent determination of effective life.

Based on JEN's response to 4.11.1, this section is not applicable to JEN.

4.12 Tax reporting – immediate expensing

This section sets out JEN's response to Section 4.12 of the Order.

4.12.1 Immediate expensing capital expenditure

Section 4.12.1 of the Order requires JEN to list and explain the types of capital expenditure (such as refurbishment capital expenditure and capitalised overheads) associated with the immediate expensing capital expenditure as reported in the data workbooks, if any.

In FY2025, no immediate expensing capital expenditure has been incurred by JEN.

4.12.2 Changes in tax policy on immediate expensing capital expenditure

Section 4.12.2 of the Order requires JEN to state if it has, since the last reporting period, changed and/or intends to change its tax policy on immediate expensing capital expenditure and explain the rationale for the change and impact of the change.

Based on JEN's response in 4.12.2, this section is not applicable to JEN.

4.13 Regulatory investment test expenditure

This section sets out JEN's response to Section 4.13 of the Order.

4.13.1 Project that has undergone a RIT-D

For each project where JEN has incurred expenditure during the reporting period relating to a project that has undergone a RIT-D in accordance with r.5.17 of the NER and the AER's RIT-D application guidelines JEN is required to provide the following details:

a) the name of the RIT-D and the date on which the RIT-D process was concluded; and

b) whether the expenditure on the project is classified as augmentation expenditure or replacement expenditure.

Table 4–13: Project

Project	Jemena Website link	RIT-D conclusion date	RIT-D status	Expenditure type	Total cumulative expenditure to date	Project
Footscray East Zone Substation Switchgear condition	https://www.jemena.com.au/electricity/jemena-electricity-network/network-information/rits/footscray-east-zone-substation-switchgear-condition/	31/12/2019	Completed	Replacement	14.32	15.11
Heidelberg Zone Substation Transformer condition	https://www.jemena.com.au/electricity/jemena-electricity-network/network-information/rits/heidelberg-zone-substation-transformer-condition/	31/12/2019	Completed	Replacement	14.85	16.50
Footscray West Zone Substation Switchgear and Relay condition	https://www.jemena.com.au/electricity/jemena-electricity-network/network-information/rits/footscray-west-zone-substation-switchgear-and-relay-condition/	22/06/2023	Completed	Replacement	26.75	40.60
East Preston (EP) Conversion Stage 6	https://www.jemena.com.au/electricity/jemena-electricity-network/network-information/rit	31/12/2021	Completed	Augmentation	12.37	17.60

	ds/east-preston-ep-conversion-stage-6/					
Comply with Bushfire Mitigation Regulations at Coolaroo	https://www.jemena.com.au/electricity/jemena-electricity-network/network-information/rit ds/comply-with-bushfire-mitigation-regulations-at-coolaroo/	31/12/2021	Completed	Augmentation	54.61	60.53
Brunswick Terminal Station – Fairfield Zone Substation 22 kV sub transmission loop capacity constraint	https://www.jemena.com.au/electricity/jemena-electricity-network/network-information/rit ds/brunswick---fairfield-22-kv-subtransmission-loop-capacity-constraint/	20/12/2023	Completed	Augmentation	0.26	0.27
Fairfield zone substation transformer No.3 condition and 4th bus	https://www.jemena.com.au/electricity/jemena-electricity-network/network-information/rit ds/fairfield-zone-substation-ff-transformer-no.3-condition-and-4th-bus	15/12/2023	Completed	Replacement	11.64	19.65

4.14 Related party information

This section sets out JEN's response to Section 4.14 of the Order.

4.14.1 Related party transactions

For each related party transaction specified in Workbook 09 – Revenue and financial statements and submitted in the Data submission workbook table 8.7.1 Profitability tax data, the electricity distributor must confirm that the contract or arrangement with the related party requires the related party to provide all relevant information to enable the electricity distributor to meet its reporting obligations (including allocation or attribution of costs of that related party contract) under this Order.

JEN confirms that the related party has provided all relevant information required for FY25 reporting obligations (including allocation or attribution of costs of that related party contract) under this Order.

4.15 Reporting of fines and penalties

This section sets out JEN's response to Section 4.15 of the Order.

4.15.1 Fines and penalties incurred

According to Section 4.15.1 where any fine or penalty has been incurred by the electricity distributor during the reporting period as a result of non-compliance with:

a) a distribution safety standard; or

b) a distribution reliability standard; or

c) a distribution service standard; or

d) the NEL or NER; or

e) the National Energy Retail Law or National Energy Retail Rules; or

f) any Act or instrument referred to in s.2D(1)(b)(ii) to (v) of the NEL,

JEN must identify and itemise each fine or penalty (including a description of the non-compliance, the size of each fine or penalty, and the relevant authority that levied each fine or penalty). JEN incurred no fines in the relevant regulatory year.

4.15.2 Attestation under Section 4.15

According to Section 4.15.2, for all such fines or penalties identified in response to section 4.15.1, JEN must provide a statement attesting that:

a) JEN has not included any of that expenditure or cost, or any part of that expenditure or cost, in the operating expenditures contained in its response to this Order; and

b) JEN has not recovered any of that expenditure or cost, or any part of that expenditure or cost, from end users; and

c) JEN has not sought to pass through any of that expenditure or cost, or any part of that expenditure or cost, to end users.

JEN has not sought to pass through these penalties to end users.

4.15.3 Attestation under 4.15.3

According to Section 4.15.3 of the Order where no such fines or penalties have been identified in response to section 4.15.1, JEN must provide a statement attesting that no such fine or penalty has been incurred.

Given that JEN has provided a response to the section 4.15.1 requirement, attestation under paragraph 4.15.1 requirement is not applicable for the relevant regulatory year.

4.15.4 Exclusions

According to Section 4.15.4 of the Order the fines or penalties identified in section 4.15.1 exclude any payments made in accordance with the AER's incentive schemes (including guaranteed service level payments under Chapter 6 of the AER's service target performance incentive scheme) or any relevant jurisdictional guaranteed service level scheme.

JEN confirms that the payments outline in section 4.15.1 exclude any payments made in accordance with the AER's incentive schemes.

4.16 Tariff variations

This section sets out JEN's response to Section 4.16 of the Order.

4.16.1 Material changes in tariff structure

According to Section 4.16.1 of the Order, JEN must provide an explanation of the timing and nature of any material changes in the level and structure of tariffs in the reporting period.

There are no material changes.

4.16.2 Material tariff reassignments

According to Section 4.16.2 of the Order, JEN must provide an explanation of any material tariff reassignments in the reporting period.

There are no material tariff reassignments.

4.17 Vegetation management

This section sets out JEN's response to Section 4.17 of the Order.

4.17.1 List of regulations

According to Section 4.17.1 of the Order, JEN must provide a list of regulations that result in a material cost on performing vegetation management works (including, but not limited to, bushfire mitigation regulations).

- Electricity Safety Act 1998
- Electricity Industry Act 2000
- Electricity Safety (Bushfire Mitigation) Regulations 2023
- Electricity Safety (Electric Line Clearance) Interim Regulations 2025
- Electricity Safety (Management) Regulations
- Electricity Safety (General) Regulations 2019
- Environment Protection Act 2017
- Flora and Fauna Guarantee Act 1988
- Occupational Health and Safety Act 2024
- Occupational Health & Safety Regulations 2017
- Blue Book – Code of Practice on electrical safety for work on or near high voltage electrical apparatus
- Green Book - Code of Practice on electrical safety for distribution businesses in the Victorian Electrical Supply Industry
- AS 4373-2007 (Significant Vegetation)
- AS 1418.10 (Cranes, Hoists and Winches)

4.17.2 List of self-imposed standards

According to Section 4.17.2 of the Order JEN must provide a list of self-imposed standards from the electricity distributor's vegetation management program.

- JEN Electric Line Clearance Management Plan
- JEN Bushfire Mitigation Plan
- JEN Customer Complaints Procedure
- JAA HSE PR 0025 Working at Heights Procedure
- VEM 20-50 Assessment Procedure (Jemena)
- VEM 10-05 Safety Observer/Offsider, Emergency Response & Single Person Work Procedure
- VEM 10-09 Guidelines for Conforming to Electrical Safety Requirements
- VEM 10-08 EWP Procedure
- VEM 10-06 Tree Climbing Procedure
- VEM 21-03 Management of Threatened Flora and Fauna
- VEM 20-02 Hazardous Tree and 56M Management Procedure

All vegetation crews are trained in tree identification, cutting techniques and tree physiology. Some special situations may require greater expertise (expert Arborists).

4.17.3 Explanation of the cost impact of regulations and self-imposed standards

According to Section 4.17.3 of the Order, JEN must explain the cost impact of regulations and self-imposed standards on performing vegetation management work in the reporting period.

The cost of managing vegetation in accordance with regulations and self-imposed standards is increasing year to year, but not limited to the following factors:

Literal compliance

The 2015 Regulations introduced a significant change from the requirement to have vegetation compliant in the HBRA during the period from 1 November each year to the end of the declared fire danger period (typically 31 March of the following year). This has resulted in a significant increase in resources to both assess and cut vegetation until a full transition from the 2010 regulations was achieved. The program's transition period was completed in 2019. The strict compliance introduced in the 2015 regulation continues in the 2020 iteration of the regulations.

Habitat Trees

The 2015 Regulations also added the requirement for DNSPs to ensure that Fauna with a conservation status in Victoria of "vulnerable", "endangered" or "critically endangered" is identified. Once a tree containing threatened fauna is identified, cutting or removal of that tree must be undertaken outside of the breeding season for that species, wherever practicable. JEN has engaged the services of a qualified environmental officer to undertake a review of the network and constantly monitor cutting programs to ensure that threatened fauna is protected.

Consultation

In the 2005 Regulations, a minimum notice period was specified (14 days) before cutting, with no expiration date of the period. In the 2015 Regulations, this was changed and a 45-day window for trees to be actioned in was introduced. When that window is exceeded, the customers must be re-notified. This has the effect of increasing time spent notifying customers, increasing time reapplying for suppression, and altering the annual program.

Vegetation program management costs are also increasing due to increasing customer expectations. This has resulted in additional consultation with customers, community groups and councils.

Service lines

There is an increased focus on the management and clearing of service lines (section 84(2)(a) of the Electricity Safety Act).

JEN was required to increase the number of personnel assessing service lines due to the more stringent requirement to notify all customers with vegetation infringing the regulated space around a service line. In contrast, the previous regulations only required customers who had solid contact between their tree and the service line to be notified. JEN has also engaged a vegetation expert to manage this program and to follow up with customers who have service lines with solid contact to ensure they clear trees for which they are responsible under the Electricity Safety Act.

JEN's administration costs have also risen with the requirement to send out multiple letters to customers with offending vegetation if they fail to clear it within the predefined period.

Other Responsible Person (ORP) follow-up

As with service lines, Energy Safe Victoria has increased its focus on JEN to have a program in place to ensure that councils maintain their trees in accordance with the Electricity Safety Act and subordinate regulations. The regulations now require that vegetation management responsibility formerly ascribed to entities such as VicRoads, Metro Rail, Melbourne Water, etc., is now the responsibility of JEN.

JEN also manages the Other Responsible Person, private electric lines, and service lines in this program and follows up with ORPs who have non-compliances to ensure they clear their trees from overhead electric lines.

JEN absorbs costs for provision of network management (e.g. reclose suppression and processing of Permit to Work applications) to ORPs for cutting offending trees that were not cleared in a timely manner. This renders these trees unsafe to be cut by normal crews. In general terms, the closer the tree is to electric lines when it needs to be cut, the more expensive the safety requirements are for the work. Normal crews generally work well outside the clearance space and therefore are the least cost option. Although shutdowns are generally the most expensive, Live Line crews are more expensive than normal crews. Not all councils are alike, and most cite inadequate budgets as the reason for non-compliance, which in turn makes the program more expensive for the council and for JEN.

Additional requirements introduced under the Electricity Safety (Electric Line Clearance) Regulations 2015 (2015 ELC regulations)

There were three material changes in the 2015 ELC regulations for JEN. These are the a) compliance with the Amenity Tree Standard AS4373, b) additional notification and consultation requirements and c) compliance with the requirement to provide assistance to councils.

The changes in the obligations relating to amenity tree cutting practices will require JEN to incur additional costs to engage or train more qualified labour and changes in cutting equipment to comply with AS4373.

Additional notification and consultation obligations introduce an increase in costs that are driven both by the increase in the number of notices JEN must send out and additional information JEN must put in each notice. Each notice requires additional work to comply with the 2015 ELC regulations such as including a diagram of specific tree details, including a dispute resolution procedure and researching whether a tree is of cultural, environmental, historical, ecological or aesthetic significance.

It is now a mandatory requirement for JEN to provide assistance to local councils in relation to technical information about the overhead line (i.e. sag and sway dimensions) and information on safe cutting methods.

All three new requirements are expected to increase in cost over the next few years as councils and JEN develop processes to comply with these step changes in the 2015 ELC regulations.

HSE

To comply with the Occupational Health and Safety Act, JEN is constantly reviewing all components of their operations and investing time and resources into equipment, training, auditing and monitoring all crews to ensure that we have a safe workforce and community.

Victorian Bushfires Royal Commission (VBRC) Recommendations

These recommendations were enforced using “directions”. Directions were made using mechanisms existing in the Electricity Safety Act 1998, specifically Section 141(2)(d) of the Electricity Safety Act 1998, requiring Jemena to amend our Electricity Safety Management Scheme.

RECOMMENDATION 30

The State amends the regulatory framework for electricity safety to require that distribution businesses adopt, as part of their management plans, measures to reduce the risks posed by hazard trees—that is, trees that are outside the clearance zone but that could come into contact with an electric power line, having regard to foreseeable local conditions.

The implementation of Recommendation 30 required JEN to develop a Hazard Tree assessment and cutting program for the Hazardous Bushfire Risk Area. This program is in addition to JEN’s existing electric line clearance programs and incurs significant additional costs.

RECOMMENDATION 31

Municipal councils include in their municipal fire prevention plans for areas of high bushfire risk provision for the identification of hazard trees and for notifying the responsible entities with a view to having the situation redressed.

Energy Safe Victoria (**ESV**) requires JEN to “assist” municipal councils (per Recommendation 31) to meet their Hazard Tree management obligation and electric line clearance generally. This is adding significant cost to JEN’s vegetation management program.

RECOMMENDATION 34

The State amends the regulatory framework for electricity safety to strengthen Energy Safe Victoria’s mandate in relation to the prevention and mitigation of electricity-caused bushfires and to require it to fulfil that mandate.

There were eight recommendations made directly targeting the major electricity companies in Victoria. Three were vegetation-related, listed above as recommendations 30, 31 and 34. ESV used the mandate of recommendation 34 to strengthen acts and regulations in their jurisdiction, resulting in additional costs to JEN.

4.18 Reconciliation of expenditure

This section sets out JEN's response to Section 4.18 of the Order.

4.18.1 Reconciliation of expenditure

According to Section 4.18.1 of the Order JEN must identify all non-network operating expenditure items that have been reported against more than one operating expenditure category. The report must specify the relevant categories and expenditure amounts for each non-network expenditure item allocated to multiple categories, enabling reconciliation to the total non-network operating expenditure reported on a mutually exclusive/collectively exhaustive basis to meet the requirement for Opex by purpose.

Non-network operating expenditures items that have been reported against more than one operating expenditure category: Motor Vehicle Opex reported in data workbook 2.6 non-network is also reflected under the Opex by Purpose categories as outlined in Tables 4-14 and 4-15 below:

Table 4–14: Workbook 2.6.1 - Non-network Expenditure Non-Network Expenditure

Motor Vehicles	Opex ($)
Car	32,829
Light commercial vehicle	125,174
Elevated work platform (LCV)	-
Elevated work platform (HCV)	177,434
Heavy commercial vehicle	2,483
Total motor vehicle expenditure	**337,919**

Table 4–15: Workbook 2.1.2– Standard Control Opex by Purpose

OPEX BY PURPOSE	Motor Vehicle related costs ($)	Other costs ($)	Total Standard Control Services- Excluding dual function assets ($)	
			Direct	Indirect
Vegetation management	13,038	5,964,667	5,977,705	
Maintenance	119,385	8,001,281	8,120,665	
Emergency response	192,903	5,180,596	5,373,500	
Non-network	156	28,582,748	28,582,904	
Export services	3,824	986,989	990,813	
Network overheads	8,613	24,213,573		24,222,187
Corporate overheads		22,469,733		22,469,733
OPEX BY PURPOSE	**337,919**	**95,399,587**	**49,045,587**	**46,691,919**

4.19 Benchmarking asset base

This section sets out JEN's response to Section 4.19 of the Order.

4.19.1 Benchmarking asset base values using the Optional additional approach

According to Section 4.19.1 of the Order, if JEN wishes to report benchmarking asset base values in accordance with the Optional additional approach set out in Appendix A Data workbook instructions, Section 8.1.5 Optional additional approach, it must:

a) Submit the economic benchmarking asset base tables prepared using the optional additional approach as a separate data submission

b) Provide a basis of preparation detailing the estimation of the asset base data.

We have not provided benchmarking asset base values using the Optional additional approach.

4.20 Taxable income adjustments

This section sets out JEN's response to Section 4.20 of the Order.

4.20.1 Differences due to disallowed interest expenditure

According to Section 4.20.1 of the Order JEN must provide in its basis of preparation, the methodology used to determine the permanent differences due to disallowed interest expenditure and specify the interest expenditures it has assessed to be non-deductible.

JEN did not incur any interest deductions that were not deductible.

4.20.2 Prior year tax adjustments

According to Section 4.20.2 of the Order, JEN must provide in its basis of preparation, details of the prior year tax adjustments, including the reasons for the change (e.g. change in legislation, court judgment or Australian Tax Office correspondence where relevant).

JEN did not incur any prior year tax adjustments.

4.20.3 Reported tax losses carried forward

According to Section 4.20.3 of the Order, if JEN has reported tax losses carried forward in the Data submission workbook table 8.7.1 Profitability tax data and financial statements, it must provide an explanation of the factors that have resulted in the carried forward tax losses.

JEN did not report any carried-forward tax losses.

4.20.4 Supporting calculation for reported tax losses carried forward

According to Section 4.20.4 of the Order JEN must report any tax losses that have been used by the electricity distributor during the regulatory year. The electricity distributor must provide supporting calculations for the tax losses used.

Based on JEN's response to 4.20.3, this section is not applicable to JEN.

4.21 Interest expenditure

This section sets out JEN's response to Section 4.21 of the Order.

4.21.1 Methodology to allocate interest expense

According to Section 4.21.1 of the Order, JEN must provide in its basis of preparation, in relation to its interest expenditure:

a) a description and explanation of the methodology used to allocate the interest expenditure. This methodology should provide:

   i) the specific debt that has been allocated to the electricity distributor's core regulated services;

   ii) the general debt that has been allocated to the electricity distributor's core regulated services;

   iii) the method used to allocate the specific debt and general debt between the regulated and unregulated assets held at the group level, and also to the core regulated services; and

   iv) the method used to allocate related party interest to the electricity distributor's core regulated services, to the extent related party debt has been included in the specific or general debt allocations; and

b) if available or applicable to JEN, details of the characteristics of the portfolio of debt being allocated to it, including:

   i) the value of drawn debt allocated to the electricity distributor's core regulated services;

   ii) the portfolio-weighted average term of debt instruments giving rise to interest expense reported; and

   iii) any additional detail in its basis of preparation, that the electricity distributor would consider relevant in understanding the allocated interest expenditure

The methodology in relation to interest expense and liabilities is described in detail in the basis of preparation for the Data submission workbook table 8.7.1.

No related party interest has been included in JEN's interest expense.

4.22 Small scale incentive schemes

This section sets out JEN's response to Section 4.22 of the Order.

4.22.1 Customer service incentive scheme

According to Section 4.22.1 of the Order, for every reporting year for which a customer service incentive scheme applies to the electricity distributor JEN must report the information specified in the AER's regulatory determination that applied the scheme (applicable regulatory determination). The information must be reported in a form consistent with the requirements set out in the applicable regulatory determination, or as otherwise agreed with the AER.

JEN does not have a customer service incentive scheme.

4.22.2 Basis of preparation for customer service incentive scheme

According to Section 4.22.2 of the Order, information reported under section 4.22.1 is required to be included in the basis of preparation submitted by the JEN.

JEN does not have a customer service incentive scheme. This requirement is not applicable to JEN.

4.22.3 Assurance requirements for customer service incentive scheme

According to Section 4.22.3 of the Order, information reported under 4.22.1 is subject to the assurance requirements set out in the applicable regulatory determination.

JEN does not have a customer service incentive scheme. This requirement is not applicable to JEN.

4.22.4 Export service incentive scheme

According to Section 4.22.4 of the Order, for every reporting year for which an export service incentive scheme applies to JEN, it must report the information specified in the applicable regulatory determination that applied the scheme. The information must be reported in a form consistent with the requirements set out in the relevant regulatory determination, or as otherwise agreed with the AER.

JEN does not have an export service incentive scheme. This requirement is not applicable to JEN.

4.22.5 Basis of preparation for export service incentive scheme

According to Section 4.22.5 of the Order, information reported under section 4.22.4 is required to be included in the basis of preparation submitted by JEN.

JEN does not have an export service incentive scheme. This requirement is not applicable to JEN.

4.22.6 Assurance requirements for export service incentive scheme

According to Section 4.22.6 of the Order, information reported under 4.22.4 is subject to the assurance requirements set out in the applicable regulatory determination.

JEN does not have an export service incentive scheme. This requirement is not applicable to JEN.

4.23 Large projects

This section sets out JEN's response to Section 4.23 of the Order.

4.23.1 Order Requirements

According to Section 4.23.1 of the Order, for each large project reported in the Data submission workbook table 7.5 Large projects JEN must report:

a) the date of an AER determination to incorporate the expenditure forecast for the large project into the maximum allowed revenues for JEN

b) whether the project is a contingent project (as defined in the NER)

c) the expenditure forecast for the reporting year; the difference between forecast and actual expenditure; and drivers of the difference.

JEN provides the following information in response to Section 4.23.1 of the Order.

4.23.1.1 Large Project Information

Table 4-16 provides information on the capex projects reported in Data submission workbook table 7.5 Large Projects. It should be noted that no opex projects were reported.

Table 4–16: Large Project Information – Capex Projects

Project Name	Date of Regulatory Determinations	Contingent Project?	FY25 Forecast Expenditure ($)	FY25 Actual Expenditure ($)	Variance ($k)
DC02 - West Footscray (Stage 3)	N/A	No	-	3,791,943	3,791,943
DC04 - Tullamarine (Stage 1)	N/A	No	-	22,600,926	22,600,926
DC07 - Brooklyn (Stage 2)	N/A	No	-	7,537,957	7,537,957
DC09 - West Footscray	N/A	No	-	116,591	116,591
DC10 - Westmeadows	N/A	No	-	53,623	53,623
DC11 - Craigieburn	N/A	No	-	16,422,655	16,422,655
DC12 - Tullamarine (Stage 2)	N/A	No	-	3,075,794	3,075,794
DC19 - Yarraville	N/A	No	-	2,130	2,130
DC20 - Craigieburn	N/A	No	-	73,954	73,954
DC21 - Broadmeadows	N/A	No	-	29,633	29,633
DC22 - Craigieburn	N/A	No	-	17,441	17,441
DC24 - Campbellfield (Stage 1)	N/A	No	-	43,268	43,268
DC30 - Brooklyn	N/A	No	-	3,093	3,093
FW Redevelopment	26 May 2016 28 October 2020 30 April 2021	No	-	18,989,292	18,989,292

4.23.1.2 Project Cost Variance Information

It is noteworthy that a majority of the projects reported in the Data submission workbook Table 7.5 Large Projects are Data Centre connection projects. These projects were not foreseen when JEN prepared its revised regulatory proposal in December 2020, hence they have no capex included in the regulatory determination capex forecast. This is the sole driver of the variance between FY25 actual expenditure and forecast expenditure.

FW Redevelopment is a project currently in the delivery phase. When JEN submitted its regulatory proposal in January 2020, two business cases were submitted as supporting documents, one for the replacement of secondary equipment and one for the replacement of the 22kV outdoor buses and bus tie circuit breakers. Table 4-17 contains a summary of the scope of both business cases submitted.

Table 4–17: FW Redevelopment Project

Project Name	Scope Summary
Replace Footscray West (FW) Zone Substation Relays	Replacement of all secondary equipment at Footscray West Zone Substation (**FW**). This includes: • X & Y Transformer Protection Relays; • No.1 & No.3 Capacitor Bank Protection & Control Relays; • DC Supply Systems; • Feeder Management Relays; and • Backup Earth Fault and Master Earth Fault Relays.
Replace Footscray West (FW) Zone Substation Switchgear	Replacement of the existing 22kV and 66kV switchgear with new modern equivalents and installing them to current standards, including the retirement of the outdoor 22kV transfer buses.

Subsequent, more detailed assessments of the condition of the assets at FW revealed additional issues with the three zone substation transformers and eight 54-year-old feeder exit cables. The final business case scope, approved in January 2023, recommended constructing a new zone substation within the perimeter fence of the existing substation and replacing the eight feeder exit cables. Economic modelling indicated this was the most prudent and efficient method to address the prevailing issues at FW. JEN has also implemented a modular zone substation standard at FW whereby as much construction work as possible was completed offsite. An example of this is the prefabricated control building.

4.24 Circuit capacity

This section sets out JEN's response to Section 4.24 of the Order.

4.24.1 Methodology for Estimated Overhead and Underground Network Weighted Average MVA Capacity by Voltage Class

According to Section 4.24.1 of the Order, JEN must describe in its basis of preparation the methodology used to report in the Data submission workbook table 3.5.1.3 Estimated Overhead Network Weighted Average MVA Capacity By Voltage Class, and table 3.5.1.4 Estimated Underground Network Weighted Average MVA Capacity By Voltage Class.

The methodology is described in detail in the basis of preparation for Data submission workbook table 3.5.1.3 and 3.5.1.4.

4.24.2 Methodology for to estimate circuit capacity

According to Section 4.24.2 of the Order JEN must explain any changes in methodology used to estimate circuit capacity implemented for the reporting period.

JEN did not make any changes to the methodology used to estimate both overhead and underground circuit capacity implemented for the reporting period.