Jemena Electricity Networks (Vic) Ltd

2026-31 Electricity Distribution Price Review
Revised Regulatory Proposal

Attachment 05-01

Response to the AER's draft decision - Capital expenditure

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Glossary

Current regulatory period	The regulatory control period commencing 1 July 2021 and concluding 30 June 2026
Draft Plan	An early version of our regulatory proposal which we consulted on with our customers
Economic life	The age of an asset at which the total cost of providing the required level of service from the asset no longer represents the lowest long-run cost to customers of providing that required service (i.e. after considering alternatives)
ES Regulations	Electricity Safety (Bushfire Mitigation) Regulations 2023 (Vic)
Estimated allowance	The total capital expenditure allowance approved for the 2021-26 regulatory period, plus the adjustments we proposed in our reopener application.
Gross allowance	The total capital expenditure allowance approved in a price reset regulatory determination for a regulatory control period inclusive of capital contributions
Gross capital expenditure	Total capital expenditure, inclusive of amounts that are customer-funded through capital contributions
Hosting capacity	The capacity of the network to accommodate bi-directional power flows due to exports from distributed energy resources
ICT Technology Plan	Our proposed non-network ICT
Initial regulatory proposal	JEN's regulatory proposal submitted to the Australian Energy Regulator (AER) on 31 January 2025.
Net capital expenditure	Gross capital expenditure, less capital contributions and disposals
Next regulatory period	The regulatory control period commencing 1 July 2026 and concluding 30 June 2031
Panel	The Victorian Government's Expert Panel on Distribution Resilience Review (2024)
Probability of exceedance	The likelihood that a given level of maximum demand forecast will be met (or exceeded) in any given year. A forecast of 10 POE maximum demand is the level of annual demand that is expected to be exceeded one year in ten.
Regulatory proposal	Our proposal to the AER to review electricity distribution prices for the next regulatory period.
Revised regulatory proposal	JEN's regulatory proposal submitted to the AER on 1 December 2025.
Reset RIN	The Regulatory Information Notice served by the AER on 17 October 2024, requiring Jemena Electricity Networks (Vic) Ltd. to provide specific information pertaining to the distribution determination for the period 1 July 2026 to 30 June 2031
RIN Response	Our response to the information sought by the AER in the Regulatory Information Notice served on 17 October 2024
Technical life	The typical expected life of an asset before it fails in service under normal operating conditions. The technical life may differ across networks due to different operating and environmental factors, as well as between asset classes.

Abbreviations

AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
CBRM	Condition Based Risk Model
CPI	Consumer Price Index
CER	Customer Energy Resources
ESC	Essential Services Commission
GSL	Guaranteed Service Level
HBRA	High Bushfire Risk Area
HSE	Health, Safety and Environmental
ICCS	Incremental Cost Customer Specific
ICSN	Incremental Cost Shared Network
IFRC	International Financial Reporting Interpretations Committee
IR	Incremental Revenue
ISO	International Organisation for Standardisation
IT	Information Technology
JEN	Jemena Electricity Networks (Vic) Ltd
LBRA	Low Bushfire Risk Area
LV	Low Voltage
MCR	Marginal Cost of Reinforcement
NEL	National Electricity Law
NER	National Electricity Rules
RIN	Regulatory Information Notice
SaaS	software-as-a-Service
SCADA	Supervisory Control and Data Acquisition
ST	SubTransmission
VEBM	Victorian Emergency Backstop Mechanism

1. Overview

Highlights

- We propose a revised net capital expenditure of $1.3B, which is $32M or 2% lower than our forecast under the initial regulatory proposal.
- Our revised capital expenditure is 58% higher than the Australian Energy Regulator's (**AER's**) draft decision

We welcome the AER's draft decision which found that several elements of our proposed capital expenditure are prudent and efficient.

In preparing this revised regulatory proposal, we have considered the AER's feedback and sought to address the AER's concerns. We have done this by reviewing key inputs (such as our demand forecast), updating and refining our economic analysis and developing revised business cases.

In some cases, this resulted in changes to our forecast, for instance, we have removed augmentation projects linked to data centres, some resilience projects and some innovation projects. However, in most cases, our updated analysis confirms that many of the projects are still required. We have attached the additional supporting documentation and materials required to substantiate the need for these projects and programs.

We forecast a lower net capital expenditure of $1,335M under our revised regulatory proposal for the next regulatory period. Overall, our revised forecast is $31M lower than our forecast capital expenditure in the initial regulatory proposal (Figure).

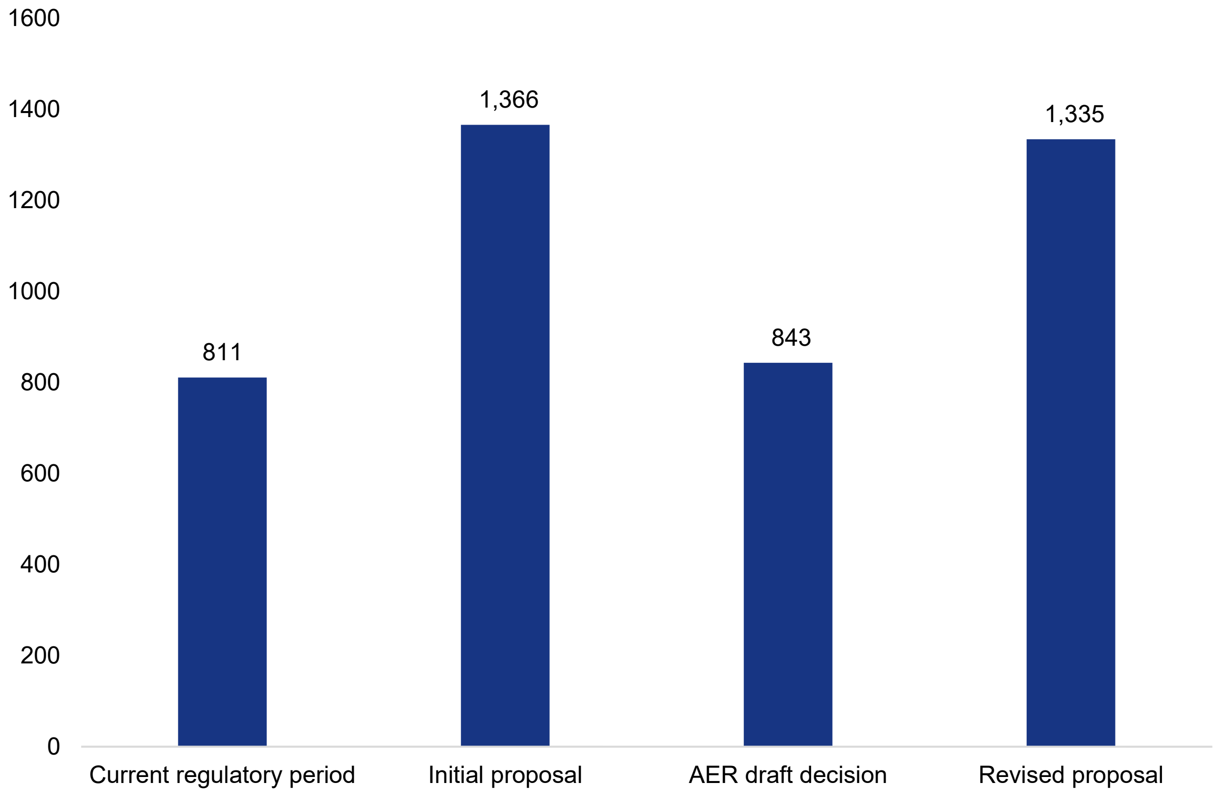
We do not consider that the AER's draft decision, which aligns closely with historical capital expenditure levels, adequately reflects the evolving obligations of distribution network service providers (**DNSPs**). Historical spend was based on a relatively stable network environment, whereas the next regulatory period will require significant investment to meet a number of critical challenges including:

- **Network Reliability**. Aging infrastructure and increased demand variability mean we must invest in asset replacement and augmentation to maintain reliability standards. Deferring or underfunding these programs risks higher outage rates and customer dissatisfaction.
- **Energy Transition Requirements**. The rapid integration of customer energy resources/distributed energy resources (CER/DER), electrification, and decarbonisation targets necessitate upgrades to accommodate two-way power flows, advanced voltage management, and system security. These changes require substantial capital investment in new technologies, ICT systems, and grid reinforcement—far beyond historical norms.
- **Ongoing greenfield and infill development**. We must augment our already highly utilised network to support new housing supply across our network area.
- **Large customer connections such as data centres**. Connections expenditure relates to the costs we incur in connecting new customers to our network. Connections are not discretionary or within our control. Various regulatory instruments require us to offer connection services to customers.[1]

Limiting expenditure to historical trends ignores these forward-looking obligations and could compromise compliance with reliability standards and the National Electricity Objective (**NEO**), while slowing progress toward Australia's energy transition goals.

[1] Such as Chapter 5A of the NER and the Essential Services Commission Electricity Distribution Code of Practice.

Figure 1-1: Comparison of actual and forecast net capital expenditure ($2026, million)[2]



We summarise in Table 1.1 the AER's draft decision including how we have addressed or adopted them. All dollar values in this document are expressed in $2026 unless stated otherwise.

2 Capital expenditure for the current regulatory period accounts for JEN's cost pass through applications for the Victorian Emergency Backstop Mechanism (approved by the AER in 2024) and the 4 cost pass through applications recently submitted by JEN to the AER.

Table 1.1: Key elements of the AER's draft decision and our response

Capital expenditure	AER draft decision[3]	Adopted AER recommendations?
Connections	The AER accepted our business-as-usual connection forecast but removed major and data-centre connections where there was any material uncertainty on whether a connection would occur. This reduced our net connections capex from $366.4M to $211M. The biggest change related to data centre connection capex where the AER accept 100% of inflight projects (where a Connection Works Agreement (CWA) has been signed) and 50% of 'Enquiry to Offer' projects. The AER requested additional evidence, beyond what we have already provided, on the likelihood that each connection will progress to a Connection Works Agreement (CWA).	✓ Our revised regulatory proposal applies the AER's approach to our current connection pipeline and removes expenditure where we cannot meet the AER's information expectations, largely where there is a degree of uncertainty. For data centres, we only include expenditure where a Connection Works Agreement has been signed (in-flight) or will soon be signed (firm offer). Our revised regulatory proposal net connection forecast is $349M, higher than the AER's draft decision of $211M, largely due to projects progressing through the connection process. It is not possible to meet the AER's draft decision expectations *and* produce a forecast which reasonably reflects a realistic expectation of demand or the efficient costs of meeting that demand. Accordingly, our revised proposal connection forecast is $231M below what we expect to incur. We look forward to continuing to work with the AER so that future decisions can produce the best possible estimate in the uncertain circumstances we face.
Augmentation	The AER did not accept our augmentation capital expenditure forecast of $270M. The draft decision included $150M in augmentation capital expenditure due to concerns with our peak demand forecast, reducing demand-driven augmentation expenditure to $100M as a placeholder based on historical expenditure. The AER accepted the bulk of our non-demand driven augmentation spend but did not accept our project to alleviate constraints on our operational communications network due to concerns with our economic analysis, reducing the forecast by $9M.	✓ On demand-driven augmentation, we have addressed the AER's concerns by updating our forecasting approach. After we made these changes, we re-evaluated our augmentation program. Aside from the removal of projects driven by data centres, we found no material change in our augmentation program. We also asked Endgame Analytics to review our demand forecast to ensure we had addressed the AER's issues and to produce an alternative forecast as a cross-check. Applying this forecast results in a $17M *higher* augmentation forecast, indicating that our forecast is conservative. We have retained the majority of our forecast and excluded data centre driven augmentation to produce a revised demand-driven augmentation forecast of $143M. ✓ In respect of our operational communications network project, we revised our economic analysis taking into account the AER's feedback. We found that our preferred solution remains the most economic option and have retained the project in our forecast.

3 AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025.

Capital expenditure	AER draft decision[3]	Adopted AER recommendations?
Replacement	The AER did not accept JEN's net replacement expenditure forecast of $380M (net of the Maribyrnong project[4]). It included a substitute estimate of $230M (net), which is 39% lower than JEN's forecast.	✓ Our revised regulatory proposal addresses the AER's concerns and recommendations. Supported by new or enhanced business cases, our revised regulatory proposal net replacement expenditure forecast is $390 ($419M gross). The $10M increase in forecast from the initial regulatory proposal is due to our revised proposal to expand the scope of the Upgrade to substation locks and security systems. This will enable us to meet our regulatory obligations.
Network resilience	The AER did not accept JEN's network resilience capital expenditure of $20M (including the Maribyrnong project) and included an alternative estimate of $1M capital expenditure. The main driver for the decrease is the AER's rejection of the JEN's proposed Maribyrnong project for lack of sufficient justification. The AER has accepted our proposed capital expenditure for the Mobile emergency response vehicle and mobile generators as prudent and efficient.	✓We welcome the AER's draft decision to accept our proposed capital expenditure for the Mobile emergency response vehicle and mobile generators. We acknowledge the AER's re-categorisation of the Maribyrnong project as a network resilience initiative. However, given this change in treatment—and alternative assessment criteria—we are withdrawing this project from the revised reguatlroy proposal.
Innovation	The AER did not accept JEN's capital expenditure forecast of $4 million for network innovation and has included an alternative forecast of $2M.	✓Our revised regulatory proposal accepts the AER's feedback. We reassessed and refined our innovation program for the next regulatory period. We forecast capital expenditure of $3M ($2024) for our innovation program for the next regulatory period. We discuss this in more detail in a separate attachment titled *JEN – Att 03–02 – Innovation Fund Proposal.*
CER	The AER did not accept JEN's CER forecast of $85M capital expenditure and has included a substitute forecast of $18M, which is 79% lower than JEN's capital expenditure proposal.	✓We have not adopted the AER's proposed recategorisation of this expenditure. However, our revised proposal addresses the AER's feedback. We have reduced the scope of the three initiatives that the AER has recategorised as CER. These projects are included as part of our forecast capital expenditure for augmentation and ICT.

[4] Also referred to as Relocating assets that are in high-flood risk zones which the AER has re-categorised as a network resilience project in its draft decision.

Capital expenditure	AER draft decision[3]	Adopted AER recommendations?
Non-network - ICT	The AER did not accept JEN's information and communications technologies (**ICT**) capital expenditure forecast of $153M. It included $104M ICT capital expenditure which is lower than JEN's proposal. The draft decision included an alternative forecast of $29.7 million for recurrent ICT capital expenditure, which is based on the past 4.5 years of actual data. It accepted the drivers behind 9 of our 13 proposed non-recurrent ICT capital expenditure (net of CER) as prudent and efficient.	✓ Our revised regulatory proposal applies the AER's approach for setting the recurrent ICT capital expenditure. We have provided additional support documents to support some of the non-recurrent capital expenditure projects, for which the AER has included an alternative estimate of $0 or partial capital expenditure. We propose two new non-recurrent capital expenditure projects: cyber security program and the Victorian Emergency Backstop Mechanism 2 (**VEBM2**), with a total forecast expenditure of $7M. This is to address recently identified risks and regulatory obligations that were unknown/uncertain at the time of the initial regulatory proposal. Our revised regulatory proposal is $133M which is $20M lower than our forecast spend under the initial regulatory proposal.
Non-network–Other	The AER has accepted our forecast capital expenditure for fleet replacements and property as prudent and efficient. The AER's draft decision is silent on our proposed capital expenditure for fleet growth, which was submitted to the AER as part of our response to information request#5 in April 2025.	✓We welcome the AER's decision to accept our proposed expenditure for fleet replacements and property in the next regulatory period. For the revised regulatory proposal, we seek additional capital expenditure to address fleet-growth requirements that are essential to delivering our expanded replacement and augmentation capital works program.
Capitalised overheads	The AER did not accept JEN's proposed overhead amount of $128M (net) or $222M (gross) and substituted $98M and $160M, respectively. The AER did not accept JEN's approach of using a single-year base (2023–24) to forecast overhead compared with the AER's standard approach of using a 3-year average of historical actual overhead.	✓Our forecast of capitalised corporate overheads partially adopts the AER's draft decision. Our revised regulatory proposal adopts a 4-year average, including 2024-25, rather than the 3-year average in the draft decision. However, based on Farrierswier's analysis, we propose updating the fixed/variable split to 50%/50% (compared with the AER's draft decision of a 75%/25% split). Empirical evidence suggests that retaining the 75/25 split would materially understate capitalised overheads over the next regulatory period.

Figure 1-2, Table 1–2 and Table 1–2 provide more details about our revised forecast capital expenditure including the key drivers of change.

Figure 1-2: Change in forecast net capital expenditure from the initial regulatory proposal to the revised regulatory proposal ($2026, million)

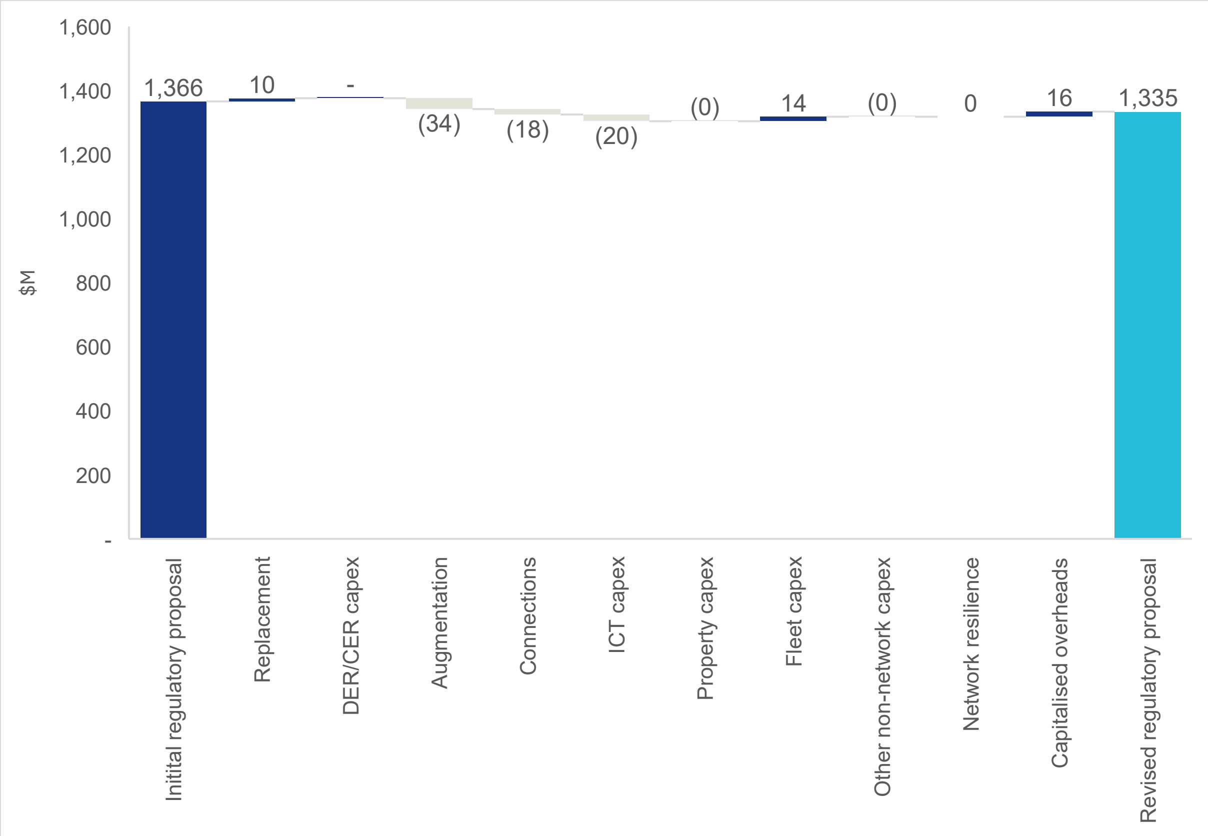


Table 1–2: Comparison of forecast net capital expenditure ($2026, million)

Capital expenditure	Initial regulatory proposal (Re-categorised)	AER draft decision	Revised regulatory proposal
Replacement	380.1	229.8	390.5
Augmentation	269.5	150.1	235.2
Connections	366.4	211.0	348.8
ICT	153.6	103.7	133.1
Property	17.4	17.0	17.4
Fleet	30.8	30.7	45.1
CER integration	0.0	n/a	n/a
Resilience	19.8	1.3	19.8
Non-network – Other	1.4	1.4	1.4
Capitalised overheads	127.5	98.2	143.4
Total net capital expenditure	**1,366.3**	**843.3**	**1,334.7**

Notes: The initial proposal categorisation has been restated to align with the revised regulatory proposal mapping. The draft decision categorisation has been restated to allocate the modelling adjustments to their respective categories. The total capital expenditures for the initial regulatory proposal and draft decision have not changed.

Table 1–3: Comparison of forecast gross capital expenditure ($2026, million)

Capital expenditure	Initial regulatory proposal (Re-categorised)	AER draft decision	Revised regulatory proposal
Replacement	408.9	247.3	419.3
Augmentation	269.5	150.1	235.2
Connections	1102.6	562.5	1067.6
ICT	153.5	103.7	133.1
Property	17.4	17.0	17.4
Fleet	33.6	33.5	47.9
CER integration	n/a	n/a	n/a
Resilience	19.8	1.3	19.8
Non-network – Other	1.4	1.4	1.4
Capitalised overheads	222.2	159.5	244.8
Gross capital expenditure	**2,228.8**	**1,276.3**	**2,186.5**
Less capital contributions	859.7	430.2	849.1
Less asset disposals	2.8	2.8	2.8
Net capital expenditure	**1,366.3**	**843.3**	**1,334.7**

Notes: The initial proposal categorisation has been restated to align with the revised regulatory proposal mapping. The draft decision categorisation has been restated to allocate the modelling adjustments to their respective categories. The total capital expenditures for the initial regulatory proposal and draft decision have not changed.

2. Connections

Our connection capex forecast can be split into three components:

- **Business as usual connections** – As the AER accepted this aspect of our initial regulatory proposal forecast, we have made no further changes or updates.[5]
- **Major (non-data centre) connections** – We have accepted the AER's draft decision for these connections.[6] We have retained capex for known connections and removed capex for 'future' connections, where we have not yet received a connection application but anticipate receiving one, given the historical trend.
- **Data centre connections** – We have updated our forecast to apply the AER's suggested forecasting methodology. We now include only connections for which we have signed or are highly confident we will soon sign a Connection Works Agreement (CWA).

Overall, to address the AER's concerns, we have removed expenditure where there is a low degree of uncertainty with respect to large connections, data centres or otherwise. This is because the AER's expectations around supporting information for this expenditure cannot be met.

We note the challenge that we – both ourselves and the AER – face is needing to forecast connections 6-7 years ahead, in the midst of the energy transition and an unprecedented boom in data centre investment. Unfortunately, we do not have all of the information that we would like, and even if we did, the future may still differ.

Higher than expected connections – which we cannot avoid or control – leads to increased expenditure, puts pressure on our broader investment program, and in turn affect the service delivered to our customers.

Since we lodged our initial regulatory proposal, the AER has modified the CESS to allow ex-post adjustments to remove penalties from higher than forecast connections.[7] As a result, the financial and consumer risks from forecasting errors related to large connection capex has materially reduced.

This change has enabled us to accept a connection capex forecast which excludes connections that are likely to occur but where the information available to us is incomplete or has the potential to change – consistent with the expectations set in the AER's draft decision.

In our view, this approach does not produce a forecast that reasonably reflects a realistic expectation of demand or the efficient costs of meeting that demand.[8] We look forward to continuing to work with the AER to improve the connections forecasting methodology so that future decisions can produce the best possible estimate in the uncertain circumstances we face.

A comparison of our initial regulatory proposal, the AER's draft decision and our revised regulatory proposal is shown in Table 2.1.

5 AER 2025, *Draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031,* p.28 Available here.

6 AER 2025, *Draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031,* p.33 Available here.

7 AER 2025, *Capital Expenditure Incentive Guidelines for Electricity Network Service Providers, p*.10 Available here.

8 To meet the capital expenditure criteria set out in Rule 6.5.7(2).

Table 2.1: Connections capex ($2026, million)

		Initial regulatory proposal	Draft decision	Revised regulatory proposal
Gross	Business as usual	259.0	252.7	259.4
	Major (non-data centres)	139.6	96.7	98.7
	Data centres	704.0	213.0	709.5
	Sub-total	**1,102.6**	**562.5**	**1,067.6**
Capital contributions	Business as usual	119.5	116.8	119.8
	Major (non-data centres)	103.4	72.2	73.6
	Data centres	513.2	162.5	525.4
	Sub-total	**736.2**	**351.5**	**718.8**
Net	Business as usual	139.4	135.9	139.7
	Major (non-data centres)	36.2	24.6	25.1
	Data centres	190.8	50.6	184.1
	Total	**366.4**	**211.0**	**348.8**

Small differences between the initial regulatory proposal, the draft decision and our revised regulatory proposal due to updated real escalation.

2.1 Data centres

After considering the AER's feedback, we have reduced our forecast for data centre connections in our revised regulatory proposal. We now only include connection capex for in-flight projects (where a CWA has been signed) and firm offer projects (where we are confident a CWA will soon be signed).

We do not include expenditure for any other connection in our pipeline or for enquiries we anticipate receiving in the future.

Figure 2-1 below shows our overall forecast. The shaded elements (in-flight and firm offer) are included in our proposal while the excluded categories (enquiry and future) are outlined. This figure shows that our forecast is very conservative relative to our overall pipeline and has near-term bias as it only includes projects that we are certain will proceed. While we expect the majority of the current connection enquiries to require connection projects and for additional connection requests to be lodged, we have included no expenditure for these likely projects.

Figure 2-1: Data centre connection forecast ($2026, million, direct escalated)

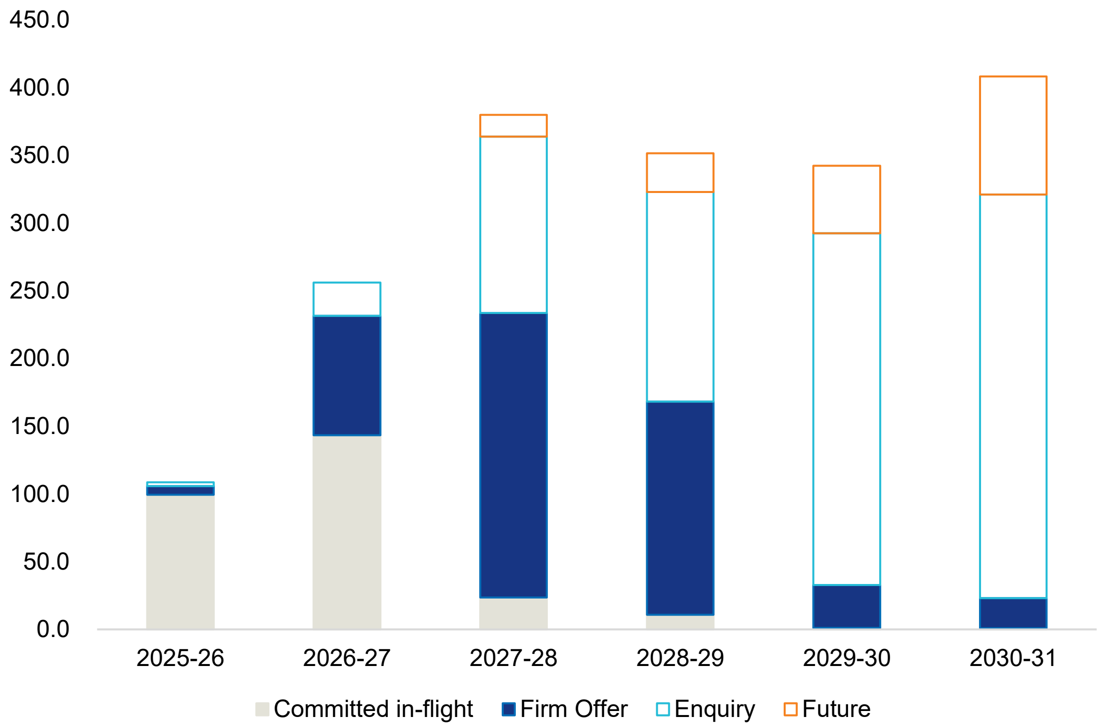


Table 2.2 compares our revised regulatory proposal forecast relative to the AER's draft decision and the current forecast. We note for:

- **In-flight projects** – we have adopted the AER's approach of including projects with a CWA. Our forecast is higher than the AER's draft decision as more projects have proceeded to a CWA since our initial regulatory proposal in January.
- **Enquiry to offer** – rather than apply the AER's approach of a 50% weighting, we have included those with a firm offer (those that are close to signing a CWA) and excluded all others.
- **Future projects** – although we have refined our forecasting methodology (reducing the forecast from $315M in our initial regulatory proposal to $182M) we have not included this expenditure in our revised regulatory proposal.

We provide further details below.

Table 2.2: Data centre connections capex ($2026, millions)

		Draft decision	Current forecast	Revised regulatory proposal
Gross	In-flight	66.0	184.7	184.7
	Firm offer	147.0	524.7	524.7
	Enquiry	N/A	867.4	-
	Future	-	181.6	-
	Sub-total	**213.0**	**1,758.5**	**709.5**
Capital contributions	In-flight	48.1	128.0	128.0
	Firm offer	114.3	397.4	397.4
	Enquiry	-	676.3	-
	Future	-	141.6	-
	Sub-total	**162.5**	**1,343.3**	**525.4**
Net	In-flight	17.9	56.8	56.8
	Firm offer	32.7	127.3	127.3
	Enquiry	-	191.1	-
	Future	-	40.0	-
	Total	**50.6**	**415.1**	**184.1**

Committed in-flight projects

The first category relates to connections where a CWA has been signed. The AER is satisfied that these projects are required[9] and considers that a signed CWA likely demonstrates that the costs are prudent and efficient.[10]

Consistent with our initial regulatory proposal and the AER's draft decision, we continue to include these projects in our revised regulatory proposal forecast. We provide copies of the CWA's in *JEN – RP – Support – DCxx – xx'location'xxxx – Signed Contract – date - Confidential* and project cost estimates in *JEN – RP - Support – Data Centre PEM Index – 20251201 - Confidential*.

Enquiry to offer projects

The second category includes connections where we have received an enquiry but have not yet signed a CWA. The AER accepted 50% of connections capex for projects in the enquiry to offer stage.

The AER reduced the forecast on the basis that the enquiries we received were 'highly speculative'. The AER considered that there was significant overlap and there was the potential that multiple enquiries related to the same data centre market opportunity.

The AER recommended that we prepare a forecast that weights projects based on the 'actual' probability of progressing to a CWA within the forecast period, with these weights supported by evidence of how often projects progress at their respective stages of maturity.

9 AER 2025, *Draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031,* p.31 Available here.

10 AER 2025, *Draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031,* p.31 Available here.

To address the AER's concerns we have divided these projects into two sets:

- **Firm offers** – Projects where we are in the final stages of finalising a CWA. These projects generally have a combination of a completed feasibility study, planning approval (or extensions of existing data centres), have secured land, and/or have been publicly announced. Our experience is that 100% of projects that reach this stage result in a signed CWA.
- **Enquiries** – All other projects in our pipeline. This includes a range of projects where we could have provided preliminary advice or are currently undertaking feasibility studies. Each of these applications are for distinct locations and specific customers, generally established data centre operators. Some are publicly announced, have planning permits, and are currently in the feasibility stage.

Our revised regulatory proposal includes all firm offers, but no capex related to enquiries. Our net capex forecast for this category is $127.3 million. This is about 40% of all projects in the overall enquiry to offer category ($318.4 million). We also consider that the forecast is materially below what would be produced if we probability weighted all connection enquiries in our pipeline.

Overall view

A summary of our data centre connection pipeline is provided in **Error! Reference source not found.**. This i ncludes the number of projects as well as the *connection capacity*. We note that connection capacity cannot be directly compared to *electricity consumption* or *maximum demand* forecasts, such as those prepared by Oxford Economics for AEMO or Baringa on behalf of the AER. Connection capacity refers to the capacity of the connection assets, while maximum demand forecasts take into account factors such as ramp-up and are materially lower.

Table 2–3: Connection pipeline by connection capacity and project number

	In flight	Firm offer	Enquiry
Projects	10	6	16
Connection capacity (MW)	1,393	1,200	3,079

We can confirm that each of these projects are unique and not duplicates[11] as each connection relates to a specific customer and location.

In flight connections – i.e. those with signed CWAs – amount to 1,393MW, is significant when compared to the total rated capacity installed in the whole of Sydney (1,820 MW) and Melbourne (930 MW) over the last 10 years.[12]

This highlights that the data centre investment is real, is a material uplift on historical trends and data centre investment is concentrated in our network area. As we outlined in our initial regulatory proposal, this is because data centre investment is spatially concentrated generally and focused in network areas due to factors such as proximity to population centres and other data centres, land prices and availability.[13]

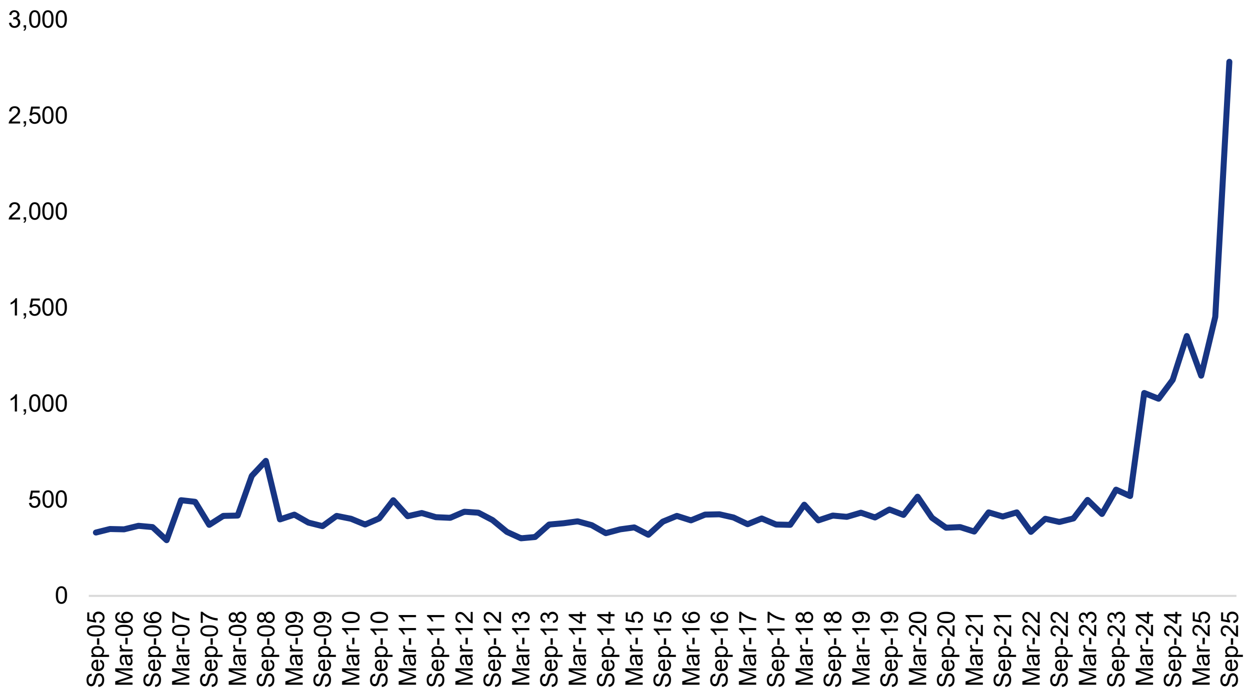
What we are observing is also appearing in national statistics. As shown in Figure 2–2, Australian investment in information media and telecommunications equipment has been historically flat at about $500 million up until December 2023. Investment surged to $1 billion in March 2024 then most recently to $2.8 billion in September 2025.

[11] Duplicates—where customers seek connection offers from multiple network providers for a single purpose—should not be confused with requirements for redundancy where a customer may seek offers for multiple connections, and possibly at multiple sites.

[12] Oxford Economics 2025, *Data Centre Energy Demand, Final Report,* p.8 .Available here.

[13] Attachment 5.01 Capital Expenditure, p.26 Available here.

Figure 2–2: Information media and telecommunications equipment ($million, chain volume measure, $2023-24)



Source: ABS, Private New Capital Expenditure and Expected Expenditure, Australia, September 2025

As requested by the AER we provide full transparency on all firm and enquiry data centre connection offers received. This includes:

- Information outlining why we have allocated each data centre project to either firm offer of enquiry (as well as details such as connection capacity, customer names, locations, etc.) in *JEN – RP – Support – Data Centre Projects Justification EDPR 2026-31-20251201 – Confidential*
- Unsigned CWA's in *JEN – RP – Support – DCxx – xx'location'xxxx – Signed Contract – date - Confidential*
- Cost estimates in *JEN – RP Support – Data Centre PEM Index – 20251201 – Confidential.*

Future

The last category is for connections that we anticipate but have not yet received a connection application. Our initial forecast was based on a top-down forecast derived from connection enquiry data.

The AER found that our analysis was difficult to replicate and invited us to refine our model in our revised regulatory proposal. The AER acknowledged that there could be data centres constructed towards the latter years of the forecast period where direct evidence is not currently available. The AER did not include any future data centre connection capex in its draft decision.

We expect that data centres will continue to seek connections in our network area for two reasons:

1. At a broader level, data centre capacity is expected to continue to grow, as evidenced by the variety of forecasts[14] and more recently by Oxford Economics' forecast for AEMO.[15]

[14] Including McKinsey, Jeffries, Citigroup, Goldman Sachs, Mandala, the International Energy Agency (IEA), CBRE. Jemena 2025, 2026-31 Electricity Distribution Price Review Regulatory proposal, Attachment 5.01 Capital expenditure, p. 26 Available here.

[15] Oxford Economics 2025, *Data Centre Energy Demand,* Available here.

2. The underpinning drivers of data centre investment in our area – that data centres are spatially concentrated and built in geographic clusters close to population centres with favourable land prices and available – sis not expected to change.

As the local distribution network service provider, we have a unique perspective. We see and engage with connection applications directly and in turn have greater local knowledge than any other organisation – as data centre developers operate in a competitive market and their projects are not always public. Accordingly, we have not sought to engage an independent forecaster as suggested by the AER.

Since our initial regulatory proposal, we revisited our forecast and corrected an error (which we understand is why the AER couldn't replicate our analysis). Nevertheless, given the AER's concerns we have not included our future forecast as part of our revised regulatory proposal.

Capex model

We note that our revised proposal capex model includes all data centre projects in our pipeline. All data centre projects with capex in the 2026-31 regulatory control period (next regulatory period) are categorised as an Inflight, Firm offer or Enquiry connection project – see column I of *Input* | *JEN Mapping.* We have included this information to provide complete transparency to the AER.

While all projects are included in the capex model, the expenditure for these projects do not flow into forecast capex. Only the projects marked to be included in column K of *Input* | *JEN Mapping* are included in forecast capex. This takes effect through the modifications to formulas in columns X to AB in table 48 of sheet *Calc* | *Project Costs.*

We also note that as requested by the AER we have separately identified concrete poles in our capex model following the same approach as outlined in our response to the AER's information request.[16] This has been reflected in the projects *Concrete poles - replacements* and *Concrete poles – connections* with unique IDs *Other 1 and Other 2* respectively. These are not new projects. We have accepted the AER Draft Decision *Concrete poles* capital expenditure forecast. To facilitate the draft decision forecast values, projects in the capex model from the 'Subtransmission' and 'Distribution system assets' asset classes have been proportionally reduced to reallocate capex to the *Concrete poles* projects noted above. This is not additional capital expenditure. This change was made to apply different asset lives in the PTRM.

Overheads and risk

Lastly, we note the AER's concerns regarding overheads and risk. In preparing this revised regulatory proposal we have ensured that the data centre cost inputs in the capex model do not include overheads or a risk allowance.

2.2 References

The revised connections capital expenditure outlined in this section is supported by a body of materials outlined in Table 2.4.

Table 2.4: List of the attachments supporting our forecast connections expenditure

Name	Author
JEN – RP - Support – Data Centre PEM Index – 20251201 - Confidential	JEN
JEN – RP – Support – Data Centre Projects Justification EDPR 2026-31-20251201 – Confidential	JEN
JEN – RP – Support – DCxx – xx'location'xxxx – Signed Contract – date - Confidential	JEN
JEN – RP – Support – DCxx – xx'location'xxxx – Draft/Issued CWA – date - Confidential	JEN

16 AER 2025, *Draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031,* p.19 Available here. For the basis of the Draft Decision *concrete poles* forecast, see also Jemena, *Response to AER information request #036, 2 July 2025*, pp. 14–16.

3. Demand driven augmentation

Our initial regulatory proposal was primarily focused on addressing network constraints driven by new housing – generally greenfield in the north and north-west as well as infill in our central areas. We also included projects to address constraints driven by data centres as well as those on our low-voltage network.

The AER did not accept our forecast and made a placeholder decision to reduce our program to align with historical trends. We identify two main findings in the AER's draft decision (and supporting consultant reports):

- **Our economic and engineering analysis as well as cost estimates (where reviewed) are reasonable**. The AER's technical reviewer, EMCa, considered a sample of projects (but not the underpinning demand forecast) and found that the identified need, timing and cost estimates reasonable.[17] The AER did not raise any issues or concerns with our engineering or economic analysis.

- **The AER had concerns with our demand forecast.** The AER considered that we had not provided compelling evidence of an uplift in demand, although it recognised that maximum demand on our network would increase.[18]

While the AER did not accept our demand forecast, it did accept the forecast Blunomy prepared for CitiPower, Powercor and United Energy (CPU). We also relied on a demand forecast prepared by Blunomy, who applied a similar (if not identical) forecasting approach. Unlike CPU, we combined this forecast with our internal bottom-up forecast. The AER, and their consultants Baringa, were concerned about the transparency of this approach.

The AER, and Baringa, were also concerned about how we included large data centre connections in our peak demand forecast.

To address the AER's feedback we:[19]

1. Moved to entirely rely on the Blunomy forecast, consistent with the approach adopted by CPU and accepted by the AER. We no longer prepare an internal bottom-up forecast or undertake any reconciliations or adjustments – the primary issue raised with our demand forecast.

2. Removed all data centre loads from the peak demand forecast that are used to drive our augmentation program.[20] We are no longer proposing augmentation related to data centres or associated contingent projects. We instead include augmentation required to support data centres as part of our connections forecast, and only include projects required to support inflight or firm connections.

After we made these changes, we re-evaluated our augmentation program. Other than the removing projects driven by data centres,[21] we found that there was no material change in our augmentation program.

The changes we have made to our demand forecast entirely address the AER's concerns as we now apply a methodology that the AER considers produces a realistic expectation of demand.[22]

As updating our demand forecast does not materially change our augmentation forecast, EMCa's findings – that the economic and engineering analysis which developed the program is reasonable – continue to hold. The AER raised no other concerns or issues with our proposed program.

[17] EMCa also considered that our risk assessment reasonable, the range of options identified reasonable, that we selected the appropriate/prudent solution, the= scope of works sufficiently detailed. EMCa made some changes to our analysis (and requested additional sensitivities) around project timing but found that these changes do not have a material impact on our forecast (and in some cases moved projects forward).

[18] AER 2025, *Draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031,* p.36 Available here.

[19] A full list of how we have considered the feedback provided by Baringa is provided in Appendix B.

[20] For the demand forecast which underpins our augmentation forecast. In-flight and firm offer data centre connections (and any associated augmentation) are included in our connections forecast. Our energy forecast is aligned to, and consistent with, our connections forecast.

[21] Projects included in our major customer network development strategy.

[22] As evidenced by the AER's acceptance of the demand forecasting methodology applied by CPU.

Given the customer consequences of underinvestment in augmentation, we asked Endgame Analytics to produce an alternative forecast. Overall, the forecast is similar but there are differences at the spatial level. Applying the Endgame Analytics' demand forecast results in an augmentation forecast $17 million higher than what we are proposing. This suggest that not only is our forecast reasonable but potentially understates our augmentation requirements.

The potential for our forecast to understate augmentation requirement is also highlighted by comparing Blunomy's forecast of demand growth in our network relative to what AEMO is forecasting for Victoria as a whole. Blunomy is forecasting materially lower demand growth than what AEMO expects in its Step Change and Accelerated Transition scenarios.

This risk is asymmetric. If demand is materially lower than what we expect our proposed program remains the most economic approach. This is shown by our sensitivity analysis which considers the potential for customer benefits (an indication of lower demand given the link with unserved energy) to be 10% lower than expected. This results in no change to the preferred option in all network development strategies. This outcome is consistent with EMCa's analysis of constrained feeder SBY-031. EMCa tested the impact of using a POE50 forecast and found that this has no impact on preferred timing.[23] Similarly, EMCa found that the value of customer reliability would need to be reduced by 25% to change the project timing.[24]

The robustness of our program and the insensitivity to material reductions in demand mean that even if the AER does have residual concerns with our demand forecast (despite adopting a methodology it has previously accepted) these concerns are unlikely to result in any changes to the augmentation forecast.

While we are proposing an uplift in augmentation relative to prior period spend, the need for an increase is not surprising given our history of constrained investment, the material increase in demand we and AEMO are forecasting, the need to support an increase in housing supply and our network's high levels of utilisation. Even with our proposed augmentation program, utilisation will continue to rise. This is consistent with our approach to "use more before building more".

Although we model the customer impacts of insufficient capacity as 'unserved energy'; the practical implications of the AER's proposed augmentation program will be an inability to support the increasing housing supply in our network area. If our network backbone is not reinforced and insufficient to support housing growth, this risks delays to connections until capacity is available. This is an outcome that is not in the long term interests of customers or the wider community.

For our revised regulatory proposal, we have removed all augmentation projects related to data centres but otherwise retained all elements of our initial proposal augmentation forecast. This includes our expenditure for our low voltage and distribution substation augmentation – which the AER reduced but did not raise any issues within its draft decision. A comparison between our initial regulatory proposal, the AER's draft decision and our revised regulatory proposal is shown in Table 3.1 below.

23 We applied this test to all of our network development strategies and found that this did not change the projects required in the 2026-31 period.

24 EMCa 2025, *Review of* aspects *of proposed network related expenditures,* p.67. Available here.

Table 3.1: Load driven augmentation capex ($2026, millions)

		Initial regulatory proposal	Draft decision	Revised regulatory proposal
Network Development Strategies	Northwestern growth corridor	29.5	17.6	29.6
	Northern growth corridor	38.8	23.1	38.8
	11kV central area	27.3	16.2	27.3
	22kV central area	14.4	8.6	14.5
	Major customer (sub-transmission)	19.2	11.4	-
Other	Fairfield	2.1	1.2	2.1
	Low voltage circuit and distribution substation	31.6	18.9	31.6
	Total	**162.9**	**97.1**	**143.9**

3.1 We have responded to the AER's concerns

The AER found that our forecast was opaque, difficult to replicate and not well evidenced. The AER considered that the issues were systematic and that in turn it did not have a reasonable basis to accept our demand forecast or to construct a more robust forecast. The AER did not form its own view of what a realistic expectation of demand would be – a key element of the capital expenditure criteria[25] – but set a placeholder forecast and encouraged us to address the concerns raised by Baringa.

Baringa's concerns related to the transparency of our forecasting approach, the lack of clarity around how we reconciled the Blunomy forecast and our own bottom-up forecast, that we did not model CER uptake at the spatial level, that Blunomy's methodology in some areas were unclear, and that our approach to forecasting data centre block loads lacks strong reasoning, is subjective and difficult to reproduce.

We have considered the feedback provided and have:

3. **Improved the transparency around our proposal** – by simplifying our forecasting approach and updating our demand forecast documentation. We provide further details on our own approach[26] and have asked Blunomy to update its documentation to provide the additional detail requested.[27] We also asked Endgame Analytics to review our revised approach. We note Endgame Analytics considered that our demand forecasting method "*..is sophisticated; however, it is neither unnecessarily complex nor difficult to understand.*"[28]

4. **Changed our methodology and no longer undertake bottom-up and-top down reconciliation** – We now solely rely on Blunomy's spatial and system level forecasts. This brings us into line with the approach adopted by CPU, removes the need to any reconciliation adjustment (which drove the majority of the concerns related to transparency) and ensures that CER is modelled spatially.

5. **Removed data centre loads** – We have removed all data centre loads (and other uncommitted large customer connections) from our demand forecast. As a result, we are no longer forecasting any augmentation expenditure related to our large customer network development strategy. No other network development strategy included data centre loads.

1. We reevaluated our augmentation forecast using the updated forecast and found that this made no material difference. The change resulted in three projects needing to commence in the 2026-31 period[29] and one project

25 NER. Cl. 6.5.7(c)(1)(iii).

26 See JEN - RP - Support - Short form demand forecast methodology - 20251201 – Public.

27 See JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 – Confidential.

28 See JEN – Endgame Analytics – RP – Support - Demand forecasting review report – Public p.16.

29 Augment section of NH0-002 ($0.06M), Augment feeder NS-18 ($0.8M), and Augment feeder NS-17($0.1M).

moving back.[30] As the net change was less than $50k we considered the overall change immaterial and have not updated our forecast.

2. Appendix B provides a detailed summary of all the changes made to address all of the concerns raised by Baringa.

3.2 Relative to AEMO's 2025 ESOO our forecast is conservative

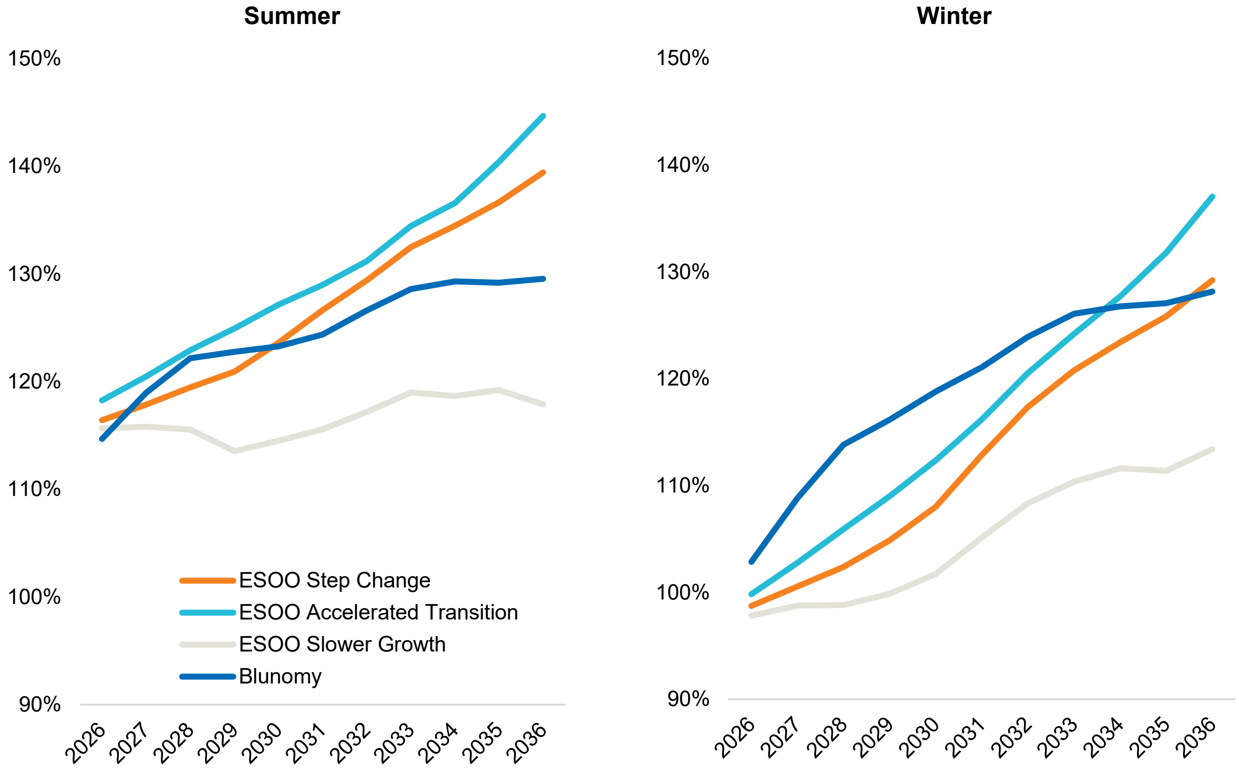
We have compared the 2025 Blunomy forecast for our network against AEMO's 2025 Electricity Statement of Opportunities (ESOO) forecast for Victoria as a reasonableness check. This comparison is shown in Figure 3-1 below.

We present the forecasts as percentage differences to 2024 summer peak demand to:

- Compare forecast increases on a consistent basis (given that AEMO's forecast is for the whole of Victorian and Blunomy's forecast is for our network).
- Show the relativities between winter and summer demand. With the electrification of gas it is possible that our network will shift from a summer to a winter peaking.

AEMO's forecasts are also valuable as a cross check given the multiple scenarios produced to identify over and under-investments risks. We present AEMO's Step Change, Accelerated Transition and Slower Growth scenarios which are the three most likely scenarios. AEMO applies a weighting of 46% for the Step Change scenario and 27% for the Slower Growth and Accelerated Transition scenarios.[31]

Figure 3-1: Comparison of Blunomy's forecast versus AEMO's 2025 ESOO (POE10, MW)



[30] New Feeder FT0-012 ($1M).

[31] AEMO 2025, *2026 ISP Scenario Weighting,* Available here.

Overall, the comparison shows that Blunomy is forecasting a materially lower summer peak demand growth than AEMO in both the Step Change and Accelerated Transition scenarios. The gap is 2.3% - 4.6% percentage points by the end of the next regulatory period and 9.9 -15% by the end of the next 2031-36 regulatory period.

We note that AEMO is also forecasting a slower growth scenario. However, given that our demand growth is largely driven by greenfield and infill development, and that societal and government focus on improving housing supply, we consider that this scenario is particularly unlikely for our network.[32]

This indicates that there is unlikely to be any systemic upward bias in Blunomy's demand forecast and there is a material risk that our forecast understates forecast demand.

We note that in winter Blunomy is forecasting higher peak demand growth than AEMO is forecasting for the whole of Victoria in the Step Change scenario. However, currently, winter peak demand growth is not a material driver of our augmentation forecast.

3.3 Alternative forecast cross check

Given the AER's concerns with our demand forecast, and the criticality of our augmentation forecast, we commissioned an alternative forecast by Endgame Analytics as a cross check to the Blunomy forecast.

Endgame Analytics applied a component-based framework which – given the AER's feedback to date – focused on simplicity, explainability and reproducibility. The forecast spatially allocated CER and did not include any large industrial loads. An overview of the methodology applied is available in attachment *JEN – RP – Support - Endgame Analytics – Alternative demand forecast report.*

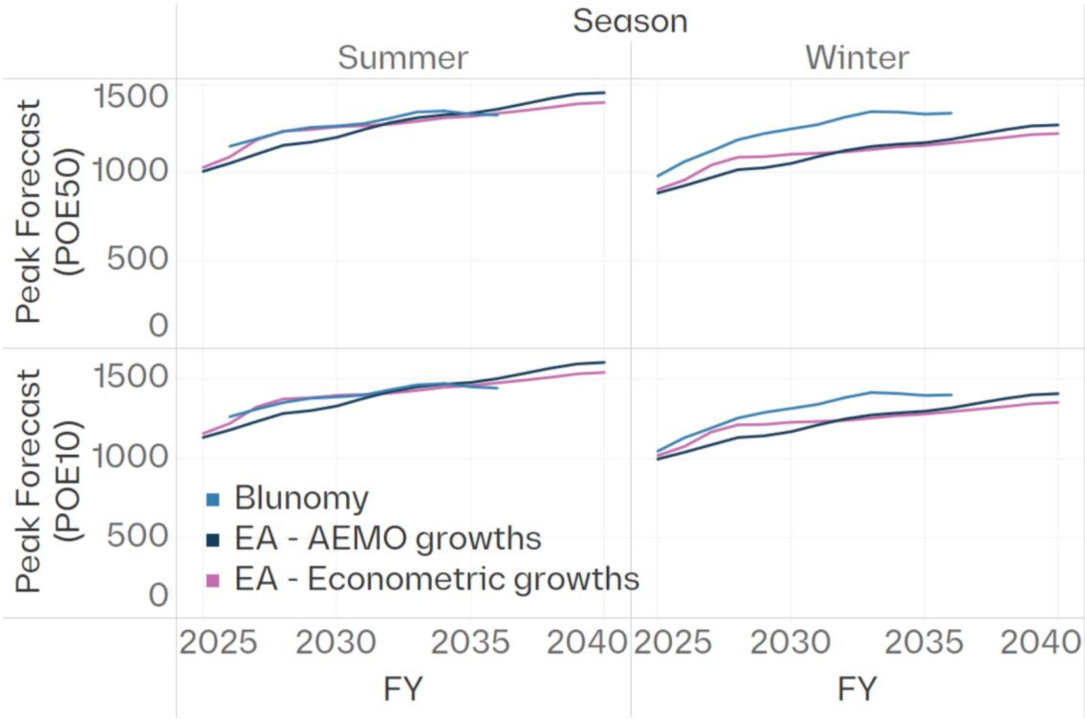
Although a different methodology was applied, Endgame Analytics' summer forecast at the system level is close to those prepared by Blunomy. The results at the system level are shown in Figure 3-2 below.

As with the comparison to AEMO, Blunomy's winter forecast is higher than Endgame Analytics' forecast. Endgame Analytics' suggests that this is due to differences in how the electrification of how water and cooking is estimated. This is not to suggest that Blunomy's approach is incorrect, just that different assumptions result in different results. Regardless, this difference has no impact on our augmentation forecast as it is driven by summer not winter demand.[33]

32 As covered further in section 3.6.

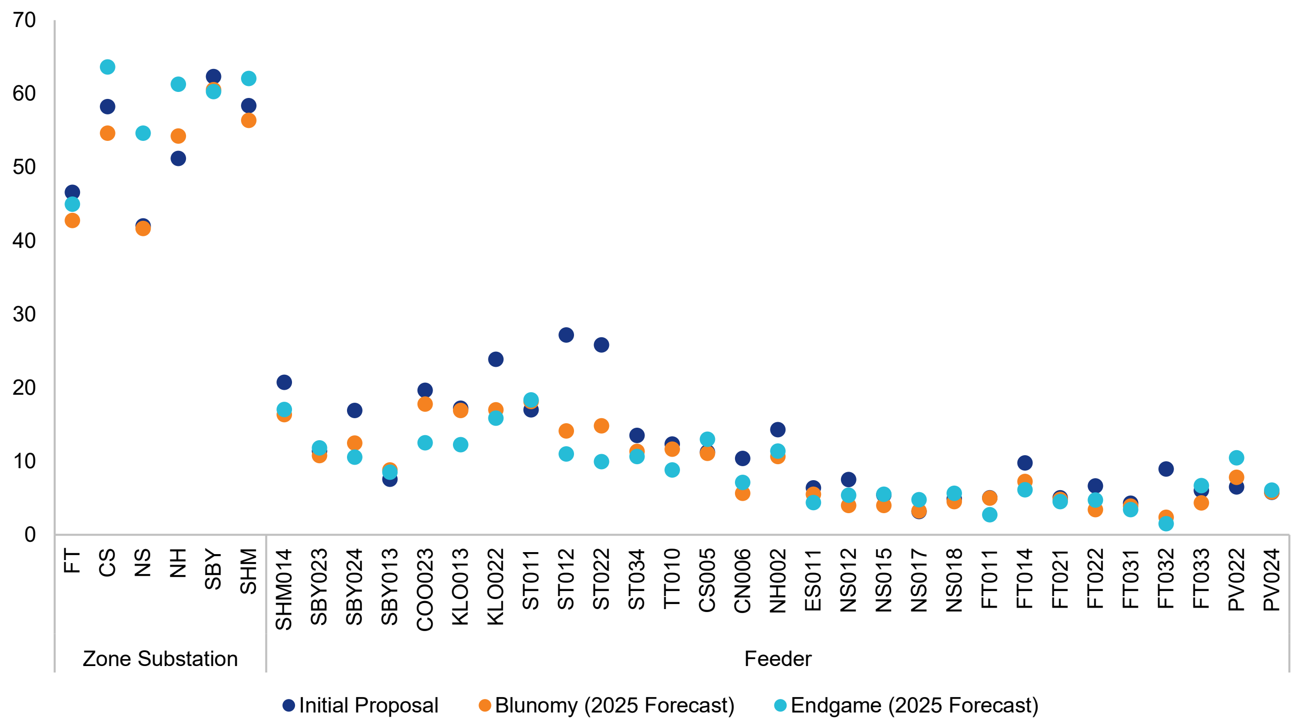
33 And our asset ratings are also higher providing some additional capacity.

Figure 3-2 Comparison of system peak demand forecast by source, season and POE (MW)



While the forecasts are similar at the system level, our augmentation requirements are based on a spatial view of demand. The difference in load forecasts is shown in Figure 3-3 below. Broadly, Endgame Analytics forecasts higher demand for our Zone Substations but lower demand for feeders.

Figure 3-3 Maximum demand constrained zone substations and feeders (50POE, 2031, Summer) MVA



We identified the impact of applying the alternative Endgame Analytics' demand forecast on our augmentation program. This resulted in some changes to the optimal timing of some projects as outlined in Table 3.2 below. For completeness we show the timing included in our initial proposal, the current view based on Blunomy's 2025 forecast and the result of Endgame Analytics forecast.

We shaded rows grey where a project can be deferred to the 2031-36 period and orange where a project is required to be moved forward.

If we relied instead on the Endgame Analytics forecast, we would defer 4 projects with a total value of $17.7M. However, we would also need to move forward 4 projects with a total value of $34.7M. Overall, applying Endgame Analytic's demand forecast results in a $17M higher augmentation forecast.

Table 3.2: Changes in augmentation capex from demand forecast updates[34]

Network Development Strategy	Project	2026-31 Capex[35]	Initial Proposal	Current view	Endgame
North Western Growth Area	New feeder SHM-013	$4.1M	2026	2026	2027
	Reconfigure and augment steel section - SBY24	$1.1M	2029	2029	2030
	Install Regulator - SBY23	$0.3M	2030	2030	2031
	New feeder SBY-022	$2.5M	2026	2027	2027
	New feeder SBY-014	$5.2M	2026	2026	2027
	New feeder SBY-015	$3.8M	2027	2027	2036
	3rd 66/22 kV transformer at SHM	~$10M	2033	2035	2027
	New feeders SHM31 and SHM32	~$12M	2033	2035	2027
Northern growth corridor	Coolaroo No.1 bus cable transfers	$3.9M	2027	2027	2028
	Augment feeder BD0-008	$1.7M	2026	2028	2033
11kV Central Area	3rd Transformer and 66kV Works at FT	$8.7M	2029	2029	2036
	Augment BTS-NS 22kV Loop	$2.2M	2028	2028	2027
	Augment feeder NS-18	$0.9M	2031	2030	2027
	Augment feeder NS-17	$0.1M	2030	2027	2027
	Augment feeder FT21	$0.4M	2029	2028	2028
	Offload feeder FT0-011	$0.1M	2029	2028	2036
	New feeder ES0-031	$3.5M	2026	2027	2036
	Augment feeder PV 24	~$0.8M	2034	2032	2027
22kV Central	Augment CS	~11.4M	2036	2036	2028
	Augment section of NH0-002	$1M	2030	2030	2031
	Augment feeder TT0-011	$1.6M	2028	2028	2031

34 Noting we only list projects where the timing has changed.

35 Escalated, $2026 Real for the projects included in our capex forecast. Where projects are not included we have applied the rounded $2024 estimate set out in our Network Development Strategies.

3.4 Our augmentation forecast is robust to material changes in demand inputs

While we have addressed the AER's, and Baringa's concerns, with our demand forecasting methodology, we note that it does not automatically follow that any concerns with a demand forecast translate into concerns with our augmentation forecast.

What matters is whether any modifications to our demand forecast would change the consequence augmentation forecast.

As noted earlier, we have considered the impact of updating our demand forecast to address the AER's concerns and found it does not result in a material change. We also considered the impact of applying Endgame Analytics forecast and found that this would *increase* our augmentation forecast.

These results are not surprising given the relatively high amounts of unserved energy that is at risk if we do not address capacity constraints across our network. The customer cost of this unserved energy, applying the AER's 2024 valuation of the value of customer reliability (VCR), comes to about $1.1 billion – about 9 times higher than the cost of the augmentation program. This is shown in Table 3.3.

Table 3.3: Present value of costs and benefits (preferred option) - present value terms

	Capital and operating costs	Customer value of unserved energy	NPV
Northwestern growth corridor	30.5	167.0	136.5
Northern growth corridor	53.4	736.5	683.1
11kV central area	20.1	112.2	92.1
22kV central area	17.2	98.1	80.9
Total	**121.2**	**1,113.8**	**992.6**

We also tested our augmentation approach across a range of sensitivities in each case our preferred option does not change – indicating that our investment program is robust. In particular, we note that customer benefits 10% lower sensitivity. This case provides an indication of the outcome if demand is materially lower than forecast. This is shown in Table 3.4.

The results are robust for two reasons. First, the relatively large amount of unserved energy our augmentation avoids. Second, our preferred option is generally the lowest cost technically feasible option available.

Table 3.4: Ranking of preferred option by sensitivity test

	Baseline	Customer Benefit 10% Lower	Customer Benefit 10% Higher	Discount Rate 1% Higher	Discount Rate 1% Lower	Capital Costs 30% Higher	Capital Costs 30% Lower
Northwestern growth corridor	1	1	1	1	1	1	1
Northern growth corridor	1	1	1	1	1	1	1
11kV central area	1	1	1	1	1	1	1
22kV central area	1	1	1	1	1	1	1

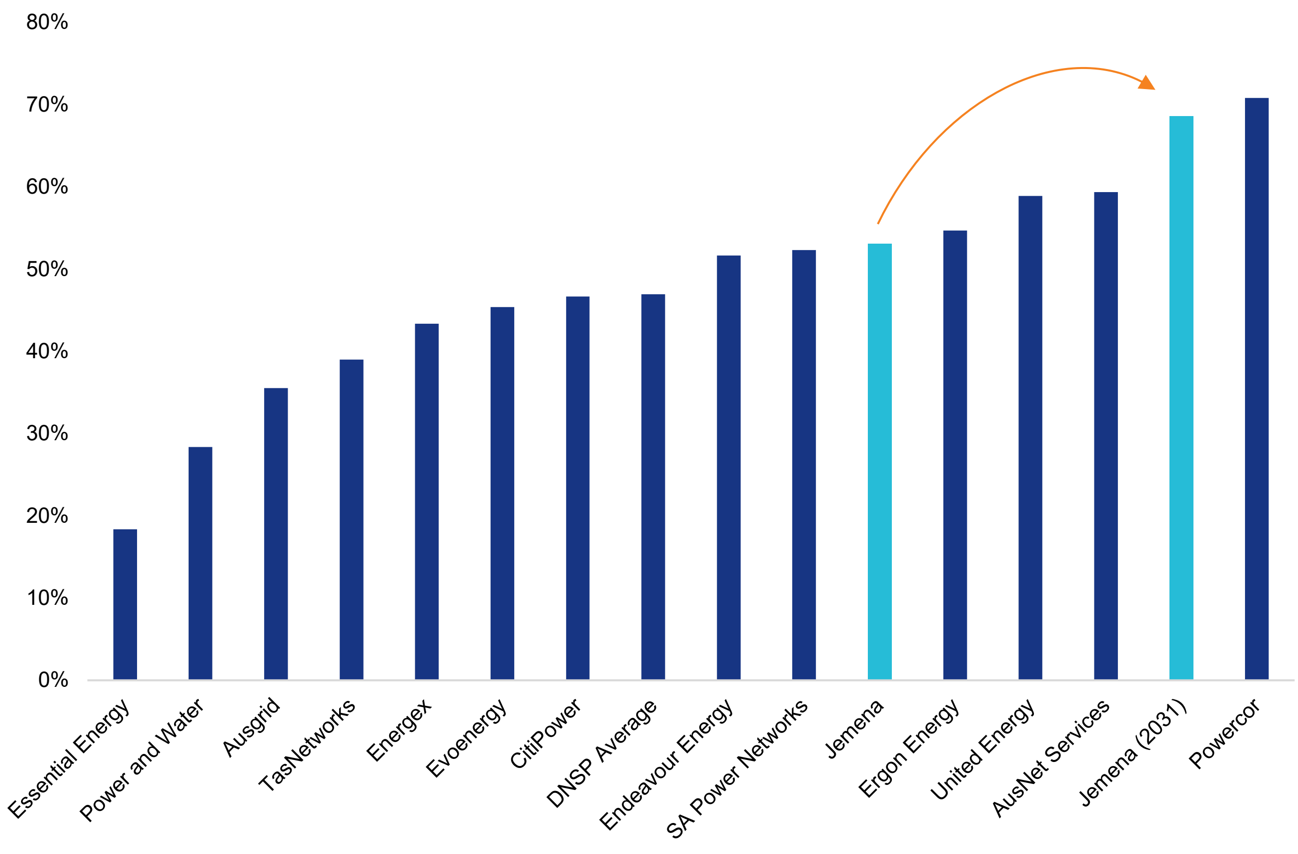
3.5 We are using more before building more

We are planning to use more before we build more. We are only augmenting our network to address spatially concentrated greenfield and infill development within our network area (where utilisation is particularly high).

We are planning to accommodate increased load from electrification, such as increased electric vehicle charging and electrification of gas, with almost no impact on our high-voltage augmentation program. Under our proposed augmentation forecast, we will bear the very real risk (as shown by AEMO's forecast by scenario) of higher than expected, or more spatially concentrated peak demand growth.

Our track record of making the most out of existing assets is demonstrated by Figure 3-4 which shows that our network currently has one of the highest levels of utilisation. Not only is our utilisation high, but it is increasing. Utilisation recently increased from 52.0% in 2022 to 53.1% in 2023, which is consistent with our forecast where we expect utilisation to grow – even taking into account our proposed augmentation program – to 68.6% in 2031.

Figure 3-4 Zone Substation level utilisation by distribution network service provider[36]



[36] Data based on 2024 utilisation as reported in the AER's 2025 electricity distribution network operational performance data. Jemena (2031) reflects our forecast utilisation in 2030-31.

3.6 Risks to customers from a low augmentation forecast

While we have focused on the AER's technical concerns with our demand forecast, it is important not to lose sight of the tangible customer impacts that under-investment in augmentation spend may cause.

Capacity constraints from insufficient augmentation risk more frequent and longer outages. It also risks delays to connections (which may need to wait until sufficient capacity is installed and available) risking economic development and housing supply in our network area.

We note that our program is largely driven by greenfield and infill development. This is illustrated by the forecast housing growth in our network area, both in the next regulatory period *as well as* the following 2031-36 regulatory period, as shown in Table 3.5.

Table 3.5: Victorian in Future (VIF) population projections by area of our network

Network Development Strategy	Main growth areas	2026-31 Capex ($M)	2026-31	2026-36
North-Western growth corridor	Sunbury, Plumpton, Diggers Rest	29.6	25,000	52,000
Northern growth corridor	Mickleham, Craigieburn, Greenvale /Yuroke	38.8	25,000	48,000
11kV central area	Moonee Ponds, Glenroy, Kensington	27.3	12,000	25,000
22kV central area	Coburg, Heidelberg, Reservoir	14.5	18,000	36,000
Total		**110.2**	**80,000**	**161,000**

If we do not undertake augmentation when required – which is a material risk if the AER's draft decision augmentation forecast – our network would not have sufficient capacity to support the increasing housing supply. In this scenario, to avoid widespread outages, we may need to delay new connections until capacity is available.

Underinvestment in augmentation would come at a large customer cost in terms of reducing housing supply. This is counter to clear community and government preferences. Housing affordability is one of the most important issues facing Australians – as shown by recent surveys undertaken by SEC Newgate and JWS Research[37] and the focus of Commonwealth and Victorian Government policy, such as the National Housing Accord and Victoria's housing statement.[38]

We note the link between cost-of-living concerns and housing affordability, as highlighted by ABC vote compass.[39] This highlights that reducing our augmentation spend risks restricting housing supply and in turn housing affordability.

We recognise that the AER's concerns relate to our initial regulatory proposal demand forecast, rather than the need for augmentation. However, we encourage the AER to consider the strong community sentiment and government policy which is driving structural changes in the housing market and increased housing supply (and in turn our augmentation requirements) when it forms a view on what is a realistic expectation of demand.[40] Our role in facilitating increased housing supply was raised in our initial regulatory proposal but did not appear to be considered by the AER (or its consultant Baringa) in its draft decision on our augmentation program.

37 See here, here and here.

38 See here and here.

39 See here.

40 Notably required by Rule 6.12.1(c)(2) and 6.5.7(c)(1)(iii).

3.7 References

The revised load driven augmentation capital expenditure forecast is supported by the materials outlined in Table 3.6.

Table 3.6: List of the attachments supporting our forecast demand driven augmentation expenditure

Name	Author
JEN – RP – Support - Short form demand forecast methodology - 20251201 - Public	JEN
JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 - Confidential	Blunomy
JEN - RP - Support - 2025 demand forecast breakdown – 20251119 - Confidential	JEN / Blunomy
JEN - Endgame Analytics - RP - Support - Alternative demand forecast – Confidential	Endgame Analytics
JEN – Endgame Analytics - RP – Support – Alternative demand forecast report – Public	Endgame Analytics
JEN – Endgame Analytics - RP – Support - Demand forecasting review report – Public	Endgame Analytics

4. Non-demand driven augmentation

Although the AER found the majority of our non-demand driven augmentation program prudent and efficient,[41] the AER:

- Did not accept our project to alleviate capacity constraints on our operational technology communication network and ensure that our pole top devices can continue to be remotely operated.
- Reduced our proposed innovation expenditure to $1.7m.

Table 4.1: Non-demand driven augmentation capex ($2026, millions)

Project	Initial regulatory proposal	Draft decision	Revised regulatory proposal
Preston and East Preston	46.0	45.3	46.1
Operational technology – communications network	8.8	0.0	8.8
Voltage and power quality	40.5	0.0	26.1
Innovation	4.4	1.6	3.4
Grid stability and flexible services	5.2	5.0	5.2
Resilience	1.8	1.1	1.8
Total	**$106.7**	**$53.0**	**$91.4**

Small differences between the initial regulatory proposal, the draft decision and our revised regulatory proposal due to updated real escalation.

We have considered the AER's draft decision. In this revised regulatory proposal, we:

- Retained our operational technology communication network projected. Our reasoning is provided below.
- Refined our innovation program. Further detail on this element of our proposed is set out in attachment *JEN – Att 03 – 02 – Innovation Fund – 20251201 – Public*

4.1 Operational technology communication network

Our operational technology communication network supports the operation of remote controllable pole top field devices, such as Automatic Circuit Reclosers and Remove Controllable Gas switches and in turn plays a critical role in ensuring the safe, reliable and efficient operation of our network. The installation of additional remote controllable devices has led to capacity constraints and, in turn, communication failures.

We proposed to undertake a project to address these capacity constraints and in turn ensure that pole top field devices can be remotely operated. Without this project we will not always be able to remotely detect, diagnose and resolve network issues to reduce reliably and safety risks.

The AER acknowledged this is a valid need and that this project could be prudent,[42] but decided to only include a placeholder of $0m due to three concerns around our economic analysis. Specifically, the AER was concerned that a potentially lower VCR figure with lower event probabilities would lead to the base case (status quo) being the preferred option.

[41] The bulk of non-demand augmentation relating to our program of works to convert our Preston and East Preston distribution networks from 6.6kV to 22kV. See AER 2025, *Draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031* p.38. Available here.

[42] See AER 2025, *Draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031* p.38. Available here.

Derivation of VCR figures

The first concern relates to how the Value of Customer Reliability (VCR) was derived.[43] In reviewing the AER's feedback we acknowledge that it was not clear how the value we used has been calculated as it cannot be easily traced to the AER's 2023 update of VCR values.

The value applied could not be directly traced back as we calculated a weighted average of the VCR values based on the customer segments our network serves. To show this missing link, we provide our calculations in *JEN – RP – Support – Operational Technology Communications Network Upgrade – CBA Model – 20251201*.

We also note EMCa's concerns with our calculation of the avoided cost at asset failure. Given this value was immaterial in this business case we have removed this element from our economic analysis.

Application of the 2024 VCR figures

The AER also considered we should update our VCR figures to use the results of the AER's final report on the 2024 Values of Customer Reliability. As we noted in our regulatory proposal,[44] the latest figures were published on 18 December 2024 too late to be integrated into our regulatory proposal which was required to be submitted on 31 January 2025.

As requested by the AER we have updated our analysis to incorporate the latest VCR values. As expected, making this change increases the economic value of our preferred option.

Probability of adverse events

The last concern of the AER related to the probability of an adverse event: where a communication capacity constraint impedes the remote operation of pole top field devices and leads to a longer than necessary supply outage.

In our initial regulatory proposal, our cost benefit analysis was considered the number, probability and cost of an event to determine the annual economic cost (risk) as shown in Table 4.2. The AER did not raise any concerns with the cost of the event.[45]

Table 4.2: Original assumptions

Option	Number	Probability	Cost	Annual risk cost
Do nothing (base case)	1	100%	$1.7m	$1.7m
Upgrade as standalone project (proactive approach) - preferred	1	20%	$1.7m	$0.4m
Opportunistic upgrade with other projects (reactive approach)	1	50%	$1.7m	$0.9m

The AER acknowledged the uncertainty regarding the probabilities of these kinds of events. However, it was concerned that our only source for the probability of an event was advice from our control room operators.[46] The AER indicated that we should provide further justification for our choice of event probabilities and/or sensitivity test our NPV analysis by using different probabilities.

Given the feedback provided by the AER, we increased the granularity of the cost benefit analysis by considering constraints at the access point level. We identified that SAIDI is materially higher in access point constrained

[43] See AER 2025, *Draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031* p.39. Available here.

[44] JEN 2025, *2026-31 Electricity Distribution Price Review Regulatory Proposal, Attachment 05-01 Capital expenditure,* p.45, footnote 107. Available here.

[45] Which was based on average maximum demand for a SBY feeder and the average outage duration.

[46] See AER 2025, *Draft decision, Jemena electricity distribution determination 1 July 2026 – 30 June 2031* p.39. Available here.

areas. Given that there are likely cofounders which also have an impact, we identified the relative degradation in SAIDI between FY22 and FY24 to conservatively estimate the impact of constrained access points on SAIDI.

Table 4.3: SAIDI - minutes per customer

	FY22	FY24	Difference
Network average	45.2	43.8	-1.3
Communication network constrained areas	55.5	54.4	-1.1
Difference	**10.3**	**10.5**	**0.2**

We then considered the following options:

1. Do nothing (base case) – where the current level of unserved energy is unchanged.
2. Upgrade as standalone project (proactive approach) – In this option we address all constrained access points by FY32.[47]
3. Opportunistic upgrade with other projects (reactive approach) – we excluded this option in this analysis and instead considered a more feasible alternative option 4.
4. Slower approach - In this option we address all constrained access points by FY36. This option replaced the Opportunistic upgrade with other projects (reactive approach) we initially considered. This option differs by nature, cost and benefits.

We assume that as each of the 47 constrained access points are addressed, we remove the FY22-FY24 degradation in SAIDI and bringing performance in constrained areas closer to historical networkwide average performance.

Updated economic analysis

The results of updating the VCR and the applying more granular assumptions around the customer benefits from alleviating access point constraints does not change the most economic option as shown in **Error! Reference source not found.**. Accordingly, we have retained this project in our revised regulatory proposal.

Table 4.: Operational technology communication network economic analysis (relative to base case) ($2023, million)

	Initial	Revised
1. Do nothing (base case)	-	-
2. Upgrade as standalone project (proactive approach) - preferred	**11.4**	**12.7**
3. Opportunistic upgrade with other projects (reactive approach)	3.7	N/A
4. Slower approach	N/A	7.1

We note that this project will not result in STPIS benefits as it will only deliver improvements which bring performance back in line with the historical averages used to set STPIS targets.

47 The program concludes in FY31 to we recognise the benefit in the following year.

4.2 Voltage and power quality

As part of our initial regulatory proposal, we proposed a Voltage & Power Quality Management Program originally aimed at facilitating additional solar exports while ensuring network voltage and power quality remain within a safe, compliant range.

The AER considered our program taking into account advice from EMCa. The AER, and EMCa were concerned that there appears to be little risk of non-compliance and considered that the net present value of the program was negative.

The AER recommended we consider a more targeted project to maintain voltage compliance restricted to areas with elevated over-voltage risk and limited to dynamic voltage control capabilities rather than the full suite of reactive and capacitor bank expenditure. The draft decision set a placeholder forecast of $0M.

We have considered the AER and EMCa's feedback as well as new information not available and not presented in our initial regulatory proposal. This includes the sharp performance degradation in over-voltage compliance since mid-2024 as well as an under-voltage event during the 2nd – 4th of February 2025. In particular we note that during the 2025 event:

- A total of 22,411 customers (or 5.95% of customers) experiencing steady-state voltages below 216V for more than 1% of the calendar week. These customers were dispersed across 1,115 different distribution substations and 29 different zone-substations supply areas, and

- 10,604 customers (or 2.8% of customers) experiencing extreme under-voltage below 207V. Their locations were spread across JEN's network - including 673 different distribution substations and 28 different zone substation supply areas.

Following an investigation of the root cause of this event we presented a plan to the Essential Services Commission to rectify this issue, by targeting the 'worst served' under-voltage areas by installing and upgrading transformers and low voltage circuits. Our voltage and power quality program has been updated to align with this rectification program.

We note that some of the rectification works will be implemented through the Low voltage circuit and distribution substation program included in demand-driven augmentation (and we have ensured no overlap or double counting). As detailed in section 3, while the AER reduced this program as part of its overall concerns with our demand forecast, we have addressed these concerns and retained this program in our revised regulatory proposal.

Full details of our re-evaluation of our Voltage & Power Quality Program is provided in *JEN – RP – Support – Voltage and PQ Management – Business Case – 20251201.* Overall, we found that expenditure is still required to maintain voltage in line with our compliance obligations.

Accordingly, in this revised regulatory proposal we are proposing a more limited program exclusively focused on maintaining our obligations to maintain network voltage.

4.3 References

The revised connections capital expenditure outlined in this section is supported by a body of materials outlined in Table 4.4.

Table 4.4: List of the attachments supporting our forecast connections expenditure

Name	Author
JEN – RP – Support – Operational Technology Communications Network Upgrade – CBA Model – 20251201	JEN
JEN – RP – Support – Voltage and PQ Management – CBAM – 20251201	JEN
JEN – RP – Support – Voltage and PQ Management – Business Case – 20251201	JEN
JEN - RP - Support - Voltage and Power Quality Management - EDCoP Performance and Cost - 20251201	JEN

5. Replacement capital expenditure

Highlights

- We proposed a net replacement expenditure of $390M or $419M (gross) for the revised regulatory proposal.
- Our revised gross forecast is $10M higher than our forecast in the initial regulatory proposal given our proposal to expand the scope of our proposed upgrade of zone substation locks and security system from 16 sites to 29 sites.

5.1 Summary

The AER has not accepted our forecast net replacement expenditure $380M for the next regulatory period. It has provided an alternative allowance which is 39% lower than our initial regulatory proposal. We provide an overview of the AER's draft decision and our response in Table 5.1.

Table 5.1: AER draft decision and JEN response

	AER draft decision	JEN response
Relocation of assets that are in flood risk zone areas (Maribyrnong project)	Re-categorised as a network resilience project instead of a replacement project. Further, the AER did not accept the forecast expenditure for the project given lack of evidence to support the forecast expenditure.	We acknowledge the AER's re-categorisation of this project as a network resilience initiative. However, due to time constraints, we are unable to complete the AER-required risk assessment model, options analysis, historical flood data review, and climate modelling ahead of the revised regulatory proposal.[48]
Pole replacement	Accepted JEN's proposal	We welcome the AER's draft decision.
Pole top structure	Did not accept in full; included a partial allowance; open to JEN providing further justification	We addressed the AER's draft decision by providing additional support to support the forecast volume, including an estimate of the probability of failure for pole top structures using the Weibull curve.
Proposed three zone substation (ZSS) redevelopment (Coburg North, Coburg South and North Heidelberg)	Did not accept given estimated cost of risk is considered overstated; included an alternative forecast of $0 as a placeholder, open to JEN providing further evidence to support the projects.	We undertook further analysis to address EMCa's concern that our estimated cost of risks for the three ZSS redevelopments is overstated.
Individual switchgear projects/programs without a business case	Did not accept because there is no business case, open to JEN providing further evidence to support these projects	We are submitting a business case to support our proposed BLTS 22kV switchgear replacement project.

[48] We note that this item is erroneously included in our revised regulatory proposal capital expenditure model.

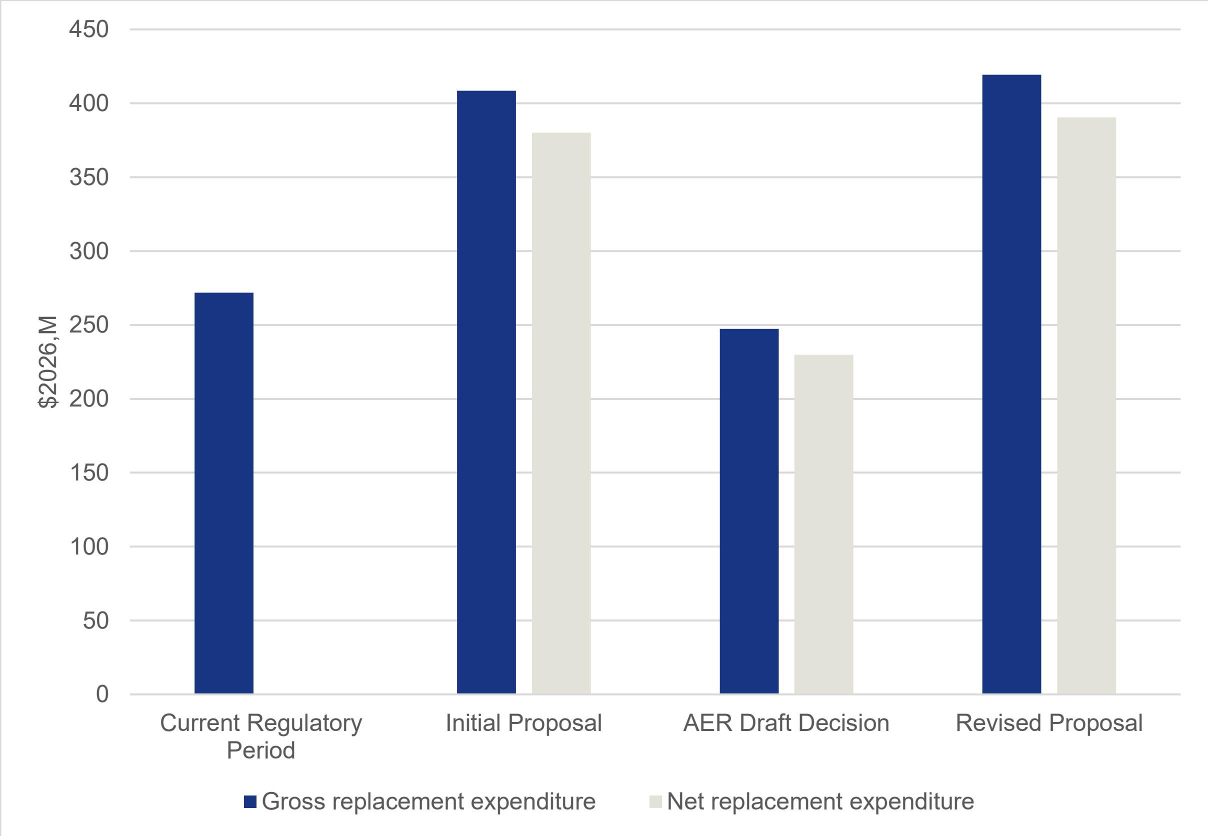
	AER draft decision	JEN response
Routine and non-routine replacement projects/programs justified using asset class strategies	Accepted some of our proposed non-routine projects/programs with justification documents Did not accept some of the routine and non-routine projects; requested JEN to submit business cases	We are submitting business cases in response to the draft decision.
SCADA, network control and protection systems	Did not accept the CS relay but has accepted the other replacement projects	We undertook further analysis to address EMCa's concern that our estimated cost of risks for the three ZSS redevelopments is overstated.
Other asset replacements	Accepted our proposal including the upgrade of substation locks and security systems	We welcome the draft decision. For the revised regulatory proposal, we are expanding the scope of our proposed upgrade of substation locks and security systems from 16 sites to 29 sites.

Figure 5-1 provides a comparison of JEN's actual and forecast replacement expenditure in various scenarios.

The AER's draft decision replacement expenditure is lower than our expected replacement expenditure for the current regulatory period. This is inadequate as it compromises our ability to maintain a reliable network and to invest sustainably. For example, the AER in its draft decision has included a placeholder of $0 to our proposed $95M redevelopment of Coburg North (CN), Coburg South (CS) and North Heidelberg (NH) zone substations (ZSS) due to concerns about overstated benefits. We have undertaken further analysis in response to the AER's draft decision. Our analysis of risks and optimal timing for these projects strongly supports the implementation of these projects in the next regulatory period. It is our expectation that having adequately addressed the AER's concerns, it will approve our proposed replacement expenditure for the ZSS redevelopments in full. These projects are critical to address major safety and supply risks for 60,000+ customers by replacing aging, failure-prone, non-compliant, and unsupported equipment.

Our revised forecast replacement expenditure broadly aligns with our initial regulatory proposal but slightly higher. The $11M difference is due to our proposed expansion of the scope of the Upgrade zone substation locks and security systems from [redacted]

Figure 5-1: Comparison of total replacement expenditure ($2026, million)



Notes: The initial regulatory proposal shown above excludes our proposed Relocating assets that are in high-flood risk zones (Maribyrnong project) which the AER has re-categorised as a network resilience project. Our initial regulatory proposal is $427M gross replacement expenditure.

Table 5.2 provides a more detailed breakdown of our revised regulatory proposal compared with our initial regulatory proposal and the AER's draft decision.

Table 5.2: Comparison of forecast replacement capital expenditure per asset group ($2026, million)

Replacement expenditure	JEN initial regulatory proposal (excluding the Maribyrnong project) (a)	Initial regulatory proposal (AER mapping) (1) (b)	AER draft decision[49] (c)	Revised regulatory proposal (d)(2)
Poles	57.7	57.7	57.5	56.3
Pole top structures	44.6	44.6	25.9	44.8
Overhead conductors	12.3	12.5	11.1	12.3
Underground cables	31.7	31.8	21.4	31.7
Service lines	32.4	32.5	26.4	32.7
Distribution transformers	9.9	19.8	10.7	

[49] Numbers were taken from AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, Table A1.2, pp. 21-22.

Replacement expenditure	JEN initial regulatory proposal (excluding the Maribyrnong project) (a)	Initial regulatory proposal (AER mapping) (1) (b)	AER draft decision[49] (c)	Revised regulatory proposal (d)(2)
Switchgear	74.4	85.5	0.0	128.1 (3)(4)
Substation transformers	26.7	7.1	0.0	
SCADA, network control & protection systems	44.7	51.5	34.3	27.9 (5)(6)
Other	74.3	65.5	63.9	85.6 (7)
Gross replacement capital expenditure	**408.9**	**408.9**	**251.2**[50]	**419.3**
Less contributions and disposals	28.8	28.8	20.4	28.8
Net replacement capital expenditure	**380.1**	**380.1**	**230.8**	**390.5**

(1) While the AER has re-categorised the replacement expenditure for distribution transformers, switchgear, substation transformers, SCADA, network control and protection systems and Other as shown in column (b) and highlighted in blue, the total replacement expenditure for these assets of $380M matches exactly our forecast replacement expenditure for these assets as shown in column (a).

(2) There might be some very slight changes to forecast expenditure due to updated labour escalation and inflation rates.

(3) The AER has re-categorised the projects under the distribution transformers, switchgear and substation transformers asset categories but we were not able to match their breakdown. As a result, we presented the total replacement expenditure instead for these three asset categories. For the AER's easy reference, we outline in Appendix B our mapping of replacement expenditure per asset type.

(4) In the initial regulatory proposal, the total replacement expenditure for distribution transformers, switchgear and substation transformers is $111M. For the revised regulatory proposal, it has changed to $128M. This is because the protection relay components of the CN and NH ZSS redevelopments which total $17M were moved to Switchgear as per the AER's approach of putting the total project costs of the three zone substation redevelopment projects under switchgear. The exception is the CS ZSS relay, which as per the AER's approach remains under SCADA, network control and protection systems.

(5) The AER has re-categorised the projects under SCADA, network control and protection systems (under column (b)) but we were not able to match their breakdown. Instead, the breakdown we used is based on the asset/project categorisation we have adopted for the initial regulatory proposal. For the AER's easy reference, we outline in Appendix B our mapping of replacement expenditure per asset type.

(6) The revised regulatory proposal for SCADA, network control and protection systems is lower by $17M compared with the initial regulatory proposal of $44.7M. This is due to transfer of the costs associated with CN ZSS' and NH ZSS' protection relays to switchgear as explained in (4) above.

(7) The revised regulatory proposal for Other is $11M higher than the initial regulatory proposal. This is due to our proposed expansion of the scope of the Upgrade zone substation locks and security systems from 16 sites to 29 sites.

The AER noted that it does not approve an amount of forecast expenditure for each individual capital expenditure driver of project/program. It instead used its findings on the different capital expenditure drivers to assess a regulated business' proposal as a whole and arrive at an alternative estimate for total capital expenditure.[51]

The AER's draft decisions and expectations on our proposed zone substation redevelopments and pole top structures are clear. The AER has also encouraged JEN to provide business cases and cost benefit analysis for other large asset classes such as overhead conductors, underground cables and service lines. It noted its consultant's feedback that:

> *Jemena has placed significant emphasis on the materials included in its asset class strategies (Distribution, Primary plant and Secondary plant) to support the proposed projects and programs, including justification for the scope, timing and efficient cost. Whilst these were useful summaries, they typically lacked the analysis that we would expect to find that justify the forecast expenditure.*

[50] We note that this total capital expenditure which we took from the AER's draft decision on capital expenditure (Table A1.2) does not align with the $247.3M total expenditure under the AER's draft decision capital expenditure model. We were not able to reconcile the difference.

[51] AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, p.9.

> *Jemena has largely relied on condition-based methods to determine the scope of its forecast programs. EMCa noted that a large proportion of expenditure was not supported by economic analysis, rather relying on inspection- or condition-based methods. They considered the absence of economic analysis did not assist with determining how the prudent and efficient replacement program has been determined.*

In response to the draft decision and feedback from the AER consultant, we have developed business cases for our remaining routine replacement projects and programs that previously did not have supporting business cases. As part of this revised regulatory proposal, we are submitting the following additional justification documents:

1. 8 new business cases to support a number of our routine replacement projects, which we have justified in our initial regulatory proposal using our asset class strategies

2. updated business case for the CN, CS and NH ZSS redevelopment projects which clearly addresses the AER's concerns and recommendations

3. pole top structure strategy business case which clearly articulates the basis of our forecast replacement volume and expenditure

4. updated business case for the Upgrade of zone substation locks and security systems, of which the scope has been expanded from 16 sites to 29 sites.

Overall, we consider that we have provided adequate supporting information (based on bottom-up assessment) to justify that our forecast replacement expenditure, which were given a partial allowance or a placeholder of $0 by the AER, are prudent and efficient.[52]

The following sections set out a more detailed response to the draft decision. For clarity and focus, we have limited our response to areas where we do not agree with the draft decision.

5.1.1 Pole-top structures

The AER has not accepted JEN's forecast replacement expenditure of $45M for pole top structures in the next regulatory period. It has included an alternative forecast of $26M, which is 42% lower than JEN's forecast, aligning with actual historical volumes.

In its draft decision, the AER.[53]

- noted that JEN's forecast replacement volumes have increased substantially from the current regulatory period
- was not satisfied that our forecast is prudent and efficient as this increase has not been adequately explained and appears to be based on extrapolation of historical volumes
- encouraged JEN to reconcile the historical based forecasting method used against proposed increased volumes.

[52] Given the gaps between the results of JEN's and the AER's repex model even after we have addressed the errors raised by the AER during the information request process, we have not used the repex modelling in our revised regulatory proposal. We have used a bottom-up assessment instead in relation to the new supporting information we are providing as part of the revised regulatory proposal.

[53] AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, pp. 20, 22.

Our revised regulatory proposal

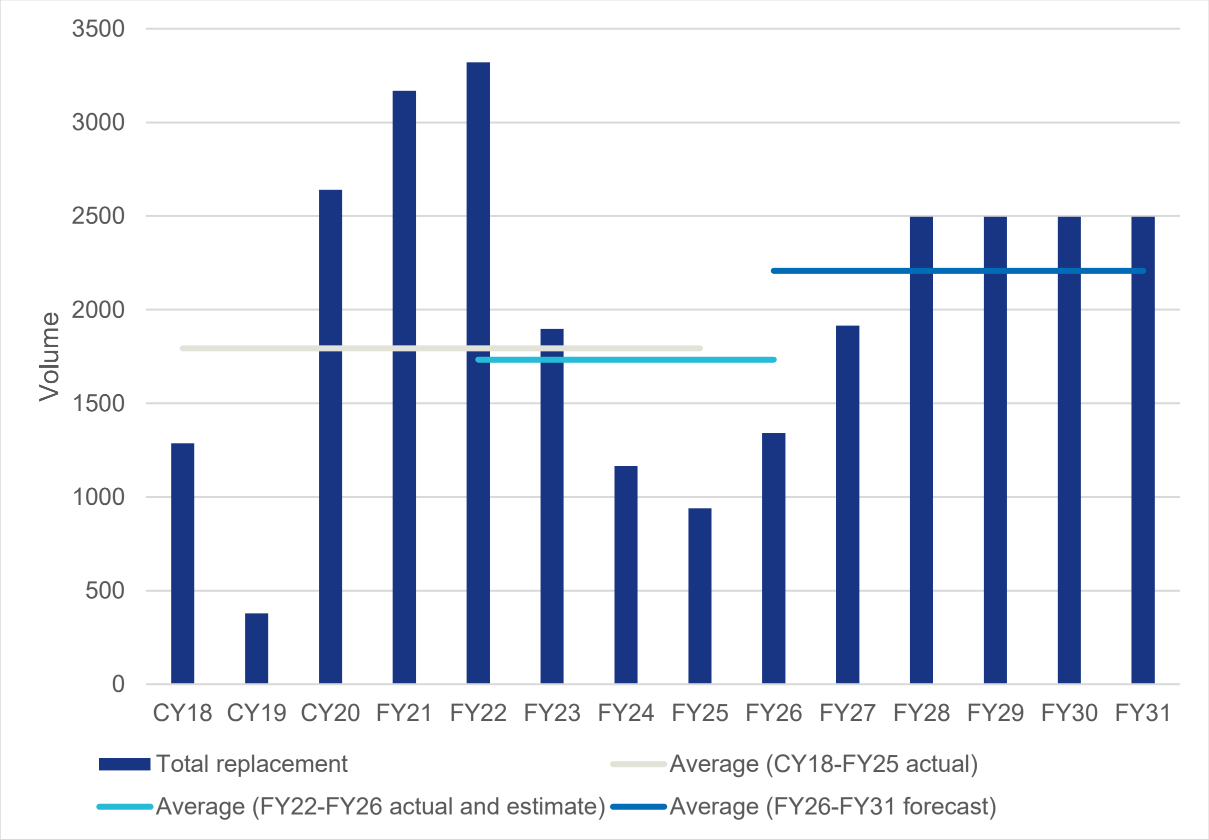
JEN's forecasting method for pole top structure is based on a combination of modelling, asset population data, inspection outcomes, and engineering judgement. This integrated approach enables prudent and efficient management of our pole top structure asset class.

JEN has prepared the attached *JEN – RP – Support - Jemena Pole Top Structures – Business case* to address the AER's concerns. It explains our replacement strategy and the basis of our pole top structure replacement volumes for the next regulatory period. It also explains the difference, including the reasons, between our forecast replacement volumes and the replacement volumes suggested by the historical trend and the most recent Weibull analysis for the pole top asset class.

In summary:

- JEN has introduced a more rigorous inspection strategy starting from 2022. Our rigorous inspection strategy has enabled us to identify and remediate faults early resulting in deferred replacement volumes during the current regulatory period (see Figure). However, the condition of aged pole top structure assets continues to deteriorate. As these assets approach end-of-life and exhibit increasing signs of poor condition, further deferral is no longer prudent or sustainable. The forecast increase in replacement volumes reflects a necessary shift from short-term remediation to long-term asset renewal, ensuring continued network reliability and safety.

Figure 5-2: Actual and forecast replacement volumes, pole top structures

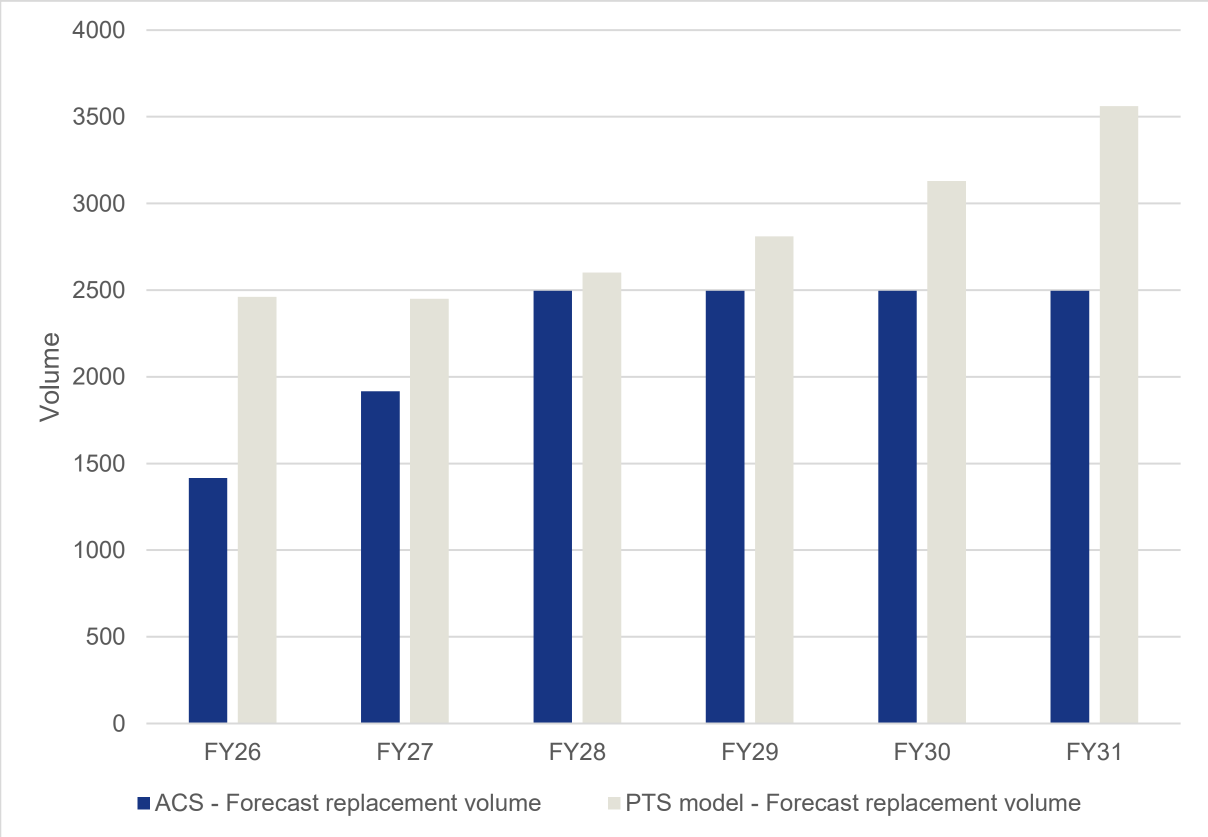


- JEN's forecast replacement volumes of 11,904 pole top structures are lower than as determined through our most recent PTS Weibull modelling (14,552) as shown in Figure . This is due to JEN asset and risk management strategy where we prioritise condition-based replacement of pole top structures informed by a rigorous inspection program rather than relying solely on asset age.

This approach enables the extraction of the maximum practicable residual life from assets, while maintaining reliability and safety in accordance with the National Electricity Objective and 'as far as practicable' (AFAP) requirements under the Energy Safety Act.[54]

Nevertheless, replacement volumes driven by asset condition are expected to increase significantly over the next regulatory period. This trend is primarily due to the aging population of wooden crossarms, many of which were installed between 1960 and 1990, are now entering the wear-out phase and exceeding their nominal lifespan and are developing condition issues. The inspection program continues to provide valuable insights into asset condition, allowing JEN to manage this emerging replacement demand prudently and efficiently.

Figure 5-3: Forecast replacement volumes, pole top structure: ACS vs PTS Weibull modelling



JEN has carefully considered the AER's feedback and has addressed the concerns raised through a detailed explanation of our forecasting methodology, inspection strategy, and asset condition assessments. The attached strategy paper demonstrates that our forecast volumes are not based on a simple extrapolation of historical data, but are underpinned by a condition-based, risk-informed approach that reflects prudent and efficient asset management.

Our revised regulatory proposal maintains the originally submitted replacement volumes, as we are confident that the forecast is justified, necessary, and aligned with our commitment to safety, reliability, and cost-effectiveness. Many of our pole top structures have been aging and failures rates have been increasing. We do not consider an allowance based on status quo is a prudent and efficient approach. Table 5.3 shows our efficient forecast replacement expenditure for the next regulatory period.

Table 5.3: Forecast replacement expenditure, pole top structure ($2026, million)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Initial regulatory proposal	7.1	9.3	9.3	9.4	9.5	44.6

54 National Electricity Law, section 7, Electricity Safety Act, clause s83B, Electricity Safety Act, s98.

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
AER draft decision						25.9
Revised regulatory proposal *	**7.1**	**9.3**	**9.4**	**9.5**	**9.6**	**44.7**

* The revised regulatory proposal forecast expenditure is slightly different from the initial regulatory proposal due to updates on inflation and labour escalation rates.

References

The revised pole top structures replacement expenditure outlined in this section is supported by a body of materials outlined in Table 5.4.

Table 5.4: List of attachments supporting our pole top structures replacement expenditure

Name	Author
JEN – RP - Support – Pole top structures – Business case - 20251201	JEN
JEN - RP – Support – Pole Top Structures Replacement Volumes - 20251201	JEN

5.1.2 Overhead conductors – undersized neutral replacement program

The AER has not accepted JEN's forecast replacement expenditure for overhead conductors in full. It has provided an alternative forecast of $11.1M which is $1.4M or 7% lower than our proposal.

Given the AER's consultant's (EMCa) unfavourable review of our proposed undersized neutral replacement program, it is our understanding that the reduction in forecast expenditure relates to the $1.4M undersized neutral replacement program.

EMCA[55] noted that JEN has not provided sufficient information to determine whether the basis of the program is prudent and efficient, or that it is not already included in its reactive power quality program. It further observed that:

- Based on the program description provided by JEN as part of the information request process, the program appears to be reactive in nature, and that it is more likely to form part of a response to quality of supply investigations (or complaints). EMCA also noted that as a reactive program, it is therefore more likely to be included as operating expenditure (through phase balancing) or in the augmentation program allowance for the purpose of network reinforcement or upgrades arising from the outcome of JEN's quality of supply augmentations and not as a new augmentation program.
- JEN did not provide details on how we have determined the replacement volumes except saying that the population of undersized neutrals was sourced from the GIS.

In its draft decision, the AER encouraged JEN to provide business cases and cost benefit analyses for asset classes such as overhead conductors, underground cables and service lines.[56]

Our revised regulatory proposal

An undersized neutral conductor refers to a neutral wire that has a smaller cross-sectional area than required by electrical standards for the expected load. The neutral conductor was typically not expected to conduct high currents. However, with the evolution of electronically switched power supplies and exported energy with distributed solar, neutral currents have appreciably increased resulting in some overloaded neutrals. Undersized

55 EMCa, *Review of aspects of proposed network related expenditures*, Jemena Services 2026-2031 regulatory proposal, August 2025, pp. 33-35.

56 AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, p.9.

neutrals can cause poor supply quality, unsafe stray neutral/earth currents, and ultimately significant electrical and safety events upon failure.

In the event of neutral failure, single-phase customers may be exposed to phase-to-phase voltages, causing extensive damage to household appliances. Additionally, voltage instability, flicker, and harmonic distortion become more prevalent, especially in areas with high concentrations of electronically switched devices. As noted in the business case, recent incidents have demonstrated the severity of these risks. A failed neutral event on 01/11/2018 at Barrington-Parnell Fault led to sustained supply interruptions affecting 99 customers, with approximately 50% reporting damage to electrical appliances. Similarly, on 2/7/2018 a failed neutral at Harrick-Translink led to an outage affecting 8 customers. These incidents highlight the need for mitigation activities.

We have considered several options to address the risks posed by undersized neutral conductors. We have considered a reactive approach which involves inspecting and securing high impedance neutral connections, typically in response to customer-reported faults. While this approach can resolve issues locally, it is inherently reactive and does not address underlying systemic risks. It relies on fault detection after incidents occur, which limits its effectiveness in preventing future safety hazards. Additionally, the cost difference between repairing or replacing just the neutral conductor and replacing the entire conductor set with LV ABC is minimal. This option also fails to address other underlying issues such as ageing conductors and deteriorating insulation.

Among the 6 options considered, our costs benefit analysis shows that a targeted replacement of undersized conductors in high-risk areas using appropriately rated LV ABC is the most economically feasible option. This option involves identifying areas where impact of undersized neutral is high and upgrading existing conductors in those locations to appropriately rated LV ABC. By focusing on customers most affected by undersized neutrals, this approach improves safety, power quality and reliability while ensuring cost-efficiency. It provides an economic and scalable solution that addresses the issue where it matters most. This option is considered both practical and economically prudent and is therefore recommended.

We also confirm that this program is not included in any of our reactive power quality program.

In view of the above, our revised regulatory proposal maintains the originally submitted forecast replacement expenditure for overhead conductors of $12.3M which includes our proposed undersized neutral replacement program.

Table 5.5 shows our efficient forecast replacement expenditure for overhead conductors for the next regulatory period.

Table 5.5: Forecast replacement expenditure, overhead conductors ($2026, million)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Initial regulatory proposal	3.8	0.9	2.7	3.7	1.2	12.3
AER draft decision						11.5
Revised regulatory proposal	**3.8**	**0.9**	**2.7**	**3.7**	**1.2**	**12.3**

References

Our proposed undersized neutral replacement capital expenditure is supported by the material outlined in Table 5.6.

Table 5.6: List of attachment supporting our undersized neutral replacement expenditure

Name	Author
JEN – RIN – Support – Undersized Neutral Replacement - Business case	JEN

5.1.3 Underground cables – routine underground cable replacement projects

The AER has re-categorised the Maribyrnong project[57] as a network resilience project instead of a replacement project. As a result, it has removed the Maribyrnong project's underground cable component spend of $7.9M from the forecast expenditure for underground cable. This has led to our forecast expenditure for underground cable to decrease from $39.6M to $31.8M. We accept the AER's draft decision.

The AER has not accepted the forecast replacement expenditure of $31.8M (net of Maribyrnong project underground cable component) for underground cable in full. In its draft decision, the AER:

- has provided an alternative forecast expenditure of $21.4M which is $10.4M or 33% lower than the forecast expenditure
- noted EMCa's observation that JEN has placed significant emphasis on the materials included in our asset class strategies to justify our proposed projects and programs, and that while they were useful summaries, they typically lacked the analysis that it would expect to find that justify the forecast expenditure
- has encouraged JEN to provide business cases and cost benefit analyses for asset classes such as overhead conductors, underground cables and service lines.[58]

Our revised regulatory proposal

Based on our understanding of the AER's draft decision, the AER has accepted the drivers for our proposed underground oil-filled cable replacement projects supported by a business case, while it has not considered as prudent and efficient the drivers behind projects justified solely by asset class strategies. Given this, we have developed a business case for our routine underground cable replacement projects, with a total project cost of $10.4M which we previously justified this capital expenditure using JEN's electricity distribution asset class strategy. This expenditure aligns with the AER's cut on our forecast expenditure of $10.4M.

The proposed routine underground cable replacements are necessary to mitigate risks associated with cable failures on JEN's network. Key risks include deterioration of HV XLPE cables due to water treeing; degradation of paper-insulated (MI type) HV cables caused by insulation breakdown and moisture ingress; and the need to replace certain LV pillars and cabinets due to asbestos presence and corrosion-related termination failures.

Doing nothing is not a credible option, as it would expose JEN's network to unacceptable reliability and safety risks and would be inconsistent with established asset management standards.[59] To address these risks, we propose the minimum level of investment necessary to maintain current network reliability and meet compliance obligations when assets fail during the next regulatory period. In line with JEN's policy, assets that cannot be efficiently inspected—based on their supply criticality and risk profile—are operated to failure. This approach underpins our proposal for routine underground cable replacements. While we considered a more proactive replacement strategy, such an approach would not represent a prudent or efficient use of resources.

Our revised regulatory proposal maintains the originally submitted forecast replacement expenditure for underground cable replacements of $31.8M as shown in Table 5.7.[60]

Table 5.7: Forecast replacement expenditure, underground cables ($2026, million)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Initial regulatory proposal	1.3	15.2	9.6	8.9	4.6	39.6
AER draft decision						21.4

57 Referred to as Relocation of assets that are in flood risk zone areas in the capital expenditure model.

58 AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, p.9.

59 Australian asset and risk management standards ISO 55001 and ISO 31000:2018. We also must adhere to the standards set by the Essential Service Commission of Victoria's Electricity Distribution Code of Practice and other additional standards specific to some asset classes.

60 $39.6M less $7.9M underground cable component of the Maribyrnong Project.

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Revised regulatory proposal	**1.3**	**11.6**	**6.5**	**7.7**	**4.6**	**31.8**

References

The underground cable replacement expenditure outlined in this section is supported by a body of materials outlined in Table 5.8.

Table 5.8: List of attachments supporting our underground cable replacement expenditure

Name	Author
JEN - RP – Support – Underground Cable Replacement - Business case - 20251201	JEN
JEN - RP – Support – Underground Cable Replacement – Model - 20251201	JEN

5.1.4 Service lines – service lines replacement projects

The AER has not accepted the revised forecast replacement expenditure of $32.4M for service lines in full. In its draft decision, the AER:

- has provided an alternative forecast expenditure of $26.4M which is $6M or 19% lower than our initial regulatory proposal
- noted EMCa's observation that JEN has placed significant emphasis on the materials included in our asset class strategies to justify our proposed projects and programs, and that while they were useful summaries, they typically lacked the analysis that it would expect to find to justify the forecast expenditure
- has encouraged JEN to provide business cases and cost benefit analyses for asset classes such as overhead conductors, underground cables and service lines. [61]

Our revised regulatory proposal

While not explicit, it is our understanding from the AER's draft decision that:

- it has accepted the driver behind our proposed service rectification program
- that the $6M reduction in replacement expenditure relates to our $10.6M proposed expenditure for routine replacements of services lines. This means that the AER has partially accepted the drivers for some of our routine service line replacement projects, but it is not clear to us which projects.

To address the AER's draft decision, we have developed a business case to support our forecast expenditure or routine service line replacements.

The failure of an overhead service line can interrupt the customer's supply and carries fire ignition risks in some areas. It poses health and safety risks to staff and the general public. Once defects are detected service lines are replaced. They are not repairable.

Doing nothing in the next regulatory period is not an option as it would expose JEN's network to unacceptable reliability and safety risks and would be inconsistent with established asset management standards.[62] As we also

[61] AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, p.9.

[62] Australian asset and risk management standards ISO 55001 and ISO 31000:2018. We also must adhere to the standards set by the Essential Service Commission of Victoria's Electricity Distribution Code of Practice and other additional standards specific to some asset classes.

noted in our initial regulatory proposal, we have traded-off and deferred the replacement of service lines (without increasing the risk profile of or performance of this asset class) in the current regulatory period due to the increased need to prioritise replacement of ageing and in poor condition poles. This deferral means these services must be replaced in the next regulatory period.[63]

Our preferred approach is to invest in the replacement of service lines upon asset failure as set out in the attached business case based on historical trends. This will enable us to maintain network performance, reliability and meet compliance obligations. We do not consider doing more than what we have proposed to represent a prudent or efficient use of resources.

Our revised regulatory proposal maintains the originally submitted forecast replacement expenditure for service lines of $32.4M as shown in Table 5.9.

Table 5.9: Forecast replacement expenditure, service lines ($2026, million)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Initial regulatory proposal	7.4	6.9	6.0	6.0	6.0	32.4
AER draft decision						26.4
Revised regulatory proposal	**7.5**	**7.0**	**6.1**	**6.1**	**6.1**	**32.7**

* The revised regulatory proposal forecast expenditure is slightly different from the initial regulatory proposal due to updates on inflation and labour escalation rates.

References

Our proposed service lines replacement capital expenditure is supported by the material outlined in Table 5.10.

Table 5.10: List of attachments supporting our service lines replacement expenditure

Name	Author
JEN – RIN – Support – Service Replacements - Business case	JEN

5.1.5 Switchgear and transformer

Given interrelatedness, we are discussing switchgear and transformer together in this section. We proposed a total replacement expenditure of $111M (net of the transformer component of the Maribyrnong project). The AER, in its draft decision, has included a placeholder of $10.7M (mainly for transformers) which is $100M or 90% lower than our initial regulatory proposal.

The AER has included the full costs of the CN, NH and CS redevelopment projects (except for the relay components of CS) under switchgear for analysis purposes. The AER noted that it was unable to establish that any of the proposed switchgear programs were prudent and efficient, and therefore included a placeholder expenditure of $0 for switchgear.

In its draft decision, the AER[64]:

- noted its EMCa's findings that we have not provided compelling information to support the identified risk at the three substation sites and that the transformer works are necessary.
- noted that we proposed two further non-routine switchgear related projects with no supporting business cases provided.

63 JEN, Att 05-01 Capital Expenditure – 20250131, p.94.

64 AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, pp. 20-21.

- included a placeholder of $10.7M for JEN's transformer replacement program which is 60% lower than JEN's initial regulatory proposal.

The AER encouraged JEN to investigate the probability of failure underpinning the cost benefit for the overall zone substation redevelopment program of works noting that these programs represent a significant proportion of the overall unmodelled forecast replacement expenditure as well as a major proportion of the reduction to JEN's forecast. Affected asset classes include substation transformers, switchgear and SCADA.

EMCa has made a number of specific comments about our proposed zone substation redevelopments which we have addressed in the following sections.

Our revised regulatory proposal

For our revised regulatory proposal, we forecast a total replacement expenditure of $128M for switchgear and transformers. While this exceeds the $111M forecast for switchgear and transformer replacement under the initial regulatory proposal (see column (b) of Table 5.11), this is due to presentation only. We have aligned with the AER's approach by including the protection relay components of CN and NH within switchgear, ensuring full costs for CN, NH, and CS are captured under switchgear, hence the difference. The exception is the CS relays replacement project which remains separately costed under SCADA, network control, and protection systems in the capital expenditure model.[65] Refer to Appendix B for JEN's mapping of forecast replacement expenditure.

Table 5.11: Forecast replacement expenditure, switchgear and transformer ($2026, million)

Replacement expenditure	JEN Initial regulatory proposal (excluding the Maribyrnong project) (b)	Initial regulatory proposal (AER re-categorised) (1) (b)	AER draft decision (c)	Revised regulatory proposal (d)(2)
Distribution transformers	9.9	19.8	10.7	128.1
Switchgear	74.4	85.5	0.0	
Substation transformers	26.7	7.1	0.0	
Total	**111.0**	**112.7**	**10.7**	**128.1**

CN, CS and NH ZSS redevelopments

We have updated the business cases for the proposed CN, CS, and NH ZSS redevelopments to address concerns raised by the AER's consultants.

65 There are four distinct projects under JEN's zone substation redevelopment program:

1. CN ZSS redevelopment
2. Replacement of CS 22kV switchgear (arc flash risk), 66kV isolators, 66kV circuit breakers, earth switches, and transformer bushings
3. Replacement of NH 22kV switchgear, 66kV circuit breakers, 66kV isolators, and earth switches
4. Replacement of CS relays (classified under SCADA, network control, and protection systems).

In the initial regulatory proposal, we allocated costs across major asset categories—transformers, switchgear, and protection relays—using the share of material costs as the basis for the proxy estimate. Specifically:

- For CN (Project 1) and NH (Project 3), we estimated the proportion attributable to transformers, switchgear, and protection relays.
- For CS (Project 2), we estimated the share for transformers and switchgear.

These approximations were then applied to distribute total project costs across the relevant asset categories and were used in JEN's repex modelling and capital expenditure attachment for the initial regulatory proposal. The proxy allocation was used for presentation purposes only.

1. Risk is now modelled consistent with AER guidance and industry practice

EMCa found that we did not model risk in accordance with AER guidance or industry practice. EMCa identified that our risk modelling did not follow AER guidance or industry practice. They noted that asset replacement planning typically assumes an increasing probability of failure over time, with the rate of increase linked to asset condition.[66] EMCa advised that Weibull functions are commonly used for this purpose, as they enable risk-cost analysis by producing an increasing cost curve that can be compared against intervention costs.[67] They further highlighted that standard Weibull functions and parameters are available from industry sources and other DNSPs, which could be applied to JEN's network and compared against our observed experience.

To address this issue, we engaged a technical expert to advise us on an appropriate Weibull distribution and parameters for the primary equipment, that is, transformers and circuit breakers, at each ZSS proposed for replacement. We provide an overview of our approach in the box immediately below.

Probability of Failure – CN transformers

Our technical expert relied on the IEEE paper "Investigation into Modelling Australian Power Transformer Failure and Retirement Statistics" (Martin et al., IEEE Transactions on Power Delivery, Vol. 33, No. 4, August 2018). This study analysed failure and retirement data for 97% of the 6,057 utility-owned transformers in mainland Australia and Tasmania, covering 564 events between 2000 and 2015. Using locally sourced data from almost all Australian utilities, the authors applied Weibull analysis to estimate useful life and age-related failure probabilities across voltage classes. Based on these outcomes, our expert developed a Weibull curve for transformers <66 kV and identified the position of the CN units on that curve.

Probability of failure – CN, CS and NH circuit breakers

Our technical expert relied on JEN asset data and reliability statistics from CIGRE's internationally recognised surveys on high-voltage equipment. This approach, detailed in our technical expert's report supporting report underpins the analysis for our proposed ZSS redevelopments.[68]

Probability of failure – secondary equipment (protection relays)

JEN adopted a literature review approach to determine Weibull distribution parameters for protection relays due to insufficient failure data on our network, likely resulting from our proactive replacement strategy. Using limited internal data could skew statistical analysis and reduce reliability. Our review identified several studies, and for the CN, CS, and NH ZSS business cases, we adopted the Weibull parameters used in Ergon Energy's protection relay program, which was accepted by the AER.[69] Ergon operates within the Australian NEM, making it a more relevant comparator than international sources. This approach aligns with EMCa's recommendation to use Weibull functions and parameters from other DNSPs where applicable.

We accept our technical expert's advice on the probability of failure for primary equipment. The approach relies on a peer-reviewed IEEE study that analysed failure and retirement data for almost all utility-owned transformers in Australia, using robust statistical methods such as Weibull analysis. This ensures the assessment is based on comprehensive, locally relevant data and aligns with industry best practice, providing an evidence-based estimate of failure probability for CN ZSS transformers.

For circuit breakers, the approach is reasonable because it uses JEN asset data and reliability statistics from CIGRE's internationally recognised surveys, which aggregate extensive operational data from utilities worldwide.

66 EMCa, *Review of aspects of proposed network related expenditures*, Jemena Services 2026-2031 regulatory proposal, August 2025, p. 15.

67 EMCa, *Review of aspects of proposed network related expenditures*, Jemena Services 2026-2031 regulatory proposal, August 2025, p. 15.

68 K-BIK Power Pty Ltd, Review of Assets for Replacement of Substations within Jemena's Network, November 2025 - Confidential and Privileged.

69 Ergon Energy, *Protection relay replacements business case*, 25 January 2024; and AER, *Ergon Energy electricity distribution determination 2025 to* 2030, Attachment 5, Capital expenditure, p. 62.

This ensures the assessment is based on authoritative, statistically robust information and aligns with global best practice for high-voltage equipment reliability.

For secondary equipment, our approach to adopt the Weibull distribution underpinning the protection relay program business case submitted by Ergon Energy as part of its most recent revenue proposal is consistent with EMCa's suggestion that Weibull functions and parameters are available from other DNSPs that can be applied to our network.

Figure , Figure and Figure , shows the estimated probability of failure for primary (dash lines) and secondary assets within the CN, CS and NH ZSSs. Given that an outage associated with a protection relays failure occurs only during a network fault, we estimate the likelihood of consequence (LoC) for each type of protection relay by multiplying the probability of relay failure with the observed frequency of network fault. Our analysis shows that the likelihood of consequence of the secondary equipment increases over time as further asset deterioration occurs.

Note that Figure , Figure and Figure only show the probability of failure for a subset of the protection relays to illustrate the outcomes of the analysis. We have examined failure modes for each of the 47 protection relays at CN and NH ZSSs and 37 protection relays at NH ZSS and it is this aggregated analysis that underpins our economic assessment.

Our revised analysis shows that the probability of failure increases over time as further asset deterioration occurs. These results underpin our calculation of risks under our updated business cases for CN, CS and NH ZSS redevelopments.

Figure 5-4: Coburg North - Probability of failure: transformer, circuit breakers and secondary equipment

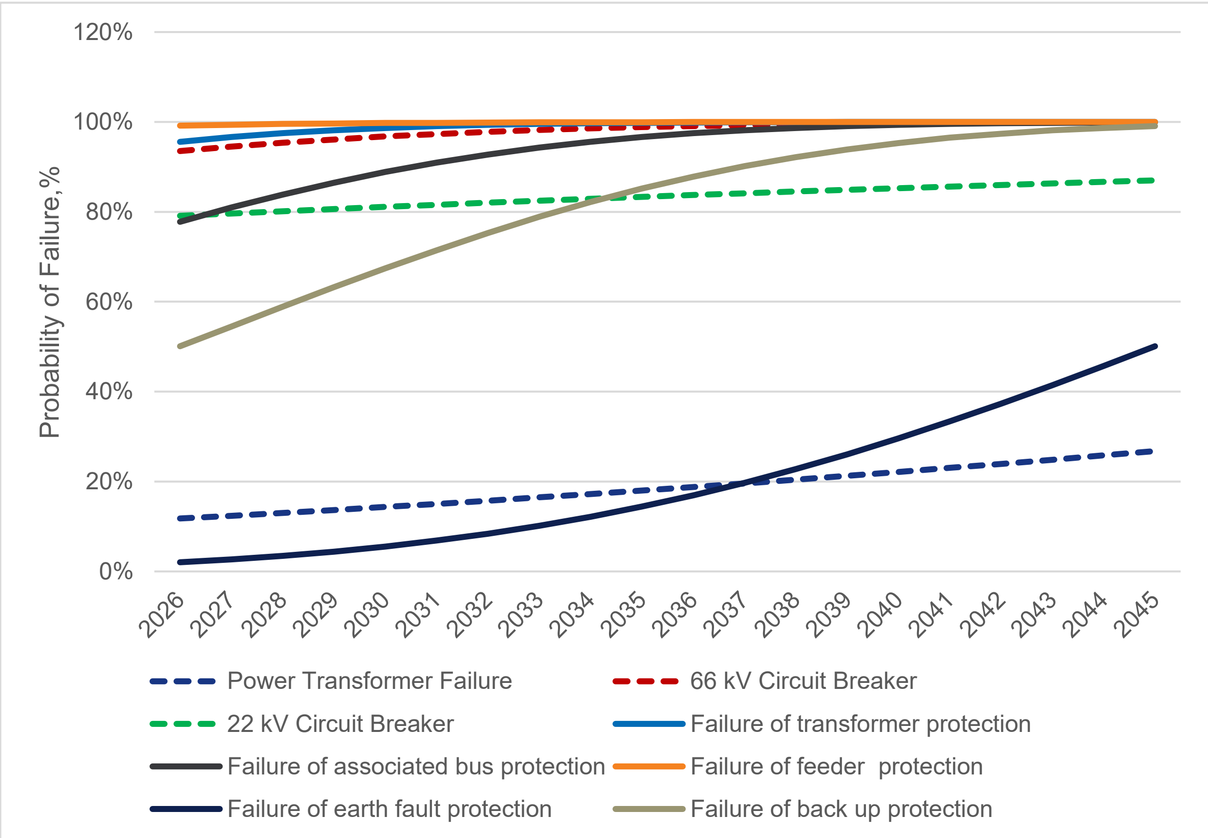


Figure 5-5: Coburg South - Probability of failure, circuit breakers and secondary equipment

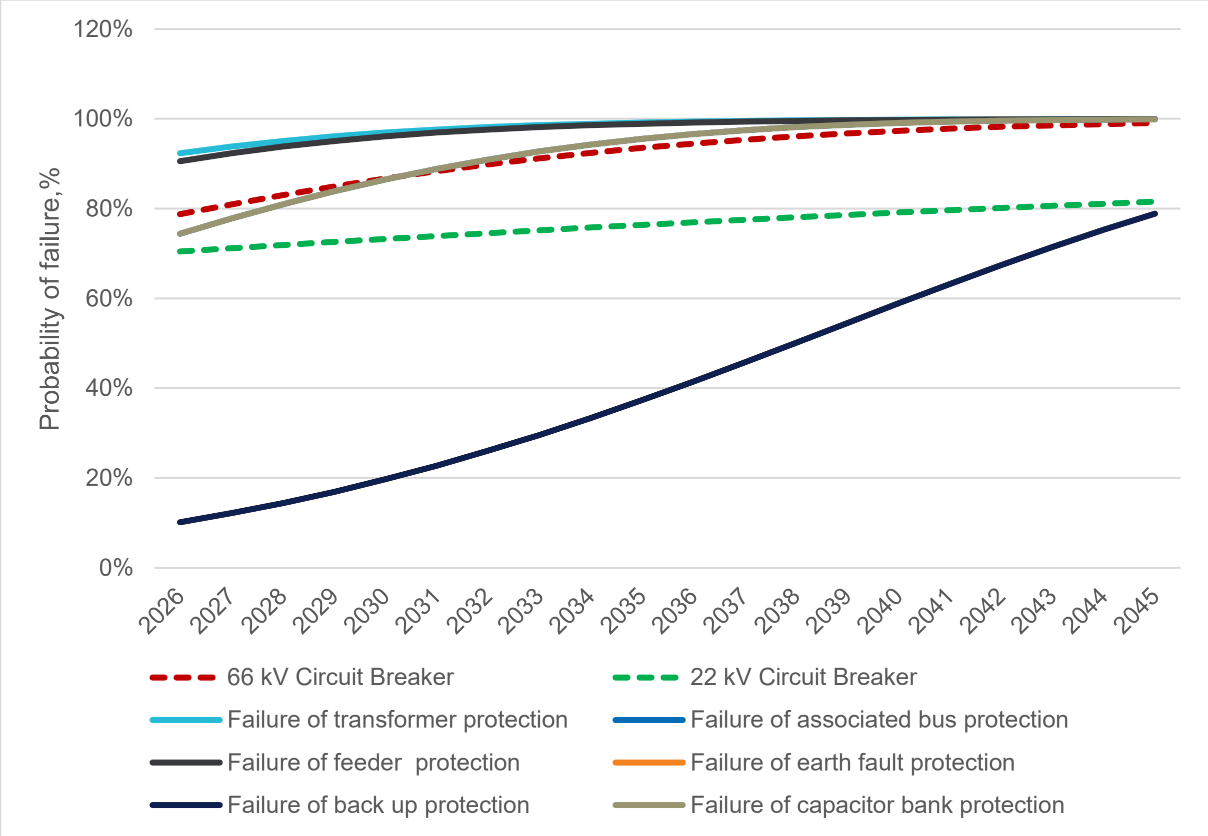
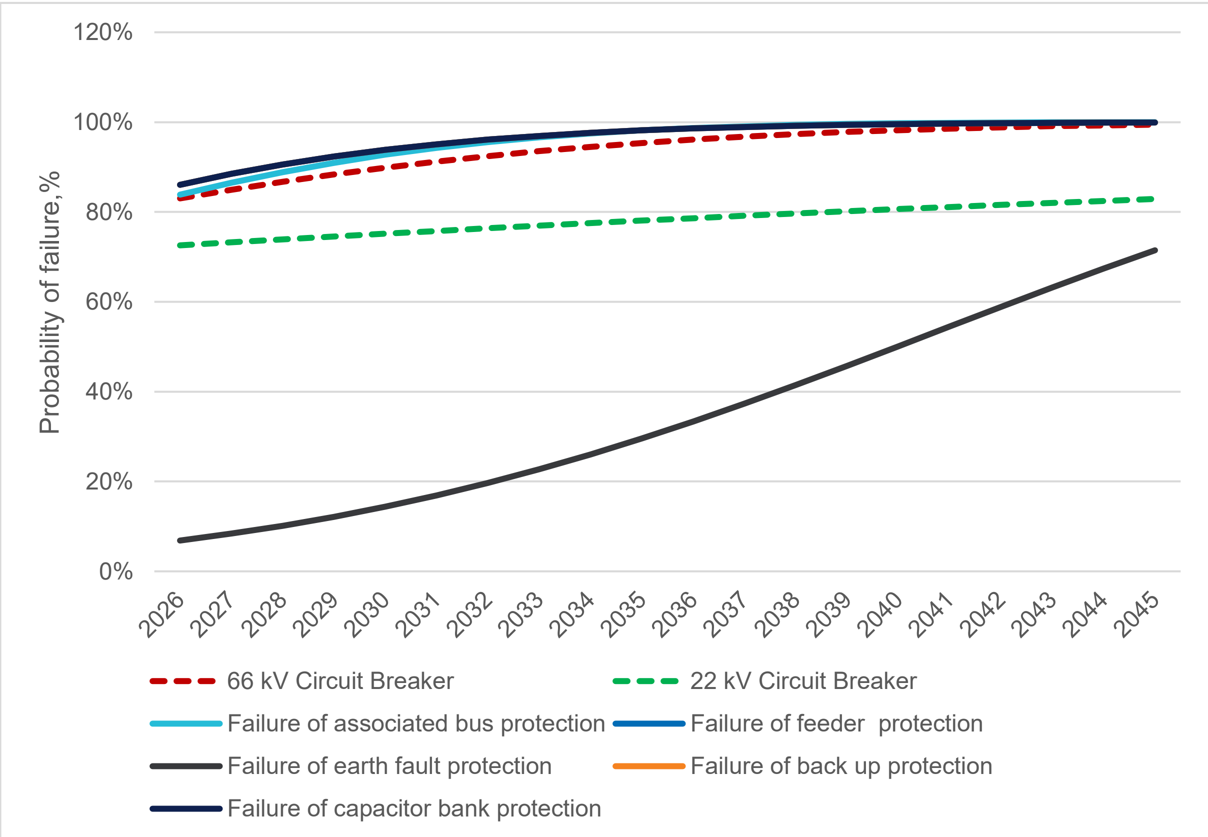


Figure 5-6: North Heidelberg - Probability of failure: circuit breakers and secondary equipment



EMCa's other comments and our response

EMCa noted that in JEN's Condition-Based Risk Management (CBRM) '13 transformers were identified in the 'red' zone and only two transformers are planned for replacement (and a further two for retirement)' and that 'this cast doubt on the level of reliance that Jemena has placed on the CBRM model outcomes, or 'red' zone as a trigger for replacement'.[70]

The 13 transformers being referred to relate to the following transformers in 7 zone substations:

- Airport West (AW) – transformer 3
- Broadmeadows (BD) – transformers 1, 2 and 3
- Coburg North (CN) – transformers 1 and 2
- Epping (EP) – transformers 3 and 4
- Footscray (FF) – transformer 3
- Heidelberg (HB) – transformers 1 and 3
- Northcote (NT) - transformers 1 and 3.

The three transformers for HB and FF ZSSs have been replaced in the current regulatory period. The 2 transformers for EP ZSS are proposed to be retired in the next regulatory as reflected in our forecast augmentation expenditure.

The three transformers at BD ZSS, 2 transformers at NT ZSS and 1 transformer at AW are due for replacement in the 2031-36 regulatory period. While their health index of 7.0 to 9.84 is high (although slightly lower than CN's transformers) the CN ZSS is being prioritised as part of addressing the significant reliability issues identified at the CN ZSS. As noted above, the probability of failure for both primary and secondary assets at CN ZSS is high.

EMCa also noted that JEN has indicated that it has completed a network asset risk assessment for assets installed at the three zone substations targeted for the next regulatory period, but they were not provided with a copy of the risk assessment.[71] We have provided a summary of the risk assessment in the original business cases for the three ZSS redevelopments. But we are submitting the full register of risks for each ZSS as part of the revised regulatory proposal.

2. Load duration curve underpins estimate of load at risk

EMCa considered that our estimated cost of consequence for an outage was overstated due to two factors:

- An overstated probability of failure due to risk not being modelled consistently with AER guidance or industry practice
- An assumption that the outage occurs at the time of peak load and extends for 12 hours.[72]

We have addressed the issue about the probability of failure in the section immediately above.

Turning to the second point, EMCa suggests that energy at risk is more reasonably determined from an estimate of average load or by using a load duration curve, rather than assuming that the event occurs at the time of peak load. We have now adopted EMCa's recommendation by estimating load at risk with reference to the 50th and 10th percentiles of the forecast load duration curve over the 20-year assessment period for each of the three zone

70 EMCa, *Review of aspects of proposed network related expenditures*, Jemena Services 2026-2031 regulatory proposal, August 2025, p. 43.

71 EMCa, Review of aspects of proposed network related expenditures, Jemena Services 2026-2031 regulatory proposal, August 2025, p. 42.

72 EMC[a], *Review of aspects of proposed network related expenditures*, Jemena Services 2026-2031 regulatory proposal, August 2025, p. 46.

substations. Specifically, we estimate the energy at risk by applying a 70 per cent weighting to the 50th percentile forecast load duration curve and a 30 per cent weighting to the 10th percentile load duration curve.

Further, we now assume that fully restoring supply to customers in the distribution network would take 90 minutes for the different scenarios that we have developed, noting that this is a very conservative assumption. Our experience of the time it takes to undertake the onsite inspection and investigate the case of an outage, which is a combination of remote and manual switching and transferring load to adjacent network, suggests that restoring supply would take considerably longer. However, we have adopted this conservative approach to mitigate concerns that the benefits of redeveloping the three zone substations are overstated.

3. A load-weighted value of customer reliability (VCR) based on the AER update is used

EMCa recommended that the VCR should be calibrated for the study area and be based on the 2024 AER update.[73] We have now adopted this approach. To illustrate, we show in Table 5.12 the calculation of the load-weighted VCR used in our analysis for the CN ZSS. We have adopted the same load weighted VCR approach for the CS and NH ZSSs.

Table 5.12: Calculation of load-weighted VCR, CN

Load type	VCR ($/kWh)	Weighting (%)
Commercial	34.39	34.7%
Industrial	33.49	9.3%
Residential	49.23	56.0%
Weighted VCR	**42.62**	

4. Optimal timing of the proposed investments has been assessed

The final concern raised by EMCᵃ in the context of the ZSS replacement business cases is that there was no evidence of an assessment of optimal timing.[74]

We assessed optimal timing consistent with the AER's guidance, that is, through a comparison of the annualised benefits with the annualised costs of the proposed investment under a range of alternate assumptions. The results of our optimal timing analysis confirm the need for the CN, CS and NH ZSSs to be redeveloped in the next regulatory period.

References

Our proposed ZSS redevelopment replacement expenditure outlined in this section is supported by a body of materials outlined in Table 5.13.

Table 5.13: List of attachments supporting our CN, CS and NH ZSS replacement expenditure

Name	Author
JEN – RP – Support - Coburg North Zone ZSS Redevelopment – Business case	JEN
JEN – RP – Support - Coburg North ZSS Substation Redevelopment – Cost benefit analysis model	JEN
JEN – RP – Support - Coburg North ZSS – PoF and quantified risks – Primary equipment	JEN
JEN – RP – Support - CN CS and NH ZSS – PoF and quantified risks – Secondary equipment	JEN
JEN – RP – Support - Coburg North ZSS Redevelopment – Risk register	JEN
JEN – RP – Support - Coburg South ZSS Redevelopment – Business Case	JEN

[73] EMCa, *Review of aspects of proposed network related expenditures*, JEN Services 2026-2031 regulatory proposal, August 2025, p. 15.

[74] EMCa, *Review of aspects of proposed network related expenditures*, JEN Services 2026-2031 regulatory proposal, August 2025, p. 46.

Name	Author
JEN – RP – Support - Coburg South ZSS Redevelopment – Cost benefit analysis model	JEN
JEN – RP – Support - Coburg South ZSS – PoF and quantified risks – Primary equipment	JEN
JEN – RP – Support - Coburg South ZSS Redevelopment – Risk register	JEN
JEN – RP – Support - North Heidelberg ZSS Redevelopment – Business case	JEN
JEN – RP – Support - North Heidelberg ZSS Redevelopment – Cost benefit analysis model	JEN
JEN – RP – Support - North Heidelberg ZSS – PoF and quantified risks – Primary equipment	JEN
JEN – RP – Support - North Heidelberg ZSS Redevelopment – Risk register	JEN
JEN – K-BIK Power – RP – Support – Review of substation replacements – Report	K-BIK Power

BLTS 22 kV switchgear replacement project

The AER and EMCa noted that JEN proposed BLTS 22 kV switchgear replacement project without providing a business case. We have now developed a business case to support the implementation of this project in the next regulatory period.

The Brooklyn Terminal Station (BLTS) currently supply the Melbourne and Metropolitan Board of Works (MMBW) sewage pumping station on Millers Road, Brooklyn. This site is recognised as a critical load, as it delivers essential sewage services to Melbourne.

Asset inspections have identified significant age and obsolescence risks. The EMAIL WR 345GC oil-filled circuit breakers (CB) models installed at BLTS exceed 40 years of service and are no longer supported by the original manufacturer, resulting in all repairs requiring custom or refurbishment solutions. Furthermore, two of the high voltage cable sections connected to these CBs have surpassed 55 years of operational life, raising concerns over safety, environmental impact, and the ongoing security of electricity supply to this critical customer.

In recent years, two of three high voltage cable sections supplying the sewage pumping station have been replaced. The final cable section is approaching end-of-life and continues to age, increasing the likelihood of deterioration-related failures, compounding overall supply risk.

To address these issues, three options were assessed. The preferred option is a stand-alone program to replace both at-risk 22kV oil-filled CBs (MB28 and MB29) and the final high voltage cable section to meet current network standards. This program will reduce operational risk, ensure environmental compliance, and secure electricity supply to this essential infrastructure

Our revised regulatory proposal maintains the originally submitted forecast replacement expenditure for the BLTS 22kV switchgear replacement project as shown in Table 5.14.

Table 5.14: BLTS 22kV switchgear replacement project forecast expenditure ($2026, million)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Initial regulatory proposal		2.9	3.4			6.3
AER draft decision		0.0	0.0			0.0
Revised regulatory proposal		2.9	3.4			6.3

References

Our proposed BLTS 22kV switchgear replacement expenditure outlined in this section is supported by a body of materials outlined in Table 5.15.

Table 5.15: List of attachments supporting our BLTS 22kV switchgear replacement expenditure

Name	Author
JEN – RP – Support - Replace BLTS 22kV switchgear – Business case	JEN
JEN – RP – Support - Replace BLTS 22kV switchgear – Model	JEN

Other distribution switchgear replacement projects

JEN has proposed several switchgear replacement projects in addition to the CN, CS and NH ZSS redevelopment projects. In its draft decision, the AER has included a placeholder of $0 for JEN's other distribution switchgear replacement projects.

Our proposed projects are mostly routine replacements. As the consequences of a failure of distribution switchgear are relatively low, we will continue to employ a predominantly replace-on-failure approach for most overhead switchgear, though replacement may also be undertaken if a need is identified through inspection when a network operator uses the equipment. Our forecast expenditure for the replacement of failed or significantly deteriorated gas switches, indoor or kiosk switchgear and LV switchgear is therefore based on our expectation of consistent asset failure rates into the future. The actual replacements will also continue to be driven by the results of the various ongoing inspection programs.

In our initial regulatory proposal, we justified these routine replacement projects using JEN's distribution asset class strategies. We have now developed a business case to further justify our proposed expenditure.

Our revised regulatory proposal maintains the originally submitted forecast replacement expenditure for the next regulatory period as shown in Table 5.16.

Table 5.16: Other distribution switchgear replacement forecast expenditure ($2026, million)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Initial regulatory proposal	3.7	4.1	4.9	5.9	5.9	24.6
AER draft decision	0.0	0.0	0.0	0.0	0.0	0.0
Revised regulatory proposal	**3.7**	**4.1**	**4.9**	**5.9**	**5.9**	**24.6**

References

Our proposed Other distribution switchgear replacement expenditure outlined in this section is supported by a body of materials outlined in Table 5.17.

Table 5.17: List of attachments supporting our Other distribution switchgear replacement expenditure

Name	Author
JEN – RP – Support - Switchgear replacement – Business case	JEN
JEN – RP – Support - Switchgear replacement – Model	JEN
JEN – RP – Support - Compliance Switchgear replacement – Business case	JEN

Other distribution transformer replacement projects

The AER has not accepted our forecast expenditure for distribution transformer replacements in the next regulatory period. However, it is our understanding from the AER's draft decision and EMCa's review that the partial expenditure of $7.1M allowed in the draft decision relates to our proposed targeted zone substation transformer bushings replacement program which involves testing of approximately 60% of 66kV transformer bushings (covering 17 substations) and assessing their condition prior to conducting any bushing replacement. EMCa considered that the targeted nature of this program is prudent and reasonable.[75]

It is our understanding from the AER's draft decision that it did not accept the drivers behind our forecast expenditure for JEN's routine distribution transformer replacement program with a total cost of about $10M (net of the Maribyrnong project's transformer component). The program involves replacing pole mounted and ground/indoor distribution transformers, transformer/substation kiosk and kiosk refurbishment. As we have noted in our initial regulatory proposal, our forecast replacement volume of 45 per year is generally consistent with the historical average annual replacement of 46 per year over the previous and current regulatory periods.[76]

In our initial regulatory proposal, we justified these routine replacement projects using JEN's distribution asset class strategies. We have now developed a business case to support our proposed $10M expenditure further.

Our revised regulatory proposal maintains the originally submitted forecast replacement expenditure for the next regulatory period as shown in Table 5.18.

Table 5.18: Distribution transformer forecast replacement expenditure ($2024, million)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Initial regulatory proposal*	2.0	2.0	2.0	2.0	2.0	10.0
AER draft decision						0.0
Revised regulatory proposal	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**10.0**

* In the initial regulatory proposal this is $20.5M because it includes the $10.6M transformer component of the Maribyrnong Project as per the AER's draft decision to categorise this project as network resilience. Removing this component, the total forecast expenditure for distribution transformer is $10M. Our revised regulatory proposal is different from the initial regulatory proposal because we have removed the Maribyrnong project transformer component

References

Our proposed distribution transformer replacement expenditure outlined in this section is supported by a body of materials outlined in Table 5.19.

Table 5.19: List of attachments supporting our distribution transformer replacement expenditure

Name	Author
JEN – RP – Support - Distribution Transformer Replacement – Business case	JEN
JEN – RP – Support - Distribution Transformer Replacement – Model	JEN

75 EMCa, Review of aspects of proposed network related expenditures, JEN Services 2026-2031 regulatory proposal, August 2025, p. 38.

76 Total distribution transformers replaced/to be replaced in the previous and current regulatory period is 462 divided by 10 years is 46.2.

5.1.6 SCADA

The AER has re-categorised some projects to be SCADA, network control and protection systems and has included them accordingly. It has resulted in an initial regulatory proposal expenditure of $51.5M as shown in Table 5.13. Note that the total forecast replacement expenditure has remained at $408.8M (gross) which suggests that some projects have only been re-categorised and not removed.

In the draft decision, the AER included a lower allowance of $34.3M and noted that EMCa's analysis of this expenditure is closely related to its advice on switchgear above (CN, CS and NH ZSS projects). The AER noted EMCa's finding that JEN has not established the ZSS SCADA works are necessary.[77]

It is our understanding from the AER's draft decision that the $17M difference between the re-categorised initial regulatory proposal of $51.5M and the draft decision allowance of $34.3M therefore relates to the Replacement of CS relays which costs $17M.

As noted in the section '**CN, CS and NH ZSS redevelopments'** above, we have addressed all the concerns and recommendations by the AER and EMCa in relation to our proposed zone substation redevelopments. Our updated business case for the CS ZSS redevelopment shows that our preferred approach to redevelop the CS ZSS substation remains the most prudent and efficient approach among several options considered. The optimal timing analysis also confirms that the redevelopment is needed in the next regulatory period. For these reasons, it is our expectation that the AER will approve our proposed $17M expenditure for the Replacement of CS relays.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[77] AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, pp. 21-22.

[78] EMCa, Review of Aspects of Proposed Network Related Expenditure, SOCI Protected, August 2025, p.53.

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6. Non-network capital expenditure – Information, Communications and Technology

6.1 Summary

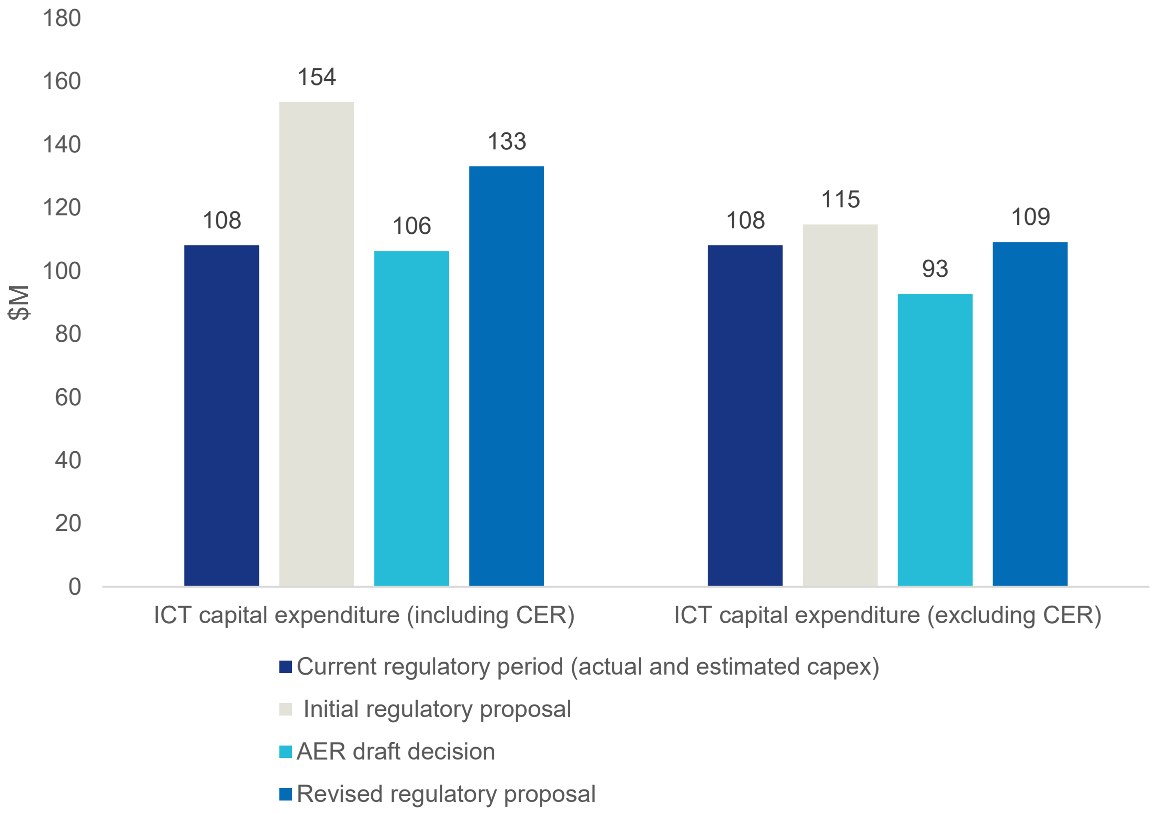
The AER has approved a lower forecast of information and communication technologies (**ICT**) capital expenditure for JEN for the next regulatory period as shown in Figure 6-1. The draft decision is 31% or 22% lower than our initial regulatory proposal for with and without the ICT capital expenditure components customer energy resources (**CER**) projects, respectively.

In summary, the AER:

- accepted the drivers behind 11 of our proposed 19 non-recurrent ICT projects as prudent and efficient
- did not accept our approach to setting the forecast recurrent capital expenditure
- did not accept or only partially accepted the drivers behind the remaining 8 non-recurrent ICT projects.[79]

We have carefully reviewed the AER's draft decision, and after further assessments we have revised our forecast ICT expenditure for the next regulatory period. Our revised forecast ICT capital expenditure is lower than our forecast under the initial regulatory proposal as also shown in Figure 6-1.

Figure 6-1: Comparison of ICT capital expenditure (with and without CER, $2026, million)



* The estimated $106M is based on the AER draft decision of $29.7M recurrent ICT capital expenditure and around $75.8M non-recurrent expenditure (ICT and CER).

79 AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, section A.5, pp. 39-47.

6.2 Our revised regulatory proposal

This section provides an overview of our revised regulatory proposal for ICT for the next regulatory period. Our more detailed response and justification for our revised regulatory proposal is detailed in the attached *JEN – RP – Att 05-01A Technology expenditure addendum*. It provides a consolidated view of our proposed ICT expenditure, encompassing both capital and operating components and therefore ensures transparency and facilitates a clear understanding of the scope, justification, and alignment of these investments with regulatory obligations and business requirements.

For the next regulatory period, our revised regulatory proposal forecast ICT expenditure is $133M (including CER), which is $20M lower than our forecast of $153M (including CER) under our initial regulatory proposal (Table 6.1). Excluding CER, our revised forecast is also lower than what we have proposed under our initial regulatory proposal.

Overall, to address the AER's concerns, we have undertaken further assessments and considerations of our forecast expenditure and have provided further supporting information for the relevant expenditure. In the following sections we provide an overview of the basis of our revised forecast ICT expenditure.

Table 6.1: Revised forecast ICT expenditure ($2026, million)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Including CER						
Recurrent	6.4	6.5	6.6	6.8	6.9	33.1
Non-recurrent	32.2	14.6	20.9	19.2	13.0	100.0
Total ICT capital expenditure	**38.6**	**21.1**	**27.5**	**26.0**	**19.9**	**133.1**
Excluding CER						
Recurrent	6.4	6.5	6.6	6.8	6.9	33.1
Non-recurrent	30.3	13.9	13.4	10.0	8.4	76.0
Total ICT capital expenditure	**36.7**	**20.3**	**20.0**	**16.8**	**15.3**	**109.2**

6.2.1 Recurrent ICT capital expenditure

The AER did not accept our forecast recurrent ICT capital expenditure which is based on a 5-year average of actual and estimated recurrent capital expenditure.[80] It provided an alternative forecast of $29.7M based on 4.5 years of actual ICT recurrent expenditure data.

We have adopted the AER's preferred approach. Our revised forecast recurrent capital expenditure of $33.1M has been estimated using the actual recurrent capital expenditure for the period FY21-FY25.

We also addressed the AER's request to disclose any cybersecurity-related recurrent ICT capital expenditure in our revised regulatory proposal.[81] While JEN is not generally required to itemise recurrent expenditure, the AER requested this for transparency in assessing future cybersecurity costs.

Table 6.3 outlines our forecast ICT recurrent capital expenditure, including the share attributable to cybersecurity. Further details on the basis of the recurrent cybersecurity costs are provided in *JEN – RP – Att 05-01A Technology expenditure addendum*.

80 AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, p. 40.

81 AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, p. 41.

Table 6.2: Recurrent capital expenditure ($2026, million)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Recurrent capital expenditure (JEN non-cyber-related)	6.0	6.2	6.3	6.4	6.7	31.6
Recurrent capital expenditure (JEN cyber-related)	0.4	0.3	0.3	0.4	0.2	1.6
Total recurrent ICT capital expenditure	**6.4**	**6.5**	**6.6**	**6.8**	**6.9**	33.1

Totals differ slightly due to rounding adjustments.

6.2.2 Non-recurrent ICT capital expenditure (including CER)

We welcome the AER's draft decision to accept the drivers behind 11 of our proposed 19 ICT non-recurrent projects as prudent and efficient. For the remaining eight non-recurrent ICT projects we proposed the following for the next regulatory period:

- maintain proposal consistent with the forecast spend under the initial regulatory proposal (1 project)
- propose a lower or higher forecast capital expenditure compared to the forecast spend under the initial regulatory proposal (3 projects)
- Do not proceed with the proposal (4 projects).

We provide a summary of our revised proposal for non-recurrent ICT capital expenditure in Table 6.3. As noted above, refer to *JEN – RP – Att 05-01A Technology expenditure addendum* for our detailed response to the AER's draft decision.

Table 6.3: Non-recurrent ICT capital expenditure AER draft decision and JEN response

	AER draft decision[82]	JEN response
Adopt draft decision		
1. Digitising network switching 2. Geographic information system lifecycle enhancement 3. Market system interface replacement 4. Network operation geospatial enhancement 5. Emergency backstop lifecycle 6. Customer systems 7. Dynamic network planning with automation 8. Outage preparedness and response 9. 3D digital twin 10. FN - Foundational Distributed UFLS (Underfrequency Load Shedding) Capabilities 11. FN - Strategic Network Analytics Platform (SNAP) - Data Hub	Accepted JEN's proposed capital expenditure as prudent and efficient	We welcome the AER's draft decision that these non-recurrent ICT capital expenditures are prudent and efficient. We accept the AER's draft decision and have made minor changes as follows: • Market system interface replacement has now been incorporated in Market interface technology enhancements. • Outage preparedness and response is partially included under Customer systems.

82 AER, Draft decision, Jemena electricity distribution determination, 1 July 2026-30 June 2031, Attachment 2 – Capital expenditure, September 2025, sections A.5 (ICT) and A.6 (CER).

	AER draft decision[82]	JEN response
Maintain proposal		
12. End user computing	Did not consider this capital expenditure as prudent hence not accepted.	We do not agree with the AER and have included our forecast expenditure as it is and have provided additional justification.
Propose a different level of forecast capital expenditure		
13. Flexible trading arrangements (**FTA**)	Acknowledged the JEN is required to undertake this project but did not accept the proposed capital expenditure on the basis that it remains uncertain whether this expenditure should be classified as standard control services (**SCS**) or ancillary control services (**ACS**). It included a placeholder of $0.	We do not agree with the AER's classification for FTA as ACS and have addressed why FTA should be classified as SCS. The amount for FTA and MITE has been revised based on new information since developing our initial regulatory proposal. We recently submitted pass through applications for FTA and MITE costs to be incurred in the current regulatory period and have included the revised forecasts in the application for the next regulatory period in our revised regulatory proposal.
14. Market interface technology enhancements (**MITE**)	Acknowledged that the forecast is prudent but considered it to be likely over estimated, and therefore not efficient. It included an alternative estimate of $12.5 million.	
15. FN - Flexible exports	Did not accept the forecast capital expenditure of $25.6M for flexible services (import and export) on the basis that these services could be justified at much lower cost. The AER included an alternative estimate of $9.1M.	We have provided an alternate option for flexible exports that is lower in costs than the previously proposed option in our initial regulatory proposal. We are therefore proposing a reduced forecast expenditure for JEN's flexible export services.
Do not proceed		
16. FN - Flexible imports	Did not accept the forecast capital expenditure of $25.6M for flexible services (import and export) on the basis that these services could be justified at much lower cost. The AER included an alternative estimate of $9.1M.	We accept the AER's draft decision – withdrawn; focus is on flexible exports
17. Customer education	Did not consider this capital expenditure as prudent hence not accepted.	We withdraw the proposed project. We note that the AER's draft decision on our Tariff Structure Statement noted the importance of customer education programs in supporting tariff reform and encouraging demand response, which can contribute to lower prices over time. However, by rejecting our proposed step change, the AER has constrained our ability to deliver these programs at the scale required.
18. FN - VVC (Volt Var Control) rollout	Did not accept the forecast capital expenditure for Voltage and Power Quality Management of which the VVC (Volt Var Control) rollout is a component.	We accept the AER's draft decision – withdrawn.

	AER draft decision[82]	JEN response
19. FN – Network Analytics Program	Did not accept the forecast capital expenditure because JEN did not provide sufficient information to support the need for the investment and did not provide quantitate evidence to demonstrate prudency and efficiency of its forecasts.	We accept the AER's draft decision – withdrawn.

6.2.3 Non-recurrent ICT capital expenditure – new additions

We are proposing two new non-recurrent ICT capital expenditure for the next regulatory period: Cybersecurity program and the Victorian Emergency Backstop Mechanism2 (**VEBM2**) with a total forecast expenditure of $6.8M (Table 6.2).

Table 6.4: New non-recurrent capital expenditure forecast, Cybersecurity program and VEBM2 ($2026, million)[83]

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Cyber	1.7	1.2	1.3	1.5	0.8	6.5
VEBM2	0.3					0.3
Total new additions	**2.0**	**1.2**	**1.3**	**1.5**	**0.8**	**6.8**

6.2.3.1 Cyber

For our revised regulatory proposal, we are proposing an additional $6.5M non-recurrent ICT capital expenditure to address recently identified risks that were unknown at the time of the initial regulatory proposal.

Operational Technology (OT) underpins JEN's ability to operate a safe, reliable, and efficient electricity distribution network, but it is increasingly exposed to cyber security risks that could disrupt supply, damage assets, or compromise safety. Our strategy to address these risks is outlined in *JEN – RP – Att 05-01A Technology expenditure addendum*. As these risks were identified after JEN's initial regulatory proposal was submitted, the solutions and costs to address them were not included in that proposal. Our revised regulatory proposal now incorporates these measures to strengthen OT security and resilience.

6.2.3.2 VEBM2 reform

The Victorian Government established the Victorian Emergency Backstop Mechanism in orders made in 2023 and 2024 (**VEBM1**) to ensure that all new and replacement variable distributed photovoltaic (**DPV**) systems connected to Victorian distribution networks can be remotely interrupted or curtailed when the relevant DNSP is directed by the AEMO in a minimum system load event

In October 2025, updated licence conditions (VEBM2) were gazetted, imposing additional obligations on DNSPs like JEN.[84] These include near real-time installer notifications to test inverter-server connectivity, customer notifications within 24 hours for persistent disconnections, new reporting requirements within 10 business days, and improved redundancy for utility server restoration. These changes significantly impact JEN's digital systems, operational processes, and customer procedures.

83 JEN – RP – Att 05-01A Technology Expenditure.

84 Victorian Government Gazette, No S 553, Thursday 9 October 2025, Ministerial Order specifying licence conditions 2025.

While JEN previously implemented arrangements for VEBM1 funded through an AER-approved pass-through in 2024,[85] VEBM2 introduces new compliance requirements that demand immediate system upgrades, installer interface enhancements, and operational adjustments.

We recently submitted pass through applications for VEBM2[86] costs to be incurred in the current regulatory period and have included revised forecasts for the next regulatory period in the revised regulatory proposal.

References

6.2.4

Our proposed ICT capital expenditure outlined in this section is supported by a body of materials outlined in Table 6.5.

Table 6.5: List of attachments supporting our ICT capital expenditure

Name	Author
JEN – RP – Att 05-01A Technology expenditure addendum	JEN
[redacted]	[redacted]
JEN - RP - Support – Cybersecurity Program - CBA Model - 20251201	JEN
JEN - RP - Support - Customer Systems Lifecycle - CBA Model - 20251201	JEN
JEN - RIN - Support - End User Computing - CBA Model - 20250415	JEN
JEN – RP - Support - Flexible exports - CBA Model - 20251201	JEN
JEN - RP - Support - FTA pass through application – 20251104	JEN
JEN - RP - Support - FTA Appendix B pass through expenditure model - 20251104	JEN
JEN - RP - Support - MITE pass through application – 20251030	JEN
JEN - RP - Support - MITE Attachment A pass through expenditure model - 20251030	JEN
JEN - RP - Support - VEBM2 pass through application – 20251105	JEN
JEN - RP - Support - VEBM2 Appendix C pass through expenditure model - 20251105	JEN

85 AER, AER determination – Jemena VEBM cost pass through – 20 September 2024.

86 *JEN - RP - Support - VEBM2 pass through application – 20251105.*

7. Non-network – fleet

7.1.1 Forecast fleet expenditure - replacement

JEN welcomes the AER's draft decision to accept our proposed fleet vehicle replacement expenditure of $33.6M for the next regulatory period. The AER's draft decision will enable us to replace (or, where economic, rebuild) end-of-life vehicles to achieve our target level of risk associated with our fleet assets over the medium term. It will ensure that JEN meets its fleet asset management objectives of:

- ensuring the safety of employees, contractors and the public
- ensuring fleet is available for timely emergency response
- achieving the efficient cost of fleet management.

7.1.2 Forecast fleet expenditure - Growth

In April 2025 and in response to the AER's information request #05, we submitted our proposal for additional fleet to account for growth in replacement and augmentation capital expenditure.[87] We have repeated our proposal in the following sections below.

Given the uplift in capital expenditure requirements, we have commenced expanding the size of our workforce. We expect to add an additional 90 people (mostly field staff) each year for the next three years. To support this additional workforce, we will need an additional fleet beyond what was included in our initial regulatory proposal.

Specifically for the next regulatory period, we require 78 additional fleet including:

- *10 elevated work platforms (EWPs)*
- *1 new heavy commercial vehicle*
- *67 light commercial vehicles.*

As we are expanding the workforce now, we need these support fleet vehicles to also be in place as soon as possible. As a result, purchasing these additional vehicles is not a feasible option. Instead, we will adopt operating expenditure solutions in the short term by:

- *Hiring the additional EWPs, heavy commercial vehicles and trailers on a short-term basis until these new fleet items can be purchased and delivered over FY26 and FY29.*
- *Lease or hire light commercial vehicles and passenger vehicles. In FY30 and FY31, we will purchase (rather than continue to lease) these vehicles, consistent with our asset class strategy. Our fleet-growth forecast expenditure is presented below in Table xx.*

For the next regulatory period and consistent with what we submitted to the AER in April 2025 as part of our response to the information request #05 we are proposing a revised capital expenditure of $48M to also include an allowance for growth related fleet. Table 7.1 shows our revised regulatory proposal for fleet capital expenditure in the next regulatory period.

Table 7.1: Fleet – replacement and growth forecast capital expenditure ($2026, million)

	FY27	FY28	FY29	FY30	FY31	Total
EWP	2.8	10.8	4.3	1.4	1.8	21.0
HCV	2.4	1.2	1.1	0.0	0.0	4.8

87 JEN, *Response to information request IR – 005, Capex questions for multiple drivers*, 10 April 2025, section 8.

	FY27	FY28	FY29	FY30	FY31	Total
LCV	6.6	1.4	2.2	4.9	1.1	16.1
PV	0.9	0.6	1.2	1.0	0.1	3.7
Plan and trailer	1.1	0.5	0.3	0.1	0.1	2.1
TOTAL	**13.7**	**14.5**	**9.0**	**7.4**	**3.0**	**47.7**

7.1.3 References

Our revised fleet capital expenditure outlined in this section is supported by the material outlined in Table 7.2.

Table 7.2: JEN fleet model (replacement and growth)

Name	Author
JEN – RP – Support - JEN Fleet Model - 20251201	JEN

8. Capitalised overheads

In its draft decision, the AER did not accept our initial regulatory proposal to forecast capitalised overheads based on a single base year (2023–24). Instead, the AER substituted its own forecast based on a 3-year average of historical overheads for 2021–24 and applied a 75% fixed and 25% variable split. This resulted in a lower forecast of capitalised overheads for the next regulatory period than that proposed in our initial regulatory proposal.

In response, we have revised our proposal to:

- Expand the averaging period to include actual data for 2024–25, which became available after the AER's draft decision was published, making it a 4-year average (2021–25).
- Adopt a 50% fixed and 50% variable split, rather than the AER's default 75%/25% assumption.

We believe this better reflects the actual behaviour of our capitalised overheads over time and the costs we expect to incur over the next regulatory period.

8.1 Our revised approach

8.1.1 Averaging period

Our actual capitalised overheads have changed significantly over time, especially in recent years as our direct capital expenditure has increased. Our initial regulatory proposal sought to address this by using our most recent year of actual data (i.e., 2023-24) to forecast capitalised overheads. The AER rejected this proposal. It considered that we had not adequately justified departing from its standard forecasting method.

We appreciate that using a 3 or 4 year averaging period, rather than relying on a single year as the starting point, can provide a more stable and representative basis for forecasting capitalised overheads. That is a key feature of the AER's standard method. Our revised regulatory proposal adopts the 4-year 2021–25 period, which adds the 2024-25 year to the 3-year average adopted in the draft decision.

8.1.2 Fixed and variable weights

However, we also recognise that there is an important link between the reference period used and the assumed fixed and variable weights applied to it. A mismatch between the two can lead to material under or over statement of forecast capitalised overheads.

The draft decision adopted the default 75% fixed and 25% variable assumption included in the AER's standard forecasting method. We understand that this assumption originates from an analysis considered by the AER when making its determinations for the Queensland DNSPs for the 2015–20 regulatory periods. However, it was not obvious that the assumption was appropriate for the 2021–24 averaging period to which it was applied in the draft decision.

Prompted by this concern, we engaged Farrierswier to assess whether the 75% fixed and 25% variable (75/25) assumption remains appropriate for our proposed updated period (2021–25). These findings suggest the 75/25 assumption no longer reflects the true relationship between capitalised overheads and direct capital expenditure.

Farrierswier found that JEN's overheads have remained steady at around 15% of direct capital expenditure over the past seven years, indicating a strong year-on-year correlation with direct capital expenditure. Their analysis showed that JEN has experienced a significant increase in variable capitalised overheads since the AER first applied the 75/25 split to JEN as shown in Table 8.1. Retaining the 75/25 split would materially understate capitalised overheads over the 2026–31 regulatory period.

Table 8.1: JEN SCS actuals for the 2021–26 regulatory period (Real$2021, $million)

	Historical period (CY16–CY18 avg)	2021–25 actuals				
		2021-22	2022-23	2023-24	2024-25	Average
Capex attracting overheads	$90.4	$143.5	$176.6	$176.0	$228.52	$181.1
Capitalised network overheads						
Fixed (as per allowance)	$12.7	$12.8	$12.9	$12.9	$12.9	$12.9
Variable (implied)	$4.2	$8.3	$12.5	$16.9	$22.1	$14.9
Total	$16.9	$21.1	$25.4	$29.8	$35.0	$27.8
Fixed / variable split	**75 / 25**	**61 / 39**	**51 / 49**	**43 / 57**	**37 / 63**	**46 / 54**

If the 75/25 split were accurate when setting 2021–26 allowances, it implies a fixed overhead of $13M per annum (in Real$2021). In practice, our capitalised overheads have risen to an average of $28M per annum, driven by higher capital expenditure requirements. The fixed portion now represents only 46% of total overheads, with the variable component having increased significantly.

Farrierswier also undertook regression analysis that showed the relationship comprises 17% fixed and 83% variable components. Farrierswier notes that the AER has also moved away from 75%/25% split for SA Power Networks (SAPN) which proposed a 100% variable overhead approach.

Based on these findings, Farrierswier concluded that:[88]

> *Our analysis suggests that a 75% fixed and 25% variable assumption may not be appropriate when forecasting JEN's capitalised overheads for the 2026–31 regulatory period.*
>
> *Even if that assumption were appropriate when determining allowed capitalised overheads for the 2021–26 regulatory period, the significant growth in JEN's capex over that period implies that the 75% fixed portion is now significantly less and no more than 50%. Empirical analysis reinforces this logic, with regression results suggesting that the component is materially lower than previously assumed, with only around $4.7 million (Real$2021) of overheads being fixed each year—or just 17–28% of capitalised network overheads, depending on the period considered.*
>
> *Given this, we suggest that JEN assume that no more than 50% of its actual capitalised overheads over the 4-year period from 1 July 2020 to 30 June 2025 are fixed. Our empirical analysis may support a value that is even lower than that.*

Based on Farrierswier's analysis, we propose updating the fixed/variable split to 50%/50%. Applying 50%/50% fixed/variable split is consistent with empirical evidence that suggests that the variable weight is noticeably higher as shown in Table 8.1.

8.2 Our revised forecast

Table 8.2 compares our revised capitalised overhead forecast to that in our initial regulatory proposal and the AER's draft decision.

88 Farrierswier, 17 November 2025, *Memo: capitalised network overheads for the 2026–31 period*, p.8.

Table 8.2: Capitalised overhead forecasts ($2026, million)

	FY27	FY28	FY29	FY30	FY31	Total
Initial regulatory proposal	44.3	44.6	45.3	45.1	42.9	222.2
Draft decision	47.1	33.0	25.5	28.8	25.0	159.5
Revised regulatory proposal	**61.6**	**61.3**	**48.8**	**37.8**	**35.3**	**244.8**

8.2.1 References

Our revised capitalised overhead forecasts are supported by the material outlined in Table 8.3.

Table 8.3: Supporting material for the revised capitalised overhead forecasts

Name	Author
JEN – farrierswier - RP – Support - Memo - Capitalised overheads - 20251117	Farrierswier

9. Contract labour escalation

In our initial regulatory proposal, we applied real labour escalation to both internal and contractor labour costs, using forecast movements in the Wage Price Index (**WPI**) for the electricity, gas, water and waste services (**EGWWS**) sector in Victoria. This approach reflects expected growth in unit labour costs above inflation and ensures forecast expenditure reflects efficient and prudent costs.

In its draft decision, the AER rejected the use of WPI for escalating contractor labour costs and substituted a zero real labour escalation, allowing only CPI growth for 2025-26 to 2030-31.[89] We do not agree with the AER's approach. We are concerned that limiting escalation for contractor labour to CPI risks understating the efficient costs JEN must incur to provide network services. To assess this, we engaged HoustonKemp, who concluded that:

1. **Same labour market, same escalation logic**

   Internal and contracted labour are inherently similar and supplied within the same labour markets. DNSPs compete with other DNSPs, contracting firms, and utility providers for skilled labour. The rationale for applying WPI-based escalation to internal labour applies equally to contractor labour. There is no basis for treating them differently.

2. **CPI-only escalation is unrealistic and inconsistent with NER/NEL principles**

   Over time, unit labour costs have generally exceeded inflation and are forecast to do so. Assuming CPI-only growth for contractor labour does not provide JEN a reasonable opportunity to recover at least its efficient costs, contrary to the revenue and pricing principles under the National Electricity Law (NEL) and the capital expenditure criteria under the National Electricity Rules (NER).

3. **Potential unintended outcomes**

   Escalating contractor labour at a lower rate than internal labour could result in unintended outcomes, including DNSPs favouring internal labour, even when contractor labour is the least-cost option, to secure higher future allowances. This outcome is inconsistent with incentive based regulatory objectives.

4. **Productivity concerns are already addressed in WPI**

   The AER has previously expressed concerns that WPI-based escalation may overstate contractor labour costs if productivity improvements are not taken into account. However, the construction and composition of WPI indicated that it is net of productivity changes, and therefore no further adjustment is required. In addition, there is no evidence to suggest that productivity differs between internal and contractor labour.

HoustonKemp's analysis demonstrates that applying WPI-based escalation to contractor labour provides a realistic expectation of future costs and better satisfies the capital expenditure criteria. We therefore request the AER to reconsider its draft decision and adopt an approach consistent with these principles.

9.1.1 References

Our approach to apply real escalation to contract labour is supported by the report outlined in Table 99.1.

Table 99.1: Supporting material for real escalation to contract labour

Name	Author
JEN - Houston Kemp - RP - Att 05-03 Contract labour escalation report - 20251125	Houston Kemp

[89] AER, *Draft decision, Jemena electricity distribution determination, 1 July 2026 - 30 June 2031, Attachment 2 – Capital expenditure*, September 2025, p.13.

Appendix A
RIN Table

A1. RIN Table

Clause 1.3.5 of the reset RIN requires us to update our response to sections 4.4.4 and 4.4.5 of the notice. These updates are provided below.

Current regulatory period

Clause 4.4.4 requires:

For total capital expenditure expected to be incurred in the current regulatory control period, provide:

(a) a comparison of the total expenditure, disaggregated by expenditure category or driver, to the total forecast capex allowed for the current regulatory control period;

(b) an explanation of the drivers of differences noted in response to section 4.4.4 (a), for example the impact of efficiency gains, major new projects, project deferrals or rescoping, changing regulatory obligations, asset age, or other factors;

(c) a list of projects deferred in the current regulatory control period and included in the forecast capex for the forthcoming regulatory control period, and the rationale for the deferral.

We provide a comparison of total expenditure disaggregated by category in Table A1-2 below.

Our initial regulatory proposal provides an explanation of the allowance and actual spend by category. See Attachment 5-01 Capital Expenditure and our Technology Plan. However, there have been some changes, also shown in Table A1-2 below.

The primary reason for the differences is that our initial regulatory proposal reported an estimated allowance which included capital expenditure included in our reopener application (which we subsequently withdrew)[90] while the allowance reported in this revised regulatory proposal does not.[91] This can be seen primarily in the changes to connections and augmentation categories.

Table A1- 1: 2021-26 capital expenditure

	Initial proposal		Revised proposal	
Category	Estimated allowance	Actual / estimate	Allowance	Actual / estimate
Replacement	254.5	271.9	254.0	301.2
Connections	567.0	623.3	236.0	533.0
Augmentation	192.7	202.8	175.6	197.7
Non-network	159.3	141.8	149.3	191.4
Network overhead	125.7	169.7	109.2	169.8
Gross expenditure	**1,299.1**	**1,409.6**	**924.1**	**1,393.2**
Less capital contributions	*404.4*	*561.9*	*160.6*	*484.2*
Less disposals	-	*2.0*	*0.6*	*1.5*
Net expenditure	**894.8**	**845.7**	**762.9**	**907.5**

We also updated our actual / estimated spend to reflect actuals and estimated information for FY25 and FY26. As many of our data centre customers reapproached us seeking even large connections that originally

90 See here for more information.

91 We note that we have also not included adjustments for approved or proposed pass through amounts.

contemplated, this delayed some projects and lowering connection capex (and capital contributions) relative to what we reported in our initial regulatory proposal.

The difference between non-network capex is primarily due to the four ICT related cost pass through events (FTA, MITE, VEBM2, and accelerated meter roll-out) which occurred and have increased costs higher than we estimated in our initial regulatory proposal in FY25 and FY26.

The higher actual replacement expenditure for FY25 was due to higher volume of required conditioned based replacement of sub-transmission installations, poles (including reinforcements) and sub-transmission communications and protection equipment.

Forecast regulatory period

Clause 4.4.5 requires

For forecast capex for the forthcoming regulatory control period, provide:

(a) a comparison of the total forecast expenditure by category or driver to the total capital expenditure expected to be incurred in the current regulatory control period;

(b) an explanation of the drivers of differences noted in response to section 4.4.5 (a), for example the impact of expected efficiency gains, major new projects, project deferrals or rescoping, changing regulatory obligations, asset age, or other factors

We provide a comparison in Table A1-2 below.

The explanation of material differences between capital expenditure expected to be incurred in the current and forecast period is provided in our initial regulatory proposal (specifically Attachment 5.1 – Capital expenditure and our ICT Technology Plan).

As we outline in these documents, we are forecasting an increase in investment requirements to respond to the data centre boom (increasing connection capex), the condition of our assets (requiring an uplift in replacement expenditure) and fleet replacement (non-network). We also note that augmentation is increasing due to greenfield and infill development, which given existing network utilisation, requires an uplift in investment to address forecast constraints. Further, the increase in the level of investment also requires an uplift in overheads (as outlined in section 8).

We have updated our 2026-31 forecast largely to take into account feedback provided by the AER. While these factors change the specific forecasts the broader explanation of changes across investment requirements in 2021-26 and 2026-31 remains unchanged.

Table A1–1: 2021-26 and 2026-31 capital expenditure

	Initial Regulatory proposal		Revised regulatory proposal	
Category	**2021-26**	**2026-31**	**2021-26**	**2026-31**
Replacement	271.9	427.3	301.2	437.8
Connections	623.3	1,102.6	533.0	1,067.6
Augmentation	202.8	269.5	197.7	235.2
Non-network	141.8	207.2	191.4	201.1
Network overhead	169.7	222.2	169.8	244.8
Gross expenditure	**1,409.6**	**2,228.8**	**1,393.2**	**2,186.5**
Less capital contributions	*561.9*	*859.7*	*484.2*	*849.1*
Less disposals	*2.0*	*2.8*	*1.5*	*2.8*

	Initial Regulatory proposal		Revised regulatory proposal	
Category	2021-26	2026-31	2021-26	2026-31
Net expenditure	**845.7**	**1,366.6**	**907.5**	**1,334.7**

Note that 2026-31 replacement expenditure includes network resilience.

Appendix B
JEN mapping for replacement expenditure

B1. Revised replacement expenditure forecast

The purpose of this appendix is to show how we have grouped or mapped together replacement projects for the AER's easy reference.

In some instances, we were unable to match the AER's mapping for replacement capital expenditure in the draft decision, particularly those that related to switchgear, transformer, SCADA and Other replacement expenditure. Table B1–1 show JEN's mapping. We note that the mapping allocation might slightly differ, but the total capital expenditure remained at $419M as proposed for the revised regulatory proposal.

Table B1–1: JEN mapping of forecast gross replacement expenditure (direct costs), $2024, million

Project	Unique ID	FY27	FY28	FY29	FY30	FY31	EDPR Total
POLES							
Pole Replacement (Incl. Pole Top) - HV	A166	0.72	1.40	1.41	1.43	1.44	6.40
Pole Replacement (Incl. Pole Top) - LV	A170	0.41	0.80	0.80	0.81	0.82	3.64
Pole Replacement (Incl. Pole Top) - ST	A171	0.07	0.16	0.16	0.16	0.16	0.71
Pole Reinforcement - HV	A32	0.29	0.31	0.31	0.32	0.32	1.54
Pole Reinforcement - LV	A175	0.52	0.53	0.53	0.54	0.54	2.66
Pole Reinforcement - ST	A177	0.05	0.05	0.05	0.05	0.05	0.23
Undersize Pole Replacement	A477	0.22	0.47	0.48	0.48	0.49	2.14
Undersize Pole Reinforcement	A480	0.07	0.15	0.15	0.15	0.15	0.66
Pole Replacement - replacement of staked poles - HV	A528	0.18	0.79	0.79	0.80	0.81	3.37
Pole Replacement - replacement of staked poles - ST	A534	0.07	0.29	0.29	0.29	0.29	1.22
Pole Replacement - replacement of limited life poles unsuitable for staking - HV	A535	0.11	0.45	0.46	0.46	0.47	1.95
Pole Replacement - replacement of limited life poles unsuitable for staking - LV	A536	0.06	0.26	0.26	0.26	0.26	1.11
Pole Replacement - replacement of limited life poles unsuitable for staking - ST	A537	0.01	0.05	0.05	0.05	0.05	0.21
Concrete poles - replacements	Other 1	6.09	6.09	6.09	6.09	6.09	30.47
Total - Poles		**8.87**	**11.78**	**11.84**	**11.89**	**11.94**	**56.32**
POLE TOP STRUCTURES							
ST Insulators Replacement	A218	0.04	0.04	0.04	0.04	0.04	0.18
HV Crossarms Replacement	A221	1.82	1.84	1.85	1.87	1.89	9.27
HV Insulators Replacement	A227	0.13	0.13	0.13	0.14	0.14	0.68
LV Crossarm Replacement	A228	5.01	7.08	7.15	7.23	7.30	33.77
ST Crossarm Replacement	A241	0.12	0.18	0.19	0.19	0.19	0.86

Project	Unique ID	FY27	FY28	FY29	FY30	FY31	EDPR Total
Total – Pole top structures		**7.11**	**9.27**	**9.36**	**9.46**	**9.56**	**44.76**
OVERHEAD CONDUCTORS							
Ampact Connectors	A444	0.03	0.03	0.03	0.03	0.03	0.17
LV Line Clash Mitigation	A109	0.02	0.02	0.02	0.02	0.02	0.08
HV Open Wire Conductor Repl	A159	0.08	0.08	0.08	0.12	0.17	0.53
LV Open Wire Conductor Repl	A164	0.43	0.43	0.43	0.44	0.44	2.16
Overhead Line Fault Indicator Replacement	A381	-	-	0.18	0.32	0.26	0.77
HV Line Clash Mitigation	A507	0.02	0.02	0.02	0.02	0.02	0.08
LV Mains Removal in HBRA	A162	-	-	-	-	-	-
Facade Rectification Program	A401	3.10	-	1.66	2.41	-	7.17
Undersized Neutral Replacement	A165	0.15	0.30	0.30	0.31	0.31	1.37
Total – Overhead conductors		**3.8**	**0.9**	**2.7**	**3.7**	**1.2**	**12.3**
UNDERGROUND CABLE							
HV U/G Cable Replacement	A208	0.19	0.18	0.19	0.19	0.19	0.94
LV U/G Cable Replacement	A210	0.14	0.14	0.14	0.15	0.15	0.72
HV U/G Termination Replacement	A239	0.39	0.39	0.40	0.40	0.40	1.98
LV U/G Termination Replacement	A213	0.54	0.54	0.54	0.55	0.56	2.74
Replace Metal Trifurcating Boxes	A209	-	1.40	0.99	1.04	0.47	3.90
ST U/G Cable Replacement - BLTS-TH2 Oil Filled Cable	A354	-	-	-	0.84	1.03	1.87
ST U/G Cable Replacement - YVE-NT Oil Filled Cable	A357	-	-	-	1.46	1.77	3.23
ST U/G Cable Replacement - BLTS-NT Oil Filled Cable	A358	-	-	0.85	1.03	-	1.88
ST U/G Cable Replacement - TTS-CS-CN Oil Filled Cable	A359	-	-	1.71	2.08	-	3.80
ST U/G Cable Replacement - TTS-NEI/NH-WT Oil Filled Cable	A360	-	1.39	1.68	-	-	3.07
ST U/G Cable Replacement - WMTS-FE1 Oil Filled Cable	A361	-	7.55	-	-	-	7.55
BTS-FF ST Underground Oil Filled Cable Replacement	A448	-	-	-	-	-	-
Total – Underground cable		**1.3**	**11.6**	**6.5**	**7.7**	**4.6**	**31.7**
SERVICE LINES							
Service Fault Replacement	A152	0.86	0.87	0.88	0.87	0.86	4.3
Replace Serv and Alter Terms	A153	0.58	0.58	0.58	0.58	0.58	2.9
Install Disconnect Device	A155	0.04	0.04	0.04	0.03	0.01	0.2
Replace Services - Planned	A156	0.48	0.67	0.68	0.68	0.69	3.2

Project	Unique ID	FY27	FY28	FY29	FY30	FY31	EDPR Total
Pillar to Pillar	A211	0.04	0.04	0.04	0.04	0.04	0.2
Service Rectification Program	A157	5.45	4.76	3.84	3.89	3.93	21.9
Total – Service lines		**7.5**	**7.0**	**6.1**	**6.1**	**6.1**	**32.7**
SWITCHGEAR - DISTRIBUTION							
Indoor/Kiosk Switch Repl	A143	0.23	0.35	0.35	0.35	0.35	1.6
LV Switchgear Replacement	A142	0.03	0.04	0.04	0.04	0.04	0.2
Gas Switch Replacement	A144	0.37	0.78	0.79	0.79	0.80	3.5
HV Isolators Replacement	A147	0.52	0.53	0.53	0.54	0.54	2.7
LV Isolator Replacement	A149	0.46	0.46	0.46	0.47	0.47	2.3
Fuse Unit Replacement	A217	0.08	0.08	0.08	0.08	0.08	0.4
ACR Replacement	A469	0.23	0.23	0.23	0.23	0.24	1.2
HV Isolator Replacement (Single)	A900	0.03	0.03	0.03	0.03	0.03	0.1
Replace ILJIN and HV overhead GFB switches	A285	1.12	-	0.89	1.89	1.90	5.8
Distribution S/S switchgear replacement (indoor and ground type)	A195	0.56	1.34	1.29	1.25	1.24	5.7
Compact LV boards (J type fuses) in indoor subs	A399	0.11	0.27	0.26	0.25	0.25	1.1
Total – Switchgear - Distribution		**3.7**	**4.1**	**4.9**	**5.9**	**5.9**	**24.6**
SWITCHGEAR – ZSS							
Procurement of strategic spares (primary)	A21	-	-	-	-	0.44	0.44
Replace BLTS 22kV switchgear	A262	-	2.95	3.36	-	-	6.31
Replace CS 22kV switchgear (arc flash risk), 66kV isolators, 66kV CB, earth switch and transformer bushings	A19	-	2.84	8.52	6.02	-	17.37
Replace MAT 66kV busbar and isolator	A346	-	-	-	0.75	1.08	1.83
Replace NH 22kV switchgear, 66kV CB, 66kV isolator and earth switch	A29	-	-	-	4.24	10.62	14.86
CN zone substation redevelopment	A31	21.61	23.91	-	-	-	45.52
Total – Switchgear - ZSS		**21.6**	**29.7**	**11.9**	**11.0**	**12.1**	**86.34**
TRANSFORMER - DISTRIBUTION							
Kiosk Refurbishment	A108	0.08	0.08	0.08	0.08	0.08	0.40
Trans Ground/Indoor Repl	A243	0.45	0.45	0.45	0.46	0.46	2.27
Trans Pole Mounted Repl	A140	0.91	0.92	0.92	0.93	0.93	4.62
Transformer/Subs Kiosk Repl	A148	0.53	0.53	0.53	0.53	0.53	2.65

Project	Unique ID	FY27	FY28	FY29	FY30	FY31	EDPR Total
Installation of oil sampling points to OLTCs	A80	0.00	0.00	0.00	0.00	0.08	0.08
Replace all 66kV EE SRBP bushings	A327	0.00	0.57	1.19	0.61	0.00	2.37
Replace GOB bushings	A906	0.00	0.00	0.00	0.67	1.41	2.07
Replace GSA transformer bushings	A199	0.28	0.59	0.60	0.61	0.60	2.67
Total – Transformer - Distribution		**2.25**	**3.13**	**3.77**	**3.89**	**4.09**	**17.13**
SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS							
Replace FW relays	A126	0.00	0.00	0.00	0.00	0.00	0.00
Replace zone substation battery banks and chargers	A133	0.00	0.00	0.39	0.95	1.47	2.81
MPLS installation programme	A137	0.00	0.36	0.86	0.82	0.80	2.84
Sub-transmission communications and protection equipment replacement	A508	0.00	0.00	0.00	0.00	0.00	0.00
Procurement of strategic spares (secondary)	A186	0.00	0.00	0.23	0.23	0.00	0.46
PSCN switches, router replacement and installation programme	A38	0.00	0.00	0.00	0.10	0.18	0.28
Communications pole top radio replacement	A46	0.00	0.00	0.00	0.00	0.00	0.00
RTU replacement programme	A113	0.00	0.00	0.00	0.35	0.92	1.27
Supervisory cable and fibre optic cable replacement programme	A55	0.00	0.00	0.00	0.83	2.23	3.06
Replace CS relays	A259	0.00	2.81	8.43	5.95	0.00	17.20
Total – SCADA, network control and protection systems		**0.00**	**3.17**	**9.91**	**9.24**	**5.60**	**27.92**
OTHER REPEX							
Customer recoverable works							
CAP REC WORKS - IN LINE POLES / STAYS	A319	3.10	3.00	2.92	2.86	2.83	14.71
CAP REC WORKS - INTERSECTION REALIGNMENT (CRR)	A530	0.00	0.00	0.00	0.00	0.00	0.00
CAP REC WORKS - SUBS. MODIFICATION	A322	0.52	0.51	0.49	0.48	0.47	2.47
CAP REC WORKS - UNDERGROUNDING OF ASSETS	A323	2.21	2.14	2.09	2.04	2.02	10.50
CAPITAL/REC WORKS - SUBTRANS ASSET	A318	1.75	1.69	1.64	1.60	1.58	8.26

Project	Unique ID	FY27	FY28	FY29	FY30	FY31	EDPR Total
Melbourne Airport Rail Asset Relocations - Work Package 1	A47	0.00	0.00	0.49	0.46	0.00	0.95
Melbourne Airport Rail Asset Relocations - Work Package 4A	A135	0.00	0.00	0.90	0.84	0.00	1.74
Melbourne Airport Rail Asset Relocations - Work Package 4B	A383	0.00	0.00	0.90	0.84	0.00	1.74
Melbourne Airport Rail Asset Relocations - Work Package 6	A315	0.00	0.00	0.90	0.84	0.00	1.74
North East Link Project (NELP) Asset Relocations - Rivergum Package	A375	0.00	0.00	0.00	0.00	0.00	0.00
North East Link Project (NELP) Asset Relocations - Yallambie Package	A372	0.00	0.00	0.00	0.00	0.00	0.00
Recoverable Works (Roads)	A234	0.07	0.07	0.07	0.07	0.07	0.36
Total – Customer recoverable works		**7.65**	**7.41**	**10.40**	**10.02**	**6.97**	**42.46**
Emergency works							
Recoverable Works (emergency)	A231	0.00	0.00	0.00	0.00	0.00	0.00
Rectification of Damaged Assets	A6	3.84	3.73	3.63	3.56	3.53	18.30
Total – Emergency works		**3.84**	**3.73**	**3.63**	**3.56**	**3.53**	**18.30**
Others							
Efflorescence in buildings (TMA and SHM)	A408	0.00	0.00	0.00	0.41	0.45	0.87
Replace zone substation fences	A15	0.00	0.00	0.00	0.00	0.22	0.22
Upgrade zone substation earth grids	A204	0.00	0.00	0.00	0.11	0.24	0.35
Upgrade zone substation locks and security systems (swipe cards)	A173	4.82	4.03	4.17	4.99	3.25	21.27
Zone substation property minor capex works	A957	0.23	0.23	0.23	0.23	0.24	1.16
Bird/Animal Proofing Net Assets	A110	0.04	0.04	0.04	0.04	0.04	0.18
Surge Diverter Replacement	A216	0.17	0.17	0.17	0.17	0.17	0.84
Total - others		**5.26**	**4.47**	**4.61**	**5.95**	**4.61**	**24.89**
Total – Other repex		**16.75**	**15.61**	**18.65**	**19.53**	**15.11**	**85.65**
GRAND TOTAL – GROSS REPLACEMENT EXPENDITURE		**72.84**	**96.19**	**85.63**	**88.42**	**76.31**	**419.38**

Appendix C Specific demand forecasting concerns

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C1. Specific demand forecasting concerns

This appendix details how we have responded to each of Baringa's concerns.

Table C1–1: How we have considered the Baringa's feedback

Description	Baringa's feedback	Response
Significant concerns		
Data centres	We consider Jemena's assumption for including data centres within their demand and consumption forecasts has not been clearly justified. In Jemena's methodology, it is stated they consider all current enquiries received for DCs, irrespective of how advanced the connection process is. This contrasts to the other Victorian DNSPs that only consider 'committed and contracted' DCs in their demand forecasts. [92]	Data centre loads are not included in the demand forecast which drives our revised proposal augmentation program at all. We note that data centre loads were only included in the demand forecast applied in the Major Customer Network Development Strategy. Expenditure related to this strategy has not been included in our augmentation forecast.
Other block load forecasts	Related to the assumption used for data centres, Jemena has base, low and high scenarios for their block load forecasts. The final block load maximum demand is based on a weighted average, that is weighted 50% to the 'base' scenario, 25% to the 'low' scenario, and '25%' to the high maximum demand forecast scenario. The assumption adopted is that the likelihood of connection is driven by level of advancement of connection process, but it is unclear the rationale for adopting a speculative weighted average that contributes to demand, and we would better consider tangible evidence from prospective connections on their progress towards commercial operation. [93]	We have updated our forecasting methodology to only include committed large customer loads.
Native demand forecasting: reconciliation	Jemena forecasts native demand both in their internal bottom-up forecast and Jemena's consultant's top-down forecast. While Jemena states these forecasts are undertaken independently, their internal bottom-up forecast relies on the consultant's modelling for a key input. [94]	We have changed our approach to only rely on Blunomy's Vision spatial forecast.
Native demand forecasting: logistic functions	While logistic functions are generally considered reasonable for population growth, this overall approach is not well documented and difficult to validate. [95]	Blunomy provide further details in section 6.2.2 of *JEN – RP – Support – Blunomy – Detailed demand forecasting methodology – 20251121 -confidential.*
Spatial disaggregation	We have significant concern about Jemena's approach to spatial disaggregation [of CER] as this is not reconciled to their system-level approach.[96]	We have updated our forecasting methodology to apply and use Blunomy's Vision forecast which spatially disaggregates CER. This is a shift from our Initial Proposal where we applied a top-down approach to distribute

[92] Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.29. Available here.

[93] Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.29. Available here.

[94] Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.30. Available here.

[95] Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.30. Available here.

[96] Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.31. Available here.

Description	Baringa's feedback	Response
		CER uptake at the spatial level via our reconciliation process.
Inclusion of modelled connection growth at the spatial level	We consider it would be better practice to include more modelled, population-driven connection growth at the spatial level (i.e. EV, PV, and population-driven growth). Jemena's overall approach is not ideal and therefore would recommend more detailed demand drivers to be modelled at the spatial level.	We have updated our forecasting methodology to apply and use Blunomy's Vision forecast which spatially disaggregates and models population-driven connection growth at the spatial level.
Major customer blockloads	We have significant concern with Jemena's approach to incorporating major customers into their demand forecasts due to the high level of subjectivity[97]	We have updated our forecasting methodology to only include committed large customer loads.
Major customer blockloads	Materiality thresholds could be established based on minimum size (e.g., 1MW) and/or relative to the capacity of the assets (e.g., 5% of the asset capacity) to mitigate the potential overlapping with the trend component. Jemena's consultant's approach to addressing the potential overlap between blockloads and other components of the modelling for system-level demand may not be sufficient as it is limited to population-driven blockloads, and may also fail to properly account for the impact of other demand drivers such as electricity price increases, demand management and greater energy efficiency that continue to drive down demand from the existing broader customer base.	The threshold for major customer/data centre blockloads applied is based on customer connection to our subtransmission network (e.g. 66 kV network voltage level) and is separated from our underlying demand forecast so that there is no overlap. Blunomy Vision forecasting methodology spatially accounts for other material demand drivers such as electricity price increases and energy efficiency. Further detail is set out in Chapter 6.2 of *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 -confidential.*
Review of forecasting approach	We have significant concern with Jemena's description of their forecasting review process and consider their approach could be better clarified and improved. Jemena states they review their methodology on an annual basis, comparing their bottom-up forecast demand to recorded actuals and investigate any discrepancies. It is unclear how discrepancies are addressed or if overall internal forecasting methodology undergoes a review. [98] Meanwhile, the consultant methodology provided outlines significant detail on the spatial forecast methodology, however, this is inconsistent with their role of providing a system-level forecast.	We note that we have changed our forecasting approach to rely on the Blunomy forecast, including for spatial forecasts. Further information on our forecasting approach (which has been updated to address the feedback received) is provided in *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 -confidential.*
Northern Growth Corridor	On reviewing Jemena's approach to spatial disaggregation for the Northern Growth Corridor Business Case (slides 43-46), we found calculation errors in Jemena's forecast numbers. These errors included demand components by feeder not summing to the feeder's MD and block load contribution to MD exceeding the block loads in the source data.	We can confirm that there are no errors in the loads applied in our Northern Growth Corridor Network Development Strategy. We note: • Baringa could not reconcile total demand to its individual components as planned load transfers were not taken into account.

97 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.33. Available here.

98 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.35. Available here.

Description	Baringa's feedback	Response
		• Baringa considered that two identical loads (same address, construction date and estimated load) were a potential double counting. This is not correct. It is instead a single large load divided into two and supplied by two different feeders.
Energy consumption block loads	We consider the major customer approach that Jemena is proposing for block loads to be somewhat unreasonable given the high materiality on the forecast. Block loads are taken from the 2023 peak demand forecasting. It is unclear why the block loads from the latest peak demand forecast are not being used. Block loads and data centres make up 83% of the total energy consumption growth using their weighted average load uptake rate. This is then explained to be used as an input of the capacity update which are then moderated. Given the materiality, we would expect to see more evidence justifying the load uptake profiles of major customers and block loads. [99]	The demand forecast which underpins our augmentation forecast does not include data centres and only includes committed large customer loads. Our energy forecast is aligned with our connection forecast. It includes loads from data centres inflight or where we have issued a firm offer.
Moderate concern		
Understandability of Bayesian Neural Network model	Jemena's use of historical data is somewhat unreasonable as it is not transparent and unable to validated. The starting point maximum demand at HV Feeder level uses historical, weather-corrected and transfer-corrected data. In the top-down model, historical demand, weather data, and calendar data feed into the short-term model. Using a Bayesian Neural Network (BNN), this model generates a range of stochastic demand outcomes driven by weather scenarios (based on 12 year historical data). Usage of a BNN is reasonable for capturing multiple nonlinear relationships. However, the algorithm is complex, not transparent and difficult to validate without clear data. We therefore consider this approach is not easily reproducible as Jemena has not sufficiently described how this is being derived from Jemena's consultant's model. [100]	Further information on our forecasting approach (which has been updated to address the feedback received) is provided in *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 -confidential.* We note that Endgame Analytics has reviewed the methodology and found that while it is sophisticated it is neither unnecessarily complex nor difficult to understand, see *JEN – Endgame Analytics – RP – Support - Demand forecasting review report*
Usage of HDD and CDD in model methodology	We have a moderate level of concern with Jemena's weather normalisation approach because it does not sufficiently factor the impact of heating degree days (HDD) and particularly cooling degree days (CDD) in the regression. The methodology for max demand normalisation states that historical second-order regression determines relationship between temperature and maximum demand. Raw degrees C is not the best driver of demand, as demand does not increase monotonically with temperature (peaking at either	We have shifted to relying on the Blunomy forecast, where the approach to weather normalisation is set out in Chapter 3 and section 6.2.3, see *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 -confidential.*

99 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.38. Available here.

100 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.32. Available here.

Description	Baringa's feedback	Response
	high or low temps). We consider it would be preferable to use HDD and CDD in the regression. Regression process describes deleting unwanted points to improve the curve fit. Our analysis shows that weather normalisation is only applied to the summer forecast as Jemena considers the sensitivity is negligible during winter.[101] We consider this somewhat unreasonable as the low temperature impacts are important for demand forecasting given the trend towards heat electrification	
Validation of bottom-up forecasts	We consider Jemena's approach to validating their bottom-up forecasts to be somewhat unreasonable, as we have concerns about the independence of their bottom-up and top-down forecasts as Jemena's consultant's modelling plays a key role in both. Jemena produces the bottom-up forecast, which is scaled to match system level top-down forecast by Jemena's consultant. However, the key input to Jemena's internal bottom-up forecast is provided by their consultant. In addition, the block loads included at different levels of the networks may not be the same, as each may differ in what have been captured in the trend and other components. However, it is unclear from the information submitted by Jemena about the approaches to block loads at the spatial level vs system-level, and how they reconcile to each other. [102]	We have updated our forecasting methodology to rely solely on the spatial Blunomy forecast – and no longer undertake any reconciliation. How block loads are treated in the Blunomy forecast is set out in Chapter 12 of *JEN – Blunomy – RP – Support – Detailed demand forecasting methodology – 20251121 - confidential.*
Using the latest AEMO input	We are not satisfied that Jemena's explanation of the use of AEMO scenarios is reasonable. Their methodology describes alignment with the 2023 max/min demand forecast, and therefore relies on out-of-date AEMO 2023 inputs. All AEMO inputs should be sourced from the latest update available at the time and linked to the relevant scenario. Using the latest AEMO scenario and forecasting update would demonstrate that Jemena's forecast is based on the most recent input information. [103]	The Blunomy forecast has been updated to use the latest AEMO 2025 IASR inputs. Please refer to *JEN - RP - Support - Short form demand forecast methodology - 20251201 – Public.*
Energy consumption QA process	It's unclear what review or QA processes are performed on the energy consumption forecasts because this has not been clearly outlined in the information provided by Jemena. [104]	We worked with and reviewed the outputs from Blunomy, which prepared our energy consumption forecasts. We reviewed the forecasts with and without data centre loads, including at a more granular tariff class level. This process ensured our larger data centre energy consumption forecasts were accurately

101 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.32. Available here.

102 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.34. Available here.

103 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.38. Available here.

104 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.38. Available here.

Description	Baringa's feedback	Response
		allocated between our large business high voltage and subtransmission tariff classes.
Some concern		
Growth rate for business numbers	Our analysis indicates that Jemena's residential and business customer numbers grow with the population growth rate (however we have some concern regarding the growth rate for business numbers as this is not clearly stated within the methodology).[105]	Blunomy provide further details in Chapter 14 of *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 -confidential.*
Description of economic growth in methodology	We have some concern with Jemena's assumptions for economic growth because their methodology documents do not refer to a clear primary source and the process for model ingestion. Jemena's consultant is stated as the independent forecaster source for Jemena's underlying organic economic growth, adopting GSP forecasts from AEMO's ISP. However, the methodology has not clearly explained the incorporation of economic growth into native demand. [106]	Blunomy provide further details on how macroeconomic drivers are considered when forecasting demand per customer segment in section 6.2.3 of *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 -confidential.*
CER uptake not at spatial level	We have some concern with Jemena's technological uptake forecast because it is unclear the extent to which the methodology contributes into the system-level demand forecast. System-level EV, PV, and BtM BESS uptake are provided in Jemena's consultant's top-down model. [Redacted] While this is a reasonable for the system-level, it does not accurately take into account the potential discrepancies in the granular locational detail across different parts of Jemena's network[107]	We have updated our approach and now solely rely on Blunomy's forecast, which includes a spatial CER forecast.
BESS demand profiles	BESS profiles are produced by Jemena's consultant. By default, Jemena's consultant derives battery profiles based on historical data. This generally aligns with the BESS acting to optimize self consumption (i.e. charging from solar). Output demand shows BESS contributing (rather than reducing) to increasing max demand and reducing min demand, which is counter-intuitive although the impact of this is very small. [108]	The BtM BESS sample data used to define battery profiles has been updated and in turn results in this item no longer being observed in the model results. The updated battery profiles have resulted in BESS reducing demand during peak times.
EV ISP Forecast used are out of date	The top-down peak demand forecast incorporates AEMO Step Change, however the EV forecasts use ISP inputs, which are out of date.[109]	The Blunomy forecast has been updated to use the latest AEMO 2025 IASR inputs. Please refer to *JEN - RP - Support - Short form demand forecast methodology - 20251201 – Public.*
Customer numbers	Jemena states that it projects their residential customer numbers using the VIF 2023 population	We note that our forecasts are based on independent 3rd party forecasts.

105 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.27. Available here.

106 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.27. Available here.

107 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.30. Available here.

108 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.34. Available here.

109 Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.34. Available here.

Description	Baringa's feedback	Response
	and household projections, and projects non-residential customer numbers using Victorian GSP growth rates sourced from AEMO. However, the customer number forecasts included by Jemena in the RIN grow by a uniform 9.1% over the regulatory period across each of the residential, small business and C&I customer segments. This uniform growth rate is a surprising outcome given the residential and non-residential customer numbers have different drivers. [110]	
Energy consumption approach	Jemena uses a relatively consistent approach between their native demand forecasting and energy consumption, although we do have some concern with the degree of reconciliation between the two outputs.[111]	Blunomy provides further details in section 15.4 of *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 -confidential..*
Limited concern		
BtM BESS model impact	We note that the model assumes BtM storage is acting to increase max demand and also reduce minimum demand, whereas we would expect the impact to be reversed. This assumption has not been able to be validated and has raised a minor concern for us.[112]	The BtM BESS sample data used to define battery profiles has been updated and in turn results in this item no longer being observed in the model results. The updated battery profiles have resulted in BESS reducing demand during peak times.
Timing		
Forecast inputs used	Instead of using AEMO's Feb 2025 IASR update, Jemena should update to the latest information available which will be July 2025 IASR plus any further updates in ESOO. [113]	The Blunomy forecast has been updated to use the latest AEMO 2025 IASR inputs. Please refer to *JEN - RP - Support - Short form demand forecast methodology - 20251201 – Public.*
Customer numbers	We understand Jemena's the customer number forecasts in Jemena's proposal RIN are now outdated and different from their current view on customer number forecasts. We recommended Jemena updated their revised proposal RIN with their latest customer number forecasts and ensure those forecasts align with their stated methodology.	We updated our revised proposal customer number forecast for pricing purposes using the latest information available. We note we have not updated our connections forecast as this was accepted by the AER.

Table C1–2: Additional information requested

Description	Baringa Comment	Action Taken
BtM Battery Calculations	Evidence and example of calculation of BtM storage contribution to peak demand	The BtM BESS sample data used to define battery profiles has been updated and BESS no longer contribute to increasing peak demand.
Data centre and block load calculations	Evidence from each prospective connections (data centres and other major customers) on their	In reference to data centres and other major customers, our demand forecast which underpins our augmentation forecast does not

[110] Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.36. Available here.

[111] Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.37. Available here.

[112] Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.28. Available here.

[113] Baringa 2025, *Distribution demand forecast assessment: Review of Jemena's 2026-31 regulatory proposal,* p.48. Available here.

Description	Baringa Comment	Action Taken
(demand and energy)	progress towards commercial operation, including but not limited to: • materiality threshold applied • information sources and supporting documents from the requested parties • method for calculating the loads or validating the loads requested • whether the load is included or excluded from load forecasts at zone substation and above due to potential overlapping. Methodology for identifying overlap with organic population growth Evidence and breakdown for load uptake profiles Evidence of reconciliation of block loads at spatial-level vs system-level	include any data centre loads. It only includes committed loads from one major customer connected to the sub-transmission network. Our energy forecast is consistent with our connection forecast (see section 2.1– and only includes in-flight and firm offer connections.
Calculation of population /GSP driven growth	Calculation of population/GSP driven growth	See section 6.2.3 and Chapter 14 of *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 - confidential.*.
Explanation on manual interventions	Evidence and example of manual intervention for adjustments and their scale for the organic growth rate	These adjustments are no longer made as we now rely solely on the Blunomy forecast.
Energy consumption methodology explanations	Additional detail on energy consumption methodology	See chapter 15 of *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 -confidential.*.
CER uptake combined approach	Explanation of how bottom-up methodology feeds into system-level forecast	We no longer apply this methodology. Instead, we solely rely on the Blunomy forecast.
BNN validation	Calculation and worked example of BNN outputs	See section 16.3 of *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 -confidential.*.
Validation with historical data	Data and example evidence of Monto Carlo simulation to validate historical outcomes	See section 16.3 of *JEN – Blunomy - RP – Support – Detailed demand forecasting methodology – 20251121 -confidential.*.