Jemena Electricity Networks (Vic) Ltd

2026-31 Electricity Distribution Price Review Regulatory Proposal

Attachment 05-01

Capital expenditure

Table of contents

List of tables

List of figures

List of appendices

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Economic life	The age of an asset at which the total cost of providing the required level of service from the asset no longer represents the lowest long-run cost to customers of providing that required service (i.e. after considering alternatives)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
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 Australian Energy Regulatory to review electricity distribution prices for the next regulatory period.
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 between networks due to different operating factors, environmental factors and 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 and context

We forecast a total gross capital expenditure of $2.2B or $1.4B net (after customer contribution terms) in the next regulatory period, a 58% increase from our expected capital expenditure for the current regulatory period.

Around half of our forecast gross capital expenditure is for connections driven by increased demand for connections from large customers, including data centres. The remaining half of our forecast expenditure will help us to meet and address the key operating challenges we have started to experience during the current regulatory period and will continue to experience during the next regulatory period. Our forecast spend will help us to:

- invest in asset replacement programs to maintain our network's reliability and manage risk
- manage the growing challenges associated with maximum and minimum demand and address the greater reliance on the electricity network to support the substitution of reticulated gas and transition to transport electrification
- accommodate more customer energy resources into our network, benefitting all customers
- leverage new technology solutions to use our network more efficiently, respond more quickly to changing customers' expectations and deliver a more efficient service.

Our forecast addresses our customers' expectations on affordability and the level and quality of service that they expect. We take this to mean our customers will pay no more than necessary for safe and reliable services. We do this by ensuring that our proposed projects and programs are prudent and efficient and based on the option that will give our customers the highest net benefit over the long term. We have submitted justification documents as part of our regulatory proposal.

To further demonstrate prudency, our forecast is the result of progressive and various iterations informed by our customers' feedback, the AER's initial feedback on our key capital projects and the latest demand forecast and information on major connection applications. We tested the scope of our proposed investments and identified how we can deliver the best value for our customers given their competing priorities. As a result, our forecast for each capital expenditure category under the regulatory proposal is lower than what we have proposed in the Draft Plan. The exception is the forecast expenditure for connections which has increased significantly since then. Our forecast has been updated to reflect the latest information and developments on new major connections, including data centres. Nonetheless, despite the increase in costs, our broader customers would benefit even more from increased demand from major customer connections by reducing customer bills in the next regulatory period.

We have developed our forecast consistent with the capital expenditure objectives and criteria contained in the National Electricity Rules (NER) and the Australian Energy Regulator's various guidance and guidelines as demonstrated throughout this attachment and through our supporting documents. We have also been guided by our ISO55001 accredited governance framework ensuring a prudent approach has been followed.

All dollar values in this document are expressed in $2026 unless stated otherwise. Where appropriate we use $2024 to provide alignment with business cases and supporting documentation.

1.1 Our forecast capital expenditure

Transformative forces are driving significant change. The energy system as a whole – gas, electricity, transport – is transforming due to the global push to reduce emissions to reduce the impact of climate change while we are at the beginning of the artificial intelligence revolution. This revolution, together with the existing digital transformation trend, is driving a massive surge in data centre investment. Closer to home, the top community concerns include the cost of living, housing affordability and inflation.

We are at the centre of each of these global and local forces. We are fortunate to have the opportunity, and responsibility, to play our role to:

- support emission reductions by ensuring our network can accommodate electrified gas and transportation loads.
- ensure consumers benefit from the energy transition by facilitating the adoption of consumer energy resources.
- connect data centres, which are concentrated in our network area, by delivering economic benefits for our local community and leading to reduced bill reductions from lower average unit costs.
- play our role in improving housing affordability by facilitating supply in greenfield and existing areas.
- support new and existing business access electricity to reduce supply costs and in turn cost of living and inflation.

While the opportunity is significant, so are the risks. Our network is ageing, and the components of our network have reached end of life. We are also conscious of the link between our network performance and the broader social licence and customer trust underpinning the energy transition. For instance, if the electricity system is not considered reliable or resilient, this will lead to delays in the electrification of gas and transport. There is also the risk that the benefits of the energy transition are not shared equally across our customer base.

Lastly, there are substantial risks, as experienced in overseas networks, in adding significant loads. This can lead to connection delays or decreased reliability with flow on societal and economic consequences.

In this context we have developed a capital expenditure forecast of around $2.2B for the next regulatory period or $1.4B in net (after customer contribution terms) – a 58% increase from current period capex.

Under the current regulatory framework, connecting customers are expected to pay their way to connect and not have this cost recovered from existing customers. To achieve this, we charge large connecting customers a capital contribution after accounting for the amounts we charge through their network bills. Only the net capital expenditure is recovered through network tariffs.

The increase in forecast expenditure will be across the different capital expenditure categories, with the megatrends associated with the energy transition, data centres, poor asset conditions and regulatory obligations driving the substantial increases. The megatrends significantly influence not just JEN's expenditure needs but also the other distribution network service providers (DNSPs).

Table 1–1 outlines the breakdown of our forecast expenditure for the next regulatory period.

Table 1–1: Forecast gross capital expenditure, $2026, millions

	2021-26		2026-31
Category	Estimated allowance	Estimated expenditure	Forecast expenditure
Replacement	254.5	271.9	427.3
Connections	567.0	623.3	1,102.6
Augmentation	192.7	202.8	269.5
Non-network	159.3	141.8	207.2
Non-network – ICT	*120.1*	*125.0*	*153.5*
Non-network - Other	*39.2*	*16.8*	*53.7*
Network overhead	125.7	169.7	222.2
Gross expenditure	**1,299.1**	**1,409.6**	**2,228.8**
Less capital contributions	404.4	561.9	859.7

	2021-26		2026-31
Category	Estimated allowance	Estimated expenditure	Forecast expenditure
Less disposals		**2.0**	**2.8**
Net expenditure	**894.8**	**845.7**	**1,366.3**
Included above			
CER integration	19.4	17.6	84.5
Network resilience			3.2

Notes: The capital expenditure allowance includes expenditure related to cost pass-through application for the Victorian Emergency Backstop Mechanism (approved by the AER in 2024) and the re-opener application (which the AER is currently considering). Excluding these applications, the Gross capital expenditure allowance is $926M. Our allowance is estimated because the AER's decision on our reopener application is outstanding at the time of submitting this JEN 2026-31 Proposal.

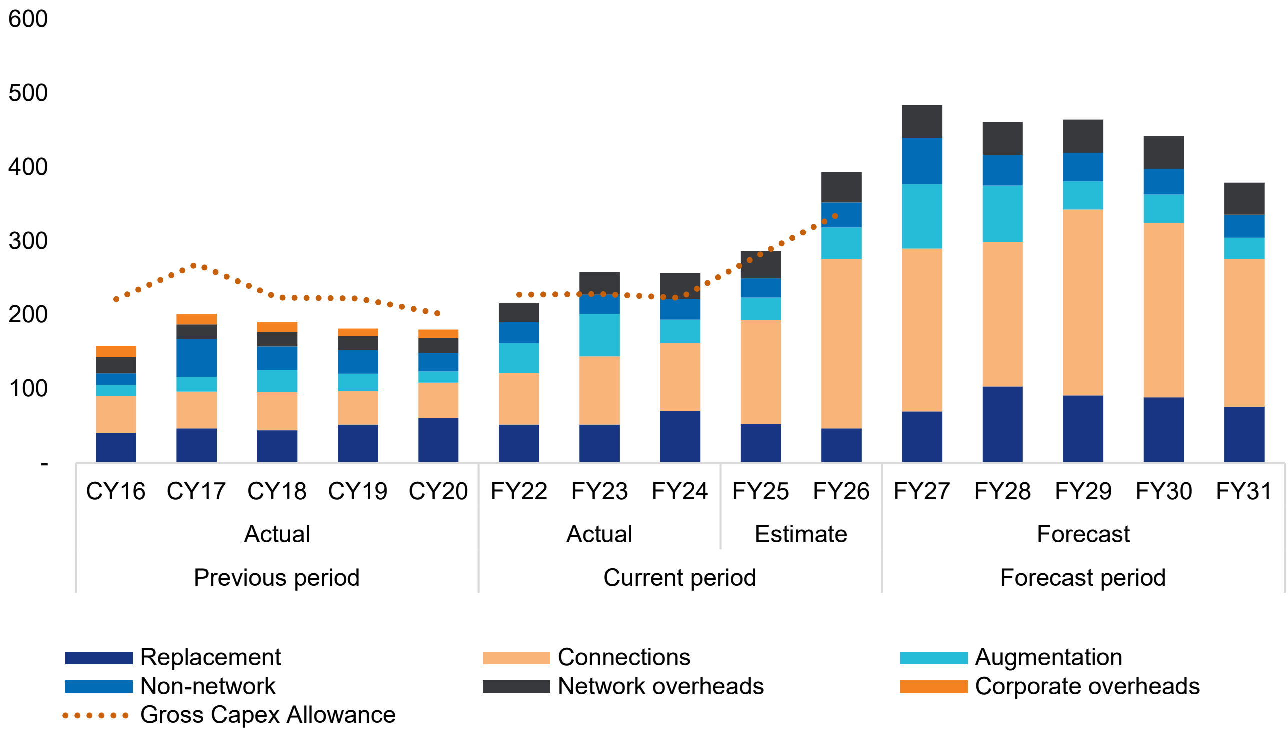
The indicated capital expenditure for customer energy resources (CER) integration and network resilience are for presentation purposes only. In this table, the CER integration capital expenditure is captured under Augmentation and Non-Network ICT while the forecast capital expenditure for network resilience is captured under Non-Network – ICT and Non-network -Other.

The estimated expenditure for Non-network – ICT includes SaaS that have shifted to operating expenditure in FY26. This figure differs from the total Non-network ICT expenditure in section 8, as the latter excludes SaaS.

The gross capital expenditure and net capital expenditure in Figure 1-1 and Figure 1–2, respectively, reflect the changing operational challenges JEN has started facing and will continue to face. Traditionally, our forecast is generally predictable and shaped by our customers' expectations, regulatory obligations regarding the safety, reliability, and security of the network, and forecasting new connections. Our actual capital expenditure for the previous regulatory period is reflective of these key drivers. However, our operational challenges have started to change during the current regulatory, and we expect these challenges to continue and become even more challenging over the next regulatory period.

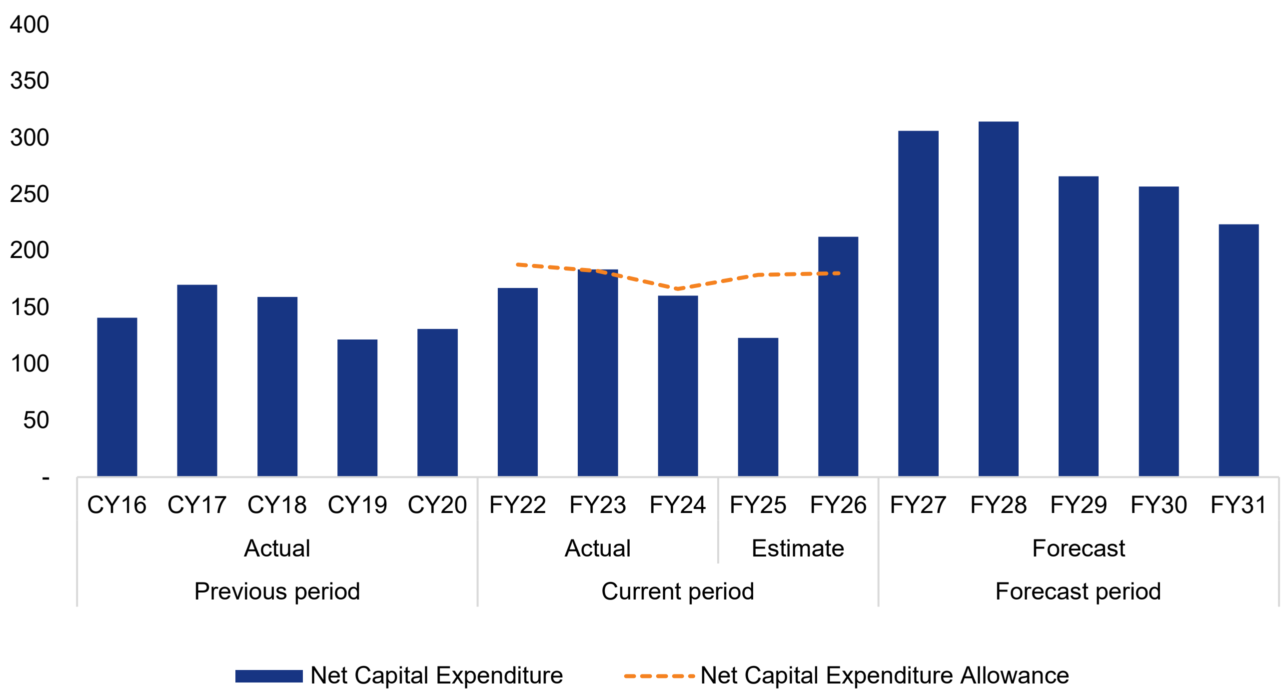
We provide an overview of the operating challenges or key drivers influencing our estimated capital expenditure for the current regulatory period and our forecast spend in the next regulatory period. The regulatory proposal documents and this attachment discuss these operating challenges in more detail.

Figure 1-1: Gross capital expenditure, $2026, millions*



*Gross allowance refers to the allowance approved by AER for the current regulatory period plus the cost pass through application for the Victorian Emergency Backstop Mechanism (VEBM) and our reopener application. See further explanations in section 1.2 below.

Figure 1–2: Net capital expenditure, $2026, millions[1]



1.1.1 Overview of challenges affecting JEN's current and future operations

Data centre boom

For JEN, one of the most significant challenges is accommodating demand for major customer connections such as data centres. As shown in Figure 1-1, our expenditure for connections has started to increase significantly during the current regulatory period and is expected to become even higher in the next period. The data centre boom has been primarily driven by the emergence of Artificial Intelligence (AI), cloud computing, big data analytics, and other technologies, all demanding extensive local data storage and processing power. Given JEN's optimal location, many data centres are favouring JEN's network.

Data centres are energy-intensive and need to be operational 24/7. They are designed with high levels of electricity redundancy to minimise the chance of a power outage. This means that when they connect to the network, costly upgrades are often required to ensure they can get all the electricity they need all the time. The other challenge with data centres is the unforeseen size and volume of these connections. As of September 2024, new major connections have collectively sought >3,800 MW of capacity from JEN, which is approximately 200% of JEN's existing installed substation capacity. The situation is unprecedented for JEN, and yet we have a regulatory obligation to offer to connect them.[2] Timing of entry is another challenge for us. This is why we are proposing several contingent projects due to uncertainty in timing.

Nonetheless, despite the increased costs, our existing customers benefit from connecting additional major customers to our network. This is because the largely fixed network costs are spread across a larger customer base, thereby reducing the average cost per customer and lowering future bills. In addition, new connecting customers are required to make an upfront contribution which ensures that our existing customers do not pay more than they would without the addition. Therefore, although we are forecasting gross capital expenditure to increase, the increase in net capital expenditure is much more moderate as we are also forecasting capital contributions to partially offset the gross capital expenditure.

[1] As outlined in 3.4, we are moving to reporting customer contributions on 'as commissioned' to an 'as incurred' basis. As part of this, we have made an adjustment in 2024-25 (higher contributions) to account for contributions from FY22-FY24 projects which have not yet been reported (but would have if we had been reported on an 'as incurred' basis).

[2] NER, Cl. 5A.F.1(a) and Cl. 5A.F.4(a).

> Section 3 details our forecast expenditure for connections including how data centres drive our capital expenditure requirements for the next regulatory period.

Energy transition

There are five global megatrends that are currently driving the energy transformation. Climate change, customer choice, policy changes, the rapid development of technology, and the current cost of living challenge have all accelerated the rapid transformation of the Australian energy market. Our network must adapt to this new environment for the long-term interests of our customers. The five global megatrends that have influenced our regulatory proposal are decentralisation, decarbonisation, electrification, the rise of energy storage and digitisation.

> We discussed these five global megatrends in more detail in chapter 3 of the 2026-31 Proposal, Attachment 03-01[3] and in sections 3 and 4 below.

As a part of the five global megatrends, more households and businesses are transitioning towards full electrification and are investing in Consumer Energy Resources (CER).[4] To support this change, our network must adapt to meet our customers' expectations and accommodate the increasing divergence between higher maximum demand and lower minimum demand, decentralised energy exports and customer energy storage. To meet these changing expectations, we need to increase the physical capacity of the network and/or implement projects that will safely maintain the voltage and frequency levels of the network while accommodating more CER. Complementing these upgrades with investments in our digital capabilities will contribute to delivering an efficient outcome for customers and enabling access to renewable energy and new market products and services. Limiting CER export, by deferring augmentation, CER and ICT projects, is not our preferred option as it is not consistent with our customers' expectation of facilitating the transition to renewable energy sources. It also increases system security risks.

> Sections 3 (Connections), 4 (Augmentation), 5 (CER Integration) and 8 (Non-network – ICT) discuss in detail our forecast expenditure aimed to address the challenges brought by the five global megatrends.

Existing condition of assets

Many of our LV poles and pole top structures are aging, and our condition-based assessments and actual inspections show that many of them are at risk of failure in the next regulatory period if they are not replaced or reinforced. In addition, there is a strong need to redevelop three of our major zone substations. The primary and secondary equipment at Coburg North, Coburg South and North Heidelberg zone substations are at risk of failure due to their age, poor condition and poor serviceability, resulting in increasing safety and security of supply concerns. Together, these three projects will address significant safety risks and mitigate supply risks to over 60,000 customers by replacing old and deteriorated equipment to achieve performance levels consistent with current standards.[5] Not replacing is no longer an option given it will not enable us to maintain the reliability of our network.

In addition, our capital expenditure on vehicles will need to increase as the fleet is reaching end-of-life in the next regulatory period. Also, we need to expand our Tullamarine depot, the current size and design is insufficient to support business growth and maintain compliance with relevant regulations.

---

3 *JEN - Att 03-01 CER integration Strategy.*

4 CER are small-scale energy resources owned by customers, which can produce, store or vary how they use energy. CER includes rooftop solar, batteries and electric vehicles and more traditional assets such as hot water heaters and pool pumps.

5 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.

> Sections 6 (Replacement) and 9 (Non-network – Other) discuss in detail our forecast expenditure for replacement and non-network Other capital expenditure including the key drivers.
>
> In addition to maintaining network reliability, we propose some minor capital expenditure to address our customers' expectations on network resilience. See section 7 for details.

Customer expectations

As detailed in the main proposal documents, we have engaged extensively with our customers. They have clearly expressed their priorities for the next regulatory period. First and foremost, they want us to prioritise affordability. Addressing this concern—in the context of capital expenditure—they want us to:

- prioritise investment in maintaining the network reliability and resilience
- digitise and automate the network to make it smarter, more responsive and operate more efficiently.
- operate sustainably, support decarbonisation and renewable energy transition.

The challenge for us is to deliver the outcomes our customers expect at the most affordable price and to thoughtfully consider any trade-offs. This is key to our consideration of projects and programs underpinning our forecast capital expenditure. Our view is that if we include projects and programs which are assessed to be prudent and efficient then we are meeting our customers' expectations on affordability. Prudent and efficient investments may not mean lowest cost for our customers now, but they are the options that will provide the highest net benefit to our customers over the long term.

We further address affordability concerns by not proposing some projects that have uncertain timing. Instead, we propose two major augmentation projects are be treated as contingent projects as it avoids our customers paying for projects that may not be required. Some ICT projects have also been excluded from our proposal given uncertainty in scope and timing of market reforms at this stage.

> Our consideration of our customers' expectations re addressed throughout the various sections of this Attachment.

Regulatory requirements

In addition to our standing regulatory obligations to maintain the safety, security and reliability of our network, there are new regulatory obligations or expectations influencing our capital expenditure proposal. These include:

- **Non-network ICT**. JEN needs to comply with the evolving regulatory and market requirements related to the National Electricity Market (NEM) Reform Program. The program, largely being administered by the Australian Energy Market Operator (AEMO), is large and complex and aims to address essential change as ageing coal-fired generators are retired and replaced by an expanding array of new technologies, including large-scale renewable energy generation and storage systems, complemented by rapid growth in consumer energy resources.[6] We expect that most of the NEM Reform Program will be implemented over the next regulatory period.
- In order to comply with the NEM Reform Program, we need to expand our capacity and capability to ensure we can meet the emerging regulatory requirements and support a smooth and effective transition to the future energy system, supporting a more modern, secure, and sustainable energy market. Our approach is to include the Flexible trading arrangements and Market Interface Technology Enhancement reform projects in the JEN 2026-31 Proposal.

[6] AEMO, NEM Reform Program.

- **Network resilience**. Network resilience is the ability of the electricity network to withstand and recover from the effects of a natural hazard or disaster, such as floods, storms and bushfires. Following the extreme storm events on 13 February 2024, the Victorian Government initiated a review by an independent panel (Panel) on network service provider processes and performance through extreme weather events. The Victorian Government has accepted most of the Panel's recommendations and some of these recommendations may become obligations on businesses like ours.
- Our 2026-31 Proposal includes some minor capital expenditure to maintain our network's resilience in the face of increasing climate risks. We expect to have more obligations with respect to network resilience once the Victorian Government implements the relevant recommendations made by the Panel. We will seek to recover costs through regulatory processes once clearer.

> We provide more details about these new regulatory requirements in section 7 (Network Resilience) and sections 8 (Non-network ICT).

Continued growth in residential housing

The volume and type of connection applications are driven by housing demand (a function of population and interest rate movements etc.[7]), supply (including materials, labour costs and land releases) and government policy, none of which are certain. Based on recent experience, the growth on our network is significant and with the current setting we see this continuing.

> Sections 3 (Connections) and 4 (Augmentation) discuss in detail our forecast expenditure related to growth in residential and subdivision connections.

1.1.2 Looking ahead

As we have set out in this JEN 2026-31 Proposal and the sections below, JEN is adopting a range of strategies to manage investment in the context of unprecedented operational challenges we are facing. This involves a robust assessment of the existing capacity, utilisation and limits of our network; introduction of tariffs or direct control measures such as the VEBM to help us manage minimum demand risk and proposing non-network solutions to accommodate more CER. Even with these strategies, additional investment in our network is required.

> In prioritising capital projects, we are mindful of the asymmetric risk of under-investment with sustained increases in maximum demand (winter and summer) and data centre rollout. The asymmetric risk of under-investment in our network emerges because any delays in responding to increasing demand creates disproportionate negative outcomes when demand exceeds our network's capacity. The risk is asymmetric because the consequences of under-investment lead to much higher costs (outages, system failures, customer satisfaction) than if investments were made earlier. The benefits of waiting to invest often include only short-term savings.
>
> Additionally, delays can result in "capacity deficits," where existing infrastructure becomes increasingly stressed, and we face higher costs to repair, maintain, or temporarily upgrade services and we cannot quickly scale up our network in response to surges in demand. Once the need for additional capacity becomes urgent, the ability to add infrastructure to the network is constrained by time and regulatory processes so getting the timing right for investment is critical.
>
> All these risks can have cascading negative effects on the JEN's performance, customer satisfaction and even the economy.

7 Another potential factor is the reduction in the 3% home loan bank buffer test as flagged in Eyers J & Kehoe J, Calls to reduce the 3pc home load bank buffer test, *The Australian Financial Review* 24 October 2024. Available here.

Our forecast capital expenditure is prudent and efficient. We have developed it based on our capital expenditure objectives which in turn has been informed by our customers' expectations, the operating challenges discussed above, and the capital expenditure objectives and criteria contained in the National Electricity Rules. Our objectives are to:

- meet customers' expectations that we should maintain our current levels of network reliability at the most efficient cost over the long term
- manage safety, environmental, electrical system and security risks to as low as practicable and comply with all applicable regulatory obligations efficiently over the long term
- connect new customers to the electricity network and meet the changing energy needs of existing customers, ensuring we can meet or manage expected demand for all customers
- optimise exports and imports from distributed energy resources and CER to the distribution network. We have developed our capital expenditure forecast with these objectives in mind. We forecast our capital expenditure through a 'bottom-up' process and followed the AER's expenditure guidelines when developing our capital expenditure forecast.
- meet our customers' expectations that our network and communities are able to withstand and recover from extreme weather events.

We have also been guided by the AER's various guidance/guidelines as demonstrated throughout this Attachment and through our supporting justification documents. We have also been guided by our internal ISO 55001 accredited governance framework ensuring prudent and efficient investment.

1.2 Historical performance

Our estimated total Gross capital expenditure for the current regulatory period is $1.4B. This is 9% higher than our estimated allowance of $1.3B.[8] As shown in

Figure 1–3, our estimated expenditure for replacement, augmentation and non-network are generally consistent with our allowance for the current regulatory period.[9] Major spending for the first three years of the current regulatory period is on replacements of primary assets in four of our major zone substations, pole reinforcements and replacements, high voltage (HV) and low voltage (LV) crossarm replacements and feeder augmentation.

We expect to exceed our estimated allowance for connection capital expenditure due to unexpected and unprecedented levels of growth in major customer connections, particularly data centres. We anticipate this will continue over the next regulatory period, which is reflected in our forecast for connections capital expenditure. In contrast, our spend for non-network expenditure is estimated to be lower than the allowance for non-network capital expenditure.

Despite increasing capital expenditure, we perform well when comparing to our peers. Since 2020, JEN ranks eight (against 13) on capital multilateral partial factor productivity as set out in the AER's latest Annual Benchmarking Report.[10] This benchmark performance suggests that despite JEN's scale disadvantage, we are managing to produce more with less relative to our peers.

[8] Allowance includes proposed adjustments consistent with our reopener application.

[9] Original allowance refers to the AER approved allowance for the current regulatory period. The reported capital expenditure allowance for the current regulatory period incorporates the AER approved cost pass through application for the VEBM and assumes that reopener application is approved as submitted to the AER.

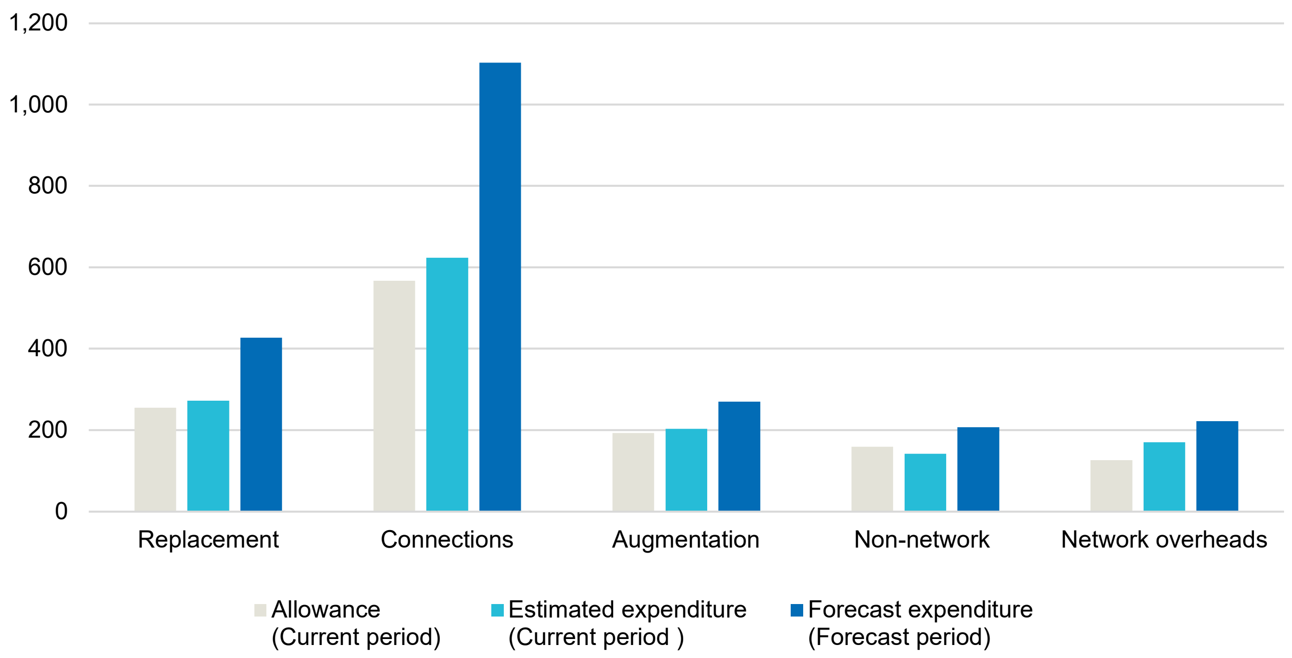
[10] AER, Annual Benchmarking Report, Electricity distribution network service providers, November 2024.

Capital expenditure allowance

The capital expenditure allowance of $1,299M includes expenditure related to cost pass-through application for the Victorian Emergency Backstop Mechanism (approved by the AER in 2024) and the re-opener application (which the AER is currently considering).[11] Excluding these applications, the Gross capital expenditure allowance is $926M.

Our allowance is estimated because the AER's decision on our reopener application is outstanding at the time of submitting this JEN 2026-31 Proposal.

Figure 1–3: Gross capital expenditure, $2026, millions



1.3 List of capital expenditure related attachments

The proposed capital expenditure outlined in this attachment is supported by a body of materials, forecasts and models. The key documents are outlined in Table 1–2. Other related materials can be found in the Document Index.[12]

Table 1–2: List of the main capital expenditure attachments supporting this proposal

Attachment	Name	Author
Att 05-02	Energy forecasts report	JEN
Att 05-03	Peak demand forecasts report	JEN
Att 05-04	Customer numbers	JEN
Att 05-06	AER repex modelling	Houston Kemp
Att 05-07	Real cost escalation report	Oxford Economics
Att 05-09	Connection policy	JEN

11 See AER, Determination, Jemena, Victorian Emergency Backstop Mechanism Cost Pass Through and JEN, Application to reopen the 2021-26 Electricity Distribution Price Review Determination, Reopening JEN's distribution determination capital expenditure, October 2024

12 *JEN - RIN 2 - Document Index.*

Attachment	Name	Author
Att 05-10M	SCS Capex model	JEN
RIN - 4.4.1	Connections Capex Forecast Summary Report	JEN
Support	Spatial Level Maximum Demand Forecast Methodology	Blunomy
Support	JEN Load Forecast Methodology	JEN

2. Regulatory expectations

We have developed our proposal consistent with the AER's expectations set out in the Better Resets Handbook as shown in Table 2–1.

Table 2–1: Compliance against the AER expectations under the Better Resets Handbook

AER expectation	Explanation
Top-down testing of forecast capital expenditure, including at category level	
Demonstrate total forecast spend is not materially above current regulatory period spend. Justify projects/programs driving the step-up with cost benefit analyses	**Achieved.** Due to the health and condition of our network assets and the forecast connections, expenditure over the next regulatory period for replacement and connections need to increase. Accordingly, to support the AER's assessment we have developed robust business cases, investment briefs and network development strategy documents for the projects/program underpinning our higher forecast. These supporting documents clearly explained the need, the credible options considered, the outcomes of the cost-benefit analysis and consideration of our customers' expectations.
Provide reasons if recurrent expenditure is materially different from current expenditure levels	**Achieved**. We have tested each category against historical levels of spend. Our recurrent forecast expenditure for non-network ICT is based on historical expenditure. Where relevant, forecasts for routine replacements takes into account historical levels of spend (customer initiated works and minor capital expenditure). Any major departure from historical capital expenditure is justified either in business cases, investment briefs and asset class strategies submitted as part of this regulatory proposal.
Provide cost benefit analyses to support non-recurrent expenditures	**Achieved**. All our non-recurrent capital expenditure is supported by economic analysis.
Provide reasons if modelled forecast repex is materially higher than AER repex model threshold	**Achieved.** Our modelled forecast repex is 27% lower than the AER repex model threshold ($237M and $302M, respectively, in $2024). There are variances between the AER repex model threshold and our own modelled repex at an asset group level, which can be expected when comparing a top-down predictive modelling approach to a bottom-up forecast. We explain in section 6.3.2.1 the reasons for these variances.
Explain new capital expenditure categories	**Achieved**. There are two new categories of spend: network resilience and CER integration. This is consistent with recent AER regulatory practice.
Evidence of prudent and efficient decision making on key projects and programs	
Provide evidence of the network's need against the capital expenditure objectives	**Achieved**. Our forecast capital expenditure is supported by robust business cases, investment briefs and network development strategy documents for the projects/program underpinning our higher forecast. These supporting documents clearly explained the need within the context of the capital expenditure objectives under the NER.
Provide evidence of quantitative cost benefit analyses which demonstrate that different feasible options (including non-network options) were considered that the preferred option maximises net benefits	**Achieved**. Our business cases, investment briefs and network development strategy documents are supported by quantitative cost-benefit analyses, which demonstrate that our proposed projects/programs are based on the option that will give the highest net benefits to our customers.
Where relevant, provide evidence of accounting for trade-offs between capital and operating expenditures	**Achieved**. We have demonstrated this in our business cases (where relevant). Our asset class strategies also set out in detail JEN's consideration of capital and operating expenditure trade-offs when making a decision on replacements. We have submitted our asset class strategies as supporting justification documents for the regulatory proposal.

AER expectation	Explanation
Evidence of alignment with asset risk and management standards	
Provide evidence of alignment to good asset and risk management standards	**Achieved**. Our asset management system is accredited under the ISO55001 standard, and we are committed to continuing to align our asset management processes to this standard. Further, we use a probabilistic approach to network planning and have based our asset replacement program on measures of network health.
Genuine customer engagement on capital expenditure proposals	
Engagement includes impacts of capital expenditure proposal on the regulatory asset base (RAB) and long-term price outcomes for customers	**Achieved**. In the Draft Plan, which we released for public consultation in September 2024, we set out our proposed capital expenditure and its impact on the RAB. We also presented the overall impact of our proposal on prices. After the Draft Plan, we did further iterations to our capital expenditure and prior to finalising the regulatory proposal, we held two deep dive sessions with our People's Panel on 19 and 25 November 2024. Among other things, we presented and sought feedback on our revised capital expenditure proposal, including its impact on the RAB and on prices. In response to the People's Panel recommendations on customer education, network resilience and innovation, we presented a series packages/options for the People's Panel to consider. The regulatory proposal reflects the options that the People's Panel has recommended. *JEN – MosaicLab Att 02-22 Customer Deep Dive Outcomes Report* summarises the outcomes of the deep dive sessions.
Engagement on the need for capital expenditure (including on service outcome) and options the network has considered	

3. Connections

> - We are forecasting net connections capital expenditure – what is recovered through network bills – of $275.3M. Before accounting for customer contributions towards their connection costs this is $1.1B, 77% higher than current period expenditure.
> - The increase is primarily due to the seismic global surge in data centre investment, driven by the deployment of cloud services and the emergence of artificial intelligence.
> - While mostly funded by project developers, data centre connections will bring substantial benefits to:
>   - Our customers – the significant volumes from these customers will reduce average unit costs and drive down network bills.
>   - Our local community – through the growth in high-tech jobs and higher levels of economic activity.
>   - The wider economy – through the creation of critical infrastructure required to support ongoing innovation and productivity in the digital age.
> - We will also continue our recurrent program to connect smaller residential and business customers. This forecast is based on the long-standing approach to project costs based on a three-year average (resulting in a conservative bias) and the application of third-party forecasts.

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[13] require us to offer connection services to customers (including embedded generators) on request.

Putting aside regulatory requirements, connecting new customers:

- **Improves housing availability and affordability**. Residential connections provide access to electricity, a service essential to modern life. Ensuring timely connections ensures that we do not delay increases in housing supply and that we play our part to alleviate community concerns around housing – which are currently second only to cost of living pressures.[14]
- **Supports economic opportunities for our local community.** Connecting new businesses to our network supports job creation and broader economic benefits through higher levels of activity. The surge in data centre investment provides an unprecedent opportunity through the creation of high-tech jobs in short supply.
- **Brings broader economic benefits via reduced pressure on inflation and cost of living and supporting higher levels of innovation and productivity.** Facilitating timely connections to commercial and industrial customers enhances the productive capacity of the Australian economy reducing inflation and the cost of living. These benefits are felt not just in our local community but Australia the wider Victorian and Australian economies. Further, the surge in data centre investment is vital to creating the critical infrastructure required to support innovation and enhanced productivity through the development and adoption of cloud and Artificial Intelligence opportunities.
- **Lowers bills for existing customers.** A larger customer base enables us to spread our mostly fixed costs over more customers.[15]

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

[14] As identified by IPSOS (see here) and SEC Newgate (see here).

[15] While higher levels of capital expenditure generally mean a higher regulatory asset base and in turn customer bills, the opposite is the case with connection capital expenditure. The bill reducing benefits of a larger customer base more than offset the increase from higher levels of expenditure.

- **Supports emissions reductions.** Appropriately sized connections ensure sufficient access to our future decarbonised electricity system. For example, ensuring new customers have adequate capacity to support electric vehicle charging.[16]

Customer feedback through the course of developing this proposal touched on these benefits:

- Residential customers recommended that we champion the use of renewables (solar) and energy storage (batteries) in new building developments and new estates and noted that electric vehicle charging could become a requirement for new suburbs and housing developments.[17]
- Local councils told us to consider options to speed up the delivery of infrastructure (including connections and capacity upgrades). Councils identified that this in turn would enable them to more quickly deliver community benefits.
- Large customers requested that we make connections quicker and less resource-intensive for customers.[18]
- One response to our draft plan was concerned that we hadn't accounted for the increase in housing needed to address the housing shortage.[19]

Forecasting approach

In developing our connections forecast, the importance of timely connections and how to consider customer feedback has been at the forefront of our mind.

The key challenge we face is how to prepare an accurate forecast and ensure we have sufficient funding to undertake connections when requested by applicants. Insufficient funding risks delays to improved housing supply, reduced inflation, reduced network bills, and emissions reductions.

In preparing our forecast for the next regulatory, we divide our program into three segments:

- **High-volume connections –** the vast majority of connections for residential dwellings, sub-divisions for new estates as well as commercial and industrial connections with maximum demand below 10 MW. This segment is recurrent. Expenditure varies annually in line with residential development and economic activity.
- **Major customers –** connecting large (greater than 10 MW) businesses, industrial facilities, major infrastructure projects or large generators. This expenditure tends to be 'lumpy' depending on broader economic development in our network area.
- **Data centres –** connections to specialised facilities which house IT infrastructure. These facilities have substantial power requirements and can require up to 300 MW – equivalent to 75,000 residential customers with a peak demand of 4 kW. Given the scale and materiality of these connections these connections have been split out from the major connections segment.

As the number of connections is not within our control forecasting accuracy is limited. The outturn number of connection applications we receive will depend on factors such as the overall level of investment in housing and new developments, government policy settings and other factors.

For high-volume connections, we manage forecasting risks by using our established, AER accepted, forecasting methodology. Due to the recurrent nature of these connections, we base our forecast on the current level of expenditure and trend forward costs based on movements volumes based on independent third-party forecasts.

16 The achievement of emissions reduction targets is now part of the NEO and part of the capital expenditure objectives (Rule 6.5.7(a)(2)(5)).

17 *Att 02-19 People's Panel Recommendations* (Recommendation 14, page 19).

18 *Att 02-05 Large customer forum report - 20241203*

19 *Att 02 -21 - Draft Plan Feedback Report*, p.17.

Given the 2-to-3-year lead time between connection application and connection, we can accurately forecast major connections and data centres connections in the short-term. However, a key learning over the current regulatory period, is that our historical forecast approach for larger connections in the medium to long term can be improved.

Outturn expenditure is substantially higher than forecast and required us to use the never-before-used reopener provisions in the Rules to ensure we are sufficiently funded.[20] This experience, together with independent forecasts on the level of industrial and data centre development, indicates that these larger connections will continue.[21] Accordingly, we have improved our forecasting methodology for these connections.

How connections are funded

Customer connections are funded through a combination of network tariffs and connection charges. Connection charges are calculated consistent with the regulatory frameworks in which we operate. The remainder of the costs we incur are recovered through network tariffs.

In this regulatory proposal, we forecast both:

- Gross capital expenditure – the total expenditure we expect to incur.
- Capital contributions – the revenue we expect to recover from connection charges.

We subtract capital contributions from gross capital expenditure to obtain 'net capital expenditure'. It is net capital expenditure which is added to our regulatory asset base and recovered through network tariffs. This approach ensures that we do not recover our costs twice.

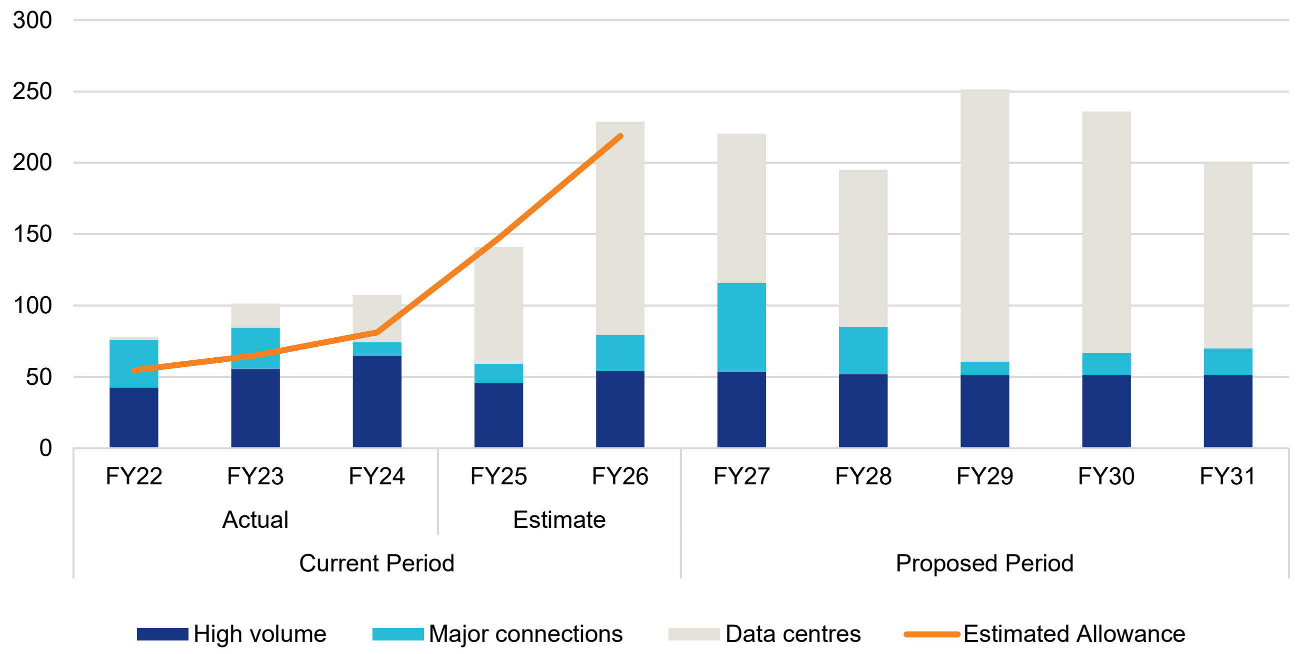
Forecast

Actual and forecast connections expenditure is shown in Figure 3-1. The growth in major connection and data centre connection capital expenditure is stark and highlights the medium to longer term forecasting issues we note above.

20 On 15 October 2024 we applied to the AER to reopen the capital expenditure component of the 2021-26 distribution determination as a result of the unforeseen major connection and data centre connection capital expenditure. Further information is available here.

21 Consistent with the capital expenditure criteria set out in Rule 6.5.7(c)(3).

Figure 3-1: Gross connections capital expenditure, actual and forecast, $2026, millions[22]



Data centre connections, from a standing start in 2022, now makes up about half of overall connection capital expenditure. The surge in data centre demand and investment is driven by the growing adoption of cloud services and artificial intelligence (AI). This boom is not temporary and widely expected to continue over the next 5 - 10 years.

While data centre growth is a global phenomenon, our network will remain a focal point of this surge in investment due to Melbourne's increased suitability (increased connectivity and capacity constraints in adjacent markets) and our network location's desirability.

These large connections represent a significant opportunity for our local community. The surge in data centre investment will lead to the creation of local high-tech jobs and higher levels of economic activity in our network area, supporting local businesses. Further, the data centres themselves will provide the critical infrastructure required to drive ongoing innovation and productivity improvements across Victoria and Australia as a whole through the ongoing development and use of cloud and AI technologies.

The economic importance of data centres is widely recognised. The UK Government has designated data centres as critical national infrastructure to give industry the 'ultimate reassurance' that the UK will always be a safe home for investment.[23] While on 22 January 2025 President Trump announced a $500 billion (USD) 'Stargate' project to invest in AI infrastructure, including data centres.[24]

While we are forecasting a substantial increase in capital expenditure, this expenditure will result in bill *reductions.* This is for two reasons:

- Network charges reflect net capital expenditure – and we are also forecasting a substantial increase in contributions consistent with the increase in gross capital expenditure. While we are forecasting $704.0M in data centre connection costs we will only recover $127.1M through network charges.

22 Estimated allowance includes proposed adjustments consistent with our reopener application.

23 Rt Hon Peter Kylie MP, *Tech Secretary welcomes foreign investment in UK data centres which will spur economic growth and AI innovation in Britain.* 14 October 2024. Available here.

24 Open AI, *Announcing the Stargate Project, 21 January 2025*. Available here.

- Data centres add very large loads onto our network and in turn allow us to share our largely fixed costs across greater volumes of energy. In short, data centres will reduce average unit costs and lead to network bill reductions.

Our data centres connections program will reduce our customer bills, provide economic opportunity in our local area and underpin critical infrastructure required to drive innovation and productivity across Victorian and Australia as a whole.

Overall, we are forecasting $275.3M in net connections capital expenditure. A relatively modest increase of $112.3M in the context that we expect gross capex to increase by $479.3M.

Table 3-1: Standard control connections capital expenditure, $2026, millions

	2021-26		2026-31
	Estimated allowance[25]	Actual/estimate	Forecast
High-volume connections	195.4	226.7	259.0
Major connections	90.8	110.0	139.6
Data centres	280.8	283.6	704.0
Total	**567.0**	**623.3**	**1,102.6**

3.1 High volume connections

Residential, commercial and industrial connections below 10 MW are relatively steady with a year-to-year variation driven by the level of development and economic activity in our network area.

Given the recurrent nature of high-volume connections, we adopt a top-down forecasting methodology. We calculate a base level of spend based on three-year average of actual revealed costs. The base is then adjusted to reflect expected changes in the level of connections (up or down). These adjustments reflect movements in independent third-party forecasts of residential dwellings activity (for residential and subdivisions connections) or non-residential construction (for business connections). Where required, we also make adjustments to our forecast where we expect costs to differ from what we have observed historically.

Our methodology is consistent with the historical approach we have previously applied, and the AER has previously approved. It is also consistent with AER's forecasting approach for other recurrent costs, such as operating expenditure.

Relying on independent third-party projections ensures that our forecast reflects a realistic expectation of the relevant inputs required to achieve the capital expenditure objectives in the National Electricity Rules.[26] However, it also means that tour expenditure forecasts (and in turn the allowances) are largely dependent on the accuracy of these forecasts. Higher (or lower) forecast economic activity will result in higher (or lower) connections expenditure relative to the allowance.

3.1.1 Residential and subdivision

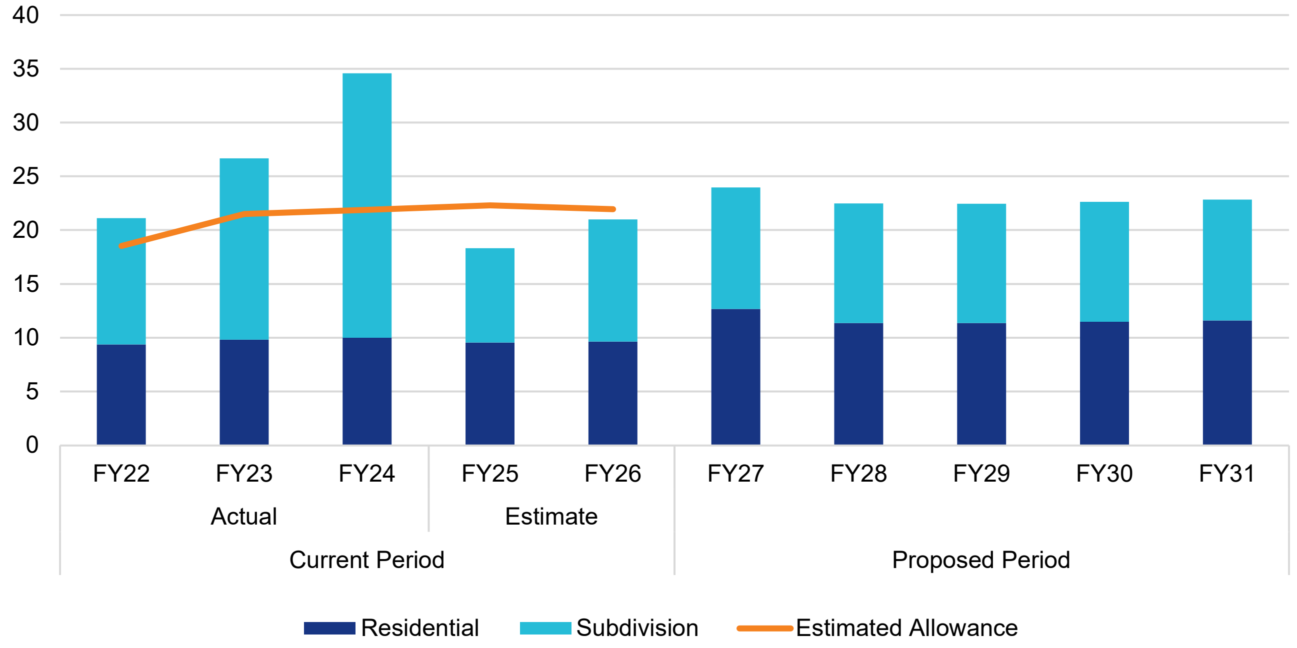
Our combined residential[27] and subdivision connection forecast is shown in Figure 3-2. We expect expenditure to remain constant relatively flat relative to average historical expenditure.

25 Allowance includes proposed adjustments consistent with our reopener application.

26 National Electricity Rule 6.5.7(c)(iii).

27 Residential connections relate to connecting customers who purchase energy principally for personally, house or domestic use at premises. Subdivision connections related to connecting un-reticulated lots or areas to the distribution network for residential subdivisions.

Figure 3-2: Residential and subdivision connection expenditure, $2026, millions[28]



Forecast connection volumes

Forecasting residential and subdivision connection expenditure, where volumes are entirely out of our control, is challenging. The volume and type of connection applications are driven by housing demand (a function of population and interest rate movements, and other factors.[29]), supply (including materials, labour costs and land releases) and government policy.

None of these factors are static. The RBA is expecting interest rates to fall,[30] while the Commonwealth and Victorian governments have each set new home targets[31] and increased housing funding.[32] To support the achievement of these targets, the Victorian government is delivering a series of planning reforms[33] to increase supply, including plans to increase housing density in the inner and middle rings of Melbourne.[34]

Despite these significant tailwinds, our forecast[35] is based on the more conservative long-term (2023 to 2051) population and household projections produced by the Victorian Government.[36] The forecast growth in residential connection numbers is shown in Figure 3-3 below.

28 The allowance reflects the allowance set by the AER in its decision on our proposed reopener application.

29 Another potential factor is the reduction in the 3% home loan bank buffer test as flagged in Eyers J & Kehoe J, Calls to reduce the 3pc home load bank buffer test*, The Australian Financial Review* 24 October 2024. Available here.

30 See page 4, here.

31 A national target to build 1.2 million new homes over the next five years with specific Victorian commitments (see here) and a Victorian target to build 800,000 new homes within a decade (see here).

32 This includes the Commonwealth's $10 billion Housing Australia Future Fund and $2 billion Social Housing Accelerator as well as Victoria's $5.3 billion Big Housing Build and $2.1 billion homebuyer fund.

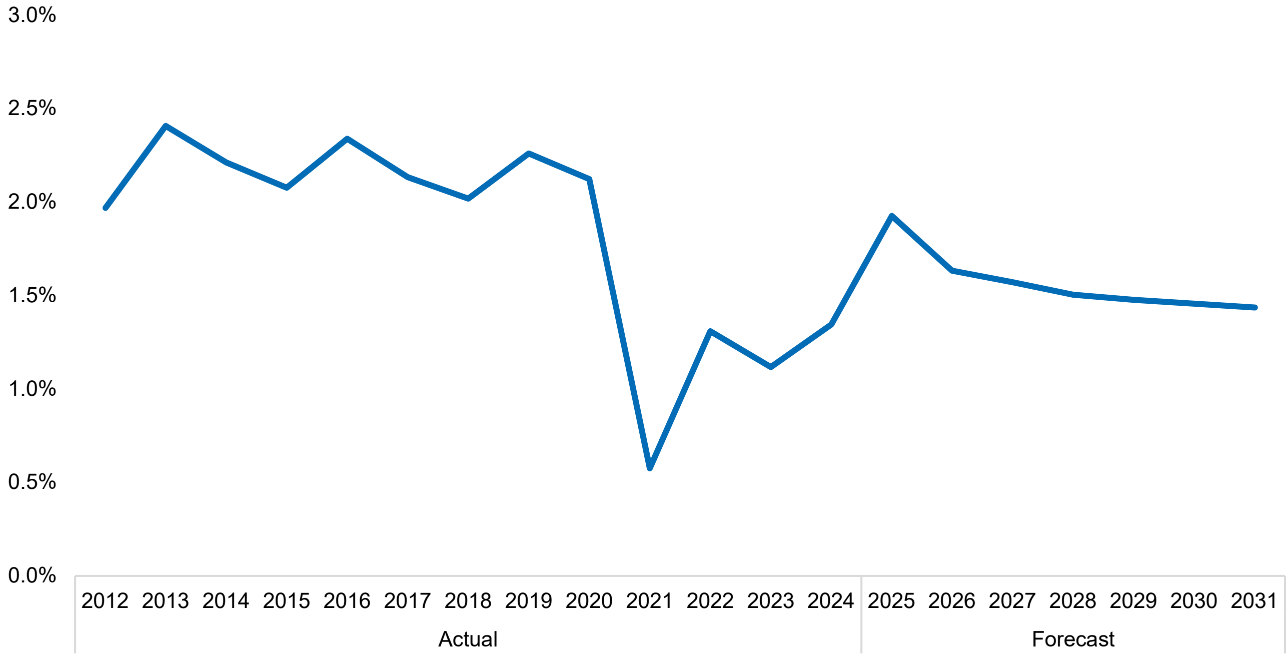
33 Include planning reforms, clearing development application backlogs, and the development of train and tram zone activity centres, of which at least two are in the JEN network area.

34 Victorian Government 2023, *Victoria's Housing Statement, the decade ahead 2024 -2034*, p.21 Available here.

35 The residential connection forecast is calculated for our network by Blunomy, who identifies the household growth in our network area.

36 Victorian in Future 2023 (VIF 2023), available here.

Figure 3-3: Growth in residential connection numbers (%)



Given the developments outlined above, it is possible that residential connection activity will be higher than long-term projections suggest. It would not be surprising if connection numbers rose to be above the pre-COVID-19 trend.

Base expenditure

Historically, we have projected connection expenditure from a three-year average of revealed actual costs as reported in our Regulatory Information Notice (RIN) response templates. We applied this approach to smooth-out outlier years on the premise that historic connections numbers are relatively stable.

However, connections over the current regulatory period have not been stable. Connections were substantially lower than the historical trend in 2021-22 and 2022-23 due to the impact of COVID-19. Overall expenditure rebounded in 2023-24 due to an increase in subdivision development. There is a risk that our forecast, which continues to apply the three-year average (including data from 2021-22 and 2022-23) has a downward bias.

Ensuring sufficient capacity to support emissions reduction

The last element of our forecast is an adjustment to account for the impacts of electrification on our new connection expenditure. While electrification has the potential to increase costs for a range of connections, the impact is most acute for medium and high-density connections as:

- Under the National Construction Code 2022 energy efficiency standards (which commenced in Victoria on 1 May 2024)[37] apartment buildings must be designed with space for switchboards and EV charging infrastructure for 100% of car parking spaces. These requirements require capacity to be a minimum of 7 kW to 48 kW (depending on building class) – significantly higher than the EV charging capacity of most households who currently use a standard power socket (2.4 kW).[38]

- The phase out of gas connections for new dwellings, apartment buildings and residential subdivisions which require planning permits.[39]

37 National Construction Code 2022, Volume one, Section J, Part J9D4.

38 CSIRO 2022, *Electric vehicle projections 2022,* p.46. Available here.

39 See Victorian planning provision and all planning schemes amendment VC 250. See here for further details.

To understand the impact on connection capital expenditure, we considered a sample of projects and found that the most cost-effective option increased costs by 3.8%.[40] We only apply this adjustment to medium density housing expenditure (which makes up 29% of our residential and sub-division program) resulting in a modest overall adjustment of 1.1%.

Forecasting methodology summary

The specifics for preparing the forecast in the current regulatory period forecast and the next regulatory period are summarised in Table 3-2.

Table 3-2: Residential and subdivision connections gross capital expenditure forecasting approach

	2021-26	2026-31
Base	Average of calendar years 2016, 2017 and 2018 (most recent RIN data available).	Average of financial years 2022, 2023 and 2024 (most recent RIN data available).
Trend	Customer number forecasts prepared by ACIL Allen.[41]	Customer number forecast prepared by Blunomy. This forecast is based on the Victoria in Future population forecast, adjusted for known connections.[42]
Step	N/A	Electrification adjustment to medium density connections to reflect higher load requirements as a result of electrification.[43]

3.1.2 Business connections

Figure 3-4 shows a two-period view of business connections expenditure. Outturn 2021-26 expenditure was materially higher than expected. The primary reason for the allowance was that non-residential construction activity was significantly higher than we expected. Based on third party independent forecasts, we expect that this higher level of activity will continue through the next regulatory period.

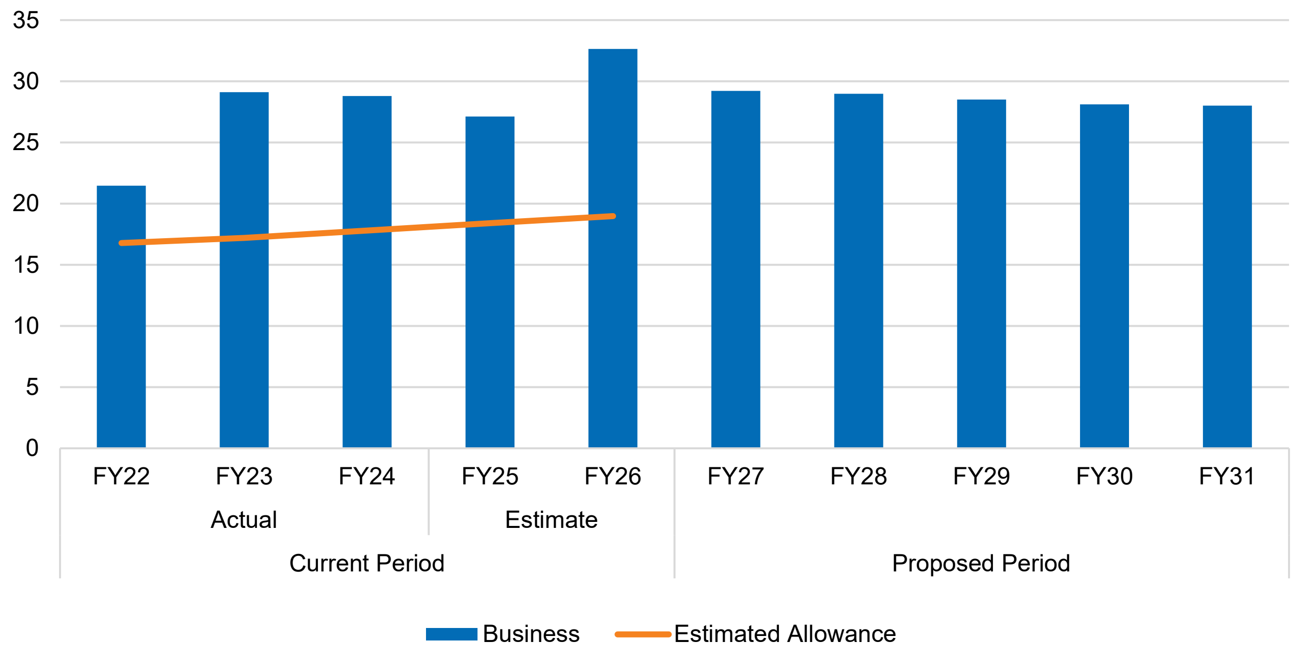
40 *JEN - RIN - Support - Customer Connections Forecast Methodology*, section 5.2.3.1.

41 The AER made an additional adjustment for the effect of COVID-19 for FY22.

42 *JEN – Blunomy Att 05-03 Peak demand.*

43 1.1% adjustment make up of applying a 3.81% adjustment to medium density housing (29% of our connections expenditure) to reflect the change in housing design to accommodate the electrification of gas and transport.

Figure 3-4: Businesses connections gross capital expenditure, $2026, millions



Forecast construction activity

As with residential and subdivision connections, business connections are outside of our control and challenging to forecast. We seek to manage the forecasting risk by adopting independent third-party forecasts. For business connections, we trend forward our base level costs by the annual change in the expected value of work to be undertaken in select non-residential construction subsectors[44] forecast by the Australian Construction Industry Forum (**ACIF**).[45]

As shown in Figure 3-5, 2021-26 non-residential construction activity has been substantially higher than the ACIF forecast in November 2020 – which is why outturn expenditure is higher than the allowance. Figure 3-5 also shows that the higher level of activity is expected to continue into the next regulatory period.

44 Specifically, industrial, miscellaneous and other commercial. We exclude accommodation, education, entertainment and recreation, health and aged care, offices and retail/wholesale trade. Using all non-residential sectors would result in a material higher forecast for 2026-31, as the excluded sectors are forecast to grow at a higher rate over the forecast period.

45 Due to timing factors in the development of our forecast we relied on the June 2024 ACIF forecast and did not incorporate . Figure 3-5 also includes ACIF's November 2024 forecast. The increase in the forecast is driven by the 'other commercial' category, the category which covers data centres.

Figure 3-5: ACIF Forecast of non-residential Victorian construction activity, $2026, millions

[redacted]

Base expenditure

As with residential and subdivision expenditure, we forecast business connections from using a three-year average of revealed expenditure reported in our Regulatory Information Notice response templates,[46] on the implicit assumption of generally stable connection numbers.

This approach includes 2021-22 expenditure, which (as shown earlier in Figure 3-4) is significantly lower than current levels of spend. This results in a quirk where although the ACIF is forecasting non-construction economic activity to continue to rise, our forecast is lower than current expenditure levels.

We have identified that this could be corrected by either moving to a single base year (FY24) or adjusting the trend to reflect that it is being applied to a three-year average rather than a single year. However, at this stage, we have decided to maintain the three-year average.

[46] Note we remove major customer connections from this data (projects above 10 MW) to avoid the potential for double counting these costs as these projects are forecast separately, as outlined in section 3.2.

Forecasting methodology summary

A summary of our 2021-26 and 2026-31 forecasting approaches is outlined in Table 3-3.

Table 3-3: Commercial & industrial high volume connections gross capital expenditure forecasting approach

	2021-26	2026-31
Base	Average of calendar years 2016, 2017 and 2018 (most recent actuals available). Major connections costs (forecast separately) excluded to avoid double counting.	Average of financial years 2022, 2023 and 2024 (most recent actuals available). Major connections costs (forecast separately) excluded to avoid double counting.
Trend	ACIF's November 2020 forecast of industrial, miscellaneous and other commercial construction for Victoria. Values for 2025-26 were extrapolated using an exponential smoothing algorithm.[47]	ACIF's June 2024 forecast of industrial, miscellaneous and other commercial construction for Melbourne.[48] No extrapolated values.
Step	None.	None.

3.2 Major connections

Major connections relate to large 'lumpy' projects to connect major developments in our network area.[49] While customer-specific factors drive each connection, overall level of activity is influenced by broader macroeconomic drivers.

A challenge in forecasting these connections is the difference between our regulatory proposal forecasting time horizon of 7 years (as our forecast is prepared 18-24 months in advance of the 5-year regulatory period) and the 2–3-year typical connection lead time.

We can use customer information obtained from preliminary enquiries or connection applications to forecast *known connections*. However, customer information provides limited visibility of *future connections,* connections beyond the typical connection lead time of 2-3 years (i.e. up to about 2027-28), which we do not yet know about.

Historically, we have only forecast *known* connections. We then produced cost estimates (for both connection assets and upstream augmentation[50]) for each of these connections consistent with our Cost Estimation Methodology.[51] Our historical forecasts did not include expenditure for *future* connections.

As evidenced by our experience over the current regulatory period where we had to reopen our expenditure forecast, *future* connections can be material. As a result, we have adjusted our approach to include a top-down estimate to ensure that our overall forecast reflects a realistic estimate of demand.[52]

47 The Excel Forecast ETS function.

48 We moved to use the Melbourne (rather than Victorian) forecast, given that JEN's network is located in a part of greater Melbourne. This change results in a slightly lower forecast (an average annual change in activity 0.09 percentage points lower) over the 2024-31 forecast period.

49 Where maximum demand exceeds 10 MW.

50 Included in our augmentation forecast.

51 There are cases where we undertake connection studies and develop multiple options to present to the customer. In cases where a customer has yet to commit to a specific option, but there is a high probability that the project will proceed in some form, we have included the option that we consider is most likely to be selected by the customer.

52 As required by the capital expenditure criteria set out in Rule 6.5.7(c)(1)(iii).

3.2.1 Known major connections

For the 2026-31 period we are forecasting to connect eight customers based on information available from preliminary enquiries and connection applications. Seven of the eight connections will be delivered by 2027-28, year two of the 2026-31 regulatory period.

3.2.2 Future major connections

To forecast future connections, we apply a top-down approach as granular information on connections numbers, capacity and in turn costs is not available.

Our top-down forecast is guided by the ACIF's independent third-party forecast of Melbourne's construction activity. As shown by Figure 3-6, the ACIF is forecasting that Victorian non-residential and engineering construction activity in the 2026-31 period will be higher than the average for the 2021-26 period and broadly similar to the level of construction we are currently seeing.[53]

The ACIF explains that:

- [redacted]
- [redacted]

Figure 3-6: ACIF engineering and non-residential value of work done in Victoria (Index 2023-24 = 100)

[redacted]

We then forecast future connections in overall capacity (MVA) terms. We forecast connection capacity rather than the number of connections as this better reflects the cost incurred in making each connection. This is also consistent with how Ofgem's 'volume drivers' – a price control uncertainty mechanism used to vary connection allowances based on outturn capacity – are applied.[54]

[53] ACIF 2024, *Australian Construction Market Report,* p. 26

[54] For example, see page 24 here.

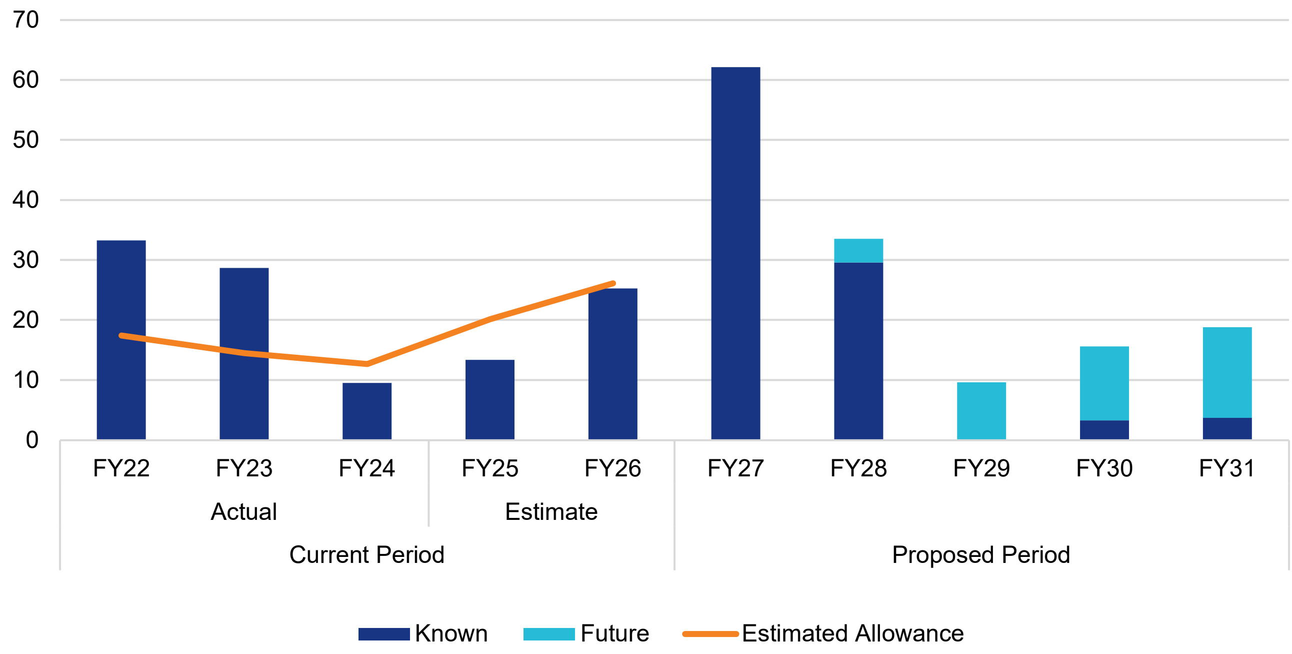
Forecast future connections are derived from known customer load over a 10-year period.[55] We apply this forecast from 2027-28 (4 years into our forecast) beyond the typical horizon for known connections. We forecast future connection volumes based on the assumption – consistent with the ACIF forecast – that future connections will be similar to the current level of major customer connection activity we can observe.

We then multiply the forecast connection capacity by the average unit cost of known connections (on a MVA basis) to derive forecast capital expenditure.

3.2.3 Overall major connections forecast

The last step in our approach is to undertake a sense check to determine whether the overall forecast, comprising both known and future connections, is a reasonable and realistic estimate of demand.

Figure 3-7: Major connection gross capital expenditure, $2026, millions[56]



Overall, as shown in Figure 3-7, we are forecasting $27.9M per year in major connection capital expenditure which:

- Is consistent with the ACIF's forecast that construction activity will be higher across the 2026-31 regulatory period relative to the overall 2021-26 regulatory period.
- Is conservative. While the ACIF is forecasting expecting construction activity to be largely flat relative to current levels, we are forecasting overall major connection expenditure, even with the inclusion of our future component of our forecast, reduce as known connections end.
- Ensures no duplication or double counting between the known and future forecast components. The initial years of the forecast are solely made up of known connections, reflecting the visibility we have over the 2–3-year time horizon. In 2027-28 (year 4 of our forecast and year two of the 2026-31 regulatory period), the future connection forecast begins and gradually rises, reflecting that over time, the known connection forecast will increasingly understate the level of connection expenditure required.

55 Specifically, we project future connections using the moderated customer demand forecast (outlined in section 4.1.3) which is distinct from the sum of connection capacity (e.g. total customer supply request). These forecasts differ as the moderated customer demand forecast is focussed in identifying the load on our shared upstream network (taking into account factors such as diversity and ramp up in aggregate) while the capacity for a connection asset is sized based on customer requirements.

56 Allowance includes proposed adjustments consistent with our reopener application.

We note that a connection forecast based solely on known connections would result in connection expenditure reducing over the 2026-31 period. This forecast would not be realistic (or supported by available third-party forecasts) and in turn would not comply with the capex criteria in the Rules.[57] Given these factors we consider that our forecast reflects a reasonable and realistic expectation of future demand.

3.3 Data centre connections

Over the last few years, data centre investment has surged, driven by the increased adoption of cloud computing and artificial intelligence (AI). The attractiveness of our network area has led to a massive increase in data centre connections and a substantial increase in expenditure requirements. The size of the increase was so large that it required us to trigger the never-before-used reopener provisions in the Rules to ensure that we are sufficiently funded.[58]

Global data centre demand is not slowing down. McKinsey, Jefferies, Citigroup and Goldman Sachs are all forecasting significant global compound annual growth rates in the order of 15 – 20% over the period to 2030.[59]

Investors are responding. This has led to seismic market movements:

- The value of NVIDIA, who produce data centre hardware, has tripled. NVIDIA is now the largest company in the world by market capitalisation.[60]
- Significant investment in Australian data centres has been announced. For example, Amazon has announced it will invest $13.2 billion in its Australian cloud computing business while Microsoft is investing $5 billion in computing capacity and capability. [61] Mandala, on behalf of the five largest data centre operators, has forecast that $26 billion in investment by 2030 will be required to meet Australian data centre demand.[62]
- Large amounts of capital are being raised to develop new data centres. Public examples include NEXTDC, CDC Data Centres and DigiCo Infrastructure[63] as well as the increased valuations and sale of existing operators such as the Australian based AirTrunk, whose sale became the 5th largest Australian corporate transaction ever.[64]

Mandala forecast that overall Australian data centre capacity is expected to increase by 230% from 1,350MW in 2024 to 3,100 MW in 2030.[65]

These investments are spatially concentrated. Data centres are built in geographic clusters based on subsea cable connectivity, proximity to population centres, resilience, land price/availability, reliable communication networks as well as access price of renewable electricity.[66] The International Energy Agency (IEA) has found that

57 Rule 6.5.7(c)(1)(iii)

58 On 15 October 2024 we applied to the AER to reopen the capital expenditure component of the 2021-26 distribution determination as a result of the unforeseen major connection and data centre connection capital expenditure. Further information is available here.

59 McKinsey & Company 2024, *AI power: Expanding data centre capacity to meet growing demand.* 29 October. Available here. Jefferies 2024, *Data Centers & AI: Powering the Future,* p. 10 Available here. Citigroup 2024, *Data Centre Powerplay: The Chips Have to Go Somewhere*, 29 May. Available here. Goldman Sachs 2024, *Generational growth AI, data centers and the coming US power demand surge*, p.3. Available here.

60 As of January 2025.

61 See here and here.

62 Mandala 2024, *Empowering Australia's Digital Future: Data Centres: Essential digital infrastructure underpinning everyday life,* October. p.13 and Pp 17-18. Available here. Reported prepared on behalf of AirTrunk, Amazon Web Services, CDC Data Centres, Microsoft and NEXTDC.

63 Thompson S, Sood K and Rapaport E, Game on! $16b CDC Data Centres posts IMs, calls for bids by Christmas, *The Australian Financial Review* 5 November 2024. Available here. Bennett T, *NextDC raises $750m for Asia land grab, racing AirTrunk,* 10 September 2024. Available here. Thompson S, Sood K and Rapaport E, Inside David Di Pilla's plans for a blockbuster $1.6b data centre IPO, *The Australian Financial Review* 11 November 2024. Available here.

64 See here and Smith P, Blackstone clinches data centre giant AirTrunk in deal of the year, September 4 2024. Available here.

65 Mandala 2024, *Empowering Australia's Digital Future: Data Centres: Essential digital infrastructure underpinning everyday life,* October. p.13. Available here.

66 Mandala 2024, *Empowering Australia's Digital Future: Data Centres: Essential digital infrastructure underpinning everyday life,* October. Available here.

data centre spatial concentration is materially higher than steel mills (which have similar power demand) and warehouses.[67]

We have observed that operators often build data centres in clusters of three[68] or more. This approach helps minimise disruption by ensuring that if one facility is affected by a power outage, cooling failure, or localised natural disaster, services can fail over to another data centre with minimal downtime. These facilities are typically located within tens of kilometres of each other due to the need for ultra-low latency required for rapid data replication and near-instantaneous failovers to maintain efficient and resilient application performance.

In Australia, data centres are concentrated in Sydney and Melbourne.[69] Over the next 5-10 years, data centre capacity is expected to grow more quickly in Melbourne. This is due to several factors, including new subsea cables increasing Melbourne's international connectivity (historically a relative strength for Sydney),[70] capacity constraints in Sydney and other Tier 1 markets in the APAC region (such as Singapore and Hong Kong)[71] as well as land availability/pricing.

Melbourne data centre development is concentrated in Central, Western and North Melbourne[72] – our network area – due to land availability, reliable communication network, pricing and proximity to demand centres.

Melbourne-specific forecasts over the past 12 months include:

- In October 2024, CBRE's forecast, based on Melbourne's pipeline of committed and potential data centre capacity could rise to ~2,100 MW.[73]

[redacted]

Due to our unique position as distribution network service provider and receiver of connection applications we have more market information on data centre development in our network area than any other forecaster. This includes the data centre operators themselves (who do not have visibility of other players) and AEMO (whose forecasts rely on information we provide).

We currently have visibility of 24 known data centre projects[75] amounting to 4,000 MW of capacity requested which will require connection works over the 2026-31 period.[76] We note:

- The enormity of the data centre pipeline cannot be overstated. It amounts to about 40% of the current Victorian peak demand (~10,000 MVA) and is about 4 times higher than the peak demand in our network alone (~1,000 MVA).
- Data centres are increasing in size. Facility size is shifting from 5 – 20 MVA to 200 – 300 MVA.

67 See IEA 2024, *What the data centre and AI boom could mean for the energy sector.* Available here. Morgan Stanley 2024, *Exploring the upside potential and risks for NEXTDC, Goodman, power and resources,* p.3.

68 The third data centre not only providers an additional layer of redundancy and helps maintain data integrity but also allows for majority-vote quorum systems that can protect against data corruption or split-brain scenarios.

69 AEMO 2024, *2024 Electricity Statement of Opportunities, August 2024,* p.35. Available here.

70 Including the Hawaiki Nui cable in 2027 and the Sydney-Melbourne-Adelaide-Perth cable in 2026.

71 CBRE Research 2024, *Australia's Data Centres,* p. 22. Available here.

72 See Structure Research 2023, *Data Centre Report: Australia*, p.9. Figure available here and Morgan Stanley 2024, *Exploring the upside potential and risks for NEXTDC, Goodman, power and resources,* p.14.

73 CBRE Research 2024, *Australia's Data Centres,* p. 22. Available here.

74 [redacted]

75 Several of requiring connections to be made in stage. The overall number of data centre connection projects is 35.

76 This does not include data centre connections in the 2022-26 period.

- Based on the data centre connection pipeline we see; third party forecasters are likely underestimating the growth in capacity (or overall capacity is likely to be more highly concentrated in our network). We are seeing the capacity of *individual* data centres exceeding some projections for cumulative load up to 2030.

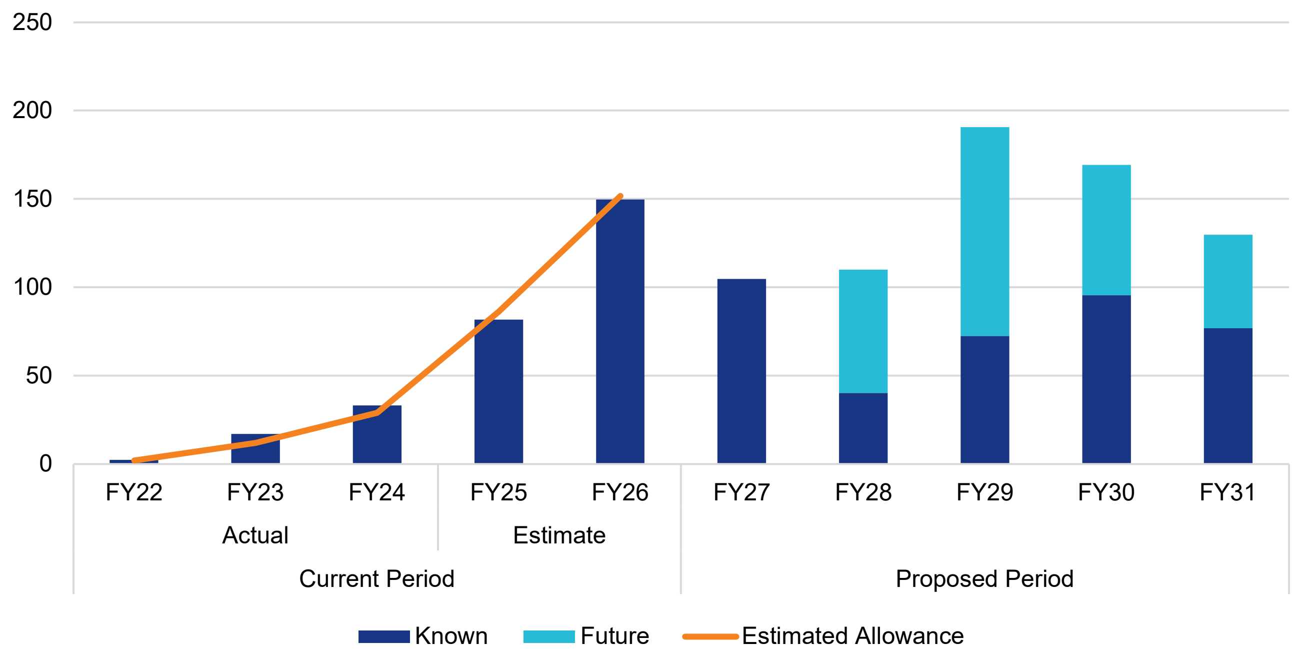
3.3.1 Forecast

As with our major connections segment, we forecast data centres through a combination of known and future connections. Our known connection forecast is based on the data centre connection projects we have visibility of.[77]

The future connection forecast is, as with our major connections, based on a top-down forecast derived from our known connection forecast. However, for data centres we factor in an expected tapering of connections over time to reflect that the current boom is not expected to be sustained indefinitely.

The overall data centre connection forecast is shown in Figure 3-8 below. It shows how overall, we expect that the expenditure will increase driven by the continued boom in data centre investment before tapering off towards the end of the regulatory period.

Figure 3-8: Data centre connection gross capital expenditure, $2026, millions[78]

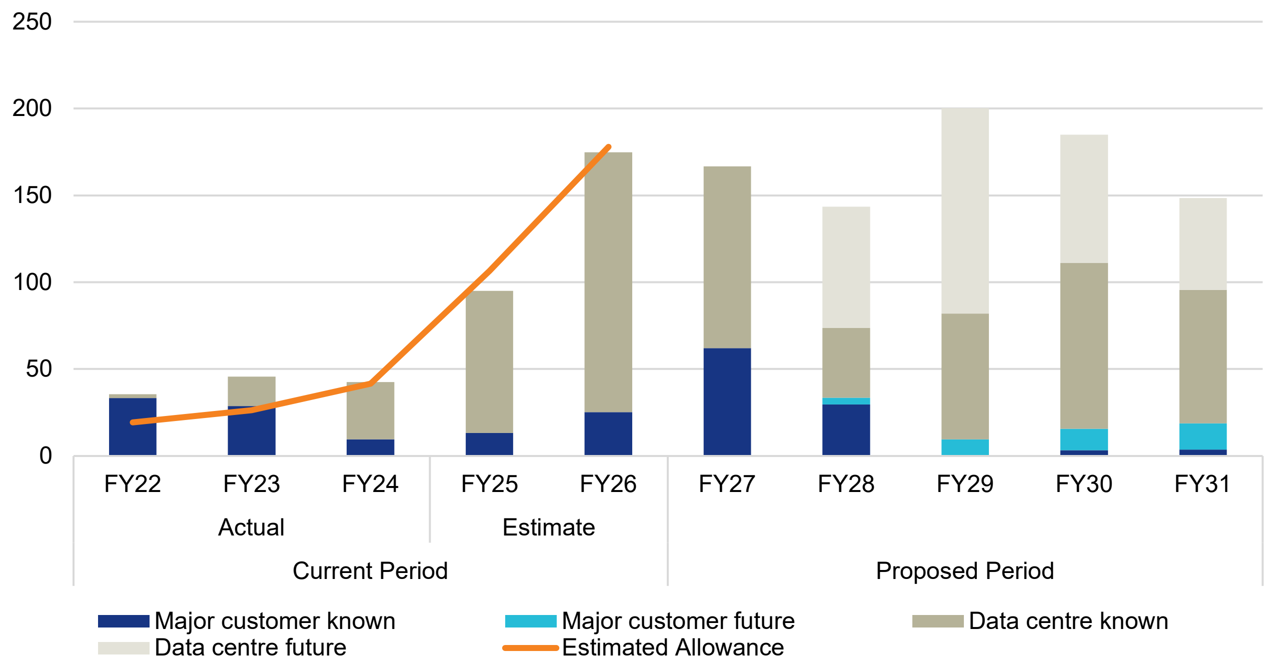


The combined major customer and data centre forecast is shown below in Figure 3-9.

77 We include projects where an offer has been accepted, an offer has been issued, a feasibility study has been requested for completed or where the applicant owns the property. This amounts to 35 connection projects for 24 known data centre projects.

78 Allowance includes proposed adjustments consistent with our reopener application.

Figure 3-9: Major connection and data centre connection gross capital expenditure, $2026, millions[79]



3.4 Capital contributions

As customer connections are funded through a combination of network tariffs and connection charges, we must forecast both gross capital expenditure (the costs we expect to incur) as well as capital contributions (the revenue we expect to recover from connection charges). It is net capital expenditure (gross expenditure minus contributions) which we recover through network tariffs.

How connection charges are set

The cost to connect customers to our network can vary. For the vast majority of smaller connections – such as households and small businesses in established areas requiring less than 100 Amps[80] – we can make a relatively quick assessment. For these customers we charge a set fee for this connection service. This is a basic connection service and is an Alternative Control Service.

For our more significant connections – greater than 100 Amps and usually where the augmentation of our network is required – the activities and costs are more complex. For these connections we:

1. Assess the costs of the connection.
2. Calculate future revenues we may potentially earn from the connection (Incremental Revenue, **IR**).

If the costs exceed incremental revenue, we charge this amount to make the connection. This charge is a 'capital contribution' towards the costs we incur. In this case, these connection services are classified as a Standard Control Service.

79 Allowance includes proposed adjustments consistent with our reopener application.

80 In essence, connections where augmentation is not required.

We assess these connections in accordance with regulatory requirements, including the AER's connection charges guideline[81] and the Essential Services Commission's Electricity Distribution Code of Practice,[82] as well our connection policy.[83]

In some cases, a connection may require us to build more capacity in our shared network than is required by the connecting customer. Where this occurs, we calculate capital contributions by applying standard augmentation rates ($/kVA) derived from the marginal cost of reinforcement. This amount is referred to as Incremental Cost Shared Network (**ICSN**). This approach ensures that connecting customers pay for the capacity they will use but do not pay for additional extra capacity that others will use in the future.

Costs for assets only used by the connecting customer (Incremental Cost Customer Specific, **ICCS**) are wholly paid for by that connecting customer.

Using these principles, which are set out in regulatory guidelines and our connection policy, we determine the capital contribution in each connection offer using the following formula:

Capital contribution = IR – ICCS – ICSN

How we forecast capital contributions

To ensure we produce the best and most realistic forecast of capital contributions,[84] we forecast capital contributions as a percentage of gross expenditure. The percentage is based on historical contributions observed by connection type e.g. smaller business customer, medium business customer, large industrial and data centres.

The exception is where we have a connection agreement with the large customer, in which case our forecast reflects this agreement.

Lastly, we note that we have historical reported capital contributions on an 'as commissioned' basis consistent with statutory auditing standards. Consistent with the AER's November 2024 guidance note we will move to reporting contributions on an 'as incurred' basis from 2024-25 onwards for connection projects above $200,000 and which span more than 12 months. Consistent with this approach we are forecasting capital contributions on an 'as incurred' basis. Further discussion on this change and the implications for the Capital Expenditure Sharing Scheme is provided in *Att 07-01 - Incentive mechanisms*.

3.5 References

The proposed connections capital expenditure outlined in this section is supported by a body of materials, forecasts and models as outlined in Table 3–4.

Table 3–4: List of the attachments supporting our forecast connections expenditure

Attachment	Name	Author
Att 5-09	Connections policy	JEN
RIN Support	Customer Connections Forecast Summary Report	JEN
RIN Support	Customer Initiated Capital Forecast Model	JEN
RIN Support	Customer Connections Forecast Methodology	JEN
RIN Support	Future Major Projects Forecast Model	JEN

81 AER, *Connection charge guidelines for electricity customers, Under chapter 5A of the National Electricity Rules Version 3.0*, April 2023. Available here.

82 ESC, *Electricity Distribution Code of Practice, Version 2,* Available here.

83 *JEN – Att 05-09 Connection Policy*.

84 Consistent the capital expenditure criteria set out in Rule 6.5.7(c)(1)

4. Augmentation

- Ongoing growth, the energy transition, and the growth in cloud and artificial intelligence technologies will require our network to expand in size and criticality.
- Over the next 10 years, peak demand on our network will almost double. This places substantial pressure on what is already one of the most highly utilised networks in Australia.
- Despite these pressures, we are proposing a disciplined program of $223.9M – only 16% above current period spend – to supply greenfield as well as medium and high-density infill growth. This investment will primarily support our radial high-voltage network, where improving utilisation is not a feasible option.
- The surge in data centre investment will put significant strain on our network. Based on current information, we expect to require $99.2M to strengthen our 66kV sub-transmission backbone. However, as we have time to refine our approach and incorporate new information on the location and size of these loads, we are instead forecasting $19.2M in capital expenditure along with two new contingent projects. Our proposal aligns regulatory approval with our decision making and ensures customers do not fund this expenditure until it is required.
- Although the electrification of transport and gas will significantly increase demand, we are not forecasting any material expenditure driven by these new loads. Instead, we will continue our approach, facilitated by our Consumer Energy Resources (CER) Strategy and innovation fund, of using our existing network before building more.

Greenfield and infill development together with the surge in data centre investment will put substantial pressure on the capacity of our network to securely, safely and reliably supply electricity to our customers over the next regulatory.

The primary customer consequences of insufficient capacity are outages. However, insufficient capacity can also prevent or delay development in our network area. This can cause significant societal and economic costs by preventing increases in housing supply, reduced economic opportunities for our community, as well as higher inflation for the economy as a whole. Insufficient capacity on our network also has the potential to delay electric vehicle uptake and undermine trust in the energy transition.

These risks are not theoretical. Other networks in similar circumstances, particularly those supplying clusters of data centres, have had capacity constraints that have led to substantial connection delays and, in turn, stymied economic and housing development.[85]

Consistent with the capital expenditure objectives in the rules and our regulatory requirements set out in the Electricity Distribution Code of Practice[86] we develop plans to meet or manage expected demand, comply with our regulatory obligations (with respect to power quality and bushfire safety etc.), play our role in supporting the achievement of emission reduction targets and maintain the reliability of our services.

Growing demand across our network, facilitated by investment in augmentation, will lead to lower average unit costs and lower bills. Our approach of applying a disciplined approach to network investment, with customers' affordability concerns front of mind, has avoided unnecessary costs.

Our demand forecast, on which most of our augmentation program is based, applies best practice methodologies together with the latest developments in demand forecasting. Where actual data is available and where possible we rely on official government and AEMO projections. This includes electric vehicle charging assumptions which implicitly include the impact that our CER strategy will in reducing charging at peak times.

We constrain investment by ensuring we ‘use more before we build more.’ We have identified a series of creative approaches, particularly with our proposed meshed sub-transmission network, to implement relatively small upgrades to accommodate higher loads. For instance, opportunities to optimise our asset utilisation by

85 For instance in West London (see here)., Ireland (see here) and Netherlands (see here).

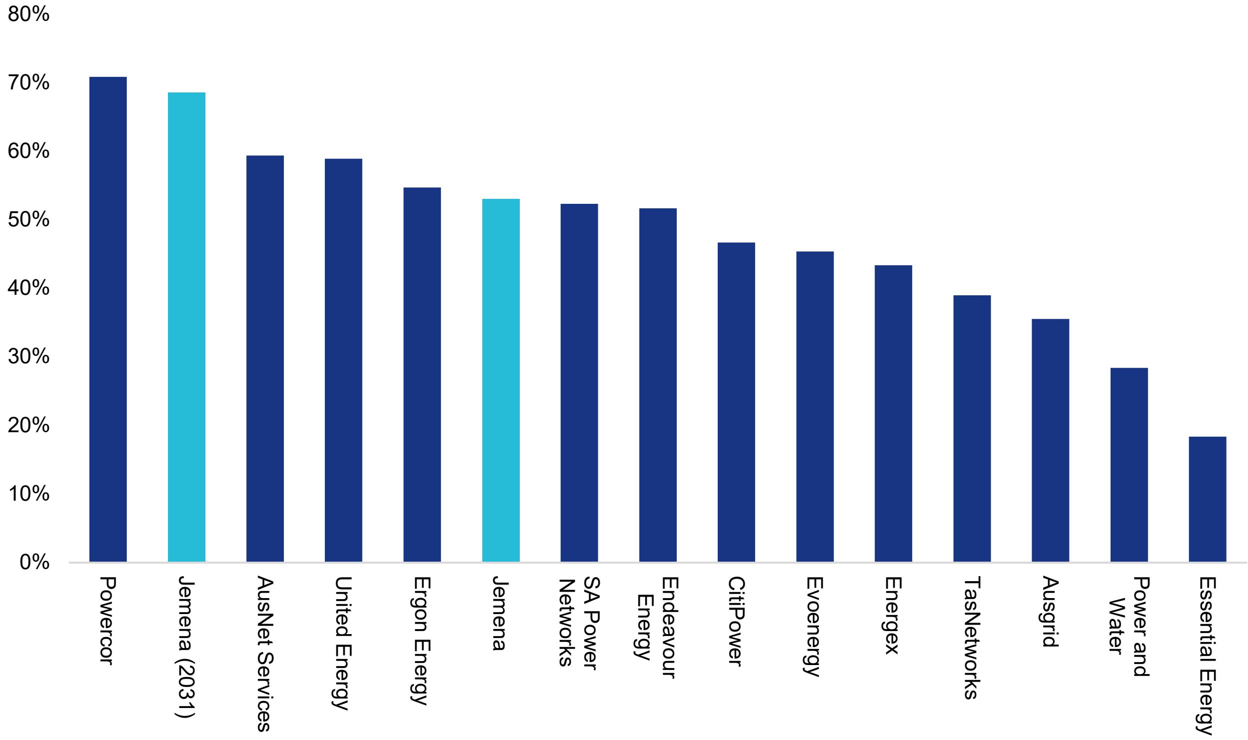
86 Clause 19.2, available here.

undertaking small extensions to tie our sub-transmission loops together creating a meshed sub-transmission network. This allows under-utilised assets to be better utilised reducing costs.

Our approach means that we are able to accommodate increased load from electrification, such as the increase in electric vehicle charging, with almost no impact on our augmentation program. This is demonstrated by sensitivity analysis where we removed all electric vehicle charging loads from our demand forecast. In this unrealistic scenario we found that our preferred network development approach continued to provide the greatest net economic benefits. Removing all electric vehicle charging loads only enabled $1.1M in expenditure to be deferred to the next regulatory period.

The increased demand on our network combined with our disciplined approach, as shown in Figure 4-1, will increase our zone substation utilisation from 53% (already above average) to 63% over the 2026-31 regulatory period.

Figure 4-1: Zone Substation level utilisation by distribution network service provider[87]



Most of our expenditure is required to accommodate greenfield and large infill developments. The other major driver of expenditure is the need to accommodate the pipeline of major customer and data centres seeking to connect to our sub transmission network. Despite identifying a potential pipeline of 4,000 MVA of additional load – which is about 4 times our summer peak demand of 1,081 MVA – for the purposes of forecasting load on our shared network, we have moderated this forecast down to 480 MVA.

We found that most economic approach to accommodating these additional loads is to spend $99.2M of sub-transmission line upgrades in the next regulatory period. However, we also identified that an investment decision on $80M of this program is not required until 2027. This provides time for us to consider further information on customer load requirements and load uptake before making a final investment decision.

While the rules allow all of this expenditure to be included in our capital expenditure forecast, we identified an alternative approach where we can seek an adjustment to the allowance once we make an investment decision through the contingent project mechanism. We have decided to adopt this approach as it aligns regulatory approval with our internal decision-making and ensures that customers do not fund such a large amount of expenditure earlier than necessary. Accordingly, for the next regulatory period, we have proposed including $5.1M

87 Data based on 2023 utilisation as reported in the AER's 2024 electricity distribution network operational performance data. Jemena (2031) reflects our forecast utilisation in 2030-31.

of expenditure to accommodate these high loads together with two contingent projects; rather, than propose the full $99.2M required now.

As shown in Table 4-1, over the current regulatory period load related expenditure has been above the estimated allowance. This is large due to the increase in expenditure on our sub-transmission network to accommodate the surge in data centre investment.

Our augmentation category also includes non-load-driven expenditure. This includes the costs to complete our program to move East Preston to a modern 22kV voltage and retire end-of-life assets, as well as the costs to maintain Rapid Earth Fault Current Limiter (REFCL) compliance. We expect that this category of spending will reduce in the next regulatory as the REFCL program concludes.

For regulatory reporting purposes, our augmentation category also includes the network (but not ICT) components of our CER Integration Strategy. For completeness Table 4-1 presents augmentation with and without CER. Our CER program is outlined in section 5.

Table 4-1: Augmentation capital expenditure, $2026, millions[88]

	2021-26		2026-31
	Estimated allowance	Actual/estimate	Forecast
Load driven augmentation	87.0	100.3	164.7
Other	86.3	93.3	59.2
Total (excluding CER)	**173.3**	**193.6**	**223.9**
CER (network component)	19.4	9.4	45.7
Total (including CER)	**192.7**	**202.8**	**269.5**

4.1 Demand forecast

Maximum demand forecasts play a critical role in our network planning process. They are used to identify the location, timing and probability that insufficient network capacity will ‘constrain’ the total amount of energy which can be delivered (leading to outages). This provides insight into the expected performance of our network and, importantly, implications for customers.

As we need to match demand to our network assets, we prepare a series of forecasts for each of our high-voltage feeders, zone-substations, sub-transmission lines and system as a whole. We also need to account for expected changes in peak demand over time due to various demand drivers.

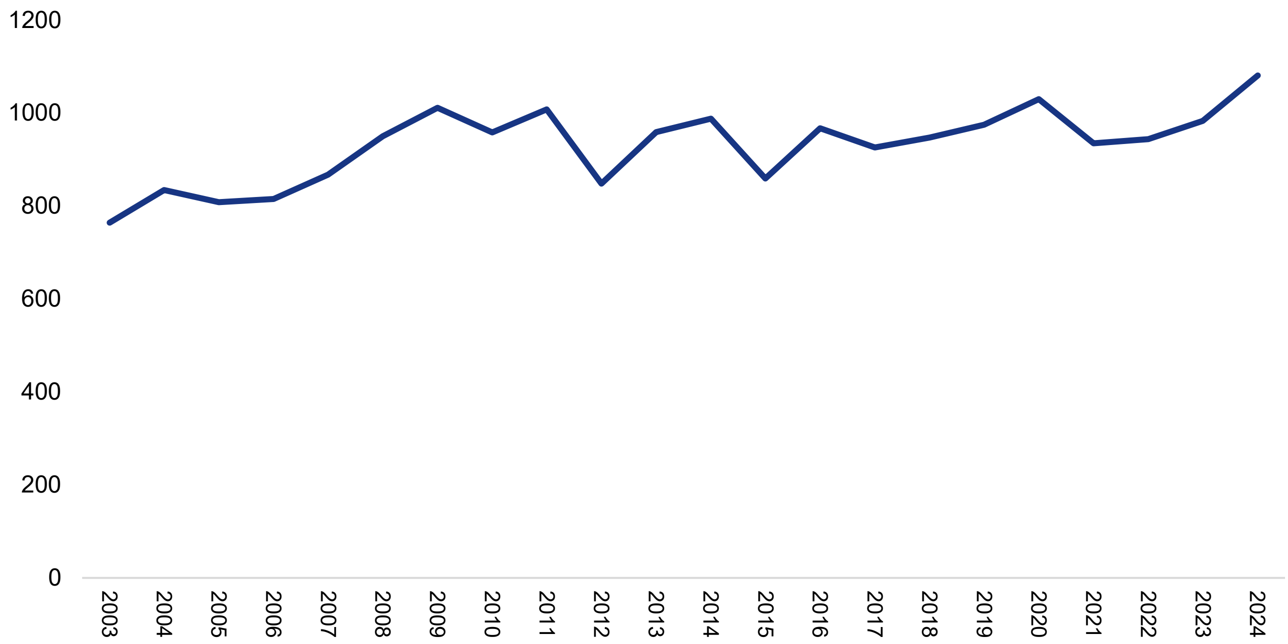
Demand patterns are customer led and continually evolve. As shown in Figure 4-2, increased adoption of air-conditioning led to significant growth in summer peak demand in the early 2000s. Peak demand growth has since been more moderate in part due to the growth in solar penetration, which has shifted the peak from the afternoon to the evening. Over the last 3-4 years, due to overall milder summer maximum temperatures,[89] and the impact of COVID-19, we have seen lower levels of peak demand. In 2024, even with a relatively moderate summer we saw a new high of 1,081 MW.[90]

88 Estimated allowance includes proposed adjustments consistent with our reopener application.

89 Over the past 4 calendar years annual maximum temperatures at Melbourne airport have been 39.7 °C, 41.3 °C, 38.4 °C and 40.5 °C, all below the 20 year average (41.9 °C) and peaks seen in 2019 (46.0 °C) and 2009 (46.8 °C).

90 Maximum demand was reached at 4:40 PM on 22 February 2024. The maximum temperature that day as 37.2 °C at Melbourne airport.

Figure 4-2: Annual observed summer peak demand (MW)[91]



Historically, our maximum demand forecasting approach has focussed on understanding how the relationship between weather and summer peak demand. We identified these relationships by applying statistical techniques to observed weather and network data.

Looking forward, we expect that:

- **Peak demand will continue to grow** – in summer, winter, at the system level, in existing areas as well as across different layers of our network (low-voltage, high-voltage and sub-transmission levels). This is due to ongoing infill and greenfield development (bolstered by government policies to increase housing supply), the electrification of gas, the roll-out of electric vehicles and the surge in data centre investment.
- **Demand patterns to become more complex.** Peak demand will not be *just* driven by high summer temperatures but will also be driven by electric vehicle charging patterns and cold weather. These demand drivers will depend on the increased deployment of CER (such as solar and batteries), as well as changes in wholesale market price patterns as we shift towards a decentralised renewable energy-based system.
- **Peak demand will be moderated** by our CER Integration Strategy and initiatives implemented as a result of our Innovation Fund. These measures will ensure we have the flexibility to either adapt and overcome challenges (or take advantage of opportunities) stemming from technological, regulatory and customer-driven change.

However, forecasting the impact of these factors is difficult due to several factors:

- **Limited historical data** to understand both the individual impacts of, and or interactions between, each demand driver.
- **Wide range of plausible futures**. Demand growth will depend on several factors such as housing policy developments and electric vehicle take-up – which are all uncertain.
- **Uncertainty around the pace and location of these changes**. Demand drivers are likely to affect different parts of our physical network differently. Looking at network aggregates is not sufficient to identify network constraints. Geographically concentrated electrification will lead to different spatial demand outcomes (and likely greater needs to address network constraints) relative to a more uniform uptake.

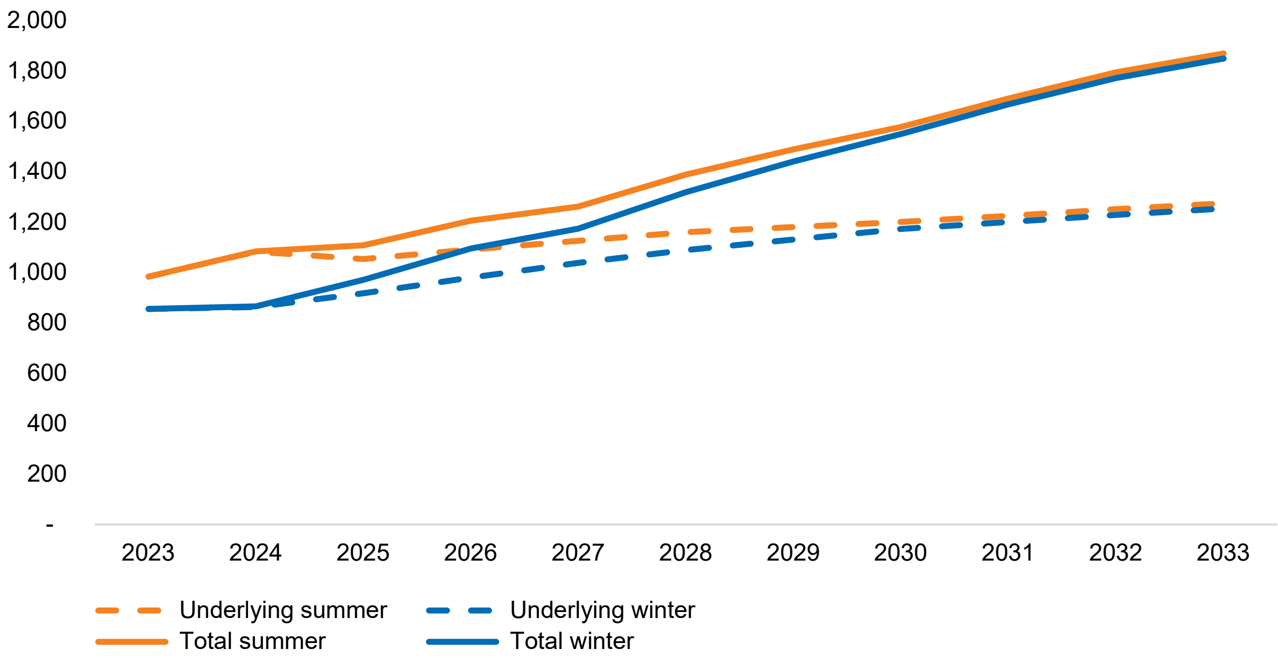
[91] Coincident Raw System Annual Maximum demand measured at the transmission connection point.

In addition to these factors, we need to forecast the impact of the data centre boom (and other major connections) on our network. Given their size, these very large loads are generally supplied via our sub-transmission system.

Our forecast has two main components. The first is the 'underlying forecast' the demand forecast made up of our bottom-up spatially granular forecast reconciled to a top-down forecast, consistent with prior AER guidelines on best practice forecasting. The second component is a specific major customer forecast to account for very significant loads seeking to connect to our sub-transmission network (not captured by our underlying forecast).

Figure 4-3 presents our forecasts split by winter and summer and between our underlying and total demand. It shows that the underlying peak summer demand is increasing due to greenfield development, infill, and the adoption of electricity vehicles. Winter peak demand increases at a much faster rate due to electrification over time, closing the gap with summer peak demand. In addition, significant new loads, in particular data centres drive substantial increases in total demand. Overall, we are forecasting maximum demand to almost double to 1,800 MW by the mid-2030s.

Figure 4-3: Network maximum demand forecast (50% POE MW) underlying and total[92]



4.1.1 Methodology

Our demand forecasting methodology is the result of 15 years of continuous development. We have reviewed, updated and refined our approach over time. Our method is consistent with what the AER considers best practice,[93] incorporates the latest developments in demand forecasting and ensures that future demand drivers, together with the impact of our CER Integration Strategy, are taken into account.

Our underlying forecast is based on:

- **Bottom-up forecast** – a forecast built up from the high-voltage feeder level based on normalised and moderated network and customer connection data to provide an accurate spatial view of demand at an asset level. Load is aggregated up and diversified to produce zone-substation, sub-transmission and system forecasts.

92 Summer 2023 and 2024 and winter 2023 data is actual.

93 For example, we refined our approach to include the features and elements the AER considers necessary to be considered best practice (as outlined here). Specifically, our forecast incorporates key demand drivers, validates spatial bottom-up forecasts against an independently prepared top-down forecast, adjusts for load transfers, normalises for whether, considers the maturity of each service area, and only includes discrete block loads which exceed a set threshold (to avoid double counting).[93]

- **Top-down forecast** – a probabilistic system-wide forecast based on an econometric demand model that incorporates long-term demand drivers such as Victorian Government population projections, CER uptake (using AEMO's inputs and assumptions) and the impact of our CER Integration Strategy. This forecast is then cross-checked against AEMO's forecast for Victoria.

Consistent with prior guidance from the AER, the bottom-up and top-down forecasts are reconciled by scaling the bottom-up forecast so that it aligns with the top-down system forecast. This reconciled forecast forms our 'underlying forecast.'

Given the significant number of new customers being connected to our 66kV sub-transmission level of our network we have prepared two separate forecasts of these loads. The first for load from known customers and the second from future customers which will connect beyond the horizon of our known connections. Further details on each element are provided below.

4.1.2 Underlying forecast

Bottom-up system forecast.

Our bottom-up forecast is built up from demand forecasts for each individual feeder where we take weather-correct observed peak demand, then add and subtract expected changes in load. This includes load changes driven by:

- **New connections** – We forecast load based on all known connection applications. Maximum demand for each connection is moderated down to benchmark levels (i.e., less than what customers forecast their load to be). Diversity factors (i.e., the degree to which their maximum demand will coincide with the maximum demand for that feeder) are then applied.
- **Growth in existing load** – forecast by applying benchmark growth factors, depending on the organic load growth observed on each feeder. These growth factors are very low, averaging 0.29% per annum across our network.[94]
- **Disconnections and load reductions** – reflecting information we have recovered from our larger customers.
- **Planned load transfers** – loads are moved between feeders to take into account proposed known load transfers from committed projects.

Feeder-level demand is aggregated to prepare zone and sub-transmission forecasts. We apply further diversity factors to account for feeders and zone substations peaking at different times.

The end result is a highly accurate, spatial (with load allocated to individual assets) short term forecast. However, this forecast only includes a limited number of connections (only those that have lodged a connection application) and does not factor in the impact of demand drivers (including the impact of CER) over the medium to long term.

Top-down system forecast

Our top-down forecast is prepared at the system level using Blunomy's Vision Demand Forecasting model.[95] Blunomy's model forecasts a complete demand time-series (rather than just the peak demand) which enables structural changes in load patterns as well as the impact of new technologies of maximum (and minimum demand) to be considered.

94 Growth factors are applied on a feeder-by-feeder basis based on the level of development in that network area. Typically, each feeder is considered slow decline (-1%), no growth (0%), slow growth (0.5%), medium growth (2%), high-growth (4%), extremely high growth (6%). The average growth factor applied is 0.29% (for both summer and winter) which means that the average level of development selected is between no and slow growth.

95 Vision is a cloud-based platform, developed in Python, using various associated technologies to produce forecasts, such as Tensorflow for machine learning. It produces a range of forecasting information, presented in a web-based user interface (rather than the traditional excel model).

Blunomy's forecast is made up of several components, outlined in Table 4-2. Each year, Blunomy updates its forecast based on the prior year's performance and includes the latest data available, such as data from AEMO.[96]

Table 4-2: Components of Blunomy's demand forecast

Component	Forecast basis
Native demand	Native demand represents typical electricity use, excluding emerging technologies such as solar, electric vehicles and the electrification of gas. For example, for residential customers this might include lighting, plug-in appliances and any existing electric heating and cooking installations. Forecast native demand is based on the combination of: • A short-term model that forecasts demand conditional on weather and calendar conditions (day of week, etc.). • A long-term model that takes into account macro-economic and demographic factors (such as gross state product, electricity prices, energy efficiency and forecast cooling and heating degree days, etc.) to estimate the yearly trend in energy consumption. The overall forecast is produced by scaling the short-term model by trend in the long-term model.
Block loads	Additional load from new large connections to our network. This forecast is based on expected maximum demand and a typical load profile applied to each industrial and commercial connection. Residential connection data is not included as this load is captured by the native demand component of the model (Blunomy apply the official Victorian state government projections of population). Blunomy also adjusts the load to reflect the time it takes for a new connection to reach their mature load (ramp-up).
CER (Solar, Electric Vehicles and Battery Storage)	A separate forecast for each technology – solar, batteries and electric vehicles – is produced based on forecast uptake and a demand profile, taking into account how customers will consume and generate power throughout the day and over the year. • **Solar** – demand profile is based on a typical solar panel in Victoria factoring in irradiance, temperature etc. Forecast uptake is based on AEMO's forecast for Victoria with an allocation to our network based on historical penetration rates and socio-demographic characteristics. • **Batteries** – demand profile is derived from a sample of meter data by modelling how a battery would behave given each connection's solar and native demand profiles. The model assumes that a battery is typically paired with rooftop solar, and battery update is allocated to our network in the same proportion as solar uptake. • **Electric vehicles** – demand profiles based on AEMO's charging profiles together with AEMO's forecast of electric vehicles. Electric vehicles are allocated to our network based on historical electric vehicle registration together with demographic data. AEMO assumes that over time less charging will occur in peak times, as customers take advantage of cheaper prices and the proportion of dynamic and system-controlled charging increases. [97]
Electrification of gas	Similar to CER, the impact of the electrification of gas is based on a load profile and uptake profile. Several load profiles are used for each customer segment (residential, commercial and industrial) and appliance type (space-heating, hot-water and electrifiable low-heat industrial processes). For example, residential space-heating is modelled from historical air-conditioning data, whereas industrial load profiles are assumed to match the historical load shape. The total amount of gas to be electrified is based on gas usage data. This load data is allocated to our network on the basis of LGA and feeder locations.

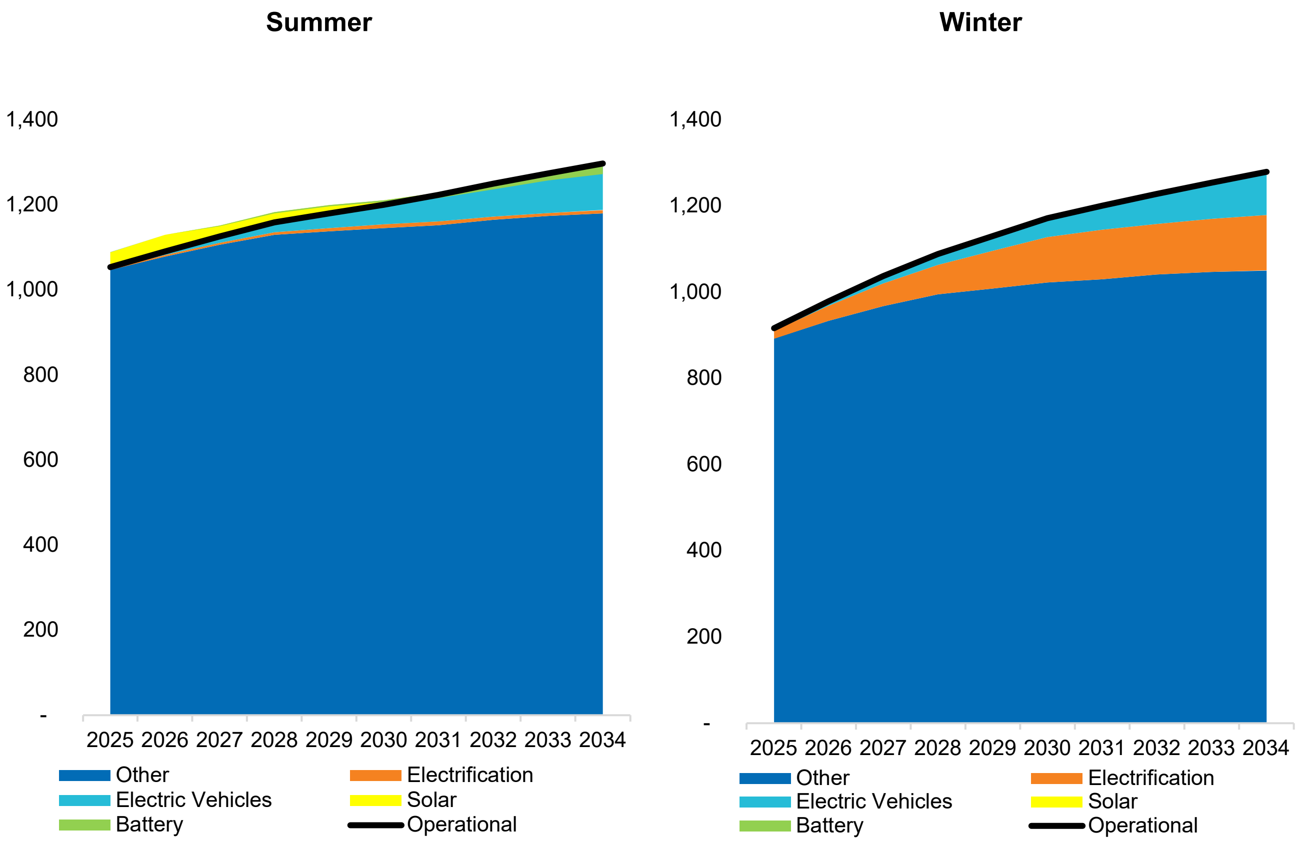
96 Other data and assumptions, such as the Victorian state government projection of population and households, are not updated as frequently.

97 See here, page 15 and also shown here page 19.

As shown in Figure 4-4, Blunomy is forecasting:

- **Summer peak demand** to grow consistently with the increased size of our network. Continued solar uptake initially moderates the growth in peak demand; however, the impact wanes over time as the peak shifts to later in the evening. The impact of electric vehicles will be minor over the next regulatory period but will become the leading factor driving peak demand growth in the 2030s. Electrification is not expected to have a material impact on summer peak demand.
- **Winter peak demand,** initially much lower than summer peak demand, grows much more rapidly, primarily due to the electrification of gas and the suburban nature of our network. Although winter peak demand is not expected to exceed summer peak demand in the next regulatory period, the gap is expected to close over the 2030s.

Figure 4-4: System coincident demand (POE 50, MW, excluding data centres)



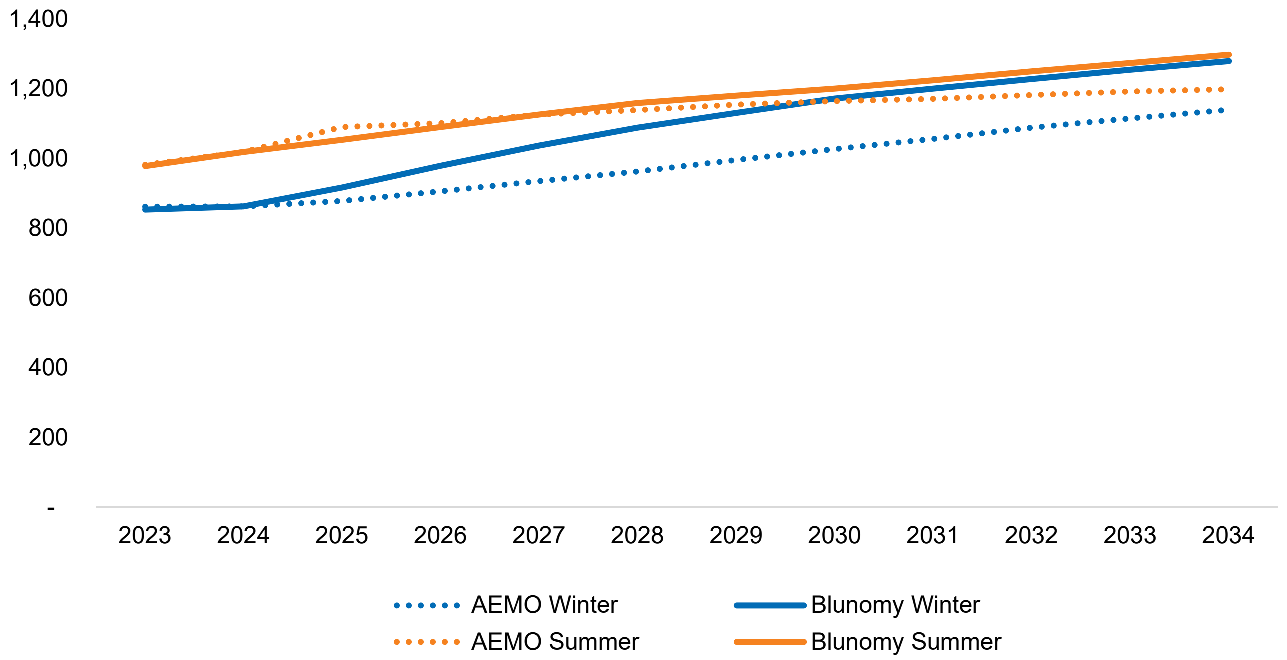
As a cross-check, we compared Blunomy's forecast against AEMO's forecasts for Victoria (scaled down to JEN network demand in 2023). The purpose of the comparison is to verify the reasonableness of Blunomy's forecast.

It is important to keep in mind that the forecasts are not directly comparable. For example, our network has the highest proportion of residential customers across all Victorian networks, which means that the impact of electrification and electric vehicles will be higher for our network than for Victoria as a whole.

Overall, Blunomy's and AEMO's summer peak demand forecasts are similar. As shown in Figure 4-5, AEMO's forecast is marginally higher over the next regulatory. This figure presents the 70:30 weighted average of the POE10 and POE50 forecasts, as this is what we use for network planning purposes consistent with good electricity industry practice.

There is a difference between the AEMO and Blunomy peak demand forecasts for winter, due to faster load growth as well as higher load growth from electric vehicles and electrification. This is not unexpected given that our network has a higher proportion of residential customers.

Figure 4-5: System coincident demand (POE 50 excluding large customer forecast)



As we note further below, it is the summer peak which drives our augmentation program. This is largely for two reasons. First, winter peak demand remains lower than summer peak demand. Second, our network assets generally have greater capacity in winter due to colder temperatures.

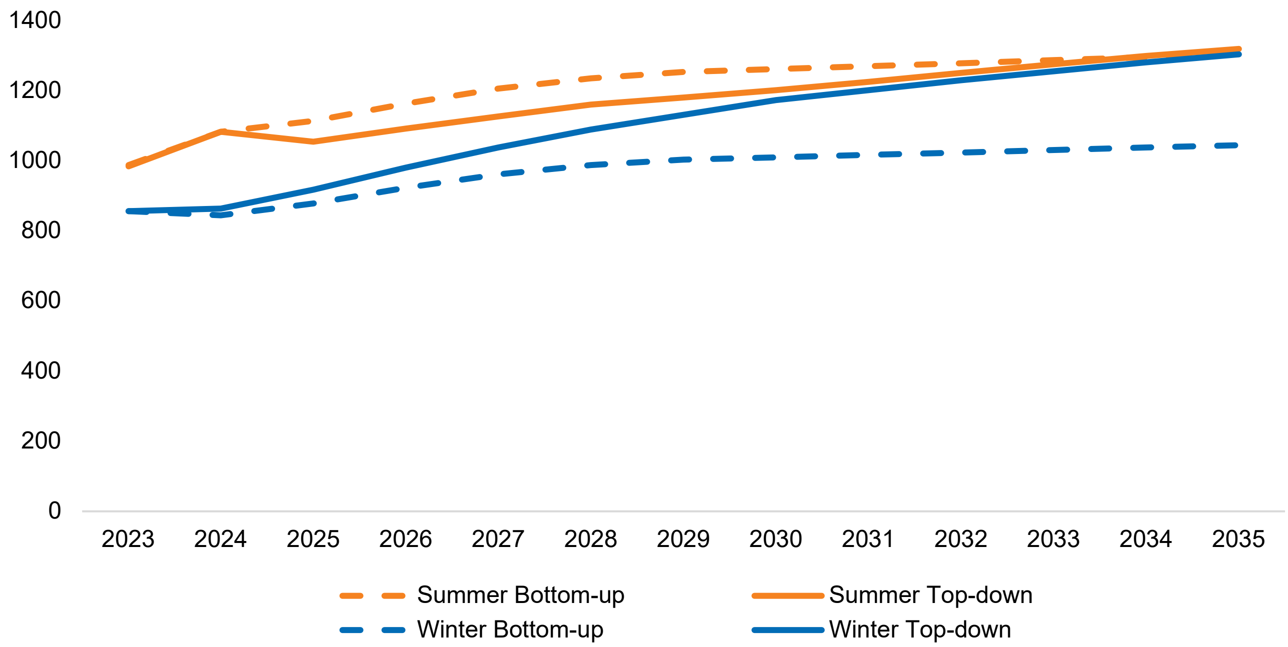
We also note that Blunomy prepares a minimum demand forecast for each asset in our network using the same data and a similar approach for its maximum demand.[98]

Reconciliation of bottom-up and top-down forecast

Consistent with guidance from the AER, we adjust the bottom-up forecast to reconcile it with the top-down system view. A comparison of the two forecasts is shown in Figure 4-6. For summer peak demand, the primary driver of our augmentation program, this reconciliation process results in a reduction in forecast demand. For our winter demand forecast, the reconciliation process results in an *increase* in peak demand. This is unsurprising as our bottom-up forecast does not take into account the impact of electrification and electric vehicles.

98 In turn this approach is how we identify demand from micro resource operations and non-registered DER providers to supply into our network.

Figure 4-6: Top-down versus bottom-up forecasts (POE50)



4.1.3 Major customers and data centres forecast

As outlined in section 3.3, over the last few years, data centre investment has surged, driven by increased adoption of cloud computing and artificial intelligence. We have identified 24 known data centre projects in the pipeline of potential projects with a combined load of 4,000 MVA[99].

To forecast new load on our sub-transmission network, we prepare two separate forecasts.

Known major customer and data centre connections

The first is for known connections. Based on customer connection applications, we prepare a moderated view of load based on the status of each project. This moderation takes into account the probability that the connection occurs, timing delays of initial load uptake, delays in when customers reach their ultimate load (ramp-up) and the potential for the ultimate demand to be less than forecast.[100]

In each scenario, the moderation assumptions are very conservative as they assume that data centre developers, consistent with other project developers, overstate their demand requirements and are optimistic with their timing assumptions.

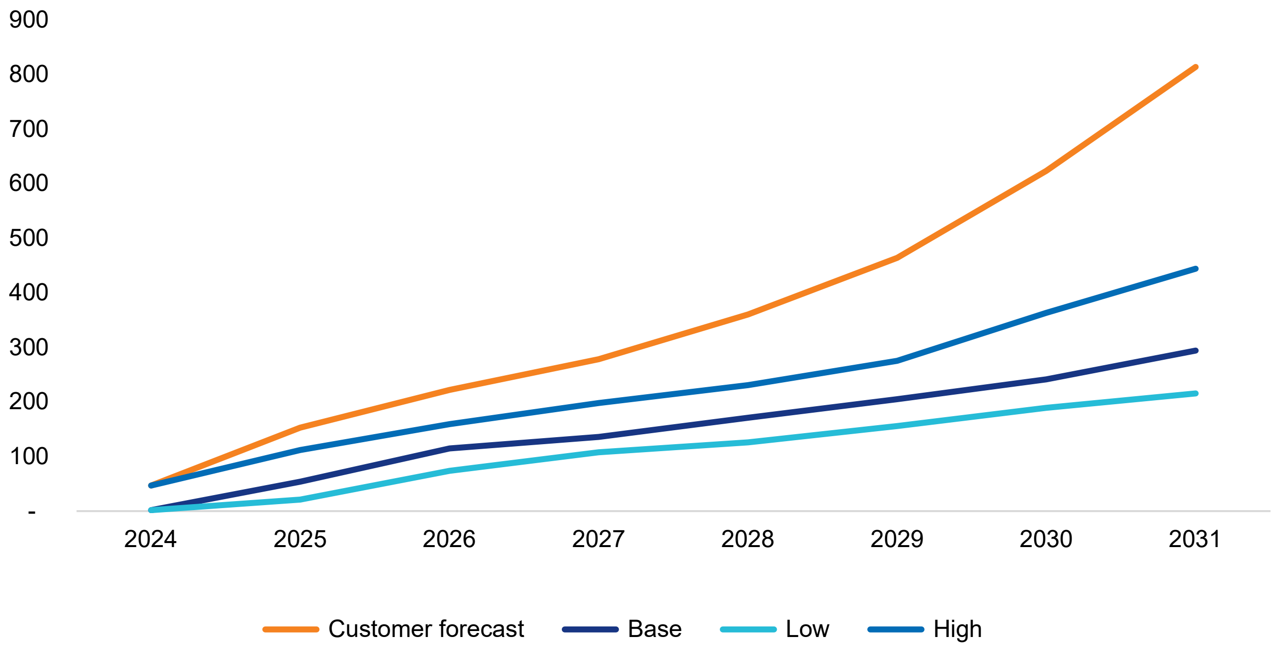
This may not be the case. There are significant differences between data centres and other loads, such as a new commercial or residential development. In particular, the electricity supply is central to the operation of a data centre, rather than a smaller ancillary input. Data centre capacity is measured in megawatts. Further, operators tend to own other facilities, providing them with an accurate understanding of their load requirements. Unlike residential and commercial developments, we do not have historical data to calibrate these adjustments. Given this context, it is possible that our conservative adjustments underestimate actual load outcomes.

[99] Known data centre projects as of August 2024.

[100] As we note in *RIN – Support – Major Customers NDS – Forecast Methodology* we apply three sets of moderation assumptions (low, base, high) then produce a weighted average (50% on base, 25% on low and high). This results in a forecast very similar to the base forecast shown in Figure 4-7 and Figure 4-8.

Our known major customer and data centre customer connection forecast is shown in Figure 4-7. We note that our base forecast of 466 MVA of additional capacity by 2031[101] is significantly less than the customer forecast of 1,295MVA and the total requested capacity of the connections of 4,000 MVA.[102]

Figure 4-7: Know major and data centre customer connection forecast (MVA) by scenario



Known major customer connections

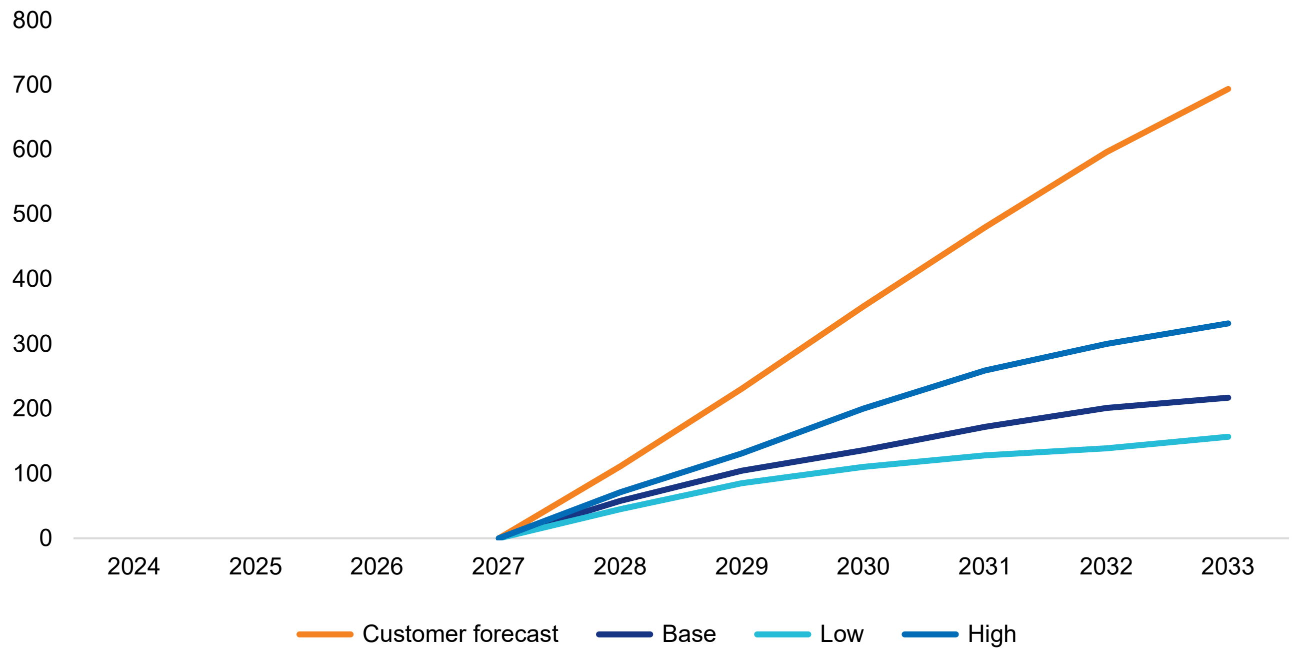
The second forecast we prepare is for future major connections for which we do not yet have a connection application. This forecast is based on an extrapolation of the known customer load forecast. We assume that data centre connections will reduce as the surge in investment abates over time. For major connections (outside of data centres), we assume that these connections continue at a level similar to what we have observed in the past.

As the forecast is based on the known customer load forecast, we prepare corresponding forecasts by scenario. These are shown in Figure 4-8. The forecast is zero for the first four years (2024-2027) to reflect that this forecast is for connections for which we do not yet have a connection application.

[101] Comprising 151 MVA and 314 MVA for major customers and data centres respectively.

[102] Noting that connection assets are sized to customers requested capacity while our demand forecast reflects the impact of the connection on coincident demand, which takes into account diversity, ramp up etc.

Figure 4-8: Future major and data centre customer connection forecast (MVA) by scenario



Our future connection forecast for the period to 2030-31 is 172 MVA.[103] We note that the total of the known and future connection forecast is 466 MVA which is lower than the customer forecast (1,295 MVA) and the overall connection capacity requested by data centres of 4,000 MVA.

Table 4-3: Summary of the major customer, data centre known and future forecast (MVA)[104]

	Known	Future	Total
Major customers	99	53	**152**
Data centres	195	119	**314**
Total	**294**	**172**	**466**

4.2 Network Development Strategies

The next step in our network planning process is to identify solutions (network or non-network) to the constraints identified by our demand forecast.[105] We then evaluate the technical and economic viability of these solutions to determine the most economic technical feasible option.

At the centre of our assessment is our probabilistic planning approach[106] which takes into account the likelihood and severity of each constraint to calculate the expected cost to customers from an outage. We calculate this cost by multiplying expected unserved energy against the Value of Customer Reliability set by the AER.[107]

103 Comprising 53 and 119 MVA for major customers and data centres respectively.

104 These are known major customer connection projects as of August 2024.

105 These constraints are not limited to outages. We also consider regulatory requirements with respect to power quality and safety. For instance, the impact of load on cable capacitance and in turn the performance of Rapid Earth Fault Current Limiter protected feeders. This can require a network (or non-network) solution to ensure compliance with Victorian bushfire safety regulations.

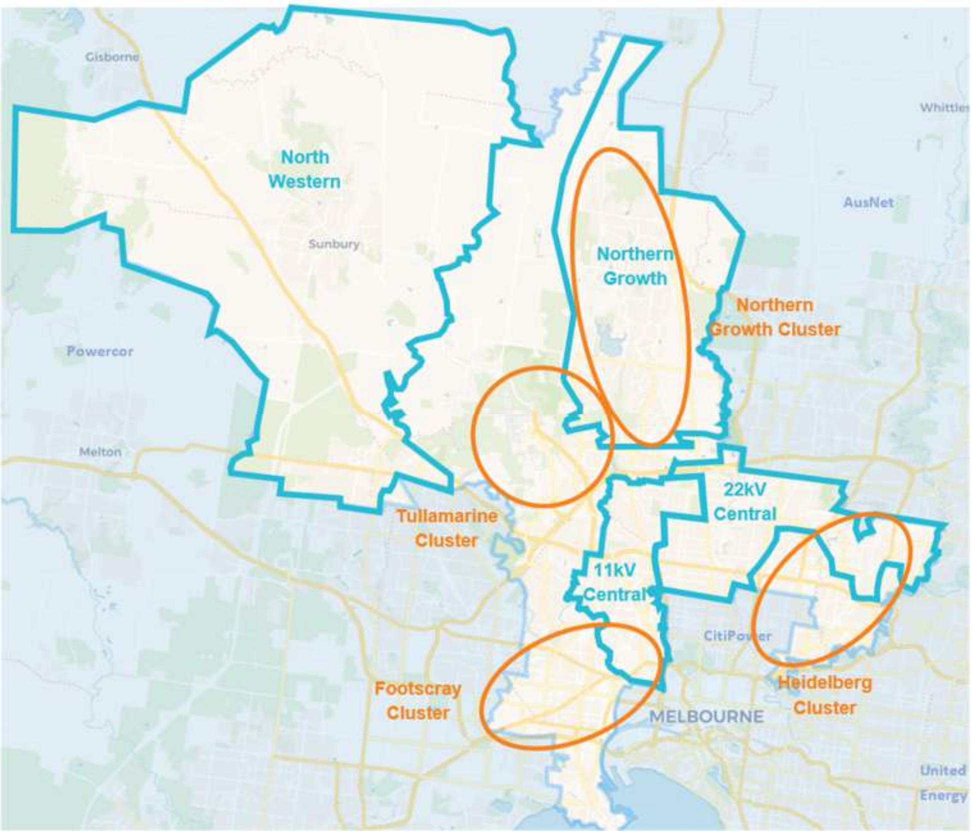
106 In limited circumstances we apply a deterministic approach where required to maintain the safety of the distribution, system such as high-voltage feeders operating above the maximum safe loading limit, individual distribution substations and low-voltage networks that are at risk of an unsafe failure.

107 Our current network development strategies are based on the 2019 VCR estimates published by the AER. The AER released the 2024 VCR on 18 December too late to be integrated in our latest plans. The latest VCR, for residential customers, is significantly higher $49.23/kWh versus $25.84/kWh which means that our analysis understates the customer costs of outages.

To determine the most economic option, we compare the customer costs of expected outages against the costs of implementing a solution to unlock capacity through network, non-network or other innovative solutions. Our approach is consistent with the Victorian Electricity Distribution Code of Practice[108] and capital expenditure objectives in the National Electricity Rules.

Solutions are evaluated on an area-by-area basis to ensure we consider geographic constraints as well as interactions between the high-voltage, zone substation and sub-transmission levels of our network. This enables us to identify the most efficient option to address the identified needs. For instance, by identifying where we can shift load between existing assets to avoid building new infrastructure. Figure 4-9 shows each network development areas (aside from the major customer network development strategy which covers our entire network) and the key data centre clusters.

Figure 4-9: Network Development Areas and data centre / major customer clusters



Overall, our network development strategies require an investment of $130.0M over the next regulatory to deliver $1.9B in net economic value, primarily through avoiding or reducing outages.

Table 4–4: Load driven augmentation expenditure, $2026, millions

	Component	Capital expenditure
Network Development Strategies	Northwestern growth corridor	29.3
	Northern growth corridor	40.6
	11kV central area	27.3
	22kV central area	14.4
	Major customer (sub-transmission)	19.2
Other	Fairfield	2.1
	Low voltage circuit and distribution substation	31.6
Total		**164.7**

108 Clause 19.2, available here.

4.2.1 North western and northern growth corridors

Load growth in our north western and northern growth corridors is predominately made up of low and medium density residential and greenfield development. Growth in these areas is significant. The population in the north western growth corridor is expected to double (increase by 91,000 people) by 2046. In the northern growth corridor, the populations of Craigieburn and Mickleham are expected to grow by 41,000 by 2041 – a 50% increase.

To supply these greenfield areas, we need to build new feeders and supporting zone-substation assets at a cost of $70.1M, as the existing network is either not sufficient or does not yet exist. The works required are summarised in Table 4–5.

As part of our economic analysis, we tested our proposed plans across a range of standard sensitivities[109] and found that in no scenario does the preferred approach change.

We note that although we have modelled the consequence of inadequate capacity using unserved energy; in practice, if we do not extend our network to these areas housing and economic development will not be able to proceed. This would mean that we would not be able to play our role to in alleviating community concerns around housing, which are currently second only to cost of living pressures.

Table 4–5: North western and northern growth corridors network development strategy, $2024, millions

Network Development Strategy	Plan	Net Economic Value
North Western Growth Corridor Sunbury Plan (Option 4)	• 1 load transfer • 2 new regulators (address voltage issues) • 5 new feeders • 1 feeder augmentation • Upgrade Sunbury transformers No.1 and No.3	98.1
Northern Growth Corridor Craigieburn Plan (Option 2)	• 7 new feeders • 1 feeder augmentation • Coolaroo bus cable transfers and bus feeder works • New Craigieburn Zone Substation • Third transformer at Craigieburn Zone Substation (2033)	437.5

4.2.2 Existing 11kV and 22kV central areas

Load growth in our existing 11kV and 22kV central areas is driven by infill, high-rise developments, residential sub-divisions and major customer developments. Despite high utilisation and material increases in load forecast, we have prepared a very low forecast of $41.7M.

We are forecasting limited expenditure as we plan to address load constraints by making the most of our existing network and, in turn, limiting the need for new assets. We do this by transferring load across our network. We also constrain costs by uprating existing feeders (by reconductoring with higher capacity lines) and making relatively small investments to connect feeders – increasing our ability to shift load to feeders with spare capacity.

Utilisation in our existing areas is high. Figure 4-10 shows zone substation utilisation in 11 kV central area.[110] This graph is not an exception. There are high levels of utilisation on our sub-transmission lines and a number of feeders in both our 11kV and 22kV central areas.

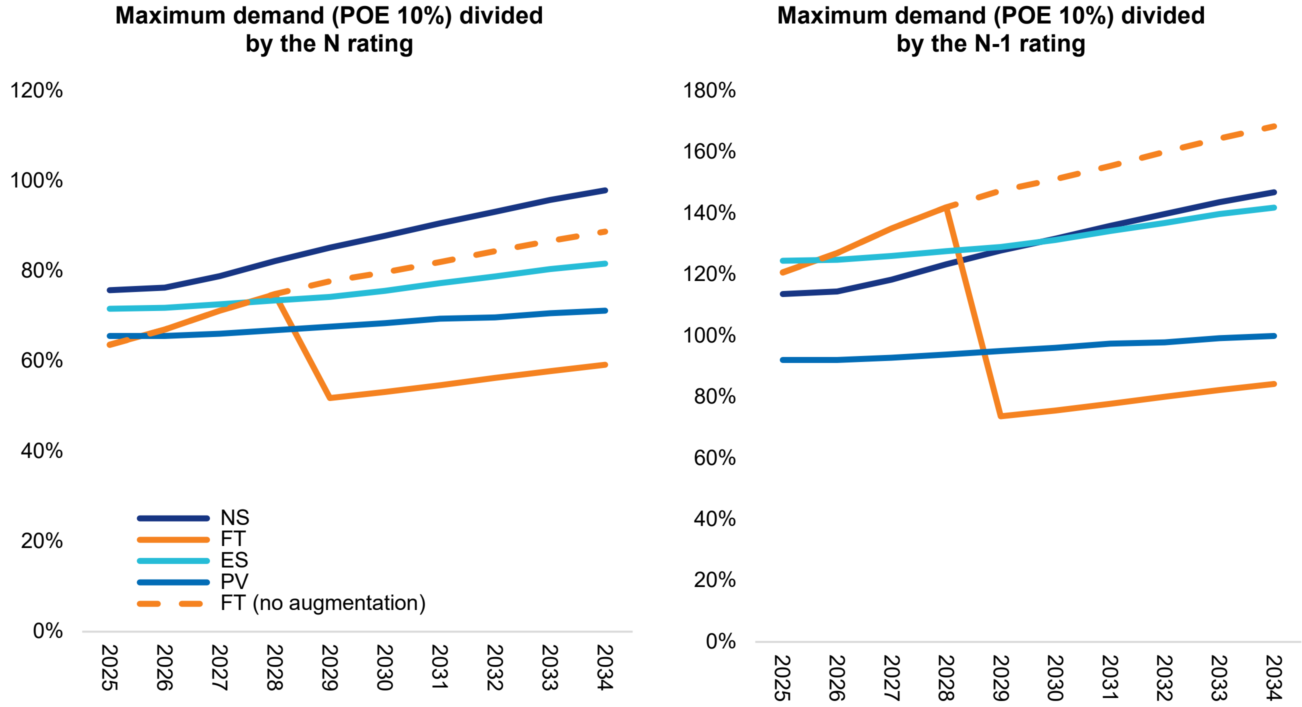
Figure 4-10 also shows that utilisation will materially increase over the next two regulatory periods. This is a function of strong demand growth – over the 2025 to 2031 period we expect peak demand to rise by 13% and

[109] Value of customer reliability +/-10%, capital and operational costs (+/-30%) and discount rates (+/-1%).

[110] At the zone substation level for our 11kV central area this is limited to installing a 3rd transformer at Flemington Zone Substation (FT). Forecast utilisation for this asset in the base case (i.e. with no investment) is shown by a dashed line.

16% in the 11kV and 22kV central areas[111] – together with constrained investment and limited increases in network capacity.

Figure 4-10: Forecast 11kV central area zone substation utilisation[112]



Notably, the only zone-substation works in our central areas is the addition of a third transformer at Flemington Zone Substation (FT). Other works include augmenting our sub-transmission network and, where there is no other feasible or economic alternative, building new feeders. These works are summarised in Table 4–6.

As with our growth corridors, we tested our approach using standard sensitivities. Given that the electric vehicle uptake is a primary driver of summer peak demand (as shown in Figure 4-4 earlier), we also tested an additional demand sensitivity with no charging during peak periods.[113]

While not realistic, this sensitivity provides insight on whether our augmentation program could be reduced further if our CER Integration Strategy, innovation fund and tariffs were more effective than anticipated and could shift all charging to outside of the peak window in the next regulatory.

Notably, in this scenario there was no change to our preferred option. We also examined whether the optimal timing of any individual solution which comprised part of the preferred option would change. We identified that only one project – the $1.1m ($2024) augmentation of feeder NH0-002 – could be deferred from the next regulatory period.[114]

This remarkable outcome reflects several elements:

- We design and plan our network to use what we have before we build more, constraining expenditure requirements.

111 At the zone-substation and sub-transmission level, summer peak demand 10% POE. See table 2-6 in *RIN – Support – 11kV Central Area – Network Development Strategy* and *RIN – Support – 22kV Central Area – Network Development Strategy*

112 Maximum demand based on the base case forecast. In our preferred option we shift 2 MVA from NS to FT.

113 For completeness we also tested this sensitivity for our growth corridors and found no change in the preferred option or the timing of any of the solutions.

114 RIN – Support – 22kV Central Area – Network Development Strategy, table 6-3.

- Our demand forecast applies a conservative approach to forecasting electric vehicle loads and already reflects the impact of our CER Integration Strategy and cost reflective tariffs by assuming charging behaviour changes over time (see Table 4-2). This means that removing the already conservative view of demand has a smaller impact.
- Infill development in existing areas is significant.

Lastly, we also note that, as with our growth corridors, insufficient capacity will delay or halt infill development and undermine the Victorian government's planning reforms which aim to increase housing density and allow 70% of new homes to be in established areas.[115]

Table 4–6: 11kV and 22kV central area network development plans, $2024, millions

Network Development Strategy	Works	Net Economic Value
11kV Central Area Flemington Plan (Option 2)	• 3 new feeders • 4 feeder augmentations • 3rd transformer at Flemington Zone Substation and associated 66kV works • Augment Brunswick Terminal Station to North Essendon Zone Substation 22kV lines	70.5
22kV Central Areas North Heidelberg Plan (Option 2)	• 3 feeder augmentations • 1 load transfer • Augment the TTS-NH(NEI)-NEL-WT-TTS 66kV loop	895

4.2.3 Fairfield

The population in our Fairfield supply area is expected to grow by 24.1% by 2036. Growth is made up of a significant increase in the number of infill developments (apartments and townhouses) along with commercial developments, such as Yarrabend.

This growth is forecast to placed constraints on our existing Fairfield network. Due to limited transfer ability (as the surrounding network has been moved to the modern 22kV voltage), to ensure ongoing reliable supply we need to augment our feeders to maintain reliability.

4.2.4 Major customer development strategy

Our major customer development strategy is focused on how we are going to accommodate known and future connections to our zone substation and sub transmission network. We are seeing, and expect to continue to see, very high levels of new load being connected to our sub-transmission system. This is due to:

- **The large size of each connection**. Our pipeline indicates that the new media size for data centres is increasing to 150 – 200 MVA per connection. For context, a standard 22 kV high-voltage feeder on our network has a capacity of less than 15 MVA.
- **The large number of connections**. We have identified more than 30 data centres in our connection pipeline, and there is no sign of these connection numbers reducing.

As noted earlier in section 4.1, overall, we have identified a data centre connection pipeline of 4,000 MVA of load to our network – or about 4 times higher the current peak demand.

[115] Victorian Government 2023, *Victoria's Housing Statement, the decade ahead 2024 -2034*, p.41 Available here.

To accommodate this substantial increase in load, we forecast our capital expenditure requirements in two parts. First, we identify the optimal augmentation plan to accommodate known customer connection requests. Second, we forecast augmentation requirements for future connections that have not yet been lodged.

Known connections

Our augmentation program for known connections reflects the location and demand requirements specified in each connection application we have received. As outlined in section 4.1.3, we moderate forecast requirements down to 312 MVA.

We then evaluate three options, each targeting different levels of unserved energy.[116] The purpose of this analysis is to identify which investments are 'no-regrets' – and likely to be required in all plausible scenarios – and what investments will be required only if the forecasted load materialises. These options are set out in Table 4–7.

Table 4–7: Major customer development strategy outcomes, $2024, millions

Option	Total Capital expenditure[117]	Present Value of Reliability	Net Present Value (NPV)
Option 1 - Do Nothing	0.0	0.0	0.0
Option 2 – Base Development Plan *Aim to address 50% of unserved energy risk*	51.6	473	418
Option 3 – High Development Plan *Aims to address 100% of the unserved energy risk*	230.2	676	469
Option 4 – Low Development Plan *Aims to address up to 50% of the unserved energy risk*	33.9	254	218

Option 3 High Development Plan is the credible option with the highest net economic benefits. Although this option requires substantial investment ($230.2M) to strengthen our sub-transmission network, these costs are offset by significant reductions in unserved energy ($676M) – even though the analysis was considered over a short 10-year time horizon. Extending the analysis out by an additional 10 years (still much shorter than the economic life of the investments) would materially increase the reliability benefits.

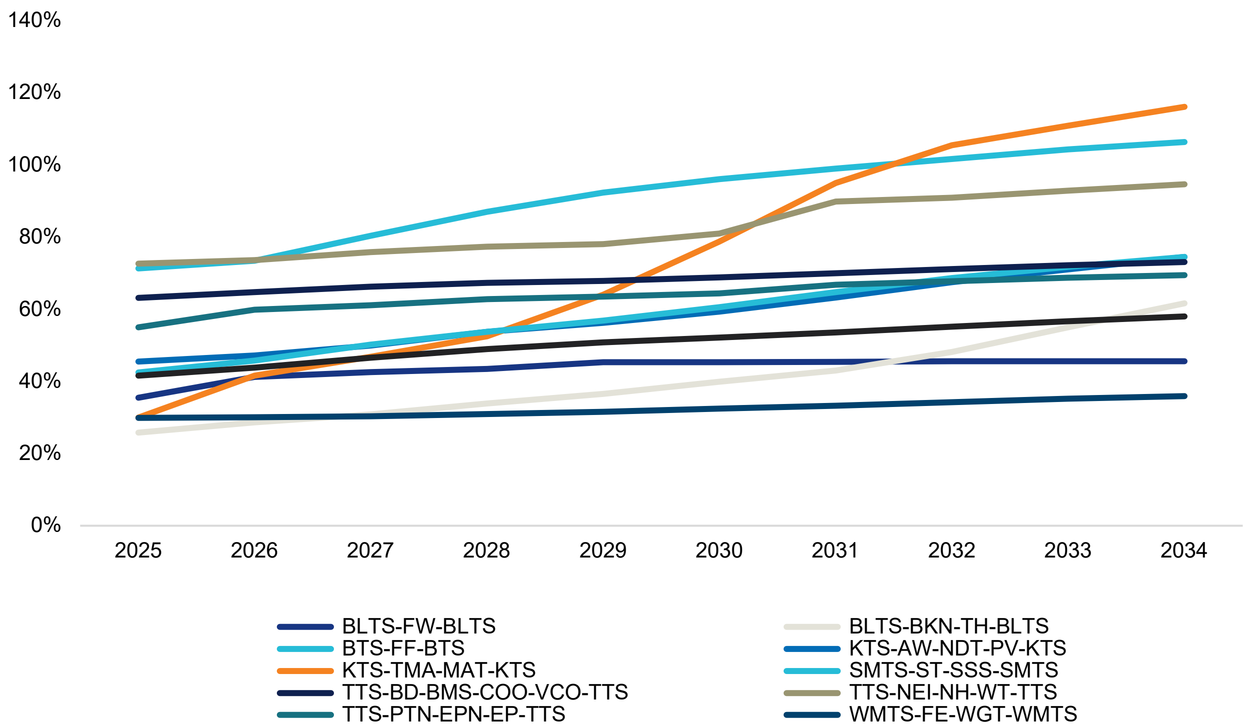
We recognise that both the costs and potential benefits are large. This is because adding such large loads puts significant pressure on our highly utilised sub-transmission system, as shown by Figure 4-11. By 2034, summer peak demand[118] will exceed the N-1 rating of 4 of 11 of our zone-substations and 9 of 11 of our sub-transmission lines. In our *Do Nothing* base case, we forecast 5,230 MWh of unserved energy which would cost consumers $263M ($2024) in 2034.

116 We also considered using demand management and battery energy storage systems to meet peak demand requirements. These options costs significantly more than the Options 1-4. We also note that we have used similar language (low, base, high) to develop moderated demand scenarios and to consider development plans. To be clear, all development plans are based on the identical moderate customer demand forecast. That is, the low development plan does *not* align with the high scenario customer demand forecast.

117 Includes capital expenditure across multiple regulatory periods and future augmentation capital expenditure.

118 10% POE.

Figure 4-11: Forecast sub-transmission line utilisation (POE10% on N rating)[119]



Consistent with the regulatory investment test for distribution (RIT-D), the capital expenditure objectives, and the Electricity Distribution Code of Practice, *Option 3 High Development Plan* would usually be included in our capital expenditure forecast.

However, our analysis also identified that *Option 2 Base Development Plan* is identical to the preferred option until 2028 and requires significantly less capital expenditure. Table 4–9 presents the components of *Option 2 Base Development Plan* and the additional projects required to shift to *Option 3 High Development Plan* in the next regulatory period.

Table 4–8: Base and High Development Plans, $2026, millions

Approach	Component	FY27	FY28	FY29	FY30	FY31	2026-31
Base	New 66kV line incomer at FW No.2 66kV bus	1.6	-	-	-	-	1.6
	Tie TH-FW 66kV loops	1.3	-	-	-	-	1.3
	Augment KTS-AW 66 kV line	2.2	-	-	-	-	2.2
	Subtotal	**5.1**	**-**	**-**	**-**	**-**	**5.1**
	New KTS-ADT-VDT 66 kV line (Tullamarine Cluster)	-	16.5	-	-	-	16.5

119 Calculated using our 10% PoE summer maximum demand forecast and n-1 rating for each line.

Approach	Component	FY27	FY28	FY29	FY30	FY31	2026-31
Projects to move to 'high'	New KTS-ATK 66 kV line (Tullamarine Cluster)	-	19.1	-	-	-	19.1
	Second new 66 kV circuit from BLTS	-	-	-	4.9	-	4.9
	EPN Third Transformer (Heidelberg)	-		-	14.9		14.9
	New Zone Substation to offload NH and EPN (Heidelberg)	-	-		24.6	-	24.6
	Subtotal	**-**	**35.6**	**0.0**	**44.4**	**-**	**80.0**
	Total	**5.1**	**35.6**	**0.0**	**44.4**	**-**	**85.1**

As a prudent and efficient network service provider we will not make a final investment decision on these additional works until we have more information firming customer load requirements. This will occur as new applications are lodged (or increased) and as connection offers are accepted by project developers.

As expenditure to deliver *Option 2 Base Development Plan* represents the minimum 'no regrets' level of investment, these projects have been included in our 2026-31 capital expenditure forecast.

For the additional expenditure to deliver *Option 3 – High Development Plan* we have the choice to either:

1. Include the expenditure in our capital expenditure forecast as it is required to achieve the capital expenditure objectives in the Rules.
2. Propose two contingent projects, one for the Tullamarine cluster ($35.6M ($2024)) and another for the Heidelberg cluster ($39.5M ($2024)). This option is available as the expenditure is required to achieve the capital expenditure objectives, exceeds the threshold in the rules,[120] and an appropriate trigger event can be defined to be reasonably specific and capable of objective verification.

In making this decision we considered the materiality of the projects, the uncontrollable nature of the expenditure driver (the size and location of customer connections) and uncertainty around the ultimate solution – which can change as we received new connection applications.[121]

We concluded that the best approach would be to align the regulatory approval with our internal decision-making process. This ensures that customers do not fund such a large expenditure until it is required. We provide further details on our proposed contingent projects in Appendix D.

Future connections

The second part of our major customer network development strategy is the costs to augment our network to accommodate future connections (those beyond the connection application window). We expect 172 MVA of load from new connections (not currently included in our known connections forecast) in the next regulatory period.

As we do not know the specific location of these connections, we have instead forecast costs by applying a unit rate per unit of capacity required. This approach is consistent how Ofgem's volume drivers are applied.[122]

The unit rate is based on historical costs incurred in previous augmentations divided by the load requirements of these connections.[123] As a result, the unit rate implicitly takes into account that our existing network can accommodate a proportion of the new load.

[120] The greater of $30 million or 5% of our annual revenue requirement in the first year of the next regulatory control period ($16.2 million).

[121] Given the pipeline of projects, we do not consider it likely that demand will be less than we forecast. Based on ongoing discussions with project developers it is more likely to be higher than we are forecasting. If this occurs, we may need to revisit the optimal solution.

[122] Volume drivers are a price control uncertainty mechanism which varies allowances based on capacity connect and unit costs on an ex-post basis. For example, see page 24 here.

[123] This differs from a unit rate to *install* a given MVA of capacity. If we developed a unit rate using this approach, the forecast would be materially higher.

Applying the historical unit rate to forecast future connections results in a forecast of $14.1 million. This forecast is very low, primarily as the unit rate implicitly assumes that our network will be able to accommodate new loads to the same extent as we have in the past. This is a very conservative assumption given the very high levels of network utilisation on our sub-transmission system, particularly in areas supplying data centre clusters.

Major Customer Network Development Strategy

The summary of our overall major customer network development strategy is set out in Table 4–9. Our capital expenditure forecast includes the base and future components totalling $19.2M for the next regulatory. The two contingent projects in the Tullamarine and Heidelberg sub-transmission clusters of our network require expenditure of $75.1 million.

Table 4–9: Major Customer Network Development Strategy Program, $2026, millions

	FY27	FY28	FY29	FY30	FY31	2026-31
Base[124]	5.1	0.0	0.0	0.0	0.0	**5.1**
Future[125]	1.5	2.7	4.8	3.0	2.1	**14.1**
Tullamarine Cluster Contingent Project[126]	0.0	35.6	0.0	0.0	0.0	**35.6**
Heidelberg Cluster Contingent Project[127]	0.0	0.0	0.0	39.5	0.0	**39.5**

4.2.5 Low voltage circuit and distribution substation program

Our fleet of distribution substations and their associated low-voltage (LV) circuits serve as network assets that form the key interface between the broader electricity network and our customers. We have approximately 6,530 distribution substations and 13,844 low-voltage circuits that supply the majority of our connected load.

One threat to network performance is overloaded, above capacity, distribution substation transformers and low-voltage distribution circuits. Overloaded assets suffer from reduced lifespans, pose public safety hazards, and lead to poor-quality electricity supply and severe outages.

To manage this threat, we implement an annual program to identify overloaded assets and evaluate whether augmentation or the implementation of non-network solutions can efficiently reduce safety and reliability risks.

Over the past 10 years, we have replaced an average of 27 distribution substations each year. This program has been successful in gradually reducing the number of overloaded assets, which has, in turn, improved safety and maintained reliability for our worst-served customers.

Over the current regulatory period, we have targeted distribution substations primarily in Hazardous Bushfire Risk Areas (HBRA) locations – as these sites has the highest risk to both network reliability and safety. This approach also allowed us to temporary reduce the costs of the program by undertaking works together with our HBRA mitigation activities we delivered in the current period.

For the next regulatory period we considered whether to halt, reduce or maintain our distribution substation augmentation program, taking into account current capacity utilisation, increasing maximum demand, the electrification of gas and transport, as well our CER Integration Strategy.[128]

We identified that the option with the highest net economic benefits (and the option that also provides the greatest safety benefits) is to maintain the current strategy until our CER Integration Strategy implements flexible import

124 Expenditure required to complete the Augment KTS-AW 66 kV line, New 66kV line incomer at FW No.2 66kV bus and ST-SSS 66 kV Line Extension projects which will commence in the current regulatory period.

125 Referred to as *DC Growth Projects – Augmentation component [Future Major Customers Projects]* in our forecast capital expenditure model.

126 Comprising two components the New KTS-ADT-VDT 66 kV line and New KTS-ATK 66 kV line.

127 Comprising two components the EPN Third Transformer and New Zone Substation to offload NH and EPN.

128 The strategy for addressing voltage and power quality issues is covered under "Voltage and PQ Management Strategy".

services. Once this occurs in 2032, we will be able to use non-network solutions to manage overloaded transformers risks and defer further augmentation and in turn reduce the number of distribution substations augmentation each year.

4.2.6 References

The proposed load driven augmentation expenditure outlined in this section is supported by a body of materials, forecasts and models as outlined in Table 4–14.

Table 4–10: List of the attachments supporting our forecast augmentation expenditure

Attachment	Name	Author
RIN Support	2024 Distribution Annual Planning Report	JEN
RIN Support	JEN Spatial Level Maximum Demand Forecasts Model 2024	JEN
RIN Support	Spatial Level Maximum Demand Forecast Methodology	Blunomy
Att 5-03	Peak demand forecasts report	JEN
RIN Support	JEN Maximum Demand Forecast 2024	JEN
RIN Support	JEN Maximum Demand Forecast – Terminal Station with Major Customer	JEN
RIN Support	Network Augmentation Planning Criteria	JEN
RIN Support	JEN Load Demand Forecast Procedure 2024	JEN
RIN Support	North-Western Growth Corridor Network Development Strategy	JEN
RIN Support	Northern Growth Corridor – Network Development Strategy	JEN
RIN Support	11kV Central Area Network Development Strategy	JEN
RIN Support	22kV Central Area Network Development Strategy	JEN
RIN Support	Feeder Augmentation at Fairfield – Relief Capacity Constraint – Business Case	JEN
RIN Support	Major Customers Network Development Strategy	JEN
RIN Support	Distribution Substation Augmentation Strategy	JEN

4.3 Other

The second component of our augmentation forecast is non-load-driven augmentation. As summarised in Table 4-11 we are forecasting this expenditure to reduce in the next regulatory period. Further detail on each program is provided below.

Table 4-11: Other capital expenditure, $2026, millions

	2021-26		2026-31
	Allowance	Actual/estimate	Forecast
Preston and East Preston	31.4	20.6	46.0
Rapid Earth Fault Current Limiter (REFCL)	51.1	57.2	0.0
Fault Location, Isolation and Service Restoration (FLISR)	0.0	11.8	0.0
Innovation	0.0	0.0	4.4
Other	3.8	3.7	8.8
Total	**86.3**	**93.3**	**59.2**

4.3.1 Preston and East Preston

We are currently delivering our final stages of a long-term staged program of works to convert our Preston and East Preston distribution networks supplied (via the Preston and East Preston zone-substations) from a voltage level of 6.6 kV to 22 kV. Previous stages of this project have been considered and approved by the AER in both the previous regulatory period and the current regulatory period.[129] We have allocated this project to augmentation consistent with prior guidance from the AER.[130]

These areas were originally established in the 1920s. The Preston and East Preston zone substations were refurbished in the 1950s and 1960s. Due to the condition of the equipment at these zone substations, there is a high probability of failure and high safety risks due to step and touch potentials. Further, the legacy distribution voltage of 6.6 kV across the Preston area reduces the ability to accommodate additional loads (due to limited transfer capacity, restricted supply options and higher connection costs), has higher losses and reduced resilience.[131]

Given asset condition and load growth drivers, in 2008 we commenced a staged program of works to convert these areas to a modern 22 kV voltage, as outlined in Table 4-12

Table 4-12: Preston Area Conversion Program

Objective	Conversion Stage(s)	Status
1. Transfer as much load as possible away from Preston/East Preston Zone Substations 6.6 kV to nearby 22 kV zone substations.	Preston Stages 1, 2 and 3 East Preston Stages 1 and 2	Completed 2008 – 2012
2. Establish 22 kV supply capacity (new East Preston Zone Substation) within the Preston area to enable converting / transferring load away from Preston to continue.	East Preston Stage 3	Completed 2015

129 AER 2020, Final Decision, *Jemena distribution determination 2021 to 2026 Attachment 5 – Capital expenditure,* p.5-26. See here and AER 2016, Final Decision, *Jemena distribution determination 2016 to 2020 Attachment 6 – Capital Expenditure,* p.6-48. See here.

130 AER 2016, Final Decision, *Jemena distribution determination 2016 to 2020 Attachment 6 – Capital Expenditure,* p.6-48. See here.

131 Several poles support up to three high voltage circuits.

Objective	Conversion Stage(s)	Status
3. Transfer all load away from Preston and retire Preston zone substation 6.6 kV assets.	Preston & East Preston Stage 4 Preston Stage 5	Completed 2016 2017
4. Add additional 22 kV supply capacity within the Preston area to enable converting / transferring load away from East Preston Zone Substation to continue and enable some load to be transferred back from nearby zone substations to address capacity constraints.	Preston Stage 6	Completed 2020
5. Transfer all load away from East Preston, retire East Preston zone substation 6.6 kV assets and convert an isolated portion of FF90 from 6.6 kV to 22 kV.	East Preston Stages 5	Completed 2022
	East Preston Stages 6	In construction
	East Preston Stages 7	Planned for 2028
	East Preston Stages 8	Planned for 2030

At each stage we have re-evaluated the costs, benefits and options before proceeding. This includes considering the potential for non-network alternatives and replacing like-with-like rather than moving these assets to the modern 22 kV voltage level.

Our most recent analysis takes into account our latest load forecast and asset condition reports and confirms that completing the final two stages of the program has the lowest costs and highest net market benefits of all credible options.[132] This analysis did not quantify safety risks or the risk of aged electromechanical relays causing loss of supply which, if included, would strengthen the case for continuing with our current approach.

The remaining two stages will be completed over the next regulatory period as per Table 4–13.

Table 4–13: Remainder of East Preston Program of Works, $2026, millions

Stage	Scope of works	Cost
East Preston Stage 7	Continue with the feeder conversion works to transfer load from existing East Preston Zone Substation to the new East Preston Zone Substation by: • Establishing two new 22 kV feeders from new East Preston Zone Substation from the new No.2 22 kV bus • Transfer and convert eight 6.6 kV feeders to 22 kV.	28.6
East Preston Stage 8	• Install a new 22 kV feeder from new East Preston Sone Substation No.2 22 kV bus to convert the remaining feeders EP34, EP36 and EP41 from 6.6 kV to 22 kV • Convert an isolated section of feeder FF90 from 6.6 kV to 22 kV. • Decommissioning and removal of all East Preston ‘zone substation assets.	17.4

132 East Preston Area Network Development Strategy

4.3.2 Rapid Earth Fault Current Limiter (REFCL)

Over the 2021-26 regulatory period, we installed Rapid Earth Fault Current Limiter (REFCL) devices at our Coolaroo Zone Substation to comply with the then-new technical requirements in Victoria's Electricity Safety (Bushfire Mitigation) Regulations. These standards were introduced in response to the 2009 Black Saturday bushfires and subsequent Bushfire Royal Commission.

REFCL devices place additional limitations on our network. This is because REFCL devices, specifically the arc suppression coils, have technical limits of network capacitive current. As underground cables have far higher capacitive currents than overhead lines, this substantially limits the length of underground cables a REFCL can protect.[133] RECFL requirements also limit the load transfer capability on the REFCL protected feeders to nearby non-REFCL protected feeders limiting the degree to which we can 'mesh' our feeders to improve resilience and increase network capacity.

We consider and factor in these constraints as part of each network development strategy.[134] In particular, in developing our Northern Growth Corridor network development strategy, we have identified that the cable capacitance of the Coolaroo zone substation bus No.1 and 2 will exceed the design rating of the REFCL in 2028.

Accordingly, our Northern Growth Corridor network development strategy includes measures to address this constraint. Specifically, to transfer some underground cables to adjacent feeders supplied from other zone substations. This will cost $5.9 million in the next period.

4.3.3 Fault Location, Isolation and Service Restoration

In the current regulatory period, we identified that installing Fault Location, Isolation and Service Restoration (**FLISR**) technology helps maintain the reliability and resilience of our network. Maintaining the reliability of our network is increasingly important given ongoing electrification, increased dependency on our network and in turn greater customer consequences of outages.

Prior to FLISR, customers on a faulted feeder may be off supply for an extended period while field crews arrive, investigate, locate the fault, make necessary repairs and perform the manual switching required to restore supply.

FLISR allows for the automatic isolation of a faulted section of our network and, where possible restoring the remaining customers by transferring them to adjacent feeders – allowing the network to 'self-heal' – without the direct intervention of human network controllers. FLISR also assist field crews by reducing the area they need to patrol to find the fault location, resulting in shorter outage durations.

Accordingly, despite not being included in our forecast of our allowance for the current regulatory period, we are deploying 200 remote-controlled switches to implement FLISR over the current regulatory period. As of January 2025, FLISR has successfully operated for 31 distinct events, each time reducing the number of customers affected by a sustained outage by 60% than would otherwise have been the case.[135] This technology will provide ongoing reliability and resilience improvements to our network.

We are not proposing further FLISR related expenditure over the next regulatory.

4.3.4 Innovation

Electrification and the uptake of CER have the potential to deliver lower whole-of-system energy costs for customers and support the achievement of Victorian and Australian emissions reduction targets. Unlocking these benefits will require our network to continue its evolution from being one part of the energy mix, largely providing one-way energy flows, to becoming the single critical platform which underpins almost all energy use in our network area.

---

133 Underground cables add approximately four times more capacitive current compared to overhead conductors on a per kilometre basis.

134 We also consider the benefits of REFCL devices in our augmentation program.

135 60% of customers in each affected area only experienced a momentary outage of 3 minutes or less.

By definition, the transformation of our energy system and our network requires fundamental change across almost all facets of how we operate, interact with our customers (and other stakeholders), and deliver energy. For instance, we will need to:

- Adopt new technologies to ensure we can manage two-way flows across our network, to limit additional costs and avoid unnecessarily rationing access to our network. We note that these costs (in terms of network prices and reduced network access) could affect the most vulnerable members of our community the most.
- Explore new commercial arrangements between our network and our customers and other stakeholders (such as aggregators). This includes exploring how we can continue to evolve our network tariffs, e.g. the potential for a tariff which suits electric vehicle owners or to ensure we continue to send cost-reflective pricing signals, in a way that is not only accepted by the community but empowers customers to respond to these signals.
- Deliver energy to customers where they need it. This may mean delivering energy to customers at curb side locations (e.g. on our poles) – closer to customer vehicles – rather than to their home. This could ensure customers who cannot charge their vehicles at home are not left behind, increase day-time EV charging (when electricity is cheaper and has the lowest carbon intensity), and reduce network constraints.

Where possible, our regulatory proposal includes projects and programs to reduce costs and maximise value for our customers (for instance, our CER Integration Strategy). However, history teaches us that transformation does not occur in a linear manner. Technological advancement, regulatory change, and, most importantly, evolving customer needs cannot be reasonably predicted or forecasted with any certainty.

We will encounter known unknowns and unknown unknowns that could put barriers in place, preventing customer value from being maximised and in turn slow or delay the energy transformation – or lead to higher than necessary costs. We are particularly conscious that if we do not respond to customer concerns as the energy transformation proceeds, we – the energy industry as a whole, including the AER – will lose customer trust and the social licence required for a successful transformation.

While the cost of these hurdles could be significant, they can likely be surmounted at a relatively low cost if timely and early investments are made. For instance, by trialling new technology to ensure it can be deployed in a timely manner or by testing new commercial models with stakeholders and customers at a small scale to identify and iron out potential issues before they are scaled up. However, to maximise customer benefits and minimise long-term costs, consistent with the NEO and the capital expenditure criteria, it is essential that we have the flexibility to address issues as they arise and move quickly to take advantage of new regulatory and technological developments.

As part of our extensive engagement program, customers told us that they want us to remain at the forefront of renewable energy and innovation, ensuring that no customers are left behind. Customers told us that they are willing to pay for innovation and support us in having flexibility in the period. We put forward four different options (the 'do nothing' option plus three alternative innovation packages). The consensus was 'Package 2 Innovation with Impact' got the balance right between innovation and affordability.

Consistent with the direction from our customers, we are proposing an innovation fund over the period of $8M ($2024) split 50-50 across capital expenditure and operating expenditure which will focus on:

- Supporting future network innovation and capability development for JEN through trial and demonstration initiatives.
- Supporting energy equity within the JEN customer base by trialling innovative business models.
- Supporting nationwide future network development through knowledge sharing, collaboration and engagement.

Given that it is not possible to prepare individual project business cases years in advance with the detailed analysis and rigour as we have for the rest of our program and to provide additional comfort to the AER around the prudency and efficiency of this expenditure, we have proposed that any money approved as part of the fund will be subject to the core tenets outlined in Figure 4-12 below. These tenets have been informed by the AER's regulatory decisions in respect of similar innovation funds proposed by other networks.

Figure 4-12: JEN's Innovation Fund Core Tenets

4.3.5 Operational Technology – Communications network

The last component of non-load driven augmentation is our program to alleviate capacity constraints on our operational technology communications network. This network supports the operation of remote controllable pole top field devices, such as Automatic Circuit Reclosers and Remote Controllable Gas switches, and in turn plays a critical role in ensuring the safe, reliable and efficient operation of our network.

Over time, the installation of remote controllable devices has increased to improve the capability, safety and functionality of our network (for instance, through the implementation of FLISR and REFCLs as described above). However, this has led to capacity constraints and in turn communication failures where bandwidth has not been sufficient, generally in areas of our network which rely on a radio backhaul link. The increasing need to install remote controlled devices on a dynamic electricity distribution network also results in higher data requirements from our current operational technology communications network. Network traffic will increase, and capacity constraints will become more acute if current technology is not replaced.

Communication failures prevent the remote operation of our equipment and in turn the functionality of our network. They also make it difficult to detect, diagnose and resolve network issues and which result in poor reliability and increased safety risks. A failure of a single pole top device on a high-voltage feeder could lead to 4,100 customers being off supply for 90 minutes until the field device is manually operate of the fault repaired.

Our economic analysis, which considered a probabilistic view of the likelihood and severity of critical network outages, found that the economic approach is to address the issue by replacing radio links with fibre optic backhaul links and limiting the number of remote devices connected to each access point. Accordingly, over the next regulatory we will incur $8.8M to address these communication links, with a focus on bushfire prone areas which have a higher proportion of remote-controlled devices.

4.3.6 References

The proposed non-load capital expenditure outlined in this section is supported by a body of materials, forecasts and models. The key documents are outlined in Table 4–14.

Table 4–14: List of the attachments supporting our forecast augmentation expenditure

Attachment	Name	Author
RIN Support	East Preston Area Network Development Strategy	JEN
Att 03-02	Innovation fund	JEN
RIN Support	Operational Technology Communications Network Upgrade – Business Case	JEN

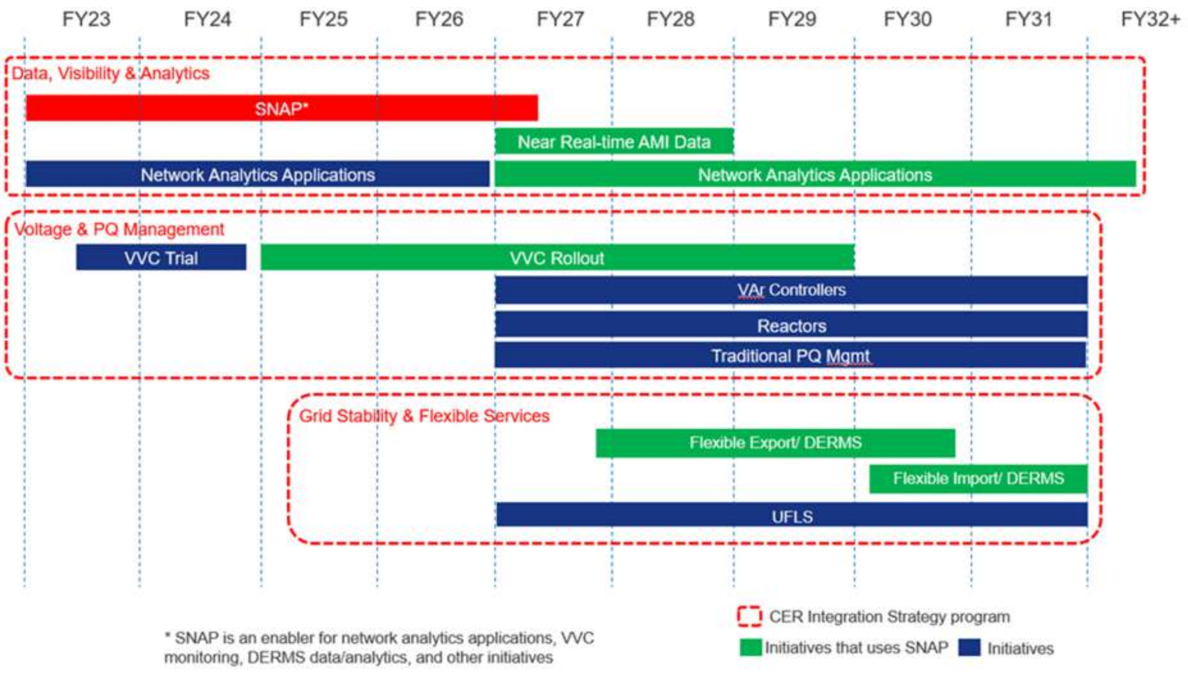
5. CER Integration

- We forecast a total capital expenditure of $85M in the next regulatory period for us to integrate more CER into our network in a safe, secure and reliable manner. Forty-one percent ($39M) of the total CER integration forecast capital expenditure is ICT related with the remaining amount being network related.
- Our proposed CER integration programs and initiatives include Data Visibility and Analytics, Voltage and Power Quality Management and Grid Stability and Flexible Services.
- CER integration will also require a step change in our operating expenditure in the regulatory period. We cover the details of our proposed step change in operating expenditure due to the CER integration in Attachment 06-04.[136]

Our customers have told us that it is important to them that JEN connects its customers to a renewable energy future, by facilitating the integration of Consumer Energy Resources, or **CER** into the electricity distribution network and facilitating the electrification of the economy.[137] CER includes rooftop solar, batteries, electric vehicles and energy management systems, which are often located on the consumers' side of the electricity meter.[138]

We have developed our CER Integration Strategy which we plan to deliver through a combination of network operations (Asset Management) and new ICT (Digital) capability. Figure **5**-1 shows our three proposed programs and supporting initiatives to deliver our CER Integration Strategy and our indicative timing to implement them. Strategic Network Analytics Platform (**SNAP**) (in red) in the Data Visibility and Analytics program is an enabler for a number of initiatives (in green) in JEN's CER Integration Strategy.

Figure 5-1: JEN's CER integration strategy programs and initiatives



136 JEN - *Att 06-04 Operating expenditure step changes.*

137 JEN – *Att 02-01 – Customer engagement.*

138 CER was previously referred to as Distributed Energy Resources (DER), however CER does not include front of meter batteries DER on our network. For the purposes *of JEN – RIN – Support – Att 03-01 – CER Integration Strategy* we refer to CER to also include front of meter batteries.

Key customer benefits of our CER Integration Strategy include:

- CER enablement – improved export capability and reduced CER curtailment, demonstrated using the AER's Customer Export Curtailment Value (**CECV**) methodology.
- Reliability of supply – maintained reliability of supply by managing and adapting to the changes in electricity demand from CER uptake and usage of the network, the electrification of the gas and transport sectors, and the change in new and existing customers' requirements for electricity, based on the Values of Customer Reliability (**VCR**) methodology.
- Regulatory compliance – improved appliance safety and reduced consumption by maintaining voltages within regulatory limits and satisfying system security through enabling grid stability by AEMO and power quality regulatory requirements using a suite of solutions using an efficient cost approach to achieving our compliance obligations.

5.1 Forecast capital expenditure

We forecast a total capital expenditure of $85M for CER integration in the next regulatory period (Table 5–1). This will enable JEN to:

- address the identified needs and existing analytics platform limitations and improve the operational management of the network through the **Data Visibility and Analytics (DVA) program**. The DVA program will also help us maintain customer safety and improve operational planning during the energy transition.
- respond to the challenges and opportunities associated with increasing CER penetration and the associated influences on network voltage and power quality through the **Voltage and Power Quality Management (Voltage and PQ) program**. The program will enable us to achieve near real-time optimised control of network voltage and reactive power flow to maintain compliance with Electricity Distribution Code of Practice (**EDCoP**) standards and reduce CER curtailment.
- respond to the challenges and opportunities associated with increasing numbers of CER and their associated influences on power system security and network operating limits through the **Grid Stability and Flexible Services program**. The program will enable us to achieve near real-time optimised control of CER active power operating envelopes to keep the grid stable and to deliver flexible export and import distribution services using dynamic operating envelopes.

Collaboration between the ICT and Network teams is increasingly vital for JEN with the growing digitalisation and complexity of the energy landscape. As the grid modernises with smart technologies and automation, ICT provides the digital infrastructure needed for real-time data collection and analysis while the Networks team manage the physical infrastructure. Together, they ensure a resilient and adaptable grid capable of accommodating the demands of renewable energy integration. It relies on advanced digital tools to monitor grid health and manage load fluctuations.

“Building a digital, data-driven infrastructure ensures Jemena can handle the growing complexity of energy systems. The adoption of automation, analytics, and enhanced applications supports power system security and facilitates new market participants, enabling more agile and responsive networks.” - Energy Reference Group

Table 5–1: CER Integration strategy, forecast expenditure, $2026, millions (direct cost)

Program	FY27	FY28	FY29	FY30	FY31	Total
Data Visibility and Analytics program						
ICT	3.3	1.8	1.8	1.8	1.9	10.7
Voltage and Power Quality Management program						
Asset Management	9.0	10.8	9.0	5.0	6.7	40.5
ICT	0.1	0.0	0.0	0.0	0.0	0.1
Grid Stability and Flexible Services program						
Asset Management	0.3	0.7	1.3	1.9	1.0	5.2
ICT	0.4	3.4	8.1	9.6	6.6	28.0
Total CER Integration	**13.1**	**16.7**	**20.2**	**18.3**	**16.2**	**84.5**
Asset Management	9.3	11.4	10.3	6.8	7.7	45.7
ICT	3.8	5.2	9.9	11.4	8.5	38.8

Our forecast expenditure is prudent and efficient as demonstrated in our program documents and investment briefs. It represents the level of funding necessary to achieve the requirements under the NER, efficiently meet our obligations and customers' expectations, and promote their long-term interests. Our proposed program and initiatives are based on detailed assessments of credible options that can address the need to provide reliable and safe services in a changing environment and meet customer expectations.

Many of our customers recommended that we digitise and automate the network to make it smarter, efficient, more responsive and ready for future energy-related issues. Our customers also expect us to prioritise network reliability, resilience and power quality; to operate sustainably; to support decarbonisation and renewable energy transition and to ensure electricity prices are affordable.[139] In response to our Draft Plan released in August 2024, customers reiterated their concerns about affordable prices, support for network reliability, and the future network strategy (which we now refer to as CER Integration Strategy).[140] Our proposed programs will address these concerns.

Lastly, we note that our CER Strategy builds on the work we implemented over the current 2021-26 period in particular around grid stability and our dynamic voltage management pilot. In the current period we expect to incur $17.6M very close to the allowance of $19.4M.[141]

We describe in detail our proposed program and initiatives in various attachments to the regulatory proposal, including Attachment 03-01,[142] Attachment 06-04[143] and *JEN -RIN – Support – Technology Plan* (where relevant).

We have also developed robust program documents and investment briefs supporting the CER programs and initiatives. These supporting documents demonstrate that our proposed programs and initiatives are prudent and efficient and give the highest net benefits to our customers.

139 *JEN, Att 02-01 – Customer engagement.*

140 *JEN, Att- 02-18 – Draft Plan Feedback Report.*

141 We note that the allowance was included in our network augmentation category; however, outturn spend was split between network expenditure ($9.4M) and ICT programs ($8.2M).

142 *JEN – 03 – 01 CER Integration Strategy.*

143 *JEN – Att 06-04 Operating Expenditure step change.*

5.2 References

The proposed CER integration expenditure outlined in this section is supported by a body of materials, forecasts and models. The key documents are outlined in Table 5–2.

Table 5–2: List of the attachments supporting our forecast expenditure for CER integration

Attachment	Name	Author
Att 03-01	CER Integration Strategy	JEN
RIN Support	Technology Plan	JEN
RIN Support	Data Visibility and Analytics Program	JEN
RIN Support	Data Visibility and Analytics Program – Investment Brief	JEN
RIN Support	Grid Stability and Flexible Services Program	JEN
RIN Support	Grid Stability and Flexible Services Program – Investment Brief	JEN
RIN Support	Voltage and PQ Management Program	JEN
RIN Support	Voltage and PQ Management Program – Investment Brief	JEN
Att 06-04	Operating expenditure step changes	JEN
Att 06-01	Operating expenditure	JEN
Att 02-01	Customer engagement	JEN

6. Replacement capital expenditure

Highlights

- Our assets are ageing, and this has contributed to the current poor condition of our assets. Many of our poles and pole top structures have been installed more than 40 years ago which means that a large portion is entering the latter stages of their expected useful life. Poles reinforced as early as the1960s and 1970s cannot be further re-staked given the high risk of failure. Some of our major zone substations' primary and secondary assets are about to exceed their expected useful life. While age of our assets is not the main basis for replacement and reinforcement, it is a key input to our condition-based assessment of assets.
- In this context, we have developed a gross replacement expenditure of $427M, or $395 net (after customer contribution terms) in the next regulatory period. While our forecast is higher than the estimated replacement expenditure for the current regulatory period, our modelled repex is 27% lower than the threshold modelled repex predicted by the AER's model.[144]
- **Non-routine replacements**. Our higher forecast expenditure is heavily influenced by non-routine asset replacements, reflective of the risks posed by combined poor asset condition, age profile and regulatory requirements to maintain the reliability, security and safety of our network. Our forecast expenditure will enable us to:
  - **Redevelop three major zone substations.** The redevelopment of the Coburg North (CN) zone substation and partial redevelopment of Coburg South (CS) and North Heidelberg (NH) zone substations will address serious safety risks and mitigate supply risks to over 60,000 customers by replacing old and deteriorated equipment with a history of failures and which is non-compliant with current standards, maintenance-intensive or no longer supported by the manufacturer.
  - **Relocate assets that are in high-flood risk zones (Maribyrnong project).** The project will mitigate the risk of flood damage to assets, ensuring continuous operation and reducing the potential for service interruptions during flood events. This initiative aims to maintain the reliability and resilience of said infrastructure, safeguarding both the assets and the community.
  - **Replace customer recoverable works.** This relates to works that we must undertake at the request of customers, councils, government authorities and other third parties to relocate or otherwise rearrange our assets, generally to allow for works to be undertaken on other infrastructure. It also relates to repairing damage to our distribution network following an identifiable third party's act or omission, for which that party is liable. The associated replacement costs are recoverable from customers who requested the service/work and, therefore, not recovered from JEN's broader customers.
- **Routine replacements.** Our forecast will also enable us to continue with our pole and pole top structures replacements. Many of our poles and pole-top structures are ageing, and our condition-based assessments show that many of our wooden poles are at risk of failure in the next regulatory period if not replaced or reinforced.
- In response to the Draft Plan, our customers reiterated that they want affordable prices and also expect us to maintain the reliability and reliance of our network. After several iterations, our proposed expenditure for replacements has materially decreased. In developing our regulatory proposal:
  - We propose not to spend more than what is needed to maintain the reliability and security of our network, that is, we do not propose to invest more money in order to improve the reliability of our network.
  - We only included prudent and efficient replacement programs and projects consistent with the requirements of the NER and the AER. Major non-routine programs and projects are supported by asset class strategies and business cases and are based on the option which gives the highest net benefits for our customers over the long term.

[144] Modelled repex includes forecast replacement expenditure for poles, service lines, underground cables, overhead conductors, transformer and switchgear as per the AER's approach.

6.1 Summary

The proposed condition-based replacement expenditure accounts for 19% of our total capital expenditure forecast. Monitoring, managing, and maintaining asset condition are essential components of JEN's assessment management strategy. Assets that are approaching the end of life are at risk of failure if left unactioned. There are also health and safety risks that can impact stakeholders when assets fail. In addition, the quality of service we provide to our customers would decline, and we would fail to comply with our regulatory obligations, potentially negatively impacting the stability of the broader electricity system. These are significant risks, and therefore, the asset replacement program has been developed to address these risks and also to meet the expectations of our customers.

Our replacement expenditure forecast has been developed using the engineering expertise of our Asset Management team and its detailed knowledge of our network assets and customers' requirements. This includes the condition of existing assets, the factors likely to impact the health of our network over the next regulatory period and expected changes in the energy usage behaviour of our customers over the forecast period.

We have forecast a gross replacement expenditure of $427M in the next regulatory period which is 57% higher than our estimated replacement expenditure for the current regulatory period.

We outline in Table 6–1 our forecast replacement expenditure. We provide more details about our forecast replacement expenditure for each asset category in the succeeding sections below.

Table 6–1: Forecast replacement capital expenditure, $2026, millions

Replacement expenditure	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Poles	9.1	12.0	12.1	12.2	12.3	57.7
Pole top structures	7.1	9.3	9.3	9.4	9.5	44.6
Overhead conductors	3.8	0.9	2.7	3.7	1.2	12.3
Underground cables	1.3	15.2	9.6	8.9	4.6	39.6
Service lines	7.4	6.9	6.0	6.0	6.1	32.4
Transformers	10.3	17.1	8.8	6.3	4.8	47.2
Switchgear	11.4	18.1	16.0	14.8	14.2	74.4
SCADA, network control & protection systems	5.9	9.7	9.9	10.5	8.7	44.7
Protection systems	5.9	9.3	8.4	7.2	3.1	34.0
Communications	0.0	0.4	0.9	1.7	3.2	6.2
Other	0.0	0.0	0.6	1.5	2.4	4.5
Others	13.1	13.9	16.4	16.6	14.3	74.3
Customer-initiated asset relocation works	7.6	7.4	10.0	9.6	7.0	41.6
Emergency recoverable works and rectification of damaged assets	4.0	3.9	3.8	3.7	3.7	19.0
Other assets	1.5	2.7	2.7	3.2	3.6	13.8
Gross replacement capital expenditure	**69.4**	**103.0**	**90.9**	**88.3**	**75.7**	**427.3**
Less contributions	6.0	5.9	7.5	7.3	5.6	32.4
Net replacement capital expenditure	**63.3**	**97.2**	**83.3**	**81.0**	**70.1**	**395.0**

About 40% of our forecast gross capital expenditure is for the replacement of transformers, switchgear and SCADA, network control and protection systems. This is driven by our proposed redevelopment of CN, CS and NH zone substations. We need to address serious safety risks and mitigate supply risks to over 60,000 customers by replacing old and deteriorated equipment with a history of failures and which is non-compliant with current standards, maintenance-intensive or no longer supported by the manufacturer.

Forecast expenditure for poles and pole-top structures replacements follows with a 24% share, reflecting our routine replacements of aging assets that are in poor condition and at risk of failure. Expenditure for customer-initiated asset relocation works and customer recoverable works also accounts for a big share of forecast spend. We discuss the details in the sections below.

Our forecast expenditure has undergone several iterations to ensure that we include only projects or programs that will meet our replacement objectives. It is supported by our asset class strategies. Our proposed high-value, non-routine replacement projects are further supported by robust business cases that are submitted as part of the regulatory proposal.

> Our replacement expenditure objectives:
>
> - meet our customers' expectations of affordability and maintaining network reliability
> - manage safety, environmental, electrical system and security risks to as low as practicable and comply with all applicable regulatory obligations prudently and efficiently over the long term.

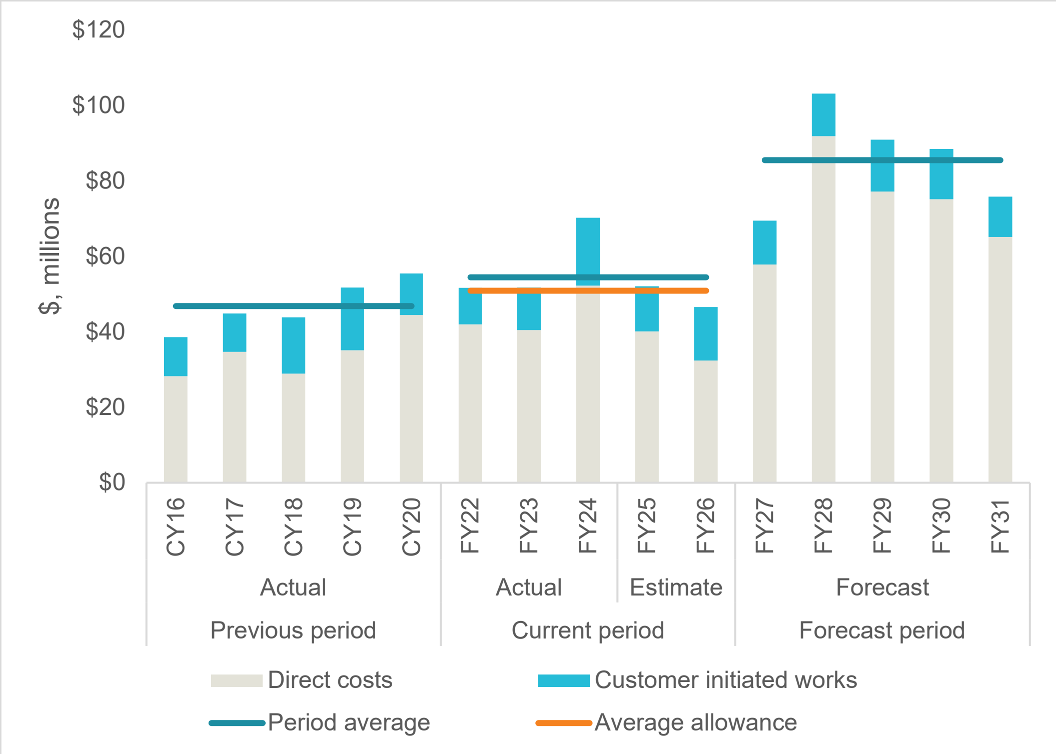
In developing a prudent and efficient forecast expenditure, we have been guided by the principles in the AER's Asset Replacement Application Note, the expenditure objectives, factors, and criteria in the NER, and well-accepted industry practices and standards.

6.2 Historical trend

We set out in Figure 6-1 our replacement expenditure from the previous to the next regulatory period, including the average for each regulatory period. It shows that:

- our expected replacement expenditure for the current regulatory period is slightly higher than our actual replacement expenditure for the previous regulatory period
- our expected replacement expenditure for the current regulatory period slightly exceeds our allowance
- our forecast gross replacement expenditure for the next regulatory period is materially higher than our expected spend in the current regulatory period due to a number of key non-routine replacement projects that we must undertake in the next regulatory period, as mentioned above and in more detail in the following sections.

Figure 6-1: Replacement expenditure, $2026, millions



6.3 Our approach to developing our forecast replacement expenditure

We have used a combination of the following methods and considerations in developing our replacement expenditure:

- bottom-up assessment
- top-down and benchmarking processes
- consideration of our network's reliability performance in terms of SAIFI and SAIDI.

We also ensured that our forecast expenditure is consistent with the AER's expenditure guidelines relevant to asset replacement.

6.3.1 Bottom-up assessment

Using condition and consequence measures, we take a risk-based approach to determining whether we need to replace our assets. The drivers for replacement expenditure include a deterioration in the condition of an asset or its environment and where increases in maintenance costs mean it is more cost-effective to replace an ageing asset than continue to maintain it.

We manage and plan asset replacement by grouping our assets into a set of classes, for which we develop project and program-level forecasts. For some critical assets, we develop a condition-based risk model to support our evaluation of the probability of asset failure and rates of future failures. Once we have identified a need, we develop and evaluate replacement options. We then develop a cost estimate for each option, given the scope of works and relevant unit cost schedules for those options.

Our unit costs are based on a robust procurement process, which ensures the technical suitability and cost-effectiveness of a purchase. We use competitive tender processes when procuring the supply of goods and services, which are consistent with our procurement policy and strategy (see C1.6 for more information).

Our asset class strategies for distribution, primary plant and second plant assets outline the methods employed, analysis undertaken and actions to be taken to optimally manage our assets. Our business cases for non-routine high value projects or programs are robust and clearly outline the need for the replacement, the credible options we have considered and our reasons for selecting the recommended option. Among several credible options, we have selected the option with the highest net benefits for our customers over the long term.

We discussed the results of our bottom-up assessment for the different asset categories in section 6.5 below. Our bottom-up assessment approach ensures that our replacement expenditure is only the amount necessary to continue supplying our customers based on their current and likely future requirements. Section 3.2.1 of our expenditure forecasting methodology provides more information about our bottom-up cost assessment for our forecast replacement expenditure.[145]

6.3.2 Top-down assessment and benchmarking

The AER replacement expenditure model is one of the key methods used to undertake a top-down evaluation of asset replacement requirements. One advantage it has over the other methods is that it applies benchmarking across peers in the National Electricity Market (NEM) and is the preferred method used by the AER. This approach allowed us to cross-check and validate our own replacement expenditure forecast (developed on a bottom-up basis) against one developed using a top-down predictive methodology which takes into account benchmark unit costs and asset lives from other electricity distribution networks.[146]

The AER replacement expenditure model provides a high-level overview of the forecast replacement expenditure for modelled assets. The AER used it to determine whether a more detailed bottom-up assessment is warranted and guide its development of a substitute replacement expenditure forecast, if necessary. However, it’s disadvantage is that it has no visibility of actual asset condition and of assets that need intervention, hence, our approach to use both top-down and bottom-up assessments in developing our replacement expenditure.

6.3.2.1 Results of the top-down assessment

We engaged independent expert Houston Kemp (HK) to undertake an assessment of our modelled replacement expenditure. We have accepted HK’s assessment and considered it to be robust and consistent with the AER’s approach.

Forecasts of modelled replacement expenditure we produced for the following four scenarios:

- Historical scenario: historical unit costs and historical asset lives
- Costs scenario: NEM benchmark unit costs and historical asset lives
- Lives scenario: historical unit costs and NEM benchmark asset lives
- Combined scenario: NEM benchmark unit costs and NEM benchmark asset lives.[147]

The AER’s approach sets the replacement expenditure model (repex model) threshold equal to the higher of the ‘cost’ scenario and the ‘lives’ scenario.

Our modelling shows that our replacement expenditure threshold is the ‘cost’ scenario as shown in Figure 6-2. The ‘cost’ scenario threshold is \$302M. This is 118% higher than the AER’s threshold replacement expenditure forecast for the current regulatory period and 27% higher than our forecast replacement expenditure for modelled assets in the next regulatory period.[148]

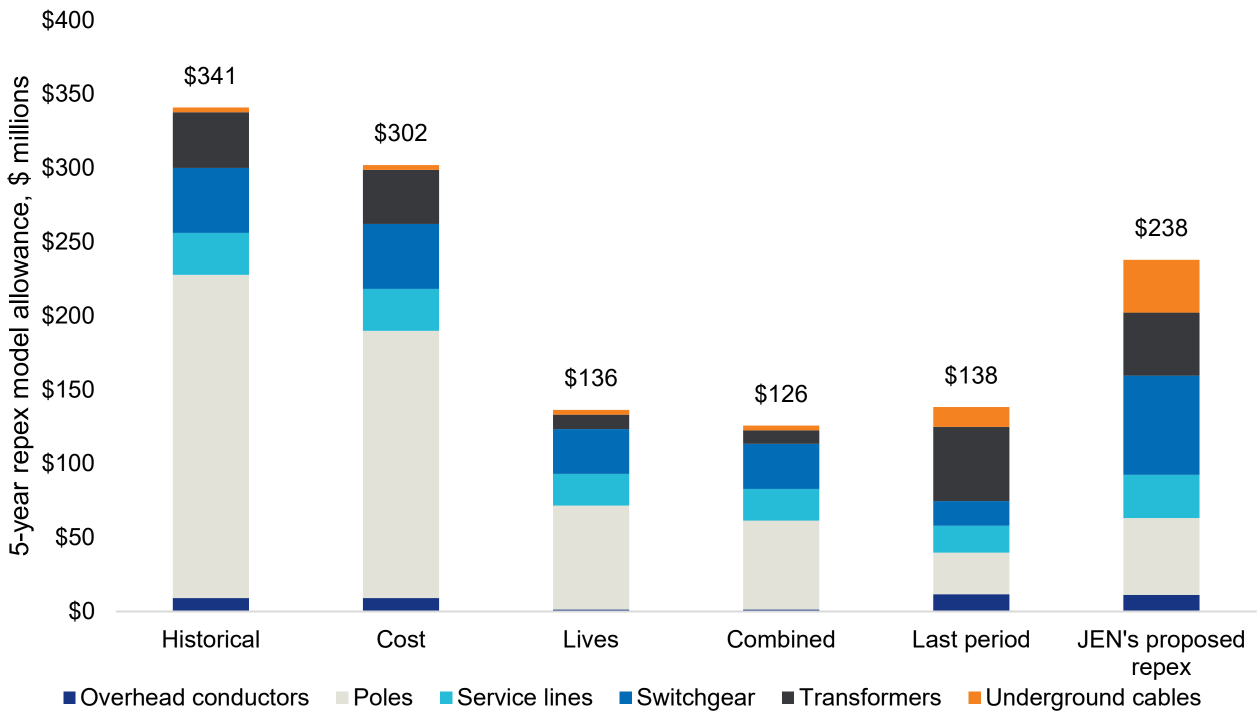
[145] Jemena Electricity Networks (Vic) Ltd, 2026-31 regulatory control period, Expenditure forecasting methodology, 28 June 2024.

[146] This analysis used benchmark model parameters for other electricity distribution businesses published by the AER as part of its recent price determination for New South Wales electricity distribution businesses and recent draft decision for South Australian Power Networks, Energex and Ergon Energy.

[147] AER, AER repex model outline for electricity distribution determinations, February 2020, p.6.

[148] Modelled assets include: poles, overhead conductors, underground cables, service lines, transformers and switchgear as per the AER’s requirements under the ‘AER repex model outline for electricity distribution determinations, February 2020’.

Figure 6-2: Results of replacement expenditure modelling, $2024, millions (direct costs)



There are variances between the repex model, and our own replacement forecast at an asset group level, which can be expected when comparing a top-down predictive modelling approach to a bottom-up forecast. Following are some key observations on these differences:

- The repex model threshold for pole replacement has increased significantly which is consistent with our increasingly ageing poles. We are proposing a higher spend on pole replacement consistent with condition-based assessments of our existing poles.
- The repex model threshold for switchgear has increased significantly. In comparison, our replacement expenditure for switchgear is forecast to increase at a higher level. This is due to the inclusion of non-routine, high-value assets associated with the redevelopment of CS, CN and NH zone substations.
- The repex model threshold for the transformer asset class has decreased. In contrast, we forecast a significant increase in our expenditure on transformer replacement due the inclusion of non-routine and high-value assets associated with the redevelopment of CN, CS and NH zone substations and the relocation of assets that are in high-flood risk zones (Maribyrnong project).
- Our forecast expenditure for service lines, underground cables, and overhead conductors are higher than the repex model threshold. The difference is mainly due to non-routine replacements that we are proposing to undertake in the next regulatory period to address the network reliability risks identified by our condition-based assessments. The Maribyrnong project has also contributed to the increase in our forecast expenditure for underground cables.

Details of our forecasts are discussed in the succeeding sections. Refer to Attachment *Houston Kemp Att 05-06 AER repex modelling* for a full description of our repex modelling assessment approach and results.

6.3.3 Consideration of customers' expectations of network reliability and affordability

Our customers have told us to prioritise investing in reliability by assessing, building, and maintaining the network to meet changes in operating conditions and meet future demands. Our residential customers have told us they see great importance in investing in network infrastructure with a focus on:

- improving and maintaining service standards and customer experience
- reducing the frequency of power outages
- continuing to invest in upgrading the network's ability to "self-heal"
- having the flexibility to accommodate network growth and future demand.

However, affordability is also a key concern for our customers. Our forecast does not include additional costs to improve network reliability, as our customers have told us they do not see the value in paying for these improvements. They did, however, tell us that we needed to maintain our current levels of service and therefore our forecast does include expenditure to ensure that the level of reliability we currently provide does not degrade. In addition to maintaining network reliability, we also take into account health and safety risks, resilience and life cycle costs.

As shown in Figure 6-3 and Figure 6-4, over the last three years, our reliability performance has been almost equal to our targets, and therefore, there is the risk of exceeding our targets in the next regulatory period without intervention. If we exceed our reliability performance targets, then we would not meet our regulatory obligations, our replacement objectives, and our customers' expectations that we maintain the reliability of our network.

Figure 6-3: Reliability over time-unplanned SAIFI (measures the frequency of outages)

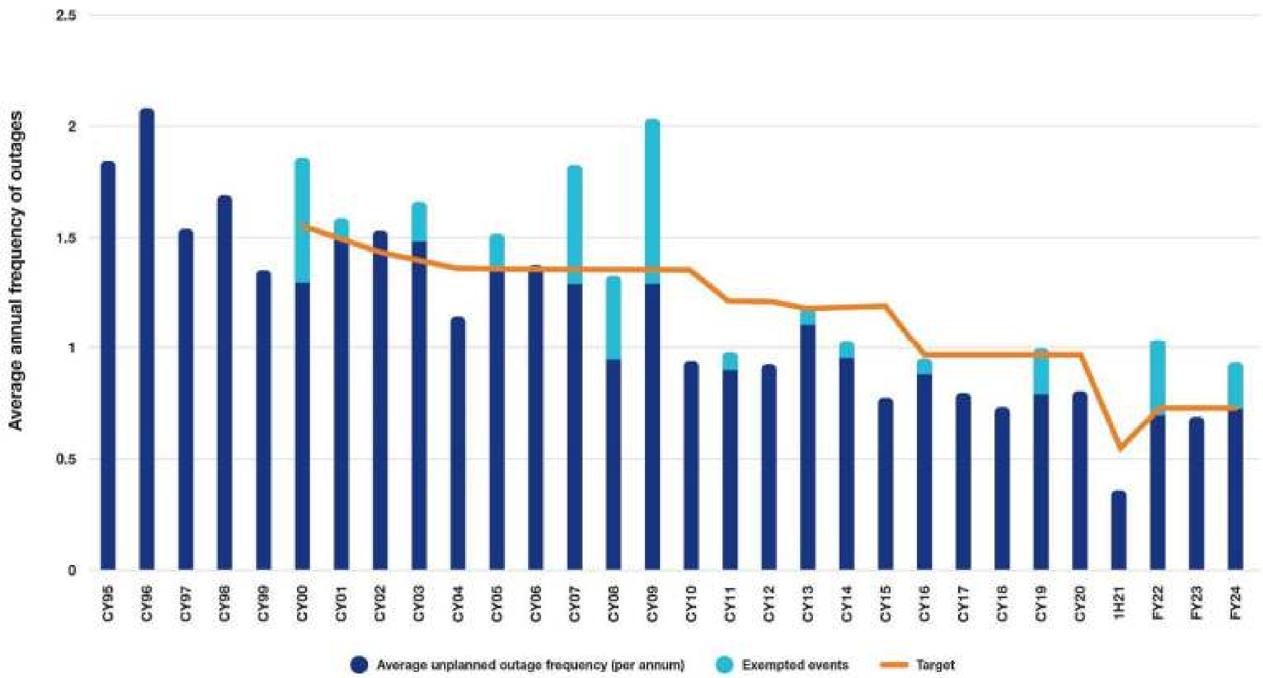
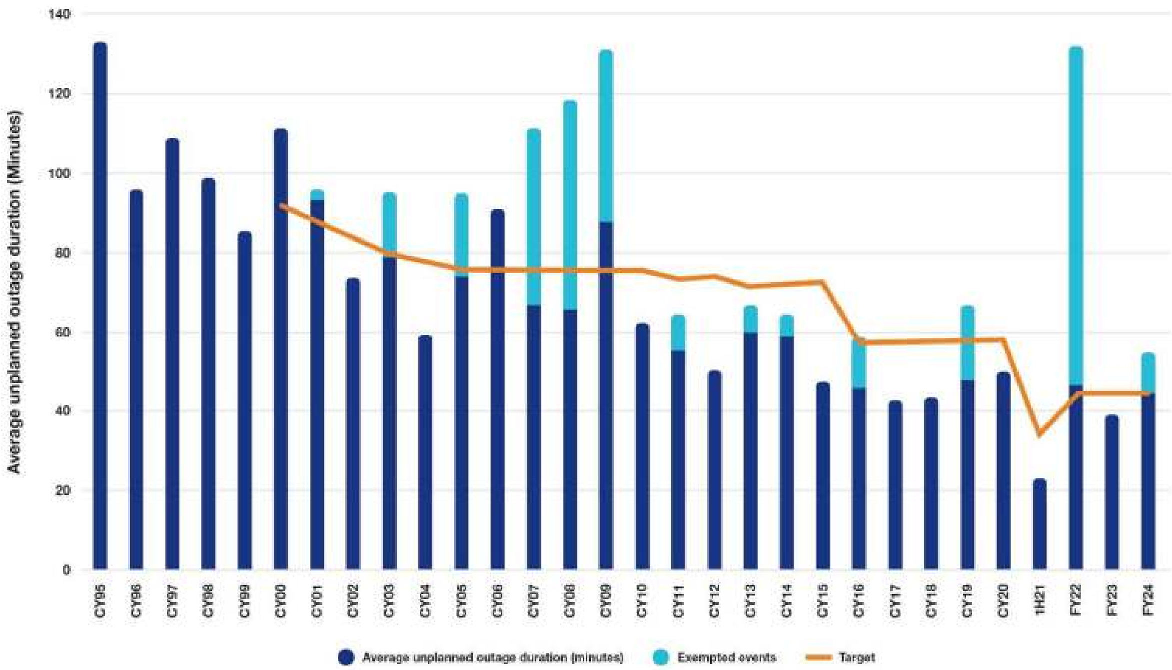


Figure 6-4: Reliability over time-unplanned SAIDI (measures the duration of outages)



6.4 Our approach to asset replacement planning

Our approach to asset replacement planning is risk-based and aims to:

- **Promote the Health, Safety and Environmental (HSE) culture** that proactively seeks to control HSE risks.
- **Optimise asset availability** by monitoring, recording and evaluating asset performance to minimise the probability of future failure and maintain current service levels.
- **Optimise asset life cycle** by deferring asset replacement expenditure if it is safe to do so and would be more efficient to undertake additional maintenance and/or inspection activities instead. We undertake asset inspection, testing, and maintenance programs across all of our assets. In cases where the replacement of an asset can be efficiently deferred, we may undertake demand management activities which form part of our operating expenditure forecast.
- **Standardise and apply established design principles** to minimise the design and life cycle costs of assets installed. Standardisation of specifications for purchasing primary plant assets, together with the new modular design and construction standard, can reduce risk and costs. This approach achieves efficiencies through the use of standard designs, portable buildings (which can be scaled to suit requirements), maximising work tasks off-site and standardising site construction. These coordinated and integrated designs are particularly focused on attributes of robust long life, security, reliability and cost-effectiveness.[149]

Most network assets, or their components, will fail at some stage due to their condition, age or other external factors. This generally requires capital expenditure to replace a failed or deteriorated asset with one that can meet the service requirements we have for that asset[150]—which, in broad terms, are for us to meet our customers' expectations that we efficiently maintain the reliability and quality of our network services over the long term.

149 Jemena Electricity Networks, Strategy, Electricity Distribution Asset Class Strategy, December 2024, p.13; Jemena Electricity Networks, Strategy, Electricity Primary Plant Asset Class Strategy, December 2024, p.13; Jemena Electricity Networks, Strategy, Secondary Plant Asset Class Strategy, December 2024, p.12.

150 As noted above, in some situations there may be opportunities to replace an asset with one of a smaller capacity if this still allows us to meet our customers' service expectations.

The expected number of significant asset failures within a population is a crucial piece of data we consider in our asset replacement planning. We can forecast this data using techniques such as Condition Based Risk Management (CBRM) modelling (refer to section 6.4.1).

For a given level of planned asset replacement activity, if the expected number of asset failures is decreasing (or increasing), then it is reasonable to conclude that the replacement program will improve (or worsen) network reliability, security and safety, all of which are related to the number of asset failures. In the context of our customers' expectation that we maintain the safety and reliability of our network services over the long term, we have developed our replacement expenditure forecast to allow us to:

- avoid an increase in the number of asset failures (thus preventing a deterioration in the quality of our services that would otherwise occur)
- decrease the number of asset failures where there are serious safety risks, such as for some older overhead service lines.

When forecasting the activities and replacement expenditure required to ensure we can continue to maintain our service levels and comply with all relevant regulatory obligations, we apply two broad approaches to asset replacement planning:

- replace before failure—replace the asset in anticipation of an unrepairable failure
- replace on failure—replace the asset following an unrepairable failure.

We determine the most prudent and efficient replacement planning approach for each asset type by considering the risks associated with that asset's failure (including safety and environmental) and the criticality of the asset in supplying services to customers. Because the failure of some electricity network assets can have safety and service reliability consequences, we replace many asset types just prior to the end of their technical lives to avoid in-service failures. Our Electricity Safety Management Scheme further explains our approach to condition-based replacement of critical assets to avoid asset failure and the associated safety risks, as opposed to planning for them to fail while in service.[151]

It should be noted that regardless of the replacement approach adopted, decisions on whether to undertake a like-for-like replacement or with an asset of higher or lower capacity are made using the best available information about future demand requirements. Additionally, in some very limited circumstances, we may be able to avoid replacing an asset entirely where there is no longer any requirement for that asset and not replace it upon failure.

Importantly, where we plan to replace a critical asset before failure, we assess asset condition to optimise the timing of our replacement decisions and avoid the early replacement of assets that are likely to continue to perform as required. We apply multiple methods to estimate the likely time of failure of an asset and therefore optimise replacement timing, including:

- assessing the condition of assets through field inspections and testing
- analysing asset failure history to identify emerging trends.

These methods are reflected in our approach to applying CBRM to our asset replacement planning, as discussed below.

> Our asset management system is accredited under the ISO55001 standard. This is consistent with the AER's expectation that electricity distribution businesses' risk and management standards are aligned with industry standards on good asset and risk management and consistent with well-established relevant Australian industry standards.[152]

151 Electricity Safety Management Scheme, November 2024.

152 AER, Industry practice application note: Asset replacement planning, July 2024, p.9.

6.4.1 Condition Based Risk Management modelling

We use CBRM modelling to aid our replacement planning assessments for several key asset types including poles, crossarms, distribution and zone substation transformers and distribution and zone substation switchgear. CBRM is a model that uses asset information to provide a quantitative risk evaluation across an asset population, including the expected number of asset failures and economic risk values for each asset class. We have applied these models to guide our asset replacement planning to ensure we efficiently continue to maintain the safety and reliability of our network at current levels consistent with our regulatory obligations and customer expectations.

CBRM Health Index explained

CBRM calculates a Health Index of an asset, which is a means of combining information on the asset's age, environment and duty, as well as specific condition and performance information, to give a comparable measure of condition for individual assets in terms of their proximity to end of life and probability of failure. The conceptual relationships between Health Indices, asset remaining life and probability of failure are illustrated below.

Condition	Health Index	Remnant life	Probability of failure
Bad	10	At end of life (<5 years)	High
Poor		5-10 years	Medium
Fair		10-20 years	Low
Good	0	>20 years	Very low

The Health Index reflects the extent of asset degradation using the following scale:

- Low values (in the range 0 to 4) represent some observable or detectable deterioration at an early stage. This may be considered as normal aging, i.e. the difference between a new asset and one that has been in service for some time but is still in good condition. In such a condition, the probability of failure remains very low, and the condition and probability of failure would not be expected to change significantly for some time.
- Medium values of health index, in the range 4 to 7, represent significant deterioration, with degradation processes starting to move from normal aging to processes that potentially threaten failure. In this condition, the probability of failure, although still low, is just beginning to rise and the rate of further degradation is increasing.
- High values of health index (>7) represent serious deterioration, i.e. advanced degradation processes now reach the point that they threaten failure. In this condition, the probability of failure is now significantly raised, and the rate of further degradation is likely to continue increasing.

The methodologies we use to develop the forecast of replacement volumes do not require an explicit representation of the distribution of the asset life (via the parameterisation of a normal distribution or some other function, as is required by the AER's replacement expenditure model). However, our CBRM modelling does implicitly allow for the variability in the asset life across the asset population (through the input of other data which represents the condition and service environment of assets) and also reflects Perks' equation[153] to estimate the probability of failure of an asset, and in turn, calculate the risks of asset failure over the analysis period.

Refer to *JEN – RIN – Support – Condition Based Replacement Management (CBRM) Guideline* for details.

6.4.2 Routine and non-routine asset replacement

Within our replacement expenditure program, we have both routine and non-routine works, reflecting differences in the nature of the assets, their replacement needs and our forecasting approaches. For groups containing low-cost and high-volume assets, we generally plan and undertake asset replacements on a routine basis—that is, we produce aggregate replacement volume forecasts for the asset population (based on information about asset condition) and apply a unit cost of replacement to derive our replacement expenditure forecast. For groups

[153] This can be used to estimate the probability of an asset failure based on an asset's age or condition.

containing high-cost and low-volume assets, we adopt a detailed risk-based analysis, which involves forecasting replacement needs and costs on an asset-specific basis.

The sub-sections below further describe our forecast replacement expenditure for each asset group, including the key drivers. Supporting documents, such as our three asset class strategies and business cases for high-value non-routine projects, are submitted as part of the regulatory proposal. Appendix C1 summarises our cost estimation methodology, including the process we use to develop detailed cost estimates that underpin our capital expenditure forecast.

6.4.3 References

The proposed capital expenditure outlined in this attachment is supported by a body of materials, forecasts and models. The key documents are outlined in Table 6–3. Further additional supporting materials are outlined in the succeeding sections below.

Table 6–2: List of replacement expenditure attachments

Attachment	Name	Author
Att 05-06	AER repex modelling	Houston Kemp
RIN Support	Condition Based Replacement Management Guideline	JEN

6.5 Forecast expenditure for each asset category

This section discusses our forecast replacement expenditure for each of the main asset categories, including the key drivers for the forecast.

6.5.1 Poles

Poles are used to support the overhead conductors that transmit electricity around our distribution network, in addition to carrying other assets such as public lighting and telecommunications cables. We own approximately 106,000 poles (of which about 25,000 are dedicated public lighting poles).[154] 55% of our poles are made of wood, 27% of steel and 18% of concrete. About 17,000 of our poles are currently staked.

Poles are of criticality importance. Their failure can pose serious safety and bushfire ignition risks and cause supply interruptions. Maintaining the structural and electrical integrity of our pole population is fundamental to achieving our network performance and the safety of the network as a whole. These outcomes are consistent with our regulatory obligations and our customers' expectations that we maintain our current levels of network reliability.

Our overall strategy for pole replacement is to continue to replace all poles before they become unserviceable, based on assessments of their condition. To save on costs, limited life (LL) or unserviceable (US) poles are assessed for suitability for staking before making any replacement decision. The exception is the High Bushfire Risk Areas (HBRA) where poles identified as LL or US are replaced using concrete poles wherever technical and safety considerations permit.

Based on our condition-based assessment of our poles, we propose to replace/reinforce about 6,700 poles over the next regulatory period with a total expenditure of $58M.

154 We also manage over 1,300 Private Overhead Electric Line (POEL) poles and over 6,300 poles owned by other authorities (such as Telstra, Tramways, Powercor) but supporting our electricity network. The forecast replacement expenditure excludes the costs associated with public lighting poles, which is recovered directly from our public lighting customers.

6.5.1.1 Our forecast expenditure

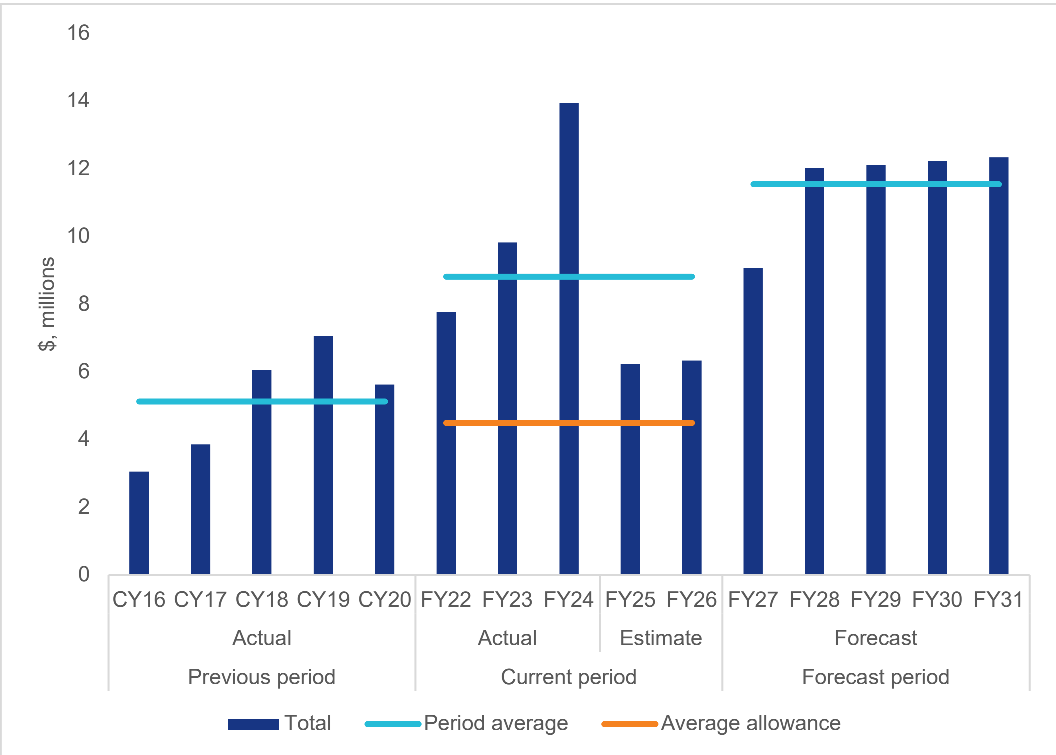
Poles need to be either reinforced or replaced before failure, while any poles that have failed in service also require replacement. For the next regulatory period, we propose to continue our routine condition-based reinforcement and replacement program. We also propose non-routine replacement of our aging staked poles and LL poles not suitable for staking.

We forecast to spend $58M on pole replacements and reinforcements over the next regulatory period (Table 6–3). This is 31% higher than our estimated spend for the current regulatory period. Figure 6-5 shows the pole replacement expenditure over the three regulatory periods.

Table 6–3: Poles replacement expenditure, $2026, millions

Asset	Forecast period					
	FY27	FY28	FY29	FY30	FY31	Total
Routine replacement						
Conditioned-based pole replacement	6.1	6.4	6.4	6.5	6.6	31.9
Condition-based pole reinforcement	0.9	1.0	1.0	1.0	1.1	5.1
Non-routine replacement						
Replacement of staked poles	1.2	2.7	2.7	2.7	2.8	12.1
Replacement of limited life poles unsuitable for staking	0.9	1.9	1.9	1.9	2.0	8.6
Total	**$9.1**	**$12.0**	**$12.1**	**$12.2**	**$12.3**	**$57.7**

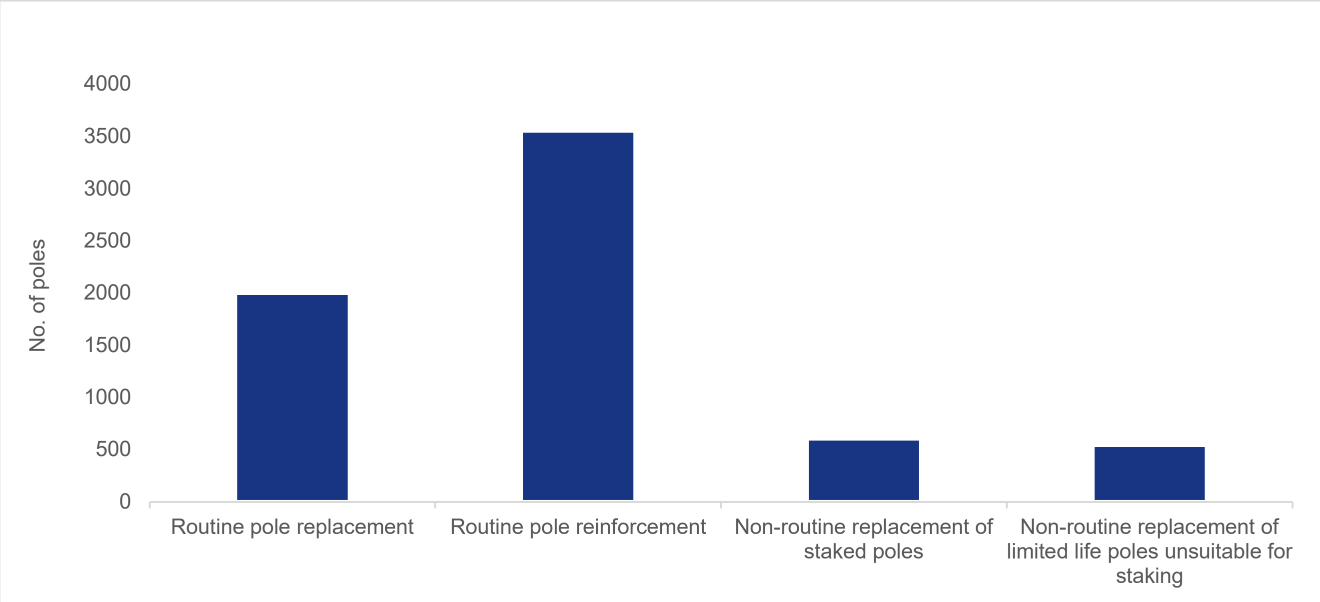
Figure 6-5: Poles replacement expenditure, $2026, millions



Our condition-based assessment of poles has shown that many of our aging poles are in poor condition and at high risk of failure in the next regulatory period if not replaced. We propose to replace or reinforce a total of 6,700 poles at risk of failure over the next regulatory period (Figure 6-6), of which around 53% is for reinforcement instead of outright replacement. We consider this to be a prudent and efficient approach given our customers will continue to receive a maintained level of service from the extended lives of our poles at a much lower cost.

We also propose to continue replacing staked poles and LL poles which have been assessed as not suitable for further staking or staking, respectively. Staked poles cannot be re-staked and therefore need replacement during the next regulatory period, otherwise they are at high risk of failing.

Figure 6-6: Forecast number of poles to be replaced or reinforced, 2026-31



> Our proposed expenditure for poles replacement/reinforcement is prudent and efficient. It is supported by a robust assessment of our poles' age, performance and condition and risks. We provide a summary of our assessment in the following sections while our Electricity Distribution Asset Class Strategy provide more details.[155]
>
> Further, our forecast is based on unit costs which are significantly lower compared to the NEM's median unit cost as shown in the repex model developed by Houston Kemp for JEN. The repex model has predicted a material increase in JEN's poles replacement expenditure (by $152M) for the next regulatory period, which is nearly triple our proposed expenditure for poles replacement.
>
> Overall, our proposal will ensure that our service levels are maintained at the lowest possible cost for our customers. This is exactly what our customers expect from us.

6.5.1.2 Our poles' age profile, performance and health

This section summarises the outcomes of our assessment of our poles' age profile, performance, health and the risks associated with not undertaking our proposed replacements/reinforcements for the next regulatory period.

Age profile

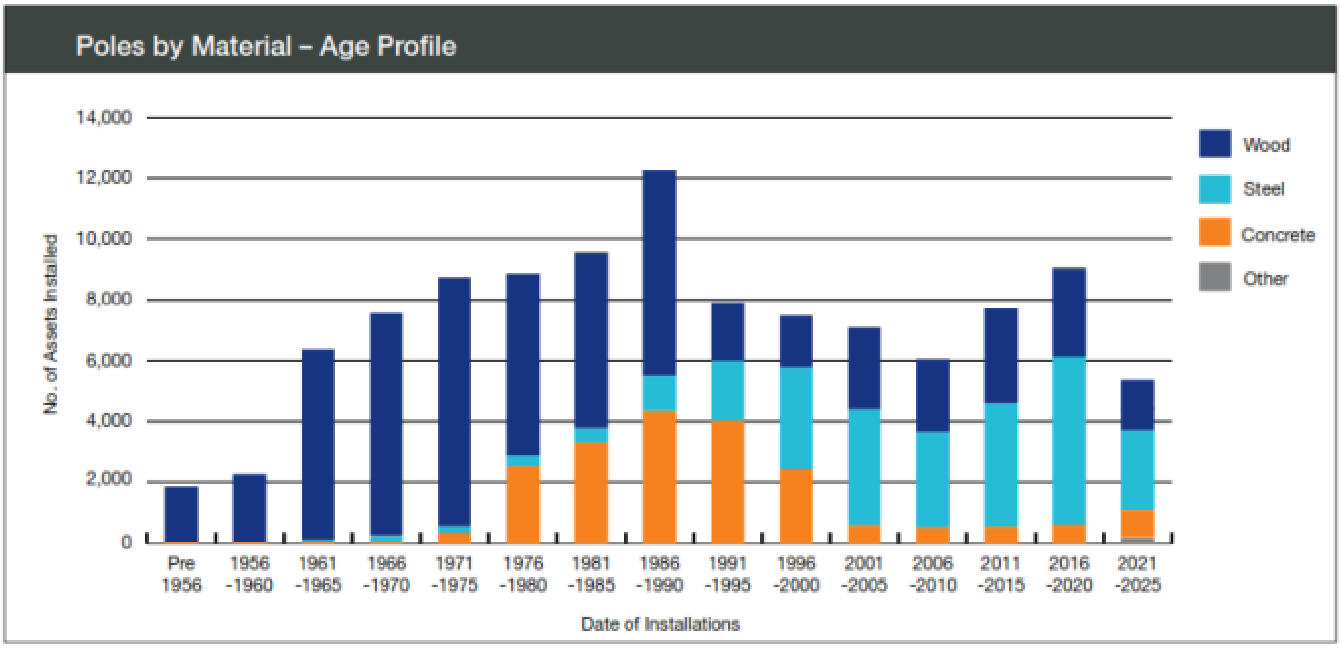
Wooden poles are the oldest among our poles. Many of our wooden poles have been installed more than 40 years ago as shown in Figure 6-7. They have an average age of 39 years, which means that a large portion is entering the latter stages of their expected useful life of 54 years.[156] Further, our analysis of the age of wooden poles when they were removed shows an average age of 37.26 years which indicates a significantly shorter life span compared to expected. Concrete poles have a longer expected life span of 70 years. The average age of JEN's

155 *JEN – RIN - Support – Electricity Distribution Asset Class Strategy.*

156 We estimate that about 27% of our wooden poles are older than their expected useful life of 54 years.

concrete pole population is 31 years, with 81% of the concrete pole population being under 40 years of age. They are generally younger compared to our wooden poles.

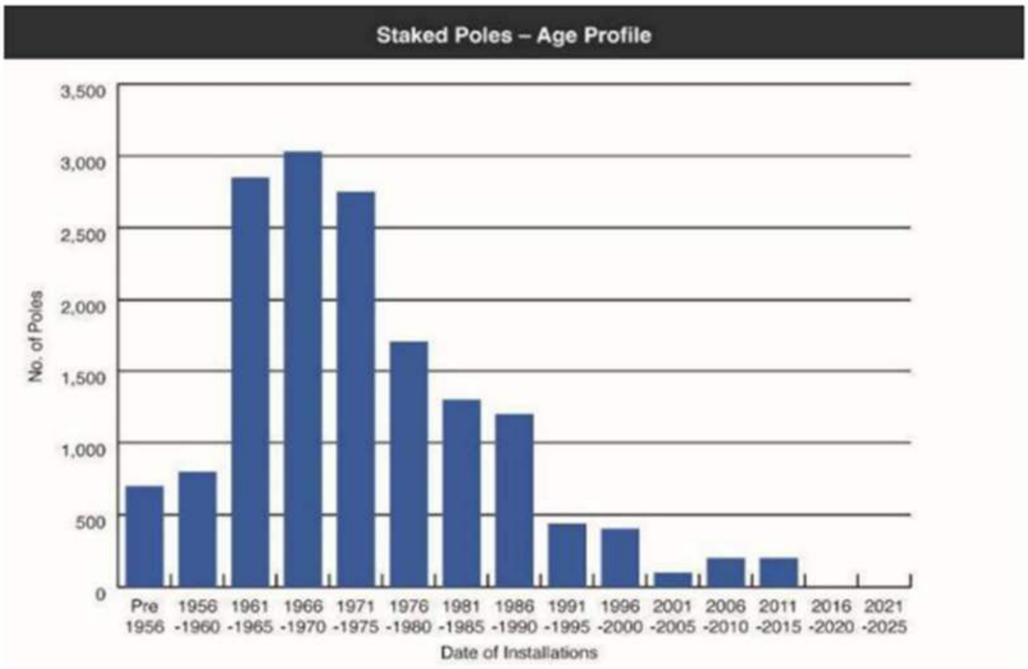
Figure 6-7: Poles by material, age profile (as of 2024)



Source: Strategy, Electricity Distribution Class, December 2024, p.21.

Staking LL and US poles is a life extension treatment and is a cost-effective method of extending asset life. However, as shown in Figure 6-8, a large number of our 17,000 staked poles were reinforced as early as the 60s and 70s. About 50% of them are installed on wooden poles that have exceeded their expected life of 54 years. They cannot be re-staked and therefore need replacement, otherwise they are at high risk of failing. About 21% of our forecast pole replacement expenditure is for the replacement of staked poles.

Figure 6-8: Staked pole, age profile (as at 2024)



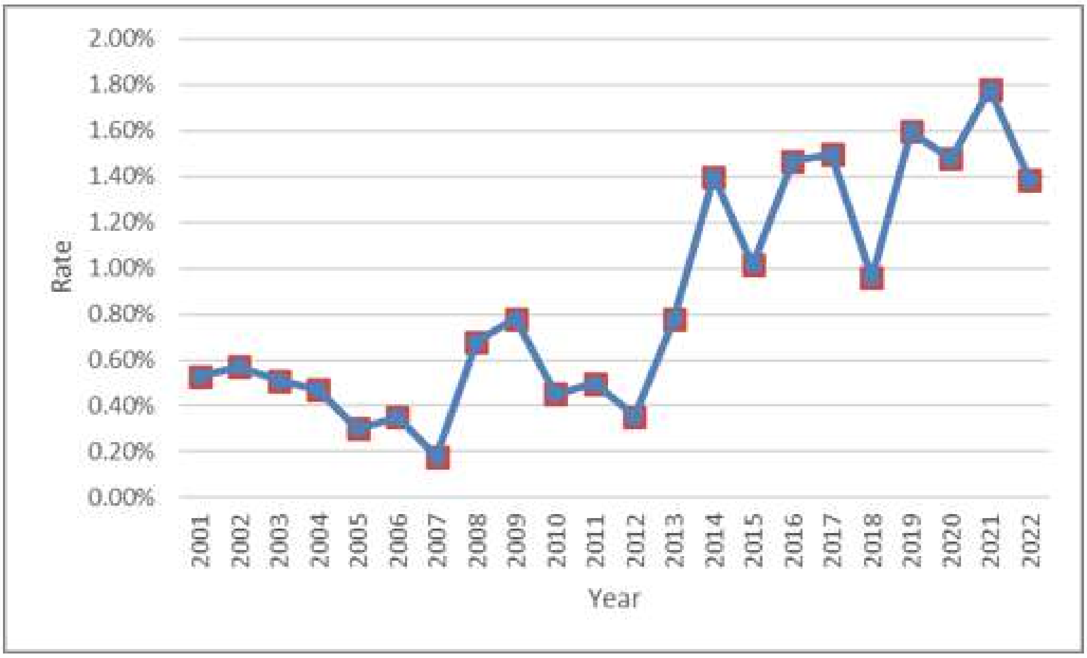
Source: Strategy, Electricity Distribution Class, December 2024, p.22.

While age of our poles is not the main basis for poles replacement and reinforcement, it is a key input to our condition-based assessment of poles.

Performance

Condemnation rates and in-service failure rates provide information about the performance of poles. The condemnation rate is calculated by dividing the sum of LL poles and US poles by the total pole population in that year. Annual condemnation rates can vary due to characteristics of the poles in areas under inspection, however the overall trend is clearly increasing as shown in Figure 6-9. This condemnation rate is consistent with the above trend of increasing proportion of pole population exceeding technical life.

Figure 6-9: JEN pole condemnation rate (% as a total of pole population)



Source: Strategy, Electricity Distribution Class, December 2024, p.25.

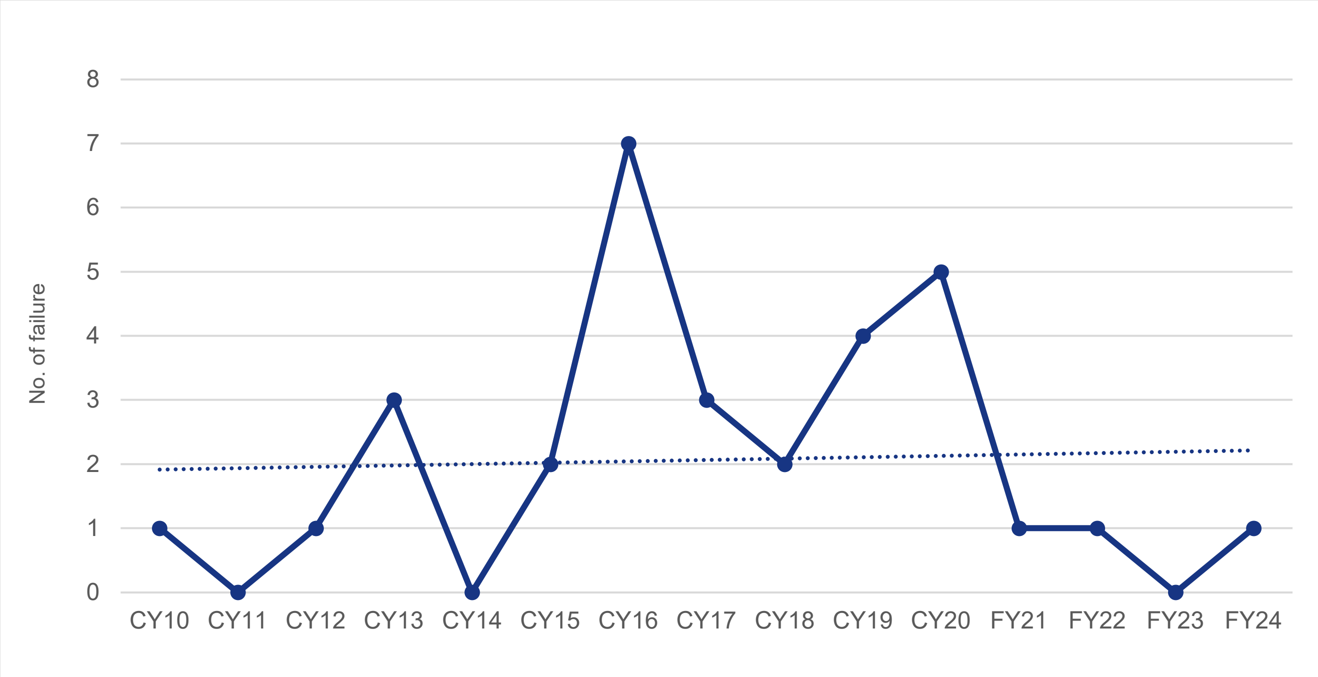
We also measure the performance of our poles through unassisted in-service pole failures. We would be unable to maintain our current level of network reliability in the future if there was an increase in the number of in-service pole failures. Figure 6-10 shows that the number of in-service pole failures fluctuates over time but is trending upwards (linear). While in-service pole failures have recently improved, they could easily increase to a higher level over the next regulatory period, given many of our wooden poles have reached or are reaching their expected useful life. The older the poles, the more prone they are to higher failure rates due to wear and tear.[157] They also become more vulnerable and at a higher risk of failure during extreme weather events.

The current improvement in the number of asset failures is due to actions being implemented to mitigate the risk of in-service pole failures through modification and tuning of the asset inspection criteria. We aim to maintain our low level of pole failure over the next regulatory period, consistent with our customers' expectations of maintaining network reliability.

> Despite overall failures remaining very low, pole condemnation rates are trending upward, posing a risk that replacements could increase unexpectedly in the future. Our pole replacement expenditure forecast has therefore been developed to allow us to continue to replace all poles before failure, based on assessments of their condition.

[157] See Energy Network Australia's description of the Bathtub Curve. The bathtub curve maps the engineering failure rate over time for a group of assets: in the early stages assets might fail due to defects; during the middle life of the assets, failure rates might be low; as assets reach their end of life, the failure rate increases because of built up wear and tear.

Figure 6-10: Number of in-service pole failures[158]



Condition-based assessment

In developing our forecast, we also considered options such as reducing pole replacement expenditure from current levels, undertaking age-based (rather than condition-based) replacement, performing replacements instead of life-extending reinforcements, and running assets to failure. However, we consider that replacement based on asset condition is the most efficient use of resources as it focuses more on assets that require attention.

We propose to continue our ongoing programs of work to reinforce or replace poles which have reached the end of their technical life and can no longer be maintained economically. Individual poles which require reinforcement or replacement are identified through routine pole inspections, which we regularly undertake in accordance with Victorian regulatory requirements.[159]

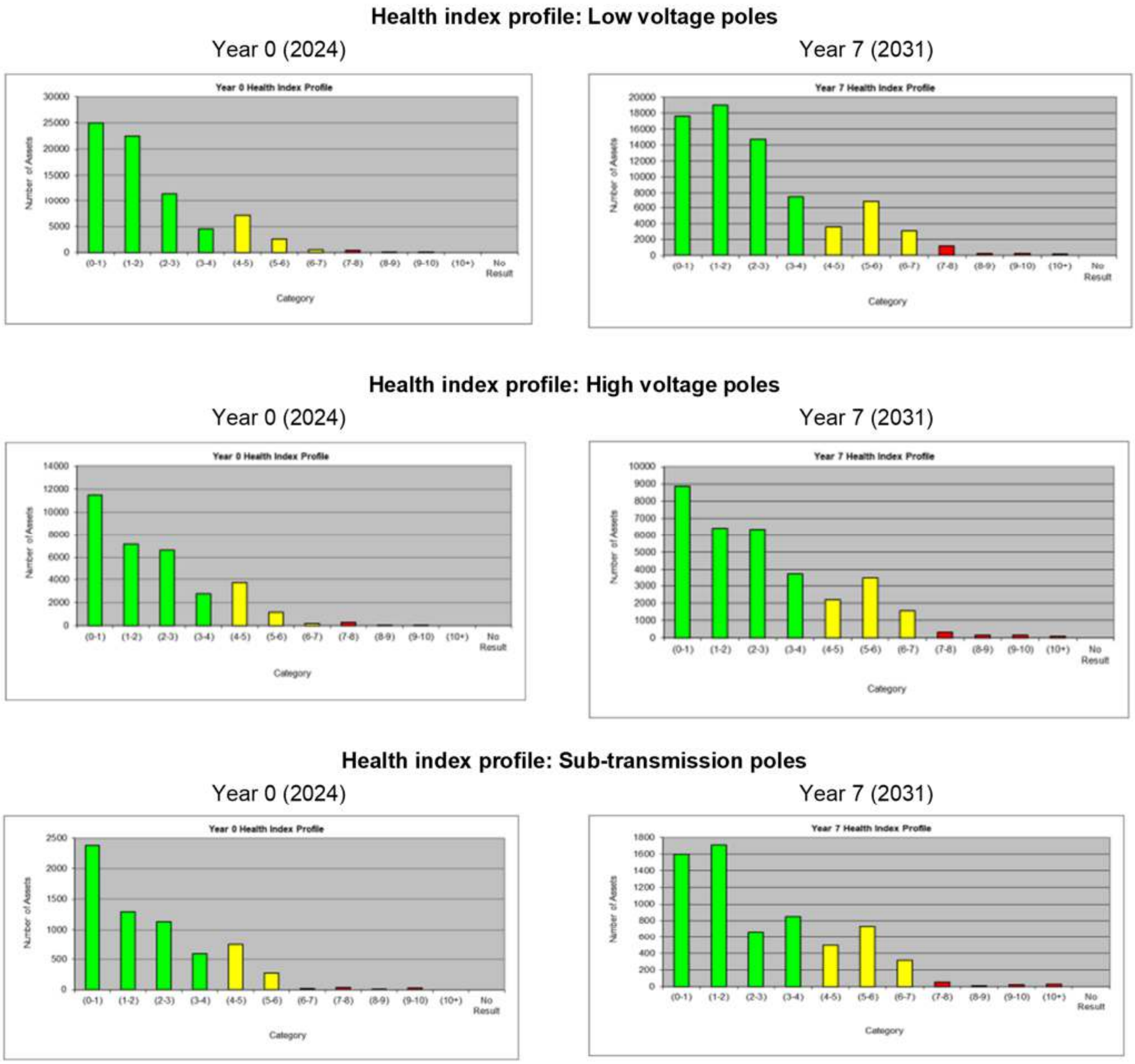
Our CBRM modelling shows that if we were to cease carrying out our pole replacement program in the next regulatory period, the condition of our poles would continue to deteriorate, as illustrated in the right column of Figure 6-11. Our condition-based replacement programs are designed to broadly maintain the current level of risk associated with poles as illustrated in the left column of Figure 6-11. Our forecast pole replacement/reinforcements will therefore allow us to maintain our current level of reliability over the next regulatory period.

> Under our CBRM guideline, high values of health index (>7) represent serious deterioration. It means advanced degradation processes now reach the point that they threaten failure. In this condition, the probability of failure is significantly raised, and the rate of further degradation is likely to continue increasing.

[158] Source: JEN's historical RIN C 2.2.

[159] *Electricity Safety (Bushfire Mitigation) Regulations 2013* s 7(1)(i) sets out maximum inspection intervals, and requires more frequent inspection of assets in HBRA.

Figure 6-11: Health index profile for poles (as of 2024)[160]



6.5.1.3 References

The proposed capital expenditure outlined in this section is supported by a body of materials, forecasts and models. The key documents are outlined in Table 6–4.

Table 6–4: List of pole replacement expenditure attachments

Attachment	Name	Author
Att 05-06	AER repex modelling	Houston Kemp
RIN Support	Condition Based Replacement Management Guideline	JEN
RIN Support	Electricity Distribution Asset Class Strategy	JEN

[160] Strategy, Electricity Distribution Class, December 2024, pp. 29, 31-33.

6.5.2 Pole-top structures

Pole top structures are made up of crossarms, insulators, insulator ties and other equipment at the top of a pole which are used to attach conductors to poles. We currently have around 114,460 crossarms which are predominantly used as part of the pole top structure.

Pole top structures are assessed as low critically asset due to consequence of pole top failure in terms of operational and health safety impacts. Nonetheless, the failure of pole top structure components can result in a loss of supply to customers, high-voltage injections (causing customer property damage) and fire starts. More than half of our crossarms are LV wooden types and highly susceptible to pole top fires. We need to mitigate the risks associated with safety and bushfire; and also ensure that we are compliant with our regulatory obligations on network reliability. Pole top structures need to be replaced before failure to mitigate safety and customer supply risks.

We assessed the need for pole top structures replacement against a number of measures and criteria including failure rates, CBRM (driven by age and health asset index), actual outcomes of condition monitoring and inspections. For the next regulatory period, we used the lower forecast of crossarms to be replaced as suggested by our actual asset condition monitoring and inspections. We consider this to be a prudent and efficient approach because it will still enable us to maintain the reliability of our pole top structures at a lower cost for our customers.

We forecast to spend about $45M in replacing about 11,900 pole top structures over the next regulatory period. About 75% of expenditure will be for the replacement of LV crossarms which are the most at risk of failing if not replaced. Unlike poles, there is no reinforcement option for the pole top structures.

6.5.2.1 Our forecast expenditure

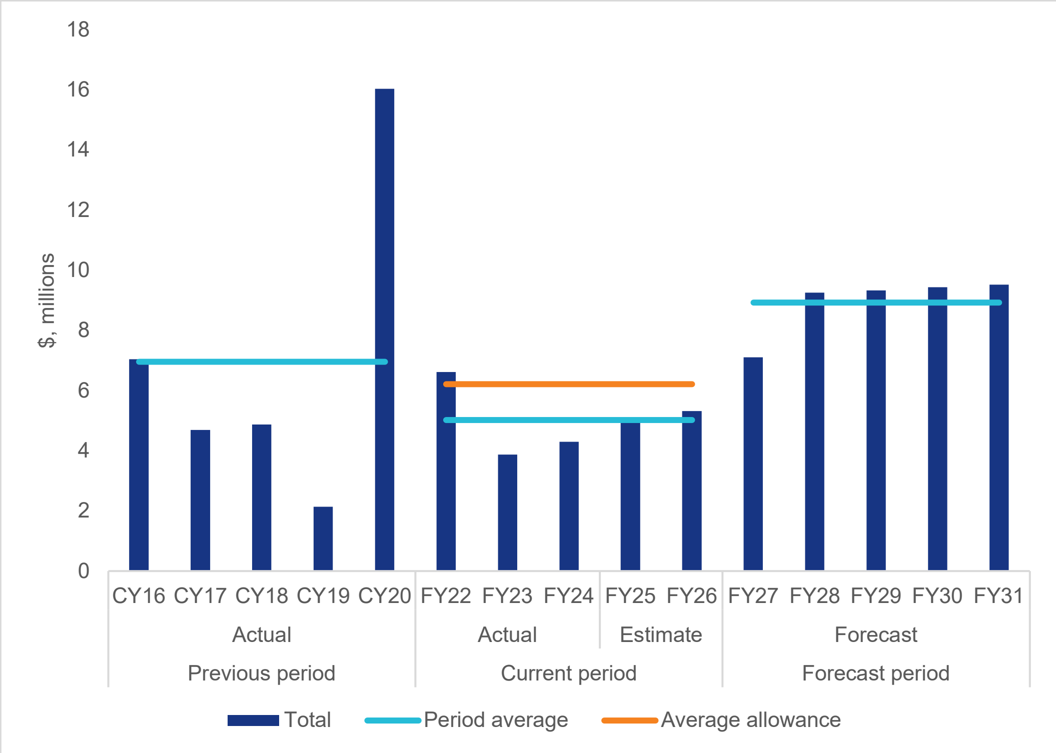
We must replace pole top structures before they fail. Unlike poles, there is no reinforcement option for the pole top structures. For the next regulatory period, we propose to continue our condition-based replacement program of works targeting those assets with the highest risk of in-service failure. We will also continue our risk-based targeted replacement program, specifically designed to replace wooden cross-arms with newer steel cross-arms to reduce the risk of pole top fire ignition.

We forecast to spend $45M on pole top structures replacement over the next regulatory period as set out in (Table 6–5). This is 78% higher than our estimated spend for the current regulatory period, which is consistent with our forecast higher volume of replacement. Figure 6-12 shows the pole top structures replacement expenditure over the three regulatory periods.

Table 6–5: Pole top structures replacement expenditure, $2026, millions

Asset	Forecast period					
	FY27	FY28	FY29	FY30	FY31	Total
Pole top structures	7.1	9.3	9.3	9.4	9.5	44.6

Figure 6-12: Pole top structure replacement expenditure, $2026, millions



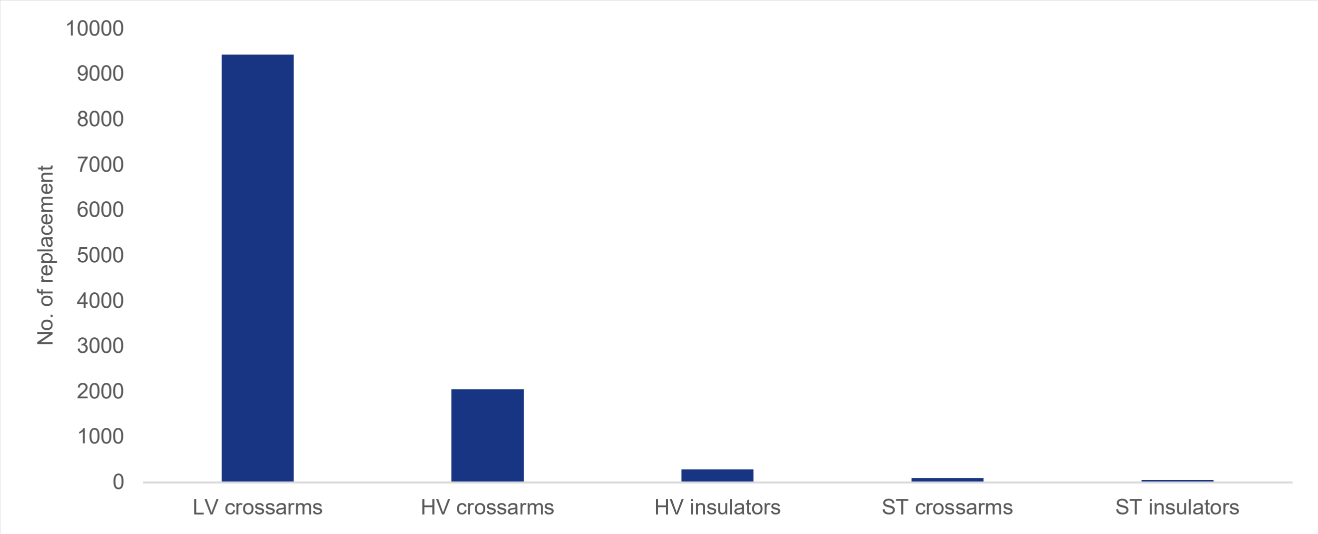
Our condition-based assessment and the outcomes of our actual asset monitoring and inspections found that many of our aging pole top structures, particularly LV crossarms are at high risk of failure in the next regulatory period. The historical failure rate for LV crossarms has also been trending upwards. A future decrease in health and therefore increase in the number of pole top structure failures would make it unlikely that we could maintain our current level of network reliability.

We propose to replace 11,903 pole top structures (crossarm) in the next regulatory period (Figure 6-13). This is higher than our estimated number of pole top structures to be replaced in the current regulatory period of 6,784 but not significantly higher than the actual pole top structures replacement of 9,307 in the previous regulatory period. Our pole top structure replacement expenditure forecast will allow us to continue to replace the pole top structures which pose the highest risk of failure or fire start based on assessments of their condition, age and operating circumstances.

Our forecast expenditure is prudent and efficient. Our condition-based assessment has suggested a higher volume of crossarms to be replaced but we adjusted it for the actual results of our asset monitoring and inspection to a lower forecast volume and in turn lower forecast expenditure.

We summarised the outcomes of our assessment of pole top structures age, performance and condition in the following sections.

Figure 6-13: Forecast pole top structures to be replaced



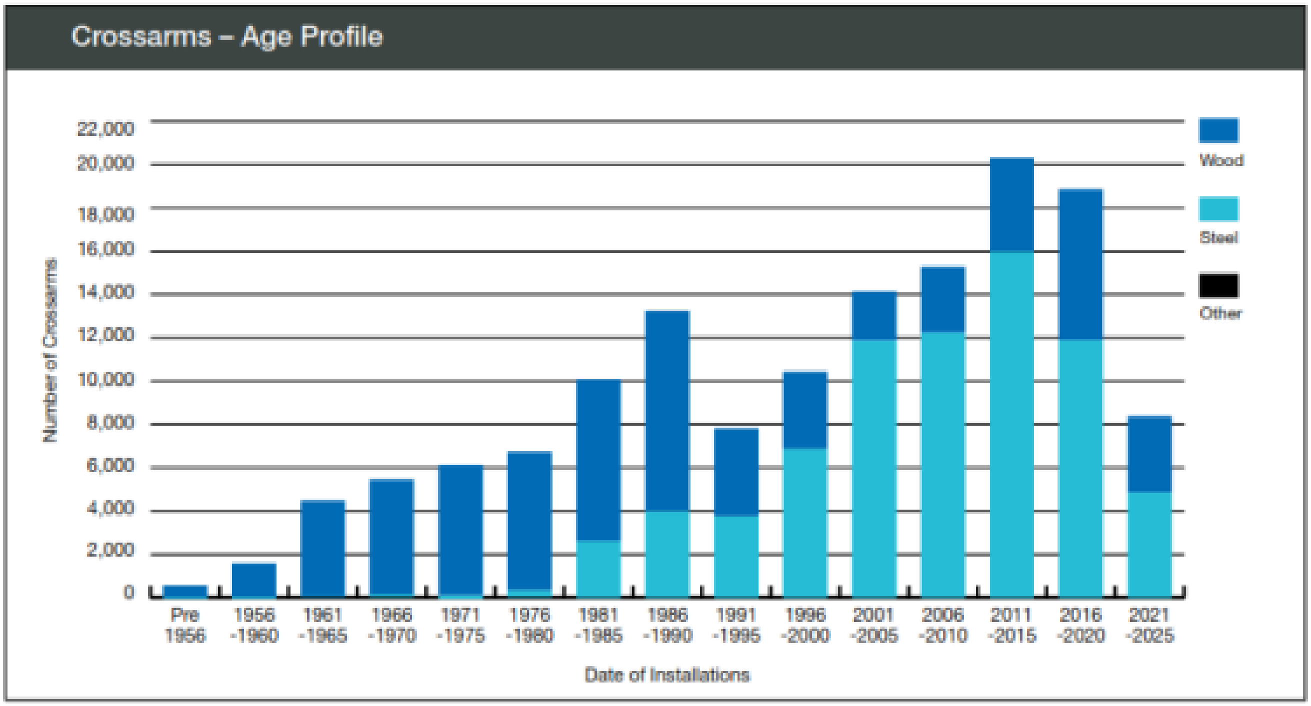
6.5.2.2 Our pole top structures' profile, performance and health

This section summarises the outcomes of our assessment of our pole top structures' age profile, performance, health and the risks associated with not undertaking our proposed replacements/reinforcements for the next regulatory period.

Age profile

Pole top structures have an expected technical life of 45 years for wood crossarms and 70 years for steel crossarms, provided they are installed correctly. About 58% of our crossarms are made of wood and as shown in Figure 6-14, many of them were installed in the 60s and 70s and has therefore exceeded the expected average wood crossarm life of 45 years. We estimate that there are more than 21,000 crossarms (both steel and wood) over the age of 45 years. Age is a key input to our condition-based assessment of pole top structures.

Figure 6-14: Pole top structures age profile, by material (as at 2024)



Source: Strategy, Electricity Distribution Class, December 2024, p. 55.

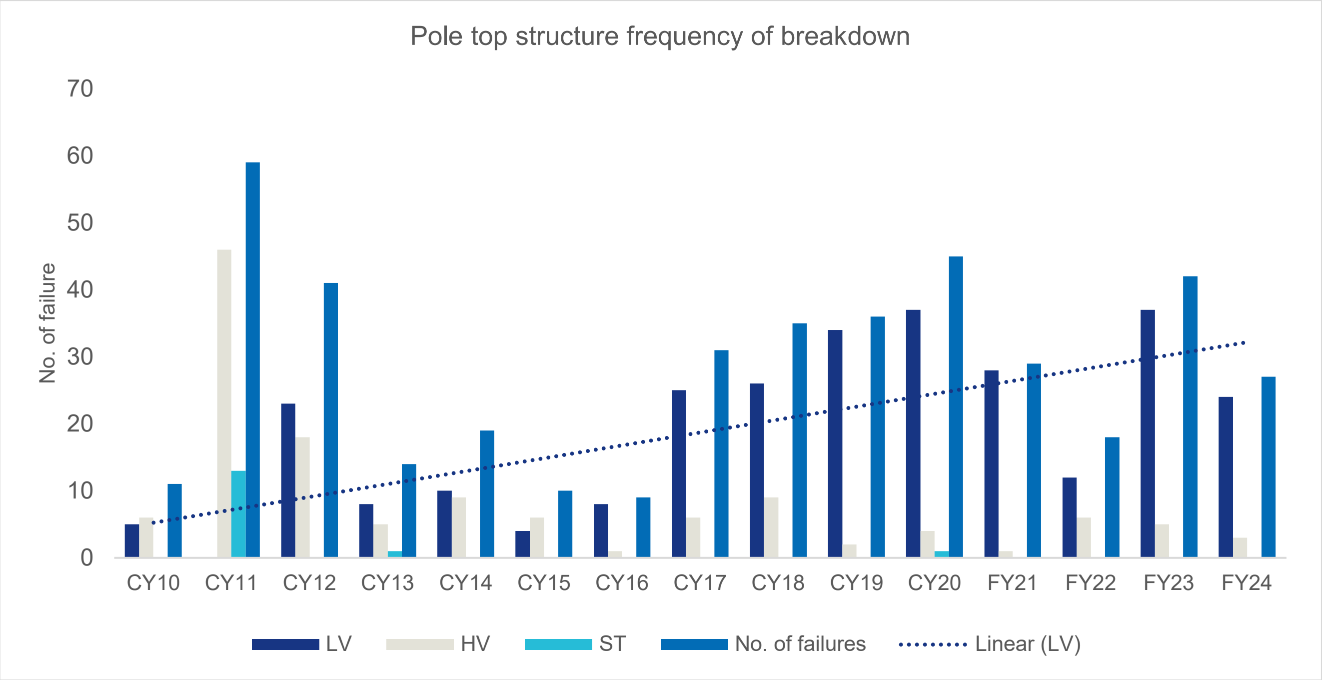
Performance

We assessed the performance of our pole top structures based on the frequency of breakdowns or in-service failures and outcomes of actual asset condition monitoring and inspections. We also monitor their performance against the Bushfire Mitigation Index.

The number of pole top structure breakdowns have fluctuated over the period 2010 to 2024 with an average of about 27 per year (Figure 6-15). [161] However, the trend clearly shows that is has been significantly increasing. JEN's LV crossarms (all made of wood) have the greatest number of asset failures, with an average of 19, over the same period. This reflects the age profile of our wood crossarm population of which a large portion are operating beyond their expected asset life. These pole top structures need to be replaced, otherwise, they could lead to loss of supply and failure for us to meet our regulatory obligations; cause harm to the health and safety of our staff, contractors and the public; and could also lead to claims for property damage and risk of a fire start.

The number of in-service ST and HV crossarm failures is trending downward as a result of our pole top mitigation program which targets at risk timber ST and HV crossarms and replace them with new steel crossarms.

Figure 6-15: Pole top structure frequency of breakdown[162]



As part of our corrective maintenance measure, we assess whether pole top structures have achieved the performance targets for critical activities in our Bushfire Mitigation and Inspection/Maintenance programs. Assets which did not meet the performance targets are considered as high-risk assets. This condition monitoring assessment has suggested a lower number of LV crossarms and insulator assemblies need to be replaced in the next regulatory period compared with what our CBRM has suggested (see below). We adopted the lower volume in developing our forecast expenditure. We consider this to be a prudent and efficient approach because it will still enable us to maintain the reliability of our pole-top structures at a lower cost for our customers.

161 The causes of pole top structures failure varies and include age of crossarms; crossarm fire; insulator failure; breakage of the mounting hardware or steel crossarm due to severe corrosion of steel components; breakage of crossarms, insulators and hardware due to external influences such as vegetation impact and extreme wind; and insulator flashover due to external influences such as vegetation contact, lightning, birds and other animals.

162 Sourced from RIN. Chart only considers in service crossarm failures and includes crossarm failures caused by pole top fires.

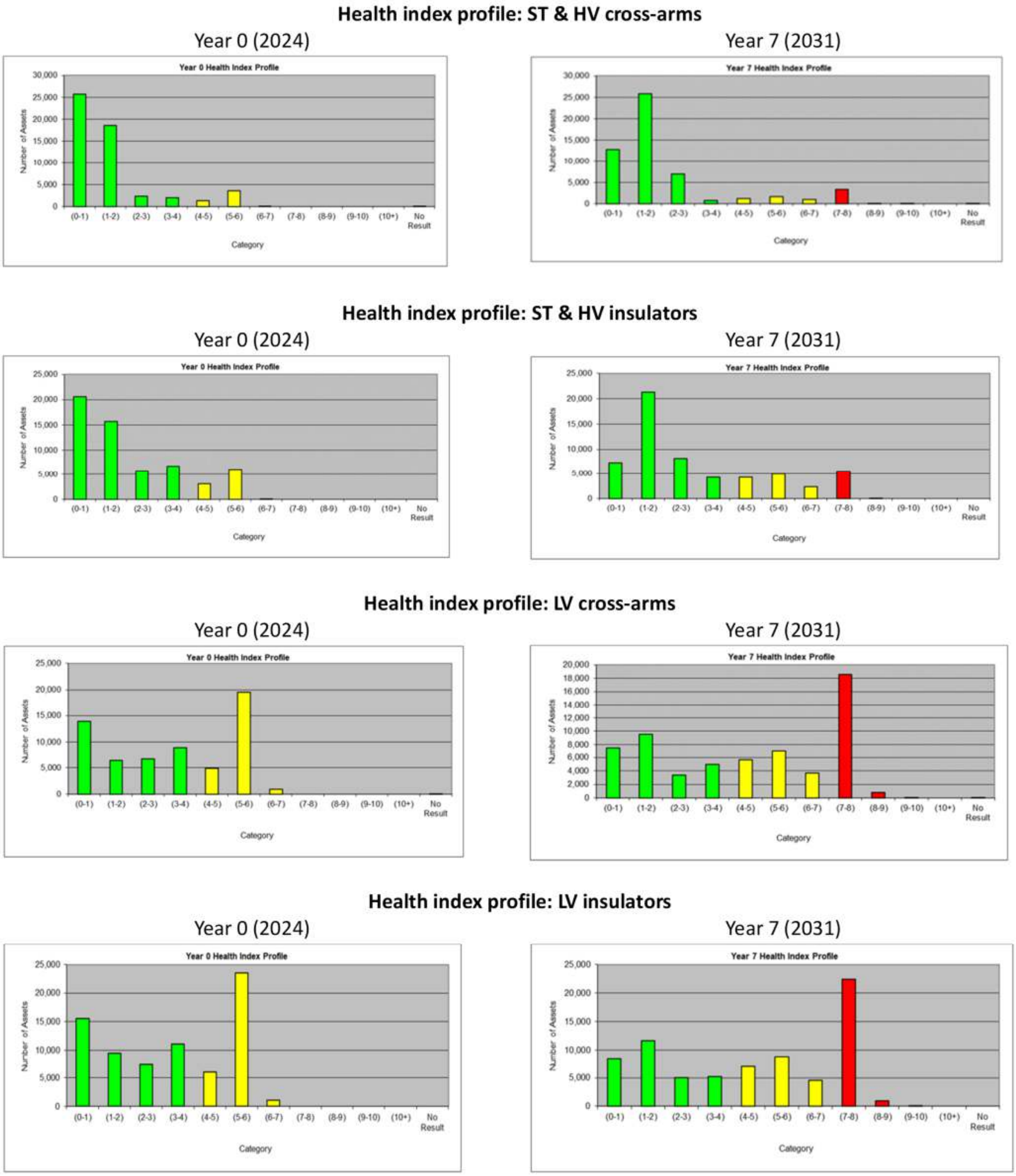
Condition-based assessment

Our CBRM modelling shows that about 18,450 pole-top structures are at risk of failure and need to be replaced in the next regulatory period (Figure 6-16), including:

- **ST and HV crossarms and insulators** – A total of 430 HV and SV crossarms and associated insulators, which have exceeded their 45-year life expectancy, need to be replaced annually over the next regulatory period in order to maintain the network risk of ST and HV crossarm and insulator assembly failures at the 2024 levels.
- **LV crossarms and insulators –** A total of 3,260 LV crossarms and associated insulators need to be replaced annually over the next regulatory period in order to maintain the risk of LV crossarms and insulator assembly failures at the 2024 levels. However, our asset class strategy only proposes to replace about 2,000 crossarms and insulators per year over the same period after adjusting for the results of our asset condition monitoring and inspections.

> As discussed above, we adopted the lower forecast of 11,903 pole-top structures suggested by our condition monitoring assessment compared to 18,450 suggested by the CBRM. We consider this to be a prudent and efficient approach because it will still enable us to maintain the reliability of our pole-top structures at a lower cost for our customers.

Figure 6-16: Health Index profile, pole top structures (as at 2024)[163]



Source: Strategy, Electricity Distribution Class, December 2024, pp. 59-63

163 The left hand column shows the current health index of our pole top structures. The right hand column shows the forecast deterioration of the health of our pole top structures over the next regulatory if replacement activities are not undertaken. The CBRM treats crossarms and insulators as an assembly and assesses the risk on this basis.

6.5.2.3 References

The proposed capital expenditure outlined in this section is supported by a body of materials, forecasts and models. The key documents are outlined in Table 6–6.

Table 6–6: List of pole replacement expenditure attachments

Attachment	Name	Author
RIN Support	Condition Based Replacement Management Guideline	JEN
RIN Support	Electricity Distribution Asset Class Strategy	JEN

6.5.3 Overhead conductors

Overhead conductors are used to transport electricity on the overhead parts of our network and includes equipment such as connectors (but excludes service lines between the network and customers' properties). Our distribution network has conductors which comprise around 4,500 km of overhead circuits, and which are made of various materials depending on the voltages they carry (ranging from LV to ST) and the era in which they were installed.

Overhead conductors have a higher visual impact on the community and generally provide less reliable service as they are more susceptible to environmental and other external interference.

Conductors are a highly critical asset, as their failure can pose serious safety and fire ignition risks (particularly in HBRA) in addition to customer supply interruptions and damage to customer property. Some types of conductors, when in poor condition, pose a significant safety risk to our crews and, therefore, cannot be worked on live, which results in additional (planned) customer supply interruptions and increased operational costs. The condition of overhead conductors degrades with use and, over time, is affected by factors such as corrosion and wind vibration (they may also fail due to external influences, such as trees falling on lines). **Degradation in conductor condition is not repairable and therefore, replacement is required before failure.**

Replacement of overhead conductors is condition-based and supported by the outcomes of our asset inspection program and fault/failure history information.

We forecast to spend about $12M in replacing overhead conductors and associated equipment over the next regulatory period. About 58% of our forecast spending will be for the non-routine replacements associated with the Façade Rectification Program, a program we started during the current regulatory period. A prioritised work program has been developed to replace and make the existing façade mounted installation on the JEN LV network safe; otherwise, said installations could impose safety risks to the general public.

6.5.3.1 Our proposed expenditure

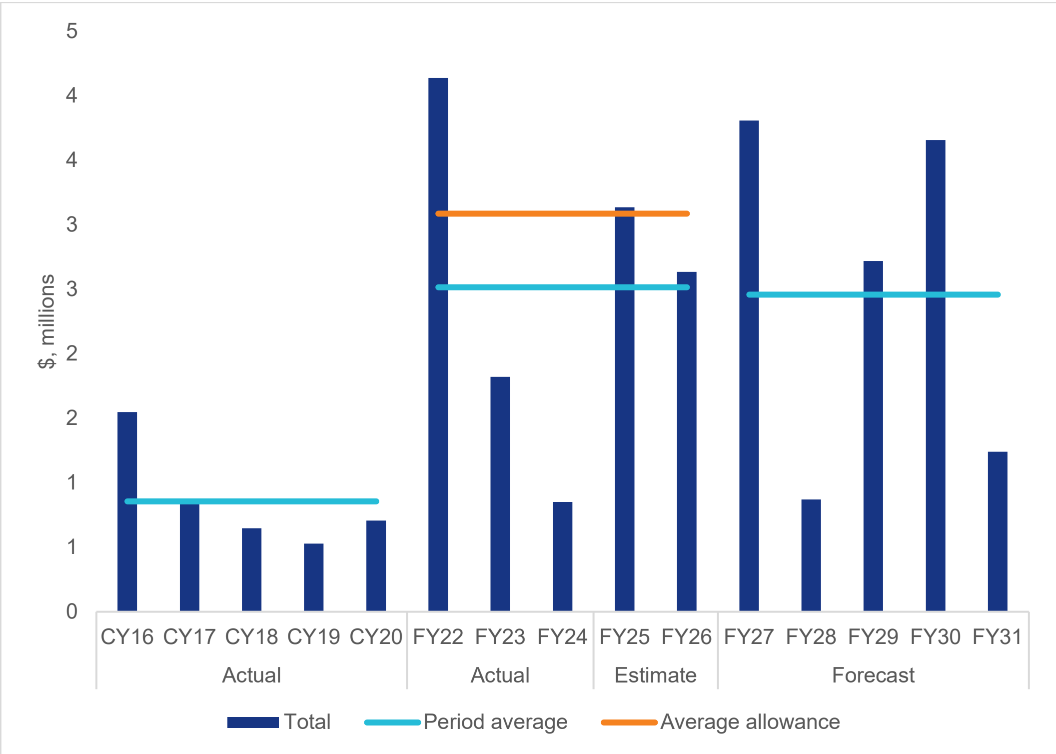
We propose to continue our condition-based replacement of overhead conductors (and associated equipment). Our primary focus is to stabilise and maintain asset performance through the replacement of conductors with identified poor performance issues.

We forecast to spend $12M on overhead conductor (and associated equipment) replacements over the next regulatory period (Table 6–7). This is 2% lower compared to our expected spending in the current regulatory period.

Table 6–7: Overhead conductor replacement expenditure, $2026, millions

Asset	Forecast period					
	FY27	FY28	FY29	FY30	FY31	Total
Routine						
Condition-based replacement program	0.6	0.6	0.8	0.9	0.9	3.8
Non-routine						
Façade rectification program	3.1	0.0	1.7	2.4	0.0	7.2
Undersized neutral replacement	0.1	0.3	0.3	0.3	0.3	1.4
Total	**3.8**	**0.9**	**2.7**	**3.7**	**1.2**	**12.3**

Figure 6-17: Overhead conductor replacement expenditure, $2026, millions



The key driver of our forecast expenditure is the non-routine façade rectification program, which we introduced during the current regulatory period. Façade-mounted assets have been identified as posing an unacceptable risk to public health and safety following an investigation by Energy Safe Victoria in 2021. It was identified that 24 sites at ten different locations required immediate attention and that if not addressed they would pose safety risks to the general public. Since then, JEN has undertaken temporary make safe works at all of the sites.

For the next regulatory period, we are proposing the implementation of permanent solutions for 12 sites at two different locations on the network: High Street, Preston and Macaulay Road, Kensington. Low voltage supply cables at these locations are currently positioned atop shop façades. At some sites, Low Voltage Aerial Bundle Cables (LV ABC) and wiring with deteriorated insulation is located in proximity to metallic surfaces on shop verandas. This presents hazards for individuals requiring access to these areas.

Temporary remediation solutions have been implemented, however, permanent solutions that comply with current standards must be implemented to address the residual risk to public safety. We have an obligation to plan and develop our network to comply with network performance obligations and minimise the risk associated with asset failure. Our proposed façade rectification program meets the safety objectives under the NEO, NER, and Victorian Electricity Distribution Code of Practice. It will minimise the risk associated with asset failure and, therefore, ensure the safety of our network and our customers.

> Refer to *JEN – RIN – Support – Facade Mounted Asset Replacement Program – Business Case* for details about the need for the project, the risks associated with non-implementation, the credible options considered and how we have considered our customers' expectations.

In addition to the façade rectification program, our forecast spend will enable to us to continue with our routine replacements of ageing and poor-conditioned overhead conductors. **Degradation in conductor condition is not repairable and therefore, replacement is required before failure.**

Many of our LV overhead conductors were installed in the 1960s and 1970s and have either exceeded or are almost at the end of their useful life of 50 to 60 years (Figure 6-18). Our inspection and maintenance records have also shown that the annual failures of overhead conductors and connectors have been increasing, especially for LV and HV conductors (Figure 6-19).

The consequence of failures of conductors and connectors can include equipment damage, supply outages and damage to customer's equipment. However, the '**high**' criticality assigned to this asset group results principally from the risks associated with the following three major failure consequences:

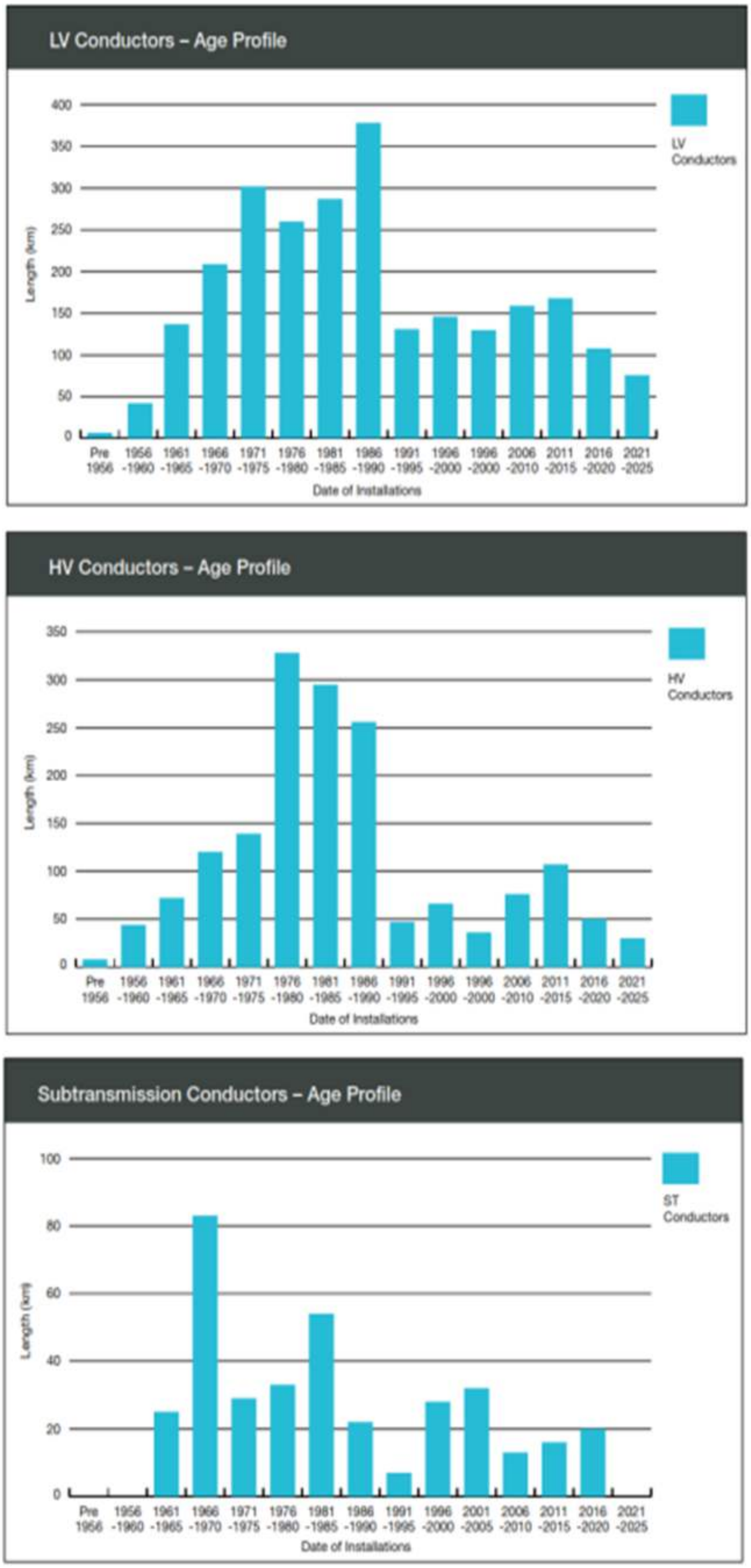
- supply interruption
- fire start including bushfire start
- electric shock or electrocution associated with live conductors on the ground.

Our forecast replacement program is designed to allow us to maintain our current level of risk associated with these assets into the future, allowing us to meet our customers' expectations that we maintain our current levels of network service reliability.

> JEN's repex modelling also predicted a decrease in replacement expenditure for overhead conductors but it forecasts a higher level of decrease compared to our forecast expenditure.[164] The difference is due to our non-routine proposed façade rectification program, which is not yet captured under the predictive repex model, hence the different outcomes. Nonetheless, overall, our forecast total replacement expenditure remains within the threshold predicted by the repex model for the next regulatory period.

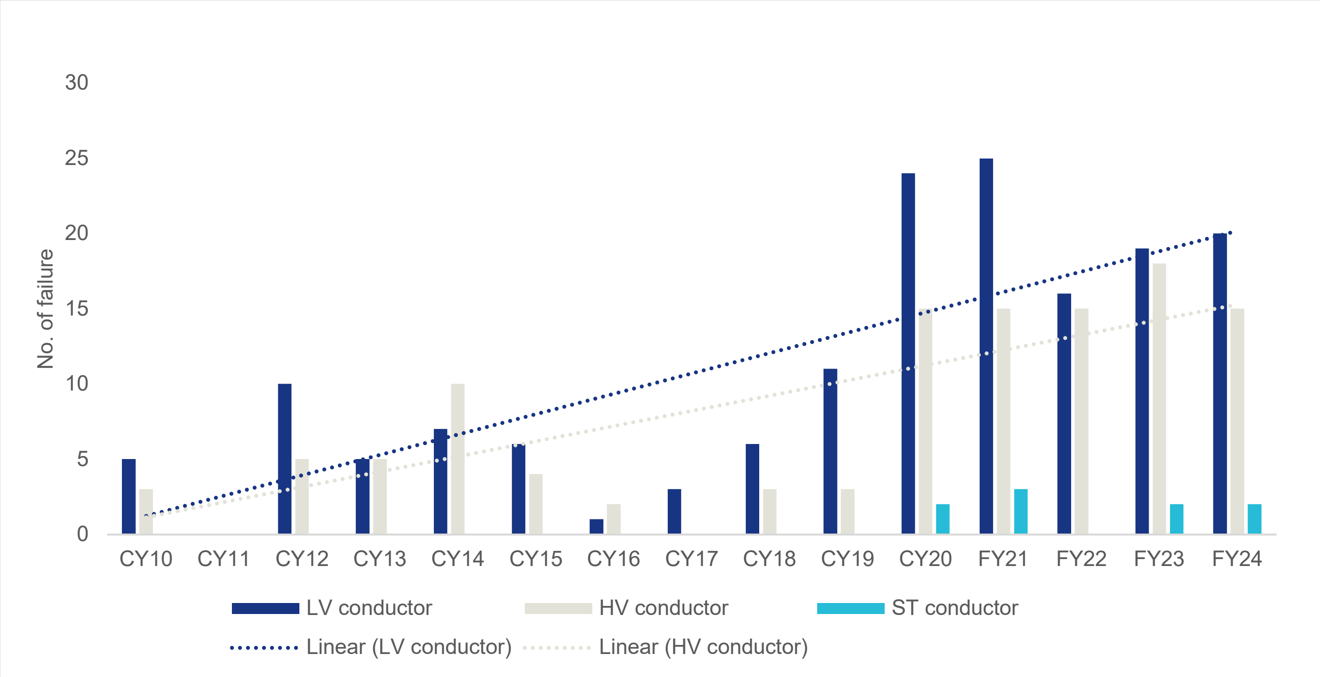
[164] Refer to Attachment JEN - Houston Kemp Att 05-06 AER repex modelling, p. 8.

Figure 6-18: Overhead conductors' age profile



Source: Strategy, Electricity Distribution Class, December 2024, pp. 81-82

Figure 6-19: Overhead conductor and connector failures[165]



6.5.4 References

The proposed capital expenditure outlined in this section is supported by a body of materials, forecasts and models. The key documents are outlined Table 6–8.

Table 6–8: List of pole top structures expenditure attachment

Attachment	Name	Author
RIN Support	Condition Based Replacement Management Guideline	JEN
RIN Support	Electricity Distribution Asset Class Strategy	JEN
Att 05-06	AER repex modelling	Houston Kemp
RIN Support	Facade Mounted Asset Replacement Program – Business Case	JEN

6.5.5 Underground cables

Underground cables transport electricity in the underground parts of our network, as well as pits and pillars. Our network includes around 2,461 km of underground cables, ranging from LV to ST. In addition, we have around 1,476 km of low-voltage service cables.[166]

Underground cables operate with a higher level of reliability than overhead networks as they are less susceptible to environmental and other external interference. However, their construction is more expensive than overhead network assets and is likely to be less costly in terms of maintenance. Our underground distribution system now comprises about 45% of our total network length.

165 Source: JEN's RIN C 2.2.

166 This group of cables are those that are run from the service tee joints on the LV mains cables to the service pits, pillars or customers service and metering cubicles.

The underground distribution system has an asset criticality of **Significant** due to lengthy repair times and our limited ability to respond to some types of faults due to limited availability of skilled technicians.[167] Some sub-transmission cables, particularly oil-filled cables installed between the 1930s are considered **High** risk and impacts our ability to respond to a fault or leak in the oil insulating system.

The failure of an underground cable can pose a severe safety risk in some cases, particularly where cable insulation has completely broken down or in the event of the failure of an outdoor cast iron cable termination box. Underground cables most commonly fail due to the breakdown of their insulation, caused by factors such as water ingress or physical damage.[168] Cable failure can also cause the loss of supply to customers in a varying degree depending on the cable's voltage.

Our principal method of assessment of the performance of the underground distribution system is based on the monitoring of asset failures and maintenance notifications. Assets that cannot be efficiently inspected based on their supply criticality and risk profile are run to failure. This is an appropriate lifecycle management strategy when the consequences of failure do not include any risk of injury or harm and where the failure rate is low. We consider this approach to be more efficient compared to proactive replacement and therefore helps reduce our forecast underground cable replacement expenditure in the next regulatory period.

We forecast to spend about $40M in replacing underground cables (and associated accessories) over the next regulatory period.

6.5.5.1 Our proposed expenditure

We must replace underground cables and their associated equipment before failure to mitigate safety and customer supply risks. We also need to replace assets that have failed in service.

We forecast to spend about $40M on underground cable (and associated accessories) replacements over the next regulatory period (Table 6–9). This is significantly higher than our estimated spend for the current regulatory period. Figure 6-20 shows JEN's replacement expenditure for underground cables over three regulatory periods.

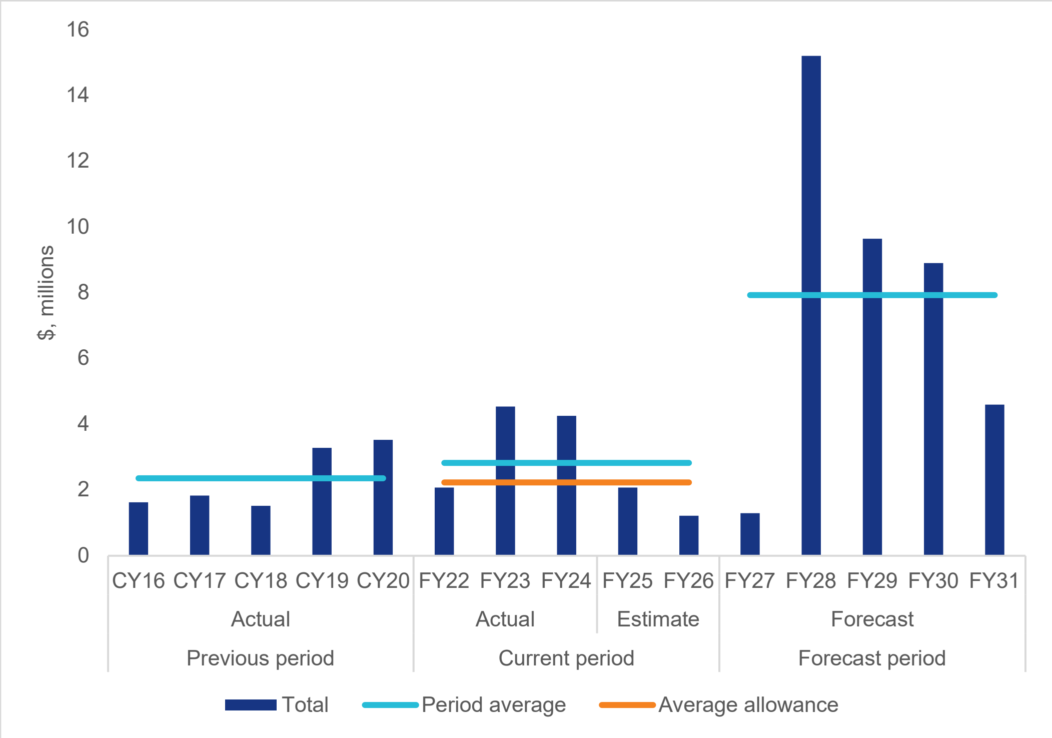
Table 6–9: Underground cable replacement expenditure, $2026, millions

Asset	Forecast period					
	FY27	FY28	FY29	FY30	FY31	Total
Routine						
Longer term replacement program for U/G cables and terminals	1.3	4.9	4.4	2.57	1.3	14.4
Non-routine						
Replacement of oil filled ST underground cable and replacement of metal trifurcating boxes	0.0	10.3	5.2	6.4	3.3	25.2
Total	**1.3**	**15.2**	**9.6**	**8.9**	**4.6**	**39.6**

[167] For example, damage caused by a third party to one of our oil-filled sub-transmission cables during the current regulatory period led to it being out of service for several months and could have significantly impacted supply reliability to a large number of customers if this event had occurred during summer when demand was higher.

[168] Note that cable failure due to damage by third parties is covered under our emergency recoverable works sub-category (within 'other replacement expenditure') as set out in section 6.5.12.2 of the Asset Class Strategy for distribution.

Figure 6-20: Underground cable replacement expenditure, $2026, millions



Historically, we have been spending $2M-$3M on average for the replacement of underground cables annually. For the next regulatory period, we forecast to spend an average of around $8M annually to enable us to undertake the following two major projects: 66kv Oil-filled cable replacement program and the Maribyrnong project. Together, they account for around 84% of our forecast expenditure for underground cable replacements.

66kv Oil-filled cable replacement program

JEN has approximately 7km of 66kV oil filled underground cables installed. We propose to replace the 66kV oil filled cables installed within the following sub-transmission network loops:

- Brooklyn Terminal Station-Yarraville-Newport
- Brooklyn Terminal Station-Tottenham
- Thomastown Terminal Station- Coburg South-Coburg North
- Thomastown Terminal Station – North Heidelberg - Nilsen
- West Melbourne Terminal Station – Footscray East.

The 66kV oil filled cable are nearing end of life with rectification of repairs posing material risks to employee safety and reliability and security of customer supply. These assets require replacement with modern equivalents to ensure that we maintain the electrical and safety performance of our network. Table 6–10 shows the issues associated with 66kV oil-filled cable assets.

Table 6–10: Current issues with JEN's 66kv oil filled cables (as at 2024)

Issue	Description
Asset condition	The existing cables are 60 years old and near end of life. Historically there has been an increasing trend to failure and defects on these cables, interrupting supply to customers and resulting in single contingency network operations.

Issue	Description
Asset near obsolescence	This type of cable is also no longer widely supported by manufacturers with maintenance and repair works requiring external resources and bespoke materials and equipment.
Safety and network operational performance	The technology used in this type of cable is based on a pressurised oil system which leads to inefficient maintenance and repair times in comparison to modern equivalents.
Environmental impact	The oil filled cables insulating medium can be detrimental to the environment should a cable failure or defect occur that results in oil leaking into the surrounding environment.

This is consistent with what we have stated in our 2021-26 price reset proposal about oil-filled cable replacement, where we noted that:

> *we have not included any sub-transmission cable replacements in our forecast capital expenditure for the next regulatory period. However, we expect our expenditure to replace these assets will increase in the years following the next regulatory period.*[169]

> We have developed a robust business case for this project.[170] The business case has demonstrated that our proposed project is prudent and efficient and is based on the option which will give the highest net benefits to our customers. It describes the need for the project, the risks associated with non-implementation, the credible options considered and how we have considered our customers' expectations.

Relocation of assets that are in high flood risk zones within the Flemington area (Maribyrnong project)

Following the 2022 Maribyrnong River floods, Melbourne Water updated its flood risk modelling in line with Australian Rainfall and Runoff (ARR) guidelines, which is the industry standard for flood modelling. This modelling activities reclassified many of the communities JEN serves as 'high-flood risk zones'.

Our proposed project involves relocating assets in high-flood-risk zones within the Flemington area (Maribyrnong project) to reduce the risk of these assets suffering flood damage, which could cause an outage, inconveniencing customers and hindering restoration efforts The initiative aims to enhance the reliability and resilience of said infrastructure, safeguarding both the assets and the community. In addition, safeguarding our assets from flood damage also ensures we do not have to replace them sooner than expected and helps maintain affordability and price stability for customers.

The Maribyrnong project focuses on moving the assets from flood susceptible locations and finding new locations out of the flood plain on higher ground as a way to negate the impact on the assets from a flood event. The assets identified to be moved include 23 distribution pillars, pits and cabinets, 19 distribution substations and 3 sub-transmission cables. The process of moving assets will involve extensive network planning, council and customer support and planning approvals.

> During the development of the Draft Plan, we have considered the Maribyrnong project to be one of our Network Resilience projects and have consulted our customers on that basis. Our customers have supported the implementation of this project during the next regulatory period. We explain in section 7 our customers' support for this project, including our reasons for treating it as a network replacement project instead of network resilience.
>
> Notes: The expenditure associated with the Maribyrnong project's transformer component is captured under our forecast spend for transformer replacements in section 6.5.7.

169 JEN, 2021-26 Electricity distribution price review regulatory proposal, Attachment 05-01, Forecast capital expenditure, January 2021, p.41.

170 *JEN – RIN – Support – 66kV Oil Filled Cable Replacement Program – Business Case*.

In addition to the above two projects, we propose to continue our routine longer-term replacement program for underground cable assets based on our asset inspection program (for equipment where reactive testing can be carried out or cable termination boxes and pits which can be visually inspected) and asset performance and records of fault data. This involves the replacement of HV and LV underground cables and cable terminations that have been assessed to be at risk of failure if not replaced during the next regulatory period.

JEN's repex model predicted a decrease in the expenditure for the replacement of underground cables[171] whereas we proposed an increase. The difference is mainly due to our proposed two non-routine, high value projects which we need to implement to maintain the reliability and safety of our network, as discussed above. Nonetheless, overall, our forecast total replacement expenditure remains within the threshold predicted by the repex model for the next regulatory period.

6.5.5.2 References

The proposed capital expenditure outlined in this section is supported by a body of materials, forecasts and models. The key documents are outlined in Table 6–11.

Table 6–11: List of underground cable expenditure attachments

Attachment	Name	Author
RIN Support	Electricity Distribution Asset Class Strategy	JEN
Att 05-06	AER repex modelling	Houston Kemp
RIN Support	66kV Oil Filled Cable Replacement Program – Business Case	JEN

6.5.6 Service lines

Service lines form the connection between the distribution network and a customer's point of supply. This asset class includes overhead services, as well as associated hardware such as termination clamps, brackets and connectors. Individually, LV overhead services are one of the least expensive items on the distribution system, but as an asset class, their volume and therefore value is significant.

We currently own and operate more than 158,000 overhead services. Several different types of services (materials and designs) have been installed since the 1930s and many remain in place today. However, several of these older technologies are no longer considered suitable to remain in service due to the safety risks they pose—we refer to these types of services as '**non-preferred**'. Non-preferred service lines comprise 46% of those currently in service. One of our existing controls to mitigate risk is to replace obsolete or non-preferred services over the next 11 years (to be completed by 2035) at a rate of approximately 6,000 services per year.

The overhead service line sub-asset class has an asset criticality score of High due health and safety risk to staff and the general public caused by electrical shocks associated with broken or high impedance neutrals.

The failure of an overhead service can interrupt the customer's supply and also carries fire ignition risks in some areas. The risk of failure for some non-preferred service types is higher due to existing flaws in their design or materials. We will continue to proactively replace LV overhead services lines by identifying and replacing all 'non-preferred services' in a targeted area based on asset performance. All new LV overhead services lines are constructed using Aerial Bundle Cable (LVABC).

Overhead services are replaced based on condition. Once defects are detected service lines are replaced. **They are not repairable.**

We forecast to spend about $32M in replacing service lines over the next regulatory period. The key driver for our forecast expenditure is the non-routine replacement of non-preferred services in the next regulatory period.

[171] JEN - Houston Kemp Att 05-06 AER repex modelling, p. 8.

6.5.6.1 Our proposed expenditure

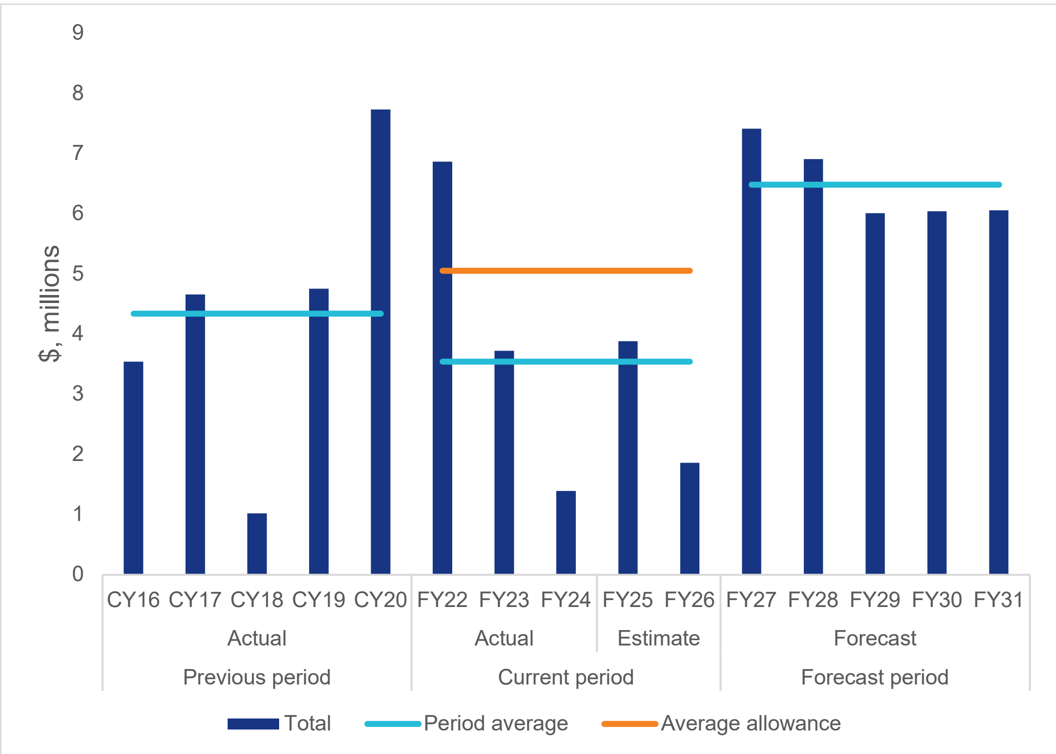
We propose to continue our non-preferred service replacement program (also called the Service Rectification Program) and conditioned-based replacement programs in the next regulatory period.

We forecast to spend around $32M on service line replacements over the next period (Table 6–12). This is 83% higher than our expected spend for the current regulatory period. Figure 6-21 shows JEN's service line replacement expenditure over three regulatory periods.

Table 6–12: Service lines replacement expenditure, $2026, millions

	Forecast period					
Asset	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**Total**
Routine						
Conditioned-based replacement program	2.0	2.2	2.2	2.2	2.1	10.6
Non-routine						
Non-preferred service replacement program (also called Service Rectification Program)	5.4	4.7	3.8	3.9	3.9	21.8
Total	**7.4**	**6.9**	**6.0**	**6.0**	**6.1**	**32.4**

Figure 6-21: Service lines replacement expenditure, $2026, millions



Historically, we have been spending $3.5M-$4M on average for the replacement of service lines annually. For the next regulatory, we forecast an annual average spend of around $6M per year, primarily driven by our non-preferred service replacement program, followed by our ongoing conditioned-based replacement program. In the current regulatory period, we have been required to invest significantly more than the allowance on our pole asset class. This is due to an increased volume of poles that, based on condition, have reached the end of life. As a result, we have been able to "trade-off" and defer the replacement of service lines without increasing the risk profile or performance of this asset class. This deferral means that these services must be replaced in the next regulatory period.

Non-preferred service replacement program

All LV overhead services have an expected technical life of 40 years, and a significant portion of the asset population that will exceed this age during the next regulatory period are the non-preferred service types. The population of non-preferred service lines currently poses the following risks:

- safety risks to customers caused by deteriorated service neutrals
- fire-starts due to overhead service failure
- failure to comply with ground clearance regulations.

We commenced this program in 2010 in response to a growing number of customer safety incidents. Our analysis of incidents has determined that non-preferred service line types are primarily responsible for neutral service test failures and resulting safety incidents. The objective of our non-preferred service replacement program is, therefore, to address the safety risks listed above by replacing all non-preferred services with our current standard ABC type.

During the next regulatory period, we propose to continue our program of replacing non-preferred overhead service lines with their modern equivalents (mitigating safety risks). About 70% of our forecast volume of service lines to be replaced are non-preferred service lines (Table 6–13). This will:

- reduce the risk of electrical shocks to customers by addressing the deteriorating non-preferred service population
- minimise the potential for fire starts
- rectify non-compliant low overhead services.

Our non-preferred replacement program will address several safety and condition issues in addition to high-impedance neutrals.

In developing this program, we considered alternatives including not proactively replacing non-preferred services and replacing higher or lower volumes per annum (therefore completing the removal of all non-preferred services in a shorter or longer timeframe). Continuing to proactively replace a similar number of services as we have during the current regulatory period represents an optimal balance between the costs of this program and the need to mitigate the safety risks posed by these assets.

We expect to replace all non-preferred services by 2035. Once this program is completed, our replacement expenditure for service lines is expected to reduce.

Condition-based replacement program

We inspect and test LV overhead services every three years in the HBRA and every five years in the LBRA, in line with regulatory obligations. We also conduct visual inspections of services for mechanical integrity to leverage synergies with concurrent vegetation management, height measurement and maintenance activities. The routine inspection and testing of services is mandated by the Electricity Safety (Bushfire Mitigation) Regulations 2013. All services identified through inspection or testing activities as defective are replaced with their modern equivalent (aerial bundled cable).

In addition to our asset inspection program, we also monitor service lines failure to assess asset conditions. As shown in Figure 6-22, service lines failure has been on an increasing trend for LV residential. The failure of an overhead service line can interrupt the customer’s supply and also carries fire ignition risks in some areas.

Figure 6-22: Service lines failure

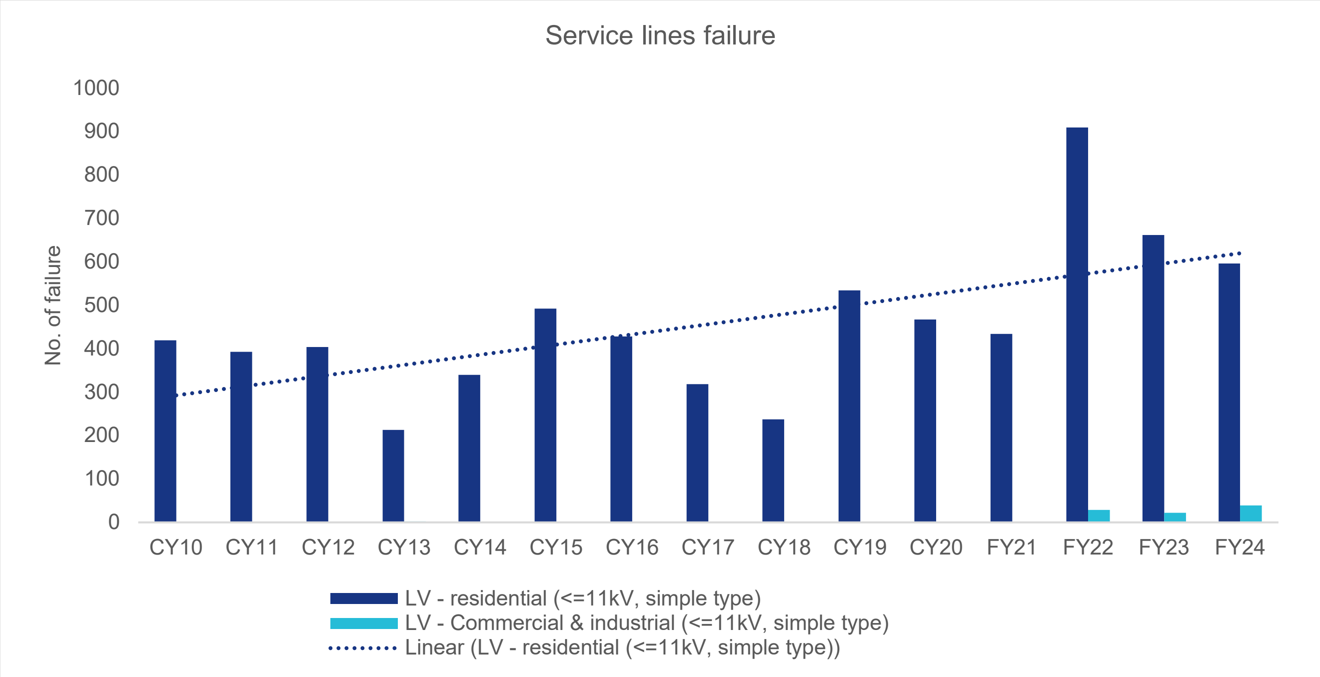


Table 6–13 sets out the forecast number of replacements underpinning our forecast expenditure for service lines.

Table 6–13: LV Overhead service line – forecast replacement volume

LV overhead service	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total FY27-FY31
Service fault replacement	607	607	900	900	900	900	900	4,500
Replace service and alter terminations	408	386	380	380	380	380	380	1,900
Install disconnect device	50	126	212	212	212	142	65	843
Replace services – planned	764	745	541	745	745	745	745	3,521
Service rectification program (non-preferred service)	2,292	0	6,106	5,283	4,227	4,227	4,227	24,070

Our forecast expenditure is prudent and efficient. The replacement programs will allow us to maintain the current level of risk associated with these assets maintain our network performance and address our compliance requirements under the Electricity Safety (Management) Regulations 2019, the AS/NZS 3560.1 (Electric Cables) and our own technical specifications for overhead conductors and underground cable.

The JEN's repex model has similarly predicted an increase in replacement expenditure for service lines.[172] Our forecast spend will increase at a higher level than what the repex model has predicted due to our non-routine replacements of legacy non-preferred service lines. Nonetheless, overall, our forecast total replacement expenditure remains within the threshold predicted by the repex model for the next regulatory period.

172 JEN - Houston Kemp Att 05-06 AER repex modelling, p. 8.

6.5.6.2 References

The proposed capital expenditure outlined in this section is supported by a body of materials, forecasts and models. The key documents are outlined in Table 6–14.

Table 6–14: List of service lines expenditure attachments

Attachment	Name	Author
RIN Support	Electricity Distribution Asset Class Strategy	JEN
Att 05-06	AER repex modelling	Houston Kemp

6.5.7 Transformer

Transformers convert the voltage of power between different levels as it moves around our network. This sub-category of expenditure covers two types of transformers which have different replacement drivers:

- transformers located inside zone substations, which convert power from sub-transmission to high voltage, and whose replacement is non-routine in nature
- distribution transformers located throughout the distribution network on poles or in kiosks or other structures, which convert high voltage to low voltage, and whose replacement is routine.

We currently have around 6,500 distribution substations and 66 zone substation transformers.

Zone substation transformers are critical assets. Zone substation transformer failure is relatively rare (around 1 in 15 years) and can be caused by factors including insulation or connector deterioration, overloading or through-faults from other network equipment. But the failure of a zone substation transformer can cause significant customer outages—a typical urban zone substation has three transformers supplying more than 10,000 residential customers, and in some cases up to 30,000 customers. The failure of a zone substation transformer also carries safety and environmental risks, such as oil spillage and possible fire. Our approach to the lifecycle management of zone substation transformers is, therefore, to undertake inspection and maintenance activities to efficiently optimise their economic life and to explore opportunities to extend the life through activities such as refurbishment where economic to do so, but to eventually replace them before an in-service failure to mitigate against the safety and customer supply risks described above.

Distribution transformers have an asset criticality score of moderate. Distribution transformers can fail due to similar reasons, such as deterioration, overload or through-faults. However, when compared to a zone substation transformer, distribution transformers are less critical, and their failure is relatively moderate risk, generally only causing the loss of supply to a small number of customers.[173] Our approach to the lifecycle management of distribution transformers is therefore usually to replace them reactively (after an in-service failure), noting also that some distribution transformers may at times be replaced before the end of their technical life with a unit of larger capacity due to load growth (however this is considered augmentation expenditure and not replacement).

We forecast to spend about $47M for transformer (and associated equipment/assets) replacements in the next regulatory period driven by non-routine, high value projects.[174]

[173] For pole mounted transformers the number of customers supplied ranges between 1 and 370 customers.

[174] The Australian Government is consulting on a Regulation Impact Statement (CRIS) on Distribution transformers. The CRIS recommends expanding the scope of regulation and making the minimum energy performance standards more stringent for these transformers. The CRIS recommended that the existing Greenhouse and Energy Minimum Standards (GEMS) determination should be amended as soon as practicable and should cover electricity distribution transformers with power ratings from 10 to 5,000 kVA (for single-phase and Single Wire Earth Return [SWER]), 25 to 5,000 kVA (for three-phase), a system high voltage (Um) up to 36 kV and a low side voltage up to 1.2 kV. (The current Determination covers distribution transformers with a maximum power rating of 2,500 kVA system highest voltage up to 24 kV. It does not mention low-side voltage).

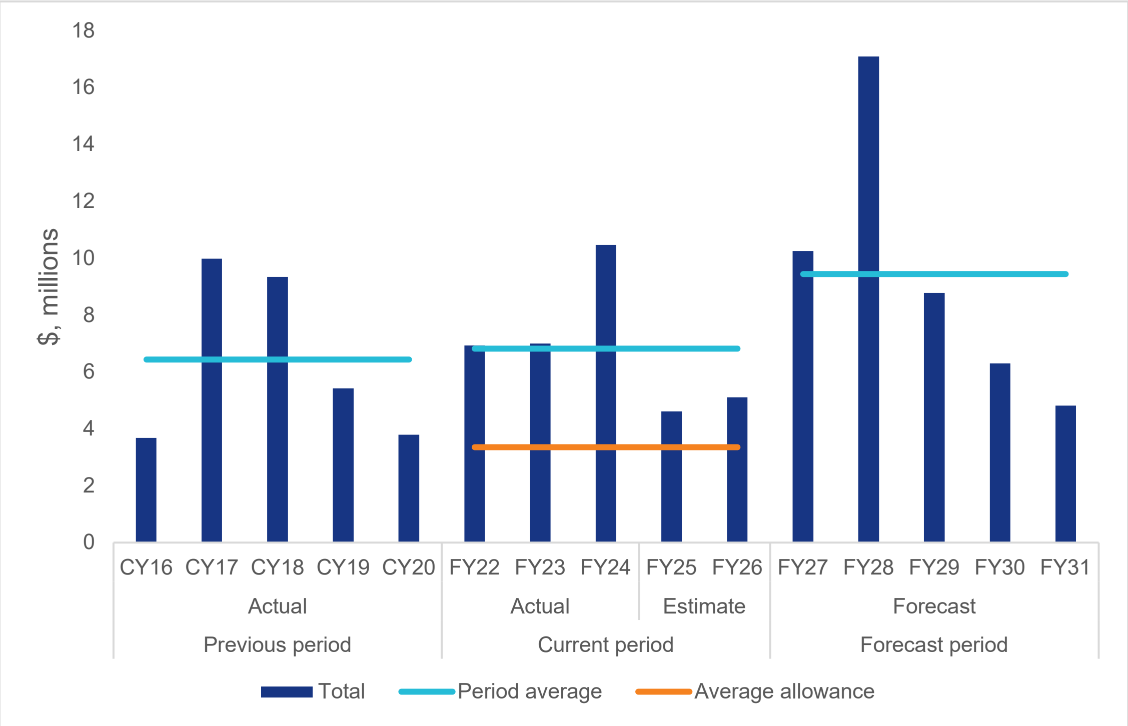
6.5.7.1 Our proposed expenditure

We forecast to spend about $47M for transformer (and associated equipment/assets) replacements in the next regulatory period (Table 6–15). This is 39% higher than our expected spend for the current regulatory period. Figure 6-23

Table 6–15: Transformers replacement expenditure, $2026, millions

Asset	Forecast period					
	FY27	FY28	FY29	FY30	FY31	Total
Distribution transformers	2.0	6.8	6.2	3.5	2.0	20.5
Zone substation transformers	8.3	10.3	2.6	2.8	2.8	26.7
Total	**10.3**	**17.1**	**8.8**	**6.3**	**4.8**	**47.2**

Figure 6-23: Transformers replacement expenditure, $2026, millions

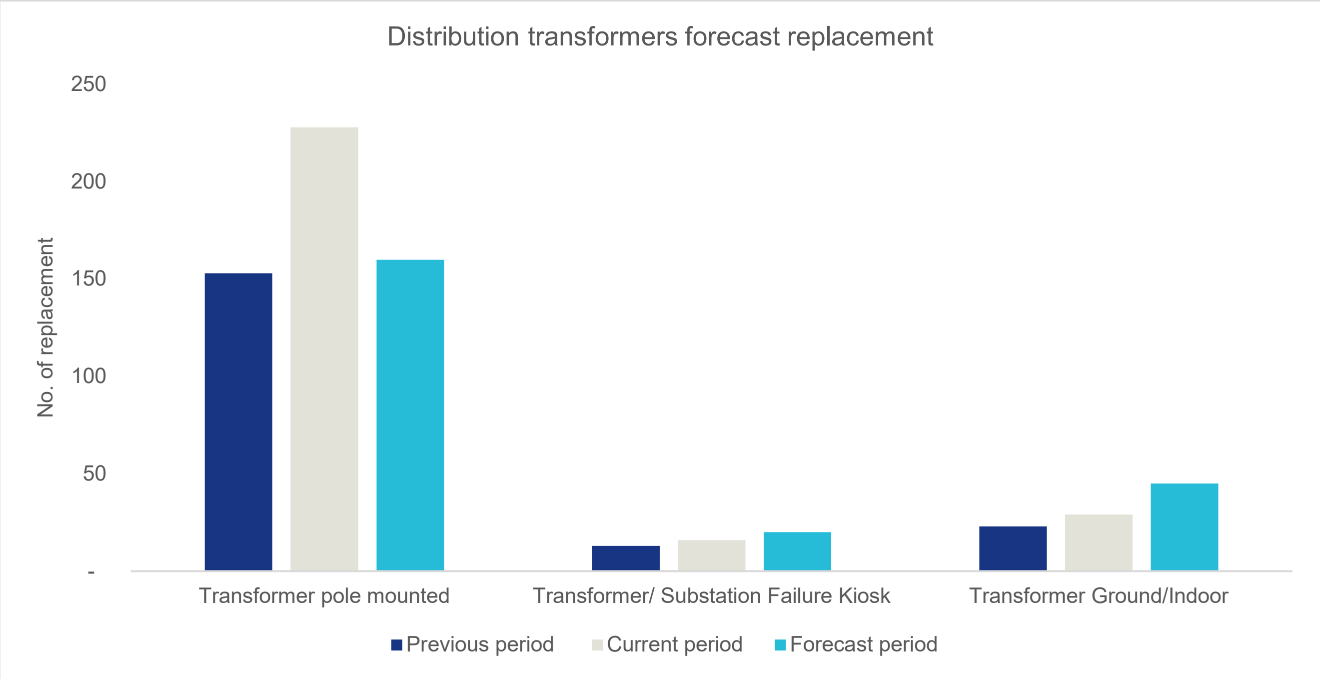


Historically, we have been spending $6M-$7M on average for the replacement of transformers. For the next regulatory period, we forecast to spend an average of around $9M annually. Our forecast expenditure will enable us to:

- replace ageing and at risk of failure transformers at the CN zone substation and transformer bushings at CS and NH zone substations.
- undertake our 66kV bushing replacement program. This targeted transformer bushings replacement program involves testing 66kV transformer bushings and assessing their condition prior to conducting any bushing replacement. The test, analyse and replace (if required) approach ensures that the risks are not only treated effectively but also efficiently. We forecast that, at most, 36 sets of 66kV transformer bushings will potentially be replaced.

- relocate distribution transformers and related assets that are in high flood risk zones. This is part of the project Relocation of assets that are in high-flood risk zones (Maribyrnong project). The project will mitigate the risk of flood damage to assets, ensuring continuous operation and reducing the potential for service interruptions during flood events.
- continue with our routine distribution transformer replacements. We forecast to replace a total of 225 (or an average of 45) distribution transformers and the refurbishment of kiosks (Figure 6-24) over the next regulatory period. Our forecast volume of replacement is lower than our estimated replacement for the current regulatory period (total of 273 and average of 55) and higher than the previous regulatory period (total of 189 and average of 38). But it is generally consistent with the historical average annual replacement of 46 per year over the previous and current regulatory periods.[175]

Figure 6-24: Distribution transformers historical and forecast replacement



The JEN's repex model has predicted a decrease in replacement expenditure for transformers,[176] which is in contrast with our forecast increase in spending. The difference in results is due to the inclusion of the above-mentioned non-routine, high value projects which we need to implement during the next regulatory period to ensure that we maintain the reliability of our network. Nonetheless, overall, our forecast total replacement expenditure remains within the threshold predicted by the repex model for the next regulatory period.

Overall, we consider that our proposal addresses our customers' expectations about affordability and maintaining network reliability. Our forecast expenditure is prudent and efficient. Our forecast number of routine distribution transformer replacements is consistent with the average historical trend. Our forecast is also supported by a conditions-based assessment of our distribution transformers, which ensures that we are only proposing to replace distribution transformers that are at risk of failure in the next regulatory period.

Our redevelopment of the CN, CS and NH and bushings replacement program are supported by robust business cases and asset class strategies. The scope of these projects is based on the option that will provide the highest net benefits to our customers over the longer term compared with the other credible options considered. The assets are old and failing. We are meant to implement some components of CS and CN in the current regulatory period but have to defer to accommodate more urgent projects. We cannot afford to delay their implementation further.

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

176 JEN - Houston Kemp Att 05-06 AER repex modelling, p. 8.

We also consider that our modular approach to zone substation redevelopment is a prudent and efficient approach and beneficial to both JEN and our customers as explained below.

The modular approach to redevelopment

In line with JEN initiatives to provide a safe working, cost efficient and effective management of network assets, our preferred option of zone substation redevelopment proposes to adopt a modular concept approach for all equipment installed on site. JEN intends to adopt modular equipment for all new asset installations at greenfield and brownfield sites when a significant amount of works is required, or space allows for modular equipment to be installed. We first adopted the modular approach to the Footscray West zone substation redevelopment which is targeted for completion during the current regulatory period.

The principle of the modular concept utilises a building block approach and enables a complex system to be broken up into smaller independent units called modules. In the case of zone substation asset, these key modules take the form of transformer, switchgear, buildings and secondary systems. Modular equipment is standardised and repeatable and incorporates opportunities for improvement during the specification and design phase reducing construction, commissioning and lowering operating costs. The approach therefore promotes efficiencies and lower costs for our customers. It is also a practical and safe approach because the existing zone substation will be able to continue to operate while the new substation is being built off site.

Furthermore, modular equipment is widely available from manufacturers and provides additional benefits in asset flexibility/configurations, reliability, scalability and safety which are essential in meeting our regulatory obligations and customers needs.

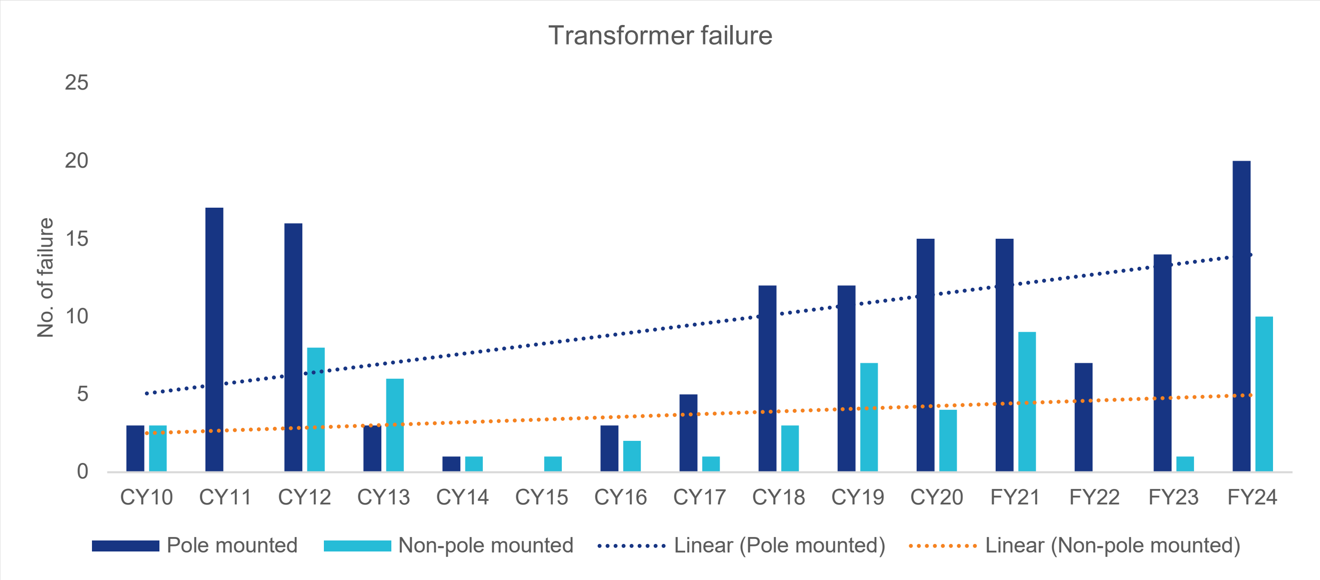
6.5.7.2 Our approach to transformer replacement

Distribution transformers

Our approach for replacement of distribution transformers continued to be based on (reactive) replacement, that is, after an in-service failure. We maintain a minimum stock level of transformers to ensure that any failed transformer can be replaced promptly to minimise customer outage duration. Alternative approaches such as undertaking age or condition-based replacement (rather than running these assets to failure) would likely result in the replacement of assets with some remaining useful life not utilised. Such an approach would provide a lower net benefits to customers over the long-term compared to our reactive replacement approach.

Our assessment shows that the in-service annual failure for distribution transformers have been fluctuating but on an increasing trend particularly for pole mounted distribution transformers and ground outdoor/indoor transformers (Figure 6-25). This is likely to continue over the next regulatory period.

Figure 6-25: Distribution transformer in-service failure



In addition, our CBRM modelling forecast a failure rate of between 19 and 25 over the next regulatory period for our pole mounted transformers ranging from minor to major failures (Figure 6-26).[177] In order to maintain the assessed risk at the current levels (year 0 being 2024) and the health index profile associated with the operation of these assets, we propose to replace about 20 pole mounted distribution transformers per year over the next regulatory period.

Our CBRM modelling forecast a failure rate of about 22 per year for non-pole type transformers (ranging from minor to major failures) over the next regulatory period. In order to maintain the assessed risk at the current levels (year 0 being 2024) and the health index profile associated with the operation of these assets we propose to replace about 9 transformers per year over the next regulatory period.

Our forecast expenditure for distribution transformers is prudent and efficient. The proposed replacements of failed pole-mounted, ground-mounted and indoor transformers are based on an expectation of consistent asset failure rates in the future—resulting in a total of 225 (or an average of 45 per year) to be replaced during the next regulatory period. As mentioned above, overall, this will be generally consistent with our historical annual average replacement of 46 per year.

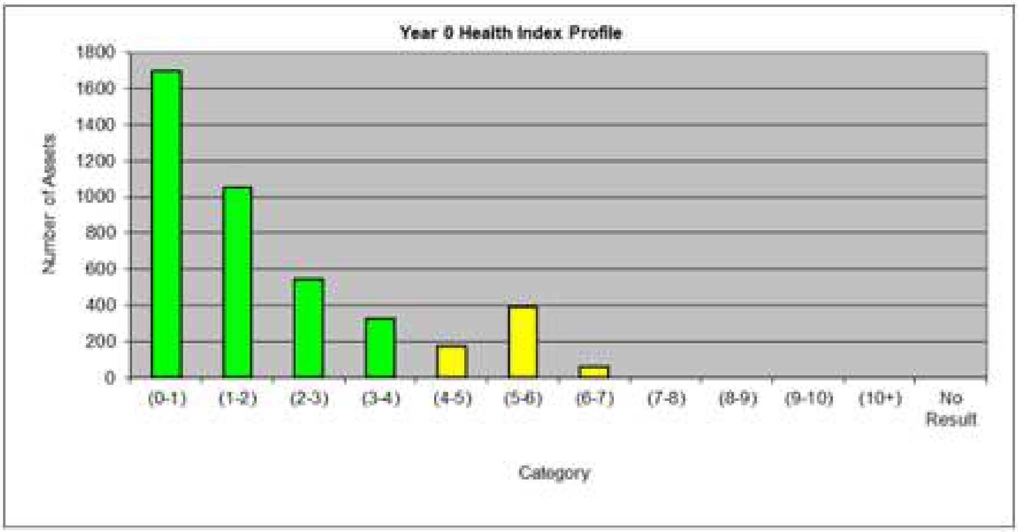
The project that drives the higher forecast spend for distribution transformers is the transformer component of the Maribyrnong project. During the development of the Draft Plan, we have considered the Maribyrnong project to be one of our Network Resilience projects and have consulted our customers on that basis. Our customers have supported the implementation of this project during the next regulatory period. We explain in section 7 our customers' support for this project, including our reasons for treating it as a network replacement project instead of network resilience.

Notes: The expenditure associated with the Maribyrnong project's underground cable component is captured under our forecast spend for underground cables in section 6.5.5.

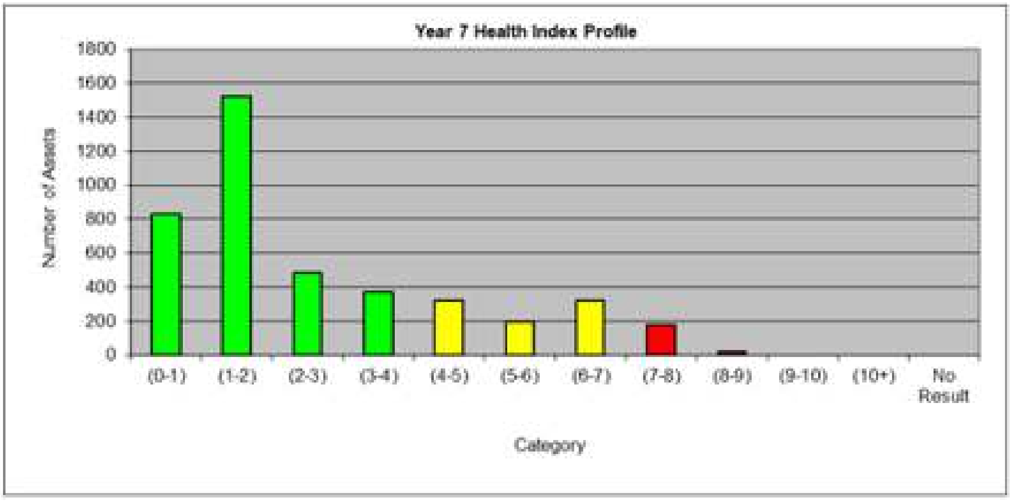
[177] Failures can range from a minor failure (maintenance work required) to a major failure that includes replacement of the unit (20 failures requiring replacement).

Figure 6-26: Pole mounted transformer, Health index profile

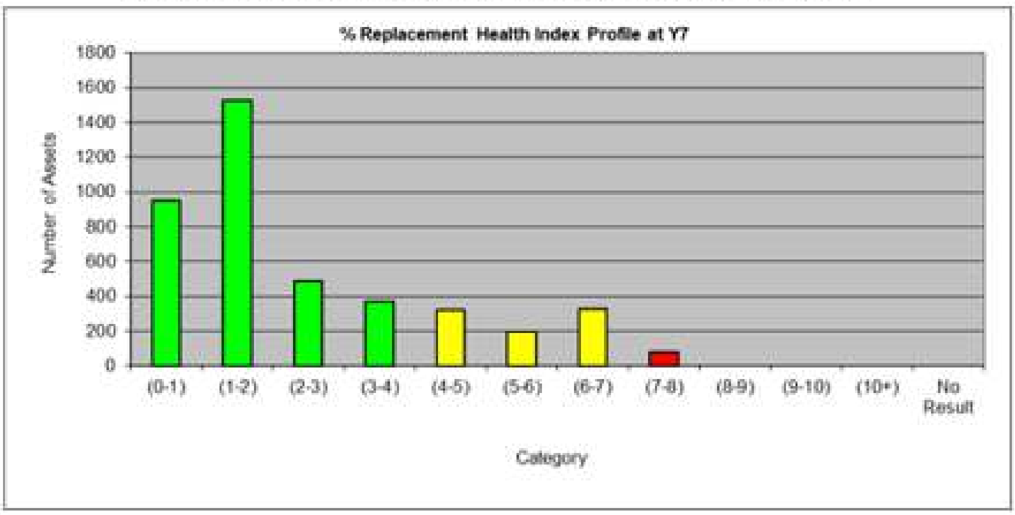
Year 0 (2024) Health Index Profile



Year 7 (2031) Health Index Profile



Year 7 (2024) Health Index Profile - assuming 0.4% replacement rate



Source: Strategy, Electricity Distribution Class, December 2024, pp. 121-122

Zone substation transformers

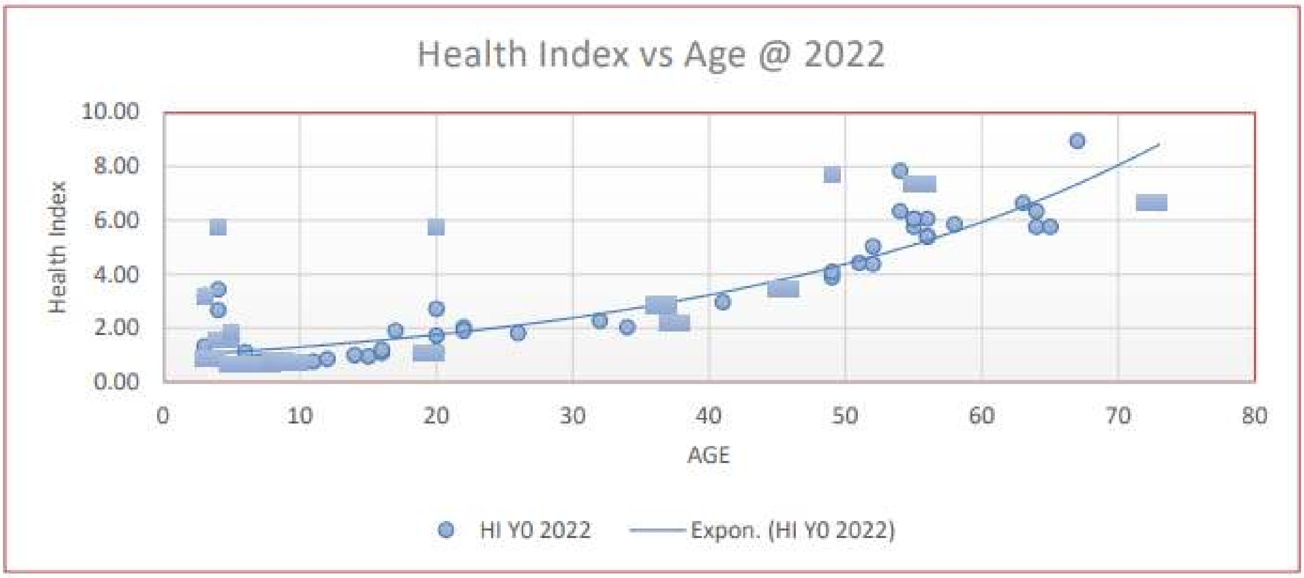
We employ a condition-based **non-routine** replacement planning approach for our zone substation transformers. This approach is a prudent asset management approach given these assets' high criticality, relatively small population and a relatively high level of detailed condition information available about individual transformers. Our replacement expenditure forecast includes expenditure to continue our approach of replacing zone substation transformers and related equipment to mitigate against the significant consequences of in-service failures. We propose to continue targeting the replacement of units based on detailed condition assessments, safety and environmental risks and the level of customer supply risk if a failure were to occur—this includes considering network capacity constraints (or lack thereof) in our replacement planning.

During the next regulatory period, we need to redevelop the CN, CS and NH zone substations. The redevelopment, to be implemented using the modular approach, will involve replacing the primary and secondary assets within those zone substations. This section only includes the expenditure related to transformer (and associated equipment) for these three zone substations.

Coburg North zone substation redevelopment

The No.1 and 2 transformers are approaching the end of life and have reached a service life of 57 years and will be over 60 years old when replaced. The No.1 and 2 transformers have a very high moisture and acid levels, and the latter is leaking oil badly, which increases the likelihood of catastrophic failure with transformers in operation at the end of its lifecycle. Our CBRM shows that transformer No.1 and No.2 at the Coburg North zone substation have a health index above 7, indicating an elevated probability of failure in the next regulatory period. It is expected that transformers in the poorest condition will also be among the oldest units. As Figure 6-27 shows, there is a reasonable correlation between transformer age and high health index.

Figure 6-27: Correlation between transformer age and health index



Our forecast expenditure will allow us to replace transformers No.1 and No.2 in the CN zone substation. The No.3 transformer will also be replaced and later relocated and installed as the No.3 transformer at CS zone substation as part of our proposed partial rebuild of CS zone substation.

Transformer bushings in the Coburg North zone substation will also be replaced as part of the redevelopment. All transformer HV bushings have been identified for replacement due to historic failure and catastrophic consequences, such as fires destroying the total transformer. Replacing the bushings will also warrant HV current transformer (CT) replacement, affecting the turrets and transformers and requiring extensive testing before returning to service.

CS and NH zone substations partial redevelopment

Transformer HV bushings in the CS and NH zone substations have been identified for replacement due to historic failure and catastrophic consequences, such as fires destroying the total transformer. Replacing the bushings will also warrant HV current transformer replacement, affecting the turrets and transformers and requiring extensive testing before returning to service.

The No.1 and 2 transformer HV bushings are a synthetic resin bonded paper (SRBP) oil to air condenser bushing and 54 years old. In 2021, arcing damage was detected on the capacitor taps and the associated secondary wiring on all three phases of the No.2 Transformer 66kV bushings. Replacement of the indoor zone substation transformer bushings will require careful planning with extensive testing required to return the transformer to service.

> We set out in the business cases our detailed assessment of the condition and associated risks with transformers and transformer bushings at the CN, CS and NH zone substations. We have also developed and submitted as part of the regulatory proposal a business case supporting our bushings replacement program.
>
> The business cases discussed in detail the identified need for the projects, the credible options we have considered, the cost-benefit analysis undertaken and the most prudent and efficient solution for our network and customers over the long term.
>
> **Note**: Only $1M of the Maribyrnong project's costs is included in the transformer forecast expenditure. The other costs are captured under underground cables replacement expenditure.

6.5.7.3 References

The proposed capital expenditure outlined in this section is supported by a body of materials, forecasts and models. The key documents are outlined in Table 6–16.

Table 6–16: List of transformer expenditure attachments

Attachment	Name	Author
RIN Support	Electricity Distribution Asset Class Strategy	JEN
RIN Support	Primary Plant Asset Class Strategy	JEN
Att 05-06	AER repex modelling	Houston Kemp
RIN Support	Coburg North ZSS Redevelopment – Business Case	JEN
RIN Support	Coburg South ZSS Redevelopment – Business Case	JEN
RIN Support	North Heidelberg ZSS Redevelopment – Business Case	JEN
RIN Support	66kV Bushing Replacement Program – Business Case	JEN

6.5.8 Switchgear

Switches are used to control the flow of electricity on the network. In the event of a network fault, switches are used to isolate the location of the fault and minimise the number of customers who need to remain off supply, allowing the safe restoration of supply to others. Switchgear can be considered in two groups:

- zone substation switchgear—circuit breakers located within zone substations, at both the high voltage and sub-transmission levels
- distribution switchgear, located on lines throughout the network—includes automatic circuit reclosers, air break and gas-insulated load break switches, remote-controlled gas switches, isolators and LV outdoor switches.

Zone substation switchgear can fail due to high resistance connections, mechanical degradation, moisture ingress (for outdoor installation) or manufacturing faults. A typical zone substation has three 66 kV circuit breakers and between 8 and 12 distribution feeders, supplying up to 30,000 customers. The mechanical breakdown of a zone substation circuit breaker—and its resultant failure to operate—can, therefore, have significant customer supply consequences and pose serious safety public risks.

Condition based replacement is our preferred asset replacement strategy as it ensures assets are replaced at a time in their life cycle that ensure maximum utilisation. The replacement activity is driven by the asset inspection programs and JEN's policies as they relate to the maintenance of obsolete and air break type switches and disconnectors.

Distribution switchgear can fail due to factors including high resistance connections or components, insulation breakdown, degradation of mechanical components or auxiliary component failure (like communication or control systems for remote-controlled devices). The main consequence of distribution switchgear failure is a loss of supply. Distribution switchgear has a low criticality score due to the minor consequence of failure.

We propose to continue replacing zone substation switchgear once all cost-effective maintenance and life extension options have been exhausted and condition monitoring indicates a deteriorated condition and likely in-service failure, prioritising those with the highest risk.

We forecast to spend around $74M to undertake our switchgear (associated equipment/assets) replacement over the next regulatory period driven by non-routine, high value projects.

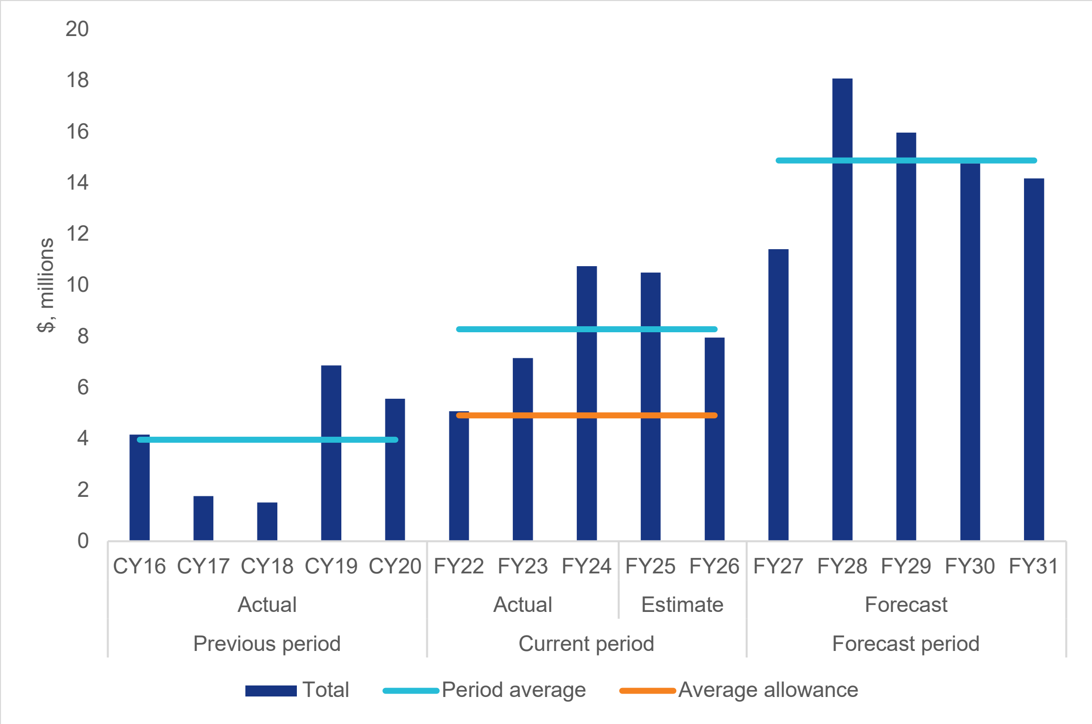
6.5.8.1 Our proposed expenditure

We forecast to spend around $74M for switchgear (and associated equipment/assets) replacements in the next regulatory period (Table 6–17). This is 80% higher than our expected spend for the current regulatory period. Figure 6-28 outlines our replacement expenditure from the previous regulatory period to the next regulatory period.

Table 6–17: Switchgear replacement expenditure, $2026, millions

Asset	Forecast period					
	FY27	FY28	FY29	FY30	FY31	Total
Distribution switchgear	3.7	4.1	4.9	5.9	5.9	24.6
Zone substation switchgear – non routine	7.7	14.0	11.0	8.9	8.3	49.8
Total	**11.4**	**18.1**	**16.0**	**14.8**	**14.12**	**74.4**

Figure 6-28: Switchgear replacement expenditure, $2026, millions



Our higher forecast spend is heavily influenced by our proposed redevelopment of CN, CS and NH zone substations. Their switchgear cost components alone account for around 55% of our proposed expenditure for switchgear replacement. The primary and secondary equipment at these zone substations are at risk of failure due to their age and poor condition, resulting in increasing safety and security of supply concerns while the equipment is in service. Together, these three projects will address serious safety risks and mitigate supply risks to over 60,000 customers by replacing old and deteriorated equipment with a history of failures and which is non-compliant with current standards, maintenance-intensive or no longer supported by the manufacturer.

Our forecast expenditure will also allow us to continue our ongoing condition-based replacement program for routine switchgear replacements over the next regulatory period. We need to ensure that the level of in-service failures are at least maintain to the current safe levels.

The JEN's repex model has predicted a significant increase in replacement expenditure for switchgear.[178] Our forecast increase in total spend is comparatively higher than what the repex model predicted due to our non-routine, high value switchgear projects. Nonetheless, overall, our forecast total replacement expenditure remains within the threshold predicted by the repex model for the next regulatory period.

Overall, we consider that our proposal addresses our customers' expectations about affordability and maintaining network reliability. Our forecast expenditure is prudent and efficient. Our forecast is prudent and efficient. Our forecast expenditure for routine replacements are supported by robust conditions-based assessments, which ensures that we are only proposing to replace distribution switchgears that are at risk of failure in the next regulatory period. Moreover, the key projects underpinning our non-routine replacement expenditure are based on the option that provides the highest net benefits to our customers over the longer term.

As discussed in section 6.5.7.1, we also consider that our modular approach to zone substation redevelopment is a prudent and efficient approach and beneficial to both JEN and our customers.

[178] JEN - Houston Kemp Att 05-06 AER repex modelling, p. 7.

6.5.8.1 Our approach to replacing switchgear

Distribution switchgear

As the consequences of a failure of distribution switchgear are relatively low, we will continue to employ a predominately 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.

Our proposed expenditure is based on the following outcomes of our condition-based assessment of assets:

- **Air break switches.** To maintain the risk profile for air-break switches at approximately current levels (year 2024) of 3.28 failures per year, the CBRM forecasts a need to replace about 25 air break switches per year over the next regulatory period. We propose to replace 25 air break switches per year with gas switches given air-break switches are already obsolete.

- **HV isolators.** To maintain the risk profile for HV isolators at approximately current levels (year 2024) of 15 failures per year, the CBRM forecasts a need to replace about 68 HV isolators per year over the next regulatory period, otherwise, the annual failure is predicted to increase to 25 per year. We propose to replace 68 HV isolators per year over the next regulatory period.

- **Iljin gas switches**. In October 2022, an incident occurred in which a gas gauge fell from a pole mounted Iljin 24kV SF6 gas load break switch on the United Energy Network during operation. The incident was caused by corrosion of the aluminium gas gauge. Following this incident, we inspected and assessed our 238 Iljin switches. It has been identified that more than 54% of the JEN Iljin switches have an aluminium gas gauge showing signs of deterioration. In addition, some of the ILJIN switches low gas interlocking mechanism have been found seized, and not functioning as required due to the build-up of corrosion, dirt and grime during performance testing. As a result of these defects and the associated safety hazards, a replacement program has been initiated, prioritising the repair or replacement of 192 Iljin gas switches in the next regulatory period.

- **LV overhead switchgear**. Replacement is based on condition and reactive replacement as a result of in-service failure. Approximately 1% of the population or 150 units are replaced annually. We propose to continue our ongoing approach to replacement to maintain the in-service failure at the current level.

We also propose to replace a small number of deteriorated automatic circuit reclosers (**ACR**), a type of device first installed in the 1990s. This program will aim to address declining insulating gas pressure in this equipment (identified through our inspection and remote asset monitoring programs), with replacement once pressure falls below a certain level being the most effective means of addressing this issue.

Section 4.7 of our distribution plant asset class strategy discusses the issues associated with distribution switchgear, including their life expectancy and age profile, our requirement that they should meet Australian Standards, the results of our CBRM analysis, risk profile and our life cycle management of these assets.

Zone substation switchgear

We propose to continue replacing zone substation switchgear once all cost-effective maintenance and life extension options have been exhausted and condition monitoring indicates a deteriorated condition and likely in-service failure, prioritising those with the highest risk.

For the forecast period, we propose to undertake major switchgear replacement programs at the CN, CS and NH zone substations as part of said zone substations redevelopment. The risks identified at both CN and CS zone substations are generally the same, with both designed initially to similar standards and constructed at a similar time. Risks and issues identified at each zone substation, and our proposed works to address these needs are set out in Table 6–18.

Together, the three zone substation redevelopment projects will address serious safety risks and mitigate supply risks to over 60,000 customers by replacing old and deteriorated equipment with a history of failures and which is non-compliant with current standards, maintenance-intensive or no longer supported by the manufacturer. The individual business cases contain more detailed information about these projects and the needs they are addressing.

Table 6–18: CN, CS, and NH switchgear replacement

Site	Issues identified	Proposed works
CN	• One 57-year-old 66 kV circuit breaker with a history of mechanical and catastrophic bushing failures. This type of circuit breaker (LG4C) is no longer supported by a manufacturer and spare components are no longer available. • One 34-year-old oil-filled 66 kV circuit breaker is maintenance intensive; it has a nitrogen gas leak and is no longer supported by the manufacturer. • The outdoor 22kV oil filled circuit breakers (type 345GC) are 57 years old and their condition has degraded. This family of breakers have a history of mechanical failure and catastrophic bushing failures. The switchgear is no longer supported by the manufacturer and mechanism/bushing spare parts are depleting. The 345GC switchgear has a history of oil leaks from the circuit breaker and internal isolator compartments and this requires increasing operating expenditure to manage. • The 3AF 22kV circuit breakers were originally designed for indoor (metal clad) operation. However, the 3AF units at Coburg North zone substation were installed within individual outdoor cubicles. The manufacturer no longer supports them, and mechanism spare parts, including vacuum interrupter spares, are depleting. The 3AF switchgear does not comply with current switchgear standards for electrical internal arc fault containment, which presents a health and safety risk to JEN personnel. • All three outdoor 22 kV circuit breakers are non-compliant with current standards for electrical arc fault containment. • 22 kV transfer bus has known defects, including pin and cap insulators prone to failure.	Replace existing 22 kV and 66 kV outdoor circuit breakers with modern equivalent indoor switchgear, installed to current standards, and the replacement of the outdoor 22 kV transfer buses. Works to be undertaken in 2026 to 2028. **Note: the full cost of redeveloping the CN is included in our forecast expenditure for transformer.**
CS	• One 58-year-old 66 kV circuit breaker with a family history of mechanical and catastrophic bushing failures. Spare parts are not available and the manufacturer no longer supports the model. Circuit breaker controls operate at a different voltage to JEN standard. • Two indoor 22kV metal clad buses and associated circuit breakers manufactured by Sprecher and Schuh, type HPTw306-FS, are around 50 years old and their condition has degraded where reliability, employee safety, and security of customer supply is affected. The switchgear is non-compliant with current standards and partial discharge is occurring on the 22kV buses. The switchgear is no longer supported by the manufacturer with no spare parts available. • Partial discharge has been detected on the 22 kV switchboard during routine testing, with intrusive inspection indicating irreversible insulation degradation that risks catastrophic failure. • Oil leaks detected on circuit breakers which indicate risk of circuit breaker failure. • Switchgear is non-compliant with current standards for electrical arc fault containment.	Replace two existing 66kV circuit breakers 22 kV buses and switchgear, and replace one with modern equivalent equipment, installed to current standards. Works to be undertaken in 2028 to 2029.

Site	Issues identified	Proposed works
NH	• The current 1-2 66kV bus tie Circuit Breaker (CB) are a type with a history of mechanical failure and catastrophic bushing failures. This CB type (LG4C) is also no longer supported by the manufacturer with spares unavailable. • The three indoor 22kV metal clad buses and associated circuit breakers manufactured by Sprecher and Schuh type HPTw306-FS (1976) are around 50 years old and their condition has degraded where reliability, employee safety and security of customer supply is affected. The switchgear is non-compliant with current arc fault containment standards and partial discharge is occurring on the 22kV buses. The switchgear is no longer supported by the manufacturer with no spare parts available.	Replace two existing 66kV circuit breakers and three modular 22kV switchboards with modern equivalent indoor switchgear, installed to current standards. Works to be undertaken in 2030 to 2031.

6.5.8.2 References

The proposed capital expenditure outlined in this section is supported by a body of materials, forecasts and models. The key documents are outlined in Table 6–19.

Table 6–19: List of switchgear forecast expenditure attachments

Attachment	Name	Author
RIN Support	Electricity Distribution Asset Class Strategy	JEN
RIN Support	Primary Plant Asset Class Strategy	JEN
RIN Support	Secondary Plant Asset Class Strategy	JEN
Att 05-06	AER repex modelling	Houston Kemp
RIN Support	Coburg North ZSS Redevelopment – Business Case	JEN
RIN Support	Coburg South ZSS Redevelopment – Business Case	JEN
RIN Support	North Heidelberg ZSS Redevelopment – Business Case	JEN

6.5.9 SCADA, network control and protection systems

This replacement expenditure category[179] can be further disaggregated into the following sub-categories, each of which is discussed in the sections below:

- protection systems
- communications infrastructure
- other.

Our forecast replacement expenditure is $45M driven by non-routine, high value replacement projects.

[179] Consistent with the category definitions in the Reset RIN, all SCADA, network control & protection system equipment is located on the network side of gateway devices (routers, bridges etc.) at corporate office sites.

6.5.10 Our proposed expenditure

We forecast to spend around $45M for this asset category in the next regulatory period (Table 6–20) which is materially higher than our expected spend for the current regulatory period. Figure 6-29 outlines the longer trends in our SCADA, network control and protection systems expenditure.

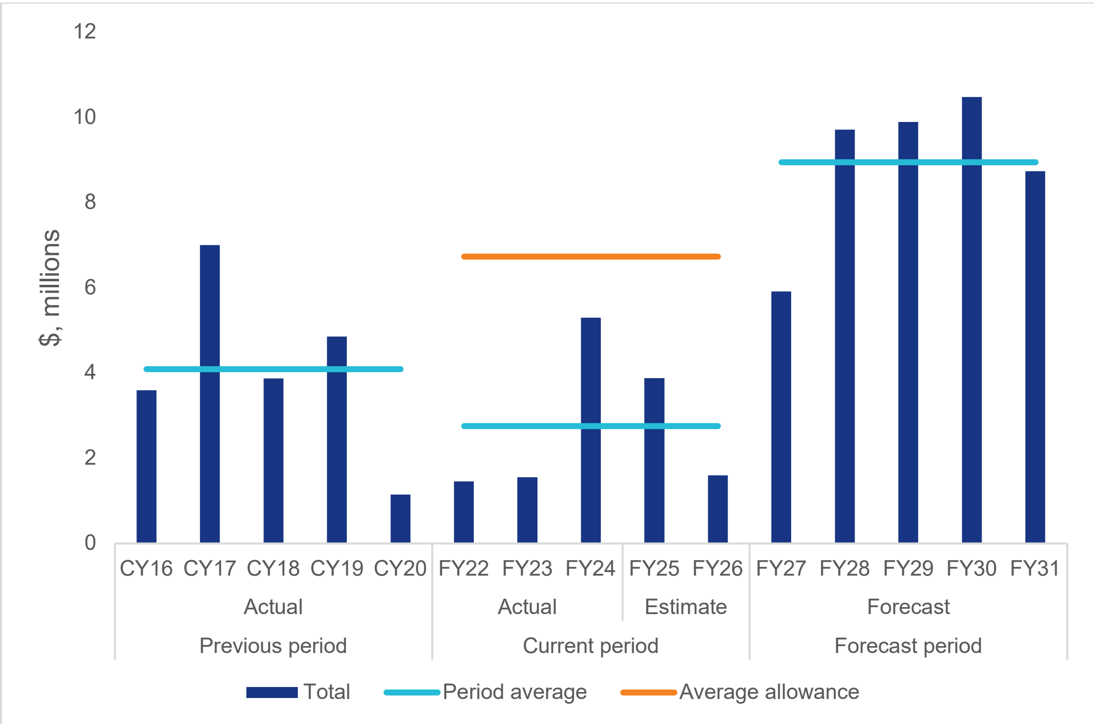
About 76% cent of our forecast expenditure will be for protections systems associated with our the CN, CS and NH zone substation redevelopment.

We discussed in the following sections our forecast expenditure for each sub-class category.

Table 6–20: SCADA, network control and protection systems replacement expenditure, $ 2026, millions

Asset	Forecast period					
	FY27	FY28	FY29	FY30	FY31	Total
Protection systems	5.9	9.3	8.4	7.2	3.1	34.0
Communications infrastructure	0.0	0.4	0.9	1.7	3.2	6.2
Other	0.0	0.0	0.6	1.5	2.4	4.5
SCADA, network control and protection systems	**5.9**	**9.7**	**9.9**	**10.5**	**8.7**	**44.7**

Figure 6-29: SCADA, network control & protection systems replacement expenditure, $2026, millions



6.5.10.1 Protection systems

This sub-category covers zone substation protection and control systems, including relays and power supplies. Our condition-based replacement of protection and control schemes represents the most significant portion of expenditure within the SCADA, network control and protection systems replacement category. The protection and control schemes within our zone substations are considered critical systems within our network. A correctly functioning scheme ensures the safe and reliable operation of our sub-transmission system and our HV network.

The purpose of these assets is to rapidly detect faults in the network and send signals to switchgear to isolate those faults. This action minimises the impact of a fault on customer supply and ensures dangerous fault currents do not result in safety hazards or damage to equipment. The failure of a relay to operate when required to do so, therefore, represents a significant safety risk to our staff and members of the public.

For the next regulatory period, we proposed to replace the protection systems related to the replacement of relays and other protection equipment as part of the CS, CN and NH zone substation redevelopments. Most protection relays are legacy electromechanical and do not have real-time monitoring. These relays are used to protect major primary plants. The electro-mechanical relays at CS, CN and NH zone substations are 50 years old, with a design life of 40 years. Without monitoring, failure of these relays can remain undetected, exposing the network to reliability and safety risks. Additionally, Analogue Electronic and Digital relays at the three zone substations are also operating at end-of-life increasing the risk of asset failure.

Each of the three projects is designed to reduce the risk of poor operation and performance of deteriorated relays and protect against degradation in network safety and performance. Additionally, these projects will address the physical space limitations and health and safety risks associated with some of the control buildings which house this equipment.

Timing for three of these projects is planned to achieve delivery efficiencies by replacing relays in conjunction with the replacement of other equipment within the zone substation. As noted above, the CN, CS and NH relays will be replaced concurrently with the replacement of other primary and secondary equipment at those zone substations (see sections 6.5.7 and 6.5.8). There are several equipment performance and degradation issues at each of these stations, and our forecast expenditure reflects the most prudent and efficient option of rebuilding all equipment within the same delivery project.

> We set out in the business cases our detailed assessment of the condition and associated risks with protection systems at the CN, CS and NH zone substations.
>
> The business cases also discuss in detail the identified need for the redevelopment of these zone substations, the credible options we have considered, the cost-benefit analysis undertaken and the most prudent and efficient solution for our network and customers over the long term.

6.5.10.2 Communications infrastructure

This sub-category includes equipment deployed throughout our network which provides connectivity between network devices and zone substations, our SCADA system and our control room. The visibility, monitoring, operation and control of our network—and therefore the reliability of supply to customers—is dependent upon these assets performing as required.

Specific assets within this category include communications network devices, remote terminal units, multiplexer systems, iNet radio and communications equipment and cables. Consistent with the definitions contained in the Reset RIN, SCADA and network control assets located on the corporate office side of gateway devices are classified as non-network IT and communications and are covered in section 8.4.

Our focus for the next regulatory period is to continue replacing end-of-life network communications equipment to ensure network performance is not negatively impacted, in addition to strengthening security management of field communications devices in response to growing threats of cyber-attacks and physical security breaches—consistent with our heightened focus on the cybersecurity of non-network IT and communication assets outlined in section 0.

6.5.10.3 Other SCADA, network control & protection system assets

For the next regulatory period, we propose to replace zone substation battery banks and chargers which have reached the end of its technical life or is otherwise exhibiting performance issues which would prevent them from accurately monitoring network performance and faults. We also propose a small amount of expenditure for the procurement of strategic spares for our secondary plant equipment. Our Secondary plant asset class strategy provides more information about the risks associated with our zone substation battery banks and chargers, and the need for spares.

6.5.10.4 References

The proposed capital expenditure outlined in this section is supported by a body of materials and forecasts. The key documents are outlined in Table 6–21Table 6–19.

Table 6–21: List of SCADA, network control & protection system assets forecast expenditure attachments

Attachment	Name	Author
RIN Support	Secondary Plant Asset Class Strategy	JEN
RIN Support	Coburg North ZSS Redevelopment – Business Case	JEN
RIN Support	Coburg South ZSS Redevelopment – Business Case	JEN
RIN Support	North Heidelberg ZSS Redevelopment – Business Case	JEN

6.5.11 Other

This category includes all other asset replacement expenditure, and consists of:

- customer-initiated asset relocation works
- emergency recoverable works
- other assets.

We forecast to spend around $74M (gross) or $42M net (after customer contribution terms) for these other assets. We provide more details below.

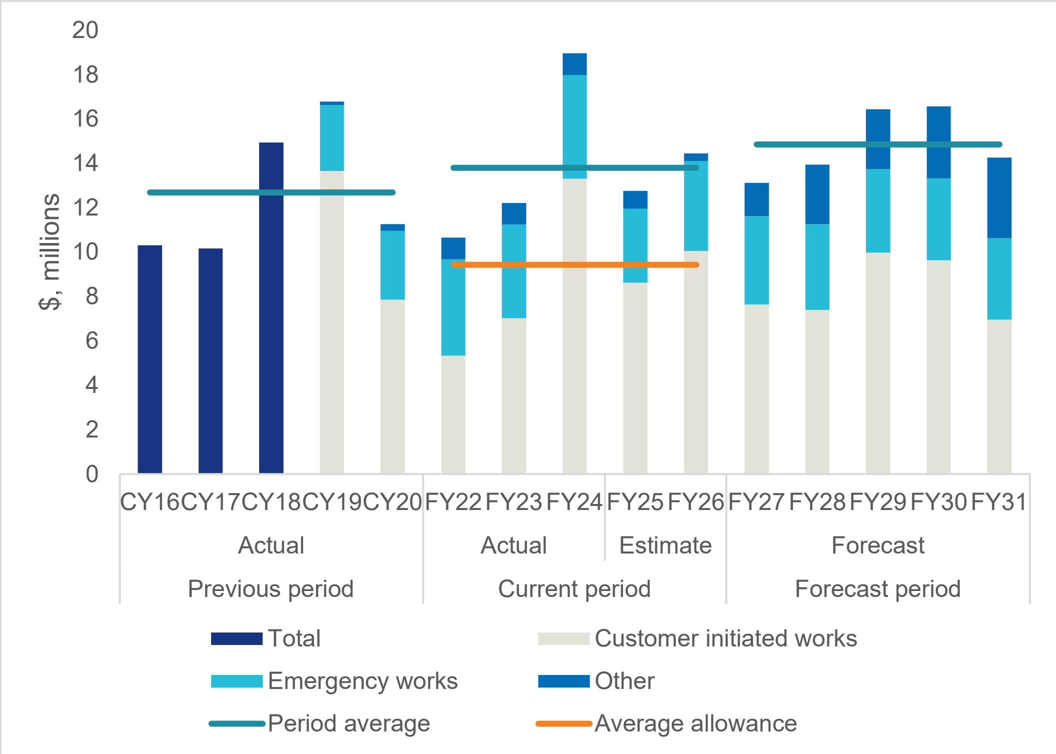
6.5.12 Our proposed expenditure

Each of these three areas is discussed in the sections below. Our forecast capital expenditure for the 'Other' category is set out in Table 6–22 while our expenditure over three regulatory periods is shown in Figure 6–30.

Table 6–22: Forecast replacement expenditure, Other, $2026, millions

Asset	Forecast period					
	FY27	FY28	FY29	FY30	FY31	Total
Customer recoverable works	7.6	7.4	10.0	9.6	7.0	41.6
Emergency recoverable works	4.0	3.9	3.8	3.7	3.7	19.0
Other assets	1.5	2.7	2.7	3.2	3.6	13.8
Gross replacement expenditure	**13.1**	**13.9**	**16.4**	**16.6**	**14.3**	**74.3**
Capital contributions	6.0	5.9	7.5	7.3	5.6	32.4
Net replacement expenditure	**7.1**	**8.1**	**8.9**	**9.3**	**8.7**	**42.0**

Figure 6–30: Replacement expenditure – Other, $2026, millions



6.5.12.1 Customer-initiated asset relocations

This expenditure relates to works we must undertake[180] at the request of customers, councils, government authorities and other third parties to relocate or otherwise rearrange our assets, generally to allow for works to be undertaken on other infrastructure, such as road construction.

We have developed our forecast consistent with the service classification set out in the AER's final Framework & Approach for the next regulatory period[181] and in accordance with the requirements of the Essential Services Commission's Electricity Industry Guideline 14.[182] As such, while significant in gross terms, this capital expenditure is almost entirely funded up-front by the party requesting the works, and therefore has no material impact on our regulatory asset base or the prices paid by other customers.

Similarly to connections expenditure, this expenditure is wholly driven by customer requests, with levels of activity related to the volume of infrastructure construction activity occurring in our network area. To forecast this gross expenditure, we adopt the same top-down approach as we do for general connections expenditure, as described in section 3. This methodology involves taking an average of our annual asset relocation expenditure over the recent years to set the base expenditure and trending this annual expenditure forward to reflect changes in forecast growth (both positive and negative) in infrastructure construction activity in Victoria. We derive forecast growth rates in infrastructure construction activity using the Australian Construction Industry Forum's (ACIF) forecasts of activity in the road engineering and bridge, railway and harbour engineering segments. [redacted]

180 Consistent with the requirements of our Electricity Distribution Licence.

181 AER, *Final framework and approach – AusNet Service, CitiPower, Jemena, Powercor and United Energy 2026-31, July 2024*, p. 26. 'Third party initiated asset relocations/re-arrangements, including under the Victorian Electricity Distribution Code of Practice is listed under common distribution services as a SCS.

182 This includes recognition of any avoided costs for other customers which may result from the requested works.

Throughout the next regulatory period, we expect the levels of demand from customers for asset relocation activities to be lower compared with recent years. This is due to the completion of several transport infrastructure projects under the Victorian Government's Big Build program. The forecast increase in customer initiated works in the financial year 2029 is associated with the relocation of assets directly related with the Melbourne Airport Rail Link construction.

Trends in our asset relocation expenditure are shown in Figure 6–30.

Figure 6–31: Value of infrastructure construction activity in Victoria (as at May 2024)

[redacted]

6.5.12.2 Emergency recoverable works

This category of expenditure relates to work to make the network safe and maintain supply to customers by repairing damage to our distribution network following an act or omission by an identifiable third party and for which that party is liable. This includes damage to poles caused by motor vehicle accidents, damage to underground cables caused by unauthorised excavation works or damage to overhead lines caused by high vehicles. The activities required to rectify such damage can vary widely but often involve the replacement of assets after they have been damaged.

Emergency recoverable works are classified as Standard Control Services. To develop our forecast emergency recoverable works expenditure, we:

- took an average of our actual direct costs of rectifying damage over calendar years 2022 and 2023
- reduced these costs by the average amount successfully recovered from liable third parties who caused this damage—resulting in a 'net' amount of emergency recoverable works expenditure under the proposed service classification for the next regulatory period[183]

[183] This adjustment to our 'base' years of expenditure ensures we have accounted for the difference in regulatory cost recovery treatment between the current and new classifications. Under the new classification, amounts which we are unsuccessful from recovering from a liable third party (for example, where the party defaults or is unable to pay) will be included in our regulatory asset base.

- applied a scale escalator—reflecting forecast growth in our network's circuit length—to our emergency recoverable works annual net expenditure, to account for expected annual increases in the value of damage and associated recoveries.

Figure 6–30 shows our longer-term trends in our emergency recoverable works expenditure. We forecast a slightly lower instances of impacts on our assets by third parties.

6.5.13 Other assets

There are some other types of assets that are not covered by any of the AER's preferred replacement expenditure categories. As shown in Table 6–22 above, we forecast an expenditure of $14M for Other assets in the next regulatory period. The key is the non-routine upgrade of [redacted]. We also forecast a small amount of expenditure related to routine bird/animal proofing net assets and surge diverter replacements.

[redacted]

Figure 6–30 shows our replacement expenditure for Other assets over three regulatory periods. We expect to exceed our allowance for the replacement of Other assets during the current regulatory period due to the non-routine, [redacted]

6.5.13.1 References

The proposed capital expenditure outlined in this section is supported by a body of materials and forecasts. The key documents are outlined in Table 6–23.

Table 6–23: List of Other replacement forecast expenditure attachments

Attachment	Name	Author
RIN Support	Electricity Distribution Asset Class Strategy	JEN
RIN Support	Primary Plant Asset Class Strategy	JEN
RIN Support	Secondary Plant Asset Class Strategy	JEN
RIN Support	[redacted] – Business Case	JEN

7. Network resilience

As outlined in Chapter 3 of the 2026-31 Proposal, climate change is impacting the way we provide electricity distribution services. The poles, transformers and wires we use, are coming under increase pressure from extreme weather events resulting in longer and more wide-spread outages. At the same time, the proliferation of electrical devices and broader electrification means customers are increasingly reliant on the electricity network.

This Given the increasing intensity and number of extreme weather events across Victoria and the NEM, as well as the resulting electricity outages, policymakers and regulators have begun investigating and developing adjustments to the regulatory framework to address this emerging challenge. Recent reviews include:

- The Victorian Government's Expert Panel Resilience Review (2021)
- The AER's Guidance Note on Resilience Issues (2022)
- The Victorian Government's Expert Panel Resilience Review (2024)
- The AER's Value of Network Resilience (VNR) (2024)
- Integrating Distribution Network Resilience in the National Electricity Rules (2025)

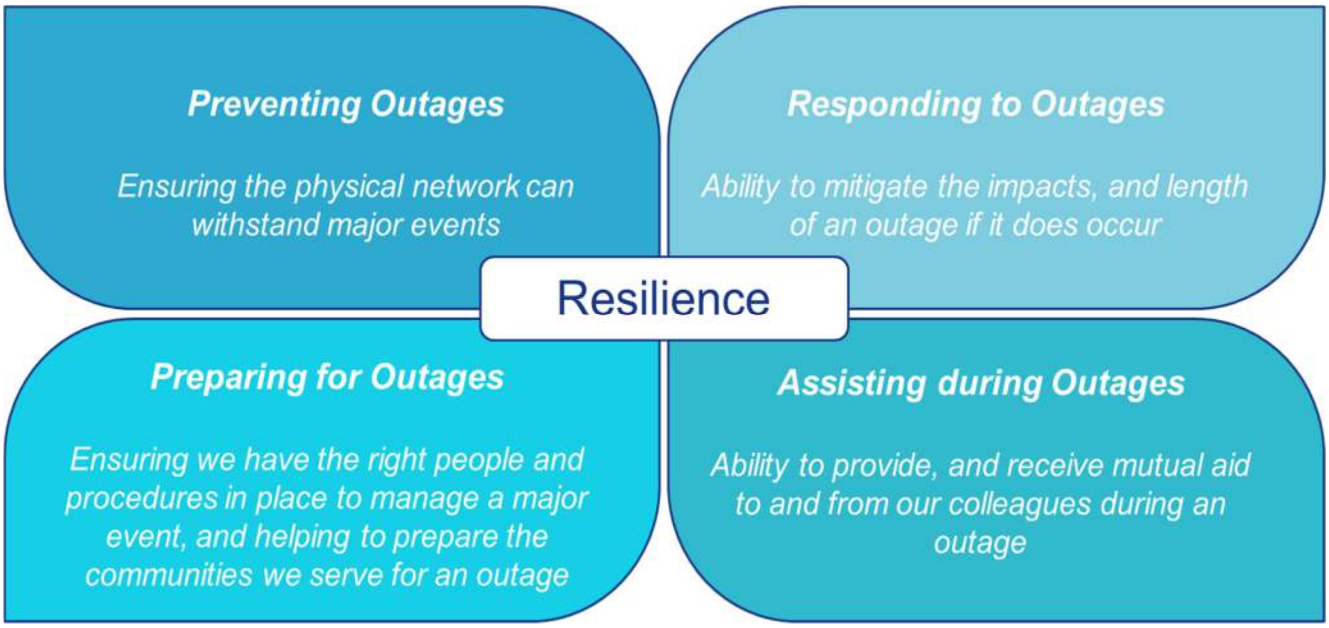
Network resilience is defined as "…the network's ability to continue to adequately provide network services and recover those services when subjected to disruptive events"

— AER, Network Resilience a note on key issues

This interest in network resilience has been reflected in what we heard from our customers through JEN's Price Reset engagement process.[184]

In light of the requirements and recommendations included in the various policy and regulatory reviews listed above and the preferences of our customers, JEN has developed a resilience matrix, which illustrates our view of the four key tenets of network resilience and the role we as a responsible network operator should play in supporting broader community resilience.

Figure 7-1: JEN's core resilience tenets



[184] Further details on JEN's engagement outcomes can be found in '*JEN - Att 02 – 01 – Customer Engagement*, 2025'.

7.1.1 Preventing Outages

Ensuring the physical network can withstand extreme weather events, so customers are less likely to experience a long duration outage.

Updated Melbourne Water flood modelling (released in April 2024) shows that a number of JEN assets are located within a high flood risk area.[185] The risk of a major event occurring which could cause a long - duration outage is significantly higher than previous modelling suggested and JEN believes it would not be prudent asset management to leave them in place as this risk could be avoided/minimised if these assets were relocated.

Given that the driver of this project is the avoidance of long-duration outages caused by an extreme weather event, JEN engaged our customers on this spend as a 'resilience' project. Customers were first consulted on this expenditure in August 2024, following the publication of JEN's Resilience Addendum, during a 'trade-offs' discussion during which customers were presented with four resilience packages, each with different costs and customer outcomes attached.[186] Following the session, 91% of customers supported this level of expenditure (or higher) stating concerns around energy equity and the identified need of this investment;

> *"It is very important to recognise the areas of investment based on the need as of the urgency and critical effect of investment" – People Panel's Member, August 2024*

> *"As risk of extreme weather events increases over coming years investment in all network assets will continue, keeping the risk in mind and investing more heavily into high risk areas or high priority areas. Targeted investment does not have to be an all or nothing Jemena could target the high need area first and give a portion of the investment to general areas, the aim is to secure the network without taking risk of loss of service and on the other hand saving customers extra expense" – People Panel's Member, August 2024*

Following on from this session, JEN further refined the scope and cost estimates associated with this project and presented the resulting bill impacts to our customers during an October 2024 costed options session. This session focused on the 'risk of paying twice'. Again customers expressed strong support for this project;

> *"We chose package 2 because the funding was well focused on targeting an area of concern." – People's Panel Member, October 2024*

However, while we are confident our customers support this expenditure and climate impact modelling suggests the risk of a flood (and associated long-duration outage) will continue to increase into 2050,[187] JEN does not believe the current level risk of a long-duration outage, as evidenced by newly published Melbourne Water flood-risk modelling is tolerable. This is incompatible with the AER's resilience assessment criteria which requires networks to maintain current service levels in the face of increasing climate risk.[188]

Therefore, JEN has chosen to categorise this expenditure as part of our 'modelled repex'. Although we are bringing forward the replacement of some of these assets (in order to relocate the asset outside the flood risk plane) we believe this is prudent and efficient asset management as:

- It would ensure we are maintaining the current level of network reliability.
- Flood damage to these assets would significantly reduce their useful asset life and would necessitate early replacement.
- Replacing these assets as part of our ongoing replacement programme allows us to make use of economies of scale and scope. If we were to wait until a major event caused the assets to fail, the total replacement costs could be higher (due to staff overtime rates, etc.).

> Further details on this expenditure can be found in 'JEN - RIN - Support -Electricity Distribution Asset Class Strategy'.

185 Furth information on Melbourne Water's updated flood risk modelling can be found here: Maribyrnong River Flood Model | Melbourne Water.

186 JEN, Network Resilience, JEN Draft Plan Addendum, August 2024.

187 *JEN - AECOM - Att 03-03 - Joint Victorian Climate Change Study Final Report.*

188 AER, Network Resilience: Note on Key Issues, April 2022.

7.1.2 Preparing for Outages

Ensuring the right people, processes and digital systems are in place to effectively manage a major outage if one were to occur.

The Victorian Government Network Outage Review Expert Panel noted a number of preparatory activities which they believe networks should have undertaken in order to be better placed to support customers during an outage. While the majority of our proposed expenditure under this tenet is operating expenditure, JEN has included $1.9M ($2024) of ICT capital expenditure to maintain and upgrade our outage notification systems. While the majority of this expenditure is required to ensure JEN can continue to meet our EDCoP requirements,[189] approximately 17% will be spent upgrading the system (beyond normal lifecycle maintenance) so JEN can better identify and communicate with life support customers. As this is closely linked to the Victorian Government's Network Outage Review, we have categorised this expenditure as 'resilience'.

> Further details on this expenditure can be found in *RIN – Support – ICT Investment Brief - Outage Preparedness and Response*.

7.1.3 Responding to Outages

Ability to offer practical support to customers during a long duration outage and reduce the impact or duration of the outage.

JEN is proposing $1.3M capital expenditure in the coming regulatory control period to purchase a mobile emergency response vehicle (**MERV**) and two temporary generators, which will be used to power key community assets during a long-duration outage (Table 7–1). While these investments will not prevent customers experiencing an outage, or lessen the duration of an outage, they do provide a 'community hub' within affected communities. This gives affected customers a location in which they can charge their devices, cook simple meals, stay cool/warm and access information about the likely duration of the outage and the support available to them in person. Additionally, as these are non-network resources, they are not subject to the 'risk of paying twice'

Table 7–1: Network resilience forecast expenditure, $2026, millions[190]

Asset	Total capital expenditure. $2026, millions
MERV	$0.6
Procurement of two LV generators	$0.7
Total	$1.3

> Further details on this expenditure can be found in *JEN – RIN – Support –Outage Preparedness and Response.*

7.1.4 Assisting during Outages

Formalising mutual aid agreements between Victorian DNSPs and ensuring we are ready to provide and receive aid, when needed.

No capital expenditure is required for this metric.

189 Essential Services Commission, Electricity Distribution Code of Practice, d 11.8 – 13.3.2.

190 As noted in section 7.1.2, JEN has included $1.9M ($2024) of ICT capital expenditure to maintain and upgrade our outage notification systems. The cost for the procurement of two LV generators is not captured in section 9.3.3 hence there is no double-counting.

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

- We forecast a total capital expenditure of $154M for Information, Communications and Technology (ICT) in the next regulatory period. This is 32% higher than our expected capital expenditure for the current regulatory period.[191]
- The main drivers for our forecast capital expenditure are a number of non-recurrent capital projects which we need to implement to support or enable our CER integration strategy (new capability), comply with mandatory market reforms and maintain existing business requirements.
- Our forecast ICT capital expenditure is consistent with our customers' expectations that we should digitise and automate the network to make it smarter and more efficient. However, affordability is also a top concern for our customers. Among others, our proposed capital expenditure addresses these priorities by:
  - proposing only efficient and prudent ICT capital projects. Our proposed non-recurrent ICT projects are either based on the least cost option or the option that will give the highest net benefits for our customers over the long term.
  - only including those market reform related ICT projects where timing and scope are known. Depending on the Australian Energy Market Operator's (AEMO) timing and scope for its market reforms, we will consider the related ICT projects (with an estimated total cost of $90M) in our revised proposal to the AER in December 2025 or through the AER's cost pass through mechanism. This prudent approach ensures that our customers will only be paying for prudent and efficient ICT expenditure.
  - undertaking procurement for ICT program of work, through a competitive process, to ensure value for money for our customers.
- Our proposed ICT capital expenditure is supported by robust investment briefs/business cases and a comprehensive ICT technology plan, which are submitted as part of the regulatory proposal.

8.1 Summary

- ICT enables us to operate a safe and reliable electricity network and keep support services, such as billing and call centres, running. ICT assets play a critical role in supporting the efficient delivery of services to customers, and their importance grows as the digitisation of the network accelerates.
- ICT plays a more significant role in enabling CER integration during the energy transition over the next ten years. We will deploy technologies that will help us connect our customers to renewable sources of energy safely and efficiently and accommodate more CER and DER without compromising the reliability and security of our network. ICT systems are effective means of meeting the needs of customers in the energy transition and can help defer future investments in network augmentation.
- In the next regulatory period, we will also deploy other technologies in response to market obligations outlined under AEMO's post-2025 NEM reform program. This includes Flexible Trading Arrangements (FTA) and Market Interface Technology Enhancement (MITE).
- Unlike network assets, which remain relatively static over their long life spans, digital systems have a short lifecycle due to technical obsolescence and changing customer requirements. This—along with increasing digitisation and the pace of change—means our need to invest in digital systems is increasing.

[191] This percentage change is based on the estimated expenditure for Non-network – ICT, excluding SaaS. When comparing our forecast expenditure to the estimated expenditure for the current regulatory period (which includes SaaS), the increase amounts to 22%.

Our ICT capital expenditure objectives:

- meet our customers' expectations that we should maintain our current levels of network reliability at the most affordable and efficient costs over the long term
- manage safety, environmental, electrical system and security risks to as low as practicable and comply with all applicable regulatory obligations efficiently over the long term
- optimise exports and imports from distributed energy resources and CER to the distribution network.

We forecast a capital expenditure of $154M for ICT in the next regulatory period. This is 32% higher than our expected capital expenditure for the current regulatory period.[192] While there is an overall increase in the ICT requirements, the magnitude of our capital expenditure has decreased relative to the previous regulatory period because of changes in the interpretation of the international financial reporting standards (IFRS) standards, which see a lot of these costs being treated as operating expenditures.

Our forecast capital expenditure builds on a strong and stable foundational IT landscape which we have developed during the previous and current regulatory periods. Our focus or key drivers for the next regulatory period are:

- to deliver new IT capabilities as enablers of our CER Integration Strategy and to improve the way we provide information and communication channels to customers. As we move toward a more sustainable energy future, we are investing in new digital capabilities that will support critical areas such as asset health monitoring, grid stability, system flexibility, and market integration, ensuring our infrastructure can adapt to the demands of a renewable energy landscape.
- to continue the maintenance of IT infrastructure and applications reaching the end of their useful lives—including through our like-for-like ('base') recurrent expenditure which is lower than our estimated recurrent expenditure during the current regulatory period.
- to comply with new electricity market obligations. With a constantly evolving regulatory landscape, digital technologies will play a vital role in enabling JEN to meet new obligations. In alignment with ongoing Post-2025 NEM market reforms, our Digital team is expanding its capability to manage the complex new market obligations associated with the energy transition. This increased capability will ensure we can meet regulatory requirements and support a smooth and effective transition to the future energy system, supporting a more modern, secure, and sustainable energy market.
- to protect our IT systems in response to growing cybersecurity threats.
- to address our customers' expectations on affordability, maintaining reliability, automation and digitisation.

We outline in Table 8–1 our forecast ICT expenditure. We provide more details about our forecast expenditure for each type of ICT category in the succeeding sections below.

Table 8–1: Forecast ICT capital expenditure, $2026, millions

ICT	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Recurrent - base	6.6	6.7	6.9	7.0	7.2	34.4
Total recurrent	**6.6**	**6.7**	**6.9**	**7.0**	**7.2**	**34.4**
Non-recurrent – compliance	15.0	9.1	0.0	0.0	0.0	24.1
Non recurrent – maintain	6.7	2.2	3.0	4.1	5.6	21.6
Non-recurrent – new capability	7.3	11.5	19.4	19.2	16.0	73.4
Total non-recurrent	**29.1**	**22.8**	**22.4**	**23.2**	**21.6**	**119.1**

[192] This percentage change is based on the estimated expenditure for Non-network – ICT, excluding SaaS. When comparing our forecast expenditure to the estimated expenditure for the current regulatory period (which includes SaaS), the increase amounts to 22%.

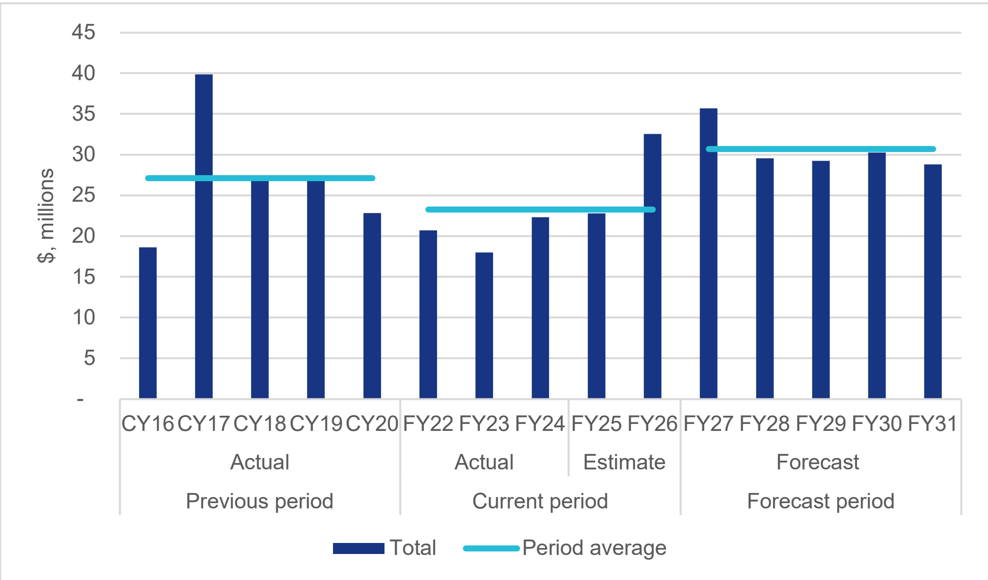
ICT	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Total ICT capital expenditure	**35.7**	**29.6**	**29.2**	**30.3**	**28.8**	**153.5**

8.2 Historical trend

Figure 8-1 shows our annual historical and forecast expenditure including the average for each regulatory period. It shows that:

- Our expected ICT expenditure for the current regulatory period is lower than our capital expenditure for the previous regulatory period. The International Financial Reporting Interpretations Committee's (IFRIC) guidance note requiring SaaS-related expenditure to be treated as operating expenditure has shifted approximately $13M from capital expenditure to operating expenditure from the previous to the current regulatory period. However, this reduction in capital expenditure is more than offset by the expected higher capital expenditure in financial years 2025 and 2026 relating to three market reform obligations under the Post-2025 NEM market reforms: MITE (2025-2028), FTA (2025-31) and Integrated Price Responsiveness (IPR) (2025-26).
- Our estimated expenditure for the current regulatory period of $116M ($2026, which excludes SaaS-related costs) is 9% lower than our allowance of $128M ($2026, which includes SaaS-related costs) for the current regulatory period In JEN's Technology Plan, we describe the projects that we have implemented during the current regulatory period.

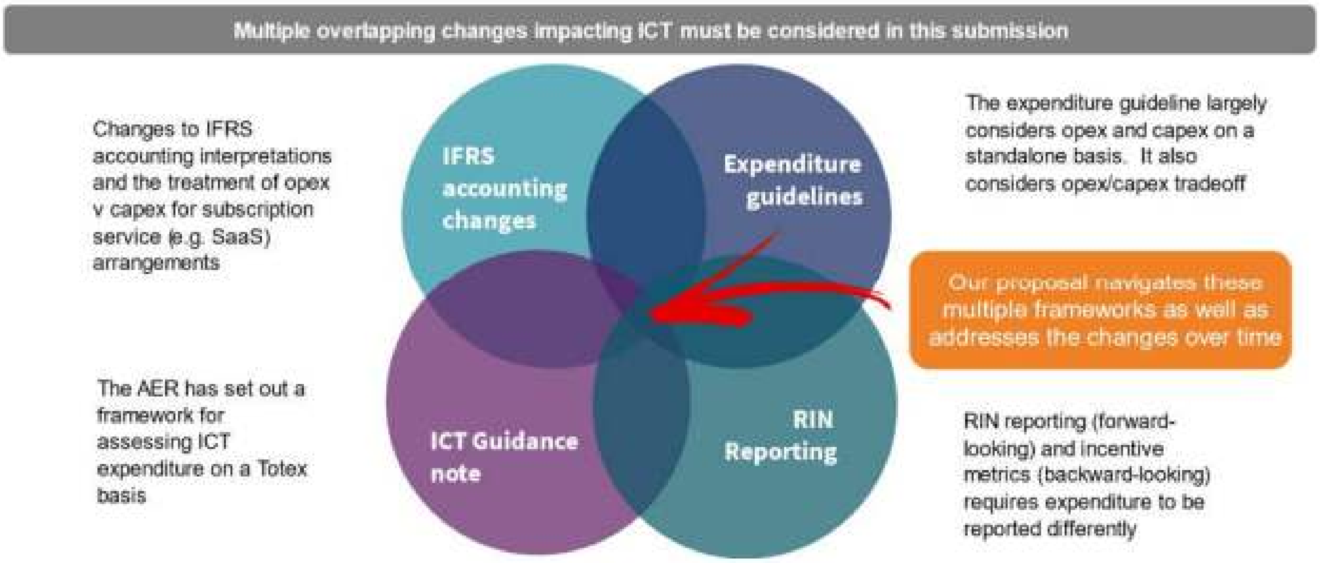
Figure 8-1: Non-network - ICT capital expenditure, $2026, millions



8.3 Our approach to setting our forecast ICT expenditure

Our forecast non-network ICT capital expenditure is guided by our capital expenditure objectives mentioned above. We are also guided by several external factors, including regulatory and IFRS requirements, all of which must come together to ensure our ICT forecast is efficient and complies with various obligations. Figure 8-2 below outlines the various standards, obligations, guidelines, and frameworks within which we must operate to develop a compliant ICT forecast.

Figure 8-2: Standards, obligations, guidelines and frameworks we must operate within to develop a compliant ICT forecast



8.3.1 Forecasting methodology

To forecast expenditure in the next regulatory period, we have adopted the ICT expenditure treatment outlined in the AER's non-network ICT Capital Expenditure Guidance Note (Figure 8-3).

Figure 8-3: ICT Expenditure Treatment

Expenditure Cycle	Operating expenditure	Capital expenditure
Non-Recurrent	>5 years	>5 years
Recurrent	Annually	2 to 5 years

Based on the AER's Guidance Note, we have classified our ICT capital expenditure into the following:

- **Base recurrent capital expenditure** – we set this forecast expenditure by taking the five-year average capital expenditure expected to be incurred between financial years 2021 and 2026 because this is the most recent known capital expenditure and therefore more reflective of our expected capital spend on ICT. The forecasting approach works on the assumption that this type of expenditure occurs on a cyclical (recurrent) basis, with cycles occurring between one and five years. Our approach is consistent with the AER's preferred approach of using a five-year rolling average when undertaking trend analysis on historical recurrent expenditure.[193]

[193] AER, *Non-network ICT capex assessment approach*, November 2019, p. 10.

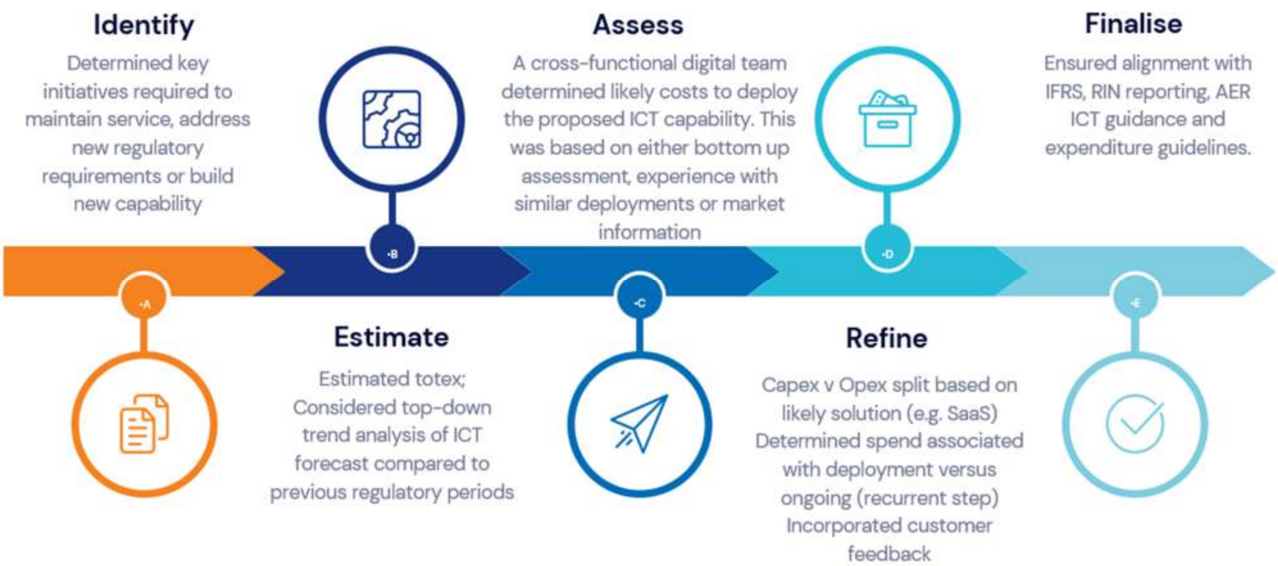
- **Step change to base recurrent capital expenditure** –The AER's ICT assessment approach notes that there may be legitimate reasons for increases in recurrent IT capital expenditure over time:[194]

  > *For example, additional recurrent ICT expenditures may be required after the implementation of non-recurrent projects to maintain that new service or functionality. In such cases, the distributor must be able to provide evidence to explain the need for this forecast variation in expenditure from historical trend.*

- We have not identified any step change to our base recurrent capital expenditure.

- **Non-recurrent capital expenditure** – this category of forecast expenditure occurs on cycles of more than five years or has not previously occurred at all. This type of expenditure is not present in the current regulatory period and, therefore, cannot form part of the recurrent capital expenditure. We adopt rigour in developing our forecast non-recurrent capital expenditure as shown in Figure 8-4.

Figure 8-4: JEN forecasting expenditure approach for non-recurrent ICT capital expenditure



Our proposed non-recurrent capital expenditure for the next regulatory period is supported by investment briefs for the projects underpinning the forecast non-recurrent spend. Depending on how well-defined the project requirements are, estimate of project costs are generally based on proxy costs (from similar projects we have undertaken in the past), bottom-up assessment (where requirements, scope and solution are known) or market information (indicative quotes from vendors).

Technology changes are frequent, and technology roadmaps are always subject to change and provide guidance rather than facts. Technology and business requirements may change between the preparation of our regulatory proposal and the initiation of an ICT project within the next regulatory period. As part of our ICT Governance process, when we are considering making any investment, we will undertake further options analysis using the most recently available information, including detailed costing and benefits assessment relating to the implementation of each option.

Overall, we consider that by choosing the most appropriate estimation method, we have achieved realistic and reliable cost projections that balance efficiency with precision based on the maturity of project requirements.

[194] AER, *Non-network ICT capex assessment approach*, November 2019, p. 10.

8.4 Forecast ICT Expenditure

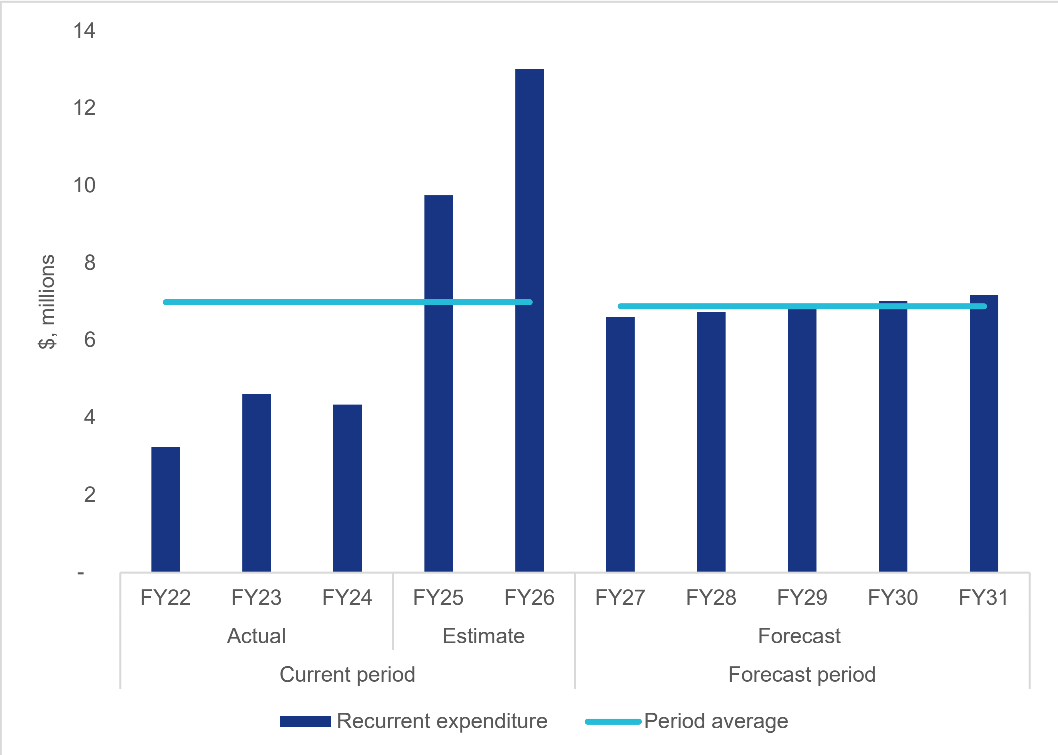
Consistent with the approach outlined in Section 8.3 - Our approach to setting our forecast ICT expenditure, this section outlines our proposed ICT Expenditure for the next regulatory.

8.4.1 Base recurrent capital expenditure

Recurrent expenditure is project activity – usually lifecycle upgrades – that would normally occur at least once in every five-year regulatory period. Generally, all hardware replacement is recurrent.

As shown in Figure 8-5, our forecast recurrent base expenditure for the next regulatory period is $7M on average per annum, which is consistent with out expected average equivalent spend during the current regulatory period. We have used our estimated recurrent ICT capital expenditure over the current regulatory period as basis for setting our forecast expenditure. This approach is consistent with the AER's preferred approach of using a five-year rolling average.

Figure 8-5: Recurrent capital expenditure, $2026, millions

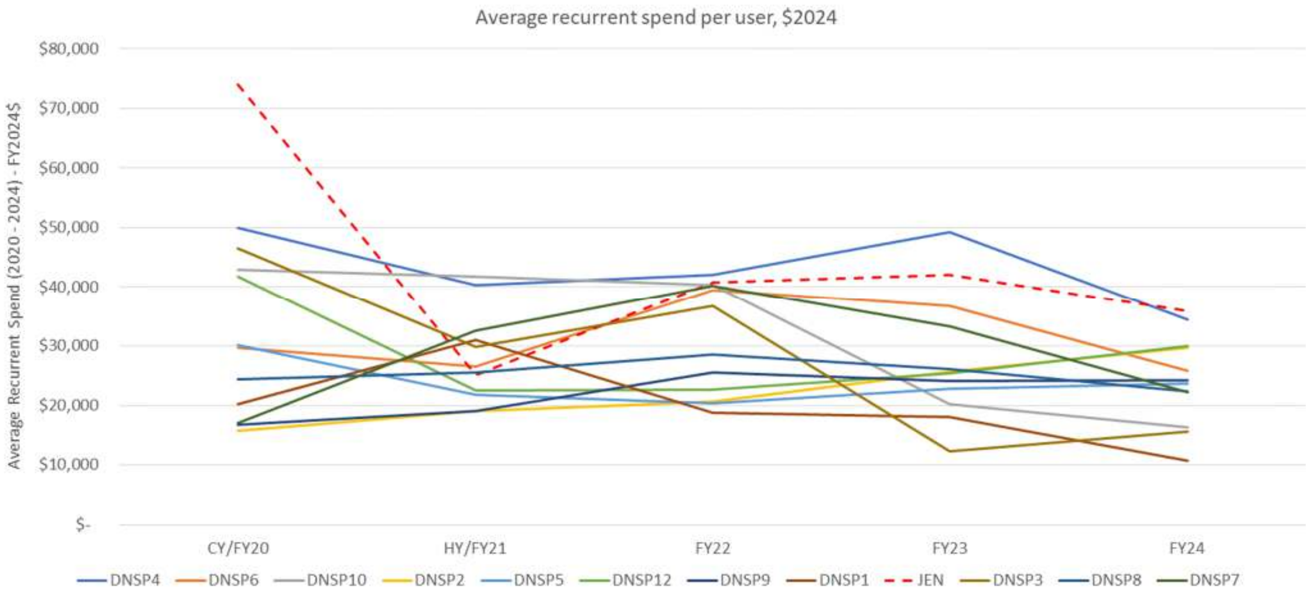


8.4.1.1 Benchmarking of our recurrent ICT expenditure

JEN consistently ranks as one of the most efficient DNSPs in terms of ICT costs within the NEM. We benchmarked our recurrent ICT expenditure (recurrent ICT operating expenditure plus total recurrent ICT capital expenditure) over the period 2020-24 against other DNSPs, consistent with the approach outlined by the AER.[195] As shown in Figure 8-6, JEN's average ICT recurrent spend per IT user is slightly above the average compared to other DNSPs in the NEM. However, this investment enables us to achieve an overall lower cost for customers, which is a better demonstration of efficiency, as shown in Figure 8-7. By embracing technology and leveraging our ICT capabilities JEN can deliver efficient services.

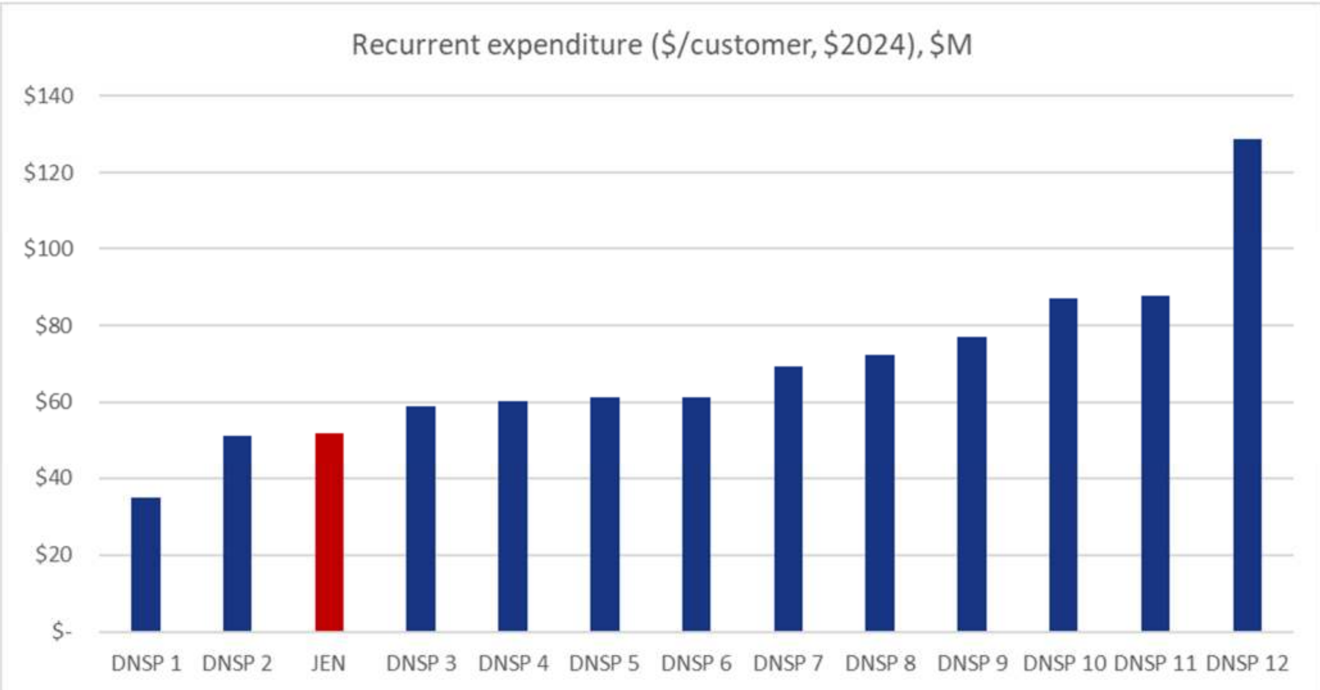
[195] AER, Non-network ICT capex assessment approach, November 2019, p.10.

Figure 8-6: Recurrent ICT expenditure per user – 5 year rolling average



As shown in Figure 8-7, JEN is one of the most efficient DNSPs in the industry. This is evident through our low average recurrent spend per customer, which places us among the top-performing businesses in terms of cost efficiency. Our ability to optimise scale by leveraging shared resources across our group has been instrumental in achieving this. Even when benchmarked against larger organisations, our recurrent expenditure remains significantly below the average. This operational efficiency allows us to provide exceptional value while upholding the highest standards of service for our customers.

Figure 8-7: Average Recurrent Spend by Customer Numbers compared to DNSPs across the NEM



8.4.2 Non-recurrent expenditure

Within our forecast of non-recurrent expenditure, we have applied three sub-categories consistent with the AER's approach[196]—maintaining systems, compliance and new capability. Trends in non-recurrent expenditure over time are generally less useful to examine than recurrent expenditure, as the drivers for and magnitude of different non-recurrent projects will vary considerably from one regulatory period to the next due to a wide range of factors. We discuss each subcategory in Table 8–2.

Table 8–2: ICT value drivers

IT value driver	Description
Maintaining existing services, functionalities, capability and/or market benefits	• Many of our investments where we implement and maintain ICT systems that underpin the basic processes of managing the electricity network and performing the meter-to-market functions. • Expenditure for maintaining existing services may not always yield positive NPV. Justification of the chosen most efficient cost option is based on an investment brief considering various timing, scope options, and/or alternative systems and service providers, with past expenditure factored in where applicable.
Complying with new / altered regulatory obligations / requirements	• Any activity which is specifically required to respond to new or altered regulatory requirements. • It is possible that the costs of such investments will exceed the measurable benefits. As such, the least cost option will likely be the preferred approach to addressing the NER expenditure criteria.
New or expanded ICT capability, functions, and services	• Investments that deliver additional benefits to customers which are not specifically regulatory requirements. • This expenditure requires justification through cost-benefit analysis to demonstrate benefits exceed costs (positive NPV). Where benefits exceed costs, consideration has also been given to self-funding of the investment.

8.4.2.1 Non-recurrent capital projects

Unless otherwise noted, all investment briefs and other supporting documents referred to in this table are provided as supporting materials in JEN's Reset RIN Response. Table 8-3 sets the projects underpinning our forecast non-recurrent expenditure.

Table 8-3: Non-recurrent capital projects proposed for the next regulatory period, $2026, millions

Investment Brief Title	Description
Maintaining existing services, functionalities, capabilities and/or market benefits	
Customer Systems Lifecycle	JEN must regularly maintain its customer systems to ensure we continue to meet our operational and regulatory obligations and to meet customer expectations for accessible, timely information. This investment brief outlines the need to continue to maintain existing systems that provide services to customers. This includes fault reporting tools, contact management systems, connection and application services, and communications. **Total non-recurrent capital expenditure: $2.99M**

196 AER, *Non-network ICT capex assessment approach*, November 2019, s 2.1.

Investment Brief Title	Description
Digitising Network Switching	The objective of this initiative is to digitise the management of operational instructions and integrate digital switching processes and a non-verbal communication solution for field staff. JEN has been committed to an enforceable undertaking with the Essential Services Commission (ESC) to implement a program of works aimed at mitigating these risks during the current regulatory period and must continue to invest to maintain this lower level of risk. **Total non-recurrent capital expenditure: $12.77M**
Emergency Backstop Lifecycle	This initiative aims to undertake major and minor upgrades of JEN's Low Voltage Distribution Energy Resource Management System (LV DERMS) system that underpins the mandated Victorian Emergency Backstop Mechanism (VEBM) to ensure ongoing system availability and reliability required to meet the new regulatory requirements. **Total non-recurrent capital expenditure: $6.89M**
End User Computing Lifecycle	This initiative aims to undertake lifecycle replacement of field mobility devices (primarily tablets with some mobile phones that are used for core business applications) and collaboration equipment (e.g., room conferencing and audio-visual equipment) that have not been replaced during the current regulatory period. **Total non-recurrent capital expenditure: $3.04M**
GIS Lifecycle Upgrade	This initiative aims to undertake a major upgrade of JEN's Geographic Information System (GIS) to ensure ongoing system availability and reliability. **Total non-recurrent capital expenditure: $4.08M**
MSI Replacement	This initiative aims to replace Jemena's Market System Integration (MSI) platform to maintain ongoing system availability and reliability, which directly impacts critical processes such as life support and remote de-energisation / re-energisation. **Total non-recurrent capital expenditure: $1.58M**
Network Operations Geospatial enhancements	This initiative aims to deliver ongoing essential enhancements to the JEN GIS suite of applications by focusing on maintaining the asset data and supporting processes that these spatial systems underpin. This will improve asset data capture, analysis, accessibility, reporting and sharing of information required to continue to promote efficient, safe, and reliable service delivery for our customers. **Total non-recurrent capital expenditure: $3.01M**
Complying with new / altered regulatory obligations / requirements	
NEM Reform - Market Interface Technology Enhancements	The objective of this initiative is to implement Identity and Access Management (IDAM), Industry Data Exchange (IDX) and Portal Consolidation that have been identified as a set of initiatives within the National Energy Market (NEM) reform implementation program to provide foundational and strategic frameworks that the upcoming reform initiatives can leverage. These initiatives are collectively referred to as Market Interface Technology Enhancement (MITE). **Total non-recurrent capital expenditure: $17.54M**
NEM Reform - Flexible Trading arrangements	The objective of this initiative is to implement the required system and process changes to address the recent Flexible Trading Arrangement (FTA) rule change. The Australian Energy Market Commission (AEMC) is introducing flexible trading by enabling small and large customers to have their Customer Energy Resources (CER) separately identified and treated independently in market settlements - allowing them to engage with multiple service providers if they choose to. It also enables minor energy flow metering, for connection arrangements not currently considered in the National Energy Market (NEM) metering framework (Type 8 and 9 meters). **Total non-recurrent capital expenditure: $4.42M**

Investment Brief Title	Description
Outage Preparedness and Response	Ensure that JEN consistently meets customer needs and compliance obligations regarding outage communications while also ensuring that underlying systems can accommodate non-standard customer needs. **Total non-recurrent capital expenditure: $2.17M**
New or expanded ICT capability, functions, and services	
Customer Education	To develop and implement new and expanded ICT capability to deliver integrated customer education programs that: • builds energy literacy. • builds customer capability to prepare for the energy transition. • enhances customer experience and the accessibility of information for everyone. • supports customers to take on a more active role in energy generation and management. **Total non-recurrent capital expenditure: $4.82M**
3D Digital Twin	The solution ingests multiple artifacts such as imagery, point cloud and sensor data to build a 3-dimensional network physical twin along with tools to manage planning and design workflows. **Total non-recurrent capital expenditure: $5.77M**
Dynamic Network Planning with Automation	This initiative aims to digitise the process of managing network drawings by removing the manual keying of as-designed and as-build drawings from AutoCAD paper/PDF drawings into JEN's GIS. **Total non-recurrent capital expenditure: $11.21M**
CER Integration: New or expanded ICT capability, functions, and services	
Foundational Distributed UFLS (Underfrequency Load Shedding) Capabilities	Implementation of a network and control solution for Under Frequency Load Shedding, to shed load in times of under frequency, allowing network operators to access via a dedicated B2B interface. This enables us to strategically respond to the challenges and opportunities associated with the increasing number of CER in our network. **Total non-recurrent capital expenditure: $2.09M**
Flexible exports	Implementation of a Flexible Export function for generation devices such as Photovoltaic including the ability to set dynamic export limits. **Total non-recurrent capital expenditure: $15.16M**
Flexible imports	Implementation of a Flexible Import function for load devices such as EV charging including the ability to set dynamic load limits. **Total non-recurrent capital expenditure: $10.78M**
Network Analytics Program	Implement network analytics applications to comply with emerging regulatory requirements, deliver JEN operational and safety improvements, and enable JEN to adapt to DER growth. **Total non-recurrent capital expenditure: $9.14M**
Strategic Network Analytics Platform (SNAP) - Data Hub	Creating a strategic platform for analytics, model serving, data integration and other use cases using a modern data lake, network model, streaming platform, network analytics development environment and associated API services to provide foundational capability across the business. **Total non-recurrent capital expenditure: $1.53M**
VVC (Volt Var Control) rollout	Solutions to manage voltage and power quality across the network in light of changes due to increased CER/DER penetration, optimisation of active and reactive energy flows and manage voltage compliance. **Total non-recurrent capital expenditure: $0.13M**

8.5 How we have addressed our customers' priorities

We have sought customers' feedback on our Draft Plan. Similar to what we have heard during our customer engagements prior to developing our Draft Plan, our customers have expressed a number of expectations which are relevant to ICT capital expenditure.

Our customers' feedback on the Draft Plan (related to ICT)[197]

- Affordability is a top priority for our customers.
- Out of nine proposed initiatives outlined in the Draft Plan, our customers have ranked the following initiatives as:
  - Upgraded systems to keep customers better informed with near real-time information at times they need it the most **(second)**
  - New digital technologies to improve electricity system management and enable new sustainable products and services **(third)**
  - A new portal to provide tailored information based on customer preferences and language needs with energy information **(ninth).**
- Many of those who made a submission are supportive of our CER Integration strategy which aims to connect our customers to renewable sources of energy.

Our forecast ICT capital expenditure is consistent with our customers' expectations that we should digitise and automate the network to make it smarter and more efficient. However, affordability is a top concern for our customers. In developing our forecast ICT capital expenditure, we addressed our customers' affordability concerns by ensuring that we are only including efficient and prudent ICT investments. Our proposed expenditure:

- only included non-recurrent ICT capital projects that are either based on the least cost or the highest net benefits for our customers over the long term, ensuring efficient costs for our customers
- does not include market reform-related ICT projects with uncertain timing and scope. These projects are estimated to be $90M (Table 8–4). Depending on the AEMO's timing and scope for these market reforms, we will consider these ICT projects in our revised proposal to the AER in December 2025 or through the AER's cost pass through mechanism. We consider this to be a prudent approach.

In addition to the above, we pursue efficiencies by using a shared services delivery model for our range of ICT assets, with a significant portion of technology being shared between our regulated gas and electricity distribution networks. This approach enables Jemena to achieve enhanced efficiencies for both regulated businesses by sharing the relatively fixed costs of a large portion of ICT capital expenditure across a larger customer base (hence lower costs per customer), as opposed to incurring these costs individually.

We also closely follow our ICT Project Management Lifecycle and Governance process. Before making a final investment decision, we carefully evaluate each proposed project, which can sometimes lead us to implement alternate, more economic solutions or adjust timelines compared to those outlined in our initial price review forecast. Additionally, we prioritise ICT projects across our portfolio by continually reviewing emerging risks, priorities, and regulatory requirements. As a result, the delivery of projects or allocation of funds may differ from what was initially forecast. This has led to the reduced spending seen across the financial years 2022-24. We will adopt the same approach in the next regulatory period.

197 JEN – Att 02-21 Draft Plan Feedback Report, September 2024.

Table 8–4: Post-2025 NEM market reforms with uncertain timing and scope

Reform unknowns	What we know	Potential impact on JEN	Status	Cost 'Guestimate'
DER datahub and registry services *Establish a DER Data Hub to provide efficient and scalable data exchange and registry services for DER between industry actors and potential augmentation of DER Register to enable more efficient and permission-based sharing and access to information.* **nem-reform-program-initiative-briefs.pdf (aemo.com.au)** **pg.38**	• Consultation process has not begun. • No documentation has been published. • Project scope is still in development; however it is assumed IDX/IDAM investments will facilitate this registry	Unknown	**Highly Uncertain** No details on: • Timing, • Scope, • Will it go ahead	**$11.5M** capex:$8M opex:$3.5M
Distribution Local Network Services *To identify ways to make it easier for DER aggregators to trade local network support services with DNSPs/Distribution System Operators (DSOs), through greater visibility of local network. constraints aligning the definitions of local services and how they are traded between regions* **nem-reform-program-initiative-briefs.pdf (aemo.com.au)** **pg.36**	• Consultation process has not begun. • No documentation has been published. • Project scope is still in development may be limited to guidelines around information to be published (potential overlap with Network Visibility) and a definition of 'local services'	**Unknown**	**Highly Uncertain** No details on: • Timing, • Scope, • Will it go ahead	**$26M** capex:$20M opex:$6M
DER Operating Tools *To identify and develop, in collaboration with DNSPs, new DER operational tools that may be required by each party, which can work together to maintain efficient and secure power system operations at times when up to 100% of system load can be met with DER.* **nem-reform-program-initiative-briefs.pdf (aemo.com.au)** **pg.40**	• Consultation process has not begun. • No documentation has been published. • Have not yet established the need for these tools or what they may be.	**Unknown**	**Highly Uncertain** No details on: • Timing, • Scope, • Will it go ahead	**$16M** capex:$12M opex:$4M

Reform unknowns	What we know	Potential impact on JEN	Status	Cost 'Guestimate'
EV Charging *Ensure that agencies and market participants have sufficient visibility of emerging electric vehicle supply equipment (EVSE) for effective planning and management of the system.* **Submission AEMO to AEMC - EVSE rule change - 12 December 2023.pdf**	• Rule change proposal lodged 23rd December 2023 • No public consultation has begun. • Aiming to align with current data reporting cycles, with the first trench of data due May 2026 (pre EDPR) • Likely impact on Jen: potentially requires changes to IT systems, obligations in connection agreements and/or service and installation rules.	**Medium** Impact likely depend on if Jen currently captures this data and/if we require an audit of connections already in situ	**Highly Uncertain** No details on: • Timing, • Scope, • Will it go ahead	**$15.5M** capex:$12M opex:$3.5M
Bill Transparency *Efficient arrangements to provide ongoing transparency of consumer bills and the impacts of different services and circumstances, to support better consumer protections and understanding of consumer needs in the market transition and streamline current inefficient retail reporting.*	• Consultation paper publish 20th July 2023 - draft report due 26th September 2024 • Obligations are focused on retailers (no networks made submissions at consultation stage)	**Low**	**Quite Uncertain** Unsure of • Timing, • Scope, • Will it go ahead	**$11M** capex:$8M opex:$3M
Network Visibility Optimise benefits from DER and network assets for all customers, by informing market stakeholders making DER planning decisions and managing network capacity risks. **Network visibility | Australian Energy Regulator (AER)**	• Consultation paper published 7th July 2023 – no further movement/published documentation • At consultation stage, NSW businesses suggested that many of the requested data categories are not currently collected	**High**	**Quite Uncertain** **Unsure of** • Timing, • Scope, • Will it go ahead	**$11M** capex:$8M opex:$3M

8.6 ICT technology plan and supporting business cases

We are providing as part of this submission our ICT Technology Plan and investment briefs supporting our non-recurrent ICT capital expenditure.

The ICT Technology Plan sets out the essential technology tasks JEN carries out to ensure that our systems remain sustainable and secure and that we always maintain operational safety to safeguard the security and reliability of our electricity network. The plan describes our overarching strategy and decisions concerning non-network ICT, and how these result in efficient ICT capital and operating expenditure that supports the long-term interests and expectations of our customers. It also reflects opportunities to introduce new and innovative technology options to optimise how services are delivered to customers, where prudent, efficient and sought by our customers.

Investment Briefs (IBs) accompany the Technology Plan. IBs are intended to provide an extra level of insight into how we will meet our future challenges through the specific projects within our forecast ICT expenditure program. Each IB sets out the objective of the project, the problem being addressed, the scope, credible options that have been considered to deliver the most prudent and efficient technology solution, and how the project aligns with our customers' expectations. Each is supported by a cost-benefit analysis.

8.6.1 References

The proposed capital expenditure outlined in this section is supported by a body of materials and forecasts. The key documents are outlined in Table 8–5.

Table 8–5: List of Non-network – ICT forecast expenditure attachments

Attachment	Name	Author
RIN Support	Support – Technology Plan	JEN
RIN Support	ICT Investment Brief - Customer education	JEN
RIN Support	ICT Investment Brief - Digitising Network Switching	JEN
RIN Support	ICT Investment Brief - Emergency Backstop Lifecycle	JEN
RIN Support	ICT Investment Brief - End user computing	JEN
RIN Support	ICT Investment Brief - GIS lifecycle upgrade	JEN
RIN Support	ICT Investment Brief - MSI replacement	JEN
RIN Support	ICT Investment Brief - Network Operations Geospatial enhancements	JEN
RIN Support	ICT Investment Brief - Outage Preparedness and Response	JEN
RIN Support	ICT Investment Brief - Reform - Market Interface Technology	JEN
RIN Support	ICT Investment Brief - Reform - Unlocking CER benefits - Flexible Trading arrangements	JEN
RIN Support	ICT Investment Brief – SAP Migration	JEN
Att 03-01	CER Integration Strategy	JEN
RIN Support	Data Visibility and Analytics Program	JEN
RIN Support	Data Visibility and Analytics Program – Investment Brief	JEN
RIN Support	Grid Stability and Flexible Services Program	JEN
RIN Support	Grid Stability and Flexible Services Program – Investment Brief	JEN
RIN Support	Voltage and PQ Management Program	JEN
RIN Support	Voltage and PQ Management Program – Investment Brief	JEN

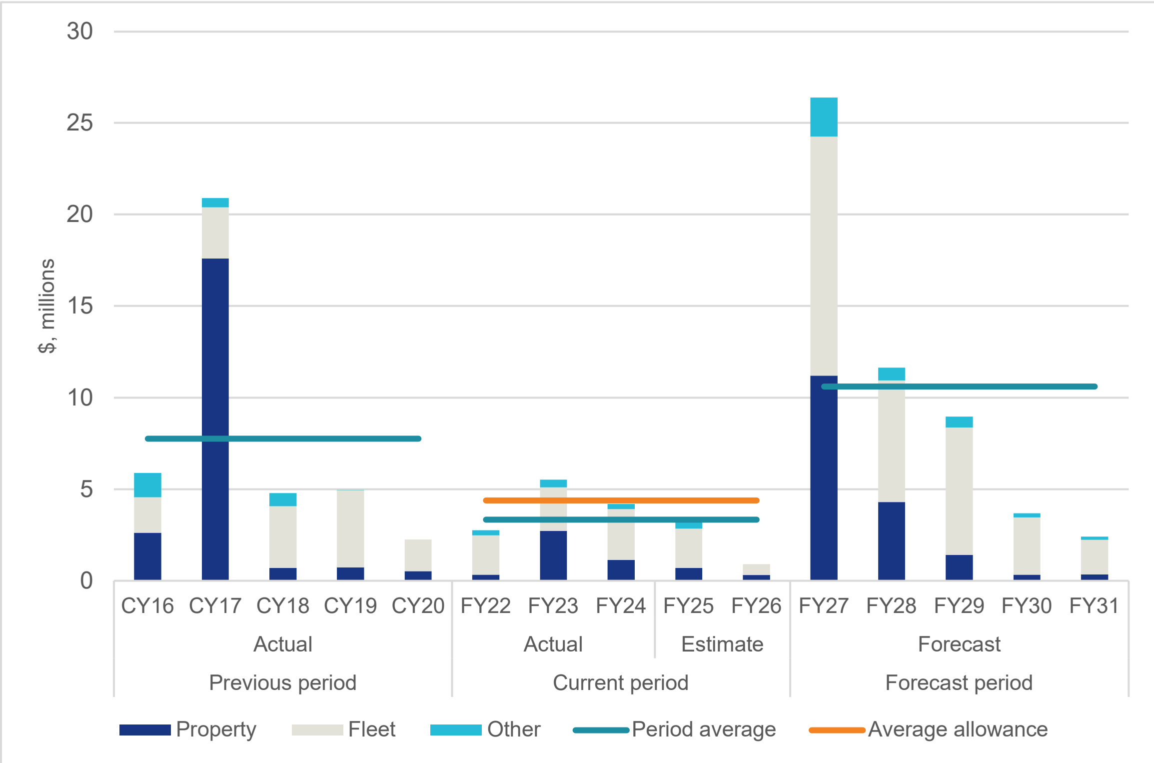
9. Non-network – other capital expenditure

Non-network - other capital expenditure accounts for around 2.4% of our forecast gross capital expenditure forecast. Other non-network assets enable the delivery of our services. They predominately comprise the following items:

- fleet
- property and buildings
- tools and equipment.

We forecast a total non-network capital expenditure of $52.3M for the next regulatory period, which is materially higher than our estimated expenditure for the current regulatory period. Figure 9-1 shows our historical forecast of other capital expenditure costs for non-network. We have minimal in the current regulatory period.

Figure 9-1: Gross Non-network – other capital expenditure, $2026, millions



Key drivers for the increase are:

- Increased number of vehicles reaching end of life in the next regulatory period and increasing vehicle unit costs. Many of the high cost EWPs we purchased during the previous regulatory period are due for replacement or rebuild in the next regulatory period consistent with the Australian Standard AS1418.10 and AS2550.10. Many of our light commercial vehicles and passenger vehicles are also reaching end of life in the next period and will therefore need to be replaced consistent with good industry practice replacement timeframes.
- Significant increase in the unit cost of vehicles since the last price reset. Based on our most recent tender, the cost of elevated work platforms has increased significantly between 2019 and 2024 and is forecast to increase further given the demand for specialised fleet across the NEM over the next 5 years.
- Expansion of the Tullamarine Depot at 77 Keilor Park Drive. This fit for purpose facility was designed specifically for the efficient operation of JEN's activities that are required to support the delivery of electricity distribution services. The expansion will involve key construction and fit out works, facilitating future workforce requirements, compliance with building code obligations. The project is forecast to be implemented in FY27.

Property expenditure is particularly lumpy due to the long-lived nature of the assets involved. Therefore, it's best to observe the long-term trends rather than period-to-period expenditures when assessing expenditure cycles as shown in Figure 9-1 above.

9.1.1 Fleet

Motor vehicles and specialised plant allow personnel to travel around our distribution area to perform planned construction and replacement activities as well as emergency fault response, repair, maintenance and inspection activities. Our fleet assets are critical to enabling us to deliver standard control services to customers and are particularly important in the context of us efficiently maintaining the safety and reliability of our network.

To ensure we can deliver our investments, undertake maintenance and inspections and respond to network incidents we will need to replace or rebuild some of our fleet. Our data also shows that the ratio of vehicle per FTE has been decreasing which suggests that there is a need to increase the number of our fleet for our staff to effectively and efficiently provide the required services to our customers.

We propose to invest about $32M on fleet in the next regulatory period. This excludes our forecast spend for the deployment of mobile emergency response vehicle (MERV) which is captured in the network resilience program, trailers and plant which are discussed in the sections on Network resilience (section 7) and Non-network - other capital expenditure (section 9.3.3), respectively.

9.1.1.1 Forecast expenditure

Our forecast reflects the expenditure required 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. Continuing to use vehicles which are reaching their end of life increases the risk that the unplanned withdrawal from service of a vehicle (for example, due to mechanical breakdown) would result in not enough vehicles available for use. This reduces our ability to continue to use existing degraded assets significantly beyond their economic lives while still maintaining our network service levels in the future.

Our proposed replacement will ensure that we meet our 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.

Table 9–1 sets out forecast expenditure for the next regulatory period while Figure 9–2 shows our expenditure on fleet over three regulatory periods.

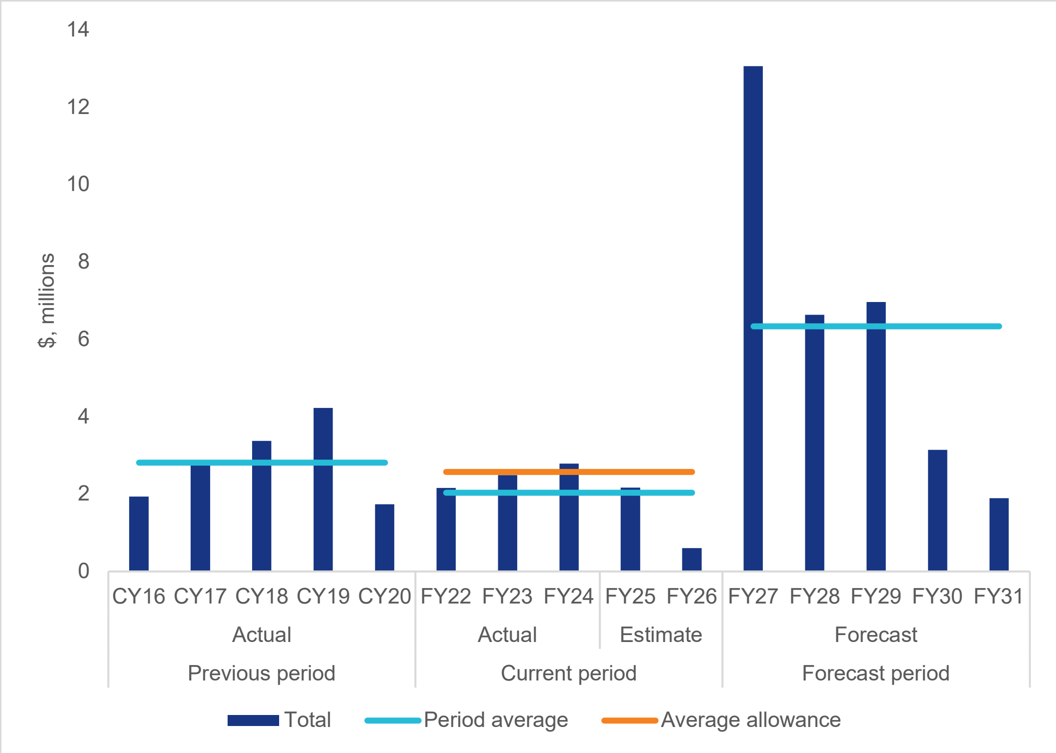
Table 9–1: Forecast fleet vehicle expenditure by category, $2026, millions

Vehicle category	FY27	FY28	FY29	FY30	FY31	Total
Replacement/Rebuild - Elevated Work Platform (EWP)	2.9	3.1	2.3	1.3	1.9	11.5
Replacement - Heavy Commercial Vehicles (HCV)	2.4	1.3	1.3	0.0	0.0	5.0
Replacement - Light Commercial Vehicles (LCV)	6.9	1.6	2.2	1.3	0.0	12.1
Replacement - Passenger vehicle (PV)	0.9	0.6	1.1	0.5	0.0	3.1
Total motor vehicle expenditure	**13.1**	**6.6**	**7.0**	**3.1**	**1.9**	**31.7**

(1) This excludes the cost for the deployment of Mobile Emergency Response Vehicle of $0.59M, which is included in our forecast expenditure for network resilience. It also excludes the forecast expenditure for plant (material handling, excavator) and trailer which were captured under Non-network Other capital expenditure. Plant and trailer are not part of the vehicle fleet for RIN reporting purposes.

As shown in Figure 9–2 our estimated expenditure for the current regulatory period is generally consistent with the AER approved allowance for JEN's fleet replacement.

Figure 9–2: Fleet vehicle expenditure, $2026, millions



9.1.1.2 Key drivers

Our forecast spend is materially higher than our estimated expenditure for the current regulatory period. This is driven by the increasing number of vehicles reaching the end of life in the next regulatory period and increasing vehicle unit costs. In addition, we are comparing our forecast expenditure with a lower base. As we have noted in our 2021-26 Plan to the AER, our forecast fleet expenditure for the next regulatory period is approximately 40% cent lower than our actual and estimated expenditure during the current regulatory period.[198] This is partly because we have already purchased high cost EWPs during the previous regulatory period. These high cost EWPs are due for replacement in the next regulatory period as discussed in more detail below.

In practice, a range of factors will determine the optimal replacement age for a vehicle in order to minimise total lifecycle cost - such as how a particular vehicle is used, the conditions it is used in, its model and whether it has any mechanical defects. We, therefore, undertake safety and condition inspections at regular intervals before a decision is made about replacement, rebuild or any deferment.

Forecast volume

Table 9–2 outlines the number of vehicles underpinning our forecast expenditure for the next regulatory period.

Table 9–2: Forecast number of vehicles for replacement, rebuild, 2026-31

	FY27	FY28	FY29	FY30	FY31	Total
EWP Small	2	1	2	1	2	8
EWP Large		3	2			5

[198] JEN, 2021-26 Electricity Distribution Price Review Regulatory Proposal, Attachment 05-01, Forecast capital expenditure, January 2020, p.113.

	FY27	FY28	FY29	FY30	FY31	Total
EWP Large Rebuilt	2	2	1	1	1	7
HCV Large	1	3	3			7
HCV Medium		2				2
HCV Borer			1			1
HCV Borer & Jinker Rebuild	2					2
LCV Utility	28	10	16	2		56
LCV Utility Field	15	5	10	6		36
LCV Utility Van	33	2	1	6		42
PV	15	10	20	8		53
Total	**98**	**38**	**56**	**24**	**3**	**219**

We replace our vehicles based on the individual performance and condition, and consistent with good industry practice replacement timeframes. For our LCVs and PVs this is generally at the 150,000km mark (about 5 years old). However, there are times we replace some vehicles slightly earlier (4 years) based on the vehicle's safety or historical data where we have seen increases in maintenance costs and down-time in specific vehicle models.

> As shown in Table 9–3 shows, our replacement planning timeframe for LCVs and PVs compares favourably with other similar DNSPs. This is the same approach we used in forecasting our fleet replacements for the current regulatory period.

Table 9–3: SG fleet comparison of vehicle replacement planning thresholds

Company	Passenger Vehicle	Light Commercial Vehicles	Heavy commercial vehicles and plant
Essential Energy	60 months/150,000 km	60 months/150,000 km	10-15 years
Powerlink	48 months	48-84 months	8-10 years
Ergon	48 months/100,000 km	150,000 km	10-15 years
Energex	3 or 5 years	60 months	10-15 years
SA Power Networks	60 months/150,000 km	60 months/150,000 km	10 years (EWP) 15 years (crane)
Powercor	60 months/150,000 km	60 months/150,000 km	10-15 years (EWP) 10 years (HCV)
Downer	36 months/90,000 km	36 months/90,000 km	7-10 years
Ausgrid	60 months/150,000 km	72 months/150,000 km	15 years
JEN	60 months/150,000 km	60 months/150,000 km	10-15 years (EWP) 10 years (HCV)

Source: SG Fleet, January 2025.

Many of our LCVS and PVs will be reaching end of life in the next regulatory period.[199] Based on the assessment of our existing LCVs and PVs against the replacement timeframes, plus case-by-case conditional assessment,

199 Refer to Attachment JEN – RIN – Support – Fleet Asset Class Strategy – 20250131 for details including information on vehicle utilisation.

we need to replace a total of 187 vehicles in the next regulatory period. If not replaced, and if operated beyond their lifespan expectations, these vehicles would exhibit condition degradation beyond the level we target for this asset class over the medium term. Left unaddressed, this elevated degradation has the potential to result in an increase in fleet maintenance costs in the near future and unreliable field operations by our staff, both of which are not in the long-term interest of our customers.

The replacement of EWPs is also driving our forecast spend for the next regulatory period. While the forecast volume is low, it is a high value vehicle. We used the Australian Standard AS1418.10 and AS2550.10 as a guide in replacing EWPs. According to these standards, EWPs either need to be replaced or rebuilt with new units after ten years of age (for Single-person EWPs) or rebuilt at 10 years and replaced with a new unit prior to the next 15-year anniversary (for large EWPs). From time to time, a large EWP may be deemed unsuitable for rebuilding after the initial 10 years of service. This can be attributed to extreme factors, such as but not limited to prolonged use in harsh environments, extreme metal fatigue, or being uneconomical to rebuild.

Many of these EWPs were purchased in the previous regulatory period and are about to reach end-of-life in the next regulatory period. Our assessment of our existing EWPs against the Australian Standards AS1418.10 and AS2550.10 and a case-by-case conditional assessment highlight that 13 EWPs will need to be replaced, while seven large EWPs will need to be rebuilt during the next regulatory period.

We also propose to replace or rebuild HCVs (crane/crane borer) which we purchased during the previous regulatory period. Our assessment of our HCV assets against the Australian Standard AS1418.10 and AS2550.10 and case- by-case conditional assessment suggests that a total of 10 HCVs will need to be replaced while two HCV borer and jinker will need to be rebuilt during the next regulatory period.

> Overall, we consider our approach to be the prudent and appropriate approach. Our approach is consistent with the AER's expectation that electricity distribution businesses' risk and management standards are aligned with industry standards on good asset and risk management and consistent with well-established relevant Australian industry standards.[200] It is also consistent with the approach used by other DNSPs as shown in Table 9–3 above, and our assumed replacement cycles under our 2026-31 Plan for the current regulatory period.
>
> To further demonstrate prudency, we propose to extend the lives of our EWPs and HVCs by rebuilding some of them instead of outright replacement which will be more costly for our customers.

Unit costs

The unit cost of vehicles has also contributed to our forecast expenditure. The global supply chain issues since the coronavirus pandemic and microchip shortages have led to higher vehicle prices. Our most recent tender shows that the unit costs across EWPs have increased significantly between 2019 and 2024. This has contributed significantly to the level of our forecast expenditure.

While supply chains are recovering, we expect that prices for our predominately light commercial fleet will continue to increase with the introduction of:

- The Australian Government's New Vehicle Efficiency Standard which is expected to come into effect from 1 January 2025 with a catch-up period until around 2028. This standard implements a maximum annual average level of carbon emissions across a manufacturer's overall car sales. To sell the larger vehicles, manufacturers will need to sell more fuel-efficient models as an offset or purchase credits from another supplier. This will increase the cost of the vehicles we require.

200 AER, Industry practice application note: Asset replacement planning, July 2024, p.9.

- 'Euro 6d' equivalent noxious emissions standards for light vehicles (including commercial vehicles with a gross vehicle mass up to 3.5 tonnes). All light vehicle models approved and supplied to Australia for the first time on or after 1 December 2025 will need to comply with these standards. This will increase the costs of new vehicles as they will need to be fitted with new emission reduction technologies.[201]

Consideration of our customers' expectations

Our customers expect us to innovate and plan for the future so that they can access affordable electricity in the longer term as we move towards a lower carbon future. When discussing corporate responsibility and addressing sustainability and evaluation our carbon footprint during a People's Panel engagement session, our customers provided recommendations that JEN should continue to commit to and improve on its environmental practices and continuously reduce its impact on the environment. This includes investigating and implementing operational improvements to reduce environmental impacts, including transitioning to electrified fleet vehicles. The People's Panel further recommended Jemena replace existing equipment that has reached the end of their life cycle with sustainable alternatives.[202] Customers who have responded to our Draft Plan have ranked as top priority the replacement of vehicles with those that are more environmentally friendly to increase the sustainability of our operations.[203] In addition, our customers also expect JEN to prioritise affordability for customers.

Over the next regulatory period, we will continue to evaluate the adoption of new technologies, including consideration of hybrid, electric and hydrogen powered vehicles. We expect that these will become an increasing practicable and efficient option. This is due to the expected cost increases for internal combustion engine options (as outlined above). However, our fleet principles of having fit-for purpose-vehicles at an efficient cost will remain to be our primary considerations when evaluating these new vehicle technologies.

Nonetheless, we have set ourselves an aspirational target of converting 25% of our fleet to either hybrid, electric of hydrogen powered vehicles over the next 5-years. While these vehicles will bring significant benefits, they also cost more to purchase. However, as we expect the costs of the various options to become more comparable and to ensure we balance our customers' expectations of cost and emissions, we have not included these additional costs in our forecast at this stage. Our forecast has been prepared on the basis that we will continue to use like-for-like vehicle types. We will continue to analyse these trade-offs during the next regulatory period and procure the drive train type which meets our operating requirements and represents the least-cost option over the vehicle's total lifecycle, consistent with our fleet management principles.

Procurement approach

We periodically assess our procurement approach (leasing or outright purchase) for vehicles and our desired vehicle attributes such as drive train type (for example, internal combustion engine or electric) to ensure our fleet assets continue to be fit for purpose and represent the lowest total lifecycle cost. Our most recent analysis demonstrated that outright ownership represents a lower cost to our customers on a lifecycle basis for all vehicle types, noting also that ownership provides more flexibility for us to reduce our fleet size in the future if necessary, without incurring lease break costs. We have therefore proposed expenditure to procure vehicles within our forecast capital expenditure for the next regulatory period and have not proposed any operating expenditure step changes relating to vehicle leases. This is consistent with our procurement approach during the current regulatory period.

Nonetheless, leasing remains an alternative option should there be unavoidable supply shortages that lead to procurement delays similar to those that occurred during the pandemic.

Consideration of growth-related requirements

We are forecasting increased capital expenditure in the next regulatory period due to an increase in forecast new connections, including data centres and increased replacement activities. This will require the purchase of additional vehicles to meet our regulatory obligations and to assist us in delivering the required additional services.

---

[201] Department of Climate Change, Energy, the Environment and Water and Department of Infrastructure, Transport, Regional Development, Communications and the Arts 2023, Improving Australia's fuel and vehicle emissions standards – Final impact analysis, May 2023, pp.71, 82.

[202] MosaicLab, *Jemena People's Panel Process Report*, May 2024, p.43.

[203] JEN – Att 02-21 Draft Plan Feedback Report, September 2024, p.5.

The predominant change in the next regulatory period, when compared with the current regulatory period, is the nature and volume of the assets to be constructed, operated and maintained – predominately asset and resource-intensive assets, namely 66/22kV zone substations and 66kV sub-transmission lines. Driven by unprecedented growth in data centres we require the following additional vehicles:

- 2 - 18m Elevating Work Platforms for overhead line construction resources
- 4 - 24m Elevating Work Platforms for overhead line construction resources
- 1 line construction truck for overhead line construction
- 6 light commercial service body vehicles for overhead, underground and substation resources
- 3 light commercial dual cab (4x4) for overhead, underground and substation resources
- 2 light commercial dual cab for overhead crew team leader and zone substation fitters
- 1 light commercial van for faults and metering and servicing
- 1 AWD passenger vehicle for additional Electrical Network Operator.

9.1.2 Property

> Our buildings and property capital expenditure forecast covers expenditure on buildings and fixed furnishings at JEN's depots (which we own) and corporate offices (which we lease but are responsible for office fit-outs).
>
> We forecast to spend $18M for building and property over the next regulatory period, which is higher than our estimated expenditure for the current regulatory period. The key driver of our forecast expenditure is the Tullamarine Depot Augmentation.

Our key objectives for our property asset class (buildings and fit outs) are to:

- support growth in the network and changes in business requirements
- ensure the safety of employees, contractors and the public
- maintain compliance with legislative/regulatory requirements
- maintain the property portfolio with a view to lowering the environmental impact, including greenhouse gas emissions

To meet our objectives, JEN adopts a lifecycle strategy of proactive management for our property asset class. Our proactive management approach involves preventative maintenance and a fix on fail approach. We properly maintain our buildings and fit outs to ensure the working environment for JEN's employees is structurally safe and operationally efficient. Lifecycle management plans are in place for all major sites. There are also strategies in place to address preventative maintenance, energy efficiency and efficient space utilisation for major sites. Our proactive approach conforms to Australian standards, legislation and manufacturer warranties.[204]

Our maintenance and replacement expenditure are also affected by the nature of ownership of the property or site. JEN holds the overall responsibility for the lifecycle management plan and all maintenance for properties/sites it owns, but for leased sites JEN's responsibility for maintenance (and during the expiry if the lease) is dictated by the terms of the lease.

[204] For example, the National Construction Code and various Australian Standards (AS) and Codes which provide the minimum necessary requirements for safety, health, amenity and sustainability in the design and construction of new buildings (and new building work in existing buildings) throughout Australia; and Disability and Discrimination Act 1992 (Cth) which sets out the requirements for property and building accessibility and facilities. Our proactive lifecycle management approach is also guided by JEN's Network Operator Rules JEN issues as part of its Electricity Safety Management Scheme.

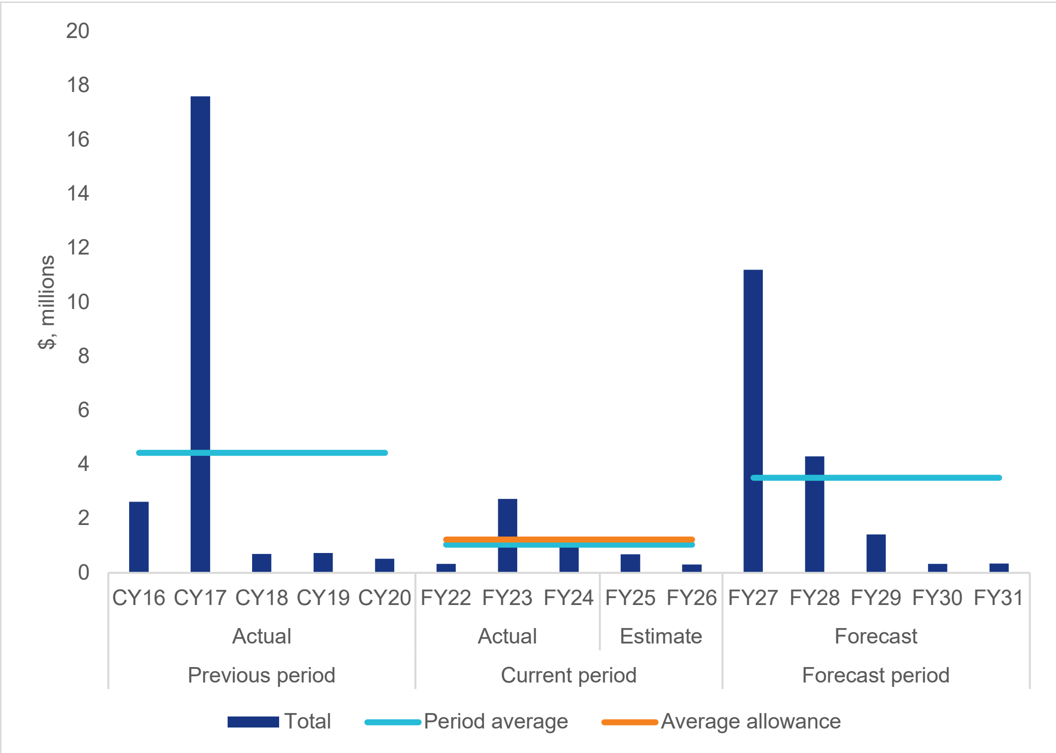
9.2 Forecast expenditure

Table 9–4 and set out our forecast and historical expenditure on property. Our forecast is materially higher than our expected expenditure for the current regulatory period due to a lumpy and high value expenditure associated with our proposed expansion of our Tullamarine Depot. However, on average, it is consistent with our actual expenditure for the previous regulatory period where we also had a lumpy spend in CY17. If we are to remove the lumpy spend in CY17 and the lumpy forecast for FY27 (primarily driven by the Tullamarine depot augmentation), our forecast average spend will only be slightly higher than the average capital expenditure for the current and previous regulatory period.

Table 9–4: Forecast non-network buildings and property expenditure, $2026, millions

Category	FY27	FY28	FY29	FY30	FY31	Total
Buildings and property	11.2	4.3	1.4	0.3	0.3	**17.6**

Figure 9–11: Non-network buildings and property expenditure, $2026, millions



9.3 Key drivers

9.3.1 Tullamarine Depot Augmentation

We need to increase the operational capacity and functionality of our Tullamarine Depot in order to address the issues we have identified at the site including those that relate to its design and functionality, ability to support business growth, compliance with relevant regulations and energy efficiency. After considering a number of options, including doing nothing, we propose to expand the site by building an additional 979m^2 of office space above the existing warehouse office space and an 86 additional staff car parking spaces. The project will cost $8M (in $2026) and will be implemented in FY27.

We consider our proposed expansion to be prudent and efficient. We have developed a robust business case, considered a number of credible options and have selected the option which will provide the long term benefits to customers. Our proposed Tullamarine Depot Augmentation project is consistent with our objectives for the property asset class listed above.

> Refer to the *JEN – RIN - Tullamarine Depot Augmentation – Business Case* for details about the need for this expansion, the identified risks, the credible options we have considered and our consideration of our customers' expectations.

9.3.2 Other property projects

We also propose to undertake the necessary property augmentation works at our three sites: Tullamarine, Collins St and Broadmeadows. Some components of their fit-outs have reached the end of their useful lives (> 11-13 years old), and we need to ensure that they remain compliant with building and safety regulations.

There are projects which are aimed at maintaining the currency of office accommodation and other facilities to promote a highly productive and engaged workforce, including ensuring that all sites continue to meet health and safety, Disability Discrimination Act and Building Code of Australia requirements. Examples of end of life replacement are the office floor coverings and office furniture at the Broadmeadows office and the uninterruptable power supply at Tullamarine depot.

The bitumen road surface at the Tullamarine property is now more than 10 years old and has deteriorated due to the high daily traffic volume from heavy trucks loading and turning. As a result, the surface has broken up, presents a health and safety hazard and requires replacement. Further, minor building improvements include the replacement of the gantry crane bollards and an upgrade to the hot room used to store electrical equipment in a warm environment so as to avoid moisture ingress.

At Tullamarine depot, which is also the location of the warehouse, materials stored outside and vehicles have been targets of thieves who enter and exit the site by damaging fencing. Despite the electronic security system having recently been upgraded, further improvement of the security fencing and gates is required to further deter thieves. This will prevent project delays due to materials being unavailable or vehicles being damaged or stolen.

The Heavy Vehicle (Mass, Dimension and Loading) National Regulation 2013 stipulates the maximum load that different types of vehicles are allowed to carry.[205] To ensure compliance with this regulations, a weighbridge is proposed at the Tullamarine depot. This will enable field crews to weigh the loaded vehicles to ensure compliance.

At the Broadmeadows depot, an additional exit point from the carpark is necessary for safety purposes, given the increase in the personnel working from the site and the congestion associated with the single point of entry and exit.

Our forecast capital expenditure on items such as office furniture and equipment is included under the non-network other category[206]—refer to section 9.3.3.

Given the growth in the investment in the electricity network in the next period, this is reflected not only in increased field-based resources but also office-based resources. This is reflected by the proposal to expand the Tullamarine depot for additional office-based capacity, and also the expansion of the accommodation associated with the Collins St Control Room and the SCADA laboratory facility. As we continue to automate the network in the next period, the volume of assets installed in the field that require control and monitoring capability from the Control Room will increase significantly and this requires additional SCADA testing capability.

It is important to have a back-up Control Room in order to ensure continuity of being able to monitor and control the electricity network in the case of an unplanned SCADA or communications outage or an emergency evacuation. Our exiting back-up Control Room facility is a modest solution which is only suitable for use in the case of emergencies. The fit out and the electrical and communications backbone infrastructure has reached end of life and requires replacement in the next regulatory period.

205 For more information refer to: National Heavy Vehicle Regulator, General mass and dimension limits, accessed 28 January 2025.

206 Consistent with the expenditure category definitions contained in the Reset RIN.

We also propose other minor capital expenditure to address unforeseen damage or failure of building systems, fixtures or fittings.

> As noted in section 9.2 above, if we are to remove the lumpy spend in CY17 and the lumpy forecast for FY27 (primarily driven by the Tullamarine depot augmentation), our forecast average spend will only be slightly higher than the average capital expenditure for the current and previous regulatory period.

9.3.3 Other

This category covers expenditure on non-network assets other than those which fall into the categories set out above. The non-network - other capital expenditure contained in our forecast consists of:

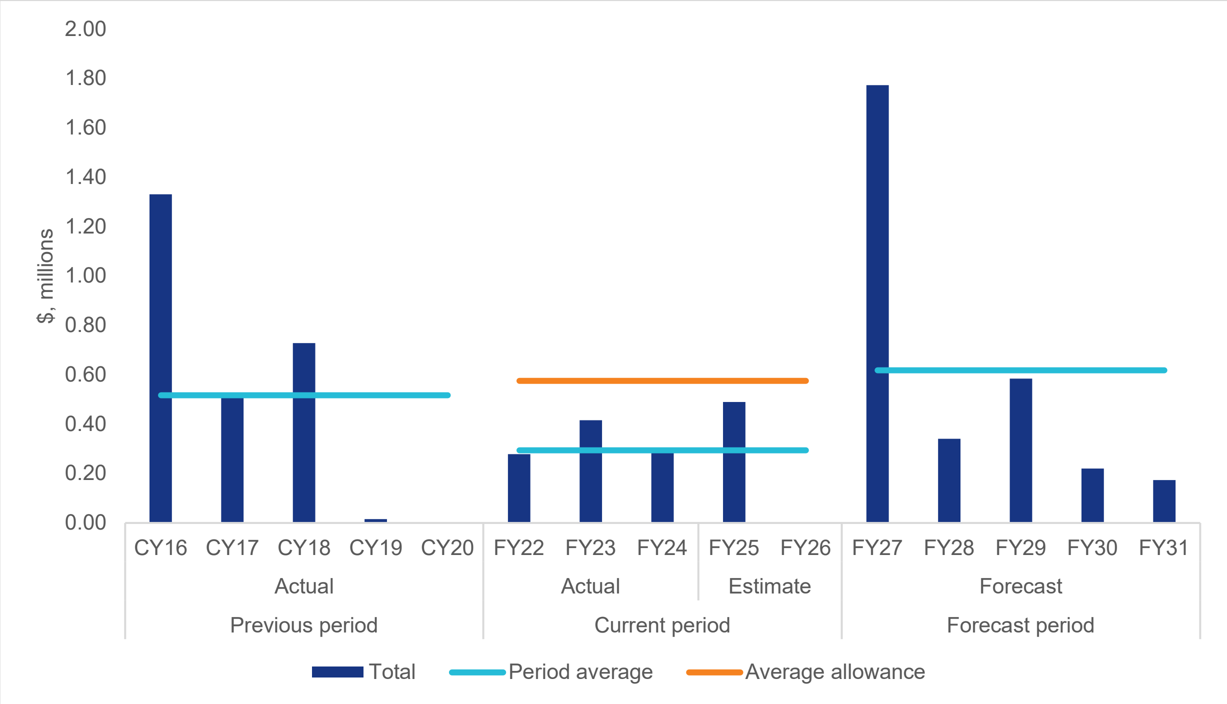
- **Tools and equipment used by personnel working on JEN's network.** Tools and equipment are replaced periodically to ensure they continue to perform as required. We forecast a lower spend on tools and equipment for the next regulatory period compared to our expected expenditure for the current regulatory period.
- **Office furniture.** This includes non-fixed items of office furniture and equipment, such as desks, chairs and kitchen equipment. During the next regulatory period we will replace chairs in our Tullamarine and Broadmeadows sites, which have reached the end of their useful lives. This will ensure that we maintain the safety and comfort for our staff which can lead to higher productivity and also prevent injuries.
- **Other plant and equipment which does not fall within a motor vehicle category.** We have some types of mobile plant (such as trailers, forklifts and other equipment fitted or connected to vehicles) which do not fall within a category of motor vehicle as defined by the Reset RIN. The characteristics of these assets and our approach to their lifecycle procurement, maintenance and replacement are consistent with our approach to motor vehicle assets as set out in Table 9–3 and described further in our Fleet Asset Class Strategy. We replace trailers at the end of their useful lives to ensure they remain in a safe and roadworthy condition and can be relied upon to support network operations. In our planning, we adopt a 15-year replacement cycle for trailers. However, each asset is subject to safety and condition inspections and is only replaced when it is unable to meet our requirements.

We forecast a total expenditure of $3M over the next regulatory period. Table **9**–**5** shows our forecast expenditure while Figure 9-3 shows our capital expenditure over three regulatory periods.

Table 9–5: Forecast non-network, other expenditure by category, $2026, millions

Category	FY27	FY28	FY29	FY30	FY31	Total
Tools and equipment	0.5	0.1	0.1	0.0	0.1	**0.9**
Office furniture and equipment	0.1	0.0	0.1	0.0	0.0	**0.3**
Trailers and non-motor vehicle plant	1.1	0.3	0.3	0.2	0.1	**1.9**
Total non-network other expenditure	**1.8**	**0.3**	**0.6**	**0.2**	**0.2**	**3.1**

Figure 9-3: Non-network, Other expenditure, $2026, millions



The main driver for the increase in capital expenditure is our proposed replacement of trailers and plant assets. Our assessment of the condition of the asset indicates that we need to replace the plant and trailers shown in Table 9–6. Without the lumpy forecast spend in FY27 to replace 30 trailers, our forecast expenditure will only be slightly higher than our actual expenditure in the previous regulatory period. Through prudent and efficient management of the fleet assets in the current regulatory period, we have been able to defer the replacement of some assets without increasing the risk profile for this asset class or impacting the reliable delivery of our services.

Table 9–6: Number of trailers and plant to be replaced, 2026-31

	FY27	FY28	FY29	FY30	FY31	Total
Plant	1	3	3	1	1	9
Plant - Material Handling	3	3	-	-	-	6
Plant - Excavator	1	-	-	-	-	1
Trailer	25	3	4	5	1	38
Total	**30**	**9**	**7**	**6**	**2**	**54**

Refer to Attachment *RIN – Support - Fleet Asset Class Strategy* for details about our plant and trailers' age and condition.

9.3.3.1 References

The proposed capital expenditure outlined in this section is supported by a body of materials and forecasts. The key documents are outlined in Table 9–7.

Table 9–7: List of Non-network - Other forecast expenditure attachments

Attachment	Name	Author
RIN Support	Fleet Asset Class Strategy	JEN
RIN Support	Property Asset Class Strategy	JEN

Attachment	Name	Author
RIN Support	Electricity Distribution Asset Class Strategy	JEN
RIN Support	Tullamarine Depot Augmentation – Business Case	JEN

10. Overheads

Our total capital expenditure forecast for the next regulatory period includes an amount reflecting the capitalised portion of our overhead expenditure. This reflects indirect expenditure for activities we carry out to support the delivery of our capital programs.

Our capital expenditure forecast for the next regulatory period includes capitalised network overheads only, consistent with the current regulatory period. All our corporate overheads are treated as operating expenditure.

The AER's forecasting method for capitalised overheads in the standardised SCS capital expenditure model[207] is to apply a 75% fixed and 25% variable percentage to the direct capital expenditure attracting overheads and based on the historical average overheads over the current regulatory period (i.e. FY22-FY24). This is also consistent with JEN's forecasting approach in the decision for the current regulatory period.

However, this approach will not adequately capture JEN's unique circumstance for the forecast period. JEN's capital expenditure program is expected to undergo significant change from the last two years of the current regulatory period driven by an unprecedented increase in data centre connections, major infrastructure projects, gas substitution and increased regulatory obligations. As shown in Figure 1–2 and Figure 1–3, we expect this trend to continue and magnify in the next regulatory period. As a result, the overheads required to adequately support our capital expenditure program—such as network planning and control, asset strategy, compliance and project governance—is also expected to increase significantly.

Due to these significant changes in capital expenditure, the AER's historical averaging approach (based on FY22-FY24) will not reflect the network overheads JEN expects to incur in the remaining two years (FY25-FY26) of the current regulatory period and the next regulatory period. For our initial proposal, we have therefore based our forecasts for capitalised network overheads on the actual FY24 overheads only (while maintaining AER's preferred 75%/25% fixed to variable cost ratio) as the more recent data better reflects the trends we anticipate in the next regulatory period.

Our forecasting method is set out below:

- Calculate the fixed portion of capitalised network overheads by multiplying 75% to the actual FY24 capitalised network overheads and then escalating by the forecast real labour escalation[208]
- Calculate the variable portion of capitalised network overheads by
    i. multiplying 25% to the actual FY24 capitalised network overheads to estimate the variable overheads
    ii. dividing the estimated variable overheads by direct capital expenditure that attracts network overheads for FY24 to estimate the variable overhead proportion
    iii. applying this proportion to the forecast direct capital expenditure that attracts network overheads for the forecast period FY25-31
- Sum up the fixed and variable portions of the overheads and allocate it proportionally to forecast capital expenditure projects attracting overheads.[209]

[207] AER, *Standardised SCS Capex Model - 16 December 2021.xlsb*

[208] The real labour escalation rates are taken as an average of Oxford Economics (Attachment 05-07) and Deloitte Access Economics (placeholder from the draft decisions of Ergon and Energex).

[209] The calculation of our capitalised overheads are provided in sheets 'Input|Overheads' and 'Calc|Overheads' of attachment *JEN - Att 05-10M SCS Capex model.*

11. Deliverability

We have a strong track record in efficiently and successfully delivering works for our distribution network. Our operating program delivery approach is based on an outsourced model for the delivery of field works. This means that we rely on contractors to deliver works rather than maintaining a field labour force itself. We currently have one primary contractor to provide the majority of our electricity field works. However, we may use a range of contractors to deliver significant capital projects such as in the next regulatory period.

We maintain a robust governance framework to monitor and control all activities undertaken by our contractors, with oversight of operations and program delivery. Our Electricity Asset Investment team is responsible for developing JEN's Capital and Operating Work Plan, which confirms the timings and costs of proposed works for a rolling two-year period. The Electricity Asset Investment team is then responsible for:

- issuing statements of work to contractors
- contractor management, including reviewing and approving contractor pricing, scopes and timings, work program oversight and audits
- approving invoices for work once completed and handed over to JEN.

Our higher capital expenditure forecast for the next regulatory period represents a bigger deliverable program of works. Our primary contractor has a proven track record in successfully delivering electricity field services for JEN and other DNSPs. Furthermore, our contract allows it to subcontract work to other service providers where efficient to optimise its delivery of services to us—for example, in cases of high workloads or where specialist services such as complex civil works are required.

> For our detailed delivery plan please refer to *JEN – RIN – 4.4.3 - Asset Management Delivery Plan*.

Appendix A
Compliance with the National Electricity Rules

A1. Compliance with the National Electricity Rules

We have considered whether our planning and forecasting processes, and our resultant capital expenditure forecast, are consistent with the capital expenditure objectives[210] and capital expenditure criteria,[211] as well as considering the capital expenditure factors[212] set out in the NER.

Our forecasting processes explicitly considers the drivers of capital expenditure set out in the capital expenditure objectives, and through our international best practice governance framework we have addressed the matters raised in the criteria. In relation to the resultant capital expenditure forecasts, our forecast capital expenditure is consistent with the requirements of the NER in that it reflects expenditure which is both prudent and efficient.

A1.1 Why our capital expenditure forecast is required to achieve the objectives in clause 6.5.7(a) of the NER

We have developed our capital expenditure forecast to achieve four key objectives set out in section 1.1.2. These objectives also reflect and are consistent with the capital expenditure objectives set out in the NER. We have primarily achieved this by (among other things):

- Conducting detailed analysis of the actual condition and age of our assets
- Assessing the sufficiency of our current compliance with regulatory obligations to identify required investments for corrective actions
- Assessing foreseeable changes in the external environment that will impact the level of risk associated with the provision of services to customers, and therefore the capital expenditure required to address these risks
- Quantifying customer-initiated requests to connect to our network as informed by expert demand reports and actual demand forecast from our large customers, including data centres.
- Developing a CER integration strategy and proposing efficient and prudent investments that will ensure that exports and imports from CER to our network are optimised.
- Incorporating real cost escalators to our input costs prepared by independent experts.

The table below summarises how we have complied with each of the capital expenditure objectives.

Capital expenditure objective	NER reference	Actions to ensure compliance
Meet or manage the expected demand for standard control services over that period	6.5.7(a)(1)	We have forecast our relevant capital expenditure categories to take into account the maximum demand, consumption, customer number and construction activity forecasts prepared by Blunomy and the Australian Construction Industry Forum. Our demand forecast associated with data centres has also been informed by actual information provided by said customers.
Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services	6.5.7(a)(2)	We have assessed our current compliance processes against our obligations as well as assessing any necessary corrective actions and additional new obligations. Our existing systems and processes—including our governance framework and ISO 55001-certified Asset Management System—ensure that our compliance with all applicable regulatory obligations is planned and maintained.

210 NER cl 6.5.7(a).

211 NER cl 6.5.7(c)(1).

212 NER cl 6.5.7(e).

Capital expenditure objective	NER reference	Actions to ensure compliance
To the extent there is no applicable regulatory obligation or requirement in relation to: (i) the quality, reliability or security of supply of standard control services; or (ii) the reliability or security of the distribution system through the supply of standard control services, to the relevant extent: (iii) maintain the quality, reliability and security of supply of standard control services; and (iv) maintain the reliability and security of the distribution system through the supply of standard control services	6.5.7(a)(3)	Our capital expenditure forecast has been developed with consideration of the impact of our changing external environment, compliance obligations, the actual condition of our assets and their age, the current and forecast utilisation of our assets and the effect these influences have on the quality, reliability and security of supply of standard control services. Where no applicable regulatory obligation exists, our expenditure forecasts are targeted at maintaining the current quality, reliability or security of supply, and maintaining the reliability and security of the distribution system. This is also consistent with the views our customers have expressed through our engagement program in relation to their preferences around service levels.
Maintain the safety of the distribution system through the supply of standard control services	6.5.7(a)(4)	Our capital expenditure forecast has been developed with consideration of the impact of our changing external environment, compliance obligations, the actual condition of our assets and their age, the current and forecast utilisation of our assets and the effect these influences have on the quality, reliability and security of supply of standard control services. We have also considered trends in asset failures and customer reports of safety issues as these may be indicative of potential safety issues in the future. Our forecast capital expenditure will allow us to comply with our Electricity Safety Management Scheme (ESMS). Our ESMS, which is overseen by Energy Safe Victoria, is a key control in ensuring the safety of the distribution system is maintained. Safety is JEN's number one priority.
Contribute to achieving emissions reduction targets through the supply of standard control services.	6.5.7(a)(4)	Our capital expenditure reflects prudent and efficient projects identified under our CER integration strategy. These projects will optimise and enhance the safe and reliable integration of CER into our network contributing to Victoria's and Australia's emissions reductions target. We also proposed to purchase environmentally friendly vehicles if it will be more efficient to do so.

A1.2 How our capital expenditure forecast reflects the criteria in clause 6.5.7(c) of the NER

We have developed our capital expenditure forecast to comply with the capital expenditure criteria specified in the NER. We have primarily achieved this by:

- employing our best-practice expenditure planning and governance processes, including our ISO 55001-accredited Asset Management System, to ensure that optimal planning and investment decisions are made which minimise the total lifecycle cost of achieving our expenditure objectives and providing services to customers

- engaging an external expert to develop maximum demand and customer number forecasts, and continuing to use a risk-based, probabilistic planning approach to our augmentation and replacement expenditure
- applying Condition Based Risk Management modelling to ensure our replacement activity volumes are based on the best available information about the actual condition and health of our assets, allowing us to only replace (or remediate) assets when necessary, in order to maintain service levels, avoiding unnecessary early replacements
- using efficient unit rates—which have been influenced by the strong incentives of the Capital Expenditure Sharing Scheme during the current regulatory period—to develop key parts of our capital expenditure forecast, in addition to obtaining independent bottom-up cost verifications of several major non-routine projects we propose to undertake
- fully exploring the potential for capital-operating expenditure trade-offs and non-network alternatives in our augmentation, replacement and non-network expenditure forecasting, with our proposal allowing us flexibility to undertake demand management (operating expenditure) where economic to reduce load at risk due to growing demand
- employing combinations of bottom-up and top-down forecasting methodologies when developing our proposal, including using top-down methods to challenge bottom-up forecasts, and ensuring delivery and scope efficiencies are reflected in our total forecast expenditure
- considering future levels of customer demand and opportunities to de-rate assets in our replacement planning, resulting in us reducing our replacement expenditure forecast compared to undertaking like-for-like replacements
- employing our robust cost estimation methodology and procurement processes to ensure all input costs to our capital expenditure forecast are efficient
- considering interdependencies with other areas of our regulatory proposal, particularly our operating expenditure forecast (which reflects the expenditure required to support ongoing asset maintenance and inspection activities which are necessary in the context of our efficient condition-based asset replacement and augmentation programs)
- not including any *expenditure for a restricted asset*[213] in our forecast.

A1.3 How our capital expenditure forecast accounts for the factors in clause 6.5.7(e) of the NER

The NER sets out the capital expenditure factors the AER must have regard to when deciding whether or not it is satisfied that our capital expenditure forecast reasonably reflects the capital expenditure criteria. The table below sets out points we consider relevant to each of the capital expenditure factors.

Capital expenditure factor	NER reference	JEN comments
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period	6.5.7(e)(4)	As a high-level assessment of relative capital efficiency, JEN ranks eight on capital multilateral partial factor productivity as set out in the AER's Annual Benchmarking Report (November 2024).[214] This benchmark performance suggests that despite JEN's scale disadvantage, we are managing to produce more with less, relative to our peers.

[213] As set out in the NER, *expenditure for a restricted asset* means capital expenditure for a *restricted asset*, excluding capital expenditure for the refurbishment of that asset.

[214] AER, Annual Benchmarking Report, Electricity distribution network service providers, November 2024.

Capital expenditure factor	NER reference	JEN comments
The actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods	6.5.7(e)(5)	JEN has a proven record in responding efficiently to expenditure (and related service performance) incentives while still safely and reliably delivering services to customers. We have illustrated trends in our capital expenditure over preceding regulatory control periods throughout this document.
The extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity customers as identified by the Distribution Network Service Provider in the course of its engagement with electricity customers	6.5.7(e)(5A)	We have engaged extensively with our customers in developing our regulatory proposal, including our capital expenditure forecast. Chapter 2 of our 2026-31 Plan details our engagement program while Attachment 02-01 addresses customer feedback in more detail.
The relative prices of operating and capital inputs	6.5.7(e)(6)	As outlined in our Asset Class Strategies, we employ whole-of-lifecycle management planning for our assets, which considers strategies and options over the entire life of an asset (from planning to disposal) to deliver the lowest long-term sustainable costs required to achieve our objectives. Lifecycle management focusses on ensuring an effective and efficient balance between maintenance (operating expenditure) and replacement (capital expenditure) of assets, based on analysis of asset safety, cost, risk and reliability. Additionally, we have utilised consistent input cost escalators for our capital and operating expenditure forecasts.
The substitution possibilities between operating and capital expenditure	6.5.7(e)(7)	We routinely analyse ways to optimise the economic life of our assets, with various examples of this analysis are included throughout our regulatory proposal and supporting materials. We continuously seek to optimise our expenditure decisions. During a regulatory period, this may result in us increasing operating expenditure in place of planned capital expenditure—or vice-versa—where efficient. For example, we assess whether asset replacement can be deferred by substituting capital expenditure with further maintenance—where it leads to lower long term average costs to our customers—having regard to the safety and reliability risks associated with these decisions. We also assess whether network augmentation and replacement projects can be deferred by utilising non-network alternatives, such as demand management.
Whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8A or 6.6.2 to 6.6.4	6.5.7(e)(8)	Our capital expenditure forecast reflects the prudent and efficient expenditure required for us to maintain our current levels of network reliability, consistent with the incentives provided by the Capital Efficiency Sharing Scheme, Service Target Performance Incentive Scheme, Demand Management Incentive Scheme and the Demand Management Innovation Allowance Mechanism.
The extent the capital expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms	6.5.7(e)(9)	Our forecast capital expenditure has been developed through our capital forecasting and governance process outlined in this document and our Procurement Policy, which ensures prudent and efficient procurement outcomes. Refer also to JEN's response to Section 4.15 of the reset RIN notice for a description of the relevant related party agreement.

Capital expenditure factor	NER reference	JEN comments
Whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b)	6.5.7(e)(9A)	Our proposed forecast capital expenditure does not include an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network options	6.5.7(e)(10)	We have considered at length the potential for efficient and prudent non-network options when developing our capital expenditure forecast. Through this process, we did not identify any situations where a non-network solution represented the most prudent and efficient option to address an identified need. Our business cases, submitted as part of the 2026-31 Plan, have considered non-network option as one of the credible options where relevant. We will continue to assess opportunities to employ non-network options during the next regulatory period, and as a result may substitute operating expenditure for capital expenditure where prudent and efficient to do so.
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	6.5.7(e)(11)	Our capital expenditure forecast includes a number of projects that are subject to the Regulatory Investment Test for Distribution, as described in section A1.5 of this Appendix.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is a capital expenditure factor	6.5.7(e)(12)	The AER has not notified JEN of any other factors it considers relevant.

A1.4 Allocation of expenditure to standard control services

Consistent with the requirement of NER clause 6.5.7(b)(2), JEN's forecast capital expenditure reflects expenditure which has been properly allocated to standard control services in accordance with the principles and policies set out in the JEN CAM.[215]

A1.5 Capital expenditure for options which have satisfied the RIT-D

Consistent with the requirement of NER clause 6.5.7(b)(4), JEN's forecast capital expenditure for the next regulatory period includes capital expenditure that is for an option that has satisfied the regulatory investment test for distribution in relation to following projects identified in Table A1–1.

215 The JEN CAM that has been approved by the AER and is to apply during the next regulatory period is available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/cost-allocation-method/jemena-cost-allocation-method-2019.

Table A1–1: Capital expenditure for options which have satisfied the RIT-D, 2026-31, $2026, millions

Project	Section reference in this document	Proposed capital expenditure (direct costs only)
Coburg North zone substation redevelopment	Section 6	45.57
Coburg South zone substation redevelopment	Section 6	34.5
North Heidelberg transformer, switchgear and relay condition	Section 6	14.8
East Preston conversion stage 7 and stage 8	Section 4	44.1
Establish New Feeder SBY-031 to address SMH thermal capacity constraint	Section 4	6.5
Thomastown-NEI-North Heidelberg-NEL-Watsonia 66 kV loop capacity constraint	Section 4	11.3
Sydenham and Sunbury area capacity constraint	Section 4	11.2
Flemington area capacity constraint	Section 4	8.7

A1.6 Key assumptions underlying our capital expenditure forecast

Consistent with the requirements of NER clause S6.1.1(4) and (5), the key assumptions underlying our capital expenditure forecast are listed in our response to paragraph 1.8 of Schedule 1 to the Reset RIN and a certification of the reasonableness of these key assumptions by the directors of JEN is provided as Attachment 12-04.

A1.7 Explanation of significant variations between forecast and historical capital expenditure

Consistent with the requirement NER clause S6.1.1(7), an explanation of any significant variations in the forecast capital expenditure from historical capital expenditure is provided in Table A1-2.

Table A1–2: Comparison between forecast and historical gross capital expenditure (2026, $M)

Capital expenditure category	Current regulatory period	Next regulatory period
Replacement	271.9	427.3
Connections	623.6	1102.6
Augmentation	202.8	269.5
Non-network	141.8	207.2
Capitalised overheads	169.7	222.2
Total	**1,409.6**	**2,228.9**

1) Gross capital expenditure.

Key drivers of the differences between our current regulatory period's and forecast capital expenditure include:

- strong demand from commercial and industrial customers, including data centres for connections
- condition- and risk-based replacement of a number of types of existing assets (including poles, pole top structures), and major zone substation rebuild projects which includes Coburg North, Coburg South and North Heidelberg zone substations.
- new initiatives to be undertaken as part of our CER integration strategy in response to growing DER penetration and regulatory requirements

- a number of non-recurrent capital projects we need to implement to support or enable our CER Integration strategy (new capability), comply with AEMO's mandatory market reforms and maintain existing business requirements
- relocation of assets that are in flood-risk zone areas with Flemington (the Maribyrnong project) to maintain reliability of the relevant assets and our network.

This document provides further detail on our forecast capital expenditure for the next regulatory period and our expected capital expenditure for the current regulatory period.

Appendix B
Asset management system governance

Jemena
bringing energy to life

B1. Asset management system governance

B1.1 Jemena's Asset Management System

B1.1.1 Asset Business Strategy

The purposes of our Asset Business Strategy are to:

- provide a comprehensive analysis of potential future trends over the long-term (i.e. 20 years)
- identify our customers' long-term preferences and ensure that they shape our long-term planning
- identify innovations and changes in technology, policy, and regulation, and their likely influences on how we provide services
- ensure network safety and service quality over the long-term
- assess expenditure scenarios on our overall network performance
- provide a high-level forecast of service costs over the next 20 years, cognisant of the changes in the operating environment which are likely to occur over this time.

B1.1.2 Asset Class Strategies

Our Asset Class Strategy documents describe the performance and risks of each class of asset that we use to enable the provision of services to customers. We divide our network assets into four asset classes. Asset Class Strategies are designed to enable the optimum development of asset strategies and plans, and provide information about:

- asset class profiles, including the type, specifications, life expectancy and age profile of the asset class in service across our network
- asset strategies, including key strategies and plans that support Jemena's Business Plan, Asset Management Policy, strategies and objectives, and inform the development of expenditure plans and programs of work
- asset risks, issues and criticality
- asset performance, including information about performance objectives, measures and analysis
- asset expenditure assessments, including expenditure decision-making processes (and how expenditure options are analysed)
- historical and forecast expenditures
- whether to renew or dispose of assets that have reached the end of their economic life based on their performance, risks and/or supply security or service level requirements.

JEN aims to ensure that we optimally manage our assets in our customers' long-term interests. Our Asset Class Strategies use leading asset management techniques to ensure we strike an efficient balance between capital and operational expenditure through the consideration of total lifecycle management costs. However, different asset classes will have different lifecycle management strategies; therefore, we examine these options and trade-offs for each asset class.

B1.1.3 Network Development Strategies

We produce Network Development Strategies for specific geographic regions within our network area. Each region's Network Development Strategy provides information about emerging capacity risks and options to economically mitigate these risks. Each document is developed in accordance with our network augmentation planning criteria[216], and sets out:

- specific investment drivers and details of the network constraint(s)
- a summary and analysis of each credible option (including assessments of gross market benefits, net market benefits, and sensitivity analysis)
- the assessment methodology and assumptions (including information relating to economic planning, demand forecasts, asset ratings, Value of Customer Reliability, network outage rates, discount rates and cost estimates)
- a preferred option to mitigate an identified constraint.

B1.1.4 Asset Management Plan and Asset Investment Plan

The Asset Management Plan (and accompanying Asset Investment Plan) sets out an integrated approach to the activities undertaken by JEN to manage its asset lifecycles to ensure the efficient, JEN-wide delivery of optimum outcomes over the medium term.

The purposes of these documents are to:

- detail the operating environment and our customers' expected levels of service
- summarise risks and opportunities, contingency planning, and governance
- identify the type, number, condition and performance of JEN's assets, and their associated technical and commercial risks
- deliver on the JEN Asset Management Strategy and Objectives, including formal obligations and regulatory requirements and define the optimal and sustainable management of our assets in customers' long-term interests
- inform the capital and operating expenditure requirements set out in our Capital and Operational Work Plan
- ensure all investment decisions and strategies are aligned to the capital and operating expenditure objectives, criteria and factors as set out in clauses 6.5.6 and 6.5.7 of the National Electricity Rules.

JEN's Asset Investment Plan focusses on network assets while providing cross-references to more detailed strategies and plans for to non-network expenditure such as non-network IT.

We develop our Asset Management and Investment Plans consistent with our capital planning governance processes described in section B1.2. Once developed, JEN's Asset Investment team puts forward a complete annual program of capital works to the Executive General Manager Jemena Networks, which is then subject to the approval of the Chief Financial Officer and Managing Director.

B1.1.5 Capital and Operational Work Plan

The purposes of the Capital and Operational Work Plan are to define:

- the activities JEN needs to carry out over the next two years to enable the provision of services to customers—namely the designing, constructing, operating, maintaining and supporting our electricity distribution network
- the scope of these activities and the various categories that are used to group and present expenditures (both capital and operating expenditure)
- the associated projects and budgets.

216 RIN Response – *JEN network augmentation planning criteria paper.*

B1.2 Asset Management System Governance

B1.2.1 Structures, authorities and responsibilities

The responsibilities and authorities of key functions within the Jemena Group are defined through an organisational structure underpinned by position descriptions managed via Jemena's human resource management systems. Additionally, we maintain a comprehensive RASCI (Responsible, Accountable, Supportive, Consulted, Informed) mapping of these positions to processes (the identification of who is responsible, accountable, supporting, consulted and informed).

Structures, authorities and responsibilities relevant to the Jemena Group's asset management system—which JEN utilises—include the following:

- **Jemena Managing Director.** Accountable for the management of Jemena, and responsible for setting Jemena's Business Objectives, Vision and Values, under the guidance and support of the Board of Directors.
- **Executive General Manager Networks.** Accountable for the Jemena Group's Asset Management System and chairs the Group-wide Asset Management System Review Committee (**AMSRC**), which has responsibility for the Asset Management System as a whole. Also develops Jemena's Asset Management Policy (which is signed-off by the Managing Director).
- **Asset Management System Review Committee.** Provides general and senior management with a forum to monitor and review the Asset Management System to ensure it is fit for purpose and delivers the Jemena Business Plan.
- **General Manager Asset and Operations (Electricity Distribution).** Responsible for ensuring the control of asset-related risks for JEN.

Further information is provided below on the roles and responsibilities of various committees within our asset management system governance.

B1.2.2 Asset Management System Review Committee

The AMSRC is responsible for JEN's asset management system, including providing governance, ensuring alignment with business objectives and reviewing processes. Its functions include:

- directing the on-going development and implementation of the asset management system including alignment with other assets within the Jemena Group
- promoting the asset management system throughout the organisation while managing any interdependencies with corporate initiatives, strategies and objectives, developments, and business functions
- evaluating and ensuring the asset management system's sustained performance and continual improvement with respect to business policy, strategy, objectives, and planning
- implementing quality assurance via audits, including tracking compliance with legal and regulatory requirements and ensuring the completion of audit recommendation actions.

Management review of the asset management system is also completed through the AMSRC, the membership of which includes senior members from across the Jemena Group's Asset Management teams.

B1.2.3 Operational Forums

We have two operational forums which monitor our performance in terms of expenditure and service to customers:

- **Operational performance management forum.** This forum monitors the performance and progress of JEN's routine and non-routine capital and operating works (excluding IT) and KPIs, including facilitating business case approvals for projects as required.
- **Asset Performance Reviews.** This forum monitors the performance of JEN assets and the quality of service they deliver to customers, considering key performance indicators such as supply reliability, power quality and performance against guaranteed service levels.

B1.2.4 Standardisation Committees

Achieving our objectives relating to the asset performance and lifespan required of the equipment used within the distribution network requires a risk-based approach to the introduction of engineering changes and new technologies. Such changes in technologies and their potential opportunities, risks and impacts are considered through technical standards, which we maintain for our network.

We construct (or procure) new assets in accordance with our set of pre-defined technical standards to minimise the number of different assets and configurations across the network, thereby reducing procurement costs and operational and maintenance costs (including responses to plant failure), as well as minimising the number of spares which need to be held.

Standard development and modification is undertaken by several specialist areas within JEN that have responsibility for particular asset groups. For example, protection standards are developed by Asset Engineering's Protection and Control Group and the Primary Plant group develops primary plant standards. A system of standardisation committees has also been used for the development of standard designs, policies and procedures associated with the design and construction of primary plant and distribution system assets.

The standardisation committees comprise stakeholders from across JEN with technical expertise in asset management and planning, works delivery, construction and health, safety, environment and quality, to ensure a broad cross-section of input into standards development. These expert stakeholder committees collaboratively undertake standardisation activities in accordance with the JEN Standards Development and Modification Procedure. Risk assessments form part of the standard development process.

There are five constituted standardisation committees. The level of activity in each area determines committee meeting frequency and meeting formality. Membership of the committees can vary depending on the issue under consideration and the expertise required. New committees can be established to address the particular problems if required.

The standardisation committees are as follows:

- **Cables and Ground Mount Substations Standardisation Committee.** The focus of this committee is the standardisation and design of sub-transmission, high voltage and low voltage underground cable systems and indoor, ground mount and kiosk-type distribution substations. This includes the materials and equipment associated with these systems and the civil requirements for distribution substations.

- **Overhead Lines Standardisation Committee.** The focus of this committee is the standardisation and design of structures and engineering systems associated with the sub-transmission, high voltage and low voltage distribution networks. This includes the materials and equipment related to these systems. The scope extends to customers' service connections to the network.

- **Servicing Standardisation Committee.** The focus of this committee is the standardisation of the design and construction of overhead and underground services for customer installations and includes services supplied direct from substations.

- **Zone Substations Primary Standardisation Committee.** The focus of this committee is on the design and construction of primary plant and facilities associated with zone substations and terminal stations that contain JEN assets. This includes the material and equipment associated with these installations and the civil and structural requirements.

- **Victorian Protection and Control Working Group** The working group is represented by all 5 Victorian distribution businesses with its focus being on optimising design standards, philosophies and approaches for protection and control systems for Network assets.

B1.3 Asset Information Management

Information is another key pillar of an effective asset management system and asset management decision making and activities. High quality and readily accessible information such as asset descriptions, performance measures, design parameters and the functional location is vital to the development of effective Asset Class Strategies and a range of other planning and operational decisions within our asset management system. We, therefore, maintain a comprehensive content management framework to facilitate the effective storage of electronic and non-electronic records.

Examples of asset information that may be required to facilitate effective decision making within the asset management system include:

- performance measures (depending on the criticality of the asset class and the selected lifecycle strategy, this may include failure rates, plant availability, plant defects, and corrective maintenance rates)
- asset identification numbers
- design parameters
- the functional location of the asset
- asset descriptions, including vendor details
- ratings, voltage level and operational requirements
- individual asset condition records
- commissioning dates
- operational expenditure
- capital expenditure
- regulatory reporting information
- risk management
- contingency and business continuity planning.

JEN uses several systems for managing its asset information. Maintaining an information management systems provides for common terminology for financial and non-financial information, enabling vertical information flows from senior management to operational areas, and horizontal flows between the asset management, financial management and risk management functions. This helps facilitate efficient communication and better integration of information sources to enable more effective planning, operations and reporting.

Jemena also maintains a content management framework, which is heavily informed by the asset management system. Records are either kept electronically or stored/archived as hard copies. Record retention timeframes are determined by either statutory or commercial requirements, or by individual teams, depending on the information contained within the records and how it is used for asset management decision making. The Human Resources and Health, Safety, Environment and Quality function within Jemena is responsible for our content management framework.

The electronic content management technologies we use to store and maintain content relevant to JEN include:

- HSEQ, a quality management system
- ECMS, our enterprise content management system
- Drawbridge, a drawing management system
- GIS, a geographic information system
- SAP, our business operations and customers relationship management system
- the JEN intranet team sites
- network drives.

For JEN asset management, all key asset management documents are managed, tracked, reviewed and continuously improved in accordance with the Key Asset Management Document Register. Project documents, asset drawings and geographical asset information are all managed through controlled electronic record storage systems.

B1.4 Change Management

Effective governance and continuous improvement requires change to be implemented seamlessly and effectively to minimise the risk of unexpected outcomes. Internal or external changes affecting assets, asset management or the asset management system can impact JEN's ability to achieve its asset management strategy and objectives, which can have adverse consequences for customers and other stakeholders. As a result, planned changes require evaluation and management to mitigate potential issues before implementation.

Some of the key areas requiring change management include:

- continuous improvement to or changes arising from a review of asset management policy, the asset management system, Asset Management Strategy and Objectives, Asset Management and Investment Plans, or the delivery of the Asset Management and Investment Plans
- organisational structures, roles or responsibilities
- processes or procedures for asset management activities
- new assets, asset systems or technology (including obsolescence)
- changes in customers' expectations of the services we provide
- factors external to the organisation (including new legal or regulatory requirements)
- supply chain constraints
- demands for products and services, contractors or suppliers, and
- demands on resources, including competing demands.

B1.5 Asset Risk Management

Risk management is a further key component of an effective asset management system, by providing a structured process for identifying risks, identifying preventative actions or controls, and minimising the impacts if events do occur. Jemena maintains an organisation-wide risk management framework, and risk management activities within our asset management system are carried out in accordance with Jemena's Risk Management Policy, Risk Management Manual and Risk Management Guidelines.

Jemena maintains a team which is the organisation-wide custodian of risk management. The General Manager Risk is accountable for the management of corporate risks, while the Asset Risk and Assurance Manager is responsible for the management of risks specific to our electricity network.

We use our Risk Management Framework to develop individual risk matrices. Through this framework, risks are monitored and reported to the Jemena Leadership Team, Executive Risk Management Committee and Board Risk Management Committee.

Further detail on how risk management is explicitly applied in relation to capital planning and governance is provided in section C1.5.

B1.6 Asset Management System Compliance

Jemena maintains a company-wide Compliance Management Framework to ensure compliance with regulatory obligations which relate to its operations. All of Jemena's material compliance obligations are recorded and managed within the Jemena Compliance and Risk System, which is designed to comply with Australian Standard 3806. We have several designated Compliance Program Managers who are responsible for maintaining this system and monitoring and reporting on Jemena's compliance in their respective areas.

Our compliance and safety procedures are described in our Electricity Safety Management Scheme (**ESMS**), with Electricity Safety Management Plans used to address key compliance risks. Our ESMS itself is reviewed quarterly by management at the ESMS Management Review Committee and also at the Asset Public Safety Committee.

Jemena's Leadership Team reviews summarised compliance management performance reports quarterly. Additionally, the Jemena Risk Committee monitors, reviews and evaluates the implementation of the Risk Management Framework, facilitating the development of a common, organisation-wide risk management approach by:

- implementing the framework
- sharing information with broad applicability across all areas of the organisation
- reporting on the progress of risk management framework implementation
- integrating risk management with business-as-usual activities.

B1.7 Asset Management System Audit

As part of our compliance management activities, we conduct systematic reviews of compliance through audits. The internal audit team is responsible for non-technical audits within Jemena and reports to the Audit Committee directly to ensure transparency. Internal audits are designed to assess the effectiveness of controls put in place as a consequence of a particular management system, which may include the following:

- **Jemena Compliance and Risk System.** As per the evaluation of compliance, all audit actions are monitored and tracked through the Jemena Compliance and Risk System (OMNIA), with formal reports generated monthly to track their progress. Once an action is closed, the internal audit team reviews the outcomes.
- **Asset Management System Review Committee.** In addition to the internal audit team's reviews, the Asset Management System Review Committee is responsible for reviewing the asset management system and its continued 'fit for purpose' status.
- **Audit and Risk Management Committee.** This committee governs and controls the internal auditing procedures, approves and prioritises regular audit action reports, and conducts completed action reviews.

Additionally, we conduct both internal and external audits to ensure safe fieldwork practices are maintained.

B1.8 Asset Management System Improvement

A key component of Jemena's process of continuous improvement involves ongoing performance monitoring, with corrective and preventive actions resulting from audits (technical and risk) and incident investigations being input into the Jemena Compliance and Risk System. Opportunities for improvement may also be realised from other internal and external sources. We have, therefore designed our asset management system to be readily adaptable to easily accommodate change by ensuring a simple and effective method for identifying improvements is available.

B1.8.1 The role of the Asset Management System Review Committee

The Asset Management System Review Committee is responsible for determining opportunities and assessing, prioritising and implementing actions to achieve continuous improvement and reviewing its subsequent effectiveness.

This role includes:

- non-conformity and corrective action, particularly for emergency, failure and incident investigation
- examining trends in performance
- evaluation of compliance
- internal and external audits of our asset management system
- management review
- empowering employees to make suggestions
- change management.

B1.8.2 Our approach to continuous improvement

As a further approach to continuous improvement, JEN actively seeks to acquire knowledge about new asset management-related technology and practices, including new tools and techniques. These are evaluated to establish their potential benefits and risks, and if appropriate, are incorporated into both the Asset Business Strategy and individual Asset Class Strategies. Examples include:

- active participation in professional bodies and industry associations
- conferences, seminars, publications and journals
- benchmarking and technology transfer initiatives, and competitor check-ups
- engaging specialist organisations to provide advisory or audit services
- research and development
- consultation with customers and suppliers.

Appendix C
Capital planning governance and forecasting

Jemena
bringing energy to life

C1. Capital planning governance and forecasting

C1.1 Capital project prioritisation

To ensure the efficient deployment of capital, JEN maintains a process to rank and prioritise projects proposed for inclusion in our program of capital works. The process provides a consistent approach to the evaluation of projects in relation to customer, risk mitigation, strategic and financial benefits, ensuring that all our investments are robustly evaluated to deliver a net customer benefit, to mitigate unacceptable risks and to deliver an expected return on investment that is acceptable to our shareholders. Given many of our investments are very long term in nature, this evaluation needs to account for long-term trends in customer demands and customer needs, growth in competing alternatives for customers and risk in future industry scenarios.

> In prioritising capital projects, we are mindful of the asymmetric risk of under-investment with sustained increases in maximum demand (winter and summer) and data centre rollout. The asymmetric risk of under-investment in our network emerges because any delays in responding to increasing demand create disproportionate negative outcomes when demand exceeds our network's capacity. The risk is asymmetric because the consequences of under-investment leads to much higher costs (outages, system failures, customer satisfaction) than if investments were made earlier. The benefits of waiting to invest often include only short-term savings.
>
> Additionally, delays can result in "capacity deficits," where existing infrastructure becomes increasingly stressed, and we face higher costs to repair, maintain, or temporarily upgrade services. Unlike other forms of investment, we cannot quickly scale up our network in response to surges in demand. Once the need for additional capacity becomes urgent, the ability to add infrastructure to the grid is constrained by time and regulatory processes. By then, it may be too late for us to avoid the negative impacts.
>
> All these risks can have cascading negative effects on the JEN's performance, customer satisfaction and the economy.

High-level steps involved in this process include:

- identifying all potential capital projects, including customer connections, asset replacement and network augmentation and non-network projects;
- identifying mandatory projects, such as customer-initiated connections projects and projects commenced in the previous year;
- defining projects sufficiently to enable their comparison with other projects;
- identifying risks, net customer benefits, strategic benefits and financial benefits for each project;
- ranking the projects in order of net customer benefit; and
- removing projects from the planning horizon where their net customer benefit is relatively low and not sensitive.

Our project prioritisation process also allows us to optimise our planning and maximise our delivery efficiency by considering:

- **Project coordination opportunities.** Where possible, we seek to coordinate projects which will occur at the same location, for example, a zone substation. Opportunities for such coordination may often arise for asset replacement projects, such as switchboard and secondary equipment replacement.
- **Long lead-time projects.** The replacement of some equipment at zone substations, such as transformers and switchboards, can require very long lead times—in some cases, the delay between placing an order for such equipment and it is delivered by the manufacturer can be 18 months. By factoring these lead times into our project prioritisation, we can ensure equipment is procured at a competitive price and the timing of the project's commissioning is optimal.

- **Constraints on timeframes for project commissioning or works.** We identify certain projects that must be completed before summer to ensure that network constraint are addressed before the likely period when peak demand will occur. This is most common for augmentation projects, such as new transformers, zone substations or feeders, the augmentation of sub-transmission lines or feeders, or establishing tie lines between feeders. Other types of projects, such as zone substation switchboard replacements, can generally only be performed during limited time windows (such as winter or spring, when peak demand is forecast to be lower), in order to limit the risk of supply disruptions for customers.

- **Identification and acquisition of land and easements.** We commence the identification and acquisition of properties and easements for zone substations well in advance of the construction of those assets, to ensure their availability and certainty of required planning permits and other approvals. For new zone substations typically needed in areas of greenfield urban growth, land may be scarce or in high demand. Additionally, community and stakeholder expectations are continually evolving, meaning we must consider factors such as visual amenity, electromagnetic field exposure, perceived reductions in neighbouring property values and environmental impacts of new zone substations. We are committed to the early and rigorous community and stakeholder engagement to provide transparency around the need for and benefits of proposed works. We, therefore, consider the potential benefits of securing land early in the subdivision process to avoid higher costs of developing a zone substation in an already developed area, weighed up against long-term forecasts of the required location of new demand and infrastructure.

This process ensures that our capital expenditure forecast is optimised and provides an integrated, coordinated and prioritised program of works aligned to our strategy and objectives, therefore delivering maximum benefits to our customers over the long-term.

C1.2 Our Project Management Methodology

Project management is an essential tool in the construction and management of our assets in line with our objectives and customers' long-term interests. To drive the prudent and efficient selection and delivery of capital projects, we have a standardised Project Management Methodology (**PMM**). Our PMM is structured around a seven sequential 'gates' which provide management focus at key points within the project's life, ensuring we deliver projects on time, within cost and to the required quality, in a safe, reliable and efficient manner. There are four phases within our PMM, illustrated in Figure C1–1.

Figure C1–1: Project Management Methodology phases

Projects officially commence with the issue of a Preliminary Project Mandate document, produced as part of pre-project planning and assessment activities. This ensures that we only incur costs undertaking detailed design for projects which are included within our plans and consistent with our asset management objectives. The first two stages are focussed on planning and design to a level of detail and certainty sufficient to obtain a final investment decision.

Following final investment decision, the project moves into the delivery phase, which entails any necessary further detailed design work, when a gate four certificate is issued to verify that the project is ready to commence construction in a safe and controlled state. Mobilisation, construction and commissioning activities can then proceed. Finally, the close phase ensures that high quality technical and financial asset records are produced and archived promptly, in accordance with regulatory requirements.

Products, outcomes and associated gates for each phase of our PMM are explained further in Table C1–1.

Table C1–1: Project Management Methodology phase descriptions

Phase	Product	Outcome	Gate
	Pre-project A supported infrastructure objective, as defined in the preliminary project mandate	Asset Investment Plan/Capital and Operating Works Plan updated to reflect the potential project	
Initiate	**Option** An articulated asset scope with delivery concept and constraints	Option confirmed	Gate 1
Plan & define	**Scope definition** A refined and validated, technically feasible design	Scope and requirements defined	Gate 2
	Plan Technical design, cost estimates and project delivery details sufficient to obtain approval	Detailed project plan	
	Approve An approved and funded project	Final investment decision and delivery approval	Gate 3
Deliver	**Prepare & mobilise** A finalised design and plan, ready for construction	Ready for construction	Gate 4
	Construct The project is fully mobilised and is in a ready state to commence the delivery stage	Project mobilised	
	Finish A functioning asset, ready for commissioning	Construction complete	Gate 5
	Commission A quality asset accepted by the owner as ‘fit for service’	Project delivered	Gate 6
Close	**Settle** A fully documented asset and a completed project		
	Close A fully capitalised asset and a closed project	Project closed	Gate 7

C1.3 Cost estimation

Our capital expenditure forecast is comprised of individual cost estimates, which we have developed by applying the principles set out in the JEN Cost Estimation Methodology.[217] We apply our Cost Estimation Methodology consistently to provide a robust estimating framework that employs the best available information to develop project estimates, depending on the nature and timing of the project. Our approach:

- provides accurate and consistent project estimates for all works, recognising the nature of the proposed work and its likely timing;
- ensures that business cases and forecast programs have been estimated using appropriately sourced, realistic and efficient input data;
- provides project estimates that account for safety, environmental and regulatory requirements;
- identifies opportunities for innovation;
- identifies the risks associated with the relevant works and ensure that these are communicated to Project Managers (for example the likelihood of encountering rock during excavations);
- ensures appropriate estimates are prepared at different stages of our Project Management Methodology;
- ensures risk is treated appropriately, recognising that JEN undertakes a portfolio of projects and programs of work, and scope adjustment factors should be applied at the portfolio level;
- ensures value for money for our customers; and
- ensures there is a formal change process if circumstances change for a project.

C1.3.1 Estimation techniques

We use a combination of two broad estimation techniques for capital projects—top-down and bottom-up. These ensure our project estimates are fit-for-purpose in the context of our Project Management Methodology (and its various gates) and the different planning horizons of our various plans, from our rolling two year Capital and Operating Work Plan to our seven-year Asset Investment Plan (and our regulatory proposal's forecast capital expenditure).

We employ three types of cost input in developing our cost estimates (which form part of our capital expenditure forecast), ensuring our estimates best reflect the actual efficient costs we forecast to incur:

- actual historical costs of completed projects of a similar scope;
- input from experienced engineering, design and construction personnel; and
- quotations from external service providers.

217 Our Cost Estimation Methodology for network assets is provided as JEN-RIN-4.4 Jemena Electricity Networks Cost Estimation Methodology – 20250131. We employ a separate approach to non-network ICT expenditure to reflect the unique characteristics of ICT assets and the uncertainty created by the fast pace of technological developments and fact that the price review planning horizon for ICT assets (up to seven years) can be longer than the lives of those assets. The approach to developing capital expenditure for non-network ICT is set out in JEN – RIN – Support – Technology Plan.

C1.3.1.1 Top-down estimation

Our top-down estimation technique relies on historical data from completed projects (or programs) of similar scope to estimate the cost of future projects. We maintain historical data using internal databases, with information sourced from:

- historical data from past projects;
- recent tender prices;
- expected labour costs; and
- contractor prices.

C1.3.1.2 Bottom-up estimation

Our bottom-up estimation technique involves our experienced engineering, design and construction personnel working with the design brief and functional scope of a proposed project to estimate the cost of each individual work package. We have estimating templates for major categories of work based on appropriate design and construction standards using bills of materials, standard task lists and base planning objects. In some cases, bottom-up project cost estimates may use quotes from third-party service providers—refer to section C1.6 for further information about our procurement process.

C1.4 Business case assessments

We develop business cases to ensure that all capital investment decisions are prudent, efficient and best promote the long-term interests of our customers. Each business case uses a combination of technical, economic and financial analysis to determine the optimal solution and timing to address an identified need, and covers three key elements:

1. The project need, including:
   - Discussion of potential issues, such as deteriorating asset condition/performance or network capacity constraints, and the implications (impacts or risks) to customers arising from this issue
   - Relevant regulatory obligations that the project will address, such as new requirements for the provision of settlement data to the market operator
   - The project's objectives with reference to Jemena's Business Plan, strategic objectives, customer views and the National Electricity Rules' capital expenditure objectives[218]
   - Consideration of our customers' priorities or expectations.
2. Options to address the project need, including:
   - Quantifying costs and risks of each option, including assessment of alternative project timings (e.g. deferral) and non-network alternatives
   - Assessing the costs and benefits to customers of each option.
3. A recommended optimum solution that maximises net benefits to customers, including:
   - Financial analysis to demonstrate the project is financially viable and represents the option which will best promote the long-term interests of customers, consistent with the National Electricity Objective
   - Identification of mechanisms by which the project will be funded, including internal Delegation of Financial Authority approvals.

Factors and attributes considered in our business case financial and economic evaluations are outlined in Table C1–2.

[218] NER cl 6.5.7.

Table C1–2: Business case financial and economic evaluation factors

Key consideration factor	Attributes
Capital inputs	• Capital investment • Profit or loss on the sale or disposal of assets
Non-capital costs	• Operating expenditure • Regulatory incentive scheme penalties
Benefits	• Regulatory incentive scheme rewards • Avoided/reduction in future operating costs • Avoided/reduction in future capital costs • Avoided supply risk • List of unquantifiable benefits

C1.5 Risk management

Effective risk management is an essential part of efficient capital planning and governance and is integrated into our organisation's culture. All risk management activity within JEN is governed by our Risk Management Policy, summarised in Figure C1–2. We undertake risk management in conformance with AS/NZS 31000:2018.[219] This involves the identification, evaluation and efficient management of all credible risks to ensure they are acceptably mitigated.

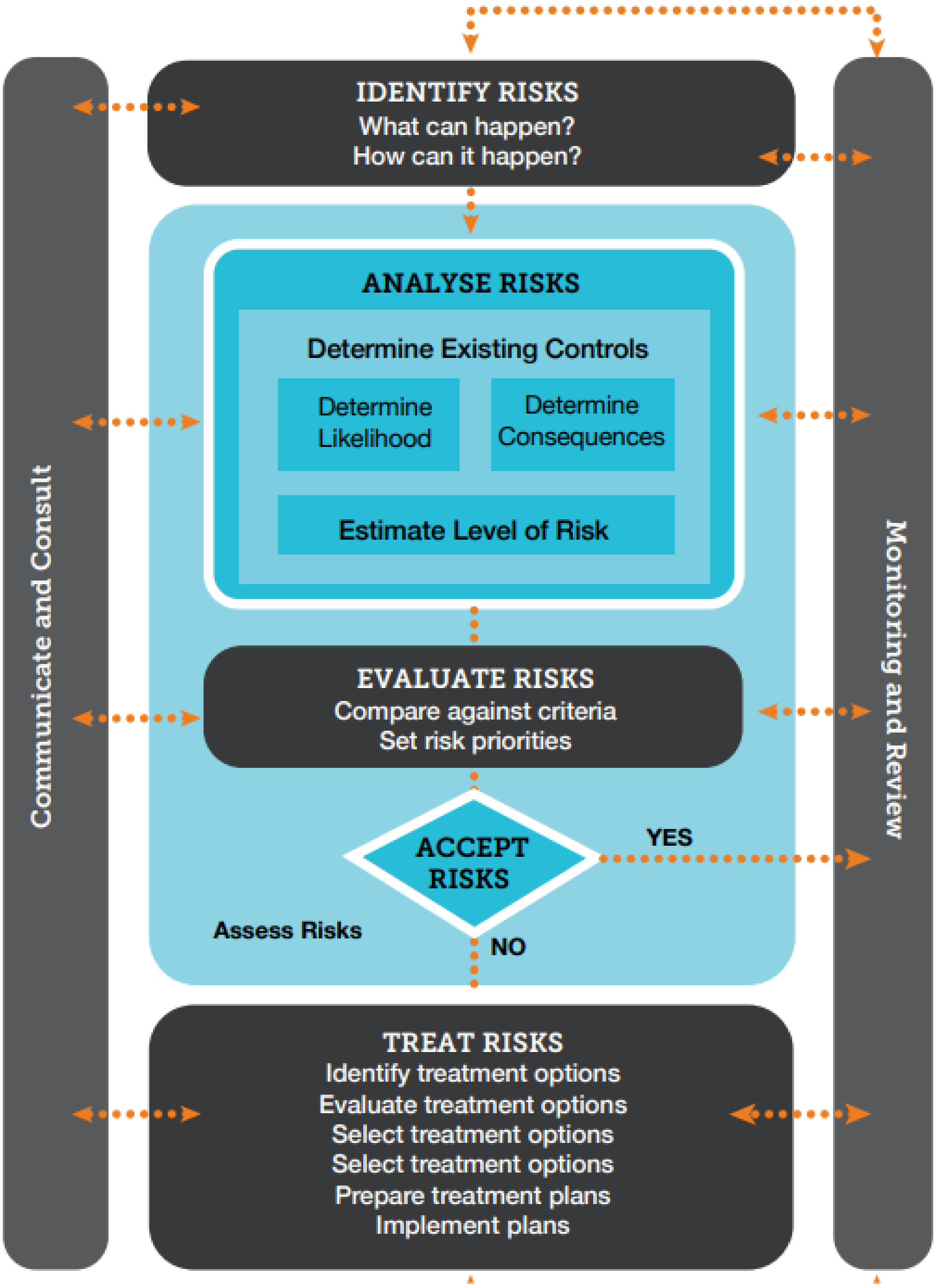
Risk management concepts feature as a factor in our planning and decision making at several levels, from strategy through to operations, with examples including:

- all significant projects undergoing a risk assessment phase, with risk management concepts influencing decision making on aspects such as contractor management;
- risk management influencing our asset management planning, such as the development of our Asset Class Strategies;
- risk assessments being carried out as a part of change management when there are significant changes to processes, equipment or materials; and
- field-based activities completed by contractors being monitored through targeted, risk-based audits.

We assess risks using risk criteria tables, with action plans then developed by a nominated risk owner to plan, monitor and report on the implementation of identified treatment actions. Identified risks are recorded in risk registers, with progress against actions usually being monitored at six-monthly intervals and more frequently in the case of critical tasks.

[219] This publication was last reviewed and confirmed in 2023 and therefore remains current (source: ISO 31000:2018 Risk management — Guidelines).

Figure C1–2: JEN Risk Management Policy



Risk assessment framework

Once a risk is identified, we assess it by establishing a rating for its likelihood (Table C1–3) and consequence (Table C1–4), then combine these ratings using a matrix to determine an overall risk rating (Table C1–5) and risk management approach (Table C1–6).

Table C1–3: Risk likelihoods

Likelihood	Description	Guide
5 – Almost certain	Event is expected to occur in most circumstances	Will almost certainly occur once (or more) within one year, or >75% probability of occurrence, or has occurred recently and likely to occur again.
4 – Likely	Event will probably occur in most circumstances	Will probably occur at some time in the next two years, or 51%-75% probability of occurrence, or has a history of occurrence or could be difficult to control due to some external influences.
3 – Possible	Event should occur at some time	Might occur at sometime within the next five years, or 26%-50% probability of occurrence.
2 – Unlikely	Event could occur at some time	Might occur at sometime within the next ten years, or 5%-25% probability of occurrence.
1 – Rare	Event may occur only in exceptional circumstances	Improbable occurrence only in exceptional circumstances (i.e. may only occur in more than 10 years), or <5% probability of occurrence.

Table C1–4: Risk consequences

Rating	Description[1]	Financial		Operational	Health, Safety & Environment		Employee	Regulatory & Compliance	Brand / Reputation / Stakeholders
		EBITDA / Cash Flow	Recoverable Value[3]		Health and Safety[4]	Environment			
Catastrophic	Potential disastrous impact on SGSPAA strategies or operational activities. Widespread stakeholder concern / interest.	> 5% of EBITDA[2] (> $50M). Imminent liquidity / cash flow problem – 100% utilisation of undrawn credit facilities & cash at bank.	> 5% or $600M of Recoverable Value of SGSPAA's Assets	Loss of electricity supply to >15% Customers (50,000) >24 Hrs or supply to 2 Zone Substations >24 Hrs. Loss of gas supply to > 5% Customers (75,000) or supply to major geographical areas[4] Business interruption of a critical activity for > 7 days and cannot recover to minimum business continuity objectives (SGSPAA Assets).	1 or more fatalities (staff, contractors or member(s) of the public). Significant destruction of key internal asset or third party property.	Harm to the natural environment and/or cultural heritage that cannot be remediated[5]. >20% tCO2e actual / forecast increase of unintended or unmitigated annual Scope 1 and 2 GHG emissions from the lower of relevant SGSPAA targets / forecasts.	Skill set/ capability of >35% of business critical roles[6] lost within a 3 month period	Major regulatory restrictions and/or govt. interventions. Possible loss of licence to operate. Frequent regulatory or policy violations / breaches. Major litigation, with a possibility of punitive damages. Significant fines, prosecutions and jail terms possible.	Sustained and hostile public campaign. Reputation impacted with majority of key stakeholders. Sustained and critical stakeholder criticism.
Major	Significant impact on SGSPAA strategies or operational activities. Significant stakeholder concern / interest.	3-5% of EBITDA ($30M - $50M). Liquidity / cash flow may be adversely affected – 100% utilisation of undrawn credit facilities.	3-5% or $360 - $600M of Recoverable Value of SGSPAA's Assets	Loss of electricity supply to > 2 % Customers (7,400) >24 Hrs. Loss of gas supply to > 1% Customers (15,000). Business interruption of a critical activity for > 7 days (SGSPAA Assets).	Total permanent disability (staff or contractors). Multiple hospitalisations, permanent disability and/or life threatening injuries affecting member(s) of the public. Significant damage to internal assets or third party property.	Harm to the natural environment and/or cultural heritage with remediation difficult (multi-year management). >15% tCO2e actual / forecast increase of unintended or unmitigated annual emissions Scope 1 and 2 GHG emissions from the lower of relevant SGSPAA targets / forecasts.	Skill set/ capability of 20 – 35% of business critical roles lost within a 3 month period	Regulatory investigations or govt. review. Some regulatory or policy violations / breaches. Litigation involving significant senior management time. Major fines or penalties and prosecutions possible.	Significant adverse public attention and/or heightened concern from stakeholders. Reputation impacted with significant number of stakeholders. Significant stakeholder criticism/negativity.
Severe	Moderate impact on SGSPAA strategies or operational activities. Moderate stakeholder concern / interest.	1-3% of EBITDA ($10M - $30M). Liquidity / cash flow may be affected – 50% utilisation of undrawn credit facilities.	1-3% or $120-$360M of Recoverable Value of SGSPAA's Assets	Loss of electricity supply > 1% Customers (3,700) > 24 Hrs. Loss of gas supply to > 0.1% Customers (1,500). Business interruption of a critical activity for 1 - 7 days (SGSPAA Assets).	Single permanent partial disability (staff or contractors). Medical aid required for member(s) of the public. Some loss of or damage to third party property.	Harm to the natural environment and/or cultural heritage that can be remediated (<1 year management). >10% tCO2e actual / forecast increase of unintended or unmitigated annual emissions Scope 1 and 2 GHG emissions from the lower of relevant SGSPAA targets / forecasts.	Skill set/ capability of 10-20% of business critical roles lost within a 3 month period	Regulator requires formal explanations & remedial action plans. Fines or penalties from legal issues, breaches / non-compliances.	Persistent public scrutiny. Reputation impacted with some stakeholders. Some stakeholder concern/negativity.
Serious	No material impact on SGSPAA, issues are dealt with internally.	0.1-1% of EBITDA ($1M - $10M). Liquidity / cash flow impact absorbed under normal operating conditions – 25% utilisation of undrawn credit facilities.	0.1-1% or $10-$120M of Recoverable Value of SGSPAA's Assets	Loss of electricity supply to > 1% Customers (3,700) > 6 Hrs. Loss of gas supply to > 100 Customers or any contract customer. Business interruption of a critical activity for 1 day (SGSPAA Assets).	Medical treatment injury or lost time injury (staff or contractors). On-site first aid to a small number of member(s) of the public, lost time.	Harm to the natural environment and/or cultural heritage requiring minimal remediation (at the time of impact). >5% tCO2e actual / forecast increase of unintended or unmitigated annual emissions Scope 1 and 2 GHG emissions from the lower of relevant SGSPAA targets / forecasts.	Skill set/ capability of 5 – 10% of business critical roles lost within a 3 month period	Isolated regulatory or policy violations / breaches. Fines or penalties possible.	Sporadic, adverse media/public attention. Limited adverse reputational impact. Minor stakeholder complaints.
Minor	Negligible impact on SGSPAA, issues are routinely dealt with by operational areas.	< 0.1% of EBITDA (< $1M). Negligible impact on liquidity / cash flow.	< 0.1% or $10M of Recoverable Value of SGSPAA's Assets	Loss of electricity supply to <1,000 Customers up to 6 Hrs. Loss of gas supply to > 5 residential customers. Business interruption of a critical activity for a few hours (SGSPAA Assets).	Minimal impact on health & safety (staff, contractors or member(s) of the public).	Harm to the natural environment and/or cultural heritage requiring no active remediation and/or able to self-remediate. 0-5% tCO2e actual / forecast increase of unintended or unmitigated annual emissions Scope 1 and 2 GHG emissions from the lower of relevant SGSPAA targets / forecasts.	Skill set/ capability of <5% of business critical roles lost within a 3 month period	General regulatory queries. No violations / breaches, fines or penalties.	Negligible media/public attention, reputational impact and/or little or no stakeholder interest.

Table C1–5: Risk matrix

		Consequence				
		Minor	Serious	Severe	Major	Catastrophic
Likelihood	Almost certain	Moderate	High	Extreme	Extreme	Extreme
	Likely	Moderate	Significant	High	Extreme	Extreme
	Possible	Moderate	Moderate	Significant	High	Extreme
	Unlikely	Low	Low	Moderate	Significant	High
	Rare	Low	Low	Moderate	Moderate	Significant

Table C1–6: Risk management approach

Rating	Approach
Extreme	• Requires immediate action. Highest priority risk to treat. • Action plans prepared and usually implemented within 1 month. Status of risk should be monitored monthly. • Monitored by Board/Board's Risk, Health, Safety & Environment Committee (**RHSEC**)/Executive Risk Management Committee (**ERMC**)/Leadership Team or Managing Director/Executive General Manager (**EGM**).
High	• Requires immediate attention. Must manage with senior-level monitoring. • Action plans prepared and usually implemented within 3 months. Status of risk should be monitored monthly. • Monitored by RHSEC/ERMC/Leadership Team or EGM/General Managers (**GM**).
Significant	• Requires management attention with a degree of priority. • Action plans prepared and usually implemented within 6 months. Status of risk should be monitored every 6 months. • Monitored by RHSEC/ERMC/Leadership Team or EGM/GM.
Moderate	• Requires routine to periodic monitoring. • Action plans prepared and usually implemented within 6-12 months where benefits outweigh the costs. Status of risk should be monitored at least every 6 months. • Monitored by GM, escalated to EGM if risk consequence or likelihood is increasing.
Low	• 'Business as usual' – should not require much attention but should be reviewed at least annually. • Ongoing control as part of the management system. Risk facilitators to maintain a register of low risks and reassess annually. • Monitored by managers, escalated to GM if risk consequence or likelihood is increasing.

C1.6 Procurement

We maintain a robust procurement process which ensures technical suitability and cost-effectiveness of a purchase are the primary selection criteria. We use competitive tender processes when procuring the supply of goods and services, consistent with Jemena's Procurement Policy.

We apply a strategic procurement approach to developing, establishing and managing all sourcing and procurement contracts. This includes identifying procurement opportunities across the Jemena business, which drive benefits through the aggregation of demand and the standardisation of ordering and logistics processes. Strategic procurement is a proven method for managing higher value, higher risk or medium to long-term procurement activities and projects and has been adopted as standard practice by numerous organisations in Australia and internationally.

Our Strategic Sourcing and Supply Chain team also provides support to the rest of the business in the development and implementation of contracts and service level agreements. We use equipment specifications based on relevant Australian or International Standards and have a standardised tendering process. We continually developments in the markets for the products and services we procure, and we re-evaluate our contracts periodically. We currently have period contracts in place for major plant items, listed below, and we have plans to re-evaluate all of these tenders within the next five years:

- zone substation transformers
- zone substation and distribution switchgear
- distribution transformers and kiosks
- underground cables and overhead conductor
- distribution hardware (overhead terminations, conduits, clamps, fasteners etc.)
- electrical conduits and cover slabs
- poles
- crossarms
- insulators
- surge arrestors
- high voltage fuses.
- Meters

Appendix D
Contingent projects

Jemena
bringing energy to life

D1. Contingent projects

As outlined in section 4.2.4, the most economic approach to accommodating known connections on our sub-transmission network requires that we incur $85.1M over the next regulatory period.

As $80M of this expenditure will not be required until 2028, we have decided that rather than including this expenditure in our regulatory proposal we will instead propose two contingent projects. This approach aligns regulatory approval with our internal decision-making and ensures that customers do not fund such a large expenditure until it is required. It also enables us to reduce forecast capital expenditure to accommodate known customer loads on our sub-transmission network from $85.1M to $5.1M.

Proposed contingent projects

We propose two contingent projects to accommodate large new loads on two separate parts of our sub-transmission network:[220]

- **Tullamarine Cluster** – specifically the 66 kV lines connecting Tullamarine Zone Substation (TMA), Pascoe Value Zone Substation (PV), two customer Zone Substations (MAT and NDT), Airport West Zone Substation and Keilor Terminal Station.
- **Heidelberg** – specifically the East Preston Zone Substation (EPN).

The forecast expenditure for the Tullamarine and Heidelberg Cluster is set out in Table D1–1.

Table D1–1: Proposed Contingent projects, $2026, millions

Project	Component	FY27	FY28	FY29	FY30	FY31	2026-31
Tullamarine Cluster	New KTS-ADT-VDT 66 kV line	-	16.5	-	-	-	16.5
	New KTS-ATK 66 kV line	-	19.1	-	-	-	19.1
Heidelberg	EPN Third Transformer	-		-	14.9		14.9
	New Zone Substation to offload NH and EPN	-	-		24.6	-	24.6
Total		**-**	**35.6**	**-**	**39.5**	**-**	**75.1**

We note that both contingent projects have two components. In each case, the two components together form a single project to resolve an identified need for investment: new load driving capacity constraints on specific parts of our network and in turn uneconomic levels of unserved energy.

We note that these separate components are sometimes referred to as individual projects for internal purposes, largely as they can be delivered through two packages of work. However, the ordinary[221] and economic interpretation – consistent with the National Electricity Rules[222] – is that the purpose is to address an identified need. This means that if several components are required to address an identified need, together, these components form a project. Put another way, delivering only one of the two components in each project would not address the identified need.

220 Further details on these clusters is provided in our Major Customer Network Development Strategy.

221 E.g. defined by Wiktionary as *A planned endeavor, usually with a specific goal and accomplished in several steps or stages.* See here.

222 See for instance the definition of RIT-D project in Rule 5.10.2 and the definition of an actional ISP project in Chapter 10. This is also reflected in Rule 6.6A.1(b)(1) which focuses on the outcomes of the project (specifically whether the project achieves the capital expenditure objectives).

Trigger event

In April 2024, the AER approved a contingent project for Ausgrid for a new sub-transmission substation due to connection applications with large load requirements in Macquarie Park. We note Macquarie Park is the location of another data centre cluster.

Given the parallels with the pressures on our sub-transmission system, we have based the trigger events for our proposed contingent projects on the AER's determination for Ausgrid's Macquarie Park contingent project.[223] The proposed trigger events are shown in Table D1–2.

Table D1–2: Proposed contingent project trigger events

Tullamarine Cluster	Heidelberg
• Jemena Electricity Networks receives a connection application or applications for loads in Tullamarine that cannot be supplied from the existing Tullamarine Cluster of our sub-transmission network. • The AER is satisfied that Jemena Electricity Networks has completed a Regulatory Investment Test for Distribution (RIT-D) to determine the preferred credible option to connect and supply the load or loads, pursuant to the NER. • A commitment from Jemena Electricity Networks to proceed with the preferred credible option from the RIT D, subject to the AER amending Jemena Electricity Networks 2026-31 regulatory determination pursuant to the NER. To provide objective verification of this trigger, a letter from the Managing Director of Jemena Electricity Networks will be sent to the AER to confirm such commitment.	• Jemena Electricity Networks receives a connection application or applications for loads in Heidelberg that cannot be supplied from the existing East Preston and North Heidelberg Zone Substations. • The AER is satisfied that Jemena Electricity Networks has completed a Regulatory Investment Test for Distribution (RIT-D) to determine the preferred credible option to connect and supply the load or loads, pursuant to the NER. • A commitment from Jemena Electricity Networks to proceed with the preferred credible option from the RIT D, subject to the AER amending Jemena Electricity Networks 2026-31 regulatory determination pursuant to the NER. To provide objective verification of this trigger, a letter from the Managing Director of Jemena Electricity Networks will be sent to the AER to confirm such commitment.

We consider the trigger event appropriate, particularly as it builds on the work previously undertaken by Ausgrid and the AER to develop appropriate triggers for the Macquarie Park contingent project. We note that the proposed trigger events are also consistent with the factors set out in Rule 6.6A.1(c):

a) Reasonably specific and capable of objective verification. The events can be verified by providing connection application data, completing a RIT-D and receiving a letter from our Managing Director.

b) A condition or event that, if it occurs, makes the undertaking of the proposed contingent project reasonably necessary in order to achieve any of the capital expenditure objectives. If one or both of the events occur, we will need to augment our network to maintain supply meet the expected demand and maintain the quality, reliability and security of supply of standard control services.

c) A condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the distribution network as a whole. The events are targeted at specific locations of our sub-transmission network: the Tullamarine cluster of sub-transmission lines and the East Preston Zone Substation.

d) Described in such terms that the occurrence of that event or condition is all that is required for the distribution determination to be amended under clause 6.6A.2. The trigger event is defined consistent with the AER's previous approach for similar contingent projects.

Lastly, we note that the occurrence of these events is not only probable but highly likely. However, the expenditure is substantial and the timing and scope (and in turn costs) of the optimal solution may change as we receive new information on the number and size of connection applications in each part of our sub-transmission network. For

[223] AER 2024, *Final Decision, Ausgrid Electricity Distribution Determination 2024 to 2029,* pp 50 -51. Available here.

these reasons we have proposed two contingent projects rather than including the associated expenditure in our capital expenditure forecast.

Regulatory requirements

We demonstrate compliance with the contingent project requirements set out in Rule 6.6A.1 in Table D1–3 below.

Table D1–3: Contingent project requirements – Rule 6.6A.1(a1&b)

Requirement		Consideration
(a1)	Proposed contingent capital expenditure that is included in a regulatory proposal of a Distribution Network Service Provider must not include expenditure for a restricted asset, unless that Distribution Network Service Provider has submitted an exemption application with the regulatory proposal, which requests an asset exemption under clause 6.4B.1(a)(2) in respect of that asset or class of asset for the contingent project.	Our proposed contingent project does not include expenditure for restricted assets.
(b)(1)	the proposed contingent project is reasonably required to be undertaken in order to achieve any of the capital expenditure objectives	The proposed contingent projects are required to: • meet or manage the expected demand for standard control services over the next regulatory.[224] • maintain the quality, reliability and security of supply of standard control services.[225] If these projects do not go-ahead unserved energy will rise to 1,414 MWh per annum by 2034. Over the 10-year period to 2034 – noting that these projects will be implemented in 2027-28 and 2029-30 – this will cost consumers $203M.[226]
(b)(2)(i)	the proposed contingent capital expenditure is not otherwise provided for (either in part or in whole) in the total of the forecast capital expenditure for the relevant regulatory control period which is accepted in accordance with clause 6.5.7(c) or substituted in accordance with clause 6.12.1(3)(ii) (as the case may be)	No expenditure to deliver the proposed contingent projects has been included in our regulatory proposal. The proposed projects are discrete and do not overlap with the other augmentation programs included in our proposal.

[224] Rule 6.5.7(a)(2)

[225] Rule 6.5.7(a)(3)

[226] Due to the 10-year time-horizon of our economic analysis we do not include reliability costs from unreliability in 2035 and beyond. This means that the economic benefits of the contingent projects, through reducing reliability deterioration, are materially understated.

Requirement		Consideration
(b)(2)(ii)	the proposed contingent capital expenditure reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors, in the context of the proposed contingent project as described in the regulatory proposal	Our proposed contingent projects reflect the efficient costs to achieve the capital expenditure objectives and are costs a prudent operator would incur based on the realistic demand forecast, as outlined by our Major Customer Network Development Strategy.[227]
(b)(2)(iii)	the proposed contingent capital expenditure exceeds either $30 million or 5% of the value of the annual revenue requirement for the relevant Distribution Network Service Provider for the first year of the relevant regulatory control period, whichever is the larger amount	Forecast capital expenditure to deliver the Tullamarine and Heidelberg contingent projects is $35.6M and $39.5M respectively. This exceeds the $30M threshold. We note that the $30M threshold applies as 5% of our annual revenue requirement in the first year of the next regulatory period is $16.2M (and is less than $30M).
(b)(3)	the proposed contingent project and the proposed contingent capital expenditure, as described or set out in the regulatory proposal, and the information provided in relation to these matters, complies with the relevant requirements of any relevant regulatory information instrument	There are no applicable requirements for contingent projects in any relevant regulatory information instrument.
(b)(4)	the trigger events in relation to the proposed contingent project which are proposed by the Distribution Network Service Provider in its regulatory proposal are appropriate	The trigger events we have proposed are based consistent with Rule 6.6A.1(c) (as outlined above) and are consistent on similar trigger events previously determined by the AER for distribution network services providers in similar circumstances.

[227] See, *RIN - Support -Network Development Strategy - Major Customers*.