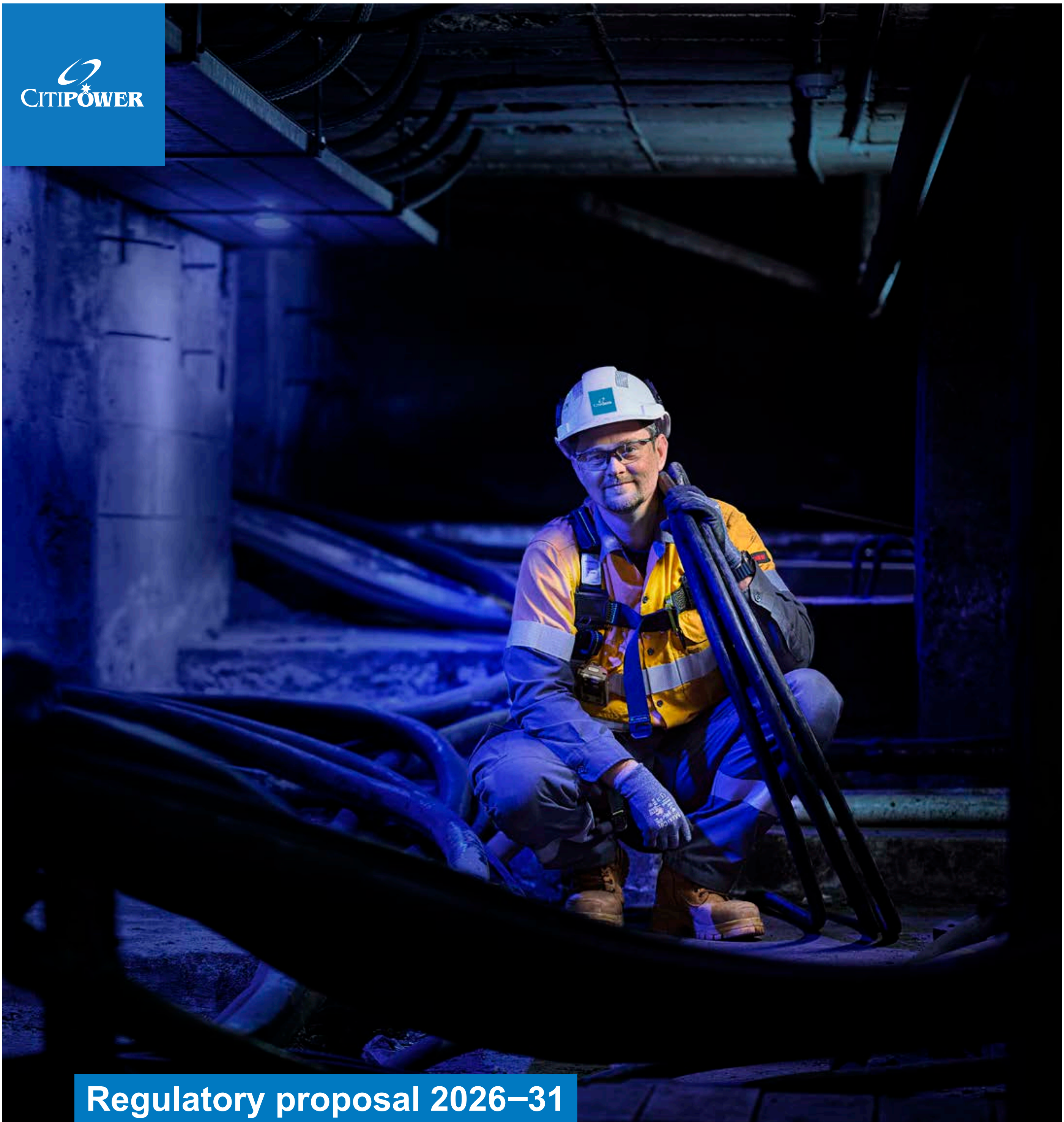

Regulatory proposal 2026–31

Part B: explanatory statement

Revenue and expenditure forecasts

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Acknowledgement of Country

CitiPower acknowledges and respects the Traditional Owners as the original Custodians of the lands and waters our networks cover; lands First Peoples have occupied for tens of thousands of years.

CitiPower pays our respects to Elders past and present and acknowledge their ancient and continuing connection to Country.

About this document

Every five years, the Australian Energy Regulator (AER) reviews our forecast plans for approval. This determines the services we deliver, and the revenue we recover from our customers.

In September 2024, we published a draft proposal setting out our preliminary plans for the 2026–31 regulatory period. This draft sought feedback from our customers and key stakeholders to further test or validate what we have heard from them throughout our extensive engagement program.

Our regulatory proposal builds on this draft, and represents our formal submission to the AER for the 2026–31 regulatory period. It comprises three separate parts that should be read together:

- part A – provides context for our proposal, outlines our engagement journey, and the service outcomes our customers expect us to deliver
- part B – sets out the revenue and expenditure required to deliver these service outcomes
- our tariff structure statement, which includes both our compliance documentation and explanatory statement setting out the reasons and derivation of our proposed tariffs.

Our regulatory proposal is also supported by a large volume of supplementary material, including revenue and expenditure modelling, business cases for key investments, and broader explanatory documentation.

This document represents part B of our regulatory proposal.

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1. Overview

As an essential service provider, we deliver electricity to a 157km^2 area covering Melbourne's CBD and inner suburbs. This area includes critical business hubs and some of Australia's most iconic sporting and cultural facilities, such as the Melbourne Cricket Ground, the National Tennis Centre and the Victorian Arts Centre.

Residential households represent approximately 83 per cent of our 340,000 customers and we also support nearly 9,000 commercial and industrial businesses, and 42,000 small and medium businesses. Although households represent the majority of our customers, commercial and industrial businesses are the largest users of electricity.

As outlined in part A of our regulatory proposal, we provide a consistent, dependable and affordable service every day:

- we are the most reliable distribution network in Australia; our customers experience less minutes off supply than any other network, with just 21 minutes off supply, on average, in 2024
- our customers face the lowest network charges in Victoria and second-lowest nationally
- the value of our regulated asset base (RAB) is low relative to the volume of energy we deliver, meaning we are delivering more value for customers with less infrastructure.

The scale and scope of the energy transition though is fundamentally changing the nature of our electricity network and the service levels expected by our customers.

Customer behavioural preferences are also evolving, and more frequent and severe climate extremes are making us more dependent on electricity than ever before. These changes are intersecting with typical network drivers like growth, safety and regulatory compliance, and asset risk.

At the same time, economic conditions and rising input costs are making business operations more expensive, for both our networks and customers.

The extent of electrification will also quickly challenge our existing network. In particular, significant growth is expected from electric vehicles and the substitution of residential gas, more data centres and battery storage.

Our investment program for the 2026–31 regulatory period outlines a balanced approach that aligns with customer expectations for a reliable, safe and resilient electricity supply while also enabling a fair and just transition. This includes a combination of business-as-usual programs and targeted projects, recognising that many investments will support multiple service level outcomes.

We must also continue to meet our ongoing compliance and safety obligations. These non-discretionary programs comprise the majority of our expenditure requirements.

We will deliver these investments with no increase to nominal average annual distribution bills for residential customers between 2026 and 2031. In addition, we are proposing a $2 average annual reduction in metering charges

1.1 Stakeholder feedback is reflected across our proposal

Our engagement program for our regulatory proposal commenced in 2022 and has reached more stakeholders and customers than ever before.

Initially, our engagement focused on exploring customer and community needs more broadly, followed by more targeted sessions on key themes. This included a range of engagement activities, from large-scale mass forums, community workshops, focus groups, in-depth interviews and quantitative surveys, and targeted bi-lateral meetings.

A fulsome overview of our stakeholder engagement program is set out in our engagement attachment and is summarised briefly below.[1] Key findings are also detailed in the corresponding expenditure chapters.

1.1.1 Customer service level outcomes

Throughout our regulatory proposal, we have sought to demonstrate where, how and why (or not) we have reflected stakeholder feedback in our decision-making. To do this, we first developed a set of service expectations based around the key themes identified by our customers as critical to their future energy supply.

In part A of our regulatory proposal, we mapped each of these key themes to our proposed service expectations and customer outcomes. As shown in figure 1.1, we also mapped our engagement forums directly to our expenditure categories, noting these typically reflect a one-to-many relationship.

In September 2024, we challenged the extent to which our proposed investments met customer and stakeholder expectations through the publication of our draft proposal and the 'test and validate' phase our engagement program. Our engagement mapping for test and validate is shown in figure 1.2.

Our draft proposal

Our draft proposal provided a transparent and comprehensive view of our preliminary plans for the 2026–31 regulatory period. Engagement from our customers and stakeholders on our draft proposal has been wide-reaching, with over 450,000 video views across social media, and an estimated total audience of more than 1.1 million customers.

In addition to stakeholder and customer feedback, the Customer Advisory Panel (CAP) provided a detailed report on their findings on our draft proposal. The CAP found there was much to commend in our extensive and sustained program of customer and stakeholder engagement (including initial steps taken to engage fully with First Peoples), and welcomed our emphasis on affordability. The CAP also provided further feedback on improvement opportunities.

A comprehensive set of recommendations from the CAP is set out in their report, and we have sought to address these throughout our regulatory proposal.

Fundamentally, the service level outcomes included in our regulatory proposal have remained consistent with those published in our draft proposal, as our 'test and validate' engagement largely supported our preliminary approach. However, we were strongly challenged to do more in some areas, including investing further in our vulnerable customer package to ensure it is effective.

In comparison to our draft, our regulatory proposal has also been updated to reflect more recently available data, and made greater use of contingent projects and pass-through events for large projects with uncertain timing.

The 2026–31 regulatory period though remains one of considerable change, with cost drivers and growing customer needs that are beyond our capacity to control or manage with historical levels of investment. In total, our regulatory proposal represents an increase in our expenditure forecasts relative to our draft. The corresponding bill impacts, however, represent a reduction (consistent with our draft proposal).

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1 CP ATT SE.01 – Stakeholder engagement attachment – Jan2025 – Public.

FIGURE 1.1 STAKEHOLDER ENGAGEMENT MAPPING: DEEP AND NARROW

Key engagements	Electrification and CER integration	Augmentation	Replacement	Resilience	Connections	Information and communications technology	Property, fleet and other non-network	Operating expenditure	Metering	Public lighting	Tariffs and pricing
Customer Advisory Panel: Ensure the diverse and changing needs of our customers were properly understood, balanced and reflected in business plans	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
Future Home Demand report: Ethnographic research process with Monash University to understand emerging energy trends in everyday household life	✓	✓	✓	✓	✓			✓			
Flexible services: Understand preferences and priorities for potential flexible service products	✓	✓			✓	✓		✓			✓
Government reviews: Outline our role in supporting customers and communities before, during and after extreme weather events				✓		✓	✓	✓			
Customer values research: Quantification of the relative importance that customers place on our services, and willingness-to-pay	✓	✓	✓	✓		✓	✓	✓			
Customer Service Incentive Scheme (CSIS) research: Quantitative survey measuring the relative importance that customers place on improvements in our services				✓				✓			
Vulnerable customer engagement: Exploring challenges facing customers experiencing (or at risk of) vulnerable circumstances, including during the energy transition	✓	✓	✓	✓		✓		✓	✓		✓
Energy transition summit and Future network forum: Identify service level expectations for management of emerging energy technologies, including rooftop solar and electric vehicles, and challenge future demand inputs	✓	✓	✓			✓		✓			✓
Customer energy futures: service level options paper: Customer expectations on service level outcomes for CER and electrification	✓	✓	✓			✓		✓			✓
Storage integration consultation paper: Outline and seek feedback on proposed approach to integrate storage connecting to our networks					✓						✓
Economic growth forum: Understand and identify key concerns for commercial and industrial customers, including tariff preferences	✓	✓	✓		✓						✓
Trade-off forums and quantitative surveys: Challenge customer willingness-to-pay or trade-off discretionary initiatives and service level outcomes, including overall bill impacts	✓	✓	✓	✓			✓	✓			✓
Joint distributor forums: Multiple forums to inform the development of tariff structures, resilience investment framework and how to best support customers experiencing vulnerability	✓			✓				✓			✓
Public lighting consultation paper: Test proposed public lighting service offerings and future investment plans										✓	✓

FIGURE 1.2 STAKEHOLDER ENGAGEMENT MAPPING: TEST AND VALIDATE

Key engagements	Electrification and CER integration	Augmentation	Replacement	Connections	Information and communications technology	Property, fleet and other non-network	Operating expenditure	Metering	Public lighting	Incentives	Tariffs and pricing
Customer Advisory Panel: Ensure needs of our customers were understood, balanced and reflected in business plans	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Town hall: Provide an overview of our draft proposal and opportunity for customers to provide feedback directly to executive management	✓	✓	✓		✓		✓	✓			
Community roundtable: Seek customer feedback on key draft proposal initiatives and level of investment	✓	✓	✓				✓	✓			
First People's engagement: Attended VACSAL football and netball carnival to seek feedback on proposed First Peoples program	✓						✓				✓
Energy Users Association of Australia (EUAA) engagement: Seek commercial and industrial customer feedback on key draft proposal initiatives and level of investment	✓	✓					✓				✓
Commercial and industrial interviews: Understand commercial and industrial customer concerns and support for draft proposal initiatives and tariff changes	✓	✓	✓				✓				✓
Quantitative study: Better understand customers' willingness to change consumption habits and understanding and support for tariffs, metering replacement and network control	✓							✓			✓

1.2 Our expenditure forecasts have been developed through a robust governance process

Our investment governance framework—which to date has delivered our customers the second lowest network charges and best reliability performance in the National Electricity Market (NEM)—encompasses a set of principles, guidelines and controls that support planning, forecasting, decision-making, risk management and performance evaluation. This framework covers the capital and operating expenditure which directly relates to our network assets, as well as non-network investments that support the operation of our network.

As far as practicable, we have applied this governance framework in forecasting our expenditure needs for the 2026–31 regulatory period.[2]

For example, the investments included in our regulatory proposal are based on a consistent set of values applied through robust cost-benefit analysis and quantified risk-based assessments. These values align with standard AER assumptions (e.g. the value of customer reliability, customer export

[2] Our investment governance framework is set out in the attached: CP RIN 27 - Governance, forecasting and deliverability overview - Jan2025 – Public.

curtailment value and value of emissions reduction), or those determined through our quantified customer value analysis.

Development of our customer values

In 2021, we completed a significant body of work with our customers to develop an estimate of the value they place on various services, such as network resilience and enabling solar exports. These values were designed to be additive to other value measures, such as the AER's value of customer reliability (VCR).

We were the first network businesses in Australia to incorporate such values into our internal investment assessment approach. That is, these values are now contributing to the prioritisation of our capital program to support the likelihood that any investments align with our customers' expectations.

At the recommendation of the CAP, these values were re-tested and updated in 2024 to ensure they remain reflective of our customer's views. This reflected the view that the economic environment had changed materially, and the question of whether customer's preference had evolved as well.

The development of our expenditure forecasts also occurred through multiple expenditure iterations that progressively refined our investment portfolio. This process continually challenged and limited expenditure to those investments that deliver clear value for our customers.

In total, our iteration challenge process directly removed over $250 million of investments. It has also driven revisions in our demand forecast assumptions (to better align with customer and stakeholder feedback) that have further reduced our expenditure proposals.

The application of our governance framework has been supplemented by challenges to our investment strategies and forecasts through input and oversight from the CAP. A key focus of the CAP has been on ensuring the diverse and changing needs of our customers are properly understood, balanced and reflected in business plans.

Another part of our expenditure challenge process included research to understand residential and small-medium business customers' willingness to pay for proposed initiatives, individually and collectively, through deliberative trade-off forums and quantitative surveys on key topics. In these sessions, customers were provided evidence of the expected outcomes and individual and cumulative bill impacts from different investment levels.

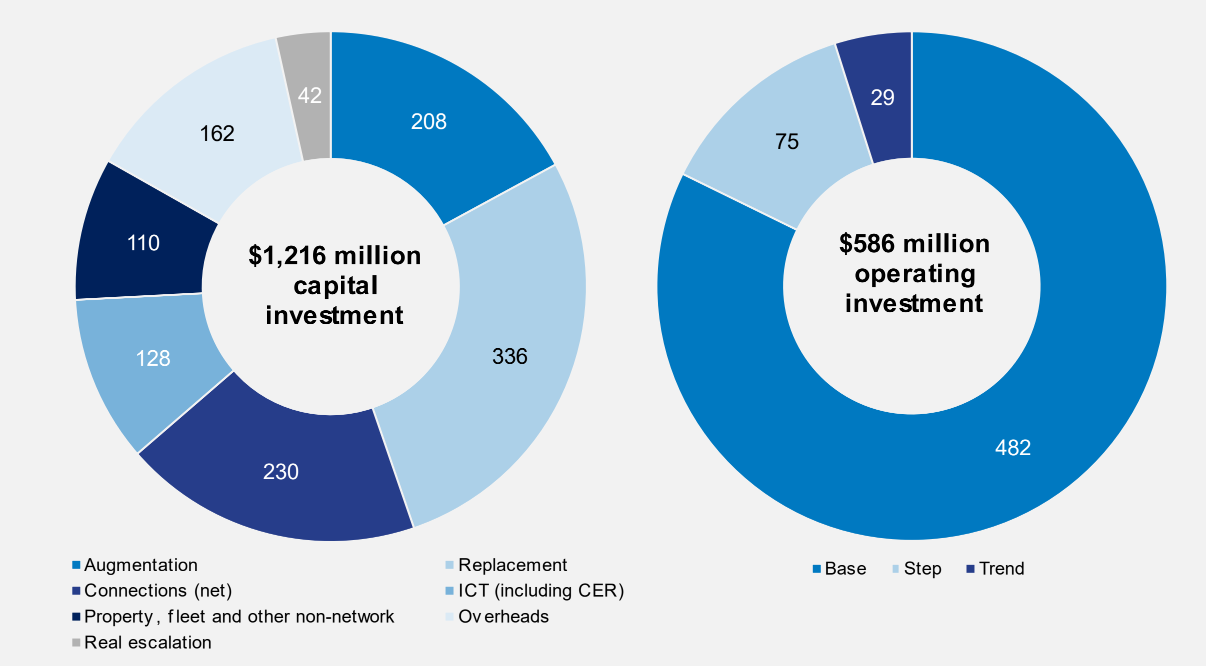
The outcomes of these customer trade-offs have been reflected in our expenditure forecasts.

1.2.1 Our expenditure forecasts

A summary of our proposed capital and operating expenditure forecasts for the 2026–31 regulatory period is set out in figure 1.3. As noted earlier, these forecasts were developed based on a robust governance framework.

Further detail on the basis of these forecasts is set out in the respective expenditure chapters.

FIGURE 1.3 CAPITAL AND OPERATING EXPENDITURE FORECASTS: 2026–31 ($M, 2026)



Note: Augmentation expenditure is net of disposals and the 'trend' component of operating expenditure is net of our productivity adjustment. Totals may not add due to rounding.

Proposed capital expenditure

Our net capital expenditure in the current regulatory period will be lower than the AER's allowance (but will exceed this allowance after one-off asset disposals are excluded).

Melbourne's journey through the pandemic, in particular, was more challenging than elsewhere in Australia. Peak demand and consumption in the CBD and inner-city fell by 20–30% during lockdowns, and the uncertainty around when business and community activity would return deferred some major augmentation works. Our augmentation spend on consumer energy resources (CER) integration was further lowered due to efficient management, driven by the stronger than expected performance of our dynamic voltage management system (DVMS) and other low cost interventions like our industry-leading work to identify and address incorrect customer solar settings with solar manufacturers.

These reductions, however, were offset by rising input costs that arose during the pandemic, and supply chain pressures that have not abated (as demand for labour and materials remains strong, both globally and domestically).

Connections activity in the current regulatory period was also above the AERs allowance.

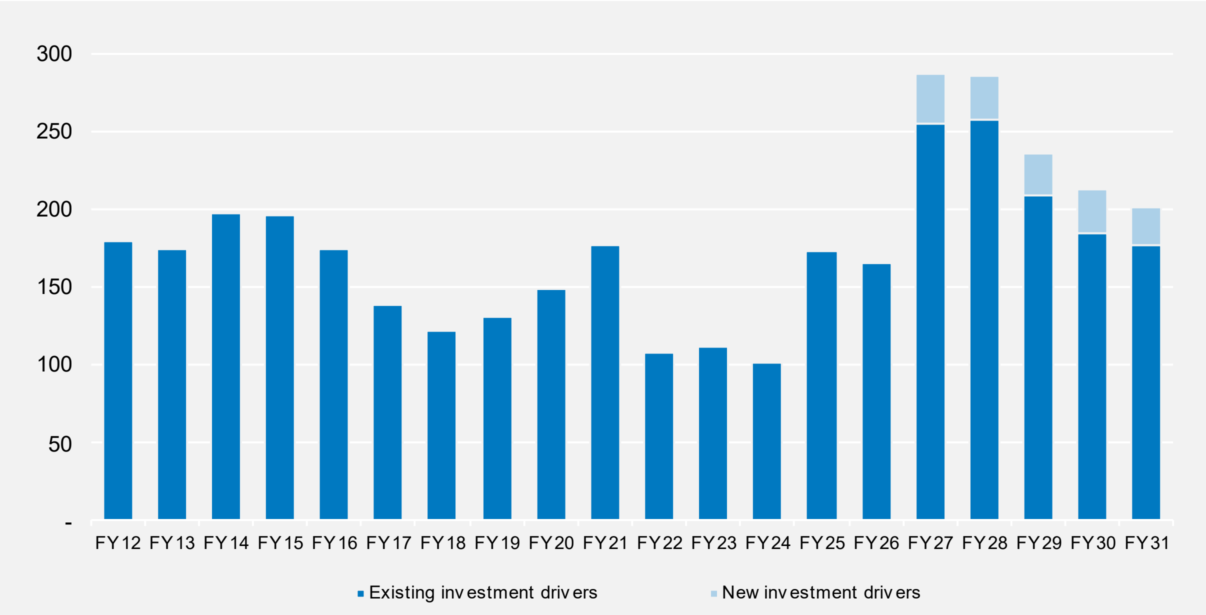
The drivers of our capital expenditure forecast for the 2026–31 regulatory period are discussed in detail further in this document. At a high level, these drivers include the following:

- continued modernisation works, including the progressive offload and decommissioning of aged zone substations and low-capacity network in the inner north, driven by their underlying condition and risk
- electrification of transport and gas, customer growth and CER integration, with the extent of this change being that annual consumption and peak demand across our network in 2031 are expected to be 26 per cent and 7 per cent higher than they are today
- asset replacement forecasts are increasing to manage condition and defect trends, and risk in our distribution and zone substation assets, including underground cable, switchgear and transformers

- our information and communications technology (ICT) portfolio includes upgrades to our cyber-security, the replacement of our enterprise resource planning and billing system, CER integration, and additional regulatory compliance associated with post-2025 national energy market (NEM) reforms
- upgrades at our inner-city Burnley depot to maintain customer response times and support our increasing works program. We also need to redevelop our head office and establish a new training facility for our growing workforce.

Overall, our capital expenditure is forecast to increase in the 2026–31 regulatory period relative to recent periods, but is not dissimilar to our longer-term historic levels. A summary of our total capital investment over multiple regulatory periods is shown in figure 1.4, with the impact of new drivers in the 2026–31 regulatory period shown separately.

FIGURE 1.4 ANNUAL NET CAPITAL EXPENDITURE ($M, 2026)



Note: New investment drivers include, for example, customer-driven electrification and new CER investments (such as to introduce flexible services). The driver of the uplift in FY27 and FY28 includes in-flight modernisation works.

Proposed operating expenditure

Our operating expenditure forecast for the 2026–31 regulatory period has been developed using the AER's standard 'base-step-trend' approach.

As set out in our operating expenditure chapter, the key drivers of this forecast include our proposed step changes in vegetation management, ICT investments (including CER integration and reflecting the changing nature of IT solutions and market reforms), and our program to better support customers experiencing or at-risk of experiencing vulnerable circumstances (including our First Nations customer package).

1.2.2 Our revenue forecast

Our expenditure forecasts are a direct input to our revenue building block approach, which consistent with the National Electricity Rules (the Rules), has been used to calculate our revenue requirement. This revenue requirement is summarised in table 1.1 and represents a 10 per cent uplift on the current regulatory period.

Our approach also uses the AER's roll forward model (RFM) and post-tax revenue model (PTRM), standard AER approaches for depreciation, asset lives and the rate of return, and has been prepared in accordance with our currently approved cost allocation method.

Further detail on these approaches is set out in our revenue and control mechanism attachment.[3]

TABLE 1.1 REVENUE REQUIREMENT ($M, NOMINAL)

BUILDING BLOCK	FY27	FY28	FY29	FY30	FY31
Return on assets	137	150	164	176	188
Regulatory depreciation	94	100	110	123	133
Operating expenditure	111	122	128	135	141
Revenue adjustments	1	-2	3	7	3
Corporate income tax	8	7	10	17	23
Unsmoothed revenue requirement	350	377	415	458	487
Revenue X factor (%)	**-2.8%**	**-1.0%**	**-1.0%**	**-2.0%**	**-3.0%**

Note: Totals may not add due to rounding.

1.2.3 Customer bill impacts

Affordability was a key theme throughout our engagement program, recognising the prevailing cost of living challenges. In the context of the energy transition, however, customer sentiment was also focused on how our network can enable and unlock customer 'value' now and in the future—as noted by the Customer Advisory Panel, the big message on affordability from most, though not all customers, is about value rather than cost.[4]

This value recognises that in the longer-term, electrification is expected to deliver significant benefits for all customers. For example, recent research from the Australian Energy Market Commission (AEMC), Energy Consumers Australia (ECA) and other independent third parties have all outlined the long-term benefits of electrification.

For our regulatory proposal, the nominal average annual estimated distribution bill impact from our investments over the 2026–31 regulatory period, compared to 2025–26, is outlined in table 1.2 (calculated in accordance with the AER's bill impact template). These impacts reflect a modest bill reduction, and at the same time, our customers will receive a further reduction in nominal meter charges.

3 CP ATT 1.01 – SCS revenue and control mechanism – Jan2025 – Public.
4 Customer Advisory Panel, Report on draft proposals for 2026–31 reset, November 2024.

TABLE 1.2 NOMINAL AVERAGE ESTIMATED BILL IMPACT

CUSTOMER TYPE	DISTRIBUTION CHARGES[(1)]	METERING CHARGES[(2)]
Residential	-$0.11	-$2.37
Small business	-$0.26	-$2.37

(1) Any final impact to customers will depend on factors such as the willingness of electricity retailers to reflect our price reductions in their pricing, actual energy consumption and the impacts of financial service performance incentive schemes.

(2) Metering charges are shown for a single-phase meter; if the customer has a three-phase meter, these savings will be greater.

2. Electrification and CER integration strategy

The 2026–31 regulatory period is one of critical change, as the pace and scale of electrification accelerates through the energy transition and customer behavioural preferences evolve.

The scale and scope of these changes—particularly in Victoria—mean that our energy system in the future will need to function very differently to the energy system we have now. Decisions made today need to be fit for purpose for tomorrow.

To better understand and plan for these changes, including the urgency of any potential response, we developed our electrification and CER integration strategy. Given the impact of electrification and greater uptake of CER, our strategy involves the following:

- using enhanced, industry-leading forecasting capabilities to better understand potential customer and network impacts (including capacity and voltage constraints)
- maximising utilisation of our existing infrastructure and exhausting all possible low-cost solutions
- optimising any remaining economic constraints and undertaking no-regrets investments that enable customers to derive value from their CER.

Importantly, while investment to support electrification and CER integration will come at some cost to customers, the long-term benefits will materially outweigh these to deliver overall value for customers, even customers who cannot fully electrify. For example, the AEMC recently projected electrification (including our draft proposal investments) to drive a 19 percent fall in Victorian electricity prices to 2031.[5]

Stated alternatively, the risks and consequences of not acting now will be a slower and more disruptive energy transition, including higher costs for customers, poorer service level outcomes and higher emissions that may fail to deliver on committed targets.

The components of our electrification and CER integration strategy are summarised below with each component discussed in further detail throughout this section. Customer and stakeholder feedback has played a key role in the development of this strategy.

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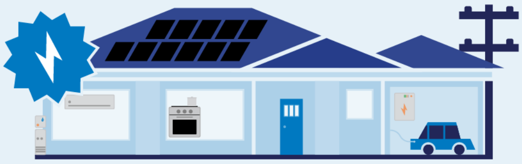
5 Australian Energy Market Commission, Residential electricity price trends, 2024, p. 32.

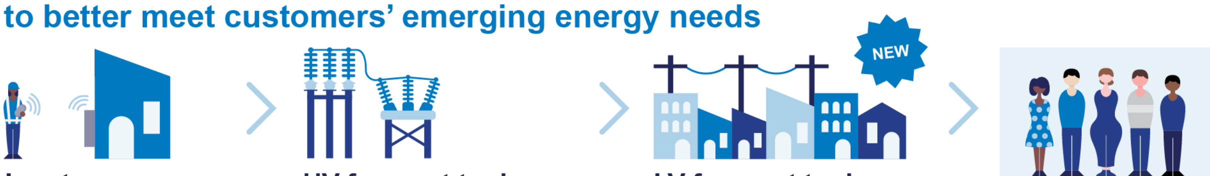
FIGURE 2.1 OVERVIEW: ELECTRIFICATION AND CER INTEGRATION STRATEGY

Customers are increasingly electrifying their homes to save money and look after the environment

All customers benefit from electrification through lower prices



We have developed industry leading forecasting capabilities to better meet customers' emerging energy needs



Inputs
Using smart meter data, customer insights and industry/government forecasts

HV forecast tool
Including **daily** minimum and maximum demand forecasts (**thermal**) for every **ZSS and HV feeder**

LV forecast tool
Including **30-minute** minimum and maximum demand forecasts (**thermal and voltage**) for every **LV and HV asset**

More accurate customer impacts quantified

We are maximising utilisation and exhausting all possible low-cost solutions

2021–26	2026–31	2031 onwards	Initiative type
Cost-reflective tariffs			B
Network optimisation (e.g. inverter compliance, hot water shifting)			B
Built	Dynamic voltage management system (DVMS)		B
Built	Victorian emergency backstop mechanism		E
Semi-automated	Non-network marketplace		B
	Build	Enhanced data visibility	B
	Build	Flexible exports	E
	Build	Flexible load	L

B Both load initiative and export initiative E Export initiative L Load initiative

And optimising remaining augmentation

Identifying where single HV solutions can remove multiple LV constraints

Efficiently balancing proactive and reactive investments to deliver lowest long-term costs to customers

Assessing future replacement needs in augmentation planning to future-proof for electrification

Enabling customers to derive value

95% of customers can freely export 99% of the time

All customers can **export up to network limits**

All customers have **universal access to standard wall charging**

Maintain existing performance for all customers to provide confidence in the energy transition

2.1 What we've heard from our customers

The success of the energy transition, and broad-scale electrification, is deeply dependent on a positive customer experience. Our customers need confidence in their energy system to have confidence to fully electrify their homes and lifestyle.

To ensure our electrification and CER integration strategy is informed by these customer expectations, our engagement program included multiple energy transition and future-focused stakeholder summits, and our partnership with Monash University in the development of the Future Home Demand report.[6]

Energy transition summit and Future energy network forum

Recognising the fundamental changes that are occurring as part of the energy transition, we released an options paper and facilitated two separate forums to explore the priorities and expectations of customers and stakeholders on the utilisation and management of emerging energy technologies.

Focusing on rooftop solar, electric vehicles (EV) and electrification of gas, we sought preferences on service levels and investment options to better identify customer value propositions.

Participants were committed to greater equality, with a response to the climate emergency guiding their service level preferences, and highlighted the importance of capacity increases.

Stakeholders also supported a measured approach to EV charging enablement, and recognised that forecasts for electrification of gas were too conservative to achieve net zero by 2050 but the logistics of electrifying gas were challenging.

Monash University: Future Home Demand report

In 2023, we partnered with Monash University to better understand longer term behavioural trends to inform electricity sector planning. This involved research inside our customers' homes, with questions about their lifestyles, energy use practices and how they expected these to change in the future.

The study was a multi-staged research project with 36 households, supported by a survey of 1,325 customers. The study identified household implications for energy forecasting and generated insights for EV adoption, charging practices, demand management opportunities and future peak scenarios.

In addition to developing clear outcomes, our engagement focused on key input factors such as how customers expect to adopt and use CER and electrification technologies. These inputs are used in our demand forecasts, which underpin our entire regulatory proposal.

We also held mass market trade-off evaluation forums where customers chose between several cost and service levels for different initiatives. Customers at these forums supported investments to enable more solar export and improve stability of EV integration.

The key findings from our engagement around customer expectation and preferences on electrification and CER integration are summarised in table 2.1.

6 CP ATT SE.10 – Monash University - Future home demand – Jul2023 – Public.

TABLE 2.1 KEY ENGAGEMENT FINDINGS

Solar export

Customers and stakeholders advocated for strategic investments in grid capacity, empowering consumers to make informed decisions and drive renewable energy integration while preventing anyone from being left behind.

Our customers echoed a commitment to equity for solar exports and felt strongly about responding to the climate emergency. They prioritised emissions reduction, highlighting the importance of capacity increases to support positive flexible export outcomes and more hosting capacity.

Sentiment towards solar exports is positive with a focus on maximising solar energy output with smarter solutions. Customers prioritise self-consumption over export and strongly oppose export tariffs as they perceive them as additional costs.

Stakeholders expressed a collective belief in the benefits of flexible solar exports. Preferences for supporting solar-driven capacity improvements to avoid ‘wastage’ of renewable energy emerged, however latent concerns about non-solar customers bearing the cost of solar upgrades also emerged.

Electrification of gas

There were mixed views on the speed of electrification of gas, with some stakeholders suggesting forecasts were too conservative and that net-zero targets would be missed, where others suggested that cost and industry logistics to decarbonise were prohibitive.

New builds were considered the path of least resistance to electrify gas, whereas existing homes were seen as more challenging to electrify. Induction cooktops and space heating are the most likely household technologies to be electrified.

Customers expressed concern about the impact electrification may have on stability of the grid, particularly in the evening where induction cooktops would contribute to peak demand and in winter where heating has predominately been powered by gas.

Electrification of transport

Customers generally view EVs favourably, recognising their potential to support rapid decarbonisation and their economics due to rising fuel prices. Customers see a future-ready network as tied to the widespread adoption of EVs, while ensuring quality at a reasonable cost.

However, some stakeholders expressed uncertainty about the speed of EV uptake, with remaining concerns about upfront cost (where government incentives are seen as a key requirement for uptake). Network reliability and availability of charging infrastructure were seen as barriers to overcome.

81 per cent of customers said they preferred to charge their EV at home, with 71 per cent of those customers preferring faster (level-two) charging and 29 per cent preferring slower (level-one) charging. Access to charging facilities continues to affect EV uptake.

Customers continue to have set views of how and when to charge electronic devices, which is likely to translate into EV charging and automation settings.

Customers generally support managed charging, however 96 per cent of customers require manual or override settings, indicating a strong preference to maintain control.

Stakeholders recognised the need for investment and a measured approach.

Commercial and industrial customers

Commercial and industrial customers consider power quality and network reliability as the most significant factors affecting their business operations. They experience a spectrum of challenges related to interruptions, harmonics, power factor, voltage sags and surges.

Power disturbances, even if momentary, were reported to have material implications for these customers including substantial disruptions to production, loss of inventory, delays with cleaning and sterilising, and revenue loss. Power quality is seen as in increasing concern through the energy transition as more equipment becomes electrified.

Commercial and industrial customers shared concerns about access to future load and operational sustainability, and therefore prioritised unrestricted access to electrical supply and improvements to power quality that meet their operational needs as network demand continues to grow.

Energy storage was also assessed by customers as a viable option to support power quality improvements.

2.1.1 Test and validate

Our CER integration and electrification initiatives are highly tangible to customers because they contain several ‘touch points’ and deliver direct benefits for customers.

As part of our test and validate program, we endeavoured to understand more about the profiles, key motivators and barriers that influence consumer willingness to modify energy consumption habits. We also assessed consumer awareness, understanding and responsiveness to time-of-use energy tariffs, acceptance of network control and our overall program of investments.

Broadly, customers supported our proposed investments and our overall program of investments represented value for the services we delivered:

- 53 per cent of small and medium business customers and 51 per cent of residential customers were unfamiliar with the concept of time-of-use tariffs
- 52 per cent of small and medium business customers and 72 per cent of residential customers felt that lowering energy bills was the biggest motivator to shift energy usage to off-peak times
- 71 per cent of customers supported bill increases to enable more solar exports for all customers
- 79 per cent of small and medium business customers and 53 per cent of residential customers planned to replace their gas appliances with electric appliances over the next five years.

Customers also contributed their views on our programs related to CER integration and electrification. These findings are discussed in the context of our proposed investments below.

2.2 Customers are increasingly electrifying and investing in CER

The way our customers are using electricity is rapidly changing, with state and federal government policies influencing adoption of new technologies. This transformation of electricity needs is occurring at the same time as more typical network investment drivers like population growth, asset risk and safety persist and/or grow.

Considering all these factors holistically, annual consumption is expected to grow by 26 per cent, and peak demand by 7 per cent by the end of our 2026–31 regulatory period.

2.2.1 Net-zero commitments

The Victorian Government has a strong and enduring commitment to electrification, with a major focus on decarbonising the energy and transport sectors on its pathway to net-zero.

The pathway is supported by its objective of achieving net-zero by 2045. This commitment is further supported by legislated interim targets, including:

- 50 per cent reduction in carbon emissions by 2030 (below 2005 levels)
- 65 per cent of Victoria's electricity coming from renewable sources by 2030 (increasing to 95 per cent by 2035).

The achievement of these targets is driving new supply and demand-side interventions, and customer behavioural change.

2.2.2 Renewable generation and BESS deployment

To put the scale of the Victorian Government net-zero commitments into context, achieving 95 per cent of Victoria's electricity from renewable sources (by 2035) is expected to require around 30GW of wind and solar. This equates to more than two and a half times the renewable capacity that exists today.

The amount of renewable generation connected directly to our distribution network remains small, but is expected to grow. Much of this renewable generation is provided by solar PV, with over 100MW of rooftop systems now installed by our residential customers. The capacity of this rooftop solar has doubled in the last five years alone, and is forecast to triple by the end of 2031.

While rooftop solar provides many benefits, including savings for customers and a reduction in Victoria's carbon emissions, high solar uptake can also lead to system security challenges such as minimum system load.[7] During December 2023, for example, Victoria set a record low for minimum operational demand.

Looking forward, the Australian Energy Market Operator (AEMO) are forecasting negative operational demand for Victoria in 2027.

2.2.3 Electrification of transport

EVs will transform our electricity grid, for both EV and non-EV owners, with increased consumption from wide-spread adoption having the ability to lower per-unit energy charges for all customers.

AEMO forecasts rapid growth in EV uptake, with 28 per cent of our customers expected to have an EV by 2031. This is almost 10 times the number of EVs on the road today.

AEMO's forecasts are consistent with existing Victorian Government policy, including its stated goal of a fully decarbonised road transport sector by 2045. This policy objective is supported by a target of 50 per cent of all new light vehicle sales to be zero emissions vehicles by 2030.

Collectively, the electrification of transport will increase Victoria's electricity usage by 5 per cent in 2031. Any impacts of EV charging on our network, however, will be heavily dependent on customer charging behaviour and geographic factors such as the localised concentration of EVs (including for our network, the need to support significantly more EV charging than the number of EV-owners because of EV charging at work or at major hubs, such as the CBD, shopping or transport precincts).

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7 Minimum system load typically occurs when demand from the grid is low and the output from solar is high, and can lead to local or state-wide blackouts.

2.2.4 Electrification of gas

Victoria has the highest percentage of gas connections in Australia, with around 80 per cent of residential homes connected to gas. We are more dependent on gas than any other jurisdiction, with triple the average annual consumption of New South Wales and South Australia customers, and seven-times that of Queensland. We also use over 40 per cent more than ACT and Tasmanian customers who live in similar cool climate zones.

In 2022, the Victorian Government published its Gas Substitution Roadmap.[8] This roadmap outlined the pathway to transition away from residential gas in Victoria, with the first key step being the ban on new residential gas connections from January 2024.

AEMO forecasts that the electrification of gas will result in an additional 2,600GWh of electricity being consumed per year by Victorians, primarily for space and water heating. This is expected to increase consumption by 7 per cent, improve utilisation and shift areas of our network to winter peaking.

2.2.5 Population growth

In 2023, Melbourne overtook Sydney as Australia's largest city. This continued a trend of strong population growth across Victoria.

Much of this growth has, and continues to be, within our network boundaries. In the CBD and inner-city, this includes increasing density with single dwelling premises being converted to multi-story and all-electric buildings.

By 2031, AEMO forecast population growth of 13 per cent, or an additional 880,000 people calling our state home. In our network area, this is equivalent to an additional 105,000 people.

2.2.6 Behavioural change

In 2023, we partnered with Monash University to better understand longer term behavioural trends to inform electricity sector planning. This involved research inside our customers' homes, with questions about their lifestyles, energy use practices and how they expected these to change in the future.

The study identified household impacts and implications for energy forecasting. The research generated insights for EV's and charging practices, demand management opportunities and future peak scenarios.

Monash's findings support the view that working and studying from home will be a permanent feature. They also identified increasing trends towards greater in-home care, recreation and home automation. These trends all add to the increasing dependency on a reliable supply from the electrification of our energy system.

2.3 Enhanced forecasting capabilities allow us to better understand customer impacts

The changes above, both individually and collectively, are transforming our network. Our ability to forecast these changes, and understand their potential impacts on our network and customers, is fundamental to ensuring efficient outcomes and delivering desired customer experiences.

2.3.1 HV network

Our HV network forecasting tool is well established, and has been used and refined within our planning and asset management practices for multiple regulatory periods.

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8 Victorian Government, Gas Substitution Roadmap, 2022.

This tool generates detailed demand forecasts across our entire HV network, from our transmission connection to our distribution substations. It considers a wide range of information such as customer usage, customer insights, network topology, AEMO data, industry research, tariff impacts and weather to forecast probabilistic minimum and maximum demand through Monte Carlo simulation.

The tool accounts for all change drivers like residential and commercial gas electrification, EV growth and charging profiles, solar PV and batteries. This includes expected usage assumptions—for example, our HV forecasting tool weights EV adoption to dwellings that have a location to charge EVs (i.e. EVs are more likely to be adopted by a customer living in a house compared with a customer living in an apartment).

It also accounts for macroeconomic factors like energy efficiency, population growth, gross state product, income, home ownership and more to assess locational network impacts.

2.3.2 LV network

The uptake of new customer-centric loads is creating significant change and uncertainty on our LV network. These changes are impacting customers already.

To manage this increasing uncertainty, and more accurately assess the locational impacts of the energy transition, we developed new LV analysis and forecasting capability that significantly improves the sophistication and granularity of our forecasts.

This is a fundamental evolution in our forecasting capability, leveraging the extent of our smart meter population, and sets us apart from other distributors (who are typically required to rely on simplified archetype modelling).

Specifically, our LV forecasting tool uses power flow modelling to analyse the impacts of forecast energy use for every customer on our network. This analysis identifies the location and severity of both thermal and voltage impacts across our entire HV and LV network every 30 minutes. This power flow modelling incorporates real customer data as a starting point and considers the interconnected nature of electricity networks, where load on each asset has an impact on other interconnected assets—in total, it relies on over 800 billion data points through the computation process.

Our new LV forecasting and analysis capability builds on our HV forecasting tool and we can now assess the holistic impact of all change drivers (e.g. solar export, EV charging, electrified gas and general growth) simultaneously. The tool details the location, severity and impact of each constraint over time and we have developed economic assessments that leverage outputs from the tool.

We have also aligned our EV charging forecasting assumptions in our LV forecasting tool with the findings from Monash University's Future Home Demand report.

FIGURE 2.2 TIME-SERIES, CUSTOMER LEVEL THERMAL AND VOLTAGE FORECASTS

Traditional forecasting

Focussed on understanding single asset impacts where constraints are considered in isolation.

Key outputs:

- HV assets
- thermal constraints
- daily minimum and maximum demand
- LV assessments limited to direct impact on individual circuits

Enhanced forecasting

Our new approach considers our network as an interdependent system where constraints are considered holistically.

Key outputs:

- HV **and LV** assets
- thermal **and voltage** constraints
- forecasts demand in **30-minute intervals**
- LV assessments based on **power flow modelling** which considers **localised network** and **customer impacts**

Customer outcomes

Better network and customer visibility providing more accurate and granular forecasts, allowing us to better utilise existing network capacity and have better certainty on when and where to invest.

The criticality of accurate forecast tools is becoming further evident in predicting, and acting on, customer impacts. Today, we are observing in practice that a few EVs on a single residential street can be enough to create network constraints that severely impact customers.

For example, below is a case study on EV charging demonstrating some of the challenges our customers are experiencing now. This issue is not isolated; we have received numerous similar complaints from our customers where their EVs have not charged.

The prevalence and severity of undervoltage-driven constraints will grow over time as customers continue to electrify.

CASE STUDY: DAY-TO-DAY ACTIVITIES IMPACTED BY UNDERVOLTAGE

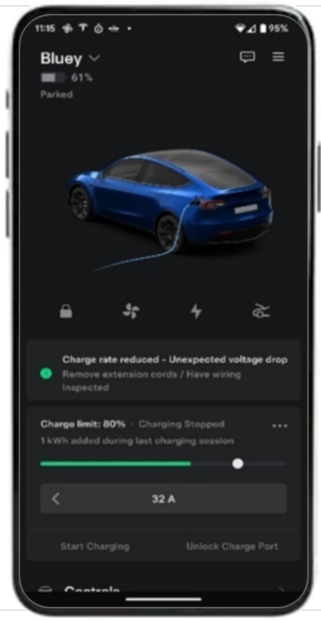
A customer in Balwyn complained to us that their **EV was not charging, impacting their day-to-day activities. The customer has resorted to modifying appliances away from electrification to manage power quality.**

The customer was notified via their phone application that their charging was interrupted due to voltage drop issues. Undervoltage was found to be causing the interruptions to the customers' EV charging, where their voltage levels regularly dropped below 213V.

We **installed a new pole-top substation and LV circuits to remediate this issue at a total cost of $413,000**.

*"Due to the recent supply issues, I've **moved the electric hot water load to instantaneous gas hot water heating to remove the 3.6KW load during peak usage**"*

Quote from customer in Balwyn



2.4 Exhausting all possible low-cost solutions to optimise outcomes

Throughout our current regulatory period, we have taken several steps to maximise the utilisation of our existing infrastructure to support electrification and CER. These low-cost solutions have delivered significant benefits for customers.

Examples of some of our low-cost approaches are outlined in table 2.2, with the impacts of these tools reflected in our revealed historical data (e.g. tap settings), and/or in our input assumptions (e.g. future tariffs). These low-cost approaches will be supported by the functional capabilities developed through our role as the distribution system operator, including our upgrades to our advanced distribution management system (ADMS) providing greater real-time visibility of customer behaviour.

For the 2026–31 regulatory period, we are building on this existing 'toolkit' to ensure we exhaust all possible low-cost solutions ahead of any augmentation. New low-cost solutions are a key feature of our electrification and CER integration strategy, and include wider testing of third-party capabilities, enhancing data visibility for stakeholders, maximising customers' ability to export to our network, and preparing for flexible load products.

A fulsome description of each of these proposed investments is provided in section 2.4.1.

TABLE 2.2 EXISTING LOW-COST SOLUTIONS

SOLUTION	DESCRIPTION
Cost-reflective tariffs	Implementing increasingly cost-reflective tariffs to incentivise consumption outside typical peak demand periods and increase network utilisation. For example, implementing a CER tariff that rewards customers for exporting during peak demand periods. Further information is available in our tariff structure statement
Adjusting asset settings	Low-cost augmentations that use existing capacity more effectively, for example, setting distribution transformers to different voltage set points (known as tapping) or balancing customer load across the three phases to stabilise power quality
Inverter compliance	Proactively identifying 40,000 non-compliant inverters in Victoria and working with installers and manufacturers to ensure compliance, improving local power quality and export outcomes for customers
Solar pre-approval	Implementing streamlined pre-approval for customer solar export connection requests in five minutes, based on local network power flow analysis
Dynamic voltage control	Optimising voltage levels across our HV network to maximise voltage compliance and power quality outcomes for customers
Victorian emergency backstop mechanism	Investment to meet the Victorian Government’s legislation to maintain system security and limit the impact of minimum operating demand during peak solar generation periods by temporarily limiting generation or increasing demand
Hot water load shifting	We are also planning to build on our hot water load shifting trials to shift our controlled load hot water heating from overnight to the middle of the day. This will increase electricity demand in the middle of the day and support more solar export

2.4.1 Proposed CER integration investments: 2026–31 regulatory period

We are proposing to build on our existing low-cost solutions, with new capabilities in the 2026–31 expected to further exhaust all possible low-cost options. These capabilities include utilising new tariffs, offering flexible services for CER, improving data capture and availability, and increasing visibility for third-parties to remediate network constraints.

Collectively, we expect these solutions will create optionality, and will deliver improved services and lower prices for customers over the long term.

Cost reflective tariffs

We are proposing a suite of simple, efficient and adaptable tariffs for our 2026–31 regulatory period that are the most cost-reflective tariffs we have ever implemented. Our tariffs provide better pricing signals for customers to use and export electricity in ways that shift consumption away from peak periods and incentivise consumption during off-peak periods to increase network utilisation.

COST REFLECTIVE TARIFFS	COST
Our stakeholders expected that we introduce price signals for flexible resources, while maintaining simplicity and predictability across our tariff portfolio. We are proposing an opt-in two-way CER tariff that includes an export charge from 11am to 4pm and an export rebate from 4pm to 9pm. The tariff targets retailers and aggregators who can use flexible import and export devices such as home batteries and EVs with vehicle-to-grid capability to support the network. For commercial and industrial customers, we are implementing a winter incentive demand period and non-residential flexible connection tariffs. The non-residential flexible connection tariffs are largely targeted at integrating community batteries and grid-scale storage into our network, but also accommodate other potential flexible technologies. EV charging stations will continue to be able to opt out of demand tariffs if they consume less than 160MWh per annum, and we plan to trial tariffs for dedicated low voltage EV charging sites, such as pole-mounted EV chargers.	-

Note: For further detail, refer to our tariff structure statement: CitiPower Tariff Structure Statement 2026—31 – Explanatory Statement – Jan2025.

Network data visibility

We currently publish annual network and constraint data through our Rosetta network visualisation portal. However, with the growth in CER on the LV network, customers are seeking improved LV insights to make more informed decisions. We are observing an increasing amount of network data requests across a range of stakeholder such as, councils, market participants, customers, and Government.

NETWORK DATA VISIBILITY	COST
We are proposing to implement an improved customer portal presenting our physical network that will publish constraint and spare capacity data in a more usable, interactive, and timely way. This will enable more opportunities for a range of stakeholders to better understand connection opportunities as well as unlocking potential innovation. Our involvement in the AER and Victorian Government network data trial uncovered the ‘pain points’ that need to be improved including data timeliness, useability, and level of detail available. We are continuing our involvement in the network visibility program to incorporate the learnings into our proposed program. Customers through our test and validate program called for equitable access to data, ensuring all customers regardless of location or size could leverage this information. Customers supported our proposed data visibility program noting that equitable access to practical, timely and extensive data would be beneficial.	CAPEX $1M OPEX $1M

Note: For further detail, refer to our attached business case: CP BUS 2.03 – Network data visibility – Jan2025 – Public.

Non-network platform

In 2023, we partnered with the non-network solution platform, Piclo, to run a trial where we tendered our forecast network constraints. Non-network solutions have the potential to provide significant benefits for customers as third-parties may be able to address network constraints more efficiently than building more network.

Our current experience is that it takes time and commitment to successfully foster development of a third-party non-network solution market. A mature non-network marketplace has the potential to significantly improve network utilisation and lower costs for customers.

NON-NETWORK MARKETPLACE	COST
We are proposing to implement a procurement platform to create an automated marketplace where our constraints will be visible and actionable for third-parties to immediately resolve. Although expected uptake from third-party providers may be low initially (reflecting international experience, particularly that of the United Kingdom), encouraging market participation takes time to build and our platform will encourage market maturity. Notwithstanding this, we expect to defer $0.5m of augmentation in the 2026–31 regulatory period and have reduced our augmentation proposal accordingly. We will also absorb any operating expenditure costs associated with procuring these services. Through our test and validate program, stakeholders supported this innovative investment despite the current market for third-party suppliers being new.	CAPEX $1M OPEX $1M

Note: For further detail, refer to our attached business case: CP BUS 2.02 – Non-network marketplace – Jan2025 – Public.

Flexible exports

The capacity of rooftop solar is forecast to triple by the end of 2031. This reflects the many benefits provided by rooftop solar, including savings for customers and a reduction in Victoria's carbon emissions.

Our networks' existing capacity to host solar exports (or our 'intrinsic hosting capacity') is being increasingly utilised as more solar connects. For example, 2 per cent of new solar customers in 2024 have been offered static zero export limits of less than 5kW because the available local intrinsic hosting capacity has been used by existing solar customers (who under existing standard connection agreements are provided static 5kW export limits if capacity is available). With the network quickly reaching its hosting capacity, and significantly more solar to be connected in the period, the proportion of export limited customers is expected to dramatically increase. Across Victoria, we are also facing imminent minimum demand issues from static uncontrolled PV exports, as evidenced by the Victorian Government's emergency backstop mechanism.

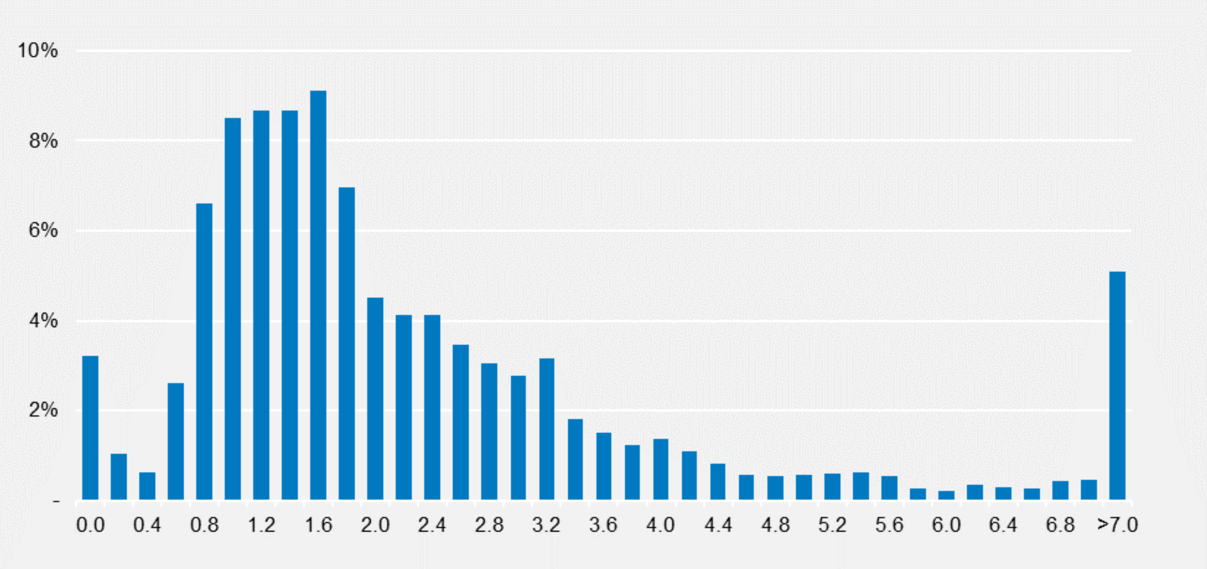
Intrinsic hosting capacity assessment

We used our LV forecast tool to assess the intrinsic hosting capacity at each customer connection point across our network.

Overall, and as shown in figure 2.3, we found that the median intrinsic hosting capacity to support exports is 1.6kW per customer. This means that half of our network can support solar exports of 1.6kW per customer and the other half would be constrained.

Our network's total intrinsic hosting capacity to support small-scale solar is 460MW, which we expect to become more utilised over 2026–31, particularly in urban areas with high solar penetration.

FIGURE 2.3 PERCENTAGE OF CUSTOMERS WITH INTRINSIC HOSTING CAPACITY (KW)



FLEXIBLE EXPORTS	COST
Our customers have expressed expectations that we place more emphasis on fairness and equity for solar exports, prioritising long-term approaches and employing smarter solutions. To better use our existing hosting capacity, we are proposing to implement flexible export products that will vary customers' export limit through the day based on the available network capacity. This will utilise our existing infrastructure to enable an additional 92GWh of export for customers over 2026–31, equivalent to the total annual generation of 15,000 5kW solar systems, with even more future benefits. All solar customers will be offered a flexible export product, including existing export limited solar customers who will be eligible but may need inverter upgrades to support a flexible product depending on the age of their system. We are also planning to enable more equitable long-term access to exports for all customers, by reducing our standard static export limit from 5kW to 1.5kW because existing network intrinsic hosting capacity is being eroded and customers will have the option of a more efficient flexible export product. Customers and stakeholders at our energy transition summit expressed a collective belief in the benefits of flexible export products, stemming from economic considerations and a desire to support sustainable initiatives for future generations. 71 per cent of customers at our trade-off forum supported bill increases of $1.30 or more to support solar exports. Support for our flexible exports program was reinforced through our test and validate roundtables, where stakeholders preferred equal allocation of capacity across flexible customers and noted that sentiment focused on balancing fairness, network constraints and clear communication to foster realistic customer expectations. We are proposing no export-driven augmentation across our 2026–31 regulatory period. After accounting for the benefits of flexible exports, no efficient augmentation sites were identified using the AER's customer export curtailment value and value of emissions reduction. There was also limited support throughout our broader engagement program for network augmentation to enable more solar exports (in contrast to using smarter solutions such as flexible products).	CAPEX $8M OPEX $9M

Note: For further detail, refer to our attached business case: CP BUS 2.01 – Flexible services – Jan2025 – Public.

Flexible load

EV adoption will be a key driver of load growth on our network for many years to come, and as customer experience and confidence with EVs grows, flexible load products are likely to play a role in ensuring efficient investments. For example, EV charging is likely to be somewhat flexible for many customers.

Our research with Monash University indicates that over 50 per cent of customers may be amenable to automating some of their EV charging as long as they have the ability to override automated signals. Customers and stakeholders at our energy transition summit, however, shared mixed views about the necessity and customer appetite for flexible load products.

FLEXIBLE LOAD	COST
We are proposing to develop and refine the capability to implement flexible load products during the 2026–31 regulatory period, in preparation for scale implementation of flexible load products during our 2031–36 regulatory period. Developing this capability in 2026–31 will require us to build systems, ensure interoperability, iteratively learn from trials, and refine our understanding of how customers adopt and respond to flexible load products. Our approach recognises the mixed support from our customers and stakeholders and allows time for further engagement on design and implementation to ensure that customers are comfortable with flexible load products and they are not seen as a barrier to the energy transition.	CAPEX $1M

Note: For further detail, refer to our attached business case: CP BUS 2.01 – Flexible services – Jan2025 – Public.

2.5 Optimising the remaining augmentation portfolio with no-regrets investments

All else equal, our electrification and CER integration strategy prioritises low-cost solutions ahead of network investment.

Our low-cost solutions, however, will be supplemented by targeted no-regrets network upgrades in the 2026–31 regulatory period that improve capacity and provide customers with more ability to consume and export electricity. These investments include our customer-driven electrification program.

Importantly, these investments are also optimised. For example, our customer-driven electrification program minimises costs to customers by considering the following:

- HV solutions have been identified where these are more efficient than upgrading multiple LV sites in similar areas
- overlaps with our conductor replacement expenditure program have been identified and removed from our forecasts
- non-network solutions have been assumed to defer some LV augmentation, particularly late in the 2026–31 period, which has reduced our proposed electrification program.

As the nature of these investments are primarily adding capacity to our network, we consider these in more detail in our augmentation chapter.

2.6 Enabling customers to derive value from their CER investments

As a package, our proposal enables customers to derive more value from their investments and maintains strong quality of supply that enables EV charging and minimises reliability impacts. These outcomes are consistent with our key engagement findings.

TABLE 2.3 CUSTOMER SERVICE LEVEL COMMITMENTS

CUSTOMER SERVICE LEVEL	DESCRIPTION
95 per cent of customers can freely export 99 per cent of the time	• 95 per cent of customers can export unconstrained 99 per cent of the time, meaning nearly all customers will have no export constraints most of the time • Although 5 per cent of customers will have partial constraints more than 1 per cent of the time, this is still more preferable than a static zero export limit
All customers can export up to network limits	• All export customers can export using available network capacity rather than reserving capacity for some customers and using static zero export limits for other customers • We will ensure customers can export as much as possible while maintaining safety and reliability
All customers have universal access to standard wall charging	• All customers can charge EVs using standard wall plugs • Availability to connect wall-mounted fast chargers at home (e.g. level-two chargers) remains dependent on network capacity • Flexible load products are expected to create future levers to facilitate more fast charging and shift charging away from peak periods
Maintain existing performance for all customers to provide confidence in the energy transition	• Maintain existing voltage performance for customers to facilitate EV charging and minimise reliability impacts of EV charging on all nearby customers • Adhering to mandatory voltage compliance obligations will support customer service levels for export and load

3. Augmentation

Augmentation expenditure is investment to support capacity-driven reinforcement and expansion of our network footprint.

Additionally, augmentation can be driven by factors that are not related to demand, such as maintaining adequate protections for system security and ensuring sufficient communications infrastructure to support network operations.

In the current regulatory period, we are expecting to underspend our augmentation allowance due to:

- peak demand and consumption in the CBD and inner-city fell by 20–30 per cent during lockdowns, and the uncertainty around when business and community activity would return delayed some major augmentation works as part of our modernisation program
- deferred augmentation works for the Tavistock Place supply upgrade following lower localised connections post-COVID
- better than expected performance from operational solutions to enable solar exports, including our DVMS and industry-leading work to identify and address incorrect customer solar inverter settings
- lower than expected costs for the Russell Place supply offload due to the limited extent of required structural works.

Looking forward, electrification of gas and transport are key drivers of demand-driven augmentation for the 2026–31 regulatory period. We forecast these holistically alongside macroeconomic growth factors, behavioural change and CER. These forecasts are underpinned by our demand forecasting tools, that as set out in our electrification and CER strategy, allow us to understand expected customer impacts in more detail than any other network in Australia.[9]

Accordingly, our proposal includes investment to modernise lower capacity areas of our network and facilitate growing demand, enable customer electrification of gas and transport, and maintain system security (including our specific CBD obligations).

Since our draft proposal, our augmentation forecasts have decreased by over $90 million, primarily driven by revised (lower) AEMO assumptions for both CER and electrification uptake, and additional options analysis for our modernisation program. We have also proposed to treat some larger augmentation works as contingent projects.

A summary of our augmentation investment in the current and future regulatory period is shown below.

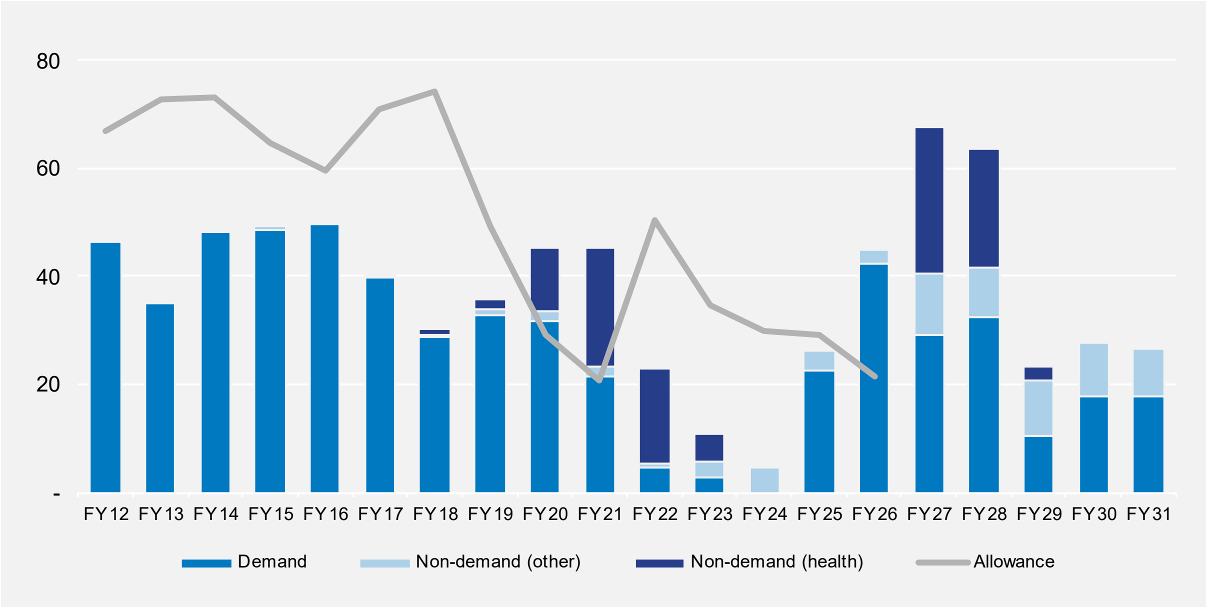
TABLE 3.1 TOTAL AUGMENTATION INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Augmentation	109	208

Note: Disposals have not been netted off.

9 Our forecasts (including for other expenditure categories) are based on the AER's 2019 VCR study, escalated in accordance with the AER's specified methodology. In late-December 2024, the AER published its new, 2024 VCR values. We are yet to assess the impact of these changes, but will consider these through the development of our revised regulatory proposal.

FIGURE 3.1 ANNUAL AUGMENTATION INVESTMENT ($M, 2026)



3.1 What we've heard

Our engagement program sought to understand customer expectations and preferences around the energy transition to inform the development of our proposal and ensure that it delivers value for customers. In particular, we focused on customer preferences and electrification rates.

Our electrification and CER integration strategy describes the central themes identified through our engagement, including support for strategic investments to facilitate electrification of gas and transport.

TABLE 3.2 KEY ENGAGEMENT FINDINGS

	Customers consistently highlighted the importance of a reliable energy supply, with the majority of customers having an appetite to maintain current reliability. Customers are becoming increasingly dependent on electricity given working from home trends and forecast electrification, and flagged a concern for reliability outcomes in their future.[10]
	Our customers echoed a commitment to equity for solar exports and felt strongly about responding to the climate emergency. They prioritised emissions reduction, and the importance of capacity increases to support positive flexible export outcomes
	Customers generally view EVs favourably, recognising their potential to support rapid decarbonisation. Customers see a future-ready network as tied to the widespread adoption of EVs
	There were mixed views on the speed of electrification of gas, with some stakeholders suggesting forecasts were too low and that net-zero targets would be missed, where others suggested that cost and industry logistics were prohibitive

10 This was both an output from customer engagement and observed on-the-ground via our Monash University Future Home Demand report. For further detail, refer to: Monash University, Future Home Demand, 2023.

Commercial and industrial customers prioritised unrestricted access to electrical supply and improvements to power quality that meet their operational needs as demand continues to grow on the network

3.1.1 Test and validate

Through our test and validate engagement, we sought to understand whether our customers supported our proposed programs of investment in our draft proposal.

During a series of roundtables, our customers affirmed support for investment to manage increasing load across our network, primarily driven by greater EV uptake.[11] Customers were concerned about ensuring that new infrastructure was equipped to handle future technological and capacity demands. This included preparing for increased electrification of homes and transportation, as well as integrating new energy sources like solar and batteries.

> *"We need to make sure that this investment isn't just about fixing old problems but also preparing for the future energy landscape" – CitiPower participant*

> *"If we're going to upgrade, we should think ahead and build in extra capacity to avoid further disruption down the line" – CitiPower participant*

Our customers prioritised our ability to access data about where EVs were owned and charging, noting that this knowledge was essential for us to plan for the next regulatory period and make informed decisions. Our customers also emphasised the need for time-of-use tariffs to influence charging behaviour to mitigate against peak demand increases.

Our commercial and industrial customers expressed broad support for investments to maintain or improve power quality, citing this and reliability as their top priority. They conveyed a clear understanding that these investments were necessary to support growth, but expressed desire for more detail on how investments would lead to improvements in reliability and voltage management. Businesses intending to integrate renewable energy, including solar and battery storage, supported investments to address network constraints and improve overall electricity access.

Further detail on specific customer feedback is discussed with the relevant investments below.

3.2 Our proposed response

Our augmentation portfolio considers a range of network and non-network options to deliver the service level outcomes that our customers have identified as valuable to them.

Due to the high-density nature of our network—more than 50 per cent of our network is underground—our augmentation expenditure is typically more expensive than other networks and leads to a 'lumpier' expenditure profile.

3.2.1 Demand-driven augmentation program

Increases in localised peak demand are a major driver of our augmentation proposal.

We forecast that peak demand across our network in 2031 will be 7 per cent higher than it is today. This increase reflects the changes in customer technology adoption and use, described in more detail in our CER and electrification strategy.

[11] Forethought, Test and Validate Roundtables: Produced for CitiPower, Powercor and United Energy, 2024, p. 36.

Peak demand growth is also driven by increasing population. Our network is expected to have 16 per cent population growth by 2031, driven by higher density living supported by changes in planning standards and a return to Melbourne's CBD following the impacts of the pandemic.

An overview of our key demand-driven augmentation projects proposed for the 2026–31 regulatory period is outlined below.

BRUNSWICK MODERNISATION PROGRAM	COST
The legacy design of our inner-city network comprises sections of lower capacity and poorer condition assets. We have efficiently managed this risk over time through an ongoing modernisation program (e.g. we have progressively offloaded and decommissioned several aged zone substations, driven by their underlying condition and risk). This has allowed us to maximise the safe utilisation of our existing assets, while only triggering zone substation re-builds at the optimal timeframe. In the current regulatory period, we will have commenced two-health driven projects that will continue into the 2026–31 regulatory period. These projects are the offload of our Brunswick (BK) zone substation to West Brunswick (WB), and the offload of our Fitzroy (F) zone substation to Collingwood (CW). A regulatory investment test for distribution (RIT-D) has been published for these works. These projects will improve safety by decommissioning poor condition assets and improve network contingency options by upgrading the existing 80-year old 6.6kV capacity network to the higher capacity 11kV network used more broadly throughout our network. As part of our original Brunswick supply area plan, as set out in our draft proposal, we also intended to re-develop our decommissioned Brunswick (C) zone substation to facilitate in-fill growth and electrification. Further refinement of our credible options has identified a more preferable lower cost solution is to instead install a new third transformer at our CW zone substation. This has reduced our expenditure proposal by approximately $42 million.	$59M

Note: For further detail, refer to our attached business case: CP BUS 3.03 – Brunswick modernisation – Jan2025 – Public.

ZONE SUBSTATION CAPACITY UPGRADES	COST
Several zone substations across our network require the installation of additional transformer capacity to support growing demand and customer numbers. These upgrades will continue to provide reliable electricity supply for customers supplied by our Collingwood (B) and Bouverie St (BQ) zone substations. In addition to these works, we have also proposed contingent projects for major re-developments at our Laurens Street (LS) and Richmond (R) zone substations. Consistent with stakeholder feedback, the costs of these works have not been included in our proposed augmentation expenditure and instead will only be triggered if defined thresholds are met. Further detail on these contingent projects, including the relevant triggers, is set out in our managing uncertainty chapter.	$28M

Note: For further detail, refer to our attached business case: CP BUS 3.05 – Collingwood supply area – Jan2025 – Public and CP BUS 3.02 – Bouverie Queensberry supply area – Jan2025 – Public.

FEEDER UPGRADES	COST
Several HV feeders across our network are expected to require augmentation to maintain reliable electricity supply to customers. These works are driven by localised load growth leading to specific feeders exceeding their thermal rating (which places asset operation at risk). Each feeder project is separately assessed and is supported by individual forecasts, technical feasibility assessments and economically justifiable business cases.	$9M

Note: For further detail, refer to our attached business case: CP BUS 3.08 – Feeder thermal augmentation program – Jan2025 – Public.

3.2.2 Customer-driven electrification

As outlined previously, the electrification of gas and transport stands to increase consumption and peak demand across our network in the 2026–31 regulatory period (and beyond). Several independent bodies, including the AEMC, Energy Consumers Australia and the SEC have each found that all customers stand to benefit from electrification through lower household bills, even for customers who do not electrify themselves.

This electrification is typically occurring at the LV level of our network, with growing peak demand and increasing consumption from electrified homes and transport drawing more voltage, leading to lower voltage levels supplied to local customers. Lower voltage levels can cause unstable power quality, impact appliance function, lower appliance lifespan and reduce customers' ability to charge EVs.

To limit the impact that poor voltage levels can have on customers, we are obligated under jurisdictional regulatory instruments to maintain voltage levels between 216 and 253 volts at least 99 per cent of the time. Functional compliance is met if these limits are maintained across at least 95 per cent of our customers.[12]

[12] The Electricity Distribution Code of Practice is a jurisdictional instrument administered by the Essential Services Commission that regulates our activities to ensure they are undertaken in a safe, efficient and reliable manner. See, for example, Essential Services Commission, Electricity Distribution Code of Practice, 2023, clause 20.4.2.

We achieved functional compliance within the current regulatory period (as shown in figure 3.2), due in large part to the performance of our DVMS and exhausting lower-cost investments such as addressing solar inverter settings, tap changes and phase balancing.

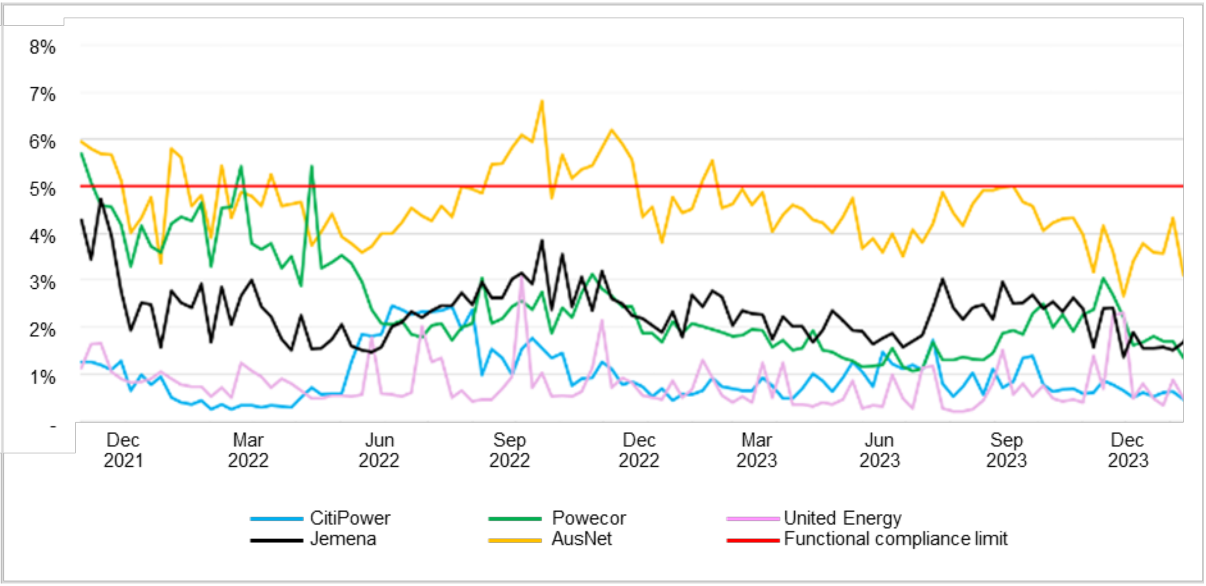
Case study: dynamic voltage management

We were one of the first networks in the country to dynamically optimise voltage levels through our DVMS. The DVMS uses our smart meter data readings to optimise voltage levels, considering our voltage compliance obligations to maintain voltage levels between 216 and 253 volts.

The DVMS sends a signal to each zone substation that specifies an optimal voltage set point level every 15 minutes. This maximises the number of customers who have compliant voltage levels as demand and localised voltage levels vary throughout the day.

Our network now provides amongst the most optimised and compliant voltage levels to customers in the country. DVMS will continue to be a key network management tool, however, further opportunities to improve voltage performance using DVMS are limited because all zone substations in our network are already optimised.

FIGURE 3.2 HISTORICAL OVERVOLTAGE NON-COMPLIANCE



Source: Essential Services Commission, Voltage performance data, 2024.

While we are functionally compliant today, some customers are still receiving poor voltage outcomes. When customers receiving non-compliant voltage outcomes complain to us, we are further obligated under jurisdictional instruments to resolve their voltage supply issues as soon as practicable.[13]

Through our engagement program, our customers have consistently demonstrated concern with the impact that electrification will have on the stability and power quality of the network, impacting their customer experience. Customers were also apprehensive of the network's capability to cope with increasing electricity use, particularly to facilitate electrification and net-zero technologies.

Additionally, more than 80 per cent of customers participating in our collaborative Future Home Demand study with Monash University preferred to charge electric vehicles at home, highlighting the importance of stable power quality at a customer level.

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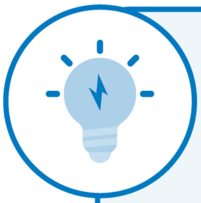
13 Essential Services Commission, Electricity Distribution Code of Practice, 2023, clause 15.2.1.

CUSTOMER-DRIVEN ELECTRIFICATION	COST
To assess the value of options to support customer-driven electrification, we considered the optimal balance between proactive and reactive approaches. These options are summarised below in figure 3.3, with our preferred option to improve service levels (consistent with option three). Proactive investment is more efficient than reactive investment because we can plan works in advance, target high-value sites, utilise efficiencies in service delivery and implement long-term efficient solutions such as tendering the constraint on our non-network procurement platform. In terms of customer outcomes, proactive investment will also allow more customers to charge EVs more often and reduce the power quality impacts of EV charging on other nearby customers. Our proposed customer-driven electrification program reflects a primarily proactive approach that would improve voltage performance levels for our customers through the 2026—31 regulatory period. This program will ensure that an additional 5,500 non-compliant customers will receive compliant voltage levels and enable 12GWh of additional compliant load. Our proposed investment comprises distribution substation upgrades, offloads and LV network reconductoring. These investments were further optimised, consistent with our electrification strategy (shown in figure 3.4). Customers have supported our electrification investment program. At our trade-off forums, 31 per cent of customers supported $40m of investment (with residential bill impacts of $0.83 p.a) and an additional 39 per cent supported $60m of investment (with residential bill impacts of $1.24 p.a) to facilitate increased EV charging and reduce EV-related outages. Customers at our test and validate forums typically supported our proposal, acknowledging growing demand and infrastructure challenges.	$39M

Note: For further detail, refer to our attached business case: CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public.

FIGURE 3.3 OPTIONS TO ADDRESS CUSTOMER ELECTRIFICATION

FIGURE 3.4 OPTIMISED AUGMENTATION SOLUTIONS

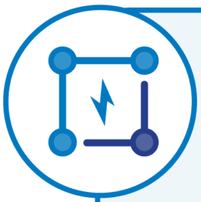


Identifying where single HV solutions can remove multiple LV constraints

- Where localised clusters of LV constraints were identified, we assessed whether a HV solution would be more economic
- HV solutions can be cheaper and more effective than several LV solutions because they improve capacity for more customers. This means HV solutions can future-proof a wider network area to support greater electrification and growth

Efficiently balancing proactive and reactive investments to deliver lowest long-term costs to customers

- Sites that are targeted for proactive investment deliver benefits for the greatest number of customers (i.e. least-regrets investment) and limits negative customer experiences
- Proactive investment reduces less efficient reactive investment (that we are obligated to deliver as soon as practicable following customers complaints), leading to more efficient service delivery outcomes
- Our balanced approach will build customer trust through the energy transition with better outcomes and lower long-term costs



Assessing future replacement needs in augmentation planning to future-proof for electrification

- As many of our existing assets are approaching their end-of-service life, we have considered any overlaps between forecast electrification needs and our replacement program
- It is more efficient to upgrade these assets once than it is to replace like-for-like now and upgrade again in the future
- This lowers costs for customers and is consistent with stakeholder feedback that we should be planning for a net-zero future

Electrification capex that delivers value for customers

- Our proposed augex portfolio comprises no-regrets projects that are expected to deliver materially higher benefits than costs valued under AER VCR frameworks
- Network upgrades will support growth and electrification while maintaining voltage compliance
- Our expenditure will enable all customers to charge electric vehicles and minimise customer impacts of localised EV charging

3.2.3 Non-demand augmentation

We must also manage our network to consider drivers that are not related to demand, but are vital to meeting compliance obligations, maintaining adequate protections for system security and ensuring safety and reliability for customers. Our non-demand investments relate to CBD security of supply, improving under-frequency load shedding, ongoing relocation activities and upgrades to communications infrastructure.

CBD SECURITY OF SUPPLY	COST
CBD security of supply standards require us to be able to maintain electricity supply after the loss of two 66kV sub-transmission line elements, with an allowance of 30-minute switching time after the loss of the first element.[14] This is commonly referred to as 'N-1 secure' planning standards. The Dockland supply area has been identified as a region of high load growth with numerous applications for large load connections such as for the Crown Plaza, Melbourne Quarter and the North Wharf. The 66kV network supplying Docklands has insufficient remaining capacity to support the load transfers required to meet the planning standards. Our preferred solution is to install three new 11kV feeders from the Little Bourke St zone substation to the Montague zone substation, which will maintain compliance with the CBD security of supply planning standards. Even with these 11kV feeders, we are still likely to breach our CBD security of supply planning obligations in the north-west of the CBD grid towards the end of the 2026–31 regulatory period. We would be required to rebuild our currently decommissioned Spencer St (J) zone substation to maintain compliance. However, to manage inherent uncertainty around future forecasts and to ensure customers are only required to pay for investments as they are required, we are proposing to treat the likely need to re-build our currently de-commissioned Spencer St (J) zone substation as a contingent project rather than including the cost in our regulatory proposal. Further detail on this contingent project, including the relevant trigger, is set out in our managing uncertainty chapter.	$19M

Note: For further detail, refer to our attached business case: CP BUS 3.04 – CBD security of supply – Jan2025 – Public.

[14] Essential Services Commission, Electricity Distribution Code of Practice, 2023, clause 19.

UNDER-FREQUENCY LOAD SHEDDING	COST
An under-frequency event is when a large-scale transmission outage occurs, such as the trip of a large generator or a major transmission interconnector, and results in an under-supply of electricity to meet demand. If unaddressed this would pull system frequency down significantly, leading to broad scale blackout. UFLS is a scheme that sheds load instantaneously to maintain supply demand balance, frequency and system security. AEMO have increasingly raised concern at the load available under its UFLS scheme due to embedded generation in distribution networks and have recommended Victorian distributors explore options to address this risk.[15] Our proposed investment responds to AEMO's concerns through moving UFLS capability from our 66kV connection points at transmission terminal stations to the 22kV and 11kV feeder exits within our network at select zone substations, prioritising zone substations with large wind and solar farm connections. This will reduce the potential number of customers that would be load-shed in an emergency event and improves Victoria's system security (in line with other jurisdictions, who already have UFLS capability below the zone substation level).	$10M

Note: For further detail, refer to our attached business case: CP BUS 3.09 – Under frequency load shedding – Jan2025 – Public.

YARRA TRAMS POLE RELOCATION	COST
Yarra Trams operates and maintains Melbourne's tram network, with tram lines typically running through space-constrained inner-Melbourne areas. We currently use Yarra Trams' infrastructure to support the attachment of our network assets, where practicable, to avoid duplicating infrastructure. Yarra Trams has an ongoing 15-year program to relocate and replace their aging poles. Through this process, we must remove and either re-attach or re-locate our assets (depending on the location of the new Yarra Trams pole, which typically differs from the location of the existing pole). Our options analysis demonstrates that utilising Yarra Trams' infrastructure continues to be the most efficient option to supply many inner-city areas.	$20M

Note: For further detail, refer to our attached business case: CP BUS 3.11 – Yarra Trams pole relocation – Jan2025 – Public.

[15] Australian Energy Market Operator, Under Frequency Load Shedding: exploring dynamic arming options for adapting to distributed PV, 2023, p. 12.

COMMUNICATIONS INFRASTRUCTURE	COST
Our communications infrastructure requires upgrades and expansion to manage increasing capacity constraints across our network. A key component of our program is fibre optic upgrades that connect key assets and support the reliable operation of centralised communication systems. Communication networks are an integral part of the electricity network as they support network visibility, remote automation, asset monitoring, network management and data acquisition. Existing capacity in our fibre optic communications network is highly utilised and there is little contingency to manage faults or failures. This expenditure is to improve the capacity of our fibre optic network to support customer growth and maintain reliable operation of our communications network.	$4M

Note: For further detail, refer to our attached business case: CP BUS 3.10 – Fibre capacity upgrades – Jan2025 – Public.

4. Replacement

The replacement of existing assets occurs as the condition of our network infrastructure deteriorates over time, and/or associated asset risks grow.

As assets deteriorate, they become less reliable, less safe, and more costly to maintain. At some point, intervention (e.g. replacement, refurbishment, or decommissioning) is required to maintain service levels and/or comply with regulatory obligations.

In the current period, we will materially exceed our regulatory allowance for replacement activities, particularly for poles, pole-top structures and underground cable. This expenditure reflects rising input costs, noting the impacts of the pandemic and ongoing global supply chain pressures have limited the ability for contract management to mitigate these uplifts.

Increasing expenditure is also consistent with a longer-term trend of increasing asset replacements of high-volume distribution assets, which is reflective of the characteristics of our underlying asset populations.

For the 2026–31 regulatory period, these replacement trends are largely forecast to continue. The key drivers of increasing replacement include the following:

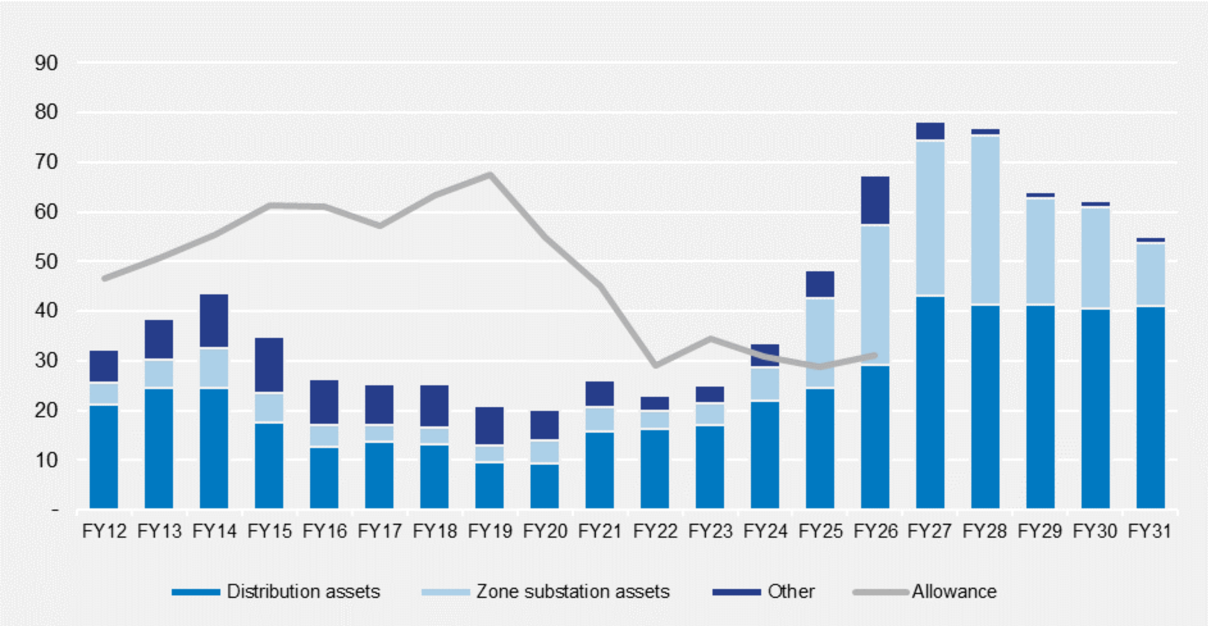
- uplift in underground cables: we are observing growing risk as a result of the increasing deterioration of cable condition, with these uplifts a prudent, no-regrets step toward more sustainable, long-term replacement volumes
- uplift in distribution switchgear: we are observing growing defects and are proposing to increase replacement volumes to manage risk. In addition, our uplift includes the continuation of our program to replace switches which are deemed inoperable due to safety concerns, leading to operational restrictions to protect our workforce
- uplift in zone substation transformers: we are proposing targeted investment to manage increasing risk of existing zone substation switchgear and transformers assets, based on sophisticated risk-modelling (that was previously accepted by the AER). Notwithstanding these proposed interventions, residual risk across our zone substation assets is forecast to remain higher than the risk-levels we carry today (reflecting input costs growing at faster rates than asset or site-specific risks).

A summary of our replacement investment in the current and future regulatory period is shown below.

TABLE 4.1 TOTAL REPLACEMENT INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Replacement	197	336

FIGURE 4.1 ANNUAL REPLACEMENT INVESTMENT ($M, 2026)



4.1 What we've heard

A central theme of our stakeholder engagement program was reliability, safety, and resilience. Broadly, our customers want to stay connected with a safe and uninterrupted electricity supply that can withstand both normal and extreme weather.

Our replacement program and asset management practices are critical to these outcomes, as well as to maintaining affordability and our position amongst the lowest cost distributors in Australia.

TABLE 4.2 KEY ENGAGEMENT FINDINGS

	Customers value safety of their electricity network and community
	Customers consistently highlighted the importance of a reliable energy supply, with the majority of customers having an appetite to maintain current reliability
	Customers are becoming increasingly dependent on electricity given working from home trends and forecast electrification.[16] Customers flagged a concern for reliability outcomes in their future
	Customers continue to value affordability, particularly in times of high inflation. Customers expressed a strong preference for stable and predictable pricing structures, noting they are more comfortable with gradual increases rather than sudden step-ups

16 This was both an output from customer engagement and observed on-the-ground via our Monash University Future Home Demand report. For further detail, refer to: Monash University, Future Home Demand, 2023.

While we did not specifically engage on our detailed replacement program during the test and validate stage, we did further engage with customers on their electricity usage patterns. A high proportion of our customers indicated their preference for an electrified future to enable the energy transition, with significantly varied customer views on whether they would be willing to be flexible with their load.

Similarly, 79 per cent of small and medium business customers and 53 per cent of residential customers indicated plans to replace their gas appliances with electric appliances over the next five years. The substitution of gas will increase energy at risk from asset failures across our network.

4.2 Our proposed response

We take great pride in the role we play in providing an essential service for our communities. With increasing electrification, due to gas-substitution and transport needs, technology, and behavioural change, the consequence associated with outages is increasing; the impact of outages will be felt by customers more in the future than previously.

In the context of the electricity transition, our replacement program is therefore critical to ensure customers have trust in their energy system to have confidence to fully electrify their homes and lifestyle.

Accordingly, our replacement investment in the 2026–31 regulatory period will deliver on the following customer outcomes:

- maintain reliability outcomes for our customers in an electrified future by maintaining underlying asset condition for those with the highest risk and consequence, while safely managing an increase in reliability risk to balance affordability and reliability trade-offs
- only propose replacement based on risk or condition-based modelling to ensure assets are replaced only when benefit outweighs the costs, given affordability concerns
- gradually increasing replacement rates of asset classes (including underground cables) where a majority are deteriorating due to condition and load increases, to limit risks of deliverability constraints and price spikes in future years.

4.2.1 Our replacement forecast method

In considering our replacement needs, we monitor asset performance indicators, including asset failures, high priority defects, and asset condition. These indicators inform our underlying asset management response—for example:

- increasing asset failures indicates a likely need to act immediately and review asset management practices
- increasing high-priority defects indicates a likely need to act soon to increase interventions over time
- deteriorating condition indicates a likely need to act soon (relative to asset management thresholds), and/or undertake risk-based assessments.

The consideration of these indicators varies for different asset classes, recognising that managing lower-value distribution assets with large, aging populations requires different considerations to managing higher-value zone substation assets.

An overview of the different forecasting techniques that are applied across our asset categories is summarised in table 4.3.

TABLE 4.3 SUMMARY OF FORECASTING APPROACH

CATEGORY	SUMMARY
Fault or unplanned	Fault or unplanned forecasts are responses to asset failures that caused outages, including those due to external factors (such as third-party damage). It is based on our historical five-year average faut replacement volumes
Corrective	Corrective forecasts address conditional failure associated with deteriorated asset condition, defects, and non-compliances to legislated requirements or industry standards (such as Australian Standards): • condition-based forecasts are derived from asset condition models, which are used to predict future asset condition based on current measurable condition data and annual deterioration rates that have been informed by independent analysis. An increasing volume of assets in deteriorated condition indicates an increase in future interventions is required, regardless of the current asset performance • defect forecasts are based on the statistically best fit model for our recent historical high priority defects. A historical average model was adopted for the majority of our distribution assets' defect forecast • compliance forecasts are based on a least cost compliance basis
Risk-based	Risk-based forecasts are based on a quantitative cost benefit assessment of intervention costs compared with the risks of failure, where the risk reduction benefits outweigh the intervention costs. For risk-based assessments, asset interventions are informed by the following: • the probability of failure based on historical failures, asset condition and degradation information • the consequence of failure including cost to repair or unplanned replacement, decreased customer service levels, safety, and environmental hazards

Upon a decision to intervene on an asset, a range of options are also considered, particularly for our risk-based assessments. Within our cost-benefit analysis, we typically consider options to replace the asset, increase maintenance and/or life extension, retirement, or non-network solutions, with the aim to maximise community benefits from the analysis.

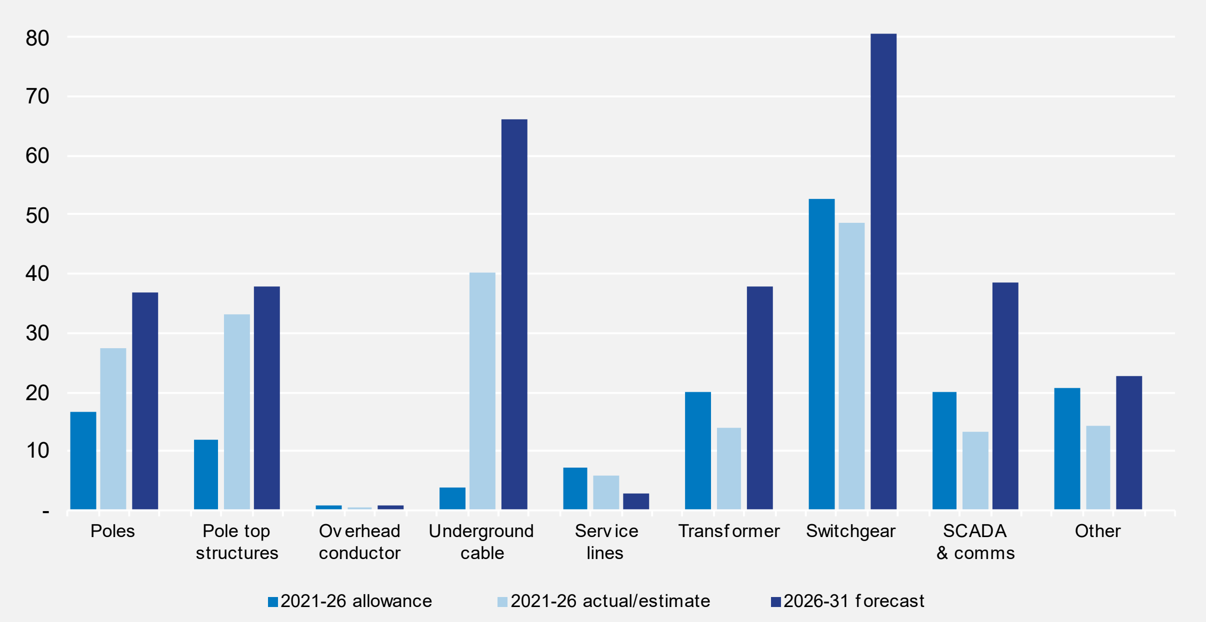
Increasingly, our asset management strategies are also needing to consider future electrification drivers (to avoid early replacement of assets due to increased capacity needs) and/or to meet longer-term deliverability challenges (particularly for high-volume assets).

4.2.2 Our replacement forecasts

Figure 4.2 presents our forecast investment for the 2026–31 regulatory proposal across our key asset categories.

Broadly, we are observing increases in replacement needs for most asset categories. The replacement drivers for each asset category are described in more detail below, and include a combination of volume increases (reflecting ongoing deterioration in the underlying asset populations) and unit rate pressures.

FIGURE 4.2 HISTORICAL AND FORECAST INVESTMENT BY ASSET CLASS ($M, 2026)



Note: Category totals shown above are consistent with our reset RIN. These may differ from category level forecasts shown below, as major plant replacement works (such as switchboard replacements) are allocated across multiple RIN categories to reflect the nature of the work undertaken.

Distribution assets

Distribution assets are our 'lower value, high volume' assets. This category includes poles, pole top structures, conductors, service lines, distribution switchgear and transformers, and underground cables.

Our distribution asset replacement program comprises faults, corrective and risk-based forecasts.

The key areas of focus for our 2026–31 distribution asset portfolio include underground cables and distribution switchgear. We are forecasting increasing risk in these assets due to deteriorating condition.

While to date we have been able to limit customer impacts from deteriorating asset health via automation and sectionalisation of our network, there is only so much that can be done until asset failures result in negative customer impacts. In addition, given their underlying age and condition profile, increasing asset replacements now through a structured program is likely to represent no-regrets investments.

POLES	COST
In the current regulatory period, we are observing an increasing proportion of wood poles being identified as unserviceable or requiring additional management controls, due to deterioration. Consistent with this, we are proposing an uplift in our wood pole interventions in the 2026–31 regulatory period. Our forecast of wood pole interventions is based on historical fault and observed defects, as well as the predicated measured condition of our poles based on existing data and an annual decay rate. The decay rate has been developed based on independent statistical analysis. Our forecasts also reflect a volume-weighted average of our most recent unit rates derived from our audited RIN data. These rates have increased throughout the current regulatory period relative to those set out in the AER's final determination.	$37M

Note: For further detail, refer to our attached asset class overview: CP BUS 4.01 – Poles – Jan2025 – Public.

POLE TOP STRUCTURES	COST
Our existing asset management approach for pole top structures has generally maintained our existing network performance. Consistent with this, our proposed cross-arm intervention volumes for the 2026–31 regulatory period are lower than the corresponding replacements in the 2021–26 regulatory period. Our total forecast expenditure for the 2026–31 regulatory period, however, represents a small increase on the current period. This is driven by higher average units in the forecast period.	$38M

Note: For further detail, refer to our attached asset class overview: CP BUS 4.02 – Pole top structures – Jan2025 – Public.

OVERHEAD CONDUCTORS	COST
Our forecast includes a decrease in overhead conductor replacement expenditure, noting the overall volume of overhead conductor replacements in our network has been low historically.	$1M

UNDERGROUND CABLES — COST

$64M

Our proposal includes an increase in underground cables replacement expenditure. Recent evidence shows that HV cable risks are increasing, with growing numbers of HV cable defects. These trends are consistent with the deteriorated condition of HV cables, and in the absence of any intervention by 2031, 36 per cent of our underground cable population (i.e. ~550km) is forecast to be at high risk of failure.

Further, around 220km of our underground cables are highly aged—that is, greater than 80 years old—with 73 per cent of these being HV cables.

In comparison, our recent average cable replacement volumes have been around 5km per annum.

Our intervention forecast proposes the replacement of the 10 highest-risk cable sections on our network, based on our condition-based risk management (CBRM) modelling.

We are also proposing the prioritised replacement of 85 pitch-filled metallic box terminations as part of an ongoing 10-year program (and consistent with the approach undertaken across the industry). These terminations have been found to fail explosively, and can scatter molten pitch and metal fragments that pose a safety and reliability risk to people and property.

Note: For further detail, refer to our attached asset class overview: CP BUS 4.04 – Underground cables – Jan2025 – Public,

SERVICE LINES — COST

$3M

Our proposal reflects a reduction in replacement volumes for service lines based on the low-risk condition of these assets.

Note: For further detail, refer to our attached asset class overview: CP BUS 4.05 – Services lines – Jan2025 – Public.

DISTRIBUTION TRANSFORMERS — COST

$17M

Our proposal includes an increase in distribution transformer replacement expenditure. In the current regulatory period, defects and failures of our distribution transformers have been increasing, mainly driven by the deteriorating condition of indoor and kiosk transformers. Further analysis on defect type shows that most of these defects are due to oil leaks.

Our distribution transformer replacement forecasts for the 2026–31 regulatory period are mostly based on forecast annual asset defect rates and forecast asset population, consistent with independent statistical analysis on the best fit of our historical data. Notably, our forecasts exclude the impacts of additional testing and inspection activities recently introduced.

Note: For further detail, refer to our attached asset class overview: CP BUS 4.06 – Distributoin transformers – Jan2025 – Public.

DISTRIBUTION SWITCHGEAR	COST
Our proposal includes an increase in distribution transformer replacement expenditure. Just over half of our distribution switchgear forecast interventions for the 2026–31 regulatory period are driven by distribution switchgear defects and faults. These are forecast based on historical annual asset defect rates and forecast asset population, consistent with independent statistical analysis on the best fit of our historical data. Our forecast also includes two risk-based replacement programs to address specific safety and network reliability risks posed by the operation of a subset of our high voltage (HV) air-break switches (ABS), and ring main units (RMUs) that are without oil or gas gauges. The safe operation of our distribution switchgear is a critical concern in the ongoing management of our distribution switchgear—for example, if our field crew operate switchgear with insufficient oil or gas insulation, it can result in catastrophic failure of the switchgear that can result in injury or death. These safety concerns have been raised by our operators, the Electrical Trades Union and WorkSafe Victoria, and have led to their restricted operation. The restricted operation on these two switches also increases other risks for customers, such as network reliability risk. This is because the next switch upstream or downstream must be operated instead, resulting in more customers being off supply than necessary. Our risk-based programs will manage the replacement of this switchgear over a 10-year period.	$52M

Note: For further detail, refer to our attached asset class overview: CP BUS 4.07 – Distribution switchgear – Jan2025 – Public.

4.2.3 Zone substation assets

Zone substation assets are our 'higher value, low volume' assets. This category includes all the electrical assets within zone substations, including zone substation transformers, switchgear, relays, and communication assets.

Our zone substation assets are managed based on the risk and condition of the asset. Our quantified risks include reliability risk for our customers, environmental risk, and safety risk.

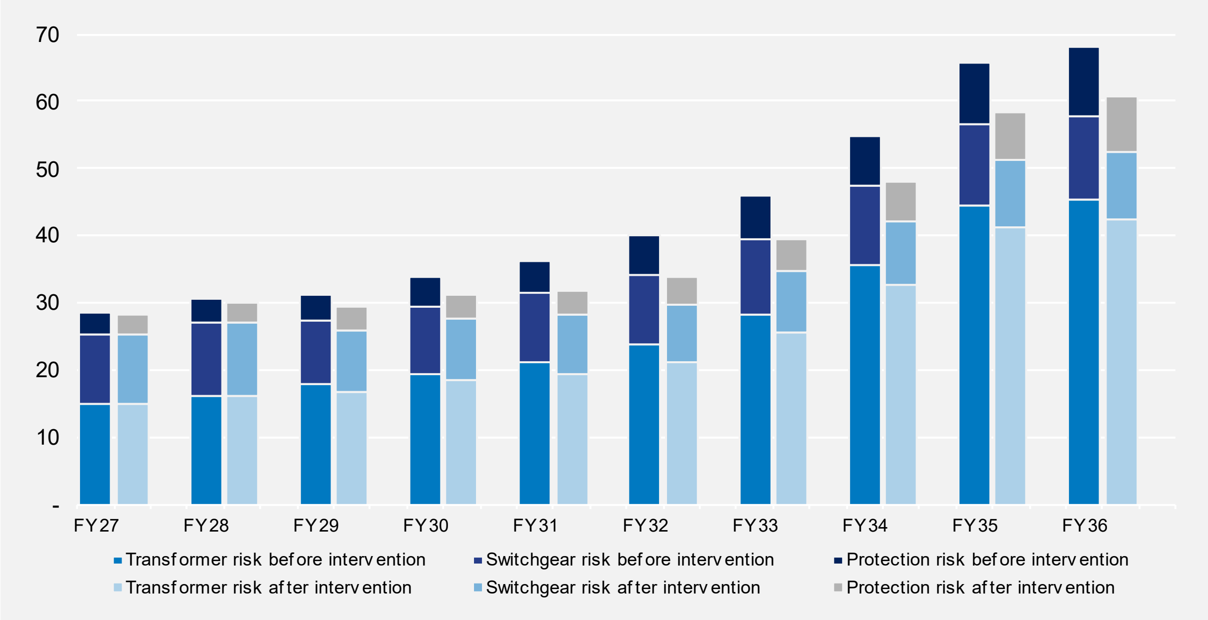
Over time, we have improved the way in which we forecast risk-based zone substation transformer and switchgear intervention. Risk is assessed based on the likelihood of the asset failing, but consequences of failure now consider the impact on the entire zone substation (instead of focussing on individual asset impacts).[17]

The improved risk assessment provides greater consideration on the unique characteristics of a given zone substation, including available redundancy and load transfer capability. In practice, it means not all high-risk zone substation assets are targeted for intervention and this ensures our forecast replacements are only the most prudent and efficient.

[17] Refer, for example, to our asset risk quantification guide: CP ATT 4.01 – Asset risk quantification guide – Jan2025 – Public.

As shown in figure 4.3, however, our proposed zone substation replacement program will result in overall zone substation risk increasing over the 2026–31 regulatory period. This is primarily driven by growing transformer risks.

FIGURE 4.3 COMBINED ZONE SUBSTATION ASSET RISK ($M, 2026)

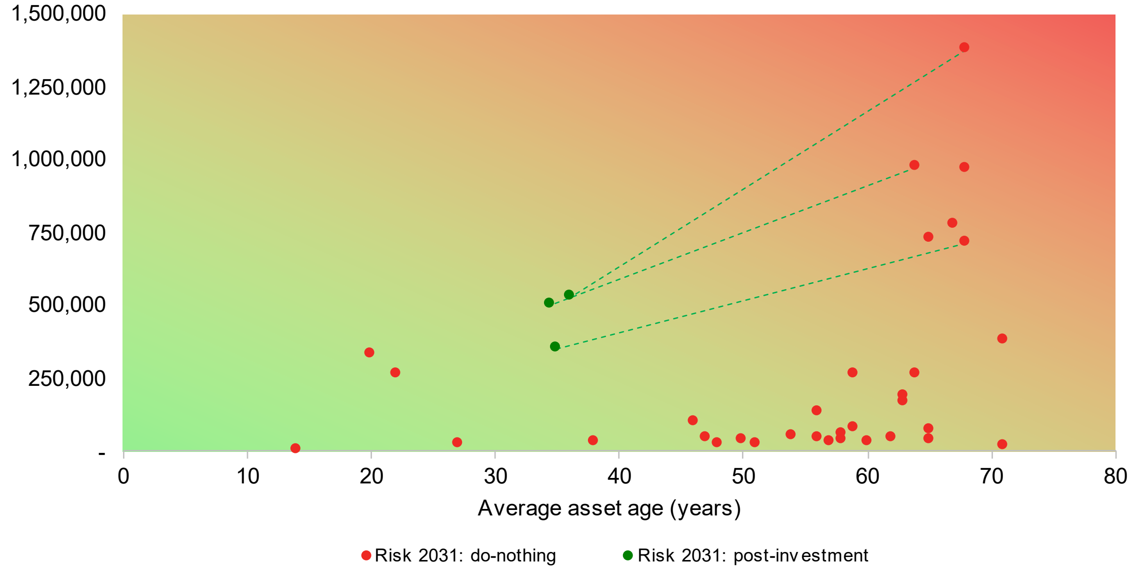


Further detail on individual zone substation asset categories is provided below (and in their corresponding asset class overviews).

ZONE SUBSTATION TRANSFORMERS	COST
We are proposing a targeted zone substation transformer replacement program for the 2026–31 regulatory period, with replacements at our existing Armadale, Northcote and Victoria Market zone substations. Of the 93 zone substation transformers in our network, our improved risk management approach has identified three economic zone substation transformer replacements. This approach is further illustrated in figure 4.4 (with age is used as proxy for condition for illustration purposes), where not all high-risk zone substation sites are targeted for intervention. Instead, our risk assessments ensure our forecast replacements are only the most prudent and efficient. The cost of transformer replacements have been estimated based on recent like-projects and reflect that labour, contract and materials prices have escalated significantly in recent years.	$29M

Note: For further detail, refer to our attached asset class overview: CP BUS 4.08 – Zone substation transformers – Jan2025 – Public.

FIGURE 4.4 AGGREGATED ANNUALISED TRANSFORMER RISK PER SITE ($)



ZONE SUBSTATION SWITCHGEAR	COST
Our zone substation switchgear forecast represents an increase in expenditure from the current 2021–26 regulatory period. This forecast comprises the replacement of several switchboards, with three of these representing in-flight projects that will commence this regulatory period. The uplift is driven by the increasing risk of fault or plant failure due to deteriorating condition of the current switchgear, and increasing consequences of failure. The increase in switchgear expenditure also reflects rising input costs of the labour, contract and materials to replace these assets. Overall, our zone substation switchgear program results in a reduction in risk over the 2026–31 regulatory period. However, total zone substation level risks across our portfolio are increasing between FY27 and FY31, even after these proposed interventions.	$76M

Note: For further detail, refer to our attached asset class overview: CP BUS 4.09 – Zone substation switchgear – Jan2025 – Public.

PROTECTION	COST
We are proposing an increase in protections replacement expenditure driven by the increasing risks from end-of-life protections relay. During the current period, defects and failures have continued to increase steadily. This reflects the underlying characteristics of our relay population, and consistent with this, network risk is projected to increase significantly in the absence of further intervention. The uplift is also driven by high voltage switchboard replacements. It is prudent to simultaneously replace the existing relays during these replacements where there is risk to manage.	$13M

Note: For further detail, refer to our attached asset class overview: CP BUS 4.10 – Protection and control – Jan2025 – Public.

5. Connections

Connections expenditure supports the connection of new customers on our network. These connections can vary from residential houses to large residential and commercial towers and warehouses.

Nearly all connections involve a customer contribution. Therefore, forecasting connection investment requires an assessment of customer contributions as well as future connection activity.

For the current regulatory period, actual connection activity is expected to exceed the allowance provided in our final determination. This has placed pressure on our entire network capital program given connections expenditure is not discretionary (i.e. we are obliged to facilitate all connection requests under our electricity distribution licence).[18]

The growing challenges and impacts of forecasting connections has led to our proposal to exclude connections from future capital efficiency sharing scheme (CESS). This proposal is discussed in the managing uncertainty chapter.

For the 2026–31 regulatory period, the key drivers of connections investment are as follows:

- future gross connection activity is forecast to be above historical expenditure. This reflects the strong rebound being experienced in residential connections following the pandemic (although we do forecast a slight slowdown in commercial and industrial activity due to changes in working habits that has resulted in increasing office and retail vacancies across central Melbourne)
- data centre connections are increasing, with additional capacity of 139MW forecast, predominately in the final two years of the 2026–31 regulatory period. These forecasts were not included in our draft proposal, but are now based on expert advice from LEK and committed projects. A high customer contribution rate has been forecast to these connections, meaning the substantive connection costs are not borne by our general customer base.

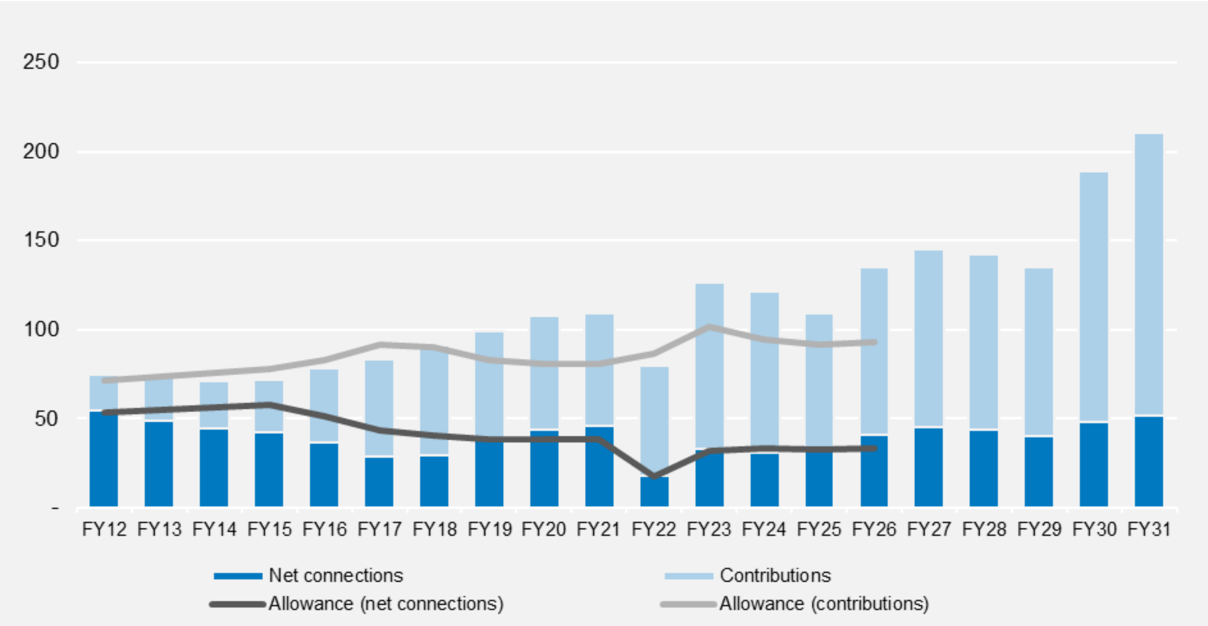
A summary of our connection investments in the current and future regulatory period is shown at Table 5.1 below.

TABLE 5.1 TOTAL CONNECTIONS INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Connections (gross)	572	822
Customer contributions	417	592
Connections (net)	**155**	**230**

[18] Essential Services Commission, Electricity distribution licence, CitiPower Pty Ltd, as varied on 3 August 2022.

FIGURE 5.1 ANNUAL CONNECTIONS INVESTMENT ($M, 2026)



5.1 What we've heard

As part of our engagement program, our discussions with customers and stakeholders focused on their perceptions of future connection activity and how that will intersect with the energy transition. We also asked them to consider any barriers that exist today, or may emerge, in connection processes.

Engagement with smaller customers primarily occurred through Monash University's Future Home Demand report and for larger customers (predominantly renewable energy proponents) through our Generator Steering Committee. Other stakeholders were engaged through our Future Energy Demand workshop, dedicated CAP workshop, bilateral discussions with intending connection applicants and meetings with the DEECA and real estate developers. [19]

We also published a consultation paper on integrating storage into our networks in February 2024 seeking comment and submissions from energy storage proponents. Feedback from that engagement has been incorporated.

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[19] See, for example: Forethought, Future Energy Network Forum, January 2024.

TABLE 5.2 KEY ENGAGEMENT FINDINGS

The cost of connections should not impede the energy transition. Consideration should be given to managing transition-based connection costs that may arise for customers who may face vulnerability
Access to new connections (and by extension, the right to an affordable and reliable supply) should be as equitable
Whilst there are mixed attitudes to EV adoption, there was no support for cross subsidisation of EV related connections (public or private)
Large load customers wanted increased options to reserve capacity on the network (firmer access) and in some circumstances, greater opportunity to provide non-network solutions
The Victorian Government wanted barriers to residential CER adoption to be minimised. This included no up-front fees and consistency in the treatment of three-phase upgrades to support electrification

5.2 Our proposed response

The Electricity Distribution Code of Practice (EDCoP) requires us to make an offer to connect any customer seeking a connection to our network.[20] How these offers are calculated and presented is defined by the AER's service classification decisions, and our connection policy.

Our regulatory proposal includes a connection policy to govern connection charges for the 2026–31 regulatory period. Our connection policy is required to be consistent with the connection charge guideline for electricity customers and receive AER approval. Our connection policy is attached to this proposal and discussed further below.

Consistent with customer and stakeholder feedback, we have not proposed material changes to how we prepare customer connection offers. For example, we will continue to ensure the costs of the energy transition are collected where possible from those that benefit.[21]

We did not receive any further feedback from customers and stakeholders on connection investment following the release of our draft proposal. We have therefore maintained the approach adopted in our draft proposal (with many of these already underway in the current regulatory period). The approach includes:

- providing a wider range of service options for larger customers. This includes more optionality with respect to network tariffs, network access and accessibility to non-network markets through our demand management platform
- reforming how we apply alternative control charges in preparing connection offers

[20] Essential Services Commission, Electricity Distribution Code of Practice, May 2023.

[21] For the avoidance of doubt, our connections policy will be expanded to accommodate other changes brought about by the energy transition. These include provisions related to static zero limits, stand-alone power networks and flexible export products.

- working with regulators to tackle the behaviour of incumbent declared transmission network system operators that impacts larger connections.

Further detail on our demand management platform, and changes to our charges are set out respectively in our electrification and CER strategy and alternative control services chapters.

5.2.1 Forecasting connections activity

Developing a robust forecast methodology is critical in ensuring we are sufficiently funded to deliver a prudent and efficient capital program. For the 2026–31 regulatory period, our gross connections forecasts are based on the following:

- for most customer segments, connection activity projections were supplied by Macromonitor, a leading provider of economic forecasting and research services to the construction industry. The information sought from Macromonitor was customised to encompass the boundaries of our network.[22] These forecasts have been updated for this proposal reflecting the latest available macroeconomic data
- data centre connections have been included for the first time based on forecasts provided by LEK.[23] These data centres are most likely to be located in the Fisherman's Bend area
- projections (aside from data centres) were applied to the most recent year of audited RIN data (2023–24). We used a single year of data as the baseline given the impact the pandemic had on historical connection activity (i.e. where restrictions on construction distorted connection activity, making it less reliable as a basis for future forecasts)
- for similar reasons, unit rates are based on 2023–24 RIN data. A major commercial project has been excluded from the calculation of unit rates for 2023-24 to ensure comparability of 2023–24 with future years.

5.2.2 Contribution rates

Forecasting contribution rates is complicated. Contribution rates are dependent on expected future revenue from each connection which is a function of energy consumption patterns and network tariffs.

Since the draft proposal, network tariffs and the weighted average cost of capital (WACC) have been updated to reflect approved network tariffs for the 2024–25 financial year and changes in the cost of debt. Actual data on customer offers has also been updated to include a further five months of analysis.

Changes to the National Construction Code, energy efficiency requirements, growth in solar rooftop, electrification, changes in network tariffs and evolving customer trends are changing consumption behaviour.[24] For the draft proposal, a variety of forecast and actual information was applied to model future contribution rates including tariff projections, the Monash University Future Home Demand report and internal trial information. The consumption forecasts, however, were static. This assumption was highly unrealistic given the rapidly evolving energy landscape.

We have adopted a more dynamic approach to consumption forecasts for this proposal, with LEK engaged to model the long-term consumption trends (2026–61).[25] Understanding longer term trends is essential given the estimation of contributions required is subject to a 30-year analysis for residential connections.

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[22] Macromonitor, Forecasts by Region, Report prepared for CitiPower, Powercor and United Energy, August 2024.
[23] LEK, Data centre load forecasts, Databook to inform CPU's electricity distribution regulatory determinations, October 2024.
[24] Australian Building Codes Board, National Construction Code, 2022.
[25] LEK, Customer electricity use and data centre forecasts, Databook to supplement residential load forecasts, October 2024.

LEK's analysis considered future building standards, house size, solar uptake, EV uptake, behind the meter storage, energy efficiency (appliances), behavioural change and demand response. Each consideration was modelled for its impact on each tariff component (peak, off-peak and saver).

The impact of each consideration was varied, and multi directional. The largest impacts have arisen from increased EV uptake and growth in behind the meter storage.

Further there was a shift in behaviour resulting in more consumption being incurred during saver periods and less during peak periods. Off peak consumption remains constant.

LEK's work was applied to historical residential contribution data retrieved over the period 2022–24.

Whilst the sophistication of modelling contribution rates for residential customers has improved, this has not been replicated for commercial and industrial customers. Commercial and industrial customers are highly heterogenous making the application of broad assumptions difficult. We have therefore maintained a static approach to their future consumption based on observed contribution rates over the period 2022–24.

5.2.3 Data centres

We have included data centres as a new connection category, in addition to those identified in the reset RIN.

The absence of observable contribution rates for this category made it challenging to estimate their future consumption. Further, the lack of homogeneity in this type of connection makes assuming contribution rates hazardous.

Nonetheless, we have assumed a contribution rate of 85 per cent. This is slightly below what has been observed for existing data centre connections (91 per cent), however, the parties we are presently negotiating with, or have made inquiries, are seeking to have their own servers reside in their data centres. This provides us greater confidence in their projected consumption forecasts, as they are not reliant on market uptake.

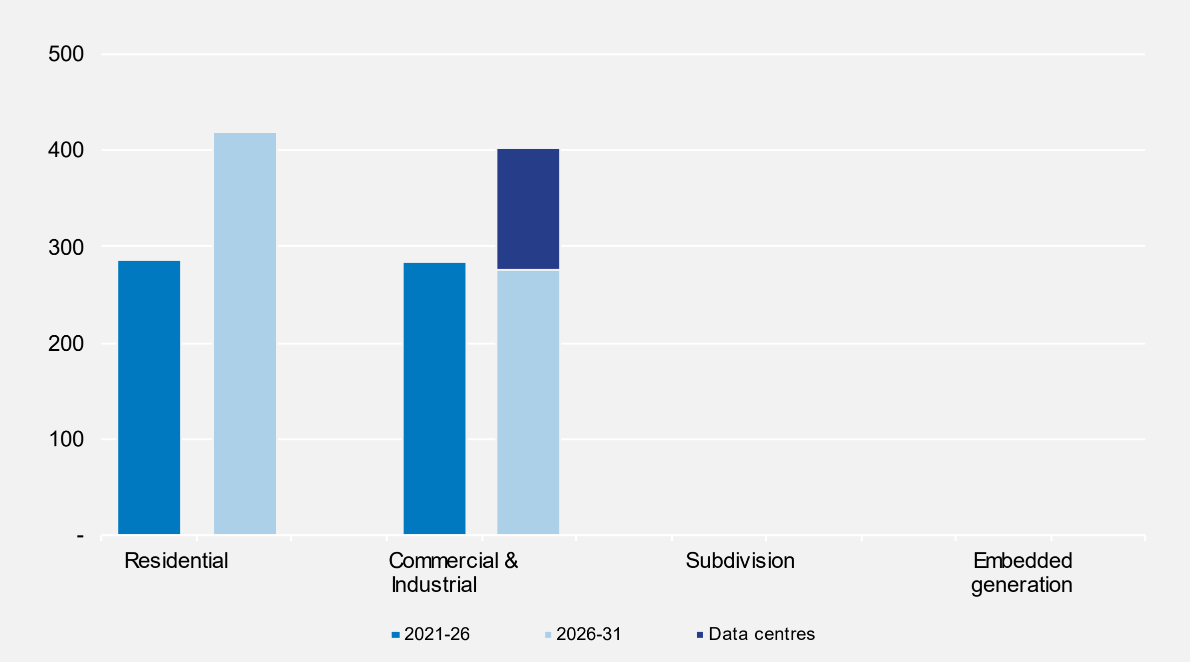
5.2.4 Connections by segment

Figure 5.2 shows connection activity for the 2026–31 regulatory period by segment, with growth in connection activity forecast in both customer categories.

Underlying commercial and industrial developments remains consistent with history, with impacts from a slowing Victorian economy and weaker demand forecast over 2025 to 2027 mostly felt in the health sector and commercial tenancies. At a total category level, however, this is offset by continued growth in data centres.

Residential growth is forecast to rise, driven by an increased demand for housing, particularly in medium and high-density developments across Melbourne.

FIGURE 5.2 GROSS CONNECTION ACTIVITY BY SEGMENT ($M, 2026)



5.2.5 Connection policy

At the commencement of each regulatory period we are required to implement a new connection policy. The connection policy must comply with the AER's connection charge guideline and be approved as part of the final determination.[26]

As noted earlier, our connection policy remains largely the same as that in place over the current regulatory period. Several changes to the Rules, however, have necessitated the following new inclusions in the connection policy:

- changes to requirements for micro-embedded generation and storage connections to support the introduction of emergency backstop requirements
- introduction of an upfront fixed connection application fee payable by customers prior to receiving a connection offer
- a quoted service charge to support provision of a higher standard service should that be sought by a customer
- new provisions to support the introduction of export limits consistent with the AER's flexible exports guidance notice.

Further discussion on the new charges is available in the alternate control services chapter. The remaining changes related to minimum backstop and export limits are consistent with required regulatory changes.

[26] AER, Connection charge guidelines for electricity customers, October 2024

6. Information and communications technology

Information and communications technology (ICT) is integral to a modern electricity distribution network. ICT includes all the platforms, systems, databases and electronic devices we use to enable the delivery of our services, as well as all the underlying infrastructure required to run our ICT program.

Our reliance on ICT is increasing as a key means of managing and operating our network in smarter, more flexible and lower-cost ways. This reliance will continue to increase as the network and the services we provide undergo considerable change. For example, the successful delivery of our CER ICT investments, such as developing an ICT system to enable flexible exports, will allow us to defer or avoid future augmentation of the network. Similarly, the replacement of our billing system will enable the deployment of new dynamic tariffs in the future that will better reflect the benefits of consumer resources.

A summary of our ICT investment in the current and future regulatory period is shown below.[27] For the current period we are forecasting a minor ICT overspend. This overspend is driven by higher than expected recurrent expenditure as well as the addition of AEMO NEM reform expenditure.

For the 2026–31 regulatory period, we are forecasting a step up in capital expenditure reflecting the following drivers:

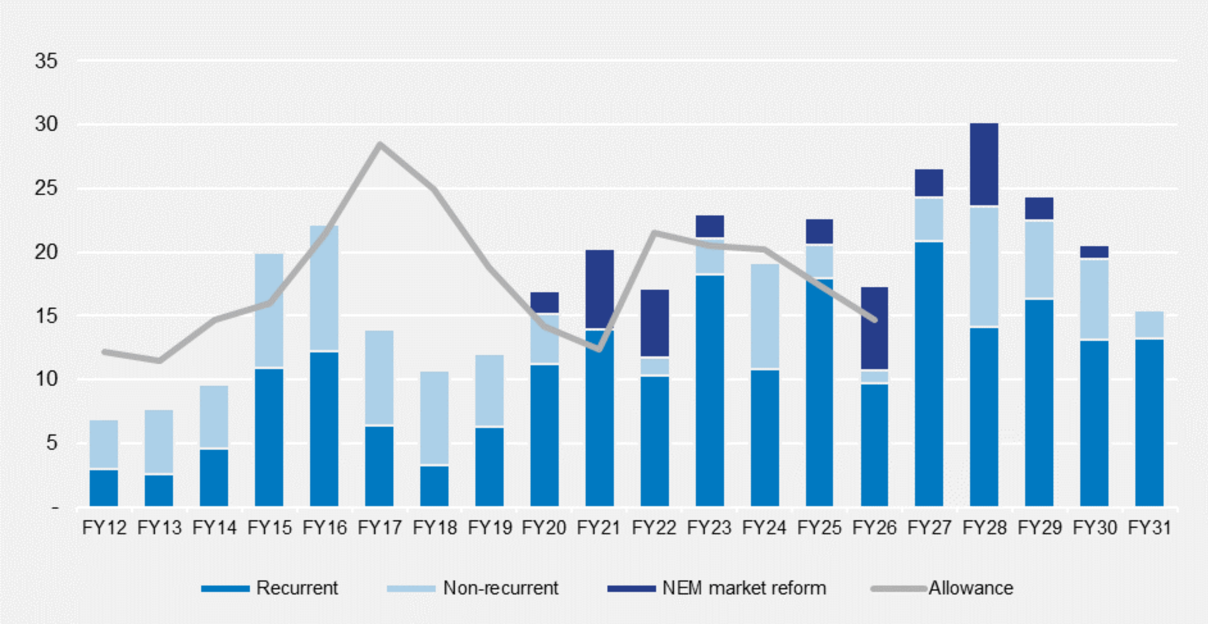
- a small uplift in our recurrent investment program linked to infrastructure and system refreshes
- an uplift in our non-recurrent ICT investment program, which includes upgrading our cyber-security position and the replacement of two of our core ICT systems that are critical to the energy transition
- new compliance requirements related to AEMO's NEM reform program, noting these have been updated since our draft proposal to reflect updated compliance timeframes that have brought forward investment into the 2021–26 regulatory period.

TABLE 6.1 TOTAL ICT INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Recurrent	67	78
Non-recurrent	16	28
AEMO NEM reforms	16	12
Total	**99**	**118**

[27] Excluding CER, which is outlined in our electrification and CER integration strategy in chapter 2.

FIGURE 6.1 ANNUAL ICT INVESTMENT ($M, 2026)



6.1 What we've heard

For customers, ICT is a key enabler of the new services they increasingly want to access. For example, our customers want us to enable more rooftop solar exports, but are seeking lower cost solutions than traditional augmentation. As outlined previously in this document, our proposed flexible export services to enable this customer outcome will be delivered by an ICT solution.

Similarly, we've heard that customers want us to use innovation and technology to maintain a positive customer experience. They highlighted that efficient, easily accessible and responsive customer services were a priority.

We also tested customer expectations on cyber-security and ICT system replacement with our CAP, noting the technical nature of this issue. Recent large scale cyber breaches that have impacted some of Australian's largest companies demonstrate the growing cyber risks critical infrastructure providers face. These risks will continue to grow as we further digitalise and decentralise the electricity system. Similarly, our core ICT systems are now outdated and will be unable to provide the functionality required to meet the challenges of the energy transition.

TABLE 6.2 KEY ENGAGEMENT FINDINGS

Customers want us to enable more rooftop solar exports, but are seeking smarter solutions than traditional augmentation
Customers want us to use technology and innovation to maintain a positive customer experience
The CAP recognised the importance of improving our cyber security systems given recent large scale cyber breaches that have impacted some of Australia's largest critical infrastructure providers
The CAP supported replacing some of our key systems that have become outdated, ensuring we have the appropriate systems to meet the expected service levels of our customers now and into the future.

6.1.1 Test and validate

Following the release of our draft proposal, we also sought further feedback from the CAP as part of our test and validate engagement.

A key recommendation of the CAP was to continue, in partnership with the Victorian Government, to pursue tariff reform to enable all residential customers to have access to dynamic tariffs. Without investment in our ICT systems to enable dynamic distribution tariffs, we may act as a handbrake in delivering this reform.

6.2 Our proposed response

Our forecast ICT program for the 2026–31 regulatory period will allow us to maintain the currency of our existing ICT services and capabilities, unlock new benefits for our customers, and respond to changes in the energy market giving rise to new regulatory obligations.

Our ICT program will:

- continue to maintain and refresh our existing ICT investments
- enable the export of more solar through the development of flexible export services
- enable increased access to network data by digitalising our network
- ensure we are able to provide dynamic tariffs by upgrading our billing system
- enable a more data driven energy transition by modernising our core systems
- minimise the risk of a major cyber event by upgrading our cyber security
- ensure we comply with all new regulatory obligations stemming from the post-2025 NEM market reforms.

As part of our evaluation process, we engaged EY to undertake a review of our risk monetisation framework. As part of this review, we have developed clear guidelines on monetising a range of both business and IT specific risks. We have applied this guideline consistently across our ICT expenditure portfolio.[28]

6.2.1 Recurrent ICT investment

Recurrent ICT relates to maintaining and refreshing existing ICT services, functionalities and capabilities. Our forecast recurrent ICT investments are a small increase on current period expenditure.

Under our recurrent ICT investment program we will continue to refresh and update our IT systems prudently and efficiently to ensure we can provide the service levels expected by our customers. We outline some of our major recurrent expenditure categories below, with further information set out in our attached recurrent ICT business cases.

NETWORK MANAGEMENT	COST
The network management systems comprise core operational systems that play a critical role in ensuring that we effectively and efficiently manage our network. These systems have a real-time 24/7 requirement to provide control and monitoring of customers' supply reliability and network performance, as well as providing tools to ensure network, employee and public safety is maintained. We need to invest in maintaining currency of critical system functionality that provides a key role in managing the electrical distribution network.	$16M

Note: For further detail, refer to our attached business case: CP BUS 6.05 - Network management systems - Jan2025 – Public.

INFRASTRUCTURE REFRESH	COST
There are a number of aging assets (both hardware and software) that are being managed as part of their replacement cycle. As part of our infrastructure refresh we will be moving some of our on premise infrastructure to cloud based solutions. Replacing and refreshing these assets will ensure that our infrastructure is maintained and that we have access to a variety of infrastructure solutions that best match our processes and systems.	CAPEX $14M OPEX $3M

Note: For further detail, refer to our attached business case: CP BUS 6.04 - Infrastructure refresh - Jan2025 – Public.

END USER DEVICE MANAGEMENT	COST
End user devices include computers, laptops, mobile phones and tablets, and meeting room technology. Our field and office staff use these devices to complete day-to-day work. As devices reach the end of their useful life, their performance deteriorates, they become technically obsolete and capacity constrained, and have increased security risks. We therefore replace these devices on an ongoing cycle.	$10M

Note: For further detail, refer to our attached business case: CP BUS 6.08 - End user device management - Jan2025 – Public.

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28 For the full risk monetisation guideline refer to CP ATT 6.02 – EY - IT risk monetisation framework – Aug2024 – Public.

MARKET COMPLIANCE	COST
The rules and obligations under which we operate often change to ensure the currency and relevance of the regulatory framework. While the AEMC and other government and regulatory bodies will continue to make structural changes to the Rules, smaller unidentified changes to regulated guidelines, procedures and obligations will also continue. These changes are needed to improve implementation of the Rules and deliver best-practice processes. This investment is required to maintain compliance with all regulatory and market obligations, and is forecast based on historical costs.	$7M

Note: For further detail, refer to our attached business case: CP BUS 6.09 - Market compliance - Jan2025 – Public.

OTHER RECURRENT CATEGORIES	COST
In addition to the four categories identified above we will also have recurrent investments linked to maintaining currency for: • market systems • telephony • enterprise management systems • IT facilities • customer enablement. Recurrent investment is also required to support our ongoing cyber security and ERP and billing system needs, however recurrent expenditure associated with these two investments is included in our non-recurrent investments for these systems.	$25M

Note: For further detail, refer to our attached business case: CP BUS 6.06 - Market systems - Jan2025 – Public; CP BUS 6.11 - Telephony - Jan2025 – Public; CP BUS 6.07 - Enterprise management systems - Jan2025 – Public; CP BUS 6.10 - Customer enablement - Jan2025 – Public. IT facilities expenditure is included in CP BUS 7.04 - Property recurrent expenditure - Jan2025 – Public.

6.2.2 Non-recurrent ICT investment

Non-recurrent ICT relates to ICT investments that unlock new benefits for customers. Our non-recurrent ICT investment program will ensure we continue to evolve our network capabilities to enable the services expected by our customers.

Our non-recurrent forecasts represent an uplift on current period expenditure, with this uplift driven by the replacement of two of our core ICT systems, and increasing cyber security needs.

ERP AND BILLING SYSTEM REPLACEMENT	COST
We are upgrading two of our core systems; our ERP system and our billing system. Our ERP system is used for our core payroll, human resources, finance and assessment management systems. Our billing system is responsible for recording and issuing our network tariff bills and managing a range of market and customer data management processes. These core systems are ageing rapidly, with our billing system now over 25 years old. Both systems must be upgraded to modern standards as we will no longer receive vendor support to help us maintain and update these systems. We are now one of the last remaining customers worldwide who are using our current billing system. Continuing to use our old systems without the associated support will significantly increase the risks of system failures and will require a growing number of resources to keep the system running. The ageing systems are unlikely to meet changing customers demands and will be unable to support our growing IT footprint. Moving to modern systems will ensure we continue to safely support and manage our assets. It will also provide us with core systems that are better able to integrate new and innovative services to customers. These services, such as new and dynamic tariffs, will be needed to support the energy transition and better maximise the value of CER. An upgraded billing system is also critical to allow for changes in future tariffs. Without investment in the 2026–31 regulatory period, we will be unable to provide dynamic tariffs until ~2035, well beyond when these tariffs will likely be required.	CAPEX $29M OPEX $10M

Note: This includes both recurrent and non-recurrent expenditure related to this project. For further detail, refer to our attached business case: CP BUS 6.01 - ERP & billing system replacement - Jan2025 – Public.

CYBER SECURITY	COST
As an essential service, our networks play a crucial role in providing safe and reliable electricity to our customers and communities, which can be put at risk by malicious cyber-attacks. Cyber-attacks include not just unauthorised access of IT systems or phishing of sensitive information, but malicious actors are increasingly targeting operational technology (OT systems), such as supervisory control and data acquisition (SCADA) systems. Any disruption to supply of electricity or the release of sensitive information due to a cyber-attack can have serious implications for customers, businesses, the government and communities. The increasing use of data and digitalisation across our network is creating a growing number of touchpoints that malicious actors may attempt to breach to gain access to our systems. To ensure our network remains safe and reliable and that network and customer data remains protected, we are upgrading our cyber security. Without improvements in cyber security we will have an increasing risk of a material cyber breach. Our proposed investment will reduce the risk of a material cyber breach of our network that could have the potential to lead to large-scale unplanned outages of our system. It will also strengthen the protection of our growing database of network and customer data. Our targeted cyber security investment will bring us to an SP2+ level under the Australian Energy Sector Cyber Security Framework (AESCSF), with a focus on practices and anti-patterns that provide the greatest level of benefit.	CAPEX $5M OPEX $5M

Note: This includes both recurrent and non-recurrent expenditure related to this project. For further detail, refer to our attached business case: CP BUS 6.02 - Cyber security - Jan2025 – Public.

6.2.3 AEMO NEM reform expenditure

The Energy Security Board (ESB), in collaboration with other key regulatory bodies, has set a pathway to modernise the NEM to better meet the community's evolving wants and needs and move towards a net-zero future. Known as the post-2025 NEM reforms, these changes are to accommodate the increasing uptake of new technologies, including CER.

Many of these reforms are being implemented through AEMO reviews, with implementation timeframes expected during the 2026–31 regulatory period. Each of these reforms will require significant changes to our IT systems and processes.

AEMO NEM REFORMS	COST
We have included two projects in our 2026–31 regulatory period that are driven by AEMO NEM reforms:	CAPEX $12M OPEX $3M

Flexible trading arrangements (FTA)

This investment links to the AEMC's rule change focused on unlocking CER benefits through flexible trading. It will:

- enable large customers to engage multiple energy service providers
- allow for the separation of flexible CER from passive loads leading to innovative products and services
- allow market participants to use in-built measurement capability in technology such as EV chargers and smart streetlights.

In order to meet updated AEMO compliance timelines, we have moved forward the timing of our FTA investments, with a significant portion of this investment now expected in the 2021–26 regulatory period. In November 2024, the AER approved an extension to the timeframe for submitting a cost pass-through application associated with these changes.

Market Interface Technology Enhancements (MITE)

This investment includes a number of foundational initiatives to enable the NEM reform program. It will support a single unique credential to access all AEMO hosted applications and create a unified stakeholder experience. This includes investments in:

- identity and access management
- portal consolidation.

Note: For further detail, refer to our attached business case: CP BUS 6.03 - AEMO NEM reforms - Jan2025 – Public.

In addition to the FTA and MITE investments, AEMO has also proposed changes to the industry data exchange. Improvements to the industry data exchange will create a national CER data exchange to better coordinate flexible CER.

At the time of writing this regulatory proposal we do not yet have enough information to develop expenditure related to this reform. Once these reform rule changes are final, we will review and update our proposed investments as part of our revised regulatory proposal.

7. Property, fleet, and other non-network

Our property and fleet portfolio includes buildings (including security, compliance, and sustainability), motor vehicle fleet, and tools and equipment.

Our property and fleet allow us to serve our communities by ensuring the appropriate people, resources and materials are located across our networks. This allows us to respond to outages, fix faults, maintain our network, and connect new customers. Our depots and fleet are also a key factor in the health and safety of our workers and staff.

For the current period, we are forecasting a property and fleet overspend. This is driven by additional spending on tools and equipment, and the rectification of fleet allocations across our shared networks. For property, we have fundamentally delivered on our 2021–26 proposals; we completed the significant building compliance and security investments that were included in the AER's allowance.

For the 2026–31 regulatory period, the key drivers of investment include the following:

- an uplift in property expenditure, comprising our Burnley depot and head office redevelopments, and the establishment of a purpose-built training facility
- an uplift in our fleet investments, due to rectified allocation across our shared networks and electrification to reduce emissions (in line with customer feedback)
- tools and equipment investment in line with current period expenditure.

Our program also includes modest sustainability investments to meet community expectations regarding our environmental, sustainability and governance practices.

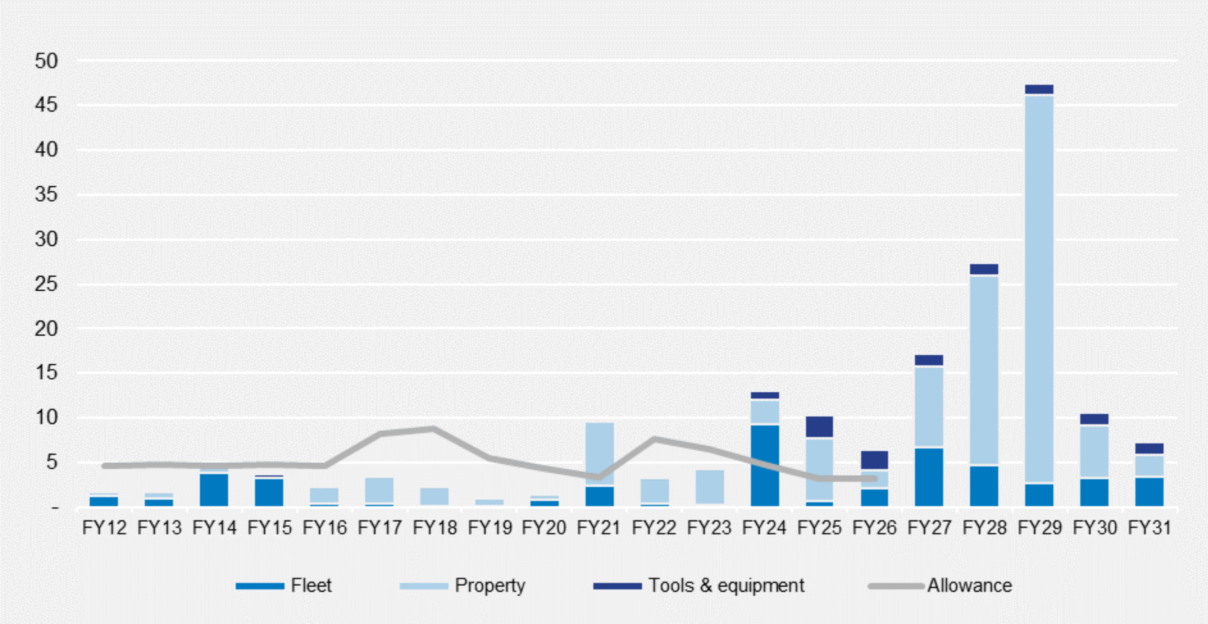
Overall, our forecast for property, fleet and other non-network investments is slightly higher than our draft proposal, driven by revised costs for our purpose-built training facility and updated allocation of shared costs between our networks.

A summary of our fleet, property and other non-network investment in the current and future regulatory period is shown below.

TABLE 7.1 TOTAL FLEET, PROPERTY AND OTHER NON-NETWORK ($M, 2026)

DESCRIPTION	2021–26	2026–31
Property	19	82
Fleet	13	21
Tools and equipment	6	7

FIGURE 7.1 ANNUAL FLEET, PROPERTY AND OTHER NON-NETWORK ($M, 2026)



7.1 What we've heard

Across our extensive stakeholder engagement program our customers consistently highlighted the importance of a reliable energy supply. As Victoria electrifies and demand increases, so too will the value of reliability and the consequence of time-off-supply.

Our non-network (other) programs are critical to maintaining a reliable energy supply in our communities.

TABLE 7.2 KEY ENGAGEMENT FINDINGS

	Customers consistently highlighted the importance of a reliable energy supply, with most customers having an appetite to maintain current reliability
	Customers indicated a commitment to environmental sustainability and a strong appetite to pay for emissions reductions

7.2 Our proposed response

Our property and fleet investment in the 2026–31 regulatory period will deliver on the following customer outcomes:

- maintain average reliability in an electrified future by preventing efficiency deterioration at our core Burnley depot
- improve environmental sustainability through a targeted program prioritising the least cost and highest impact investments to reduce emissions
- maintain efficient long-term operational deliverability; ensuring workforce sustainability throughout the energy transition via the development of a purpose-built training facility.

Further detail on these investments is provided below.

7.2.1 Property

Our buildings are vital to delivering the core operations of our network. Non-network property assets comprise depots, zone-substation control rooms, head office, contact centre, and network and security control rooms.

Our forecast property investments are outlined below.

BURNLEY DEPOT REDEVELOPMENT	COST
We are proposing to redevelop our Burnley depot, which has insufficient storage, layout, and capacity for the growing works program. The original building was originally constructed in 1924, and is the sole depot serving the whole CitiPower network. Our current depot for example, is unable to hold the necessary stock levels to accommodate project requirements (including our pole replacement program). With increasing population and electricity dependency, it is crucial that this depot is fit-for-purpose to allow us to meet our community's needs.	$55M

Note: For further detail, refer to our attached business case: CP BUS 7.03 – Burnley depot upgrade – Jan2025 – Public.

TRAINING FACILITY	COST
We are proposing to develop a dedicated training facility to enable the continued safe and effective training of apprentices and field workers. A training facility is crucial to the continuation of our training program which allows apprentices and trainees to gain hands-on experience with electrical infrastructure prior to working on live assets. Our existing training facility does not have sufficient capacity to train a growing workforce for the energy transition, presenting a material risk to our workforce sustainability. Having an effective training facility will allow us to recruit and train more apprentice line workers into the business, and to cater for the growth in recruitment of line workers, enabling long-term deliverability of our core operations. Since our draft proposal, the scope of the training facility has increased to enable comprehensive apprentice training capabilities. This will allow us to meet enterprise agreement obligations for apprentice intake volumes. Further, this will allow for induction and refresher training to be undertaken at a purpose-built facility.	$9M

Note: For further detail, refer to our attached business case: CP BUS 7.02 – Training facility development – Jan2025 – Public.

HEAD OFFICE	COST
We are proposing to redevelop our head office at the expiration of our 15-year term lease, during the 2026–31 regulatory period. Our head office houses over 1,000 employees and contractors, playing a critical role for the business housing key corporate and network functions as well as the central control room for CitiPower and Powercor. Fit-for-purpose facilities are essential in enabling the safe and continued operation of our network. Outdated facilities can lead to deterioration in productivity, staff retention and morale. Our current head office will require enhancements due to significant age and restricted flexibility in working arrangements and needs.	$7M

Note: For further detail, refer to our attached business case: CP BUS 7.01 – Head office refurbishment – Jan2025 – Public.

7.2.2 Other property works

Other property works include improvements to the security of our critical assets, and improvements in building accessibility. Following strong customer engagement feedback, a sustainability program is also included.

PHYSICAL SECURITY	COST
Our physical security program includes CCTV replacement and upgrades to enable integration with our security control room, dual-factor authentication, and kiosk fencing at critical sites identified in accordance with the Security of Critical Infrastructure Act (2018). Physical security is crucial to maintain safety and security of supply of our network. In 2021–26 we have undertaken works to uplift the security of our assets, particularly the construction of a purpose-built security control room. However, instances of security breaches, including attempted break-ins and copper theft, continue to rise. In accordance with industry best practice, we take a proactive approach to safety and security to support a safe and secure environment for customers, the public and our industry workers.	$4M

Note: For further detail, refer to our attached business case: CP BUS 7.04 – Property recurrent expediture – Jan2025 – Public.

BUILDING UPGRADES	COST
Our building compliance program includes works to ensure our buildings are secure, compliant, safe, and accessible. We have engaged an external contractor to audit select depots for accessibility compliance, as a representative sample of other impacted depots. We have also engaged an independent fire door specialist to audit our buildings in 2022. Our forecast includes the continuation of our works to replace 217 fire doors, as identified by the audit, which have already begun in the current regulatory period.	$3M

Note: For further detail, refer to our attached business case: CP BUS 7.04 – Property recurrent expediture – Jan2025 – Public.

ENVIRONMENTAL SUSTAINABILITY	COST
Our customer engagement program evidenced that customers place value on reductions in emissions, however, there is a trade-off between sustainability and affordability. We engaged with the CAP on a framework to consider this balance. We are proposing a targeted sustainability approach prioritising the least cost and highest impact investments, to balance cost and value. This includes the addition of battery storage at our Burnley depot, and EV charging infrastructure at Burnley and head office, to facilitate our roll-out of EVs.	$3M

Note: For further detail, refer to our attached business case: CP BUS 7.04 – Property recurrent expediture – Jan2025 – Public.

7.2.3 Fleet

Fleet is an essential enabler in supporting the investment, maintenance, and operational activities of our network. Our fleet strategy and investment aim to align our asset management and acquisition with the businesses' current and evolving requirements to ensure good customer outcomes.

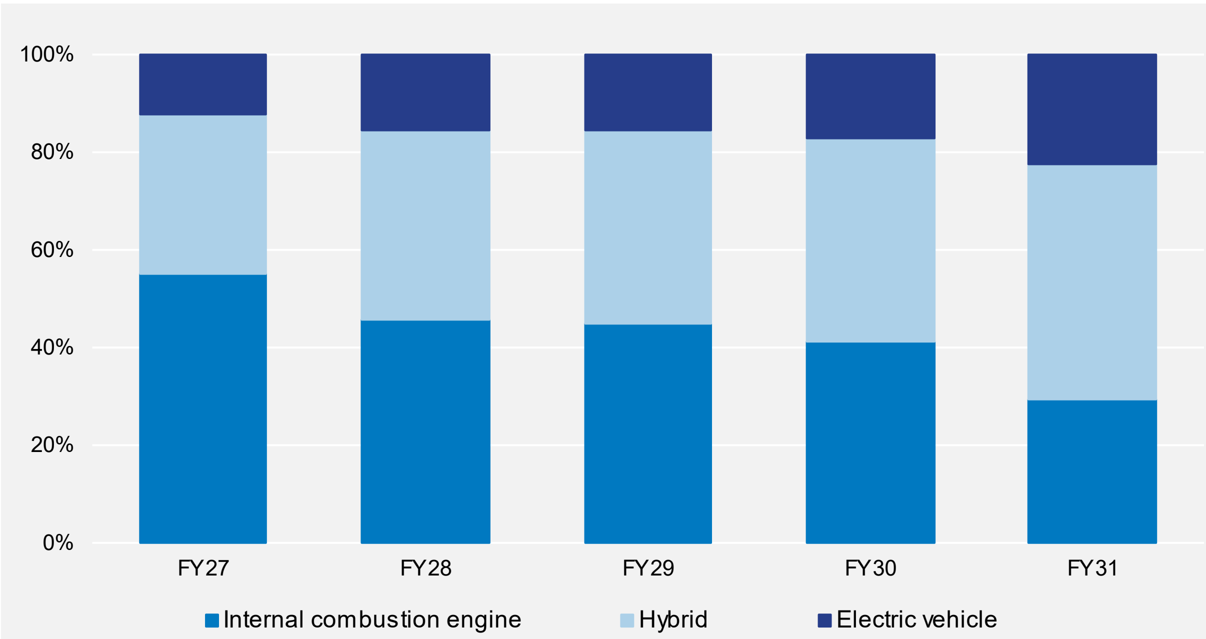
FLEET REPLACEMENT	COST
The current regulatory period has seen unprecedented global events with wide-reaching impacts on global supply chains. This impacted procurement, with unit costs increases and supply shortages in these markets. Our 2026–31 fleet replacement forecast includes a step-up on our forecast actuals, reflecting the updated allocation of shared costs between our networks. Our fleet is also expected to service a growing workforce and a growing population in the 2026–31 regulatory period, reiterating the importance of maintaining a safe and effective resource pool.	$20M

Note: For further detail, refer to our attached model: CP MOD 7.05 - Fleet - Jan2025 – Public.

FLEET ELECTRIFICATION	COST
We worked with our stakeholders on determining the right level of EV uptake as well as considering the Victorian Government's Zero Emissions Vehicle Roadmap. Our fleet forecast includes modest additional capex for fleet electrification, with a focus on hybrid vehicle replacement to promote emissions reduction without compromising affordability—given the urban nature of our network, and strong customer preference for sustainability investment, a significant proportion of our fleet will be hybrid vehicles in 2031 (as shown below). Our assessment approach for fleet electrification also incorporates the AER's recently published value of emissions reduction. Our approach evaluates the total cost of ownership of vehicle electrification, including a negative operating expenditure step-change due to reduced operating costs of hybrid and electric vehicles. This represents an optimised hybrid/EV uptake rate that maximises economic efficiency and emissions reduction.	$1M

Note: For further detail, refer to our attached model: CP MOD 7.05 - Fleet - Jan2025 – Public.

FIGURE 7.2 HYBRID AND ELECTRIC VEHICLE UPTAKE (%)



8. Operating expenditure

Operating expenditure is the day-to-day cost required to operate and maintain our distribution network. It covers our ongoing maintenance programs, vegetation management, fault responses, customer support services and corporate costs.

8.1 What we've heard

Throughout our engagement with customers and key stakeholders, a consistent theme has been the importance of an affordable electricity supply. This reflects the cost-of-living challenges we all face in today's economic environment, and the need to balance this against preferences for new services (such as those associated with the energy transition).

Our engagement program has also focused on testing our customers' willingness to pay for new services. The key findings from our engagement program, relevant to our operating expenditure forecasts, are summarised below.

TABLE 8.1 KEY ENGAGEMENT FINDINGS

Customers want us to ensure the cost of energy services is reasonable and affordable for all customers
Vulnerable customer advocates want us to ensure price sensitive vulnerable customers are empowered to manage their usage
Customers want value for money in their electricity services and want to ensure costs are invested in a meaningful way
Ensure our environment is protected from cyber security attacks
Commercial and industrial customers believe CER enables reliability

8.1.1 Test and validate

Our draft proposal set out our proposed customer assistance package to support customers who may be, or are at risk of, experiencing vulnerable circumstances. As part of our test and validate engagement at our roundtable discussions, our customers provided consistent feedback that reinforced the value of this assistance package.

Customers indicated they supported the package as it:

- highlights the importance of accountability tracking and communication of outcomes, especially as success was defined by the impact made

- builds strong partnerships in the community to deliver greater impact and ensure support is provided to vulnerable customers
- highlights the need to increase investment to assist other vulnerable groups facing energy poverty.

Our test and validate engagement phase also sought feedback on key CER integration programs that are reflected in our proposed operating expenditure step changes. For example:

- customers supported our proposed data visibility program, noting that equitable access to practical, timely and extensive data would be beneficial
- customers supported our flexible exports program, preferring equal allocation of capacity across flexible customers.

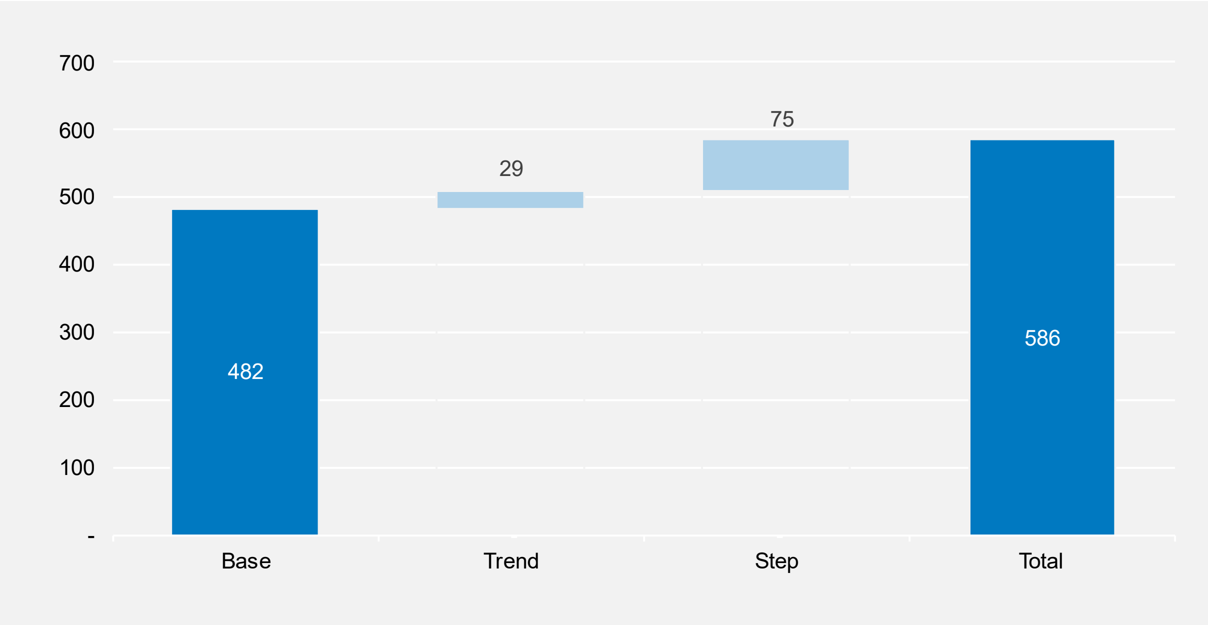
As outlined earlier in the respective CER chapter, our customers were supportive of our proposed investments.

8.2 Our proposed response

Consistent with the AER's preferred approach, as set out in its Better Resets Handbook, we have forecast operating expenditure using a 'base-step-trend' approach.

A summary of our proposed operating expenditure is shown below in figure 8.1.

FIGURE 8.1 TOTAL OPERATING EXPENDITURE ($M, 2026)



Note: Totals may not add due to rounding.

8.2.1 Proposed base year

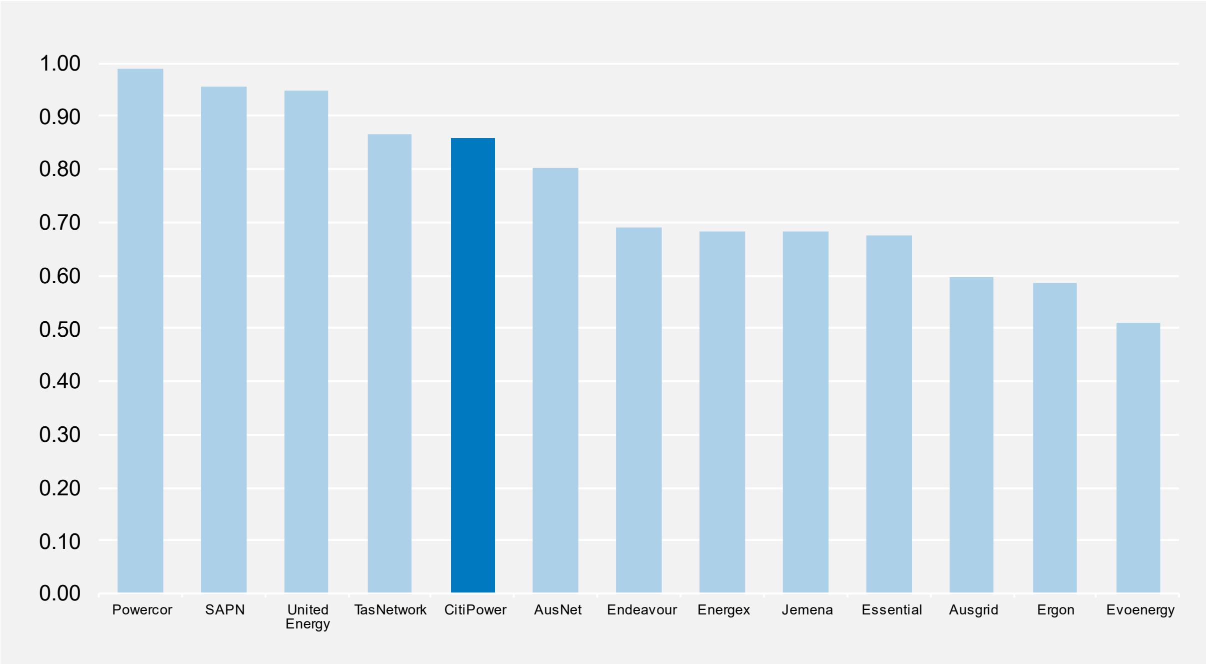
Under the AER's preferred forecasting approach, the first step is to determine the efficient revealed cost base year of expenditure. Where distributors are efficient, customers benefit through downward pressure on network charges and customer bills.

The AER reports annually on the productivity growth and efficiency of distributors, on both an individual network and industry level. They use economic benchmarking to measure how efficiently we deliver services over time and compared with our peers.

Specifically, the AER assesses whether distributors' base year operating expenditure is efficient using its operating expenditure econometric modelling, which produces average operating expenditure efficiency scores over time. The AER considers that distributors with an efficiency score above 0.75 are 'benchmark comparators' that have had efficient operating expenditure over time.

Our average operating expenditure efficiency score in the AER's most recent benchmarking report is 0.86, indicating that we are a benchmark comparator with efficient operating expenditure. Customers benefit from this efficiency through lower network charges.

FIGURE 8.2 AER'S AVERAGE OPERATING EXPENDITURE EFFICIENCY SCORES



Source: AER, Annual Benchmarking Report, Electricity distribution network service providers, 2024, figure 14, p. 35.

For our regulatory proposal, therefore, our proposed base year is the penultimate year of the current regulatory period (i.e. FY25). We consider this is an appropriate reference point as it will be the most recent year where audited actual data will be available at the time of the AER's final decision.

Base year adjustments and category specific forecasts

A base year adjustment may be required to modify the base year to ensure it accurately reflects changes in the operating environment and ensures an accurate expenditure forecast.

Alternatively, a category specific cost is an operating expenditure forecast for specific categories of costs that are expected to vary significantly from that incurred in the base year, and therefore necessitate separate consideration.

We have identified the following three adjustments for the 2026–31 regulatory period:

- guaranteed service levels (GSL) – these are payments we make to customers who experience reliability less than the specified performance thresholds in the Electricity Distribution Code. These payments are volatile as they are based on a range of exogenous factors. We have therefore removed GSL payments from the base year, and replaced them with a new GSL payment rate with a placeholder increase of 15 per cent and volumes based on the average of the last three financial years (i.e. from 2021–22 to 2023–24)[29]

- licence fees – we must make payments to the Essential Services Commission (ESC) for our distribution licence. Licence fees have been increasing faster than forecast and given its variability and materiality, we removed licence fees from the base year. Consistent with the AER's final decision for jurisdictional schemes in our current regulatory period, we propose to recover actual licence fees from ESC through the price control mechanism over the 2021–26 regulatory period
- network innovation – we are seeking an innovation allowance that would allow us to research, test, and implement innovative ideas that have the potential to drive long-term value to customers but are not currently funded under the regulatory framework. Through our test and validate phase of customer engagement, we received strong customer support for our proposed innovation allowance, both in terms of the amount of expenditure and the key focus areas for investment.

8.2.2 Proposed trend forecast

Our base year operating expenditure is escalated by applying forecast trend growth. This trend adjusts for changes in services (output growth), real changes in output prices (price growth) and improvements in productivity (productivity growth).

Output growth

Output growth is the change in costs in relation to changes in the demand for network services. It is measured by changes in customer numbers, circuit length and peak demand.

We have forecast output growth using inputs from a range of sources, including our smart meter data, and AEMO and Victorian Government forecasts. The output growth drivers we have used are those described in the 2024 AER annual benchmarking report, including customer numbers, circuit length and ratcheted maximum demand

We have weighted these growth drivers using output elasticities from the 2024 Quantonomics benchmarking report, as set in our operating expenditure model.[30] The forecast amounts for each growth driver are also described in our operating expenditure model.[31]

We have applied output growth as a percentage growth rate to our revealed base year, using the AER's four operating expenditure econometric benchmarking models.[32]

Price growth

Real price growth accounts for increases in prices that are expected to be over and above inflation. We consider real price growth separately for labour, and non-labour.

For labour growth, we used an average of independent forecasts for the utilities industry Wage Price Index growth in Victoria, plus the legislated 0.5 per cent increase for superannuation guarantee.[33]

Given the temporal nature of labour forecasts, we will update these for our revised regulatory proposals.

Our regulatory proposal also forecasts zero real non-labour price growth, notwithstanding there is evidence that material costs will continue to increase at a rate above inflation. This is particularly the

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29 This placeholder will be updated in our revised proposal, following finalisation of the new rate that is expected to be available in 2025.
30 See the input rate of change tab in: CP MOD 1.05 - Opex - Jan2025 - Public.
31 See the input rate of change tab in: CP MOD 1.05 - Opex - Jan2025 - Public.
32 Including Cobb-Douglas least squares, Translog least squares, Cobb-Douglas stochastic frontier analysis and Translog stochastic frontier analysis.
33 Specifically, see: AER, SA Power Networks Electricity Distribution Determination 2025 to 2030, Draft decision, and CP ATT 8.01 – Oxford Economics - Labour escalation – Jan2025 – Public.

case in the electricity sector, where both global and domestic demand associated with the energy transition remain high. We have recently been absorbing these costs in an effort to maintain customer affordability, however this is unlikely to be an appropriate long-term approach.

Consistent with the AER's previous regulation determination for our business, the relative weighting applied to labour and non-labour expenditure is 59.2 per cent labour and 40.8 per cent non-labour. Our actual labour and non-labour expenditure has a much greater weighting to labour, however, the AER has not previously countenanced our proposal to update these weights.

Productivity growth

We have applied a productivity growth forecast of 0.5 per cent, consistent with the AER’s preferred productivity growth forecast set out in its Better Resets Handbook. Productivity change has been applied as a negative percentage adjustment to the revealed cost base year of operating expenditure.

As a frontier firm on the AER’s benchmarking measures, these productivity targets are increasingly challenging to deliver. For example, the fundamentals of operating a network have changed considerably over the past 10 years, and many of our investment drivers are outside our control (such as the need to meet increasing compliance obligations arising from market reforms).

8.2.3 Step changes

Our step changes for the 2026–31 regulatory proposal include those required to meet new or changing compliance obligations and deliver new services associated with the energy transition. They also reflect the impacts of changing accounting treatments associated with software as a service, and the evolving nature of ICT solutions (which are now being delivered through cloud-based technologies, rather than on-premise capital alternatives).

As such our step changes are costs not accounted for in our base year expenditure, trend forecasts or productivity growth and are therefore forecast separately. Without these step changes, we will be unable to deliver efficient service outcomes for customers or meet our new regulatory obligations related to our step change proposals.

Each of our step changes is recurrent in nature. A summary of these step changes is included in table 8.2, and where relevant, a fulsome justification is set out in the corresponding business cases.

TABLE 8.2 SUMMARY OF OPERATING EXPENDITURE STEP CHANGES ($M, 2026)

STEP CHANGE	AER CATEGORY	COST
Customer package	Major external factor	$7M
Vegetation management	Major external factor and regulatory obligation	$34M
CER integration	Major external factor	$12M
Cloud services	Capex / opex trade-off	$11M
ICT modernisation and new capability	Major external factor and capex / opex trade-off	$12M
Fleet electrification offset	Major external factor	-$0.1M

Customer package

The customer package combines several programs to improve services to our customers, especially those at risk of some form of energy poverty. These programs have been developed based on feedback from our customer engagements, and from the CAP.

As part of our process, and in response to a suggestion from the AER's Consumer Challenge Panel, we empowered the CAP to determine which customer programs were included in our draft proposal. The programs included are:

- energy care – a community outreach approach with in-person literacy programs to help interpret bills and understand energy consumption
- community energy fund – supporting inclusiveness and an equitable energy transition
- vulnerable customer assistance program – targeted at assisting customers and communities' transition away from gas-based appliances
- energy advisory services – enhance our data advisory program to support community information requests
- First Peoples program – the program aims to respond to community feedback with a strong focus on education, access to low energy appliances for vulnerable customers and energy audits. This program also aims to support First Peoples adoption of renewable energy both at a household and community level, as well as putting programs in place for climate emergencies.

Following our draft proposal, we incorporated feedback from our test and validate engagement, and updated our customer package (as attached).[34] Specifically, we made the following changes:

- expenditure has been uplifted to reach a meaningful number of customers to provide tangible customer impact
- a vulnerable customer strategy is being developed, to further identify where we are uniquely well-placed to support customer in vulnerable circumstances. The CAP will be consulted in the development and implementation of this vulnerable customer strategy
- incorporated partnerships with organisations and community groups to deliver our programs
- established an internal working group to refine the principles, governance and operation of all elements of the customer assistance package.

Our revised customer package was then tested with both the CAP and FPAC. FPAC endorsed the First Peoples program, and the customer program in its entirety was endorsed by the CAP. Both the CAP and FPAC supported the business intent and value that this aims to bring to both First Peoples customers and customers at risk of vulnerable circumstances.

The CAP and FPAC articulated that appropriate governance and evaluation of the programs was a key requirement for successful program delivery.

Vegetation management

In Victoria, the Electricity Safety (Electric Line Clearance) Regulations (the Code) govern how we inspect and manage vegetation, and our Electric Line Clearance Management Plan (ELCMP) outlines our standards and practices for tree cutting or removal, including rectification timing.

Unlike our general safety obligations that require us to minimise risk as far as practicable, our vegetation clearance obligations are deterministic. That is, the Code requires that no vegetation enters the minimum clearance at any time (i.e. it is not a risk-based assessment).

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34 For more detail refer to our attached business case: CP BUS 8.02 – Customer assistance package – Jan2025 – Public.

In 2018, following a major review of our vegetation clearance management and contract arrangements, we introduced new technologies to provide faster and more accurate visibility of our network. Specifically, we commenced using light detection and ranging (LIDAR) technology to replace our ground-based vegetation inspection practices.

The application of LIDAR has improved across several years, with a steady-state level of maturity and confidence in the accuracy of the outputs being achieved from around 2022. We have also been on a continuous improvement journey through this time, including the procurement of additional infrastructure (e.g. our aerial fleet, as well as more mechanical cutting equipment), and providing longer-term contracts to our third-party providers to encourage growth in available labour resources.

The use of LIDAR, however, has naturally identified more 'known-unknowns' and technical non-compliances than we previously had the ability to identify. As a result, we have been prosecuted by ESV for failing to clear vegetation in accordance with the Code.

In effect, our regulatory obligation to comply with the Code has changed during the 2021–26 regulatory period. This is because, while the Code requirements are deterministic and have not themselves changed, the standard of compliance with these requirements required by law is informed by what is possible, having regard to industry best practice. As a result of our industry leading vegetation management program, industry best practice has evolved during the 2021–26 regulatory period, such that the standard of Code compliance that is possible has increased significantly. This new standard of compliance constitutes a change in a 'regulatory obligation or requirement' for the purposes of the National Electricity Law.

Our regulatory proposal, therefore, includes an operating expenditure step change reflecting the cost of achieving compliance with the Code at a point in time, and compliance with the ELCMP at all times. Following our draft proposal, we have updated our modelling so that we achieve this level of compliance in FY29. This better recognises the likely time required to build a resource pool capable of delivering the expected volume of works.

This incremental expenditure is to increase the volume of cutting undertaken, with further detail set out in our vegetation management business case.[35]

At the same time, we have been engaging with ESV and the Victorian Government to seek amendments to the Code to better support the role of technology in managing vegetation clearance risks. The existing Code is due to sunset in mid-2025, with revisions subject to a public Regulatory Impact Statement (RIS).[36]

Cloud services

The changing nature of the ICT market offerings mean that many services are now offered as cloud-based solutions, rather than on-premises infrastructure. Cloud services are able to offer greater flexibility and scalability compared to tradition infrastructure solutions.

Following accounting rule clarification in early 2021, costs associated with the implementation of cloud services are now classified as operating expenditure. This is due to IT products transitioning from local data centres to cloud-based hosting. Prior to this changes to these costs had been incurred as capital expenditure. To meet our accounting requirements for the 2026–31 regulatory period we have included our cloud implementation costs as an operating expenditure step change.

Further detail on the components of this step change are set out in the corresponding ICT business cases.[37]

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[35] CP BUS 8.01 – Vegetation management – Jan2025 – Public.

[36] We will consider the outcomes of this RIS in the development of our revised proposal.

[37] CP BUS 6.01 – ERP & billing system replacement – Jan2025 – Public; CP BUS 6.02 – Cyber security – Jan2025 – Public; CP BUS 6.04 – Infrastructure refresh – Jan2025 – Public.

ICT modernisation and new capability

Throughout the 2026–31 regulatory period we will be implementing a range of ICT modernisation and new capabilities to meet the needs and expectations of our customers. Once these new capabilities are established, we will require additional operating expenditure to run and maintain these capabilities. This includes supporting our new ERP and billing system, new enhancements associated with AEMO NEM reforms, as well as our new cyber capabilities that will improve threat prevention, monitoring and detection.

Further detail on the components of this step change are set out in the corresponding ICT business cases.[38]

Insurance premiums

The cost of insurance premiums has been increasing over time, driven by factors such as bushfire risk and other natural disasters. Our insurance premiums are expected to increase further in the short-term, however, there remains uncertainty about medium-term projections (particularly given recent events in California, and the international nature of the insurance market).

We have not included a step change for insurance premiums in our regulatory proposal, but plan to re-assess the insurance market at the time of our revised proposal.

[38] CP BUS 6.01 – ERP & billing system replacement – Jan2025 – Public; CP BUS 6.02 – Cyber security – Jan2025 – Public; CP BUS 6.04 – Infrastructure refresh – Jan2025 – Public; CP BUS 6.03 – AEMO NEM reforms – Jan2025 – Public.

9. Incentives

There are a number of mechanisms and schemes within the regulatory framework that incentivise us to continually improve our service levels to customers or maintain service levels efficiently.

For the 2026–31 regulatory period, we propose to continue the same incentives schemes as currently in place, with the addition of a new innovation allowance to deliver long-term benefits to customers through innovative projects beyond demand management. These schemes are outlined below.

TABLE 9.1 PROPOSED INCENTIVE SCHEMES FOR THE 2026–31 REGULATORY PERIOD

INCENTIVE SCHEME	SUMMARY
Capital Expenditure Sharing Scheme (CESS)	The CESS provides us with incentives to undertake efficient capital expenditure. Where we are able to make efficiency gains these are shared with customers, with customers receiving 70-80 per cent of these efficiencies
Efficiency Benefit Sharing Scheme (EBSS)	The EBSS provides us with incentives to undertake efficient operating expenditure. Where we are able to make efficiency gains these benefits remain with us for six years after which the full value of the benefit is passed onto customers
Service Target Performance Incentive Scheme (STPIS)	The STPIS incentivises us to maintain and improve network performance, and balances incentives in the EBSS and CESS to reduce expenditures. This ensures consumers receive benefits from genuine efficiency gains and not at the risk of a decrease in network performance
Customer Service Incentive Scheme (CSIS)	The CSIS is designed to incentivise customer services in accordance with customer preferences. It focuses on customer service levels in areas where customers value improvement
Demand Management Incentive Scheme (DMIS)	The DMIS provides us with financial incentives to undertake efficient expenditure on non-network solutions to manage peak electricity demand. This lowers the cost of managing peak electricity demand for customers
Demand Management Innovation Allowance Mechanism (DMIAM)	The DMIAM provides funding for research and development in demand management projects that have the potential to reduce long-term network costs. The DMIAM supports the development of ideas that may form part of the DMIS in the future
F-factor scheme	The F-factor scheme provides financial incentives to minimise the number of fire starts within high fire danger zones and times. This scheme is specific to Victoria
Innovation allowance	The innovation allowance is intended to support the broader development of research, trials and pilots, where such projects can provide long-term benefits to customers

The CESS, EBSS and STPIS have been part of the regulatory framework for a number of years, and we continue to respond strongly to the incentives provided by these schemes.

The AER recently conducted a review of these three schemes, noting that the CESS, EBSS and STPIS have 'driven significant improvement in performance through efficiency gains.[39] The review highlighted that together the schemes across the NEM had reduced revenue per customer by 35 per cent since 2014–15, while also improving the frequency and duration of outages by 20–30 per cent.

The AER further noted that 'while the network service providers have been rewarded for the efficiency gains, the majority of benefits have gone to consumers.[40]

9.1 EBSS

We propose to continue to apply the EBSS to standard control operating expenditure over the 2026–31 regulatory period to ensure we have strong incentives to pursue efficiencies which deliver lower costs to customers over the long term. We propose to continue applying the EBSS in accordance with the AER's EBSS guideline and exclude the following costs from the 2026–31 carryover:

- debt raising costs,
- the demand management innovation allowance (DMIAM)
- GSL payments
- expenditure related to our proposed innovation allowance.

Applying the EBSS is consistent with the AER's framework and approach paper and our forecast operating expenditure for the 2026–31 regulatory period, which will be based on our actual efficient 2024–25 operating expenditure.

We have applied the AER's EBSS to calculate the revenue increments and decrements for the 2021–26 regulatory period, as outlined in the attached model and in table 9.2.[41]

The 2026–31 EBSS revenue adjustments will be updated with the latest available information for the purposes of the AER's draft and final determinations.

[39] AER, Review of incentives schemes for networks – Final decision, April 2023, p. 4.
[40] AER, Review of incentives schemes for networks – Final decision, April 2023, p. 4.
[41] CP MOD 1.06 - EBSS - Jan2025 – Public.

TABLE 9.2 EBSS CALCULATION ($M, 2026)

DESCRIPTION	FY22	FY23	FY24	FY25	FY26
Adjusted benchmark EBSS operating expenditure	115	114	117	116	117
Actual EBSS operating expenditure	89	93	99	95	96
Incremental efficiency	1	-5	-3	3	-
Carry-over year	FY27	FY28	FY29	FY30	FY31
EBSS carry-over	**4**	**-5**	**1**	**3**	**-**

9.2 CESS

We propose to continue applying the CESS to standard control expenditure in accordance with the AER's CESS guideline over the 2026–31 regulatory period. This ensures we have incentives to minimise project costs and pass on a proportion back to customers.

Consistent with the CESS guideline and the AER's framework and approach paper we propose using forecast depreciation to establish the opening RAB for the following regulatory period 2026–2031. However, we propose excluding connections expenditure from the CESS as this expenditure is broadly outside the control of network providers (see below). We also propose to exclude expenditure related to our innovation allowance.

We calculate the 2026–31 CESS revenue increment or decrement as follows:

- calculate the cumulative underspend or overspend for the current regulatory period in net present value terms
- apply the network sharing ratio of 30% to any underspend amount up to 10%
- apply the network sharing ratio of 20% to any underspend amount above 10%
- apply the network sharing ratio of 30% to any overspend
- deduct the 2021–26 financing benefit or cost of the underspends or overspends.

We have not adjusted the CESS calculation to exclude any deferred projects, as these do not meet the AER’s requirements for exclusion from the CESS (e.g. we have not materially underspent our regulatory allowance for the 2021–26 regulatory period).[42]

Our detailed calculation of the 2026–31 CESS revenue adjustments arising from the true up for 2020 and the first half of 2021 actual net capital expenditure has been added into the attached model.[43] A summary of the CESS outcome is shown in table 9.3.

The 2026–31 CESS revenue adjustments will be updated with the latest available information for the purposes of the AER’s draft and final determinations.

42 AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, April 2023, p. 8.
43 CP MOD 1.07 - CESS - Jan2025 – Public.

TABLE 9.3 CESS CALCULATION ($M, 2026)

DESCRIPTION	PRESENT VALUE
Total efficiency gain	65
Network service provider share	20
Financing benefit	-10
CESS payment in 2026–31	**11**

9.2.1 Excluding connections expenditure from the CESS

While we agree that the CESS allows both distributors and customers to share the benefits of improved network performance, we propose that the CESS should be narrowed to only include capital expenditure that is within the control of network providers. For this reason, we consider the intent of the CESS would better align with the practical outcomes of the scheme if expenditure related to connections was excluded.

Connections expenditure is linked to the number of customers requesting connection to our network. The number of connection requests in any given regulatory period, both in terms of the nature and number of connections, is entirely outside of our control.

We must make an offer to any customer seeking a connection to our network, even when actual connection expenditure is already above our forecasts. This can place the overall capital program under significant pressure.

Given that connections expenditure is non-discretionary, we consider that applying a CESS penalty on top of the connections expenditure does not reflect the intent of the CESS, which is meant to incentivise efficiency gains.

The energy transition is also making it increasingly difficult to forecast connections expenditure due to:

- increased uncertainty of the number and nature of future connections
- recent emergence of new types of large connections such as data centres, batteries and EV charging stations
- difficulty of forecasting customer contributions.

Based on the increasing difficulty in accurately forecasting connections expenditure, we consider that the removal of connections expenditure from the CESS is appropriate.

9.3 STPIS

Over the 2026–31 regulatory period we propose calculating the STPIS targets, incentive rates and major event day (MED) threshold in accordance with the AER's 2018 STPIS guideline as follows:

- use historical performance data over the five-year period from 1 July 2021 to 30 June 2026
- apply the updated VCR as determined by the AER to determine the incentive rate
- calculate the MED using a beta of 2.5 consistent with the 2021–2026 application of the scheme.

We propose to not apply the GSL component of the STPIS scheme as we are subject to the Victorian jurisdictional GSL scheme. We also propose to not include the telephone answering component of the STPIS in favour of our proposed CSIS.

Our proposed STPIS targets, incentive rates and MED threshold are set out in table 9.4 with additional detail available in our incentives and targets models.[44]

TABLE 9.4 STPIS TARGETS AND INCENTIVE RATES FOR THE 2026–31 PERIOD

PARAMETER	NETWORK SEGMENT	TARGET	INCENTIVE RATE
Unplanned SAIDI	CBD	7.45	0.02
	Urban	24.26	0.07
Unplanned SAIFI	CBD	0.08	1.00
	Urban	0.32	3.82
MAIFIe	CBD	0.02	0.08
	Urban	0.18	0.31
MED threshold	Network	1.5	

9.4 CSIS

The 2021–26 regulatory period was the first time we introduced an incentive scheme related to customer service levels. Over this period, we have exceeded our targets in all but one instance, delivering significant customer benefits. This was achieved through the continued investment in our people and processes.

For the 2026–31 regulatory period we again propose to include a CSIS in place of the telephone answering component of the STPIS. We have undertaken customer engagement to further understand what services customers value, and whether these have changed since the 2021–26 regulatory period.

We have also engaged with the CAP throughout our CSIS development. This has allowed us to incorporate the CAP's feedback on the design of the original customer engagement, the results of that engagement and on each potential CSIS measure. We also sought comprehensive feedback on our final proposed measures. Following these sessions, the CAP has provided its endorsement of our proposed CSIS.

We consider our current CSIS remains well aligned with our customer preferences. As such, our proposed CSIS for the 2026–31 regulatory period introduces only minor changes to our CSIS measures. Our proposed CSIS:

- maintains the SMS notification delivery measure, noting changes we have already made in relation to the structure of our SMS responses. These changes were made following customer feedback that our SMS's should provide additional information
- expands our grade of service measure to capture both contact centre fault calls and general inquiries, which is reflective of feedback we have received from customers (who want our contact

[44] CP MOD 9.03 - STPIS targets - Jan2025 – Public; CP MOD 9.02 - STPIS incentives - Jan2025 – Public.

centre to be responsive to all customer calls). We have also increased the revenue at risk associated with this measure to better align our CSIS with potential investment opportunities.

The total value of the revenue we will risk is +/- 0.5 per cent of our annual revenue for the 2026–31 regulatory period. This equates to approximately $2 million per year.

Table 9.5 sets out our proposed CSIS measures with the relevant revenue at risk, baseline target and incentive rate. Our full CSIS proposal for the 2026–31 regulatory period is attached to this regulatory proposal.[45]

TABLE 9.5 PROPOSED CSIS FOR THE 2026–31 PERIOD

CSIS MEASURE	REVENUE AT RISK	BASELINE TARGET	INCENTIVE RATE
SMS notification	0.20%	69.5%	0.04%
Grade of service	0.30%	73.4%	0.04%

9.5 DMIS and DMIAM

We propose to include the DMIS and DMIAM in the 2026–31 regulatory period, consistent with our current regulatory period. Applying these satisfies the requirements of the National Electricity Law (NEL) by providing an incentive to use more demand management, which can defer augmentation and create option value, potentially lowering costs in the long term.

The demand management projects we have undertaken through the DMIAM during the 2021–26 regulatory period are set out in table 9.6.

TABLE 9.6 DMIAM PROJECTS: 2021–26 REGULATORY PERIOD

PROJECT/PROGRAM	SUMMARY
Residential demand management program	We undertook research to better understand the effectiveness of residential demand management as an alternative non-network solution across different customer segments
Trial tariff project	We trialled new network tariffs from 1 July 2022 which could shift demand away from peak demand times to minimum demand times
Low voltage DERMS and flexible exports trial	This project implemented new demand management capabilities to more effectively manage distributed energy resources. The LV DERMS trial provided real-time control of DER while the flexible exports trial focused on specific types of rooftop solar customers that have previously been constrained

Table 9.7 provides our proposed DMIAM allowance for the 2026—31 regulatory period, calculated in accordance with the AER's guidelines.[46]

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45 CP ATT 9.01 - CSIS - Jan2025 – Public.
46 AER, Demand management innovation allowance mechanism, December 2017, p. 8.

TABLE 9.7 DMIAM ($M, 2026)

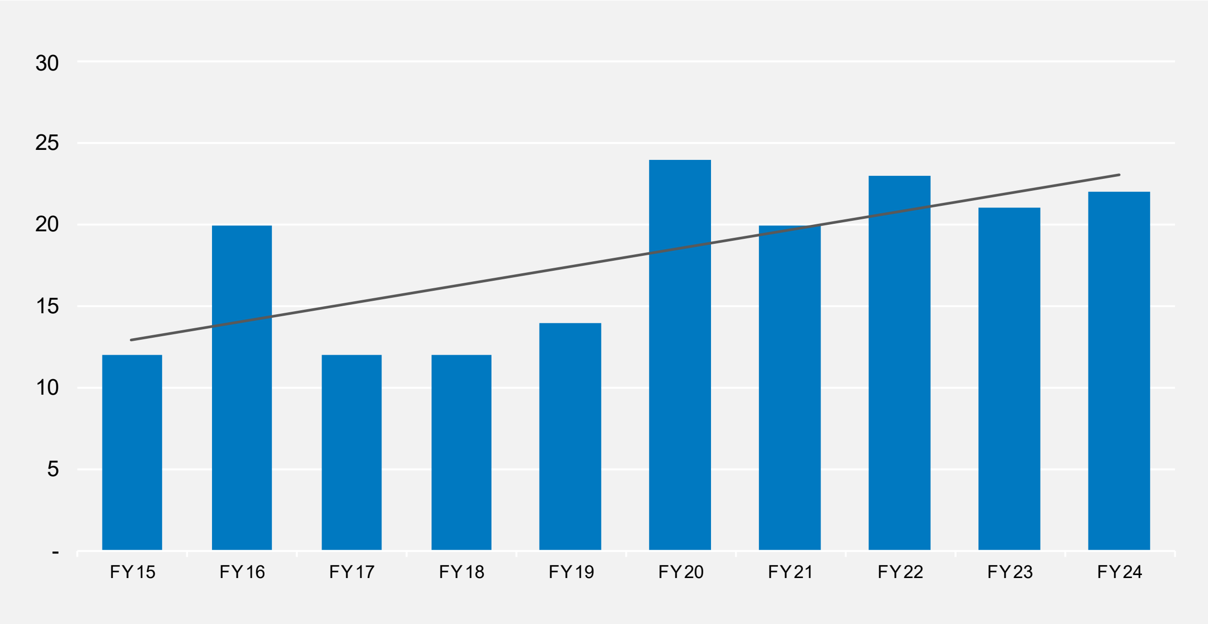
DESCRIPTION	FY27	FY28	FY29	FY30	FY31
DMIAM	0.54	0.54	0.54	0.55	0.56

9.6 F-factor scheme

We propose to continue to apply the F-factor scheme during the 2026–31 regulatory period, consistent with the AER's framework and approach paper. The F-factor scheme is a Victorian Government scheme introduced following the 2009 Black Saturday bushfires that provides incentives to limit powerline ignitions.

Figure 9.1 demonstrates historical fire starts on our network. Fire starts on our network have, on average, been steadily increasing over time but remain low in overall terms.

FIGURE 9.1 NUMBER OF FIRE STARTS



9.7 Innovation allowance

We are seeking an innovation allowance that would allow us to research, test and implement innovative ideas that have the potential to drive long-term value to customers, but are not currently funded under the regulatory framework. Through our test and validate phase of our customer engagement we received strong customer support to our proposed innovation allowance both in terms of the amount of expenditure and the key focus areas for investment.

The current innovation incentive framework is narrow in scope and is mostly limited to innovation in demand management through the DMIS and DMIAM. While these two schemes have been successful in delivering innovation to demand management, there are a broader range of innovation opportunities that can provide long-term benefits to customers.

Innovation, by definition, involves developing and testing new processes and technologies, where the scope may not yet be clearly defined and the potential benefits uncertain. These types of projects do not lend themselves to the AER’s current regulatory process (which requires a higher level of certainty around the costs and benefits of a project, i.e. projects must be set out 5–7 years in advance, with associated business cases and cost benefit models). Having funding linked only to the innovative projects identifiable so far in advance runs the risk that highly innovative opportunities that may only be identified during the regulatory period are unable to be undertaken.

Our current approach to innovation internally is based on a two-year lifecycle that includes a 'fail fast' mentality.[47] This makes it difficult to forecast the exact projects that would be undertaken over the full five-year regulatory period. This same difficulty occurs when thinking about customer focussed innovation.

Due to these practicalities, our preference would be for an innovation allowance that is agreed upon at the beginning of the regulatory period but does not require specifying each of the individual innovation projects throughout the regulatory period. We consider that such an allowance would also lead to the better utilisation of the AER's regulatory sandbox(see below) by providing the desired level of funding in relation to innovation more broadly, rather than the level of innovation funding associated with projects that can be demonstrably proven prior to the regulatory period.

Regulatory sandbox

In 2023 the AER established a regulatory sandbox function that enables the trial of new innovative products and services. The sandbox facilitates trials by granting trial waivers, which temporarily exempts an innovator from having to comply with specific rules that may be creating a barrier to the trial proceeding.

Given the fast paced and dynamic nature of innovation, the sandbox is an important development to assist businesses quickly and efficiently trial innovative solutions that have the potential to deliver long-term customer benefits.

We understand that currently the sandbox is being underutilised, which is likely linked to the limited funding options available for innovation projects outside of demand management innovation. Providing distributors with an innovation allowance linked to the desired level of innovation customers are willing to fund, will provide the funding businesses require to invest in innovation more broadly. In this environment, the sandbox will be a key complementary tool that will allow distribution networks to trial innovative solutions that may deliver long-term customer benefits.

We propose to include an innovation allowance of $7.5M, that would be drawn upon across the regulatory period. We have set out our proposed innovation projects for the initial two years of the regulatory period which equates to approximately 50 per cent of our proposed allowance. We will then seek to provide specific innovation projects for the remaining three years during the regulatory period.

In recent AER decisions, the AER has approved innovation expenditure for some distributors as part of their capital expenditure forecasts. We have included our proposed innovation expenditure in our capital and operating expenditure forecasts consistent with this approach, however we consider an innovation incentive framework similar to the DMIAM but with a broader scope of innovation opportunities would better align with how innovation is treated in practice, and in unregulated sectors.

The innovation allowance will focus on three key areas:

- **assisting the energy transition** – innovation to support community uptake of appropriate energy solutions

47 For clarity, our internal innovation focus is on productivity enhancement initiatives. These are already incentivised under the CESS and EBSS, and accordingly, would not be the focus of this innovation allowance.

- **improving customer experiences** – innovation to improve power quality issues for sensitive industry processes, provide more localised real time information to customers and undertake tariff optimisation trials
- **developing sustainable networks** – innovation to improve performance and capacity for renewable energy, increasing grid stability and developing new technologies to support localised climate modelling and forecasting.

Further details on our innovation expenditure, including the projects we propose to undertake during the initial two years of the 2026–31 regulatory period and proposed governance arrangements are set out in our innovation allowance attachment.[48]

[48] CP BUS 9.01 - Innovation allowance - Jan2025 – Public.

10. Uncertainty framework

Historically, changes in consumer demand have been gradual, allowing for relatively stable and predictable growth. However, the ongoing energy transition is dramatically changing how customers interact with the energy network, impacting both the amount and timing of electricity consumption.

This section sets out our proposed approach to managing this uncertainty, including the use of nominated pass-through events and contingent projects.

10.1 The energy transition is bringing greater uncertainty

The current regulatory framework is not fully equipped to handle the fast-moving and significant changes brought about by the energy transition. The current uncertainty mechanisms within the regulatory framework do not provide adequate flexibility to account for potential changes in electricity consumption and demand during a regulatory period. Instead, the framework relies predominately on forecasts made prior to the start of the regulatory period.

Without greater ability to account for uncertainties in future electricity demand, we may not have sufficient funding to deliver the network services that customers expect and value. Without the necessary infrastructure in place, customers are likely to experience lower service levels, including:

- additional capacity constraints and more frequent low voltage events: policy initiatives driving the shift from gas and internal combustion engines to electric options will increase electricity demand and without timely investment will exacerbate maximum and minimum demand events. This will limit customer’s ability to benefit from their own CER
- poorer reliability: such as outages caused by overloaded circuits from increasing demand on the LV network
- reduced power quality: the integration of more renewable energy sources, rooftop solar, batteries, and EV chargers will complicate maintaining consistent power quality. This can be particularly damaging for our large commercial and industrial customers whose machinery can be damaged, or operations disrupted (at significant cost), by fluctuations in power quality.

Additionally, delivering infrastructure investments reactively, at a later date than prudent, and within a compressed timeframe will inefficiently drive-up long-term costs for customers.

Government policies are expected to bridge the gap between current emissions and emission reduction targets

Victoria has a number of emission reduction targets on its pathway to net zero, as shown in table 10.1.

TABLE 10.1 VICTORIAN EMISSION REDUCTION TARGETS

DESCRIPTION	2030	2035	2045	2050
Emissions target	45-50% reduction	75-80% reduction	Committed net-zero	Legislated net-zero

Source: DEECA, Victoria’s Climate Change Strategy

The Victorian Government will likely need to introduce new policies to ensure that Victoria is able to meet its emission reduction targets. For example, in its zero emissions vehicle (ZEV) roadmap, the Victorian Government has set a target of 50 per cent of new light vehicle sales to be zero emissions vehicles by 2030.[49] Strong EV uptake is needed to reach 50 per cent market share by 2030 and an even faster uptake is required to meet emissions targets. It is therefore reasonable to expect that the Victorian Government will introduce new initiatives to incentivise the uptake of EVs to meet its announced targets.

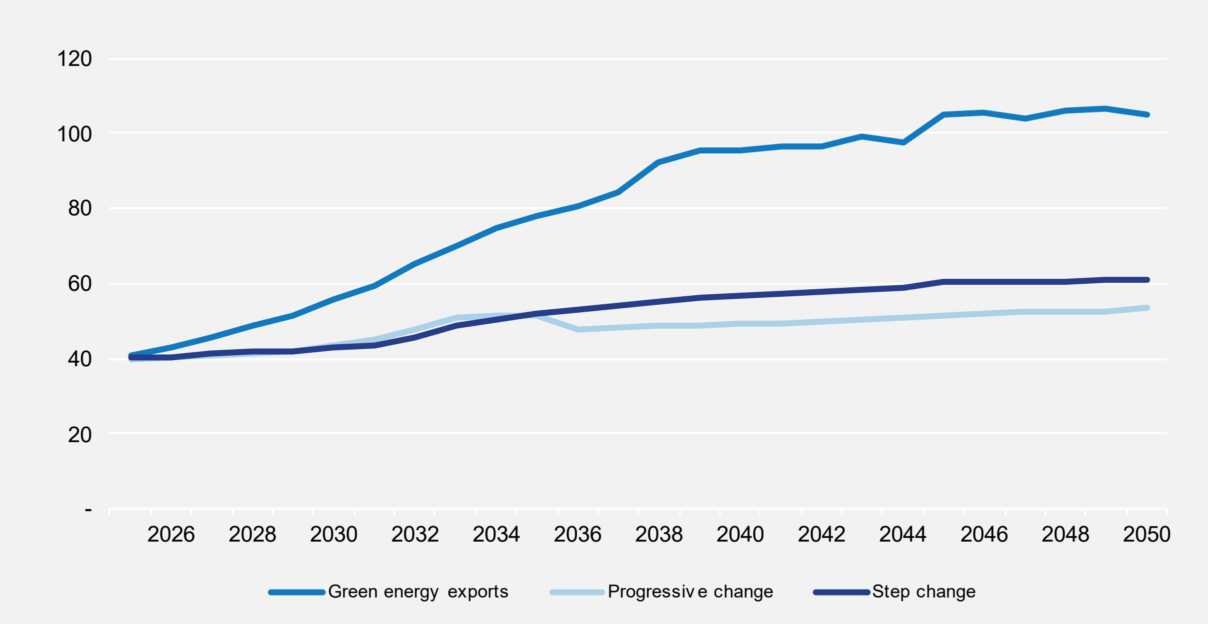
While any increase in expenditure required to deliver these government policies may be accounted for under the uncertainty framework (e.g. as a regulatory change, under the pass-through mechanism), any complementary or subsequent increase in electricity consumption beyond the government policy will not. For example, a household may decide to purchase an EV based on a government incentive. This may then accelerate additional electrification within a household to maximise the benefits of full electrification. It is important that an uncertainty framework captures the additional consumption that may occur due to future government policies, ensuring that distribution networks can accommodate all increases in electricity consumption and demand.

There is considerable uncertainty with the path the energy transition will take

In developing its system plan, AEMO includes a number of different scenarios based on how the energy transition may take shape. While AEMO considers the step change scenario to be the most likely pathway for the energy transition, it acknowledges that the transition is far from certain. The rate at which EVs replace internal combustion engine vehicles, the adoption of rooftop solar and batteries, and the speed at which households move away from gas are subject to a range of factors that are closely tied to government policies.

Due to the extent of these uncertainties, AEMO's long-term plans encompass multiple scenarios to account for different transition paths. One of these paths is the green energy exports scenario. In this scenario, Australia's development of an energy export industry through increased renewable energy, coupled with a faster electrification process, would lead to a substantial increase in energy consumption in Victoria. By 2030, operational consumption (i.e. consumption after accounting for household rooftop solar and batteries) under the green energy exports scenario would be 30 per cent higher than AEMO’s step change estimates.

FIGURE 10.1 VICTORIAN OPERATIONAL CONSUMPTION FORECASTS (TWH)



Source: Australian Energy Market Operator, Electricity Statement of Opportunities, 2024.

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[49] DEECA, Victoria’s Zero Emissions Vehicle Roadmap, 2021.

Given the Victorian Government's commitment to drive electrification of homes and businesses, there is a high likelihood that electricity consumption may exceed the step change scenario in the 2026–31 regulatory period. It is therefore prudent that the regulatory framework also accounts for the potential for consumption to be higher than the step change scenario predicts.

10.2 Our proposed response

The uncertainty regime under the Rules comprises pass-through events, capital expenditure reopeners and contingent projects. These mechanisms deal with expenditure that may be required during a regulatory period, but which is not able to be predicted, or predicted with reasonable certainty, at the time of preparing or submitting a regulatory proposal to the AER. Given the high level of uncertainty associated with the energy transition and customer affordability concerns, we consider the uncertainty framework can be utilised to ensure customers are not required to fund investments as they are needed.

This is also consistent with feedback we have received from the CAP. In its report on our draft proposal, the CAP highlighted the growing need to address and better plan for uncertainty given the likely changes of the energy transition, while also considering that one of the key messages from customers was ensuring affordability.[50]

Rather than building up our expenditure forecasts to cover every possible eventuality, we therefore propose nominated pass-through events and contingent projects in this regulatory proposal to enable us to request additional funding from the AER during the regulatory period if the future state of the distribution network is materially different from forecast. The exclusion of the costs of these uncertain events from our regulatory proposal ensures our customers face the lowest possible prices.

Table 10.2 summarises our proposed nominated pass-through events, with contingent projects for the 2026–31 regulatory period set out thereafter. The majority of our nominated pass-through events are events that have previously been accepted by the AER, and we do not propose any changes to these definitions.

We are also proposing three new pass-through events. Further details around each of the nominated pass-through events and contingent projects, including proposed triggers, are set out in our uncertainty attachment.[51]

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[50] CP ATT SE.30 – CAP - Report on Draft Proposal – Nov2024 – Public.
[51] CP ATT 10.01 - Managing uncertainty - Jan2025 – Public.

TABLE 10.2 NOMINATED PASS-THROUGH EVENTS

TYPE OF EVENT	CHANGES FROM CURRENT DEFINITION
Insurer credit risk event	No changes proposed from current definition
Insurance coverage event	No changes proposed from current definition
Natural disaster event	No changes proposed from current definition
Terrorism event	No changes proposed from current definition
Retailer insolvency event	No changes proposed from current definition
Fault level event	Additional event to address the risk that a part or parts of the distribution network will exceed fault level limitations and require upgrades to comply with relevant safety, contractual and regulatory obligations
Electrification event	Additional event to address the uncertainty around the pace of electrification, as electrification requires additional investment in the network
AEMO participant fee event	Additional event to address the potential for AEMO to alter its electricity market participant fees leading to a material increase in the costs to us in providing direct control services

10.2.1 Contingent project: Lauren street (LS) zone substation rebuild

The inner north of Melbourne is currently experiencing a period of rapid growth. This growth will likely be accelerated with the construction of the Arden Precinct. The Arden Precinct is a 44 hectare urban renewal area located around the new Arden Station in North Melbourne. We will be installing a third transformer at the Bouverie Queen (BQ) substation to accommodate growth in the inner north area, however, should additional demand growth occur we will likely need to rebuild our LS zone substation.

Given the uncertainty regarding demand growth in this area, which is heavily linked to the Victorian Governments plans for the Arden Precinct, we have included the LS zone substation rebuild as a contingent project. This means funding for this investment will only be sought if specific demand triggers are met within the 2026—31 regulatory period.

We propose the following trigger for this event:

- we prepare a business case and relevant regulatory investment test for distribution documentation, including a cost-benefit analysis that demonstrates that the preferred option is rebuilding the LS zone substation; and
- we obtain all relevant internal approvals to proceed with the project.

Our estimate of the cost of these works is approximately $70 million ($2026).

10.2.2 Contingent project: Spencer Street (J) zone substation rebuild

Under the Electricity Distribution Code of Practice (EDCoP), we have an obligation to strengthen the security of supply in the Melbourne CBD.[52] To maintain this security of supply we use an 'N-1 Secure' supply security standard.

Based on our demand forecasts for the Docklands area, the Little Bourke Street (JA) zone substation will become non-compliant with its N-1 Secure rating during the 2026—31 regulatory period. To maintain N-1 Secure compliance we will need to rebuild the J zone substation. However, given the forecast high load growths in the Docklands area there is some uncertainty as to whether the forecast demand will occur. To accommodate this uncertainty we have included the J zone substation rebuild as a contingent project, this means funding for this investment will only be sought if specific demand triggers are met within the 2026–31 regulatory period.

We propose the following trigger for this event:

- our forecast of load growth in the area supplied by the JA zone substation increases relative to the forecast of load growth set out in CitiPower's regulatory proposal; and
- the increase in forecast load growth will result in us not being able to maintain a N-1 secure rating in respect of the JA zone substation in circumstances where two new jumbo feeders from the Montague Steet (MG) zone substation to Docklands South are constructed, without also implementing the J zone substation project in the 2026–31 regulatory period.

Our estimate of the cost of these works is approximately $54 million ($2026).

10.2.3 Contingent project: Richmond (R) zone substation rebuild

The R zone substation supplies customers in the Richmond, Cremorne, South Yarra and Toorak areas. We expect demand to increase in these areas during the 2026—31 regulatory period driven by population growth and Victorian Government housing policies, including plans to replace single dwelling homes and existing social hosing with large apartment towers.

Based on our demand forecasts we consider the preferred option is to transfer load from the R substation to adjacent substations. However, if demand exceeds our forecast we will need to rebuild the R zone substation to allow for greater load capacity.

Given the uncertainty regarding demand growth in this area, which may be accelerated by Victorian Government housing policies, we have included the R zone substation rebuild as a contingent project. This means funding for this investment will only be sought if specific demand triggers are met within the 2026–31 regulatory period.

We propose the following trigger for this event:

- we prepare a business case and relevant regulatory investment test for distribution documentation, including a cost-benefit analysis that demonstrates that the preferred option is rebuilding the R zone substation; and
- we obtain all relevant internal approvals to proceed with the project.

Our estimate of the cost of these works is approximately $68 million ($2026).

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52 Essential Services Commission, Electricity Distribution Code of Practice, 2032, clause 19.5.5(b).

11. Alternative control services

Alternative control services (ACS) are a set of specific services provided by networks that are not covered by standard network tariffs but are available on request.

11.1 Metering

In 2009, the Victorian Government mandated the Victorian distributors to roll-out advanced metering infrastructure (AMI) meters in residential and small commercial premises consuming up to 160MWh per annum. As we provide metering services, we therefore act as both the electricity distributor and the metering coordinator for those properties.

Our initial meter roll-out was completed between 2009–2013, and as such, the existing meter population is reaching the end of its economic life.

For the 2026–31 regulatory period, the key driver of our forecast metering investment is the proposed proactive replacement of 33 per cent of the total meter population. As discussed below, this represents a reduction in the speed of our proposed roll-out relative to our draft proposal (and corresponding expenditure).

Our proposed program will reduce the risk of high failure rates requiring disruptive and expensive reactive replacements. It will also better smooth customer meter charges, with efficiencies due to the bulk purchase of meters and lower labour installation costs from a coordinated approach.

11.1.1 What we've heard

Our engagement with our customers and the CAP discussed alternative meter replacement programs, and their corresponding customer benefits, expectations and affordability impacts.

TABLE 11.1 KEY ENGAGEMENT FINDINGS

We are expected to effectively manage the risk of significant meter failures which will result in customer disruptions and high reactive replacement costs. Customers consistently highlighted the importance of a reliable energy supply, with the majority of customers having no appetite for a deterioration in reliability performance
Customers see innovation and technology as essential drivers of an enhanced customer experience, and in particular, the potential of new technologies like smart meters and digital applications. We should address how we add value with the replacement program, making sure new meters provide additional benefits
We need to ensure there is no overlap between our forecasts for new connections, proactive replacements, and reactive replacements

Test and validate

As part of our test and validate engagement, we undertook a quantitative survey across a number of key issues outlined in our draft proposal. This included our proposed proactive metering program.

In this engagement, customers were asked to consider alternative options regarding meter replacements:

- the first option was to commence proactive meter replacements starting in 2026 while maintaining the current meter charges, which would help prevent potential failures in the coming years
- the second option was to delay proactive replacements until after 2031, resulting in decreased meter charges from 2026 to 2031, but potentially increasing charges from 2031 onwards. This delay may lead to an increased likelihood of meter failures in the future.

This discussion resulted in over two thirds of residential and SMB customers preferring us to start proactively replacing meters to prevent failures.

Through our customer engagement at the roundtable session, customers also expressed support for the proactive meter replacement program. Their feedback included the following:

- participants agreed on the importance of upgrading meters without interruptions
- a targeted rollout approach was wanted to optimise the rollout effectiveness without compromising the meter benefits
- a proactive rollout approach was considered reasonable noting that there would be immediate benefits, such as reliability of meter performance, as well as long-term visibility benefits
- communication and transparency was desired—participants wanted clear communications with customers on the purpose and benefits of the rollout
- customers required confidence that their privacy would be maintained
- enhanced data and monitoring capabilities were wanted in the new meter assets.

11.1.2 Our proposed response

Since the draft proposal, we have undertaken further analysis and research to refine our understanding of potential future failure rates of the meter fleet and the associated uncertainties. This has allowed us to make informed adjustments to the pace of the rollout, ensuring it reflects the latest insights and aligns with the anticipated needs of the network.

Our approach aims to balance operational efficiency, cost-effectiveness, and the delivery of reliable service to customers and results in the proposed proactive replacement of 33 per cent of the total meter population.

The primary reasons for adopting a proactive replacement strategy include the following:

- our aging meter population poses an increasing risk of reactive failure replacements
- the large-scale AMI roll-out necessitates a structured, proactive replacement approach
- enabling customers to benefit from increased data visibility, behind the meter energy management solutions and the next wave of energy efficiency initiatives that customers will leverage
- ensuring more stable and consistent meter charges is beneficial for customers.

We expand on these reasons below and in our attached metering business case.[53] In total, our proposed expenditure relating to our meter replacement program is shown below.

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[53] CP BUS 11.01 – Metering – Jan2025 – Public.

TABLE 11.2 TOTAL METERING INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Metering	22	109

While existing failure rates are low, there is a growing risk of an increase in reactive failure replacements

Our initial AMI roll-out population was completed in a concentrated four-year period, and these meters will all be reaching 17–21 years of age by 2031. At the time of installation, their expected service life was around 15 years (consistent with the expected life of the underlying componentry).

To date, the actual engineering life of these meters remains uncertain. These are the oldest and earliest forms of smart meters in service in Australia, and some of the oldest in the world.

The nature of these meters functionality and componentry is that they are less likely to fail due to metrology errors (i.e. being inaccurate) and more likely to fail due to an electronic component coming to end-of-life and taking out major functionality like onboard power-supply, communication, display, memory storage and time keeping. Electronic components age through ongoing use, exposure to excessive heat or cold, voltage spikes, moisture/corrosion and even insect infestation.

This means it is reasonably expected that our metering population begins failing soon, and that we need to manage this fleet to avoid a systemic failure of large volumes of aged meters. The risk of reactive failure replacement increases the longer proactive measures are delayed, and reactive failures tend to be significantly more costly and disruptive than planned proactive replacements.

A structured approach is prudent and efficient given the scale of the program

Given the substantial volume of the AMI roll-out population—our initial roll-out comprised over 300,000 meters—a proactive approach to meter replacement is both prudent and more efficient, and will minimise disruptions for customers. In contrast, reactive replacements (following a failure that leads to functional loss) will increase customer inconvenience, and incur delivery inefficiencies that drive up costs, ultimately burdening customers with higher bills.

We propose to commence our proactive meter replacement in 2026–27 and replace one third of the total meter population over the 2026–31 regulatory period. A 12-year proactive meter replacement program will reduce risks associated with wide-scale failures and expensive reactive replacements.

To deliver this program, we ran an expression of interest in 2024 and will tender for AMI meters in the first half of 2025. The expression of interest provided us with technology capability and indicative pricing based on both business-as-usual volumes and proactive replacement program volumes.

Current AMI meters are from a technology stack developed 20 years ago. It is important to ensure that whatever meter technology we decide to use is a robust technology that will serve our needs for the next 20 years, to avoid functional or technical obsolescence. In this context, we intend to use new AMI 2.0 meters that are distributed intelligence (DI) meters with a co-processor on the meter for real time data analytics on the meter, without interrupting the metrology processor and its energy data measurement and processing.

Our approach will smooth metering prices over time

Our proposed approach of spreading proactive replacements over 12 years will also have the advantage of avoiding volatile metering charges.

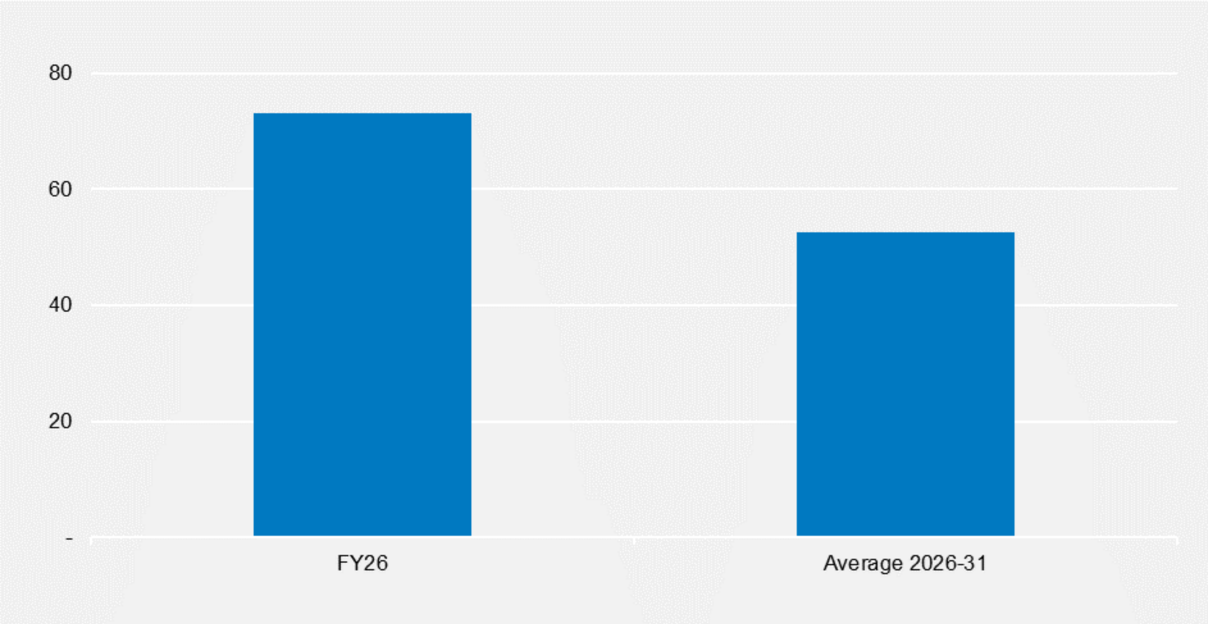
Our metering revenue forecast for the 2026–31 regulatory period is shown below. Notwithstanding the expenditure increase associated with a replacement roll-out, metering revenue will remain relatively stable due to the impact of lower depreciation (as existing meters become fully written down).

TABLE 11.3 TOTAL METERING REVENUE ($M, 2026)

DESCRIPTION	2021–26	2026–31
Metering	121	97

This revenue outcome will be reflected in the expected average charge for single-phase meters over the 2026–31 regulatory period, relative to the final year of the current regulatory period (as shown below).

FIGURE 11.1 SINGLE-PHASE METER CHARGE ($, 2026)



11.1.3 We address the impact of electrification and EV fast charging on our connections and additions profile

On 1 January 2024, new gas connections for new dwellings, apartment buildings, and residential subdivisions requiring planning permits were phased out. As a result, we expect to see a significant increase in the following:

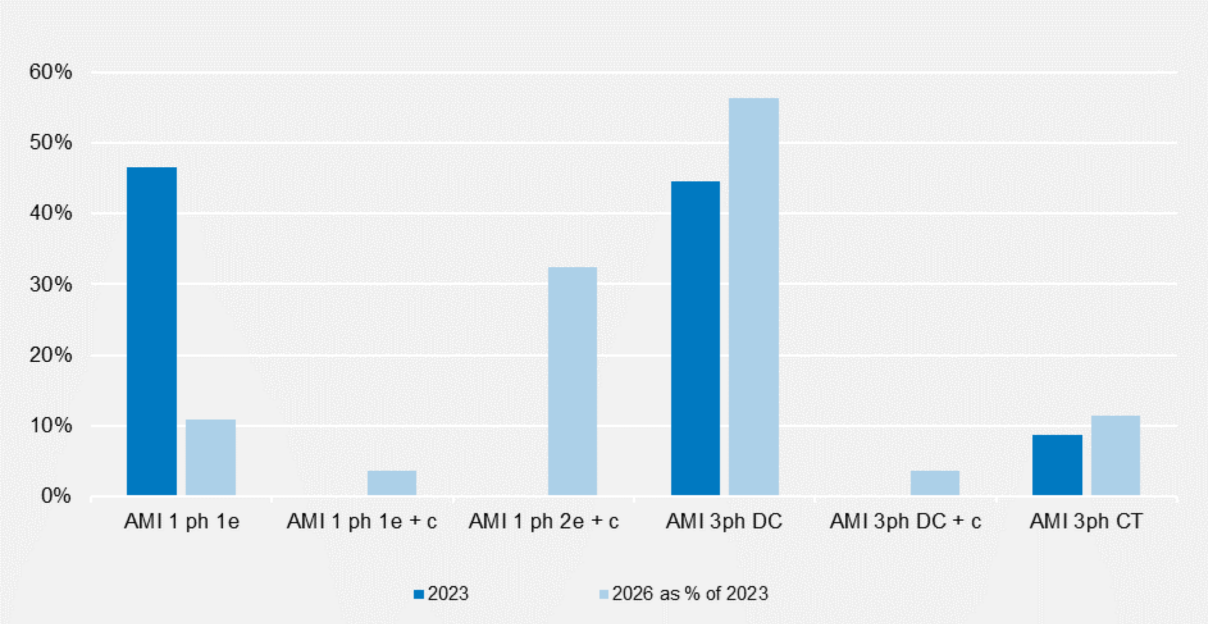
- single-phase two element connections due to heat pump electric hot water systems displacing existing gas hot water systems (under the Victorian Government subsidies)
- a move to three-phase new connections and requested upgrades due to both gas space heating being replaced by electric space heating, and uptake of EV fast charging.

Today, we are seeing growth in three-phase installations year-on-year and these are expected to continue to increase. Our forecast of new connections includes a substantial reduction in single-phase one element meter installations, and a corresponding increase in single-phase two element and three-phase meters.

The number of supply alterations and metering alterations are also forecast to increase as gas hot water and gas space heating customers move to electricity.

Our expectation is that demand for single-phase two element and three-phase meters will increase in the 2026–31 regulatory period as shown in figure 11.2.

FIGURE 11.2 NEW CONNECTIONS



11.2 Public lighting

We provide public lighting services to 9 local councils and the Department of Transport and Planning (DTP). The provision of public lighting services and the respective obligations of our business and public lighting customers are regulated by the Victorian Public Lighting Code.

There are approximately 53,000 public lights installed across our network. Of these, 33,000 (62 per cent) have been upgraded to Light Emitting Diodes (LEDs), providing improved energy efficiency and maintenance outcomes for our customers.

The cost of these services is charged to customers through an operation, maintenance, repair and replacement (OM&R) charge per light. All other public lighting services are treated as quoted services.

11.2.1 What we've heard and our proposed response

In July 2024, we conducted a structured stakeholder consultation session with representatives from local councils and the DTP. This session identified key topics for the public lighting sector in the 2026–31 period.

The following sections outline what we heard from local councils and the DTP in more detail, and our proposed response. Further details are provided in our public lighting attachment.[54]

Transition to LED public lighting

During our consultation process, councils supported the proactive replacement of non-LED residential lighting that will be banned in the next regulatory period.

Councils further indicated interest in the introduction of standard lanterns with a warmer colour temperature (2700k/3000k). We consider this as a future offering in our standard material list. We have already approved some non-standard lanterns with 2700k/3000k.

[54] CP ATT 11.01 – Public lighting – Jan2025 – Public.

In response to council feedback, and for the following reasons, we plan to convert all public lighting to LED over time to:

- meet Australia's commitments in the Minamata Convention in 2021 to eliminate the use of mercury vapour (MV) in lamps and more recently to also prohibit the use of compact fluorescent lamps (CFL) from the end of 2026 and T5 fluorescent lamps from end of 2027
- respond to customer expectations regarding energy cost savings
- support both Victorian and Commonwealth Governments' commitment to lower carbon emissions, through lower energy consumption
- provide further energy efficiency opportunities when combining LED lights with smart control devices.

There was also interest from some councils to proactively replace non-LED major road lighting. We acknowledge the outstanding efforts made by some councils in proactively replacing these lights, however, we wish to affirm that lantern replacements for non-banned light types will be undertaken upon reaching the end of their operational life.

Implementation of a central management system

We propose to introduce a basic central management system (CMS), together with the development of an agreed smart PE cell operation protocol, prior to the start of the 2026–31 regulatory period.

We propose to spread the operating cost of the CMS across all light types, incurring a minimal incremental charge on a per light basis.

Councils have shown support for a CMS to be established in order to enable dimming, constant light output and improve fault restoration.

LED lamps in decorative lanterns

We propose to continue retrofitting LED lamps to existing non-standard decorative lanterns.

This allows councils to navigate the discontinuation of mercury vapour and compact fluorescent lamps effectively and enables the continuation of the functional and aesthetic benefits of these fixtures while embracing modern, energy-efficient, and environmentally friendly lighting solutions.

Solar powered lights

Councils indicated interest in solar lighting as a potential OM&R service. We will continue to complete current trials to be in a position to include this service in our 2031–36 price period.

Transitioning legacy lighting schemes

We propose to give councils management and control of public lighting in non-trafficable parks, gardens and laneways to help ensure safety and access.

This decision stems from increasing challenges in accessing public lighting infrastructure in these areas. These difficulties are largely due to elevated service expectations imposed by park managers, typically the councils themselves.

Further, many larger councils have expressed support for this initiative, particularly if financial assistance is provided to facilitate the transition.

Additionally, the growing use of laneways as active spaces, featuring awnings, tables, chairs, and bollards, has further restricted access for maintenance and service activities.

We appreciate the challenges to transition existing lighting back to councils located in parks, gardens, walkways and laneways. We are hopeful that council's undertaking capital works can potentially assist in this transition.

11.2.2 Tariff changes

Our prices for public lighting services are regulated by the AER separately from our distribution network tariffs. However, our network operations facilitate the provision of these services, affording us the opportunity to leverage economies of scale in the planning, delivery and administration.

Our current public lighting tariffs are developed to reflect the type of technology in use (LED or conventional) and road type (major or minor).

This approach ensures charges are consistent and stable over time and easy to understand.

When the impact of reduced energy consumption is considered, we expect the transition to LED lighting will ultimately reduce the overall cost of public lighting for councils and the DTP.

We propose to apply the same weighted average price increase across all light types.

We are forecasting moderate real price increases mainly driven by:

- dedicated public lighting poles are reaching end of serviceable life that will require replacement or staking resulting in increased capital spending
- replacement of non-LED lights with LED lights will continue to reduce OM&R spending
- increases in the regulated rate of return.

11.3 Re-classification or modification of existing services

11.3.1 Connection application fee

We currently charge customers who submit a negotiated connection application an upfront fee to cover the average administration and high-level design costs for similar connections.

The main purpose of this fee is to recover administration and high-level design costs from those connection applications who ultimately don't accept their connection offer, to ensure that these costs are not paid by other customers.

The application fee is charged as an ACS quoted specification and design enquiry service which was approved by the AER in our 2021–26 final determination. Our connection application fees were reviewed by the AER in 2024 and there was a view that the fees more closely resemble an ACS fixed fee service.

> We propose to re-classify connection application fees as an ACS fixed-fee service.

11.3.2 Reserve feeder maintenance

Reserve feeder maintenance costs are currently classified as an ACS quoted service.

The administrative cost of calculating a reserve feeder maintenance charge for each reserve feeder, every year, does not justify the small amount of revenue that is collected from this charge.

Furthermore, the charge is more readily calculated as an average per kVA cost at each voltage level.

> We propose to re-classify reserve feeder charges as an ACS fixed-fee service with fixed fees per kVA of reserve feeder capacity approved by the AER.

11.3.3 Provision of data

The AER's framework and approach paper:

- classifies the provision of basic network data, such as visibility maps and data portals, as a standard control service
- classifies the provision of data beyond basic data as an ACS and therefore the cost would be recovered from the party requesting the data

We already have an approved ACS service ‘access to network data – cumbersome requests’ the description of which will be modified to ‘customer and third-party requests for the provision of electricity network data, or consumption data outside legislative obligations, or requests for assistance to understand or interpret data, or to identify the data they require to meet their needs’.

11.4 New services

11.4.1 Enhanced connection service

The AER's framework and approach paper approved a new enhanced connection service which would provide a requesting customer with greater network capacity than they would otherwise be eligible for.

We propose to introduce a new alternative control service: management of export and load at a customer site that provides the customer greater network capacity than they would otherwise be eligible for.

11.4.2 Reversion of embedded networks

The Victorian Government has clamped down on new residential apartment embedded networks and is considering a new licencing regime for embedded networks. We anticipate an increase in the number of embedded networks reverting to no longer being an embedded network. Our basic connection charge will recover the cost of assigning NMIs and installing meters for individual units. However, we will also incur other costs such as for project management, communication, inspection of wiring and meter boards, and abolishment of meters.

We propose a new ACS quoted service ‘reversion of embedded networks’ to cover network costs which are not covered by the basic connection service.

11.4.3 Embedded generator control equipment

We need to install control equipment at embedded generation sites to enable compliance with the Victorian Government mandatory Essential System Service.

We propose a new ACS quoted service 'embedded generator control equipment' to cover the installation of control equipment at embedded generation sites to enable compliance with the Victorian Government mandatory Essential System Service.

11.4.4 Bulk conversion to 5-minute meter data

A retailer could request us to bulk convert all meters to 5-minute data. While a meter reconfiguration fee can cover a single meter request, there is no appropriate charge for a bulk request.

We propose a new ACS quoted service for requests for bulk conversion to 5-minute meter data.

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