Powercor

Regulatory proposal 2026–31

Part B: explanatory statement

Revenue and expenditure forecasts

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Acknowledgement of Country

Powercor 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.

Powercor 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

Our Powercor network delivers electricity to a 145,000km^2 area, stretching from the western suburbs of Melbourne, through central and western Victoria to the South Australian and New South Wales borders.

We are the largest electricity distributor in Victoria, with households representing approximately 87 per cent of our 930,000 customers. More than 540,000 of these customers live and work in rural areas.

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

- we are the most reliable rural distribution network in Australia, and in the face of extreme weather, have outperformed our peers in restoring supply as quickly and safely as possible
- our customers face the lowest network charges of any rural distributor in Australia
- our network utilisation is greater than any other network, and around 25 percentage points above the National Electricity Market average.

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, along with resilience expectations as 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, bushfire mitigation 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 energy storage systems (BESS).

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.

In total, our investments will result in a nominal average annual estimated distribution bill increase of just $3 for residential customers, with a corresponding $1 average yearly 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 almost 600,000 video views across social media, and an estimated total audience of nearly 1.5 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 moving faster to improve service level outcomes for regional and rural customers (as outlined above) and investing further in our vulnerable customer package.

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, remain modest and consistent with our draft proposal.

[1] PAL 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	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
Regional and rural summit: Identify priorities and preferences for rural and regional communities	✓	✓	✓	✓		✓	✓	✓			
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	✓	✓			✓	✓		✓			✓
Community resilience workshops: Understand customer lived experiences during extreme weather, and challenge our proposed resilience solutions				✓		✓	✓	✓			
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	Resilience	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	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Regional and rural summit: Understand support for key initiatives included in our proposal, and broader issues customers felt weren't being addressed	✓	✓		✓				✓				
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	✓								✓			✓
Committee for Greater Shepparton engagement: Seek feedback on approach to maintain power quality, reliability and changes to tariff structures for commercial and industrial customers	✓	✓	✓					✓				✓

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

Our investment governance framework—which to date has delivered our customers amongst the lowest network charges in the National Electricity Market (NEM), while maintaining strong performance in safety and reliability—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 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 $560 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 further 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.

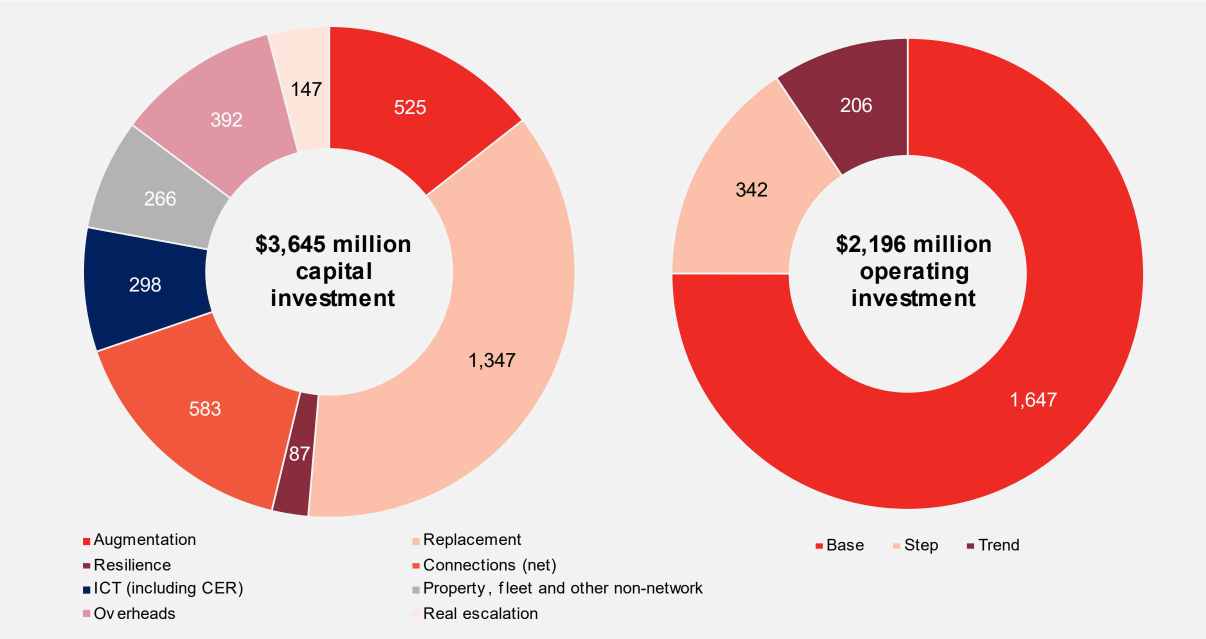
1.2.1 Our expenditure forecasts

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.

2 Our investment governance framework is set out in the attached: PAL RIN 30 - Governance, forecasting and deliverability overview - Jan2025 – Public.

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 exceed the AER's allowance (and will further exceed this allowance after one-off asset disposals are excluded). This is driven 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 that included in the AER's allowance. Our augmentation spend, however, was lower due to efficient management of consumer energy resources (CER), 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.

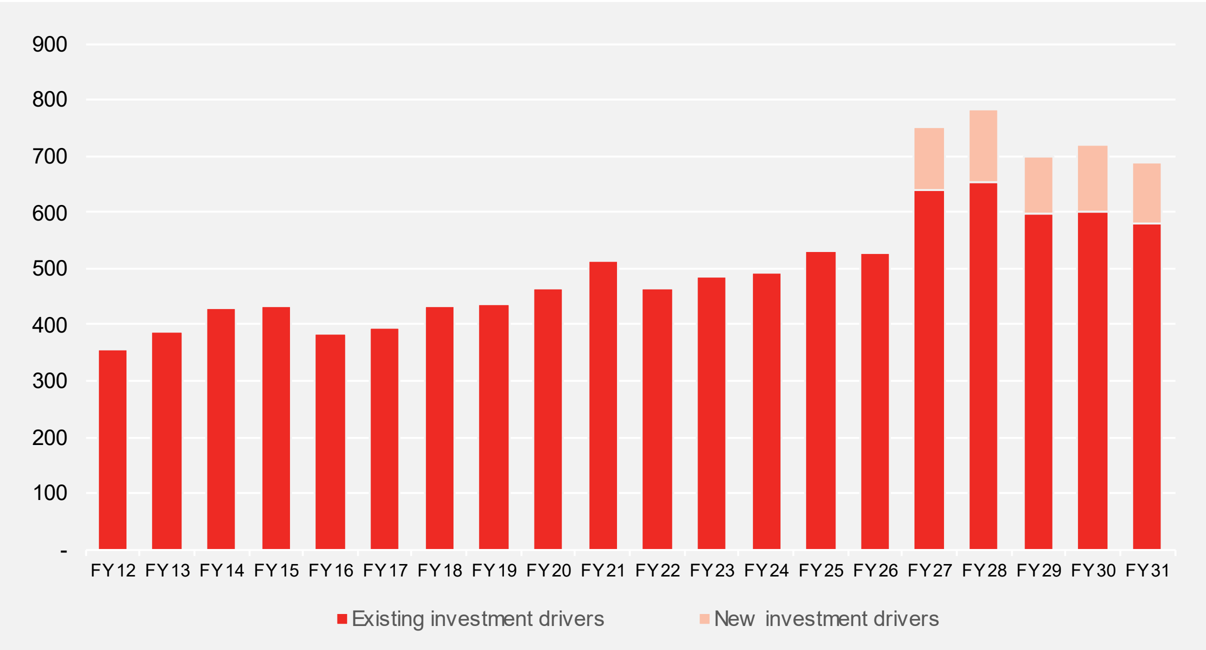
The drivers of our capital expenditure uplift for the 2026–31 regulatory period are discussed in detail further in this document. At a high level, these drivers include the following:

- we are one of the fastest growing and most highly utilised distribution networks in Australia, meaning the electrification of transport and gas, customer growth and CER integration are driving increasing augmentation. As recently as December 2024, our network surpassed its previous highest peak demand, and in total, we expect peak demand across our network in 2031 will be 29 per cent higher than it is today
- our network is located in some of the most bushfire prone areas in the world, with investment required to maintain compliance with legislated bushfire risk mitigation obligations
- asset replacement forecasts are increasing to manage our aging distribution assets, including observed condition and defect trends, and growing risk in our existing zone substation assets
- new investments are required to strengthen our network and communities against increasing frequency and severity of extreme weather. Our resilience proposal implements the recommendations of two separate reviews undertaken by the Victorian Government

- our information and communications technology (ICT) portfolio includes upgrades to our cyber-security systems, replacement of our enterprise resource planning (ERP) and billing system, CER integration, and additional regulatory compliance associated with post-2025 NEM market reforms
- continuation of our depot modernisation program, with upgrades at our Geelong depot to maintain customer response times and support our increasing works program. We also need to re-develop 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 historical investment 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, resilience, customer-driven electrification and additional risk-based programs.

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), network and community resilience, 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 25 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	378	419	464	508	560
Regulatory depreciation	152	166	186	204	219
Operating expenditure	384	438	494	526	550
Revenue adjustments	-26	-42	-20	-14	-19
Corporate income tax	-	-	-	-	-
Unsmoothed revenue requirement	887	981	1,124	1,224	1,310
Revenue X factor (%)	**-10.5%**	**-1.0%**	**-1.0%**	**-4.0%**	**-4.0%**

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. This is supported by recent research from the Australian Energy Market Commission (AEMC), Energy Consumers Australia (ECA) and other independent third parties, who 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 are modest, and at the same time, our customers will receive an offsetting reduction in nominal meter charges.

3 PAL ATT 1.01 – SCS revenue and control mechanism – Jan2025 – Public.
4 PAL ATT SE.30 – CAP – Report on Draft Proposal – Nov2024 – Public.

TABLE 1.2 NOMINAL AVERAGE ESTIMATED BILL IMPACT

CUSTOMER TYPE	DISTRIBUTION CHARGES(1)	METERING CHARGES(2)
Residential	+$3.21	-$1.04
Small business	+$7.75	-$1.04

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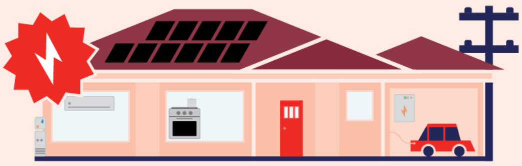
[5] Australian Energy Market Commission, Residential electricity price trends, 2024, p. 32.

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**

NEW

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

- **90% 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
- Enable **regional and rural customers** to benefit from electrification

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, EVs and electrification of gas, we sought preferences on service levels and investment options to better identify customer value propositions.

Participants supported equitable solar export outcomes and a measured approach to EV charging enablement. Participants also 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 costs and service levels for different initiatives. Customers at these forums supported investments to enable more solar export, improve stability of EV integration and support outcomes for regional and rural customers.

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

6 PAL 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 placed a significant emphasis on fairness and equity for solar exports and called for a holistic approach that reaches beyond the immediate five-year regulatory period.

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.

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, range anxiety and availability of charging infrastructure in rural areas are also 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 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 problems related to interruptions, harmonics, power factor, voltage sags and surges.

Power disturbances, even if momentary, were reported to have material implications for commercial and industrial customers including substantial disruptions to production, loss of inventory, delays with cleaning and sterilising, and revenue loss. Power quality is seen as an 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.

Regional and rural customers

Regional and rural customers believed that their communities would continually lag in customer experience relative to urban customers on reliability, solar exports, access to capacity and power quality. This was viewed as alarming in an electrified future, where customers feared for their communities' ability to participate in the energy transition.

Our regional and rural customers identified that improvements to capacity, reliability and bridging the gap between urban customers were their highest priorities. 74 per cent of Powercor customers supported investment to enhance service levels for regional and rural customers.

Communities questioned whether our electricity network could meet their future electricity supply needs in an electrified future. For many customers, the participation of regional and rural communities in an electrified future was nothing more than a 'pipe dream'.

Stakeholders almost universally recognised the need to shift planning beyond the immediate regulatory period to achieve lasting and sustainable change.

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:

- 50 per cent of small and medium business customers and 60 per cent of residential customers were unfamiliar with the concept of time-of-use tariffs

- 55 per cent of small and medium business customers and 74 per cent of residential customers felt that lowering energy bills was the biggest motivator to shift energy usage to off-peak times
- 81 per cent of customers supported bill increases to enable more solar exports for all customers
- 73 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
- just 16 per cent of small and medium business customers and 19 per cent of residential customers felt that our proposed bill impacts did not represent value for the service that they received.

Customers also contributed their views on our programs related to CER integration, electrification regional and rural investments. 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 35 per cent, and peak demand by 29 per cent by the end of our 2026–31 regulatory period.

As recently as December 2024, our network almost surpassed its previous highest peak demand (set in 2014). This near-peak event occurred far earlier in the summer season than previously experienced, and in the same month we also saw new record minimum demands (with our network acting as a net exporter of over 300MW in the middle of the day). These patterns of extremes are expected to grow with the increasing electrification of our customers' homes and businesses.

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.

Historically, this renewable generation has connected to the transmission network. However, over 2.7GW of renewables are connected directly to our distribution network, and this is expected to grow. There is also growing development activity in large scale BESS.

Much of this renewable generation is provided by solar PV, with rooftop systems installed by over 26 per cent of our residential customers. The capacity of this rooftop solar connected to our network has doubled in the last five years alone, and is forecast to double again 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 23 per cent of our customers expected to have an EV by 2031. This is more than 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.

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. This includes high population growth corridors in the west of Melbourne, greater Geelong and the Surf Coast.

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 280,000 people.

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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.

8 Victorian Government, Gas Substitution Roadmap, 2022.

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.

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 Ocean Grove complained to us that their EV was not being charged overnight when they expected it to be. They found that their car was not charged when they wanted to go to work in the morning, impacting their ability to get to work.

The customer was notified via their phone application that their charging was interrupted early in its charging cycle. Undervoltage was found to be the cause of the issue, requiring network upgrades to remediate.

> *"…the interruption occurred multiple time in the night, sometimes I didn't realise until I was ready to* ***go to work the next day*** *in Melbourne* ***and the car didn't have enough charge****."*

Quote from customer in Ocean Grove, 9 August 2023

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 such hydrogen production. 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: Powercor Tariff Structure Statement 2026—31 – Expanatory 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 $2M OPEX $3M

Note: For further detail, refer to our attached business case: PAL 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 an assessment and 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 development of market maturity. Notwithstanding this, we expect to defer $1.5m 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. However, stakeholders raised concerns that the market would prioritise lucrative urban areas over lower density regional communities.	CAPEX $3M OPEX $4M

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

Flexible exports

The capacity of rooftop solar is forecast to double 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, 5 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.

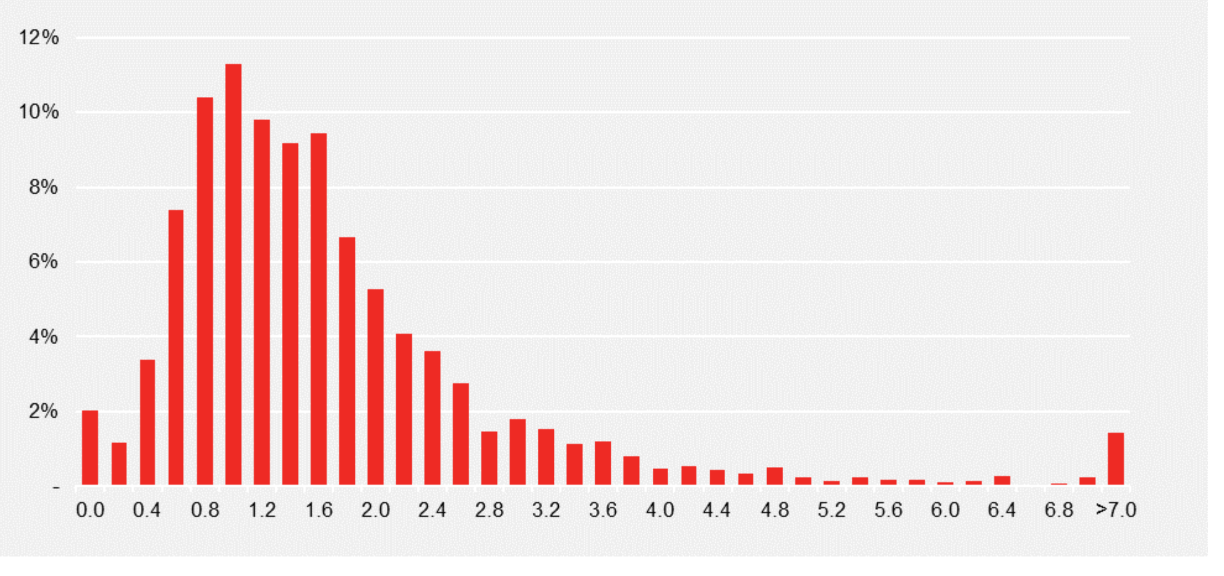
Intrinsic hosting capacity assessment

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 1.4 kW per customer. This means that half of our network can support solar exports of 1.4 kW per customer and the other half would be constrained.

Our network's total intrinsic hosting capacity to support small-scale solar is 1,350 MW. Our customers have already connected 1,300 MW of small scale solar, indicating that 96 per cent of our total network-wide intrinsic hosting capacity has already been utilised.

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 528GWh of export for customers over 2026–31, equivalent to the total annual generation of 88,000 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. 81 per cent of customers at our trade-off forum supported bill increases of $1.74 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 $18M OPEX $21M

Note: For further detail, refer to our attached business case: PAL 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 $3M

Note: For further detail, refer to our attached business case: PAL 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 and our regional and rural upgrades.

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
90 per cent of customers can freely export 99 per cent of the time	• 90 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 10 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
Enable regional and rural customers to benefit from electrification	• Deliver more capacity and improve voltage performance, supporting regional and rural electrification and generate more value from the energy transition • Future-proof aging infrastructure with least-regrets investment, consistent with customer feedback to not leave regional and rural customers behind

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 managing bushfire risk, 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:

- 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
- deferred augmentation works around the Tarneit supply area due to land and environmental issues and subsequent re-scoping
- delays at our Ballarat East zone substation to facilitate more community consultation
- general impacts associated with the pandemic, including the significant demand uncertainty and supply chain disruptions that impacted project timelines.

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 facilitate growing demand across our network (including Melbourne's western growth corridor), enable customer electrification of gas and transport, improve regional and rural equity, minimise bushfire risks and maintain system security.

Since our draft proposal, our augmentation forecasts have increased, primarily driven by increases in our regional and rural equity programs for worst served customers and customers supplied by low-capacity single wire earth return (SWER) lines.[10] Reductions in our customer electrification program have offset some of the overall increase.

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

TABLE 3.1 TOTAL AUGMENTATION INVESTMENT ($M, 2026)

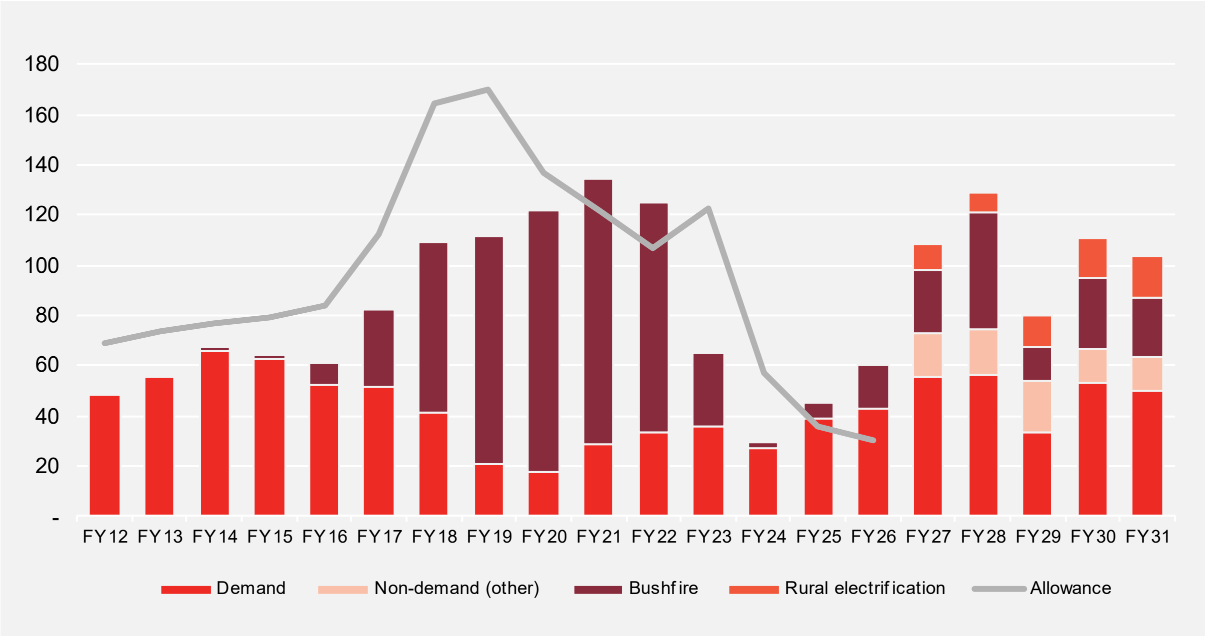
DESCRIPTION	2021–26	2026–31
Augmentation	337	526

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 as required through the development of our revised regulatory proposal.

10 Investments to support worst-served customers, including feeder-ties and stand-alone power systems were included in our resilience category in our draft 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, electrification rates, and regional and rural customer expectations.

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, improve power quality and deliver outcomes for regional and rural customers.

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.[11]
	Customers generally view EVs favourably, recognising their potential to support rapid decarbonisation. However, concern remained about reliability, equity, range anxiety and availability of charging infrastructure
	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

[11] This was both an output from customer engagement and observed on-the-ground via our Monash University Future Home Demand report.

Regional and rural customers believed that their communities would continually lag in customer experience relative to urban customers on reliability, access to capacity and power quality. This was viewed as alarming in an electrified future, where customers feared for their communities' ability to participate in the energy transition

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.[12] There was broad agreement between customers that additional investment is necessary to maintain reliability of supply as the energy transition accelerates. Customers emphasised the benefits of ensuring the sustainability of solutions, while avoiding temporary fixes.

Energy equity also emerged as a central theme during an October 2024 Regional and Rural Summit that we hosted in partnership with Farmers for Climate Action. Customers in attendance emphasised that we have not been ambitious enough to materially address the needs of their communities. They expressed frustration at perceived growing inequity of service outcomes between urban and regional customers. We sought customer views on our proposed $45m investment to upgrade sections of our SWER network to three phase power lines. There was strong support for SWER upgrades with an overarching view that $45m was insufficient.

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 within their businesses and communities, 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 such as the Western growth corridor expansion 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 support the delivery of service level outcomes that our customers have identified as valuable to them.

The expansion of our network through Melbourne's western growth corridor will support new urban development footprints, and our customer electrification program will facilitate more electrification of gas and transport and improve power quality for our customers.

We are also addressing regional and rural equity through an increase in SWER upgrades from what was considered in our draft proposal and installing alternative sources or pathways for supply, such as stand-alone power systems, in some of our worst-served and least resilient regions.

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

These investments will contribute to our delivery of a dependable and reliable energy supply that supports work, health, safety and comfort for our customers while keeping cost impacts down as Australia's most highly utilised distribution network.

3.2.1 Demand-driven augmentation program

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

As outlined previously, in December 2024, our network almost surpassed its previous highest peak demand (set in 2014). This near-peak event occurred far earlier in the summer season than previously experienced, and in the same month we also saw new record minimum demands (with our network acting as a net exporter of over 300MW in the middle of the day). These patterns of extremes are expected to grow with the increasing electrification of our customers' homes and businesses

Consistent with this, we expect that peak demand across our network in 2031 will be 29 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.

Peak demand growth is also driven by increasing population. We operate Australia's fastest growing distribution network, with population in our network area expected to grow by 14 per cent to 2031.

This growth will be particularly impactful on our network because we have the highest network utilisation in Australia (around 27 percentage points above the NEM average), with limited spare capacity to absorb future demand.

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

GREATER WESTERN MELBOURNE SUPPLY AREA	COST
The western suburbs of Melbourne are among the fastest growing regions in Australia, with demand supplied by the Altona West and Deer Park terminal stations increasing by 335MVA since 2017. Our demand forecasts indicate multiple large constraints in this growth corridor by 2031, following recent near-peak events. To meet this demand, we have considered the capacity needs of the broader area as part of a holistic planning assessment. Based on this broader assessment, we are proposing a third transformer at our Mount Cottrell zone substation, rebuilding our Bacchus Marsh zone substation and establishing a new Rockbank East zone substation. A new zone substation at Point Cook is also likely required in the 2026–31 regulatory period and was assessed as economic in our cost-benefit modelling. However, given the sensitivity of optimal project delivery timing and the scale of works being undertaken in the western growth corridor, we are proposing a contingent project for this site based on demand surpassing a relevant threshold. Further information on the trigger for our Point Cook contingent project is available in our managing uncertainty chapter.	$90M

Note: For further detail, refer to our attached business case: PAL BUS 3.07 – Greater western Melbourne 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.	$14M

Note: For further detail, refer to our attached business cases: PAL BUS 3.04 – Northern feeder thermal augmentation program – Jan2025 – Public and PAL BUS 3.05 – Metro 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.[13]

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 interventions 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.

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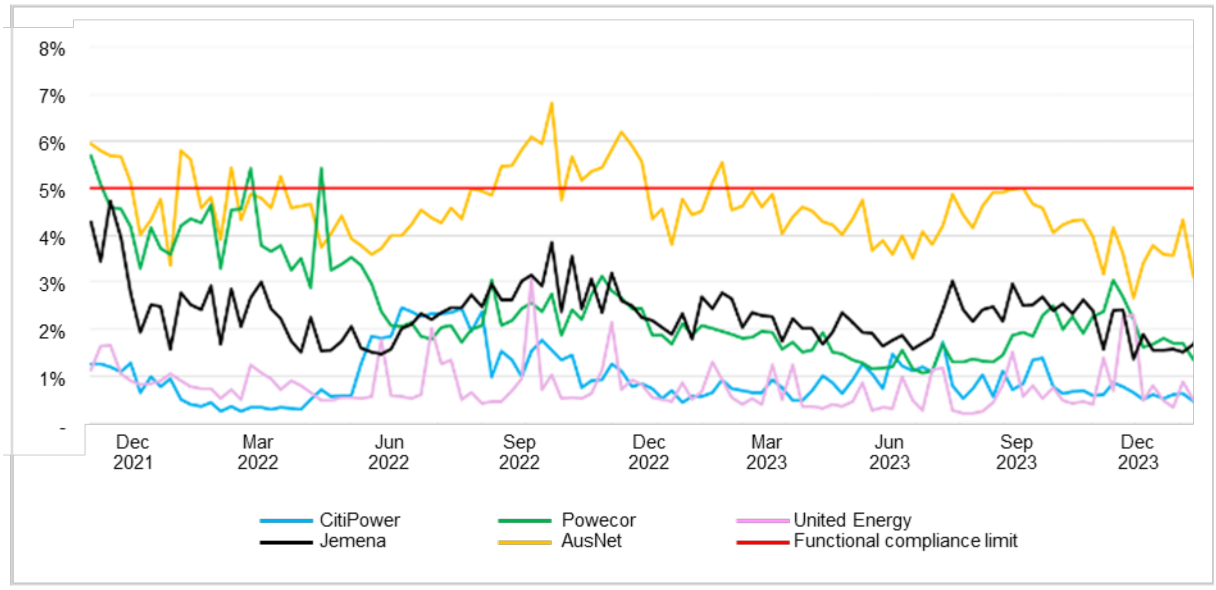
13 The Electricity Distribution Code of Practice is a jurisdictional instrument administered by the Essential Services Commission that regulates our activities to ensure they are undertaken in a safe, efficient and reliable manner. See, for example, Essential Services Commission, Electricity Distribution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

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.[14]

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.

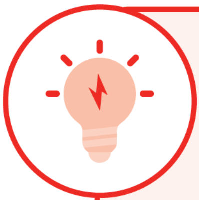
[14] Essential Services Commission, Electricity Distribution Code of Practice, May 2023, clause 15.2.1.

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 maintain service levels (consistent with option two). 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 mostly proactive approach that maintains existing voltage performance levels. This program will ensure that an additional 18,000 non-compliant customers will improve their power quality to receive compliant voltage levels and enable over 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, 30 per cent of customers supported $80m of investment (with residential bill impacts of $0.97 p.a) and an additional 43 per cent supported $120m of investment (with residential bill impacts of $1.46 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.	$97M

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

FIGURE 3.3 OPTIONS TO ADDRESS CUSTOMER ELECTRIFICATION

FIGURE 3.4 OPTIMISED AUGMENTATION SOLUTIONS

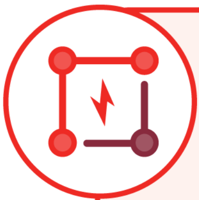


Identifying where single HV solutions can remove multiple LV constraints

- 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 Regional and rural equity

Today, our regional and rural customers incur on average four times more minutes off supply than our urban customers. They are also between two to three times more likely to receive a zero-export limit for new solar connections.

As part of our stakeholder engagement program, we have sought to better understand what our customer expectations of us were in an electrified future. This included a focus on our regional and rural customers—who represent over 60 per cent of our customer base—with two regional and rural summits held in Creswick (2023) and Bendigo (2024).

Through this engagement, our customers expressed concern about the inequity gap between the service levels of urban and regional and rural customers. While our customers and stakeholders understand that parity in service levels is not realistic, they have repeatedly highlighted that without action, the gap in service levels will continue to widen.

Customers also emphasised that a more equitable investment approach was needed, pointing out that while regional and rural areas bear the burden of hosting significant renewable energy generation, there was no plan or cohesive strategy to support regional and rural customers to achieve net-zero emissions.

Recognising the long-term and systemic nature of this problem, regional and rural customers urged us to shift our planning beyond the immediate regulatory period.

In response, we developed a regional and rural roadmap.[15] The roadmap identifies a series of long-term strategies and short-term recommendations to improve regional and rural outcomes. Solutions such as single wire earth return (SWER) to three-phase upgrades, renewable technology integration, stand-alone power systems and large-scale distribution renewable energy zone planning are recommended.

Our investment programs, described below, seek to holistically address the long-term needs of our customers in an electrified future, considering the findings from our regional and rural roadmap and positioning our networks to support the achievement of Government's electrification policy objectives.

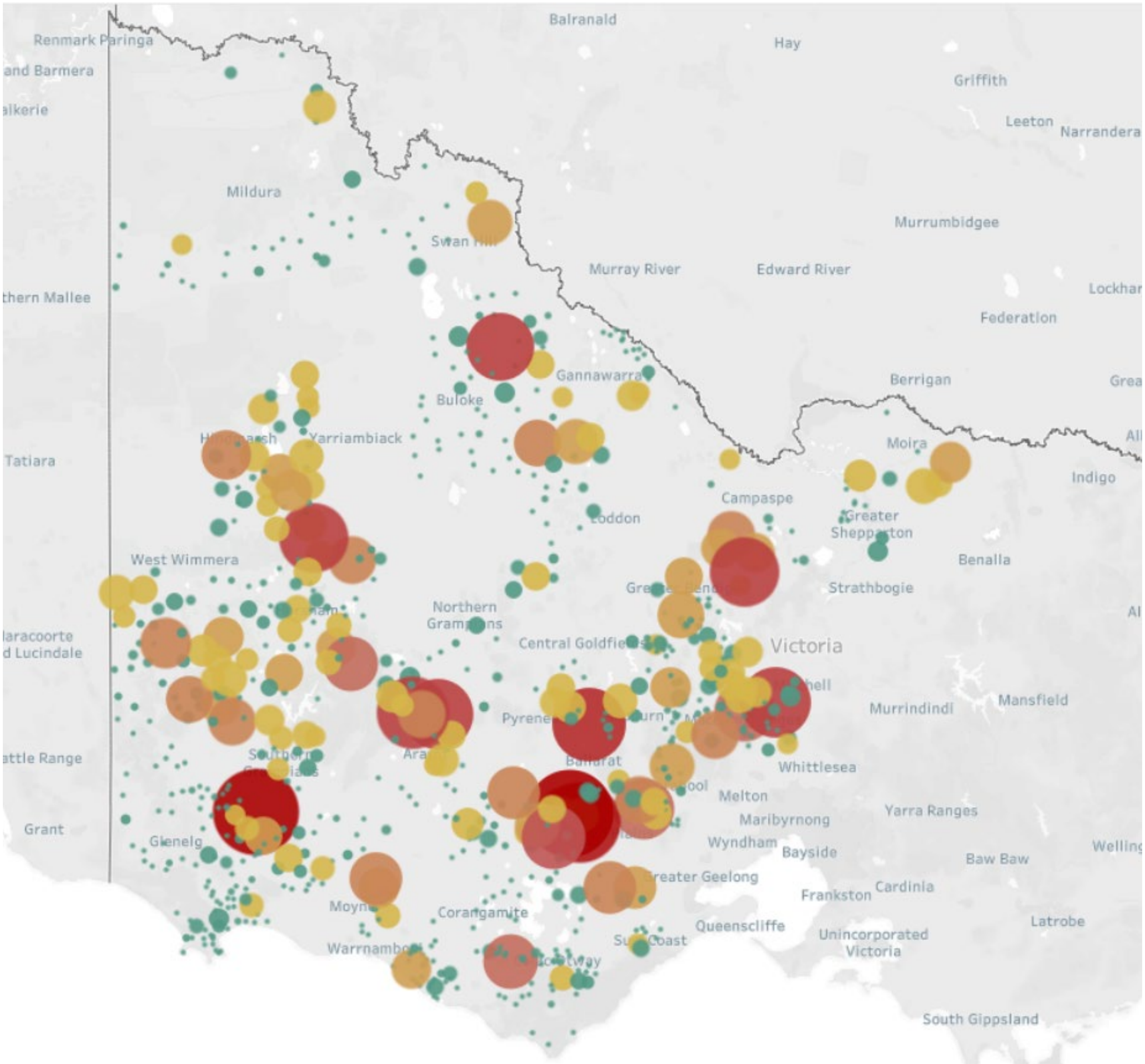
The Victorian Government, in collaboration with the Federal Government, is also conducting a review into the opportunities presented by regional and rural electrification, and the barriers to achieving electrification policy objectives. We will consider the findings from this review once publicly available.

[15] IAEngg, Powercor and AusNet Services, Regional and Rural Network Roadmap, 2024.

REGIONAL AND RURAL SWER UPGRADES	COST
Our network comprises over 21,300 km of SWER lines, with most of these lines between 55 and 70 years old. Given the ageing state of our SWER network, and the growing electrification needs of our communities, we used our time-series network forecasting tools to identify SWER networks that would benefit the most from investment, considering voltage and capacity constraints, reduced bushfire risk and the avoidance of future SWER replacements. At our trade-off forums, 74 per cent of all customers supported either a $50m program (with residential bill impacts of $0.61 per annum) or a larger $70m program (with residential bill impacts of $0.85 per annum) to improve regional and rural customer outcomes. Our draft proposal, however, only included $45m to upgrade SWER to three-phase supply. Customers at our Bendigo regional and rural summit, held in October 2024, suggested this investment program was not sufficient or ambitious enough to materially address the needs of the region. The CAP raised similar questions in its report on our draft proposal. *“The $45m investment is a drop in the ocean. It’s not enough to make a real impact”* **Powercor customer, Regional and Rural Summit** Importantly, Powercor customers (including urban customers) at our test and validate roundtables confirmed these findings. Customers cited strong support for upgrading SWER lines, identified agriculture regions as most at-risk and shared that insufficient power infrastructure was harming local business competitiveness and the ability for farmers to feed the nation. Given the strength of customer and stakeholder feedback on our draft SWER upgrade program, we have increased our proposed investment. We now propose to upgrade 600kms of SWER lines to three-phase, benefiting more than 1,300 regional and rural customers. The key areas that would benefit the most from this investment are shown in figure 3.5, and include south-west of Ballarat, Woodend, Ararat and north of Horsham, with other geographically diverse sites across our network. We have also considered the inter-relationship of this program with other augmentation and replacement works, and removed overlaps.	$63M

Note: For further detail, refer to our attached business case: PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public.

FIGURE 3.5 ENERGY AT RISK ON OUR REGIONAL AND RURAL SWER LINES



Note: Energy at risk is shown by the colour and size of the underlying bubble. Darker red shades and larger bubbles indicate higher energy at risk.

Our proposed regional and rural equity program also includes targeted investments for some of the worst served segments of our network. Customers throughout our engagement program expressed a strong desire to provide equal access to reliable energy for all customers, noting that reliable energy is crucial for safety and communication particularly in remote areas.

In recognition of this feedback, we identified 28 broad areas across our network that have experienced relatively poorer service levels—specifically, 700 minutes off supply and eight or more outages per annum. We considered potential solutions for each of these areas that would lead to targeted improvements in reliability, and assessed each for technical and commercial viability.

Figure 3.6 below summarises the outcomes of our analysis, with proposed investments set out thereafter (noting we are not seeking to intervene at all of these locations).

FIGURE 3.6 POTENTIAL INFRASTRUCTURE SOLUTIONS IN OUR WORST SERVED AREAS

FEEDER	# CUSTOMERS	AREAS - TOWNS	FIXED RESILIENCE/RELIABILITY INFRASTRUCTURE: UNDER-GROUNDING	HIGH VOLTAGE TIES	MICROGRID - BATTERY	MICROGRID - DIESEL
BAN003	4,008	Bungal, Gordon & Mt Egerton areas	✓	✔	✗	✗
WND024	1,039	Trentham town	✓	✔	✓	✓
BAN008	3,306	Daylesford, Hepburn towns	✓	✗	✓	✓
CLC003	2,036	Gellibrand, Beech Forest, Lavers Hill, Horden Value, Glenaire & Johanna areas	✓	✗	✗	✗
WND013	747	Pyalong town and area	✓	✗	✓	✓
GSB014	670	Mt Macedon area	✓	✗	✗	✗
BAS022	418	Elaine area	✓	✓	✗	✗
GHP011	203	Meredith town	✓	✓	✓	✓
CLC006 & BAS022	351	Rokewood, Dereel & Corindhap areas	✓	✔	✗	✗
BET005	341	Lake Eppalock area	✓	✗	✗	✗
CDN002	328	Carpendiet, Pomberneit & Stoneyford	✓	✓	✗	✗
WND012	322	Kerrie, Romsey	✓	✗	✗	✗
TRG024 & WBL012	489	Peterborough and Nirranda South area	✓	✔	✗	✗
CHM011	285	Apsley, Bringalbert, Langkoop & Poolajelo	✓	✗	✗	✗
GSB011	267	Bullengarook area	✓	✗	✗	✗
BAS011	262	Ballyrogan, Buangor, Burrumbeet, Beaufort, Stockyard Hill & Stoneleigh	✓	✗	✗	✗
FNS022	260	Little River area	✓	✗	✗	✗
STL005	251	Halls Gap township	✓	✗	✓	✓
CDN001	221	Chapple Vale, Cooriemungle, Simpson	✓	✗	✗	✗
CLC013	215	Wye River township	✓	✗	✓	✓
DDL012	214	Point Lonsdale	✓	✗	✗	✗
WPD022	186	Breamlea	✓	✗	✗	✗
BAN009	181	Ullina, Newlyn & Newlyn North areas	✓	✗	✗	✗
ART033	175	Carramballac, Langi Logan, Mafeking and Willaura areas	✓	✗	✗	✗
GHP022	173	Anakie	✓	✗	✗	✗

✔ Technically and commercially viable ✓ Technically viable but commercially not viable ✗ Technically and commercially not viable

ALTERNATIVE SUPPLY: SAPS AND FEEDER TIES	COST
We are proposing to install alternative sources or pathways for supply in some of our worst-served and least resilient regions. An alternative supply source can facilitate continued electricity supply in the event of an outage on one of our existing feeders where previously customers would have been off supply. Specifically, we are proposing to invest in: • four additional feeder-ties to improve supply for worst-served regions, including for communities around Gordon, Trentham, Rokewood and Peterborough. A feeder-tie links two individual feeders, allowing for supply to flow in the event one of the feeders experiences an outage • a limited number of stand-alone power systems for individual customers exposed to outages. Customers at the end of long lines are often exposed to a greater risk of outage, and a stand-alone power system can operate independently of the main grid, ensuring continued supply in the event of an outage.	$18M

Note: For further detail, refer to our attached business case: PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public.

3.2.4 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 bushfire mitigation, improving under-frequency load shedding and upgrading communications infrastructure.

Minimising bushfire risk

Victoria is one of the most bushfire prone areas in the world, with recent examples including the February 2024 and December 2024 bushfires in western Victoria.

Bushfires can be started by various causes, including faults on electricity overhead networks. We have a regulatory obligation to minimise as far as practicable (AFAP) the bushfire risk arising from our network assets.

Our customers view safety, including minimising bushfire risks, as non-negotiable. Our recent research on customer valuation of service level improvements found a willingness to pay of $11 for residential customers and $48 for business customers per annum for bushfire risk mitigation. Monash University's Future Home Demand report also found that safety ranked highest among seven household values that included sustainability, affordability and convenience.

Our bushfire mitigation program meets our compliance obligations regarding rapid earth fault current limiters (REFCLs), and seeks to further improve customer safety by minimising bushfire risk as far as practicable.[16]

We have enhanced our understanding of bushfire risk and consequence through sophisticated quantitative models based on leading Commonwealth Scientific and Industrial Research Organisation (CSIRO) research. This facilitated the identification of suitable controls to improve customer safety, with the effectiveness of these controls challenged through an independent validation process.

16 The bushfire mitigation program includes non-demand augmentation and asset replacement projects.

Further details on our assessment process and proposed investments are set out in our attached bushfire mitigation overview.[17]

MAINTAINING REFCL COMPLIANCE	COST
Following the Black Saturday bushfires in 2009, the Victorian Government mandated that distributors install REFCL technology at specific zone substations to reduce the risk of power equipment igniting a fire. We completed the initial roll-out of this program in 2023. We are also obligated to maintain compliance with strict REFCL performance standards at these zone substations. These performance standards are influenced by demand growth and in particular the increasing amount of underground network within the REFCL operational area. The continually changing nature of our network, including due to underground residential developments, has driven ongoing REFCL compliance works in the current regulatory period, and will continue throughout 2026–31. Our compliance program also includes the continuation of works to upgrade remote-controlled switches and sectionalisers on REFCL-protected feeders to restore their ability to operate with our existing automation schemes.	$95M

Note: For further detail, refer to our attached business case: PAL BUS 3.11 – Bushfire mitigation forecast overview – Jan2025 – Public.

MANAGING BUSHFIRE RISK AT HORSHAM	COST
In its January 2024 consultation paper on REFCL operations, Energy Safe Victoria (ESV) stated that a distribution business does not meet their general duties by simply adhering to prescribed requirements. Rather, it noted that it is possible that additional deployment of REFCL technology, or extending the coverage of existing REFCLs, may be a practicable means by which relevant hazards and risks are mitigated, and therefore should be done to meet general duties obligations. Our existing REFCL compliance requirements target specific zone substations, but do not cover all areas that carry bushfire risk on the network. Feeders supplied by our Horsham zone substation carry the highest fire risk of all our non-REFCL protected zone substations. Our bushfire risk modelling shows that the costs of installing REFCL equipment at our Horsham zone substation are lower than the corresponding risk reduction. We are proposing, therefore, to install a REFCL at our Horsham zone substation to minimise the risk that bare overhead 22kV feeders would ignite a fire.	$18M

Note: For further detail, refer to our attached business case: PAL BUS 3.11 – Bushfire mitigation forecast overview – Jan2025 – Public.

17 In addition to the augmentation works below, this overview includes two risk-based replacement projects.

MINIMISING BUSHFIRE RISK ON SWER ASSETS	COST
SWER lines are used to supply electricity long distances to rural Victoria, typically through farmland and vegetated areas. Over 90 per cent of these SWER lines (~21,000kms) are in higher bushfire risk areas. We are proposing to install 76kms of covered conductor on the SWER lines assessed as having the highest risk of starting a bushfire and that are also approaching their end of life. This approach reduces the risk of starting bushfires, maximises value by targeting poor condition conductors and aligns with our regional and rural roadmap. We are supplementing this approach by installing early fault detection equipment on a subset of the remaining SWER conductor. Early fault detection is a technology that remotely notifies us of deteriorated or defective assets on our network before they cause a fault or fire. We have successfully trialled the technology in the current regulatory period.	$13M

Note: For further detail, refer to our attached business case: PAL BUS 3.11 – Bushfire mitigation forecast overview – Jan2025 – Public.

Other non-demand augmentation

We are also proposing to invest in other non-demand drivers, such as under-frequency load shedding (UFLS) improvements, power quality enhancements for Northern Murray customers and communications infrastructure upgrades.

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.[18] 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).	$22M

Note: For further detail, refer to our attached business case: PAL BUS 3.10 – Under frequency load shedding – Jan2025 – Public.

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

NORTHERN MURRAY HARMONICS MANAGEMENT	COST
We are proposing a program of works that addresses harmonic distortions in the Northern Murray region. Harmonics are disruptions to frequency that can impact electrical equipment operation, which are driven by newer pumping technologies used for irrigation. Power quality was highlighted as a major concern throughout our engagement program, and this program will improve service levels in the area, leading to better equipment function and lifespan and fewer momentary outages for commercial and industrial customers.	$8M

Note: For further detail, refer to our attached business case: PAL BUS 3.08 – Northern Murray harmonics management – Jan2025 – Public.

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.	$12M

Note: For further detail, refer to our attached business cases: PAL BUS 3.06 – 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 and pole-top structures. 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 the 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:

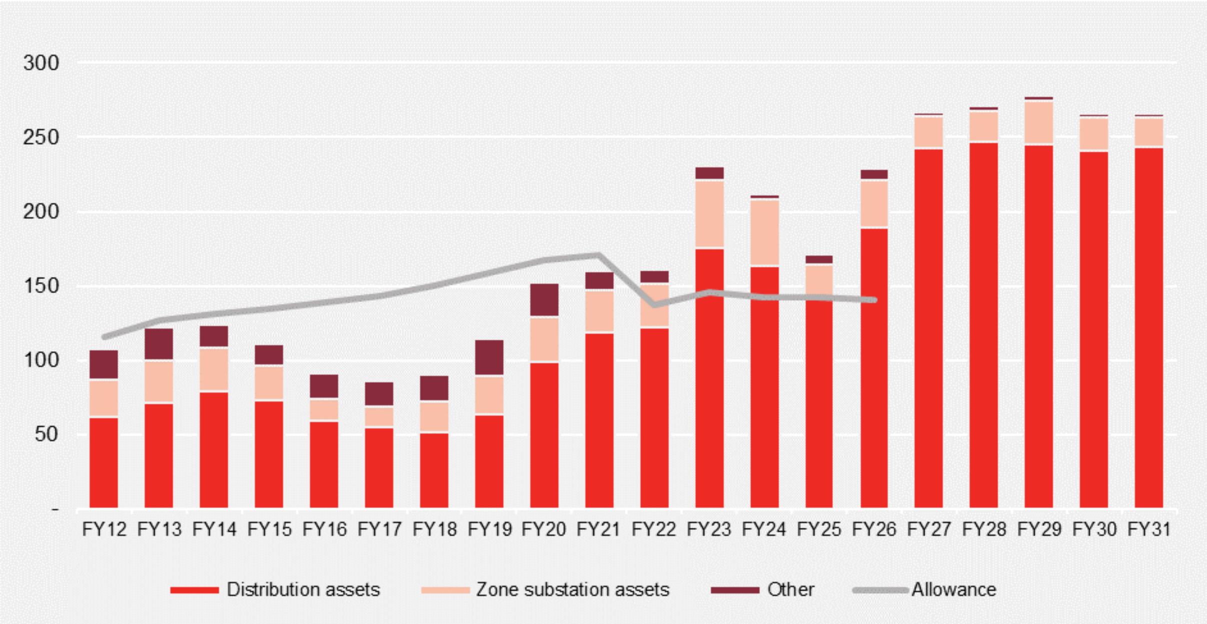
- uplift in overhead conductors and underground cables: we are observing growing defects and failures in these distribution assets and are proposing uplifts to manage the risk. We have a significant volume of these assets across our network, with over 20,000km of overhead conductor exceeding or approaching the end of its expected service life in the next 10 years. These uplifts are a prudent, no-regrets step toward more sustainable, long-term replacement volumes
- uplift in zone substation transformer and switchgear: 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	1,034	1,347

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.[19] 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

[19] 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, 73 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 overhead conductor and 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.

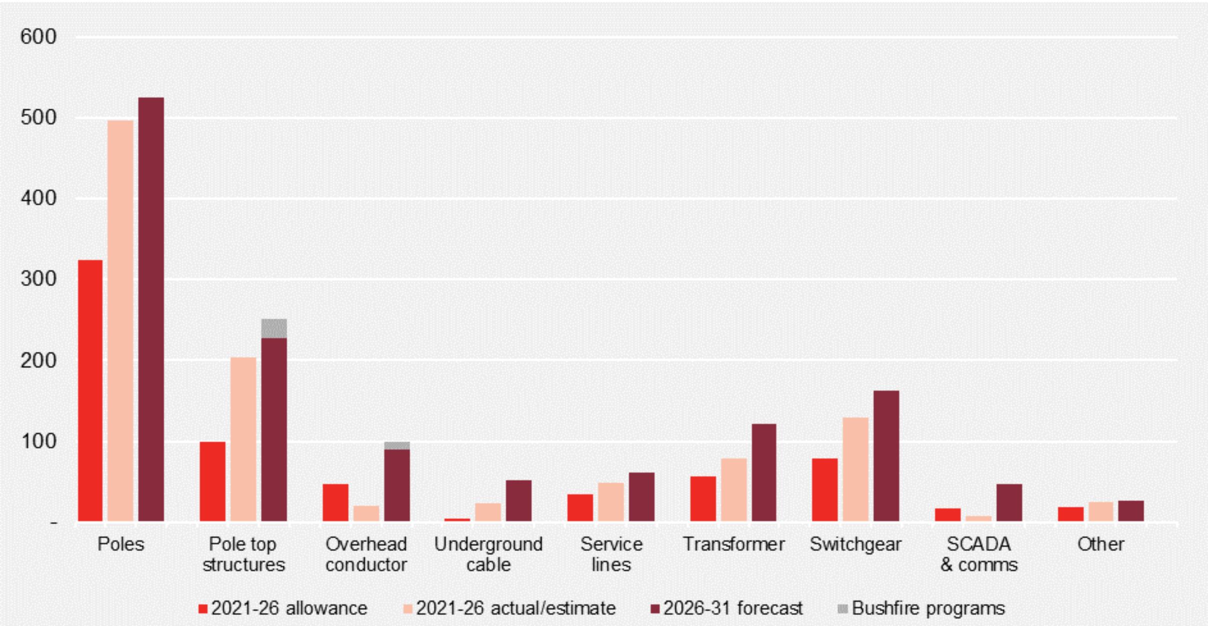
Increasingly, our asset management strategies are also needing to consider future electrification drivers (to avoid early replacement of assets due to increased capacity needs) and/or to meet longer-term deliverability challenges (particularly for high-volume assets).

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 all 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 our pole and pole-top structure populations, as these represent the largest components of our replacement portfolio. We are also observing growing defects in overhead conductors and underground cables, with a growing number of asset failures leading to outage events.

While we have been able to limit customer impacts from deteriorating underlying 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, we are entering a period where these asset category replacements will increase given a larger proportion of our assets have deteriorating condition. Similar to the ramp up of pole replacements in the current regulatory period, it is prudent to start managing the increase in replacements now to avoid unmanageable peaks in the future and spikes in prices.

POLES	COST
Our approach to managing our pole asset population involves replacements based on condition and where possible, extending the life of our wood poles through staking. For the 2026–31 regulatory period, we propose to maintain our current wood pole intervention volumes to continue to meet ESV and stakeholders' expectation of a sustainable intervention program. This program was established in the current period to meet ESV's explicit pole intervention mandate to address long-term needs over multiple regulatory cycles. These volume forecasts are supported by an alternative counter-factual based on measured decay rate analysis, existing serviceability standards and current asset management practices. 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.	$525M

Note: For further detail, refer to our attached asset class overview: PAL 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 (slightly) 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, and the inclusion of a risk-based replacement program targeting HV wood cross-arms in hazardous bushfire risk areas. This risk-based program is considered as part of our dedicated bushfire mitigation overview business case, but included in our asset replacement forecasts given the underlying nature of the program.	$252M

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

OVERHEAD CONDUCTORS	COST
Our proposal includes an increase in overhead conductor replacement expenditure. We are observing increasing high priority defects for HV conductors, which is forecast to continue to increase due to deteriorating asset condition. Currently, our health index assessment via our condition-based risk management model shows we are forecasting 35 per cent of our conductors to be in the critical health category by 2026, which is expected to increase to 45 per cent in 2031 and 61 per cent in 2036 without any intervention. Our overhead conductor forecast includes three risk-based programs, including the replacement of 66kV radial lines and a program focused on replacing deteriorated polyphase HV conductors. Both programs address the increasing risk of conductor failure causing supply interruptions to customers. We also have a compliance-driven program to rectify conductor clearance levels. We have a significant volume of these assets across our network, with approximately 20,000km of overhead conductor approaching the end of its service life in the next 10 years. While we do not replace conductors on age, it suggests our forecast replacement volumes are a no regrets investment. In addition, we understand Energy Safe Victoria (ESV) is expected to undertake an industry wide review of overhead conductor sustainable replacement volumes beginning in 2025.	$97M

Note: For further detail, refer to our attached asset class overview: PAL BUS 4.03 – Overhead conductors – Jan2025 – Public.

UNDERGROUND CABLES	COST
Our proposal includes an increase in underground cable replacement expenditure. The key driver of the uplift is our risk based high voltage underground cable replacement program, noting that our condition assessment modelling shows that in the absence of any intervention by 2031, 60 per cent of our underground cable population (i.e. approximately 1,632km) is forecast to be at high risk of failure. High voltage underground cables have historically been managed on a reactive basis with only the faulted section of cable removed and replaced. However, with increasing risk forecast because of the continued deterioration of the cable condition, entire cable replacements are becoming both prudent and economically justified.	$47M

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

DISTRIBUTION SWITCHGEAR	COST
Our proposal includes an increase in distribution switchgear replacement expenditure. This is largely driven by two risk-based replacement programs to address specific safety and network reliability risks posed by the operation of a subset of our HV air-break switches and ring main units 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. While the restricted operation on these two switches has eliminated the safety risk to our field crew, it 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. We have already begun replacing the high priority switches in the current period and are proposing to continue this program over the next ten years to replace the population of inoperable switches on our network.	$139M

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

DISTRIBUTION TRANSFORMERS	COST
Our proposal includes an increase in distribution transformer replacement expenditure. Our 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. These volumes are consistent with those completed in the 2021–26 regulatory period. In the current regulatory period, the performance of these assets has varied, but defects and failures are generally increasing. This is particularly the case for oil-leaks, consistent with changes in our obligations under the Victorian Environment Protection Act that introduced a new preventative approach to environmental protection (as opposed to the prior reactive approach of managing impacts post incident).	$100M

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

SERVICE LINES	COST
Our proposal includes a slight increase in service line replacement volumes and an associated increase in expenditure. Over the past five years, service lines high priority defects have been increasing, which is a leading indicator of future failures. Our forecast is based an annual asset defect find rate, applied differently across certain parts of the network to account for environmental factors that may influence service line condition.	$61M

Note: For further detail, refer to our attached asset class overview: PAL BUS 4.05 – Services lines – 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, unplanned replacement risk, environmental risk, safety risk, and financial risk.

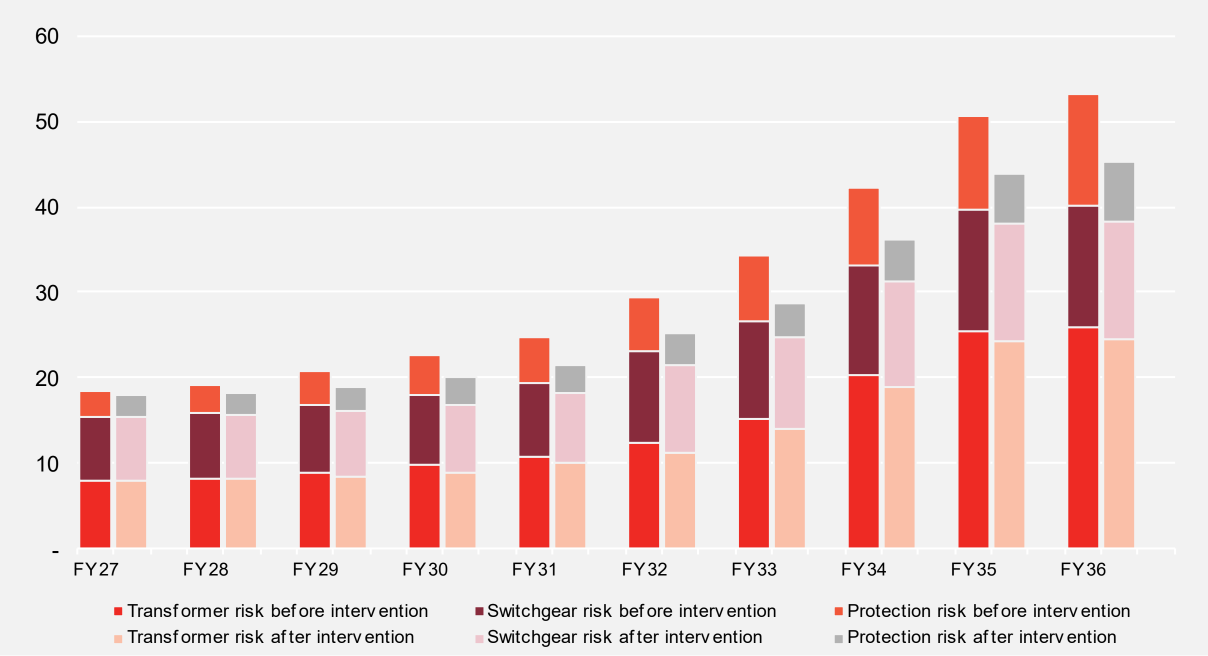
Over time, we have improved the way in which we forecast risk-based zone substation transformer and switchgear intervention. Risk is assessed based on the likelihood of the asset failing, but consequences of failure now consider the impact on the entire zone substation (instead of focussing on individual asset impacts).[20]

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.

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.

20 Refer, for example, to our asset risk quantification guide: PAL ATT 4.01 – Asset risk quantification guide – Jan2025 – Public.

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 an increase in zone substation transformer replacement expenditure, which includes the proposal of three zone substation transformer replacements in the 2026–31 regulatory period. Our proposed sites include Cohuna, Mooroopna and Shepparton North. While our improved risk management approach identified more transformers requiring intervention, only three were economic (i.e. NPV positive), reflecting that cost inputs are increasing at a faster rate than risk. While our proposed forecast will constrain this increase in risk over the 2026–31 regulatory period, the value of risk by FY31 after our proposed interventions will still be higher than at the start of the regulatory period. Our forecasts also include an environmental refurbishment program, targeting the refurbishment of 15 transformers across our network, in line with obligations under the Victorian Environmental Protection Act (2017).	$36M

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

ZONE SUBSTATION SWITCHGEAR	COST
Our zone substation switchgear forecast represents an increase in expenditure from the current 2021–26 regulatory period. This forecast includes one in-flight project that will commence this regulatory period, as well as four high-risk rural zone substations. These rural zone substation rebuilds comprise a combination of switchgear, relay and building expenditure. The driver of these works are increasing station risk, whereby the customer reliability impact would be significant. The increase in switchgear expenditure also reflects the abovementioned rising input costs of the labour, contract and materials to replace these assets.	$36M

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

PROTECTION	COST
We are proposing an increase in protection relay replacement expenditure. 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. Our risk-based approach to relay interventions will continue to focus on individual high-risk relays. By replacing approximately 14 per cent of the relay population in the next regulatory period, the risk by 2031 is reduced by approximately 42 per cent.	$29M

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

5. Resilience

Extreme weather events that cause impacts at scale are now occurring in Victoria nearly every year.[21]

For our customers, these events include flooding (in late 2022, 2023 and early 2024) and multiple wind and lighting storm fronts (in 2021, 2022, mid and late 2023, and early 2024). In total, over 923,000 sustained outages due to extreme weather have occurred in this regulatory period.

Most recently, in February 2024, more than one million Victorian customers were off supply after a major storm front crossed Victoria. This storm was significant enough to damage transmission infrastructure, as well as distribution assets. The direct cost of this event on Victoria (excluding compensation payments) was estimated at $770 million.[22]

It is widely accepted that these sorts of extreme weather events will become more frequent and more severe over time.

Note: Powercor lineworkers restoring supply in Lara following major storm damage in February 2024

5.1 What we've heard

To better understand the lived experience of our customers through these extreme events, we have engaged extensively with customers on network resilience. This involved community resilience roundtables, joint engagement with our Victorian distributors on resilience investment principles, and targeted conversations with key stakeholders through our broader regulatory reset engagement program.

21 Department of Energy, Environment and Climate Action (DEECA), Network Outage Review_Interim Report, 2024, p. 5
22 DEECA, Network Outage Review, Interim Report, 2024, p. 17.

TABLE 5.1 KEY ENGAGEMENT FINDINGS

Communities consider resilience a vital element of the energy system
Improving network resilience involves adapting to changing environmental and operational conditions
Communities expect us to play a critical role in proactive and reactive disaster management and to develop network resilience plans tailored to communities needs
Transparent communication and education are critical, especially during crises, to stay informed about outage causes, recovery times, and preparedness measures

Our engagement also highlighted the increasing dependence of our communities on a resilient electricity supply. At the same time as our climate changes, the way we live our lives is changing too:

- critical infrastructure is increasingly reliant on electricity including water, sewerage, telecommunications and internet
- increases in remote work, school and other commitments which were once in-person
- a move from inner city to more regional areas, which are more prone to extreme weather and more reliant on community and individual preparedness
- with increasing take up of hybrid and EVs, more people will begin to rely on electricity for their transportation needs over time
- as we move towards net-zero, electrification and the gas transition will increase and options for non-renewable services such as gas will decrease.

5.1.1 Test and validate

In our test and validate engagement phase, we further challenged whether our customers supported the specific initiatives set out in our draft proposal. During this engagement, our customers confirmed their strong support for improving network and community resilience—specifically, our customers:

- strongly supported investment in community support reflecting the recognition that power outages in regional areas have broader social and economic impacts. Customers welcomed the proposed expansion of our fleet of emergency response vehicles and saw the inclusion of customer support officers as a proactive step to improve local community readiness
- questioned whether we had allocated enough expenditure to network hardening given our expansive regional network and the scale of the challenges that customers are facing. However customers noted that any additional investment should prioritise areas most at risk
- considered that investment should be targeted to areas that are prone to bushfire and flood. This is because customers viewed regions prone to these extreme weather events as the most vulnerable regions in the network.

5.1.2 The Victorian Government has set clear expectations for distribution business to improve network resilience

Since 2021, the Victorian Government has initiated two separate reviews into network and community resilience. The recommendations from these reviews have strongly guided our approach to resilience.

Electricity distribution network resilience review

Following the extreme storm events in 2021, the Victorian Government engaged an expert panel to undertake an Electricity Distribution Network Resilience Review.[23]

The expert panel consulted broadly with local communities and stakeholders impacted by the extreme storms. It found loss of power caused 'considerable distress' and devastating consequences on people's lives.[24] Customers told the panel of their reliance on power in all aspects of their lives including food, water, access to funds, caring for themselves and their family and their ability to work and communicate. The panel highlighted the significant risk vulnerable and life support customers are exposed to during prolonged outages.[25]

The outcomes from this review made clear the government's expectation that we reduce both the **likelihood** and **impact** of prolonged power outages by making investments in resilience. For example, specific recommendations included:

- distribution businesses should be required to take an all-hazards approach to risk mitigation for the purposes of safety, reliability, security and resilience of the electricity system. This should result in a regular assessment of the need for investments and solutions in the most high-risk locations, from 2025 onwards
- distribution businesses should be required to partner with communities and local councils in emergency planning and response
- distribution businesses should have new obligations to improve the prioritisation of the restoration of power following an outage, and improve their communication with customers before and after prolonged power outages.

Aa a result of the review, the Department of Energy, Environment and Climate Action (DEECA) is developing a proposal to enshrine resilience objectives explicitly in the National Electricity Rules.

Network outage review

This review has since been followed by a Network Outage Review (outage review) into the more recent February 2024 storm event.[26] The outage review highlighted that distribution businesses no longer operate in an environment which is 'steady state'; we are now operating with real potential for frequent weather events that cause impacts at scale. As a result, the government expects a change in distribution businesses preparedness, response, and recovery from these events to protect the power Victorians value and the ecosystem of essential services that electricity distribution networks sustain.[27]

The outage review concluded in August 2024 with expectations that distribution businesses robustly plan for major events, align restoration with the Victorian Preparedness Framework and proactively address worst performing feeders to reduce the number and impact of outages.[28] It also highlighted the critical need for us to provide customers accurate and timely information and immediate local

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23 DEECA, Electricity Distribution Network Resilience Review, Final recommendations report, 2021.
24 DEECA, Electricity Distribution Network Resilience Review, Final recommendations report, 2021, pp. 4–5.
25 DEECA, Electricity Distribution Network Resilience Review, Final recommendations report, 2021, p. 9.
26 DEECA, Network Outage Review, Final report, 2024.
27 DEECA, Network Outage Review, Final report, 2024, p. 14.
28 DEECA, Network Outage Review, Final report, 2024, pp. 7-12.

presence and support. The review emphasised the importance of alternative solutions on the ground, such as community hubs and alternative generation to support communities.[29]

5.2 Our proposed response

Our proposed response to meet government and community expectations for both network and community resilience is focused on how we can better prepare, adapt and respond to climate extremes. This approach represents a longer-term shift towards the proactive investment cycle required by the Victorian Government.

TABLE 5.2 OUR APPROACH TO RESILIENCE INVESTMENTS

We **prepare** by hardening our network and working with communities to bolster their readiness.
We **adapt** by taking a future-proofed, no-regrets approach to our business-as-usual operations and ensuring alternative supply arrangements.
We **respond** by quickly mobilising when events occur to provide on the ground support to impacted communities.

We have also undertaken detailed climate modelling to best ensure any investments are evidence-based, and targeted at our highest-risk locations.

5.2.1 Identifying resilience options

We have undertaken detailed climate modelling to ensure all potential resilience investments are evidence-based, and targeted at our highest-risk locations.

With a changing climate giving rise to an increasing severity and frequency of extreme weather, history is no longer the best predictor of our future investment needs.

In this context, we engaged AECOM to undertake a climate impact assessment. This assessment used existing independent literature, including the Victorian Government's Climate Science Report and the Electricity Sector Climate Information, to identify and map climate risks and hazards against our network to assess our exposure to major climate risks and hazards.[30]

AECOM's report highlights our network area's exposure to extreme rainfall, bushfires and wind.

We have used to results of this work to identify where resilience expenditure will provide the greatest benefit to customers.

29 DEECA, Network Outage Review, Final report, 2024, pp. 26-27.
30 DEECA, Victoria's Climate Science Report, 2024.

5.2.2 Proposed investments

Our proposed investments to support increased network and community resilience is summarised in figure 5.1, with further descriptions of our proposed investments provided below and in our attached business case.[31]

At our trade-off forums we presented customers with a variety of options to better understand customer's willingness to pay for key resilience measures. The majority of customers—over 70 per cent—were willing to pay to improve network resilience through network hardening and community support.

We are proposing an increased resilience spend compared to our draft proposal (as foreshadowed with customers) based on further modelling with CSIRO to better understand the bushfire risk associated with our assets. The outcome of this modelling demonstrates it is in the long-term interests of customers to strengthen our network against bushfires.

These updated investments also reflect the feedback from our test and validate phase, which supported increasing resilience investments in bushfire and flood mitigation. We have, however, moderated the extent of our proposed program to balance affordability and considerations of future advancement in bushfire protection technologies. That is, we are only seeking funding for a small subset of economically viable investments related to bushfire resilience—based on locations that deliver the greatest benefits—as we consider these 'least regrets' investments.

We have also moved investments related to our worst served areas (feeder ties and stand alone power systems) to our regional and rural equity program (see section 3.2.3). This was previously included in our resilience expenditure in our draft proposal.

31 PAL BUS 5.01 – Resilience – Jan2025 – Public.

FIGURE 5.1 NETWORK AND COMMUNITY INVESTMENTS

Our customers are experiencing the increasing risks and impacts of prolonged outages

In response to the increasing frequency and severity of extreme weather events, and our customers growing dependency on a reliable supply of electricity, we are proposing to harden the network and better support communities

		Prepare	Adapt	Respond
Network hardening	**Taller poles** to increase clearance above flood levels	✓		
Network hardening	Making **poles more fire resilient** in bushfire risk areas	✓		
Network hardening	**Microgrids** in communities most exposed to prolonged outages – Apollo Bay, Ballan, Donald and Lancefield		✓	
Network hardening	**Enhanced climate modelling** to better forecast consequence and causality of extreme weather events	✓	✓	
Network hardening	**Batteries to support the communications network to** maintain remote control and monitoring of the network during an outage		✓	✓
Community support	**Additional mobile emergency response vehicles** to cater for multiple, concurrent outages			✓
Community support	**Community Support Officers**, who know and serve their communities	✓		✓
Community support	**Improved prioritisation tool** to manage risk and provide more relevant information during extreme events	✓		✓

Creating more resilient communities and networks by:

Strengthening and adapting our network to avoid time off supply

Reducing the impact of extreme weather events

Increasing on-the-ground support with people that know the local community

NETWORK HARDENING	COST
By hardening our network we are able to reduce the likelihood of an outage by making our assets less prone to failure during extreme weather events. This will be increasingly important as the frequency and severity of extreme weather events continues to grow. As part of our network hardening program we are: • installing 784 taller poles to maintain clearance levels as flood waters rise. This will allow us to better maintain supply to customers, rather than de-energising feeders to minimise safety risks under flood conditions • making poles more fire resilient in bushfire risk areas by replacing high risk wood poles with fire resistant concrete poles. Our proposal is supported by the same bushfire consequence framework used to assess the likelihood of our assets starting a fire, but instead, amended to focus on impacts from bushfires started by third parties or natural causes (e.g. lightning). This modelling indicates over 8,000 poles are economic to upgrade now, however, we are proposing to upgrade only the five highest risk segments of our network in the 2026–31 regulatory period. After accounting for all overlaps with our conditioned based pole replacement program, we will replace 1,576 poles with fire resistant concrete poles • enhancing our climate modelling to better forecast the consequences and causality of extreme weather events. Demonstrating causality is currently challenging, particularly for storm-related events, and this proposal seeks to replicate the journey to increased maturity that has occurred successfully with fire consequence modelling. Expenditure related to climate modelling is included in our proposed innovation allowance. • installing four microgrids in communities most exposed to prolonged outages. A microgrid includes its own generation source that will allow for townships and key community locations to maintain supply in the event of an outage • installing 48-hour and/or 72-hour battery capacity at 23 radio communication sites across our network to increase their resilience during disaster events and ensure communications are maintained during outages.	$83M

Note: For further detail, refer to our attached business case: PAL BUS 5.01 - Resilience - Jan2025 – Public.

COMMUNITY SUPPORT	COST
While we are seeking to prepare and adapt our network to limit the impact of extreme weather events, it is not possible to prevent all outages from occurring. We are proposing additional community support to help manage the response to these outages and minimise their impact on communities across our network. As part of our community support program we are: • deploying three additional mobile emergency response vehicles (MERVs) to cater for situations where we have multiple, widespread, concurrent outages across our network • engaging five community support officers that have extensive knowledge of their own community and play a positive role in improving communication, empowerment, and collaboration with communities. These officers will be on the ground, represent the community and be a key point of contact for emergency management. This role was expected by government and essential to customers in our engagement, both in preparing for extreme weather events and responding to them. These officers will also allow us to meet stakeholders' growing expectations to expand our participation from state-wide engagement (today) to municipal and local council engagement. In addition to assisting communities in preparing and responding to extreme weather events, the community support officers will also assist in partnering on energy renewable projects, provide advice on optimal tariffs and settings for high voltage equipment and information on demand management options, and work with life support and other vulnerable customers in their communities amongst many other activities • developing improved systems to increase our situational awareness, supporting prioritisation and visualisation during wide-scale outages. This single view will allow the various groups within our business to all access the same information and see the decisions being undertaken, and to incorporate information from a wider range of sources. The single source of truth can then be shared with external stakeholders including government, emergency management and other critical infrastructure providers. Our customers identified a need for a public facing view during engagement which has been added to the proposal. A considered IT roadmap allows for improved prioritisation and visualisation during critical periods and improved information with all key stakeholders.	CAPEX $4M OPEX $7M

Note: For further detail, refer to our attached business case: PAL BUS 5.01 - Resilience - Jan2025 – Public.

6. Connections

Connections expenditure supports the connection of new customers on our network. These connections can vary from residential houses to subdivisions, large residential/commercial properties, industrial sites and/or large-scale generation and storage.

Most connections involve the customer contributing to their connection. Therefore, connection forecasts require an assessment of future customer contributions as well as underlying 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 overall network capital program given connections expenditure is not discretionary.

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 include the following:

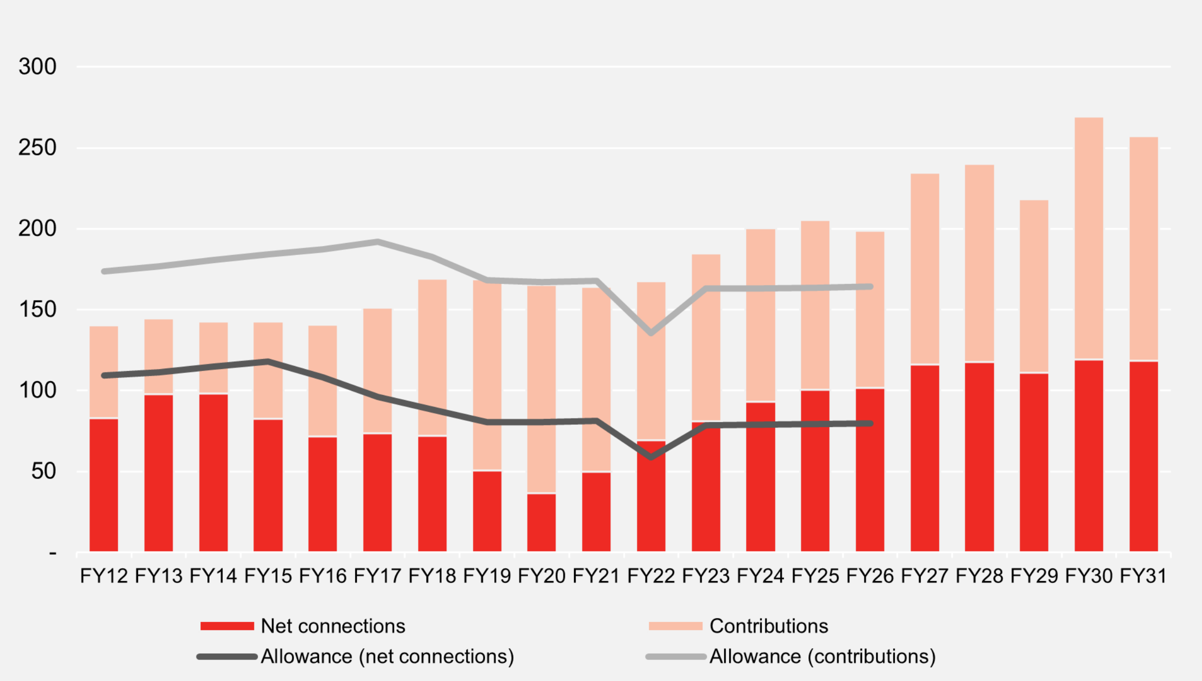
- gross connection activity for the 2026–31 regulatory period is forecast to be higher than current expenditure. Higher growth reflects our network encompassing amongst the highest connection growth areas nationally, such as Melton, Wyndham and the Surf Coast. Further, new trends emerging from electrification and energy transition are fundamentally altering the characteristics of new connections
- at a segment level, growth in connection activity is forecast across all customer categories except commercial and industrial developments. Residential and subdivision growth remains strong, driven by the continuing housing shortages across Victoria, and especially Melbourne. Grid scale renewable generation and energy storage will also grow consistent with Victorian Government carbon reduction targets (with western and northern Victoria being ideal locations for wind and solar resources)
- data centre connections are increasing, with additional capacity of 356MW forecast to accommodate a further five data centres on our network. 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 below.

TABLE 6.1 TOTAL CONNECTIONS INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Connections (gross)	956	1,219
Customer contributions	511	637
Connections (net)	**446**	**583**

FIGURE 6.1 ANNUAL CONNECTIONS INVESTMENT ($M, 2026)



6.1 What we've heard

As part of our engagement program, our discussions with customers and stakeholders focused on how they envisaged future connection activity would intersect with the energy transition, and any barriers to the connection process. This occurred with smaller customers through Monash University's Future Home Demand report and 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.

We also published a consultation paper on integrating storage into our networks in February 2024 targeting energy storage proponents.

TABLE 6.2 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 as possible. This was a key focus for regional and rural areas
Whilst there were mixed responses to EV adoption, customers demonstrated no desire to cross subsidise their connection (public or private)
Grid scale renewable generators sought more options for network access, less complexity and increased competitiveness of transmission markets (as many of these customers also require transmission augmentation to support their connection to the distribution network)
Large load customers wanted more options to preserve capacity on the grid (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

6.2 Our proposed response

The Electricity Distribution Code of Practice (EDCoP) obliges us to make an offer to connect any customer seeking a connection to our network.[32] How these offers are made 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 must be consistent with the provisions of the connection charge guideline for electricity customers and be approved by the AER. 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 ensure the costs of the energy transition are collected where possible from the beneficiaries.[33]

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

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32 Essential Services Commission, Electricity Distribution Code of Practice, May 2023.

33 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.

- providing a wider range of options for commercial and industrial customers. This includes more optionality with respect to network tariffs, grid access, and access to non-network markets through our demand management platform
- addressing urgent investment needs across regional and rural Victoria, with the intention of making future connections cheaper, easier and simpler
- reforming how we apply alternative control charges that apply to future connection offers
- working with regulators to tackle the behaviour of transmission network operators.

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

6.2.1 Forecasting connections activity

Developing robust forecast methods is critical to 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.[34] These forecasts have been updated for this proposal reflecting the latest available macroeconomic data
- internal projections were also used to forecast grid-scale storage, based on our visible pipeline of registered projects. The pipeline information for this proposal has been updated since the draft proposal
- data centre connections have been included for the first time based on forecasts provided by LEK.[35] The LEK report is based on five sites in Derrimut, Cobblebank, Laverton, Deer Park and Truganina, with capacity varying from 18MW to 158 MW
- 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 have also been based on 2023–24 RIN data.

6.2.2 Contribution rates

Forecasting contribution rates is complicated. Contribution rates are dependent on expected future revenue from each connection which is in turn 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 financial year 2024–25 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.[36] For the draft proposal, a variety of forecast and actual information was applied to model

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[34] Macromonitor, Forecasts by Region, Report prepared for CitiPower, Powercor and United Energy, August 2024.
[35] LEK, Data centre load forecasts, Databook to inform CPU's electricity distribution regulatory determinations, October 2024
[36] Australian Building Codes Board, National Construction Code, 2022.

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.

To have a more dynamic approach to consumption forecasts for this proposal, we engaged LEK to model the long-term consumption trends (2026–61).[37] Understanding longer term trends is essential given estimation of contributions required is subject to a 30-year analysis for residential connections.

LEK 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 were EV uptake and behind the meter storage.

Further there was a shift in behaviour resulting in more consumption in saver periods and less during peak periods. Off peak consumption remained 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.

6.2.3 Data centres and grid connected storage

We have included two additional connection categories from those identified in the reset RIN—data centres and grid connected batteries.

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

Nonetheless, for data centres 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 who 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.

For grid connected batteries, even less actual data is available. Based on forecasts prepared by our external demand forecast partner—Blunomy—435MW of grid connected storage is forecast to connect between 2026–2031. Internal estimates of incremental revenue and incremental costs for similar connected grid connected batteries have then been applied to derive an average contribution rate of 76 per cent.

6.2.4 Connections by segment

Figure 6.2 shows connection activity for the 2026–31 regulatory period by segment, with growth in connection activity forecast in all customer categories except embedded generation. A slowdown in underlying commercial and industrial activity is in line with a weaker Victorian economy and demand over the period 2025 to 2027, with the impact most strongly felt in warehouses, health and office buildings. At a total category level, these are offset by continued growth in data centres.

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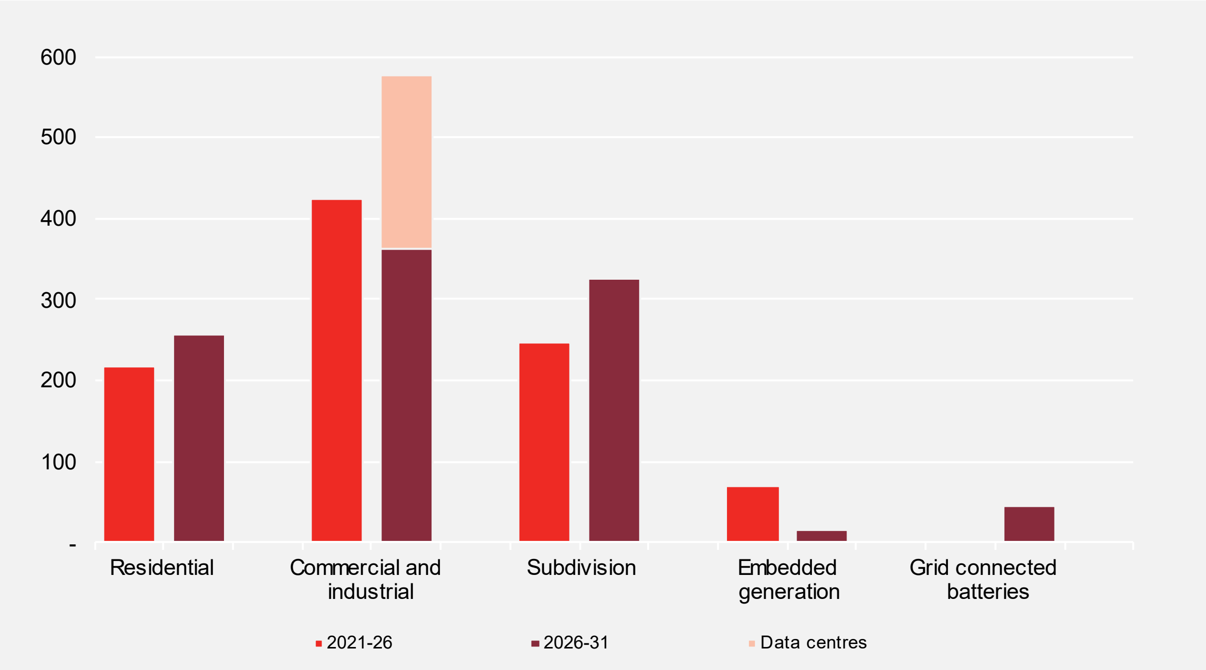
[37] LEK, Customer electricity use and data centre forecasts, Databook to supplement residential load forecasts, October 2024.

Residential and subdivision growth remains strong, driven by the continuing housing shortages across Victoria, and especially Melbourne. Grid scale renewable generation and energy storage is forecast to nearly double, consistent with Victorian Government carbon reduction targets (with western and northern Victoria being ideal locations for wind and solar resources).

FIGURE 6.2 GROSS CONNECTION ACTIVITY BY SEGMENT ($M, 2026)



6.2.5 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.[38]

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
- new provisions to support the introduction of regulated stand-alone power systems.

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

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

6.2.6 Renewable energy zones

Throughout our reset engagement program, we received feedback from regional and rural customers expressing concern with the expansion of the transmission network (especially VNI West and WRL), the cost of transmission upgrades, the lack of access for regional and rural communities to renewable energy and the cost of connection from smaller scale embedded generation and storage proponents (less than 250MW). This led to a discussion on renewable energy zones (REZs) as an alternative on the distribution network.

Although there are no distribution-REZs included in our proposal, we are continuing to consult on them given the support and encouragement we have received from many customers and stakeholders. If that support continues, and there is greater certainty provided on the regulatory treatment of REZs, we will consider their inclusion in our revised regulatory proposal. This assessment is also considering locations across our network where it may be economic to alleviate generation constraints on existing generators.

7. 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.[39] For the current period we are forecasting a minor ICT underspend. This underspend is driven by the deferral of our enterprise risk platform (ERP) replacement project, however, this underspend is largely offset by additional spending on the functional capabilities supporting our role as the distribution system operator (including ADMS upgrades and compliance with the Victorian Emergency Backstop Mechanism).

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

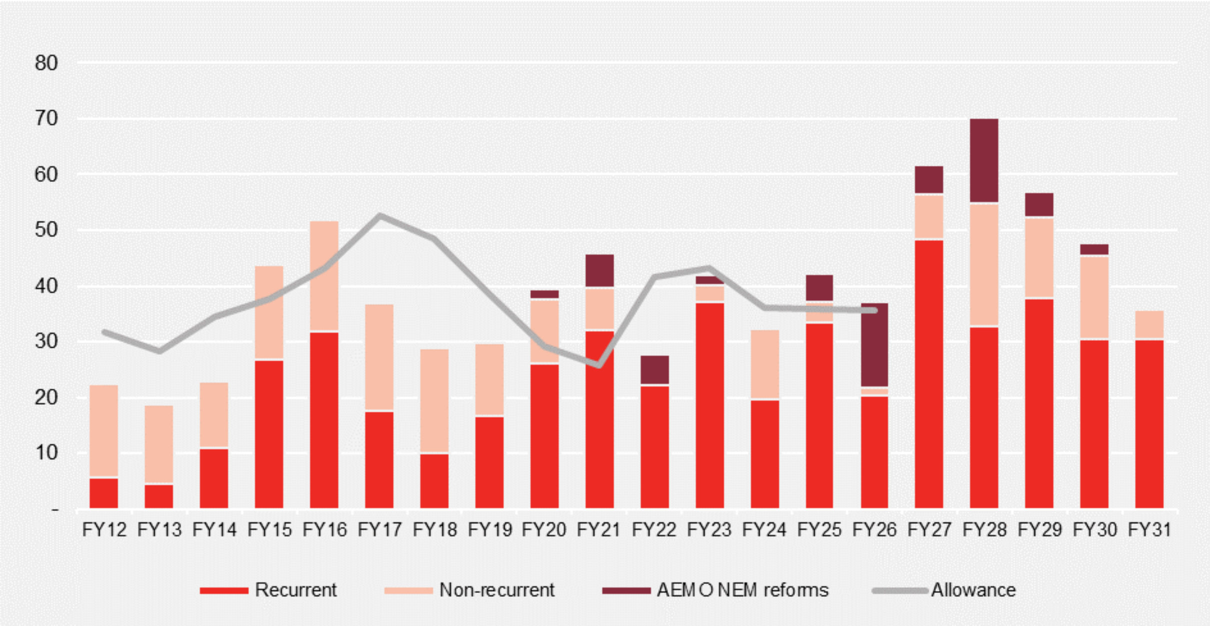
- an uplift in our recurrent investment program linked to infrastructure and system refreshes
- an uplift in our non-recurrent ICT investment program, which includes upgrading our cyber-security position and the replacement of two of our core ICT systems that are critical to the energy transition
- new 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 7.1 TOTAL ICT INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Recurrent	133	180
Non-recurrent	21	64
AEMO NEM reforms	28	28
Total	**182**	**272**

39 Excluding CER, which is outlined in our electrification and CER integration strategy in chapter 2.

FIGURE 7.1 ANNUAL ICT INVESTMENT ($M, 2026)



7.1 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 7.2 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.

7.1.1 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.

7.2 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.[40]

7.2.1 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 SYSTEMS	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.	$37M

Note: For further detail, refer to our attached business case: PAL BUS 7.05 - 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 $32M OPEX $7M

Note: For further detail, refer to our attached business case: PAL BUS 7.04 - 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.	$23M

Note: For further detail, refer to our attached business case: PAL BUS 7.08 - End user device management - Jan2025 – Public.

40 For the full risk monetisation guideline refer to PAL ATT 7.02 – 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.	$16M

Note: For further detail, refer to our attached business case: PAL BUS 7.09 - 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.	$56M

Note: For further detail, refer to our attached business case: PAL BUS 7.06 - Market systems - Jan2025 – Public; PAL BUS 7.11 - Telephony - Jan2025 – Public; PAL BUS 7.07 - Enterprise management systems - Jan2025 – Public, PAL BUS 7.10 - Customer enablement - Jan2025 – Public. For IT facilities further detail is included in PAL BUS 8.04 - Property recurrent expenditure - Jan2025 – Public.

7.2.2 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 $68M OPEX $24M

Note: This includes both recurrent and non-recurrent expenditure related to this project. For further detail, refer to our attached business case: PAL BUS 7.01 - 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 $12M OPEX $12M

Note: This includes both recurrent and non-recurrent expenditure related to this project. For further detail, refer to our attached business case: PAL BUS 7.02 - Cyber security - Jan2025 – Public.

7.2.3 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: **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.	CAPEX $28M OPEX $2M

Note: For further detail, refer to our attached business case: PAL BUS 7.03 - 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.

8. 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 minor property and fleet overspend. We have fundamentally delivered on our 2021–26 property proposals; we completed the significant depot redevelopments that were included in the AER's allowance. We will also underspend on fleet, however, this is largely offset by additional spending on tools and equipment.

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

- a reduction in property investments relative to historical levels, with our forecasts comprising the redevelopment of our Geelong depot and head office, and the establishment of a purpose-built training facility
- fleet investment, including incremental vehicle electrification, in line with current period expenditure
- 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.

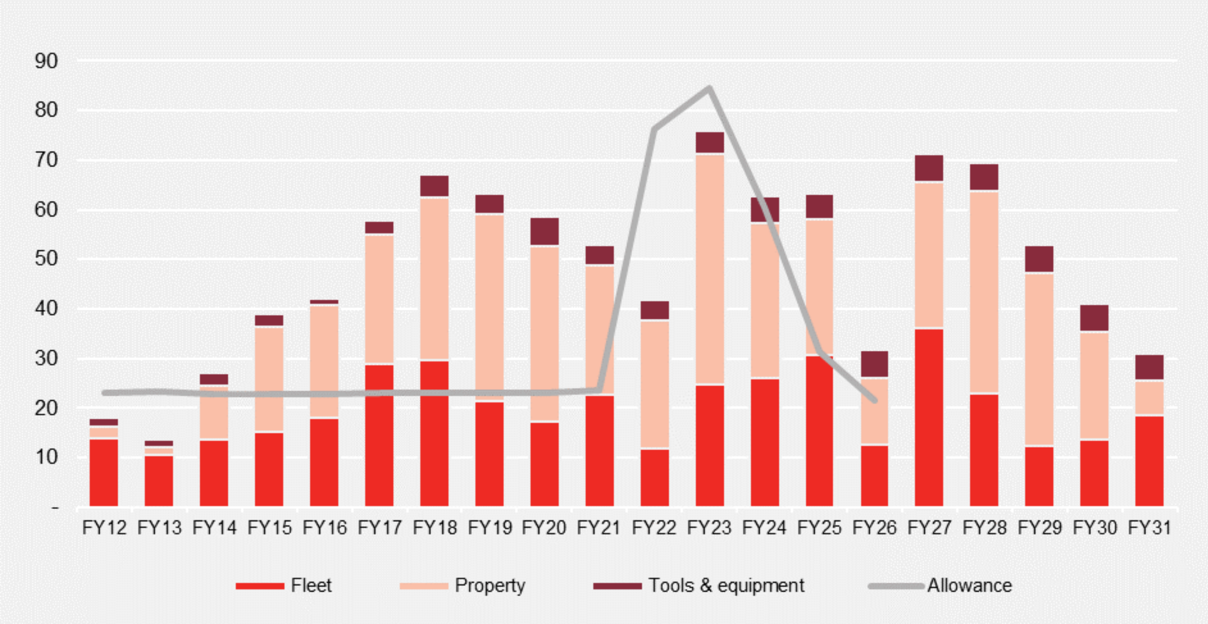
Overall, our forecast for property, fleet and other non-network investments are lower than our draft proposal, driven by the deferral of insourcing of local service agents and revised fleet needs. These reductions were partially offset by an increased scope for our training facility, with details on these changes outlined further in this section.

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

TABLE 8.1 TOTAL FLEET, PROPERTY AND OTHER NON-NETWORK ($M, 2026)

DESCRIPTION	2021–26	2026–31
Property	144	134
Fleet	106	104
Tools and equipment	25	28

FIGURE 8.1 ANNUAL FLEET, PROPERTY AND OTHER NON-NETWORK ($M, 2026)



8.1 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 8.2 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 moderate appetite to pay for emissions reductions

8.2 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 Geelong depot situated in a high population growth area
- improve environmental sustainability through a targeted program prioritising the least cost and highest impact investments to reduce emissions
- gradually ramping up programs to replace outdated infrastructure as part of a long-term plan to maintain deliverability, price stability and predictability over the long run

- maintain efficient long-term operational deliverability, ensuring workforce sustainability throughout the energy transition via the development of a purpose-built training facility, and insourcing local service agent contracts.

Further detail on these investments is provided below.

8.2.1 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 represent a step-down on current period expenditure. In the current regulatory period, we have completed upgrades to four of our existing depots, with the remaining one due for completion in late 2025. These upgrades benefit the communities we serve, the health and wellbeing of our workers, and allow works to continue to maintain existing levels of efficiency.

As noted previously, our property forecast for our regulatory proposal differs from that set out in our draft proposal. In particular, we have deferred plans to insource local service agents as we seek to offset non-discretionary increases in expenditure in other areas of our proposal. We note, however, that outsourced resource models elicited strong unfavourable views in the Victorian Government's network outage review, and subject to the Government's formal response to the review panel's recommendation, we may revisit this decision as part of our revised proposal.

GEELONG DEPOT REDEVELOPMENT	COST
We are proposing to redevelop our Geelong depot, which has insufficient storage, layout, and capacity for the growing works program. Our current depot for example, is unable to hold the necessary stock levels to accommodate project requirements (including our pole replacement program). In addition, increasing local staff are unable to utilise the depot as a regional office due to restricted space and flexibility. 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.	$45M

Note: For further detail, refer to our attached business case: PAL BUS 8.03 – Geelong 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.	$22M

Note: For further detail, refer to our attached business case: PAL BUS 8.02 – 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.	$16M

Note: For further detail, refer to our attached business case: PAL BUS 8.01 – Head office refurbishment – Jan2025 – Public.

8.2.2 Other property works

Other property works include improvements to the security of our critical assets, improvements in building accessibility and the first tranche of a long-term program to replace ageing zone-substation buildings across multiple regulatory periods. 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, high security fence upgrades, 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.	$17M

Note: For further detail, refer to our attached business case: PAL BUS 8.04 – Property recurrent expenditure – 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 identified a need to replace priority zone substation buildings, due to ageing infrastructure and asbestos which present material safety risks. However, this requires the replacement of network assets housed inside these buildings, at a material cost. Consequently, we propose a gradual approach, to maintain affordability for customers, and deliverability of works in the long term. We propose to replace the roofs of 15 aged zone substation buildings (typically built in the 1960s) to ensure safety and reliability of supply, as well as a no-regrets program to rebuild an additional five buildings.	$25M

Note: For further detail, refer to our attached business case: PAL BUS 8.04 – Property recurrent expenditure – 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. Our current program builds on the significant works completed in the current period, with solar already installed at most depots. We are proposing a targeted sustainability approach prioritising the least cost and highest impact investments, to balance cost and value. This includes the installation of solar panels on our remaining depots, the addition of battery storage and EV charging infrastructure at select depots to facilitate our roll-out of EVs.	$8M

Note: For further detail, refer to our attached business case: PAL BUS 8.04 – Property recurrent expenditure – Jan2025 – Public.

8.2.3 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.

Our forecast fleet investment is in line with current period expenditure.

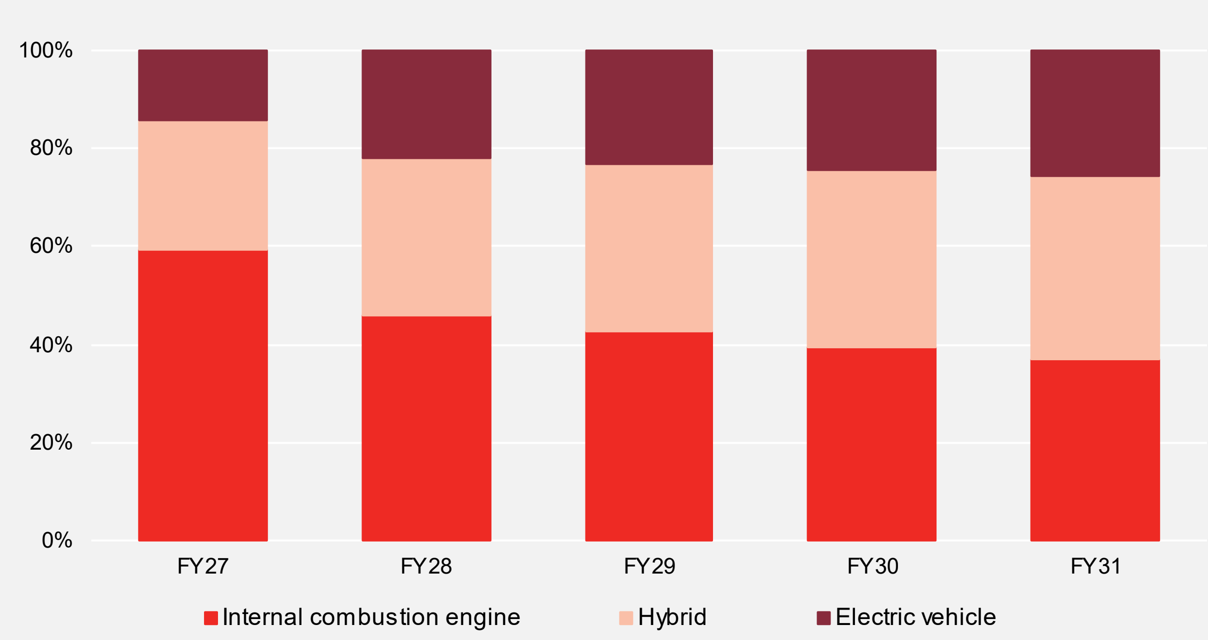
FLEET REPLACEMENT	COST
The current regulatory period has seen unprecedented global events with wide-reaching impacts on global supply chains. This impacted procurement, with unit costs increases and supply shortages in these markets. Our fleet is expected to service a growing workforce and a growing population in the 2026–31 regulatory period, reiterating the importance of maintaining a safe and effective resource pool. Despite these challenges, our fleet replacement forecast is aligned to forecast actuals in the current regulatory period. We have also revised down our fleet forecast since the draft proposal to remove an over-allocation of shared fleet from our CitiPower network.	$101M

Note: For further detail, refer to our attached model: PAL MOD 8.05 - 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, in line with our customers' preferences. 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.	$3M

Note: For further detail, refer to our attached model: PAL MOD 8.05 - Fleet - Jan2025 - Public.

FIGURE 8.2 HYBRID AND ELECTRIC VEHICLE UPTAKE (%)



9. 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.

9.1 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 9.1 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 customers, including regional and rural 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
Both regional and commercial and industrial customers believe CER enables reliability

9.1.1 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 in regional and rural Victoria.

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

- customers strongly supported improving network and community resilience because they recognised that power outages in regional areas have broader social and economic impacts. They saw the inclusion of customer support officers as a proactive step to improve community readiness
- 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.

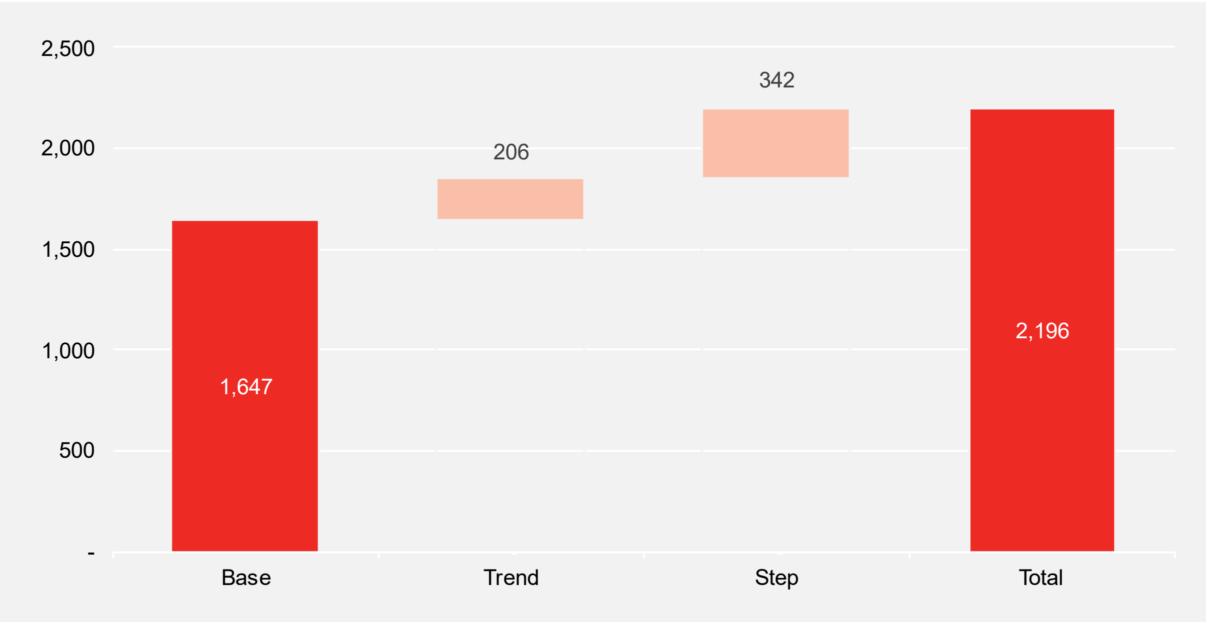
As outlined earlier in the respective CER and resilience chapters, our customers were supportive of our proposed investments.

9.2 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 9.1.

FIGURE 9.1 TOTAL OPERATING EXPENDITURE ($M, 2026)



Note: Totals may not add due to rounding.

9.2.1 Proposed base year

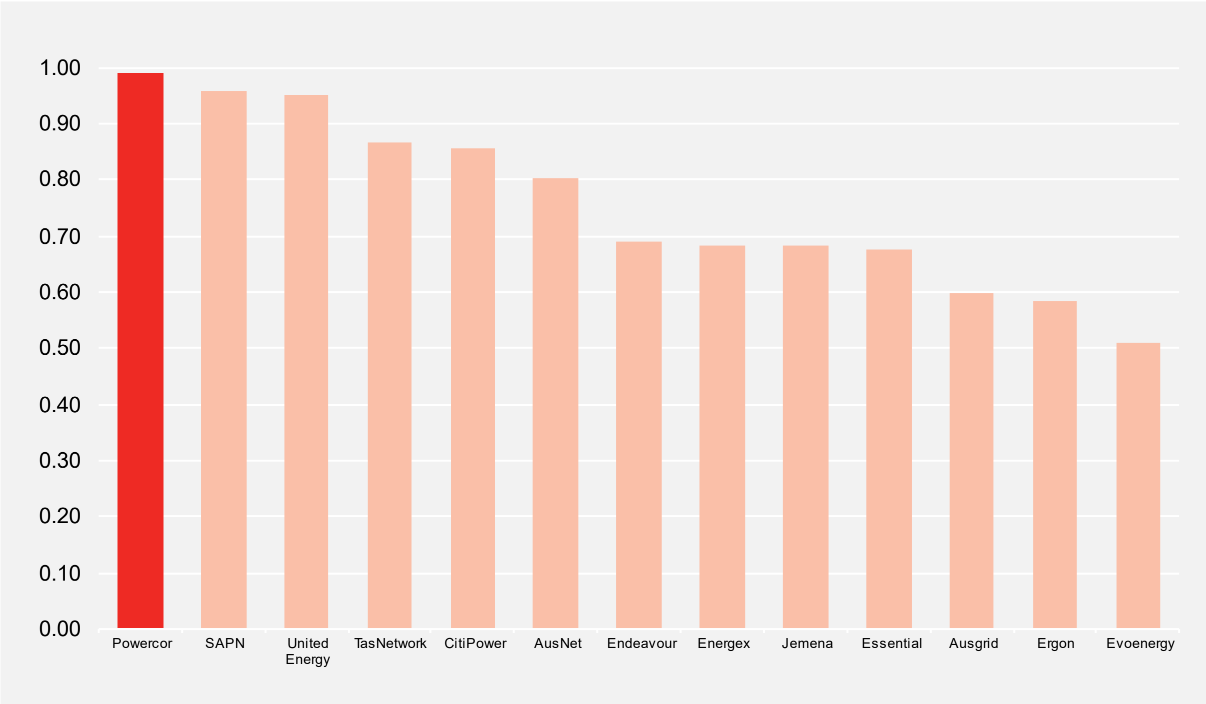
Under the AER's preferred forecasting approach, the first step is to determine the efficient revealed cost base year of expenditure. Where distributors are efficient, customers benefit through downward pressure on network charges and customer bills.

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 0.99, indicating that we are a benchmark comparator with efficient operating expenditure. Customers benefit from this efficiency through lower network charges.

FIGURE 9.2 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)[41]
- 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.

9.2.2 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.[42] The forecast amounts for each growth driver are also described in our operating expenditure model.[43]

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.[44]

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.

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41 This placeholder will be updated in our revised proposal, following finalisation of the new rate that is expected to be available in 2025.
42 See the input rate of change tab in: PAL MOD 1.05 - Opex - Jan2025 – Public.
43 See the input rate of change tab in: PAL MOD 1.05 - Opex - Jan2025 – Public.
44 Including Cobb-Douglas least squares, Translog least squares, Cobb-Douglas stochastic frontier analysis and Translog stochastic frontier analysis

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.[45]

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 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).

9.2.3 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 and network resilience. 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 9.2, with further detail provided below and in the corresponding business cases.

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45 Specifically, see: AER, SA Power Networks Electricity Distribution Determination 2025 to 2030, Draft decision, and PAL ATT 8.01 – Oxford Economics - Labour escalation – Jan2025 – Public

TABLE 9.2 SUMMARY OF OPERATING EXPENDITURE STEP CHANGES ($M, 2026)

STEP CHANGE	AER CATEGORY	COST
Customer package	Major external factor	$27M
Vegetation management	Major external factor and regulatory obligation	$233M
CER integration	Major external factor	$29M
Cloud services	Capex / opex trade-off	$26M
ICT modernisation and new capability	Major external factor and capex / opex trade-off	$22M
Network and community resilience	Major external factor	$7M
Fleet electrification offset	Major external factor	-$1M

Note: Costs include real escalation

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).[46] Specifically, we made the following changes:

- expenditure has been uplifted to reach a meaningful number of customers to provide tangible customer impact

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[46] PAL BUS 9.02 – Customer assistance package – Jan2025 – Public.

- 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).

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 attachment.[47]

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).[48]

However, based on feedback to date, we do not expect changes to our obligations under the Code that would materially amend the need for or magnitude of our proposed step change.

CER integration

As outlined in our electrification and CER integration strategy, the scale and scope of changes to our energy system—particularly in Victoria—mean our network will need to function very differently to the energy system we have now. Critical to this are our proposed new capabilities in offering flexible services for CER, improving data visibility for customers, and increasing the ability for third-parties to remediate network constraints through our non-network platform.

Collectively, these solutions will unlock value for customers, including through better utilisation of existing infrastructure and lower prices over the long-term.

Further detail on the components of this step change are set out in the corresponding CER integration business cases.[49]

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.[50]

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.

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47 PAL ATT 9.02 – Vegetation management step change – Jan2025 – Public.

48 We will consider the outcomes of this RIS in the development of our revised proposal.

49 PAL BUS 2.01 – Flexible services – Jan2025 – Public; PAL BUS 2.02 – Non-network marketplace – Jan2025 – Public; and PAL BUS 2.03 – Network data visibility – Jan2025 – Public.

50 PAL BUS 7.01 – ERP & billing system replacement – Jan2025 – Public; PAL BUS 7.02 – Cyber security – Jan2025 – Public; PAL BUS 7.04 – Infrastructure refresh – Jan2025 – Public.

Further detail on the components of this step change are set out in the corresponding ICT business cases.[51]

Network and community resilience

The lived experience of our customers through more frequent and severe weather extremes, and their growing dependency on electricity, has been a key theme for stakeholders throughout the development of our regulatory proposal. At the same time, the Victorian Government has set clear expectations on the role of distributors in improving network and community resilience.

As part of our response, our regulatory proposal includes five locally-based community support officers to be on the ground, represent the community and be a key point of contact for emergency management. These roles will also assist communities in preparing for extreme weather events.

Our step change also includes the costs associated with developing improved systems to increase our situational awareness, supporting prioritisation and visualisation during wide-scale outages.

Further detail on the components of this step change are set out in our resilience business cases.[52]

Fleet electrification offset

Our fleet forecast includes modest additional capex for fleet electrification, with a focus on hybrid vehicle replacement to promote emissions reduction without compromising affordability. A key benefit associated with the transition to electric or hybrid vehicles are reduced operating costs associated with, for example, fuel savings.

This negative step change is considered as part of our total cost of ownership model in our fleet forecast. We recognise the materiality of this step change is small, but have proposed it consistent with our customer feedback.

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.

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51 PAL BUS 7.01 – ERP & billing system replacement – Jan2025 – Public; PAL BUS 7.02 – Cyber security – Jan2025 – Public; PAL BUS 7.04 – Infrastructure refresh – Jan2025 – Public; PAL BUS 7.03 – AEMO NEM reforms – Jan2025 – Public.

52 PAL BUS 5.01 – Resilience – Jan2025 – Public.

10. 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 10.1 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’.[53] 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.[54]

10.1 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 10.2.[55]

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.

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53 AER, Review of incentives schemes for networks – Final decision, April 2023, p. 4.
54 AER, Review of incentives schemes for networks – Final decision, April 2023, p. 4.
55 PAL MOD 1.06 - EBSS - Jan2025 – Public.

TABLE 10.2 EBSS CALCULATION ($M, 2026)

DESCRIPTION	FY22	FY23	FY24	FY25	FY26
Adjusted benchmark EBSS operating expenditure	329	337	346	353	360
Actual EBSS operating expenditure	274	300	319	318	324
Incremental efficiency	30	-18	-11	9	-
Carry-over year	FY27	FY28	FY29	FY30	FY31
EBSS carry-over	**6**	**-20**	**-2**	**9**	**-**

10.2 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 underspent our regulatory allowance for the 2021–26 regulatory period).[56]

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.[57] A summary of the CESS outcome is shown in table 10.3.

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.

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56 AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, April 2023, p. 8.
57 PAL MOD 1.07 - CESS - Jan2025 – Public.

TABLE 10.3 CESS CALCULATION ($M, 2026)

DESCRIPTION	PRESENT VALUE
Total efficiency gain	-205
Network service provider share	-62
Financing benefit	3
CESS payment in 2026–31	**-64**

10.2.1 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.

10.3 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 2.8 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 10.4 with additional detail available in our incentives and targets models.[58]

TABLE 10.4 STPIS TARGETS AND INCENTIVE RATES FOR THE 2026–31 PERIOD

PARAMETER	NETWORK SEGMENT	TARGET	INCENTIVE RATE
Unplanned SAIDI	Urban	56.38	0.03
	Rural short	94.27	0.03
	Rural long	208.15	0.02
Unplanned SAIFI	Urban	0.69	1.56
	Rural short	1.05	1.58
	Rural long	2.11	1.16
MAIFIe	Urban	1.10	0.12
	Rural short	1.86	0.13
	Rural long	3.15	0.09
MED threshold	Network	6.76	

10.4 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.

[58] PAL MOD 10.03 - STPIS targets - Jan2025 – Public; PAL MOD 10.02 - STPIS incentives - Jan2025 – Public.

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
- maintains the measures of SAIDI and SAIFI for planned outages, with an updated methodology to better align the SAIDI and SAIFI measures with productivity gains or losses for a given outage event (rather than varying based on the size of our works program)
- 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 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 $5 million per year.

Table 10.5 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.[59]

TABLE 10.5 PROPOSED CSIS FOR THE 2026–31 PERIOD

CSIS MEASURE	REVENUE AT RISK	BASELINE TARGET	INCENTIVE RATE
SMS notification	0.10%	75.9%	0.04
Planned outages	0.15%	SAIDI: 58.81 SAIFI: 0.28	SAIDI: -0.04 SAIFI: -5.6
Grade of service	0.25%	71.9%	0.04

10.5 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 10.4.

[59] PAL ATT 10.01 - CSIS - Jan2025 – Public.

TABLE 10.6 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
Tarneit neighbourhood battery	We installed a 120kW/360kWh neighbourhood battery in Tarneit to address local network constraints
Electrification modelling project	We undertook research and modelling to better understand the impacts of electrification for commercial and industrial customers

Table 10.7 provides our proposed DMIAM allowance for the 2026—31 regulatory period, calculated in accordance with the AER's guidelines.[60]

TABLE 10.7 DMIAM ($M, 2026)

DESCRIPTION	FY27	FY28	FY29	FY30	FY31
DMIAM	0.99	1.0	1.0	1.03	1.06

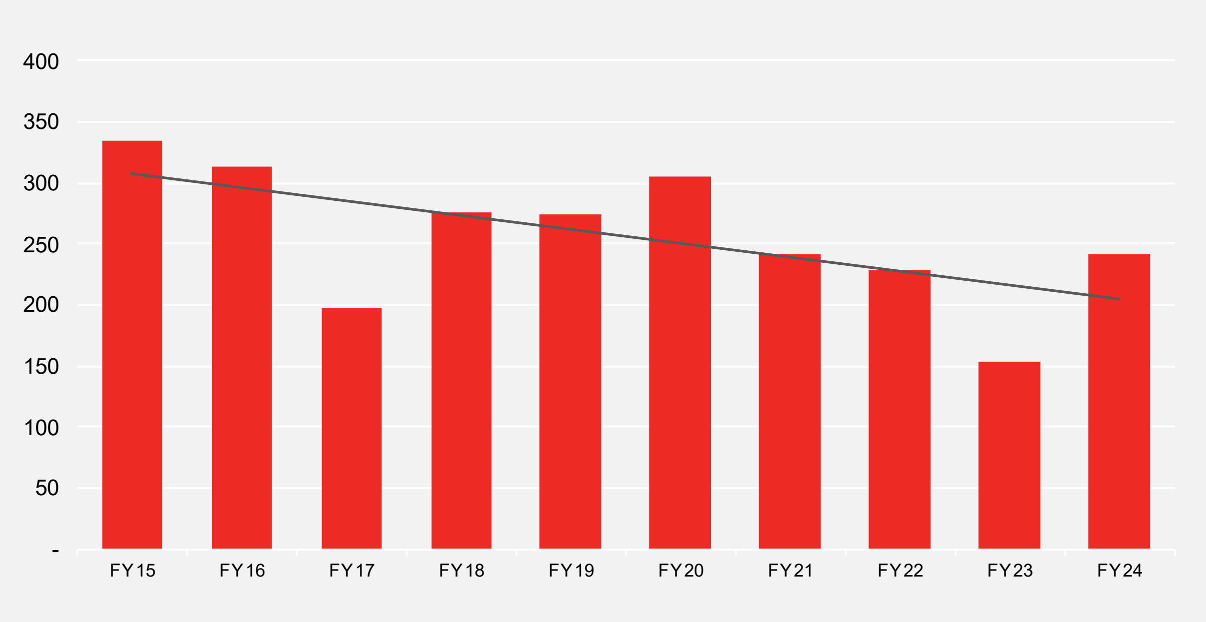
10.6 F-factor scheme

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 10.1 demonstrates historical fire starts on our network. Fire starts on our network have, on average, been steadily decreasing overtime since the introduction of the F-factor scheme.

60 AER, Demand management innovation allowance mechanism, December 2017, p. 8.

FIGURE 10.1 NUMBER OF FIRE STARTS



10.7 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.[61] 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

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61 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.

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 $20M, 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.

The innovation allowance will focus on four key areas:

- **assisting the energy transition** – innovation to support industry to electrify hard to abate areas and new arrangements and technologies to support community uptake of appropriate energy solutions
- **building network resilience** – innovation to support our deployment of SAPS and microgrids by trialling new processes and technologies
- **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 business case.[62]

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[62] PAL BUS 10.01 - Innovation allowance - Jan2025 – Public.

11. 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.

11.1 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 11.1.

TABLE 11.1 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.[63] 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.

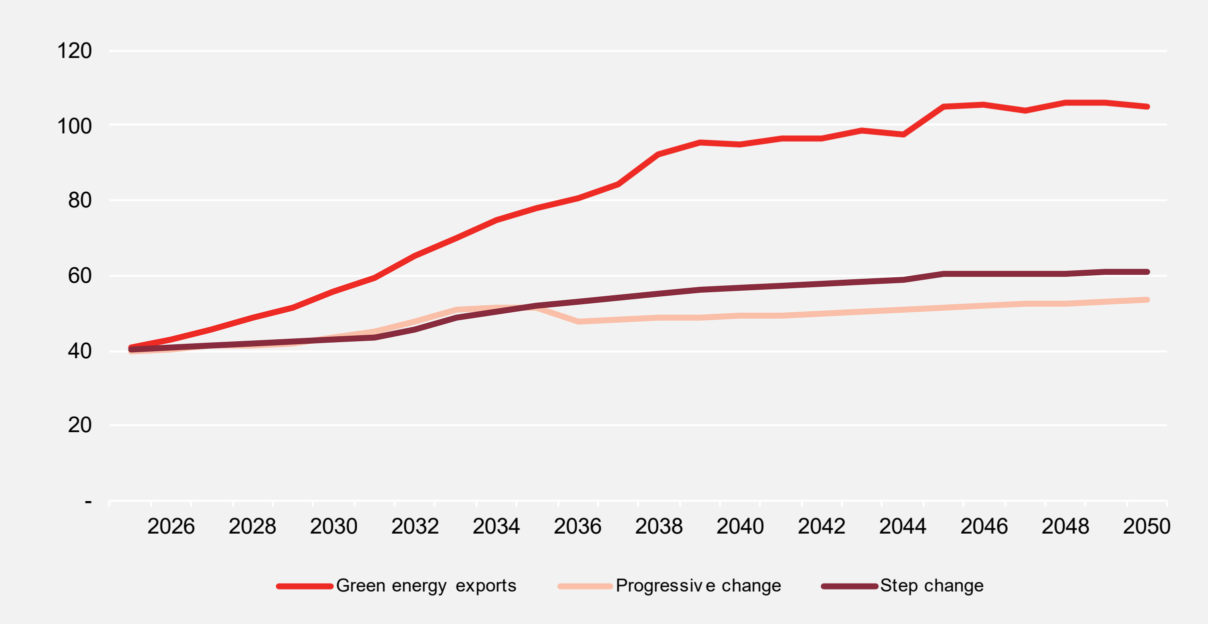
While any increase in expenditure required to deliver these government policies may be accounted for under the uncertainty framework (e.g. as a regulatory change, under the pass-through mechanism), any complementary or subsequent increase in electricity consumption beyond the government policy will not. 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 11.1 VICTORIAN OPERATIONAL CONSUMPTION FORECASTS (TWH)



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

[63] 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.

11.2 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.[64]

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 11.2 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.[65]

[64] PAL ATT SE.30 – CAP – Report on Draft Proposal – Nov2024 – Public.
[65] PAL ATT 11.01 - Managing uncertainty - Jan2025 – Public.

TABLE 11.2 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

11.2.1 Contingent project: Point Cook (PCK) zone substation

We are expecting substantial growth in the Western suburbs of Melbourne across the 2026–31 regulatory period. On current demand forecasts we will need to add a third transformer to our Mt Cottrell zone substation and re-build our existing site at Bacchus Marsh earlier in the 2026–31 period to increase capacity. A new zone substation at Point Cook is expected to be required later in the period.

However, acknowledging the inherent uncertainty in any demand forecasts, and the scale of our works being undertaken within the broader western Melbourne area, we have included the Point Cook substation 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 the construction of the Point Cook zone substation; and
- we obtain all relevant internal approvals to proceed with the project.

Our estimate of the cost of these works is approximately $58 million ($2026).

12. 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.

12.1 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 35 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.

Notwithstanding our proactive program, our customers will receive a reduction in nominal meter charges due to the impacts of lower forecast depreciation.

12.1.1 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 12.1 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.

12.1.2 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 35 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.[66] In total, our proposed expenditure relating to our meter replacement program is shown below.

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[66] PAL BUS 12.01 – Metering – Jan2025 – Public.

TABLE 12.2 TOTAL METERING INVESTMENT ($M, 2026)

DESCRIPTION	2021–26	2026–31
Metering	97	385

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 800,000 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.

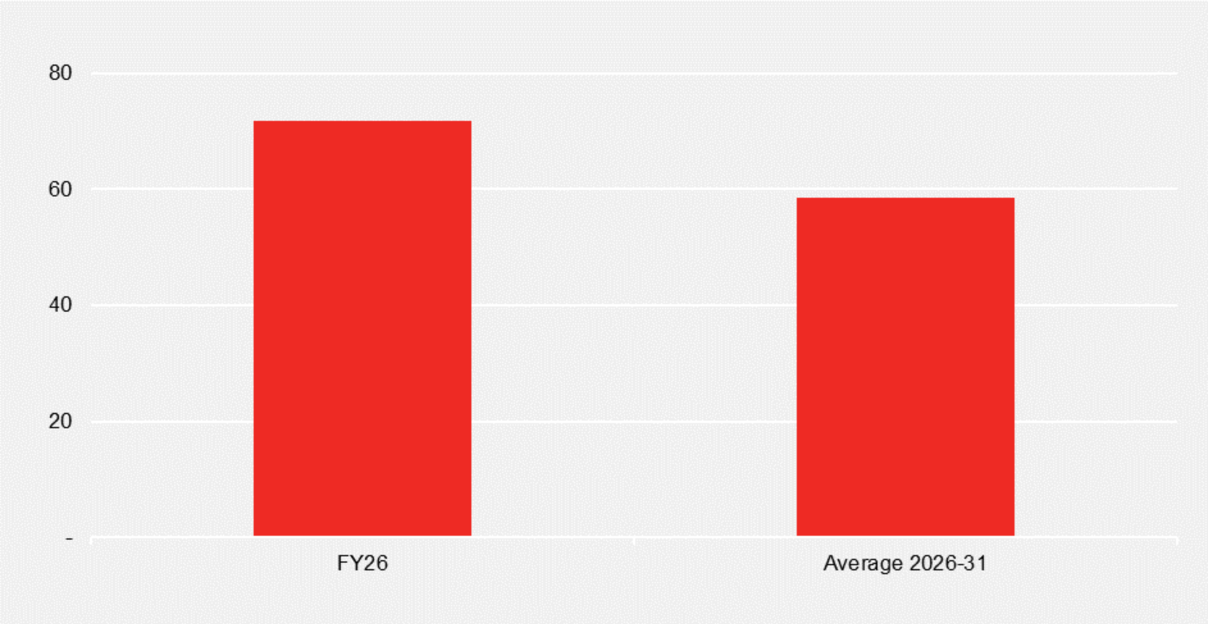
Our metering revenue forecast for the 2026–31 regulatory period is shown below. Notwithstanding the expenditure increase associated with a replacement roll-out, metering revenue will remain relatively stable due to the impact of lower depreciation (as existing meters become fully written down).

TABLE 12.3 TOTAL METERING REVENUE ($M, 2026)

DESCRIPTION	2021–26	2026–31
Metering	318	304

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 12.1 SINGLE-PHASE METER CHARGE ($, 2026)



12.1.3 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:

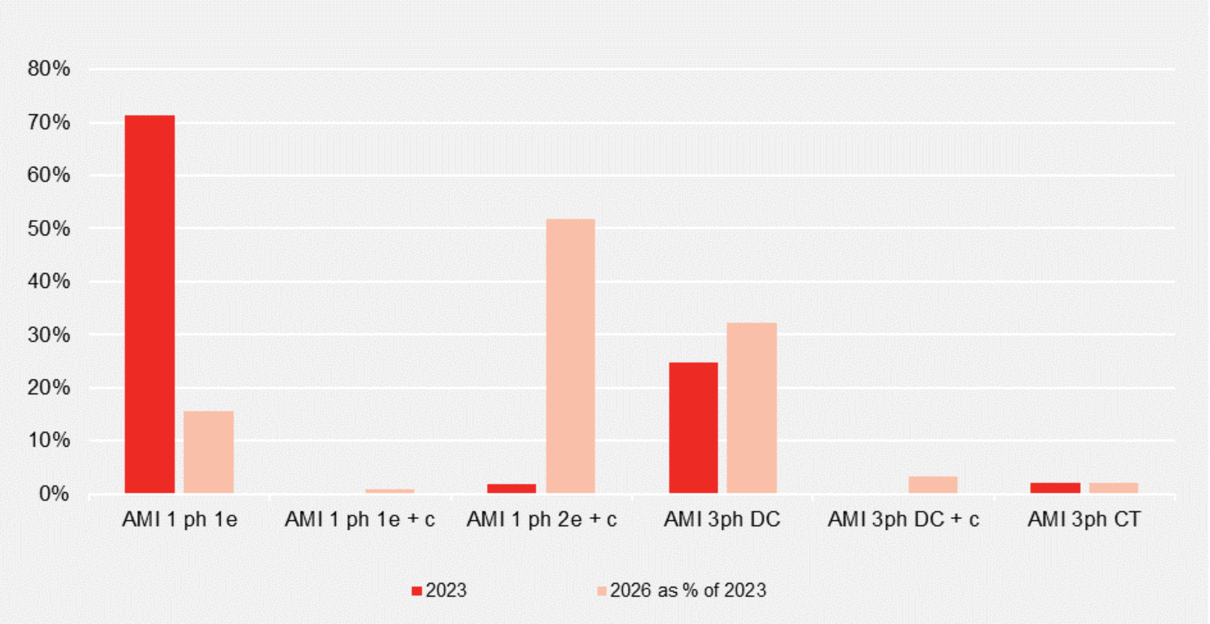
- single-phase two element connections due to heat pump electric hot water systems displacing existing gas hot water systems (under the Victorian Government subsidies)
- a move to three-phase new connections and requested upgrades due to both gas space heating being replaced by electric space heating, 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 12.2.

FIGURE 12.2 NEW CONNECTIONS



12.2 Public lighting

We provide public lighting services to 38 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 205,000 public lights installed across our network. Of these, 190,000 (93 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.

12.2.1 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.[67]

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.

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67 PAL ATT 12.01 – 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.

12.2.2 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.

12.3 Re-classification or modification of existing services

12.3.1 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.

12.3.2 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.

12.3.3 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'.

12.4 New services

12.4.1 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.

12.4.2 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.

12.4.3 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.

12.4.4 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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