AusNet

Electricity Distribution Price Review

2026-31 Regulatory Proposal

Friday, 31 January 2025

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Executive Summary

This proposal is about our customers, what they need and want now and in the future. It is about the levels of service they want and how we will deliver these for an affordable price. The next regulatory period covers the greatest period of change for electricity distribution networks since the electrification of the state. Through this early stage of the energy transition, it is critical that we understand how customers will use our network and what they expect from us, so we can make sure this change meets and keeps pace with customer's evolving needs and improving where we need to.

Our customers rely on us to provide an affordable, safe and reliable electricity supply. As our customers electrify and invest in their own energy resources, we believe that these characteristics will become more important.

It is well accepted that climate change is going to increase the frequency and severity of extreme weather events. Unfortunately, many of our customers have experienced the impact of prolonged power outages resulting from extreme weather events over the last four years, as the network has suffered damage from major bushfires in early 2020 and four major storms since. To inform our plans, many of our customers have shared their experiences of these outages, including the financial and non-financial costs they have incurred. To address the growing risk of extreme weather, we have proposed a comprehensive package of resilience investments to future-proof the network, and additional community support, balanced by affordability considerations.

In preparing our broader investment plans for the next five years, we have undertaken an extensive program of engagement and research to validate and build our understanding of our customers' concerns, needs and preferences. The findings of these engagement activities have complemented and reinforced the insights provided by our industry-leading BAU research program on our customers' ever-evolving needs.

We have listened to our customers in developing this Regulatory Proposal. We know that, for many, energy affordability and broader cost of living pressures are top-of-mind. We acknowledge that the cost-of-living crisis is profoundly impacting Victorians. Our five-year plan aims to strike a balance between investing to achieve the service levels desired by customers, while managing energy affordability and we are particularly focused on the ultimate customer bill impact of this proposal This is a difficult balance to strike, particularly as affordability concerns for many of our customers are acute, while at the same time their expectations of the electricity network are evolving. Our customers have also made it clear that improving network services can also help manage broader cost pressures, including costs that are borne by customers during outages (for example, buying a hot dinner), and (for those who are able) to electrify appliances and transport, reducing ongoing energy costs.

Another key consideration is the global imperative of transitioning the energy system to net zero. This is driving investment on our network to support and enable Federal and Victorian Government emissions and renewables targets and reforms, unlocking the benefits of the energy transition for AusNet customers and beyond. We are working closely with the Victorian Government to ensure Victorians benefit from investments we are making to meet government objectives.

In this context, and despite taking steps to reduce costs, our forecast investment requirement in the next regulatory period is 72% higher than expected investment in the current period. This uplift reflects a range of factors which are driving the need for greater investment, including new investment drivers (e.g., uplifting network resilience and regional reliability in response to evolving community expectations) and higher unit costs driven by market pressures. We have engaged deeply and broadly on whether customers are willing to pay for service improvements and, as a consequence of this engagement, have taken active steps to reduce our proposed investment requirements.

These include deferral of network expenditure where more efficient investment options are available, as well as a comprehensive top-down review and adjustments to reflect expenditure that will be funded through reliability incentive schemes. These actions are collectively referred to as 'affordability measures' and we have worked with the Coordination Group – our peak reset engagement body - and customers to develop a suite of these that will keep prices flat. In total the implementation of these measures, which include both the removal of overlaps we have proactively identified, as well as cost increases we will incur but have not sought recovery of, amount to annual savings of $13 per residential customer.

As a result, despite our rising investment needs, our plans will deliver broadly stable prices and bills, with all customers benefiting from increasing network utilisation. In its interim report on our Draft Proposal, the Coordination Group has recognised that our plans will deliver a range of service improvements at an affordable price. Importantly, our Revenue Proposal delivers a similar level of service improvements with a slight increase in real prices.

We have also proposed a set of renewed customer experience and advocacy commitments to our customers – including where we will advocate on their behalf to address a range of regulatory and policy issues impacting customers - and will hold ourselves to account to make sure we deliver what we set out to do. This accountability is important to both AusNet's management team and Board.

This proposal sets out in detail how AusNet has responded to our customers' preferences in our plans for the electricity distribution network for the regulatory period commencing on 1 July 2026 and ending on 30 June 2031 and the revenue that will be required to deliver those plans.

Our proposal has been informed by extensive customer engagement and research

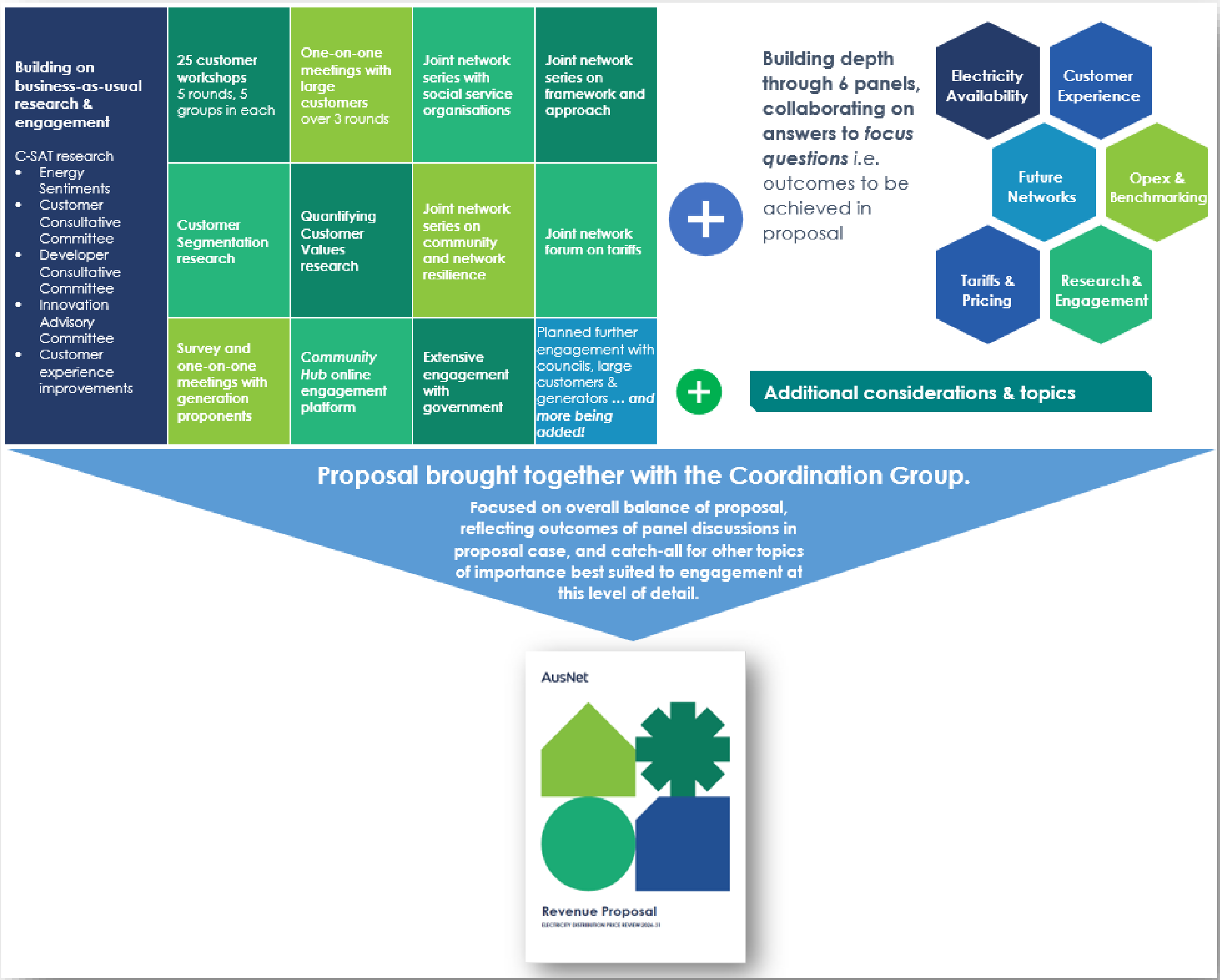
The engagement and research underpinning this Regulatory Proposal is the most extensive we have undertaken for a price review, by a significant margin. This was important to us as the decisions being made in the forthcoming regulatory period – around our role in the transition to net-zero emissions, preparing for extreme weather events and many more – will have a significant impact on our customers' lives.

We have carefully designed our EDPR engagement approach to:

- Engage broadly and deeply.
- Be sincere and genuine.
- Clearly evidence the impact our engagement has had on the proposal.

Our Panels' discussions have been underpinned by an extensive research and engagement program to understand the trends in and diversity of views among our customer base. In addition to our ongoing and business-as-usual research program we have undertaken several leading research projects to further deepen our understanding of electricity distribution customers' preferences, including our Customer Segmentation and Quantifying Customer Values research projects.

Figure 0-1 : Overview of AusNet customer engagement and research program



Source: AusNet

The messages from our customers have been clear. The energy transition has featured prominently, and customers expect AusNet to keep pace with and be ready to deliver to their evolving needs and preferences. Affordability continues to be a top priority for customers, with no one wanting to pay more for electricity than they need to. At the same time, customers expect – and are willing to pay for - a more reliable and resilient electricity supply, increasingly so as they electrify.

There is a marked difference in customers' expectations compared to five years ago, with strong key themes emerging through surveys, workshops and engagement through Customer Panels. These themes are summarised below.

Figure 0-2: The evolving expectations of our customers

Energy affordability
has always been and remains extremely important. While the energy transition may lower bills, AusNet should do what it can to contribute to affordability.

Agency
having information on what's happening, feeling supported through change, and being able to make decisions and act in their long-term interests.

Continuous improvements to customer service
across existing and new interactions.

An innovative network
with AusNet always looking for better, more efficient ways of doing things.

Preparing for net zero
by ensuring the network can support rooftop solar, large renewables and electrification of transport and gas.

More reliable electricity
including during extreme weather events that are becoming more common. This is particularly important as households electrify.

A fair and equitable transition
all including regional areas and for customers with specialised needs, which are at risk of getting 'left behind'.

- Remains a high priority for customers
- New in the last 5 years
- Become more important in the last 5 years

How feedback on our Draft Proposal has shaped this Revenue Proposal

Based on feedback received, our Draft Proposal (which was published for consultation in September 2024) generally struck the right balance between cost and service level from both a value and affordability perspective. We received consistent feedback that our Draft Proposal was focused on the right things, particularly reliability, resilience, customer experience and innovation.

We were not expecting to and did not achieve 100% satisfaction or agreement, but for the overall proposal and specific elements within, feedback was largely neutral to positive, with small numbers of customers willing to accept lower levels of service for lower prices and small numbers requesting higher levels of service with a willingness to pay more for them.

We know no one wants to pay more than they need to for electricity, but there was no consistent feedback received on areas where customers would accept AusNet cutting back on proposed service levels. Generally, there was very low appetite for cuts to the proposed service levels, assuming AusNet can achieve them, which is something small numbers of customers were sceptical of particularly in the context of resilience improvements, given the uncertainty of climate forecasts.

We understand customers want us to be looking for areas to reduce costs where it does not noticeably impact the quality of service they receive. In response, we have incorporated additional affordability measures (discussed on the next page) into this Revenue Proposal, reducing our forecast expenditure requirements during the 2026-31 regulatory period by over $100m compared to the Draft Proposal. This includes deferral of $70m of resilience spend into subsequent regulatory periods. While our modelling shows that this investment is needed to maintain network risk, it will not deliver net economic benefits to customers and, therefore, to improve the affordability of our overall plans has not been proposed.

We have made additional, but more minor changes and clarifications to our proposal in response to feedback received on our draft plans, which are outlined throughout the remaining chapters of this document.

Our plans will deliver value to our customers in 2026-31 and beyond

We are investing to uplift core services where our customers value this

We have set out to deliver plans for a value-for-money electricity supply that responds to the key messages we have heard from our customers. Consistent with their evolving expectations, what value-for-money looks like to AusNet customers is also changing. Customers expect a higher level of service than they did 5, 10 or 20 years ago, and while many are under financial pressure in a cost-of-living crisis, our customers overwhelmingly still see value in improved electricity services and are willing to pay some extra for improved and expanded services.

At the same time as supporting investment to make the network more resilient to extreme weather events, maintaining a safe and reliable network is a long-standing expectation of our customers. A dependable power supply is becoming increasingly important as households and businesses become more reliant on electricity for communications, cooking, heating, transport, to work and to manage their health and personal comfort.

We also need to invest to enable customers to use electricity (and save money) in new ways, including rooftop solar, electric vehicles and moving to all-electric homes and businesses. We acknowledge the future is difficult to forecast, and while our investment plans are underpinned by robust demand forecasts, there is a need for greater flexibility within the regulatory framework to manage uncertainty over the pace of the transition.

Our proposal also includes a range of initiatives to improve customer experience and address known customer pain points, including better customer relationship management and improved communications.

We have comprehensively tested the price and service impacts of these proposals with our customers and, based on what we have heard, our proposed investment plans appropriately balance our customers' desire for improved service levels with the importance they place on improving energy affordability.

The key outcomes our Revenue Proposal will deliver for our customers are summarised below.

Figure 0-3: The key customer outcomes we are planning to deliver, aligned to customers' expectations

Prioritising energy affordability and value for money

have always been and remain important. While the energy transition may lower household energy costs in time, we know it's important to keep our network charges as low as we can while delivering the service levels our customers expect at a price they are willing to pay.

We know no one wants to pay more than they need to for electricity, but we have not received any consistent feedback on areas customers would accept us cutting back on proposed service levels. Generally, there is very low appetite for cuts to the proposed service levels.

Our proposal delivers **flat bills** for residential customers (excluding inflation) based on:

- robust quantitative measurement and testing of the value customers place on service improvements (or degradations)
- a thorough top-down assessment to identify synergies and areas to save
- deferring investment in areas that won't significantly impact customers' experience.

Key

- Remains a high priority for customers
- New in the last 5 years
- Become more important in the last 5 years

Delivering reliable and safe electricity

including during extreme weather events. Households and businesses see value in us doing more to reduce the frequency and severity of unplanned outages, which are almost always inconvenient and can cost them. The level of funding we are proposing is to meet compliance requirements, maintain similar reliability levels for most customers with uplifts for our worst-served customers, and investments to better prepare for, and respond to, extreme weather events.

Our proposal includes[1]:

- $1,285m to maintain safety and reliability and meet compliance obligations by replacing aging assets on our network
- $121m on a novel proposal to improve reliability for customers that are worst-served. This includes $25m to upgrade the 10 least reliable feeders and $96m for a new Regional Reliability Allowance to address reliability challenges that emerge over time.
- $264m to make the network more resilient to extreme weather and $16m to reduce the impact of outages to communities when they happen.
- $27m on a new Benalla to Euroa express feeder, improving reliability for customers in the area by 74%.
- $38m to manage power quality on the network, consistent with our voltage management obligations.

Our investment plans reflect customers' willingness to pay, using data from our recent Quantifying Customer Values (QCV) research for residential customers and the AER's 2023 Values of Customer Reliability (VCR) for non-residential customers.

In December 2024, the AER published updated Values of Customer Reliability. For residential customers, these values are substantially higher than the previous values from 2019, and broadly in line with our QCV data. Our investment plans will improve reliability in line with the AER's latest data on willingness to pay to avoid outages.

Due to timing, we have not applied the AER's new VCRs to plan our investments. We will consider the implications of the new VCRs for our investment plans in our Revised Proposal.

[1] Values include overheads and are expressed in real 2025-26 terms.

Continuously improving customer service	Innovating to find better, more efficient ways to do things
across all existing and new interactions. Customers expect us to improve the efficiency and quality of their interactions with us. Our proposal includes[2]: • $49m for maintenance and upgrades to customer-facing platforms to address known customer frustrations with service continuity and accessibility, including more self-service options to make customers' interactions with us faster and easier • $11m for customer relationship managers to support large employers, councils and communities • an updated set of commitments to customers, with governance arrangements • a customer service incentive scheme (CSIS) that rewards or penalises us up to 1% of our revenue per year, based on customer satisfaction.	Including using new technologies. Our proposal includes: • $19m[3] for innovation programs over 5 years (double today's spending) while maintaining the strong customer-led governance arrangements, including an Innovation Advisory Committee.
Preparing for net zero	**A fair and equitable transition**
by ensuring the network can support rooftop solar, large renewables and electrification of transport and gas. Our proposal includes[4]: • $431m (including $149m to address constraints in the LV network) to accommodate the 13% growth in summer peak demand and 18% growth in winter peak demand from customers using more electricity, including those going all-electric on gas and transport, and electric vehicle charging • $194m to enable generation and storage to efficiently connect to the sub-transmission network.	for all, to look after those at risk of getting left behind. Our proposal includes: • reducing the reliability gap between metropolitan and regional customers • flexible solar export limits for all new systems, giving solar customers equal opportunity to send their excess generation back to the grid • adding a cheap 'solar soak' period (11am-4pm) to the residential time of use tariff, enabling all customers to benefit from solar, reducing cross-subsidisation and increasing network utilisation • taking a "technology neutral" approach to network planning and tariffs to support innovation and efficient outcomes • advocacy commitments – to deliver the outcomes customers want through the energy transition.
Building customers' agency	**Staying accountable**
by supporting them through change and helping them make decisions in their long-term interests. Our proposal includes $5m[5] for communications and education to: • build customers' ability to engage with tariffs (and save money) • make communications more reliable, accessible, specific and accurate.	and including "safeguards" in the Proposal to support revenue being spent appropriately, emerging customer priorities are being addressed and anticipated benefits are realised. This was identified as a key priority for many of our customer panels. This means a bigger role for our Customer Consultative Committee, who we will report to on progress and collaborate with on many key decisions, such as allocation of the Regional Reliability Allowance and outcomes achieved. Existing governance, including the Innovation Advisory Committee and public reporting via our annual Energy Charter Disclosure will remain.

Source: AusNet

[2] Values include overheads and are expressed in real 2025-26 terms.
[3] Made up of $8m opex and $12m in capex (does not add due to rounding). Values include overhead and expressed in real 2025-26 terms.
[4] Values include overheads and are expressed in real 2025-26 terms.
[5] Expressed in real 2025-26 terms.

We have taken concrete steps to improve the affordability of our plans

We know many of our customers are struggling with cost-of-living pressures, and we have consistently heard that they want keeping prices low to be our number one priority. Accordingly, we have had a firm eye on opportunities to reduce the cost of our plans for customers without compromising too much on service and reliability outcomes the whole way through our planning process. To this end, we are taking concrete actions to reduce the impact of our plans on customer bills by reducing costs, recognising savings and synergies from future investment and not seeking recovery for some cost increases that we will incur. These measures, which account for savings of at least $13 per year for the average residential customer and $65 per year for the average business customer, are shown in the table below.

Table 0-1: Concrete steps we have taken to improve the affordability of our plans

Good regulatory practice	Discretionary affordability measures

• Deferring $29m in network expenditure where more efficient investment options are available.
• Absorbing $3m in operating expenditure step changes and reducing other step changes by $9m by finding synergies in operations.
• Applying the following negative opex step changes:
  – $0.7m for electrifying our fleet, recognising lower energy costs of AusNet-owned electric vehicles.
  – $4m to account for savings that are expected to be delivered through the Digital expenditure program, should that be approved.
• Lowering our guaranteed service level (GSL) forecast by $2m to reflect the benefits of investment in improved reliability, should that be approved.
• Reducing our resilience and reliability capital expenditure by $8m to account for funding we will receive through incentive schemes, should that capex be approved.
• Reducing our capital expenditure by $42m to account for synergies between different capital programs.
	• Absorbing $20m of labour costs associated with expected EBA outcomes, which are not funded by the AER's standard approach to labour escalation.
	• Deferral of $70m of our resilience program into subsequent regulatory periods.
	• Lowering our guaranteed service level (GSL) forecast by $3m to absorb GSLs for controllable services from our bottom line, consistent with the approach we agreed with customers for the current regulatory period.
	• Lengthening the period over which investment in our distribution management system is paid for by customers. This lowers revenue per customer by $4 per year over the next five years.
	• Applying a discretionary productivity growth factor to our forecast of capitalised network overheads, reducing them by $4m.
	• Absorbing $4m of Digital additional opex associated with higher license costs for existing systems and platforms.
	• Absorbing $14m of additional opex associated with our increased fleet requirements.
	• Making an innovation adjustment of $0.2m to true-up for differences between actual and approved spend.

Source: AusNet

In addition, our metering charges are expected to more than halve by 2031, reducing from $83 per residential customer in 2025-26 to $39 per customer in 2030-31 (without inflation). Customers will continue to get a reliable metering service, with a gradual transition to newer, more intelligent, smart meters as we start replacing the older meters.

We are keeping bills stable, despite higher investment and other cost pressures

We are forecasting higher investment to uplift reliability, network resilience and other service levels based on customer feedback that this is value-for-money, and investment to facilitate net zero objectives. We have also seen large increases in the cost of project delivery, due to higher costs of specialized labour and materials than forecast in our last regulatory decision. It is also becoming more expensive for us to maintain the network much of which traverses challenging terrain.

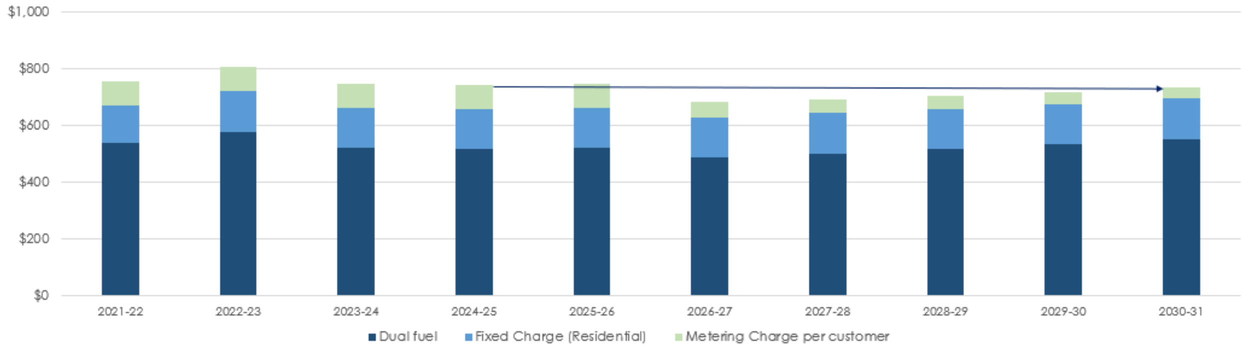
Despite these pressures, we have kept energy bills flat in this Revenue Proposal because:

- Our network will be more heavily utilised as customers' energy usage changes, lowering the per unit cost of electricity—by 2031, our network utilisation is anticipated to reach 75%, up from 60% today, which is already much higher than the 40% average across the National Electricity Market.
- Other parts of our revenues are declining—our metering revenue is anticipated to decline due to most smart meters reaching the end of their economic life, which will reduce the metering charge by half between 2026 and 2031.
- We are taking actions to improve affordability by finding areas to save without significantly compromising customers' bills.

We need to support all our customers as we gradually move from a world of fossil fuel vehicles and fossil gas-powered homes and businesses to one of renewable energies, electric vehicles and electric homes and businesses. This shift presents opportunities for customers, but also the risk that those who don't or cannot invest in building improvements, new technologies, and behavioural changes could be left behind. We have had both these groups in mind when developing our plans.

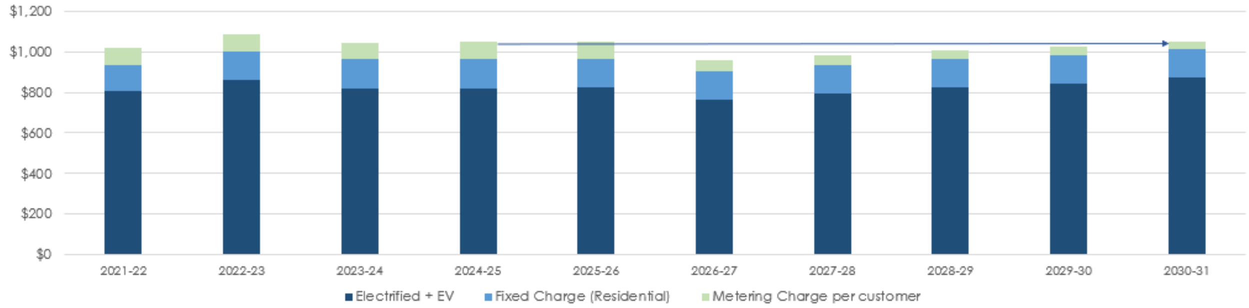
The figures below show estimated price impacts of our Revenue Proposal for different types of residential customers on their electrification journey. Customers that increase electricity usage as they electrify their energy needs (including electrified gas and transport) will pay more in distribution charges than customers with gas and no electric vehicles, due to their higher electricity use. However, these higher charges will be offset by these customers paying a single energy bill – electricity only – instead of three (electricity, gas and petrol or diesel). The assumptions behind this analysis are explained in supporting document Household energy cost analysis.

Figure 0-4: Households with gas and no EV – including the metering charge, annual costs are expected to decrease by 1% (excluding inflation) between today and 2031



Source: AusNet, assumes annual usage of 5.2MWh + incremental increase from today to 2031

Figure 0-5: Households with all electric appliances and EV – including the metering charge, annual costs are expected to stay flat (excluding inflation) between today and 2031



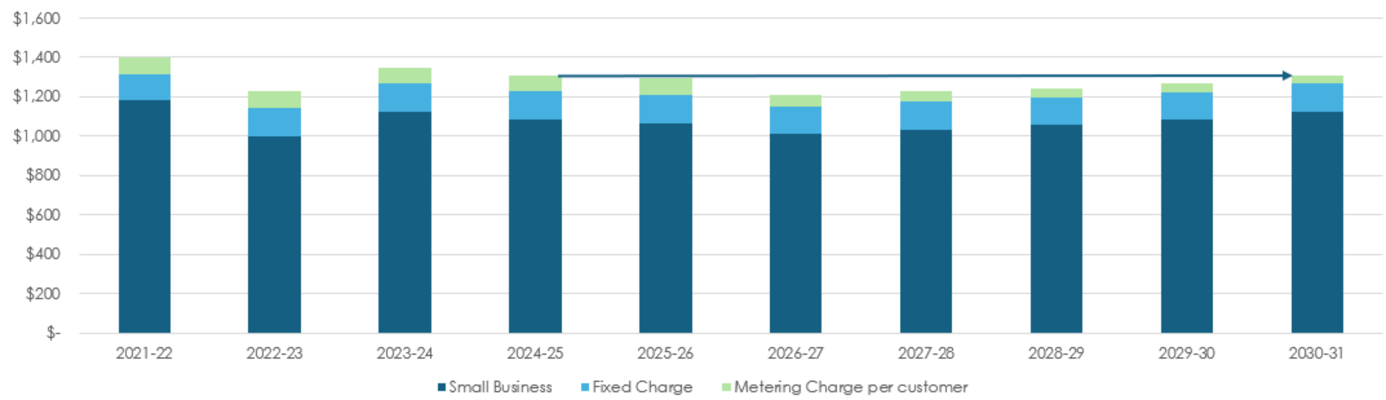
Source: AusNet, assumes annual usage of 8.3MWh + EV incremental increase to 2031

For business customers, particularly larger business customers, electrification trajectories are less clear and more variable, making it challenging to estimate bill impacts for these customers. While we expect some of these customers will electrify over this period, and therefore their bills will increase, increased electricity costs will be offset by reductions in other energy bills (e.g., gas). However, due to the diversity of potential outcomes for different business customers we note the difficulty in modelling these impacts for businesses.

Assuming usage increases incrementally from now to 2031, indicative bill impacts for business customers are as follows:

- Small (<40MWh) businesses – flat bills (excluding inflation) between today and 2031 (as shown below)
- Medium (40-160MWh) business – increase of 2% (excluding inflation) between today and 2031
- Large (>160MWh) business – increase of 2% (excluding inflation) between today and 2031.

Figure 0-6: Small businesses – including the metering charge, annual costs are expected to stay flat (excluding inflation) between today and 2031



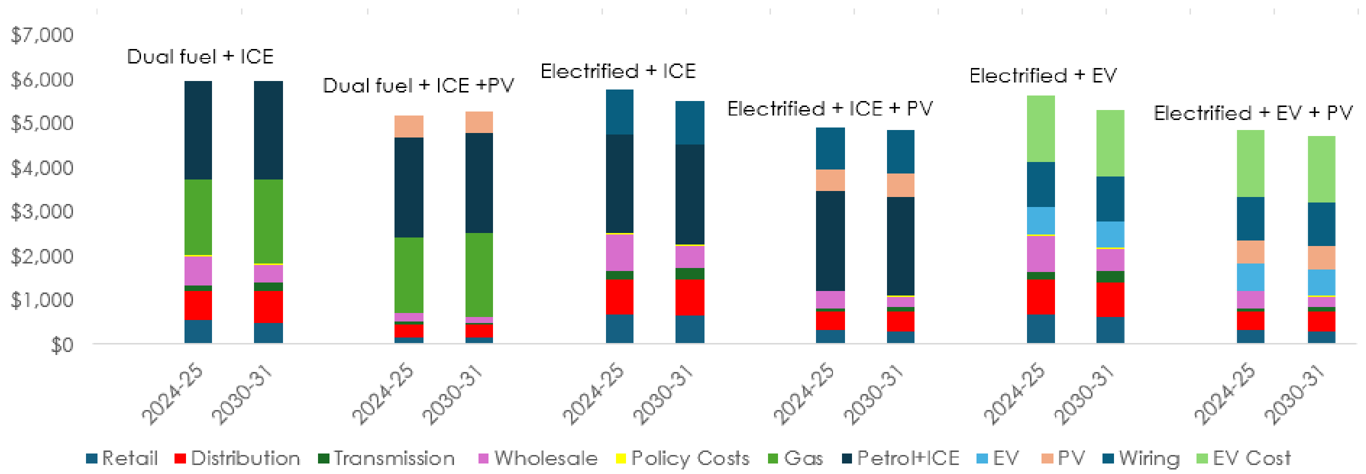
Source: AusNet, assumes annual usage of 11.7MWh

Our network charge is only one part of customers' electricity bills, and electricity bills are only one part of the overall energy bills paid for by customers. As customers increasingly electrify it is important to view our plans in the context of overall customer costs and not focus narrowly on network charges. Increased usage of the electricity network as more customers electrify helps to reduce network charges for each unit of electricity customers use, as our costs are spread over a higher base. Customers using electricity from the network more consistently throughout the day, rather than concentrating use during peak times like early evening, also helps keep costs lower by reducing the need to build more capacity.

Our plans also include investment to improve network reliability and resilience. Network outages cost households a lot, in lost food, wages, production and other costs. Investing to reduce outages means investing to unlock overall cost savings. Our customers have overwhelmingly told us they see this as worthwhile, even if they do not directly benefit from investment in reducing frequency and duration of outages.

The figure below shows the bill impacts of our Revenue Proposal for customers at different points of the electrification journey, taking account of electricity, gas and transport costs.

Figure 0-7: Household total energy bill impact analysis for different types of households and appliances over time, including running cost and costs of electrification, (real, $2025-26)



Source: AusNet.
Note: The above analysis is based on assumptions that are by nature uncertain, and actual bills may differ from the outlook shown here.

Many of the energy transition factors shaping our investment plans in the next regulatory period are expected to continue in the long-term. At the same time, pressure on AusNet to reduce its costs won't go away, and we know customers are unwilling to trade off lower prices today at the expense of steep price rises or price instability later on.

With electricity networks doing much of the heavy-lifting in the transition to net-zero emissions, and network charges forecast to rise as customers move away from gas and fossil fuel cars to electric alternatives, we have an eye to managing costs. While difficult to predict, as energy consumption and network utilisation increase, we expect charges to stay broadly the same, or perhaps even fall slightly, in the next planning period from 2031-36.

There is a need for additional flexibility in the regulatory framework to deliver the energy transition

Compared to previous price reviews, the energy transition is creating greater uncertainty when forecasting future trends and developments that will impact the electricity distribution sector. Assumptions made today for key forecasting parameters including EV take-up rates, customer charging patterns (which is difficult to forecast based on the limited evidence available today) and the rate of electrification of gas appliances may be materially different to what eventuates. In turn, this may require us to invest more, or less, in the network than will be funded under this revenue determination.

To manage this risk, we are proposing various ways to manage the uncertainty in the framework, including:

- Proposing to exclude new connection types from the Capital Efficiency Sharing Scheme; and
- Nominating a range of cost pass through events to enable our revenue determination to be revisited if specific circumstances occur.

We are also working with industry and Energy Networks Australia on a proposal for additional uncertainty mechanisms to be built into the national regulatory framework. These would enable determinations to be revisited should certain parameters, for example peak demand, turn out to be materially different to forecasts.

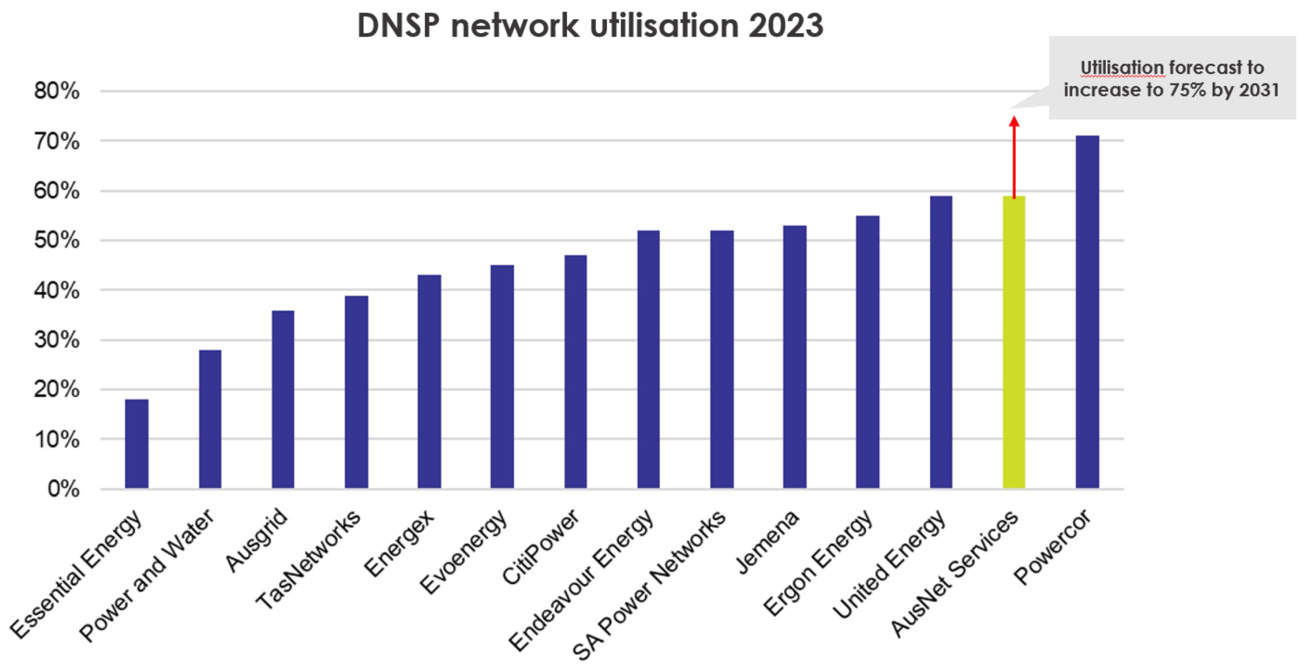
We are maximising network utilisation, and expect it to increase during 2026-31

We know we need to get the most value out of the existing network before upgrading it, given the acute cost of living pressures many of our customers are facing and the long period over which the costs of network investment are recovered from customers. AusNet has the second highest utilisation rate in the NEM, with other Victorian distributors also having high utilisation comparison to other jurisdictions. This reflects several factors unique to AusNet and our Victorian peers, including:

- Long-standing use of probabilistic planning practices, in contrast to deterministic planning relied upon in some other jurisdictions
- The use of smart meters enabling Victorian networks to plan more precisely, by having access to more granular and accurate customer load data, and
- Tariff innovation, with AusNet being the first network in the NEM to introduce Critical Peak Demand pricing for our C&I customers – a program that continues to successfully run today.

However, even with probabilistic planning, as utilisation grows, we will have less ability to absorb growing demand without network augmentation. We will continue to increase the utilisation of our assets, increasing from around 60% in 2023 to more than 75% in 2031. Regardless of their electrification journey, all AusNet customers will benefit from higher utilisation, through lower unit costs of electricity.

Figure 0-8 Network utilisation across electricity distribution networks, 2023 and AusNet forecast



Source: AER RIN data

In addition to ensuring our network investment plans reflect prudent and efficient costs, our Revenue Proposal adopts several measures to maximise network utilisation out to 2031, including:

- Looking at where capex can be deferred through the use of non-network solutions.
- Proposing a solar soak period in network tariffs and rolling these out in line with Victorian Government policy.
- Introducing flexible exports for new solar customers.
- Investing to unlock large scale renewables.
- Introducing flexible load connections for C&I customers.

We also expect electrification of EVs and gas to improve utilisation because:

- Electric vehicles use a large amount of electricity relative to most other appliances in the home, and our time of use tariff signals (if passed through by the retailer) can send customers a signal to charge outside of peak demand times, and ideally within the solar soak period.
- The impact of gas electrification on the network will be most pronounced during winter. As the network currently peaks during the summer months in many localities, the initial wave of gas electrification is expected to improve utilisation of existing capacity.

We will continue to explore ways to improve utilisation throughout the next regu

latory period, including exploring flexible load connections for EVs, trialling V2G and several other projects which form part of our proposed innovation program. Our tariff strategy also promotes this by introducing solar soak, time of use tariffs to manage maximum and minimum demand and introducing Individual Calculated Charges to provide our largest customers with targeted locational network signals.

We have worked closely with our customers to renew a comprehensive set of customer commitments

For 2026-31, we are proposing to maintain key commitments from the current regulatory period where significant opportunities for improvement remain, and new commitments to address areas that have emerged as priorities for our customers. The list of commitments has been built out through the engagement and research we have undertaken over the past 18 months, to reflect opportunities are areas for improvement identified by customers.

Our customers and stakeholders support necessary improvements that AusNet is planning to make over the next regulatory period, but they also wanted assurance these improvements are being made with several criteria in mind, including that AusNet should not seek funding for what was funded in the last reset, and assurance that customer experience and service resources will stay in place even if our ownership, Board or CEO change.

We have accepted the criteria proposed by our Customer Experience Panel and worked with them to develop a proposed set of refreshed commitments for the forthcoming regulatory period. This includes how we plan to measure and report against their progress, holding ourselves to account. We are also proposing an evolution in the way we track and report on progress based on customer feedback.

Table 0-2: Our renewed customer commitments

Commitment	Sub-commitment
Significantly improve customer experience by making customer's interactions with AusNet quicker and easier and fixing customer pain points	• Improve customer satisfaction with key points of interaction with the business • Extend meaningful and timely dedicated engagement with commercial, industrial and farm (CIF) customers, essential services, local councils and community energy groups, and improve access to key information • Proactively detect and address pain points, including through monitoring sentiment, complaints and claims • Support communities impacted by extreme weather events with onsite presence in impacted communities • Make it easier for customers to know who to contact
Provide the foundations for and promote fair and equitable outcomes for all customers in the energy transition	• Provide partnership grants to improve outcomes for specific customer cohorts, with relatively broad eligibility criteria • Advocate for fair and equitable outcomes on behalf of customers, and enable them to advocate on behalf of themselves • Action and publicly share learnings from research and innovation projects • Proactively detect, raise and address equity issues, using AusNet's unique insights
Continuous improvement of all customer communications across all channels to make them more reliable, accessible, specific and accurate	• Approach to communications during extreme weather events that is designed for specific customer requirements during these types of events • Make our communication more accessible and specific, to meet the diversity in our customers' needs and preferences, including uplifting communication for Culturally and Linguistically Diverse (CALD) customers, commercial and industrial customers and customers in specific locations on our network • Make communications more timely, clearer and more reliable in message, language and delivery • Offer preference or channel-of-choice for customer messages and ensure consistency in language and messaging • Continue to improve accuracy of information shared with customers (e.g. estimated start and finish times of planned outages) • Responsiveness to new and emerging issues, as identified by customers and through changes in technology, climate change impacts etc.
Holding ourselves to account	• Maintain a Customer Consultative Committee or equivalent, that has an appropriate mix of skills, and is sufficiently informed to hold AusNet to account on things that matter to customers • Regular check-ins with our Customer Consultative Committee on progress against the proposal commitments, and engaging on forward plans to deliver against them • Provide channels for the Customer Consultative Committee and the AusNet executive team to hear directly from customers • Continue to report annually on progress against customer commitments. Reporting would be incorporated in the annual disclosure which is part of our Energy Charter commitment, plus an addendum for any unique items

Further to our refreshed customer commitments, we are also committed to making customer experience improvements for our customers identified in the learnings from our February storm post-incident review (PIR). This includes:

- Improving the robustness of our Outage Tracker and having appropriate back-up systems in place so that customers can always have access to outage information, even if something goes wrong.
- Implementing additional methods of communication during outages, including automated services that are welcomed by some customers, while always maintaining access to contact centre staff.
- Improving the accuracy of our Estimated Times of Assessment (ETAs) and Estimated Times of Restoration (ETRs) provided to customers during unplanned outages, and training staff on the most appropriate customer communications around these metrics.
- Improving the contact details of customers in our systems, to ensure we can access as many people as possible during storms, through their preferred channel of communication.

Our customers also want us to create a better future for them through the transition, including by advocating for policy and regulatory changes that enable them to achieve their aspirations. It has never been more important for networks and other industry participants to listen to our customers' needs and preferences and evaluate whether the current regulatory frameworks continue to be fit for purpose. The figure below summarises the key areas of reform where our customers want us to actively advocate on their behalf, as co-designed with our customers and stakeholders.

These have been identified throughout our engagement process as areas where policy or regulatory settings limit customers' ability to take control of their energy futures or limit AusNet's ability to deliver outcomes in line with customers' best interests. We are already progressing conversations with governments, market bodies and decision makers on all topics presented in the figure.

Figure 0-9: Where we will advocate on behalf of our customers

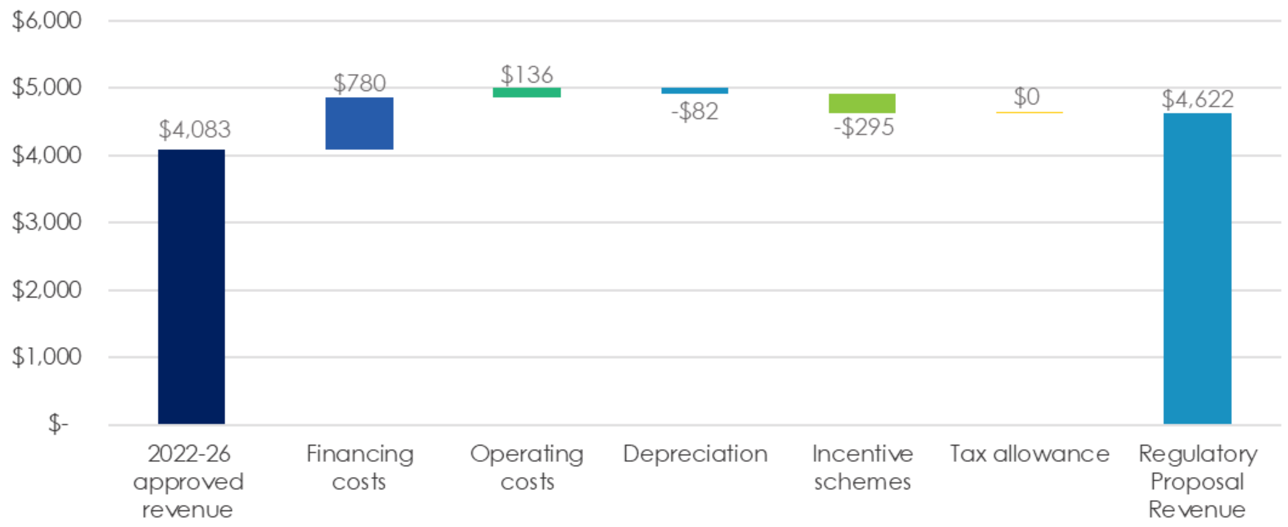
Problems for customers	We will advocate for change to...
Regional reliability can be poor and the regulatory framework provides little incentive to invest	Support reliability investment in regional communities
Narrow definitions of benefits that do not capture broader factors and societal benefits	Broaden the range of benefits included in regulatory decisions
It is too uncertain to lock in plans for 2031	Introduce targeted EDPR and Tariff Structure Statement 'reopeners'
Energy efficiency (or lack there of) not considered enough as part of the energy transition	Value energy efficiency in the energy transition
Life support customers should be better protected	Support The Energy Charter Better Together initiative to improve life support customer register management
Many customers feel disempowered by the energy transition, and risk being left behind	Build customer agency through targeted communications
Slow network tariff reform is increasing cross-subsidies between customers with and without CER	A transition to tariffs and connection agreements in a way that benefits all energy consumers in the long-term

Our plans in more detail

Our proposed revenue requirement

Our real revenue requirement for 2026-31 is 13% higher than approved revenues in the current regulatory period, with the impacts of higher interest rates and expenditure partly offset by lower incentive scheme payments and depreciation. Higher revenues will be spread across a growing base of customers and energy throughput, keeping average prices relatively flat.

Figure 0-10: Movement in revenue building blocks ($m, real 2025-26)



Source: AusNet.

Our capital expenditure forecast

Our forecast of prudent and efficient capital expenditure in the 2026-31 regulatory period of $3.5bn is 72% higher than expected investment in the current period, in net terms. This uplift addresses a range of investment drivers, including the need to:

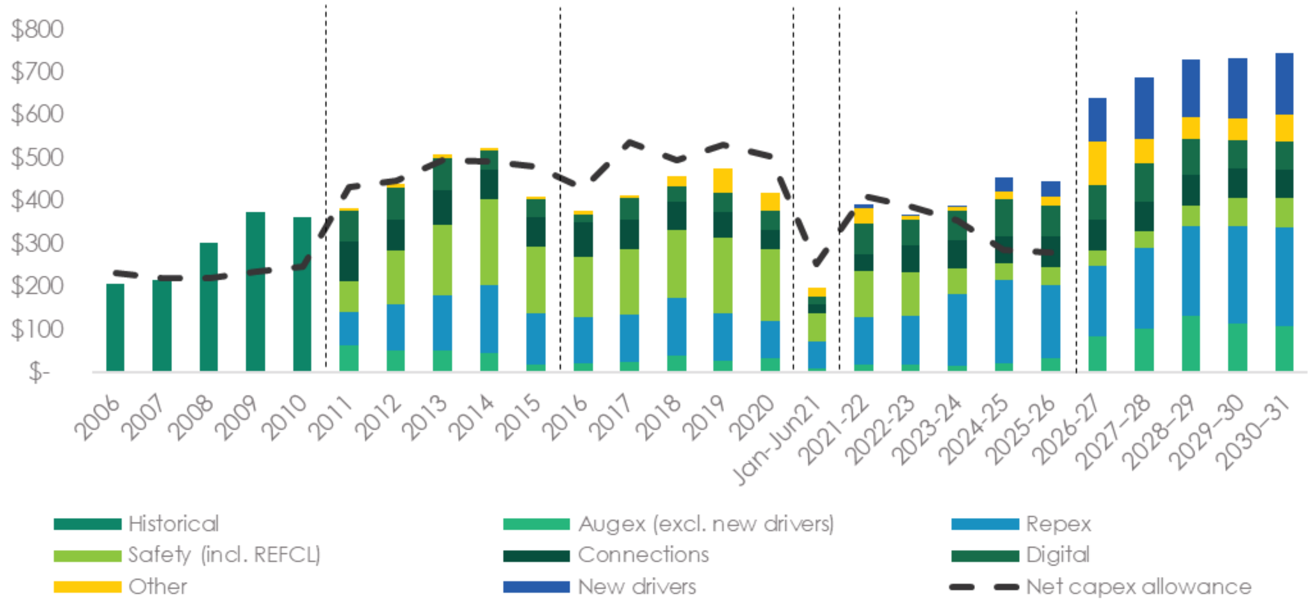
- Replace aging and deteriorated assets.
- Manage higher unit costs driven by market pressures
- Enable electrification and unlock renewable energy.
- Uplift network resilience and regional reliability.
- Commence a multi-period, risk-based strategy to upgrade and refurbish our ageing depots.
- Deliver an improved customer experience.

The increases required to fund these expenditure drivers have been partly offset by:

- Deferring $70m of resilience network hardening expenditure to beyond the next regulatory period
- A comprehensive, top-down assessment of each capex category, which has led to the removal of $42m of overlaps or synergies from the capex forecast
- Deferring $29m in network expenditure where more efficient investment options are available
- Adjustments to reflect expenditure that will be funded through incentive schemes, amounting to $8m, and
- Applying productivity growth of 0.5% to our forecast of capitalised overheads, reducing our capex forecast by $4m.

We have undertaken a comprehensive deliverability assessment of the proposed capital program. This has confirmed we have the necessary capabilities and resources in place to deliver the program and outlines the actions and initiatives we are implementing to mitigate delivery risks.

Figure 0-11: Actual, expected and forecast net capital expenditure by driver ($m, real 2025-26)



Source: AusNet.

** New drivers include resilience, large renewable connections, addressing worst served customer reliability, and smarter operations (DSO). Other includes non-network expenditure*

Our operating expenditure forecast

Our forecast of prudent and efficient operating expenditure in the 2026-31 regulatory period of $1.7bn including debt raising costs is 14% above our expected spend in the current regulatory period. This reflects large increases in the customers numbers and demand expected on our network, improvements in our digital systems to keep up with customer expectations and new obligations imposed on us that will increase our opex costs. This includes new obligations relating to bushfire safety, maintaining system security and how we prepare for and respond to extreme weather events.

With a focus on affordability, we have decided not to include in our forecasts $43 million in expected cost increases and have identified $9 million in synergies across our forecast during consultation. Additionally, we have reduced our GSL forecast by $5m to reflect our reliability related investment and the removal of GSLs for ‘controllable’ service levels, consistent with the approach agreed with customers at the last reset. We have also proposed a negative step change of $4m to reflect efficiency improvements from Digital investments, provided that expenditure is approved. AusNet’s proposed operating expenditure forecast minimises costs while ensuring that we can maintain the reliability and safety of network services and manage the expected growth in our network.

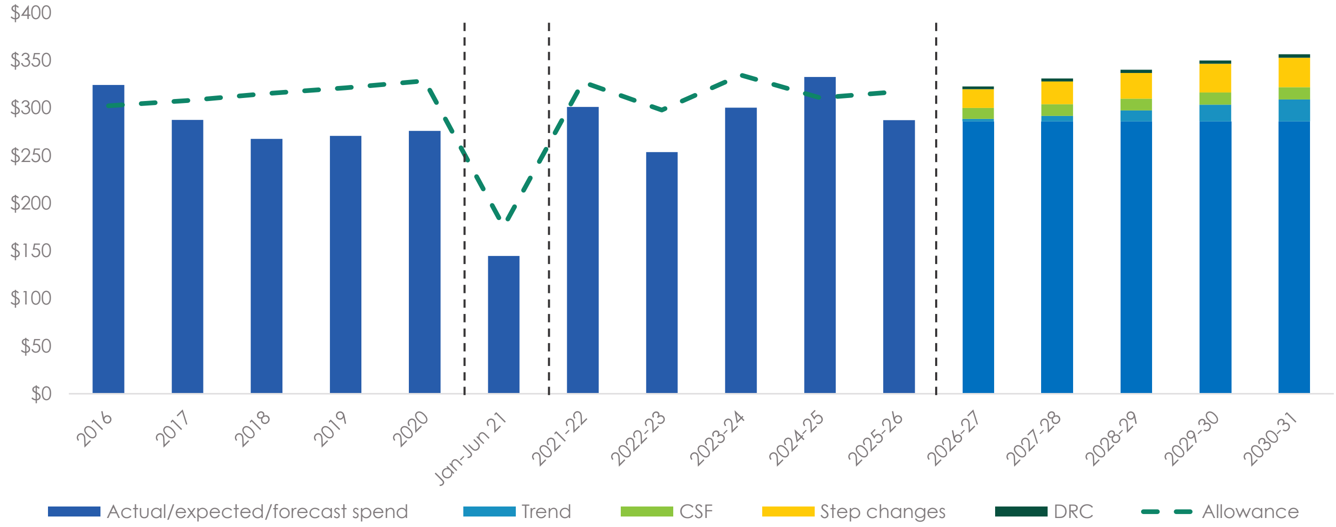
We have selected the 2022-23 year as our opex base year on the basis that it reflects:

- Ongoing, efficient opex under normal operating conditions.
- Most recent audited actual expenditure that is available at the time of submitting our Revenue Proposal.

Opex for 2022-23 passes the AER’s efficiency assessment in its Annual Benchmarking Report, published in November 2024 which shows AusNet is efficient compared to its peers.

The AER’s standard approach to real cost escalation is low compared to the labour increases we have seen in this current period and continue to face. This is an issue across Australia, and is evident through recent and ongoing EBA outcomes, which far exceed the cost escalators applied under the AER’s standard forecasting approach. Despite this, we have adopted the AER’s standard approach of averaging two forecasts of this measure, and intend to manage the additional, unfunded opex we expect to incur through further productivity savings.

Figure 0-12: Actual, expected and forecast operating expenditure by element ($m, real 2025-26)



Source: AusNet

Our tariff strategy

We are moving to a decarbonised energy system with all-electric homes and businesses, electricity for transport and energy from renewables on a small scale (e.g. rooftop solar) and large scale (e.g. solar and wind farms, and commercial battery systems). This transition is creating new challenges for the grid and the energy system, including the risk of very high evening peaks from electrification of gas and transport and minimum operational demand and reverse flow peaks during solar exports in the middle of the day. Network tariffs can play a role in managing those new challenges, by providing customers pricing signals to incentivise behavioural change.

In the past, networks have mostly needed to manage evening peaks, so tariffs have been designed to send efficient price signals by making evening usage more expensive. However, with the growing penetration of solar, there is a new opportunity to encourage all customers to increase usage to soak up the excess solar. Under our proposed tariff strategy, customers that can shift some usage from the evening peak to the middle of the day would benefit from doing so through lower network charges.

Our tariff strategy is designed to offer customers multiple opportunities to save on their energy bills through tariffs, as summarised in the below figure. The tariffs are also designed to improve equity by reducing the difference in network costs paid by customers with and without solar, where today customers with solar pay about half compared to those without solar. By making electricity very low cost during the day, both customers with and without solar can benefit from cheaper electricity during the day.

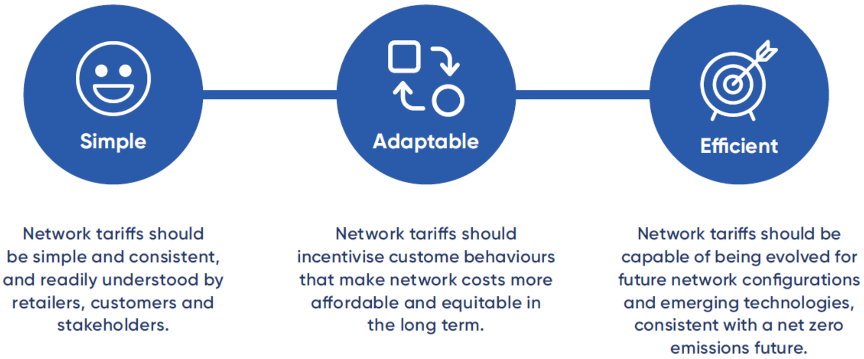
Figure 0-13: Tariff strategy for 2026-31, giving customer options to save on their bill

Enable all customers to benefit from solar by adding a cheap "solar soak" period (11am to 4pm) to the residential time of use tariff	**Reward household flexibility** through an optional CER tariff	**Reward grid-scale storage flexibility** through four new storage tariffs	**Increase optionality for commercial customers** with optional critical peak demand (CPD) tariffs as well as considering potential locational tariffs	**Build customer agency** to engage with tariffs and save money, via communications campaigns and regulatory framework advocacy

Source: AusNet

As explained in our Tariff Structure Statement (TSS) Explanatory Paper, the design of our tariff structures, assignment and transition rules are guided by pricing objectives that were developed during an extensive customer and stakeholder consultation process undertaken by the Victorian distribution businesses. During this engagement process, stakeholders supported the simplification of the existing pricing objectives for the proposed 2026-31 TSS, which are shown in figure 0-14 below.

Figure 0-14: Pricing objectives for our proposed 2026-31 TSS



Source: AusNet

Uncertainties that may impact our Revised Regulatory Proposal

While the forecasts included in this Regulatory Proposal reflect the best information currently available, there are several known externally driven uncertainties that may impact our Revised Regulatory Proposal. These include (non-exhaustive):

- Implications of the AER's 2024 VCRs for our investment plans.
- Revised demand forecasts reflecting the 2024-25 summer and updated inputs, assumptions and projections from AEMO, the Victorian Government and other external sources.
- Market conditions for bushfire liability insurance, which are volatile and may move in response to global developments such as the January 2025 Los Angeles fires.
- Implementation of the Victorian Government's response to the Network Outage Review of the February 2024 storms and other changes to the resilience regulatory framework, which continues to evolve (e.g. AEMC Rule Change Review of Resilience).
- Updates to our connections capex forecast resulting from new connection applications received.
-

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- The costs of key inputs and materials which may change in response to market-driven cost pressures.
- Any changes to our regulatory obligations or government policies that may impact our plans.

As further information becomes available regarding these uncertainties, we will engage closely with the AER, our customers and other stakeholders on any implications for our plans.

Conclusion

Our proposal represents a significant step forward in delivering the network and services that our customers need and expect in 2026-31, and beyond. While our plans require a significant increase in expenditure compared to current spending levels, this reflects the evolving needs of our network and customers, backed by rigorous cost-benefit analysis, extensive engagement, and a strong focus on deliverability. Customers have clearly voiced their expectations for improved service levels, and this proposal responds directly to them.

With network utilisation already high and forecast to grow further by 2031, our plans deliver flat bills for residential customers and a slight real increase in average prices, while maximising efficiency and value for customers so they are not paying more than they need to for the outcomes they expect. In addition to being shaped by our extensive engagement program, our proposed projects and programs have been subject to rigorous technical and economic assessment. A suite of affordability measures has been incorporated into our plans, to respond directly to our customers' affordability concerns and ensure our proposal reflects good regulatory practice.

We have also worked closely with customers to refresh and strengthen our customer service commitments, establish a set of advocacy commitments and expand on and strengthen governance arrangements, embedding transparency and accountability at the heart of our plans. The Coordination Group has recognised the value of our Draft Proposal in delivering meaningful service improvements at an affordable price, and this Regulatory Proposal goes even further – maintaining these improvements while keeping bills flat for most customers.

Our proposal strikes the right balance between investment and affordability, and is a forward-looking, responsible plan that reflects what our customers have told us they want – a network that is reliable, resilient, and responsive to their concerns, without unnecessary cost pressures.

1. Introduction

This regulatory submission sets out AusNet's proposal for its electricity distribution network for the next regulatory control period, which commences 1 July 2026 and runs through until 30 June 2031.

1.1. Structure of this Regulatory Proposal

Under the National Electricity Law (NEL) and the National Electricity Rules (the Rules), the AER is responsible for the economic regulation of electricity distribution services. In accordance with the Rules, the AER conducts a periodic review to determine our revenue requirements and other matters relating to the provision of regulated electricity distribution services.

This document is our Regulatory Proposal for the period commencing on 1 July 2026 and ending on 30 June 2031 (2026-31 regulatory period). The proposal is accompanied and supported by:

- An overview paper, which provides a plain-language summary and explanation of our Regulatory Proposal
- A tariff structure statement and an explanatory paper, which describe our proposed tariff structures and the rationale for our approach
- Completed templates and supporting information as required by the Rules and the AER's Regulatory Information Notices (RIN), and
- Appendices, supporting documents and models, which are cross-referenced in this document.

This regulatory proposal explains our revenue requirement for distribution standard control services and our proposed prices for several alternative control services including:

- Metering
- Public lighting
- Fee-based services, and
- Quoted services.

1.2. Presentation of cost information

The actual and forecast expenditure in this proposal reflects our cost allocation methodology, as approved by the AER, and is consistent with:

- AusNet's capitalisation policy, which remains unchanged from the current regulatory period, and
- The application of the AER's incentive schemes that encourage cost and service efficiencies over time.

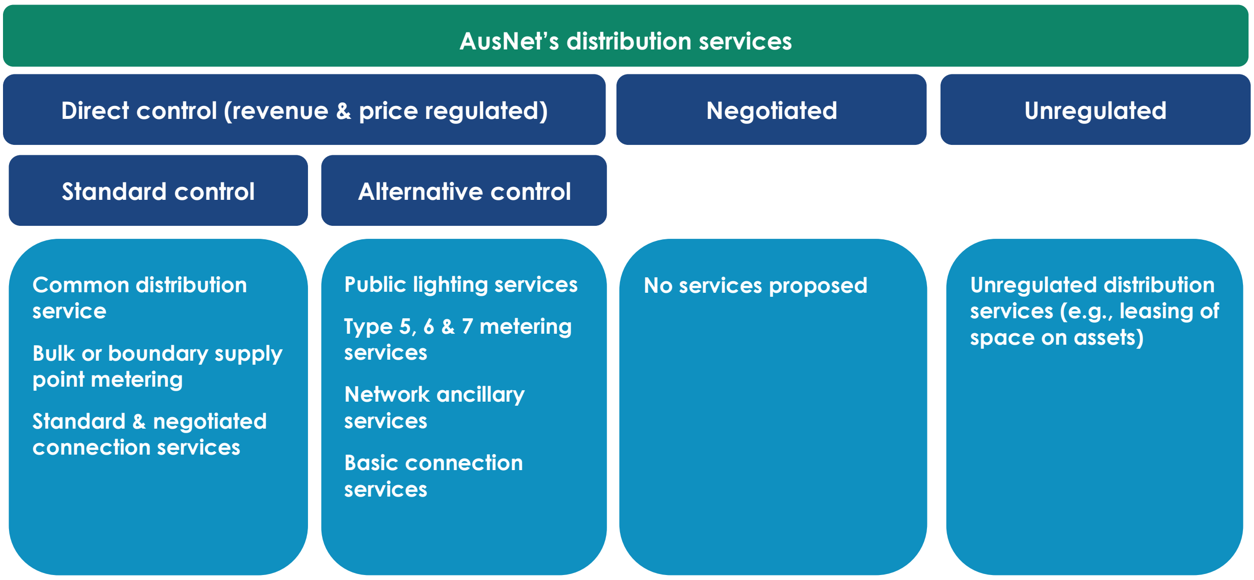
In terms of the financial data presented in this submission, it should be noted that:

- All monetary values presented exclude GST
- Unless stated otherwise, monetary values are presented in June 2026 dollars
- Where data is presented in nominal terms, an inflation forecast of 2.50 per cent per annum has been applied, consistent with our forecast of expected inflation and the AER's inflation guideline, and
- Numbers in tables may not add up due to rounding.

1.3. Definition of distribution services

This revenue proposal covers the distribution services set out in the AER's Framework and Approach (F & A) paper[6]. The diagram below shows the various available classifications.

Figure 1-1: AusNet's distribution services



A full list of services and their classifications is provided in Appendix 1B Service Classification Proposal.

This revenue proposal is consistent with the service classifications outlined in the F&A paper. Since the F&A consultation we have responded to feedback that any in-front-of-the-meter resilience services we provide to critical customers (such as other utilities) should be classified as alternative control services, rather than standard control. We consider that this fits under the definition of Connection Application and Management Services and so no change is needed to service classifications. This issue is discussed further in section 6.12 – resilience expenditure.

1.4. Supporting documentation

AusNet's Regulatory Proposal has been prepared with reference to the following documents:

- Appendix 1A – Cost Allocation Methodology
- Appendix 1B – Service Classification Proposal
- Appendix 1C - Related Party Arrangements; and
- Appendix 1D – Capitalisation Policy.

Further supporting material, which is specific to individual aspects of the proposal, are listed in the relevant sections of the proposal document.

[6] AER, Framework and Approach, July 2024. Available here.

2. Customer engagement & research

2.1. Key points

- The engagement and research underpinning this Revenue Proposal is the most extensive we have undertaken for a price review, by a significant margin. This was important to us as the decisions being made in this regulatory period – around our role in the transition to net-zero emissions, preparing for extreme weather events and many more – will have a significant impact on our customers' lives in the upcoming regulatory period and beyond.
- Our Regulatory Proposal includes higher levels of expenditure to enhance existing services and introduce new ones in response to our customers' evolving needs and expectations. This includes investment in some areas that are high priority for our customers and that they are willing to pay for (e.g. reliability improvements), but have not historically formed part of ex ante expenditure proposals or been incentivised through existing service standard schemes leading to adverse outcomes for customers. This has necessitated rigorous engagement and research to test different price and service level trade-offs with our customers, and provide the AER with the information it needs to ensure its decision-making aligns with our customers' preferences and long-term interests.
- Our engagement approach has met, and often exceeded, all requirements in the AER's Better Resets Handbook, which outlines the AER's expectations of networks' approach to engagement.
- Our engagement and research program has included:
    - Extensive customer research, hearing from over 16,000 customers via 17 unique studies, and
    - A broad program of engagement, totalling over 150 formal engagement hours with customers and other cohorts via workshops, forums, one-on-one meetings and others.
- An additional 240 formal hours (and many more informal hours) of detailed discussion time with our 6 Customer Panels, debating the outcomes to be achieved for each of our Tariffs & Pricing, Electricity Availability, Future Networks, Benchmarking & Opex and Customer Experience workstreams, supported by a Research & Engagement Panel and a Coordination Group tasked with an overarching governance and coordination role in the engagement program.
- In addition to engaging on the contents of our proposal, we have engaged extensively on the design of the engagement program itself. This includes co-designing the engagement plan via a workshop in mid-2022, collaborating with our Panels on the topics and agendas for meetings and establishing a Research & Engagement Panel at the request of customer advocates, with whom we engaged on the design of several key research and engagement activities.
- We acknowledge that some customers, customer advocates and other stakeholders do not support every aspect of this proposal for a variety of reasons, including that we're doing too little (and they're willing to pay more for a higher level of service), that we're doing too much (and it's too expensive), or that our plans include spending on an activity they don't personally see value in. Where we have heard dissenting views and trade-offs, we have acknowledged these through the proposal.
- Notwithstanding this, we strongly believe our proposal strikes the right balance between service levels and costs in the 2026-31 period, while setting us up to deliver the outcomes customers want and expect longer-term. This balance has been determined on a wide range of quantitative and qualitative engagement and research activities, and deliberations with our Panels to select approaches taken in this proposal. The Coordination Group's report on our Draft Proposal recognised the strong role our research and engagement activities played in driving our proposal, and we await their comments on this Revenue Proposal.
- We believe it is important customers are given the opportunity to participate in the regulatory reset process and have their say on our proposal. We published our Draft Proposal in September 2024 and extensively promoted that document for consultation and the channels available for customers to provide feedback. Our promotion of the Draft Proposal and opportunity to provide feedback on it reached over a million people in AusNet's distribution area.

Table 2-1: Our engagement program by numbers

Over 240 hours in deep discussion with our 6 Customer Panels & Coordination Group	**Over 150 hours** of EDPR-specific engagement with customers, communities and other key groups	**More than 16,000** people shared their views, experiences, needs, & aspirations via 17 unique research activities
22 *focus questions* guided discussion & exploration of key topics, to ensure laser focus on customer outcomes	**1,000,000+** customers reached during engagement on our Draft Proposal	**3 intensive 2-day forums** with all EDPR Panel members, AusNet board members and staff, and AER and Victorian Government staff.

Source: AusNet

Figure 2-1: AusNet panel members with AusNet staff on site in the Dandenongs

Source: AusNet

2.2. Chapter structure

The structure of the remainder of this chapter is as follows:

- **Section 2.3**: Our engagement approach
- **Section 2.4**: Outcomes of our engagement activities
- **Section 2.6**: Our proposal was "stress tested" via public consultation process
- **Section 2.7**: Our plans for post-lodgement engagement, and
- **Section 2.8**: Supporting documentation.

2.3. Our engagement approach

This chapter outlines our approach to inclusive and evidence-based engagement and research process. We have remained committed to sincere, effective, open and honest customer engagement over the two years we have been engaging on this Revenue Proposal to develop plans that reflect long-term interests of customers.

This chapter focuses largely on our engagement process – what we discussed, how and with whom.

For the overall proposal and specific elements, feedback has largely been neutral to positive, with small proportions of customers willing to accept lower levels of service for lower prices, or asking for higher levels of service with a willingness to pay more for them. We did not, and do not think it realistic to expect, that we can achieve 100% satisfaction or agreement with any or all aspects of our proposal.

The remaining chapters reflect the outcomes of our engagement process – that is, the network plans that have been developed using outputs from our engagement process and understanding of customers' long-term needs, preferences and other interests and the variation within them, as well as the expectations of the Australian Energy Regulator and Victorian Government.

2.3.1. Our extensive business-as-usual engagement and research enabled our price review engagement to start off a higher base

Listening to customers is something we do all the time – not as a one-in-five-year event when we need to develop our proposals for the Australian Energy Regulator. We conduct around a dozen research studies each year on regular or one-off topics. In addition we have several standing customer forums, account managers for key customers and segments, and engagement professionals working on the delivery of day-to-day services and major projects. We also participate in trials and research projects with universities, social service organisations and other partners. These activities give us regular and robust insights on our customers' experiences and preferences and how they are changing over time.

We have leveraged these insights in this engagement program and as a result, our 2026-31 engagement has started off a much higher base than in previous regulatory reviews. We largely knew what our customers were thinking about, how their needs and priorities were shifting, and the emerging issues they were wanting to talk about in more detail. Our price review-specific research and engagement program enabled deeper, quantitative and qualitative explorations of customer needs and priorities to select the right cost vs service level balance. This included exploring willingness-to-pay for different service levels (such as reliability).

2.3.2. Customers collaborated on our initial engagement design and its evolution

Our high-level approach to research and engagement for EDPR 2026-31 was developed in collaboration with our Customer Consultative Committee, EDPR 2021-26 engagement participants, government representatives and other key stakeholders via a workshop in October 2022. Our strategy, principles and engagement model were refined at this forum, and we collaborated-to-empowered customers to select the topics for engagement, the design and terms of reference for a Stakeholder Reference Group (SRG) and series of panels, and activities to support their deliberations in a broader engagement program. The initial engagement plan was published for public consultation in December 2022. It was treated as a living document, and the engagement plan was formally updated three times through the process.

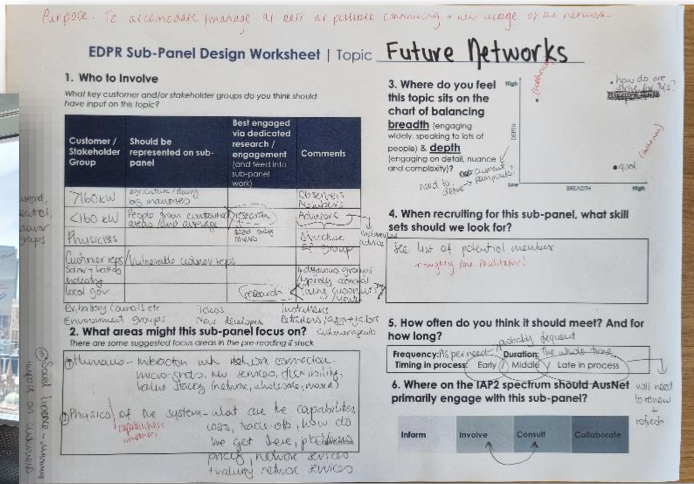
It was decided that our customer engagement program should focus on topics and issues that are meaningful to customers and where customers can meaningfully impact outcomes. This includes new expenditure categories such as resilience, areas where customers are seeking outcomes above minimum compliance standards such as reliability for worst-served customers, and novel proposals identified by AusNet for testing such as how to efficiently connect more renewables.

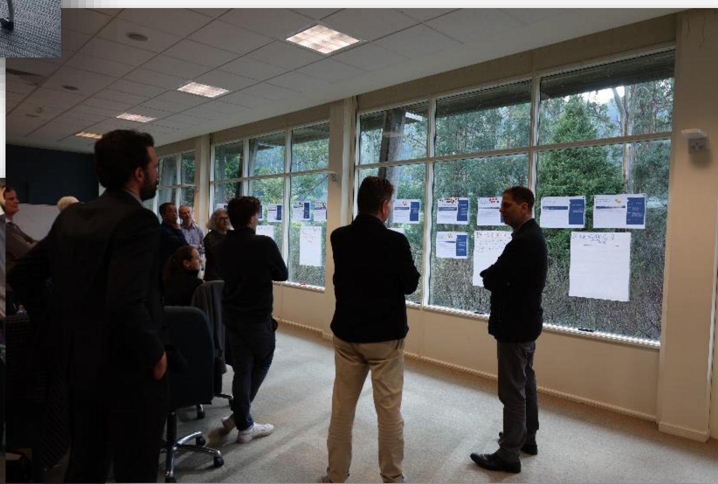
Given this, we acknowledge not *all* detailed aspects of our proposal have been engaged on, though the proposal as an overall package has.

The engagement approach evolved and expanded enormously through the process, largely driven by the wishes of the customer advocates involved in the process. AusNet was highly responsive to requests for more meetings, more analysis and additional conversations on topics. This included a restructure of the Panels early in the process to a model that better fit our engagement objectives.

Our approach incorporates and builds on the extensive customer engagement and research we do in our day-to-day activities. To strengthen our process and ensure we're respecting the extensive contributions customers and others are already providing to AusNet, insights and data already gathered have been brought into the EDPR engagement process.

Figures 2-2 to 2-5: Collaborating on the engagement program design and evolution in 2022, 2023 and 2024





2.3.3. Overview of our key engagement activities

Table 2-2: Summary of our deep and broad engagement

Deep engagement with our 6 panels and Coordination Group has determined the approach taken to key elements of our proposal	**Broad research and engagement** involving over 16,000 customers and other stakeholders has supported the deliberations of our panels
We established a set of customer panels – a new approach AusNet has taken for engagement on a price review – to engage deeply on the outcomes to be achieved in the proposal. Broad research and engagement have informed 240 hours of deliberation by our panels on the right cost vs service level balance to be achieved in the proposal. **Our 6 customer panels:** • Covered 6 workstreams: Future Networks, Tariffs & Pricing, Benchmarking & Opex, Customer Experience, Electricity Availability, and Research & Engagement. • Involved 22 customers and advocates, with most sitting on multiple panels. Membership is aligned to expertise and interest areas • Collaborated on 22 *focus questions* that defined their remit and determined meeting agendas, and clearly link the outcomes of our engagement program with the inclusions in this proposal. We empowered the panels to tell us what information they wanted to consider when answering the focus questions, which informed the agendas for meetings. • In answering the focus questions, considered things like current and desired states, including customers' current experiences, needs, expectations and willingness and capacity to pay for improvements (or save for degradations), regulations and frameworks, government objectives and directions, various options and service levels, and many other factors as relevant. **Our Coordination Group:** • Has had an overarching governance and alignment role in the engagement program, including identifying and resolving conflicts, overlaps and value-stacking opportunities between workstreams • Comprises a Chair and one representative – a *Panel Lead* – from each of the 6 workstreams • Engaged on key topics not addressed by the workstreams, such as the regulatory building blocks and price path • Authored an independent reports on the Draft Proposal and this proposal.	The purpose of our broad engagement and research was to give more customers and stakeholders an opportunity to engage and hear the views of many to inform the detailed deliberations of our panels. • **20 customer workshops** across 4 rounds in Wangaratta, Epping, Morwell/Traralgon & online (2) with more than 100 customers • **9 joint network forums** on opportunities for joint engagement (1), vulnerability (2), resilience (1), framework & approach (2), tariffs & pricing (3) • **Quantifying Customer Values study** interviewing 120 customers and surveying 3,527 customers. • **Major customer engagement** via 1 forum and 13 meetings • **2 council forums** on the overall proposal and public lighting • Customer segmentation research involving 3,263 customers • **Energy sentiments research** with 400 business and residential customers every 6 months • **Customer satisfaction (C-Sat)** research conducted monthly on customers' experiences with planned and unplanned outages, new connections and complaints • **Community interviews** conducted by panel members • **Generation developers** surveyed and interviewed • **Digital Energy Futures** study involving 200 AusNet and Ausgrid customers • **Community Hub** online engagement pages received thousands of views • **Public engagement on the Draft Proposal** reaching over 1 million customers and receiving feedback from over 200 customers via formal submissions, in customer workshops or in meetings.

Source: AusNet

2.3.4. Our engagement program meets the AER's requirements for nature, breadth and depth, and clearly evidencing the impact of engagement

The AER's Better Resets Handbook describes their expectations of networks' engagement outcomes with respect to a) the nature of engagement, b) the breadth and depth of engagement and c) clearly evidenced impact of this engagement. Our engagement program has been designed to align with these expectations while remaining flexible and responsive to participant needs.

We have responded to each of the AER's engagement program requirements below.

Table 2-3: How we have met the AER's Better Resets Handbook requirements

The AER's requirements	How we have met this requirement
a) Engaging the right way	
Sincere engagement	• Our program has had the strong support of the AusNet Board and senior leaders, who participated in and/or observed almost all engagement activities. • Our engagement program has been well-resourced, co-designed with customers, and evolved considerably with their input during the process. The considerable changes made based on participant feedback included a restructuring of the panels in mid-2023 and a significant increase in planned panel meeting time. • We resource a robust business-as-usual research and engagement program that enables more informed, transparent and nuanced discussions. • There are many examples of expenditure categories and engagement activities that came from our customers and other advocates, such as reliability for worst-served customers, voltage management and support for key organisations and communities. • We provided panel members with access to confidential and sensitive information on many aspects of our performance, operations and operating environment.
Treating consumers as partners	• We engaged consumers from the very beginning of the revenue proposal process, working with them at every stage of our planning. Research and engagement with customers to inform key decisions has been embedded into our ways of operating. Our research program is unique among networks and equips us to track trends and understand customers' preferences and variation within it in a more nuanced and robust way than can be done with engagement alone. • We collaborated with customers on the target level of influence they wanted to have on the outcomes included in this proposal with respect to each workstream. • The engagement approach evolved and expanded enormously, largely driven by the wishes of the customer advocates involved in the process. AusNet was highly responsive to requests for more meetings, more analysis and additional conversations on topics. This included a restructure of the Panels early in the process to a model that better fit our engagement objectives. • We have invested heavily in upskilling customers and other advocates to be effective representatives of customers on the details of our proposals, over a long period of time. Many of the customers and advocates engaged in this process have a long history working with AusNet, enabling them to challenge us more deeply and on a wider range of matters. • We also held workshops with groups of customers that better-reflect AusNet's broader customer base – that is, those who are not especially interested in or knowledgeable about energy matters, but who have views and can comment on what feels and sounds right for, and the expectations of customers. Their contributions were invaluable and complemented our customer panels well. We checked in with them at 4 key stages in the planning process.
Equipping consumers to engage	• We prepared detailed pre-reading packs for panel meetings that were sent in advance. Panel members were paid to prepare for meetings and to engage with each other via online *Padlet* boards prior to meetings. • We prepared a weekly bulletin to keep our panel members and key stakeholders informed on developments in the engagement process, changes in our operating environment, opportunities to engage, materials available for review, and other items of interest to the group. • We remunerated participants for their time to incentivise involvement and ensure financial capacity was not a barrier to their involvement. Some panel members chose to donate their remuneration, and a very small number elected not to be paid. • We shared extensive research and engagement from multiple sources to help panel members form their own opinions and participate in deeper and more nuanced discussions – for example, tracking and sharing how customers' feedback has changed over time and providing multiple data sources on many topics. Through research we hear from many customers, which is highly

	valued by our customers and advocates whose role it is to represent their interests in discussions on the detail. • We appointed many customers to our panels who are well-connected to communities, who have lived experience as AusNet customers and a strong personal interest in achieving great outcomes for their communities. Their participation complemented that of longer-standing and professional customer advocates' contributions, who were well-equipped to challenge on more detailed and/or historical matters, and bring insights from other jurisdictions' processes. • We paid panel members to observe and debrief on broad engagement activities, such as customer workshops and webinars. • We encouraged participants to engage directly with customers and communities and seek additional information/viewpoints beyond what we provided. • The Coordination Group was given a fund to spend at its discretion on research and engagement activities to support them in being effective advocates for AusNet customers. The Coordination Group developed its own governance framework for the fund, which supported approximately 100 hours of additional member-initiated research with AusNet customers. • Panel members were encouraged to submit topics and/or questions for various research and engagement activities we were undertaking, to support their deliberations. • We provided opportunities for our panel members to see and hear new customer perspectives. This included face-to-face meetings in different areas of the network, visits to areas impacted by extreme weather events, some guest speakers and a visit to a major customer site. • We encouraged and responded to extensive requests for more information or analysis, more resourcing and more engagement sessions.
Being accountable	• Most of our engagement was observed by at least one member of the AER's Consumer Challenge Panel (CCP) and various members of the AER's project management and technical teams. • Our engagement outcomes and materials have been published on our Community Hub page, and we have been publicly sharing summaries of key meetings and activities throughout the engagement process. We have also kept advocates and stakeholders up-to-date with what we are working on via weekly bulletins. • We engaged experienced advocates who have been able to keep us accountable to commitments and plans made in the past. • We acknowledge that not all of our engagement and research activities have been subject to the same level of scrutiny or co-design – particularly those undertaken prior to the formal commencement of our price review engagement, as well as certain business-as-usual activities that have informed this process. While we see great value in a co-designed and closely scrutinised approach, implementing it universally across all our engagement and research activities is inherently resource-intensive. Doing so would inevitably constrain the scope and breadth of engagement we can undertake and negatively impact the quality of our more operational engagement and research activities. • Where our engagement and research has not been closely scrutinised we have sought to uphold accountability and build trust through alternative measures, such as presenting longitudinal data, engaging experienced advocates who can provide continuity and insights, leveraging the expertise of our staff, and fostering confidence in the process through clear and open communication and welcoming challenge. We remain committed to finding the right balance between rigorous engagement and the practicalities of delivering meaningful and timely outcomes for the communities we serve. • We have also regularly sought feedback – informally such as through conversations and emails, and more formally such as through surveys – on our engagement approach. We have held ourselves to continuous improvement and adjusting our approaches to suit the preferences of our participants. We recognise the engagement process can't be optimised for any one individual, so have sought to make improvements that deliver the overall best approach for each engagement "group". We acknowledge that some feedback and suggestions have not been implemented because they are not in line with the preferences of the majority who would be impacted by a change, or are not practical for us to achieve.
b) Achieving breadth and depth of engagement	
Accessible, clear and transparent engagement	• For every engagement activity, we clearly described the purpose, scope, and the parameters within which decisions could be influenced, helping participants understand their role and the potential impact of their contributions. We also clearly communicated any constraints or limitations that affected the boundaries of influence and the outcomes that can be achieved, including government policy or precedent, existing feedback and insights from customers, to help participants understand the boundaries of influence. • We published engagement plans and our engagement outputs on our Community Hub site, to help those who are not directly involved in activities stay abreast of the process and participate if they choose.

	• Preparation time was provided, particularly for our panel meetings, enabling participants time to review information, seek clarification, and provide thoughtful feedback, particularly on complex or technical issues. • Materials were prepared with the audience in mind, and with input from experts and people from the target audience where practical (noting this is often not practical). We focused on accessibility and clarity of the materials, which is particularly important but also especially challenging for more complex matters. This included efforts to use plain language, visual aids, explainers, providing additional background material, and opportunities to seek clarifications (including for our panels, one-on-ones with the AusNet team prior to meetings) support participant understanding of technical topics. We also encouraged our panel members to learn from each other. • Engagement opportunities were promoted extensively and at various stages of the process, variously through social media (Facebook, LinkedIn and TikTok), our Community Hub site, and email updates to reach a broad audience. • We welcomed feedback throughout the process via a range of formal (e.g. surveys before/after engagement activities, submissions online, via email or in writing) and less formal channels (e.g. phone conversations, meetings). • Wherever possible we provided a clear timeline of the EDPR process at the outset and updated it throughout, give participants visibility and predictability. We acknowledge some may have liked more certainty and we could have been clearer, but it is advantageous to maintain flexibility in many areas to help the engagement program stay relevant and responsive to participants' input.
Consulting on desired outcomes and then inputs	• We acknowledge that the outcomes to be achieved in the proposal are tempered, necessarily and importantly, by what customers are willing to pay (i.e. what is value-for-money) and have capacity to pay (i.e. what is affordable). After initial exploration of desired outcomes, finding the right balance of cost vs service level requires bouncing between desired outcomes and input for achieving it throughout the process, so they were not completely separated. • Our ongoing research program (including our Energy Sentiments and customer satisfaction [C-Sat] tracking research) provides insights on the gaps between current and desired expectations and customer needs, which we regularly disclose information on and engage with various forums on, and informed the early planning stages for our proposal's overall strategy and our engagement. • Very early in the process we collaborated with the then-SRG on an Aspiration for this revenue proposal setting a clear, high-level objective for everything to be achieved beneath it. • Supporting early-stage engagement including our Round 1 customer workshops focused on broad, long-term outcomes, enabling a deeper exploration of priorities like reliability, affordability, sustainability, electrification of everything, customer service and how customers' needs and expectations are changing or may change over time. Our participation in the four-year *Digital Energy Futures* partnership with Monash University, Energy Consumers Australia and Ausgrid provided a framework for thinking about households of the future and was very useful in our early planning. • Our Quantifying Customer Values study was an integral piece of work to robustly test customers' willingness to pay for service level improvements (and willingness to save for degradations), to help inform the selection of the right cost vs service-level balance. • Collaborating on 22 focus questions with our panels clearly guided our exploration of outcomes to be achieved in the next layer of detail down from the Aspiration, and selecting an appropriate option (inputs) to achieve that outcome. Customer workshops were used to bring a wider range of view in and inform the panels' discussions, and act as a check-and-balance for the panels' outputs.
Engaging via multiple channels	• To gain a well-rounded understanding of consumer preferences, we adopted multiple complementary engagement methods, including customer and advocate panels, customer workshops, webinars, surveys, forums, interviews, and one-on-one discussions. Engagement methods were selected to match the nature and complexity of each topic, participants' preferences and meet various accessibility needs. • Importantly, we engaged on key concepts via multiple channels, recognising that different methodologies have different strengths (and weaknesses), and are better (and worse) for reaching different groups. On the topic of resilience, for example, we worked with our Electricity Availability Panel to determine the package in this proposal but their deliberations were informed by 15 other sources of customer insights on resilience. In another example, our Quantifying Customer Values research was excellent at gathering the views of many and giving us robust quantitative data, but testing the same concepts qualitatively in our Round 2 Customer Workshops validated the findings and provided insight into the thought patterns of customers that explain the QCV results.
Consumers' influence on the proposal	• Our 6 customer panels and Coordination Group were charged with deliberating on the selection of key inclusions for their respective workstreams in this proposal, with the broader engagement activities designed to support them. As such, the "highest" level of influence sat with our panels. • We collaborated on the "average" level of engagement on the IAP2 spectrum to be achieved by each panel, and made it clear what the parameters for negotiating were.

	• All participants, across activities including workshops and surveys were made aware of how their feedback was being used. Our panels, customer workshop participants and engaged large customers have had a clear line-of-sight to the proposal development through the process. • Our panel meetings included costed options for the panel to select from wherever practical. Our third all-panel 2-day off-site in August 2024 focused selecting a bundle of inclusions for the proposal from a set of options, clearly linking the our engagement and the overall balance of this proposal. This session was observed by an AER board member, a range of staff and two CCP members, along with Victorian Government representatives. • Participants were actively encouraged (and many did, particularly in the panel setting) to challenge assumptions, processes, and methodologies underpinning the proposal.
c) Clearly showing how customers have impacted this proposal	

Linking our proposal to consumer preferences	• The inclusion of novel expenditure categories, customer commitments and advocacy commitments is evidence of the openness we have had to reflecting customers' interests in the proposal and innovating within the regulatory framework to develop a proposal that responds to their needs and preferences.
	• Evidence of the link between customer preferences and our proposal can be found:
	  ○ embedded throughout the proposal in the relevant chapters
	  ○ in the supporting document on answers to focus questions, and
	  ○ in the independent report authored by the Coordination Group on the engagement process and extent to which customers' preferences are reflected in the Draft Proposal published October 2024, and
	  ○ in other submissions received on the Draft Proposal, and from our customer workshop participants.

Independent consumer support for the proposal	• We are proud to have published a draft plan for public feedback in September 2024 that was developed with an extensive research and engagement process.
	• Feedback received on the Draft Proposal shows broad support for the proposal and the overall balance of cost and service levels it delivers, noting we have made some adjustments to this proposal based on feedback received during this consultation. This includes resolving some areas for further engagement with our panels in November 2024 and making some affordability adjustments where they do not significantly impact outcomes for customers, noted in the Executive Summary.
	• Specific feedback from customers on our draft plan, which can broadly be taken as feedback on this proposal, can be found:
	  ○ throughout this proposal, alongside our proposed plans and the rationale for them
	  ○ in the Coordination Group's report on the extent to which the Draft Proposal reflects customers' preferences, noting the Coordination Group will submit another report on this proposal to the AER in or around March 2025
	  ○ in the Round 4 customer workshop report, which focused on "stress testing" the Draft Proposal, and
	  ○ in the submissions received on the Draft Proposal, which have been published on Community Hub and summarised in section 2.5.3.
	• We acknowledge that our proposal is not unanimously supported. There are some customers and stakeholders who think we should be proposing a different balance (either higher or lower) of service levels and costs, and there are trade-offs to be made in every decision on who pays and who benefits. We do strongly believe our proposal is in customers' long-term interests and that the feedback received on it, noting there are varying views between and within groups, supports this.

Source: AusNet

2.4. Outcomes of our engagement activities

This section provides an overview of outcomes from key engagement activities referred to throughout this proposal. It is not an exhaustive list of engagement activities or feedback received.

2.4.1. Energy Sentiments tracking research

Energy Sentiments is a bi-annual survey that provides strategic insights into customer attitudes, behaviours, and trends across AusNet's electricity and gas networks. It tracks how customer sentiments evolve over time and gathers feedback on emerging priorities and initiatives under consideration. Every Autumn and Spring, 300 residential and 100 business customers on our electricity network complete the survey, with a matching sample for gas customers.

Topics include customer perceptions of AusNet and the broader energy industry, experiences with different aspects of gas and electricity supply, and energy behaviours and future intentions. It is higher-level in nature and complements more specific and one-off research and engagement we do.

Energy Sentiments is a business-as-usual program for us, but to enhance its usefulness for this process we invited customer advocates to contribute questions on topics they wanted explored or questions they wanted to put to customers. For example, in Autumn 2024, we introduced new questions on customer intentions around load shifting based on panel members' input.

The Coordination Group's perspective on AusNet initiated research

In their report on our draft proposal, the Coordination Group provided the following comments on our research:

"The Coordination Group acknowledges that AusNet has invested considerably in its business-as-usual research program and has shared the findings of this research with panel members to help inform their views. AusNet has also continued to invite panel members to seek more detailed analysis of the research and even suggest further research. Although panel members generally considered they had sufficient information, we commend AusNet for the offer and responsiveness to our queries."

2.4.2. Customer segmentation

Our innovative customer segmentation research combined behavioural and attitudinal insights (via a survey of 3,263 customers) with actual usage patterns from smart meter data for the first time.

We now understand how households are interacting with the network (i.e. usage patterns), and the relationship between household demographics, characteristics and motivations, and their usage patterns.

Findings have been used in our demand forecasting approach for the EDPR 2026-31 and to inform aspects of our pricing and customer communications proposals. We shared the results of this study broadly across industry and government via several tailored webinars. It was also used in engagement with our customer panels, particularly to inform deliberations on fair and equitable tariff design and CER strategies.

The initial study was completed in early 2023. Updated analysis of usage profiles completed in December 2024 shows the study remains relevant, with the only material change in usage profiles being significant shrinkage of the Day-time actives segment. The key findings of the customer segmentation study are outlined in section 3.5.2.

2.4.3. Major customer engagement

We have engaged extensively with commercial and industrial customers to inform the development of our proposal. As large users with complex needs, these customers interact with AusNet regularly, making their insights particularly unique and valuable. Our large customers span a diverse range of industries, including agriculture, paper processing, water supply, chocolate manufacturing, healthcare, and grocery distribution, among many others. While their energy needs and expectations vary, many are navigating their own decarbonisation journeys, with some electrifying operations and investing in medium-scale electricity generation.

Through this process, we have gathered feedback from commercial and industrial customers on key topics such as energy priorities, tariffs and pricing, customer experience, reliability and resilience, and planned outages. Our engagement approach has largely been designed with the support of the Energy Users' Association of Australia who:

- Collaborated on the discussion guide for meetings with commercial and industrial customers
- Assisted with the design of a commercial and industrial customer forum in December 2023, and

- Provided advice on the approach to tariff engagement with commercial and industrial customers in 2024.

Additionally, several large customers participated in interviews conducted by the Research & Engagement Panel and other panel members, who reported their findings to us and their peers.

These insights have been incorporated into panel discussions and have directly influenced many aspects of our proposal, helping to shape plans that reflect and balance the needs of all our customer cohorts.

2.4.4. Quantifying Customer Values research

AusNet conducted the Quantifying Customer Values (QCV) research to measure the value customers place on a range of benefits not currently reflected in traditional investment decisions and to provide a more up-to-date value of customer reliability (VCR). The study was co-designed with research experts Lewers and the Research & Engagement Panel, and included a qualitative research stage to inform the survey design. The research has provided robust, quantitative insights into customers' priorities, and assigned tangible values to inform cost-benefit assessments and trade-off discussions.

Our study is the largest of its kind in the National Electricity Market, with 3,527 residential and business customers completing the online survey.

The research had two key components:

- Value of customer reliability and resilience, measured with a contingent valuation study and a choice model, and
- Broader benefits quantification for five services: flexible EV charging; enabling solar exports; improving reliability for worst-served customers; avoiding (or experiencing) a one-hour outage; and avoiding (or experiencing) one 24-hour outage.

This was measured via:

- Willingness to pay (for individual service improvements)
- Willingness to accept (service degradations), and
- Willingness to pay for a bundle of services, providing an important check for overall value-for-money and affordability in the context of the proposal.

Designed in collaboration with the Research & Engagement Panel

A working group comprising the Research & Engagement Panel and Mark Grenning collaborated with AusNet on many aspects of the Quantifying Customer Values study design.

The Coordination Group's report states: "*Overall, the R&E panel considers its engagement with AusNet in shaping the QCV research was timely, sincere and transparent. While AusNet led the project, the way the R&E panel worked with AusNet in the project's development was largely collaborative.* "Refer to the Coordination Group's report for more details on how the Panel was engaged in the design.

2.4.4.1. Key findings

The Quantifying Customer Values study told us:

- Customers valued reliability considerably higher (almost double) compared to the AER's VCR at the time. The AER has since refreshed its VCR calculations which is similar to our study's finding, which accounts for changes in sentiment and more up-to-date values of unserved energy.
- Both households ($37.56pa) and businesses ($118.56pa) attach a positive value to having flexibility in speed and timing of EV charging, and there is reluctance to accept managed charging
- Customers value "not wasting" solar (their own and others'), above economic levels. Both households ($52.26pa) and businesses ($197.74pa) attach a positive value to investing to enable more solar exports.
- Both households ($55.65pa) and businesses ($224.28pa) attach a positive value to improving reliability for worst served customers. We did not test a degradation case (i.e. de-investing for more outages).
- Both households ($31.68pa) and businesses ($173.04pa) attach a positive value to reduce one 1 hour-long unplanned outage per year.
- Customers value resilience above all other services tested, across all demographics. Both households ($73.44pa) and businesses ($293.16pa) attach a positive value to reducing one 24-hour-long unplanned outage per year.
- Customers are open to cost sharing even where they don't directly benefit, including on improvements for worst served customers and solar exports
- Willingness to pay for the bundle of services increases with both capacity to pay (for households) and size of business (for business), but is positive for all demographic groups. Even those households who say they cannot meet basic expenses are willing to pay for the bundle of service improvements, at $114.40 per year (compared to the network average $135.12 per year and those who live comfortably at $143.50 per year)

- Customers see the value in investing in improved services while still being concerned about affordability. Some respondents are not willing to pay for any improvements, however almost all customers expect significant compensation for service degradations
- Using the AER's methodology for calculating the Value of Reliability is not suitable for calculating a Value of Resilience (long duration outages), due to the high value of unserved energy.

2.4.4.2. Validating and applying the findings

To enhance confidence in the findings, the QCV research was complemented by qualitative engagement in our Round 2 customer workshops, where the same concepts were explored using a different methodology. Despite varied individual opinions, the findings from both approaches were highly consistent. A peer review was conducted by Scott McLean, Fellow of the Australian Research Society, to test the robustness of the study and validity of the results.

The panels and Coordination Group collaborated extensively on the decision of how to apply the results in the proposal.

The outputs of the QCV study have been applied throughout this proposal and in business cases, helping to guide decisions on service levels, network reliability, support for worst-served customers, and investments in EV charging and solar exports.

2.4.5. Customer workshops

The customer workshops were a key component of AusNet's grassroots engagement strategy, complementing other research and engagement initiatives. These workshops aimed to gather diverse perspectives from a broad cross-section of AusNet's customer base, focusing on understanding trends in sentiment, exploring a breadth of views, and generating ideas.

The purpose of the workshops was to build an understanding of overarching themes and diversity within customers' experiences, priorities, and expectations across various aspects of electricity use and services, and to test and refine elements of the proposal.

While not decision-making forums, the workshops provided critical insights to inform higher-level deliberations by the Panels (aligned with upper levels of the IAP2 spectrum). Approximately 120 customers were engaged across the four rounds. Workshops were held in each of Morwell/Traralgon, Wangaratta, Epping and two online, with four focused on residential customers and one focused on business.

The workshops were planned in collaboration with our Research & Engagement Panel and our facilitators, SenateSHJ. Professional recruiters, Focus People, recruited and selected to represent a broad cross-section of AusNet's customer base. We recorded a very low attrition rate across the process, with less than 9% of participants from Round 1 not present in Round 4.

Nearly all participants felt heard during the discussions, with 97% agreeing the format allowed them to contribute effectively, and 83% agreeing (50% strongly agree, 33% agree) that AusNet took their feedback seriously.

Designed in collaboration with the Research & Engagement Panel

AusNet worked with the Research & Engagement Panel to design many aspects of the overall approach and the 4 rounds of customer workshops.

The Coordination Group's report on our draft proposal states: "*Overall, the R&E panel considers its engagement with AusNet in shaping the customer workshops, regardless of the outcomes, was timely, sincere and transparent. While the customer workshops were initiated and led by AusNet, the way the R&E panel worked with AusNet was largely collaborative.*"

Refer to the Coordination Group's report for more details on how the Panel was engaged in the design, and for their reflections on the workshops.

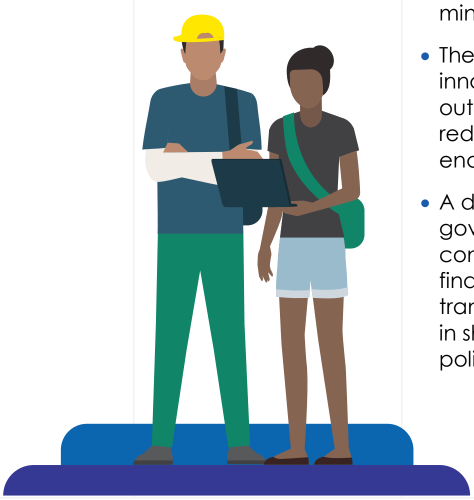
The reports from the 4 rounds of workshops and participants' feedback are provided as supporting documents. The table on the next page summaries the details and key themes from the four rounds of workshops.

Figures 2-6 to 2-8: Photos from customer workshops in Traralgon, Epping and Wangaratta



Table 2-4: Summary of key themes from the four rounds of customer workshops

	Round 1	Round 2	Round 3	Round 4
Focus	Higher-level conversation about customers' use of electricity and their plans for the future.	Priorities, balance of costs and services, and how costs of improvements to service levels should be shared. Qualitatively tested the same themes as the Quantifying Customer Values study.	Customer services, customers' propensity to change electricity use, information and/or incentives needed to change. Some also spoke about the major outage events in February 2024.	Sharing and 'sense checking' the Draft Proposal and key elements of it.
Held	29 August and 6 September 2023	10 October and 18 October 2023	12 February to 20 March 2024	8 October and 15 October 2024
Summary of key themes	• The need to improve reliability • The high cost of electricity and low value of solar • Rewards and incentives for CER are too low • The network's resilience to extreme weather • Need for more information and support on energy matters • A need for standards and guarantees for CER • The sector not being lack of preparedness for and speed of the transition to all-electric and renewables.	• The need to improve reliability and resilience, with differing views on proactive vs reactive investments • Cost-sharing preferences for improvements, including EV charging and solar exports, with mixed opinions on whether costs should be socialised or borne by beneficiaries • Strong support for enabling EV charging and solar exports, seen as worthwhile investments for convenience, flexibility, and renewable energy adoption • Sensitivity to cost of living pressures, influencing some participants to prefer minimal improvements • The importance of innovation to improve outcomes, such as reducing outages and enabling faster repairs • A desire for government to contribute to financing the energy transition, given its role in shaping energy policy.	• Timely, accurate, and accessible information is crucial, especially during outages • Continuity in interactions with AusNet is important • AI can complement service channels but shouldn't replace human interaction • Better information and support during outages are needed, particularly for vulnerable customers • Improved communication and promotion of existing services are needed • Transparency and accountability for outage durations and service levels are priorities • Innovative ideas include polls for planned outage scheduling and staff presence in public spaces during outages • Some are willing to adjust appliance usage but are less flexible with cooking and heating • Public education on energy use and tariffs is needed • Peak/off-peak pricing is seen as unfair for those who can't work from home • $100-$300 per month is expected to incentivise behaviour change.	• *"Customers found the proposal acceptable, with 94% rating it adequate or better (23% rated it very good, 56% good and 15% adequate). Generally, they supported proposed improvements and expect accountability and evidence of benefits to customers."* • Strong support for improving reliability and resilience, especially for vulnerable customers, though some raised concerns about the pace of electrification and suggested deferring certain upgrades • Positive feedback on renewables and net-zero goals, but mixed views on daytime tariff incentives, with concerns about limited accessibility • High support for transparent outage communication and relationship managers, alongside requests for clearer tariff information and expanded messaging on energy efficiency and storm preparation • Most found the proposal affordable and good value, with calls for transparency and evidence of tangible outcomes. Concerns remain about affordability for vulnerable customers, with suggestions for subsidies or support programs.



2.4.6. Joint network engagement

Beyond our own engagement program, we also participated in working groups and engagement activities with Victorian Distribution Businesses Jemena, CitiPower, Powercor and United Energy. These groups have been created for joint engagement opportunities, where it makes sense to align with other Victorian electricity networks and resulted in 9 joint engagement forums on:

- **Identifying opportunities for joint engagement**, with a forum in late 2022 held prior to the commencement of our formal engagement programs, used to inform networks' respective engagement program designs.
- **Tariff structures**, with 3 forums focusing on developing a timeline for the TSS, developing common baseline tariffs across the networks, and considering opportunities for further engagement on common tariff matters. Representatives from AusNet's Tariffs & Pricing Panel attended all joint tariff forums, along with retailers and other interested advocates and stakeholders. These joint forums have influenced the approach taken to tariffs, including the Tariff Structure Statement, considerably. The reports from the workshops are attached as supporting documents.
- **Framework and approach** matters, with 2 forums on service classifications and decisions on what distributors' role is for some new and emerging areas. Representatives from AusNet's Coordination Group attended all Framework & Approach forums, which informed the development of AusNet's Framework & Approach paper, submitted to the AER in October 2023. The reports from the workshops are attached as supporting documents.
- **Network resilience**, with a forum on common studies on climate impacts, actioning the Department of Environment, Energy and Climate Action's (formerly the Department of Environment, Land, Water and Planning) resilience review, valuing the impact of resilience, and other resilience matters. The Electricity Availability Panel attended this forum, along with a broader group of customers and stakeholders with lived experience or a personal or professional interest in resilience planning including emergency services, social service organisations and volunteers, and councils. The outcomes of the joint forum on resilience have been incorporated into our broader resilience planning activities including with the Electricity Availability Panel. The reports from the workshop are attached as supporting documents.
- **Supporting customers experiencing vulnerability**, with 2 forums identifying opportunities to better support these customers and promoting consistency in customer experience across Victoria. Representatives from several AusNet panels attended the vulnerability forums. The outputs of the joint forums on vulnerability have been acted upon separately and differently by each network. For AusNet, they have been used to aid our understanding of various groups' needs and hear from voices that may otherwise have been missed. While we have not included a "vulnerability package" as such, the needs of our various customer segments have considerably shaped our and our panels' understandings of what a "fit-for-purpose" proposal looks like. The joint network discussions informed a number of the customer commitments in the Executive Summary and fed into the broader approach for customer service and communications. The reports from the workshops are attached as supporting documents.

These joint engagement opportunities provided a more efficient way for stakeholders and customers to engage with multiple networks at the same time. Open invitations to most of these events broadened participation in our collective engagement activities.

Figure 2-9: Our first joint network forum on tariffs

2.4.7. Our 6 customer panels

In late 2022 we appointed 22 customers and advocates to a series of Panels*, via a competitive recruitment process. The panels began meeting in February 2023. Most Panel members are AusNet customers with a personal and/or professional interest in improving outcomes for their communities. Some are professional customer advocates who are not AusNet customers themselves but have been appointed to the Panels for their subject matter expertise, experiences in other jurisdictions, and/or professional affiliations with organisations advocating on behalf of energy users, and complement the contributions of AusNet customers on the Panels.

Customer panels for deep engagement organised by topic are a new approach AusNet has taken for engagement on a price review. It was clear to us early on in our planning that a multi-panel engagement model, organised by topic, was the right model for us as:

- there was too much deep engagement to do for the standard price review model (i.e. one Panel of experienced advocates overseeing the whole engagement program) to cover
- given AusNet's network has some unique challenges and it is a critical time in the energy transition, with many high-impact, long-lasting decisions to be made, we felt strongly about including AusNet customers in the engagement program alongside domain experts and experienced energy advocates, which necessitated engaging a bigger group
- it meant we could involve more customer advocates in detailed discussions to shape the proposal, and let people focus on the topics of most relevance to their interests and expertise

Five topic-specific Panels were established – *Tariffs & Pricing*, *Future Networks*, *Customer Experience*, *Electricity Availability*, and *Benchmarking & Opex* – plus a process-focused Panel to support the design of select engagement activities – the *Research & Engagement* Customer Panel.

Our panels have played a critical role in the engagement process, defining the focus areas for their respective workstreams and deliberating on them in detail. Their work has been heavily informed by the outputs of the broader research and engagement activities outlined in 2.4, but they have also considered a range of other relevant inputs such as policies and regulations, forecasts, fairness and equity, safety and, where practicable, costed options and the selection of a preferred option.

The Panels' purpose, targeted level of influence on the IAP2 spectrum, indicative topics in remit, time commitment and the types of applicants sought were initially defined in the 2022 co-design session and refined with the panels through the process.

Most of our Panel meetings ran in a very similar way – exploring a "focus question" and seeking direction from the Panel on key aspects of the decision-making. AusNet supplied a Chair for Panel meetings, as given the volume of engagement occurring it would not have been practical to have an independent Chair for these meetings. This arrangement was supported by a significant majority of our Panel members, noting a small number expressed a preference for all meetings to be independently Chaired. AusNet also supplied a secretariat. Panel members were given the opportunity to raise material issues with meeting summaries prepared by AusNet but did not review them in detail.

2.4.7.1. What we mean when we talk about Panels' support (or lack of support) for elements of the Revenue Proposal

When we refer to our customer engagement panels "supporting" or "agreeing" to a proposal, this does not imply unanimous or unqualified support. Examples of qualifications are included in the Coordination Group's report on our Draft Proposal. These panels represent a diversity of customer perspectives, with feedback reflecting a range of views. Members have been strongly encouraged to think critically as individuals and engage in constructive debate, which has been considered critical to the success of the engagement process.

Panel positions have been assessed based on the overall sentiment expressed during discussions, the extent to which qualifiers and caveats have been addressed, and whether the majority of panel members agree that the proposal aligns with customer interests. These positions have been validated by the Chair of the Coordination Group and the "Leads" for each panel.

While broad support may exist, individual members hold individual views, which have been carefully considered by both the panels and AusNet when developing positions. The support (or lack of support) of a panel should not be interpreted as full and unqualified support (or lack thereof) from each individual member.

2.4.7.2. Tariffs and Pricing

Our Tariffs & Pricing Panel spent 25.5 hours across 8 meetings as a panel and collaborated (to the extent it was able) on the approach to designing and implementing network pricing that reflects customer behaviour and electricity usage in this proposal. The panel also participated in the joint network tariffs engagement activities.

Tariffs & Pricing Panel members

- Gavin Dufty (Lead)
- Kate Hansen
- Chris Harvey
- Dean Lombard
- Nick Mason-Smith
- Jeff Nottle
- Emma Chessell (to Feb 2024)

The Tariffs & Pricing Panel designed and answered the following focus questions. Complete answers are published on Community Hub and attached as a supporting document:

1. How might we allocate revenue across different tariff classes in a balanced, justified and proportional way, that also provides support for customers with specialised needs?
2. How might we better analyse and understand customer impact, including understanding the impact of 'doing nothing', to help us make more informed decisions?
3. How might we use tariffs to enable and facilitate an energy transition without unexpected downside impact, and reflect the value of CER in the energy system irrespective of their specific technologies?
4. How might we build customers' agency on tariff choices, and smoothly support customers to transition to cost-reflective tariffs?
5. How might we ensure tariff design reflects agreed pricing objectives?

The Tariffs & Pricing Panel reached the following key agreements:

- There are limited opportunities to make substantive changes to the revenue allocation between tariff classes.
- Tariff classes should be technology neutral as much as possible, given the rapid emergence of new technologies. There was also an acknowledgement some tariffs may only be effective with specific technologies.
- Need to update the opt-in Time of Use (TOU) tariff to incorporate a low-cost solar soak period.
- In the absence of a mandatory transition to TOU (government mandated optional assignment policy), there is still value in implementing a broader communications strategy to inform the public about the changing tariffs and opportunities to save (among other topics). Noting distributors should play an active role in encouraging customers to move to TOU tariffs.
- Government policy is clear that the two-way CER tariff will be opt-in, but should have a low incentive and be available to all.
- The tariff impact assessment should be more 'personalised', including examples of customers underpaying or overpaying based on current tariffs, including understanding the impact of 'doing nothing'.

The Coordination Group's Report on our Draft Proposal provides a detailed overview of our panel members' feedback on our engagement with them and the extent to which the Draft Proposal reflects customers' views and preferences. An excerpt is below. The Tariffs & Pricing Panel met once more in November 2024, to inform on related feedback we've received on the Draft Proposal to date and confirm how the topics in the Panel's remit will be presented in this Proposal.

Excerpt from the Coordination Group's Report on the Tariffs & Pricing workstream

The panel is supportive of both AusNet's direct engagement but also the joint DNSP engagement around tariffs and tariff reform. The engagement was detailed, included a diverse group of customer classes, consumption types and those with various community energy resources. The engagement included responsive modelling, which further enhanced and nuanced consumer preferences. This was expressed in adjustments to the peak rate window, the strength of the price signals, the appetite for two-way pricing and preferences regarding the community energy resource tariff. Unfortunately, the key enabling piece for the introductions of the supported tariffs is contingent on a change in the Victorian government policy

2.4.7.3. Future Networks

Our Future Networks Panel spent 37.5 hours across 10 meetings as a panel and working with us to plan for the future of the network and integrate and maximise value from new technologies for the benefit of customers.

The Future Networks Panel designed and answered the following focus questions. Complete answers are published on Community Hub and attached as a supporting document:

1. How might we best prepare for, and accommodate, the anticipated electrification of gas and transport loads (and other fuels)?
2. How might we support communities to realise their needs and energy aspirations?
3. How might we lay the foundations for a low-cost decarbonised future, where everybody can benefit?
4. How might we unlock more value for customers and reduce unit costs through an efficient mix of smart grid technology and new capacity?
5. How might we support customers in unlocking other CER value streams?

Future Networks Panel members

- Dean Lombard (Lead)
- Gavin Dufty
- Kate Hansen
- Chris Harvey
- Darren McCubbin
- Prof. Nando Ochoa Pizzali
- Emma Chessell (to Feb 2024)
- Linus Mayes (to June 2024)

The panel reached the following key agreements:

- To roll out **Flexible Exports** quickly to address minimum demand challenges and keep costs down.
- Investment in **CER integration** must be efficient, based on AER's metrics for efficiency.
- **Quantify emissions reductions** as a benefit stream from enabling export services, and **avoided network augmentation** from 'marrying up' electrification and CER integration.
- Commit to additional **information-sharing on network constraints** to help customers make more informed decisions.
- Explore **flexibility mechanisms** to accommodate change in pace of electrification.
- Only introduce **Export Service Incentive Scheme** (ESIS) if known pain points are better addressed through an incentive scheme rather than through expenditure programs.
- Support for **sub-transmission investment where it delivers benefits** to AusNet customers and broader energy consumers, particularly compared to alternative transmission connection.
- AusNet's role in **community energy** should support community energy groups and invest where efficient to do so (i.e., where there is network benefit), and include providing upfront information on network benefit and planning for an increase in demand for community energy solutions.

The Coordination Group's Report on our Draft Proposal provides a detailed overview of our panel members' feedback on our engagement with them and the extent to which the Draft Proposal reflects customers' views and preferences. An excerpt is below. The Future Networks Panel met once more in November 2024, to inform on related feedback we've received on the Draft Proposal to date and confirm how the topics in the Panel's remit will be presented in this Proposal.

Excerpt from the Coordination Group's Report on the Future Networks workstream

AusNet met nine times with the Future Networks Panel in addition to the attendance at the three all panel offsites with other AusNet stakeholders: seven times between March 2023 and March 2024 to collaboratively develop the focus questions and explore how to address them. AusNet was very responsive to the panel's input, and the panel played a key role in shaping and finalising the focus questions.; once in June 2024 for a deep dive into costed options for CER enablement and enabling electrification (as well as to discuss opportunities and options for the smart meter replacement program); once in August 2024 to revisit aspects of proposals to address the focus questions that were not yet settled, in preparation for the combined panels workshop later in August.

AusNet showed a strong commitment to engaging deeply with the panel, providing comprehensive background material and useful analysis to guide discussion and decision-making. AusNet was responsive to panel views, adjusting proposals in response to feedback, choosing options supported by the panel, and withdrawing proposals when the panel made a strong case to do so (for example, the proposed Export Services Incentive Scheme, which the panel determined was not needed due to no evidence that there was scope for a higher level of service beyond what was already justified by existing obligations). Generally, the engagement ranged from the "consult" to "collaborate" levels of the IAP2 spectrum of public participation with most being around the "involve" and "collaborate" levels

2.4.7.4. Customer Experience

Our Customer Experience Panel spent 23.5 hours across 10 meetings as a stand-alone panel and engaged on our approach to customer service, the design of our Customer Service Incentive Scheme and the updated set of customer experience commitments.

The Customer Experience Panel designed and answered the following focus questions. Complete answers are published on Community Hub and attached as a supporting document:

1. How might we minimise the adverse impacts of outages on customers?
2. How might we ensure fit-for-purpose service for all customers, including those with specialised support needs?
3. How might we meet customers' preferences on the form, content and frequency of communication, as well as educational material that improves customer experience?
4. How might we design connection processes that meet evolving customer expectations, across all our customers?
5. How might we design a CSIS that delivers maximum benefit for customers?

Customer Experience Panel members

- Emily Peel (Lead)
- John Mumford
- Jeff Nottle
- Mark Grenning
- Piang Lillian
- Tony Robinson
- Johnathan Kneebone
- Lynne Chester (to June 2023)

The panel reached the following key agreements:

- **No double counting** through the CSIS and customer experience expenditure.
- Importance on aiming for **first call resolution** to include in the CSIS.
- Selection of mix of customer satisfaction and service level-type metrics.
- Customer satisfaction should **include all aspects** of the customer experience.
- Support to **consider increasing the CSIS** revenue at risk.
- Importance of **communication during planned outages**. This includes providing clear and informative messaging to customers and offering a variety of ways of receiving notifications.
- Importance of **improving accuracy of ETRs** during unplanned outages.
- Consider **impact of outages on businesses** (especially in smaller towns) and ensure power supply for major events.
- Support for **customised services** in planned outages and connections.

The Coordination Group's Report on our Draft Proposal provides a detailed overview of our panel members' feedback on our engagement with them and the extent to which the Draft Proposal reflects customers' views and preferences. An excerpt is below. The Customer Experience Panel met once more in November 2024, to inform on related feedback we've received on the Draft Proposal to date and confirm how the topics in the Panel's remit will be presented in this Proposal.

Excerpt from the Coordination Group's Report on the Customer Experience workstream

The panel has met eight times for 2–3-hour meetings since its establishment in March 2023. In addition, the panel's work has progressed at the three off-site AusNet meetings at which customer experience discussion and agreement was confirmed: Yarra Ranges (August 2023), Epping (March 2024) and Yarra Valley (August 2024). These two-day events provided valuable opportunities for broad discussion with AusNet as well as ratification of progress being made by the different panels.

Panel members were also involved closely in two elements of AusNet's customer research and engagement program: Members observed selected Customer Workshops in each of the rounds conducted to date at Epping, Morwell and Wangaratta where they learned first-hand about customers' expectations of AusNet with a particular focus on 2026-31 and beyond; Panel members also participated in the Customer Interview Program initiated through the Coordination Group (see Section 4.34.3 for details) in which customers across AusNet's service area consistently indicated their dissatisfaction with their customer experience.

AusNet has responded positively to the feedback provided by panel members around customer service and acknowledges that its attention over recent years to these concerns has not been consistent.

2.4.7.5. Electricity Availability

Electricity Availability Panel members

- Kieran Donoghue (Lead)
- Helen Bartley
- Emma Birchall
- Mark Grenning
- Chris Harvey
- Tricia Hiley
- Piang Lilian
- Jeff Nottle

Our Electricity Availability Panel spent 25 hours across 11 meetings as a stand-alone panel and engaged on customers' preferences regarding network reliability, resilience and availability, and striking the right balance between investments in reliability and resilience, and value-for-money and affordability.

The Electricity Availability Panel designed and answered the following focus questions. Complete answers are published on Community Hub and attached as a supporting document:

1. How might AusNet minimise adverse impacts of power quality and variability on customers?
2. How might AusNet best plan its works to minimise adverse impacts of planned outages on customers?
3. How might we efficiently improve reliability for our worst-served customers to a level that is considered value for money to all customers?
4. How might we assess how customer characteristics and activities are influencing the value they place on reliability and ensure our investment plans reflect this?
5. How might we work with customers and other stakeholders to identify and plan for resilience solutions that meet our customers' needs?

The panel reached the following key agreements:

- Investigate options to **improve reliability for poorest served customers.** Identified worst served feeders as follows: average performance over 5 years; exclude major event days; use AER Inadequately Served Customer measure; socio-economic, remoteness and life support customers shouldn't be used to identify worst served, but should be overlaid qualitatively when talking about solutions
- Include expenditure for proactive investments that **improve reliability for the 10 worst served feeders** (including projects which may not be economic)
- Include expenditure to proactively **improve network resilience** by hardening the network and investing in a range of non-network solutions (e.g., SAPS, mobile generators) where the benefits are NPV positive
- Direct costs and QCV VCRs to provide important **willingness-to-pay evidence** for use in economic assessments (direct costs warrant further consideration, e.g. an adjustment to generator purchase costs)
- **Critical customer back up supply projects** should be paid for by those customers (classified as an Alternative Control Service)
- Include expenditure to **energise Community Hubs**, with optimal locations decided via engagement with those communities and ascertain partnership opportunities
- Assess economic benefits of uplifting the **hazard tree program** to improve resilience
- Consider if and how the **customer benefits of investments** that improve reliability and resilience warrant adjustments to STPIS targets, GSL payment forecasts and maintenance opex
- AusNet to advocate for a review of **life support customer register** and play a role in improving reliability for these customers. AusNet should not undertake major investments in this area due to number of customers and cost e.g. home batteries for each customer
- **Voltage compliance** should continue to be managed through the most economic approach, but there is an expectation that AusNet should aspire to performance equivalent to other Victorian networks.

An excerpt of the Coordination Group's Report on our Draft Proposal is below. The Electricity Availability Panel met once more in November 2024, to inform on related feedback we've received on the Draft Proposal to date and confirm how the topics in the Panel's remit will be presented in this Proposal.

Excerpt from the Coordination Group's Report on the Electricity Availability workstream

AusNet and the panel met nine times, with a view to "collaborating", per the IAP2 spectrum of public participation and in line with the AER's Better Resets Handbook expectations. Most panel members also attended AusNet's three all-panel offsite meetings which included other stakeholders and where relevant issues were discussed in detail.

Panel members participated in a joint DNSP workshop on resilience. The Coordination Group also participated in a workshop on how AusNet's QCV research could inform the values it uses for unserved energy in assessing the cost-effectiveness of projects.

AusNet gave panel members the opportunity to provide feedback on AusNet's draft submissions to the AER's value of customer reliability (VCR) and value of network resilience (VNR) processes.

The panel's interactions with AusNet were constructive and ranged from "inform" to "collaborate" on the IAP2 spectrum. AusNet provided an impressive level of background information and analysis to assist the panel in its work and provided multiple channels for feedback. High levels of collaboration were achieved on the selection criteria for worst served feeders. Time pressures meant the panel did not have a chance to consider the step-up in hazard tree removal and while the panel supported the concept of the RRA, we did not land on a suitable figure nor the detail of the governance arrangements. These caveats aside, noting that there were a range of views among the panel, the relevant elements of the draft proposal are reflective of at least most of the panel's preferences.

2.4.7.6. Benchmarking & Opex

Our Benchmarking & Opex Panel spent 15.5 hours across 7 meetings engaging on opex and benchmarking-related matters. This small panels' work was focused on quite technical regulatory topics and the group were primarily engaged at an inform-to-consult engagement level.

Benchmarking & Opex Panel members

- Mark Grenning (Lead)
- Kieran Donoghue

The Electricity Availability Panel designed and answered the following focus questions. Complete answers are published on Community Hub and attached as a supporting document:

1. How might benchmarking be applied to give customers confidence they're paying no more than necessary for an efficient service?
2. How might we be confident that AusNet's opex represents value-for-money and prudent and efficient expenditure?

The panel delivered the following outputs:

The Benchmarking and Opex panel were engaged at an inform/consult engagement level. As a result, the panel reached only a small number of outcomes to be included in the EDPR Proposal:

- **Adjust GSL forecast** to reflect proposed/ funded reliability and resilience improvements
- **Choice of base year** will be subject to the AER's assessment
- **Scrutinise pole inspection cycle step change** to assess whether an adjustment needed given previous funding received.

The panel were actively engaged in discussion on opex drivers including early fault detectors, expensing corporate overheads and insurance.

The panel expressed a preference for a more ambitious 1.0% on the productivity factor to be applied. AusNet is proposing the standard 0.5% p.a. for productivity and capitalised corporate overheads. They suggested that the AER should adjust productivity benchmarking results in the 2023 annual report to account for capitalised leases which was subsequently rectified.

The panel did not provide agreement on prudency and efficiency of costs as this is a decision to be made by the AER.

The Coordination Group's Report on our Draft Proposal provides a detailed overview of our panel members' feedback on our engagement with them and the extent to which the Draft Proposal reflects customers' views and preferences. An excerpt is below. The Benchmarking & Opex Panel met once more in November 2024, to inform on related feedback we've received on the Draft Proposal to date and confirm how the topics in the Panel's remit will be presented in this Proposal.

Excerpt from the Coordination Group's Report on the Benchmarking & Opex workstream

The Benchmarking and Operating Expense panel met with AusNet on five occasions, including one in depth face to face meeting. Engagement covered 'inform' and 'consult' on the IAP2 spectrum.

The panel had a number of detailed discussions with AusNet on the base case, impact of benchmarking and trend estimates. We have also benefitted from the discussion with the AER Operating expenditure team on this topic. We had some detailed discussions on cost options in step changes and we look forward to further discussions in the coming months before being able to come to a view on our second focus question around 'value for money'.

2.4.7.7. Research & Engagement

Our Research & Engagement Panel spent approximately 120 hours of professional time engaging on the design of key research and engagement activities. Their contributions have been referenced in the sections above on the customer workshops, Quantifying Customer Values research.

The role of the Research & Engagement Panel was to work with AusNet on the design of research and further engagement activities to support the proposal and Panels' deliberations. The Panel's remit stretched across Panels to ensure they have access to customer insights needed for their discussions. The Research & Engagement Panel also participated in designing research and engagement activities and assisting with prioritisations of resources.

The Research & Engagement Panel also initiated their own independent engagement with customers, with a range of customer advocates from across Panels travelling the network meeting with customers directly and without AusNet. More details on this are in 2.4.11.

Research & Engagement Panel members

- Helen Bartley (Lead)
- Dr Tricia Hiley
- Darren McCubbin

The Research & Engagement Panel with AusNet achieved the following engagement outcomes:

- Incorporated the R&E Panel's inputs into the scope of works and selection criteria, and collaborated on the choice of supplier for the customer workshops. Collaborated on recruitment approach, locations and design of workshops.
- For the Quantifying Customer Values research, we incorporated the panel's inputs into the scope of works and selection criteria wherever practical, and collaborated on the choice of supplier. Panel engaged with supplier and AusNet team on design of the research. Panel completed extensive review into the in-depth interview guide and questionnaire to ensure all the concepts, terminologies and service benefits were described in easy and clear language for customers.
- Panel collaborated on high-level approach to resilience engagement, with local communities to be engaged on more detailed design.
- Panel engaged on the broad mix of research and engagement activities, based on inputs and suggestions from other panel members.
- Panel collaborated on a range of design elements and AusNet reflected its feedback in the design of the new C-Sat program, launched January 2025. Aspects engaged on included the platform, delivery & collection method, digital inclusion, questionnaire & drivers of satisfaction being tested and any other considerations. The Panel expressed strong support for the change, and we took away clear direction on the approach for more detailed C-Sat design elements.

An excerpt of the Coordination Group's Report on our Draft Proposal is below. The Research & Engagement Panel met one more time, in November 2024, to debrief on the Draft Proposal engagement process itself, and engage on key design aspects of AusNet's refreshed Customer Satisfaction (C-Sat) program.

Excerpt from the Coordination Group's Report on the Research & Engagement workstream

The R&E panel has met regularly with AusNet both face-to face and online. We have contributed to the design, delivery, review of and reflections on AusNet's key customer engagement and research activities specific to informing the development of its draft proposal. Panel meetings have been collegiate with healthy debate and discussion to enhance the value of AusNet's EDPR research and engagement activities, such as ensuring what is presented to customers is balanced and uses language that is familiar to customers. Key areas of R&E panel influence were: A series of Customer Workshops undertaken at different stages throughout the development of AusNet's draft proposal ; AusNet's research to Quantify Customer Values (QCV) ; resilience Research (this work is in development at the time of preparing this report).

The R&E panel has also contributed to AusNet's planning of its deeper engagement with other panels. It has acted as a sounding board for AusNet to test its proposed approach to gathering wider panel member input at the three off-site face-to-face meetings held in August 2023 at Kalorama, March 2024 at Epping and August 2024 in the Yarra Valley. Additionally, the R&E panel has provided general advice on broader customer communication and engagement related to the EDPR, such as AusNet's broader engagement to gain customer feedback on its Draft Proposal.

Additionally, AusNet funded the Coordination Group to undertake work of our choice provided it was related to and helped inform our advice to AusNet. The Coordination Group in turn agreed to fund panel members to independently gather evidence of customer needs and preferences (customer interviews) to help inform responses to the focus questions and to test customer support or otherwise for AusNet's proposals. The R&E panel was responsible for the design, delivery and oversight of the customer interviews.

2.4.8. The Coordination Group

The Coordination Group is responsible for incorporating the outcomes of Panel process into the proposal. Key to this role is working transparently and collaboratively with the Panels and AusNet and challenging AusNet, as necessary, to prepare a high-quality evidence-based proposal reflective of customers' preferences.

The Coordination Group has an overarching governance role in the EDPR 2026-31 engagement program, with a focus on:

- Working collaboratively with the panels and AusNet to prepare a high-quality evidence-based proposal reflective of customers' preferences
- Identifying and raising conflicts or overlaps between panels and working collaboratively with AusNet to identify value-stacking opportunities across workstreams, understand and resolve trade-offs for inclusion in the proposal
- Going into detail on building blocks (incorporating panel inputs) and the price path
- Reflecting customers' interests and value in technical considerations of the proposal with a clear line-of-sight from AusNet's research and engagement program
- Authoring an "independent" report(s) on the engagement process and extent to which customers' preferences are reflected in the Revenue Proposal, per the AER's requirements.

Coordination Group members

- Peter Eben, Chair
- Helen Bartley, Research & Engagement
- Kieran Donoghue, Electricity Availability
- Gavin Dufty, Tariffs & Pricing
- Mark Grenning, Benchmarking & Opex
- Dean Lombard, Future Networks
- Emily Peel, Customer Experience

Coordination Group meetings are Chaired by the Peter. The Coordination Group took their own minutes, which AusNet was given an opportunity to comment on before they were finalised by the Chair. AusNet was present for 20 of the Coordination Group's formal meetings plus meetings following each all-Panel Offsite forum but the Coordination Group also met independently numerous times through the process.

The Coordination Group oversaw a budget that they could allocate at their discretion, and invited proposals from all Panel members on beneficial research or engagement activities to address perceived gaps.

2.4.8.1. The evolution of the Coordination Group

We commenced our engagement program with a different model, with a SRG responsible for the now-Coordination Group's remit. The SRG was also much more active in the direction-setting for the price review.

In mid-2023, we took the opportunity to reflect on the first 6 months of engagement with our panel members. Based on feedback and suggestions from panel members and our own observations, we refined aspects of our engagement program to ensure we remained on track to meet our engagement objectives.

We made the following changes to the engagement approach:

- Disbanded the SRG and re-launched the sub-Panels as stand-alone Panels
- Appointed a Coordination Group with an independent Chair, responsible for working with AusNet to coordinate the Panel outputs into the overall proposal and to engage with AusNet on other important and technical considerations not addressed elsewhere in the engagement program. With the group now comprising a representative from each Panel, we empowered the Group to define its role and responsibilities
- Formed a new Panel, the Research & Engagement Panel, to work with AusNet on the design of research and further engagement activities to support the proposal and Panels' deliberations. The Research & Engagement Panel has taken this responsibility over from the SRG
- Co-designed a series of focus questions with each Panel to better focus engagement and help provide clear links between desired customer outcomes and proposal inclusions (see Appendix 2). These questions have also informed forward engagement plans and enable gaps and overlaps to be identified and managed.
- Added more time for Panels to meet and engage during 2023, so a broader range of topics could be included and allow for more in-depth discussions during meetings
- More clearly articulated how the deliberations and involvement of panel members will inform the development of our Draft Proposal
- Expanded the remit of the Benchmarking Panel to include operating expenditure (opex)
- Established a $150,000 independent budget for the Coordination Group to manage

- Welcomed one new panel member, while one decided to exit the process. A further 2 panel members changed panel to better align to their expertise and availability, and
- Added 2 new members to our Customer Consultative Committee (both are EDPR 2026-31 Panel members) to further strengthen the customer focus of this group and links between Price Review and business-as-usual engagement.

Through 2023, the Coordination Group played a key role in identifying and raising conflicts or overlaps between panels and working with AusNet to identify value-stacking opportunities across workstreams. As the program progressed, the group undertook the role to understand and resolve trade-offs for inclusion in the proposal.

From 2024 onward the Coordination Group were instrumental providing detail on building blocks (incorporating Panel inputs) and the price path. During this time the group also helped ensure that both proposal reflects customers' expectations and honours the panels' outputs and that it is balanced and efficient.

The Coordination Group provided the following comments in its independent report on the Draft Proposal:

Excerpt from the Coordination Group's Report on the program restructure

After six months operation, and following discussions with the Chair at the time, AusNet undertook a formative evaluation and reviewed its original engagement plan. The evaluation concluded that EDPR engagement could be improved by establishing the Coordination Group and a Research and Engagement (R&E) panel.

The Coordination Group commends AusNet on its willingness to reflect and listen to the views of the original SRG and from what it learnt to restructure the SRG into stand-alone panels, each with a lead, and with the leads forming the Coordination Group's membership. The Chair at the time also opted to step aside due to unrelated commitments and AusNet appointed a new Chair.

The Coordination Group also commends AusNet for establishing the R&E panel dedicated to working with the business to contribute to its EDPR customer research and engagement. The Coordination Group sees this as tangible evidence of AusNet's commitment to ensuring the business's research and engagement activities are transparent and reflect customers' views.

2.4.8.2. The Coordination Group's focus areas

The Coordination Group is responsible for incorporating the outcomes of Panel process into the proposal. Key to this role is working transparently and collaboratively with the Panels and AusNet and challenging AusNet, as necessary, to prepare a high-quality evidence-based proposal reflective of customers' preferences.

One of the Coordination Group (then the SRG's) earliest and most impactful outputs was the *Network Aspiration* they collaborated on with us. The Network Aspiration was developed in response to the panel's desire for a clear objective for the price review – that is, ultimately what we were looking to achieve through the price review. It set the high-level objective beneath which the panels developed their focus questions.

Figure 2-10: Our network aspiration

Source: AusNet

The Coordination Group has contributed in the following additional ways:

- Shared and discussed outcomes for Panel specific meetings to ensure overlaps and interactions were understood and considered
- Provided detail on the Building Blocks including deep dives on incentives, non-network spend, depreciation and innovation
- Monitored and shared external recommendations that significantly impacted the proposal
- Completed a deep dive to apply Quantifying Customer Values outcomes to our forecasts
- Provided input into the design of offsites and Panel meetings
- Regularly communicated with the AER and the CCP to keep them updated regarding engagement and key issues
- Resolved any Panel member escalations, and
- Developed and delivered the Independent Report on the Draft Proposal on behalf of all the Panels.

A meeting schedule for the Coordination Group can be found below in 2.4.6.3.

2.4.8.3. Meeting schedule

In early 2023 the SRG was established to provide support to the panels and oversight of the overall proposal and engagement process governance.

The SRG met monthly between February and May 2023, after which it disbanded and the Coordination Group formed.

The primary focuses of each SRG and Coordination Group meeting is below, noting it is not an exhaustive list of all topics discussed.

In addition, all Coordination Group agendas included the following standing items:

- Panel Leads providing updates on their workstreams, and
- AER CCP and staff providing updates, and
- An "open floor" where other issues could be raised by members and AusNet.

All the SRG and Coordination Group meeting summaries are provided as supporting documents.

Table 2-5: A schedule of our SRG and Coordination Group meetings and primary focuses

Meeting summary
SRG Meeting #1 | 23 February 2023 Ways of working, and feedback on the draft Engagement Plan
SRG Meeting #2 | 28 March 2023 Approach for the Quantifying Customer Values research, and collaborative discussion on broader customer engagement, a *network vision* and process governance.
SRG Meeting #3 | 27 April 2023 Finalising the draft Network 'Aspiration', determining next steps for customer workshops and discussing criteria for a "value-for-money" proposal
SRG Meeting #3a | 25 May 2023 Quantifying Customer Values Working Group met to agree on the purpose of the research and next steps.
SRG Meeting #4 | 25 May 2024 Process re-design and focus questions. No meeting summary is available, but the pack is attached as a supporting document.
Coordination Group #1 | 28 August 2023 Revising their purpose and agreeing on ways of working.
Coordination Group #2 | 28 September 2023 AER speaking on their expectations for the Independent Report, and extra-long Panel Lead updates.
Coordination Group #3 | 26 October 2023 Early signals pathway update, emergency backstop cost pass-through and customer workshops.
Coordination Group #4 | 30 November 2023 CCP "ground rules", early signals pathway update, March offsite agenda review, customer workshops and brand campaign

Coordination Group Deep Dive on Investment Planning Approach | 11 December 2023 Full day forum on the approach AusNet takes to economically justify capital expenditure
Coordination Group #5 | 24 January 2024 Customer interview proposal, customer workshops, resilience planning, March offsite planning, and emergency back-stop mechanism pass-through
Coordination Group #6 | 13 February 2024 Q&A with AusNet's CEO, preparation for customer workshops, preparing the Draft Proposal and the independent report, and March all-panel meeting
Coordination Group #7 | 28 February 2024 Major outage event discussion, and final preparations for the March all-panel meeting
Coordination Group #8 | 6 March 2024 Debrief on Epping offsite focused on first impressions of the Draft Proposal and areas for further work
Coordination Group #9 | 26 March 2024 Major outage event update, customer workshops update, consolidated feedback from the offsite poster sessions, Draft Proposal outline and approach to the upcoming Deep Dive on incentives, depreciation and innovation
Coordination Group #10 | 9 April 2024 Regional long-run supply planning, early signal pathway update, the upcoming Deep Dive on incentives, depreciation and innovation, and interim findings from the Research & Engagement Panel-initiated customer interviews
Coordination Group Deep Dive on Incentives, Depreciation & Innovation | 16 April 2023 Agreeing on an approach to innovation, next steps for depreciation, and an approach and to incentive schemes.
Coordination Group #11 | 23 April 2024 Non-network expenditure costed options, the AER's draft F&A decision, and an Energy Community Resilience Fund overview
Coordination Group #12 | 15 May 2024 Regulatory re-openers, and NSW determinations and lessons/implications for AusNet
Coordination Group #13 & Deep Dive on Quantifying Customer Values study | 29 May 2024 Approach for August offsite and resilience engagement, followed by a deep dive into the Quantifying Customer Values study and how to apply the results
Coordination Group #14 | 11 June 2024 February 2024 major outage event Post Incident Review findings, and implications for AusNet's planning
Coordination Group #15 | 25 June 2024 August 2024 all-panel meeting planning, expenditure forecasting methodology, and the Draft Proposal structure
Coordination Group #16 & Deep Dive on Connections | 10 July 2024 Bill impacts analysis, August 2024 all-panel meeting planning, and a deep dive to agree on an approach to network connections policies and charging arrangements
Coordination Group #17 25 July 2024 Further preparations for the August 2024 all-panel meeting and pre-meetings with panels, AusNet's new strategy and structure, and The Energy Charter the extra responsibilities AusNet has for accountability and disclosures
Coordination Group #18 | 8 August 2024 Early Draft Proposal discussion and inclusions, and final preparations for the August 2024 all-panel meeting
Coordination Group #19 | 1 November 2024 Draft proposal feedback with a focus on affordability, metering, and approach for upcoming panel meetings
Coordination Group #20 | 6 December 2024 Continuing the discussion on affordability, the process for finalising the proposal and the Coordination Group's report on it

Source: AusNet

2.5. We publicly consulted on a Draft Proposal and have responded to feedback

We believe it is important that customers are given the opportunity to participate in the regulatory reset process, and have their say on our proposal. We published a draft of this proposal in September 2024, which was developed based on the views of more than 16,000 customers and 130 hours of broad engagement, plus over 230 hours of deep engagement with our Customer Panels and Coordination Group.

The purpose of this step was to "stress test" the Draft Proposal as a whole, and the process had several components:

1. Opening appropriate channels for feedback
2. Making customers aware of the Draft Proposal and opportunity to engage
3. Receiving feedback
4. Responding to feedback in this proposal.

We extensively promoted the Draft Proposal and the channels available for customers to provide feedback, reaching over one million customers, receiving 1,949 views of our Community Hub page on the Draft Proposal, and 758 downloads of Draft Proposal.

2.5.1. We opened appropriate channels for customers to provide feedback

We provided many ways for community members to get involved and provide feedback including:

- Quick and extended surveys available on the Community Hub
- Accepting written submissions via Community Hub, email & mail
- Open invitation for people to invite us to meet
- A public webinar with 23 participants
- Large customer meetings, and
- A forum with 30 council representatives.

The AusNet Community Hub served as the central platform for all information regarding the EDPR Draft Proposal.

The dedicated proposal page featured a digital PDF of the Draft Proposal, a video of our customer panels explaining the process and key elements of the proposal, a timeline of the engagement process, and information about an upcoming webinar (later updated with the recorded video and Q&A). Customers could provide feedback through quick or detailed surveys, with submissions open for eight weeks (23 September to 17 November 2024), and incentives included a chance to win one of 10 $500 vouchers. The page also highlighted our engagement plan, collaboration with stakeholders, and added the Coordination Group's Independent Report once available.

2.5.2. We made customers aware of the Draft Proposal and the opportunity to engage

To engage with our community members we utilised various communication methods and techniques. We reached around 1 million community members with our promotion. All our communications included a call to action for feedback on the Draft Proposal.

We completed an extensive social media campaign to drive awareness of the EDPR Draft Proposal and directed community members to the Community Hub for more information and to submit feedback.

- Facebook and Instagram, reaching approximately 50,000 community members in total with paid and organic Facebook posts. We produced an animated video introducing AusNet and the EDPR through a customer-friendly lens and invited feedback. This video received over 30,000 views.

- LinkedIn engagement with over 5,500 views and 500 clicks on our Draft Proposal post – a very strong engagement rate of 9%.
- Radio promotion on ABC Radio Goulburn Murray (est. 17,000) and Shepparton (est. 16,000).
- TikTok promotion, which received over 130,000 views. Youth engagement was flagged as a priority by our Research & Engagement Panel, given they are harder to engage in processes such as our Panels and will form a significant proportion of our AusNet customer base in 2026-31.
- Local television on WIN 5.30pm News Albury Wodonga (est. audience 10,000).
- Newspaper advertisements in all 31 regional newspapers in AusNet's distribution area (excl. The Age and The Herald Sun). The advertisements appeared in every issue of the papers over a two-week period in mid-October, reaching over 700,000 customers.
- Directly contacting approximately 200 stakeholders, including social service organisations, people who'd registered to receive a copy or updates on the EDPR process via Community Hub, community energy groups, large customers, councils, CALD community members, First Nations groups, community organisations and others. We also reached out to several youth councils with invitations to meet, though there was little to no interest in engaging more deeply.
- Encouraging our Panel members to make individual submissions and/or engage with their communities to collect feedback on the Draft Proposal. Several provided their own submissions on the Draft Proposal.

2.5.3. Responding to feedback received

We received some great feedback from a wide range of customer and stakeholder profiles. It is always challenging to entice people to spend their free time commenting on electricity network services, so despite the extensive promotion we had a relatively low number of submissions on our Draft Proposal, but many we have received have been high quality and some quite detailed.

We received 10 formal submissions from individual customers and community groups, and an extensive report authored by AusNet's Coordination Group. The number of submissions is relatively low but not unexpected.

We have taken some novel actions to increase the amount of feedback received and ensure the Draft Proposal's been challenged robustly, noting that some are less formal in nature than others. They include:

- AusNet staff speaking with large customers and community groups to talk about key aspects of the proposal and collect feedback in both formal and less formal settings
- Having our 103 customer workshop participants to read the proposal and provide feedback on it prior to the sessions
- Holding a workshop for all Councils in the AusNet distribution area, and presenting on key aspects of the proposal for feedback and discussion, and to encourage them to engage internally and within their communities
- Listening to feedback and answering questions during a webinar on the EDPR Draft Proposal, and
- Our panel members collecting their own feedback and sharing it within the panel setting.

2.5.3.1. Support for the Draft Proposal

Feedback received on the Draft Proposal was broadly positive and consistent, on both the outcomes and it was seeking to achieve and its value for money and affordability overall. While customers would always like their bills to be cheaper, there was no consistent feedback on areas they would like to see us cut back on. Of our customer workshop participants, 94% rate it as adequate or better, and many highlighting the strong balance achieved between affordability and service improvements and the sentiment was similar among those who made submissions.

Again, we have not aimed for nor think it practical to achieve unanimous support for our proposal. We understand there are some customers who would like us to be doing more or less, but we strongly believe our proposal strikes the balance that is in the best overall interests overall for our customers.

Specific areas of our proposal that received support were:

- Stable network charges (before inflation) was generally seen as a positive story by customers, and the dominant sentiment in submissions and from our customer workshop participants was that appreciated AusNet's plan keeping prices down.
- Our plans for improving reliability for worst-served customers were seen to be the right approach, focussing on narrowing the "reliability gap" by investing in the poorest-performing feeders. We did not receive any feedback that customers were not comfortable with our plans to maintain today's reliability standards for most customers.
- Resilience investment was well-received, especially among those who have lived experience of natural disasters and/or long duration outages. While it is clear that customers would ideally like the power not to go out at all,

both network hardening and investments to support our response were widely seen to be worthwhile and several submissions, particularly from regional areas, expressing a view that the proposal does not go far enough to prepare for major events and that they would like to see a bigger proposal with more communities benefitting. Some customers in the workshops, particularly those from more urban areas such as those in the Epping group, did not see value in resilience investments.

- There was strong interest in the proposal for a Benalla-Euroa express feeder from those communities that expect to benefit from it
- The proposal's alignment with sustainability, government policy and net-zero goals was generally well-received. Some in the customer workshops acknowledged that even though they are not enthusiastic supporters of renewables or think the government is moving too quickly on renewables and electrification, that supporting new technologies and connecting new generation is critical for future energy security – a priority for all.
- The Coordination Group's report on our Draft Proposal included many explicit references to elements of the proposal that they support, including the following direct excerpts:
    - *"The [Electricity Availability] panel is supportive of the proposed proposals and initiatives and that they are suitable for being presented for stakeholder consideration. The panel is pleased that it will improve resilience and reliability most notably for worst served customers. The panel also supports the QCV related analysis and approach that should provide a more accurate assessment of proposed expenditure. The panel expects the detail to be reviewed by the AER and applied consistently across the proposal."*
    - *"The [Future Networks] panel is supportive of the proposed initiatives and expenditure to deliver the requirements for electrification, CER and to better integrate renewables into the network and that they are suitable for being presented for stakeholder consideration. The panel also supports the QCV with similar conditions as noted above."*
    - *"The [Customer Experience] panel is supportive of the proposed additional customer service and experience related initiatives and measures and that they are suitable for being presented for stakeholder consideration. The panel welcomes and acknowledges that if implemented appropriately it should lift customer service standards and address many pressing issues customers are facing."*
    - *"The [Tariffs & Pricing] panel is supportive of the tariff design work, the proposed tariffs and the consistent approach across the DNSPs."*

2.5.3.2. Updates made based on feedback received

Specific themes we noted, and have responded to as appropriate, are:

- All customers would like bills to be cheaper, and although they are willing to pay for improvements, they want confidence that they are not paying more than they need to for the outcomes they expect. They asked us to keep looking for areas to save without impacting the customer experience. It was also clear particularly from the customer workshops that few customers fully understand network charges, and some were surprised at how much they were paying for network services today. We also engaged with customers who cannot afford their living expenses and felt any amount was too high. Some also noted that AusNet is only one component of the bill so AusNet's price path shouldn't be interpreted as the price path for bills overall.
- Since the Draft Proposal was published, we completed a thorough top-down assessment to identify synergies and areas to save and deferring investment in areas that won't significantly impact customers' experience. These adjustments are outlined in the Executive Summary. We acknowledge the AER will also be fulfilling its role assessing the prudency and efficiency of our plans, and in doing so respect customers' expectations of higher levels of service and their willingness to pay for them.
- Another caveat over almost all support is that customers want confidence that AusNet will deliver on its plans and achieve the outcomes we are claiming in this proposal. There is also an expectation that we monitor and adjust the plans during the regulatory period to make sure they are a) as efficient as they can be, and b) on track to deliver the intended outcomes.

  In response, we have included "safeguards" in the Proposal to support revenue being spent appropriately, emerging customer priorities are being addressed and anticipated benefits are realised. This means a bigger role for our Customer Consultative Committee, who we will report to on progress and collaborate with on many key decisions, such as allocation of the Regional Reliability Allowance and outcomes achieved. The Innovation Advisory Committee will be retained as a governance committee for innovation spending – a model pioneered by AusNet in the current regulatory period, and that is working well today and now being adopted by other networks. We will also continue reporting publicly on our performance via our annual Energy Charter Disclosure.
- A number of customers asked for more evidence that customers will be better-off-overall from the connections enablement and flexible exports programs. While customers in the workshops were generally comfortable with others benefitting (even if they were not directly paying), they did want confidence that AusNet customers would benefit. We have provided more evidence to this effect in our proposal and businesses cases in response.

- Our Coordination Group and panels outlined a number of areas they wanted to engage further on, or that their support was conditional on. We have addressed these to the extent we feel we practically can:
    - In meetings in November 2024, to finalise approaches with the relevant panels on several matters including but not limited to the design of the Regional Reliability Allowance and approach to hazard tree management, and
    - Throughout this proposal, where their support was contingent on us providing various justifications or data to support the approach.

2.5.3.3. Some feedback has not changed our proposal

We did receive some feedback on our Draft Proposal, of varying strength in sentiment, that has not changed its contents.

This includes preferences of some groups that **we do not consider is broadly supported by the customer base or in customers' interests**, including:

- Higher levels of resilience investment, including from the Sandy Point community
- Reviewing our allocation of costs between tariff classes, which previously had flat prices for residential users and small price increases for large users. We have responded by not changing our current approach as any substantive changes to the revenue allocation between tariff classes may inadvertently create bill shocks.
- We continue to receive strong interest from customers for undergrounding power lines. It is the desire of some that the network be fully or partially undergrounded, especially in regional and/or disaster-prone areas. We have not included widespread undergrounding in this proposal due to the very high costs involved, which would not be aligned with customers' willingness to pay for service level improvements, but will continue undergrounding parts of the network where it makes sense to do so from an economic and/or safety perspective.
- A suggestion that AusNet abolishes its vegetation management program and find other ways to protect its assets, given the impact of tree pruning on visual amenity. We strongly feel this would not be in customers' interests, and it would be a breach of our regulatory obligations.
- Some suggestions that AusNet take a more active role than proposed in supporting community energy groups, and subsidising or dedicating resources to projects. We do not consider it to be in customers' interests to socialise the cost of community energy projects beyond what is proposed, which is to co-invest where it is cost-effective to do so. We consider further support for community energy projects to be the role of government.

Some feedback has not been incorporated because **we consider it to be outside what is reasonable within our operating framework**. This includes:

- A 1% opex productivity factor. Our Benchmarking & Opex Panel have been advocating for a 1% opex productivity factor up from the standard 0.5% which we have not reflected.
- The strongly-held view of a small group of customers in the workshops that the government or AusNet's shareholders should pay for network services and/or improvements, which we do not consider realistic.
- Suggestions of many customers that AusNet take an active role in increasing feed-in tariffs, or subsidising rooftop solar and battery systems. We consider this to be the role of government.

More detailed and/or operational feedback has been **taken on notice for consideration outside the Price Review process**, including:

- Monitoring outcomes and continuously reviewing expenditure programs as they are being delivered.
- Many requests, particularly in the Coordination Group's report on our Draft Proposal, for areas that we share information on as they are being delivered.
- Suggestions for communications campaigns. We received a lot of feedback highlighting the importance of communications and continuous improvement to them, which supports the $5m allowance for communications and education included in section 7.9.7 of this proposal and tested in the draft plan. While AusNet is not best-placed to deliver all communications on energy, we are seen to have a unique role and be well-positioned to help keep customers informed on many topics. Topics for communications suggested repeatedly during consultation on the Draft Proposal included informing customers of our plans, tariffs education, various solar matters including flexible exports and how to save money through solar, innovation activities, and network reliability and resilience plans.
- Some more operational engagement suggestions and feedback on the Draft Proposal document itself.

Some has been **taken on notice and will be addressed in the Revised Proposal**, including:

- Incorporating the latest information, particularly with respect to demand forecasts, into our final plans, and
- Considering a request to extending the FRT22 feeder, creating redundancy for the Sandy Point area.

2.6. Plans for post-lodgement engagement

We will continue engaging with customers and communities following the submission of this proposal to inform refinements to be included in our Revised Proposal. Supporting the AER's public consultation on our proposal will be a key early step in this process.

Our post-lodgement engagement strategy is designed to be flexible and responsive, adapting to feedback from the Australian Energy Regulator (AER) and other stakeholders as we progress towards our Revised Proposal.

Our post-lodgement engagement approach is designed to be flexible and adaptable, allowing us to respond effectively to the AER's review and other stakeholders' feedback on our Proposal and (if needed) prepare a Revised Proposal that meets regulatory expectations and serves the best interests of our customers.

Our Coordination Group will continue to play an important role. Consistent with the expectations of the Better Resets Handbook, the Coordination Group is scheduled to submit a report on how our Proposal is aligned (or otherwise) to customers' interests in or around March 2025. The Coordination Group will likely have some further meetings in 2025, pending the outcomes of the AER's early assessments and public consultation process.

Our refreshed Customer Consultative Committee (CCC) will serve as a central engagement body and accountability partner for us ongoing. We are currently recruiting for new CCC members following a significant refresh of the group's Terms of Reference. These Terms of Reference have been shaped considerably by our engagement process to support this proposal. The CCC may be involved in post-lodgement engagement if it is well-placed to do so, including to discuss outstanding details, such as setting targets for our Customer Service Incentive Scheme design. These discussions will occur ahead of our Revised Proposal submission, ensuring that customer insights directly inform our plans.

Depending on the Victorian Government's decisions regarding minimum reliability standards, we may reconvene the Electricity Availability Panel to engage on this important topic. This panel would likely be best-placed to engage on any new requirements or expectations regarding reliability standards, and landing on an approach for the revised proposal that is consistent with customers' interests if updates are needed.

2.7. Supporting documentation

We have included the following documents to support our engagement and research chapter:

- ASD - Coordination Group - Coordination Group Report on Draft Proposal - 31 Jan 2025 - PUBLIC
- ASD - Lewers - Quantified Customer Values - Willingness to Pay - 31 Jan 2025 - PUBLIC
- ASD - AusNet - Panel Focus Questions and Answers - 31 Jan 2025 - PUBLIC
- ASD - Nation Partners - Vic DB Resilience Workshop #1 Report - 31 Jan 2025 - PUBLIC
- ASD - Painted Dog - Customer Segmentation Research - 31 Jan 2025 - PUBLIC
- ASD - RPS - Vic DB Framework & Approach Workshop #1 Report - 31 Jan 2025 - PUBLIC
- ASD - RPS - Vic DB Framework & Approach Workshop #2 Report - 31 Jan 2025 - PUBLIC
- ASD - RPS - Vic DB Vulnerability Workshop #1 Report - 31 Jan 2025 - PUBLIC
- ASD - RPS - Vic DB Vulnerability Workshop #2 Report - 31 Jan 2025 - PUBLIC
- ASD - SenateSHJ - Customer Workshops Participant Feedback - 31 Jan 2025 - PUBLIC
- ASD - SenateSHJ - Customer Workshops Round 1 Report - 31 Jan 2025 - PUBLIC
- ASD - SenateSHJ - Customer Workshops Round 2 Report - 31 Jan 2025 - PUBLIC
- ASD - SenateSHJ - Customer Workshops Round 3 Report - 31 Jan 2025 - PUBLIC
- ASD - SenateSHJ - Customer Workshops Round 4 Report - 31 Jan 2025 - PUBLIC
- ASD - bd Infrastructure - Vic DB Tariff Structure Statement Workshop #1 Report - 31 Jan 2025 - PUBLIC

- ASD - bd Infrastructure - Vic DB Tariff Structure Statement Workshop #2 Report - 31 Jan 2025 - PUBLIC
- ASD - bd Infrastructure - Vic DB Tariff Structure Statement Workshop #3 Report - 31 Jan 2025 - PUBLIC
- ASD - AusNet - Council Forum Aug 2024 Meeting #1 Summary - 31 Jan 2025 - PUBLIC
- ASD - AusNet - Council Forum Oct 2024 Meeting #2 Summary - 31 Jan 2025 - PUBLIC
- ASD - AusNet - Customer Consultative Committee Terms of Reference - 31 Jan 2025 - PUBLIC
- ASD - AusNet - SRG Meeting #1 Summary - 23 Feb 2023 - PUBLIC
- ASD - AusNet - SRG Meeting #2 Summary - 28 Mar 2023 - PUBLIC
- ASD - AusNet - SRG Meeting #3 Summary - 27 Apr 2023 - PUBLIC
- ASD - AusNet - SRG Meeting #3a Summary - QCV Working Group - 25 May 2023 - PUBLIC
- ASD - AusNet - SRG Meeting #4 Pack - 25 May 2023 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #1 Summary - 28 Aug 2023 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #2 Summary - 28 Sept 2023 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #3 Summary - 26 Oct 2023 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #4 Summary - 30 Nov 2023 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #5 Summary - 24 Jan 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #6 Summary - 13 Feb 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #7 Summary - 28 Feb 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #8 Summary - 6 Mar 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #9 Summary - 26 Mar 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #10 Summary - 9 Apr 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #11 Summary - 23 Apr 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #12 Summary - 15 May 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #13 Summary - 29 May 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #14 Summary - 11 Jun 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #15 Summary - 25 Jun 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #16 Summary - 10 Jul 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #17 Summary - 25 Jul 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #18 Summary - 8 Aug 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #19 Summary - 1 Nov 2024 - PUBLIC
- ASD - Coordination Group - Coordination Group Meeting #20 Summary - 6 Dec 2024 - PUBLIC
- ASD - AusNet - Coordination Group Deep Dive on Investment Planning Approach - 11 Dec 2023 - PUBLIC
- ASD - AusNet - Coordination Group Deep Dive on Incentives Depreciation Innovation Meeting Summary - 16 Apr 2024 - PUBLIC
- ASD - AusNet - Coordination Group Deep Dive on QCV Meeting Summary - 29 May 2024 - PUBLIC
- ASD - AusNet - Coordination Group Deep Dive on Connections - 10 July 2024 - PUBLIC
- ASD - AusNet - Coordination Group Deep Dive on Repex Meeting Summary - 24 Jul 2024 - PUBLIC

On our Community Hub page, you can find:

- Panel meeting slide packs are confidential and can be found in the panel members' area on Community Hub which requires login details to access, and
- Full panel meeting summaries. The key points from each panel meeting, in our Panel Leads' words, are captured in the Coordination Group Meeting Summaries.

3. Network characteristics and operating environment

3.1. Key points

- We operate and manage one of the two rural distribution networks in Victoria. Split by the Great Dividing Range, our network spans from the northern and eastern suburbs of Melbourne eastward to Mallacoota, and north to the Murray River. It covers heavily forested and mountainous areas, as well as the low lying and coastal regions of Gippsland. This area includes alpine regions, rural areas, high growth suburbs of Melbourne, coastal areas and forested areas with few customers.
- Low customer density, difficult terrain and obligations to manage extreme bushfire risk make it comparatively expensive to serve our customers. It also creates challenges in providing a reliable and resilient energy service, which has been clear in the last few extreme weather events (bushfires and storms) that have impacted the network and our customers.
- Bushfire risk in our service area continues to be among the highest in the world, with the potential for catastrophic loss to life and property. Our previous $500 million investment in Rapid Earth Fault Current Limiter (REFCL) technology at 22 zone substations is mitigating bushfire risk. We also undertake more frequent asset inspections and vegetation management than interstate electricity distribution network service providers (DNSPs) in accordance with Victoria's bushfire regulations.
- We face growing challenges from the increasing frequency and severity of extreme weather events that have widespread and devastating impacts. While all other networks are experiencing the impacts of a changing climate, extreme storms and bushfires have been a particular issue in Victoria in the current regulatory period. These challenges necessitate a step change in our preparedness, response, and recovery from these events to maintain supply reliability and to protect the ecosystem of essential services that electricity distribution networks sustain. Accordingly, our Revenue Proposal contains proposed capex in a new category (resilience), and in consultation with our customers, we have developed business cases to ensure that our proposed resilience investments meet our customers' needs efficiently.
- The decarbonisation of the Victorian energy system poses challenges and opportunities for us. By 2035, electricity consumption is forecast to increase by about 50% compared to 2024, driven by the electrification of homes and businesses, uptake of electric vehicles, and new industrial load growth. In response, we are investing in new digital and data analytics-enabling technologies, and investments in least-regret network and non-network solutions that maximise option value. As the Victorian energy system continues its transition to a net zero carbon future, we will continue to respond to and address emerging network issues, to ensure our network evolves and is managed in the most efficient and agile manner to meet the rapidly changing needs of our customers in an environment of high uncertainty.

3.2. Chapter structure

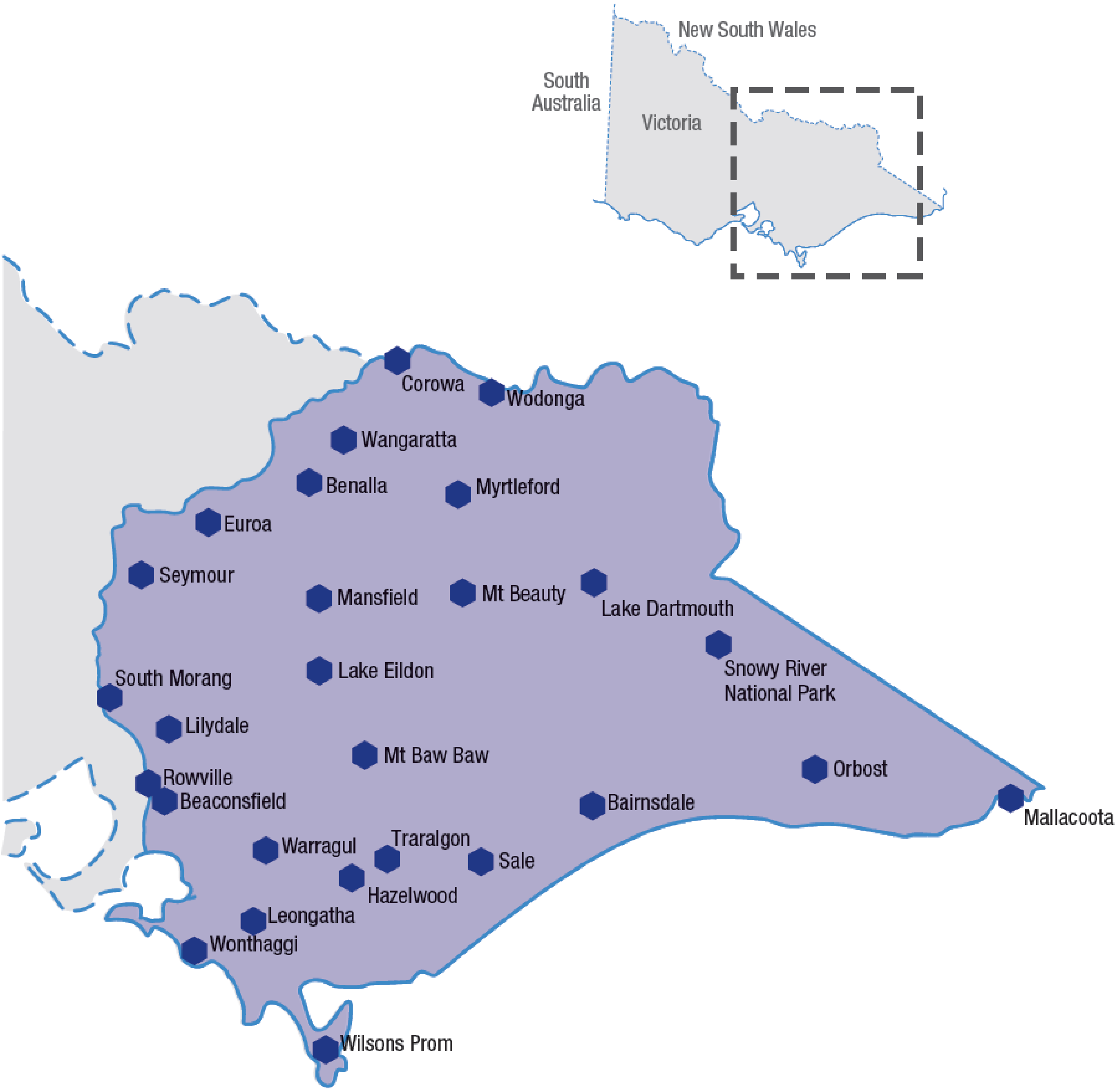
The structure of the remainder of this chapter is:

- Section 3.3 provides key statistics regarding our network and the typical volume of our annual maintenance and renewal activities
- Section 3.4 describes the physical and environmental challenges in our network area including harsh terrain, low customer density and significant bushfire and flooding risk. These factors impact our capital and operating costs;
- Section 3.5 outlines the characteristics of our customer base
- Section 3.6 explains the implications of the unprecedented changes taking place in the energy sector as Australia transitions to decarbonisation, and
- Section 3.7 examines the implications of climate change and extreme events for the resilience of our network.

3.3. Key network statistics

AusNet operates and manages an electricity distribution network serving the fringe of the northern and eastern Melbourne metropolitan area and the eastern half of rural Victoria (see Figure 3-1) delivering electricity to approximately 814,000 households and businesses.

Figure 3-1: AusNet Electricity Distribution Network



Source: AusNet.

Approximately 90% of our customers are households and around 60% of our customers are in rural areas.

The electricity network comprises a sub-transmission network that consists of predominantly overhead lines operating at 66 kV, with zone substations transforming the voltage and providing the feeder exit points for the distribution network, which generally operates at a voltage of 22 kV and consists mainly of overhead lines but also includes underground cables. Some customers in remote and low population density rural areas are supplied by Single Wire Earth Return (SWER) Medium Voltage (12.7 kV) distribution networks. Most of our customers are supplied at low voltage from distribution substations on the 22 kV network. The table below lists the key elements of our distribution system.

Table 3-1: AusNet's distribution system

Key network element	Number of elements
Zone substations	67
Distribution substations	62,830
Power and public lighting poles	431,780
Underground cable and overhead lines	45,980 kilometres

Source: AusNet AMS 20-01

Each year our renewal and maintenance activities typically include approximately:

- 115,000 poles and pole tops being inspected
- 3,000 poles being replaced
- 2,100 cross-arms being replaced
- 235 km overhead conductors being replaced, and
- 22,000 streetlights being replaced.

Our expenditure requirements are unavoidably affected by the physical and environmental attributes of our service area, which are discussed in the next section.

3.4. Physical and environmental characteristics

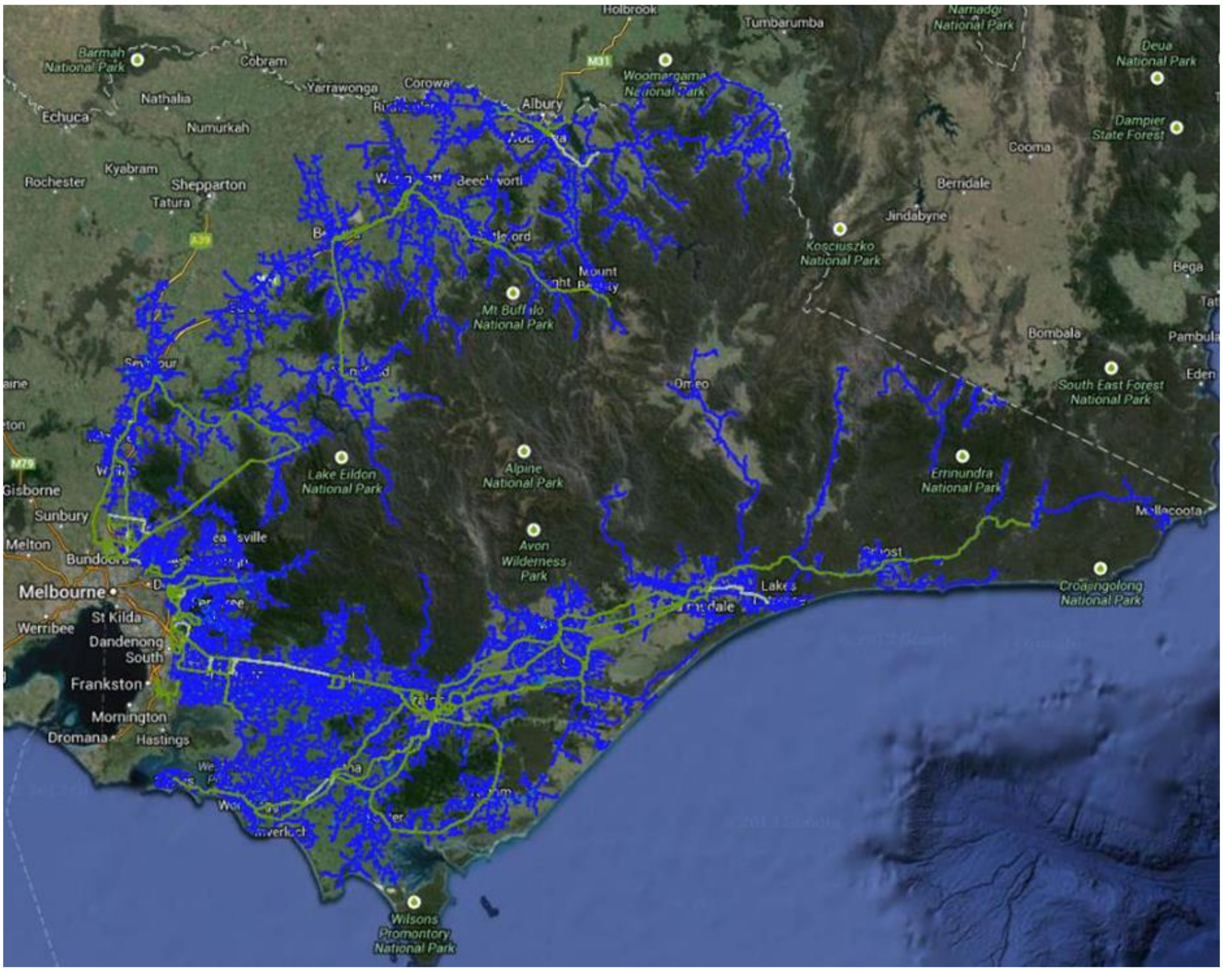
Our network has several physical and environmental characteristics that pose significant challenges to reliable service provision and impose higher costs on our business than on networks without these characteristics. These characteristics include:

- The physical separation of the network by the Great Dividing Range and associated harsh terrain
- A rural network with resulting low customer density, and
- Climate, terrain and vegetation that contribute to a high risk of bushfire and floods.

3.4.1. Physical separation of network and harsh terrain

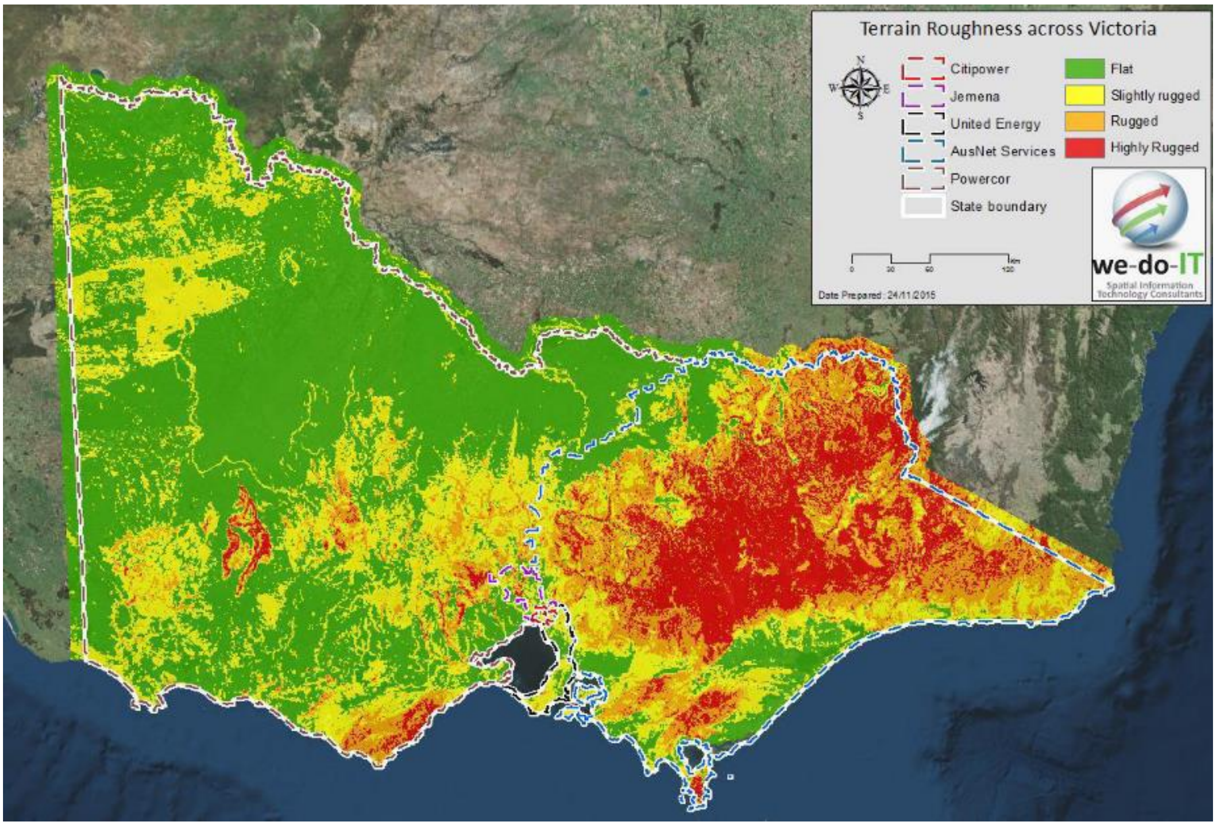
The footprint of our network is physically separated by the Great Dividing Range. Given this topography, we operate two service delivery regions, the East Region and North Region. This ensures our regional centres are appropriately resourced and that we can address challenges in an expedient manner. Consequently, our service centres tend to have lower levels of resource utilisation than other rural networks. In addition, our service teams operate across service areas that are affected by difficult terrain, as illustrated in the figures below.

Figure 3-2: AusNet's distribution network separated by the Great Dividing Range



Source: AusNet

Figure 3-3: Harsh terrain affects network operations

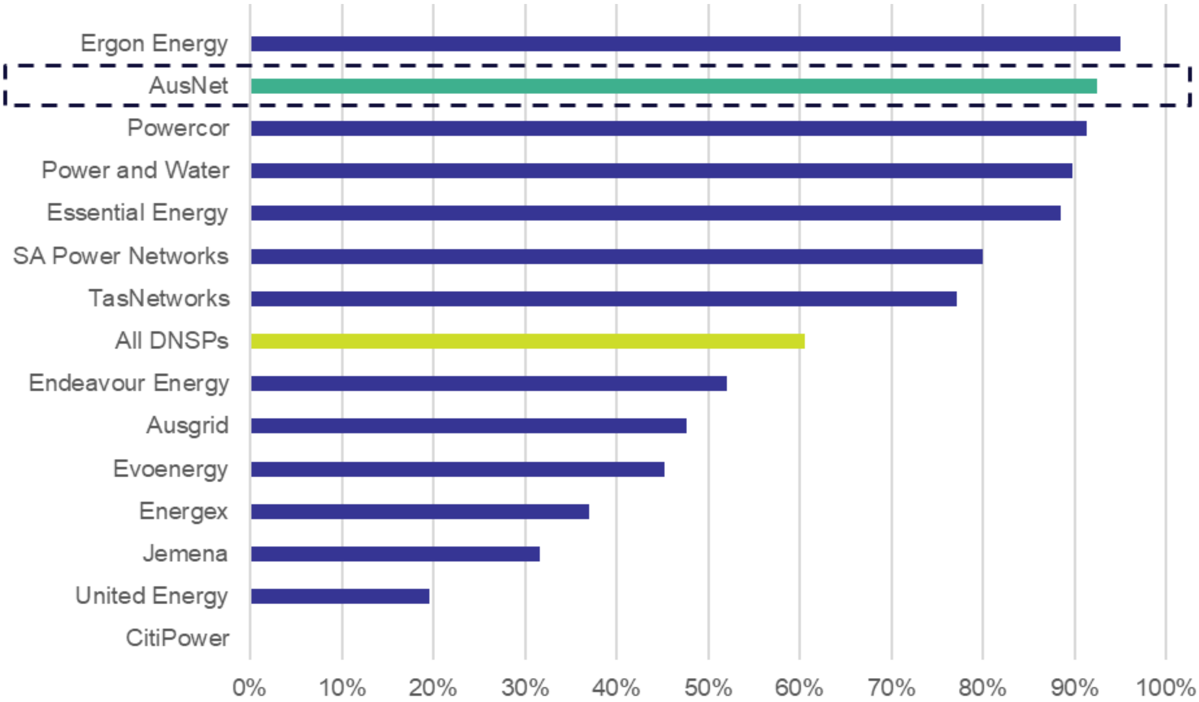


Source: AusNet.

3.4.2. Rural network with low customer density

The rural nature and physical characteristics of the topology of our network area also mean that we have low customer density compared to other DNSPs. As shown below, over 92% of our network (by line length km) is in rural areas.

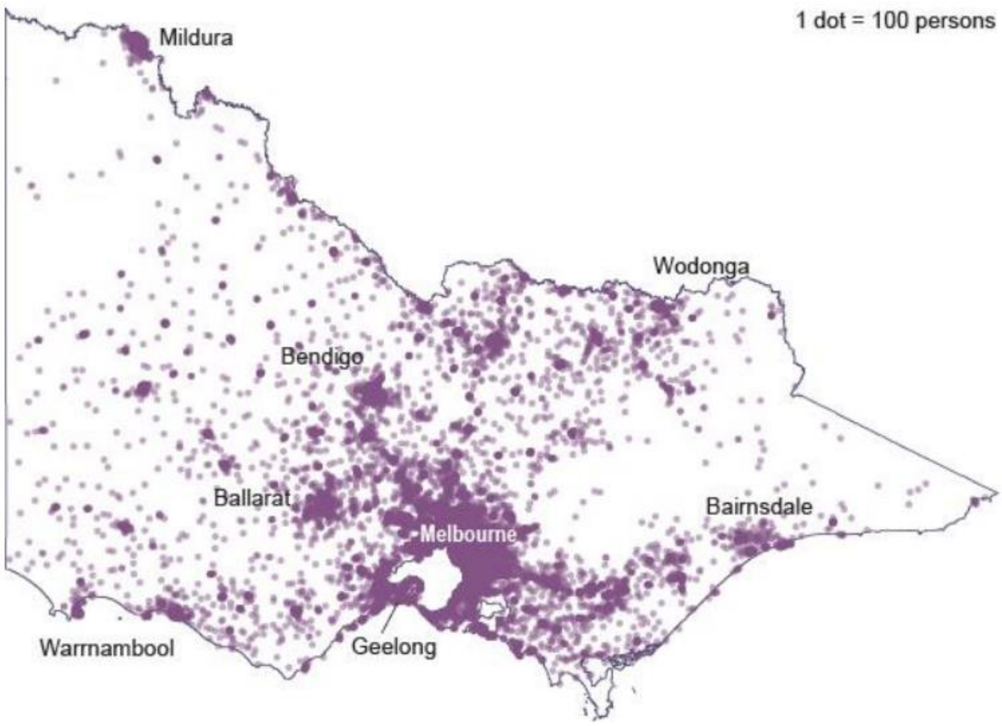
Figure 3-4: Proportion of network in rural area (km line length) in 2024



Source: Electricity Benchmarking RINs, 3.7 Operating Environment Terrain Factor Rural Proportion %.

The figure below shows that our service area has much lower customer density than our Victorian peers and results in a higher cost per customer.

Figure 3-5: Victoria population density



Source: Department of Land, Environment, Water and Planning, Population and Housing in Regional Victoria, 2020. Using 2016 census data.

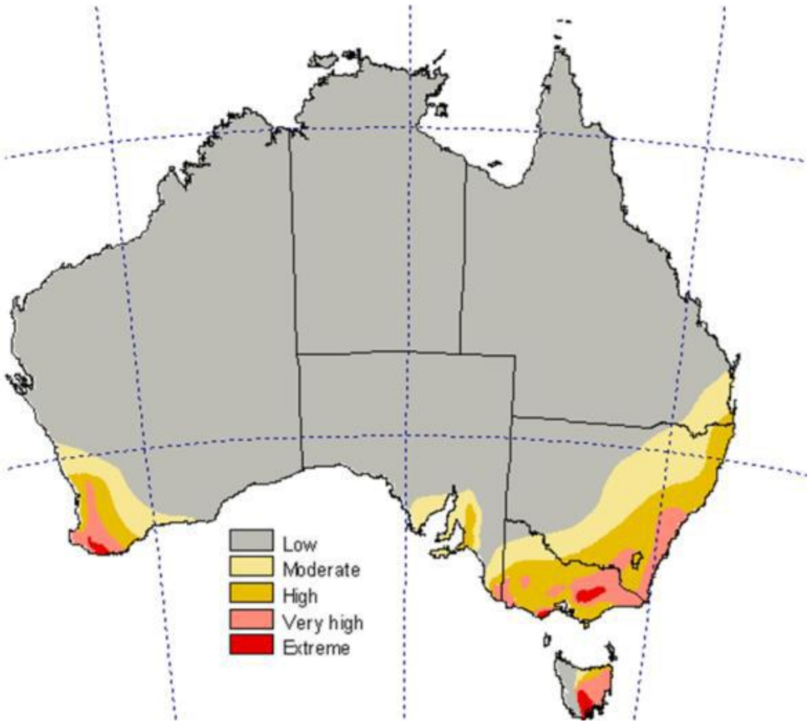
A large proportion of feeders supply low density customer areas, which is defined as lot sizes exceeding 2000 square meters (m^2). Furthermore, 25% of our distribution feeders have less than 10 customers for each km of line length.

3.4.3. High bushfire risk

The climate, terrain and vegetation of eastern Victoria contribute to the region's high level of bushfire risk. Accordingly, our service area is exposed to a particularly high level of bushfire risk, as evidenced by recent bushfire activity in our network area and the catastrophic 2009 Black Saturday bushfires.

The figure below shows the high level of bushfire risk in eastern Victoria relative to other jurisdictions. The level of bushfire risk is defined as, for a given ignition source, the likelihood of a bushfire developing multiplied by the consequence of a bushfire in that area.

Figure 3-6: Bushfire risk in Australia



Source: Blong, R., Sinai, D., & Packham, C. (2000). Natural Perils in Australia and New Zealand. Melbourne, Australia: Swiss Re Australia.

Substantial communities are settled within eastern Victoria, including in areas where there is an 'extreme' level of bushfire risk. As a result, our service area is one of the world's worst areas for bushfires with the potential to cause catastrophic losses to life and property.

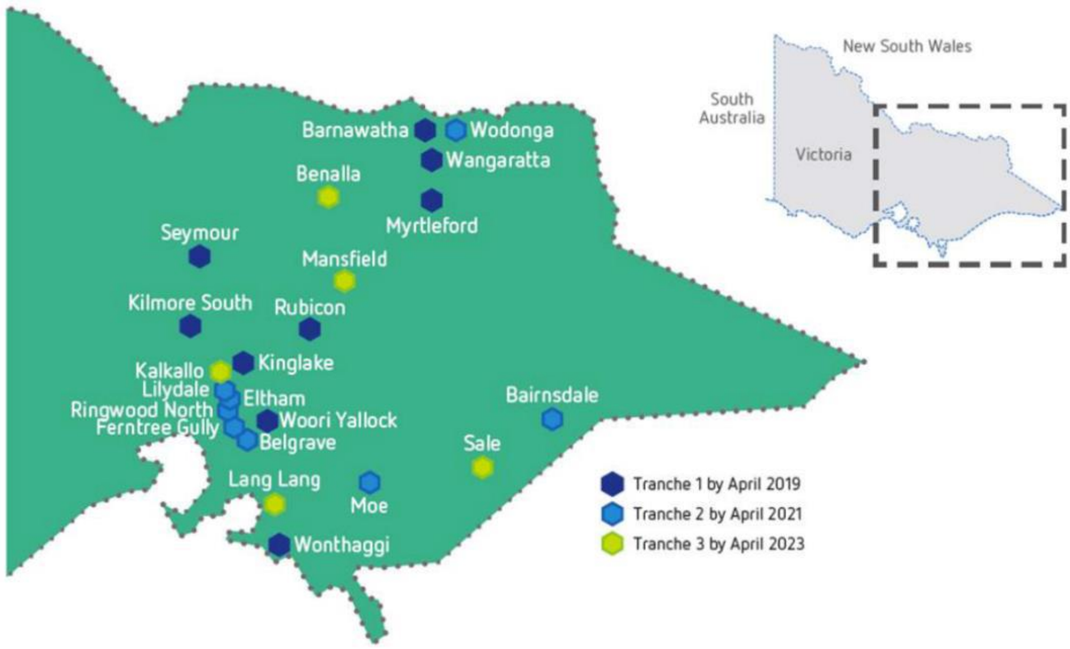
Our policy is to implement a bushfire mitigation management strategy that complies with legislative requirements and creates a harmonious balance for community safety, preservation of the environment and cost effectiveness. Specifically, we aim to:

- Minimise the risk, to as low as reasonably practicable, of fire ignitions by our distribution network assets that could become a wildfire and threaten public safety and property
- Meet the requirements of the Electricity Safety Act 1998, all relevant regulations and the Victorian Electricity Distribution Code
- Regularly review and develop management programs, processes, practices, methods and implement efficiencies for the benefit of customers and other stakeholders
- Minimise the frequency and length of disruptions to the general public
- Be committed to the safety of the community and employees engaged in the provision of services
- Preserve and enhance the environment, and
- Raise awareness of all aspects of bushfire mitigation through increased communication.

In 2016, bushfire mitigation regulations were introduced that require us to meet new performance standards for lines originating from 22 selected zone substations. The installation of Rapid Earth Fault Current Limiters (REFCLs) is the only technically feasible solution capable of meeting the specified performance requirements. This electrical protection technology is designed to minimise the fault current (energy) dissipated from phase to earth (wire to ground) faults on the 22 kV network to reduce the risk of fire ignition associated with network incidents.

AusNet has now completed this $500 million REFCL installation program, which covers more than 40,000 square km, protecting over 18,000 km of electrical powerlines and 300,000 homes and businesses.

Figure 3-7: AusNet's REFCL program



Source: AusNet.

In addition to delivering the REFCL program, bushfire risk in our service area is mitigated through our asset inspection and vegetation management programs. For example, we have approximately 218,000 poles in areas designated as hazardous bushfire risk. Inspection of these assets occurs at intervals of less than 37 months through a combination of ground (test and inspection) and an aerial-based inspection cycles.

Vegetation clearances adjacent to overhead powerlines are managed in accordance with the Electricity Safety (Electric Line Clearance) regulations. In addition, our Vegetation Management Plan is provided annually to Energy Safe Victoria for its review and acceptance. This plan includes procedures for the cyclic inspection, customer notification and consultation and the pruning and removal of vegetation to maintain the prescribed clearance spaces. Each year, approximately 268,000 powerline spans are inspected for vegetation and 5,000 hazardous trees are removed.

3.4.4. Flooding risk

Our distribution network is in areas where the average annual rainfall ranges from 600 millimetres (mm) to 1,200 mm. Some parts of the network in the Northern and Eastern regions are also affected by flooding hazards. For example, approximately 35% of all network feeders have some parts in flood hazardous areas.

3.4.5. Ageing and potentially unreliable assets

AusNet has an ageing electricity distribution network, with a significant proportion of these assets approaching the end of their technical lives.

Our asset management plans include specific tasks and activities required to optimise costs, risks and performance of the assets. A key activity carried out to optimise the costs, risk and performance of ageing and potentially unreliable assets is the development of asset category risk profiles based on asset condition data.

Condition monitoring techniques are utilised to detect early stages of asset degradation before poor condition becomes a significant risk to the safety of personnel, network reliability and the environment. A range of condition monitoring techniques are used to monitor and analyse the mechanical and electrical condition and performance of the various asset classes to accurately forecast future augmentation and replacement requirements.

Zone substation plant and equipment is subject to a combination of periodic and duty cycle inspection and maintenance programs derived from manufacturer recommendations and industry experience. Line assets are subject to cyclic inspection and other techniques such as automated image processing using high resolution aerial images, Smart Aerial Imaging and Processing (SAIP), for conductor condition assessment.

The risks associated with network assets are quantified through the application of dependability management techniques incorporating reliability centred maintenance (RCM) process. Dependability management requires the analysis of availability performance and the influencing factors of reliability, maintainability, and maintenance support under given conditions over a specified period for individual network assets. Failure Mode and Effects Analysis (FMEA) and Failure Modes, Effects and Criticality Analysis (FMECA) are the techniques employed to identify risks of the systems and equipment of the networks. These techniques subdivide the systems into elements (or subsystems) and for each element, identify ways in which it might fail, failure cause and the effects of the failure.

When necessary, the Ishikawa analysis (fishbone) method may be employed to enhance FMEA/FMECA analysis to understand the causes of potential events and the drivers of risk. This understanding is then used to design strategies to prevent adverse consequences or enhance positive ones.

Asset condition data collected during scheduled maintenance tasks is used to determine dynamic time-based probability of failures and percentage of remaining service potential (RSP) of the asset in that lifecycle phase.

Risk profiles for each asset category can then be generated and then used to establish optimised maintenance and asset replacement plans.

3.4.6. Keeping the power on in the face of challenges

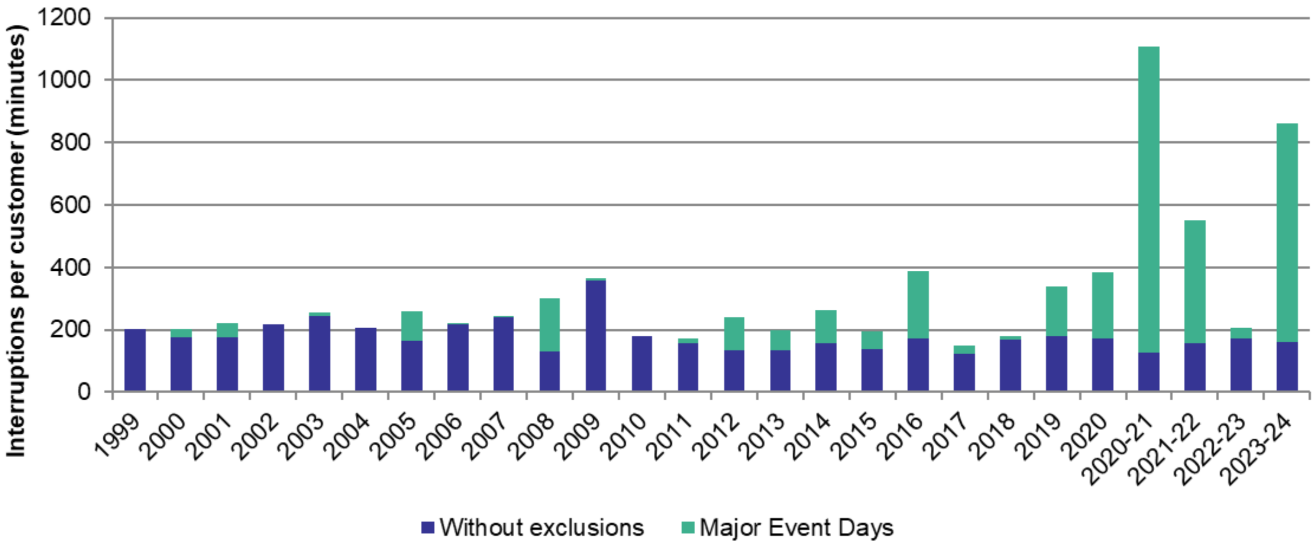
For regulatory purposes, network outages are separated into whether they occur in normal conditions or on a Major Event Day, which is statistically defined based on a threshold relating to the quantum of outages on a particular day.

From a customer perspective, outages have an impact whether they occur on a Major Event Day or not, noting that on Major Event Days the reason for the outage (e.g. a storm) may be clearer to customers, which may somewhat reduce frustration.

The below chart shows that, while our network-wide BAU reliability has remained relatively constant since 2010, Major Event Day Outages has very significantly increased. This is driven by a couple of factors:

- Around 2010 we made significant investments in uplifting reliability, including Distribution Feeder Automation (DFA) schemes, in response to the Service Target Performance Incentive Scheme (STPIS). These investments led to a step improvement in reliability. Network level reliability (measured in system minutes) has remained relatively constant since.
- Since 2020, we have experienced several extreme weather events which have resulted in very significant outages for many of our customers. These very large events have classified as Major Event Days and are described in section 3.7.

Figure 3-8: Driving reliability improvements (1999 – 2024)

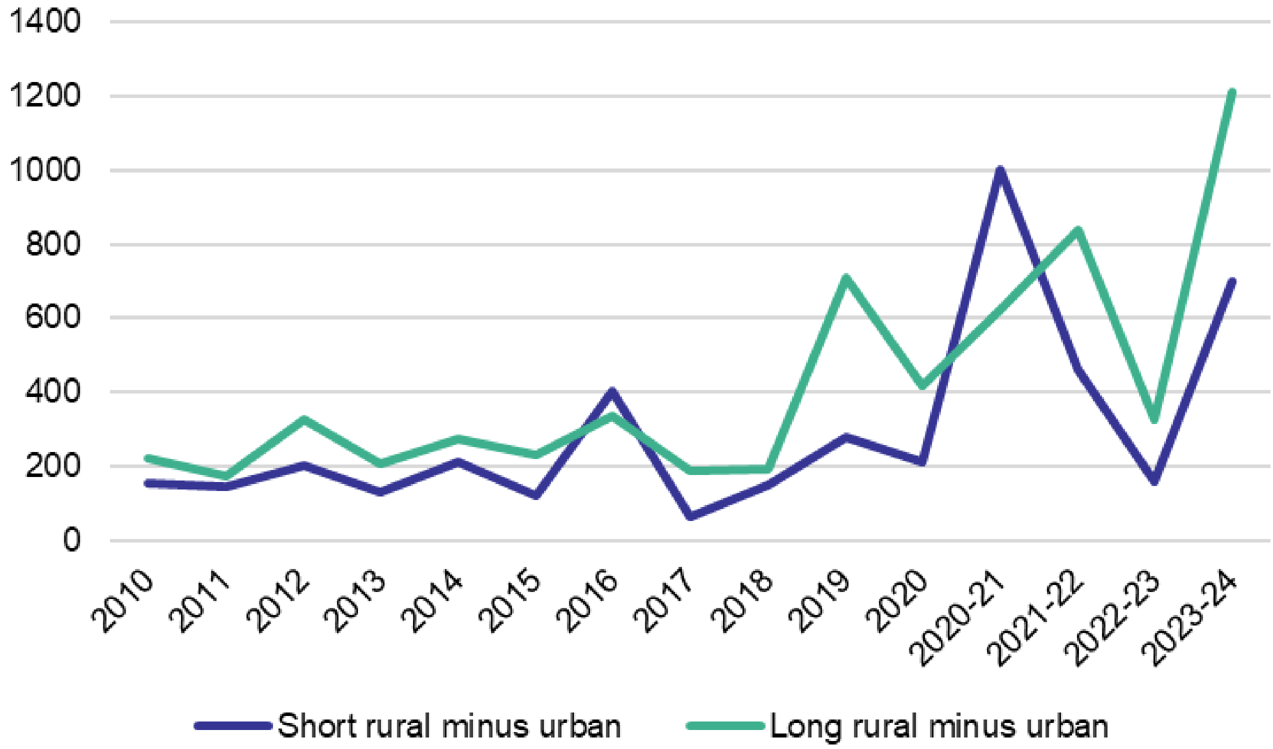


Source: AusNet RIN data

Note: System average duration of unplanned interruptions per customer (SAIDI).

Since 2010 the gap in reliability (measured by outage duration (SAIDI)) between our urban and customers in rural parts of the network has grown. This trend is very strong when including the impact of Major Event Days due to the very significant bushfires and severe storms that have impacted heavily impacted primarily rural parts of our network in the last few years.

Figure 3-9: Gap between urban and rural customer reliability (USAIDI minutes, including Major Event Days) (2010 to 2024)



Customer feedback, research and engagement has highlighted to us the issues caused by poor network reliability and resilience. Our plans to address this feedback and start to close the gap presented above through uplifting reliability and resilience are outlined in sections 6.9 and 6.12.

3.5. Our customers

The network supplies electricity to a diverse group of customers, including residential, business and large commercial and industry customers. Within these groups of customers, there are very diverse energy needs and it is our role to understand differences in customer needs and preferences and develop our plans with this in mind.

Residential Customers

- Metro
- Regional
- Using life-support equipment
- Needing financial support

Business Customers

- SMEs
- Farms
- Factories
- Supermarkets

Large Customers

- Generators
- Public service providers (e.g., hospitals)
- Other utility providers (e.g., water)

Other Customers & Key Stakeholders

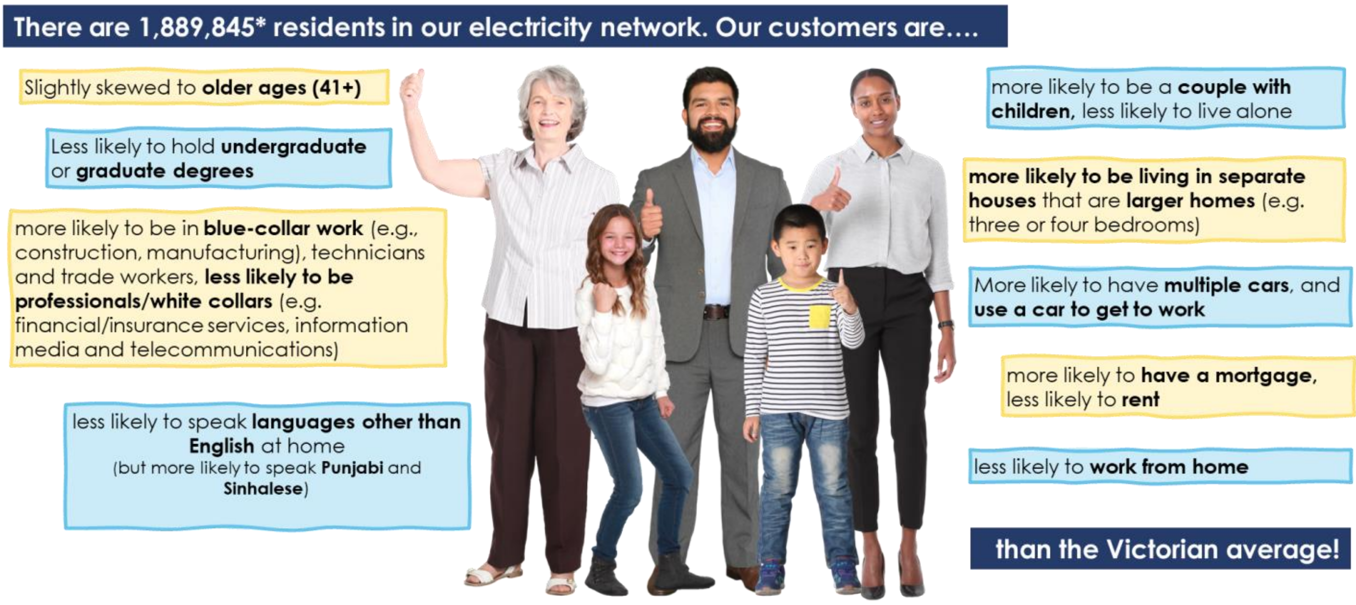
- Solar installers
- Technicians & consultants
- Local councils
- Equipment manufacturers

3.5.1. Who are our customers?

Our network covers a vast geographic area as outlined in section 3.4. While two-thirds of AusNet's network covers rural Victoria and one-third serves metropolitan areas, approximately two-thirds of our customers reside in Greater Metropolitan Melbourne, with the remaining one-third located in rural Victoria. A number of feeders in the Greater

Metropolitan Melbourne region are among the most challenging areas to serve and experience levels of reliability more similar to regional or remote areas.

A comparison of the characteristics of our residential customers with the Victorian average is shown below.



** The total number of residents aggregated in Census 2021.*

3.5.1.1. Customers experiencing vulnerability

Customers experiencing vulnerability are a diverse group including but not limited to those:

- Experiencing socio-economic vulnerability: low-income families, financial assistance recipients, job-seekers
- Having communication difficulties: English as a second language, Auslan users
- Needing life support equipment: kidney dialysis machine, oxygen concentrator, chronic positive airways pressure respirators and more, and
- Living with disability and health or medical condition.
- Five areas within our networks that are considered socio-economically vulnerable: Moe, Bairnsdale, Benalla, Wonthaggi and Morwell.

As explained in Section 2.4.6, we have been listening to the additional support we could provide to customers experiencing vulnerability. While these customers' typically priorities are largely consistent with the broad customer base – such as needing a reliable energy supply, clear communication or people available to connect them with support services and information when the power is out – they may face additional challenges or greater impacts when we don't get these services right.

We are committed to improving how we understand and respond to the diverse needs of all customers by enhancing our communication, refining support processes, and collaborating across the sector to address complex challenges. These efforts will ensure our approach remains inclusive and responsive as part of our business-as-usual activities to understand our customers' needs and the diversity within them, and inform good service design.

We have outlined our commitments to customer service improvements in the Customer Commitments in the Executive Summary. These include a commitment to continue the valuable work we have been doing in the current regulatory period through our Vulnerability Research Grant and evolving this program to be more flexible and maximise its value.

3.5.2. How do our customers use electricity?

Our customer segmentation study (described in section 2.4.2) explored how different customers used electricity, including their attitudes and behaviours. We identified five customer segments and multiple sub-segments, each with distinct consumption pattern, were discovered through the analysis of smart meter data. Some of our findings are below:

- The largest residential customer segment is Time Surfers, accounting for 65% of all customers:
  - Typically working families with school-aged children
  - High reliance on mains gas as a key energy source at home
  - Low solar adoption rate but some sub-segments showing strong adoption intention
  - Feel like they could do more to reduce household energy consumption
- Two distinctive segments of energy exporters (High and Medium Exporters) with different demographic and behavioural traits:
  - High Exporters are typically older households without children while Medium Exporters are working families with children still living at home
  - Both groups are keen adopters of renewable technologies
  - High Exporters showed strong desire to be independent from the grid
- Most Night-time Water Warmers are customers with off-peak electric hot water systems that run at night, which explains the timing of their peaked consumption
- Day-Time Actives represent the smallest of our customers, accounting for 4%:
  - Use electricity throughout the daytime
  - Typically consists of singles or couples with no children
  - They are more likely to live in newer properties, often with pools and spas.

These insights have built our understanding of our customer base and informed various parts of our revenue proposal and strategy development.

Our customers are also the lowest average users of electricity in the NEM, both in terms of energy per customer and coincident maximum demand per customer. This is driven by a few factors including a relatively high share of residential customers and a low number of heavy industrial users in our network. Our residential customers also have some of the highest share of solar PV.

Figure 3-10: Energy per customer (kwh)

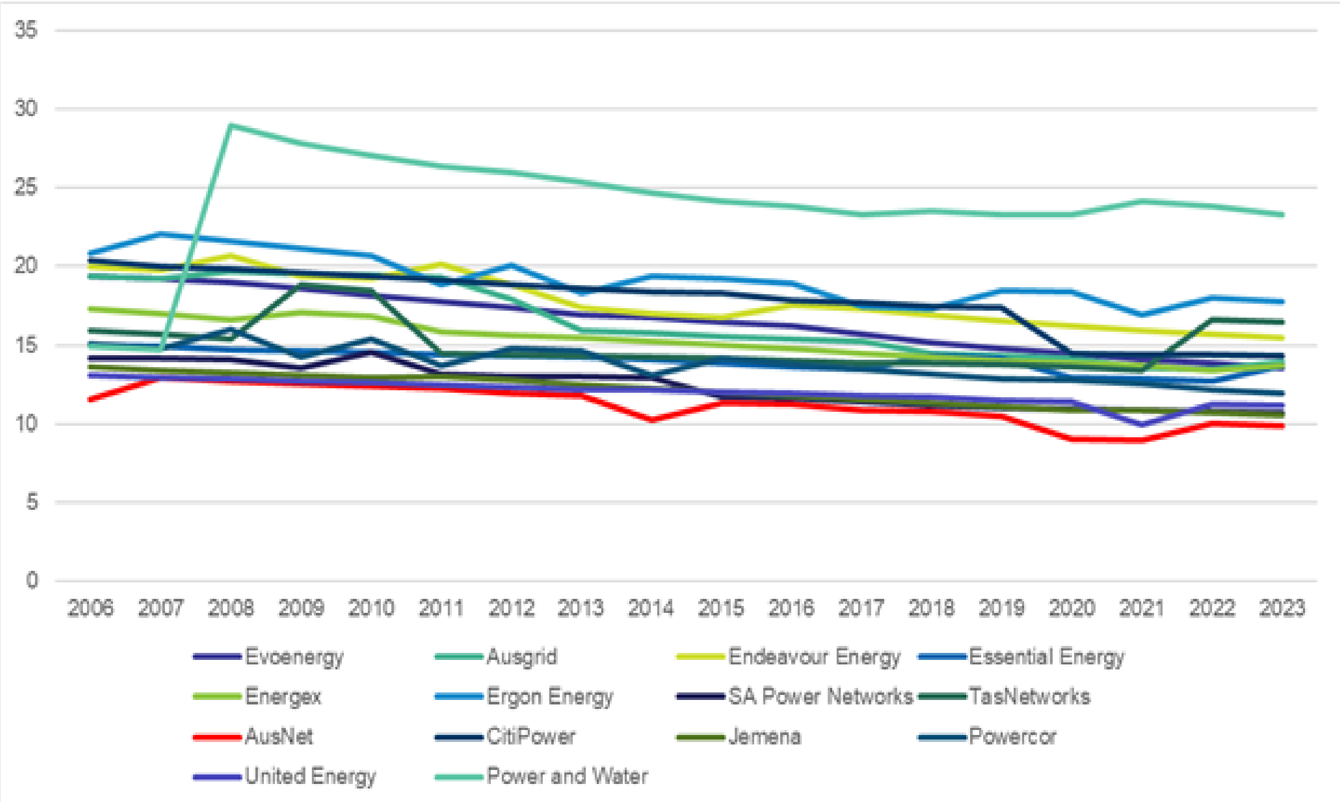
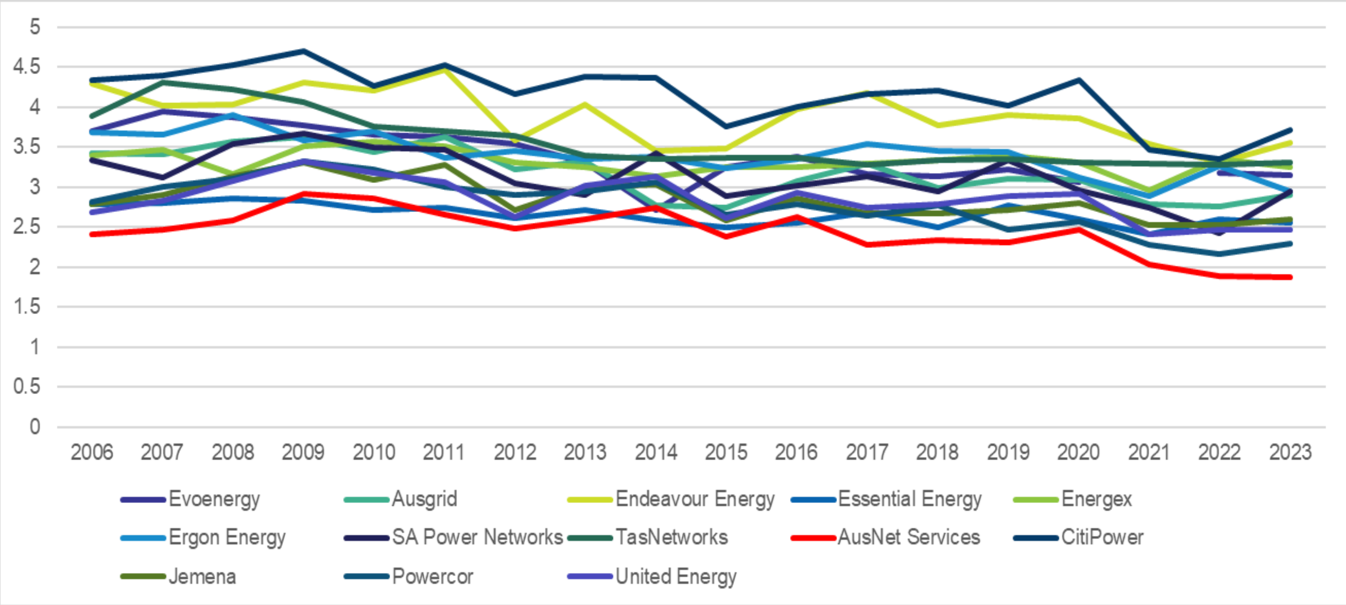


Figure 3-11: Coincident maximum demand per customer (MW)

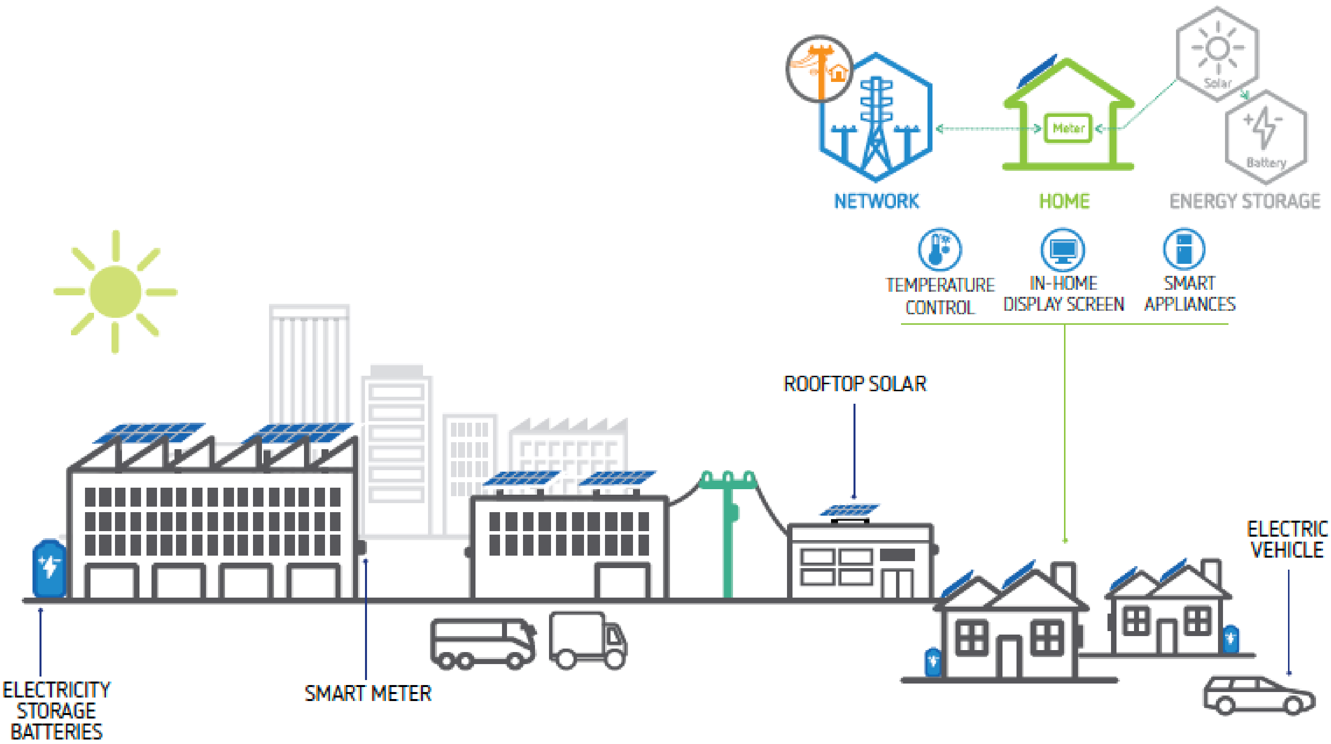


Source: AER RIN data

3.6. Decarbonisation and energy transition

The energy sector in Australia is currently undergoing unprecedented change due to decarbonisation, resulting in a fundamental shift in how electricity is produced and consumed, as depicted in the figure below.

Figure 3-12: Electricity market transition



Source: AusNet

The energy transition involves reducing emissions by changing technologies in large-scale generation. It also involves a significant increase in the installation of localised customer energy resources (CER), the most obvious example of which is the solar PV systems on customers' roofs. As we transition towards net zero, the installation of batteries and the penetration of electric vehicles will continue to increase.

Key elements of the energy market transition include:

- The decarbonisation of the electricity supply chain, transitioning from fossil-fuels to renewable generation
- A more decentralised electricity system with sustained growth in CER, particularly rooftop solar photovoltaic (PV) installations, large distributed renewable embedded generation, and customer and community battery energy storage systems (BESS)
- Electrification of the gas and transport sectors, to energy-efficient electric appliances, heat-pumps and plug-in electric vehicles (EV)
- A wider range of consumer demand-side management options, including smart appliances, home energy management systems, virtual power plant programs, demand-response programs, and other digitally enabled energy management systems, and
- The introduction in August 2021 of a Rule change to clarify that export services from CER are part of the core services to be provided by DNSPs, and that DNSPs have an obligation to efficiently integrate higher levels of CER into their distribution networks.

In August 2024, the Victorian Government published a document titled *Cheaper, Cleaner, Renewable: Our Plan for Victoria's Electricity Future*. The document forecasts that by 2035:

- Electricity use will increase by about 50% compared to 2024, driven by the electrification of homes and businesses, uptake of electric vehicles, and new industrial load growth.
- There will be an increasing amount of electricity use through the conversion of gas products to electricity and through transport, with the addition of 1.4 million electric cars and an equal amount of charging ports. Electric vehicles will consume 8 terawatt hours of electricity every year, while an additional 7 terawatt hours of annual electricity consumption will be associated with electrification - gas usage that will be replaced with electricity.
- To support this increase in consumption, about 11.4 GW of new grid-scale renewable generation projects will need to be connected to the Victorian transmission and distribution networks, with a total of 222 offshore wind turbines and 900 additional land- based turbines.
- Around 7.6 GW of additional rooftop solar (an extra 27 million solar panels) and 4.3 GW of distributed storage will be installed, including behind-the-meter batteries, demand-side participation and smaller front-of-meter assets such as neighbourhood batteries.

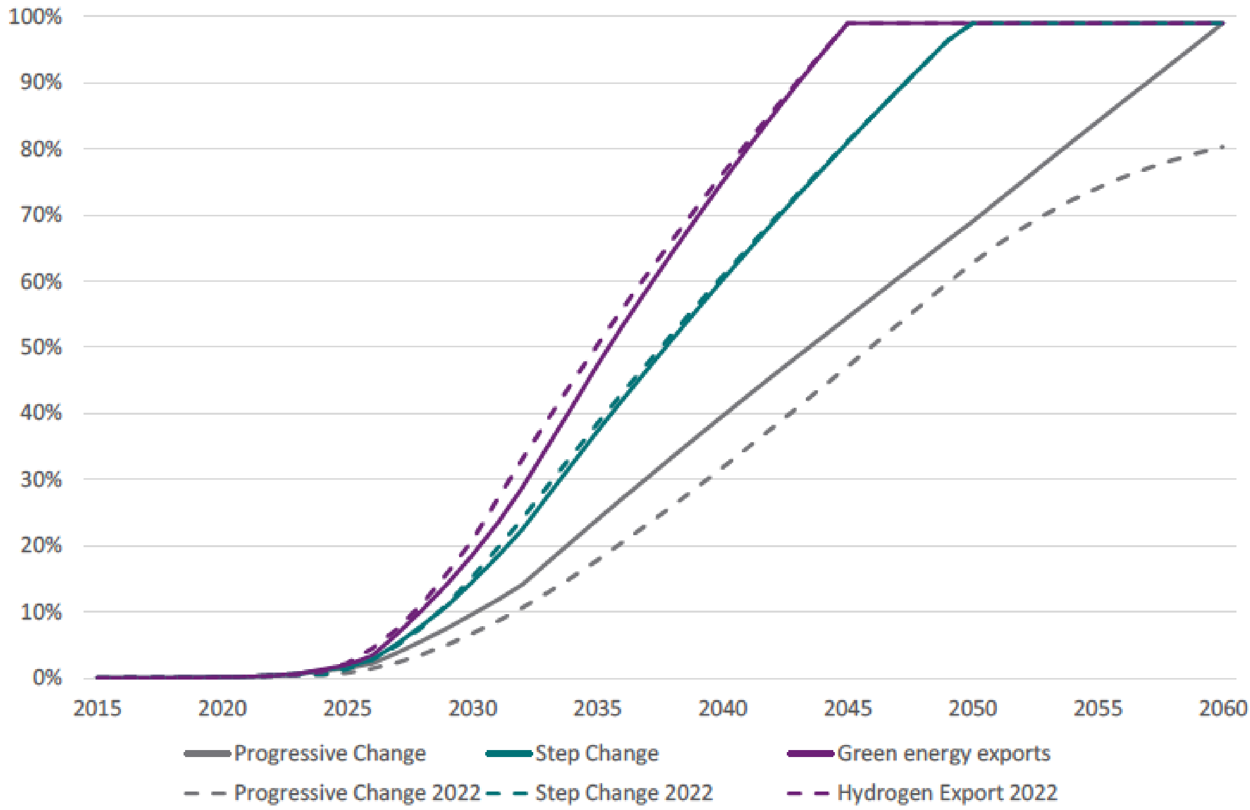
The electrification of the transport sector and switching from gas supply will continue to gather pace as Australia transitions to net zero. The Victorian Government's plans to shift away from fossil gas usage are detailed in *Victoria's Gas Substitution Roadmap*[7], a document which is updated annually. Key features of the December 2024 update include:

- Listing policy actions that have been taken to date, including the gas connections moratorium, strengthening national efficiency standards for new homes and prohibiting gas distribution businesses from providing incentives to connect gas, and
- Highlighting actions that are under consideration including energy efficiency standards for rental homes and mandating the progressive electrification of existing buildings.

To illustrate the trend towards transport electrification, the figure below shows the projected growth in the market share of electric vehicles for each of three scenarios in AEMO's 2024 ISP.

[7] Victoria's Gas Substitution Roadmap, Department of Energy, Environment and Climate Action, accessed here: Victoria's Gas Substitution Roadmap

Figure 3-13: CSIRO's projected electric vehicle market share



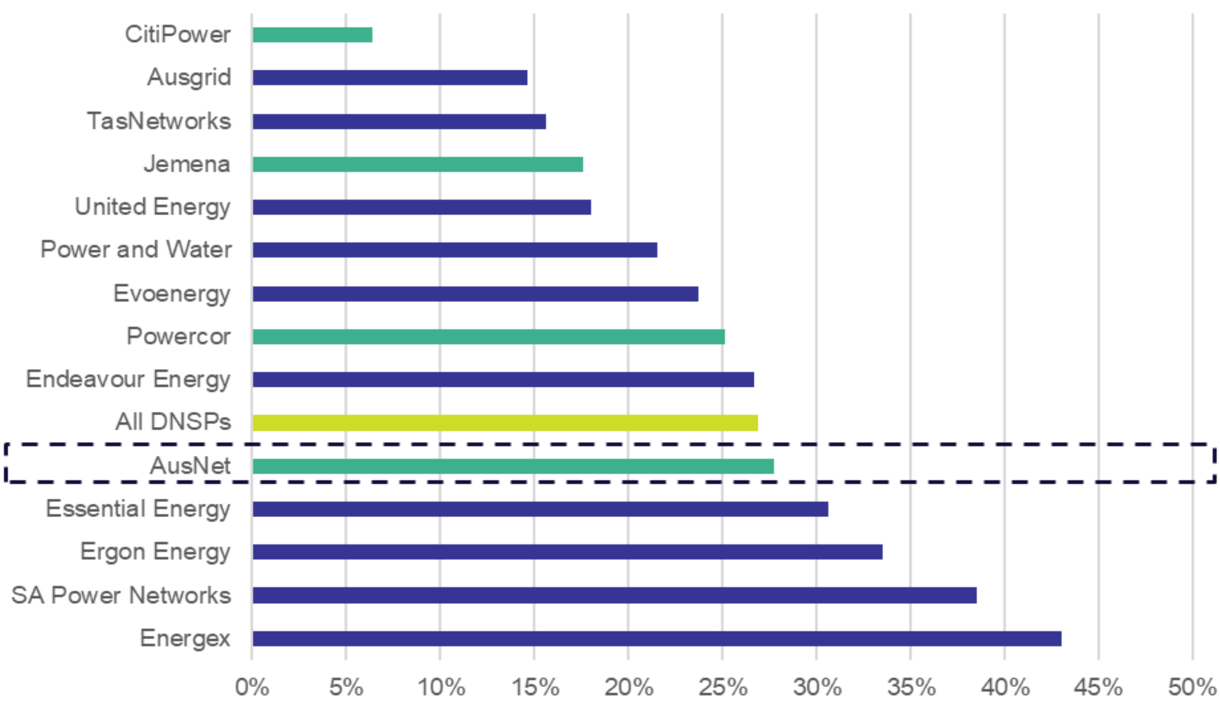
Source, AEMO, 2024 Integrated System Plan.

Both gas and transport electrification are expected to have material impacts on electricity demand and consumption, as explained in Chapter 4.

In a similar vein, the forecast increase in the installation of solar PV generation on our network is significant. Over 218,000 of our customers already have solar installations and we expect this number to be around 333,800, by 2031, an increase of around 53%.

AusNet has the highest solar penetration of the Victorian distributors, above the industry average.

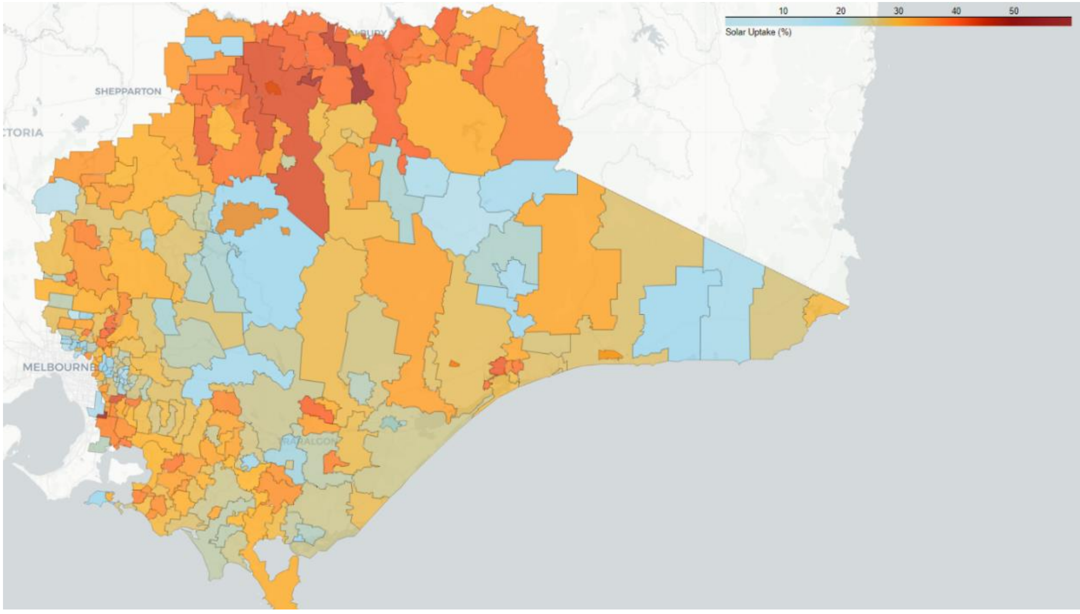
Figure 3-14: Proportion of customers using export services in 2023-24



Source: AER export services data.

The figure below shows that the level of solar penetration varies across our network. There are currently areas of our network with solar penetration greater than 50% (the red areas in the figure below).

Figure 3-15: Residential solar penetration by postcode as at November 2024

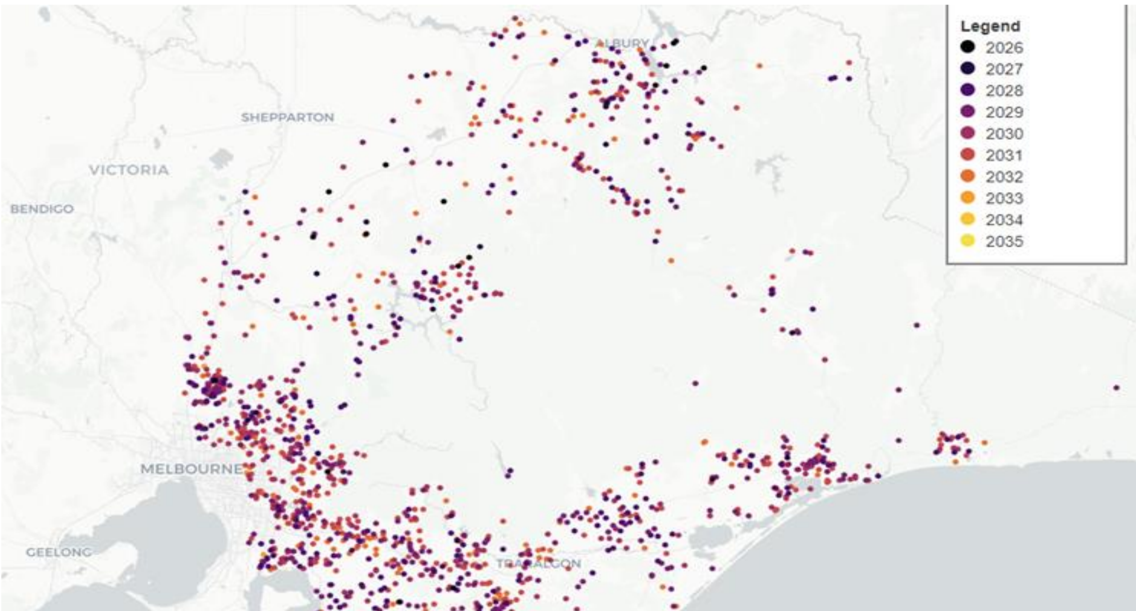


Source: AusNet.

This increase in the size and quantity of solar is creating some challenges on our network. For instance, the rising challenge of low energy demand during the day can cause power quality issues that can be harmful to customer appliances as well as to the network. Increased penetration of CER has also resulted in significant reverse power flows and light load conditions in some parts of the network, triggering augmentation of the low voltage network to manage these reverse flows and voltage levels.

The figure below shows the location of existing constraints and future emerging constraints. This shows that the limitations are relatively evenly spread across the rural and urban parts of the network. Weaker parts of the network are currently experiencing constraints, but 'stronger' areas will increasingly be impacted.

Figure 3-16: Distribution substation limitations (date at which expenditure becomes economic)



Source: AusNet.

The decarbonisation of the Victorian energy system poses challenges and opportunities for us. In response, we are investing in new digital and data-analytics enabling technologies, and investments in least-regret network and non-network solutions that maximise option value. These include:

- Investments that facilitate the growth of CER, which empower customers to generate, consume and store energy to lower their energy bills, including by supporting the network
- Rolling out flexible exports for all new solar connections by 1 July 2026, leveraging investment that has been made to meet the requirements of the Emergency Backstop scheme
- Offering flexible load connections to commercial and industrial customers and trialling flexible load connections for smaller customers
- Exploring non-network alternatives to address constraints, which has offset part of our proposed LV augmentation program, and
- Our large renewable connection program, which will facilitate the connection of the utility scale renewable generation required to replace the closure of coal plant which is forecast to withdraw by 2034-35.

As the Victorian energy system continues its transition to a net zero carbon future, we intend to continue to respond to and address emerging network needs, to ensure our network evolves and is managed in the most efficient and agile manner. This includes taking steps to become a Distribution System Operator.

We are planning the development of our network to ensure the service level performance that we plan to deliver meets the rapidly changing needs of our customers in an environment of high uncertainty.

3.7. Climate change and network resilience

Electricity networks face growing challenges from the increasing frequency and severity of extreme weather events that have widespread and devastating impacts.

Following the June and October 2021 storms in Victoria, an Expert Panel was established by the Victorian Government to examine how distribution network businesses can improve their preparedness for, and response to, prolonged power outages arising from storms and other extreme weather events. One of the Expert Panel's key recommendations was to create an obligation on distributors to adopt five-yearly Network Resilience Plans. We have developed our plan, and its costs and benefits are reflected in this Revenue Proposal.

Natural hazard events may be caused by a number of factors, including high winds, high rainfall, hail storms, lightning strikes, localised or widespread flooding, localised or widespread bushfires, and coastal surges. These events may lead to outages that are prolonged (longer than 12 hours) and/or widespread (in terms of the geographic area and the number of customers affected). The impacts of climate change are already being observed in Victoria, with the state's communities, economy, and environment already feeling its effects. Victoria's climate is projected to experience an increase in the intensity and frequency of extreme weather events including floods, heatwaves, and bushfires, as well as longer term changes in climate including higher average temperatures, reduced average rainfall and higher sea levels. This will change the profile of existing risks that AusNet manages, and potentially create new risks.

Resilience means having the investments and capabilities in place to effectively withstand and recover from disruptions, including extreme weather events. Resilience does not require the complete prevention or avoidance of impact on the power system, but a degree of mitigation and the containment of the impact of the events when they occur. In addition, customer and community resilience is greatly assisted if hubs can be established where people are able to go to obtain information, food, fuel, to charge phones or computers, have showers and receive general support.

We have developed a resilience vision, which is consistent with AusNet's company vision which is to be trusted to bring the energy today and build a cleaner tomorrow. The resilience vision has been informed by a significant amount of customer and stakeholder feedback, research and engagement and recognises that our customers and the wider community expect us to be prepared for severe weather events. Our goals are also entirely customer-focused, recognising the linkages with increasing electrification and dependence on electricity; the value customers place on our adequacy of our response; and the importance of investing in a way that makes a meaningful difference to customer outcomes. Our strategic pillars describe the types of actions that we can take to facilitate greater resilience to major storm events, recognising that these actions extend well beyond traditional network investments to include expenditure in emergency response, communications and digital technology.

The figure below sets out our vision, goals and strategic pillars for resilience.

Figure 3-17: Resilience vision and goals

Source: AusNet.

As explained in section 6.12 of this Revenue Proposal, our proposed resilience expenditure has been informed by our engagement with our Electricity Availability Panel and consumers more broadly, who have helped us to target our efforts that best meets the needs of our customers and communities.

We have recently experienced some of our worst outage events on record, caused by extreme weather:

- **2019/20 bushfires**: The "Black Summer" bushfires caused widespread devastation across regional areas and in total, 1,000km of AusNet's powerlines were affected resulting in 60,000 of our households and businesses being off supply. Over 1.5 million hectares were burnt in the fires and more than 300 homes were destroyed. This was the first time the Victorian Government declared a state of disaster.
- **June 2021 storms**: On 9 June 2021, major storms caused widespread damage across Victoria. Parts of Victoria recorded more than 280 mm of rain and experienced wind gusts of more than 100 km per hour. Three days after the event, 68,000 homes and businesses remained off supply, while more than 9,000 homes and businesses remained without supply a week later. At the time, it was the largest storm on record. In total, fourteen 66kV powerlines were taken out of service, fifty-eight 22kV powerlines reported faults and 10 zone substations went black in AusNet's distribution area. This resulted in 249,000 households and businesses being off supply.
- **October 2021 storms**: On 29 October 2021 (within months of the June 2021 storm) another storm event created widespread devastation. Damaging winds (e.g., 146 km/h at Wilsons Promontory) rain and hail hit Western Victoria, the southwest and Metro Melbourne. As a result, nearly 530,000 homes and businesses across Victoria were off supply at peak. Three days after the event, approximately 24,000 homes and businesses remained off supply, with over 2,500 homes and businesses still without supply after one week.
- **February 2024 storms**: On February 13, 2024, Victoria experienced a catastrophic storm event that damaged 12,000 km of powerlines and poles across the state's electricity distribution businesses, causing widespread power outages. Six 500kV transmission towers collapsed and AEMO instructed load-shedding of approximately 92,000 homes and businesses, state-wide. The February 2024 storm is the largest that AusNet has experienced, resulting in more than 297,000 of our customers being off supply.
- **September 2024 storms** – On 1-2 September 2024, Victoria experienced an extreme storm that caused widespread damage to many households, businesses and infrastructure and widespread outages across our network. Approximately 340,000 homes and businesses lost power. Damaging winds were recorded overnight (e.g., 146 km/h at Wilsons Promontory) and the Bureau of Meteorology likened the event to a category two or three cyclone[8]. Due to improvements in our operational response since the February 2024 storm event, all customers were restored by 8 September, 1 week after the event.

As explained in the Victorian Government's review, these events highlight that distribution businesses no longer operate in an environment which is "steady state". The potential for weather and security events that cause impacts at scale is real. This requires a step change in distribution businesses preparedness, response, and recovery from these events to protect the reliability of power Victorians value and to protect the ecosystem of essential services that electricity distribution networks sustain.[9] Accordingly, resilience is a new capex category for this Revenue Proposal and we have developed business cases for resilience investments that efficiently meet our customers' needs and expectations.

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[8] ABC News, As destructive winds die down, Victoria deals with the aftermath of violent storms 3 September 2024, link: As destructive winds die down, Victoria deals with the aftermath of violent storms - ABC News

[9] Victorian Government, Network Review into the transmission and distribution businesses operational response to the 13 February 2024 Storms, Interim Report, June 2024, page 5.

4. Demand and energy forecasts

4.1. Key points

AusNet has a regulatory obligation to connect new customers to our network, and to meet our customers' expected demand for electricity. In order to meet these obligations, we undertake granular 10 year forecasts of customer connections and spatial demand as an input to our expenditure plans. In contrast to earlier regulatory periods, we also focus on the capability of the network to enable customers to export electricity and address the associated technical challenges. In addition to forecasting maximum and minimum electricity demands which underpin our expenditure forecasts, we also prepare forecast energy consumption to enable us to set network tariffs, so that we recover revenues in accordance with our maximum allowed revenue.

Our modelling approach has significantly improved over the last decade. The granularity of our forecast method reflects the dynamic changes impacting our network, including the growing uptake of rooftop solar generation, the emergence of electric vehicles, and the electrification of gas. Granular forecasts ensure that our capital expenditure forecasts accommodate new connections, address changes in electricity usage and enable our customers to maximise the value from their CER investments.

Our forecasts for customer numbers, energy consumption and minimum and maximum demands for the 2026-31 regulatory period are set out in the table below. The key points are:

- Our customer base is forecast to grow steadily by around 1.8% per annum, in line with the Victorian Government's forecasts. Our forecast growth rate is lower than the actual and expected growth rate of 2.1% per annum for the current regulatory period.
- Energy use from the network is expected to start increasing after a decade of declining energy consumption. A key reason for this growth is the impact of electrification which will offset the impact of continued energy efficiency and increasing solar generation that tend to reduce operational energy consumption.
- Maximum demand is forecast to grow by 2.9% per annum over the 2026-31 regulatory period,[10] reflecting the underlying increase in electrification and recognising that maximum demand is likely to occur when solar generation declines late in the day.
- Minimum demand will continue to fall as solar penetration continues to increase, supported by government policies and customer interest.

Table 4-1: Demand, energy and customer number forecasts

	2026-27	2027-28	2028-29	2029-30	2030-31
Customer numbers	857,955	873,368	888,701	904,029	919,311
Energy consumption (GWh)	8,429	8,730	9,049	9,374	9,642
Maximum demand (MW)	2,185	2,252	2,317	2,385	2,449
Minimum demand (MW)	-568	-628	-669	-704	-742

Source: AusNet.

The remainder of this chapter is structured as follows:

- Section 4.2 provides a high level overview of our forecasting methodology.
- Section 4.3 explains our forecasting methodology and forecasts for customer numbers including residential, and small, medium and large business customers.
- Section 4.4 explains our forecasting methodology and forecasts for energy consumption.
- Section 4.5 explains our forecast methodology and forecasts for spatial demand including maximum and minimum demand forecasts.
- Section 4.6 explains how our forecasts satisfy the requirements in the Rules.
- Section 4.7 sets out the supporting documents for the matters discussed in this chapter.

[10] This growth rate, as well as the forecasts for maximum and minimum demand in the below table, reflect POE50 non-coincident forecasts, at the zone substation level.

4.2. Overview of the forecasting methodology

Our forecasting methodology has improved significantly over the last decade as we adapt to the factors impacting the energy and demand on our network. The most significant change has been the growth in rooftop solar which enables customers to self-consume and export excess solar back into the grid. Given that rooftop solar uptake varies significantly across our network, our forecasting methodology needs to capture granular information at specific network locations rather than be based on network averages. We are also on the cusp of further material changes in the energy landscape, expecting growth in electric vehicles, greater penetration of household, community and grid-scale batteries, and electrification of homes and businesses. These changes will affect usage patterns across our network that must be anticipated to optimise our expenditure plans.

We have progressively developed and adapted our forecasting methodology to reflect the more complex operating environment. We have implemented a 'bottom up' granular model to forecast customer numbers, energy consumption, and maximum and minimum demand. The method utilises advanced metering infrastructure (AMI) to account for differences in energy usage patterns, particularly different household types and customers with solar and other technologies.

Our model was initially developed by Monash University in 2015. We have adapted that model over time to include forecasts of minimum demand, and to account for the impact of rooftop PV, EVs and electrification of gas. The key steps in our forecasting process are:

- Extract historical data including customer numbers, operational demand, rooftop PV capacity, embedded generation, and weather and solar variables
- Forecast key inputs including customer numbers and rooftop PV and battery capacity by postcode location, using information from the Victorian Government and AEMO. This also includes forecasting uptake of electric vehicles and electrification of gas
- Simulate the future, taking into account temperature, solar, and seasonal variables, and recording the model results for 1,000 simulations, and
- Apply post model adjustments including block loads and transfers.

Further detailed information on our methodology is provided in a supporting document to this Revenue Proposal.

The values of the key inputs of the model are set out in the table below.

Table 4-2: Key inputs into the model

	2026-27	2027-28	2028-29	2029-30	2030-31
% of customers with rooftop solar	34%	35%	36%	36%	37%
Average load from electric vehicles (MW)*	17	25	35	47	60
Average load from electrification of gas (MW)*	35	52	70	85	99

Source: AusNet.

** Measured over a 30 minute period*

4.3. Customer number forecasts

We have an obligation to connect new residential, commercial and industrial customers to our network. The cost of connecting new customers is reflected in our customer connection expenditure based on forecast volumes of new connections and expected unit costs. Customer connection forecasts are also an important input to both our energy consumption and maximum and minimum demand forecasts.

The remainder of this section sets out our forecasting methodology and resulting forecasts of customer numbers for the 2026-31 regulatory period.

4.3.1. Customer connection forecast methodology

Our methodology separately forecasts the number of residential and non-residential customers that will connect to our network.

For residential customers, the starting point is to apply an independent assessment of the projected growth in households as published by the Victorian Government in its 2023 Victoria in Future (VIF) publication. The VIF report provides five-yearly snapshot forecasts of population and dwelling numbers for regions defined as Victoria in Future Small Areas (VIFSA). VIFSA regions are at Statistical Area 2 (SA2) level which are comparable to postcodes in terms of area coverage. The VIFSA level forecasts can be approximately mapped to zone substation regions and to feeders and terminal stations. Below the zone substation level, feeders are also apportioned to the nearest VIFSA (or multiple VIFSAs) to derive forecast customer numbers.

Where there is evidence that the VIF projections do not reasonably reflect expected growth, the VIF forecasts are adjusted. Any adjustment is based on recent trends and an assessment of local conditions. For example, by utilising the expert knowledge of network planners responsible for particular regions or using information from other sources, such as specific connection inquiries and/or information made available by housing developers and industry bodies.

While the VIF publication is the primary data source for forecasting residential customers, it does not contain projections for commercial or industrial customers. As there is no dependable data source on which to base trends for these customers, we:

- determine the historical relationship between the residential customer base and the customer numbers for each of the commercial and industrial sectors,
- apply this historical relationship to establish the commercial and industrial customer numbers for the start of the regulatory period, and
- project the forecasts for the remainder of the regulatory period by applying the best available information, including general data trends.

4.3.2. Customer numbers – historical and forecast

The table below shows that our total customer base has been growing by approximately 2.1% per annum during the current regulatory period.

Table 4-3: Actual (billed) customer numbers 1 Jul 2019 to 30 Jun 2024

Customer type	2019-20	2020-21	2021-22	2022-23	2023-24	Growth rate per annum
Residential	679,575	696,049	711,565	725,284	738,949	2.1%
Small Business	56,447	57,526	58,814	60,466	60,955	1.9%
Medium Business	9,657	9,752	9,851	9,873	10,003	0.1%
Large Business	3,567	3,628	3,711	3,787	3,793	1.5%
Total	**749,246**	**766,955**	**783,941**	**799,410**	**813,700**	**2.1%**

Source: AusNet.

Over the 2021-26 period, we experienced an annual average growth rate of 2.1% for our residential customers, with a slightly lower growth rate of 1.9% for small business customers. Medium and large customer numbers have continued to grow, but at a slower rate than other customer groups.

Over the 2026-31 regulatory period we expect the total customer base to increase at a lower growth rate of 1.8% per year, which means our customer base growing by more than 76,000 connections over the period. The table below shows the detailed breakdown of our forecast. The total number of customers on our network is forecast to increase to over 919,000 by 2030-31.

Table 4-4: Customer number forecasts (year ended)

Customer type	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	Growth rate per annum
Residential	765,418	779,800	794,118	808,390	822,628	836,813	1.8%
Small Business	63,097	64,063	65,028	65,967	66,915	67,868	1.5%
Medium Business	9,990	10,079	10,135	10,196	10,266	10,335	0.7%
Large Business	3,931	4,013	4,087	4,148	4,220	4,295	1.8%
Total	**842,436**	**857,955**	**873,368**	**888,701**	**904,029**	**919,311**	**1.8%**

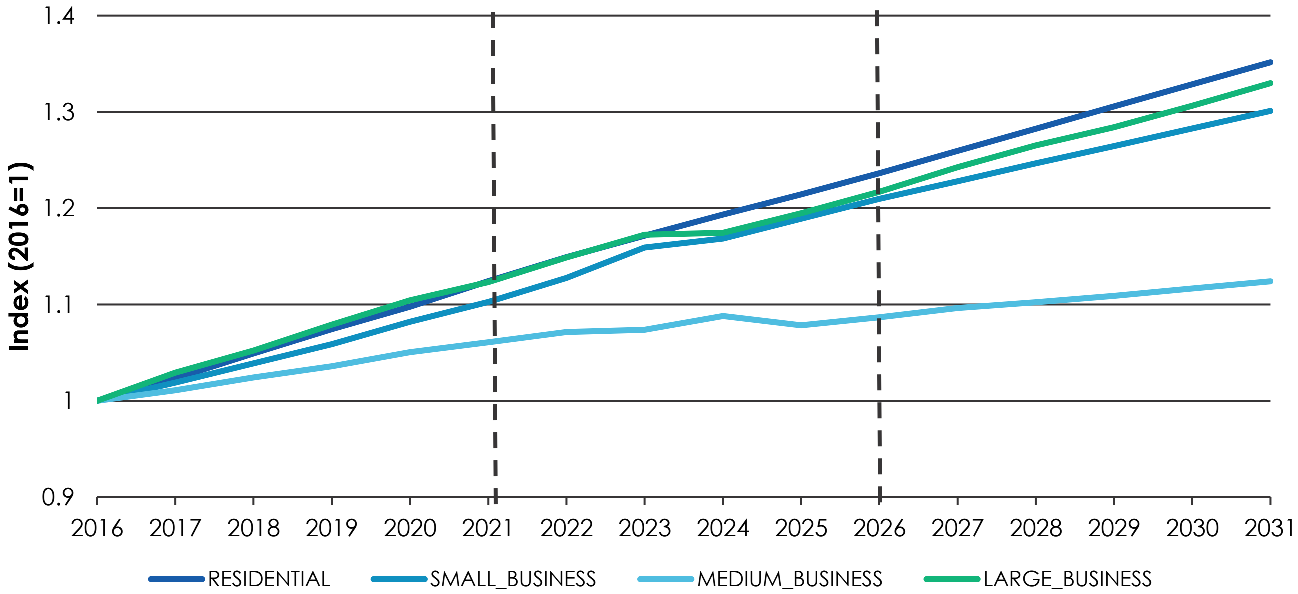
Source: AusNet.

For residential customers, we expect an average increase of 1.8% per annum in the 2026-31 regulatory period, which is a slightly lower annual increase than the current period. This primarily reflects projected population growth in the VIF publication. The growth is concentrated in key urban local government areas such as Whittlesea and Casey, which are located on the northern and south-eastern fringes of our metropolitan Melbourne network. Within our rural regions, the Shire of Baw Baw is also expected to grow strongly.

Similar to the current period, we expect continued growth in small business customer numbers of 1.5% per annum, which is a lower growth rate than the current period, as a result of a slow-down in economic activity. Similarly, we are forecasting lower rates of growth in medium and large customer numbers compared to the current period.

Figure 4-1 shows the cumulative actual and forecast growth rate in customer numbers from 2016-2031 for each customer type.

Figure 4-1: Customer number growth 2016-2031 for each customer type (financial years, index)



Source: AusNet.

4.4. Energy consumption forecasts

Annual energy consumption is the total amount of energy we deliver to our customers during a regulatory year. As already noted, energy consumption is important for tariff setting. While energy consumption forecasts do not drive our capital expenditure forecasts, they are aligned to our spatial demand forecasts given they rely on consistent inputs such as customer connections, household generation take-up and electrification.

4.4.1. Energy consumption forecast methodology

Energy forecasts are separately formulated for residential and non-residential customers, given their different consumption characteristics, such as sensitivity to weather.

The key drivers of energy consumption include:

- Expected new residential and business customer connections, including material block loads
- Adoption of electric vehicles and substitution of gas with electricity
- More extreme climate that leads to more demand for heating and cooling
- Additional energy efficiency initiatives implemented by existing and new customers
- The extent to which energy requirements are met by solar installations and batteries, and
- Economic factors such as electricity prices and broader cost of living pressures.

Figure 4-2: AusNet's detailed approach to energy forecasting

Forecast customer numbers by individual tariff

- We forecast the growth of customers by each tariff. We add more weighting to the most recent data known as 'exponential smoothing'.

Average customer usage by individual tariff

- We forecast the average customer usage by each tariff. We add more weighting to the most recent data known as 'exponential smoothing'. The forecast models applies a 12 month seasonality and incorporates exogenous variables including total days in the month, number of non-work days, Effective Degree Days, Cooling Degree Days and sunshine hours.

Electric Vehicle Load

- Using AEMO's EV data, we derive an annual consumption from electric vehicles.

Gas Electrification

- Using AEMO's gas electrification data, we derive the additional conversion from gas to electricity annual consumption.

Total Consumpion

- (Forecast consumption numbers by individual tariff x Average customer usage by individual tariff) + Electric Vehicle Load + Gas Electrification

Source: AusNet.

4.4.2. Historical and forecast energy consumption

While we have experienced steady growth in residential and business customer connections that increased energy consumption on our network, this has been offset by two factors over the last 15 years:

- Improvements in energy efficiency stemming from energy efficient electrical appliances, improved building standards for new housing and major extensions that require 6-star energy ratings in design, and energy efficiency policies focused on the residential and commercial sector.
- Growth in the number of rooftop solar PV installations that result in higher self-consumption by customers, particularly in the off-peak periods in the middle of the day.

The table below shows energy consumption for the past three years, compared to the AER-approved forecast.

Table 4-5: Actual versus forecast energy consumption 2020-23 (GWh)

	2021-22	2022-23	2023-24
Actual	7,854	7,588	7,599
Forecast	7,336	7,300	7,259
Difference	**518**	**288**	**340**

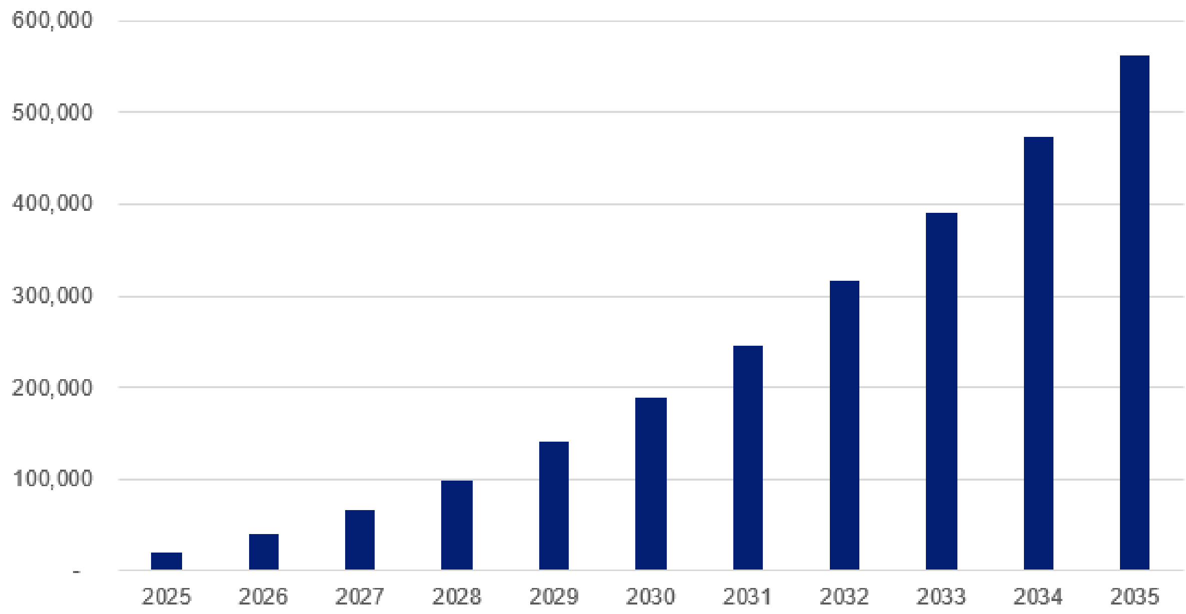
Source: AusNet.

While energy efficiency and self-consumption will continue to have a downward impact on energy consumption, there are offsetting drivers that are forecast to push energy consumption higher in the 2026-31 period. This includes:

- Electric vehicle uptake which is expected to accelerate significantly in the 2026-31 period
- The expected increase in residential and commercial customers switching from gas to electricity in the 2026-31 period, and
- Block loads related to large residential developments and non-residential developments.

Of these three drivers, the growth in electric vehicles is the primary reason why we expect energy consumption forecasts to increase in the 2026-31 regulatory period. The figure below shows that the number of electric vehicles on our network is expected to increase significantly over the next regulatory period and beyond.

Figure 4-3: Forecast number of electric vehicles



Source: AusNet.

Table 4-6 shows the forecast energy consumption by customer segment.

Table 4-6: Electricity volume forecasts 1 Jul 2026 to 30 June 2031 (GWh)

Customer type	2026-27	2027-28	2028-29	2029-30	2030-31	Growth rate per annum
Residential	4,168	4,447	4,734	5,022	5,258	6.0%
Commercial	1,380	1,392	1,402	1,413	1,422	0.8%
Industrial	2,880	2,890	2,912	2,937	2,960	0.7%
Total	**8,428**	**8,729**	**9,048**	**9,372**	**9,640**	**3.4%**

Source: AusNet.

Overall, our forecasts are in line with the medium-term forecast of annual electricity consumption published by AEMO, which also forecasts a gradual increase in consumption.[11]

4.5. Spatial demand forecasts

We plan our network to ensure that we have sufficient capacity to meet the demand from our customers at times of peak usage. A maximum demand event usually coincides with very hot or cold days, which necessitates the use of cooling or heating appliances. This generally occurs in the evening period when customers can no longer rely on their solar installations to power their houses.

We generate maximum demand forecasts at a system and spatial level. The system demand forecast represents the maximum demand that we project to be recorded across our network and provides an indication of overall growth rates. However, for the purposes of planning our network, we rely on spatial demand forecasts of the specific maximum demands at different points of our network, which are driven by location-specific factors such as the mix of residential vs commercial customers, weather conditions, energy efficiency, and uptake of solar and electrification. Therefore, the spatial demand forecast enable us to accurately forecast when a constraint may arise on our network that requires a network augmentation or a non-network solution, such as demand management.

In addition to maximum demand forecasts, AusNet also develops periods of minimum demand on our network. This generally occurs in the middle of the day during periods of high solar output combined with mild temperatures. Minimum demand is increasingly important as the power system and network can become unstable during these periods.

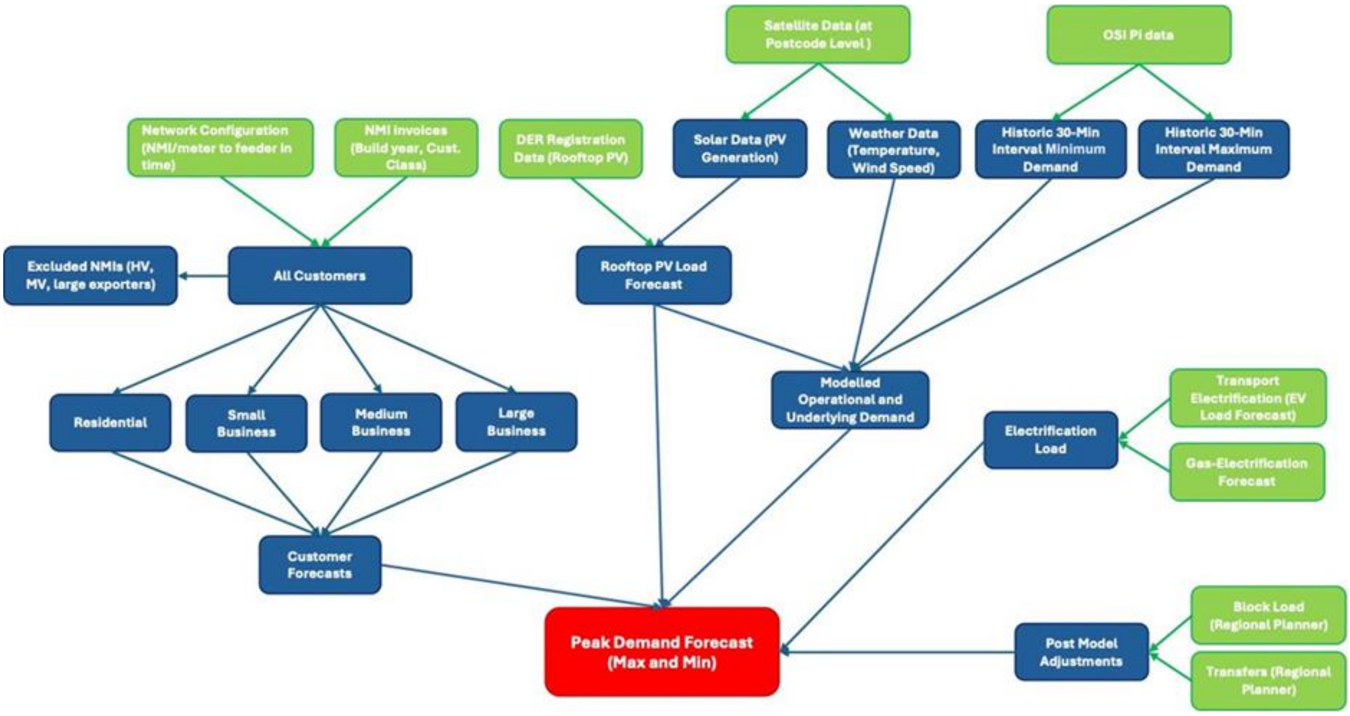
4.5.1. Spatial demand forecast methodology

Like energy consumption, maximum demand forecasts are also driven by growth in new customer connections, electrification of vehicles and gas appliances, energy efficiency, economic conditions and weather. The key difference is that maximum demand forecasts are more sensitive to extreme heat or cold, particularly in areas that have a high proportion of residential customers. Maximum demand forecasts are less affected by rooftop solar uptake as peak times occur in the late afternoon or early evening, as solar output declines. In contrast, minimum demand is predominantly driven by rooftop solar uptake as it means a greater proportion of customers will use their own solar (rather than the network) to power their homes and increases exports onto the distribution network.

Our process to develop maximum and minimum demand forecasts is depicted in Figure 4-4. The methodology relies on key inputs common to the energy consumption and customer connection forecasts, but with a focus on forecasting the maximum and minimum demand (30 minute interval) by network location.

[11] 2024 Electricity Statement of Opportunities, August 2024, p157

Figure 4-4: Overview of demand forecasting methodology



Source: AusNet.

Further detailed information on our forecasting methodology is provided in the accompanying forecasting methodology document that is provided as part of our Revenue Proposal.

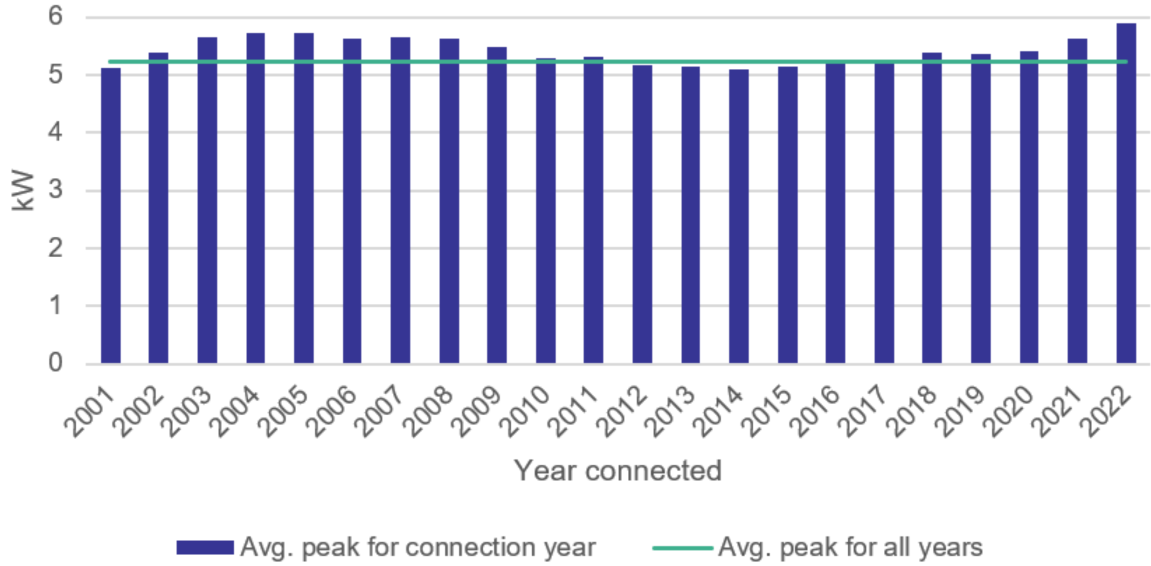
4.5.2. System maximum demand forecasts

Historically, maximum demand has tended to remain relatively constant, while energy consumption has declined. A key reason is that customers use solar to power their homes in the day, offsetting the growth in energy consumption from new customers. In contrast, maximum demand typically occurs in the evening when customers do not have the option of using solar generation to power their homes.

A second reason is that there is emerging evidence that newer connections are using more energy at the time of peak demand compared to connections built in the 2010s and in some cases, even earlier. The figure below shows the average household peak demand for non-solar customers in CY2024, by the year those customers connected to the network. In CY2024, peak demand was highest in the customers who most recently connected[12] and customers connecting in the last five years had an average peak demand that was higher than the average across all connection years. There are likely multiple drivers of this (including increasing electrification in new houses and diminishing gains from energy efficiency at time of peak) which will continue to be monitored.

[12] Customers who connected in 2023 and 2024 are excluded from this analysis, because even though there was a physical connection, those customers did not necessarily have a full 12 months of demand in CY2024.

Figure 4-5: Average household CY2024 peak demand (non-solar) by year connected



Source: AusNet.

The forecast growth rate for maximum demand is set out in the table below, with the historical and forecast trends shown in Figure 4-6. We forecast growth in maximum demand of approximately 2.9% per annum over the forthcoming regulatory period.

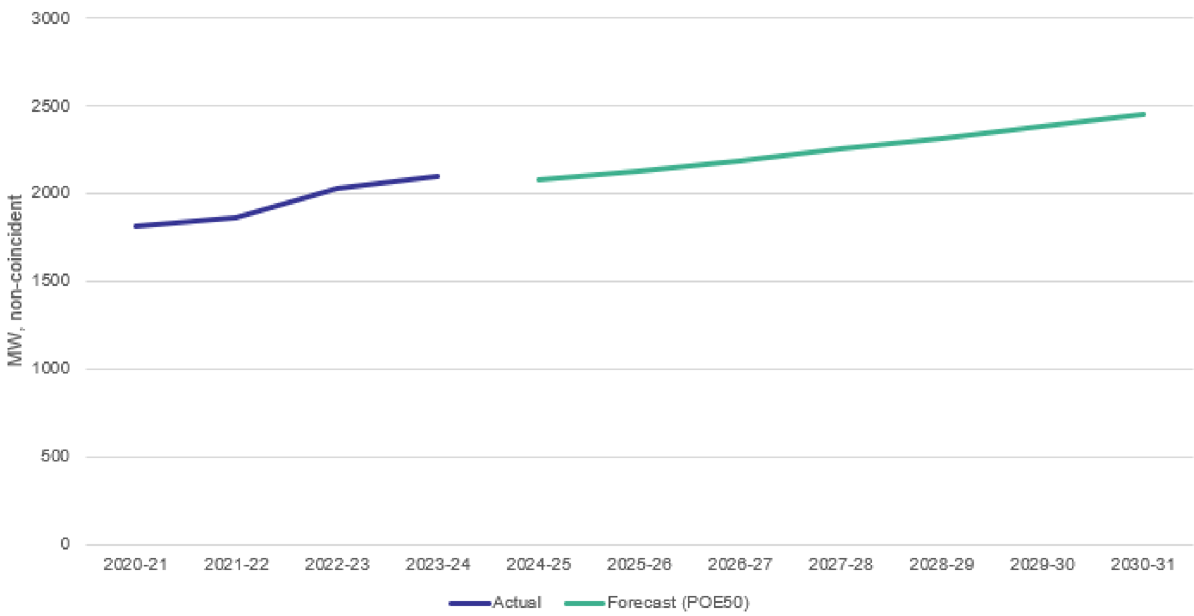
For the 2026-31 regulatory period we are proposing the introduction of a solar soak tariff to incentivise customers to shift electricity usage to the middle of the day when exports onto the network tend to peak. However, the move towards electrification will add significant load to the network, and we expect that EV customers will continue to charge their cars during maximum demand periods, which will increase the peak. Similarly, the switch-out of common gas appliances will also tend to occur outside the solar soak period, also adding to peak demand.

Table 4-7: Maximum demand: current and forecast regulatory period (non-coincidental, MW, at zone substation level, POE50)

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
Demand	2,132	2,081	2,128	2,185	2,252	2,317	2,385	2,449
Growth rate	-	-2.4%	2.3%	2.7%	3.1%	2.9%	2.9%	2.7%

Source: AusNet.

Figure 4-615: Non-coincident zone substation demand trend 2021 – 2031



Source: Economic benchmarking RINs, AusNet.

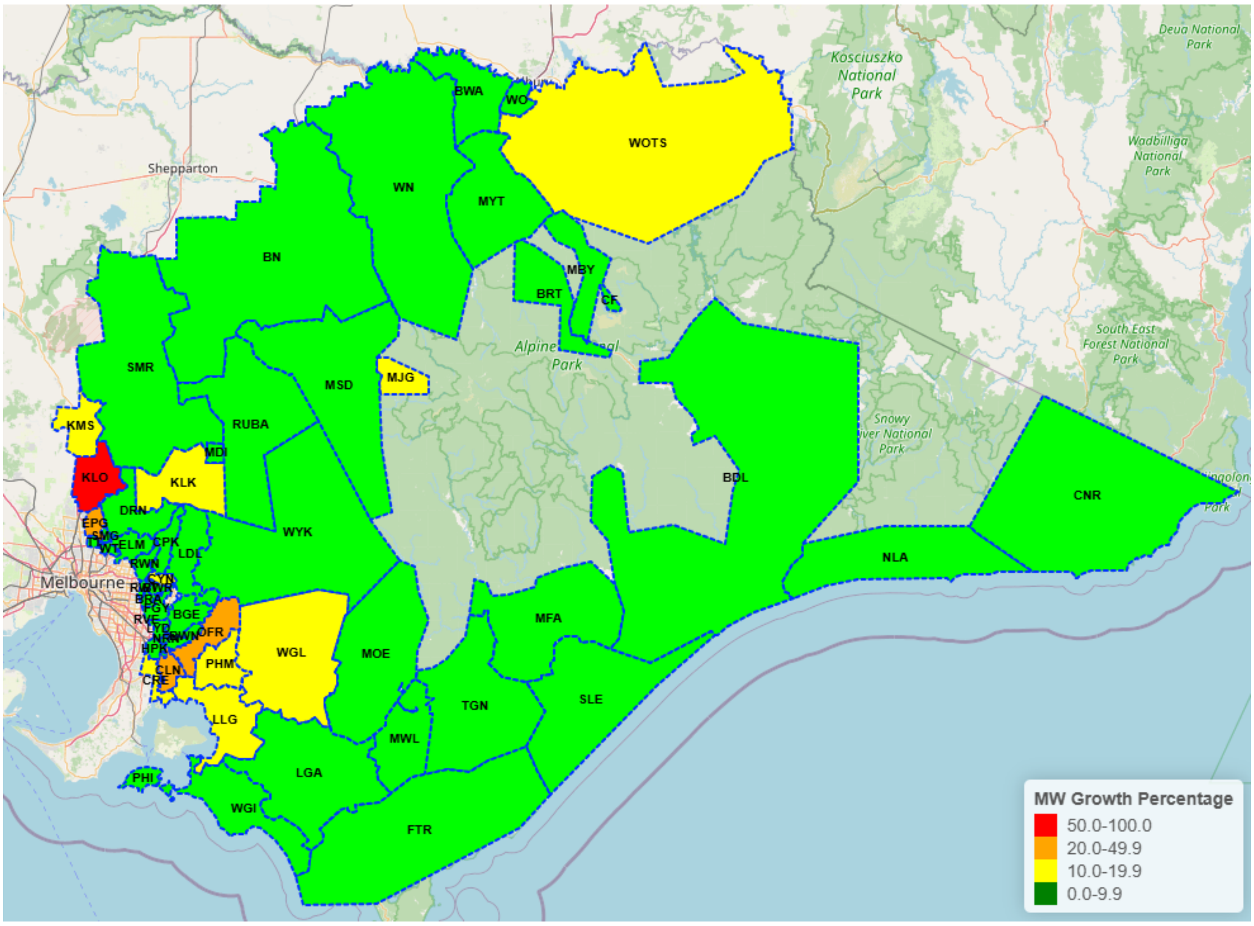
4.5.3. Areas of high maximum demand growth

Locationally, demand growth across our network will not be evenly spread. For example, customer number growth (and maximum demand) will be concentrated in two major growth corridors in Melbourne's north and southeast. More than two-thirds of growth in demand is in the population centres served by eight of our zone substations:

- Clyde North
- Kalkallo
- Cranbourne
- Officer
- Pakenham
- Warragul
- Doreen, and
- Epping.

The figure below shows where these higher growth areas are located within our network. It also demonstrates that, outside of these corridors, most of our network is forecast to have lower demand growth (the green areas) over the upcoming regulatory period.

Figure 4-7: Percentage change of maximum demand between 2026 and 2031, by zone substation



Source: AusNet.

As already noted, our spatial demand forecasts play an important role in our network planning and our capex requirements.

4.5.3.1. Minimum demand forecasts

As already explained, minimum demand on our network has continued to fall over the last decade, driven by higher uptake of rooftop solar. Despite the proposed changes to our tariff structures, we expect minimum demand to continue to fall sharply across the 2026-31 regulatory period, as shown in the figure below.

Table 4-8: Minimum demand: current and forecast regulatory period (non-coincidental, MW, at zone substation level, POE50)

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
Demand	-271	-399	-493	-568	-628	-669	-704	-742
Growth rate	-	46.9%	23.7%	15.2%	10.4%	6.6%	5.2%	5.5%

Source: AusNet.

We discuss the impact of the declining trend in minimum demand in relation to our capex plans in Chapter 6.

4.6. Why our forecasts satisfy the Rules requirements

Our forecasts for customer numbers, energy consumption and maximum demand are a realistic reflection of expected demand during the 2026-31 regulatory period, based on the best available information in accordance with the Rules requirements. We also note that:

- our forecasting methodologies have been refined, taking into account the key factors that will drive our customer numbers and maximum and minimum demand over the 2026-31 regulatory period
- our approach makes effective use of the best available data, including independently published forecasts prepared by the Victorian Government and AEMO, and
- our forecasting methodologies have been independently assessed as a reasonable approach to forecasting demand by The Centre for International Economics (The CIE).

4.7. Supporting documentation

We have included the following documents to support our maximum demand forecast:

- Appendix 4A: ASD – Demand Forecasting Methodology – 31 Jan 2025 – PUBLIC.
- Appendix 4B: ASD – The CIE – Demand forecasting methodology review – 31 Jan 2025 – PUBLIC.

5. Building block revenue requirement

5.1. Key points

The key points in this chapter are:

- The proposed revenue requirement is $4,995.8m in unsmoothed nominal dollar terms.
- In real, smoothed dollar terms, the proposed revenue requirement is $4,622.2m ($2025-26), or an average of $924.4 million. This is 13% higher than the expected revenue in the 2021-26 regulatory period.

5.2. Chapter structure

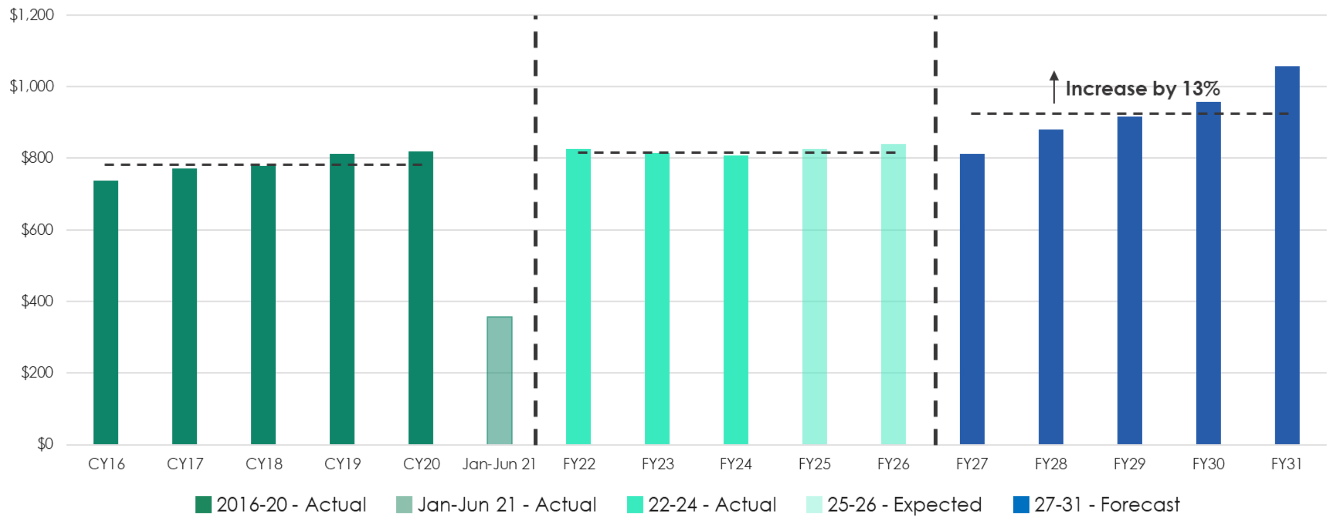
The structure of the remainder of this chapter is:

- Section 5.3 presents our revenue requirement
- Section 5.4 presents a summary of the building block components of the revenue requirement
- Section 5.5 presents our smoothed revenue requirement for each year of the forthcoming regulatory period, including a description of the X-factors adopted
- Section 5.6 sets out the average price path under the proposed revenue cap, and
- Section 5.7 sets out the relevant supporting documents for this chapter.

5.3. Summary of our revenue requirements

Based on the detailed inputs described and calculated in this proposal, our smoothed revenue requirement for 2026-31 is $924.4 million per annum ($2025-26).

Figure 5-1: Revenue requirement CY 2016 to FY 2031 ($m, real 2025-26)

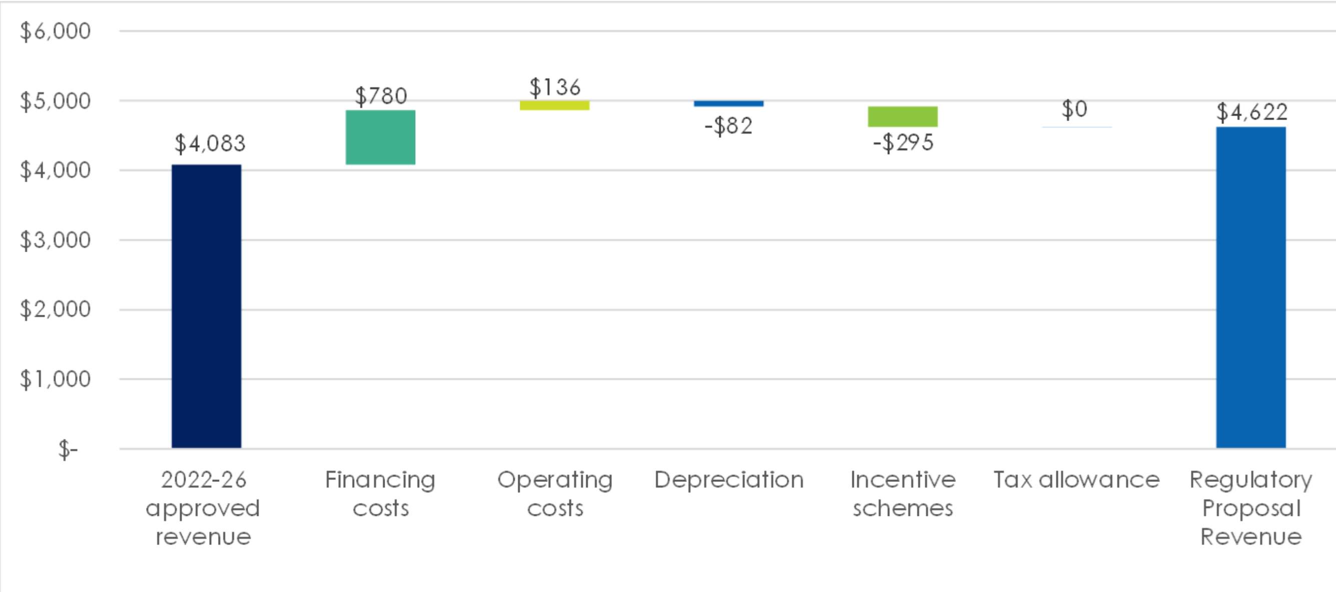


Source: AusNet

The chart below shows the movements in the regulatory building blocks that form our proposal case, compared to the current regulatory period. Our revenue requirement increased by 13% between 2021-26 and 2026-31 due to:

- revenue increases related to:
  - increased financing costs, reflecting higher interest rates and our larger capital program
  - increased operating costs needed to meet new obligations, evolving customer needs and manage a growing network and customer base.
- revenue decreases related to:
  - decreased incentive scheme payments, reflecting a large, planned overspend of our current period capital expenditure allowance
  - decreased depreciation, reflecting higher expected inflation and a reduction in the accelerated depreciation of specific assets approved at the last price review.

Figure 5-2: Movement in revenue building blocks ($m, real 2025-26)



Source: AusNet

5.3.1. How we have considered affordability in our plans

Our customers' number one priority is energy affordability. Our proposal delivers value for money by balancing this with other customer priorities including:

- More reliable network
- Continuous improvements to customer service
- Preparing for net zero
- A fair and equitable transition, and
- Building customers' agency.

As explained in Chapter 2, we have undertaken extensive customer engagement on both individual parts of the proposal, and the proposal as a package with the overall price impact in mind. This engagement includes:

- Costed options workshops with our Panels, where the service levels and price impact trade-offs were presented and discussed
- An offsite in August 2024 where key costed options were discussed in the context of the whole revenue proposal's price impacts. Sensitivity analysis to energy forecasts, the rate of return, and long-term price impact modelling was also presented and discussed. This shaped our Draft Proposal package to be tested with customers, and
- Our Round 4 customer workshops gathered feedback from a representative group of customers on the Draft Proposal as a package, to understand whether any adjustments to price and service levels should be made prior to finalising this Revenue Proposal.

We have also included a range of 'affordability measures' in our proposal, which have increased in number and value as the Revenue Proposal has been developed. These are listed in the Executive Summary. In total, these measures reduce our forecast expenditure requirements during the 2026-31 regulatory period by over $100m compared to the Draft Proposal, resulting in savings of at least $13 per year for the average residential customer and $68 per year for the average business customer. Some of these have been ideas arising from our Panels, while others were suggested by AusNet. We have done all we can to lower costs for customers while delivering the service levels customers need and expect.

Our customer engagement on price and service levels has tangibly shaped our plans and revenue requirement, as explained in the relevant sections of this document. Due to the extensive customer testing, consistent feedback received and subsequent adjustments made, we are confident that our revenue requirement meets the preferences of customers.

5.4. Building block components of the revenue requirement

The building block components and our unsmoothed annual revenue requirements for each year of the forthcoming regulatory period are shown in the table below.

Table 5-1: Unsmoothed Revenue Requirement ($m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Return on Capital	370.9	404.8	446.6	495.1	551.3	2,268.7
Regulatory Depreciation	166.6	179.2	197.7	207.9	214.3	965.8
Operating Expenditure	330.7	347.8	366.3	386.2	403.4	1,834.5
Revenue Adjustments	-36.6	-7.9	-24.2	-31.5	27.1	-73.1
Net Tax Allowance	-	-	-	-	-	68.4
Unsmoothed revenue requirement	**831.6**	**924.0**	**986.4**	**1,057.7**	**1,196.2**	**4,995.8**

Source: AusNet PTRM

The unsmoothed annual revenue requirement is calculated as the sum of the building block components, which are described in the sections below, and detailed in the chapters that follow.

5.4.1. Regulatory Asset Base

Our Regulatory Asset Base (RAB) has been calculated in accordance with the requirements of Clause 6.5.1 and Schedule 6.2 of the NER. It reflects the capital expenditure (capex) forecasts set out in Chapter 6 of this proposal, the opening RAB based on expenditure in the current regulatory period as detailed in Chapter 9, and depreciation calculated in Chapter 10. The table below sets out a summary of the derivation of our RAB for the forthcoming regulatory period.

Table 5-2: Regulatory Asset Base ($m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Opening RAB	**6,144.9**	**6,607.0**	**7,162.3**	**7,764.2**	**8,381.0**
Net capital expenditure	628.7	734.4	799.6	824.8	857.3
Opening RAB inflation addition	153.6	165.2	179.1	194.1	209.5
Nominal depreciation	-320.2	-344.4	-376.8	-402.0	-423.9
Closing RAB	**6,607.0**	**7,162.3**	**7,764.2**	**8,381.0**	**9,024.0**

Source: AusNet PTRM

5.4.2. Return on Capital

Consistent with the requirements of Clause 6.4.3(a)(2) of the NER, and in accordance with the AER's PTRM, the return on capital is calculated by applying the post-tax nominal vanilla WACC to the RAB for each year of the regulatory period. The table below illustrates the calculation of the return on capital building block. Full details of the WACC calculation are set out in Chapter 11.

Table 5-3: Return on capital allowance ($m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Opening RAB	6,144.9	6,607.0	7,162.3	7,764.2	8,381.0
WACC (% per annum)	6.04%	6.13%	6.24%	6.38%	6.58%
Return on capital	**370.9**	**404.9**	**446.6**	**495.1**	**551.3**

Source: AusNet PTRM

5.4.3. Depreciation

The calculation of regulatory depreciation was carried out in accordance with the AER's PTRM and Clause 6.5.5 of the NER and is detailed in Chapter 13. Consistent with the requirements of Clause 6.4.3(a)(1) and (3) of the NER, we have incorporated an allowance for depreciation in its building block revenue requirement. The table below lists the regulatory depreciation building blocks for each year of the forthcoming regulatory period.

Table 5-4: Forecast depreciation ($m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Nominal depreciation	320.2	344.4	376.8	402.0	423.9
Less: indexation on opening RAB	-153.6	-165.2	-179.1	-194.1	-209.5
Regulatory depreciation	166.6	179.2	197.7	207.9	214.4

Source: AusNet PTRM

5.4.4. Operating expenditure

Consistent with the requirements of Clause 6.4.3(a)(7) of the NER, we have included a forecast of operating expenditure (opex) in the building block allowance. As explained in Chapter 10, the opex forecast has been prepared in accordance with all applicable requirements of the NER and the RIN.

Table 5-5: Forecast operating expenditure ($m, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Opex (base, step and trend)	308.2	315.8	324.4	333.5	340.2	1622.1
Guaranteed Service Levels	11.1	10.8	10.7	10.7	10.7	54.0
Innovation	0.3	1.3	1.8	2.2	2.1	7.7
Debt raising costs	3.0	3.1	3.3	3.5	3.7	16.6
Total	**322.7**	**331.0**	**340.2**	**349.9**	**356.6**	**1700.3**

Source: AusNet PTRM

5.4.5. Other revenue adjustments

Consistent with the requirements of Clause 6.4.3(a)(5), (6) and (6A), we have incorporated the amounts that have been determined under the efficiency benefits sharing scheme (EBSS); the capital efficiency sharing scheme (CESS); and the shared assets guidelines. The detailed calculation of each of these building blocks was undertaken in accordance with all applicable provisions of the NER, as explained in Chapter 16 (Incentive Schemes), and Appendix 5A - Shared Assets.

We have also made an adjustment to true up the difference between what was assumed in our allowance and the actual capex/opex spend profile for our Innovation Fund projects. Our Innovation Advisory Committee (IAC) assesses projects funded through the Innovation Fund on merit without favouring capital projects over opex projects. The true up adjustment seeks to ensure the revenue derived from our fund is equal to actual spend so that our customers are not paying more than required, or AusNet is not being penalised for investment in projects different to the assumptions in the proposal. This approach ensures the Fund is not limited by discrete capex and opex allowances and can deliver greater benefits for our customers.

As we have removed the Innovation Fund spend from the EBSS/CESS, a revenue adjustment can act as appropriate mechanism to adjust for this difference. The adjustment compares the revenue allowed in the AER's 2021-26 determination with our actual/forecast Innovation Projects spend profile. We have provided a model of our calculation in Appendix 6B. The true up adjustment for the 2021-26 period is negative due to the later spend profile than assumed in our allowance. This discretionary revenue reduction also supports affordability for our customers. We received support from the Coordination Group for this adjustment.

If this adjustment were not to be accepted by the AER, networks would face an incentive to spend any approved innovation allowance late in the period and on capex projects rather than opex projects, which is unlikely to be beneficial to customers.

The building block costs are listed in the table below.

Table 5-6: Revenue adjustments ($m, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31
Opex efficiencies (EBSS)	-15.1	15.0	-	-6.1	46.4
Capex efficiencies (CESS)	-23.4	-23.4	-23.4	-23.4	-23.4
Shared Assets	0.0	0.0	0.0	0.0	0.0
Demand Management Innovation Allowance	0.9	0.9	0.9	1.0	1.1
Innovation fund true up adjustment	-0.2				
Total	**-35.8**	**-7.5**	**-22.5**	**-28.6**	**24.0**

Source: AusNet PTRM

5.4.6. Tax liability

Consistent with the requirements of Clause 6.4.3(a)(4) of the NER, we have incorporated an allowance for benchmark tax liability into the building block allowance. The detailed calculation of the cost of tax is presented in Chapter 12 of this proposal. The cost of tax calculation accords with the requirements of Clause 6.5.3 of the NER and is summarised in the table below.

Table 5-7: Benchmark tax liability ($m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Tax payable	-	-	49.6	56.7	52.8	159.1
Less value of imputation credits	-	-	28.3	32.3	30.1	90.7
Net corporate income tax allowance	**-**	**-**	21.3	24.4	22.7	68.4

Source: AusNet PTRM

5.5. Smoothed annual revenue requirement, X factor and revenue cap

The application of our X-factors in conjunction with our 'Unsmoothed Revenue Requirement' produces the following 'Smoothed Revenue Requirement'.

Table 5-8: Annual building block revenue, X factors and maximum allowed revenue ($m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Annual building block revenue requirement (unsmoothed)	831.6	924.0	986.4	1,057.7	1,196.2	4,995.8
Annual expected MAR (smoothed)	848.4	917.4	992.1	1,072.8	1,160.1	4,990.7
X factor (%)	1.50%	-5.50%	-5.50%	-5.50%	-5.50%	n/a

Source: AusNet PTRM

The PTRM Model attached to this proposal demonstrates that the smoothed and unsmoothed revenue requirements are equal in net present value terms in accordance with the requirements of Clause 6.5.9(b)(3) of the NER. The smoothed revenue for each year is also net of estimated non-tariff revenue from alternative control services.

Clause 6.5.9 requires the X factor to be set to minimise, as far as reasonably possible, the gap between smoothed and unsmoothed revenue in the final year of the regulatory period, having regard to the preferences of customers for a more stable price path.

This evidence includes research AusNet undertook for its Gas Access Arrangement Review in 2022, with a detailed survey of customers statewide (though skewed toward AusNet gas customers) to understand customers' preferences on how costs are spread over time. A detailed overview of this study is included in our Final Proposal for the 2023-28 Gas Access Arrangement period.

We believe the top-line findings of this study are broadly applicable for both gas and electricity, and likely other utility bills. The research found:

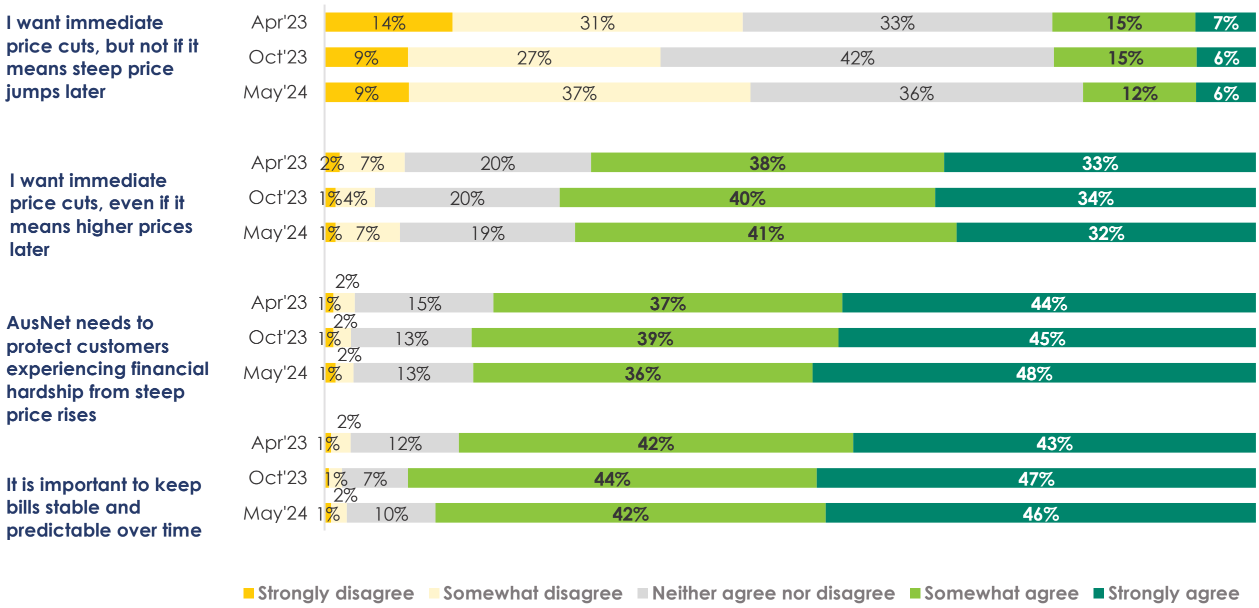
- Customers care about bill predictability and smoothness over time, and those who are impacted by the cost-of-living crisis even more so,
- Customers' preference for long-term price stability over short-term price relief if short-term price relief means pushing costs to a later time, and
- These trends hold across all demographic groups, including the key indicators of vulnerability tested. Further evidence indicates that bill predictability over time becomes more important when customers are struggling to afford their bills, as forecasting bills accurately is important for managing household budgets.

We believe the findings to still be current so have not replicated the full pricing study for this Variation Proposal, but have been monitoring for any changes in sentiment on price paths findings via:

- some informal "sense checking" with social service organisations, and
- tracking some key questions asked in the December 2022 study in our ongoing Energy Sentiments survey for both the gas and electricity waves.

The data from our most recent Energy Sentiments wave in May 2024 is compared to the data from our December 2022 study below. There is variously some softening and strengthening of sentiment across questions but it is clear that the preference for pricing stability holds true. We also examined variations in this sentiment across demographic groups and found a strong relationship between customers' self-assessment of the impact of the cost of living on their household and the importance they place on keeping bills stable and predictable over time, which aligns with the December 2022 survey and feedback from social service organisations.

Figure 5-3: Households and businesses on our electricity distribution network's views on pricing have remained broadly consistent, with a clear preference for predictability over time



Source: AusNet Energy Sentiments Research

The revenue requirement will be subject to adjustments in accordance with the control mechanism (see Chapter 18) to account for:

- the actual CPI, in accordance with the provisions set out in Clause 6.2.6(a) of the NER
- the annual return on debt update
- our actual service standard performance, relative to its service standard targets, under the Service Target Performance Incentive Scheme, and
- any deemed cost pass though event, as nominated in Chapter 15 along with those pass through events specified in Cause 6.6.1 of the NER.

To derive the 2026-27 X factor shown above, we have incorporated the outcomes of the following, approved cost pass through applications into our estimate of 2025-26 final year revenue constraint by using:

- the most recent AER approved PTRM which incorporates approved pass through amounts for the October 2021 storms and Emergency Backstop Mechanism, and
- incremental revenue recovered through the approved c-factor in 2025-26 (i.e. from February 2024 Storms, June 2021 storms, 2019-20 bushfires).

The X factors do not take into account c-factors to be recovered in the upcoming period (e.g. from Feb 2024 storms) as this smoothing is determined through the AER pass through process and is not intended to influence the X-factor calculation in the PTRM.

We have not incorporated the outcomes of our cost pass through application for the September 2024 storms as this is currently being assessed by the AER.

5.6. Average price path under the Proposed Revenue Cap

In real terms, the average revenue per customer is $1,026.7 ($2025-26), which is 3% higher than the expected revenue per customer in 2021-26 regulatory period.

Figure 5-4: Revenue per customer ($, Real $2025-26)

Source: AusNet.

5.7. Supporting documentation

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following document is provided in support of this chapter:

- Appendix 5A – Shared assets
- Appendix 5B – Innovation true up adjustment.

6. Capital expenditure

6.1. Key points

All dollar values in the Capex chapter have been expressed in direct costs (excluding real cost escalation, contractor support costs and network overheads) and real 2023-24 terms (unless otherwise stated)

The key points in this chapter are:

- The energy sector is facing an unprecedented transition, driven by government policy to achieve Net Zero and customers' new and evolving needs. In the current regulatory period, we have already started to respond to the challenges ahead by increasing our capex by 19% above the AER's approved allowance. It is apparent, however, that substantial increases in capex will be required in the 2026-31 regulatory period.
- Our approach to developing our capex plans has focused on the needs and preferences of our customers. Our understanding of the improvements that our customers want us to deliver has been greatly assisted by our extensive engagement with our Customer Panels. Our capex plans have also been informed by analysis and research, such as our Quantifying Customer Values (QCV) study that attaches a hard dollar value to each unit of unserved energy. Our plans have also been prepared in accordance with NER requirements and the relevant AER guidance notes.
- The discussions with our Customer Panels and the analysis that underpins our capex forecast has had regard to the following drivers of our capex requirements in the 2026-31 period:
  - **Resilience**. An increasing focus on resilience due to the prolonged outages experienced from the June 2021, October 2021, February 2024 and September 2024 storms. These storms are the largest on record, with 297,000[13] customers impacted by the February 2024 storm, and approximately 28,000 customers impacted by all four storms. Customers have consistently expressed concern that prolonged outages negatively affect their lives in a range of ways – including increasing stress and financially – and that network businesses need to do all that they can to quickly restore power.
  - **Renewable energy targets**. Contributing to the government's renewable energy targets has emerged as a theme in our customers' feedback. Customers want to share their renewable energy generation with others (especially neighbours) and do not want to be constrained by export limits; therefore, making the most of their upfront investments. In addition, the majority of customers have expressed that it is important to unlock capacity in the network to allow large renewable generation and storage to efficiently connect to the network.
  - **Reliability**. Our consumer engagement has indicated significant concern for those customers that experience lower than average reliability levels either because they are served by unreliable feeders or live in regions with poor reliability. In response to this feedback, we are proposing to invest to improve reliability on the 10 worst served feeders. Additionally, we are proposing to introduce a Regional Reliability Allowance (**RRA**) to address poor reliability for other regional customers, on a use-it-or-lose-it basis and with strong governance.
  - **Customer and maximum demand growth**. We are increasing our network capacity to accommodate the growth in customer numbers and maximum demand, particularly in relation to the large residential developments in Melbourne's urban growth corridors. Our proposed demand driven augmentation capex includes the construction of two new zone substations in Wollert and Pakenham South.
  - **Digital investment**. In the face of these transformative forces impacting our network and the NEM more broadly, we must have a digital strategy that allows us to continue delivering for our customers, meeting the evolving expectations of the communities we serve, and fulfil our obligations as a licensed DNSP, while remaining resilient to the changes affecting the energy sector. Our digital capex proposal puts customer outcomes at the centre of our investment plans. It includes a Customer Information Management program that will provide more personalised and tailored customer service, a very strong and consistent theme from our customer research, particularly from business customers.
  - **Compliance and safety**. Compliance with our legislative and regulatory obligations and ensuring we minimise safety-related risks as far as reasonably practicable remains a top priority. The growth in CER and solar PV, which is projected to continue to increase, creates voltage compliance issues and challenges for our load shedding schemes, which are adversely affected by reverse power flows. Our capex program

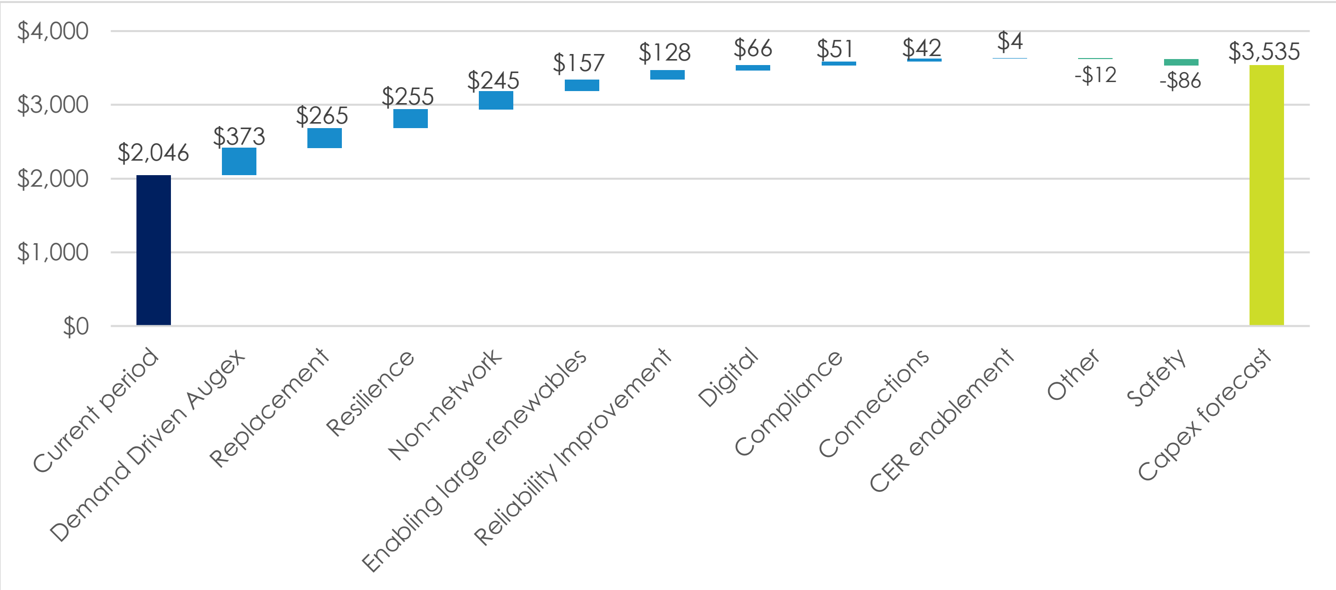
[13] *Other sources reference 255k customers which is the coincident peak customers off supply.*

includes the least cost solution to ensure that we maintain compliance. In relation to safety, we will continue to invest in REFCL technology to reduce bushfire risk and maintain compliance with the *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016*.

  - **Replacement**. It is essential to replace assets in a timely manner to avoid the consequences of in-service failure, which may expose the public and field personnel to safety risks and cause supply interruptions and potential damage to other assets. Our capex plans for the 2026-31 regulatory period reflect the impact of our aging asset base, which results in deteriorating asset condition, and increases in the costs of replacing assets.
  - **Changes to our service delivery model**. Following a comprehensive market testing process, we have engaged Zinfra as our new service delivery partner for operations and maintenance of our network, commencing in August 2025. While this change is expected to deliver significant benefits for our customers in terms of service improvements, it has consequential operational changes as our fleet assets, which were previously managed by Downer under lease or transactions, will be transferred back to AusNet's control. While the overall composition of the fleet will remain broadly similar, this change to our service model requires new investment to maintain our fleet capability and operational efficiency.

- In developing our capex plans, we also recognise that cost-of-living has been consistently ranked as the number one concern amongst our customers in the research that we have undertaken and in response, we have implemented some cost constraint measures. We have applied a top-down adjustment to remove $42m from our capex plans, and we have reduced our network overhead cost to account for potential productivity gains during the 2026-31 period (reducing our capex forecast by $4m). We have also deferred $29m of our demand driven augmentation at the LV network (due to our flexible services proposal) and $70m of our network hardening investment case. In our view, these initiatives strike an appropriate balance between the need to meet the emerging challenges on our network, as highlighted by our customers, and the affordability considerations that remain front of mind for many of our customers.
- The figure below summarises the proposed changes in each of the capex categories over the 2026-31 regulatory period compared to the current period.

Figure 6-1: A comparison of our expected capex for 2021-26 with our capex forecast for the 2026-31 regulatory period (by driver) ($m, real 2025-26)



Source: AusNet.
Note: Net capex prior to asset disposals.

6.2. Chapter structure

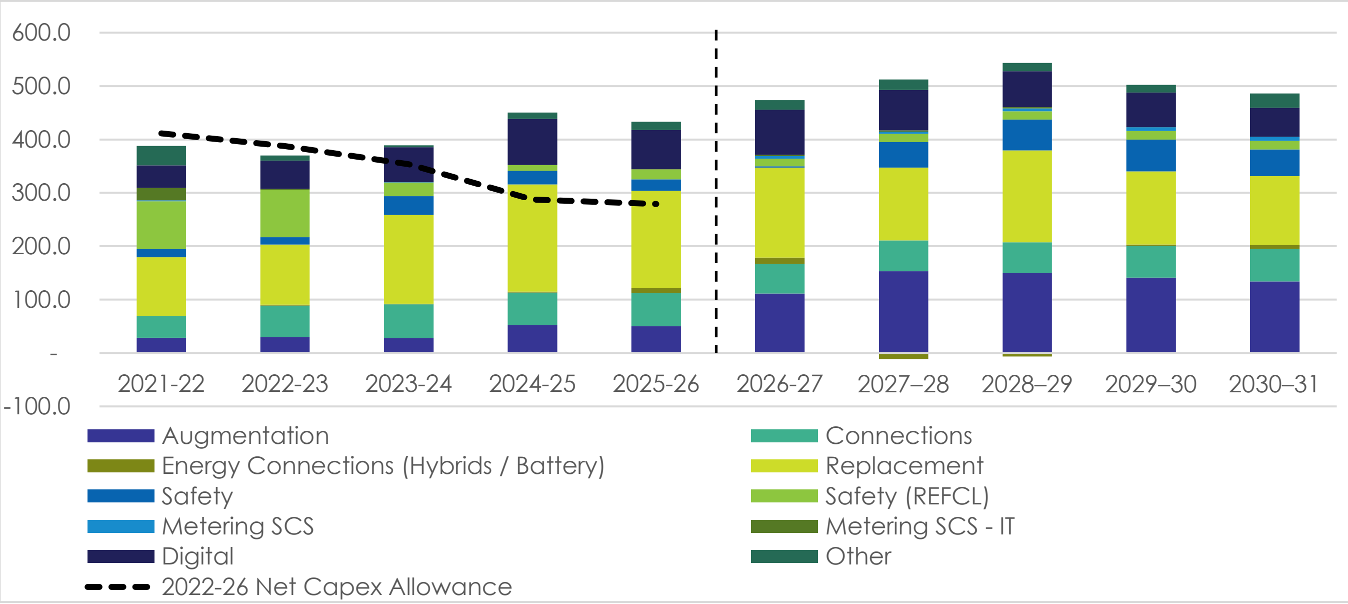
This chapter is structured as follows:

- Section 6.3 provides a summary of our capital expenditure forecasts.
- Section 6.4 explains our key inputs and assumptions, which includes engagement with our Customer Panels.
- Section 6.5 sets out our forecasting approach.
- Section 6.6 describes our demand driven augmentation expenditure proposal.
- Section 6.7 escribes our replacement expenditure proposal.
- Section 6.8 describes our CER enablement expenditure proposal.
- Section 6.9 describes our reliability expenditure proposal.
- Section 6.10 describes our connections expenditure proposal.
- Section 6.11 describes our large renewables enablement proposal.
- Section 6.12 describes our resilience expenditure proposal.
- Section 6.13 describes our digital expenditure proposal.
- Section 6.14 describes our safety and environmental expenditure proposal.
- Section 6.15 describes our compliance expenditure proposal.
- Section 6.16 describes our non-network expenditure proposal.
- Section 6.17 explains why our capex forecasts satisfy the Rules requirements.

6.3. Summary of our capital expenditure forecasts

We are proposing to invest (net capex) $3,535.1m (real 2025-26)[14] over the 2026-31 regulatory period. This is 72% or $1,460m (real 2025-26)[15] higher than our expected capex for the current 2021-26 regulatory period (see Figure 6-2).

Figure 6-2: A comparison of our expected capex in 2021-26 with our capex forecast for the 2026-31 regulatory period (net capex) ($m, real 2025-26)



Source: AusNet.

Figure 6-2 also shows that our expected capex in the current 2021-26 regulatory period to be 19% or $326.9m (real 2025-26) higher than the AER's regulatory allowance. Our expected capex is above the AER's allowance due to:

- Increasing labour and material costs due to market-driven cost pressures affecting the whole industry
- Deferral of zone substation rebuilds and some repex programs from earlier in the period
- Delays and cost increases for some REFCL compliance augex relative to the approved timing and costs
- Investments to address strong anticipated demand growth, including land purchases (not previously forecast) to accommodate new zone substations
- Overspend of connections allowance, both for load connections and unanticipated hybrid/battery connections (not previously forecast)
- Addressing unanticipated issues that have arisen over the period, including reliability issues, and
- Overspend of digital allowance to deliver Advanced Distribution Management System (**ADMS**) and customer platforms to improve resilience and customer experience.

Our capex proposal (including overhead) comprises of the following (list is a further disaggregation of the capex categories in Figure 6-3):

- $430.7m (real 2025-26) in demand driven augmentation expenditure to address growing maximum demand on the network; this is an 646% ($373m) increase on our expected capex in the current 2021-26 regulatory period
- $998.1m (real 2025-26) in replacement expenditure (repex) to replace aging assets ensuring we continue to operate in a safe and prudent manner; this is a 32% ($240.7m) increase on our expected capex in the current 2021-26 regulatory period

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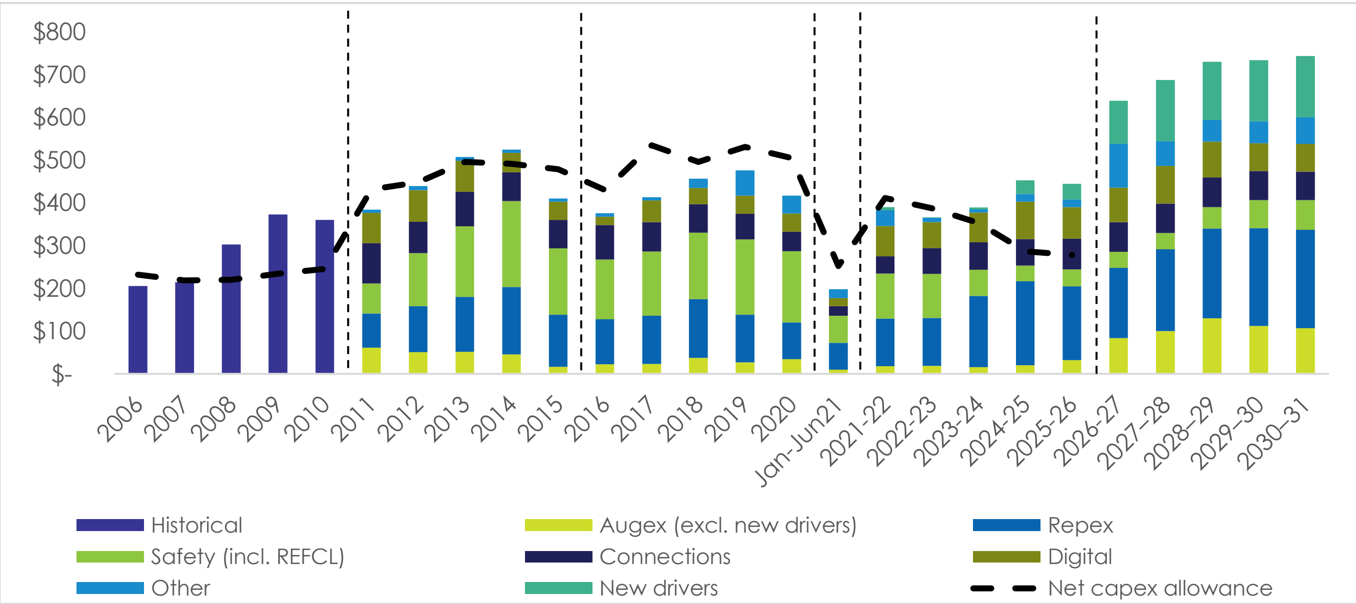
[14] Net capex prior to asset disposals.
[15] Calculated from net capex after asset disposals.

- $43.4m (real 2025-26) in CER enablement expenditure to remove export limits and constraints; this is a 9% ($3.6m) increase on our expected capex in the current 2021-26 regulatory period
- $147.8m (real 2025-26) in reliability expenditure which includes improving reliability on our 10 worst served feeders; this is a new driver compared to the current 2021-26 regulatory period
- $342.1m (real 2025-26) in customer connections expenditure; this is a 14% ($42.5m) increase on our expected capex in the current 2021-26 regulatory period
- $194.1m (real 2025-26) in large renewables enablement expenditure to unlock capacity in our sub-transmission network to enable more renewable generation and storage; this is a new driver compared to the current 2021-26 regulatory period
- $279.4m (real 2025-26) in resilience expenditure to enable the network to withstand and recover from extreme weather events that are growing in both size and magnitude; a new driver compared to the current 2021-26 regulatory period
- $422.4m (real 2025-26) in digital expenditure that will allow us to continue to meet our customers' expectations and fulfil our obligations; this is a 32% ($102.3m) increase on our expected capex in the current 2021-26 regulatory period
- $260.4m (real 2025-26) in safety and environmental expenditure; this is a 25% ($85.6m) *decrease* on our expected capex in the current 2021-26 regulatory period
- $60.2m (real 2025-26) in compliance expenditure to address emerging compliance issues (excluding safety-related compliance); this is a 580% ($51.4m) increase on our expected capex in the current 2021-26 regulatory period
- $31.5m (real 2025-26) in metering expenditure that reflects the SCS portion; this is a 27% ($11.5m) *decrease* on our expected capex in the current 2021-26 regulatory period
- $322.5m (real 2025-26) in non-network capex, and
- $2.4m (real 2025-26) in other capex.

The figure and table below provide an overarching view of our forecast for the 2026-31 regulatory period compared to our expected capex for the current 2021-26 regulatory and actual for the previous regulatory periods.

Figure 6-3: Capex forecast for the 2026-31 regulatory period compared to current and previous regulatory periods ($m, real 2025-26)



Source: AusNet

Table 6-1: Capex forecast for the 2026-31 regulatory period compared to current and previous regulatory periods ($m, real 2025-26)

	2016	2017	2018	2019	2020	Average 2016-20	HY21	2021-22	2022-23	2023-24	2024-25	2025-26	Average 2021-26	2026-27	2027-28	2028-29	2029-30	2030-31	Average 2026-31
New drivers	-	-	-	-	-	**-**	-	7.5	0.5	4.4	32.8	36.5	**16.3**	100.8	142.8	135.9	142.3	143.3	**133.0**
Augex (excl. new drivers)	22.6	23.5	37.9	27.3	34.4	**29.1**	10.1	18.5	18.7	16.2	20.7	32.3	**21.3**	83.7	100.5	130.4	112.6	107.2	**106.9**
Repex (excl. new drivers)	105.5	112.5	137.1	111.2	86.4	**110.5**	62.5	111.4	112.6	166.4	196.3	172.6	**151.8**	164.5	191.1	210.0	228.4	230.5	**204.9**
Safety (incl. REFCL)	139.9	150.5	155.7	176.6	166.9	**157.9**	63.8	105.2	102.8	61.2	36.8	40.0	**69.2**	37.4	38.2	49.9	65.6	69.3	**52.1**
Connections	81.0	68.5	66.5	59.9	45.3	**64.2**	22.5	40.7	60.8	64.4	62.2	71.5	**59.9**	69.6	68.5	69.4	68.0	66.6	**68.4**
Digital (excl. new drivers*)	19.0	51.5	38.0	42.7	43.0	**38.8**	18.5	70.3	60.4	69.9	87.0	73.7	**72.3**	80.6	88.4	84.4	65.4	64.8	**76.7**
Other	8.4	7.0	21.9	58.7	41.8	**27.6**	21.1	37.0	10.8	7.4	17.8	18.6	**18.3**	102.7	58.0	50.3	51.8	62.1	**65.0**
Total net capex	376.4	413.5	457.1	476.4	417.7	**428.2**	198.5	390.6	366.6	389.9	453.6	445.3	**409.2**	639.2	687.7	730.3	734.2	743.8	**707.0**

Source: AusNet

**New drivers include resilience, reliability, large renewables enablement and smarter operations (DSO). Our resilience forecast is a new driver made up of an augex and repex component.*

The table below presents our capex forecast over the 2026-31 regulatory period, on an annual basis, by expenditure category. Consistent with our previous approach, we have maintained reporting our safety related capex as a separate category of expenditure. However, to comply with the AER's data requirements and templates, we have also provided our annual forecast in accordance with its preferred categories. The tables below show our forecasts under both these categorisations.

Table 6-2: Capex forecast for the 2026-31 regulatory period (net capex) by year ($m, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Augmentation	163.6	188.5	188.7	188.1	195.6	924.5
Connections	58.4	58.5	58.1	59.1	60.1	294.2
Energy connections (hybrids/battery & data centres)	11.2	10.0	11.2	8.9	6.6	47.9
Replacement	171.8	231.0	277.9	277.1	273.9	1,231.7
Safety	37.4	38.2	34.7	35.0	33.3	178.7
Safety (REFCL)	-	-	15.1	30.6	36.0	81.7
Metering SCS – repex	3.8	3.6	4.8	6.9	7.4	26.4
Metering SCS – digital	-	1.6	2.5	0.9	-	5.1
Digital	92.9	99.2	86.6	75.3	68.4	422.4
Other	100.1	57.0	50.5	52.3	62.6	322.5
Total	**639.2**	**687.7**	**730.3**	**734.2**	**743.8**	**3,535.1**

Source: AusNet.

Table 6-3: Capex forecast for the 2026-31 regulatory period by year, AER preferred categories ($m, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Augmentation	156.3	182.4	195.3	206.8	219.1	959.9
Connections	176.2	165.7	164.1	162.6	163.0	831.6
Replacement	189.9	246.1	292.0	296.5	292.3	1,316.9
Non-network	193.0	157.8	139.7	128.4	131.1	750.0
Capitalised network overheads	41.5	41.6	41.8	42.0	42.2	209.1
Capitalised corporate overheads	-	-	-	-	-	-
Total gross capex	**757.0**	**793.7**	**832.9**	**836.4**	**847.7**	**4,067.6**
Customer contributions	117.8	106.0	102.6	102.2	103.9	532.5
Total net capex	**639.2**	**687.7**	**730.3**	**734.2**	**743.8**	**3,535.1**

Source: AusNet.

6.4. Key inputs and assumptions

The purpose of this section is to describe at a high-level the key inputs and assumptions that have been factored into our capex forecasts. For some of the assumptions, it is possible that they may not eventuate, and this may cause our actual capex to differ from the forecasts presented in this proposal.

Where our actual capex does vary from our forecasts, the regulatory framework ensures that the associated upside and downside risks are shared fairly between our customers and us. In addition, we are proposing a defined set of cost pass through protections and working with industry more broadly to build appropriate uncertainty mechanisms into the regulatory framework to address the heightened uncertainty associated with the energy transition (see Chapter 15).

The key inputs and assumptions discussed in this section are:

- Engagement with the Customer Panels
- Asset management strategy
- Demand forecasts and customer numbers
- Value of Customer Reliability (VCR) and Quantifying Customer Values (QCV)
- Safety and other obligations
- Quality of supply
- Changes to our service delivery model
- Labour and material escalators
- Project cost estimates and unit rates
- Contractor support costs
- Overheads
- Rewards and benefits under the Service Target Performance Incentive Scheme (STPIS), and
- Expected capex in the current 2021-26 regulatory period.

Further details on each of these inputs and assumptions are set out below.

6.4.1. Engagement with the Customer Panels

Through workshops and topic-specific deep dives, AusNet sought feedback from the relevant Customer Panels on various elements of our capex proposal to better understand customer preferences and how these should be reflected in our plans. We discuss the feedback from the relevant Customer Panels in relation to specific categories of capex later in this chapter.

In addition to seeking feedback on specific categories of capex, we held an all-Panel deliberation workshop in August 2024 where we presented our overall view of the capex forecast, including outstanding areas for feedback and where trade-offs could be made from a top-down basis. This workshop was also attended by the AER, the Victorian Government and the AER's Customer Challenge Panel (CCP).

We presented the following options and the associated benefits for the Customer Panels to deliberate on:

- **Large renewables connection projects:** choosing between investing in committed projects ($108m) versus a higher amount which encompasses committed projects plus an additional amount that is economically justified ($121m). Customer Panels supported the high case[16], but we noted an expectation from some customers and panel members that our revenue proposal include a more tangible assessment of the value unlocked by this expenditure.
- **Resilience network hardening:** four options in total, ranging from a low of 25% to a high of 100% rollout of the investment program in the 2026-31 regulatory period. Customer Panels supported a 100% rollout which was the highest of the options available.[17]
- **Worst served customers:** ranging from low of only investing in optimal projects ($25m) to a high which encompasses optimal projects plus an additional reliability fund of $100m (a total of $125m). Customer Panels supported an investment of $100m which is towards the higher end of the available options.[18]

[16] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 32.
[17] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 19.
[18] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 19.

- **Innovation:** continuing in steady state ($5m capex and $3m opex) or a more ambitious innovation program ($10m capex and $5m opex). Customer Panels supported the high case.[19]

We note that in some cases the support was not unanimous across 100% of the Panel members, as described in the Coordination Group's report, but was the majority view. More information about the work of the Customer Panels is provided in Chapter 2.

6.4.2. Asset Management Strategy

Our Asset Management Strategy (**AMS**) is central to our processes for managing our electricity distribution assets and delivering quality services to customers. The AMS sets out the medium-term strategic actions required to achieve regulatory and business performance targets, which we implement via the programs of work shown in the five-year Asset Management Plan we produce each year.

The strategic actions set out in the AMS focus on meeting our asset management objectives, which are to:

- Comply with legal and contractual obligations
- Meet customer needs
- Maintain safety
- Be future ready, and
- Maintain network performance at the least sustainable cost.

The AMS is underpinned by the regulatory and commercial imperatives of delivering efficient cost and service performance. It recognises that cost and service efficiency does not mean lowest possible cost, nor does it mean guaranteed reliability. Instead, efficiency requires the costs and benefits of all expenditure decisions to be weighed against one another. A key element in this economic assessment is the consideration of risk management for asset performance and network reliability.

The AMS has the following key functions:

- To set the framework for our holistic approach to managing network assets, and in so doing establish the linkages with and between the underpinning detailed strategies, processes and plans, and
- To provide important context for management strategies, by taking into account the demand for network services, the condition of network assets and expected trends into the future. It also has regard to the network augmentation planning process.

As the output of a strategic assessment process, the AMS also sets out the key asset management focus areas and associated strategies to manage each asset class. It provides authoritative guidance for the development of asset management works programs. The information presented in the AMS also extends to longer-term expectations for technological advancement of network assets, the functionality of the network and evolution of management approaches. As such, the AMS is a key input to our asset management plans and capex forecasts.

6.4.3. Demand forecast and customer numbers

The key statistics from our demand and customer forecasts are:

- Maximum demand (winter peak) is expected to increase by 18% over the 2026-31 regulatory period[20]
- Maximum demand (summer peak) is expected to increase by 13% over the 2026-31 regulatory period
- Minimum demand is expected to further decrease over the 2026-31 regulatory period, and
- Customer numbers are expected to increase by 9% over the 2026-31 regulatory period.

In forecasting our customer numbers and demand growth, we need to ensure our forecasts are prudent, comprehensive and in line with customer expectations. Our demand forecasting methodology is a sophisticated in-house modelling tool, designed for AusNet's specific needs. We are continuously refining our modelling approach to ensure currency and accuracy and to incorporate the latest data and trends.

While we use an AusNet-specific forecasting tool, we rely heavily on independent data sources for inputs of forecasts customer numbers and future trends. We mostly use the Australian Energy Market Operator (**AEMO**) inputs into the Integrated System Plan (ISP) or ESOO, combined with Victorian Government's VIF.

AEMO's latest 2024 ESOO was published in August 2024 which left insufficient time for us to update our feeder level demand forecast to incorporate updated assumptions and reflect these updates in our expenditure forecasts. However, our analysis shows that the impact is minimal. To account for the minor impact, we have applied a top-down adjustment to our LV augex program as the scope of works within the LV augex program changes depending

[19] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 34.
[20] Measured at the total network demand level (this definition also applies to the summer peak increase in the subsequent bullet point).

on feeder level demand forecast. We have not adjusted the rest of our capex plans because the same capex amount remains justified even if there is a minor decrease in the feeder level demand forecast. The projects and programs that we have put forward have been tested for changes to the demand forecast where the tested range (+/- 10% up to +/- 20%) is far greater than the impact of AEMO's latest 2024 ESOO. If needed, we will revisit this as part of addressing new external assumptions and inputs in our Revised Proposal.

Where independent sources are not available or are outdated, we rely on our own analysis of recent trends. For example, we have used our customer segmentation data to analyse the impact of electrifying home heating by comparing actual smart meter data from AusNet's all-electric homes and homes with gas, replacing an outdated independent estimate.

Given the nature of demand forecasting, and the large number of inputs into the model, there is always inherent uncertainty in our forecasts. However, during the current energy transition, the level of uncertainty in our forecasts is materially higher than it has been in the past, particularly regarding the rate of penetration of EVs and customer charging patterns (of which there is little evidence today). There is also uncertainty around the expected rate of electrification of existing homes, though we do expect most households to do this gradually as appliances need replacing, at least initially, rather than all at once.

As a result, we have taken a conservative approach in our demand forecasts regarding those inputs that are more uncertain. We are using inputs that are on the lower side of our expectations, for example:

- We are using AEMO's average EV usage profiles even though Victorian average vehicle use is higher compared to the average.
- We have assumed no EV fast chargers in homes, even though we anticipate around 5,000 customers per year will likely upgrade supply for fast charging.
- The electrification impact included in our forecasts only captures customers leaving the gas network, rather than existing electricity customers changing appliances progressively.

Our approach to demand forecasting was developed in collaboration with the Future Networks Panel. However, the Panel also recognised that taking a conservative approach increases the risk that we do not obtain sufficient funding to manage actual demand on our network by 2031. For that reason, we are working with ENA to build flexibility into the regime, to address uncertainty over the pace of electrification and demand growth, as has been introduced into the NZ and UK regimes.

Further information on our demand and customer number forecasts is available in Chapter 4.

6.4.4. Value of Customer Reliability and Quantifying Customer Values

The VCR estimates the value different types of customers place on reliable electricity supply for outages less than 12 hours. Specifically, it is used to convert expected unserved energy (**EUE**) – the energy that would have otherwise been delivered – into a value of EUE expressed in dollar terms. This is an important input to determining when an augmentation or asset replacement is economically justified.

The AER has an obligation to calculate and publish VCRs every 5 years. As explained in Chapter 2.4.4, in 2024 we undertook our own research to quantify a range of values customers place on electricity services (Quantifying Customer Values). As part of this we replicated the AER's methodology to calculating VCRs, using data that it specific to our network.

In preparing our proposal, we have combined our QCV results for residential customers with the AER's 2023 VCRs for non-residential customers. To distil AusNet's QCV and AER's 2023 VCRs into a single value – for valuing expected unserved energy – we weight QCV and AER's 2023 VCRs by the relevant customer groups specific to the location of the project. See tables below for the QCV and AER's 2023 VCR values that we have adopted for economic assessments and business case development.

Table 6-4: VCRs adopted by AusNet (dollars per kWh)

	Residential	Agriculture	Commercial	Industrial
Our adopted approach – AusNet's combined approach based on combining our QCV for residential customers with the AER's 2023 VCRs for non-residential customers	52.42	44.40	52.20	74.79

Source: AusNet and AER.

The AER published its 2024 VCRs (based on the 2024 Methodology) on 18 December 2024 which has left insufficient time for us to consider its implications on our capex plans. The table below compares our adopted approach (the combined approach) with the AER's 2023 and 2024 VCRs. We make the following observations:

- The AER's VCR for residential customers in Victoria has almost doubled between 2023 and 2024 (from $25.13 to $49.23 per kWh).
- The AER's VCRs for non-residential customers have almost halved between 2023 and 2024 (for example, the VCR for agriculture customers decreased from $44.40 to $22.25 per kWh).
- The AER's VCR for residential customers ($49.23 per kWh) is very close to our QCV for residential customers ($52.42 per kWh).
- The AER's VCRs are estimated using average consumption and outage data across several networks, rather than AusNet-specific data. When undertaking our QCV study, it became apparent that the use of averaging results in materially lower estimated VCRs compared to if AusNet's own data were applied. Therefore, the AER's VCRs may be biased downwards for AusNet's customers.

We will consider the implications of the AER's 2024 VCRs in our Revised Regulatory Proposal.

Table 6-5: VCR comparisons (dollars per kWh)

	Residential	Agriculture	Commercial	Industrial
Our adopted approach – AusNet's combined approach based on combining our QCV for residential customers with the AER's 2023 VCRs for non-residential customers	52.42	44.40	52.20	74.79
AER's 2023 VCRs	25.13	44.40	52.20	74.79
AER's 2024 VCRs	49.23	22.25	34.39	33.49
AusNet's QCV	52.42	32.01	32.01	32.01

Source: AusNet and AER.

6.4.4.1. Value of Network Resilience

On September 2024, the AER published its final decision on the Value of Network Resilience (**VNR**) that is an extension of their VCR to establish a value of customer resilience associated with outages greater than 12 hours. The AER's final decision uses multiplies of the VCRs to determine the initial VNRs, then applies an upper bound to the residential initial VNR. We have adopted the AER's VNR in the development of our resilience program; applying the VNR multiples to the AER's 2023 VCRs.

Given the AER's 2024 VCRs are materially different to its 2023 VCRs (as discussed above) we will consider whether to update the VNR values underpinning our resilience proposal in our revised regulatory proposal.

6.4.4.2. Views of the Customer Panels

Our Customer Panels have supported AusNet to use its own QCV figures for residential customers on the condition that the AER will satisfy itself that these values are suitably robust and have been applied in a consistent manner. However, they are unclear as to why AusNet adopted the AER's VCRs for non-residential customers (commercial, industrial, and agricultural) instead of the QCV figures for non-residential customers. We explain below why we have adopted this approach.[21]

Our QCV figures for non-residential customers were based on a survey of 349 customers with characteristics that lend itself to be classified as small businesses. The results could not be matched to the AER's business VCR categories of commercial, industrial and agriculture because of differing characteristics. The businesses within our QCV survey use less than 40 MWh of electricity per year, and they are made up of businesses with 2 to 99 employees (exclude sole traders). In contrast, the AER's business categories include small and large businesses where small businesses are those that consume less than 100MWh of electricity per year compared to large businesses that consume more than 100MWh per year. This is a mismatch in usage compared to our QCV non-residential customers.

The differing characteristics have therefore led to a modified approach where we have combined our QCV for residential with the AER's VCRs for non-residential customers.

The Coordination Group stated:

"We support AusNet's Draft Proposal to use its own figures for VCR for residential customers on the proviso that the AER will satisfy itself that these values are suitably robust and have been applied in a consistent manner. We also

[21] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 23.

support AusNet substituting in the AER's VCR for large businesses on the basis that the survey was unable to achieve a sufficiently large or representative sample of these customers. We are unclear on the rationale for AusNet also substituting in the AER's VCR for small and medium-sized businesses, given it has a larger and reasonably representative sample of these customers, and we consider AusNet should carefully consider its choices to ensure it does not appear to be cherry-picking values. In principle, AusNet could disaggregate its results further to get more granular information on customers' VCR by network location or by customer characteristics (e.g. dual fuel vs electricity only). However, this would be a new precedent and the robustness of more granular data and the equity implications would need to be carefully considered before doing so. Future consideration of customer values of reliability may need to become more nuanced and sophisticated as more and more customers adopt CER that allows them to maintain some level of supply during outages.[22]

6.4.4.3. Implementation of our adopted approach

There are minor differences in how we have implemented the combined approach in our assessment process:

- **Demand driven augex (LV augex):** we have adopted the combined approach in our central case assessment; with sensitivity testing at the AER's 2023 VCRs. Using a combined QCV/AER's 2023 VCRs approach increased our capex by approximately $15m compared to using the AER's VCRs.
- **Demand driven augex (non-LV augex) and reliability programs:** we have adopted the AER's 2023 VCRs in our central case assessment; with sensitivity testing at our combined QCV/AER's 2023 VCRs. The economic outcomes (preferred option, capex requirement, opex requirement and optimal timing) for these projects remain the same under both scenarios i.e., the preferred option, capex and opex requirements, and optimal timings are the same whether we adopt the AER's 2023 VCRs or our combined QCV/AER's 2023 VCRs approach.
- **Replacement:** we have adopted the combined approach in our central case assessment; with sensitivity testing at the AER's VCRs. Using a combined QCV/AER's VCRs approach increased our capex by approximately $50m compared to using the AER's 2023 VCRs alone. We note there was an indication that using our combined QCV/AER's VCRs could have justified a repex increase exceeding $50m, yet we have maintained a $50m increase consistent with stakeholder feedback and the analysis that we consulted on at the time.
- **All others capex investments:** we have adopted the combined approach in our central case assessment; with sensitivity testing at the AER's VCRs.

For demand driven augex (non-LV) and reliability programs, we have adopted the AER's 2023 VCRs in our central case assessment, because we wanted to highlight that the use of standard VCRs would justify our investment program (which is the same under a combined QCV/AER's 2023 VCRs approach).

The table below summarises the capex outcomes under our adopted approach to the VCR compared to if we had adopted the AER's 2023 VCRs. Our capex forecast for resilience does not vary because it is underpinned by the AER's VNR (see chapter 6.4.4.1). Our capex forecast for other projects and programs do not vary depending on whether we adopt our combined approach or the AER's 2023 VCRs.

Table 6-6: Capex outcomes under different VCR approaches ($m, direct, real 2023-24)

	Our adopted approach to the VCR – the combined approach	AER's 2023 VCRs	Comments
Demand driven augex (LV)	$119.5	$104.5	A $15m reduction in capex requirement if we adopt the AER's 2023 VCRs.
Demand driven augex (non-LV)	$200.6	$200.6	Same capex outcomes under both our adopted approach to the VCR or the AER's 2023 VCRs.
Repex	$772.6	$722.6	A $50m reduction in capex requirement if we adopt the AER's 2023 VCRs.

Source: AusNet.

6.4.4.4. Consistency of our adopted combined approach

The AER should accept the use of our combined approach – QCV for residential customers and the AER's VCRs for non-residential customers – used in the assessment of our capex proposals because the RIT-D guideline allows deviations from or adjustments to the AER's VCRs if it can be clearly justified.[23] Specifically:

- **It is consistent with the VCR objective and fit for purpose:** We developed our QCV values based on replicating the AER's 2019 VCR methodology, which has been upheld through the AER's final determination for the 2024 VCR Methodology as being consistent with the VCR objective and fit for purpose.[24]
- **It is more up to date:** We surveyed customers between December 2023 to January 2024 which is more recent compared to the AER's original survey from September/October 2019.

[22] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 23.
[23] Clause 3.4.3. of the Regulatory investment test for distribution, August 2022.
[24]AER 2024, Values of customer reliability methodology, final determination, August, p. 25).

- **It is AusNet-specific:** We surveyed over 3,500 AusNet customers to develop our QCV, including dividing the willingness to pay by actual load data sourced from our smart meters. In contrast, the AER's VCRs are segmented by climate zone and region and use broad averages.
- **It is more robust:** We surveyed over 3,500 AusNet customers, which is a far larger sample size than embedded in the AER's 2019 survey of approximately 712 in our distribution network area.
- **It meets customers' needs:** Our QCV VCR is consistent with our customers' preferences that have been tested and supports their sentiments around the growing importance of a reliable power supply.
- **We have used more robust data where it is available:** We adopted our QCV for residential customers, instead of the AER's VCR for residential customers, because they are directly comparable and the QCV values are considered robust for the purposes in which they have been applied. We have not adopted our QCV for non-residential customers because they are not directly comparable with the AER's VCRs for non-residential customers, which are considered more robust for the purposes in which they have been applied. See section 6.4.4.2.

6.4.5. Safety and other obligations

Our capex plans for the 2026-31 regulatory period reflect our commitment to achieving compliance with our safety and other obligations. In particular, we invest to meet the following legislative and regulatory obligations:

- Section 98 of the Electricity Safety Act 1998, which requires us to design, construct, operate, maintain and decommission our network to minimise as far as practicable:
  - the hazards and risks to the safety of any person arising from the network
  - the hazards and risks of damage to the property of any person arising from the network, and
  - the bushfire danger arising from the network.
- The Electricity Safety Act 1998 requires us to maintain compliance with our approved Electricity Safety Management Scheme (ESMS) and operate under an annual Bushfire mitigation plan and Vegetation management plan (provided to Energy Safe Victoria). The plans must be revised annually to ensure the ongoing effectiveness of measures to reduce the risk of electricity assets causing bushfires including inspections, maintenance and asset management.
- Clause 19 of the Victorian Electricity Distribution Code of Practice (EDCOP) requires us to manage our assets in accordance with the principles of good asset management. Under the EDCOP, we must develop and implement plans for the management of our assets to minimise risks associated with the failure or reduced performance of assets.
- Clause 13.3 of the EDCOP requires us to use best endeavours to meet customers' reasonable expectations of supply reliability.
- Clause 5.2.1 of the National Electricity Rules require us to maintain and operate the network in line with good electricity industry practice, which is defined as *"The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the national electricity system for the generation, transmission or supply of electricity or the provision of wholesale demand response under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, reliability, safety and environmental protection. The determination of comparable conditions is to take into account factors such as the relative size, duty, age and technological status of the relevant facility and the applicable regulatory instruments."*

Additionally, the *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016* came into effect in 2016 amending the *Electricity Safety (Bushfire Mitigation) Regulations 2013* (the Regulations). The Regulations required that each polyphase electric line originating from 22 prescribed zone substations must comply with performance standards specified in the Regulations by 1 May 2023. These performance standards can only be met by installing REFCLs, which at the time was a technology not previously used for bushfire risk reduction anywhere in the world. During the current 2021-26 regulatory period, we completed REFCL program across all 22 prescribed zone substations, which means our proposed expenditure for safety over the 2026-31 regulatory period is significantly less than for the current 2021-26 regulatory period. However, there is an ongoing need to augment the capacity of the REFCLs in response to higher loads to maintain compliance with the Regulations.

6.4.6. Quality of supply

Clause 20 of the EDCOP sets out quality of supply standards that apply to distributors in Victoria in relation to the following parameters:

- Voltage standards
- Power factor
- Harmonics
- Inductive interference
- Load balancing (negative sequence voltage), and
- Disturbing load.

Our capex plans are designed to ensure we maintain power supply quality within the limits specified for each parameter in accordance with the EDCOP and other relevant standards, recognising that the strong uptake of rooftop solar generation creates quality of supply issues.

6.4.7. Changes to our service delivery model

In October 2024, we announced that, following a comprehensive market testing process, we have engaged Zinfra as our new service delivery partner for operations and maintenance of our network, commencing in August 2025 and replacing Downer. We have made these changes to:

- Deliver better performance and outcomes for our customers and stakeholders (including how we respond to major weather events);
- Improve visibility and control over Operations & Maintenance activities and our works programs;
- Strengthen our presence in our communities; and
- Increase control over our operational assets across our network, by bringing key operational assets, such as depots, fleet and tools under our direct control.

These new arrangements have implications for our capex plans, as explained later in this chapter, including the unit rates used in our replacement expenditure forecasts and our fleet capex requirements.

6.4.8. Labour and material escalators

Our capex plans reflect expected changes in the cost of labour and materials during the regulatory period. As with any other commercial business, the price we pay for labour and materials is determined by competitive national and international markets.

We are forecasting that materials (non-labour) costs will grow in line with the Consumer Price Index (**CPI**) resulting in no real cost escalation. Our proposal is based on the AER's long standing approach to materials escalation. Nonetheless we consider the AER should proactively reassess this position as there are global market forces and a shortfall in materials and supplies that have and will continue to lead to real cost escalation above CPI.

We are proposing that labour costs will grow in line with the labour price growth in the Electricity, Gas, Water and Waste Services (**EGWWS**) sector. We have relied on expert independent advice (BIS Oxford Economics) to build up the rigorous forecast of expected labour price growth based on expected macroeconomic and stated specific factors. We have averaged our expert's forecast and the AER's labour costs forecast to develop the labour price growth forecast.

Further information on our labour escalation forecasts is available in Chapter 7.11.

6.4.9. Project cost estimates and unit rates

Our project cost estimates have been prepared as part of a standardised approach to developing, managing and reporting projects and programs of works, as outlined in our Project Cost Estimating Methodology. To summarise, this approach ensures that:

- Project cost estimates are prepared in accordance with specific project execution procedures and practices, including reviews and a sign-off process based on consistent, clear lines of responsibility and accountability;
- Consistent costing standards and controls are applied when we develop our project cost estimates; and
- Our capex forecasts are prepared on a P50 basis, which means there is a 50% confidence that our estimate will not be exceeded by the actual cost at project completion, and a 50% confidence that they will be exceeded.

The unit rates we use to develop our forecasts are the rates charged by our service provider with a risk margin to reflect contractual exposure to actual costs. Our rates reflect the efficient cost of delivering similar projects in our network area, recognising that we:

- Deliver our projects and programs using competitively tendered resources; and
- Have established, by competitive tender, pre-qualified panels of design and installation service providers to safely design and install works for major projects such as zone substation rebuilds.

As already noted, AusNet appointed Zinfra as its service delivery partner for distribution operations and maintenance activities. C-I-C

Our forecast unit rates and our approach to setting them are explained in further detail in the Unit Rates supporting document.

6.4.10. Contractor support costs

Our capex forecast includes contractor support costs, which reflect the overhead costs incurred by our service delivery partners that are not directly attributable to the unit rates we are charged. These costs are passed onto us through the Operations and Maintenance Services Agreement we currently have in place with Downer, which will transition to Zinfra in August 2025.

Contractor support costs have been forecast based on historical, actual costs and apply to the following capex categories, which include projects and programs delivered through OMSA arrangements:

- Replacement.
- Augex.
- Connections.

6.4.11. Overheads

Our forecast of capitalised overhead for the 2026-31 regulatory period is based on our forecast of network overhead that we expect to capitalise in accordance with our capitalisation policy. We proposed to expense all corporate overheads from 1 July 2026 which means corporate costs will not form part of our overheads. See Chapter 0 for more information on corporate overheads.

Our forecast of capitalised overhead costs is, on average, $41.8m per annum (real 2025-6) over the 2026-31 regulatory period (see table below). This is a 6.6% reduction compared to the annual average expected overhead in the current period of $44.8m (real 2025-26) and reflects the discretionary productivity growth factor we have applied (discussed below).

Consistent with our opex forecast where we have applied a productivity factor of 0.5%, we have similarly applied a discretionary 0.5% productivity factor to reduce network overheads in our capex forecast by $4m. We consulted with the Coordination Group on this issue, who were supportive of our approach of applying productivity to capitalised overheads but, consistent with their position on opex productivity growth, considered that a higher rate should be applied. Chapter 7 provides further information on the productivity factor.

Table 6-7: Capitalised overheads ($m, real 2026)

	FY2027	FY2028	FY2029	FY2030	FY2032	Total	Average
Capitalised network overhead	41.5	41.6	41.8	42.0	42.2	209.1	41.8
Capitalised corporate overhead	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Total capitalised overhead	41.5	41.6	41.8	42.0	42.2	209.1	41.8

Source: AusNet.

6.4.12. Rewards under the Service Target Performance Incentive Scheme

Proactive investments to address extreme weather events will have the secondary impact of improving our underlying reliability performance and therefore generate rewards under the Service Target Performance Incentive Scheme (**STPIS**). As such, we have estimated the value of the STPIS reward and removed it from our capex forecast (see table below).

Similarly, our reliability projects will generate rewards under the STPIS, and we have estimated the value of the STPIS rewards to net off our capex forecast.

Table 6-8: Forecast of STPIS rewards ($m, direct, real 2023-24)

		Capex requirement without STPIS rewards removed	Forecast of STPIS rewards	Capex requirement net of STPIS rewards
Resilience	Undergrounding	95.0	1.6	93.4
Resilience	Covered conductors	29.7	0.2	29.5
Resilience	Reclosers	20.0	1.3	18.7
Resilience	Pole hardening	65.6	-	65.6
Reliability	10 worst served feeders	23.5	2.8	20.7
Reliability	BN11 upgrade	23.5	1.8	21.7
Total		**257.3**	**7.7**	**249.6**

Source: AusNet

Our forecast of STPIS rewards is based on the following methodology:

- Estimating the STPIS benefits for the interventions listed above as they improve reliability to local customers. We have not estimated the STPIS benefits for other projects and programs within our capex plans as they are aimed at maintaining current reliability levels that's already embedded in the STPIS targets that we have proposed in chapter 13.
- Estimating the STPIS benefits based on analysing data from the most recent historical 5-year period and assuming the benefit is equal to the difference between:
  - annual average STPIS penalty
  - annual average STPIS penalty had the interventions existed
- Creating a cashflow analysis by applying the forecast benefits on a two-year lag as actual rewards and penalties are only realised with a two-year lag.
- Applied a discount rate of 5.56% (see table 6-9 for the basis) in our cashflow analysis to determine the NPV of the STPIS benefits.

The alternative to our adopted method – reducing our capex requirement to account for STPIS rewards – is to adjust our STPIS targets for 2026-31. We have not adopted this alternative method.

6.5. Forecasting approach

This section provides an overview of our capital expenditure forecasting approach and focuses on six elements:

- Economic Assessment of Projects and Programs, which is key to ensuring that our plans are prudent and efficient.
- Business case development, which involves translating the economic assessments into a coherent document used for internal and external approvals.
- Network Support, which involves the active consideration of non-network solutions.
- Top-down review, which recognises that a 'bottom-up' forecasting approach may overstate expenditure requirements, and that a top-down review is required to ensure that forecast expenditure reflects only prudent and efficient costs.
- Benchmarking, which tests our forecast plans by examining our performance against our peers.
- Deliverability of our forecast.

More detailed information on the forecasting approach specific to each capex category can be found in the relevant capex sections below.

6.5.1. Economic assessment of projects and programs

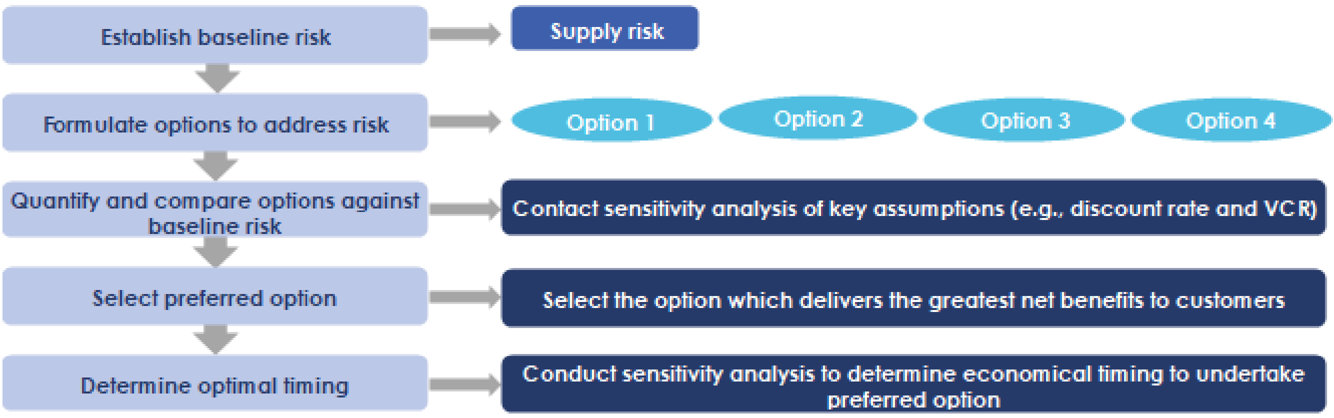
Our capex proposal meets our customers' expectations and our safety and compliance obligations prudently and efficiently as we have conducted robust economic assessments, and we have also engaged with the Coordination Group, Customer Panels and other stakeholders to ensure that our proposal reflects the "voice of the customer".

- **For most projects and programs** included in our proposal, we have undertaken significant planning studies and analysis. We have conducted robust economic assessments that compare the costs and benefits of credible options against do-nothing or Business-as-usual (**BAU**) to identify the preferred option that maximises the Net Present Value (**NPV**) to customers.

- **For safety and compliance projects and programs**, the preferred option is the lowest cost option that addresses the safety and compliance needs. However, in some limited cases, we have quantified other benefits and taken the maximisation of NPV into account.
- **For repex projects**, AusNet has applied industry standard risk-based approach consistently across asset classes to determine the optimal replacement timing based on factors such as Probability of Failure (**PoF**) and Cost of Consequence (**CoC**).

The figure below provides a general overview of the economic assessment approach for projects and programs included in this proposal; excluding the capital requirements underpinned by compliance, safety or repex as they have been assessed through a different framework.

Figure 6-4: Economic assessment approach



Source: AusNet.

The table below outlines the key assumptions that we have adopted across our economic assessments.

Table 6-9: Key economic inputs and assumptions

Input / Assumption	Description
Discount rate (real)	5.56%; the average of our forecast of pre-tax WACC as at June 2024 (4.11%) and AEMO's IASR central discount rate of 7%.[25]
Value of Customer Reliability (VCR)	We have adopted a combined approach to the VCR. Specifically, combining our QCV for residential customers with the AER's 2023 VCRs for non-residential customers for valuing expected unserved energy. See section 6.4.4 for more information.
Demand forecasts	Our demand forecasts are conservative to avoid over-investment during a period of heightened uncertainty, and we have achieved this by employing our own in-house forecasting tool that has been designed for AusNet's specific needs. See chapter 4 and section 6.4.3 for more information.

Source: AusNet.

6.5.2. Business case development

Each project and program is authorised through a business case which is a coherent and largely standalone document that explains the economic assessment. A business case document identifies the risks and needs for intervention, assesses the available options and then selects the preferred option that maximises the net benefits to customers. Each business case is reviewed by relevant engineering and financial managers against relevant asset management decision criteria.

The scope and content of each business case will depend on the nature of the assets and the key driver(s) for the proposed expenditure. For example, a program may be driven by our obligations under the Electricity Safety Act, which requires us to minimise safety risks 'as far as practicable'. In practice, this obligation means we must take steps to improve network safety unless the costs of doing so are disproportionate to the benefits. As such, the business case analysis for a safety-driven project or program will be different to demand driven augmentation projects (for example), where the benefits exceed the costs.

The exact analysis undertaken for each business case will depend on a range of factors, including:

- The expenditure drivers
- Asset criticality

[25] AEMO 2023, 2023 Inputs, Assumptions and Scenario Report, Final report, p. 123.

- Safety and risk assessment
- Volume, nature and value of asset
- Availability of information on asset condition and failure probability, and
- Applicability of models, such as repex modelling.

Our assessment approach is different for 'high volume, low value' assets and 'low volume, high value' assets. The principal difference is that population and sub-population modelling is required for large volume assets, whereas we undertake asset specific analysis for low volume assets. The overall objective, however, remains the same in each case – to deliver the lowest total cost service to our customers by ensuring that we evaluate the costs and benefits of alternative expenditure options using a robust economic assessment framework.

6.5.3. Network support

Network support refers to the suite of non-network solutions and demand management techniques used to manage risk and improve the performance of the distribution network. These services, which we generally treat as opex, include:

- Services provided by embedded generation
- Embedded storage, and
- Customer demand response.

We may enter into contracts for network support services in order to defer capex projects, reduce energy at risk levels or respond to network contingencies. We routinely consider non-network options as part of the regulatory investment test for distribution (RIT-D) assessment framework.

Growth of non-network solutions is encouraged as it can provide the lowest cost solutions for our customers. In this regard, our Grid Evolution team conducts trial projects, evaluates options and provides input to network planning processes. In addition, our Network Planning team considers the scope for embedded generation and demand management options as part of the network planning process. We support these activities by:

- Maintaining a register of demand side suppliers, and
- Developing and publishing our demand side engagement strategy.

The following initiatives are recent examples of some of the innovative actions we have taken to promote demand management solutions:

- **Commercial and industrial (C&I) demand response:** Engaging with commercial and industrial customers to develop demand response programs that can support the network during peak demand times, helping manage system reliability and capacity constraints.
- **Euroa non-network solution (NNS) Expression of Interest (EOI):** Publishing an EOI for a non-network solution to deliver up to 4.5 MW of network support at Euroa. However, no commitments were received for this solution.
- **Network Support Agreements (NSA) using battery storage:** Establishing network support agreements to utilise battery storage systems as a demand support mechanism, reducing load on the network during peak times and enhancing overall system resilience.
- **Publishing RIT-Ds as required by the NER, to invite interest from non-network providers:** Noting we have not seen a high number of responses to date.

In the 2026-31 regulatory period, we will continue to consolidate and build network support capability by:

- Strengthening our capability in the application of network support services
- Increasing the level of contracted network support where it is economic to do so, including via active consideration of the scope for non-network opex in RIT-D assessments, and
- Integrating new innovations into our business-as-usual processes.

In this proposal, we have ensured that opportunities to meet customers' needs through network support has been factored into our expenditure proposals. For example, our flexible services proposal has been justified on the basis of deferring $29m of demand driven augmentation at the LV network (see Chapter 0).

6.5.4. Top-down review

We recognise that there is scope for overlap and synergies between programs within our capex proposal for the 2026-31 regulatory period, especially where we expect work to occur at the same location or propose to replace the same asset.

Where a potential overlap between projects is present, we have removed these from our forecast of projects and programs.

Following our consideration of all the proposed programs contained in this proposal, we calculated the total value of the overlaps that we needed to remove. For our 2026-31 regulatory proposal, the overlap amount was $42m (real 2023-24), demonstrating our commitment to efficiency when developing our forecasts (and keeping prices low for customers). Further information is available in the Top Down Adjustment supporting document.

6.5.5. Benchmarking

The AER is required to have regard to its most recent annual benchmarking report as part of its assessment of our capex forecasts. We support the use of benchmarking to inform a high-level comparative view of efficiency where relevant. There are numerous benchmarking approaches, each of which provides insights into a company's performance. For electricity networks, particular attention needs to be given to the interpretation of benchmarking results, by taking account of network-specific factors that affect the headline results.

In our case, a key factor that negatively affects our overall capex productivity relates to our relatively large proportion of residential load in our customer base results with low average consumption levels leading to comparatively low energy throughput and thus lowering measured productivity.

In its most recent 2024 annual benchmarking report, the AER explained that it uses benchmarking in various ways to inform their assessment of network expenditure proposals. Additionally, it is used to measure how productively efficient networks are at delivering electricity distribution services over time and compared with their peers.

The 2024 annual benchmarking report also examined a number of other partial productivity measures, including total cost per customer. The AER states:

- Customer numbers are one of the main outputs DNSPs provide. The number of customers connected to the network is one factor that influences demand and the infrastructure required to meet that demand.[26]
- Broadly, this metric should favour DNSPs with higher customer density because they are able to spread their costs over a larger customer base. However, it is worth noting that there is a large spread of results across the lower customer density networks. Both Ergon Energy and Essential Energy have a relatively higher total cost per customer compared to other largely rural DNSPs, including SA Power Networks, Powercor, AusNet and TasNetworks. Ausgrid and Evoenergy also have relatively higher costs per customer compared to other networks with similar customer densities and some networks with lower customer densities.[27]

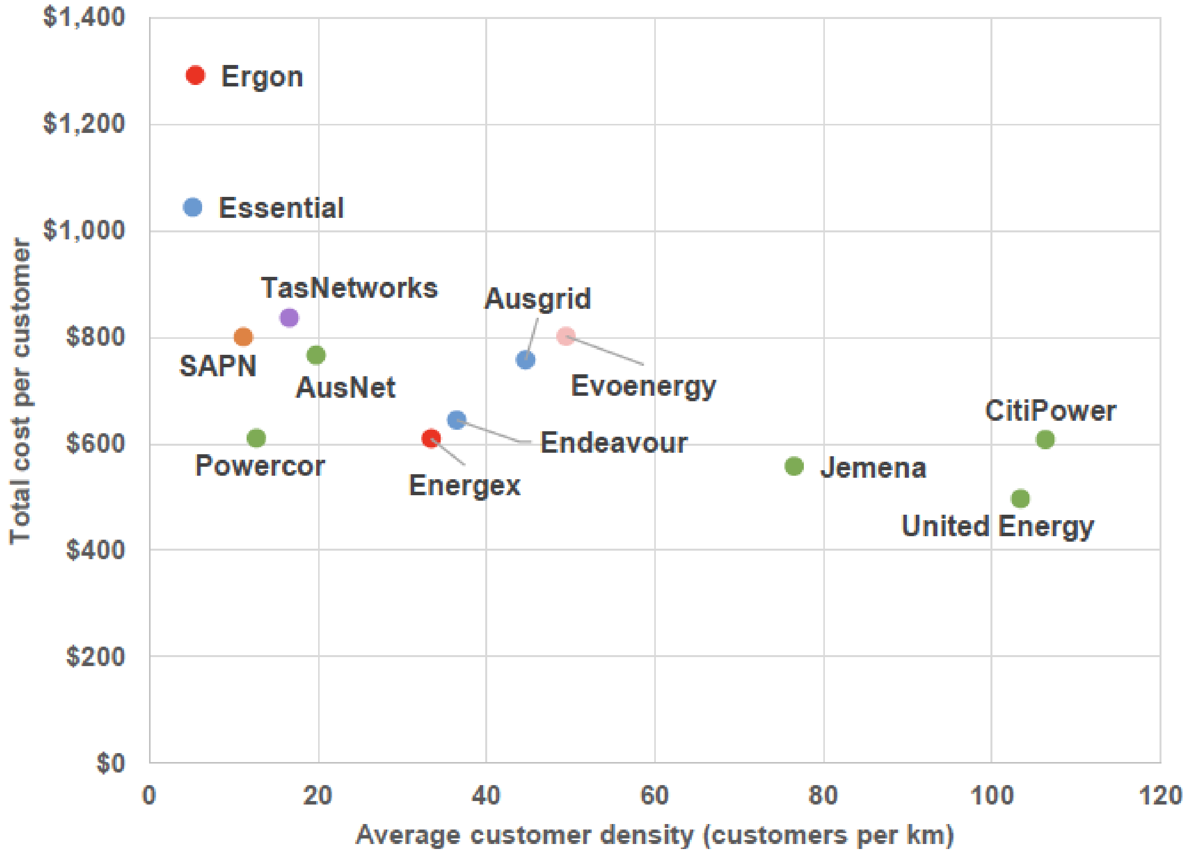
Figure 6-5 shows our total cost per customer alongside our peers. As highlighted by the AER, we have similar levels of customer density to Ergon Energy and Essential Energy, but relatively lower costs per customer, and have broadly similar costs to SA Power Networks. The AER's analysis shows that in terms of total cost per customer, we are among the best performers of the networks that have relatively low customer densities.

Similarly, we perform well in terms of total cost per kilometre of line length, as shown in the figure below.

The AER's analysis should therefore give stakeholders some confidence that our cost performance compares well with our peers and, therefore, our forecasts reflect efficient unit rates, planning and delivery processes.

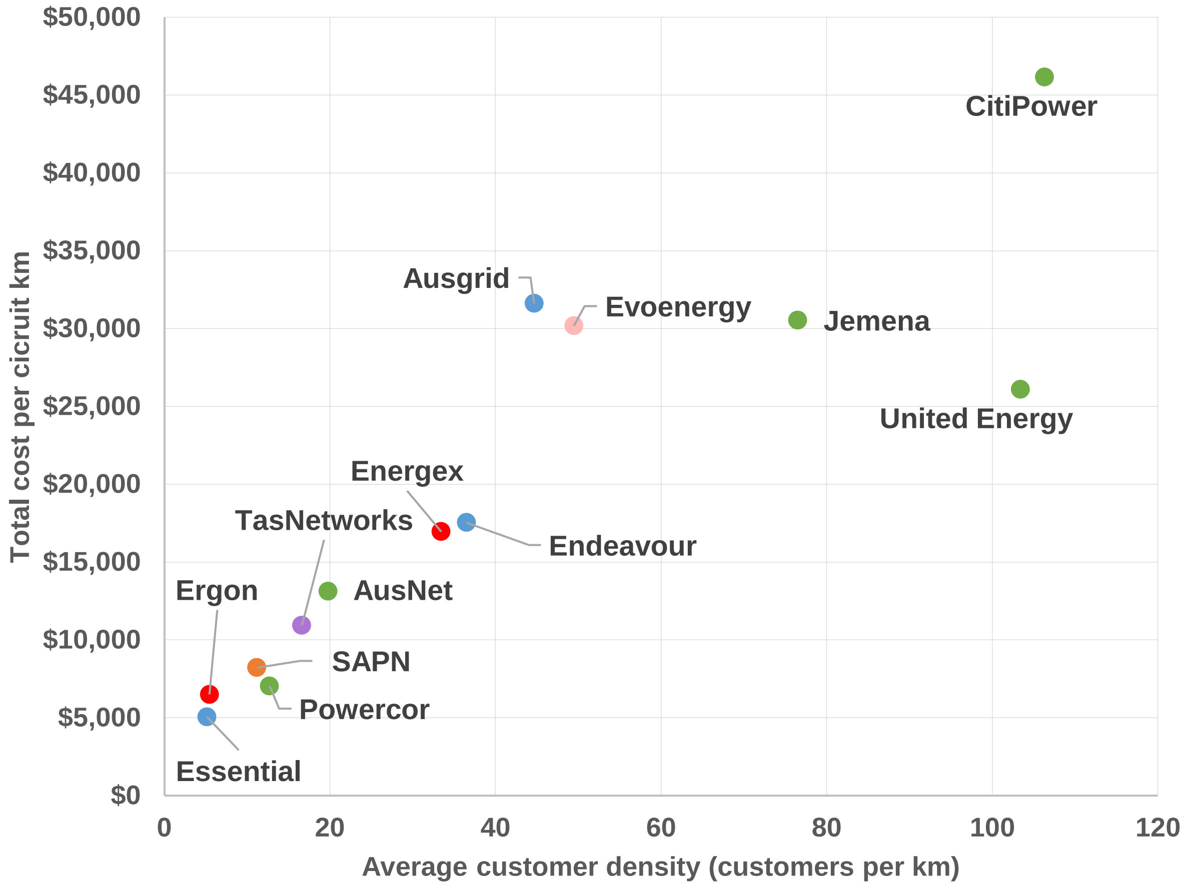
[26] 2024 AER, Annual benchmarking report, electricity distribution network service providers, November, p. 39.
[27] 2024 AER, Annual benchmarking report, electricity distribution network service providers, November, p. 39.

Figure 6-5: Total cost per customer ($2023) against customer density (average 2019–23)



Source: AER 2024, Annual benchmarking report, electricity distribution network service providers, November, p.40.

Figure 6-6: Total cost per km of circuit line length ($2023) against customer density (average 2019–23)



Source: AER 2024, Annual benchmarking report, electricity distribution network service providers, November, p.41.

6.5.6. Deliverability

Deliverability refers to the ability of the business to deliver the proposed program of work which can be demonstrated through our past track record and our strategic deliverability plan.

For many years, we have been a trusted network business to deliver large and complex projects and programs such as:

- Since 2017, we have installed Rapid Earth Fault Current Limiters (REFCLs) in 22 high bushfire-risk areas across our electricity distribution networks. They now protect over 40,000 square kilometres of our electricity distribution area.
- We installed new underground electricity cables in Falls Creek and surrounding areas. This critical work ensures a reliable electricity supply to residents and businesses in the area.
- Mount Buller engaged us to support increasing its electricity capacity ahead of the 2023 snow season. This upgrade related to a $3.6m Victorian Government grant for the resort to fund an additional supply 4MVA of supply capacity, facilitating increases to snow-making capacity and improving network infrastructure in the area. We replaced power poles and powerlines along Mount Buller Road and surrounding access roads between Merrijig and Mount Buller Alpine Village. We also installed new infrastructure along the Bourke Street ski run in Mount Buller. Our team used high voltage generators to minimise power interruptions where possible and worked closely with the local community to ensure they were informed of any property access requirements in advance.

We have developed a strategic deliverability plan to support our expanded capital expenditure proposal for 2026-31. Our strategic deliverability plan highlights the measures – both in flight and planned measures – that will enable us to rapidly scale up to deliver a capital expenditure program. This plan has regard to:

- The potential shortage of field workers given competing demands across the infrastructure industry.
- The high global demand for energy networks materials and the resultant lead-time risks.
- The ability to obtain resource commitments from prospective service providers through competitive tender process that provide an appropriate weighting towards security of supply and lead time.
- The benefit of seeking vendors from disparate global geographies as a hedge against risks such as trade sanctions, conflicts or epidemics.

In addition, we have deferred several augmentation projects beyond their economic timing, to smooth the ramp up in our capital program during the 2026-31 regulatory period and further mitigate potential delivery risks. These deferrals have also reduced our proposed revenue requirement and improved the affordability of our plans. The deferred projects are:

- REFCL compliance program
- Morwell Terminal Station (MWTS) South 66kV loop: MWTS-LGA lines upgrade
- Eastern Cranbourne 66kV loop augmentation
- New transformer at Wonthaggi
- New 22kV distribution feeders (WOTS21, SMR11 and WGL31)
- The regional reliability allowance, recognising that this program's expenditure profile is not currently based on an economic assessment, and the timing of actual spend will depend on the projects identified (and supported by our stakeholders) during the 2026-31 regulatory period.

Taking account of the above measures, AusNet's assessment is that the proposed capex for the 2026-31 regulatory period is capable of being delivered in accordance with the plans for each of the capex categories.

6.6. Demand driven augmentation

6.6.1. Key points

The key points in this section are:

- Demand driven augmentation expenditure (demand driven augex) is the capital needed to expand network capacity to meet the growth in customer numbers and the demand for energy. The value of expected unserved energy is the key driver for this expenditure.
- We have a long history of probabilistic planning which increases network utilisation and keeps network charges as low as possible i.e., probabilities are attached to the different scenarios that we test to ensure that we only invest where it is efficient to do so. As part of this economic assessment framework, we compare credible solutions against a base case of do-nothing (or business-as-usual) to identify the preferred option that delivers the highest net benefit to consumers.
- A maximum demand growth of 18% (winter) and 13% (summer) over the 2026-31 regulatory period combined with projected asset utilisation of 75% will drive constraints in our network that require augmentation over the 2026-31 regulatory period. Our current level of asset utilisation is 60%, which is already much higher than the 40% average across the NEM.
- Our demand forecasts are conservative to avoid over-investment during a period of heightened uncertainty, and we have achieved this by employing our own in-house forecasting tool that has been designed for AusNet's specific needs. We primarily use the latest inputs and assumptions from AEMO and the Victorian Government's VIF; and where they are uncertain, we have adopted inputs and assumptions on the lower end of expectations.
- Our demand driven augex forecast is consistent with historical customer behaviour in relation to cost reflective tariffs. While our tariff strategy includes a progressive increase in customers on cost reflective tariffs, including a time of use tariff with a low cost middle of the day period, customer response to time of use tariffs has been historically low and insufficient to defer augmentation.
- We have proposed a new zone substation (ZSS) in the Wollert area as one of the existing zone substations serving the area – Kalkallo ZSS – is forecast to be overloaded by 2027 under N rating which means that an urgent solution is needed to avoid power outages or curtailment. The capital investment cost of a new Wollert ZSS is $40.4m (direct, real 2023-24).
- We have also proposed a new ZSS in the Pakenham South area as the 50% Probability of Exceedance (POE) demand forecast has already exceeded the summer N-1 rating for a number of existing substations. We have assessed several credible solutions, including non-network alternatives such as network support, and our assessment concluded that a new ZSS has the highest net benefit to consumers as it avoids expected unserved energy risk compared to do-nothing, and it allows for future growth. The capital investment cost of a new Pakenham South ZSS is $49.2m (direct, real 2023-24).
- We have proposed $119.5m (direct, real 2023-24) of upgrades in the Low Voltage (LV) network to address forecast increases in constraints due to the electrification from gas-to-electricity and the uptake of EVs. Our proposal will allow for the upgrade of 958 distribution substations (DSS) and 38 SWER – representing approximately 1.6% and 7.2% of our assets respectively – which will unlock LV capacity to allow for electrification. Our LV augex forecast excludes $29m of capex that will be deferred by our flexible services proposal, reflecting an efficient capex/opex trade-off (discussed further in the opex chapter). It also excludes $12.7m of overlaps with our current period investment program.
- Constraints in several feeders, sections of our sub-transmission network and stations are also forecast to increase over the 2026-31 period making it economic to construct 3x new 22kV feeders, augment 2x 66kV loops and install a new transformer at Wonthaggi (**WGI**).
- We have undertaken extensive stakeholder consultation including deep dives on specific topics, such as demand forecasting and demand driven augex in the LV network. Our stakeholders have provided support for our forecasting approach and our proposal to invest to remove constraints in the LV network (where it is economic to do so).

6.6.2. Overview of forecast and key drivers

Demand driven augmentation expenditure (demand driven augex) is the capital needed to expand network capacity due to constraints in the network caused by increasing maximum demand in areas that are served by assets that are already highly utilised.

We are forecasting augex of $320.2m (direct, real 2023-24) over the 2026-31 regulatory period, which is 646% greater than the demand driven augex we expect to incur in the current regulatory period. Our forecast for the 2026-31 regulatory period includes $89.6m for two new zone substations in Wollert and Pakenham South and $119.5 million for distribution substations and SWER upgrades (in the LV network). A summary of our demand driven augex projects is provided in the table below.

Table 6-10: Summary of demand driven augex projects and programs ($m, direct, real 2023-24)

Type	Name	Expenditure
New Zone Substation	New Wollert ZSS	40.4
New Zone Substation	New Pakenham South ZSS	49.2
Augment 66kV loop	Augment Eastern Cranbourne 66kV loop	33.8
Augment 66kV loop	Augment East Gippsland 66kV loop	26.5
New 22kV feeder	New 22kV distribution feeder (WGL31)	16.3
New 22kV feeder	New 22kV distribution feeder (SMR11)	12.2
New 22kV feeder	New 22kV distribution feeder (WOTS21)	6.3
New transformer	New transformer at WGI	10.8
Demand driven augex in the LV network		119.5
Summer/winter network readiness program		5.2
Total		320.2

Source: AusNet.

6.6.2.1. We are getting the most out of the existing network before considering network upgrades

In developing our demand driven augex forecast, we are conscious of the need to ensure we are getting the most out of the existing network, manage demand growth and minimise the need for network upgrades, particularly given our customers' affordability concerns.

We currently have the joint-second highest utilisation rate in the NEM, with other Victorian distributors also having high utilisation rates compared to other jurisdictions. This reflects several factors unique to AusNet and our Victorian peers, including:

- Long-standing use of probabilistic planning practices, in contrast to deterministic planning relied upon in some other jurisdictions.
- The use of smart meters enabling Victorian networks to plan more precisely, by having access to more granular and accurate customer load data.
- Tariff innovation, with AusNet being the first network in the NEM to introduce Critical Peak Demand pricing for our C&I customers – a program that successfully runs today.

We will continue to increase the utilisation of our assets, increasing from around 60% in 2023 to more than 75% in 2031. However, even with probabilistic planning, as utilisation grows, network augmentation is required to address growing demand and maintain reliability across our network.

The effects of cost reflective tariffs have been considered when developing our demand and expenditure forecasts. Our tariff proposal reflects Victorian Government policy while providing greater optionality for customers. This is discussed further in our Tariff Structure Statement.

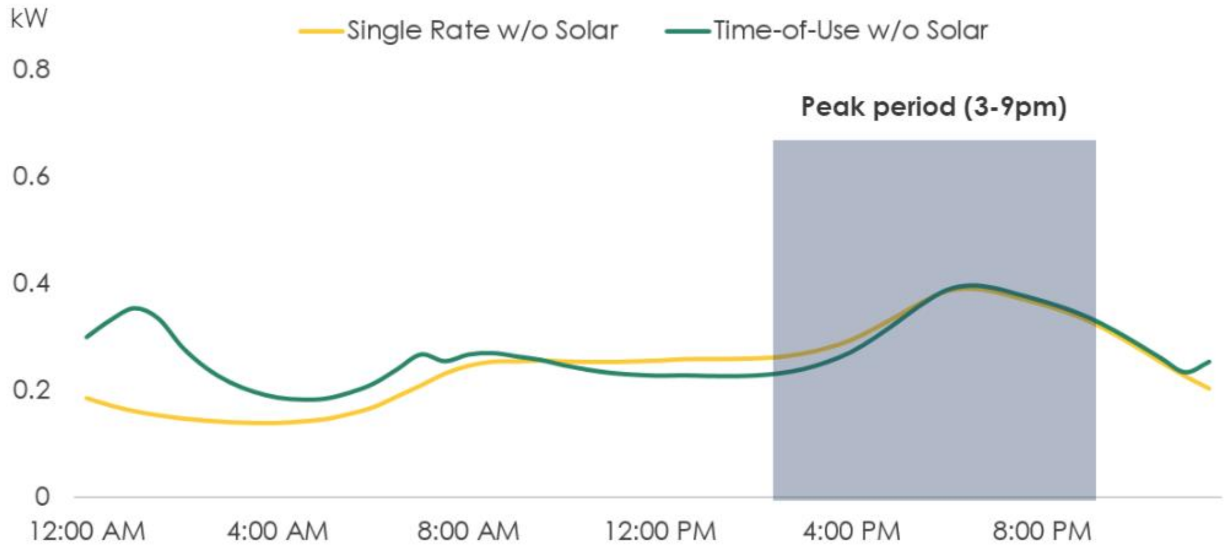
As moving to cost-reflective tariffs in Victoria is optional, we do not have certainty of tariff take-up, making it more difficult to estimate our customers' demand response. Our demand forecasts incorporate the impact of cost reflective tariffs in the following ways:

- Any historical response to tariffs is embedded as demand forecasts use history as a starting point. For residential customers this response is not material, as outlined below. For large industrial customers who participate in our Critical Peak Demand program, this response is larger, and
- For electric vehicles, our demand forecasts are based on AEMO's EV usage profiles, which determine the percentage of customers who charge during the day, at night and at peak, based on tariff response and managed charging. EV tariff response is therefore assumed in our expenditure forecasts.

In addition, evidence from smart meter data suggests that even where customers are assigned to a time of use network tariff, there is no observable difference in their peak demand compared to customers on flat tariffs. This suggests that even if an adjustment were to be made for assumed additional tariff response over the next regulatory period it would not be material.

While the 45-50% of our customer base on time-of-use tariffs is captured in the historical data that informs our demand forecasts, our research shows many of our residential customers are convenience motivated, limiting tariff engagement and response. In particular, our segmentation study shows that many of our residential customers, that contribute most to the evening peak[28], are on a single rate tariff and therefore may not change their behaviour in response to tariff reform. Our sentiments research also shows approximately 40% of customers are either unable to or unwilling to shift usage of appliances. This is reflected in the figure below which, using meter data, shows there is no difference in peak between single rate and TOU customers today.

Figure 6-7: Average daily usage per half hour intervals



We have proposed an opex step change to uplift customers communications to enable customers to build agency and provide trusted information to help customers make decisions about how they use electricity and how they invest in future appliances/CER. Providing clear information on tariffs will be part of this program, and we will monitor the effectiveness of these communications in encouraging customers to opt-in to time of use tariffs and make changes to their behaviour to respond to these signals.

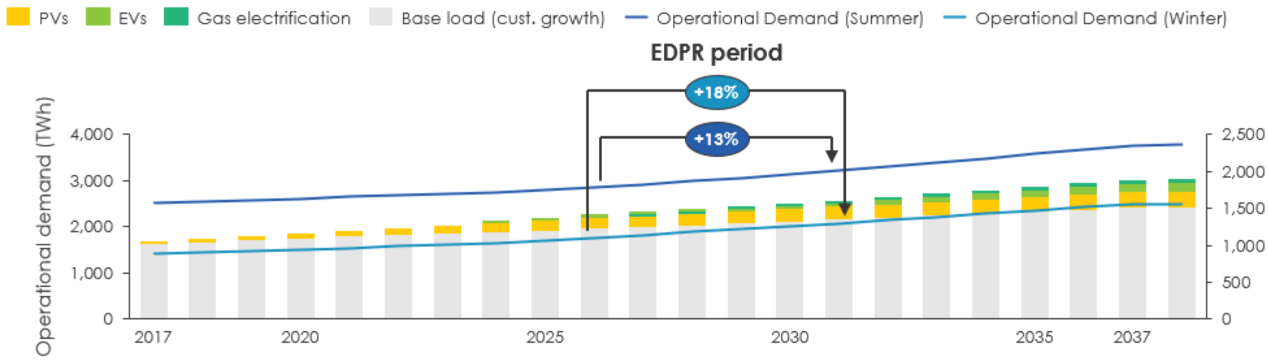
6.6.2.2. Increased network augmentation is needed to address strong demand growth and maintain reliable supply

Two of the key outputs from our forecasting tool is our forecast of customer numbers and maximum demand growth. Our customer base is expected to grow steadily by around 1.7% per annum during the 2026-31 regulatory control period; while maximum demand is forecast to grow at approximately 3% per annum (winter), reflecting the underlying increase in electrification and recognising that maximum demand is likely to occur when solar generation declines late in the day. Minimum demand will continue to fall as solar generation continues to increase.

The figure below shows our actual and forecast maximum demand in summer and winter; a 13% growth in summer and 18% growth in winter over the 2026-31 regulatory control period.

[28] Specifically, 77% of the Time Surfers segment are on a single rate tariff, relative to an average of 50%

Figure 6-816: Actual and forecast maximum demand in summer and winter, 2017 to 2037

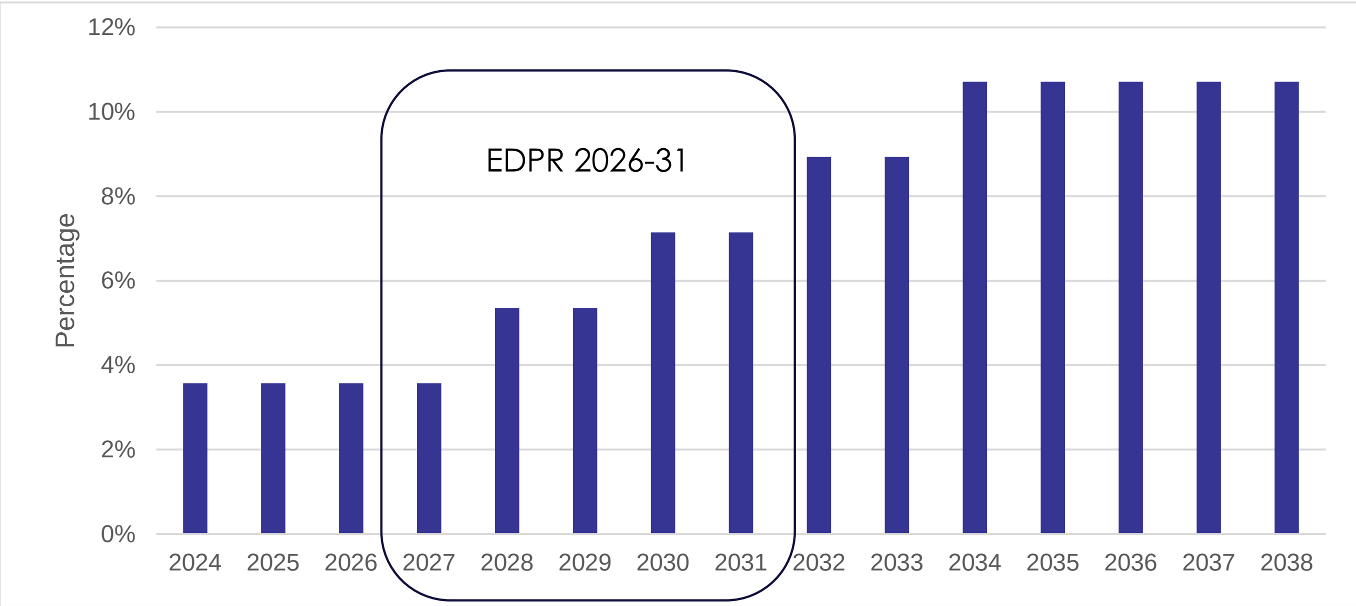


Source: AusNet

Strong growth in our customer base and maximum demand is increasing our baseline risk of expected unserved energy – or energy that would have otherwise been delivered – and therefore the need for network augmentation.

Figure 6-9 shows the proportion of zone substations where POE50 forecast demand is projected to exceed our N rating under a do-nothing approach; approximately 3.5% at the start of the 2026-31 regulatory period and increasing to approximately 7% at the end of the regulatory period. N rating is the capacity of the network element to supply power with all components in service.

Figure 6-9: Proportion of zone substations where forecast demand is projected to exceed our "N" rating



Source: AusNet

6.6.3. Methodology and key assumptions

Our probabilistic planning approach is a well-balanced approach – and a common industry practice – that involves estimating the probability of various network conditions coinciding (such as plant outages coinciding with peak import or export conditions) and weighting the events by their probability of occurrence. This allows a probability weighted supply risk (or expected unserved energy) to be calculated under a do nothing or BAU option, which is neither too high nor too low.

This method is particularly appropriate in brownfield areas where we have existing network assets that need to be reassessed when there is new information (e.g., new demand forecast, connection requests).

Figure 6-4 above provides a high-level overview of our economic assessment approach. This approach is consistent with the RIT-D. The table below outlines the key inputs and assumptions related to demand driven augex project assessments.

Table 6-11: Key inputs and assumptions (demand driven augex)

Input / Assumption	Description
Discount rate	See section 6.5.1
Value of Customer Reliability (VCR)	See section 6.4.4
Demand forecasts	See section 6.4.3
Customer engagement and research	Our demand driven augex proposal aligns with our customer engagement and research outcomes because we have tested various parts of our proposals with Panel Members (through deep dives and customer offsites) and stakeholders. The Coordination Group have provided their support for expenditure necessary to meet anticipated demand increases due to electrification of gas and transport and welcomes the inclusion of a demand management program to incentivise non-network solutions as part of it.[29] More specific details on our customer engagement and research outcomes have been described in the following sections.

Source: AusNet

6.6.3.1. Step 1: Establish the baseline risk

The baseline risk is defined as the risks that our network and customers would be exposed to under a business-as-usual or do-nothing approach. Establishing the baseline risk reveals the benefits of alternative options when implementing network or non-network solutions; our assessment framework considers these alternative options on an equal footing. The baseline risk for demand driven augex is made up of supply risk where it is defined as the risk of supply being lost to customers due to an asset failure or demand exceeding the rating of the assets. We calculate supply risk (also called the Value of Expected Unserved Energy or VoEUE) using a probabilistic planning approach whereby:

- We develop internal demand forecasts reflecting the 10% POE and 50% POE scenarios. POE stands for Probability of Exceedance, which means the 10% POE scenario is the demand forecast at which actual demand is only likely to exceed in 10% of the time.
- We then attach weights to the different POE scenarios in line with industry practice – we apply weights of 30% to the 10% POE forecast and 70% to the 50% POE forecast.
- The difference between the asset capacity and the weighted demand forecast is the expected unserved energy.
- Expected unserved energy is then multiplied by the VCR to obtain the dollar value of the expected unserved energy (this is the supply risk). We have combined our QCV for residential customers with the AER's 2023 VCRs for non-residential customers. As explained in section 6.4.4, there are minor differences in how we have implemented the approach.

6.6.3.2. Step 2: Formulate the options to address risk

Once the baseline risk is established, we analyse different options to identify the preferred option. The general options that we can typically consider for individual projects are shown below:

- **Business-as-usual or do-nothing**: used as a reference to quantify the relative benefits of options that address the baseline risk.
- **New feeder**: a new feeder can reduce the load on existing feeders and therefore reduce the expected unserved energy. New feeders can be used to remove load from one ZSS to another.
- **New transformer**: A new transformer can reduce the load on existing transformers and therefore reduce the expected unserved energy.
- **New zone substation**: A new zone substation can reduce the load on existing ZSS / feeders / sub transmission lines and therefore reduce the expected unserved energy.
- **Non-network alternatives**: For example, construct and operate a Battery Energy Storage System (**BESS**) which can reduce the expected unserved energy at a constrained site. Or contract a third-party supplier to provide network support or demand response during peak periods.

In some cases, we have analysed fewer options, because there are fewer credible options to assess. Some options are non-credible due to the size of the expected unserved energy, the configuration and practical constraints of the existing network, or future needs.

[29] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 30.

6.6.3.3. Step 3: Quantify and compare options against baseline risk

After identifying the options in step 2, we quantify their costs and benefits. Costs are determined by developing a technical scope of works, and/or applying a standard cost estimating process that utilises standard unit rates based on recent projects and contracted procurement costs. Benefits may include reduction in supply risk (reduction in the value of expected unserved energy) and/or avoided costs (e.g., reduction in maintenance costs).

To account for uncertainty in the key inputs, we undertake sensitivity analysis on the options.

6.6.3.4. Step 4: Select preferred option

Conduct a net present value (**NPV**) analysis to compare options on an equal basis, considering the time value of money. The preferred option is the option that delivers the highest NPV across a range of sensitivity scenarios i.e., offers the most benefit to customers even when accounting for uncertainty.

6.6.3.5. Step 5: Determine optimal timing

We determine the optimal timing to complete the preferred option project by identifying when the annual VoEUE risk reduction benefit is equal to (or greater than) the annualised cost of implementing the preferred option. This is the point at which the benefits of the preferred option outweigh the annualised cost of the project.

6.6.4. Projects and programs

6.6.4.1. New Wollert zone substation

Wollert is a suburb approximately 25km north of Melbourne CBD within the City of Whittlesea Local Government Area (LGA).

The identified need is to efficiently maintain a reliable supply of power to the customers in the Wollert area as forecast demand is expected to exceed the capacity of the existing Kalkallo zone substation that currently supplies the load to the Wollert area. The supply risk is materially high because the existing Kalkallo zone substation is forecast to be overloaded by 2027 under N rating even when load transfers between nearby zone substations have been accounted for.

The following options were assessed to identify the preferred solution:

- **Do-nothing**: This option considers a business-as-usual approach with customers in the Wollert supply area continuing to be supplied using the existing network infrastructure. There is no capital investment and operational and maintenance investments continues as before.
- **Option 1 new Wollert zone substation**: This option involves augmenting the network by installing a new 2x33MVA 66/22kV zone substation located close to our existing dual circuit 66 kV lines on the eastern edge of the Wollert precinct.
- **Option 2 third transformer at the existing Kalkallo zone substation**: This option involves augmenting the capacity of the existing Kalkallo substation by adding a third 33MVA 66/22kV transformer and third 22kV bus section with four 22kV feeders
- **Option 3 Battery Energy Storage System (BESS) at the existing Kalkallo zone substation**: This option involves installing a battery storage facility 10 MW, 40 MWh to the 22kV bus at the existing Kalkallo zone substation.

A new zone substation at Wollert (option 1) was identified as the preferred solution because it maximised the NPV of the options assessed, including under different sensitivity scenarios.

6.6.4.2. New Pakenham South zone substation

Pakenham is a suburb approximately 53km south-east of Melbourne CBD within the shire of Cardinia LGA.

The identified need is to efficiently maintain a reliable supply of power to the customers in the Pakenham South area as forecast demand is expected to exceed the capacity of the existing Clyde North zone substation that currently supplies the load to the Pakenham South area.

The following options were assessed to identify the preferred solution:

- **Do-nothing**: This option considers a business-as-usual approach with customers in the Pakenham South supply area continuing to be supplied using the existing network infrastructure. There is no capital investment and operational and maintenance investments continues as before.
- **Option 1 build a second transformer at Lang Lang**: This option involves building a second transformer at Lang Lang zone substation to supplement and provide contingency to the existing single transformer.
- **Option 2 new Pakenham South zone substation**: This option involves augmenting the network by installing a new 2x33MVA 66/22kV zone substation in the Pakenham South area.

A new zone substation at Pakenham South (option 2) was identified as the preferred solution because it maximised the NPV of the options assessed, including under different sensitivity scenarios.

6.6.4.3. Augment Eastern Cranbourne 66kV loop

The existing Eastern Cranbourne 66kV network loop supplies electricity to over 102,516 customers. This loop is supplied by the Cranbourne terminal station (CBTS) and is comprised of seven zone substations, including, Lysterfield (LYD), Narre Warren (NRN), Pakenham (PHM), Officer (OFR), Berwick North (BWN), Lang Lang (LLG), and Clyde North (CLN).

AusNet has identified there is a supply risk over the summer period on the existing Eastern Cranbourne 66kV network loop driven by the establishment of a new South-East Growth Corridor in the network area.

The following options were assessed to identify the preferred solution:

- **Do-nothing**: This option would entail no mitigating action beyond existing business as usual measures to address the identified risk.
- **Option 1**: Install a new Cranbourne Terminal Station to Officer (CBTS-OFR) 66kV line. This option involves installing a new 66kV line from CBTS to OFR (approximately 12km) to provide additional capacity to the northern section of the Eastern Cranbourne network loop.
- **Option 2**: Install a new Cranbourne Terminal Station to Pakenham (CBTS-PHM) 66kV line. This option involves installing a new 66kV line from CBTS to PHM (approximately 25.5km) to provide additional capacity to the Pakenham area which is experiencing rapid growth.
- **Option 3**: Install a new Cranbourne Terminal Station to Pakenham South (CBTS-PSH) and new PSH-PHM 66kV lines. This option involves installing a new 66kV line from CBTS to PHS and a new 66kV line from PSH-PHM (approximately 26.5km).
- **Option 4**: Install a new Cranbourne Terminal Station to Lang Lang (CBTS-LLG) 66kV line. This option involves installing a new 66kV line between CBTS to LLG (approximately 43.5km) to provide additional capacity.
- **Option 5**: Install a new 25MW/100MWh battery at OFR zone substation. This option involves installing a new 25MW/100MWh battery at Officer zone station to support the Eastern Cranbourne network loop during peak loading.

A new Cranbourne Terminal Station to Officer (CBTS-OFR) 66kV line (option 1) was identified as the preferred solution because it maximised the NPV of the options assessed, including under different sensitivity scenarios. Specifically, it is the least cost option yet forecast to deliver the largest reduction in supply risk relative to the other options.

6.6.4.4. Augment East Gippsland 66kV loop

The East Gippsland 66kV network loop supplies electricity to over 71,200 customers. It originates from the Morwell Terminal Station (MWTS) and is comprised of six zone substations, including Traralgon (TGN), Sale (SLE), Maffra (MFA), Bairnsdale (BDL), Newmerella (NLA) and Cann River (CNR) and is geographically very isolated. It is the longest sub-transmission network (by distance of line coverage) in AusNet's 66kV network. This network loop is particularly prone to voltage issues due to long line lengths and has limited capacity transfer ability due to its geographical remoteness.

AusNet has identified there is supply risk over the summer period on the East Gippsland 66kV network loop driven by customer growth, gas electrification of homes, and electric vehicle (EV) uptake within the region.

The following options were assessed to identify the preferred solution:

- **Do nothing**: This option would entail no mitigating action beyond existing measures to address the identified risk.
- **Option 1 Reconductor the entire Traralgon - Maffra (TGN-MFA) 66 KV line:** This option involves reconductoring the full length of the TGN-MFA line.
- **Option 2 Construct new Traralgon - Sale (TGN-SLE) 66kV line**: This option involves constructing a new TGN-SLE 66kV line by predominately rebuilding the 22kV line section adjacent to or along the Princess Highway.
- **Option 3 Establish a TGN-SLE/MFA 66kV line**: This option involves constructing a new 66kV switching station at the existing TGN-MFA from the new switching station at Sale (SLE) and reconducting the line between TGN and the new tee point.
- **Option 4 Construct a 30MW/150MWh Battery Energy Storage System:** This option involves constructing a 30MW/150MWh battery at the existing Bairnsdale 66kV switching station to provide support to a major load centre on the East Gippsland 66kV network loop.

Reconductoring the entire TGN-MFA (option 1) was identified as the preferred solution because it maximised the NPV of the options assessed, including under different sensitivity scenarios.

6.6.4.5. New 22kV distribution feeder (WGL31)

Combined growth in demand from existing (brownfield) and newly developed (greenfield) sites in the Shire of Baw Baw (for initial stages of the West Gippsland development area) is expected to increase supply risk to the area. This is due to existing 22kV distribution feeders being constrained and incapable of supplying the forecast demand.

The following options were assessed to identify the preferred solution:

- **Do nothing**: This option considers a business-as-usual approach with customers continuing to be supplied using the existing network infrastructure. There is no capital investment and operational and maintenance investments continues as before.
- **Option 1 Construct a new 22kV feeder by utilising the existing WGL11 route:** This option involves constructing a new 22kV feeder from the WGL station, which is the nearest to the proposed major development areas. The new feeder will offload the existing WGL13 feeder and provide additional support to WGL12, WGL21, and WGL24, which are also close to being constrained. The route length of the overhead 22kV feeder from WGL station is approximately 10.6 km.
- **Option 2 Construct a new 22kV feeder by utilising the existing WGL24 route**: This option involves constructing a new 22kV feeder from the WGL station, which is the nearest to the proposed major development areas. The length of the overhead 22kV feeder from WGL station is approximately 5.5 km. The new feeder is expected to end where the existing WGL24 feeder will be disconnected. This option uses the existing WGL24 line, allowing WGL24 to expand further towards the east.
- **Option 3 Construct 5MW/10MWh Battery Energy Storage System**: This option involves establishing a 5MW/10MWh BESS by 2030 to defer any investment in the network solution. This option would involve AusNet owning, building and operating a grid-connected battery at the existing WGL zone substation site.
- **Option 4 Contract external network support services to defer network investment:** This option involves procuring network support for WGL13 to mitigate thermal risk constraints.

The construction of a new 22kV feeder by utilising the existing WGL24 route (option 2) was identified as the preferred solution because it maximised the NPV of the options assessed, including under different sensitivity scenarios.

6.6.4.6. New 22kV distribution feeder (SMR11)

Nagambie township is located in the Strathbogie Shire, approximately 135 kilometres north of Melbourne and 55 kilometres south of Shepparton along the Goulburn Freeway.

In addition to the anticipated residential growth (average annual growth rate of 2.9%), C-I-C

As a result, we need to increase the ability of the 22kV network to supply the forecast demand in Nagambie and manage the increasing risk of involuntary load shedding on SMR24 22kV feeder supplied by SMR station.

The following options were assessed to identify the preferred solution:

- **Do nothing**: This option considers a business-as-usual approach with customers continuing to be supplied using the existing network infrastructure. There is no capital investment and operational and maintenance investments continues as before.
- **Option 1 Manage SMR24 capacity with mobile generators:** This option involves managing SMR24 capacity during peak demand with the assistance of mobile generators, limited to 2MW output power.
- **Option 2 Construct a new 22kV feeder to offload SM24 called SMR11**: This option involves constructing a new 22kV distribution feeder. The new feeder will utilise existing infrastructure, such as shared easements and poles, with the existing feeders along the route. There will be minimal installation of new assets.
- **Option 3 Construct 2.5MW/5MWh Battery Energy Storage System:** This option involves establishing a 2.5MW/5MWh BESS.
- **Option 4 Contract external network support services to defer network investment:** This option involves procuring network support for WGL13 to mitigate thermal risk constraints.

The construction of a new 22kV feeder to offload SMR24 (option 2) was identified as the preferred solution because it maximised the NPV of the options assessed, including under different sensitivity scenarios.

6.6.4.7. New 22kV distribution feeder (WOTS21)

The city of Wodonga and surrounding areas, including Tallangatta, are predominately serviced by 330/66/22kV Wodonga Terminal Station (WOTS). The existing built-up area of Wodonga and the township of Baranduda will be extended further into the Leneva Valley as per the development plans and will be supplied mainly by the WOTS25 feeder. This area has been subjected to several subdivisions in the last few years, and it is continuing, resulting in increasing demands on the WOTS zone substation feeders, particularly on the WOTS25 feeder.

AusNet has identified a need to increase the ability of the 22kV network to supply the forecast demand in Wodonga Council and manage the increasing risk of involuntary load shedding on WOTS25 22kV feeder supplied by WOTS station. In addition to the risk of unserved energy to existing customers, the lack of capacity of the 22kV network will prevent connecting new customers to AusNet's network in the area supplied by WOTS station.

The following options were assessed to identify the preferred solution:

- **Do nothing**: This option considers a business-as-usual approach with customers continuing to be supplied using the existing network infrastructure. There is no capital investment and operational and maintenance investments continues as before.
- **Option 1 Upgrade WOTS25 22kV feeder to a higher rating:** This option involves upgrading the existing WOTS25 22kV feeder exit cable to a higher rating, providing a 365A design rating.
- **Option 2 Construct a new 22kV feeder**: This option proposes to split the WOTS25 feeder into two feeders WOTS21 (new) and WOTS25 (existing)
- **Option 3 Construct 5MW/10MWh Battery Energy Storage System**: This option involves establishing a 2.5MW/5MWh BESS to defer any investment in the network solution. Under this option AusNet would own, build and operate a grid-connected battery at the suitable site.
- **Option 4 Contract external network support services to defer network investment:** This option involves procuring network support.

The construction of a new 22kV feeder by splitting the existing WOTS25 into two feeders (option 2) was identified as the preferred solution because it maximised the NPV of the options assessed, including under different sensitivity scenarios. This option provides the greatest benefit by providing the most significant reduction in unserved energy, allowing the 22kV feeders to be offloaded and the greatest number of customers to connect. As a result, Option 2 will provide more long-term benefits than all other options considered.

6.6.4.8. New transformer at Wonthaggi (WGI)

Combined growth in demand from existing (brownfield) and newly developed (greenfield) sites in Wonthaggi and South Gippsland (for initial stages of the Wonthaggi development area) is expected to increase supply risk to the area.

AusNet has identified a need to increase the ability of the WGI station to supply the forecast demand in Wonthaggi and South Gippsland and manage the increasing risk of involuntary load shedding of the customers supplied by the WGI station. In addition to the risk of unserved energy to existing customers, the lack of capacity of the WGI station will prevent connecting new customers to AusNet's network in the area supplied by WGI station. An investment in additional electrical capacity in this area is required to reduce these risks.

The following options were assessed to identify the preferred solution:

- **Do nothing**: This option considers a business-as-usual approach with customers continuing to be supplied using the existing network infrastructure. There is no capital investment and operational and maintenance investments continues as before.
- **Option 1 Replace 3 x 10/13.5 MVA Tx with 3 x 20/33 MVA Tx:** This option involves replacing existing transformer units with new, larger units - 3 x 20/33 MVA, which will provide a total capacity of 85 MVA and firm substation capacity of 57 MVA by 2033.
- **Option 1A Replace 1 x 10/13.5 MVA Tx with 1 x 20/33 MVA Tx**: This option involves replacing the existing transformer unit Tx3 with new, larger units - 1 x 20/33 MVA, which will provide a total capacity of 63 MVA and firm substation capacity of 57 MVA by 2029.
- **Option 2 Construct 2x 20/33MVA zone substation in Inverloch**: This option involves establishing a new zone substation in Inverloch with 2x 20/33 MVA transformers, which will provide additional capacity in the supply area and more transfer capability.
- **Option 3 Contract external network support services to defer network investment:** This option involves procuring network support.

The preferred option is Option 1A (Replace 1 x 10/13.5 MVA Tx with 1 x 20/33 MVA Tx) because it maximises the NPV of the options assessed, including under different sensitivity scenarios. This option provides the greatest benefit by providing the most significant reduction in unserved energy, allowing more capacity at the station level and the greatest number of customers to connect. As a result, Option 1A will provide more long-term benefits than all other options considered.

6.6.4.9. Demand driven augmentation in the LV network

The purpose of our LV augex investment is to facilitate maximum demand growth across AusNet's existing low voltage (**LV**) and single wire earth return (**SWER**) distribution network, driven by electrification of transport and gas (largely in homes and small businesses).

Our LV augex investment plan is a program of work needed to economically reduce expected unserved energy (**EUE**) for customers in the existing LV and SWER networks. Our capex requirement of $119.5m (direct, real 2023-24) is net of the deferred capex ($29m) due to our flexible services opex step change (see chapter 7.9.5.) which is a type of non-network solution.

Without a planned program of work, growth in demand in existing networks would result in network asset import limitations for some parts of the network, which may cause adverse impacts for customers. This includes the need to load shed customers such that AusNet's assets are not exposed to thermal overload beyond their technical rating, and customers are not exposed to steady-state over and under-voltages beyond the EDCOP limits. Load shedding is a form of outage for customers negatively impacting the reliability of their electricity supply, which is both disruptive to the economy and the wellbeing of our customers, particularly as these reliability risks are the highest during times of extreme ambient temperatures.

AusNet's LV and SWER networks were largely designed decades years ago, with many areas of the network not designed or built to absorb additional new demand from the electrification of gas and transport. Hence, a proportion of our distribution substations and SWER lines are expected to be at risk of overload over 2026-31, particularly during 5pm to 9pm on days of extreme high or low ambient temperature. The network assets most at risk are those that are already highly utilised (or overloaded) at times of maximum demand, which were originally designed for lower demand patterns. This represents 5.5% of our distribution substation population and 43% of our SWER population. The limitations on these already highly utilised assets are expected to worsen over the next regulatory control period and new sites will emerge without further investment, with the expected levels of electrification, adversely impacting the reliability and quality of supply for our customers affected.

The preferred planned program of work is a proactive program which is specifically targeted at addressing network limitations that impact customer's reliability, needed in response to the growing maximum demand expected from the electrification of gas and transport. Three options are considered in addition to the do-nothing case which are targeted at mitigating expected unserved energy in the LV distribution substation and SWER networks, these being:

- **Do nothing**: No expenditure on addressing network limitations that impact customer reliability.
- **Option 1**: Economic probabilistic planning approach to minimise the reliability impact of network import limitations on customers, by selecting network augmentation projects that have a positive net present value (**NPV**).
- **Option 2**: Economic probabilistic planning approach to minimise the reliability impact of network import limitations on customers, by selecting an efficient mix of network augmentation and non-network flexible services that have a positive NPV.
- **Option 3**: Deterministic planning approach to remove all expected unserved energy risk from the network using network augmentation projects.

AusNet proposes Option 2 at a total cost of $119.5m (direct, real 2023-24) over the 2026-31 regulatory period, which represents a prudent and efficient investment to address the impacts of electrification.

Table 6-12: Other discussion points

	Description
Combined QCV/AER's 2023 VCRs approach vs. AER's 2023 VCRs	We have used the combined QCV/AER's 2023 VCRs approach in converting expected unserved energy into a monetised value which resulted in $119.5m of prudent and efficient investment. However, we also tested the capex requirement using the AER's standard 2023 VCRs; the impact was a $15m reduction compared to the combined QCV/AER's VCRs approach. This was a part of our sensitivity testing used as a part of stakeholder engagement.
Customer engagement	We presented both options – lower capex requirement using the AER's standard 2023 VCRs and higher capex requirement using the combined QCV/AER's VCRs approach – and our Panel Members supported the higher capex requirement given our consistent use of AusNet's combined VCR in our expenditure planning.[30]
Capex deferral	Our LV augex forecast excludes $29m of capex that will be deferred by our flexible services proposal, reflecting an efficient capex/opex trade-off (discussed further in the opex chapter).
Top-down adjustment for AEMO's August 2024 ESOO forecasts	To account for AEMO's latest 2004 ESOO, we have applied a top-down adjustment (removed $1.5m) to our LV augex program as the scope of works within the LV augex program changes depending on feeder level demand forecast.

[30] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, section 10.1.1 and p. 30.

6.6.4.10. Summer/winter network readiness program

The aim of this program is to prepare our distribution network for the expected peak demand during the summer period from November to March and winter period from May to August. This is a pro-active program undertaken each year before the start of the summer and winter seasons.

Overloads are predominantly addressed by a planned program of capex. However, some new loads (e.g., imposed by major customers, movement of holiday makers in regional resorts, abnormal weather patterns and delays in delivering approved projects) can cause distribution network elements to be overloaded during peak periods unless remedial actions are taken. This program addresses these risks and strengthens constrained elements within the network.

At the end of each peak period, we analyse data from the previous peak periods including the most recently lapsed peak, to understand the potential for upcoming constraints. The types of risks that we typically identify include overloaded distribution transformers and overloaded LV circuits. The identified sites at risk and their solutions are then subject to detailed validation, scoping and cost estimation, before they are actioned and implemented prior to the start of the next peak periods.

We are forecasting a capital expenditure requirement of $5.2m for minor network upgrades to address localised load growth that other planned works cannot address. While the exact scope of works is only validated and actioned a few months prior to the start of each peak period, we have developed our $5.2m forecast based on addressing:

- Approximately 11-12 overloaded small pole type substations
- Approximately 11-12 overloaded larger pole type substations
- Approximately 35 overloaded LV circuits, and
- 7-8 overloaded feeders.

Our capital expenditure forecast ($5.2m) for 2026-31 is similar to our forecast of current period spend.

6.6.4.11. Feeder augmentations driven by customer growth

We have a pipeline of 22kV feeder projects scheduled to commence during the current regulatory period, with many carrying over into the 2026–31 regulatory period. These projects address critical requirements for our network and are aligned with our commitment to meeting customer and community needs.

Some of these projects involve the extension of existing feeders to accommodate new customer connections, ensuring that the network can meet growing demand. Others are interim solutions designed to alleviate local network constraints while we work on commissioning new zone substations (Wollert and Pakenham South). These new zone substations are crucial for improving long-term network reliability and capacity (see chapters 6.6.4.1and 6.6.4.2).

These projects have not been quantified based on the economic value of expected unserved energy because they are not tied to addressing load-at-risk scenarios. Instead, they are underpinned by the need to connect new customers in areas where either network capacity is insufficient or no network exists, such as in greenfield residential developments or industrial clusters.

For this program, our total capital expenditure forecast for the 2026–31 regulatory period is $25 million, reflecting the investment required to deliver these essential projects, support network growth, and ensure reliability for both existing and new customers.

6.6.5. Benchmarking and validation

Our probabilistic planning approach involves estimating the probability of various network conditions coinciding, such as plant outages coinciding with peak import or export conditions, and weighting the events by their probability of occurrence to assess:

- The expected unserved energy if no risk mitigation action is undertaken (continue with do nothing or BAU), and
- Whether it is economic to invest in risk mitigation action to reduce the forecast supply risk.

Investment needs are also further considered in the context of any existing adjacent network equipment and its associated replacement programs.

Our expected unserved energy forecasts have been based on:

- Our demand forecasting approach which is robust and conservative, and
- The technical rating and capacity of the network assets which have been directly sourced from our system.

Our unit rates reflect the market conditions of our industry.

6.6.6. Supporting documentation

We have included the following documents to support this chapter:

- ASD - AusNet - Distribution Annual Planning Report – 31012025
- ASD - AusNet - Network strategy – 31012025
- ASD - AusNet - Demand side engagement strategy - 31012025
- ASD - AusNet - New Wollert ZSS BC – 31012025
- ASD - AusNet - New Wollert ZSS economic model – 31012025
- ASD - AusNet - New ZSS Pakenham South BC – 31012025
- ASD - AusNet - New ZSS Pakenham South economic model – 31012025
- ASD - AusNet - Eastern Cranbourne 66kV loop augmentation BC - 31012025
- ASD - AusNet - Eastern Cranbourne 66kV loop augmentation economic model - 31012025
- ASD - AusNet - East Gippsland 66kV loop augmentation BC – 31012025
- ASD - AusNet - East Gippsland 66kV loop augmentation economic model – 31012025
- ASD - AusNet - New 22kV distribution feeder (WGL31) BC – 31012025
- ASD - AusNet - New 22kV distribution feeder (WGL31) economic model – 31012025
- ASD - AusNet - New 22kV distribution feeder (SMR11) BC – 31012025
- ASD - AusNet - New 22kV distribution feeder (SMR11) economic model – 31012025
- ASD - AusNet - New 22kV distribution feeder (WOTS21) BC – 31012025
- ASD - AusNet - New 22kV distribution feeder (WOTS21) economic model – 31012025
- ASD - AusNet - WGI new Tx BC – 31012025
- ASD - AusNet - WGI new Tx economic model – 31012025
- ASD - AusNet - Demand driven augex (LV augmentation) BC – 31012025
- ASD - AusNet - Demand driven augex (LV augmentation) economic model – 31012025
- ASD - AusNet - Summer and winter network readiness BC – 31012025
- ASD - AusNet - Summer and winter network readiness economic model - 31012025

6.7. Replacement expenditure

6.7.1. Key points

- Our replacement capex (repex) proposal focuses on expenditure that is driven by our ageing asset base and deteriorating asset condition and, therefore, is necessary to address the risk of asset failure and maintain network performance.
- Our asset management expenditure approach and investment needs are guided by our robust Asset Management strategy and framework, aligned to the international standard for asset management (ISO 55001). AusNet was one of the first distributors in Australia to obtain asset management certification and, while not currently officially certified, is committed to re-obtaining ISO certification by October 2025.
- AusNet's asset and risk management philosophies aim to prudently manage network risk are underpinned by condition- and risk-based modelling, which we have used to develop our replacement expenditure forecasts.
- Our repex investment needs are forecast to increase by 29% in the next regulatory period, due to an ageing asset base and resulting deteriorating asset condition and market-driven cost pressures, which are driving higher replacement volumes and/ or unit rates across most asset classes.
- Increased expenditure in 2026-31 is necessary to maintain network risk and avoid a deterioration in reliability, consistent with our customers' preference for stable or improved levels of reliability. As our customers electrify their homes, businesses and transport, maintaining the reliability of the existing network through prudent and efficient asset replacement is becoming increasingly important.
- Consistent with our recent decision to appoint Zinfra as our operation and maintenance service provider, effective from August 2025 and replacing Downer, we have applied Zinfra unit rates to forecast expenditure for our inspection-based programs, which account for over half of our total repex. This decision will benefit customers through lower costs in 2026-31.
- Following engagement with our customers, we have applied residential VCRs from our QCV study to forecast our repex requirements, increasing forecast investment by approximately $50m compared to a forecast based on AER 2023 VCRs.
- We will consider the impacts of the AER's 2024 VCRs for our Revised Proposal, which we note are broadly in line with our QCV findings.
- Excluding asset replacements without an age or condition driver (e.g., resilience- and safety-driven replacement programs), our proposed forecast compares favourably with the AER's repex model.

6.7.2. Overview of forecast and key drivers

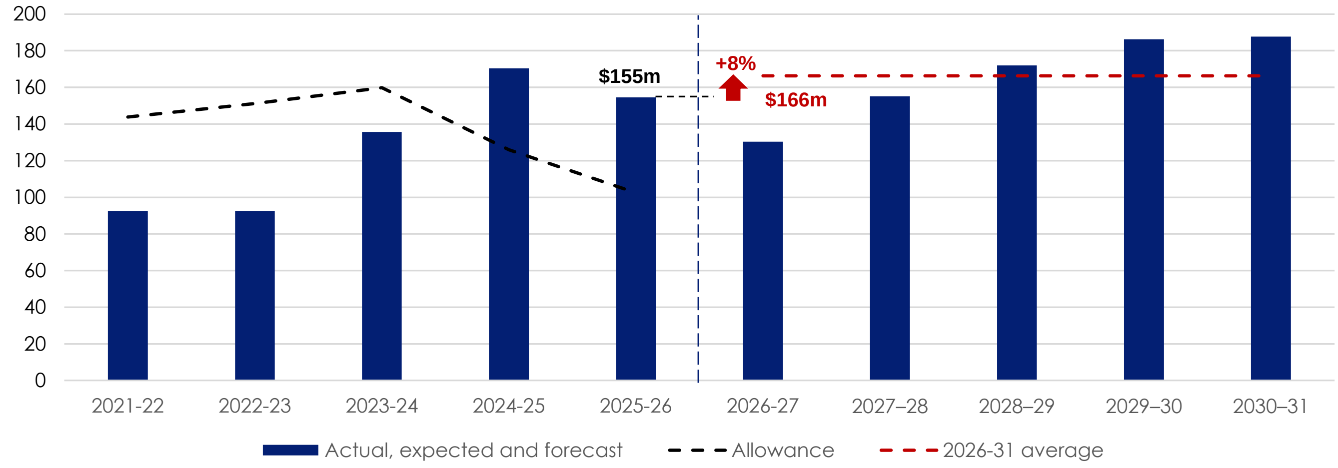
Our forecast repex for the 2026-31 regulatory period is $831.2m, which is 29% higher than our expected repex of $645.8m in the current regulatory period. As shown in the figure below, forecast annual average repex of $166m is 8% above planned spend in 2025-26 of $155m.

Forecast total repex comprises distribution asset replacements driven by age and/or condition and, therefore, excludes the following replacement expenditure categories that have different drivers (but have been included in the total repex expenditure reported in Reset RIN template XXX):

- Safety programs involving asset replacement (discussed in section 6.14)
- Resilience programs involving asset replacement (discussed in section 6.12)
- The operational technology component of our proposed ADMS investment (discussed in section 6.13)
- The component of our proposed metering communications systems replacement expenditure allocated to distribution (discussed in chapter 16)

Figure 6-10 shows our forecast for the 2026-31 regulatory period compared to our expected capex for the current 2021-26 regulatory period.

Figure 6-10: Actual, expected and forecast repex ($m, real 2023-24)



Source: AusNet

The key drivers of AusNet's repex forecast in the 2026-31 regulatory period are:

- **Deterioration in asset condition associated with increasing asset age which**, if not addressed through risk- and inspection-based asset replacement, would give rise to increased network risk and unacceptable reliability and safety outcomes for our customers. This is driving the need for higher replacement volumes for some asset classes, such as poles and switchgear, in order to maintain service levels. Ageing assets are also difficult and costly to maintain due to reduced availability of spares, lack of manufacturer support and technical obsolescence.
- **Increasing unit rates and project cost estimates reflecting external, market-driven cost pressures** associated with strong global demand for the labour, materials and other inputs needed to deliver the energy transition. Our proposed unit rate rates reflect the actual costs of recently delivered, comparable projects, and market-tested contracts with our service delivery partners. The recent decision to change service delivery partner from 1 August 2025 was informed by market testing and has moderated the forecast impact of labour and unit rate cost rises. However, these have still increased significantly compared to historical costs, consistent with the prevailing inflationary pressures in AusNet's cost base and across the sector.
- **Our repex projects and programs have been developed using an economically justified, risk-based asset management approach** and are intended to broadly maintain current levels of network risk, as measured by our QVC VCR data. This excludes the safety programs discussed in the safety section of this chapter, which are developed and assessed consistent with 'as far as practical' principles and approaches.

We consulted on our risk-based asset replacement forecasting approach with the Coordination Group, and tested a range of 'costed options' with them in a deep dive session, including lower-cost options (resulting in lower-quality services for lower prices), and a higher-cost options (improving services while increasing prices). The Coordination Group noted the technical nature of this expenditure category and expressed views on the assumption that AusNet's risk-based assessment satisfies the AER's requirements.

6.7.2.1. We apply a robust, risk-based asset management framework to forecast our repex needs

AusNet maintains a risk management system designed in accordance with AS ISO 31000 Risk Management – Guidelines to ensure risks are effectively managed to provide greater certainty for the owners, employees, customers, suppliers, and the communities in which we operate. Our repex forecast is aimed at broadly maintaining network risk through prudent and efficient asset replacements.

From a safety perspective, AusNet's Asset Management Policy and risk management philosophy is to minimise safety risks as far as practicable consistent with the provisions of Section 98 of the *Electricity Safety Act 1998* which requires it to "design, construct, operate, maintain and decommission its supply network to minimise as far as practicable:

- The hazards and risks to the safety of any person arising from the supply network.
- The hazards and risks of damage to the property of any person arising from the supply network.
- The bushfire danger arising from the supply network.

Our Asset Management Policy (see Figure 6-11) underpins our asset management strategies and plans, which are also informed by a regular assessment of the external business environment through five-yearly business and financial plans. In turn, these plans influence the asset management policy and the development of longer-term asset management strategies.

Figure 6-11: AusNet Asset Management Policy

Source: AusNet

Plans contain strategic and tactical objectives, performance targets and an overview of major works programs. Following on from plans, a plant or asset strategy is created for major asset classes (e.g. transformers, poles, conductors). The framework is completed with monitoring and evaluation of performance to identify improvement opportunities throughout the entire asset management framework.

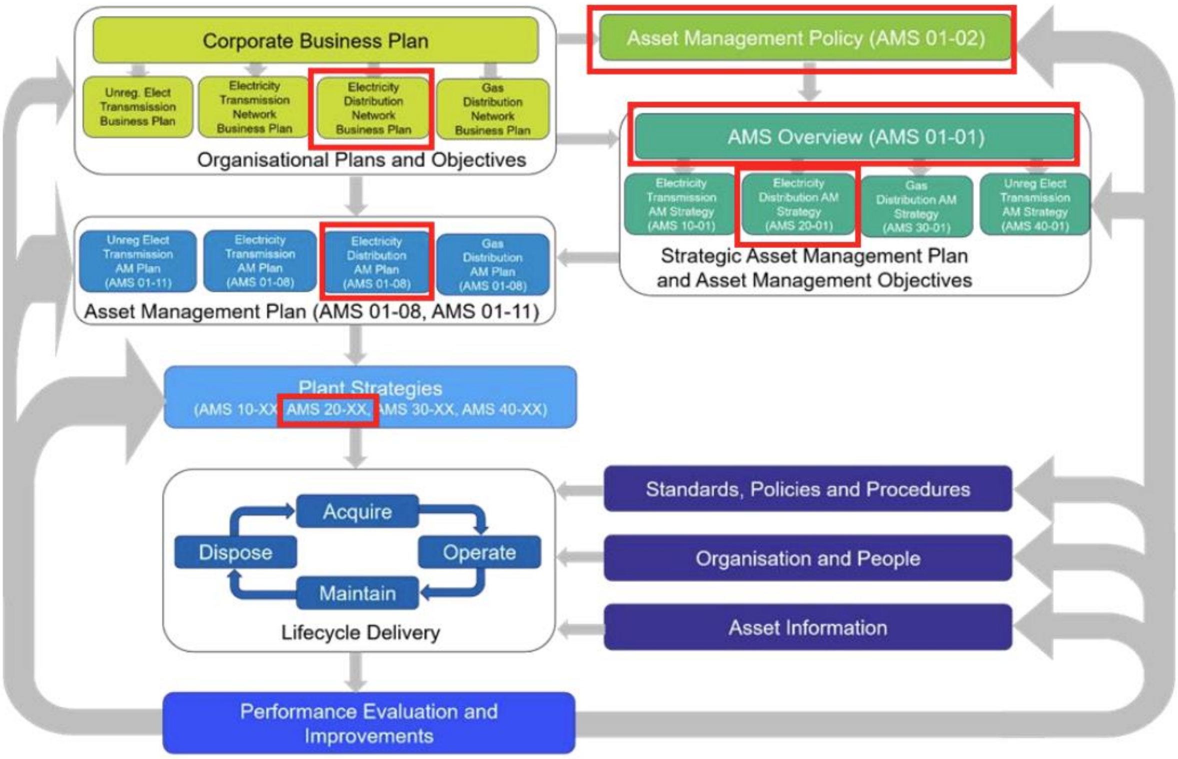
AusNet's asset management framework is shown in Figure 6-12, noting it applies to AusNet's three regulated networks (electricity distribution, electricity transmission and gas distribution). AusNet's Asset Management System is substantially aligned to the requirements for ISO 55001, and AusNet is committed to achieving full ISO55001 accreditation and certification by October 2025.

Two key aspects of our Asset Management framework as it relates to forecasting repex are our Asset Management Strategy (AMS 20-01), which sets out our asset management objectives, and our risk Assessment Methodology (AMS 01-09) sets out our risk management framework and details the approach we take to assessing and quantifying network risk, which is critical to determining the economic timing of our forecast asset replacements.

As discussed above in this chapter, to assess supply risk for our proposed repex projects and programs, we have applied residential VCRs based on AusNet's QCV project in conjunction with AER VCRs for non-residential customers.

In light of our ageing network and our objective of maintaining network risk, the application of the asset management approach detailed in this section requires an increase in replacement volumes for some asset classes in 2026-31, compared to the current regulatory period. Our proposed replacement volumes for key asset classes are discussed in section 6.7.4.

Figure 6-12: AusNet's asset management framework (red boxes highlight electricity distribution elements)



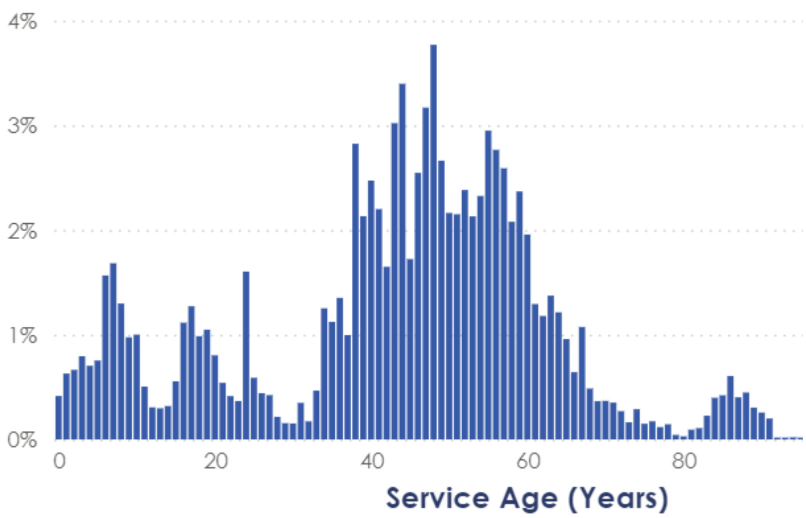
Source: AusNet

6.7.2.2. Our ageing asset base is increasing network risk and requiring higher replacement volumes

Our asset replacement decisions are heavily informed by asset condition, rather than age. However, in some cases, asset age and condition are closely correlated. Accordingly, increasing asset age can indicate increasing network risk and, therefore, the need for increased replacement rates to maintain service levels.

The figures below show the age profiles of our wood pole and bare conductor assets, which account for approximately one-quarter of our replacement forecast. Large shares of wood poles were installed over 50 years ago and, therefore, increased replacement levels will be required in the future – including during the 2026-31 regulatory period - to maintain asset performance and network risk. In particular, 64% of wood poles have now passed the 41-year mark (average end of life), with 38% that are already 10 years past their end of their technical lives – this represents 68,000 poles, compared with our proposal to replace 13,000 over the 2026-31 period. We are forecasting an increase of 10% in total pole replacement volumes; wood poles account for over 90% of the total forecast pole replacements.

Figure 6-13: Age profiles for wood poles

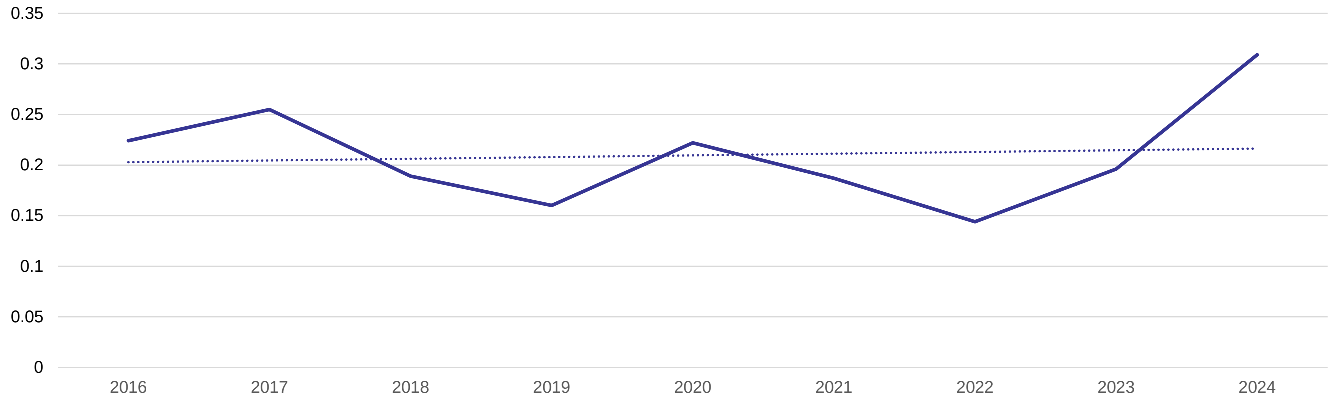


Source: AusNet

The effects of an ageing asset base on service levels are demonstrated by the chart below, which shows unplanned SAIFI due to asset failure over the last seven years. Although there is variation in performance between years, the trend indicates a gradual decline in performance on this metric as asset failure is becoming more common. It is important to note that our asset management approach does not include running assets to failure.

Nonetheless, increased asset replacement volumes in 2026-31 are necessary to address rising network risk, arrest declines in asset performance and deliver the level of reliability our customers have told us is a high priority. As our customers electrify their homes, businesses and transport, maintaining the reliability of the existing network through prudent asset replacement is becoming increasingly important. The AER's December 2024 Value of Customer Reliability publication highlighted that reliability has become more important for residential customers over the last five years for a range of reasons[31].

Figure 6-14: Unplanned SAIFI due to asset failure

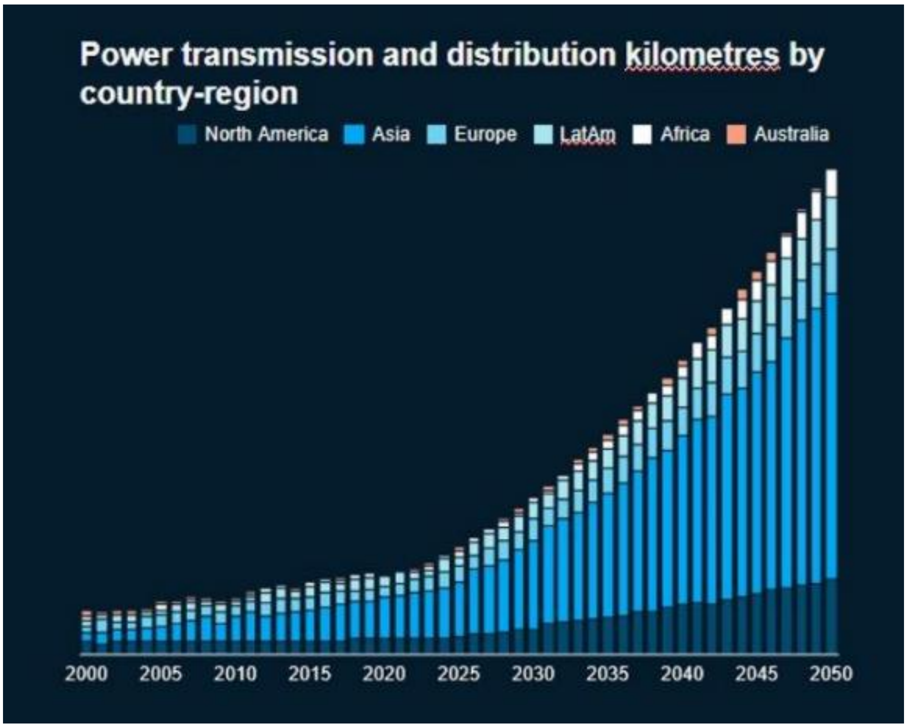


Source: AusNet

6.7.2.3. Market-driven cost pressures are increasing our repex requirements

Our increased repex needs are in part due to higher unit rates and project cost estimates, reflecting external, market-driven cost pressures. As shown in the figure below, the labour and materials used in Australia's energy transition are a small part of the global build, giving us limited influence over prices for many key inputs. Strong global demand for these inputs is placing pressure on the labour and material costs we currently face; this pressure is expected to continue to build in the next regulatory period.

Figure 6-15: Australia accounts for a minor share of global power network kilometres



In addition, public infrastructure projects such as the Suburban Rail Loop means competition for the skilled tradespeople we need to build and maintain our network. While we have identified and are implementing several

[31] AER, Values of customer reliability - final report, December 2024

initiatives to ensure we have sufficient resources in place to deliver our proposed capital program (as discussed in our Strategic Deliverability Plan), the competition for these resources continues to place upwards pressure on labour costs, which account for a significant share of our unit rates (typically around half) and project costs.

The figure below, which shows actual and forecast unit rates for various pole types, which account for one-quarter of our replacement forecast, demonstrates that rising labour and materials costs have led to material, real increases in these rates over the three-year period shown, with a weighted average increase of 9%. While additional pole replacement capex is driven by volumes, rather than unit rates, this analysis demonstrates the magnitude of the cost increases we are experiencing, which are contributing more broadly to higher repex in 2026-31.

Figure 6-16: Actual pole replacement unit rates, 2021-22 to 2023-24

C-I-C

Source: AusNet.

Our proposed unit rates are also shown in the figure above, demonstrating that our decision to partner with Zinfra for O&M services – including inspection-based asset replacement programs – has moderated increases in our repex needs. The financial benefits of this decision will flow immediately through to customers in the next regulatory period in the form of lower repex costs. Had we maintained our existing service delivery arrangements, our 2026-31 repex forecast is expected to have been around $20-60m higher.

This decision was informed by robust market testing,[32] demonstrating the prudency and efficiency of our proposed unit rates for inspection-based programs (principally pole and crossarm replacement, which account for over one-quarter of repex).

6.7.3. Forecasting methodology and key assumptions

6.7.3.1. Risk-based approach

We have applied a condition- and risk-based approach to forecast approximately one-third of our repex program requirements for the 2026-31 regulatory period. This approach reflects industry best practice and is based on a product of the Probability of Failure (PoF) and Cost of Consequence (CoC). Our Consequence of Failure (CoF) approach considers both the likelihood of Consequence (LoC) and Cost of Consequence (CoC), increasing its robustness. PoF is determined by either machine learning models or Weibull statistical methods. CoF considered both what could happen" as the Cost of Consequence (CoC) and the likelihood of the consequence (LoC).

The risk of each asset is calculated as the multiplication of probability of failure (PoF) of the asset and the consequence of failure (CoF). The risk is then extrapolated into the future accounting for forecast changes in PoF and CoF, as summarised in the figure below. This approach is discussed in detail in further detail in AMS 01-09 – Risk Assessment Methodology and in the sections below.

Economic models applying this approach to derive replacement volumes for individual asset classes have been provided as supporting documents.

[32] See ASD - Coordination Group Engagement material on Service Provider Change – 31 Jan 2025

Figure 6-17: Approach to quantifying asset failure risk

6.7.3.2. Inspection-based approach

The remainder of our asset replacement programs (inspection-based programs accounting for around two-thirds of our repex program spend) are initiated through routine inspection programs. This reactive, inspection-based replacement strategy is used to manage the majority of high-volume, low-value assets that includes (but not limited to) asset classes such as poles, cross-arms, fuses, insulators and surge arresters. Repair or refurbishment is rarely economically justifiable with the exception of poles, where pole reinforcement or staking may be used to extend the life of a pole. The business rules governing refurbishment or replacement to generate a continuous, prioritised refurbishment and replacement program are documented in *4111-1 Asset Inspection Manual* and are used in the electronic asset management system (SAP). The manual also documents the inspection schedules and deterministic serviceability criteria for assets located in public places, or on easements in private property.

6.7.3.3. Post-model adjustments

In some cases, our proposed replacement volumes differ from those determined in the economic models due to post-model adjustments we have applied to derive our forecast. Typically, these adjustments have resulted in our proposed replacement volumes being lower than the modelled volumes due to the removal of assets replacements that:

- Are being delivered in the current regulatory period.
- Form part of the scope of other replacement programs or ZSS rebuilds.
- May be deferred to subsequent regulatory periods without having unacceptable impacts on network risk.

A buildup of our proposed volumes and unit rates for each repex asset class (as well as the unit rate-based safety programs discussed in section 6.15) is provided as a supporting document.[33]

6.7.4. Projects and programs

The table below provides a breakdown of our replacement forecast for the 2026-31 regulatory period. The six shaded programs, which account for over 80% of the total repex forecast, are discussed in detail in the sections below.

Further information on the individual asset classes that comprise all of the programs shown below is available in the asset strategies and economic models that have been provided as supporting documents.

As mentioned, the expenditure shown in the table below comprises asset replacement driven by age or condition and, therefore, excludes the following expenditures:

- Safety programs involving asset replacement (discussed in section 6.15).
- Resilience programs involving asset replacement (discussed in section 6.12).
- The operational technology component of our proposed ADMS investment (discussed in section 6.14).

The component of our proposed metering communications systems replacement expenditure allocated to distribution (discussed in Chapter 16).

Table 6-13: Summary of repex forecast ($m real 2023-24)

Program	Forecast capex	% of total
Poles	184.8	24%
Conductors	110.5	14%
Switchgear	101.7	13%
Zone substation rebuilds	89.6	12%
Zone substation plant	71.9	9%

[33] See ASD - AusNet - Replacement and safety programs - cost buildup - 31 Jan 2025

Program	Forecast capex	% of total
Protection and control	65.5	8%
Cables, subs, services	58.2	8%
Crossarms	40.3	5%
Infrastructure	22.8	3%
Misc. lines	21.1	3%
Comms	6.3	1%
TOTAL	**772.6**	**100%**

Source: AusNet

** Direct costs, excludes contractor support costs allocated to repex*

6.7.4.1. Poles

The pole replacement program is the largest of our proposed repex programs, accounting for one-quarter of forecast repex. It involves the replacement of poles that, after inspection, pose an unacceptable risk in terms of public safety, bushfire ignition and/or supply reliability. Depending on a pole's condition, our replacement program can also involve remediation through staking.

Effective management of our population of over 422,000 distribution network poles is required at all stages of the asset life cycle to ensure that stakeholder expectations of costs, safety, reliability and environmental performance are met. Key pole asset management practices include inspection, maintenance, refurbishment and replacement activities. The pole inspection program is undertaken through a combination of ground (test and inspected) and aerial based inspection activities as approved by Energy Safe Victoria, satisfying the requirements for inspections and intervals outlined in the Electricity Safety (Bushfire Mitigation) Regulations 2023.

Proactive management of pole application, inspection, maintenance, refurbishment and replacement practice is required to ensure that stakeholder expectations of costs, safety, reliability and environmental performance are met. The distribution network pole inspection program is undertaken through a combination of ground (test and inspected) and aerial based inspection activities as approved by Energy Safe Victoria, satisfying the requirements for inspections and intervals outlined in the Electricity Safety (Bushfire Mitigation) Regulations 2023.

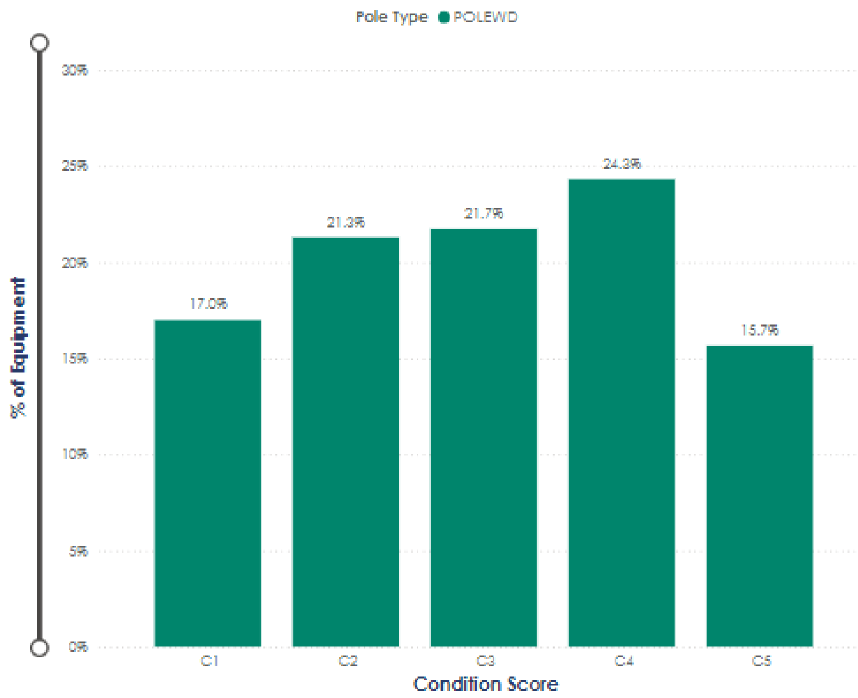
Condition-based replacement triggered by inspection programs is the fundamental strategy used to manage pole assets. The business rules governing refurbishment or replacement to generate a continuous, prioritised refurbishment and replacement program are documented in 30-4111 Asset Inspection Manual. Our pole inspection program is approved by Energy Safe Victoria and must comply with the Electricity Safety (Bushfire Mitigation) Regulations.

Ensuring adherence to safety regulations and standards is a key objective of AusNet's pole asset management strategies and practices. Key activities include conducting regular safety audits and risk assessments, managing pole assets in accordance with the Bushfire Mitigation Plan, providing ongoing safety training and competency assessments, regularly reviewing and updating emergency response plans, engaging with the community to raise awareness about electrical safety around poles, and adopting new technologies and practices to enhance network safety. By integrating these safety activities into asset management strategies, AusNet aims to effectively minimise safety risks "as far as practicable," as outlined in the Electricity Safety Act 1998 and reflected in ESMS 20-01 Electricity Safety Management System.

AusNet's pole population is aging, and some will approach their end of service life in the next regulatory period. A large proportion of our wood poles were constructed in the 1960s and 70s and are approaching their end of service life - deemed for replacement in the 2026-31 regulatory period. 64% of wood poles have now passed the 41-year mark (average end of life), with 38% that are already 10 years past their end of their technical lives – this represents 68,000 poles, compared with our proposed replacement volume of 13,000 over the 2026-31 period. Wood pole replacements account for 91.5% of total forecast pole replacements.

As shown in the figure below, approximately 16% of wood poles – approximately 28,800 - are in the poorest condition (C5) and, upon inspection, may require reinforcement or replacement. Again, this is significantly below our proposed volume of wood pole replacements of 13,000.

Figure 6-18: Wood pole condition

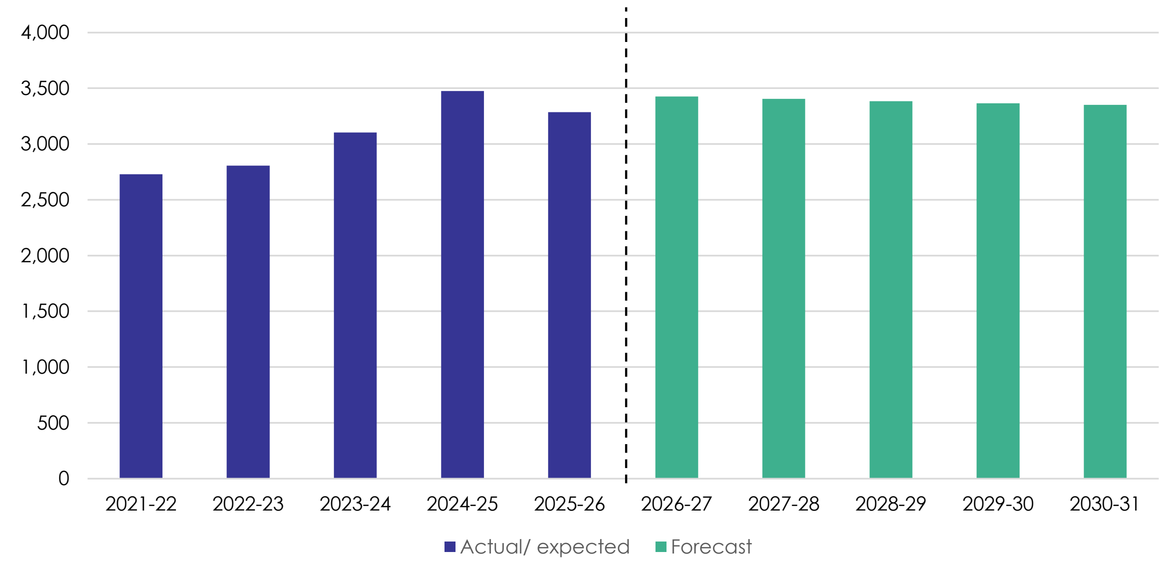


Source: AusNet

Reflecting the ageing wood pole fleet and subsequently its deteriorating asset condition, we are forecasting an increase of 10% in total pole replacement and reinforcement volumes, from approximately 15,400 in the current regulatory period to around 16,900 in 2026-31. Pole replacement and reinforcements volumes in the current and next regulatory period are shown in the figure below, demonstrating that our forecast volumes are broadly in line with planned volumes in the current regulatory year, 2024-25.

The increase in forecast pole replacement volumes is also driven by a recent change in our wood pole inspection obligations which, effective from January 2024, has decreased the inspection interval from six to five years. All else equal, this will increase the rate at which we find unserviceable poles (the find rate) and lead to an increase in asset replacement volumes. The effects of this change are also reflected in higher replacement volumes planned for 2024-25 and 2025-26.

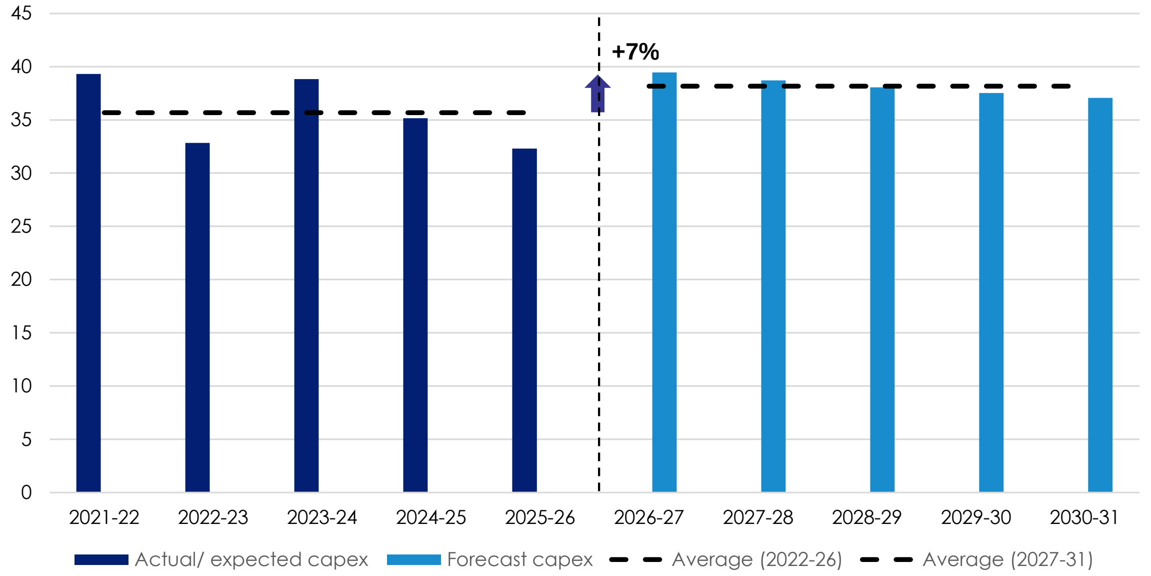
Figure 6-19: Actual, expected and forecast pole replacement and reinforcement volumes



Source: AusNet

Despite increasing volumes and market-driven cost pressures, our total forecast poles capex (including both replacements and reinforcement) of $184.8m is 7% higher than expected capex in the current regulatory period. Our change in service delivery partner has helped to moderate the effects of these factors, contributing to a slight decrease in average pole unit rates (across all pole types) between the current and next regulatory periods (including the impact of fleet and plant costs, which are not included in Zinfra rates and, therefore, form part of our forecast of non-network expenditure).

Figure 6-20: Actual, expected and forecast pole capex ($m, real 2023-24)

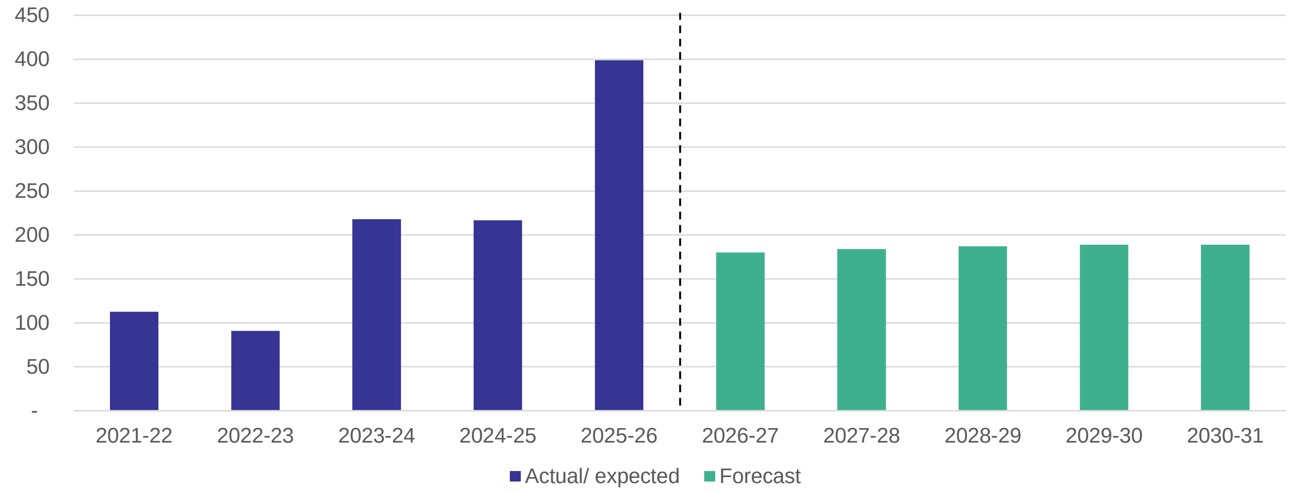


Source: AusNet
Note: Includes contractor support costs

6.7.4.2. Conductors

AusNet's conductor replacement program is the second largest of the repex programs proposed for the 2026-31 regulatory period. The volume of condition-based conductor replacement is decreasing by 10% from around 1,040 km in the current period to around 930 km in the 2026-31 regulatory period. The proposed replacement volume represents 2.4% of the overall bare overhead conductor in service across our distribution network. The scope of the program has been determined using our risk-based, economic assessment approach, taking account of the deteriorated condition of some conductor assets and the consequences of asset failure which, in the case of conductors, can have significant impacts on reliability and public safety.

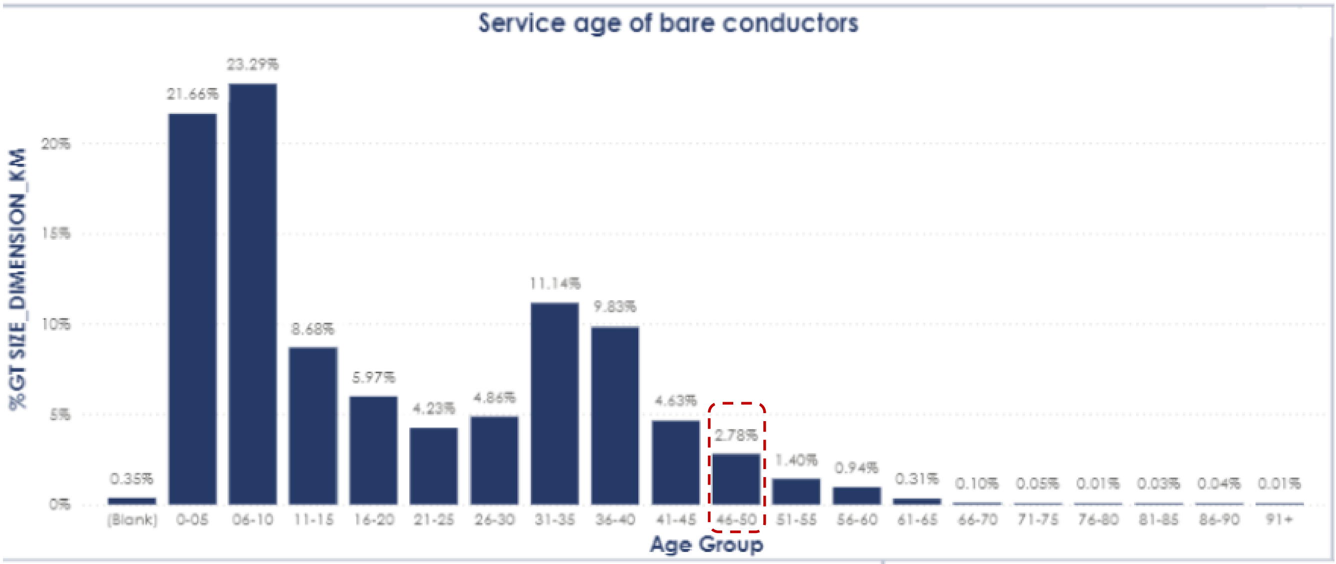
Figure 6-21: Actual, expected and forecast conductor replacement volumes



Source: AusNet

As shown in the figure below, approximately 2.8% (1,040km) of the bare conductor fleet is currently aged between 46-50 years and, therefore, will reach or exceed 50 years of age during the 2026-31 regulatory period. While our conductor replacement program is based on asset condition, rather than age, this volume is broadly in line with our proposed replacement volume for 2026-31.

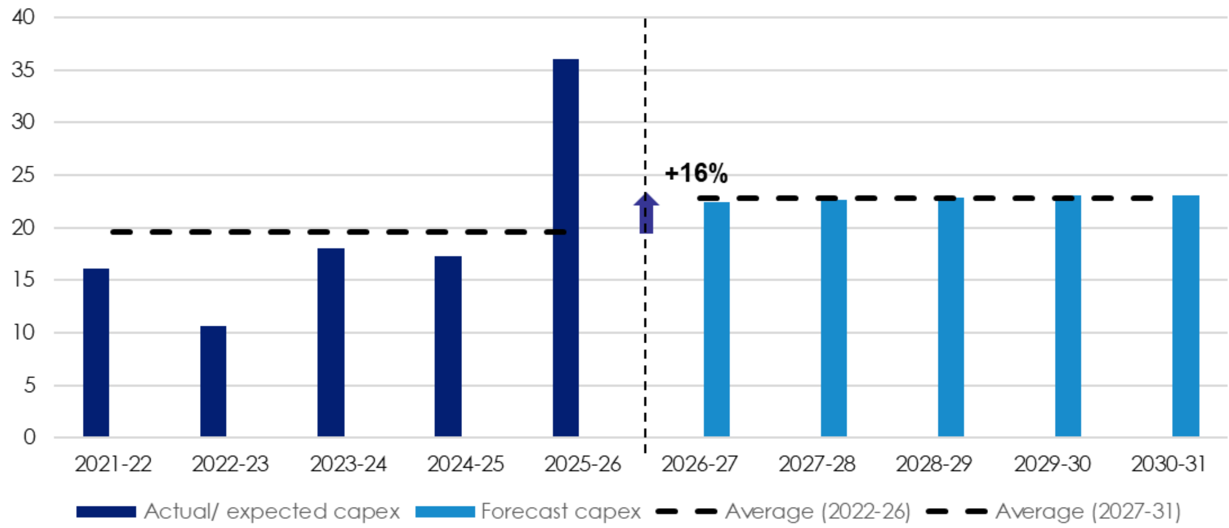
Figure 6-22: Bare conductor age profile



Source: AusNet

Despite the slight reduction in replacement volumes, our proposed conductor replacement capex of $110.5m is 16% above expected spend in the current regulatory period. This reflects increases in conductor unit rates due to market-driven cost pressures, with the average conductor unit rate (across all types) increasing by approximately 20% between the current and forthcoming regulatory periods.

Figure 6-23: Actual, expected and proposed conductor replacement capex ($m, real 2023-24)



Source: AusNet

In addition to the condition-based conductor replacement program, we are proposing to continue our safety-driven program to insulate or underground SWER and bare conductor lines in Codified Areas. This is discussed in section 6.14 – safety capex.

6.7.4.3. Switchgear

Our proposed switchgear program involves condition-based replacement of the following assets:

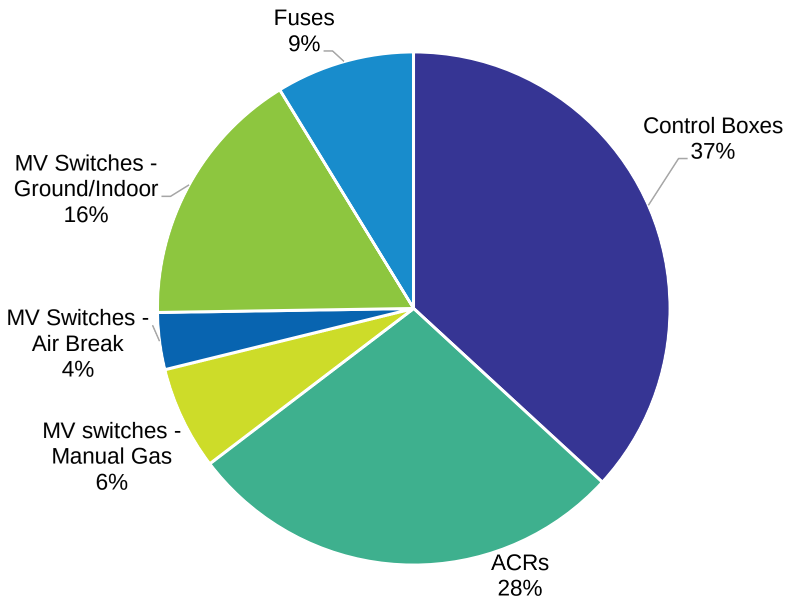
- Auto-circuit reclosers (ACRs).
- Medium Voltage (MV) switches.
- Fuses (excluding the proactive EDO fuse replacement program, which is discussed in the safety section of this chapter).
- Switch control components, including control boxes.

The primary function of MV switches and ACRs is to isolate sections of the network either for operational purposes or in response to fault events. These devices are fundamental components of our distribution network and are designed to reduce the impact of customer outages in the event of planned outages or unplanned network incidents and, hence, are critical to maintaining network reliability levels. In addition, our asset management strategies for switchgear incorporate the need to manage the inherent safety risks associated with certain type switches.

Our replacement strategies for ACRs, control boxes and MV switches reflect the following key considerations:

- Prioritise proactive replacement of poor and/or unsafe to operate key switches.
- Replace failed or poor condition non-key switches that are required to facilitate network operational switching (eg. planned outage works, load transfers).
- Replace ACR and sectionaliser control boxes that are in poor condition and are exhibiting higher defect rates
- Reactively replace place defective switches as a result of routine asset inspections. The contribution of each asset class to total proposed switchgear expenditure is shown below.

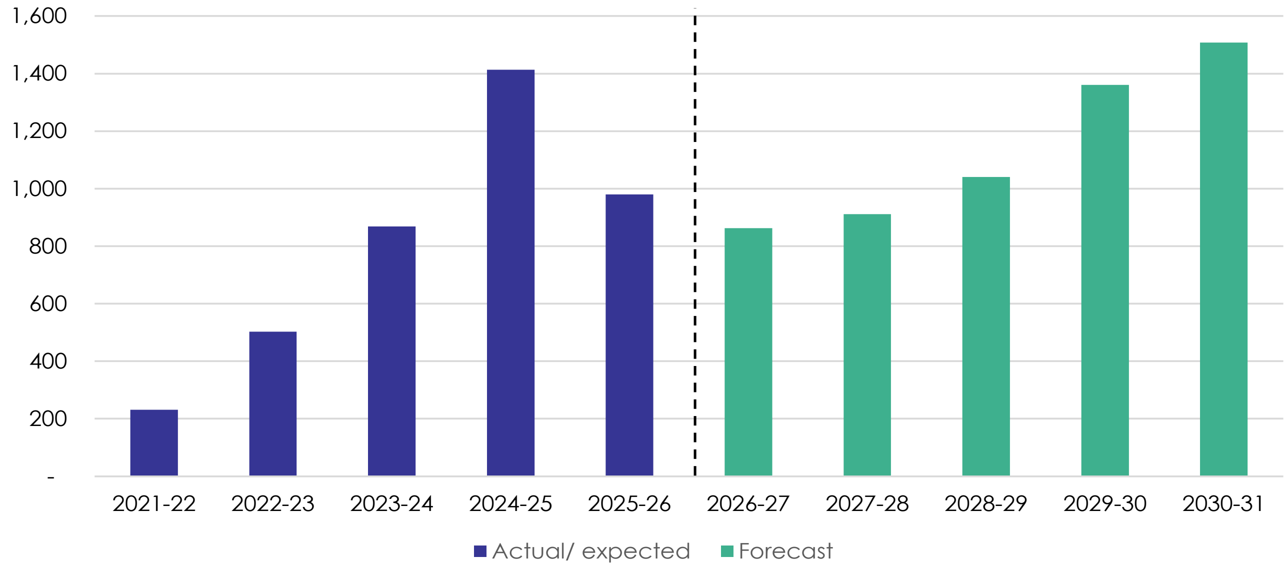
Figure 6-24: Composition of proposed switchgear expenditure



Source: AusNet

We are proposing a 42% increase in switchgear and control box replacement, from around 4,000 units in the current regulatory period to approximately 5,680 units in 2026-31.

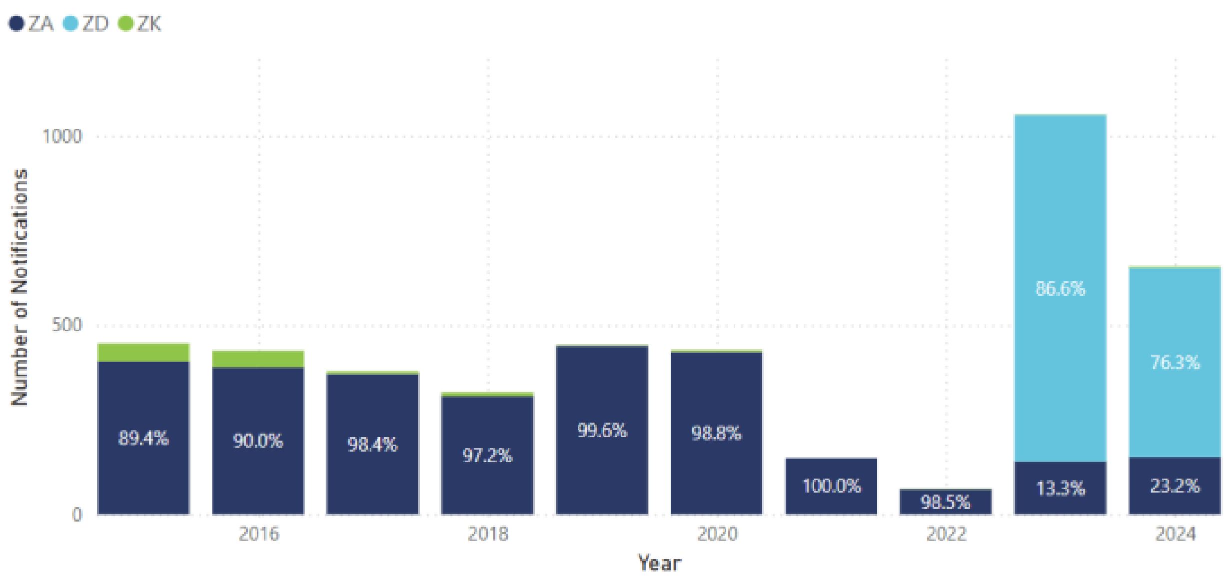
Figure 6-25: Actual, expected and forecast switchgear replacement volumes



Source: AusNet

The increase in replacement volumes required for the next regulatory period reflects the need to replace a large number of poor performing inoperable switches and control boxes to maintain service levels and prudently manage network risk. As indicated in the figure below, these assets are experiencing an increasing failure rate and deteriorating performance.

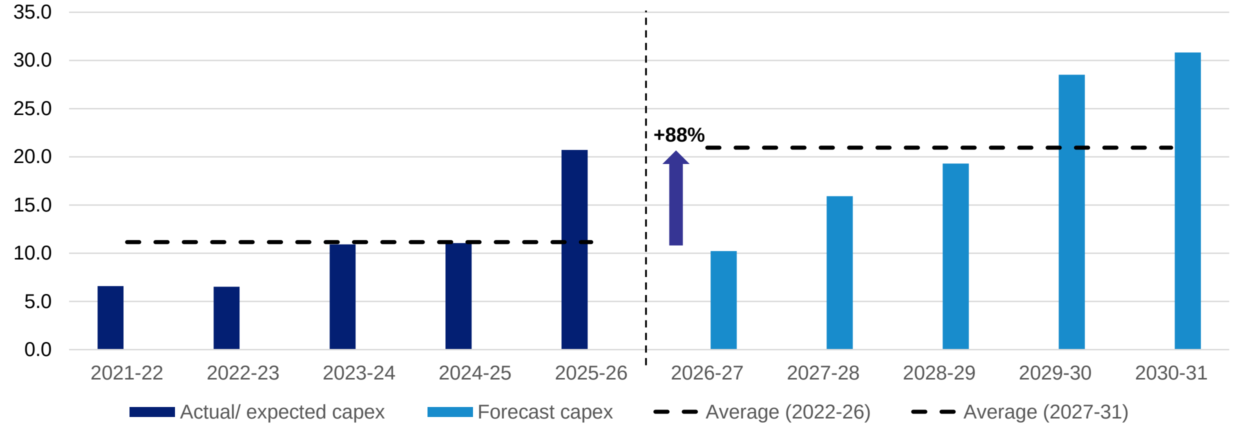
Figure 6-26: MV switches historical failure data



Source: AusNet

Reflecting higher replacement volumes, as well as market-driven cost pressures increasing unit rates, proposed switchgear replacement expenditure of $101.7m is approximately 88% higher than expected capex in the current regulatory period.

Figure 6-27: Actual, expected and forecast switchgear capex ($m real 2023-24)



Source: AusNet

6.7.4.4. Zone substation rebuild program

Zone substation rebuild projects at the following locations are proposed for the forthcoming regulatory period:

- Thomastown (Stage 2) - 22kV upgrade.
- Newmerალla refurbishment.
- Watsonia refurbishment.
- Traralgon (Stage 2) - 22kV switchboard upgrade.
- Kilmore South 22kV switch room replacement.

Works for these projects total $89.6m, around 16% lower than expected spend on similar rebuild projects in the current period of $107m. These are summarised below in Table 6-13.

Economic timing for these projects has been assessed through our risk-based, probabilistic planning approach. Where different station asset programs overlap at a location, a zone substation major refurbishment project enables us to target the replacement of deteriorated plant and equipment within zone substations most efficiently. These projects typically include the replacement of major plant such as transformers, circuit breakers and ancillary equipment, such as protection systems or panels containing asbestos. All of the projects listed above adopt the optimal combination of asset replacement to balance the benefits (a reduction in the probability of asset failure and associated consequences) with the costs of the replaced assets.

Zone substation rebuild projects at Watsonia, Thomastown and Traralgon were approved at the last determination. Following reassessments of network risk, project costs and economic timing, these projects have prudently been partially (Traralgon and Thomastown) or fully (Watsonia) deferred to the 2026-31 regulatory period. As discussed in section 13.6 – Capital efficiency sharing scheme, this deferral has not led to a material underspend of our total current period capex allowance – in contrast, we are expecting an overspend of approximately 19%.

While the Newmerella project was also found to be economic in the current regulatory period, as part of preparing our previous Regulatory Proposal we negotiated with our Customer Forum to fully defer this project to 2026-31.

Our forecast also includes $1.5m of expenditure for rebuild projects at the Traralgon (Stage 1) and Warragul zone substations. These projects, which reflect options that have satisfied the RIT-D, are currently being delivered and are forecast to be completed in 2026-27.

To avoid overlaps, the assets to be replaced in the zone-substation program have been removed from the overall replacement program, reducing the total repex forecast by $24m. Further details are in the Top Down Adjustment supporting document.

Planning reports and economic models for the five ZSS rebuilds listed above are provided as supporting documents.

Table 6-13: Overview of zone substation rebuild projects ($m, real 2023-24)

Project / Zone substation	Project description	Forecast capex
Thomastown Stage 2 (22kV upgrade)	• This substation commenced operation as a 66/22 kV transformation station in the early 1950s. Two 20/27 MVA transformers were installed in the early 1960s and a third 20/30 MVA transformer was installed in the late 1960s. Two 66 kV and eighteen 22 kV bulk oil circuit breakers were installed at this station in the 1950s and 1960s. The physical condition of some assets has deteriorated, and they are now presenting an increased risk of failure. This project involves replacing the No. 1, No.2 and No.3 Transformers and replacing the 22kV circuit breakers by 2032.	$28.7m
Newmeralla	• Newmerella (NLA) commenced operation as a 66/22kV transformation station in 1970. The two 5MVA transformers were installed in 1970, however were manufactured in 1949. The 22kV switchyard consists of three ACRs and a capacitor bank CB that were also installed in 1970. The 66kV switchyard has had some modifications since the site was established, such as new 66kV CBs in 1986 and 2015. • The physical and electrical condition of these assets has deteriorated and they present an increasing failure risk. The station 66kV bus is unswitched, hence faults on the 66kV transformer bus or either one of the transformers will result in a complete loss of supply to customers at the station. • The project will replace the transformers and 22kV switchgear.	$11.8m
Watsonia	• This substation commenced operation in the late 1950s with two 66/22 kV power transformers. A third transformer was installed in 2010 and the station now includes two 66 kV bus-tie circuit breakers and is supplied by two incoming 66 kV lines. The outdoor 22 kV switchyard consists of eleven 22 kV feeders and a 10 MVAr capacitor bank. • • To manage short circuit current levels within asset capabilities and rules requirements, only two of the power transformers operate in parallel, with the third operating as a hot spare under normal conditions via normally open 22 kV transformer circuit breakers connected to each of the 22 kV buses. This arrangement allows quick restoration to near system normal capacity following outage of either of the two normally loaded transformers. There are fifteen 22 kV bulk-oil circuit breakers at the station which were installed in the 1950s and 1960s. The physical and electrical condition of these assets has deteriorated and are now presenting an increasing risk of failure. The project involves replacing the No. 1 and No. 2 transformers and 22 kV circuit breakers.	$28.9m
Traralgon (Stage 2)	• Traralgon Zone Substation (TGN) commenced operation as a 66/22kV transformation station in 1969. There will be two 20/33 MVA transformers, one of which will replace the current two 10/13.5 MVA units in 2026, and one 20/33 MVA transformer, manufactured in 2012. • The 22kV switchyard consists of one indoor switchboard with four feeders installed in 2013, and three outdoor 22kV busses with four feeder circuit breakers (CBs) installed in 1969. • The 66kV switchyard has had some modifications since the site was established, and now consists of two 66kV lines to MWTS and one line to Maffra (MFA) one Substation. • Two of the 66kV circuit breakers were installed in 1977 are being replaced in 2026, while the other two were installed in 2013 when the new 20/33 MVA transformer was installed. A 66kV ring bus is also being commissioned at TGN and will be completed by September 2026	$11.8m

	• The physical and electrical condition of some assets has deteriorated and they now present an increased failure risk. The project involves replacing the 22kV outdoor switchgear with a new 22kV indoor switchboard.	
Kilmore South switch room replacement	• Kilmore South (KMS) commenced operation as a 66/22kV transformation station in 1966. The two transformers (13.5MVA and 30MVA) were installed in 1967 and 2011 respectively. The 22kV switchyard consists of five CBs installed in 2005, two feeder CBs, a cap bank CB that were installed in 1985. The 22kV switchgear is tired into a an indoor switchboard. The 66kV switchyard consists of 5 CBs installed in 2011 and one installed in 2023. The physical and electrical condition of these assets has deteriorated and they are now presenting an increasing failure risk. This is especially prevalent on the 22kV switchboard. • The scope of this project is to procure, construct/install, test and commission a new urban configuration 22kV switch room at Kilmore South zone substation and remove the old 22kV container switch room and control room, outdoor 22kV switchgear and associated protection and control schemes.	$7.0m
TOTAL		**$89.6m**

Source: AusNet

6.7.4.5. Zone substation plant

In addition to the zone substation rebuild program, AusNet proposes to undertake $71.9m of station asset repex during the next regulatory period. Major components of this program include:

- The replacement of 22 circuit breakers that form part of our backbone 66kV sub-transmission network. The proposed replacements are supported by cost-benefit analysis, including assessments of the risk and consequence of asset failure.
- The replacement of 5 power transformers and bushings on 39 power transformers in accordance with our asset management strategy. This strategy considers, among other issues, transformer type, asset condition and historical failure modes to optimise the replacement decision.

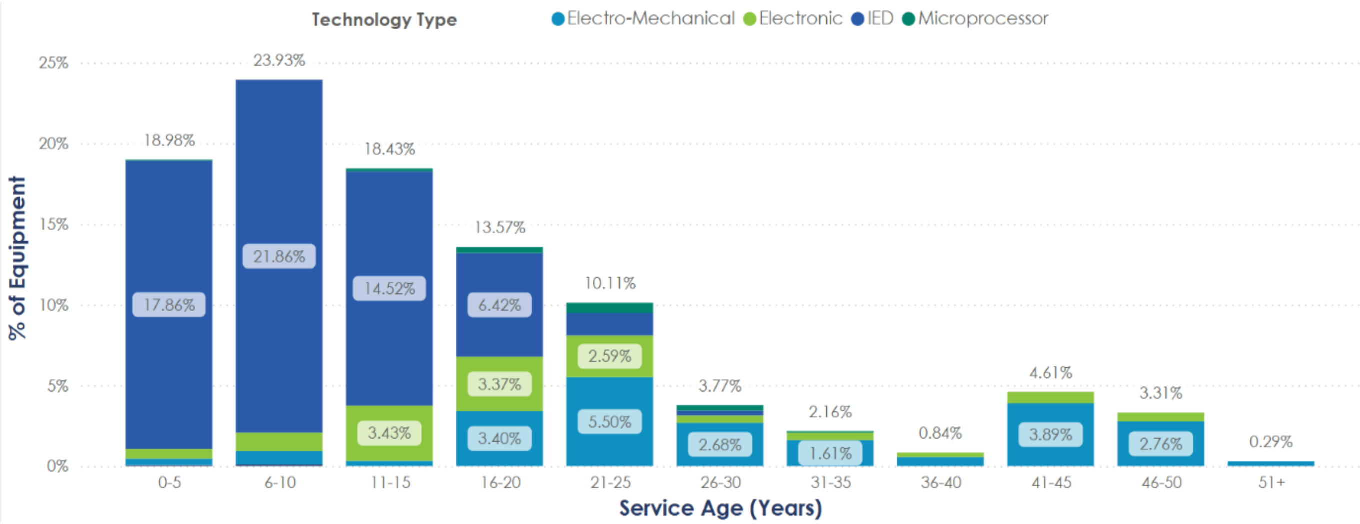
Proposed ZSS plant capex of $71.9m is around 70% higher than expected capex of $42m during the current regulatory period. This excludes the costs of replacing power transformers, circuit breakers and other plant assets as part of the current period's ZSS rebuild projects. As explained in the section above, proposed ZSS rebuild expenditure in 2026-31 is $17m lower than during 2022-26. When combined, total proposed spend for ZSS rebuilds and plant is around $13m higher than the current regulatory period. This increase is consistent with global cost pressures that in recent years have significantly increased the cost of power transformers, circuit breakers and other station assets.

6.7.4.6. Protection and control

The aim of this $65.5m program is to manage risk associated with ageing protection and control assets through targeted, proactive replacement of high risk, poor condition or obsolete assets that are past their technical service life. The proposed replacement of 175 relays represents 5 per cent of the total population and includes electromechanical relays and first-generation electronic and microprocessor-based relays, which are in poor condition, no longer supported by the manufacturer and present technical deficiencies (eg. absence of self-monitoring capabilities resulting in spurious operation and network outages).

The expected service life for protection and control relays is 20 to 25 years. The following figure shows the average service life of AusNet's relay population by technology type. The average age of relays included in AusNet's replacement program is currently 30.6 years. Reflecting the increasing age and network risk presented by these assets, the proposed expenditure is above expected protection and control investment in the current regulatory period.

Figure 6-28: Relay population by age and technology



Source: AusNet

In addition to identified relay replacements, AusNet's protection and control program includes a continuation of our auxiliary supply replacements, which includes 20 DC supply system upgrades. The planned upgrades are at identified sites where batteries and associated systems are in poor condition and present increased risk to security and availability of supply.

To maximise project efficiencies, AusNet typically aims to complete secondary asset replacements at the same time as primary asset renewal, refurbishment or augmentation works. Consequently, some secondary asset replacements occur as part of complex station projects. Only the highest risk, poorest condition or non-compliant assets located at sites where no complex station works is anticipated within the next 10 years are considered for replacement under this dedicated protection and control renewal program.

6.7.5. Benchmarking and validation

The AER uses a repex model as a statistical tool to conduct a top-down assessment of forecast repex. The model is used to benchmark repex that involves high volume asset classes – poles, overhead conductors, underground cables, service lines, transformers and switchgear.

We have used the AER's repex model to cross-check our expenditure forecast for the asset classes included within the scope of the repex model. However, to ensure meaningful comparisons between our forecast and the AER's repex model outputs, we have excluded from our forecast any replacements that do not have an age or condition-based driver. This recognises that the AER's repex model is intended to forecast replacement volumes primarily based on asset age and, as a result, including replacements with other drivers (e.g. safety) in the forecast being compared would reduce the robustness of these comparisons.

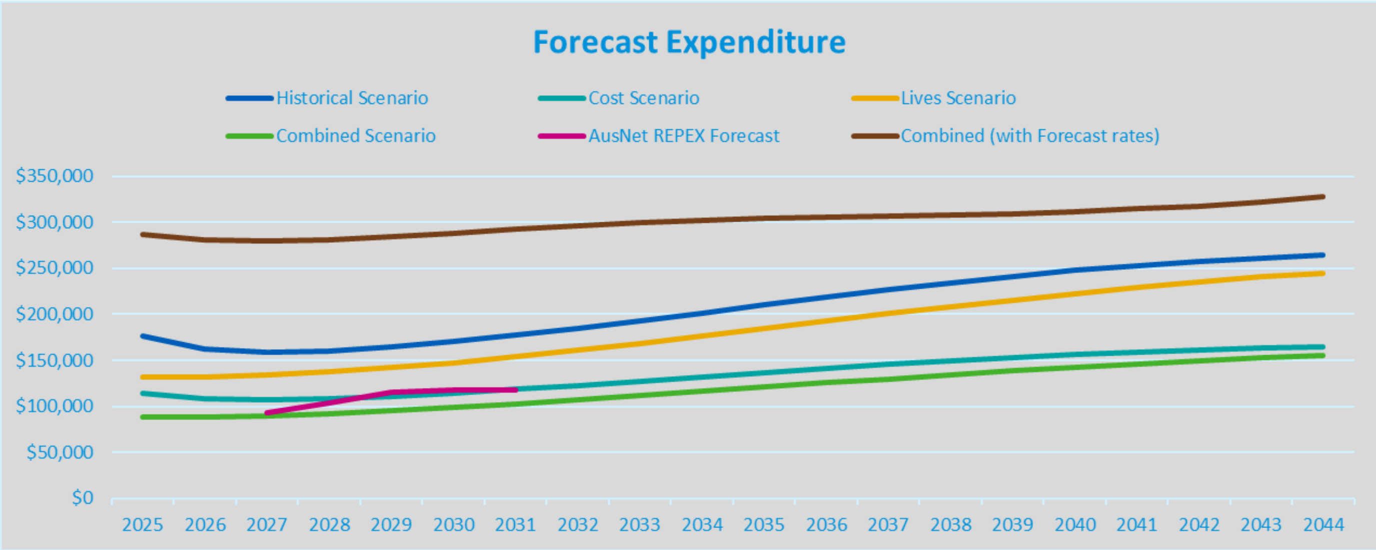
Therefore, the following expenditures are excluded from the analysis presented below:

- Safety programs involving asset replacement.
- Resilience programs involving asset replacement.
- The operational technology component of our proposed ADMS investment.
- The component of our proposed metering communications systems replacement expenditure allocated to distribution.

Based on this modelling,[34] our proposed repex for the 2026-31 regulatory period is at the lower end of the range of scenarios included in the AER's repex model. At a total level, AusNet's forecast is comparable with the AER's preferred Combined Scenario. Modelled repex accounts for a relatively high (approximately 60%) proportion of age- or condition-based repex. Therefore, despite the repex model's relatively simplistic, age-based forecasting approach and its other limitations, we consider the analysis below is indicative of the prudency and efficiency of our forecast.

[34] See supporting model "ASD - Repex model - 31 Jan 2025"

Figure 6-29: AER repex model comparisons, age- and condition-based replacements only



6.7.6. Supporting documentation

A large number of supporting documents and models support the repex forecasts outlined in this chapter, including:

- Asset Management Strategies and economic models for each asset class.
- Zone Substation rebuild assessment reports and economic models.
- AusNet - Replacement and safety programs - cost buildup.
- The Asset Management Strategy (20-01).
- Risk Assessment Methodology (AMS 01-09).
- Unit Rates.

6.8. CER enablement

6.8.1. Key points

The key points in this section are:

- Our Consumer Energy Resource (CER) enablement investment unlocks efficient levels of export capacity that benefit all AusNet customers, including those without CER. These benefits include putting downward pressure on wholesale electricity prices and reducing greenhouse gas emissions.
- From 1 July 2026, our new solar customers will be offered flexible export service, rather than imposing a static export limit. This approach will improve the efficiency of export capacity allocation, better utilise the existing network and defer network investment. Moving to flexible exports is strongly supported by our EDPR stakeholders and will be achieved through our digital capex proposal, which is explained in section 6.13.
- In developing our CER expenditure plans, we have ensured that we comply with the AER's CER/DER Integration Guidelines and applied the AER's estimated value of emissions reduction (VER).

6.8.2. Overview of forecast and key drivers

Our CER enablement forecast for the 2026-31 regulatory period is $35m (direct, real 2023-24), which is 9% ($3.6m[35]) higher than our expected capex in the current regulatory period.

As our customers continue to invest in CERs, we are committed to ensuring we can integrate their devices into the network efficiently, allowing them to extract maximum value from their investments, as well as unlocking value from CER for all our customers.[36]

In Victoria, rooftop solar penetration is continuing to grow, supported by the Victorian Government's Solar Homes program which was introduced in 2018. Currently more than 29% of AusNet households have rooftop solar. Combined with all other rooftop solar capacity across other networks, this is the largest renewable generator in Victoria.

Our forecast assumes the continuation of the Solar Homes program, which combined with further subsidies for apartments introduced by the Victorian Government in May 2024[37], will promote continuing growth in rooftop solar. We expect rooftop solar penetration to reach 39% of households across our distribution network by 2031.

We expect battery penetration to increase from today's modest level of 2% to approximately 7% by 2031. Despite this projected increase in battery penetration, most households with solar will continue to export excess energy to the grid in the middle of the day and the export amount is forecast to increase.

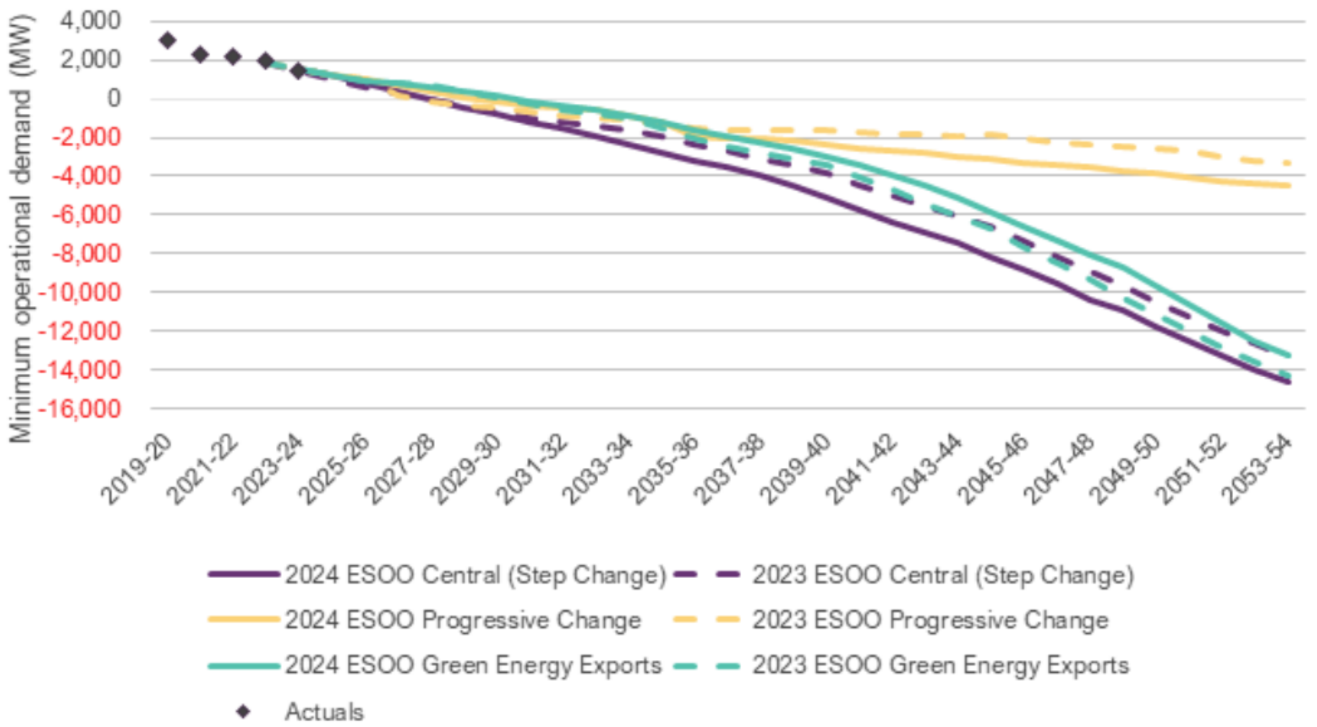
With the increasing penetration of rooftop solar, and a much smaller penetration of batteries, we will continue to experience network challenges from exports. These include:

- Increased exports can cause spikes in voltage levels, above those permitted by the EDCOP.
- Voltages variations cause inconsistencies in flows on the network, creating challenges to maintaining the reliability and consistency of supply.
- The variation in flows caused by exports can create thermal overload of assets, such as conductors and transformers, requiring more frequent and costly upgrades, while jeopardising the reliability of critical network assets.

In addition to network challenges, there is a rapidly growing minimum operational demand risk to the whole energy system, which is managed by AEMO. Minimum operational demand typically occurs in the middle of the day when solar production is high, and it is forecast to decline from approximately 1,800 MW in 2023-24 to about zero in 2027-8 and -1,000 MW in 2030-31 (Figure 6-30).

[35] 9% increase and $3.6m increase have been calculated using total cost including overhead.
[36] For the purposes of the CER enablement program discussed in this section, CER includes customers' rooftop solar and rooftop solar + battery systems—technologies that can generate electricity on the site and export into the grid. Battery systems (referred to as batteries in the remainder of this section) include only those that are installed behind the meter at a customer site. CER such as electric vehicle smart chargers and other smart devices, which do not generate or export electricity, are not considered as part of this program.
[37] https://www.solar.vic.gov.au/apartments?gad_source=1&gclid=EAIaIQobChMIh7uO1Kr6hgMV8g-DAx1LgwWYEAAYASAAEgJ1oPD_BwE

Figure 6-30: Actual and forecast Victoria 50% POE minimum operational demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Source: AEMO, 2024 Electricity Statement of Opportunities August 2024, p 160.

This risk will be managed by AEMO through various measures; however, distributors also have a role to play, through the recently implemented Victorian Emergency Backstop Mechanism (**VEBM**) but also through an efficient management of exports and demand in a way that reduces the risk of minimum operational demand occurring.

6.8.3. Methodology and key assumptions

Our methodology adopts the inputs and assumptions in the table below, in developing our economic approach for determining the efficient level of investment in export capacity for the 2026-31 regulatory period. The CER enablement program is a continuation of our current program, which includes on-going network augmentation to unlock more solar capacity, initial stages of the development of a dynamic voltage management system (**DMVS**) and the implementation of trials such as the flexible exports trial and the Energy Demand and Generation Exchange (**EDGE**) trial, which use dynamic operating envelopes for export management.

Our CER enablement program is part of our broader CER strategy which incorporates additional measures to unlock more value from all CERs (beyond rooftop solar and batteries), aligned with the National CER Roadmap.[38] The CER strategy includes initiatives that optimise network utilisation through new and innovative tariffs, including a new optional two-way CER tariff for small customers, with rewards for evening exports. Other smart initiatives for network optimisation and unlocking CER value, beyond flexible exports, include dynamic connections for commercial customers and batteries, standardisation of non-network solutions and more visibility of network conditions and constraints. Importantly, our CER Strategy and transition to DSO optimise the recently implemented VEBM foundational capability, which allows us to implement new services such as flexible exports at marginal cost while improving customer outcomes. Please refer to CER Integration Strategy attachment for the further information on our CER Strategy and section 6.8 for more detail on our smart solutions.

The table below sets out the key inputs and assumptions that we have adopted.

Table 6-14: Key inputs and assumptions (CER enablement)

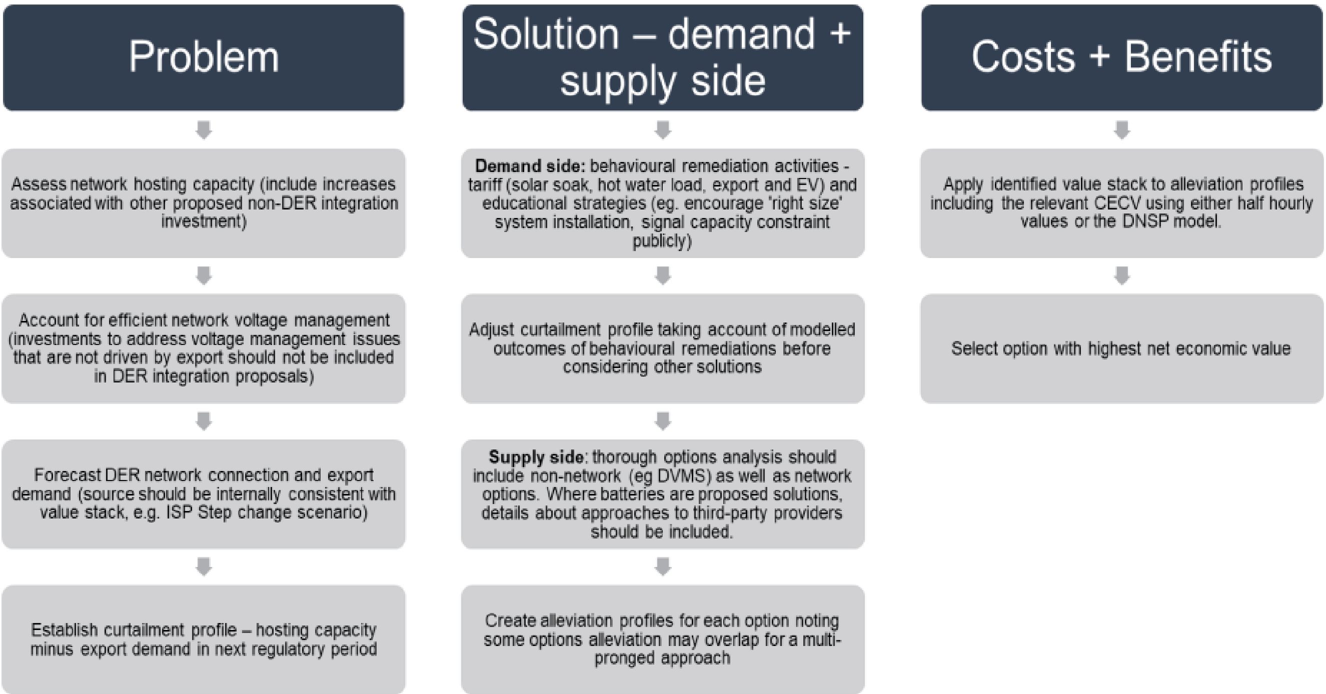
Input / Assumption	Description
Discount rate	See section 6.5.1
Value of Customer Reliability (VCR)	Not applicable
Network condition data	Network characteristics, actual voltages, operating states and demand measurements from our advanced metering infrastructure (**AMI**) and Supervisory Control and Data Acquisition (**SCADA**).
Customer segmentation research	AusNet has undertaken extensive customer segmentation research of our residential customer base, which has combined residential customer attitude surveys with AMI meter data. This innovative study provides rich and insightful new learnings about AusNet's residential customers' consumption patterns, characteristics, motivations, and attitudes towards key aspects of the energy transition. It identifies current usage patterns and through surveys, has gained an understanding into how those usage patterns may change over time with changes in customer energy usage behaviours influenced by the energy transition. Refer to section 2.4.2 for more details.
CER and demand forecasts	We use CER forecasts as an input into maximum and minimum demand forecasts. Maximum and minimum demand forecasts at an asset level are then used as drivers of our hosting capacity modelling and CER enablement investment.
Customer Export Curtailment Value (CECV)	The AER is responsible for developing the CECV annually. On 1 July 2024, the AER published new CECV values that we have used in our modelling. The AER also published emissions intensity profiles to be used by networks in combination with the CECVs and the updated distribution network service provider (DNSP) model, which are also used in our modelling.
Value of Emissions Reduction (VER)	The AER is responsible for developing the value of emissions reduction (VER) to be used in investment planning by networks, consistent with the guidance provided by the AER under the CECV and the published emissions intensity profiles. The first VER was finalised on 22 May 2024, and has been adopted in our modelling.
Customer and stakeholder feedback	We have engaged extensively on CER enablement with our customers and EDPR stakeholders, including through our Future Networks and Tariffs & Pricing Panels. The consistent feedback we receive from our end customers is that they value solar exports highly and that they do not want us to waste any generated solar energy—even to the point where they are willing to pay more than the economic value for networks to enable exports. Conversely, through engagement with our Future Networks and Tariffs & Pricing Panels (whose members typically have a higher level of energy expertise), we have been encouraged to consider efficiency and increasing network utilisation as the primary drivers of investment, to limit any inefficient costs being passed onto all customers, particularly those that do not have CER, and help keep costs down for all. We have also received feedback that there is still confusion or a lack of understanding amongst end customers regarding export limits, and why there may be differences between different parts of the network (e.g., urban and rural networks). Our Future Networks Panel has encouraged us to improve communications with our customers to simplify the messaging and ensure customers have a better understanding of how we make decisions that impact them. Specific feedback from the Customer Panels and our stakeholders have been incorporated into the following sections. Please refer to CER Integration Strategy attachment for the further information on our CER Strategy and section 6.8 for more detail on our smart solutions.

Source: AusNet

6.8.3.1. Investing efficiently to unlock export capacity

We have an economic approach to forecasting efficient investment in export capacity. Our approach is aligned with the AER's distributed energy resources (**DER**) integration expenditure guidance note. The AER's proposed process for the development of CER/DER integration expenditure is shown the figure below.

Figure 6-31: AER's process for developing CER/DER integration investment proposals



Source: AER, DER integration expenditure guidance note, June 2022, p. 5.

In accordance with the above framework, our approach involves two steps. The first step establishes the identified need by estimating the intrinsic hosting capacity of the Low Voltage (**LV**) network and the forecast demand for hosting capacity for the 2026-31 regulatory period. The second step is to assess the options for addressing the identified need, having regard to the costs and benefits. We discuss each of these steps in turn.

6.8.3.1.1. Step 1: Estimating intrinsic hosting capacity for CER and future requirements

This step employs an in-house model that captures actual network conditions and estimates future hosting capacity based on forecast maximum and minimum demand. The key drivers of outputs in the model include:

- Forecast demand—maximum and minimum demand over the modelling period across AusNet's network (forecasts are at feeder level, disaggregated to distribution substation level in the model). These are calculated by AusNet outside of the hosting capacity model and are an input into the hosting capacity model.
- Customer segmentation—capturing the usage pattens for different customer groups, and potential changes in behaviour driven by pricing signals in network tariffs, and the take up of new technologies.
- Export service offer—capturing the type of exports service each new solar customer will expect when connecting to the network. From 1 July 2026, our export service offer includes 70% take-up of Flexible Exports to maximum system size. By assuming a high take-up of Flexible Exports, the model assumes curtailment to customers' exports at times of inefficient exports (e.g., as estimated by the CECV profile).

6.8.3.1.2. Step 2: Prudent and efficient investment planning

We use the hosting capacity model to estimate where we might see voltage limitations on each AusNet asset over time (to distribution substation level), based on growth in CER and changes in customer load profiles. The hosting capacity model is an integrated model that determine the efficient level of investment for voltage compliance, LV augmentation and CER enablement. See relevant sections for more details. The hosting capacity model applies the following prioritisation:

1. Voltage compliance: The model gives top priority to investments in voltage compliance by applying an economic model that values avoided generation curtailment (that would otherwise happen from over-voltages) using the AER's CECV and VER, as well as increased consumption due to over-voltages. To estimate the least cost investment, the model assesses various operating and capital solutions and weighs up their costs and ability to deliver required improvements. See section 6.15.4.1.
2. LV augex: Once the efficient levels of voltage compliance investment have been established, the model estimates efficient levels of network capacity required to enable growth in local demand on the LV network including single wire earth return (SWER) lines. Network capacity is estimated in each case using demand and curtailment profiles of customers and their CER, which are adjusted for forecast demand and usage profiles. This approach ensures our model is technology agnostic (i.e., trends come from demand forecast, which include a combined impact of various technologies on both maximum and minimum demand).

3. CER enablement: The model then estimates the network capacity required to unlock any additional efficient levels of exports, using the AER's CECV and VER.

We tested this approach with our Future Network Panel, and they were supportive of the approach that demonstrates efficiency of investment and reliance on AER values to measure efficiency in export-related CER investment (CECV and VER). We know our customers put value on all exports and have heard from many residential customers that we should be doing all we can to avoid 'wasting' any solar exports. However, we have chosen to pursue only investment that delivers efficiency, in line with the Future Network Panel's views, as we agree with the Panel that not all exports have value, and some may cause costs and much worse customer outcomes if unmanaged (like minimum system load risks potentially leading to wide power outages). Our approach also aligns with the Future Network Panel's preference that we consider demand and export drivers holistically, to 'marry up' the different drivers and identify investments that can unlock value for both. Our model does that.

Our investment approach considers a range of solutions such as:

- dynamic voltage management system
- distribution substation and SWER line upgrades
- transformer tapping and phase rebalancing.

The model then estimates the most efficient scope of works, capex requirement and timing of investment.

As an alternative approach to our economic approach, we have modelled a deterministic approach to export management, where all sites with some export value would be augmented. Our modelling identified the economic approach as the preferred option.

6.8.4. Projects and programs

We agree with our Future Networks and Tariffs and Pricing Panels that investment in CER enablement that is economically justified will increase network utilisation and unlock value for all our customers.[39] Our proposed program adopts a prudent and efficient approach to optimising the ability for our customers to install CER and export their excess energy into the grid. Our program unlocks export capacity where it is efficient to do so, while implementing flexible services that maximise network utilisation and reduce minimum operational demand risk.

6.8.4.1.1. Flexible exports

The introduction of a 'Flexible Exports' offer for all new customers from 1 July 2026 will allow us to efficiently allocate available capacity in the network to customers based on the conditions of the network each day. This means customers get access to more export capacity across the year than they otherwise would under a conservative static approach that sets permanent limits based on worst case scenario network conditions (which may only occur a few times a year). Our flexible exports approach will be achieved through our digital capex proposal, which is explained in section 6.14.

Our flexible exports approach maximises network utilisation while also providing a fairer allocation of export capacity between customers. Flexible exports are also a tool for managing minimum operational demand, as customers' exports may be reduced to zero at times of highest risk, which may only last a few hours. The introduction of flexible exports as the default option for all new solar customers was supported by our Future Networks Panel.

6.8.4.1.2. CER enablement

The efficient volume of exports and therefore the capex requirement to support it have been estimated using the AER's CECV and the AER's VER. Our Future Network Panel supported the adoption of these values in developing our expenditure program, noting that this approach will promote efficient outcomes.

Our proposed program is forecast to integrate approximately 60,000 new rooftop solar systems and 30,000 batteries into the network and unlock 264 GWh renewable exports per annum that would otherwise need to be limited through static export limits or generation curtailment (occurring automatically at high network voltages). By enabling efficient levels of exports, the program puts downward pressure on wholesale prices, as calculated by the CECV, and leads to 16.7kt CO_2 reduction per annum, which benefits all energy consumers including those without CER.

To determine the optimal new capacity, we employed our economic approach described in the previous section against a deterministic approach to export management, where all sites with some export value would be augmented. The economic approach was identified as the preferred solution because it maximised the NPV of the options assessed, including under different sensitivity scenarios.

Table 6-15 outlines the network solutions and selected sites for the preferred option.

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[39] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, section 10.1.2.

Table 6-15: Preferred option projects

Optimum project type	Identified sites
Zone substation reactor and DVM	DRN
HV distribution feeder regulator and DVM	MOE13, EPG12, CRE21, PHM24, BGE23, RVE12, CPK11, CPK12, LDL13
DVM	MBY
HV distribution feeder augmentation	EPG21, EPG13, CLN13, CLN21, CLN12, CLN14, DRN11, CLN23, KLO14, CLN11, EPG32
Distribution substation and LV circuit augmentation	CORE MARKET, CHEVROLET FERRARI, WONTHAGGI NORTH 62F, STANTON 3, RAWLINGS 10
Distribution substation transformer replacement distribution substation tap down	75 sites
Distribution substation phase peak load balance distribution substation tap up	1,028 sites

Source: AusNet analysis.

6.8.5. Benchmarking and validation

Distribution networks are at different stages of their CER enablement journey, driven by differences in:

- rate and scale of CER connections in their network;
- jurisdictional arrangements, including:
- smart meter roll-out stage and regulations
- voltage management regulations
- emergency backstop mechanisms roll out and regulation
- embedded generation connection policies, including use of export limits, and others.
- technical capabilities, including the stages of roll-out of DVMS; and
- technical capabilities related to other dynamic or smart tools, as part of the transition to DSO.

For these reasons, benchmarking of CER expenditure is unlikely to provide much, if any, guidance regarding the prudency and efficiency of our proposed expenditure for the 2026-31 regulatory period.

6.8.6. Supporting documentation

We have included the following documents to support this chapter:

- CER Integration Strategy.
- CER Enablement Business Case.
- CER Enablement Economic Model.
- Hosting Capacity Modelling Detailed Methodology.

6.9. Reliability expenditure

6.9.1. Key points

The key points in this section are:

- In line with the strong feedback received from our customers and the preferences demonstrated through our end-customer research programs, we are proposing a reliability investment program of $118.9m (direct, real 2023-24), focussing on our worst served customers, during 2026-31.
- We are proposing $20.7m[40] to uplift reliability on our top 10 worst served feeders (identified in collaboration with our customer panels) which will benefit customers on these feeders; these feeders currently experience 4 times more outages compared to the network average. The reliability uplift is forecast to reduce unplanned minutes off supply by an approximately 25% on average for these customers.
- We are proposing to introduce a Regional Reliability Allowance (RRA) to address poor reliability for other regional customers through a program that will be prioritised in line with customer preferences. The Customer Consultative Committee (CCC) will have a role in overseeing the RRA including where and on what it can be spent on, and the outcomes delivered for customers. We are proposing the RRA should be provided on a use-it-or-lose-it basis.
- From late 2023 to early 2024, Euroa (approximately 160 km north of Melbourne) experienced unprecedented unplanned outages unrelated to storms or other weather events, with some lasting over 24 hours. The cause of the outage relates to the remote REFCL at Benalla zone substation which is being addressed in the current period. Notwithstanding the technical challenges related to REFCL, there are other concerns with BN11 that we are aiming to address with our proposed expenditure. We are proposing an economically justified, $21.7m[41] (direct, real 2023-24) project to introduce a new express feeder in the Benalla area to address the concerns.
- The introduction of a new minimum service level standard for feeders, as recommended by the Network Outage Review Expert Panel, and which received in principle support by the Victorian Government, may have implications for this expenditure category. However, it is unlikely that we will be able to address minimum service level standards through the EDPR given the scheme's design is due for government consideration in late 2025. We will work with our stakeholders and the AER on the implications for our plans and our funding requirements as these become clearer.

6.9.2. Overview of forecast and key drivers

In line with the strong feedback received from our customers and the preferences demonstrated through our end-customer research programs, we are proposing a reliability investment program of $118.9m, including for our worst served customers, for the 2026-31 regulatory period. As our proposal will improve underlying reliability, we have adjusted our forecasts to remove expenditure that would be funded through the STPIS.

Our different approach for the next regulatory period (forecasting ex ante capex) reflects the findings of our extensive engagement and research program on the increasing importance of reliable electricity supply to our customers, including in regional areas where it may not be economic to invest due to low customer density and using traditional cost-benefit frameworks. The increasing importance of reliability to residential customers, and willingness-to-pay to improve reliability, has been a key finding of the AER's recent 2024 Value of customer reliability final report. This highlighted that factors such as increasing electrification, customer perceptions and lived experience, and working from home arrangements have likely contributed to the increasing importance[42].

The table below summarises our reliability investment program, which comprises three elements: top 10 worst served feeders; a new express feeder to address issues at Benalla zone substation; and a Regional Reliability Allowance.

[40] Net of STPIS reward.
[41] Net of STPIS reward.
[42] AER, Values of customer reliability - final report, 18 December 2024

Table 6-16: Summary of our reliability investment program net of STIPS benefits (direct, real 2023-24)

	Description	Amount
Investments in the top 10 worst served feeders	Investments in the following feeders: • Bendoc (BM8B31) – Installation of two remote controlled gas switches • Cann River (CNR1, CNR2, CNR3) – Augmentation in Cann River to extend the NLA31-CNR3 tie • Kinglake (KLK11) – Additional supply to the end of the Kinglake township and remote-controlled gas switches on the north leg of KLK11 • Murrindindi (MDI1) – SWER sectionalisation • Moe (MOE13) – New feeder tie to MOE21 • Mansfield (MSD1) – 10km of targeted express overhead sections between Macs Cove and Kevington • Newmerlla (NLA31) – New feeder tie from the NLA31-CNR3 northern leg from Brodribb River to Marlo • Woori Yallock (WYK13) – Extend the adjacent WYK23 feeder to East Warburton as a further backup supply and increase sectionalisation	$20.7m[43]
BN11	A new Benalla to Euroa express feeder with a remote REFCL changeover station	$21.7m
Regional Reliability Allowance (RRA)	Projects to be identified and defined during regulatory period, in close collaboration with our CCC	$76.5m
Total		**$118.9m**

Source: AusNet

Recognising that the worst served customer and BN11 projects are expected to improve reliability under the STPIS and result in an incentive payment to AusNet, we have reduced the proposed costs of our reliability programs by $4.6m to account for these benefits. This approach ensures that customers are not paying twice for these projects – through reliability incentive payments and ex ante expenditure forecasts. Our approach to quantifying these benefits and adjusting our capex forecasts accordingly is discussed further in chapter 6.4.12.

We have also reduced our forecast Guaranteed Service Levels (**GSL**) payments to reflect the reliability improvements expected from these projects. This has led to reduction in our forecast GSL payments of $1.5m over 2026-31 (discussed further in Chapter 7 – Operating expenditure). This is consistent with the Coordination Group's views that expected reliability improvements from proposed capex plans should be reflected in our GSL forecast and STPIS targets (or AusNet should commit to fund some of the program from STPIS rewards).[44]

In developing our planned investment program, we have carefully considered the very strong support from our customers to uplift reliability in some of our worst served areas. This feedback has been consistent across all demographic groups including customers with lower capacity to pay.

6.9.2.1. Improving reliability is a high priority for our customers

Improved reliability is supported by our stakeholder engagement and research. In particular, reliability is consistently ranked the second or third highest priority (after affordability) in our Energy Sentiments tracking study and has remained a consistently high priority throughout the current cost-of-living crisis[45]. Only 68% of customers agree that AusNet's services are reliable, and 50% rank improving reliability as a high priority for AusNet[46]. Furthermore, 87% of AusNet customers say they expect regional reliability to be on par with reliability in metro Melbourne[47]. When the cost impact is considered, our research and engagement has consistently shown that most customers are willing to contribute to the cost of reliability improvements for others, even if they do not directly benefit[48].

This disparity in service outcomes will not be addressed by the STPIS, which employs average reliability targets that have not encouraged reliability improvements in areas with low population density. Over time this has led to a disparity of reliability outcomes depending on where customers are located in our network, which can drive differences in standards of living, industry development and ability to participate in the energy transition (our research indicates that concerns about electricity reliability and resilience deter customers from electrifying their gas and vehicles).

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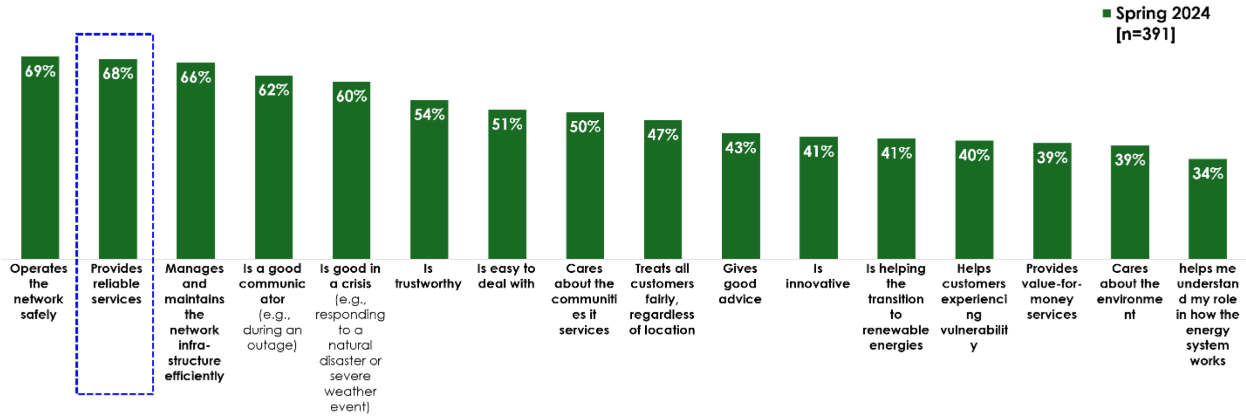
43 Gross capex is $23.5m. STPIS benefits quantified at $2.8m. Capex net of STPIS benefits is $20.7m.

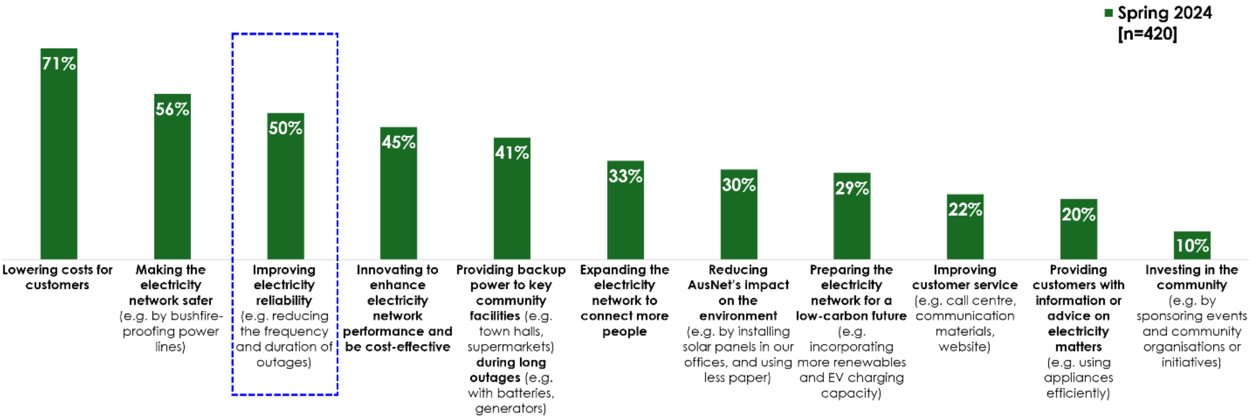
45 AusNet Energy Sentiments study
46 AusNet Energy Sentiments study
47 AusNet Energy Sentiments study
48 For example, our Quantified Customer Values study

Figure 6-3217: Results of AusNet's Energy Sentiments study

% of Agreement to AusNet's Performance



% of High Priorities (in the last 2 years)



Electricity should be as reliable in regional areas as it is in the city

	Total	Customer Type		Gender		Age				Location		
		Residential	Business	Male	Female	18-25	26-40	41-60	61+	Metro	Regional (town)	Regional (out-of-town)
[Base]	**[420]**	[315]	[105]	[202]	[217]	[39]	[131]	[147]	[103]	[287]	[102]	[31]
Strongly disagree	**0%**	1%	0%	1%	0%	0%	0%	0%	2%	0%	0%	3%
Somewhat disagree	**2%**	2%	2%	3%	1%	0%	5%	1%	1%	2%	2%	0%
Neither agree nor disagree	**10%**	9%	15%	13%	8%	8%	14%	10%	9%	11%	11%	6%
Somewhat agree	**35%**	34%	36%	36%	33%	44%	39%	32%	29%	37%	26%	39%
Strongly agree	**53%**	55%	47%	47%	58%	49%	43%	58%	59%	50%	61%	52%
Disagree [Net]	**2%**	3%	2%	4%	1%	0%	5%	1%	3%	2%	2%	3%
Agree [Net]	**87%**	89%	83%	83%	91%	92%	82%	90%	88%	87%	87%	90%

Source: AusNet.

One part of our Quantifying Customer Values (**QCV**) study (provided as a supporting document) attaches a hard dollar value to each unit of unserved energy. This part of the study replicated the AER's VCR methodology but:

- Used a far higher sample size, and
- Applied AusNet-specific consumption and outage data when deriving VCRs from survey results.

The QCV results and how we have applied these in our proposal are discussed further in section 6.4.4.

The other part of our QCV study relates to customers' willingness-to-pay (**WTP**) for other service level outcomes. We asked customers how much they would be willing to pay for a range of service improvements including improving reliability for 20,000 customers with the poorest reliability. We also asked how much more in total customers would be willing to pay for us to deliver the full range of service improvements included in the survey. We then adjusted the willingness to pay results for individual service level uplifts by 'rebasing' these so that, when added together, they did not exceed the total customers were willing to pay for all service improvements.

Our rebased WTP results for improved reliability for worst served customers is $29.88 per residential customer p.a. and $136.68 per business customer p.a. We note that applying the rebased WTP values across our customer base would result in an upper limit reliability proposal of $800 million if the investment would improve reliability to network average levels for 10,000 to 20,000 customers.

6.9.2.2. We have received positive and supportive feedback on our reliability program

The table below outlines the positive and supportive feedback that we have received in response to the reliability program in our Draft Proposal. Our reliability program for 10 worst served feeders and the RRA has evolved over time, due to new information becoming available. Specifically, at the time of our Draft Proposal, our proposed investments were $37m and $67m for worst served feeders and the RRA respectively. We have since updated the amounts to $23.5m and $76.5m for worst served feeders and the RRA respectively. While the composition has evolved, we have maintained the overall program at $100m.

Table 6-17: Feedback in response to the reliability program in our Draft Proposal

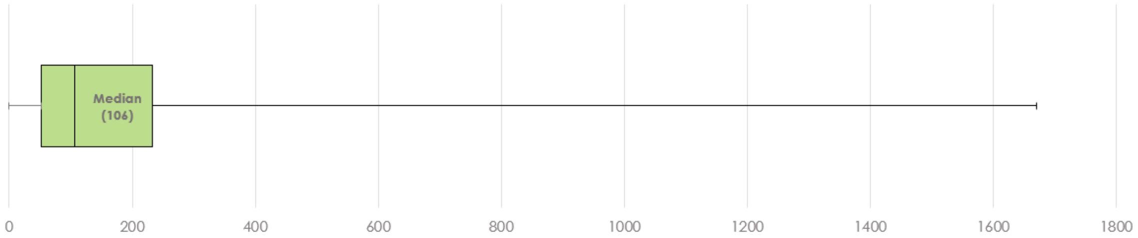
Reliability (general)	
Sandy Point community	**Supported** (92%) the inclusion of AusNet's reliability program, as proposed in the Draft, but noting it should be a minimum with 87% willing to pay more for a larger program that benefitted more customers **Suggested** AusNet look to extend the FRT22 feeder, creating a back-up option for the FRT21 feeder
Emerald Village Association	**Supported** applying a consistent approach to valuing resilience and reliability benefits
Independent submission | MM *(full name withheld)*	**Supported** the plan to maintain similar levels of reliability for most customers and focus on improvements for worst-served.
Independent submission | Jeff Nottle	**Supported** AusNet's commitment to increasing reliability of electricity supply, and the areas where the Availability Panel have had a big impact on decisions taken.
Reliability (worst served customers)	
Emerald Village Association	**Supported** improvements to reliability for worst-served customers, noting customers think metro and regional reliability should be on par. **Supported** the Regional Reliability Allowance (RRA) overseen by the Customer Consultative Committee (CCC), noting this highlights AusNet's social responsibility to address inequalities in power delivery and the increase in demand due to electrification.
Coordination Group Report	**Supported** proposed expenditure and outcomes to be achieved (acknowledging it's unlikely to pass the AER's standard cost-benefit assessment), noting that expenditure should be efficient to achieve this outcome **Suggested** the Regional Reliability Allowance (RRA) be on a use-it-or-lose-it basis **Suggested** AusNet report on how the fund is being spent and outcomes achieved **Suggested** more work be done to define the regional reliability fund purpose and criteria
Independent submission | Piang Lilian	**Supported** proposed investments in reliability for worst-served customers, and for repeating this same process in future price reviews.
Independent submission | MM *(full name withheld)*	**Supported** the commitment to replacing the poorest condition assets and improving reliability for the worst-served customers **Suggested** more work be done to fully design the Regional Reliability Allowance (RRA), but the focus should be on addressing the worst-performing regional areas with a clear identification of the specific issues and a detailed plan for improvement. For example, it would be valuable to outline the challenges in the Benalla area and how the proposal will address them. **Supported** shifting from reactive repair to proactive improvements, e.g. addressing deteriorating poles before they become urgent.

	Suggested a strong focus on improving the reliability of feeders that are causing the most problems to the worst served customers. After that, the focus should be on feeder levels. Said customers, regardless of location, should expect the same level of reliability, since everyone is paying the same for the service.
Email from large customer | *Name withheld*	**Noted** the objective of raising reliability in worst-served areas, and (while they may not directly benefit) the impact is minimal enough to not impact overall affordability.
Independent submission | Jeff Nottle	**Supported** the intention to improve reliability for the worst-served customers/ **Suggested** the Regional Reliability Allowance (RRA) be on a use-it-or-lose-it basis/

Source: https://communityhub.ausnetservices.com.au/engage/feedback

6.9.2.3. Customers served by our top 10 worst performing feeders experience far lower reliability compared to the network average

Customers served by our top 10 worst performing feeders experience far lower reliability than the majority of our customers, with the poorest feeder being off supply for an average of 28 hours a year (excluding Major Event Days or MEDs such as large storms). This far exceeds the less than 4 hours a year that 75% of our customers experience. This outcome is incentivised by the current regulatory framework which applies network average reliability targets which means networks are unlikely to invest in uplifting reliability



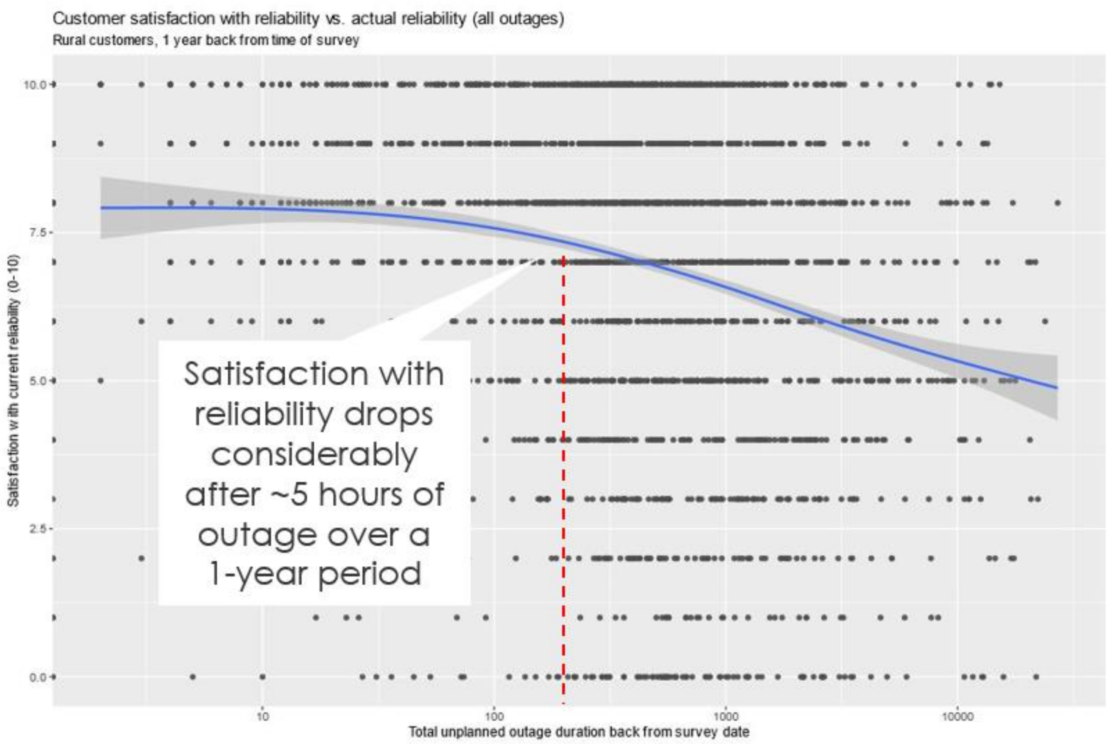
Minimum	0
Quartile 1	52
Median	106
Quartile 3	233
Maximum	1671
Mean	187

Note: 1,671 minutes = 27.9 hours

Source: AusNet.

Customers in regional areas often experience poorer reliability, which we know impacts their satisfaction with their electricity supply; satisfaction with reliability drops considerably after approximately 5 hours of outage over a 1-year period (see figure below).

Figure 6-33: Customer satisfaction with reliability



Source: AusNet.

6.9.2.4. Euroa has recently experienced unprecedented outages

From late 2023 to early 2024, Euroa (approximately 160 km north of Melbourne) experienced unprecedented unplanned outages unrelated to storms or other weather events, with some lasting over 24 hours. The primary cause of the outages relates to the remote Rapid Earth Fault Current Limiter (**REFCL**) at Benalla zone substation which has caused technical challenges on BN11 feeder that services the Euroa area.

Specifically, there are three reasons for BN11's reliability problem:

- **REFCL:** the loss of protection discrimination on REFCL is impacting more customers per fault,
- **Demand constraint:** where summer demand is greater than existing capacity, and
- **Topology/reliability:** BN11's long radial network topology with no back up supply means that customers are exposed to a higher number of faults and longer duration faults.

Due to the substantial disruption these prolonged outages are causing our customers, we have assessed a range of options to remove the demand constraint and improve reliability on BN11 and identified a solution that is economic in the next regulatory period (discussed further below). We consider it is important to address BN11's reliability issues.

6.9.2.5. Uplifting reliability is consistent with the Network outage review recommendations

Uplifting the reliability of worst served feeders is supported by the following final recommendations of the Network Outage Review Expert Panel:[49]

- Recommendation 12 relates to the need for a minimum service level standard for feeders, which if breached, would require remediation by network businesses, and
- Recommendation 13 is a licence condition for AusNet to improve the reliability of specified feeders and install quick connect points in key townships.

These recommendations were made because, after engaging broadly with customers impacted by the February 2024 storm, the Network Outage Review Panel considered that the lived experience of power outages in communities was not adequately taken into account in network investment decisions and operational behaviour[50].

Minimum service level standards received in principle support from the Victorian Government, who will consider these further in late 2025. The Network Outage Panel has provided the following guidance:

- Service level standard must account for customers' experience of prolonged power outages
- Scheme is targeted at supporting reliable electricity supply to communities at high risk of prolonged outages
- Account for limitations in the national framework by addressing network areas at risk of frequent and prolonged power outages due to poor performance, and
- Provide service improvements that better meets community needs and expectations.

We will engage in the Network Outage Review implementation process in parallel to the EDPR process, and adjust our plans as required to ensure our proposal reflects both customer preferences and any new compliance requirements (such as minimum standards), and that we can secure adequate funding. We will also remove any duplication in our expenditure forecasts that may arise if Recommendations 12 and 13 are formally implemented.

For these reasons it is possible that some of the exact solutions and feeders on which we will invest may change over the course of the EDPR review period prior to the AER's final decision; nonetheless, our proposal reflects our current view.

6.9.2.6. Consistency of reliability expenditure with the regulatory framework

We consider that the AER should approve our reliability expenditure program as being consistent with the regulatory framework in that the program appropriately balances the need to provide sufficient funding to deliver secure and reliable power supply, whilst making sure our customers don't pay more than necessary.

In particular, the NER provides the AER with discretion to make trade-offs across a range of capital expenditure objectives and factors to make decisions that contribute towards the achievement of the NEO. We consider that this program of reliability-focused expenditure appropriately balances these matters, having regard to that, this expenditure:

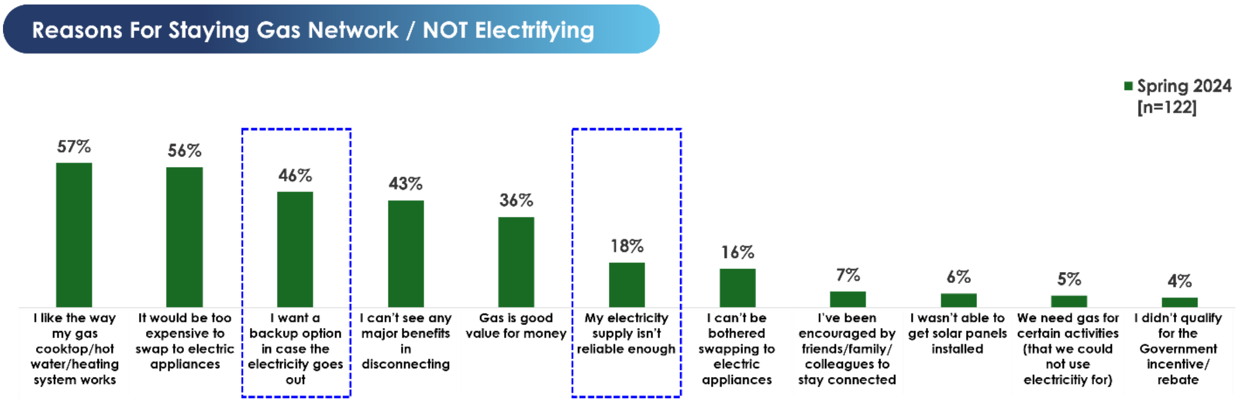
- **Seeks to maintain reliability more fairly across our entire customer base** – in particular, the 10 worst served feeder projects will improve reliability for locally connected customers by 25%, with the overall the impact on the network average reliability resulting in a 1% improvement. Whilst the program of work will result in network

[49] Expert Panel, Network Outage Review, Independent review of transmission and distribution businesses operational response to the 13 February 2024 Storms, Final Report, p. 10. Accessed here: Network Outage Review | Engage Victoria
[50] Ibid, p. 38

average reliability remaining materially the same, and well within the year-to-year variations that we expect to see, our regional customers will benefit from a more reliable service than previously experienced. This demonstrates that we are seeking to more equitably address the need to maintain reliability across our entire customer base in a measured way, with no over-investment or gold plating. As outlined in section 3.4.6, the gap in the duration of outages for urban and rural customers has grown by around two-or-three folds since 2010. Our customer research reveals some customer support for equalising reliability outcomes between urban and rural areas (albeit with no consideration of cost). Our reliability proposal does not seek to close this gap but to start to address the growth.

- **Contributes to emissions reduction targets** – in particular, our customer research reveals that customer concerns about poor reliability are the third-largest barrier to customers electrifying their homes. Reducing network outages will help address customer's concern about poor network reliability, making them more willing to shift from gas to electrical appliances in pursuit of net zero goals. See figure below.

Figure 6-34: Reasons for staying with the gas network and not electrifying



Source: AusNet's Energy Sentiments study.

- **Makes appropriate adjustments as between operating and capital expenditure, as well as to our incentive schemes** - as noted above, our reliability program is proactive in accommodating the expected reduced opex required, to take into account the reduction in GSL payments, as well as making adjustments to reflect reliability improvements under the STPIS framework.
- **Incorporates appropriate checks and balances to ensure prudency and efficiency** – our Customer Consultative Committee will have a role in overseeing the RRA including where and on what it is spent and the outcomes delivered for customers. Additionally, while the NEO and capital expenditure criteria (6.5.7(c)) makes it very clear that the AER can only accept prudent and efficient capital expenditure plans, there are no rules requirement to define and undertake cost benefit analysis for all projects included in a Revenue Proposal. This means the RRA is capable of being approved by the AER if it addresses the capital expenditure objectives (6.5.7(a)) and there are measures in place to ensure future projects funded by the RRA are prudent and efficient. We support prudent and efficient costs being included as a guiding principle with the RRA provided it appropriately balances the need for improved reliability in areas that would otherwise not be improved under the current regulatory framework. Further consultation would be needed to define this.
- **Is allocatively efficient** – Efficiency is a key tenant of the economic regulatory framework. This is typically considered in terms of productive efficiency, which relates to producing goods at the lowest cost. Another type of economic efficiency is allocative efficiency, which refers to the distribution of goods and services optimally to satisfy customer needs and preferences. Spending on network reliability is allocatively efficient when it aligns with customer preferences and willingness to pay, as we have demonstrated through robust survey evidence, and validated through engagement, including through consultation on our Draft Proposal. Allocative efficiency occurs when resources are directed to areas where they generate the greatest value for consumers. In this case:
    - Surveys confirm that customers prioritise and are willing to pay for reliability improvements, indicating these investments align with their preferences.
    - The allocation of resources to reliability uplift ensures that customers receive value in proportion to their willingness to pay, maximising social welfare.
    - By addressing customer-stated priorities, these investments ensure that spending reflects demand and delivers long-term benefits that customers explicitly endorse.
    - In relation to worst-served customers, our QCV study also tested whether customers who were not worst-served were willing to pay to uplift the reliability of those who were. This research found that all demographic groups tested were willing to pay for reliability improvements, even if they don't expect to directly benefit.

If our reliability proposal is not accepted by the AER, this will highlight gaps within the regulatory framework and its ability to support funding requests that align with customer preferences. Therefore, jurisdictional legislation (such as minimum standards, as recommended by the Network Outage Review Panel and supported by the Victorian Government in principle) will become necessary to drive positive customer outcomes.

6.9.3. Projects and programs

6.9.3.1. 10 worst served feeder improvements

The customers in AusNet's electrically remote areas experience greater outage impacts than urban customers due to the:

- Higher likelihood of faults due to greater network exposure to weather, vegetation, lightning and other fault causes correlated with the longer length of circuit between the supply and the customer.
- Higher consequence of an outage due to the lower availability of back-up supplies from adjacent feeders; lower sectionalisation and penetration of automation, meaning that more customers are impacted per fault event; and challenging terrain meaning that fault finding and repair can take longer than a shorter urban network.

Generally, feeders are overhead or underground cables that transport electricity from zone substations to supply points or direct to our customers; they can be high voltage or low voltage. We have approximately 360 feeders on our network where each feeder serves a specific geographical area.

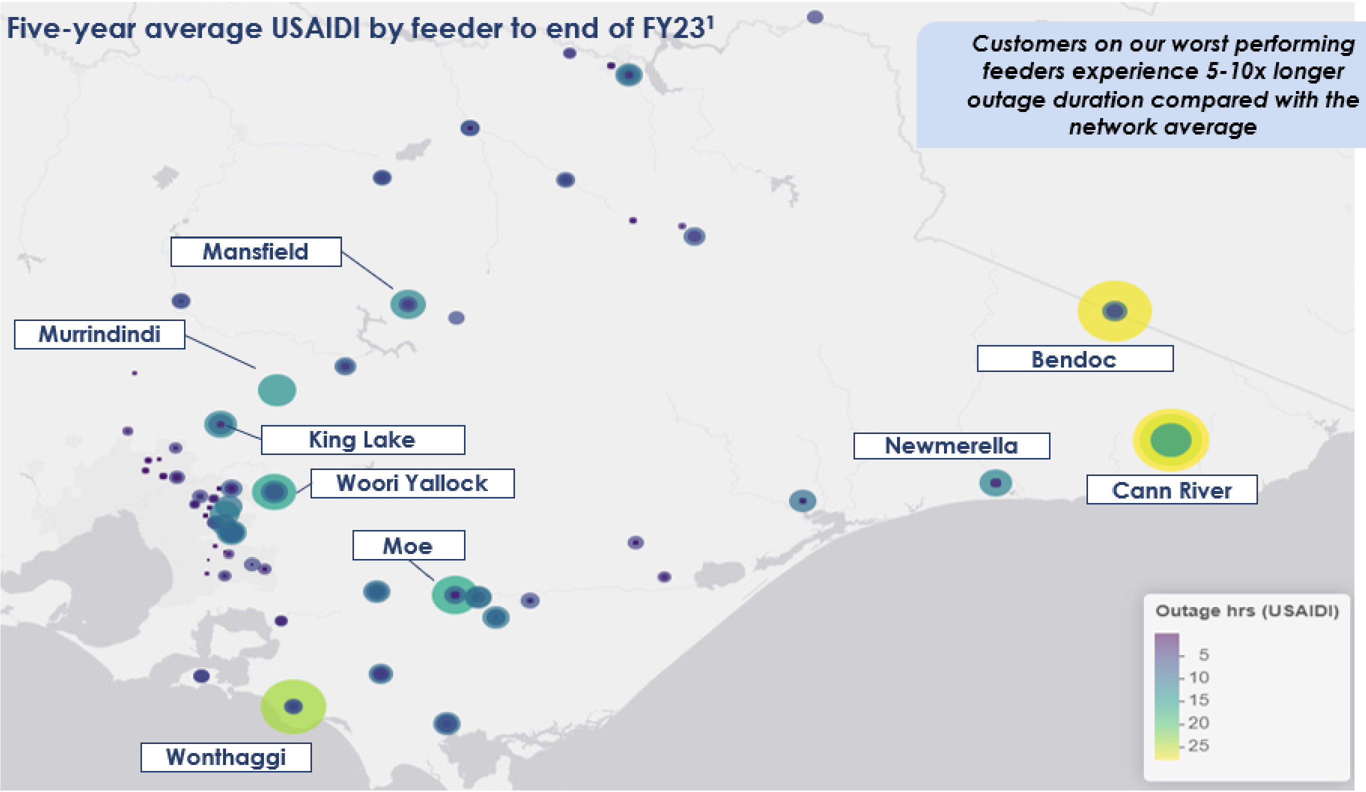
Network average reliability metrics can dilute and mask the poor performance of certain feeders due to good reliability somewhere else, while feeder level reliability metrics is far more granular and thus do not suffer from dilution to the same extent.

6.9.3.1.1. Methodology and key assumptions

- We adopted the following methodology:
- Identification of the 10 worst served feeders based on the criteria determined in conjunction with the Electricity Availability Panel:
  - Total unplanned minutes off supply (measured by variation from the average reliability level experienced by our customers) should be the primary criteria but a range of "secondary criteria" should also be accounted for. Notably remoteness, vulnerability (using the Socio-Economic Indexes for Areas (SEIFA) index) and the number of life support customers, which tend to be overrepresented on the poorest-reliability feeders.
  - It is sensible to exclude the impact of Major Events Days (MEDs) from the total unplanned minutes off supply to target underlying and ongoing poor reliability, given the solutions to address poor reliability can be quite different to those that are focused on resilience. This approach allows AusNet to develop distinct programs for resilience and reliability while also identifying and removing any overlaps.
- Identification of the problems on each feeder using five years of historical outage information, excluding MEDs.
- Identification of credible solutions for each feeder using network information, engineering input and historical unit costs.
- An economic valuation of the customer benefits (excluding MEDs) based on the energy lost during network outages and the AER's 2023's VCR – performed for the base case (do nothing) and each proposed intervention.
- A NPV assessment for each proposed intervention against the base case (do nothing).
- Selection of a preferred option based on NPV analysis, customer considerations and a sensitivity analysis using variable discount rates and costs.
- We also tested the NPV using the combined approach to the VCR i.e., combining our QCV for residential customers ($52.4/kWh) with the AER's 2023 VCRs for non-residential customers.

The 10 worst served feeders and the average reliability levels currently experienced by customers are shown in the figure below. The worst served feeders are high voltage feeders, where customers experience outages greater than four times the network average. These customers are also vulnerable compared to the network average based on SEIFA, and they are considered remote as defined by the Accessibility/Remoteness Index of Australia (**ARIA+**).

Figure 6-35: Location of 10 Worst Served Feeders identified with the Availability Panel



Source: AusNet.

6.9.3.1.2. Stakeholder feedback

Our methodology and key inputs to develop our reliability plans has centred on our consumer engagement through the Electricity Availability Panel; our All-Panel workshop in August 2024; and feedback from the Coordination Group. We have relied principally on this feedback to guide the level and type of investment that we should undertake. Once the overall direction has been settled, we adopted a standard economic assessment framework to identify the investment that delivered the best outcome for customers in terms of maximising the NPV. The remainder of this section explains the feedback we received from our consumer engagement. The detailed economic assessment is presented in the next section, which discusses the specific programs and projects for the 2026-31 regulatory period.

Our Electricity Availability Panel has advocated strongly for more equitable reliability during our engagement with them. The inclusion of investments to improve outcomes for worst-served customers is a result of their advocacy and we have collaborated extensively on the design of this expenditure category, from agreeing the criteria for "worst served customers" through to determining the right investment-level-to-outcome ratio from a range of options. As agreed with our Electricity Availability Panel, we have sought to minimise overlaps with our resilience program by focusing worst served customer investment on network areas with poor reliability during system normal conditions (excluding MEDs).[51]

We also engaged closely with this Panel on the introduction of a new reliability fund, which would allow us to invest in improving performance through targeting additional worst served customers, with flexibility to address issues as they emerge as the network evolves during the next regulatory period. While there were different views on the amount of expenditure to allocate to this fund, its introduction was supported by most Panel members.[52]

At the All-Panel workshop in August 2024, we consulted on the right level of reliability investment accounting for trade-offs between different capex categories. Specifically, we presented the options outlined in Figure 6-36. Most of the Panel Members supported $25m for uplifting reliability for 10 worst served feeders and $75 million for a regional reliability fund (that is, option 3 with an upper limit of $100 million in the figure below), subject to appropriate governance arrangements being put in place.

[51] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, section 10.1.1 and p. 19, 25 and 68.
[52] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 19 and 72.

Figure 6-36:18 Reliability options

Option 1: All "optimal" projects	Option 2: All "feasible" projects	Option 3: All "optimal" projects + $25-100m reliability fund
Feeder improvements (mainly ACRs and remote-control switches and cables)	*CMOS significantly reduced through higher cost and broader number of solutions including larger number of SAPs and km of cables*	
$25m total	***$125m total***	***$25-125m total***

In its Final Report, the Coordination Group summarised its position on our proposed worst served feeder:[53]

> *"The Panel is supportive of expenditure to improve reliability of the worst served customers on equity grounds. While expenditure should be efficient in terms of being the lowest cost to deliver the defined outcome, we do not expect it to pass the standard AER cost benefit analysis – this is why these worst served customers have had to endure poor reliability for so long."*

At the All-Panel workshop, we also presented the bill outcomes as a 'package'; that is, the overall network bill outcomes based on the Panel Members' preferred option within each capital expenditure category. This allowed Panel Members to see the impact of their preferred options holistically to enable further refinements and trade-offs to their decisions. Panel Members maintained their support for $25 million for uplifting reliability for 10 worst served feeders and $75 million for a regional reliability fund. Expenditure requirements were subsequently refined to $23.5m for worst served feeders and $76.5 million for RRA which keeps the total reliability expenditure requirement at $100 million.[54]

6.9.3.1.3. Results

Our analysis shows that undertaking investments in the 10 worst served feeders is NPV positive. Specifically, when using the AER's 2023 VCRs to quantify the reduction in expected unserved energy, the NPV is $8.1m. Under the alternative combined approach to the VCR, the NPV is $16.3m.

6.9.3.2. Regional Reliability Allowance

We are proposing to introduce a RRA to address poor reliability for other regional customers. There are pockets of customers who experience worse reliability than the average of the worst served feeders. The RRA would allow us to invest in improving performance through targeting additional worst served customers, with flexibility to address issues as they emerge as the network evolves during the next regulatory period.

A RRA of $76.5m of capital expenditure has been included in this Regulatory Proposal, providing a total of $100m investment when combined with the worst served customer program.[55] This total aligns with the feedback received from most members of our Electricity Availability Panel. Our Available Panel considered that strong governance arrangements should be in place to ensure this fund delivers customer benefits.

In developing our RRA, we have applied the following principles:

- The RRA should be provided on a use-it-or-lose-it basis, similar to the scheme for the innovation fund that was approved by the AER for the current 2021-26 regulatory period. This will ensure that AusNet does not benefit from underspending the approved expenditures. In practice, this would mean that the RRA will be embedded within our building block revenue, and any underspend at the end of the 2026-31 period would be trued up in the revenue determination for the 2031-36 period. The true up mechanism would account for inflation, and the underspend is the difference between approved revenue and the impact of actual spend on revenues due to the RRA projects, across the whole 2026-31 regulatory period (year-to-year variations do not matter). The impact of overspending against the approved revenue for RRA projects will not constitute a true up adjustment.
- It should exclude spend that is funded elsewhere through the incentive framework. That is, project costs that will be remunerated through the reliability incentive scheme should be excluded from the amounts reported under the fund.
- Our Customer Consultative Committee should have a role in overseeing the RRA including where and on what it is spent, and the outcomes delivered for customers.
- RRA should be excluded from the CESS and EBSS as any underspend should not be eligible for incentive payments under the schemes. This removes the incentive to underspend the approved expenditures.

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[53] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p.19.
[54] $24m for 10 worst served feeders is the capex requirement without the STPIS rewards removed. Once removed, the net capex requirement is $21m. See chapter 6.4.12.
[55] Capex requirement (before STPIS rewards are removed) are $23.5m and $76.5m for 10 worst served feeders and RRA respectively (direct, real 2023-24). The total is $100m (direct, real 2023-24). A negative adjustment for STPIS – of $2.8m – has been applied to 10 worst served feeders which reduces its capex requirement to $20.7m. See chapter 6.4.12.

In its Final report, the Availability Panel recommend further consultation with it to work up the governance of the RRA. It also considered that useful guiding principles could include targeting other feeders where customers are inadequately served; consulting with consumers on target feeders; setting up an advisory panel as an independent check and seeking to maximise net benefits within the budget.[56]

Subsequently, we engaged on potential criteria with our Availability Panel and received broad support for the following:

- Consider unplanned outages only
- Allow us to identify customers (not feeders) who have experienced very poor reliability over a sustained period, including because of extreme weather events
- Consider both the duration and frequency of outages, given both can impact customers' reliability experience (a multi-measure approach with weightings may therefore be necessary)
- Measure reliability relative to the network average, rather than in absolute terms (consistent with how minimum reliability standards are typically set, and the approach agreed with the Availability Panel to identify the 10 Worst Served Feeders)
- Where possible, identify 'clusters' of customers in particular network locations, in order to maximise the net economic benefits from a single project
- The Panel's support being conditional on appropriate governance arrangements, with the Customer Consultative Committee having a key role in determining where and how the money is spent, and
- Socio-economic factors being considered qualitatively.

We propose to use the following performance measure/s to identify investment under the RRA (which will be subject to stakeholder feedback and approval from the Customer Consultative Committee):

- Customer Average Interruption Duration Index (total outage hours per customer divided by number of outages)
- Customer Minutes Off Supply combined with Number of Outages (weighted approach), and
- Unplanned System Average Interruption Duration Index (USAIDI).

Consistent with the RRA providing flexibility to identify and assess projects during the next regulatory period, we have not proposed specific projects that, if approved, the fund would be allocated to. However, the types of solutions we expect to consider include:

- Covered conductor
- Remote control switches
- Auto circuit reclosers
- SAPs
- Undergrounding
- Section ties (new or upgraded)
- Span length reductions
- Feeder extensions, and
- Express overhead sections

If approved, we will work closely with our Customer Consultative Committee to prioritise projects within the regulatory period, using up-to-date information on network performance, and ensure the fund delivers value for money. This approach has proven effective in the context of innovation, where we have worked with our IAC to administer the innovation funding approved at the last reset. This approach also avoids specifying projects that could raise expectations of specific communities, that may then be deprioritised during the period, as another project better aligns with the preferences of our customer base.

Beyond this regulatory review, there is merit in exploring the impact of poor reliability on electrification and the broader energy transition, and on regional prosperity in Victoria. AusNet has a social responsibility not to further entrench or create new inequities through the energy transition based on highly varied levels of reliability. There may need to be policy support to enable both capacity and reliability uplifts in regional areas to promote equity across our broad customer base, which will need to be balanced with implications for energy affordability.

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[56] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 27.

6.9.3.3. New express feeder in Benalla (BN11)

From late 2023 to early 2024, Euroa (approximately 160 km north of Melbourne) experienced unprecedented unplanned outages unrelated to storms or other weather events, with some lasting over 24 hours. The cause of the outage relates to the remote REFCL at Benalla zone substation which has caused technical challenges on BN11 feeder that services the Euroa area. We have an in-flight project that is addressing the REFCL challenges at BN11.

Notwithstanding the technical challenges related to REFCL, there are two other key concerns with BN11 that we are aiming to address with our proposed expenditure.

- Demand constraint: where summer demand is greater than existing capacity.
- Reliability concerns: BN11 is a long radial network topology (1,207 km) with no back up supply which means that customers are exposed to a higher number of faults and longer duration faults.

The BN11 feeder supplies 4,782 customers and its supply area covers the townships of Violet Town and Euroa, and it largely falls within a high bushfire risk area.

6.9.3.3.1. Methodology and key assumptions

We undertook an exploration phase that included the AusNet team engaging with a distribution network service provider (**DNSP**) representative from another state to understand its approach to customer reliability on long feeders.

Taking the outputs of the exploration phases, we developed a set of credible options and built concept level cost estimates using unit rates. To assess each option, we undertook a quantitative approach which included:

- Identified the problems on the BN11 feeder using five years of historical outage information.
- Developed credible solutions using network information, engineering inputs and historical unit costs.
- For each option, we quantified the benefits based on expected unserved energy and the AER's 2023 VCRs relative to the base case (do nothing).
- Conducted a net present value assessment (**NPV**) for each proposed intervention against the base case (do nothing).
- Selected the preferred option based on the NPV analysis, customer considerations and a sensitivity analysis using variable discount rates and costs.

We assessed the following options:

- **Base case**: Do nothing
- **Option 1:** New battery energy storage system (BESS) for Euroa.
- **Option 2:** Partial supply of BN11 load from AusNet's RUBA12 and MSD2 feeders.
- **Option 3:** The installation of diesel generators at Euroa.
- **Option 4:** A new Benalla to Euroa express feeder with a remote REFCL changeover station.

We also tested the NPV using the combined approach to the value of customer reliability i.e., combining our QCV for residential customers with the AER's 2023 VCRs for non-residential customers.

6.9.3.3.2. Results

Our analysis shows that option 4 (a new Benalla to Euroa express feeder with a remote REFCL changeover station) is the preferred option as it maximises the NPV of all options assessed. Option 4 will address both the demand constraint and reliability concerns, and it is also the preferred option under a range of sensitivity testing, including under the combined QCV/AER's 2023 VCRs approach.

6.9.4. Benchmarking and validation

Our reliability capex forecast, for the 10 worst served feeders and BN11, are based on a thorough and extensive cost benefit analysis, specifically:

- The cost estimates that have been prepared as part of a standardised approach to developing, managing and reporting projects and programs of works (see Project Cost Estimating Methodology), and
- The benefits have been calculated consistent with our methodology as described in section 6.5.1, which is also consistent with the RIT-D guidelines.

Our RRA forecast has been based on feedback from our Panels at the all-Panel offsite in August 2024. Specifically, we presented the three options outlined in figure 6-36. Most of the Panel Members supported $25m for uplifting reliability for 10 worst served feeders and $75 million for a regional reliability fund (that is, option 3 with an upper limit of $100 million. We have since updated our capex forecast to $21m and $77m for 10 worst served feeders and the RRA respectively, reflecting updated costs and further analysis.

6.9.5. Supporting documentation

We have included the following documents to support this chapter:

ASD - AusNet - EDPR Business Case - Worst Served Feeders Program - 31 Jan 2025

ASD - AusNet - Economic model - Worst Served Feeders Program - 31 Jan 2025

ASD - AusNet - EDPR Business Case - BN11 - 31 Jan 2025

ASD - AusNet NPV Model (AER VCR) - BN11 - 31 Jan 2025

6.10. Connections expenditure

6.10.1. Key points

The key points in this chapter are:

- Customer connection expenditure is required to connect new customers to our electricity network. This is partly funded by contributions charged to customers for connecting or upgrading their supply. Only the net connections capex, being the difference between total connections and capital contributions received from customers, is recovered from all customers through distribution network tariffs.
- Customer numbers are expected to increase in the 2026-31 regulatory period, with residential and business connections forecast to grow consistently with historical trends.
- We are forecasting gross and net connections capex to be $619m and $342 million respectively over the 2026-31 regulatory period. For net connections capex, this is 14% higher than expected net connections capex the current regulatory period.
- We are reducing the forecasting risk to our customers by proposing a CESS exclusion for connection expenditure associated with rapidly evolving technologies, including data centres, dedicated grid or community scale batteries, public EV charging stations and dedicated electric bus charging infrastructure at depots.

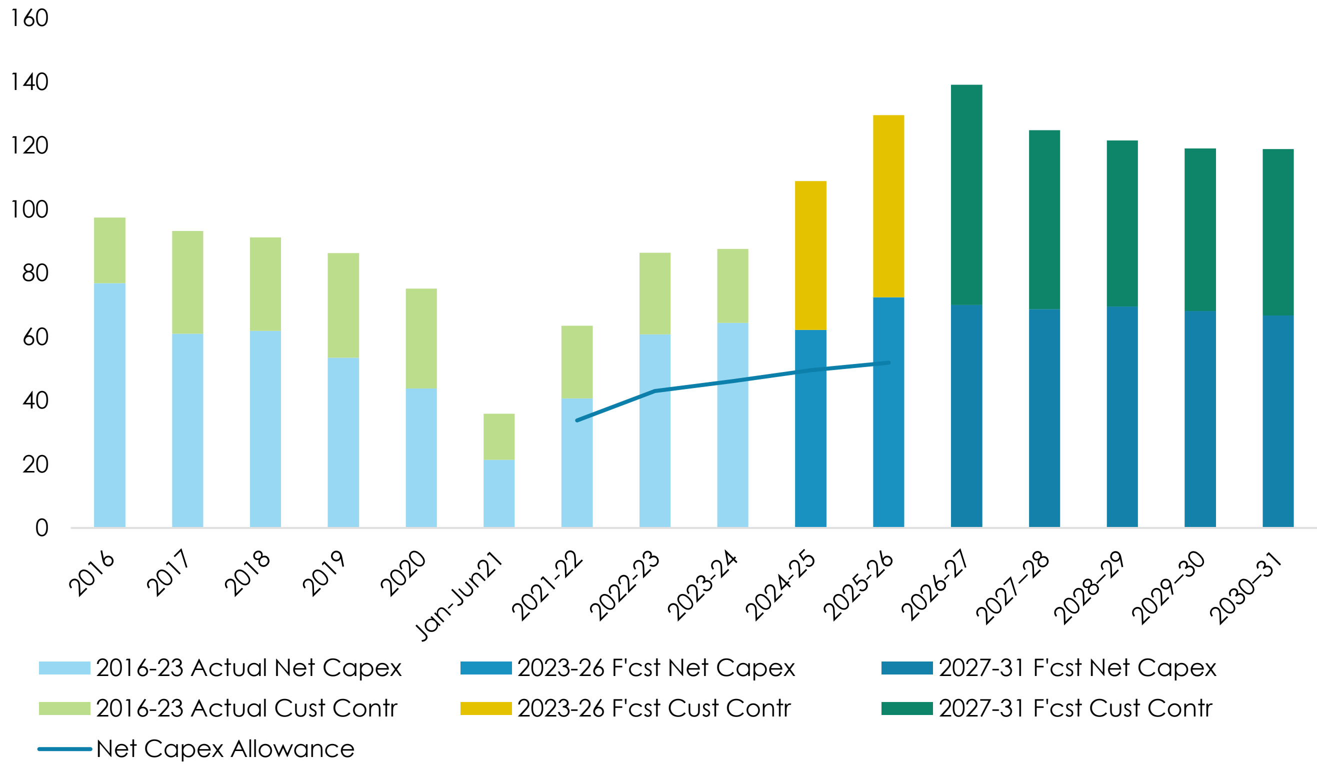
6.10.2. Overview of forecast and key drivers

NER 5A obligations[57] require us to facilitate the connection of, and contribute customer connection expenditure to, new customers connecting to the shared electricity network and customers expanding existing supply at their home or business.

Over the 2026-31 regulatory period, we are forecasting increases in gross and net connections capex to be $619m from $475m in 2021-26, and $342m from $300m in 2021-26, respectively. Only the net capex, being the difference between total connection capex and capital contributions received from customers, is included in our regulatory asset base. Our historical and forecast gross and net connections capex is shown in the figure below.

[57] NER 5A Part E, NER 5A.F.6(a)) and the AER's connection charge guideline (April 2023)

Figure 6-3719: Gross & net connections capex and contributions 2016 to July 2031 ($m real Jun-2026)



Source: AusNet

The figure above shows our forecast increase in both gross and net connections capex from growth in connection costs and volumes. We note we have or are expecting to overspend net capex allowance in all years of the current regulatory period, due for a range of reasons including:

- Increase in unit costs above the increase allowed for in our net capex allowance
- The connection volume downturn associated with COVID-19 was less severe than expected in the 2022-26 final determination,[58] which allocated a lower connection capex than our proposed connection capex
- Hybrid (battery) connections that were not included in our net capex allowance but have formed part of our actual connections capex in the current period
- The increase in expenditure in 2022-23 is due to a $10m spike in a few very large business connections (e.g., rail, water, and alpine resorts) compared to prior historical averages
- Higher unit costs contribute to increased gross connection costs in the forthcoming years.

Our key drivers for connections capex include:

- Growth in new connections (i.e., customer number growth)
- New customer types and emerging technologies
- Demand for electrification of transport and gas appliances, requiring larger and more expensive (three phase) connections
- Higher unit rates and changes to the marginal cost of reinforcement (**MCR**), customer demand, energy consumption and solar uptake estimates, and
- Available network capacity, particularly in the growth corridors where we expect new connections.

The separate inclusion of electrification of transport and new customer types are a new key driver in the forthcoming period. New customer types include:

- Hybrid and battery connections
- Data centre connections, and
- Connections for public EV charging stations and dedicated EV bus charging infrastructure at depots.

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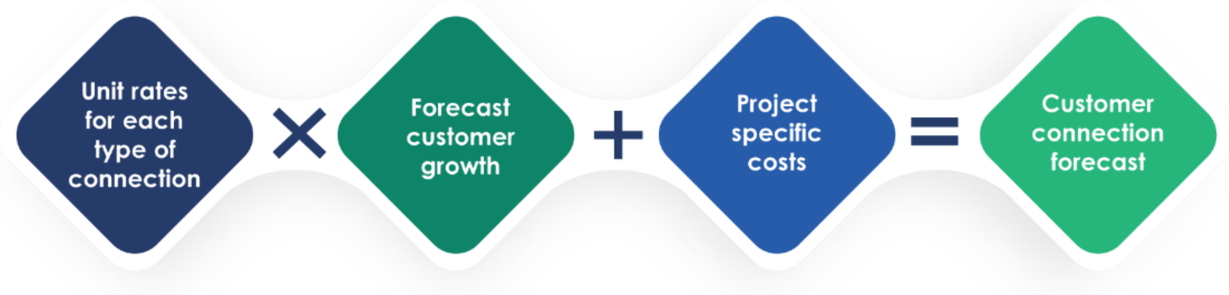
[58] 2022-26 final determination connections allowance was based on the revised Housing Industry Association's (**HIA**) forecast of a 37% decline in 2021-22. Residential housing connection volumes did not drop compared to historical trends in 2021-22.

6.10.3. Methodology and key assumptions

Customer connection capex funds the establishment of connection assets for specific customers, and the associated network augmentations needed to strengthen the network to meet the customer's demand. Our total connections capex forecast, therefore, reflects the efficient level of investment required to deliver the forecast number of new connections.

Our total forecast connection expenditure is the product of our expected customer volumes and connection unit rates, see Figure 6-38 below.

Figure 6-38: Customer connections forecasting approach



Source: AusNet

The key inputs and assumptions to our forecasting methodology are summarised in the table below.

Table 6-18: Key inputs and assumptions (connections capex)

Input / assumption	Description
Forecast customer growth	We forecast customer growth for residential, small business, commercial and industrial categories using historical growth data and forecasts provided by AEMO and the Victorian Government.
Forecasts for transformation projects in the clean energy and technology transition	We expect a surge in new types of business customers, including public EV charging stations, data centres, grid-scale batteries and battery/generation hybrid facilities. We developed forecasts using data from proponents' specific projects and the EV forecast data from AEMO's 2023 CSIRO collaboration, apportioned to our network by percent of Victorian customers.
Unit rates	Our unit rates are based on actual project costs and prices provided by contracted service provider agreements, adjusted to account for the impact of inflation and labour market factors e.g., work force OHS requirements. Additionally, these unit rates also apply to our project specific cost estimates.
Marginal cost of reinforcement and other connection assumptions	We update all assumptions that affect our connection charges using the latest information. A key input is the MCR, which has been updated to reflect the latest data on the costs of augmenting the shared network.
Demand and energy consumption for new connections	For each customer type, we apply the average demand, energy consumption and take-up of solar generation, to reflect actual data for new connections over the previous 5-year period.
Proposed CESS exclusion on connection categories associated with technologies with high uncertainty of connection volumes and cost	Excluding the following categories from the CESS that will apply in the next regulatory period: • hybrid and battery connections • data centre connections • connections for EV charging stations for public EV charging stations and dedicated EV bus charging infrastructure at depots.
Compliance with laws, codes and standards	We must comply with several regulatory obligations and legislative requirements, including NER 5A[59], Electricity Distribution Code of Practice clause 3.2, AER's connection charging guideline, AER's guidance on reporting capital contributions and the AER's approved framework and approach. These requirements prescribe which new connections we fund and the capital contribution we charge to the connecting customer.

[59] Obligations that require making a connection offer (various clauses in chapter 5A), entering into a connection contract (i.e., clause 5A.F.6) and carrying out the connection work for basic, standard and negotiated connections (i.e., clause 5A.F.6(a)).

Customer and stakeholder feedback	Feedback from our Coordination Group to: • Continue with existing connection policies that include customer contributions and avoid cross-subsidies when connecting and upgrading connections for customers electrifying gas appliances and transport; and • Exclude from our connections expenditure CESS new customer types and emerging technologies due to uncertainty in forecasting rapidly increasing volumes of EV chargers, battery/hybrids and data centres arising from the potential for changes to market trends and government policy incentives.

Source: AusNet

In the sections below, we discuss some of the principal issues arising in relation to our connections capex for the 2026-31 regulatory period.

6.10.3.1. Customer number growth

Meeting our customer needs and accommodating new customers on our network is at the heart of what we do, as reflected in our purpose to 'connect communities with reliable, affordable and sustainable energy'. NER 5A obligations[60] require us to facilitate the connection of, and contribute customer connection expenditure to, new customers connecting to the shared electricity network and customers expanding existing supply at their home or business.

To connect our new customers and meet the needs of all our customers, we need to accurately forecast our new customer growth and their maximum demand to 2031. The National Electricity Rules, our F&A and the AER's connections charge guideline require us to invest a proportion of capital expenditure to connect new customers, recognising future revenue that will be received from new customers as they consume electricity from the network will benefit all customers by reducing their future charges, given we operate under a revenue cap.[61] Therefore we recover a portion of customer connection capital expenditure from all our network customers through distribution network tariffs.

AusNet has a strong track record of accurately forecasting the number of customers connecting to our network for new residential, business and rural customers in our electricity distribution regulatory proposals. However, in the current period, our net and gross expenditure varied from the approved allowance based forecasts due to higher-than-expected forecast unit rates, inflation and the absence of HIA's forecast decline in our residential housing volumes in 2021-22. These differences resulted in higher actual connections expenditure than our allocated allowance over 2021-26.

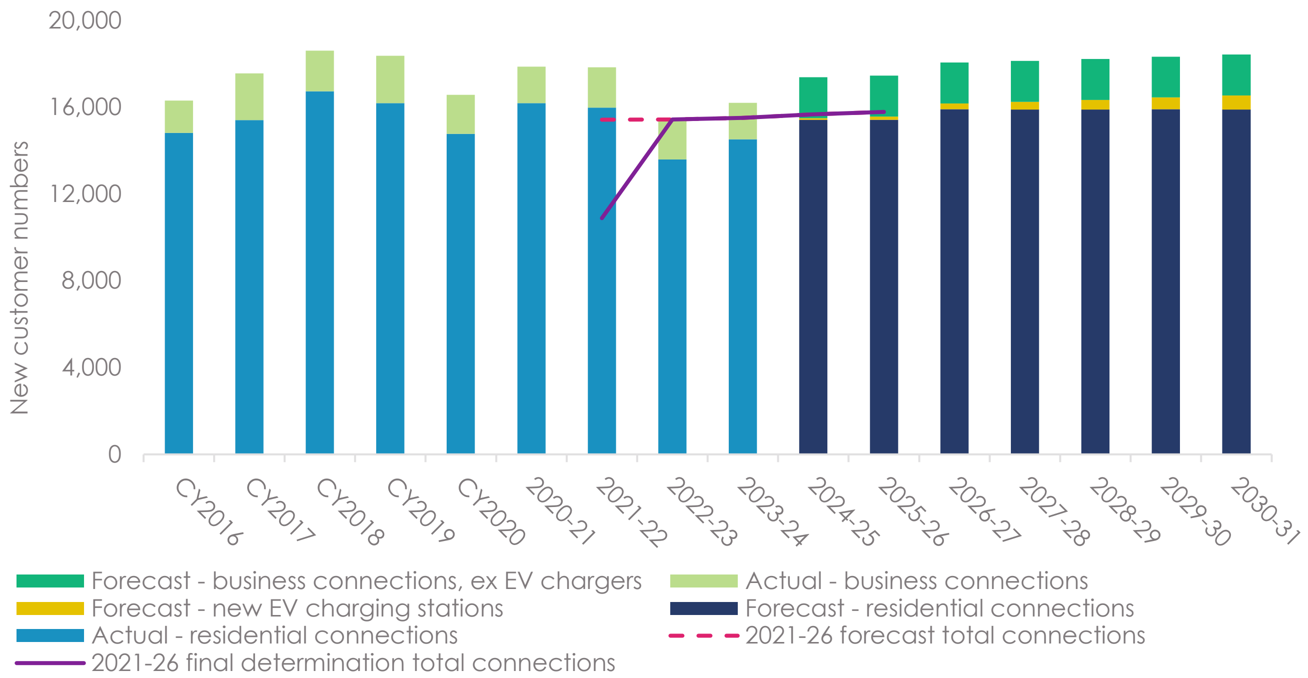
Residential customers have consistently grown in line with population growth, concentrated in new housing growth in our growth corridors, east and north of Melbourne. We forecast customer connection volumes to grow by about 79,000 new residential and 11,700 new business connections in 2026-31. Residential and business (existing types of business) connections are expected to continue with population and economic growth.

In addition, new types of business customers, such as public EV charging stations, grid batteries, energy intensive data centres, are emerging. These new types of business customers will make significant impacts to our connection expenditures by 2031.

The figure below shows our forecast and historical connections and includes the emerging connection volumes of public EV charging stations.

[60] NER 5A Part E, NER 5A.F.6(a)) and the AER's connection charge guideline (April 2023)

Figure 6-39: Gross numbers of new customer connections to our network



Source: AusNet

6.10.3.2. New customer types and emerging technologies

In the 2026-31 regulatory period, we expect unprecedented growth in the new customer types and emerging technologies, including:

- Dozens of dedicated grid or community scale batteries.
- Embedded generation and hybrid connections that support our renewable future. These new renewable energy embedded generation projects include energy storage is classified as hybrid or bi-directional connections.
- Hundreds of new public EV charging stations per year to meet the growing need for more charging locations, shown in yellow in the above figure.
- Several new data centres that keep data secure and provide new AI services with large continuous load requirements. These are often paired with contracted renewable energy generation projects.
- Bus depots electrifying their fleets for around-the-clock operations with upgrades to, at least, C-I-C.

We have observed a rapid uplift in project specific enquiries from potential applicants. This trend is expected to continue, and we need to make sure our plans allow for flexibility as the renewable energy transition progresses and technology evolves. Given the rapidly evolving trends for these types of connections, we may update our forecast in our Revised Proposal to take account of more recent information.

6.10.3.3. Customer supply upgrades from electrification

Our residential customers that are electrifying gas appliances and transport may require supply upgrades at their premises e.g., from single phase to multiphase. In most cases, this electrification need could require altered connection to the existing power lines adjacent to the premises for the cost of a fee-based charge and an electrical upgrade at their premises.

However, in other circumstances where existing shared network assets lack the capacity to meet these needs, they will require more significant connection work. The most common scenarios relate to a customer requesting three phase connection, where:

- an old (pre-2005) pit or pillar underground lines only provide single phase connections; or
- SWER, transformers or single-phase powerlines in rural and remote areas.

Currently, our connection policy and service classification treat these upgrades as 100% applicant funded Alternative Control Services (**ACS**). A question arises as to whether this policy should continue or whether some of the upgrade costs should be funded through our capex programs rather than by the connecting customers.

We sought advice from our Coordination Group on our approach to residential customer supply upgrades which are driven by the energy transition on whether to:

- continue to charge supply upgrades for residential customers as 100% applicant funded, which may lead to barriers to electrification, or
- treat some as standard control services, reducing applicant costs, to reduce barriers to electrification, moving from cost recovery from individual customers to a shared cost by all AusNet customers.

Our Coordination Group recommended that we:

- consider the broader benefits for necessary upgrades to individual customer supply to enable electrification; and
- continue to apply our existing connection policies that include customer contributions and avoid cross-subsidies.

Given this feedback, we are not proposing changes to our proposed Connection Policy.

6.10.3.4. Unit rates

Our unit rates are based on similar connection types for most categories of connection. For the 2026-31 regulatory period, we are forecasting unit rate increases for connections expenditure as a result of:

- recent labour cost escalations and inflation driven by economic factors and workforce OHS requirements
- increases in our MCR unit rates from an uplift in the volume and cost of upstream augmentation projects, as reflected in our actual costs over the previous 5-year period.

These unit rates increase impact our gross connections for all connection categories, whether applied to forecasts based on historical costs or project specific costs.

We note our unit rates used for connection forecasts do not reflect our recently tendered and agreed Zinfra contract, discussed in section 6.4.7. The implications of the Zinfra contract on actual connection project expenditure are still being assessed. For this reason, our proposed connections expenditure is based on unit rates consistent with our historical average actual project costs. If required, we will update these unit rates based on our new contract in our revised proposal.

6.10.3.5. Forecasting approach for each connection category

Our approach to forecasting each category of connections expenditure is based on the best available data. For historical data in low volume connection categories where the average cost per connection fluctuates, we use a longer-term average unit rate in our forecast. The longer-term average approach better accounts for variations in the number of projects and the characteristic of those projects, undertaken in a year. Table below summarises our forecasting approach for each category.

Table 6-19: Our approach to forecasting unit rates and connection volumes for each category

Connection category	Approach to unit rates	Approach to volume forecasts
Medium density housing	Where a third party constructs and developer gifts assets to us: Gifted LV Assets - at agreed unit cost per lot (subject to annual CPI inflation) HV Rebates - at current average unit rate (2023-24) Where we design and construct, we use the 2023-24 financial year historical unit rate.	Historical proportion of forecast residential connections
Underground service installation	Based on pre-calculated capital contributions in our proposed updated standard connection services Model Standing Offer that reflect 5-year historical average costs for 2019-24	Historical proportion of forecast residential connections
Business supply projects	5-year historical average unit rate (2019-24), except for data centres that have very high utilisation that is atypical from other business supply projects.	Historical proportion of forecast non-residential connections
Complex residential supply projects	5-year historical average unit rate (2019-24)	Historical proportion of forecast residential connections
Low Density housing - subdivision	5-year historical average unit rate (2019-24)	Historical proportion of forecast residential connections

Private electric line replacement	5-year historical average direct costs incurred (2019-24)	Forecast driven by historical average volumes
Hybrid and batteries (1.5MVA or less)	Forecasts of cost for generation connections over the 2026-31 period are based on a pipeline of projects using the latest information provided by proponents.	Forecast at project level and community battery incentives offered by Vic. Gov.
Hybrid and batteries (greater 1.5MVA)	Forecasts of costs for generation connections over the 2026-31 period are based on a pipeline of projects using the latest information provided by proponents. These costs are significant and involve network extensions in the 66 kV network.	Forecast at project level
Data centres	Forecasts of new data centre connections over the 2026-31 period are based on our best expectation, that incorporates industry trends, preliminary inquiries by data centre operators and comparable project costs.	Forecast at project level
EV charging stations for public and EV bus depots	Forecasts of EV charging stations are based on AEMO and Vic. Government forecast	AEMO's VIC EV charging profiles scenarios (draft 2024 ISP data for Step Change) apportioned by population and network size, plus project specific EV bus depots from the Department of Transport (**DoT**)

Source: AusNet

6.10.3.6. Reducing uncertainty

We are proposing a CESS exclusion on connection categories associated with evolving technologies for which the rate of connections and roll-out is highly uncertain during 2026-31, and for which there is no historical data to use for estimating forecasts. By excluding this expenditure from the CESS, we are reducing the risk of windfall gains and penalties purely from forecasting error, which has the potential to be very significant depending on market trends and government policy developments. The risk of these gains and penalties are born by both customers and the network through the CESS arrangements.

The uncertainty and scale potential scale of evolving technology-driven connections has been highlighted in Jemena's network, where the customer connections forecast related to data centres has been significant enough for them to apply to the AER to re-open their current period EDPR.[62]

Our current forecast of new technologies connecting to our network is based on growth assumptions and our visibility of forthcoming projects through connection requests as well as best available desktop studies of expected growth rates. The table below summarises the forecast volumes and the sources of uncertainty for each technology type.

Table 6-20: Impact and uncertainty with connection forecasts for new business types and associated uncertainty

Connection new business type	Connections capex impact by July 2031	Source of uncertainty
Community battery connections	An estimated 30 community battery of various sizes (20kW/40kWh – 5MW/20MWh) but typically 60kW/200kWh	Forecasts do not include future government grants and incentives. New government initiatives during the 2026-31 regulatory period could significantly impact this forecast.
Grid scale battery and renewable generator hybrids	Increasing the number of grid scale battery and renewable generator hybrids by 511% with 10 new major projects	Risk and uncertainty that not all of our anticipated projects do not proceed,[63]
Connections of public EV charging points and EV bus depots	Increasing volumes and connections capex by 790% to 2,536	Policy changes and market forces vary from AEMO's 2023 modelling assumptions, and EV charging station connection costs variations from historical averages.
Data centre connections	Two 66kV connected data centres projects expected	One project with strong interest from a data centre operator and one forecast data centre. Connection costs variations based on indicative cost estimates (based on similar connection projects) and customer contribution calculation.

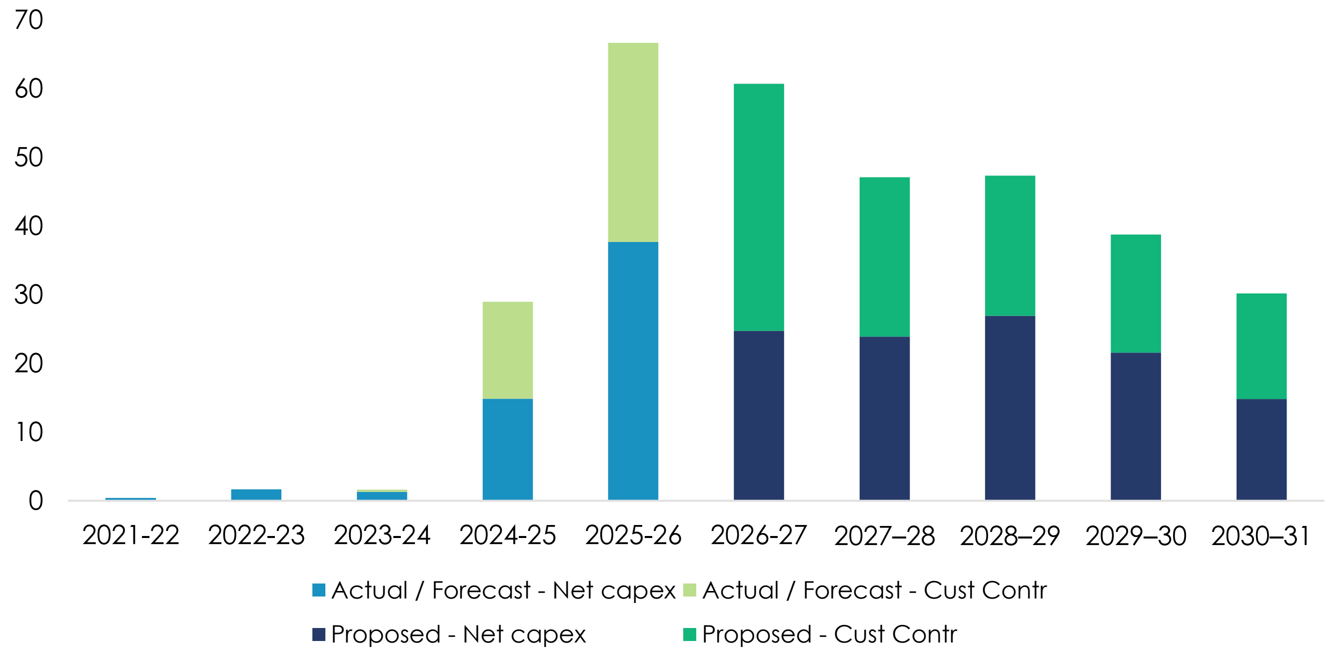
Source AusNet

[62] https://www.aer.gov.au/industry/registers/determinations/jemena-determination-2021-26/update-application-reopen-capex
[63] Based on expressions of interest from credible renewable energy proponents, we reasonably anticipate 7 hybrid projects at the start of the 2026-31 regulatory period.

The scale of growth for 2026-31 far exceeds our forecast of household customer growth (9.3%) and medium business customers (7.6%).

Forecasting connection expenditure for these new customer types is very difficult due to limited information on the scale of roll-out of these technologies to 2031 and lack of sufficient evidence of connection costs. When forecasting very high growth (expected to be required of many evolving technology connections during the energy transition (e.g. public EV charging)), forecasts become particularly sensitive to changes in assumptions and factors outside of our control. Additionally, as shown in the figure below are net capex and customer capital contributions for projects associated with grid scale hybrids, batteries and data centres take years to develop and are subject to factors outside of our control.

Figure 6-40: connection capex for hybrids, batteries, data centre, and EV charger ($m real Jun-2026)



Source: AusNet

Likewise, customer contributions are equally uncertain as every customer contribution is based on anticipated demand and consumption profiles, which are also mostly still unknown. National and Victorian policy changes in the form of subsidies or restrictions on charging customer contributions could have an even larger impact on our CESS performance outcomes and by their very nature are unpredictable and outside of AusNet's control.

In our previous determination, reflecting many of the same sources of uncertainty associated with these new connection types, the AER agreed to remove large embedded generators from our connections capex forecast and they now do not form part of our Regulated Asset Base. This arrangement is working well but is unavailable for connection types that involve a load and are therefore partly funded by AusNet to recognise these customers will contribute towards SCS revenues.

We have discussed this growing level of uncertainty with the Coordination Group, and the possible ways to manage the risk to our customers, including our proposed approach. The Coordination Group has acknowledged the risk of uncertainty is growing and that some mechanism to address this issue would be of value.

Our proposed CESS exclusion on the above categories would allow AusNet to propose our best forecast of expenditure affecting revenue. If new technology take-up exceeds expectations, and our cost estimates are materially higher than actuals, the CESS exclusion avoids our customers paying for efficiency rewards that were achieved not through efficiencies but through inaccurate forecasts. Conversely, if our estimates are materially lower than actuals, it eliminates the incentive provided by the CESS to find capex savings elsewhere, potentially at a cost to our customers in terms of service performance. The Coordination Group have provided their support for a CESS exclusion.[64]

6.10.3.7. Updates that may be required during the process

Not core methodologies but inputs and assumptions including:

- Unit rates – as flagged we are assessing whether the Zinfra contract we will be under from August 2025 should
- MCR updates

[64] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 32.

- WACC (if the latest is materially different compared to that applied in our forecast)

Large customer forecasts (including data centres) given these are lumpy and increase materially due to factors outside of our control.

CESS exclusion – depending on the updated CESS

6.10.4. Projects and programs

The table below shows the key connection projects and programs for the 2026-31 regulatory period, showing the proposed expenditure over the forecast period and the percentage each category contributes to this expenditure category.

Table 6-21: Connection projects and programs for 2026-31($m, 2026) and % of total connections expenditure

Connection category	Gross $m	% of gross connections capex	Net $m	% of net connections capex
Medium density housing	97.84	15.7%	85.3	24.9%
Underground service installation	84.92	13.6%	27.4	8.0%
Business supply projects	173.15	27.8%	121.3	35.4%
Complex residential supply projects	64.94	10.4%	15.8	4.6%
Low Density housing - subdivision	15.0	2.4%	3.4	1.0%
Private electric line replacement	3.86	0.6%	1.4	0.4%
Hybrid and BESS (1.5MVA or less)	1.95	0.3%	3.8	1.1%
Hybrid and BESS (greater 1.5MVA)	71.7	11.5%	21.3	6.2%
Data centres	42.6	6.8%	26.6	7.8%
EV charging stations for public and bus depots	67.0	10.8%	36.3	10.6%
Total	**623**		**343**	

Source: AusNet

6.10.5. Benchmarking and validation

Our forecast connection capex is the product of our customer growth projections and the applicable unit rates. The total connection capex is a mix of simple and complex connections that need to be factored into the forecasts. The customer number projections are based on a detailed 'bottom-up' and 'top-down' modelling approach. The robustness of this forecasting approach supports the use of the customer number projections in relation to the connection capex forecasts.

In terms of benchmarking, our unit rates are derived from historical cost data and previously tendered unit rates, which reflect the conditions on our network and capture efficiency improvements. The use of historical data and market tested rates provides a strong assurance that the proposed connection capex is prudent and efficient. As discussed in section 6.10.3.4, we have only recently tendered a new agreement with Zinfra, and once we assessed the impact on actual costs, we could update our unit rates in our revised proposal.

6.10.6. Supporting documentation

We have provided the following key documents in support of our connections' proposal:

- Appendix 9A – Project Cost Estimating Methodology;
- Appendix 9B – Unit rates;
- Capex Model;
- Connections Capex Forecast Model;
- EV charging station forecast model; and
- Model Standing Offer - Standard Connections

6.11. Large renewables enablement

6.11.1. Key points

- In 2023, the National Electricity Objective (NEO) was updated to include the objective of meeting emissions reduction targets set by the Federal and Victorian governments.
- AusNet's role as a distribution network service provider is to undertake network and non-network investments that are consistent with the NEO, which from 2023 includes an assessment of the benefit of emission reductions in assessing the efficiency of proposed project. Such projects, in principle, may include initiatives to unlock capacity for the growth of renewable generation and storage, including from Consumer Energy Resources (CER) as well as utility scale renewable generation and storage.
- Utility scale or large renewable generation in the distribution network is mostly concentrated in the sub-transmission (66kV) component of our network. This is the highest voltage part of the network closest to the transmission network, which attracts larger generators and storage. We are already experiencing significant growth in renewable generation in specific parts of our network that have strong renewable resources, including solar and wind.
- Our proposal is to unlock capacity in our sub-transmission network to enable more renewable generation and storage, in areas where the benefit of those investments outweighs the cost. Investing $156m in the 2026-31 period will deliver $382m of benefits, unlocking 950 MW renewables and reducing 2.1Mt CO2 emissions while also reducing wholesale electricity prices in the long term. Specifically, we have identified four projects that are expected to deliver these benefits for customers, three of which are already progressing through the RIT-D process.

6.11.2. Overview of forecast and key drivers

Our large renewables enablement forecast for the 2026-31 regulatory period is $156m (direct, real 2023-24).

The sub-transmission network (66kV network) has a critical role to play in accommodating the growth in large-scale renewables that is required if Australia is to meet its emission reduction targets; manage the closure of coal plant; and deliver the lowest cost outcome for electricity customers. The purpose of this large renewable enablement program is to identify network augmentations and non-network projects to facilitate the connection and growth in large renewable generation efficiently and prudently for the benefit of our customers.

The large renewable enablement program is a new category of expenditure, driven by the following key drivers:

- The Victorian government's legislated targets for renewable generation and emissions reductions, consistent with the emissions objective in the NEO
- Strong demand for renewable generation in our sub-transmission network, as illustrated by the growth in large generator enquiries on our network and the broader national drivers for increased renewable generation, as outlined in AEMO's Integrated System Plan
- The existing network limitations, which restrict the available capacity on our sub-transmission network to accommodate large renewable generators
- The changing role of distribution networks in unlocking more renewable generation, and
- Customer and stakeholder feedback.

We address each of these matters in turn.

6.11.2.1. Legislated renewable and emissions targets and NEO update

The NEO has been amended to recognise that the long-term interests of consumers include contributing to the achievement of government targets for reducing Australia's greenhouse gas emissions. Through the connection of additional renewable generation, fossil fuel powered generation is displaced. As such, the Large Renewable Enablement Program will promote the long term interests of consumers in accordance with the NEO.

The Victorian Government's legislated emissions reductions and renewable energy targets provide further context and impetus for the Large Renewable Connection Program. The targets are set out below:

- Legislated emissions targets
- 45-50% reduction by 2030

- Net zero emissions by 2045
- Legislated renewable energy targets
- 65% by 2030
- 95% renewables by 2035

The transition to renewable energy and electrification will be an important factor in achieving these emissions targets. Enabling greater renewable connection on the sub-transmission network will support meeting these targets by unlocking the potential for increased renewable generation capacity.

6.11.2.2. Growth in demand for renewable generation

We are experiencing significant growth in distribution-level enquiries from large renewable generators. In particular, the magnitude of the total capacity that is being sought is several multiples of the existing large renewable generation capacity and the available capacity on these portions of the network.

The figure below highlights those areas of our network where we are receiving the highest number of generator and battery enquiries. These are typically areas with good wind or solar resources, where customer density is low (e.g., farmland and rural areas). Because of low customer density and low need for electricity, these parts of the network are lower capacity than for example in urban areas.

Figure 6-41: Summary of AusNet areas with high generator connection requests

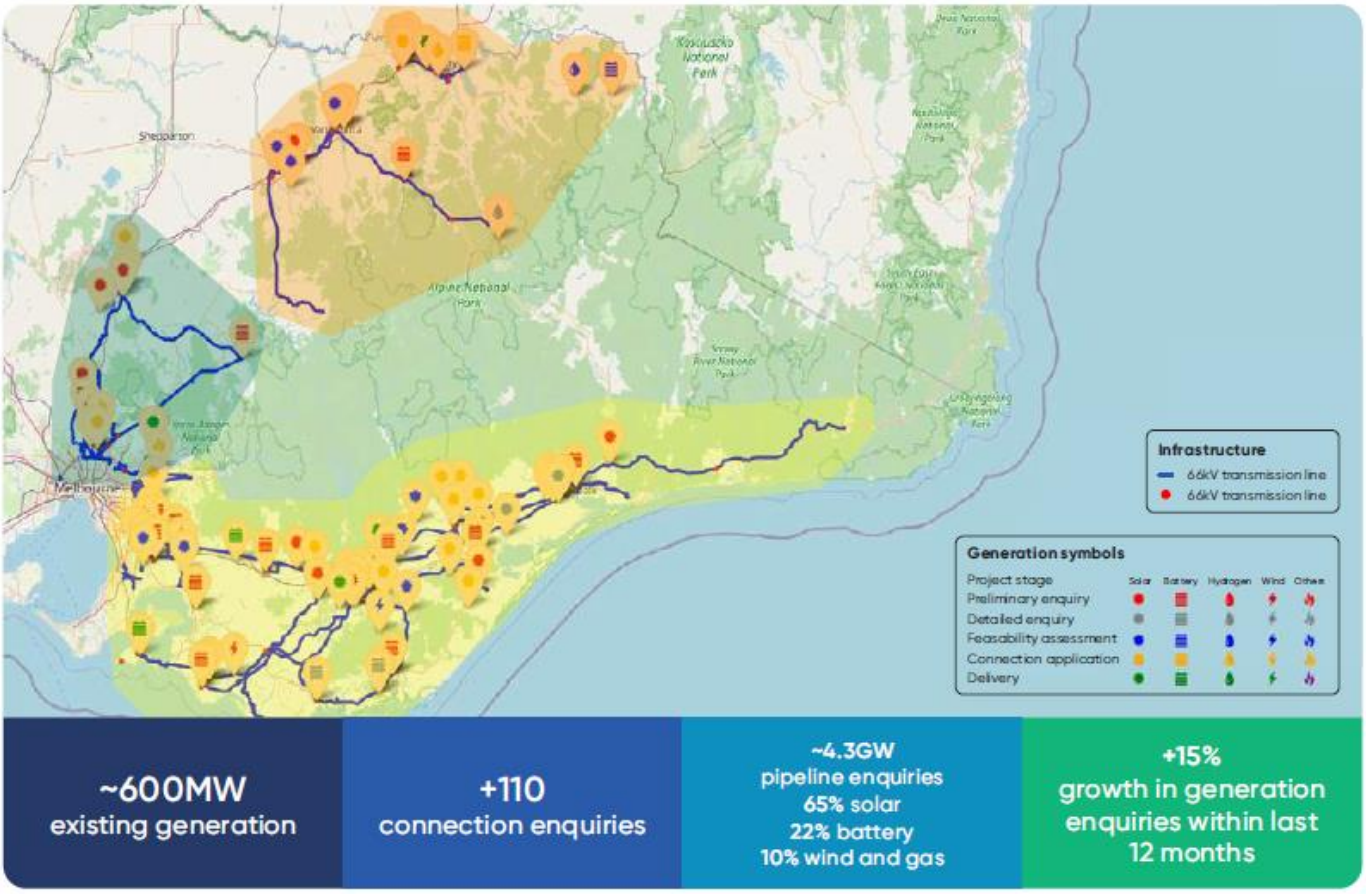


Table 6-22: Large scale embedded generation connection enquiries

	Existing large-scale generation connections	Large-scale generation connection enquires
Morwell East network	123.1 MW	1360 MW
Morwell South network	141.4 MW	865 MW
Wodonga – Barnawartha in North-Eastern Victoria	60 MW	390 MW

Source: AusNet.

AEMO's 2024 Integrated System Plan (**ISP**) observed that investment in both utility-scale and consumer-owned renewable generation is needed to meet growing demand for electricity as coal generation retires. In particular, AEMO explained that:

- Coal is retiring faster than previously announced.
- Rooftop solar and other consumer-owned energy resources are forecast to grow five-fold by 2049-50.
- Utility-scale solar and wind are forecast to grow six-fold by 2049-50.
- Renewable Energy Zones (REZs) are being planned to house most of the utility-scale assets.[65]

With most coal plant expected to withdraw by 2034-35, AEMO forecasts that approximately 82 GW of utility-scale wind and solar will be required by that date. A further increase in capacity to 126 GW is forecast by 2049-50. To put these capacity requirements into context, the current utility-scale renewable generation capacity in the NEM is only 19 GW, with a further 5 GW of capacity planned to be operational before the end of 2024. The projected growth in renewable generation connection across the NEM is therefore extremely challenging for transmission and distribution network service providers.

6.11.2.3. Changing role of distribution networks in delivering renewables targets

As indicated by AEMO's 2024 ISP, it is expected that distribution networks across the NEM will play an important role in accommodating the projected growth in renewable generation.[66] From a network perspective, it should be noted that promoting renewable generation connections at the sub-transmission level has several advantages compared to transmission connections including:

- **Social licence**—distribution upgrades are a significantly less intrusive compared to transmission towers that require easements, and therefore entail less community impact.
- **Faster project delivery**—distribution upgrades can be delivered faster than major transmission infrastructure due to less complex planning, community/stakeholder engagement and construction processes.
- **More streamlined network planning & delivery**—because AusNet is the planner as well as owner and operator of the sub-transmission and distribution network in its region, planning and delivery of upgrades is more streamlined than transmission upgrades that typically involve transmission and distribution network service providers.
- **Supply reliability risk mitigation**—augmentation at the sub-transmission level helps to mitigate supply reliability risks that may be caused by delays in progressing major transmission projects.

These advantages represent a significant opportunity to overcome the current barriers of transmission investment and accelerate the deployment of renewables to support Victoria in meeting its targets. In short, AusNet can unlock capacity for renewable generation efficiently and in a way that meets government targets at least cost, without the project delivery risks that are typically associated with transmission network growth.

6.11.2.4. Customer and stakeholder feedback

We discussed the value of networks unlocking more capacity for larger renewable generation in the sub-transmission network in detail primarily with our Future Networks Panel, then tested it more broadly with all panels and the general public during engagement on the Draft Proposal. Our panels were generally pleased to see AusNet looking for opportunities to efficiently unlock more renewable generation and leveraging existing network capacity, rather than relying solely on transmission upgrades, as has traditionally been the case. It was explicitly supported by our Future Networks Panel in the Coordination Group's report on our Draft Proposal.

We have taken this into account in designing our proposal for large renewable generation. Our proposal is to unlock capacity in our sub-transmission network for renewable generation and storage, in areas where the benefit of those investments outweighs the cost. All Victorian and NEM customers benefit from this investment through lower wholesale energy prices, as more renewable energy is unlocked.

We explained two potential investment options under this approach with our EDPR stakeholders at an all-Panel discussion at our August 2024 offsite. Initially the Future Networks Panel was unable to agree unanimously on an outcome. The broader group voted to "do more" to efficiently connect renewables (higher investment option), on the basis that it would lower overall costs of the system compared to deferring large renewables to the transmission system or connecting generators paying the whole cost of connecting without coordinated planning. The fact that upgrading the sub-transmission network uses existing easements and may defer the need for new easements and power lines, was also very attractive to some Panel members.[67]

We also received feedback that we should be considering alternative generator connections in the transmission network in assessing the value of investment in the sub-transmission network. While the sub transmission network may

[65] AEMO, 2024 Integrated System Plan, June 2024, page 49.
[66] AEMO, 2024 Integrated System Plan, June 2024, page 30.
[67] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, section 10.1.2.

be an alternative to transmission level connections for some generators, we do not consider sub transmission and transmission connections are perfect substitutes for several reasons, including generator preferences around the location of the connection, generator size, system strength requirements and level of constraints on the transmission network. As such, we cannot directly compare sub transmission network connections to transmission connections and cannot assume that generators that do not connect to the sub transmission network will therefore connect to the transmission network.

We further tested support for investments in sub-transmission to enable larger generators where efficient through our customer workshops and Draft Proposal where customers indicated support for proactive investment where it would lead to clear benefits. Our Draft Proposal's alignment with sustainability, government policy and net-zero goals was generally well-received including in relation to connecting large generators. A caveat over support for the large renewable connections enablement proposal is that customers and stakeholders want AusNet to provide more evidence that customers would be better-off-overall. While customers in the workshop were generally comfortable with others benefitting (even if they were not directly paying), they did want confidence that AusNet customers would benefit.

In addition, we conduct an annual survey of large embedded generators looking to connect to AusNet's distribution network. In our 2023 survey, we heard the upfront cost of connecting and lack of network capacity were the main obstacles applicants cited for connections at the sub-transmission level. Developers suggested the costs of upgrades should be shared where the upgrade will benefit other parties beyond the connection applicant. Our proposal is aligned with this feedback by sharing costs to alleviate constraints with AusNet, where our customers will benefit from the upgrades at locations with high demand for connection applicants.

6.11.3. Methodology and key assumptions

Our 66kV sub-transmission network was planned, built, and maintained to deliver energy to load customers, and is typically not strong enough to connect significant additional renewable generation. The ability of the distribution network to accommodate renewable generators may be limited by a number of technical considerations including:

- thermal limits
- voltage levels including voltage dips / rise and voltage fluctuations at the connection point, considering both normal and single contingency scenarios
- voltage harmonics and flicker emissions
- network fault levels
- reverse power flows
- system strength, and
- the availability of fibre optic capacity to provide communications services.

Based on renewable generation enquiries, we can anticipate the need for network augmentations that are likely to arise to address these network limitations, based on the projected growth in renewable generation capacity over the planning horizon.

As highlighted, there is a significant opportunity to unlock more customer benefits through investment that enables large renewable generation in AusNet's sub transmission network. Our planned investment demonstrably delivers net benefits to our distribution customers whilst also providing benefits to the broader NEM. This approach ensures that the Large Renewable Enablement Program is consistent with the updated NEO and capital expenditure objectives of the National Electricity Rules. It also addresses stakeholder feedback regarding 'who pays' for the augmentation, by ensuring that distribution customers are net beneficiaries from any proposed augmentation of the sub-transmission network.

While our analysis has identified several areas of our network where renewable generation enquiries are limited by current network constraints that could be relieved through augmentation, our proposed program only targets the areas which can be economically justified by quantifying the customer benefits below. Our approach is therefore consistent with the NEO and stakeholder feedback.

In broad terms, the types of customer benefits that may be delivered through investments in this program are:

- **Market benefits that lower energy costs for consumers.** Electricity from renewables is cheaper than fossil fuels. Therefore, enabling additional renewable generation in the network will put downward pressure on wholesale electricity prices.
- **Lower emissions by offsetting thermal generation with zero emissions generation.** The benefit in emissions reductions is achieved by enabling renewable generation to displace thermal generation. AusNet quantified the benefits from reductions in carbon emissions using the cost of carbon as given in the draft guidance published by the AER[68].

[68] https://www.aer.gov.au/documents/aer-valuing-emissions-reduction-draft-guidance-march-2024

- **Maintaining network reliability at lower cost.** The additional thermal capacity and redundancy provided by sub-transmission network augmentations such as additional/upgraded 66kV lines, transformers and other components will assist in ensuring that we maintain network reliability in accordance with our customers' expectations. Furthermore, the additional network capacity created would benefit load customers through future electrification requirements such as adaptation of EVs, replacement of gas appliances with electric appliances etc.

The table below outlines the key inputs and assumptions

Table 6-23: Key inputs and assumptions (large renewables enablement)

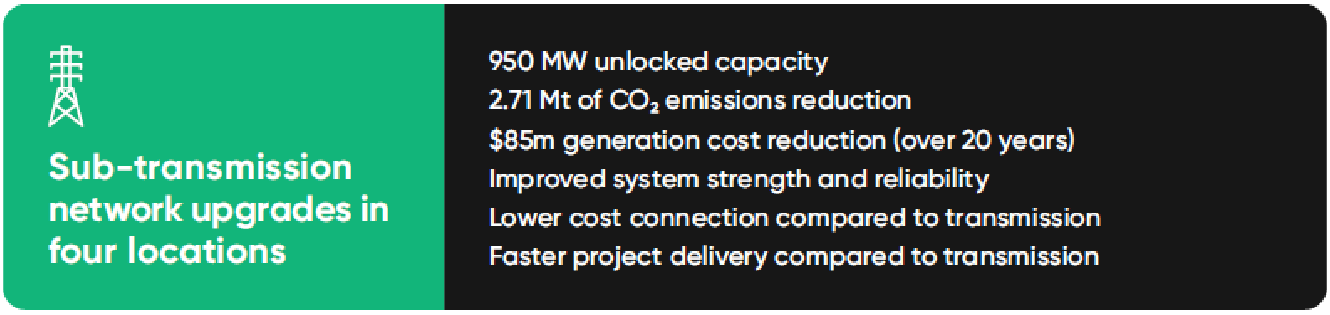
Input / Assumption	Description
Discount rate	See section 6.5.1.
Value of Emissions Reduction (VER)	The AER is responsible for developing the value of emissions reduction (VER) to be used in investment planning by networks, consistent with the guidance provided by the AER under the CECV and the published emissions intensity profiles. The first VER was finalised on 22 May 2024, and has been adopted in our modelling.
Market benefits	This is calculated in our model as a reduction in wholesale generation costs. Further on the modelling approach is outlined in our Large Renewable Connection Program document.
Customer and stakeholder feedback	The Panel were pleased to see AusNet looking for opportunities to efficiently unlock more renewable generation and leveraging existing network capacity, rather than deferring all renewables back to the transmission network planners, as has traditionally been the case.

Source: AusNet

6.11.4. Projects and programs

The figure below summarises the benefits from the proposed capex program to enable large scale renewable generation connections.

Figure 6-42: Summary of investment program to accelerate the connection of renewable generation and storage.



The summary of the net present value cost and benefit of the four projects within our investment program is summarised in Table 6-24. As explained in further detail below, a number of these projects have already progressed through the RIT-D process.

Table 6-24: Economic evaluation of options in present value terms ($m, real 2023-24)

	Total costs	Total gross benefits	Net economic benefit
Wodonga – Barnawartha	$38.88m	$99.7m	$60.8m
Morwell East – Stage 1	$5.38m	$98.72m	$93.34m
Morwell East – Stage 2	$11.24m	$63.02m	$51.78m
Morwell South	$70.71m	$120.59m	$49.79m
Total	$126.21m	$382.03m	$255.71m

Source: AusNet.

Please refer to the supporting documentation listed below for further detail on our program, modelling approach and regulated investment test for distribution (RIT-D) details.

All generator connections in AusNet's network are subject to Chapter 5 of the National Electricity Rules. However, we anticipate the direct cost to some generators may be lower as a result of the proposed investment. This has the anticipated benefit of accelerating large renewable generation on our network, in Victoria and in the NEM, and delivering the calculated benefits to our customers and across the NEM.

Our program takes into account any expected transmission constraints upstream from the sub transmission network that is being augmented. That means that when we model the benefits from our program, we model the level of constraint the generators may experience due to the transmission network congestion.

6.11.5. Supporting documentation

We have included the following documents to support this chapter:

- Large Renewables Enablement Program
- Morwell East Stage 1 – RIT Final Project Assessment Report
- Morwell South - RIT Draft Project Assessment Report
- Wodonga- Barnawartha in North-Eastern Victoria – RIT Project Assessment Conclusions Report
- Morwell East Stage 2 – Business case
- Morwell South – Economic Model
- Wodonga- Barnawartha in North-Eastern Victoria – Economic Model
- Morwell East Stage 2 Economic Model

6.12. Resilience expenditure

6.12.1. Key points

The key points in this section are:

- Over the past five years, our customers have been affected by five extreme weather events – 2019-20 bushfires, June 2021, October 2021, February 2024 and September 2024 storms – where the storms are the four largest storms on record. We have incurred a net cost of $96.2m in responding to the June 2021, October 2021 and February 2024 storms, where the pass-through applications for these events have been approved by the AER.[69]
- The February 2024 storm was particularly devastating which resulted in more than 297,000 of our customers being off supply[70]. We have taken many learnings from this event and are focussing significant resources on uplifting our emergency response, including community support, which was better received during the early September 2024 storm.
- Research has highlighted customers place the highest value on avoiding prolonged power outages of all the value streams tested in our Quantified Customer Values (QCV) project[71]. Increasingly, customers are highlighting a reluctance to electrify their gas appliances as these provide back up during outages – highlighting the need to uplift network resilience and reliability to facilitate electrification and to meet net zero targets.
- Resilience has also received increased attention from Government and regulators following recent storm events in Victoria. As a result, the regulatory framework in which we operate is evolving. Among other developments, new obligations are expected to be placed on the Victorian distribution businesses to produce 5-yearly network resilience plans, and the Victorian Government has submitted a rule change request to the AEMC which, if approved, will add network resilience to the capital and operating expenditure factors. This would require the AER to explicitly consider network resilience when setting revenues in regulatory determinations.
- The Victorian Government has indicated that the 5-yearly network resilience plans are to be submitted following the AER's final determinations for the Victorian EDPR resets.
- In response to the February 2024 storms, the Victorian Government established an Expert Panel (the Network Outage Review Panel) to inquire and make recommendations concerning the operational response of distribution businesses and other parties to this storm event. Their recommendations include:

[69] Net capex and net opex of $21.8 million and $29.5 million for June 2021 storm event; Net capex and net opex of $5.3 million and $4.4 million for October 2021 storm even; Net capex and net opex of $8.2 million and $26.9 million for February 2024 storm event.
[70] Other sources reference 255k customers which is the coincident peak customers off supply.
[71] https://communityhub.ausnetservices.com.au/research/ausnet-tomorrow-customer-insights-series/advancing-customer-outcomes-through-QCV.

  - Recommendation 11: the design and implementation of a new Extended Loss of Supply Support Payment Scheme (ELOSS) which requires distribution businesses to financially support customers during prolonged power outages.
  - Recommendation 12: a minimum service level standard for feeders, which if breached, would require remediation by network businesses.
  - Recommendation 13: apply a licence condition for AusNet to improve the reliability of specified feeders and install quick connect points in key townships.
- The Victorian Government has provided in principle, or in part, support for these recommendations. The impact of the minimum service level standards recommendation may change the nature of our resilience program. We will work with the AER and Victorian Government as these recommendations are implemented to make sure there is no overlap between our proposal and investment required under these potential new obligations.
- As a result of the increasing frequency and severity of extreme weather and customer feedback, we are proposing a new resilience expenditure category to prudently address the increasing frequency and magnitude of extreme weather events leading to prolonged power outages. Our resilience expenditure strikes a balance between ‘prevent and prepare’ and ‘respond and recover’ initiatives in a coordinated and holistic manner to deliver the best outcome for customers. Both approaches are essential because it is not possible to prevent all outages and therefore fully displace the need for timely response and recovery. Conversely, allowing for unrestricted growth in outages and diverting all resources to response and recovery would not be an optimal outcome for customers either.
- Our resilience program supports our vision, goals and strategic pillars from our Resilience Strategy, where our vision is “Our customers and other stakeholders have full confidence that we are actively preparing for, and will rapidly respond to, extreme weather events across our network”.
- Our capital expenditure requirement for resilience at $226.4m (direct, real 2023-24) comprises of $207.2m (direct, real 2023-24) for network hardening solutions and $19.2m (direct, real 2023-24) for non-network solutions. We have also invested in the current regulatory period to uplift operational response to emergency events, which we have also proposed to extend into the next 2026-31 regulatory period (see our 'Preparedness and response' opex step change in section 9).
- Network hardening solutions are infrastructure assets upgrades or improvements, primarily designed to allow the network to better withstand extreme weather events e.g., replacing wooden poles with concrete or composite poles and undergrounding overhead cables. We have proposed C-I-C of undergrounding ($93.4m), C-I-C of covered conductors ($29.5m), C-I-C of hardened poles ($65.6m), and C-I-C reclosers ($18.7m).[72]
- Non-network solutions are non-traditional solutions designed to displace or defer the need for capital intensive augmentation expenditure. Our non-network solutions primarily comprise backup power supply for 30 community hubs that are in rural and regional areas most impacted by extreme weather events ($9m). We have also proposed 25 Stand-Alone Power Systems (SAPS) which provide an uninterrupted supply of off-grid power and allows the customers to completely disconnect from the grid ($6.2m). We are also proposing modest expenditures of $3m and $1m to purchase mobile generation and four additional emergency response vehicles respectively.
- Significant expenditure is proposed due to strong customer support to invest as soon as possible to address the risk of prolonged power outages, with common feedback being that ‘there is never a good time to put up network bills, but this is important’ and recognition that resilience is a core part of our service. However, we also recognise that some customers were very concerned about energy affordability. With this in mind, since our Draft Proposal, we have deferred part of our network hardening program and reduced our proposed SAPS expenditure.
- We have considered carefully the merits of building more resilient network infrastructure given many customers have begun to invest in their own resilience. We consider our proposal is valid despite these customer-side investments given:
- Alternative sources of supply are often not perfect substitutes for grid-supplied electricity. For example, generators purchased by customers often have more limited capacities and can supply essential appliances only. Many customers with generators also report being inconvenienced by long power outages. In addition, fuel to run generators is costly, so a more resilient network can save customers money.
- Our program is justified using the AER’s Value of Network Resilience, which estimates the value of network upgrades to customers and the impacts of investments behind-the-meter have been considered by the AER in developing this.
- While some customers may be well-positioned to invest in batteries and/ or solar systems, many customers struggling with cost of living will simply not be able to afford this. The incremental network charge for our resilience program is orders of magnitude below the costs of a household battery (currently around $10,000).

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[72] Reported values are net of STPIS benefits removed from capex requirement. The capex requirement – without STPIS benefits removed – are $95m for undergrounding, $29.7m for covered conductors, $65.6m for pole hardening and $20m for reclosers. See chapter 6.4.12.

Leaving electricity resilience to each individual customer will likely both result in a poorer economic outcome (as the cost of all our customers purchasing batteries is very high) and an inequitable outcome as, due to the impacts of climate change, prolonged outages would increase over time only for those unable to afford batteries. Alternatively, the cost for every customer to purchase their own SAPS is even higher, at approximately $250k per unit which is unaffordable for the vast majority of customers.

- Our resilience proposal addresses the criteria in the AER's resilience guidance note being there is a causal relationship, provides greatest net benefit and consumers are fully informed.
- At our resilience deep dive costed options workshop, we presented the Availability Panel with our proposal to provide backup power supply to some critical infrastructure services providers i.e., water and telecommunication service providers. While there was general support for this approach, stakeholders suggested that the full charge should lie with the utility service provider. We are investigating this further and will address it as a part of our Revised Proposal. This potentially falls under the 'connection application and management services' service group which is an ACS. The AER's framework and approach paper describes it as 'works initiated by a customer or retailer that are specific to the connection point' and then proceeds to list supply improvements and enhancements projects.[73]

6.12.2. Overview of forecast and key drivers

We are forecasting a resilience augmentation expenditure of $226.4m over the 2026-31 regulatory period.

Digital investment programs that will, among other things, support improved network resilience are discussed in section 6.13. Opex step changes for resilience (hazard trees and preparedness and response) are discussed in section 7.

Table 6-25: Summary of resilience projects and programs ($m, direct, real 2023-24)[74]

Type	Description	Expenditure
Network hardening	C-I-C of undergrounding (primarily in the Dandenong Ranges) C-I-C of covered conductors C-I-C hardened poles C-I-C reclosers	207.2
Stand-Alone Power Systems (SAPS)	The installation of 25 units of SAPS.	6.2
Community hubs	The provision of backup power for 30 established community hubs; a combination of solar, battery, generator and telco equipment.	9.0
Mobile generation and batteries	To purchase four mobile diesel generators, portable station and HV battery system.	3.0
Emergency vehicles	To purchase emergency response vehicles	1.0
Total		226.4

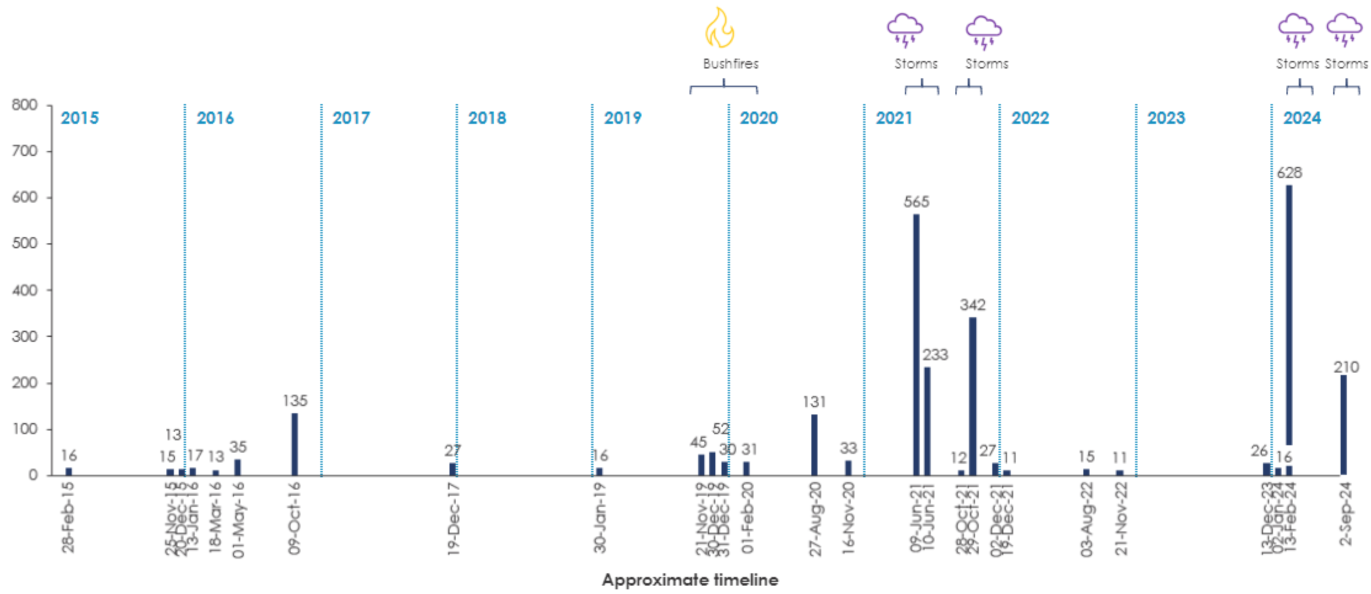
Source: AusNet

6.12.2.1. 5 extreme weather events have occurred over the past 5 years and are becoming more frequent and severe

Over the past five years, AusNet has been affected by 5 extreme weather events – 2019-20 bushfires, June 2021, October 2021, February 2024 and September 2024 storms – where the storms are the four largest storms on record. These storms highlight the risk of climate change, particularly the increasing frequency and size of extreme weather events as illustrated in figure below.

[73] AER 2024, Framework and approach – AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026-31, July, p. 34.
[74] Reported values are net of STPIS benefits removed from capex requirement. The capex requirement – without STPIS benefits removed – are $95m for undergrounding, $29.7m for covered conductors, $65.6m for pole hardening and $20m for reclosers. See chapter 6.4.12.

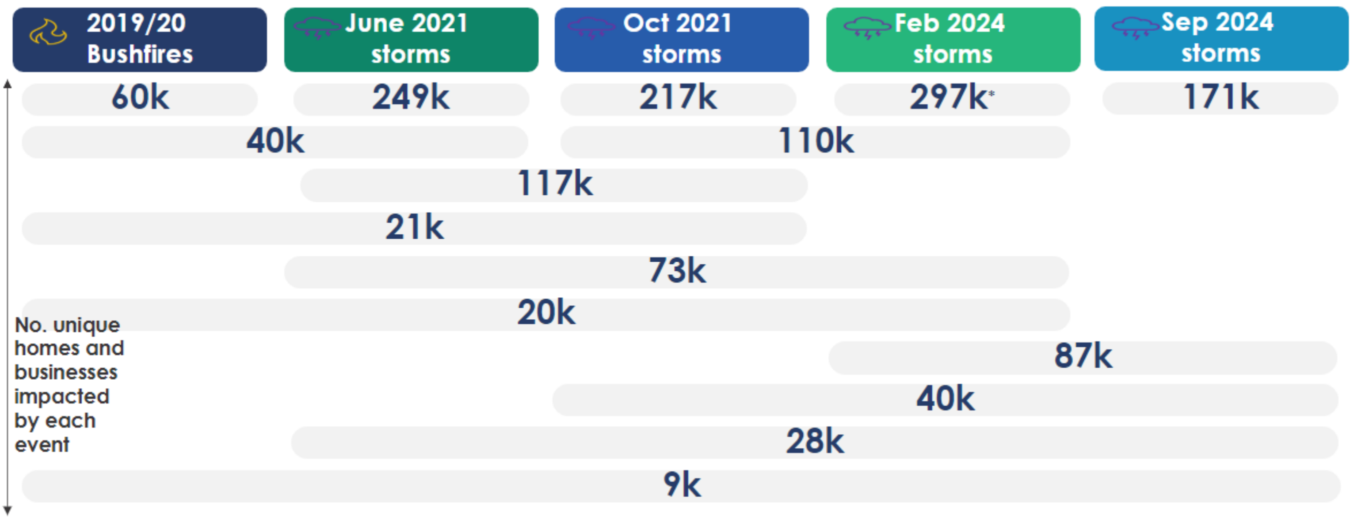
Figure 6-4: USAIDI per Major Event Day (minutes/customer)



Source: AusNet

Some customers have been affected by multiple storms, with approximately 28,000 customers being affected by all four storms. The figure below shows the numbers of customers affected by each storm event and the numbers of customers affected by multiple storms.

Figure 6-44: Number of unique homes and businesses impacted by each event



Source: AusNet

Note: Feb 2024 storms - other sources reference 255k customers which is the coincident peak customers off supply.

6.12.2.2. Network resilience has received increased attention from Government and regulators, and this is changing the regulatory landscape

Network resilience has received increased attention from Government and regulators in response to recent extreme weather events. This is particularly pertinent in Victoria as the June and October 2021 storms triggered a resilience review, and the February 2024 storms triggered the Network Outage Review:

Resilience review: In 2021, the Victorian Government initiated a review in response to the severe storms in June and October 2021. An Expert Panel was appointed to lead Phase 2 of the review to advise the Government on how the electricity distribution businesses can help reduce the likelihood and impact of prolonged power outages, to help build community resilience. Following this review, the Victorian Government supported the Panel's recommendations that:

- A rule change should be introduced. On 3 October 2024, a rule change request was submitted by the Honourable Lily D'Ambrosio MP, Victorian Minister for Energy and Resources, to the AEMC. The proposal is to add network resilience to the capital and operating expenditure factors in the Rules, which would require the AER to explicitly consider network resilience when setting revenues in regulatory determination. Additionally, the Rule change would introduce a new requirement for the AER to develop and publish distribution network resilience guidelines. The guideline will provide network businesses with more certainty around data requirements and expected outcomes when submitting regulatory proposals to the AER

- Victorian distributors should be required to develop a network resilience plan every 5-years. The plans are to be approved by a regulator where we are held accountable to the network resilience plan through enforcement measures such as civil penalties. We are awaiting further guidance on the approval process and timing for submission of network resilience plans to a Victorian regulator, and
- Further investigation should be undertaken into customers' willingness to pay for resilience, which the Panel described as "proactive measures to avoid or mitigate the impacts of natural disaster events". This recommendation is addressed by the AER's final decision on the Value of Network Resilience (**VNR**). We have also recently undertaken willingness to pay and other customer research to establish the value our customers place on a more resilient network, which we discuss further below.

Network outage review: In response to the February 2024 storms, the Victorian Government established an Expert Panel to inquire and make recommendations into the operational response of distribution businesses (among others). The following recommendations have received in principle, or in part, support by the Victorian Government which may have a significant impact on our resilience proposal:

- Recommendation 11: the design and implementation of a new Extended Loss of Supply Support Payment Scheme (ELOSS) which requires distribution businesses to financially support customers during prolonged power outages.
- Recommendation 12: a minimum service level standard for feeders, which if breached, would require remediation by network businesses.
- Recommendation 13: apply a licence condition for AusNet to improve the reliability of specified feeders and install quick connect points in key townships.
- The Victorian Government has provided in principle or part support for the recommendations above. If implemented these would likely impact our proposed program. For example, while the report does not provide any significant detail on the design of an appropriate minimum service level scheme (deliberate given the complexity) it recommends that:
  - the service level standard must account for customers' experience of prolonged power outages
  - the scheme is targeted at supporting reliable electricity supply to communities at high risk of prolonged outages
  - the scheme should account for limitations in the national framework by addressing network areas at risk of frequent and prolonged power outages due to poor performance, and
  - the minimum standard should require service improvements that better meets community needs and expectations.

We will work with both the AER and Victorian Government on the implementation of these recommendations and how they interrelate with our resilience proposal.

AER's network resilience guidance note: In recognition of climate change and the ongoing discussions around the degree of resilience for networks to adequately perform their functions, the AER developed a network resilience guidance note. The purpose of the note is to assist network businesses, consumer groups and advocates understand how resilience-related funding would be treated under the NER. The note explains that network businesses are expected to demonstrate that:

- There is a causal relationship between the proposed resilience expenditure and the expected increase in extreme weather events
- The proposed expenditure is required to maintain service levels and is based on the option that likely achieves the greatest net benefit of the feasible options considered, and
- Consumers have been fully informed about different resilience expenditure options, including the implications stemming from these options, and that they are supportive of the proposed expenditure.

The AER's network resilience guidance note was published in April 2022 prior to the rule change request to include distribution network resilience in the NER. As such, it may become superseded by the AER's guideline stemming from the rule change request. We may consider this guideline in preparing our Revised Proposal resilience forecast, depending on the timing of its publication.

6.12.2.3. Our extensive engagement and research program has highlighted the importance and value of a resilient network to our customers

Customers have consistently expressed concern that prolonged outages negatively affect their lives – quality and financially – and that network businesses need to do all that they can to quickly restore power. Reducing prolonged power outages was most highly valued by our customers, and it was the value stream that customers were most willing to pay for in our Quantifying Customer Values study, which was undertaken **prior** to the February 2024 storms. This finding is particularly important as climate change is expected to increase the occurrence and size of extreme weather events.

We have undertaken a large body of research and insights into our customers' views and preferences for resilience where the key points related to resilience are:

- **Quantifying Customer Values (QCV study):** One part of our QCV study (provided as a supporting document) attaches a hard dollar value to each unit of unserved energy. The other part of the study relates to customers' willingness-to-pay (**WTP**) for other service level outcomes. Our rebased WTP results (which considers the overall willingness-to-pay for several service level improvements, not just resilience) shows that resilience at $39.60 per residential customer p.a. ($178.70 per business customer p.a.)[75] is the highest WTP stream of all the streams considered (the others being reliability, EV charging, solar exports and improving service levels for worst served customers). This highlights the importance that our customers place on a resilient network. We note that applying the rebased WTP values deterministically across our customer base would result in an upper limit resilience proposal of $894 million if the investment guaranteed all customers would avoid one 24-hour outage per year.[76] This highlights the substantial investment customers are willing to pay for (see figure below).
- **Direct cost method**: The direct cost method uses AusNet survey and actual claims data to quantify the value of incurred expenses (e.g., loss of work/other income, property damage and generator costs) due to prolonged outages greater than 12 hours. The average expense is $635 per customer for 12-18hr outages, $797 for 18-24hr outages, and $1,523 for 24hr+ outages. When categorised by energy source(s) used by households or businesses, we can see that electricity only customers incurred the highest average expense ($1,172 per customer or $63 per hour); conversely dual fuel customers (electricity and mains gas) incurred the lowest average expense ($444 per customer or $30 per hour). See figures 6.-46 and 6-47.
- **Customer workshops**: We held five customer workshops in late 2023, where customers have shown a preference for proactive preparation for extreme weather events instead of reactive repair. See Figure 6-48.
- **Energy sentiments:** We conduct energy sentiments surveys twice a year, and for the past several years, resilience has consistently been in the top five strategic priorities for our customers (the importance is also growing). Some of the other top priorities for our customers are lowering costs, improving electricity/gas reliability and making the electricity/gas network safer. See figure 6-49.
- **Engagement with Customer Panels**: At our resilience costed options deep dive workshop in July 2024, the Electricity Availability Panel supported investments in more SAPS (from 131 to 148) and backup power for more community hubs (from 10 to 30). We have therefore looked harder at potential locations for backup power supply for community hubs and added them to our resilience proposal. However, we have decreased the number of SAPS to 25 units due to the inclusion of retirement cost of grid connected assets (among other refinements to our assumptions) into the analysis which rendered some sites to become NPV negative.

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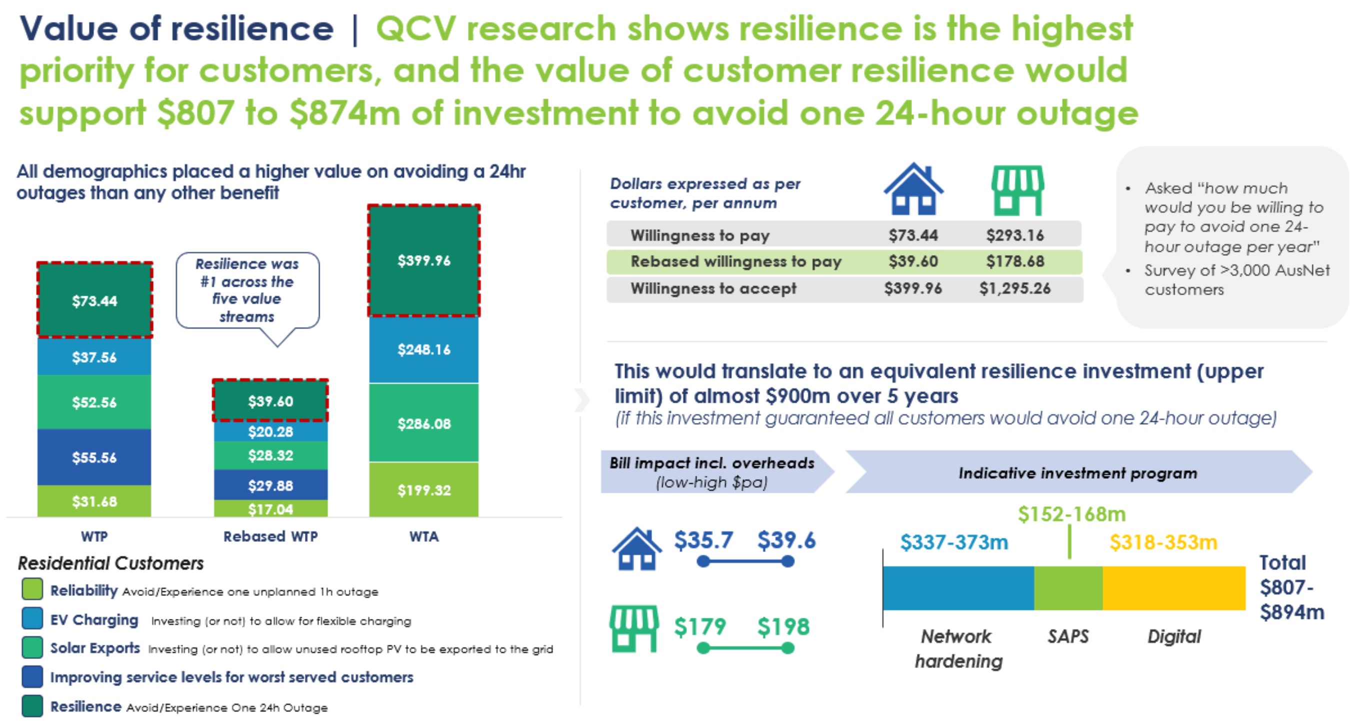
[75] https://communityhub.ausnetservices.com.au/research/ausnet-tomorrow-customer-insights-series/advancing-customer-outcomes-through-QCV.

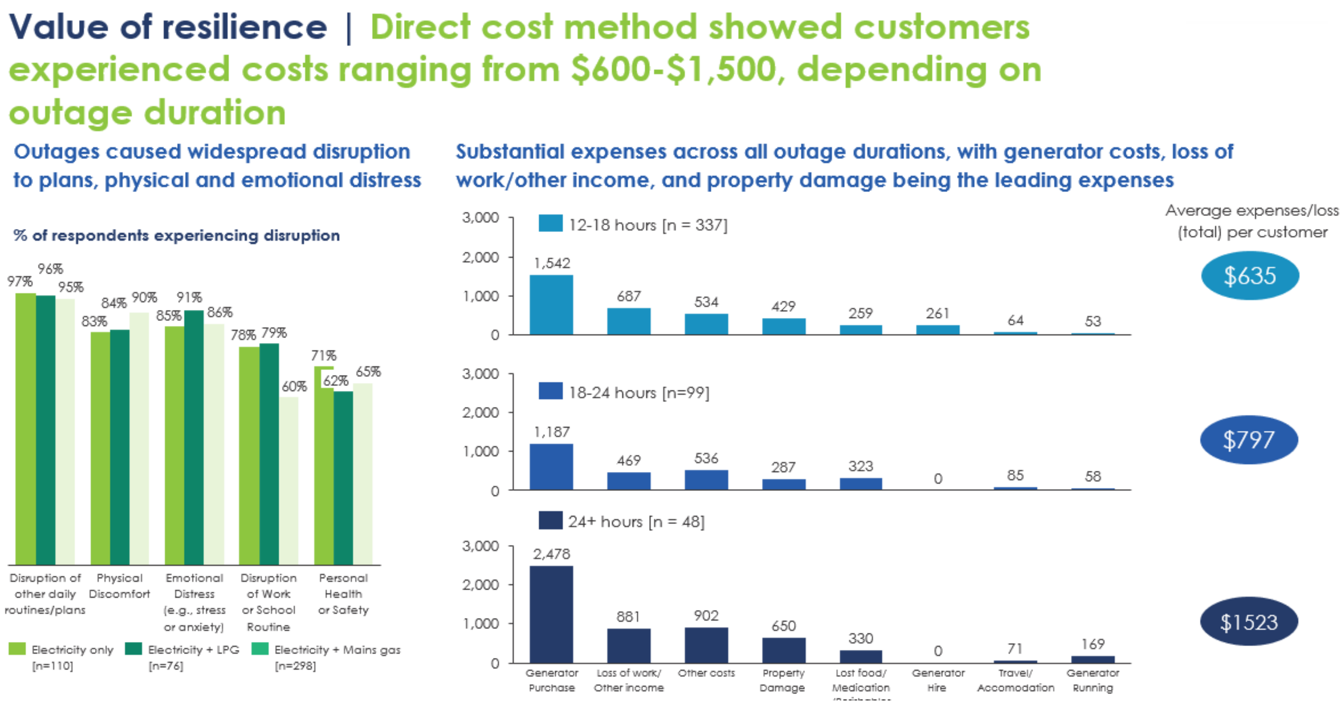
[76] Based on residential customers paying $37 p.a. and business customers paying $198 p.a.

Figure 6-45:20 Quantifying Customer Values research shows resilience is the highest priority for customers and the value of customer resilience would support $807 to $874 million of investment to avoid one 24-hour outage



Source: AusNet Quantifying Customer Values study

Figure 6-46: Direct cost method showed customers experienced costs ranging from $600-$1,500 depending on the outage duration



Source: AusNet Direct cost method study

Figure 6-47: Direct cost method results categorised by energy source(s) used by households or businesses

	Energy Source Type			Length of Outage		
	Electricity Only	Electricity + LPG	Electricity + Mains gas*	12 to 18 hours	18 to 24 hours	24 hours+
[Base]	[110]	[76]	[298]	[337]	[99]	[48]
Average Duration of the Outage	1,201 minutes	1,219 minutes	**896 minutes**	861 minutes	1,257 minutes	**1,604 minutes**
Ratio of Cost-Incurred Customers	92%	89%	**76%**	77%	90%	**100%**
Average Number of Cost-Incurred Category	2.3	2.3	**1.6**	1.6	2.4	**2.7**
Average Expenses/Loss (total)	$1,172	$1,304	**$444**	$635	$797	**$1,523**
Average Expenses/Loss (per hour)	$63	$62	**$30**	$43	$38	**$58**

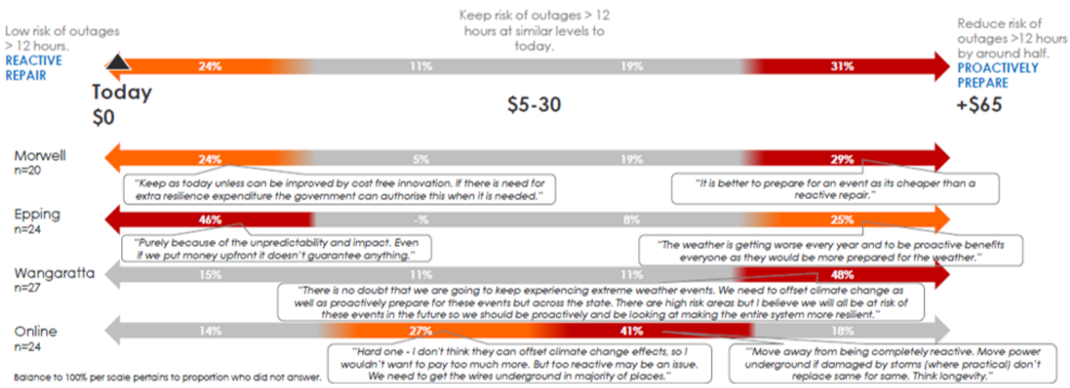
* N=9 of triple fuel (electricity, mains gas and LPG) customers are included

Source: AusNet Direct cost method study

Figure 6-48: Five customer workshops in late 2023 showed customers lean toward proactive preparation for extreme weather events

Preferences on resilience | Five customer workshops in late 2023 showed customers lean toward proactive preparation for extreme weather events

Customers who leant toward reactive repair were primarily concerned about money invested being "wasted" if an event doesn't end up occurring. This sentiment was strongest in the Epping group where customers had excellent reliability and could not see direct benefit for themselves. Some customers also questioned whether costs should be socialised across the state (like they are for disaster recovery). These workshops were held prior to the major event and prolonged outages in February 2024, which received much more media coverage than the 2021 storm events.

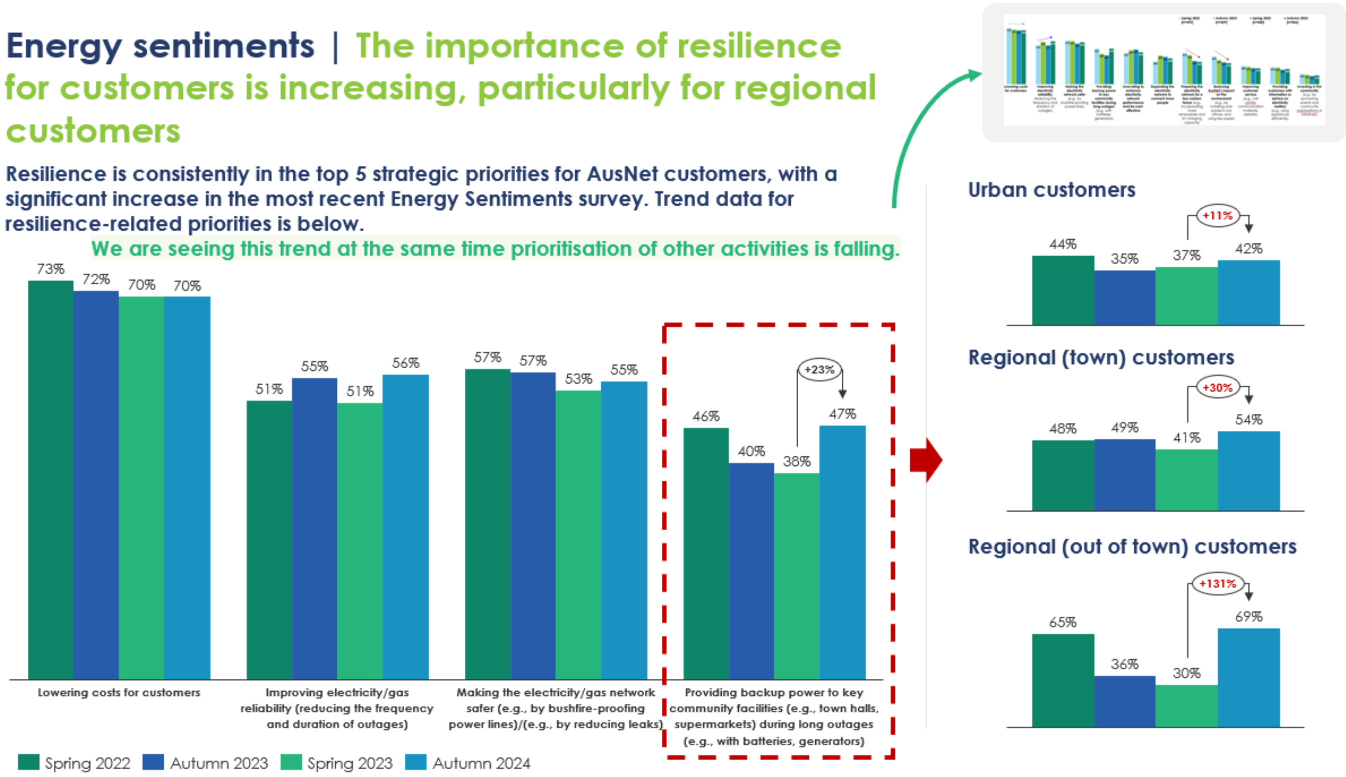


Customers who leant toward proactive preparation wanted investment in preparing as an "insurance policy" – for themselves or others. Many said that with reliance on electricity becoming greater, weather becoming more extreme, and the "cost" of long outages on communities, the importance of proactive preparation becomes greater. Some suggested it would be more efficient to spread out investment over time too given labour force capacity.

In the same workshops, customers ranked reducing the 1) frequency, 2) length and 3) impact of extreme weather events on outages as their 3 highest priorities for AusNet.

Source: AusNet analysis

Figure 6-49: The importance of resilience for customers is increasing, particularly for regional customers



Source: AusNet Energy sentiments survey

6.12.3. Methodology and key assumptions

Our methodology for determining our resilience expenditure is explained in our Resilience Strategy, which describes our vision and approach for embedding resilience into our decision-making, so that we deliver optimal outcomes for our customers. The Resilience Strategy articulates our goals and strategic pillars for achieving our vision. It has been developed with the assistance of our Electricity Availability Panel, which has provided feedback by taking a customer perspective. The Electricity Availability Panel has been invaluable in enabling us to better understand our customers' preferences regarding how we balance our resilience expenditure against other objectives, including affordability.

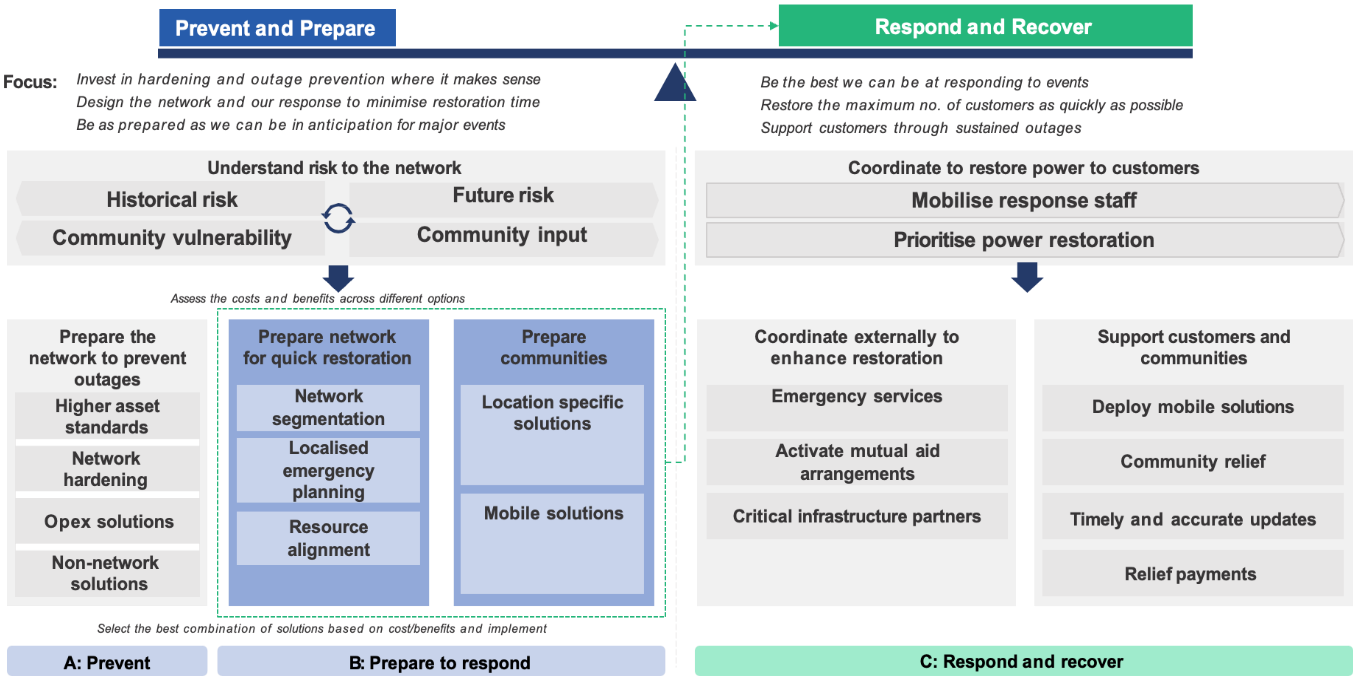
Our Resilience Strategy explains our 'balanced response framework', which is how resilience expenditure should be balanced between 'prevent and prepare' and 'respond and recover' initiatives in a coordinated manner to deliver the best outcome for customers. Both approaches are essential because it is not possible to prevent all outages and therefore fully displace the need for response and recovery and conversely, allow for unrestricted growth in outages and divert all resources to response and recovery.

The figure below shows the interaction between 'prevent and prepare' and 'respond and recover' where some of the key considerations into the right balance are:

- Where network or non-network solutions are economically sound (NPV positive) to address high risk areas (based on historical and future risks) then network or non-network solutions should take priority over the respond and recover approach.
- Network hardening solutions should be implemented where it is economic (NPV positive) to do so. Some non-network solutions (e.g., backup power for community hubs) are important supplementary measures and not mutually exclusive.
- SAPS are relatively expensive and therefore only expected to be most cost effective to install at the time when the existing service line is due for replacement. It is also most cost effective in rural and remote areas where the alternative (e.g. augmentation) is very expensive. This means we should be analysing NMI level data to identify customers being served by aging assets, with high susceptibility to outages, in rural and remote areas with high vulnerability.
- The risk of outages will always exist, so we should always have a suite of mobile generators and emergency vehicles that can be rapidly deployed. The right level of mobile generators and emergency vehicles should be informed by our historical experience and forecast need.
- Our existing hazard tree program is prioritised to target the highest risk hazard trees first. While expanding the hazard tree program would allow a larger scope of works, we note that it would be limited by amenity

concerns. Specifically, a larger scope of works would allow us to commence work on trees that are lower in priority, yet nevertheless important to address to avoid tree falls onto powerlines.

Figure 6-50: AusNet's balanced response framework for resilience



Source: AusNet

Our resilience expenditure proposal strikes the right balance between prevent, prepare, and respond and recover because:

- We have identified locations where it is economic (NPV positive) to undertake network hardening investments where if hit by a storm (or bushfire) our customers would experience reduced outages compared to no investments. Even if future storms/bushfires do not impact these areas, customers will still benefit from improved reliability under normal conditions. These locations tend to be in areas with relatively high customer density, as the required expenditure is generally significant.
- One unit of SAPS generally serves one customer (1:1 relationship) and as they are relatively expensive to deploy (with expensive associated costs, such as removing existing lines), they often only make economic sense in very remote and rural communities where the alternative (traditional network replacement or augmentation) is more expensive. Assessing the economics of SAPS requires a detailed analysis of power usage at the NMI level; we have only proposed locations where it is economic to rollout SAPS. The locations of SAPS do not overlap with network hardening investments because they rely on different metrics to become economic; network hardening requires relatively high customer densities while SAPS require relatively low customer densities. We expect to see a gradual rollout of SAPS as aging assets reach their end of life.
- Community hubs are needed in high-risk and highly populated areas or remote, rural and vulnerable regions where the probability of an outage is higher, or the resulting impact is disproportionately greater. Backup power to these priority sites is important. As such, the locations for backup power to community hubs do overlap with locations for network hardening investments, but this is expected since they are supplementary measures to the same problem. A location may need both network hardening investments and a community hub with backup power.
- The level and units of mobile generation and emergency response vehicles has been guided by our recent experience with responding to storms. Since these assets are non-location specific, they can be rapidly deployed to any area where assistance is needed. Any downtime outside of emergency mode can be diverted to address less severe outages.
- We have estimated that the value of hazard trees caused outages at approximately $17m p.a., where we can realistically achieve a $8m reduction p.a. by expanding our hazard tree program. Our expanded hazard tree program ($15 million over five years) aims to target more trees in high-risk areas, with no overlaps with our undergrounding and covered conductors program. Additional hazard tree management is expected to yield limited returns under current climate conditions particularly once amenity and the value of tree canopy are considered. See Chapter 0 for more details on our hazard tree opex step change proposal.

Behind the meter solutions such as every customer installing their own SAPS is not cost effective because it would cost roughly $250k per customer at a total cost of approximately $230 billion across a customer base of over 925,000. In the following section, we provide further information on our modelling approach for each of the elements that comprise our resilience program.

6.12.3.1. Rewards and benefits under the STPIS

Proactive investments to address extreme weather events will generate STPIS rewards. We have removed our forecast of STPIS rewards from the capex requirement. See chapter 6.4.12.

6.12.4. Projects and programs

This section provides a detailed description of our resilience program which comprises the following elements:

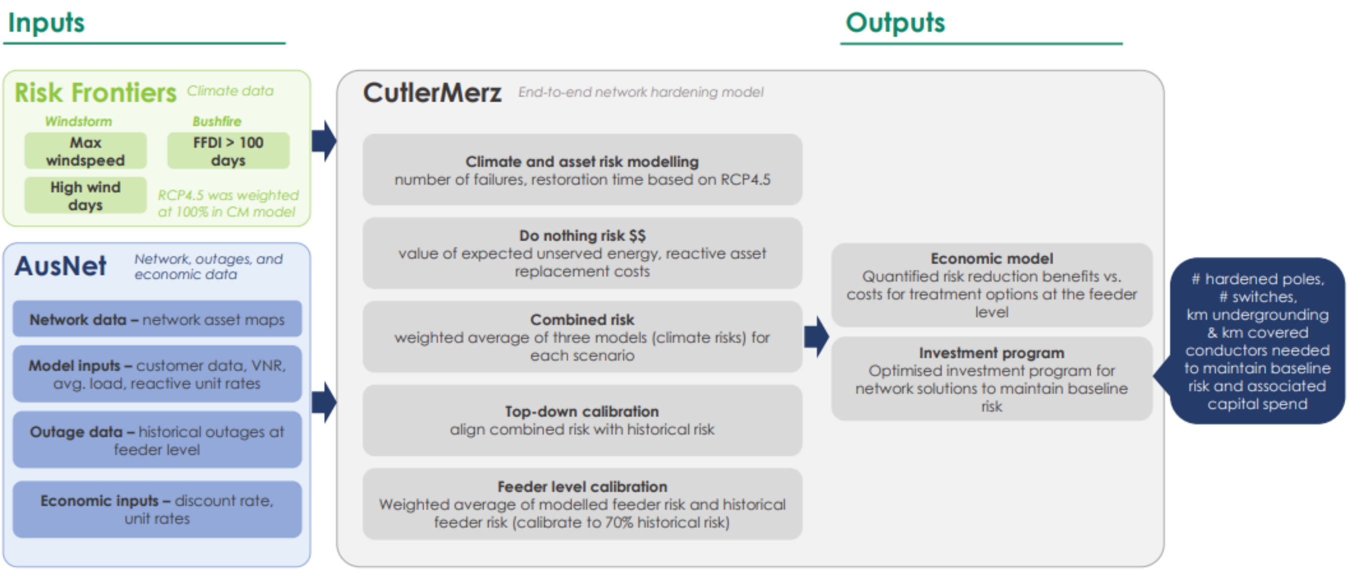
- Network hardening
- Community hubs
- Stand-Alone Power systems
- Mobile generation units, and
- Emergency response vehicles.

Network hardening is a network investment, while the remaining four elements are classified as non-network. We discuss each element in turn, including the rationale for the proposed level of expenditure for the 2026-31 regulatory period.

6.12.4.1. Network hardening

The figure below summarises our modelling approach to determine the optimal level of our network hardening.

Figure 6-51: Network hardening modelling approach



Source: AusNet

6.12.4.1.1. Methodology and key assumptions

Below is a description of the key modelling approaches that we have adopted in developing an optimised investment program. A detailed description can be found in ASD - CutlerMerz - Resilience methodology report - 10092024.

- **Step 1 – Climate data**: We procured climate data from an independent third-party provider (Risk Frontiers) which is one of the key inputs into assessing the risks on our network. Specifically, we adopted maximum windspeed, high wind days and Forest Fire Danger Index (**FFDI**) >100 as the key indicators of bushfire and windstorm risks on our network (the perils). The key indicators were provided for three Representative Concentration Pathway (**RCP**) scenarios of 2.6, 4.5 and 8.5. We have adopted the RCP4.5 scenario as a reasonable central estimate, which is consistent with the AER's approach in assessing Ausgrid's resilience proposal.
- **Step 2 - Climate Resilience Economic Model:** We engaged an independent third-party (CutlerMerz) to develop the Climate Resilience Economic Model (sometimes referred to as the end-to-end risk model).
- **Do nothing risks**: The 'do nothing risk' or inherent climate risk is quantified by forecasting the value of expected unserved energy and loss of asset due to the perils. The value of expected unserved energy (**VoEUE**) is the monetised value of energy that could not be supplied to a customer due to a fault or failure on the power system caused by the perils. This is the value of the energy that would have been delivered had there been no interruption. Loss of asset refers to the monetised value of the damage to an asset because of the climate event, based on historical reactive costs resulting from MED events for both asset repairs and replacements. An

example of this is fallen trees damaging cables due to a windstorm. These two values aim to capture the economic cost of climate perils. The quantification of the do-nothing risks is based on the change in risk levels between the baseline risk window (2000-20 average) and the end risk window (2045 to 2055 average).

- **Baseline risk window**: We have selected a baseline risk window of 2000 to 2020 as it excludes some of the extreme weather events over the past few years; 2019-20 bushfires and the June 2021, October 2021, February 2024 and September 2024 storms. We have excluded these years from the baseline risk period to recognise that the prolonged outages that followed these extreme events have been extremely costly, disruptive and traumatic for many of our customers, and we do not consider it appropriate to include these as part of a 'target' risk level. It is clear that risk levels post 2020 have been higher than desired by our customers and government.
- **End risk window**: We have selected an end risk window of 2045 to 2055 (centred on 2050) as it represents a future period that is neither too soon nor too far into the future. Year 2050 is 25 years from today.
- **Forecast risk reduction benefits**: The Climate Resilience Economic Model assesses the risk reduction benefit from potential network hardening solutions. The risk reduction benefit is the reduction in the value of expected unserved energy and asset loss compared to the 'do nothing' case.
- **Cost benefit analysis**: By assessing the risk reduction benefits against the cost of implementing the solutions, the model provides a comprehensive evaluation of the economic feasibility, so that we can identify those options that are NPV positive.
- **Calibration**: Calibration is the process of aligning forecast risks with historical/observed risks. We have applied two types of calibration (top down and feeder level) and within the feeder level calibration, we have adopted a calibration weighting of 70% to historical and 30% to modelled risks. The weightings align to the AER's preferred weighting in its assessment of Ausgrid's resilience proposal.

6.12.4.1.2. Results

CutlerMerz developed the Climate Resilience Economic Model and produced an investment program report which concludes that the optimised investment comprises C-I-C undergrounding, C-I-C covered conductors, C-I-C hardened poles and C-I-C reclosers at a cost of $302m. We have made some refinements to the model including implementing the AER's final decision for the Value of Network Resilience (VNR) and increased some of the unit rates to reflect more recent conditions[77]. This has decreased the volume of the investment program and the proposed capex for the 2026-31 regulatory period. Table 6-26 summarises our network hardening investment program for the 2026-31 regulatory period. See "ASD - AusNet - Updated climate resilience investment model – 31012025".

Table 6-26: Summary of the network hardening program

	Undergrounding	Covered conductors	Hardened poles	Reclosers
Units	C-I-C	C-I-C	C-I-C	C-I-C
Capex	$93.4m	$29.5m	$65.6m	$18.7m

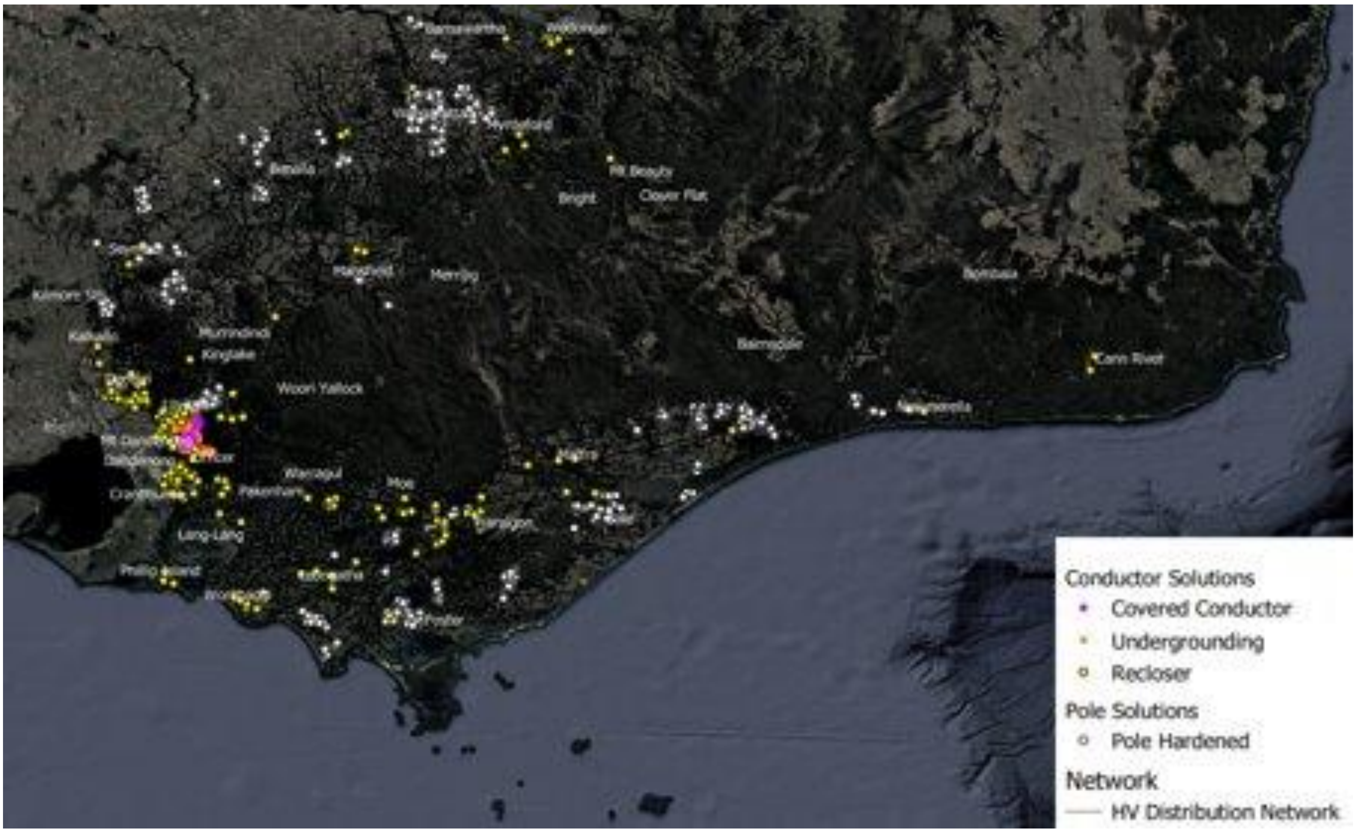
Source: AusNet.

Note: Capex requirements reported here have removed our forecast of STPIS benefits. See chapter 6.4.12.

The figure below shows the location of the investment program.

[77] C-I-C

Figure 6-52:21 Network hardening solutions



Source: AusNet

Table 6-27 shows how our proposed network hardening investment program meets the AER's requirements in its resilience guidance note.

Table 6-27: Explanation of how our network hardening proposal addresses the AER' guidance note

AER requirements	How does this proposal meet the AER's requirements
There is a causal relationship between the proposed resilience expenditure and the expected increase in extreme weather events	We combined our historical data and third-party sourced climate data (feeder level calibration: 70% to historical data and 30% to modelled risks) to quantify the value of expected unserved energy (VoEUE) under do-nothing (at the feeder level). We have compared the costs and risk reduction benefit of various solutions (undergrounding, covered conductors, hardened poles and reclosers) to identify where it is economic to undertake investments and what the solution should be. We have only considered the risk reduction benefits related to the climate change portion (avoiding the risk above current 2000-20 levels). As a result, our network hardening investment program has been identified at the feeder level, in locations that would reduce our 2050 VoEUE to current 2000-20 levels – this means there is a causal relationship between the proposed resilience expenditure and the expected increase in extreme weather events.
The proposed expenditure is required to maintain service levels and is based on the option that likely achieves the greatest net benefit of the feasible options considered	We have compared the costs and risk reduction benefit of various solutions to identify the preferred option amongst a mix of solutions (undergrounding, covered conductors, hardened poles and reclosers). Additionally, all the projects within our network hardening investment program are NPV positive. As such, we have proposed an optimal mix of solutions that achieves the greatest net benefit of the feasible options considered. We consider the right investment program will maintain our 2050 risk levels at today's 2000-20 risk levels. We have excluded 2021-24 data – which include June 2021, October 2021, February 2024 and September 2024 storms – to recognise that the prolonged outages that followed these extreme events have been extremely costly, disruptive and traumatic for many of our customers, and we do not consider it appropriate to include these as part of a 'target' risk level.
Consumers have been fully informed of different resilience expenditure	Our resilience proposal incorporates feedback from our Customer Panels, other stakeholders and the findings of the extensive customer research we have done on

options, including the implications stemming from these options, and that they are supportive of the proposed expenditure.	resilience. Specifically, our Customer Panels generally supported more proactive investment in network hardening solutions. Further details are presented below.

Source: AusNet

6.12.4.1.3. Customer feedback

At our All-Panel workshop in August 2024, customer representatives discussed the preferred level of investment for network hardening solutions. They were represented with a full network hardening investment program of $300 million; and other options that reflect a lower percentage of the full program, being 25%; 35% and 50%. The Panel generally supported the 100% rollout, although some Panel members could not express a preference based on the information provided.

In our Draft Proposal, we presented a network hardening investment program of $280 million (revised down from the $300 million) and we generally received support from customers. Specific support was expressed in submissions from the Sandy Point[78] and Emerald[79] community groups. The balance between our program and affordability was explored in customer workshops. The majority of customers supported the Draft Proposal given the increasing frequency of these events, however when pushed on whether deferring part of the program would be acceptable to put downwards pressure on bills, there was some support for deferrals.

The Coordination Group report said:

> *If affordability concerns require AusNet to find savings, the network hardening program could be spread out over two reset periods.*[80]

The SenateSHJ report on the Round 4 customers workshops said:

> *A small group of customers expressed concerns about government plans for 100% electrification and the pace of change this requires, saying this posed a risk to reliability. They suggested deferring certain speculative resilience upgrades.*[81]

As a result of the general support for a higher capital expenditure program, and the relatively minor bill impacts of network hardening investments, we have proposed $207.2m ($210m if excluding the impact of removing STPIS rewards) in network hardening investments.

6.12.4.2. Community hubs

Community hubs serve as central locations within communities where individuals can access various forms of support, resources, and services. Some of the common functions and uses of community hubs in supporting rural or remote communities include:

- **Emergency response and preparedness:** Community hubs often serve as coordination centres during emergencies, providing essential services such as shelter, resource provisions, and medical assistance. They may also offer support for emergency preparedness, including evacuation plans and emergency supplies when required.
- **Information and communication:** Community hubs act as communication hubs where residents can access information about outage restoration, services, and resources. They may provide internet access, bulletin boards, and noticeboards to provide important information to the community.
- **Social support and networking:** Community hubs offer a space for residents to connect with one another, voice concerns to support officials, come together during disaster events, and foster a sense of belonging.

6.12.4.2.1. Methodology and key assumptions

Due to its importance, we have assessed the value of providing backup power supply to community hubs compared to the business as usual or do-nothing, specifically:

- **Do Nothing:** no back up power is provided.
- **Option 1 –** Providing backup power to 30 established community hubs (exact buildings not yet established): This option involves providing back up power supply to 30 established community hubs. It would involve a combination of solar, battery, generator and telco equipment that will remain on site for use in an outage event.

[78] Sandy Point Community Power Submisison in Response to AusNet EDPR 2026-31 Proposal.pdf
[79] EVA Feedback to AusNet EDPR Proposal 2026-31.png (1408×1036)
[80] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 19.
[81] SenateSHJ 2024, Business and residential customer workshops, Round four report, November, p.6.

We have adopted the following methodology to quantify the value of providing backup power supply to community hubs:

- **Identify suitable locations**: Identify suitable locations based on historical susceptibility to major event outages and vulnerability factors (Socio-Economic Indexes for Areas and remoteness score).
- **Quantify the value of backup power supply**: Quantifying the value of backup power to a community hub is difficult because an established methodology does not exist. Instead, for each potential location, we have compared the cost of providing backup power to that location's total willingness-to-accept (**WTA**). We have assessed backup power for a specific location as being economic if the location's total WTA is higher than the cost of providing backup power over the assessment period. We have used WTA as a proxy for the value of a community hub because it can be roughly interpreted as the value that customers place on having access to a community hub. The willingness-to-accept is the minimum amount of compensation a customer would accept to lose a service and is estimated to range from $2.85 to $6.02 per customer per month, depending on the customer's location. Using Kilmore as an example:
  - The capex of providing backup power to a community hub/suitable building is $300k
  - The opex is $3k per annum.
  - The total WTA per annum is $114k, where it is the product of:
    - The number of customers within the boundary (3,328 customers)
    - A WTA value of $2.855 per customer per month since the feeders servicing the area are classified as short rural.
    - Number of months in a year (12)

See Table 6-28 for the key assumptions.

Table 6-28: Key inputs and assumptions (back up power for community hubs)

	Value	Explanation
Discount rate	5.56%	See section 6.5.1
Willingness to accept values	Residential long rural - $6.020 per customer per month (pcpm) Residential short rural - $2.855 pcpm Residential urban - $3.160 pcpm	The willingness-to-accept is the minimum amount of compensation a customer would accept to lose a service. It depends on factors such as the individual's valuation of the item, opportunity costs and personal circumstances. Sourced from our QCV study.
Customer Numbers	Location dependent	Based on the number of customers within a locality's boundary.
Socio-economic score	Location dependent	Based on Socio-Economic Indexes for Areas (**SEIFA**) scores
Remoteness score	Location dependent	Based on the ABS' remoteness score

6.12.4.2.2. Results

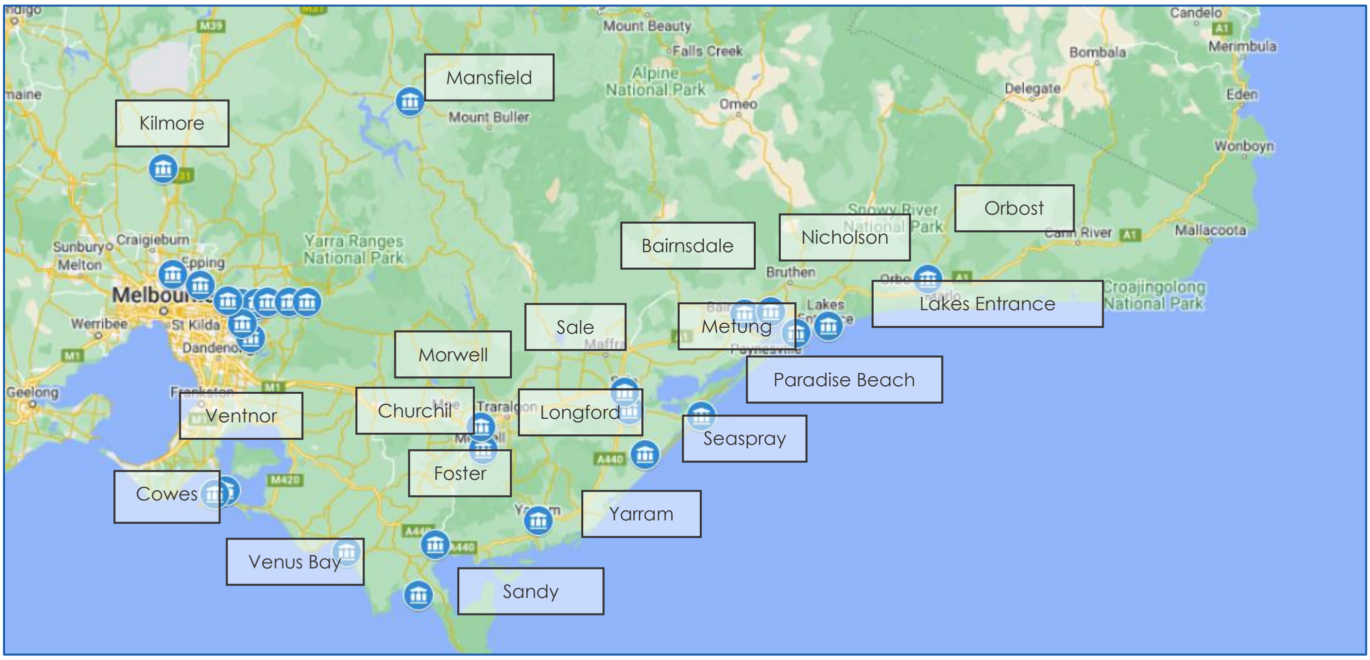
Figures 6-53 and 6-54 show locations where we have proposed to install backup power to community hubs, noting that the exact site or building within each locality is to be determined via community consultation if approved by the AER. In some cases, there will be an established community hub that could be fitted with backup power. In other cases, a community may prefer backup power to an alternative site such as a Returned & Services League (**RSL**).

All locations specified in figures 6-53 and 6-54 are highly NPV positive.

At the resilience costed options deep dive workshop with our Availability Panel, we originally proposed providing back up supply at 10 community hubs at a cost of $3m. However, our Availability Panel supported a plan for 30 community hub locations at a capex of $9m. As a result, we have reviewed other potential locations for backup power supply for community hubs and increased the number of community hubs in our resilience proposal, as shown in the figures below.

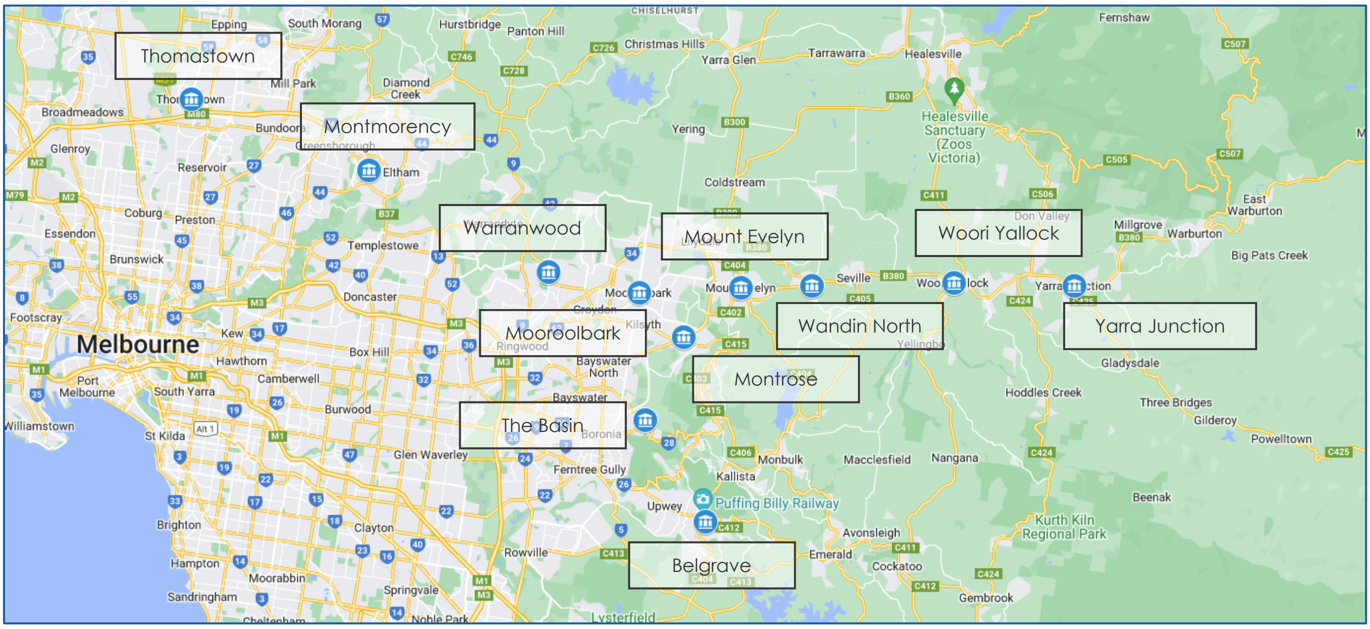
We will engage with local communities on their needs before committing to exact locations and scope as they are the key beneficiaries. This was recognised by members of our Availability Panel as important.

Figure 6-53:22 Locations where we have proposed to install backup power to community hubs [1/2]



Source: AusNet.

Figure 6-54:23 Locations where we have proposed to install backup power to community hubs [1/2]



Source: AusNet

The table below explains how our proposed network community hubs program meets the AER's requirements in its resilience guidance note.

Table 6-29: Explanation of how our community hubs proposal addresses the AER' guidance note

AER requirements	How does this proposal meet the AER's requirements
There is a causal relationship between the proposed resilience expenditure and the expected increase in extreme weather events	We have identified locations based on historical susceptibility to major event outages (as it is a reasonable indicator of future climate change locations) and vulnerability factors – as such, there is a causal relationship between our proposed expenditure for community hubs and expected increase in extreme weather events.
The proposed expenditure is required to maintain service levels and is based on the option that likely achieves the greatest net benefit of the feasible options considered	The proposed expenditure does not change service level outcomes. Rather, it lessens the impact of outages, as they can seek shelter and support services during an outage.
Consumers have been fully informed of different resilience expenditure options, including the implications stemming from these options, and that they are supportive of the proposed expenditure.	As already noted, at our resilience costed options deep dive workshop in July 2024, the Electricity Availability Panel supported investments in more backup power for community hubs (from 10 to 30 community hubs).

Source: AusNet

6.12.4.3. Stand-Alone Power systems

Stand-Alone Power Systems (**SAPS**) comprise a suite of distributed energy solutions that can provide targeted customers with supply at or close to the point of connection. These services include solar PV generation, battery energy storage and a back-up diesel generator as contingency. Suitable locations are typically located at the ends of feeders, in low customer density areas.

6.12.4.3.1. Methodology and key assumptions

We have assessed the following four options:

- **BAU**: like-for-like replacement (grid-connected assets) at the end of the existing asset's life.
- **Option 1 – SAPS**: the installation of SAPS.
- **Option 2 – undergrounding**: the replacement of existing overhead cables with undergrounding.
- **Option 3 – covered conductor replacement:** the replacement of existing overhead cables with covered conductors.

We have adopted the following methodology to quantify the benefits of the various options.

- **Identify suitable sites:** Identify suitable sites (at the NMI level) based on historical susceptibility to major event outages, vulnerability factors (Socio-Economic Indexes for Areas and remoteness score) and age of the assets. We initially identified over 100 sites with aging assets, high susceptibility to outages, and high vulnerability factors.
- **Forecast climate change risks:** One of the outputs of our end-to-end network hardening risk model (produced by CutlerMerz) is a climate change risk growth per annum at the feeder level. We have applied the climate change risk growth (at the feeder level) to our historical data. This accounts for the expected increase in climate-related risks.
- **Quantify the benefits:** The benefit for each option is its ability to reduce the value of expected unserved energy compared to the do-nothing scenario. We have adopted actual outages from the latest historical five-year period (plus a climate change risk growth) as indicative of future outages under a do-nothing approach.
- **NPV analysis**: We compared the PV costs and PV benefits of each option to select the preferred option.

We note that within each option, we also undertook an NPV analysis at the NMI level to determine the number of sites that are NPV positive.

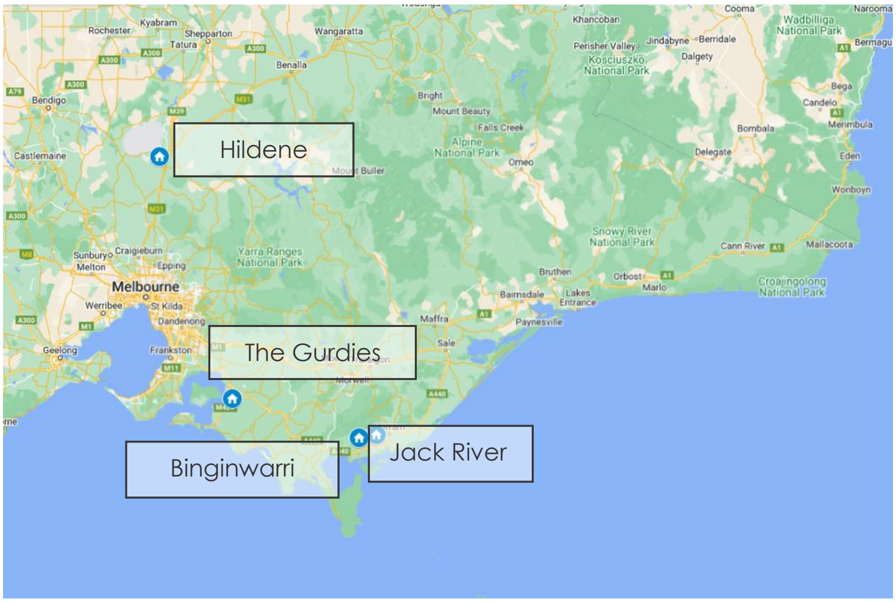
Table 6-30: Key inputs and assumptions (SAPS)

Type	Description
Discount rate	See section 6.5.1
Value of Network Resilience (VNR)	Applied the multiplies from the AER's VNR to the AER's 2023 VCRs
Upfront cost of SAPS	$248k per unit (estimate)
Ongoing operating and maintenance cost	Annual opex cost of $2k per unit per year

6.12.4.3.2. Results

The preferred option is the installation of SAPS (option 1) as it produces the highest NPV of all the options considered. Specifically, there are 25 sites within the SAPS option that are NPV positive compared to the do-nothing scenario. This means that early retirement of the existing grid connected assets, and the deployment of SAPS at 25 sites is more beneficial compared to like-for-like replacement at the end of the existing asset's life. The proposed sites for SAPS installations are shown in Figure .

Figure 6-55:24 Identified sites for SAPS installation



The table below shows how our proposed network SAPS program meets the AER's requirements in its resilience guidance note.

Table 6-31: Explanation of how our SAPS program addresses the AER' guidance note

AER's requirements	How does this proposal meet the AER's requirements
There is a causal relationship between the proposed resilience expenditure and the expected increase in extreme weather events	We have identified locations based on historical susceptibility to major event outages (and climate change risk growth as determined through CutlerMerz's end-to-end network hardening model) as it is a reasonable indicator of future climate change locations, vulnerability factors, and age of the asset – as such, there is a causal relationship between our proposed expenditure for SAPS and expected increase in extreme weather events.
The proposed expenditure is required to maintain service levels and is based on the option that likely achieves the greatest net benefit of the feasible options considered	The proposed expenditure improves service level outcomes for specific customers, but it does not change the network-average service level outcomes.
Consumers have been fully informed of different resilience expenditure options, including the implications stemming from these options, and that they are supportive of the proposed expenditure.	At our resilience costed options deep dive workshop in July 2024, the Electricity Availability Panel supported investments in 148 units of SAPS. However, we have decreased the number of SAPS to 25 units due to the inclusion of retirement cost of grid connected assets (among other refinements to our assumptions) in the analysis which rendered some sites to become NPV negative. In future regulatory periods, however, we expect increased deployment of SAPs as our network assets reach retirement age. We have conveyed this expectation to the Electricity Availability Panel.

Source: AusNet

6.12.4.4. Mobile generation units

Mobile diesel generators are units that can be quickly deployed to locations with prolonged outages to provide immediate power to the local community. The quick deployment of mobile generation following extreme weather events to power main streets or community hubs (where it is safe and feasible to do so) is an increasing focus of Government and communities, with the Network Outage Review recommending that:

- Distribution businesses have capacity and capability to connect main streets and key community assets in areas at high risk of prolonged power outages to temporary generation within 12 hours of an event.
- The Minister for Energy should apply a licence condition for AusNet to install network connection points to enable rapid installation of temporary generation in key township locations. The Victorian Government has accepted this recommendation and indicated the licence condition can be expected soon.

It is critical that we maintain an operational generator fleet to support communities, which is the BAU or 'do nothing' option. If a licence condition requiring network connection points following the Network Outage Review is adopted, we will assess the need for additional generator units and reflect this requirement in our Revised Proposal.

6.12.4.4.1. Methodology and key assumptions

We have assessed the following three options:

- **Business-as-usual (BAU)**: Four of our existing mobile diesel generators (out of a total of 6) are nearing end of life. Our BAU option involves purchasing four mobile diesel generators to replace the aging generators with slightly larger 1.5 MVA units compared to the current 1.25 MVA.
- **Option 1 – BAU plus portable station**: This option is the BAU option (purchase four mobile diesel generators) plus the purchase of a portable station infrastructure. The addition of the portable station enhances power distribution capabilities, enabling more efficient response to outage events and improved grid connectivity.
- **Option 2 – BAU plus portable station and HV battery system**: This is the most comprehensive option, which is an extension of Option 1 (purchase four mobile diesel generators and portable station) to include the purchase of a HV battery system. A portable station is a mobile unit with a transformer and switchgear on a trailer, which can be deployed quickly. In addition to backup power generation, the HV battery system enhances energy storage capabilities, providing greater flexibility, resilience, and efficiency in managing outage scenarios.

The methodology for evaluating the options involved:

- Evaluating current mobile generation deployment and energy supply behaviour
- Estimating the Value of Expected Unserved Energy (VoEUE) under do-nothing, which included a climate risk growth rate of 0.63% p.a. sourced from CutlerMerz's end-to-end model
- Estimating the reduction in VoEUE provided by acquiring critical generation equipment using the AER's VNR.
- Comparing costs and benefits across the various options to identify the preferred option that delivers highest NPV of all feasible options assessed.

We also considered the important role they have recently played in the 2024 storms:

- **February 2024 storm response**: The February 2024 storm required significant operational efforts to maintain power supply across affected areas. Generation units were deployed to critical locations, including Mirboo North, Emerald, and Cockatoo, where they helped mitigate power disruptions caused by the severe weather. The deployment in Mirboo North required the use of two 1.25 MVA generators and one 2 MVA transformer. These deployments were essential in ensuring that power was available to communities during the peak of the storm, preventing prolonged outages and reducing the need for immediate repairs to the main power infrastructure. The temporary generation capacity provided a crucial safety net for these areas, allowing residents to maintain essential services despite the storm's impacts.
- **September 2024 storm response**: The September 2024 storm saw a broader and more targeted deployment of generation assets across multiple regions. In the central region, generators were stationed at Olinda, Cockatoo, Emerald (on standby), and Gembrook, with a total capacity of 1.4 MVA. Meanwhile, in the eastern regions, power generation was deployed to Walhalla, Rawson, Erica, and Mirboo North, with 700 kVA of generation capacity. These deployments were part of a comprehensive strategy to ensure that power remained stable in both the central and eastern regions despite the ongoing storm conditions. The strategic placement of backup generation helped to minimise disruptions and improve the resilience of the power grid during these challenging weather events.

6.12.4.4.2. Results

The preferred option is option 2, the purchase of four mobile diesel generators, a portable station and a HV battery system.

6.12.4.5. Emergency response vehicles

Emergency Response Vehicles (**ERVs**) are purpose-built fleets equipped to travel through challenging conditions and can offer essential services such as mobile power generation, communication support, and first aid provisions to affected customers.

6.12.4.5.1. Methodology and key assumptions

We have assessed the following two options:

- **Business as usual:** The do-nothing approach relies on our existing fleet of four ERVs.
- **Option 1: Acquiring four more ERVs.** The acquisition of an additional four purpose-built ERVs.

ERVs provide an intangible benefit that is difficult to quantify. As such, we have compared the costs of the ERVs against forecast benefits, where the benefits quantification is based on the expected number of deployments per year, the number of customers it is expected to serve per deployment and the willingness-to-accept (WTA) value for community hubs produced by our resilience research. We have assessed the ERVs as being economic if the forecast benefit is higher than the cost of purchasing and running the ERVs. We have used the WTA for community hubs as a proxy for the value of an ERV because ERVs also provide emergency support services similar to a community hub.

We have also considered the positive feedback that we recently received from our customers. Specifically, we engaged with eight of our most impacted Local Government Areas following the September 2024 storms, and customers have expressed the following:

- ERVs is a great addition to AusNet's response approach during emergencies and it's a really good resource to support the community.
- Need earlier information on ERVs (e.g., where they will be located) and staying longer at each location during emergencies.
- ERVs could be used outside of emergency response to help build community resilience awareness and understanding.

6.12.4.5.2. Results

The preferred option is to purchase four emergency response vehicles at a total capital expenditure requirement of $1m.

6.12.5. Benchmarking and validation

It is very hard to benchmark Victorian network businesses, particularly AusNet, as we are in a unique position where we recently experienced several very large events that have had catastrophic consequences – the 2019/20 bushfires, June 2021, October 2021, February 2024 and September 2024 storms.

We have tested our resilience program with the Customer Panels and through the Draft Proposal that we published in September 2024.[82] At the August all-panel offsite, we presented our resilience proposal and our overall capex proposal as a package (with bill impacts), and there was majority support for proactive investments to improve resilience outcomes. Additionally, we received positive support for our resilience program through public submissions to our Draft Proposal. There was some feedback on cost-of-living which we have addressed by deferring $70m of our network hardening proposal to future periods.[83]

Additionally, our network hardening capex forecast is based on the unit rates in our Unit rates supporting documentation (ASD - Unit Rates-31 Jan 2025) with some upwards adjustments. The upward adjustments primarily relate to undergrounding being more expensive in the Dandenong Ranges (where we have proposed works) due to more difficult terrain and access compared to our network average topology. Undergrounding lengths will be longer than the existing overhead cable lengths due to the need to follow certain paths which may be indirect compared to overhead conductors.

Our unit rates for community hubs, SAPS, emergency response vehicles and mobile generation units are based on experience.

[82] See this link for our Draft Proposal: https://communityhub.ausnetservices.com.au/download_file/view/620/672
[83] Coordination Group 2024, Independent Report on Draft Revenue Proposal 2026-2031, Report for AusNet Services, 22 October, p. 19.

6.12.6. Supporting documentation

We have included the following documents to support this chapter:

- ASD - AusNet - Resilience strategy – 31012025 - PUBLIC
- ASD - Nous - Post Incident Review into AusNet's Response to the February 2024 Outage Event – 10072024 - PUBLIC

Network hardening:

- ASD - CutlerMerz - Resilience methodology report – 31092024
- ASD - CutlerMerz - Resilience program report – 31092024
- ASD - AusNet - Updated climate resilience investment model - 31012025
- ASD - AusNet - Network hardening BC – 31012025
- ASD - AusNet - Network hardening economic model - 31012025

Non-network solution:

- ASD - AusNet - Community BC – 31012025
- ASD - AusNet - Community hubs economic model – 31012025
- ASD - AusNet - SAPS BC – 31012025
- ASD - AusNet - SAPS economic model – 31012025
- ASD - AusNet - Mobile generation business case - 31012025
- ASD - AusNet - Mobile generation economic model – 31012025
- ASD - AusNet - Emergency response vehicle BC – 31012025
- ASD - AusNet - Emergency response vehicles economic model – 31012025

6.13. Digital expenditure

6.13.1. Key points

The key points in this section are:

- In developing our plans for the digital capex for the 2026-31 regulatory period, we have considered the needs and expectations of our customers in a rapidly changing environment, including the growth in CER, driven partly by technological change and Government policies to achieve net zero.
- Our focus is to meet our customers' needs at the lowest total cost by combining network and digital investments which will allow CER to be integrated cost effectively, increasing network utilisation, while supporting system security. Our plans must also consider the need to maintain our own systems and processes, so that they operate prudently and efficiently having regard to technology changes.
- Our digital capex proposal will enable us to:
  - Enhance our customer systems to save time for our customers and enable us to provide more tailored services
  - Modernise our network control capability to help us respond efficiently to events on our network, and manage the future of distributed energy assets
  - Uplift the consistency and quality of our data, to optimise our business processes and enable advanced analytics
  - Enhance our asset management systems, so we can manage our network efficiently, mitigate risks, and support reliability & resilience, and
  - Increase visibility of our field operations, to speed up restoration times and enable us to plan works in a time and cost-efficient way.
- We have developed a program comprising 11 components, each of which has been calibrated to balance the objective of meeting our customers' needs and expectations, while also having regard to affordability considerations.

6.13.2. Overview of forecast and key drivers

AusNet's distribution network is exposed to a rapidly evolving landscape, driven by our customers' changing expectations; increasing penetration of solar PVs and batteries; increasing frequency and severity of storm events; and new and increasing threats from external factors. In the face of these challenges, it is critical for AusNet to have a digital strategy that allows us to continue to meet our customers' expectations and fulfil our obligations as a licensed DNSP.

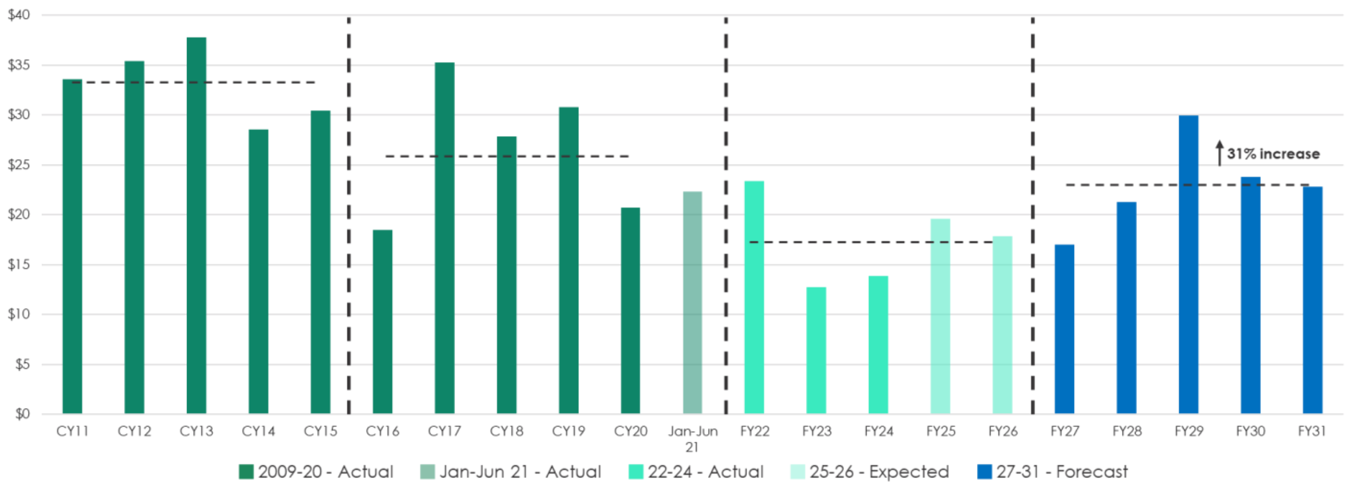
Our digital capex plans have been developed with the assistance of external consultants and technology experts to provide budget estimates, ensuring our forecasts are prudent and efficient, and in line with industry best practice. For the 2026-31 regulatory period, we are proposing digital capex of $404.2 million (real $2023-24). This represents a 22% increase in capital expenditure compared to the current regulatory period.

Figure 6-5625: Digital capital expenditure ($ millions, FY23-24 dollars)

Source: AusNet

Figure 6-57 below shows our recurrent digital capex since 2011. Our proposed recurrent digital capex for the forthcoming Regulatory Period increased by 31% compared to the last Regulatory Period, primarily driven by the scaling of digital capabilities and the necessary investments to support a more complex and digitized electricity distribution network. Despite this increase, long-term recurrent expenditure trends have remained relatively stable, and our proposed recurrent capex expenditure for the forthcoming Regulatory Period is lower than the levels of 2010-15 and 2016-21 Regulatory Periods.

Figure 6-5726: Recurrent digital capital expenditure ($ millions, 2023-24 dollars)



Source: AusNet

Our approach puts customer outcomes at the centre of our investment plans by prioritizing the delivery of what customers are telling us they want and leveraging technology and opportunities to reduce our ongoing costs wherever possible. In summary, the factors we considered when developing our digital expenditure forecasts are:

- **Customer expectations:** The growing share of total energy demand from electricity means customers will depend more heavily on continuity of electricity supply. We have closely engaged with customers and stakeholders to shape our digital capex program. Customers have expressed strong support for investments aimed at enhancing outage communication, increasing network resilience, and improving overall customer experience. Feedback highlighted the importance of timely, accurate information during outages, multi-channel communication options, and seamless interactions with AusNet.
- **Energy transition:** AusNet's distribution network is becoming increasingly complex as more customers export rooftop solar into the grid. Maintaining supply-demand balance and managing frequency and voltage within technical limits is challenging on infrastructure not originally designed for two-way power flows. This complexity will intensify over the next 20 years with the growth of electric vehicles and home batteries, requiring enhanced network control capabilities to support the ongoing energy transition.
- **Resilience:** Climate change is driving more frequent and severe extreme weather events, increasing the risk and scale of network outages. AusNet's experience with major storms—impacting up to 300,000 customers, including the record-breaking February 2024 event—has highlighted the need for enhanced ICT capabilities. In response, the Victorian Government's Network Resilience Review recommended actions such as leveraging geospatial data, improving emergency collaboration, and enhancing customer communications. As climate risks grow, AusNet must invest in digital systems to strengthen preparedness and response.
- **Cyber threats:** Keeping our digital assets secure from cyber attacks is fundamental given the risks of widescale disruption to electricity services and the criticality of protecting our customers' data. Cyber threats have intensified over the last 5 years, as cyber-attackers evolve their capabilities and the risk of state sponsored sabotage grows in an increasingly disrupted geo-political environment.
- **Digital landscape:** The possibilities of digital technologies to deliver services and operate our business efficiently is constantly expanding. A key example is the leaps in machine learning and artificial intelligence that is bringing exciting possibilities on how we plan and manage our network and business. Further, the architectural possibilities of how we manage our technology systems is also evolving including cloud and on-premises modes of delivery.
- **Reliability and safety:** Ageing infrastructure, rising demand from electrification, and growing export capacity needs are increasing pressure on AusNet's network. Innovative tools, data, and analytics are essential to extend asset life, manage risk, and optimize investment across the asset lifecycle.
- **Compliance:** digital enables us to comply with applicable regulations and requirements in a timely and efficient manner. While the need to leverage our systems and data is driven partly by the projected growth in CER and solar capacity, it is important to recognise the joint reliance of both the standard control and metering services on smart metering data and systems. Our metering services are explained in Chapter 19 of this Revenue Proposal.

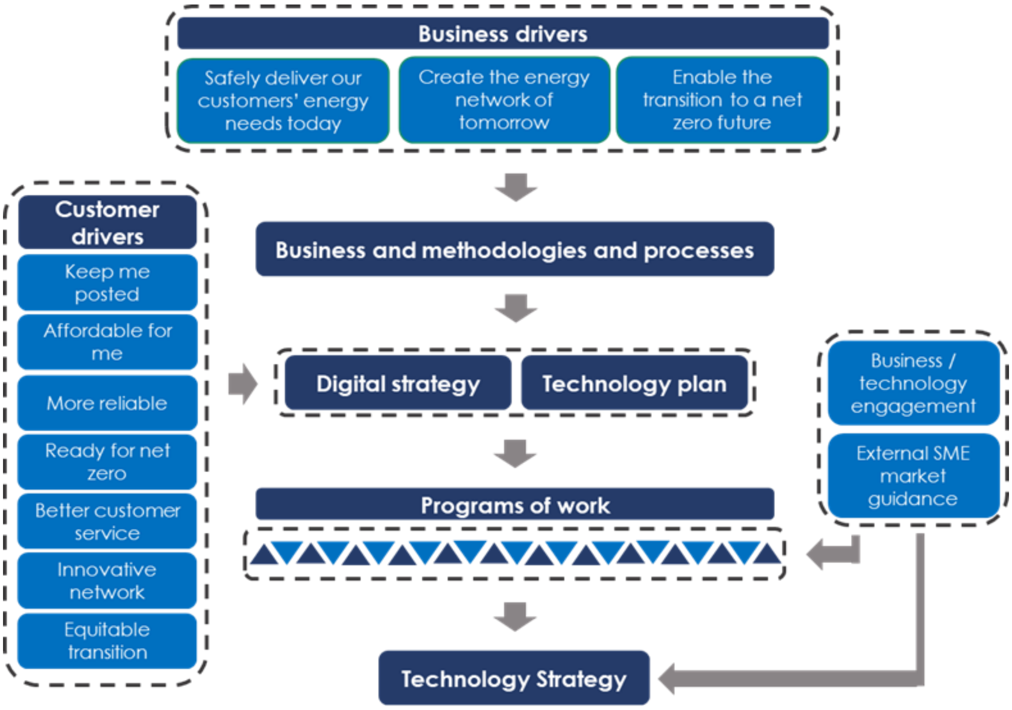
6.13.3. Methodology and key assumptions

In developing our plans for the 2026-31 regulatory period, we have:

- Considered customer needs and expectations and how these are expected to evolve during the 2026-31 regulatory period, as revealed through feedback directly through our engagement with the Customer Experience and Availability Panels;
- Carefully considered the outworkings of the February 2024 storms, including a post incident review conducted by the Nous Group, and the Victorian Government's Network Outage Review;
- Held discussions with business and technology architects, and (internal) business delivery leads to develop the scope, key objectives, and drivers of our ICT proposal; and
- Considered different options to achieve the objectives of each digital program, including trade-offs between capex and opex alternatives, and analysed the relative costs, benefits and risks of each program consistently, including standard industry labour rates.

Figure 6-58 below provides an overview of our methodology for determining our digital capex plans.

Figure 6-5827: Methodology for developing our digital capex plans



In addition to targeting the customer benefits described above, we note that our proposed expenditure:

- will contribute to the achievement of the 0.5% per annum productivity saving that has been assumed in our opex proposal, which is only achievable by carrying out the proposed digital expenditure for the 2026-31 regulatory period, and
- will achieve additional opex efficiency savings of $3.9 million, which has been included in a negative step change in our opex proposal.

Table 6-32 outlines the key inputs and assumptions.

Table 6-32: Key inputs and assumptions

Input / Assumption	Description
Discount rate	See section 6.5.1.
Value of Customer Reliability (VCR)	See sections 6.4.4. and 6.5.1.
Customer and stakeholder feedback	• Outage response communications and responsiveness: Customers told us that we need to communicate better, particularly in relation to storms and unplanned outages. customers have told us that our inability to provide accurate information quickly and regularly, particularly during an outage, has been a source of frustration, distress, and disempowerment. Customers expect us to engage more effectively with other agencies in the event of an outage to address complex risks and restore supply quickly and safely. • Information accessibility: Customers expect that we use a range of different communication channels to reflect differences in customer preferences (not all customers search for information or like to be communicated in the same way) and to ensure that there are adequate alternatives for disseminating important information in the event of telecommunication system outages. • Interactions with **customers:** Customers have told us that they don't want to wait long periods to have their queries answered, expect continuity in their interactions (i.e. not having to start afresh each time they interact with AusNet on the same or related matter) and want better visibility of progress of applications, complaints and matters raised.

Source: AusNet

6.13.3.1. Consideration of cloud based and opex options

We have also carefully considered the potential role of cloud-based technology services—both infrastructure and application, which have matured significantly in terms of cost, performance, and availability, AusNet has carefully evaluated cloud options as part of our digital strategy.

In the 2022-2026 regulatory period, AusNet sought to migrate some of our ICT infrastructure to the cloud where there were opportunities to more cost effectively support the applications. This included our legacy data and analytics capabilities that would be downsized over time. Over the last regulatory period, we completed a program to proactively move to cloud-based products, rather than renewing on premises, where this was assessed as prudent after taking into consideration system criticality and security, and the costs of migration and ongoing opex. This is reflected in the lower recurrent capex for the 2022-26 period.

Having completed migrations during the last regulatory period, we consider the current mix of on-premise and cloud ICT infrastructure reflects an optimal balance. As such, there is no further focused cloud migration program planned for the 2026-31 regulatory period. For the 2026-31 period, we continue our simplification strategy by identifying areas where technology can be simplified to reduce complexity and cost by removing waste. This includes pursuing further efficiency opportunities in our data centres and cloud optimisation.

Although there is no further focused cloud migration program planned, we have noted a trend of some vendors to migrate their products to the cloud, requiring transition in order to maintain currency (even if not justified from a cost-benefit basis). We therefore anticipate being required to migrate certain applications to the cloud as part of upgrade and lifecycle management activities. To address this, we have included operational expenditure (opex) of $3.74m in our Technology Asset Management submissions to account for these “forced” migrations. This approach ensures AusNet remains current with vendor-supported applications while maintaining the stability and security of our ICT environment.

6.13.4. Projects and programs

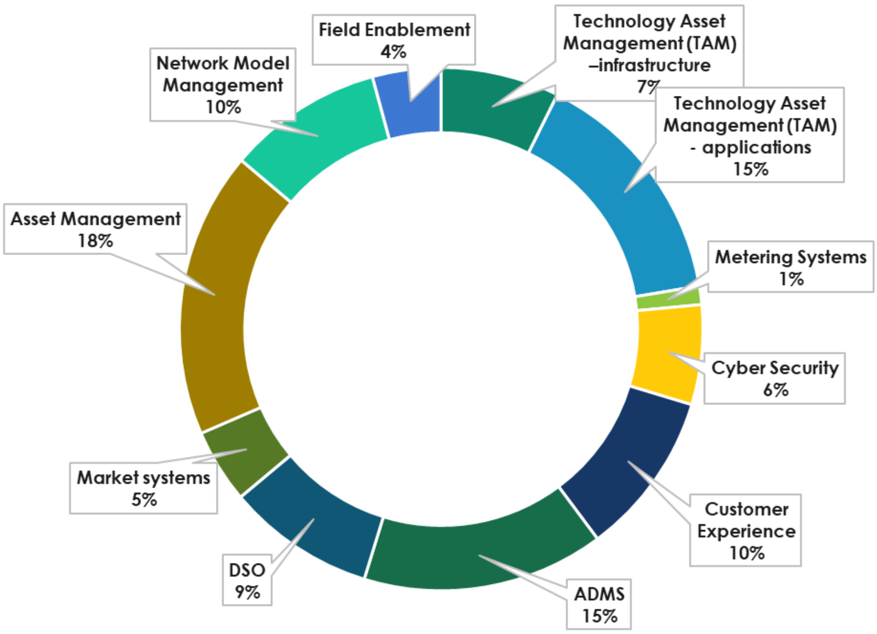
Our proposed projects and programs of work for the 2026-31 regulatory period reflect our Technology Strategy. Specifically, our proposed work programs will help us improve service levels to better manage the increasingly complex operating environment driven by evolving customer expectations, the energy transition, and other emerging risks and factors discussed in section 6.13.2 above.

Figure 6-59 below outlines our proposed projects and programs, highlighting how they align with the key objectives of our digital capex strategy for the 2026-31 regulatory period.

Figure 6-5928: Objectives of digital capex and proposed programs

Figure 6-60 below shows the breakdown of our proposed digital capex by percentage of spend over the 2026-31 regulatory period, covering the 11 proposed projects and programs listed above.

Figure 6-6029: Digital capex plans for the 2026-31 regulatory period ($m real, 2023-24) (%)



The table below shows the proposed expenditure for each of the 11 projects and programs, along with a brief description outlining the objectives and expected outcomes of each program.

Table 6-3: Proposed digital capex programs ($m real, 2023-24)

Outcome	Program	Description	Proposed Expenditure
Enable the continued functioning of our operations and support the other programs	Technology Asset Management (TAM) – infrastructure	This program will: • Maintain IT systems to ensure they are up-to-date, robust, scalable, and aligned with business and regulatory requirements to support reliable service delivery. • Optimise data centre infrastructure, including platforms, hardware, and licenses, through lifecycle refreshes to prevent system failures, reduce maintenance costs, and mitigate operational risks.	29.6
	Technology Asset Management (TAM) - applications	AusNet operates over 200 applications that require periodic patching and lifecycle enhancements. This program ensures critical systems remain supported by vendors, receive essential security patches and bug fixes, and align with AusNet's Asset Management Policy. It helps mitigate operational risks, limits downtime, maintains operating efficiency, and ensures the reliability of services essential to daily operations and customer needs.	60.8
	Metering Systems	This program ensures AusNet's metering systems remain supported, secure, and compliant with regulatory requirements. It includes recurrent lifecycle maintenance for AMI and non-AMI systems and non-recurrent upgrades to the Meter Data Management system (EnergyIP) to handle increased data from 5-minute settlement meters. The investment mitigates risks, ensures operational efficiency, and prevents penalties by maintaining vendor support and compliance with service level standards.	4.6
	Cyber Security	Investment in cyber security is required to meet current and emerging regulations and laws. This program will protect our organisational assets, including information, applications, systems, networks and end user devices from internal and external cyber security threats. It will also ensure compliance with regulatory requirements.	24.9
Enhance our systems to meet customer expectations	Customer Experience	This program enhances AusNet's systems to improve customer communications, service interactions, and operational efficiency. It focuses on maintaining and upgrading customer-facing platforms to meet evolving expectations, improve outage management, and ensure faster response times. The recommended approach maximises the use of existing systems through vendor updates and integrations, addressing customer frustrations with service continuity and accessibility. This investment ensures compliance with regulatory standards while	41.0

		reducing risks, saving time for customers and staff, and driving customer satisfaction.	
Modernise our network control capability	ADMS	AusNet's Advanced Distribution Management System (ADMS) program aims to modernize and enhance network control capabilities, ensuring the network remains resilient, reliable, and responsive to emerging challenges. This program, an in-flight project, builds on foundational improvements made during the current regulatory period. It addresses key drivers such as the rise of renewable energy, increased frequency of extreme weather events, and evolving customer and market demands. Recommendations from the NOUS Post Incident Review, following the February 2024 storms, have underscored the need for these improvements, including enhanced outage management and automation. Notably, some costs associated with this program have been allocated to the network SCADA asset life (instead of Digital), which reduces the revenue requirement for the 2026–31 regulatory period. This investment aligns with AusNet's long-term strategy to integrate Distributed Energy Resources (DER), optimize grid operations, and meet customer expectations for a secure and efficient network.	60.4
	DSO	The Distribution System Operator (DSO) program focuses on enhancing AusNet's capability to manage and integrate Consumer Energy Resources (CER) efficiently. It aims to deliver smarter network management, improve customer outcomes, and enable flexible services like dynamic export and load connections. By leveraging existing systems with targeted enhancements, the program minimizes costs and risks while aligning with customer expectations, CER integration strategies, and emerging regulatory requirements.	37.0
Uplift the consistency and quality of our data	Market systems	AusNet is upgrading its Identity and Access Management (IDAM), Industry Data Exchange (IDX), and Portal Consolidation (PC) systems to meet AEMO's NEM reform requirements. This investment ensures compliance with market regulations, enhances cybersecurity, and improves system integration. It addresses operational risks, supports future reforms, and ensures the reliability of interactions with customers and market participants. With phased implementation planned through FY27-31, this program maintains secure, efficient operations and aligns with AusNet's commitment to regulatory compliance and operational excellence.	18.5
Enhance our asset management systems	Asset Management	AusNet is investing in upgrading its asset management systems to enhance analytics, risk identification, and decision-making capabilities. This program addresses operational challenges, including aging infrastructure and the need to adapt to climate change risks, while supporting network reliability and customer satisfaction. Upgrading from manual processes to modern software will optimise maintenance, reduce outages, and better prioritise investments across the asset lifecycle. These improvements will align AusNet's practices with industry standards, enhance compliance, and deliver long-term cost savings for customers through more efficient asset management.	71.5
	Network Model Management	AusNet is integrating its ADMS and GIS systems to improve network visibility, operational efficiency, and data accuracy. This initiative enhances situational awareness for controllers, improves outage management, and supports compliance with regulatory recommendations. Incorporating advanced technologies and aligning with industry standards, the project strengthens network resilience, optimises maintenance planning, and improves customer service.	38.8
Increase visibility of our field operations	Field Enablement	AusNet's Field Operations Digital Enablement program aims to enhance the efficiency and effectiveness of managing field crews through new digital tools. These investments will improve real-time fault management, field crew tracking, and emergency response capabilities. By streamlining communication between the control room and field crews, the program will reduce restoration times, improve scheduling efficiency, and minimize service disruptions. This initiative supports AusNet's operational goals by ensuring resource efficiency, maintaining network resilience, and meeting growing customer expectations amid increasing weather events and network complexities.	17.1
Total			**404.2**

Source: AusNet

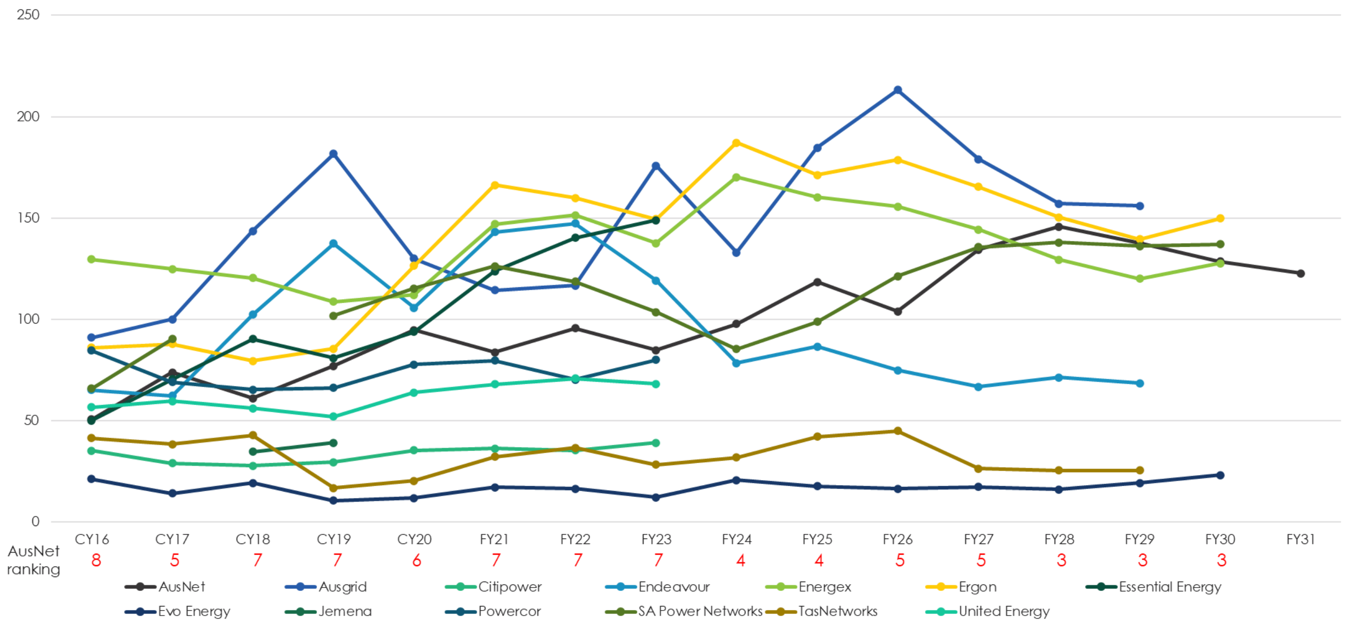
Further information on the customer (and network) benefits of each digital program is available in the Technology Strategy (Appendix 6D) and the ICT Program business cases which have been provided as part of this proposal.

6.13.5. Benchmarking and validation

AusNet benchmarks its capital expenditure against typical project costs from other Australian DNSPs, as well as its own historical performance. This approach ensures prudent management of capital investments relative to industry peers while accounting for the unique challenges specific to AusNet's network operations. We conduct benchmarking at the total cost level to ensure our expenditures reflect efficient practices and align with industry standards.

Benchmarking digital totex against other Australian DNSPs shows that our expenditures align with industry standards, demonstrating that AusNet's digital spending is comparable to peers and consistent with market expectations for effective network operations. A comparison of totex shows that our proposal enables AusNet to maintain a comparable position among Australian DNSPs, as illustrated in figure 6-61 below. We note however that this analysis is limited by availability of time series data for distributors without a recent determination and we will update this analysis in our Revised Proposal.

Figure 6-61:30 AusNet totex p.a. vs. Australian DNSPs ($m 2023-24)



Source: AusNet

6.13.6. Supporting documentation

We have included the following documents to support this chapter:

- ASD - AusNet - Technology Strategy and Investment Plan - 31 Jan 2025
- ASD - AusNet - Digital Business Case - Network Model Management - 31 Jan 2025
- ASD - AusNet - Digital Business Case - Cyber Security - 31 Jan 2025
- ASD - AusNet - Digital Business Case - Technology Asset Management Infrastructure - 31 Jan 2025
- ASD - AusNet - Digital Business Case - Technology Asset Management Applications - 31 Jan 2025
- ASD - AusNet - Digital Business Case - Metering Systems - 31 Jan 2025
- ASD - AusNet - Digital Business Case - Market Systems - 31 Jan 2025
- ASD - AusNet - Digital Business Case - Field Enablement - 31 Jan 2025
- ASD - AusNet - Digital Business Case - Distribution System Operator - 31 Jan 2025
- ASD - AusNet - Digital Business Case - Customer Experience - 31 Jan 2025
- ASD - AusNet - Digital Business Case - Asset Management - 31 Jan 2025
- ASD - AusNet - Digital Business Case - ADMS - 31 Jan 2025

6.14. Safety and environmental expenditure

6.14.1. Key points

The key points in this section are:

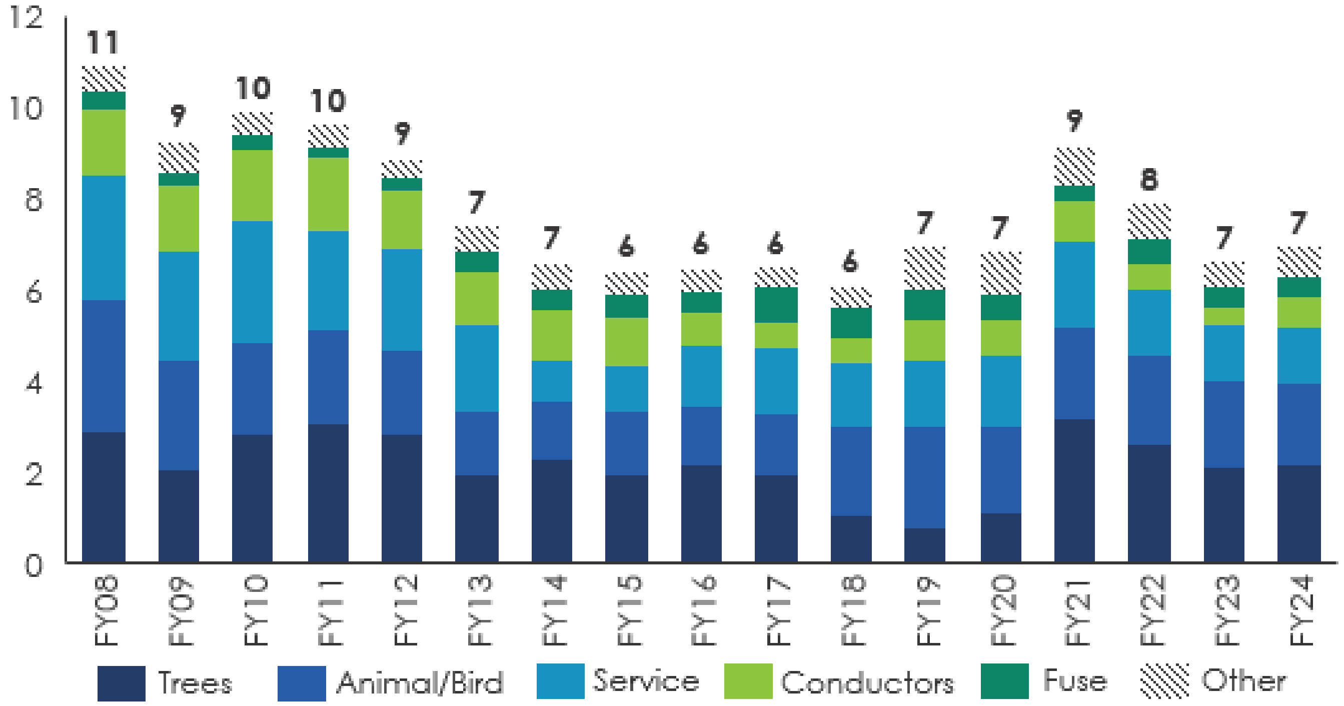
- While we have completed the REFCL installation program in 2023, there remains a need to invest in REFCLs over the 2026-31 period, to ensure that we continue to meet our Required Capacity obligation. Specifically, we need to ensure that capacitive current limit of each REFLC's Arc Suppression Coil is not exceeded due to increased demand, new customer connections and overhead conductor to underground cable conversions.
- Developing a 3D model of our network will have significant performance and safety benefits by identifying electrical line clearance breaches and encroachments of foreign objects such as vegetation and building or structure. To develop a 3D model, we need to capture the data related to our network. To date, we have captured data related to approximately 50% of our network with another 50% remaining. As such, we have proposed $10m (direct, real 2023-24) to capture the asset data related to the remaining 50%. The cost for hosting and processing our data are digital related cost that are already embedded within our digital capex forecast.
- We have identified 20km of bare SWER to be replaced with an insulated version over the 2026-31 period due to its aging condition (representing 3% of our SWER population that are located in Codified areas). On top of that, we have proposed an additional 200km of proactive upgrades - insulating or undergrounding bare SWER - that will deliver material improvements in safety. It is also consistent with the Victorian Government's RIS analysis that assumed all powerlines in Codified areas would be replaced by 2040.
- Some defects cannot be detected using traditional inspection methods as they are not visible. Failure to address these defects can be catastrophic. We have proposed to install Early Fault Detection (EFD) devices on our network, which are relatively new, innovative technology aimed at proactively identifying potential asset failures, allowing for swift deployment of field personal to remedy before the item can fail and start a fire. EFD devices operate 24/7 and has been proven to identify latent line defects to within ~10 metres.

6.14.2. Overview of forecast and key drivers

Safety has been a significant driver of expenditure over the last decade, most notably in response to the Victorian Bushfire Royal Commission (VBRC) recommendations, our self-initiated programs aimed at improving safety; and the successful delivery of the REFCL program. Our safety programs ensure that the community benefits from a materially lower safety risk.

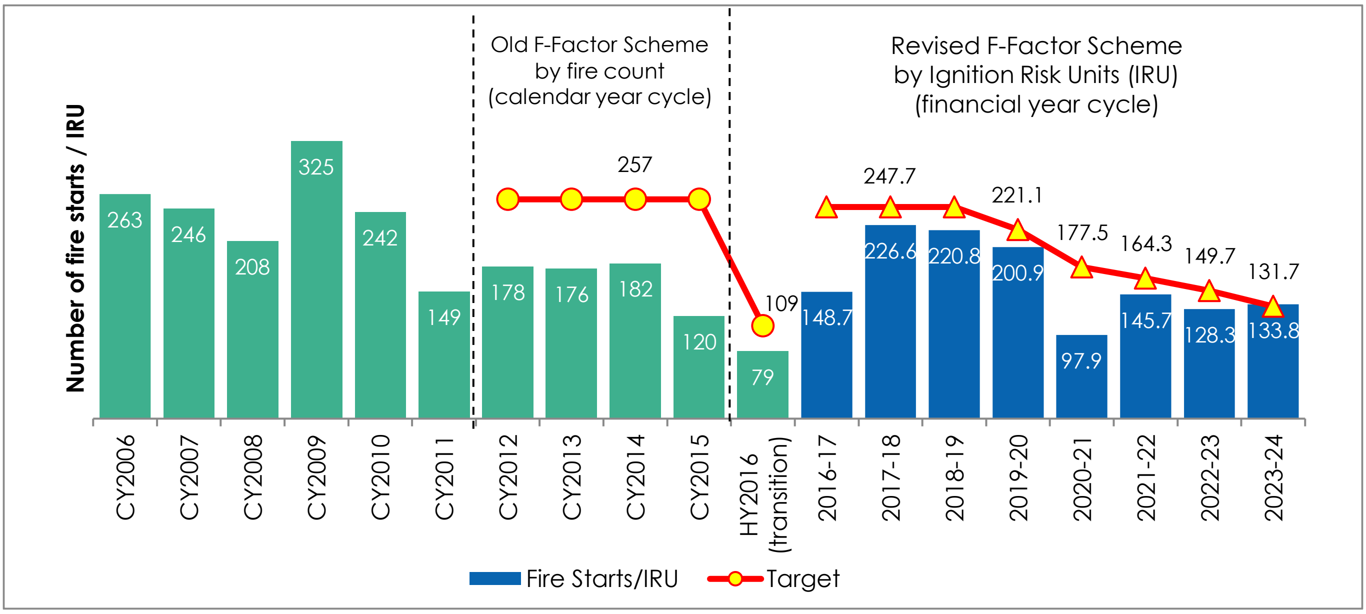
As shown in the figures below, since 2009, the number of incidents with the potential to cause a fire and the actual number of fire starts caused by our assets has fallen. These figures show that despite weather conditions worsening we have been able to achieve a slight downward trend in potential and actual fires.

Figure 6-62:31 Number of incidents with potential fire start (thousands)



Source: AusNet

Figure 6-63:32 F-factor scheme by Ignition Risk Units (IRU)



Source: AusNet.

Note 1: Under current arrangements, each fire is weighted by a "location factor" and a "fire risk (timing) factor". By applying these weighting factors to each fire, a fire will have a score called an "ignition risk unit" (IRU).

Safety capex during the 2026-31 regulatory period is forecast to be $220.3m (direct, real 2023-24), which is 25% lower than our expected safety expenditure in the current regulatory period. However, this reduced expenditure does not reflect a lessening of our commitment to safety. Rather, the reduction reflects the completion of the mandated REFCL program in 2023. Despite the program's completion, ongoing network augmentation is required to maintain REFCL compliance, due to network growth, which accounts for $65.6m of total safety and environmental forecast in 2026-31.

We are proposing to accelerate the proactive replacement of Single Wire Earth Return (**SWER**) lines in Codified Areas, from the 100km program being delivered in the current period, to 200km in 2026-31. The SWER conductor will be replaced with a combination of insulated conductor and underground cables. This program was initiated to address the recommendations of the VBRC and subsequent Powerline Bushfire Safety Taskforce to replace approximately 1,400km of SWER and bare polyphase conductor in Codified Areas by 2040.

We are also proposing to install Early Fault Detection (**EFDs**) devices on our network, as a new bushfire safety program. EFD devices are a relatively new, innovative technology aimed at proactively identifying potential asset failures, triggering field inspection and replacement. AusNet has undertaken three field trials, and the completion of these trials has confirmed the technology can reduce bushfire risk on our network. We have tested key aspects of our plans with the Victorian safety regulator (Energy Safe) and EDPR Coordination Group.

Our forecast safety and environmental capital investment is summarised in the table below.

Table 6-34: Summary of safety and environmental projects and programs

Project/Program	Driver	Capex
REFCL compliance program	Safety	65.6
Low service/conductor – data capture	Safety	10.1
Low service/conductor – reactive program	Safety	15.0
Codified Areas - Proactive insulation or undergrounding of SWER	Safety	27.2
Codified Areas – SWER & bare conductor replacement programs	Safety	10.3
Fuses	Safety	45.8
Installation of Early Fault Detection devices	Safety	12.6
Oil control upgrades – Distribution Voltage Regulators and ZSS assets	Environmental	25.6
Fall Arrest Systems	Safety	6.8
SWER Earths	Safety	1.3
Total	Safety	**220.3**

Source: AusNet.

6.14.3. Methodology and key assumptions

The safety of our employees, contractors, and customers and the community that we operate within is the number one priority for AusNet, and it is an area that we do not compromise on. As such, our safety strategy – missionZero – means zero injuries and guided by:

- Zero injuries to our people, contractors and visitors
- Zero tolerance or unsafe behaviour and acts
- Zero compromise on safety, and
- Zero impacts to our families and communities.

Our safety strategy is one of the key drivers of our capex requirement for safety; yet the following are equally important drivers of our safety expenditure forecast that we have thoroughly considered in the development of our forecast:

- The Electricity Safety Act 1998 and regulations made under the Act
- Our approved Electricity Safety Management Scheme (ESMS) and draft ESMS that has been submitted to Energy Safe for review, and
- Our approved Bushfire Mitigation and Vegetation Management Plans.

6.14.4. Projects and programs

6.14.4.1. REFCL compliance program

For a REFCL to operate with the required sensitivity as specified in the regulations, the capacitive balance of the circuits connected to the REFCL and the total capacitance of the connected circuits, must be maintained within specified ranges. The REFCL's ability to successfully detect, manage and locate phase-to-earth faults on the 22kV network is dependent on a complex combination of network conditions, including the network damping factor and the network topology. When correctly managed, the balance of these network conditions allows continued operation of the REFCL protection in compliance with the required capacity.

We met our compliance obligations by completing Tranches 1-3 of the REFCL installation program in 2023, in accordance with the regulations. However, network conditions, topology and physical constraints (such as damping factor and capacitive current limits) impact the continued correct operation of REFCLs and its ability to continue meeting the Required Capacity. As the 22kV network grows due to increased demand, new customer connections and overhead conductor to underground cable conversions, the additional cable installations will increase the total capacitive current on the network. If the network capacitive current exceeds the capacitive current limit of each REFLC's Arc Suppression Coil, network investment is required to maintain compliance with the Regulations.

We have historically taken the approach of incremental investment to maintain compliance with the regulations to ensure minimal long-term cost to customers and are proposing to maintain this approach in the 2026-31 regulatory period. This is prudent and efficient as it enables:

- Minimum works to be carried out just in time to maintain compliance with the regulation
- Planning to be based on the most up-to-date network growth and capacitive current information, and
- Application of the latest REFCL technology in this rapidly developing field.

We have developed a capacitance forecast to determine when augmentation solutions will be required to ensure that existing REFCLs remain operational and compliant. The network capacitance forecast was developed based on the characteristics of each zone substation supply area, the standard topology of cables installed for Underground Residential Developments (**URDs**) and other known network augmentation. This forecast shows that capacitive current limits at four zone substations will be exceeded in the next regulatory period and, therefore, network investment is needed at these locations to maintain compliance at the following zone substations:

- Seymour
- Wodonga TS 22kV
- Woori Yallock, and
- Kinglake.

We have forecast REFCL compliance augmentation of $65.6M for the 2026-31 regulatory period at these four locations. This amount is in line with actual/expected REFCL compliance investment in the current regulatory period, and below the investment approved for the current period. We have classified this expenditure as safety expenditure, given it is required to maintain the mandated performance standards specified in the Regulations.

The table below shows the options assessed as part of developing our forecast. This assessment has demonstrated that a combination of Option 2 and Option 3 are preferred across the above four geographic REFCL areas. Further details are available in the detailed planning report attached to this proposal.

Lastly, in December 2024, the ESV published their decision paper on the operations of REFCL. Given the timing of the publication, we will address the impact of the new guidelines in our Revised Proposal.

Table 6-35: REFCL compliance augex options assessment

Option	Discussion
Option 1 – "Do nothing"	The Business-as-Usual option maintains the status quo at which will entail no additional investment to manage the impact of the capacitive current. With a capacitive current forecast exceeding the thresholds used for forecasting purposes, the sites mentioned above may become non-compliant with the Regulations, the community served by those zone substations would be exposed to increased risk of fire starts from 22kV phase-to-earth faults, and AusNet will be subject to penalties under the Act. On this basis, Option 1 is not a credible option.
Option 2 – Installing Isolating transformers	Installing one or more isolation transformers has the effect of offloading capacitive current from the network. It is applicable to underground sections of the network only, ensuring that capacitive current from these sections does not adversely contribute to REFCL ASC limits. This is the simplest (and most mature) option technically – thus is deemed credible.
Option 3 - Remote REFCL	The remote REFCL solution is a current and compliant solution utilised at KLO, BGE and BN. It isolates part of a feeder and protects that isolated section with its own REFCL. The remote REFCL can be located no closer than 100m to the zone substation due to earthing issues. This option can be deployed as a standalone solution or along with network augmentation and installation of small isolation transformers. This option is considered credible.
Option 4 - New Zone Substation	Installing a new zone substation to reduce the capacitive is a technically viable option if the load transferred is serviced by underground cables or a REFCL is being installed at the new zone substation. This option is considered credible and is discussed further below.

Source: AusNet

6.14.4.2. Low service/conductor – data capture

We have used Light Detection and Ranging (LiDAR) to capture data related to approximately 50% of our network area. We plan on continuing LiDAR to capture the data related to the remaining 50% of our network. Once our network data is fully captured, it will allow us to develop a 3D model which will provide a detailed view of each overhead line asset.

A 3D model has significant performance and safety benefits by identifying electrical line clearance breaches and encroachments of foreign objects such as vegetation and building or structure. If left unchecked, the reduced clearances pose the potential to be accidentally bridged by a third party, animal/bird or vegetation. The consequence can be asset failure resulting in unplanned outages or fire ignition and/or electrical shock to staff, members of the public and animals/birds.

As a minimum, 3D modelling will allow AusNet to:

- Identify breaches of no go zone electrical clearances by foreign objects into the electrical corridor such as unauthorised buildings and structures
- Identify phase to phase and phase to earth structure clearances
- Identify and model circuit to circuit clearances
- Produce survey grade identification of vegetation distance to overhead lines
- Find poles leaning into traffic, and
- Identify all low conductors and conduct an automated risk assessment based on vehicle use of the terrain the conductor traverses over.

The LiDAR 3D Model program will utilise advanced data analytics and machine learning technologies to automate the identification of clearance breaches and issue for maintenance/ replacement rectification.

Using traditional line survey techniques (instead of LiDAR) can provide an accurate measurement of all clearances. However, an estimated 1 – 2 poles per hour is needed for a two-man surveyor crew to set up and complete their measurements, then back at the office or via back-office resources, process and record the information collected. Traditional survey of the network of 318,000 poles over a 5-year period would need a dedicated work force of 70-80 fully qualified surveyors for the sole purpose of surveying clearances. This is not economic.

As a result, we have proposed LiDAR as our surveying technique to capture the remaining 50% of data across our network. The estimated cost of LiDAR related to the remaining parts of our network is $10m over the 2026-31 regulatory period. The cost for hosting and processing our data are digital related cost that are embedded within our digital capex forecast. See chapter 6.13 for more information.

A sophisticated 3D model will also allow us to understand our vegetation breaches with high accuracy – that is, when vegetation encroaches into our mandated clearance zones – which requires rectification. We will consider the implications of the 3D modelling on our vegetation management practices in our Revised Proposal following further engagement with Energy Safe.

6.14.4.3. Low service/conductor – reactive program

The estimated cost to reactively respond to low service/conductor breaches is $15m over the 2026-31 regulatory period. Our forecast is based on our current BAU program of $3m p.a.

6.14.4.4. Codified areas – proactive insulation or undergrounding of SWER

The 22 kV overhead network in Codified Areas is protected by REFCL technology. However, REFCLs provide no protection against fire starts caused by SWER lines.

Codified Areas are areas of high bushfire risk, as defined under the *Electricity Safety Act 1988*. The VBRC and the subsequent Powerline Bushfire Safety Taskforce (**PBST**) both recommended undergrounding or insulating SWER lines in Codified Areas over a 10-year time period. While timeframes for this recommendation were not taken up in Victorian legislation, the VBRC and PBST established replacement rate expectations with their investment in the Powerline Replacement Fund (**PRF**).

The Victorian Government's RIS analysis assumed powerlines would be replaced over a 25-year period commencing in 2015 and finishing in 2040, that is, all powerlines would reach end of life within a 25-year period. The current regulations only require the insulating or undergrounding of lines when they reach end of life. Because the average life of conductor is significantly longer than 25 years, replacement of SWER conductor based on condition alone will not result in replacement of SWER conductor in a timeframe consistent with the recommendations of the VBRC and PBST or the assumption in the RIS (by 20240). For example, we have assumed that 20km of SWER conductor in Codified Areas will reach end of life over the 2026-31 regulatory period.

During the previous regulatory period, the PRF provided a significant amount of expenditure ($74m) to businesses to replace these assets. This program has led to material reductions in bushfire risk in these areas. In the current regulatory period, we are on track to deliver the 100km of replacement volumes approved at the last determination.

Our condition-based replacement forecast of 20km is equivalent to 3% of the total SWER conductor in Codified Areas. While we have included this condition-based replacement in our forecast (discussed below), we do not consider that limiting the rate of replacement to 3% of the SWER conductor in Codified Areas over the five years meets the expectations of our customers and stakeholders. We are, therefore, proposing an additional program to proactively insulate or underground SWER conductors in Codified Areas. The proposed program is an acceleration of the program being delivered in the current regulatory period, recognising the material improvement in safety that this investment will deliver and the need to accelerate the program to meet the VBCR and PBST's recommendations. Maintaining the current replacement rate of 100km per regulatory period would see all SWER and bare conductor replaced beyond 2050.

Instead, our proposed program, with a forecast cost of $27.2m (direct, real 2023-24), will continue and accelerate the work carried out during the current period. A replacement rate of 200km per regulatory period would see the replacement of all SWER and bare conductor by 2040, which is longer than the 10-year period recommended by the VBRC but within the 2040 timeframe.

The figure below demonstrates that while the proposed program (of 200km per regulatory period) will continue to reduce bushfire risk in Codified Areas, it is a significant step down from the volume of work carried out under the PRF. Our proposed expenditure profile balances addressing our customers' affordability concerns with our commitment to meeting the community's expectations around bushfire safety risk.

In increasing the size of this program to 200km during the next regulatory period, we have carefully considered the overall costs, and bill impacts of our proposal, as a whole. As discussed in our Executive summary, our Revenue Proposal will keep average bills broadly stable, in real terms.

Our proposed program will therefore replace approximately 200km (30%) of the 645km of SWER network in Codified Areas over the 2026-31 regulatory period with insulated overhead conductor or undergrounding. This 200km is in addition to the 20km condition-based replacement outlined earlier. This will make a significant contribution to our ongoing plan to replace the bare conductors remaining within Codified Areas.

Further information on this proposed program is available in the Enhanced Network Safety Strategy ("ASD - Enhanced Network Safety Strategy-31 Jan 2025") provided as a supporting documentation to this proposal.

6.14.4.5. Codified Areas – Condition-based SWER and bare conductor replacement

In addition to the proposed replacement of 200km of SWER in Codified Areas during the 2026-31 regulatory period, we are proposing a condition-based program to replace an additional 20km of SWER and 10km of bare conductors during the 2026-31 regulatory period. These rates are based on historical rates from the current and previous regulatory periods.

The forecast cost for these replacements is $10.3m (direct, real 2023-24).

6.14.4.6. Fuses

The operation of expulsion drop out (**EDO**) fuses can result in the expulsion of hot material, increasing the risk of bushfire ignition. They remain the largest cause of fires associated with asset failures.

EDO fuse units are no longer being installed on new and replacement work. Consistent with our approach in the current regulatory period, they are being replaced with Boric Acid or Fault Tamer fuse units. As part of the pole or crossarm replacement, EDO and Powder Filled Fuse units will be replaced at the same time. Fuse units will be replaced by either Boric Acid or Fault Tamer units.

Our proposal for the 2026-31 regulatory period sees us continuing our current EDO fuse replacement program and proactively replace approximately 1,900 EDO fuses per annum. The forecast cost for these fuses is $45.8m (direct, real 2023-24).

The proposed replacement volumes have been derived using a semi-quantitative risk assessment method using a consequence/likelihood matrix. The consequence of a fuse malfunction is assigned with a consequence cost which is determined by the bushfire effect cost, value of unserved energy, and health and safety cost. The replacement cost has been derived from historical financial records. Further details are available in the supporting AMS document.

6.14.4.7. Installation of Early Fault Detection devices

EFD devices are a relatively new, innovative technology aimed at proactively identifying potential asset failures, allowing for swift deployment of field personal to remedy before the item can fail and start a fire. We have planned a progressive program to roll out EFD devices over a number of regulatory periods. For the 2026-2031 regulatory period, we are proposing capital expenditure of $12.6m (direct, real 2023-24) to install EFD devices in the SWER network in Codified areas. This allows a measured approach to minimising bill impacts, provides time to enhance attributes library which minimises false positives and maximise response efficiency.

AusNet has undertaken three field trials, and the completion of these trials has shown:

- The EFD has proven reliable and effective in identifying defective equipment giving off invisible signals. The EFD is now deployed in countries with similar bushfire challenges to that of AusNet. The United States and Canada have deployed thousands of these units and given their success are increasing their programs. Australian utilities lag in the uptake of EFD.
- From the trials AusNet has confirmed, the source location provided by the EFD units has proven to be highly reliable with the claimed accuracy of ~10m holding true for most cases. This has proven to be invaluable in identifying what types of issues the EFD regularly detects as well as sources of interference.

We have previously presented key aspects of our plans to the EDPR Coordination Group.

We will be presenting our plans to the Victorian safety regulator (Energy Safe Victoria) as formally requested under s. 101(1) of the *Electricity Safety Act 1998*.

The program delivers safety benefits that are typically not quantified elsewhere in the framework as the f-factor incentive is relatively weak. Units would be installed across the AusNet network at approximately 3.5km spacing.

6.14.4.8. Oil control upgrades – Distribution Voltage Regulators and ZSS assets

The *Environment Protection Act 2017*, amended in 2018 and effective from July 2020, introduced the General Environmental Duty (**GED**), which requires identifying and minimising risks of harm from oil pollution or waste to protect human health and the environment.

As part of the upcoming regulatory period, AusNet will prioritise addressing outdated and non-compliant oil management systems at zone substations and distribution voltage regulator sites. AusNet will focus on replacing or upgrading infrastructure where necessary. A risk-based, prioritised approach will be applied to minimise potential risks to human health and the environment, ensuring that all feasible steps are taken to eliminate or mitigate these risks.

For Environment systems in zone substations and distribution voltage regulator sites, a risk model was developed considering likelihood and consequence in the event of an oil spill. Likelihood is based on number of Power transformers /Voltage Regulators, bunding type and magnitude of Oil leak. Consequence is based on the impact to environment, fines and remediation and restoration costs.

The environment system risk model provides the relative risk at each zone substation /Voltage regulator site. The prerequisite for a capital environment improvement project under oil control program:

- Risks can't be feasibly managed through associated asset maintenance or asset refurbishment
- Monetised risk exceeds the environment system improvement cost – i.e. improvement is economic, and
- Replacement of an associated asset will result in a material risk reduction (Station Rebuild program).

6.14.4.9. Fall Arrest Systems

We have installed Fall Arrest System (**FAS**) on 210 tower structures. We plan to install FAS on the remining 258 tower structures in the next 2026-31 regulatory period. This will ensure the Occupational Health and Safety Regulations are met.

Specifically, AusNet is mandated by the Occupational Health and Safety Regulations to provide a safe work environment to its employees both staff and contractors. As the towers in the sub-transmission fleet were constructed using old design standards, towers along certain lines lack the appropriate safety clearance between the line worker and the live conductors. To address this hazard, the tower safe access program was initiated wherein a ladder was installed along the centre of the tower body and a cable fall arrest system was installed along the access path of steel lattice towers.

Additionally, WorkSafe recommends the use of elevated work platforms (**EWPs**) as the safest method to access the towers (Level 2 control under the hierarchy of controls as per Regulation 205 of the *Occupational Health and Safety (Prevention of Falls) Regulations 2003*). However, where this is not practical, the next level recommended is a permanent fall arrest system which is a Level 3 control.

In response to the WorkSafe recommendations, the EWP option was considered but found impractical for AusNet Services due to the majority of these structures being located in country/mountainous areas inaccessible by EWPs. For multi-circuit easements, the use of an EWP is further constrained as there is restricted clearance between adjacent circuits. This constraint poses a safety risk and therefore requires continuous outages of the lines to undertake condition assessment inspections and other activities. Consequently, AusNet adopted a Level 3 control instead.

6.14.5. Benchmarking and validation

Our proposed REFCL compliance augex is below our expected REFCL expenditure (sum of compliance and augex REFCL) in the current regulatory period, which we have been incentivised to minimise (without compromising our ability to meet our safety obligations).

In relation to the other safety projects and programs, including our Codified Area proactive program, which is the largest component of the safety category, the actual costs of undertaking similar work during the 2022-26 regulatory period are the basis of our estimated costs.

It is difficult to benchmark 'safety' related costs, as DNSPs do not typically report 'safety capex'. We also recognise that, from a benchmarking perspective, the category is problematic as DNSPs are likely to apply different approaches when allocating these costs, particularly as significant proportions of repex is safety-related. In addition, we are subject to a number of legislative and regulatory obligations to make safety improvements, such as our general obligation to minimise as far as practicable hazards and risks on our supply network. In this sense, benchmarking expenditure with a view to limiting the AER's allowance would be inconsistent with our regulatory obligations.

As already noted, our forecast safety capex is substantially lower than our historical spend. Regardless of this reduction, the proposed expenditure represents the prudent and efficient costs we will incur in meeting our current safety obligations.

6.14.6. Supporting documentation

We have included the following documents to support this chapter:

- ASD - Enhanced Network Safety Strategy- 31 Jan 2025
- ASD - AusNet - Current draft ESMS - 31 Jan 2025
- ASD - AusNet - Current approved ESMS-31 Jan 2025
- ASD - AusNet - REFCL BC – 31012025
- ASD - AusNet - Conductor clearance compliance (3D Model) – 31012025
- ASD - Proactive insulation or undergrounding of SWER (Codified areas) – 31012025
- ASD - AusNet - AMS 20-52 Bare Conductors - 31012025
- ASD - AusNet - AMS 20-55 Civil Infrastructure – 31012025
- ASD - AusNet - AMS 20-64 Sub-transmission Towers, Insulators and Ground Wires – 310125
- ASD - AusNet - AMS 20-61 MV Fuse Switch Disconnectors – 310125
- ASD - Fuses – Economic model (Demo)-31 Jan 2025

6.15. Compliance expenditure

6.15.1. Key points

The key points in this section are:

- Compliance expenditure is the capital needed to maintain compliance with our network distribution licence and the regulations that we operate under. The key regulations that we operate under include the NER and the Victorian Electricity Distribution Code of Practice (EDCOP).
- Our compliance obligations with respect to safety, which includes bushfire mitigation, are covered in a separate section (see Chapter 6.14).
- Increasing solar PV penetration in recent years has led to voltage swings being outside of the operating limit which affects the quality of supply to our customers. As a result, we have proposed a voltage compliance program of works with a capital expenditure requirement of $23.3m (direct, real 2023-24). This will help us maintain functional compliance in line with our peers (we note that the EDCOP only requires functional compliance).
- We have also proposed a quality of supply program with a capex requirement of $7.2m (direct, real 2023-24) to continue our Business-as-usual (BAU) response to voltage complaints. This program addresses quality of supply issues that the voltage compliance program cannot address.
- Increasing solar PV penetration has also decreased the amount of load under the control of the Under Frequency Load Shedding (UFLS) scheme below 60%. Our obligation is to use reasonable endeavours to exercise and assist AEMO in the proper discharge of its power system security responsibilities, which means AusNet should within reason, be able to provide up to 60% of its gross load under the control of the UFLS scheme. Our investment proposal involves installing distributed UFLS at all distribution feeders and dynamic blocking[84] ($17.8m) – which gets part of the way to 60% - with any shortfall in net load requiring CERs to be curtailed. The alternative solution that achieves 60%, that does not require curtailment, is the installation of network storage which has a capex requirement of $5.2 billion (direct, real 2023-24); we do not consider this option to be cost-effective.

[84] Dynamic blocking is when the relay actively determines if a feeder shouldn't be tripped (i.e. a feeder which is net exporting to the network won't be tripped as its helping the situation).

6.15.2. Overview of forecast and key drivers

Compliance expenditure is the capital needed to maintain compliance with our network distribution licence and the regulations that we operate under. The key regulations that we operate under include the NER and the EDCOP. Our compliance obligations with respect to safety are covered in a separate section (see Chapter 6.14).

The key drivers of compliance capex are:

- Increasing solar PV penetration has led to voltage swings outside of the operating limit specified in the EDCOP.
- Increasing solar PV penetration has also reduced the amount of load under the control of UFLS scheme below a compliance level of 60%.

We are forecasting compliance capex (excluding safety) of $48.3m over the 2026-31 regulatory period.

Table 6-36: Summary of compliance augex ($m, real 2023-24)

Project	Description	Expenditure
Voltage compliance program	This is a program of works – with site-specific solutions – that achieves functional compliance at least cost. The program of works resolves the nature of the identified limitation at each site where it is economic to do so (i.e. NPV positive).	$23.3
Quality of supply program	To continue our BAU response to voltage complaints. This program addresses quality of supply issues that the voltage compliance program cannot address.	$7.2
Under Frequency Load Shedding (UFLS)	Our investment proposal involves installing distributed UFLS at all distribution feeders and dynamic blocking – which gets part of the way to 60% - with any shortfall in net load requiring CERs to be curtailed.	$17.8
Total		$48.3

Source: AusNet

6.15.3. Methodology and key assumptions

For compliance projects, the preferred option is generally the lowest cost credible option that addresses the compliance obligation. In some cases, we have quantified other benefits and taken the maximisation of the NPV into account. This approach is consistent with the RIT-D, which recognises that the preferred compliance-driven option may have a negative NPV, providing that it is the lowest cost option for meeting the compliance obligation.

In our assessment of voltage compliance and UFLS, we have quantified the benefit of avoided CER curtailment by adopting the AER's Customer Export Curtailment Value (**CECV**) and the Value of Emissions Reduction (**VER**) methodologies. These factors are included in the NPV analysis in assessing alternative options.

6.15.4. Projects and programs

6.15.4.1. Voltage compliance program

The EDCOP regulates the distribution of electricity by a distributor to its customers and promotes the long-term interests of Victorian consumers. Part 3, Clause 20 of the EDCOP details the regulatory obligations for the quality of supply for several parameters, including voltage. Victorian distributors are subject to financial penalties for non-compliance with the EDCOP regarding voltage performance, unlike most other Australian jurisdictions.

Based on the EDCOP, functional compliance is achieved when 95% or more customers have supply voltage within the range 216 V to 253 V for 99% of the time for each limit over a one-week period. The EDCOP only requires functional compliance.

AusNet's voltage performance has improved substantially over the past decade, due to programs we have already carried out to improve voltage monitoring and controls. We are operating in an environment of strong growth in solar PV connections to our network, stimulated by the Victorian Government's Solar Homes program. Additionally, we have a program of works over the remainder of the current regulatory period that will support functional compliance against the background of continuing growth in solar PVs and other factors affecting voltage compliance. While we have occasionally been non-compliant over the last few years, we expect to be functionally compliant by the end of 2025-26.

Despite the planned work for this current period, we need to continue to invest in our network over the 2026-31 regulatory period to maintain functional compliance.

AusNet has assessed the following three options:

- **Do nothing** – no expenditure to address steady-state over-voltage non-compliances with potential non-compliance penalties of up to $11.5 million.

- **Option 1 (functional compliance)** – undertaking works that would help us maintain functional compliance, also reducing voltage-curtailed generation for customers with over-voltage where economic, selecting only those projects that have a positive NPV.
- **Option 2 (full compliance)** – following the least-cost, deterministic approach to remove all steady-state voltage non-compliances. It goes beyond our obligation for functional compliance under the EDCOP, by providing compliant voltages to all customers. In other words, full compliance is when all customers (100%) have voltage within the range 216 V to 253 V for 99% of the time for each limit over a one-week period.

Options 1 and 2 involve assessing each site to identify the least cost technically feasible solution to resolve the nature of the identified limitation at that site. As such, the solutions underpinning options 1 and 2 are a combination of feasible solutions to create a program which is then subject to an economic assessment process. The solutions considered for each site include:

- Dynamic Voltage Management (DVM)
- Network capex solutions
- Switched reactors
- Transformer upgrades (lower impedance) and replacements (with wider tapping ranges)
- New transformers
- New feeders and circuits
- Splitting or reconfiguring circuits
- Network opex solutions
- Tap changes
- Float voltage setting changes and line drop compensation
- Phase balancing
- Non-network alternatives (including storage, inverter support).

AusNet has identified Option 1 as the preferred option, with a capital expenditure requirement of $23.3m (direct, real 2023-24) over the 2026-31 regulatory control period. Option 1 is the preferred option because it maximises the NPV, through achieving functional compliance at least cost. The table below outlines the solutions and sites of option 1.

Table 6-37: Program of works for Option 1 (preferred option)

Optimum project type	Identified sites
DVM	MYT, LGA, FTR, HPK, WGL, LDL, CRE, WOTS, LLG, NLA, TT, BDL, CPK, BN, ELM, MOE, EPG, MFA, BRA, PHM, LYD, MWL
Zone substation reactor and DVM	CLN, WGI, DRN, PHI, KLO, OFR, WN
HV distribution feeder voltage regulator and DVM	MYT12, LDL23, FTR23, NLA34, WGL12
Distribution substation transformer replacement distribution substation tap down	BRANDY CREEK
Distribution substation phase peak load balance distribution substation tap up	68 sites

Source: AusNet analysis

Under Option 1, over the 2026-31 regulatory control period the percentage of customers with EDCOP non-compliant voltages is expected to fall from a functional compliance level of 5% to 3.4% by the end of the period. A lower 3.4% level provides a buffer – given there's some uncertainty over solar penetration growth – and brings us closer to the levels being achieved by other Victorian DBs. Despite the increases in CER connections and increases in HV underground cable length expected over the period which both place upward pressure on network voltages, this Option 1 investment program effectively delivers an improved voltage compliance performance outcome for customers.

6.15.4.2. Quality of Supply Program

AusNet currently has a recurrent supply improvement program that aims to resolve power supply issues raised by customers. This is predominantly an urgent program (mainly triggered by customer complaints due to the lack of permanently installed quality of supply metering across the network), to address quality of supply issues.

Each year AusNet's customer service centre receives a significant number of customer complaints about quality of electricity supply. Complaints are investigated to identify the problem and develop a solution to address the issue based on least cost, often prioritising lower cost opex solutions over typically more expensive capex options. The process follows a detailed investigation proving that no technically or economically feasible alternative solution exists.

AusNet is proposing to continue this recurrent supply improvement program maintained at current regulatory control period allowance levels to address quality of supply issues on the network. The current period allowance associated with this program is $7.2m (direct, real 2023-24). This program is needed to continue to respond to and address identified and reported customer quality of supply issues, that are not otherwise addressed by other programs of work (such as the Voltage Compliance Program).

6.15.4.3. Under Frequency Load Shedding (UFLS)

UFLS is an existing load-shedding control scheme comprising a system of under-frequency tripping relays installed at each terminal station, that are triggered in a coordinated way by a major loss of generation that causes an under-frequency event due to an undersupply condition for the network load (demand) at the time. This may require a rebalancing of load to supply by dropping some of the load on the network at the time. If this is not done in a timely manner, the UFLS condition could worsen and significantly threaten system security. UFLS relays at substations can shed blocks of load (typically at the sub-transmission level) until the supply-demand balance is restored, thereby returning the power system back to a secure state.

UFLS scheme can become ineffective with the presence of reverse power flows from distributed embedded generation which can cause net generation to be seen within available load shedding blocks. This would typically happen where the CER generation within that part of the network exceeds the load in the same section. Shedding net generation blocks during an under-frequency event would make an UFLS situation worse by reducing supply further. This in turn may cause the power system to collapse, with the system frequency decline unable to be arrested as more generation is removed from the system. With the ongoing increases in the uptake of distributed roof-top solar photo-voltaic panels (DPV) within the distribution networks over the last 15 years, there is an increased risk of the load-shed blocks armed within the UFLS scheme being net generation sources at certain times of day, because local demand is exceeded by local generation.

NER clause 4.3.1(k)(2) requires AEMO to ensure there is sufficient reserve available within the UFLS scheme to arrest the impacts of a range of significant multiple contingency events affecting up to 60% of the total power system load. Clause 4.3.4(a) requires each Network Service Provider (NSP) to use reasonable endeavors to exercise and assist AEMO in the proper discharge of its power system security responsibilities. AusNet's interpretation of these clauses is that each NSP should within reason, be able to provide up to 60% of that NSP's total underlying (or gross) load under the control of the UFLS scheme. Meeting this requirement with the existing UFLS scheme installed at the terminal station level will become increasingly difficult as DPV growth continues, and the net demand as measured by the UFLS scheme reduces as a proportion of the underlying load. Load blocks with reverse power flow, and the reduced numbers of load blocks available for the UFLS scheme, are a threat to the effectiveness of the UFLS scheme in responding to a widespread loss of transmission generation.

AusNet investigated the following options to maintain the integrity of the UFLS scheme:

- **Do nothing** – no expenditure on addressing UFLS scheme compliances (i.e., retaining the existing terminal station schemes which will continue to reduce in UFLS effectiveness due to increasing CER).
- **Option 1 – Distributed UFLS at all zone substations and dynamic blocking**: installing under-frequency relays at all zone substations to provide more granular load blocks for the UFLS, with dynamic reverse power blocking implemented at each zone substation.
- **Option 2 – Distributed UFLS at all distribution feeders and dynamic blocking**: installing under-frequency relays at all zone substations to provide even more granular load blocks for the UFLS than under option 1, with dynamic reverse power blocking implemented on each distribution feeder (this is more refined compared to option 1).
- **Option 3 – Network storage supported UFLS**: installing network storage to increase the net load as a proportion of the underlying load on the network by charging (pre-contingent).
- **Option 4 – Emergency backstop mechanism supported UFLS**: leverage the emergency backstop mechanism only (pre-contingent) to curtail distributed embedded generation to increase the net load on the network. This option is considered unviable on its own as it only applies to new DPV systems and does not address legacy UFLS compliance issues.

AusNet proposes Option 2 at a cost of $17.8m (direct, real 2023-24) over the 2026-31 regulatory control period, which represents a prudent and efficient network augmentation investment to maintain system security compliance with respect to the UFLS scheme. We have proposed Option 2 as the preferred option as it is the least cost, technically acceptable solution to improve compliance of all the options considered.

Option 2 gets AusNet part of the way to 60%, where we have assumed that any shortfall in net load will be achieved by curtailing CERs. The alternative solution that achieves 60%, that does not require curtailment, is the installation of network storage which has a capex requirement of $5.2 billion (direct, real 2023-24); we do not consider this option to be cost-effective.

6.15.5. Supporting documentation

We have included the following documents to support this chapter:

- ASD - AusNet - Voltage compliance and quality of supply program BC – 31012025
- ASD - AusNet - Voltage compliance and quality of supply program economic model - 31012025
- ASD - AusNet - UFLS business case – 31012025
- ASD - AusNet - UFLS economic model – 31012025

6.16. Non-network expenditure

6.16.1. Key points

- Our non-network net capex forecast of $262m, which comprises the following components, is 218% higher than our current period expected spend A multi-period, strategic depot reset
    - South Morang training facility
    - Business-as-usual building expenditure
    - Control room refurbishment
    - Fleet and plant, and
    - Tools and general equipment.
- The increase in non-network capex is largely driven by the need to replace and refurbish several of our depots and acquire additional fleet, following a recent decision to change our service delivery partner to Zinfra from 1 August 2025. As part of replacing the existing, AusNet owned fleet, we are also planning to transition 70% of these vehicles to electric vehicles by 2031, delivering environmental and opex benefits to our customers.
- Our proposed program of depot replacements and refurbishments is underpinned by a comprehensive, long-term depot strategy. Following a long period of relatively low investment in our depots, this program is needed to maintain acceptable standards of workplace accommodation that is required by our compliance obligations, and support staff safety. Improving depot condition will also encourage staff retention and therefore support the deliverability of our capital program. Finally, this investment will support our response to outages and regional communities following storm events and mitigate the risk of more costly reactive depot maintenance, which will provide savings over coming regulatory periods.
- The approach we have developed for each element of our non-network capex forecast will enable us to meet our customers' service expectations, manage our compliance obligations prudently and efficiently, and ensure we are sufficiently resourced to deliver our proposed network capex program. While the level of capex exceeds current levels, in each instance there is a compelling case for the proposed expenditure.

6.16.2. Overview of forecast and key drivers

Table Table 6-38 summarises our proposed net non-network expenditure for the 2026-31 regulatory period. We are forecasting a total of $262m ($2023-24) for this capex category for the 2026-31 regulatory period. This is 218% higher than our expected expenditure in the current regulatory period.

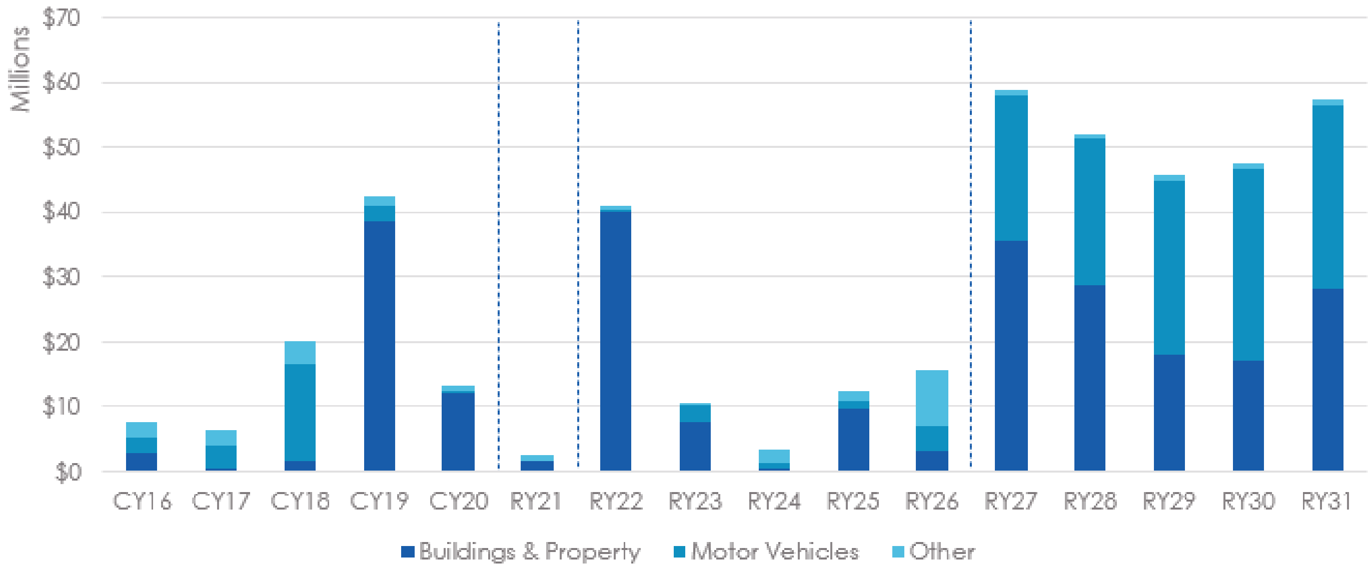
Table 6-38: Non-network capex, 2026-31 regulatory period ($m, 2023-24)

Project/Program	Total $M	% of Total
Property - capitalised leases	18.3	7%
Property, depot and station upgrades	109.2	42%
Fleet and plant	130.1	50%
Other	4.3	2%
Total	**261.8**	**100%**

Source: AusNet

The figure below shows our historical and forecast capex for the different elements of non-network capex. The increase proposed for 2026-31 reflects changes to our business model (much of our vehicle and property costs are currently embedded in unit rates charged by our service delivery partner) and the need to uplift investment in our key operational assets.

Figure 6-6433: Non-Network capex 2016 to 2031 ($m, $2023-24)



Source: AusNet
Note: CY20 and RY21 have a 6-month overlap between July- Dec 2020

In developing our non-network capex we have placed a strong emphasis on balancing affordability, service reliability, and future readiness. Customers expect us to provide reliable and safe electricity services, particularly as the network supports increased electrification and decentralization of generation. This involves getting the basics right, such as maintaining network safety, reducing bushfire risks, and replacing assets in poor condition. From a non-network capex perspective, we must ensure that:

- We have facilities that enable us to meet our customers' service expectations at the lowest total lifecycle costs.
- We replace and upgrade assets to efficiently meet the needs of our staff and contractors, and comply with our health and safety obligations.
- Respond to changing circumstances, including changes to our business model and operations that have a consequential impact on non-network capex.
- Our non-network resources are sufficient and fit for purpose to support the delivery of our capital program, which is forecast to increase by 72% in 2026-31.

In general terms, these considerations require us to consider alternative options to meet identified needs, and to select those options that deliver the highest NPV and/or minimise the total lifecycle costs of maintaining service levels, meeting our customers' expectations and our compliance obligations.

We engaged with our customers on some elements of our non-network capex forecast, with the following outcomes:

- Support for AusNet to electrify 70% of existing fleet.
- Increase in AusNet's ability to effectively respond to extreme weather events.
- No concerns raised to the approach considered for general expenditure, tools and equipment and capitalised leases. [85]

Due to the timing and sensitivity of our decision to transition to Zinfra, we were unable to engage meaningfully with our customers and stakeholders on some, material components of our fleet and depots forecasts.

6.16.2.1. Additional fleet and plant are required under new service delivery arrangements

AusNet has made material changes to its fleet and plant ownership arrangements as the new service delivery model commencing operation on 1 August 2025 will bring all leases, purchases and running costs of fleet and plant to AusNet. This differs from our current arrangements, where the majority of operational assets are owned or leased by our primary contractor, with cost recovery via unitised rates charged to AusNet.

As discussed further in section 6.17.3.5 below, the proposed increased expenditure for this category is driven by the following:

- The transfer of fleet and plant from Downer to AusNet.
- Lifecycle replacement of vehicles.
- Network expansion and capital works volume increase, increasing number of required vehicles and plant.

6.16.2.2. Changes to operating model will impact our depot capex plans

One major impact of our service delivery model change involves the transition of depot leases from Downer to AusNet. Currently, Downer leases and manages six of our depots. As we take direct control of key operational assets, these leases will be transferred to us, enabling AusNet to manage all depots. This change supports an overarching strategy of transitioning these properties to AusNet-owned assets where feasible, which will allow investments to upgrade facilities without lease restrictions.

In the past, expenditure on depots has been below the levels needed to maintain and upgrade these facilities adequately. This has resulted in lower costs for customers but has also led to the following issues:

- **Asset Degradation and Risk.** The depots have experienced visible wear and tear. As a result, the reliability and functionality of the depots at risk, with many assets now beyond their useful life and in urgent need of replacement.
- **Poor Layout and Ad-Hoc Upgrades.** The depots have been subject to irregular, minor upgrades that were not strategically planned. Over time, this has resulted in suboptimal layouts that do not adequately meet current operational demands, limiting productivity and impacting overall efficiency given expanding workforce.
- **Land, Access, and Functionality Issues**. Land availability, ease of access, and site functionality are major factors that influence the operational capacity of the depots. Many depots face constraints in terms of space, difficult access, and poorly designed layouts. Addressing these challenges is vital to improving safety, response times, and overall productivity.

6.16.2.3. Transfer of leases will impact our capitalised lease costs

From 1 April 2019, we have been capitalising leases in accordance with the changes to the Australian Accounting Standards AASB16. The accounting standard requires leases to be treated as an asset, under which the lessee has the right to use the asset and an obligation to make lease payments over the lease term. The accounting change relating to the treatment of leases gave a rise to a non-recurrent capitalised lease cost of approximately $33m in 2019.

Additional capitalised lease costs will be incurred when taking over leases for depots currently leased by Downer, totalling $2m for the 2026-31 period. To avoid overlaps with our opex forecast, we have adjusted our base year to remove the leasing costs currently charged to us by Downer (discussed further in Chapter 7).

The lease cost for each depot is estimated based on the average market lease rates for similar properties in the surrounding area. The costs are calculated per square meter, considering the local real estate market conditions, type of facility, and specific requirements of the depot. This approach ensures that lease expenses are aligned with current market standards, providing a realistic basis for budgeting. By benchmarking against comparable facilities, we ensure that the estimated lease costs reflect fair value while supporting operational requirements effectively.

[85] Coordination Group Meeting Snapshot 16 April 2024

Much of the below forecast expenditure relates to the lease renewals for AusNet's head office and control room building.

Table 6-40: Capitalised leases forecast 2026-31 ($m, 2023-24)

Year	2026-27	2027-28	2028-29	2029-30	2030-31
Capex	$0.0	$8.6	$0.0	$0.3	$9.4

Source: AusNet

6.16.3. Projects and programs

6.16.3.1. Strategic depot reset

We have developed a "Strategic Depot Reset Program", which is a comprehensive three-phase plan to transform AusNet's depot infrastructure over the next 15 years. This strategic initiative will modernise, upgrade, and reconfigure existing depots to ensure they meet evolving operational and community needs, supporting efficient and reliable electricity distribution across the network. This reset will enhance safety, functionality, and long-term sustainability to align with AusNet's proactive approach to property management. Our approach to developing this program and the associated program of work in the 2026-31 regulatory period is described in this section. Further detail is available in the Depot Strategy supporting document.

In the past, AusNet's expenditure on depots has been low compared to industry standards and below the levels needed to maintain and upgrade these facilities adequately. Improving the current state of depot facilities and bringing them up to operational standards is essential for:

- Meeting compliance requirements and workforce safety for example asbestos sheeting and fire safety standards.
- Delivering better performance and outcomes for customers and stakeholders, including enhanced responses to major weather events.
- Staff retention to support deliverability of our works programs.
- Strengthening AusNet's presence within its communities, which we know is valued by our customers based on feedback.

The figure below shows the options assessed as part of developing our proposed depot program. The Strategic Depot Reset option, which underpins our capex forecast, offers the highest net economic benefits, as well as several other quantitative and qualitative benefits that ultimately will flow through to customers through improved service levels – consistent with the feedback we have heard from our customers on the need to improve reliability and resilience - and minimisation of long-term costs.

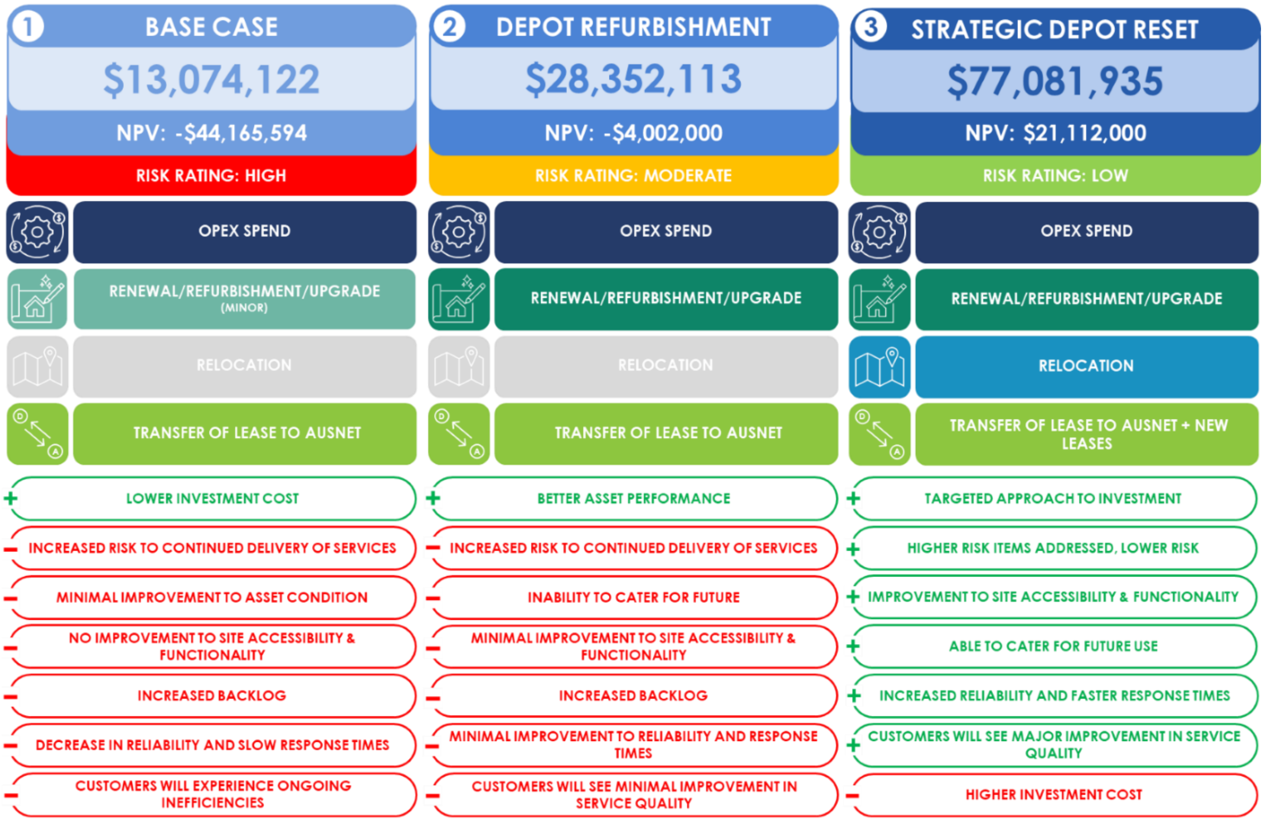
This option will focus on refurbishing and renewing existing depot facilities, implementing critical upgrades, and initiating the relocation of depots that are currently underperforming due to constraints in location or layout. The goal is to address current safety concerns, enhance functionality, and create space for operational requirements. Key actions in Phase 1 include:

- Renewals, refurbishment, and upgrades at various depots to improve asset conditions and support workforce requirements.
- Relocation of depots, including Warragul, Beaconsfield, Pakenham, and Traralgon, to more suitable sites to improve logistics, safety, and access.
- Transfer of lease ownership for several key depots to allow better control of facilities and facilitate future investments.

The total estimated cost for Phase 1 is $77.1m, comprising costs for renewals and refurbishment, relocations, and land purchases.

A detailed breakdown of sites and depots for Phase 1 can be found in the supporting document.

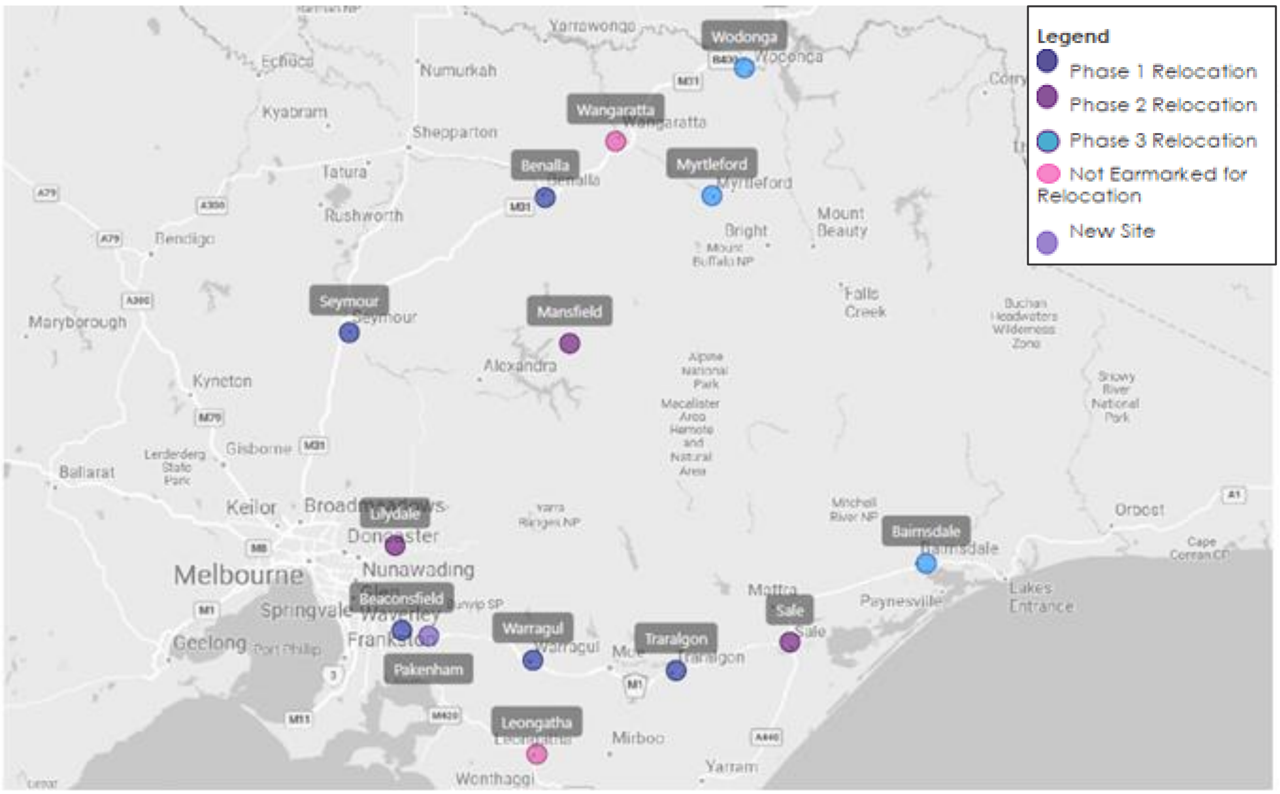
Figure 6-65: Alternative depot options assessed



Source: AusNet

The Strategic Depot Reset will involve works at the Phase 1 locations shown below that is vital to supporting our staff and the delivery of safe, reliable services to our customers during 2026-31. To prudently manage the costs, and mitigate delivery risks, of the proposed depot program, Phase 2 and Phase 3 sites will be addressed in future regulatory periods. Further information on the scope of these phases is available in the supporting document.

Figure 6-65: Map of AusNet Distribution depots highlighted for works by phase in strategic depot reset



Source: AusNet

6.16.3.2. South Morang Training Facility

We are proposing to develop a dedicated training facility at South Morang to enable our 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. The capex requirements are $26.4m in total, with cost sharing between transmission and distribution being 50% each at $13.2m.

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 growth in the recruitment of line workers, enabling long-term deliverability of our core operations. A dedicated training facility of this kind is consistent with good practice and our peers.

As part of developing this proposed project, we considered four options:

- **Business as usual**: No investment in facility and all training provided by third parties
- **Option A**: Redevelopment of the South Morang facility to create a modern training facility owned and managed by AusNet
- **Option B**: Refurbishment of the current South Morang facility to enable training for a reduced workforce, and
- **Option C**: All training outsourced to interstate, third party training providers for AusNet's full workforce.

The preferred option, Option A, will provide a range of benefits at the lowest total cost, including:

- **Organisational Efficiency**: providing a fit for purpose facility with the capability of offering a safe and efficient site, reducing the number of total training sessions needed and avoiding future opex increases
- **Training Compliance**: by developing its own facility, AusNet is able to address a need currently not met industry wide in Victoria. The facility will enable AusNet to deliver its strategic priorities and to enable Victoria to safely manoeuvre through the energy transition, and
- **Delivery Risk**: The development of the training facility at South Morang will enable AusNet to deliver its work programs proposed for 2026-31, and avoid material network risk costs associated with project deferral that is likely to occur without this facility.

Further information on this project is available in the South Morang Training Centre supporting document.[86]

6.16.3.3. Business-as-usual building expenditure

AusNet owns many buildings and properties and is responsible for their management and maintenance. These buildings include staff workplaces such as depots, and storage locations for plant and equipment. Refurbishment and upgrade expenditure is necessary to ensure existing sites are suitable to support the services delivered from each site. This typically involves items such as:

- Ongoing minor building works such as the installation of partitions
- Purchase and replacement of building capital items such as air conditioners, and
- Replacement of items such as roofs.

This expenditure relates to Business as Usual (BAU) expenditure **not** covered by the Strategic Depot Reset program. Some of these sites have an allocation with other AusNet networks. The proposed expenditure does not consist of any strategic land acquisition or sales this subsequent movements are captured in the strategic depot reset business case. For the 2026-31 regulatory period we are proposing $18.7 million for this program, or $3.7m per annum. This spend is in line with historical capex between 2016 and 2024, which has averaged $11.8m.

Table 6-41: Buildings and property capex long term historical spend ($m, 2023-24)

Year	CY16	CY17	CY18	CY19	CY20	2020-21	2021-22	2022-23	2023-24	AVERAGE
Capex	$2.8	$0.3	$1.6	$38.6	$12.0	$1.6	$33.6	$6.5	$0.3	$11.8

6.16.3.4. Control room refurbishment

The Control Room Operations Team (CEOT) has occupied the current leased premises located in [C-I-C] since prior to privatisation of the electricity industry. The current lease will expire in August 2027 providing an opportunity to plan, design and implement an ideal efficient solution for the long-term accommodation needs of the control room and associated business groups.

86 ASD - AusNet - South Morang Training Centre -31 Jan 2025

To enable the modernisation of the control room and ensure that it meets operational and technical requirements, the following investment is necessary:

- Control room fit-out and IT costs, with a specific fit-out for the control room requiring an investment of $2.2m. Slattery have provided a quote for this work which can be found in a supporting document87. The total cost of this work is equal to $5.2m, which reflects:
  - 25% escalation applied to the Slattery quote, which was provided in year 2021 and hence does not reflect increases in materials and property costs since that time, and
  - An 43% allocation to electricity distribution.

The last refurbishment of this space occurred over a decade ago, which has now reached its effective life cycle and to maintain functionality this expenditure is required.

This refurbishment would provide and continue to enable the following benefits:

- **Modernisation and integration:** Refurbishing the control room into a modern building fit-out offers the opportunity to modernise to align with current operational standards. It also facilitates smoother integration with other business units, enhancing operational efficiency and flexibility this includes designing the control room with flexible workspaces and mobile workstations to be easily reconfigured as needed to accommodate operational requirements and when teams are required to collaborate with the control room for events.
- **Continuation of same site and employee recruitment and retention:** Continuing to use a CBD location provides significant operational advantages, offering good proximity to other critical business functions and emergency services operations, which is essential for effective collaboration and quick response during emergencies. A refurbished and central location is also a more attractive option for staff recruitment and retention, due to being more accessible, having better transport links, and offering a broader range of amenities for our employees.

An in-situ refurbishment is currently our preferred option and, therefore, has been proposed. However, we are continuing to undertake more detailed analysis of options, including potential relocation of the Control Room, to ensure our long-term requirements are met. We will incorporate the findings of this assessment, including any changes to our preferred option, in our Revised Proposal.

6.16.3.5. Fleet and plant

AusNet operates a diverse fleet of vehicles consisting predominantly of car passenger vehicles and light commercial vehicles, with limited heavy commercial vehicles and elevated working platforms (EWPs) reflecting our current service delivery model.

Our vehicles allow us to ensure that we can support the delivery of services to customers for works relating to the distribution network through allowing our crews to appropriately access live components on our network and to quickly and safely reduce customer outage times. As such many longer asset life vehicles will also come under AusNet ownership, for further information on new and existing asset classes refer to 10.5 of the regulatory proposal.

Due to the change in service delivery model, the composition of our forecast fleet expenditure will be materially different to how these costs have been incurred during the current regulatory period. This reflects AusNet taking operational control of all of its fleet and as a result fleet expenditure will be incurred directly by AusNet during 2026-31, rather than form part of the unitised costs and management fees charged to AusNet under our contracting arrangements with our current primary service provider. Our forecast fleet expenditure for 2026-31 is summarised in the table below:

Table 6-42: Total Forecast Fleet and Plant Expenditure ($m, 2023-24)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Capex[88]	$23.3	$23.3	$27.8	$30.2	$29.0	$133.6
Opex	$6.7	$7.4	$7.3	$7.5	$7.1	$36.0

The opex component of our forecast of fleet expenditure exceeds the unitised costs and management fees embedded in our 2022-23 base year by approximately $14m over five years. However, we have not proposed a step change for these costs (i.e. opex associated with capex), which we intend to fund through productivity savings.

Of our gross fleet capex of $134m, $115m relates to the transfer of fleet driven by our decision to take operational control of our fleet and plant assets, which are currently provided by Downer, as part of our new service delivery arrangements. Our approach to forecasting this component of our fleet requirements is explained further below.

The remaining $19m is associated with replacement of the existing AusNet-owned fleet of light vehicles.

[87] ASD – Slattery – Control Room Refurbishment Quote – 31 Jan 2025
[88] Includes capitalised running costs related to running fleet and plant for 2026-31

Additional fleet and plant required under new service delivery arrangements

As part of developing our forecast, we assessed the total cost of ownership of the following two fleet ownership models over a 40-year horizon:

1. **Existing Service Provider Model.** Maintain the existing mix of leased and owned vehicles understood to be used by our current service provider, which predominantly involves lease arrangements (approx. 77%).
2. **Buy over time.** A 'buy over time' option which involves the progressive purchasing of vehicles over several regulatory periods, upon expiry of novated leases, leading to a fully owned suite of fleet and plant under AusNet control.

A total of 620 vehicles were included in this assessment, reflecting our forecast of vehicle requirements during 2026-31. This total fleet size includes a modest growth factor to accounts for network expansion and our proposed capital works increase forecast for 2026-31. A 40-year time horizon has been used for this assessment, to ensure the lifecycle replacement and running costs of heavy vehicles and plant (some of which have asset lives of 15-20 years) are fully accounted for.

The results of this assessment are shown below. These results demonstrate that the Buy Over Time offers the lowest long-term costs in PV terms and, therefore, is our preferred option.

Table 6-43: 40-year assessment period expressed in PV terms ($m, 2023-24)

	Capex	Opex	Total Expenditure
Existing Service Provider Model	306.1	121.7	427.8
Buy Over Time	314.7	70.7	385.4

Source: AusNet

In addition to being the most economic option over the long-term, the Buy Over Time option aligns more closely with AusNet's business objectives of owning its fleet, which will allow us to:

- Full control over the whole fleet, including how, when and what it is used for.
- Perform repairs and maintenance to our internal standards.
- Customise vehicles, as needed.

Over the longer term, this should support more efficient operations and better allow us to support the deliverability of our proposed capital programs.

The model containing the above assessment is provided as a supporting document.[89]

The benchmarking analysis set out in the next section demonstrates the efficiency of our proposed fleet expenditure.

We have also estimated that our network capex would be approximately $60m higher[90] if we maintained our current service delivery model (i.e. fleet costs continued to be incurred through unitised costs) and forecast network and fleet capex accordingly. This avoided network capex should be considered when assessing the increase in fleet expenditure we have proposed.

Our proposed fleet purchases will significantly increase the number of heavy vehicles we own, which have substantially longer lives than most of the existing AusNet fleet. Accordingly, we have proposed a new asset class to ensure these new assets are accurately depreciated over their lives. This is discussed further in Chapter 10.

Replacement of the existing AusNet-owned fleet of light vehicles

We have proposed $19m to replace the existing, AusNet-owned fleet during 2026-31. Our actual spend on fleet and plant has in recent years been low as we have looked to minimise costs, deferring some replacements into the 2026-31 period.

Nonetheless, our proposed spend of approximately $3.7m p.a. is broadly in line with long-term average spend from 2016 to 2024 of $3.1m p.a., as shown in the table below.

Through our existing fleet that AusNet fully owns we have committed to replacing these vehicles with EVs at a rate of 70% once their useful life has been reached. This will allow AusNet to be sustainable and provide opex savings to our customers in the long run. This was tested with the Coordination Group which we received support to invest in and propose a negative step change in response to the savings we expect to realise over the 2026-31 regulatory period.

[89] ASD – AusNet - Fleet NPV Analysis for Vehicle Transition - 31 Jan 2025
[90] ASD – AusNet - Coordination Group Engagement material on Service Provider Change – 31 Jan 2025

Table 6-44: Motor Vehicle capex long term historical spend ($m, 2023-24)

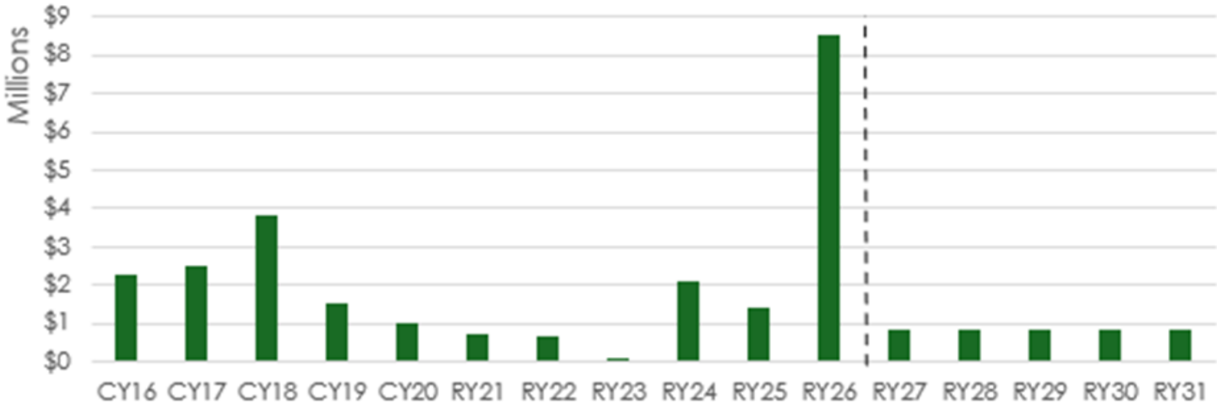
Year	CY16	CY17	CY18	CY19	CY20	2020-21	2021-22	2022-23	2023-24	AVERAGE
Capex	$2.5	$3.6	$14.8	$2.3	$0.3	$0.1	$0.0	$2.3	$1.0	$3.1

6.16.3.6. Other non-network

Other non-network includes tools and general equipment, this forecast is based on a historical average from regulatory year 2020-21 to 2023-24.

We are proposing $4.3m over 5 years which is 201% below current period spend due to a large spend on tools and equipment forecast in 2025-26 arising from the change in the service delivery partner this will negate the need to invest above historical spend in the 2026-31 regulatory period.

Figure 6-65: Other and General Equipment capex historical long term spend actuals ($m, 2023-24)

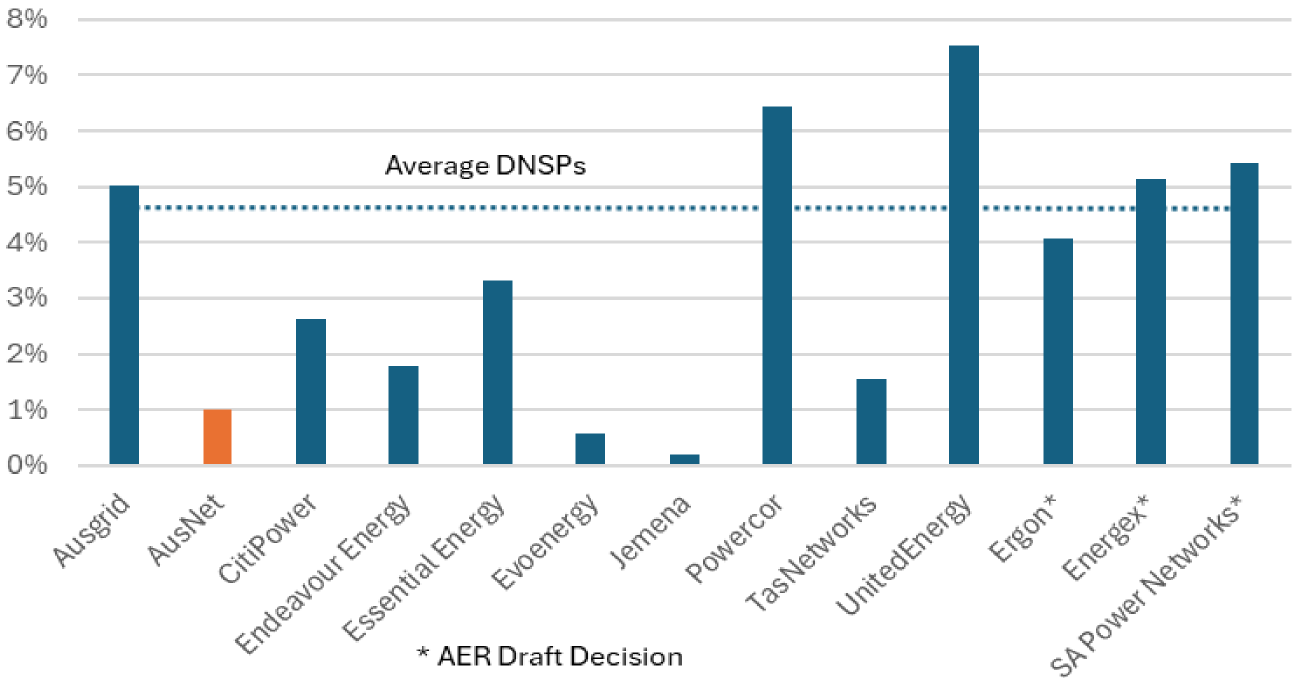


6.16.4. 6.17.4 Benchmarking and validation

Property

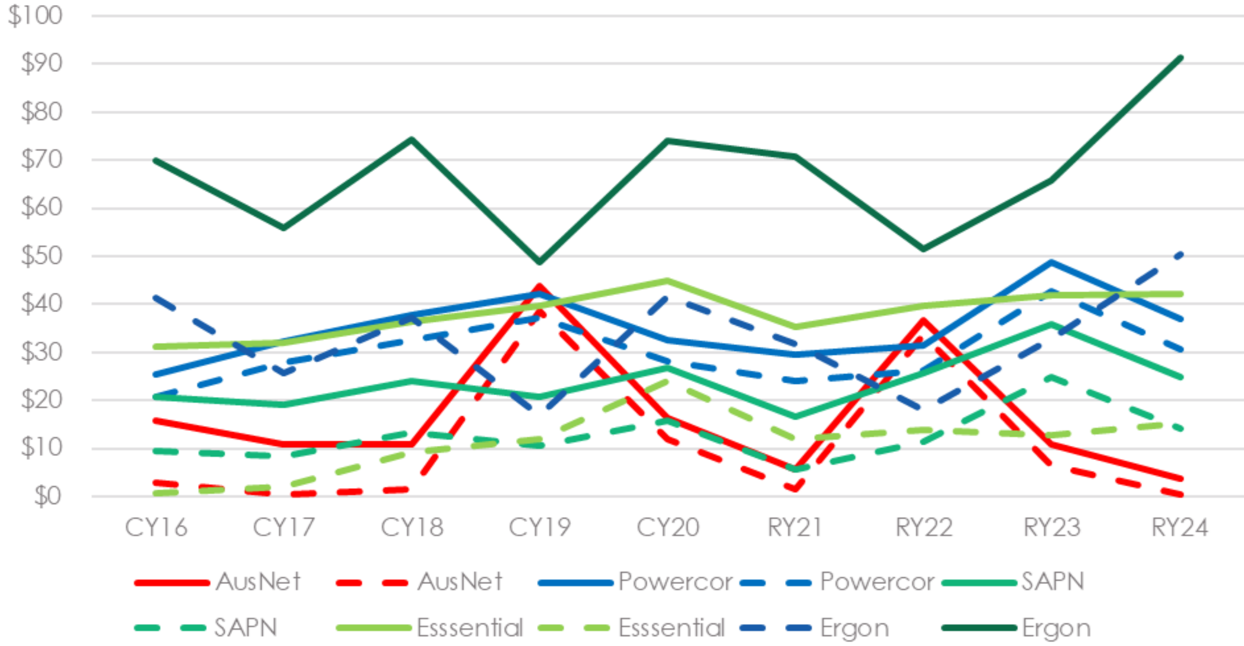
Historically, AusNet's spending on property capex was notably below industry averages, with only 1% of total capex allocated to property, compared to an industry average of approximately 4.5% of total capex. This low level of investment has contributed to the current state of the depots, which are now in need of significant refurbishments, relocations, and upgrades to align with operational needs and ensure improved safety, reliability, and service quality. The strategic depot reset project aims to secure the necessary funding to renewal, upgrade or relocate to enhance the depot infrastructure to meet operational demands and support AusNet's broader strategic initiatives.

Figure 6-66: Benchmarking AusNet property capex against other DNSPs based on most recent AER decisions as a proportion of total capex



Source: AusNet

Figure 6-67: Actual total expenditure for buildings and property 'rural' DNSPs 2016 to 2024 ($m, 2023-24)

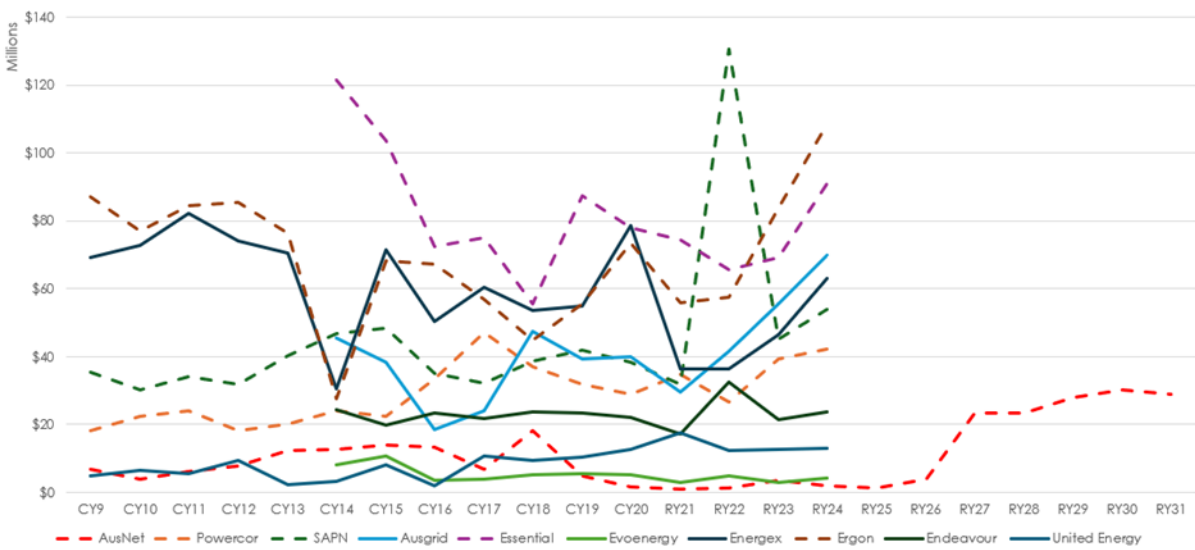


Source: AusNet
Note: Dotted line represents capex spend and solid line represents totex

Fleet and Plant

While our proposed fleet expenditure is above current period, it is broadly similar with current spending levels of peers, in particularly other rural networks that own their fleets. This is indicative of the reasonableness, prudency and efficiency of our proposed fleet spend.

Figure 6-68: Fleet and plant historical long term total expenditure DNSPs ($m, 2023-24)



Source: AusNet
Note: Dotted line represents 'Rural' network, NSW/ACT DNSPs no available data from 2009 to 2013

6.16.5. Supporting documentation

We have included the following documents to support this chapter:

- ASD - Slattery - Control Room Refurbishment Quote -31 Jan 2025
- ASD – AusNet - South Morang Training Centre - 31 Jan 2025
- ASD - AusNet - Depot Strategy -31 Jan 2025
- ASD – AusNet - Depot Strategy economic model - 31 Jan 2025

- ASD - AusNet - Fleet NPV Analysis for Vehicle Transition-31 Jan 2025

6.17. Why our capex forecasts satisfy the Rules requirements

We have developed our capital expenditure forecasts based on explicit feedback received through our engagement process, the capital expenditure objectives (NER cl 6.5.7(a)) and criteria (NER cl 6.5.7(c)(1)) and the NEO and have thoroughly addressed relevant considerations to ensure our forecasts are both prudent and efficient. In summary, our approach to developing our capex forecasts has been guided and supported by:

- **Rigorous engagement and forecasting processes**: Our regulatory proposal is underpinned by extensive engagement and research, ensuring that the proposed capex aligns with our customer preferences for affordability, reliability and resilience.[91] Our proposed forecasts incorporate external factors, which have a significant impact on our customer's lives including:
  - our role in the transition to net-zero emissions
  - facilitating growth in CER
  - preparing for extreme weather events
  - improving reliability for some of our worst served customers
- Despite the pressure for higher investments, we have kept affordability at the forefront, and made compromises on certain aspects, such as investment deferrals. This process ensures that only the most essential and justifiable components of our capex program remain, balancing the need for network investment with customers' willingness to pay.
- **Robust economic assessment framework:** All projects and programs within our capex forecast (with the exception of the RRA) are underpinned by a rigorous and robust economic assessment framework where:
  - We have adopted a robust and conservative demand forecast as input into our economic assessments of project needs and preferred option.
  - We have undertaken a thorough and comprehensive economic assessment of the available options (including non-network solutions) before selecting the preferred option that delivers the highest net benefit to customers.
  - We have used cost inputs that are prepared in accordance with specific project execution procedures and practices on a P50 basis, and unit rates are based on the rates charged by our service provider with a risk margin to reflect contractual exposure to actual costs.
  - We have generally adopted the AER's inputs when quantifying benefits (e.g., the AER's Value of Network Resilience, Value of Emissions Reduction, Customer Export Curtailment Value, and Value of Customer Reliability for non-residential customers). While we have adopted our own QCV for residential customers (and not the AER's VCR) – we have thoroughly explained why and the capex impact in Chapter 6.4.4 of our Regulatory Proposal.
- While the NEO and capital expenditure criteria (6.5.7(c)) makes it very clear that the AER can only accept prudent and efficient capital expenditure plans, there are no rules requirement to define and undertake cost benefit analysis for all projects included in a Revenue Proposal. This means the RRA is capable of being approved by the AER if it addresses the capital expenditure objectives (6.5.7(a)) and there are measures in place to ensure future projects funded by the RRA are prudent and efficient. We support prudent and efficient costs being included as a guiding principle with the RRA provided it appropriately balances the need for improved reliability in areas that would otherwise not be improved under the current regulatory framework. Further consultation would be needed to define this.
- **Benchmarking evidence**: The AER's most recent benchmarking report shows that we have similar levels of customer density to Ergon Energy and Essential Energy, but relatively lower costs per customer. Our network also performs well in terms of total cost per kilometre of line length. This supports our cost efficiency in delivering network services, while operating in an environment with lower average consumption levels.[92]

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[91] NER, cl 6.5.7(e)(5A)
[92] NER, cl 6.5.7(e)(4).

- **Proactive pursuit of operational efficiencies and alternative solutions**: In our business cases, we systematically evaluate operational efficiencies, input prices and substitution possibilities to ensure cost effective outcomes.[93] Non-network options are also rigorously considered in our economic assessments. This demonstrates our commitment to delivering the lowest long-term cost to consumers while maintaining network reliability.
- **No restricted assets:** Our capex forecast does not include expenditure for a restricted asset.
- **No related party arrangements:** Related party arrangements do not affect our forecasts.

In the table below, we have considered how each expenditure category is required to achieve the capital expenditure objectives and criteria set out in Rules. Additionally, Table 6-47 outlines how our capex forecast accounts for the factors in cl. 6.5.7(e) of the Rules.

Taken together, we are confident that our capex forecasts comply with the Rules requirements and consider that they should be accepted by the AER.

Table 6-47: Why expenditure is required to meet the relevant capex objectives

Capex category	Why expenditure is required to meet the relevant capex objective
Replacement & safety	The forecast expenditure reflects the prudent and efficient replacement of ageing and deteriorating network assets needed to maintain network reliability and safety, in line with NER cl. 6.5.7(a)(3) and (4). It also reflects compliance with regulatory obligations such as the Electricity Safety (Bushfire Mitigation) Regulations 2023, as well as other relevant safety standards and codes, including in particular ongoing REFCL expenditure (NER cl. 6.5.7(a)(2)). The program prioritises the lowest cost solutions to address asset failure risks, whilst ensuring network performance and protecting customer safety.
Demand driven augex	Consistent with NER cl. 6.5.7(a)(1), this expenditure is required to meet the expected growing demand for standard control services during the 2026-31 regulatory period. Capex forecasts reflect conservative input assumptions such as conservative demand forecast and adopting a probabilistic planning approach. The investments ensure the network can accommodate increased energy usage, while maintaining service reliability and aligning with forecast demand growth scenarios.
Resilience	Consistent with NER cl. 6.5.7(a)(3), this expenditure strengthens the network's security of supply in response to external risks, including climate change impacts, increasing frequency and size of extreme weather events and bushfire risks. Investments focus on mitigating risks to network infrastructure, ensuring continuity of supply during adverse events and safeguarding critical assets. The proposed measures align with the AER's resilience guidance, namely causal relationship, maintaining service levels and customers have been fully informed.
Connections	Consistent with NER cl. 6.5.7(a)(1) and (2), this expenditure is required to meet the expected growing demand for standard control services connections during the 2026-31 regulatory period. Capex forecasts reflect historical based unit rate, demand and growth estimates for existing customer types. Additionally, for new customer types we applied AEMO forecasts and recent interest from proponents.
CER enablement	Consistent with NER cl. 6.5.7(a)(1) and (5), this expenditure supports the integration of CER such as rooftop solar, battery storage and EVs. It facilitates efficient utilisation of the existing network capacity and enables the two-way flow of electricity, reducing the need for future network augmentation. The program aligns with the broader emissions reduction targets, by improving the network's ability to adapt to energy transition trends and enhancing customer benefits through optimised CER export opportunities.
Large renewables enablement and connections	Consistent with NER cl. 6.5.7(a)(1) and (5), this expenditure is required to unlock capacity for the growth of our customer base, and large renewable projects. The program supports the efficient integration of new connections by increasing network capacity, ensuring that export services can be delivered while maintaining network stability and minimising congestion. This investment aligns with the broader emissions reduction targets by enabling the transition to clean energy systems and supporting renewable update.
Reliability	Consistent with NER cl 6.5.7(a)(3), this expenditure ensures the network continues to maintain network average reliability and customer expectations. Our customer feedback, research and engagement highlighted concerns regarding reliability particularly for those located in rural areas, worst served and most vulnerable. Investments focus on improving performance in these areas are allocatively efficient and reflect customers' willingness to pay, with our research demonstrating that there is a strong willingness to pay for improved reliability even if customers are not directly benefiting from the upgrades. The recent increase in the AER's 2024 VCR for Victorian residential customers also supports the inclusion of reliability improvement expenditure as reflecting customer preferences. See chapter 6.9.2.6 for more information.
Compliance	Consistent with NER cl. 6.5.7(a)(2), this expenditure is required to comply with applicable regulatory obligations or requirements associated with the provision of standard control services.
Digital	This category of expenditure is required to facilitate the efficient management and operation of our entire network, consistent with NER cl. 6.5.7(a)(1) to (5). In particular: • sophisticated modelling improve the network's ability to forecast and manage expected demand at the zone substation and feeder levels (NER cl. 6.5.7(a)(1)). • communication tools are used to monitor performance and track compliance with regulatory obligations such as voltage compliance (NER cl. 6.5.7(a)(2)).

[93] NER, cl 6.5.7(e)(6).

	• analytical tools process large volumes of network data which provides insights for better decision making relating to the quality, reliability and security of our network services (NER cl. 6.5.7(a)(3)). • remote communication tools enable timely responses to operational and safety concerns, enhancing network safety and efficiency (NER cl. 6.5.7(a)(4)).
Non-network	We proposed to invest in several non-network capex programs to support operational efficiency, regulatory compliance and align with our environmental goals, in contribution to NER cl 6.5.7(a)(2), (3) and (5) including: • changes to our fleet arrangements to support emission reductions and improve long-term cost efficiency • depot investments to be able to improve our response to outages and regional storm events aligning with Victorian Government review • investments in our training facilities and capabilities to enhance capability and safety of contractors and staff.

Table 6-48 How our capex forecast accounts for the factors in cl. 6.5.7(e) of the Rules

	Description
Cl 6.5.7(e)(4)	• The AER's latest benchmarking analysis shows that our cost performance compares well with our peers and, therefore, our forecasts reflect efficient unit rates, planning and delivery processes. • We have provided benchmarking evidence within each capex category chapter.
Cl 6.5.7(e)(5)	• Chapter 0 of our Regulatory Proposal provides a long-term capex chart comparing actuals for previous periods, expected capex for the current period and our capex forecast for 2026-31. • We have also explained the drivers behind our 2026-31 capex forecast.
Cl 6.5.7(e)(5A)	• Chapter 6.4.1 of our Regulatory Proposal provides a summary of the important stakeholder feedback that we received from our Customer Panels that has influenced the new drivers within our capex forecast. • Specific feedback and details have been provided within each capex category of Chapter 6. • Importantly, our reliability forecast addresses the concerns of distribution customers which include improving reliability for some of our worst served customers, and customers are willing to pay for uplift in reliability even if they do not directly benefit. See chapter 6.9.
Cl 6.5.7(e)(6), (7) and (10)	• The economic assessments underlying each project and program adopts realistic operating costs and capital costs as inputs and considers a range of options available to address the project need, including non-network solutions such as SAPS.
Cl 6.5.7(e)(8)	• Our capex forecast is consistent with the CESS, EBSS and STPIS. Particularly given that our capex forecast has been reduced to reflect the amount of reward that we would have earned under the STPIS. • See Chapter 6.4.12 of our Regulatory Proposal
Cl 6.5.7(e)(9)	• Our project cost estimates have been prepared in accordance with specific project execution procedures and practices on a P50 basis, and unit rates are based on the rates charged by our service provider with a risk margin to reflect contractual exposure to actual costs. They therefore reflect costs that have been developed at arm's length.
Cl 6.5.7(e)(9A)	• Our forecast does not include projects or programs that would be more appropriately included as a contingent project.
Cl 6.5.7(e)(11)	• Some of our projects within the Large renewable enablement category are progressing through the RIT-D process. We have taken these projects into consideration when developing our capex forecast (though these projects are not at final report stage).

7. Operating expenditure

7.1. Key points

AusNet strives to operate and maintain a network that meets our customers' needs and expectations and represents value for money both in the short- and long term by:

- Providing safe, reliable and secure electricity distribution services
- Addressing emerging priorities, identified through customer research and engagement, and
- Supporting our customers and communities.

Our proposed operating expenditure (opex) forecast for 2026 to 2031 is $1,700 million including debt raising costs ($2025-26). This forecast is 6% or $82m ($2025-26) above our opex allowance in the 2021 to 2026 period and 14% or $203m ($2025-26) above current period spend. Below are the key drivers and affordability measures that have shaped our forecast:

We have listened to our customers and their input has shaped our opex forecast to improve the affordability of our plans ($62m). In particular, measures to address our customers' affordability concerns include:

- Absorbing Guaranteed Service Level (GSL) payments that relate to appointments, public lighting and connections ($3.2m).
- Netting off the expected reduction in GSL payments through the reliability improvements expected from our capex forecast ($1.6m)
- A negative step change for fleet electrification (-$0.7m) and digital (-$3.9m) to give back to customers expected future efficiencies.
- In line with the AER's standard approach, applying 0.5% productivity to our opex forecast, amounting to productivity gains of $21.8m.
- Identifying synergies by utilising resources for both community energy engagement and relationship managers ($9m)
- Absorbing emerging new costs related to SAPS, flexible exports and Security of Critical Infrastructure obligations($2.5m)
- Digital additional opex associated with higher license costs for existing systems and platforms ($4m)
- Additional opex associated with out increased fleet requirements ($14m)

Providing on-ground community and customer support, including during extreme events and storms

- Community engagement leads in our regions to provide support for community energy projects and major event days, in response to customers and stakeholder concerns regarding the lack of direct contact for customers with complex needs, and lack of AusNet presence in the community. This includes expanding our dedicated support resources for our commercial and industrial customers.

Our network is expanding and growing quickly, which requires additional resources to operate safely

- Over 76,000 more customers are expected to connect to our network during the 2026-31 regulatory period, which is an increase of 15%, requiring additional costs to maintain and meet demand on our network.

There are new obligations and costs required of AusNet which sit outside trend parameters and require opex step changes to manage

- The Emergency Backstop Mechanism to manage minimum system load emergencies ($21.6m)
- An ESV direction to conduct more frequent pole inspections and transition from a 6-year to 5-year cycle ($8.0m)
- Implementing Network outage review and Nous post incident review recommendations ($9.2m)

Several other step changes are necessary to manage new costs which will provide further benefits to customers:

- Digital opex to deliver the new spend as part of our capex proposal which will provide more advanced capabilities and new initiatives, such as increasing visibility of our field operations, ADMS and DSO.
- Hazard tree program, targeting at risk trees to mitigate outage durations during extreme weather events, these trees usually have some sort of structural defect and are outside of the regulated clearance zone and are at risk of failing and causing a power outage. Climate change is expected to increase the amount of vegetation outages, and our aim is to reduce climate related vegetation outages through program expansion.

- Early Fault Detection device installation to manage the costs of new technology being installed to improve the safety of our network.
- Enabling flexible services and non-network solutions to improve utilisation and avoid the need to expand the LV network

Efficient Base Year

- We have proposed 2022-23 as the opex base year due to the absence of extreme storms, which have made alternative years less suitable. Our costs in 2022-23 are also considered efficient according to the AER's 2024 benchmarking report (in fact, AusNet is a benchmark comparator firm for this year).

7.2. Chapter structure

This Opex Chapter is structured as follows:

- Section 7.3 summarises our opex forecasts.
- Section 7.4 explains our approach to forecasting opex.
- Section 7.5 provides information on our customers' preferences and feedback, with information on our engagement with the Opex and Benchmarking panel and explains how their feedback has been taken into account in our opex forecasts.
- Section 7.6 provides the key inputs and assumptions used for our opex forecast.
- Section **Error! Reference source not found.** the base year expenditure we have used in developing our forecasts.
- Section 7.8 presents our benchmarking and its relation to opex.
- Section 7.9 describes the step changes we have included in our expenditure forecasts, as well as the step changes we propose to absorb.
- Section 7.10 presents information on those elements of our opex forecast that have been subject to a bottom-up forecast.
- Section 7.11 explains how our opex forecasts have taken the trends in input costs, output growth and productivity into account.
- Section 7.12 explains why our opex forecast satisfies the requirements of the Rules.
- Section 7.13 lists the supporting documentation for this chapter.

7.3. Summary of Operating Expenditure Forecast

7.3.1. Our operating expenditure forecast is driven by strong energy and customer growth and step changes to manage new obligations, enable efficient capital expenditure trade-offs and meet evolving customer needs

Operating expenditure (opex) means the costs incurred in the operation and maintenance of our electricity distribution network. Key activities include repairing faults, managing trees near powerlines, emergency response and customer service. In 2026 to 2031 we forecast that required opex will be $1,700m including debt raising costs ($2025-26). This forecast amount is 6% or $82m ($2025-26) above our opex allowance in the 2021 to 2026 period and 14% or $203m ($2025-26) above current period expected spend. This reflects a significant forecast increase in customers numbers and demand on our network, improvements in our Digital systems to keep up with customer expectations, and new obligations imposed on us that will increase our opex costs. These include new obligations relating to bushfire safety, maintaining system security and providing an enhanced response during major event days.

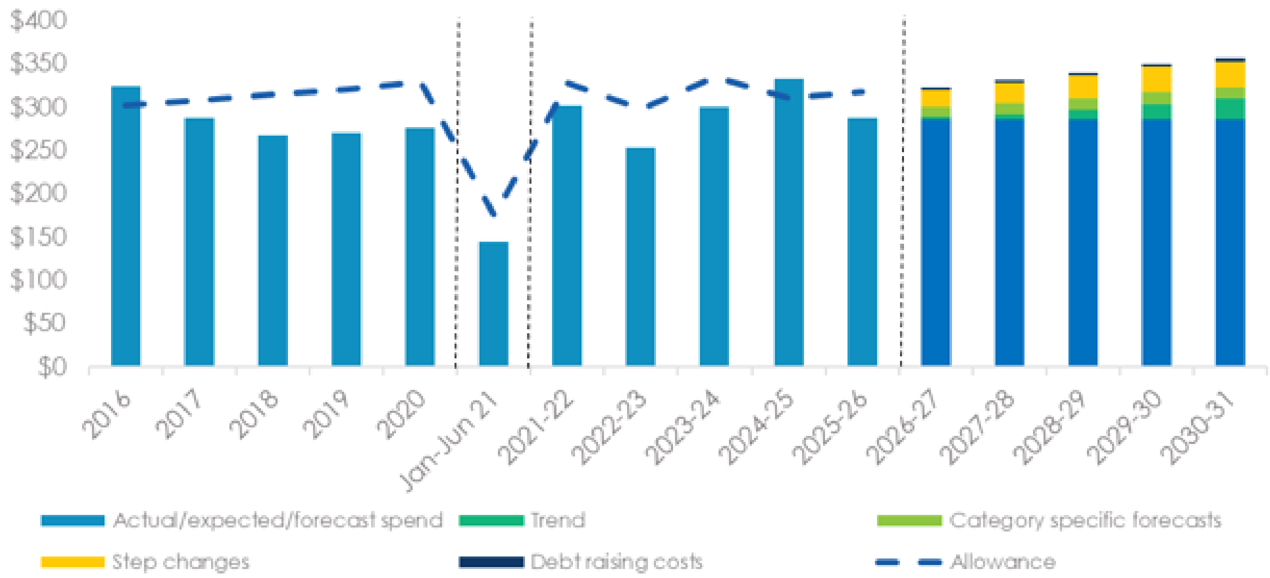
To address our customers' affordability concerns, we have absorbed $3 million in expected increases from our non-network solutions step change and have identified $9 million in future synergies that we are passing onto customers. Additionally, we have reduced our GSL forecast to reflect the benefits of our proposed reliability investment and reduced opex due to the savings to be realised by planned Digital investments and the electrification of our fleet. AusNet's proposed operating expenditure minimises costs while ensuring that we can maintain the reliability and safety of network services and manage the growth in our network.

Table 7-1: Forecast Operating Expenditure ($m, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Base Opex	285.9	285.9	285.9	285.9	285.9	**1,429.7**
Step Changes	19.6	24.0	27.0	30.1	31.0	**131.7**
Trend (Output, labour and productivity)	2.7	5.9	11.4	17.5	23.2	**60.1**
Bottom-up forecasts (Guaranteed Service Level payments, debt raising costs and innovation expenditure)	14.4	15.2	15.7	16.4	16.4	**78.2**
Total	**322.6**	**331.0**	**340.1**	**349.9**	**356.6**	**1,700.3**

Source: AusNet

Figure 7-234: Actual and forecast operating expenditure ($m, real 2025-26)

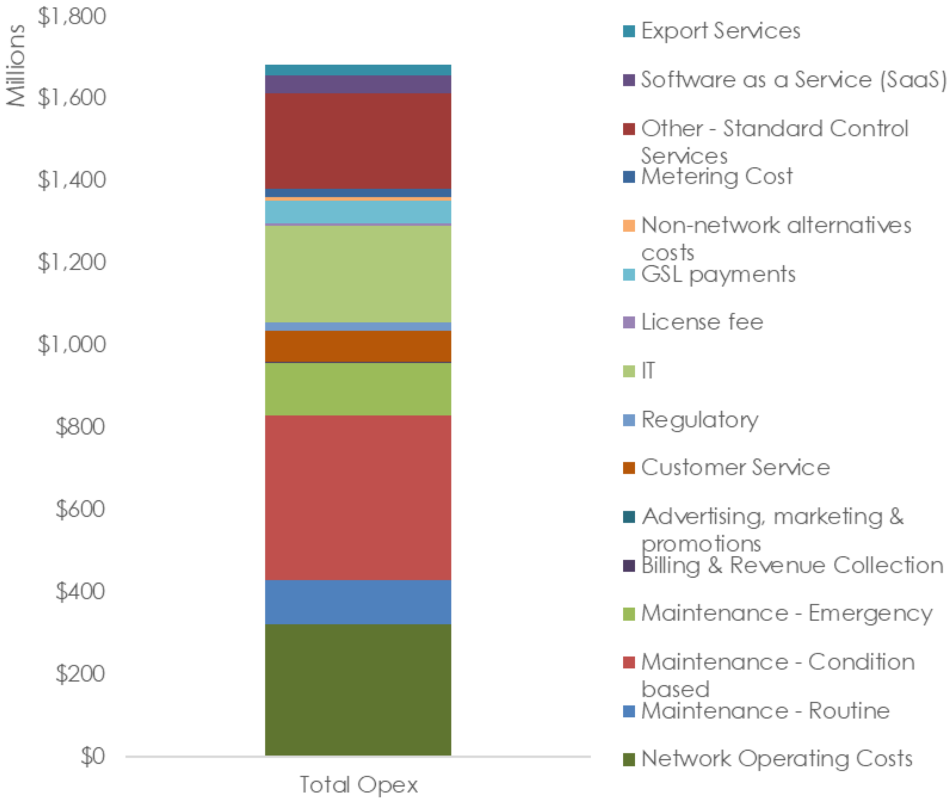


Source: AusNet
Note: Category specific forecast (includes GSLs and Innovation)

The opex forecast below is broken down by the categories we report in our annual RIN template which are well accepted expenditure categories. We note that given the use of a high-level base, step and trend forecasting approach the category forecasts are indicative of the expenditure we expect to incur for each category in 2026-31 but does not represent a bottom-up build for each category.[94]

[94] Forecasts in these categories are contained in RIN template 3.2.1.

Figure 7-335: Total forecast operating expenditure by expenditure category 2026-31 ($m, real 2025-26)



Source: AusNet
Refer to 7.9 Step changes for further information of costs above the base year.

7.4. Forecasting Approach

7.4.1. Methodology

We have used the AER's established approach to forecasting our operating expenditure, which is called the 'base-step- trend' approach. This method starts with a recent year of actual expenditure (our 'base expenditure').

We have selected the 2022-23 year as our opex base year (or the second year of the current regulatory period) on the basis that it:

- Reflects ongoing, efficient opex.
- Audited actual expenditure is available at the time of submitting our Regulatory Proposal.

Regulatory year 2022-23 passes the AER's efficiency assessment in its 2024 Annual Benchmarking Report, published in November 2024. In fact, AusNet is a benchmark comparator firm for this year, which supports the efficiency of the base year selection.

2023-24 has not been proposed as our opex base year as it was heavily impacted by the 13 February severe storm. This heavily impacted our opex due to repair costs and Guaranteed Service Level payments of $26.9 million ($2023-24) and hence reported opex for this year does not reflect ongoing, efficient opex levels. We have not proposed 2024-25 because it is similarly impacted by storm activity in August/ September 2024 and audited actual expenditure is not available at the time of submitting this Regulatory Proposal. We note that due to the interactions between the EBSS and the opex forecasting methodology, we and customers are financially indifferent to the choice of base year. These issues are discussed further in section 7.7.1.

We have also adjusted our opex base year to reflect our proposal to expense capitalised corporate overheads from 2026-27 onwards, to align with the approach used in our gas network and the other Victorian Distributors (explored further in section 7.7.2.1). The inclusion of negative adjustments has been made to acknowledge the transfer of property to AusNet, which means that the management fees currently incurred by Downer to manage these have been excluded from our forecasts.

Category specific forecast such as GSLs and Innovation are applied to account for cost increases that are not reflected in the base year, rate of change or any other element of the forecast.

Next, the opex forecasting approach adds the cost of meeting new obligations, initiatives and/or capex/opex trade-offs ('step' changes). The final stage of the process is to apply a trend or rate of change comprising:

- change in our customer numbers, line length and ratcheted maximum demand
- the expected real increase in our labour and material costs; and
- future productivity improvements.

The real cost escalators associated with labour costs are low compared to the actual real labour increases we have seen in the current period and expect to continue to face. This is an issue across Australia, and is evident through recent and ongoing EBA outcomes, which far exceed the cost escalators applied under the AER's standard forecasting approach. Despite these concerns, we have applied the AER's standard approach to real cost escalation, as discussed further in section 7.11.2.1.

While we have applied zero real escalation to non-labour costs, there is uncertainty around materials costs due to their scarcity and demand in the market. Accordingly, we are proposing a new cost pass-through event to manage real cost uncertainty, as discussed further in Chapter 15.

7.5. Customer Preferences and Feedback

7.5.1. Outcomes of Opex and Benchmarking Panel Forums

Our Benchmarking and Opex Panel engaged with us on opex and benchmarking issues, meeting for a total of 15 hours to examine these issues in detail. As explained in section 2.4.7.6, this engagement was limited to inform and consult on the IAP2 spectrum, reflecting the largely prescriptive approaches used to forecast opex and for benchmarking analysis, and our relatively settled positions on these matters which limit the opportunity for the Panel to influence outcomes. Nonetheless, we had some productive discussions with this panel which shaped the opex forecast presented in this chapter.

Meeting snapshots are available here, many of these meetings were also attended by the AER's technical teams and Customer Panel members.

Table 7-2: Explanation of opex and benchmarking components

Opex element	Our draft plan	Stakeholder feedback
Base Base year adjustment	Use 2022-23 as this is the best year representative of our opex	Acknowledged that this was a year with no storms and was the most recent audited operating expenditure. The Panel does not have strong views on the choice of base year, given this will be assessed by the AER and there are no material implications to revenue dependent on base year selection.
	Expensing capitalised corporate overheads	The Panel considered that this adjustment should be considered at a holistic level, having regard to the affordability of our proposal.
Trend Inflation (Material and labour) Growth Productivity		
	Utilise standard AER approach; continue to engage on better forecasting approaches for labour costs. Develop pass through to account for within period uncertainty.	Standard AER inflation measures accepted
	Utilise standard AER approach	Growth measures accepted
	Utilise 0.5% productivity adjustment which is the standard AER approach	The Panel would like AusNet to be more ambitious and aim for

		productivity growth above the standard AER approach of 0.5%
Step changes • ESV direction to conduct more frequent pole inspections ($8.1m) • Digital (inc. SaaS etc.) ($52m) • Flexible services and non-network solutions ($8.5m) • Fleet electrification (-$0.7m) • Resilience (Hazard tree program) ($8.0m) • Customer relationship management and broad communications ($15.8m) • Early Fault Detection ($8.2m) • Emergency Backstop Mechanism ($16.3m) • Preparedness and Response ($10.6m)	Inclusion of 9 step changes that are targeted around regulatory obligations, capex/opex trade-offs and new initiatives. • Increased pole inspections to 5-year cycles rather than 6-year • Remote curtailment in a minimum system load emergency to maintain system security • Reducing emissions and providing opex savings • Facilitating a transition to digital systems being cloud-based • Managing flexible service offerings and cloud-based CER management platforms • Stepping up emergency management specialists to assist with major event days and response • Dedicated local customer relationship managers in the regions and communication	The Panel agrees in principle with regulatory obligation step changes such as the Victorian Emergency Backstop Mechanism (VEBM), noting costs will be assessed by the AER. A negative step change relating to fleet electrification has also been included which is passed on as a saving to our customers. Our Panels have guided us to uplift customer communication to support the energy transition, and we have included an opex step change to fund this. Step changes have been refined in conjunction with feedback received from our Panels with the absorption of SAP related opex and specific labour related to flexible exports.
Category Specific Forecast		
Innovation	Includes a forecast of innovation with a representative split of total spend	This has been discussed and is based on support from our Future Networks Panel, Coordination Group and Innovation Advisory Committee.
Guaranteed Service Levels payments	GSLs have been forecast in line with the current regulatory period allowance in 2021-26 using a 5.5-year average. AusNet has netted off any anticipated improvements to the forecast related to reliability improvement capex.	The Panel supported the use of a 5.5-year average along with the netting off the GSLs related to any expected improvements through other expenditure streams.

7.5.2. Feedback on our Draft Proposal

Table 7-3: Feedback received on Draft Proposal and AusNet response

Feedback received	AusNet Response
The Benchmarking & Opex Panel indicated support for a 1%/yr productivity factor rather than the standard minimum requirement of 0.5%/yr. The Panel noted they are awaiting the AER's November 2024 benchmarking reports to help inform their view on this. The Benchmarking & Opex Panel is seeking further engagement on step changes and annual productivity. Maintenance opex should reduce due to resilience and reliability work	The 1% productivity factor has not been incorporated We have completed further engagement on step changes and productivity We have considered and no reduction is warranted. Maintenance is typically undertaken on mandated inspection cycles and impact of need for less reactive maintenance is expected to be immaterial

7.6. Key Inputs and assumptions

- **Base year** operating expenditure for 2022-23 has been sourced from our audited regulatory accounts.
- **Output growth** has been forecast using the AER's standard approach:
  - Customer numbers have been forecast in line with the net customer numbers underpinning the connections capex forecast
  - Circuit length is forecast based on a long-term historical growth rate
  - Ratcheted Maximum Demand – Forecast based on probability of exceedance 10 and 50 demand forecasts, combined with a 30/70 weighting. This weighting is consistent with our approach to augmentation planning and AEMO's Victorian Electricity Probabilistic Planning approach. Further information can be found in Chapter 7.11.3.
- **Price growth** is derived from the Wage Price Index, in line with the ABS series. This figure is an average of forecasts from two consultants (using a placeholder for the AER's forecast), consistent with the AER's standard approach.
- **Step changes and category specific forecasts** have been forecast on a bottom-up basis based on the drivers and composition of the expected cost increases.

7.7. Base year expenditure

7.7.1. Base year operating expenditure

To ensure that our base, step, and trend forecasting approach yields a prudent and efficient forecast, it is essential to start with an efficient level of base year operating expenditure (opex). For that reason, AusNet has chosen the 2022-23 regulatory year as the base year for forecasting opex, with our adjusted base year expenditure set at $286.4 million in $2026.

We selected 2022-23 for the following reasons:

- **Recent Data:** 2022-23 is recently audited data of our regulatory accounts along with other relevant financial information. Economic benchmarking and category analysis show that AusNet is efficient compared to its peers. AusNet has a long history of responding to the regulatory incentives by driving efficiency savings over time.
- **Normal Operating Conditions:** There were no abnormal events in 2022-23 that would make it unrepresentative of our typical operating environment. Therefore, it is appropriate to use 2022-23 as the base year for our expenditure forecasts for the 2026-31 regulatory period. In contrast, alternative base years of 2023-24 and 2024-25 are impacted by abnormal events such as the storms experienced in February 2024 and September 2024. While a portion of the costs associated with these events are identifiable and recovery has been sought via a cost pass through, there are additional, indirect costs (such as diversion of resources away from their BAU roles, reprioritising field crews away from day-to-day maintenance and capital works schedules, and management time and attention) which are harder to quantify. Therefore, as we are unable to accurately adjust these years to remove the impact of the storm events, it is strongly preferable not to select these years as the opex base year.
- **Impact of the Efficiency Benefit Sharing Scheme (EBSS):** The EBSS ensures that our forecast revenue requirement is unaffected by the choice of base year. This is demonstrated by Table 7-4 below assuming that step changes and category specific forecasts stay the same, which shows that opex and EBSS revenue is not materially different under the alternative base years available to us. This is due to the EBSS increasing when there are efficiency gains from Opex boosting the EBSS figure.

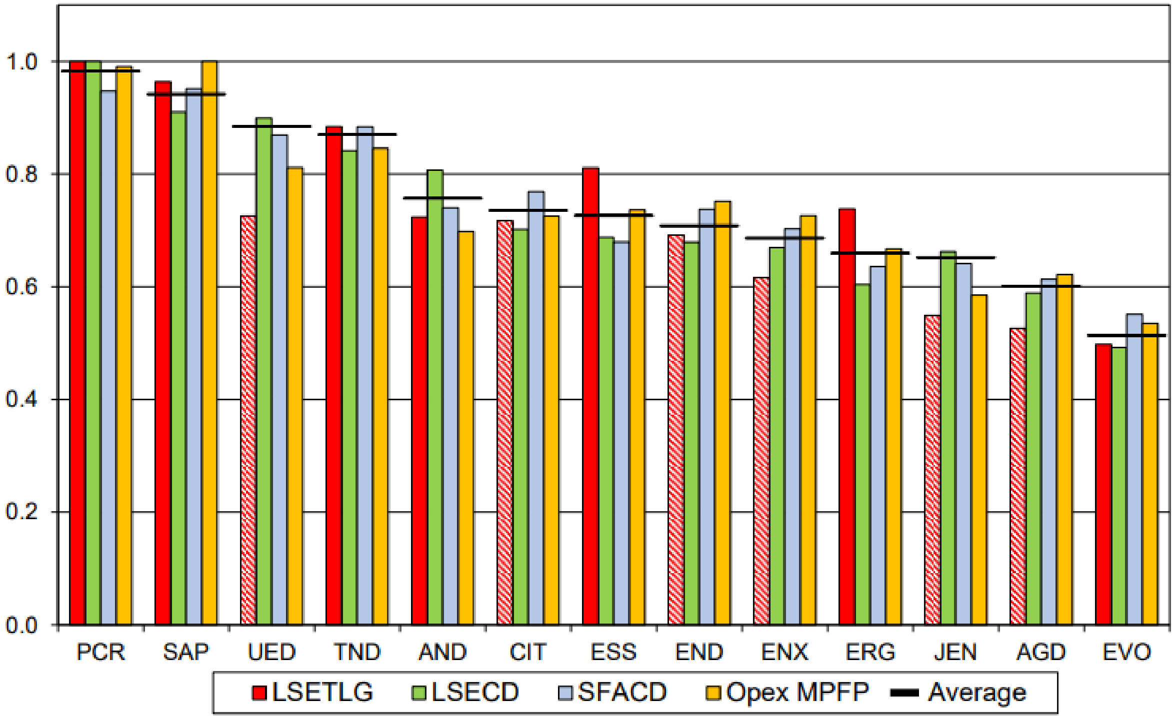
Table 7-4: Total Opex and EBSS with different base year

5-year total ($m, 2025-26)	2022-23 base year	2023-24 base year	2024-25 base year
Opex allowance	1,700.3	1,668.4	1,941.9
EBSS estimate	+40.2	+70.8	-191.6
Total	**1,740.5**	**1,739.2**	**1,750.3**

Source: AusNet

The AER's most recent benchmarking report has confirmed that AusNet's opex in 2022-23 was not materially inefficient, as the econometric model scores exceed the 0.75 threshold[95]. This is shown in the charts below.

Figure 7-3: DNSP efficiency scores, 2012-23



Source: AER 2024 Annual Benchmarking Report

We have engaged with our Benchmarking and Opex Panel on the reasons for our choice of opex base year. They have not expressed a view other than noting they expect the AER to apply its assessment framework and noting that, as discussed above, base year selection does not drive differences in our revenue requirement (i.e. both AusNet and customers are NPV neutral to the choice of base year) given the interactions between opex forecasting and the EBSS.

7.7.2. Adjustments to base year

The adjustments made to our base year of 2022-23 to ensure it is representative of efficient costs are listed below:

- -$16.2 million for movements in provisions
- Property management fees
- Expensing of corporate overheads
- Applying trend for the 2021-26 regulatory period to obtain the opex in 2025-26
- Applying escalation from 2022-23 regulatory year to 2025-26, and
- Removing estimated final year opex for categories specific such as Guaranteed Service Level (GSL) costs and Demand Management Innovation Allowance (DMIA) expenditure.

The proposed base year opex with the adjustments is $285.9 million, the table below shows how we have derived the base year amount.

[95] AER, 2024 Annual Benchmarking Report, available here: Report template

Table 7-5: Detailed explanation of operating expenditure proposal

	Amount ($m)
Actual 2022-23 opex ($m, nominal)	**223.6**
Movements in provisions	-16.2
Base year opex ($m, nominal)	**239.7**
Escalation to 2025-26 ($2025-26)	31.0
Trend to 2025-26 ($2025-26)	19.6
Remove estimate final year opex for categories forecast ($2025-26)	-7.9
Adjustments – Positive ($2025-26)	4.1
Adjustments – Negative ($2025-26)	-0.5
Estimated 2025-26 Opex ($m, real 2025-26)	**285.9**

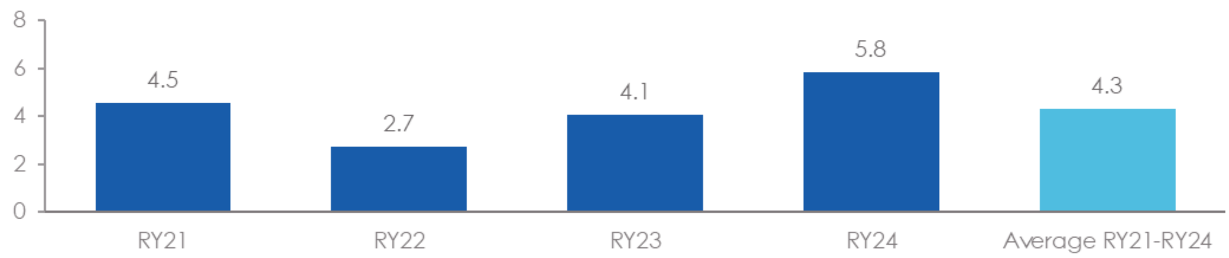
Source: AusNet.

7.7.2.1. Expensing of corporate overheads

Corporate overheads are costs related to corporate functions that are necessary to perform day-to-day tasks and activities. Our current practice is to capitalise a portion of corporate overheads that provide support to capital activities. However, we are proposing to expense all corporate overheads from 2026-27 onwards.

We have included corporate overheads in our opex forecast through a base year adjustment of $3.7m ($2022-23). This amount reflects the actual corporate overheads capitalised in 2022-23, which we consider is broadly reflective of the ongoing costs we will incur in 2026-31. This amount is slightly below average capitalised corporate overheads between 2020-21 and 2023-24, as shown in the figure below. We have not used the most recent year of actual costs (2023-24) as the basis for this adjustment, as corporate overheads were abnormally high that year and, therefore, are not reflective of the ongoing costs we expect to incur.

Figure 7-4: Capitalised corporate overheads actuals 2020-21 to 2023-24 ($m, real 2025-26)



Source: AusNet.

Our proposal to expense all corporate overheads:

- Would align the treatment of corporate overheads for AusNet's electricity distribution network with its gas network, as approved by the AER in the 2023-27 GAAR. While a transfer from capex to opex increases prices in the short term, it will deliver longer term benefits for customers as these costs will not increase the asset base and therefore incur a return on and return of capital
- Is consistent with accounting standards, which allows for the expensing of corporate overheads, and
- Is consistent with our current, approved Cost Allocation Method (CAM) document.

Expensing all corporate overheads has been proposed by the other Victorian electricity distributors, and accepted by the AER, in previous price reviews. To ensure consistency between our opex and capex forecasts, we have removed the equivalent amount of corporate overheads from our forecast of capitalised overheads.

We engaged on our proposal to expense corporate overheads with our Opex and Benchmarking Panel (including the drivers of the change and its bill impacts). The Panel considered it a matter for the AER to assess, but suggested bill impacts should be considered at an overall level, if required.

7.7.2.2. Property Management

Negative adjustment relating to the removal of Downer management for property in the base year of 2022-23 given AusNet is gaining control of all property.

7.7.2.3. Category specific forecasts (GSLs and debt raising costs)

We propose category specific forecasts (rather than base-step-trend) for two specific categories of our operational expenditure (opex): funding the GSL scheme and debt-raising costs. We have adjusted the base year expenditure by removing $7.4 million to align with the actual costs incurred in 2022-23. Our opex forecast incorporates a bottom-up approach for these costs, which is consistent with the methodology used during the 2021-26 regulatory period and the most appropriate approach.

7.7.2.4. Demand Management Innovation Allowance (DMIA)

The costs incurred under the DMIA in the base year of 2022-23 were $0.1m, which have been removed from the base year to avoid overlaps between the opex forecast and the 2026-31 DMIA.

7.7.2.5. Movement in provisions

Movement in provisions in the base year of -$16.2 million have been removed so the opex allowance best reflects the underlying recurrent opex and to align with the AER's preferred treatment of movements in provisions.

7.7.2.6. Demonstrating the efficiency of our base year expenditure

The AER's 2024 Annual Benchmarking Report has confirmed AusNet's position as an efficient benchmark comparator firm in the 2022-23 regulatory year. This has been achieved as we respond to the incentives provided by the EBSS and drive efficiencies within our network. For these reasons, we are confident that our adjusted base year expenditure reflects our efficient recurrent costs in accordance with the AER's preferred forecasting methodology.

7.8. Benchmarking

As described in Chapter 3 (Network Characteristics and Operating environment), AusNet's network is located in highly vegetated and elevated terrain and also has a high exposure to climate events such as bushfires and extreme storms, including cyclonic winds. This makes it a relatively more expensive network to run compared to other networks in the NEM. The differences in cost include vegetation management, bushfire liability insurance premiums, Guaranteed Service Level payments (GSLs) and emergency preparedness and response costs.

To make productivity benchmarking meaningful, these operating environment differences need to be adjusted for, so that productivity across networks can be accurately compared. The AER's benchmarking approach is still evolving and does not yet include adjustments for these factors. Suggested modifications to productivity and econometric benchmarking to account for these, and some other, factors are included in Appendix 7A – Benchmarking Proposal.

This section contains various benchmarking metrics that provide insights into AusNet's efficiency and performance.

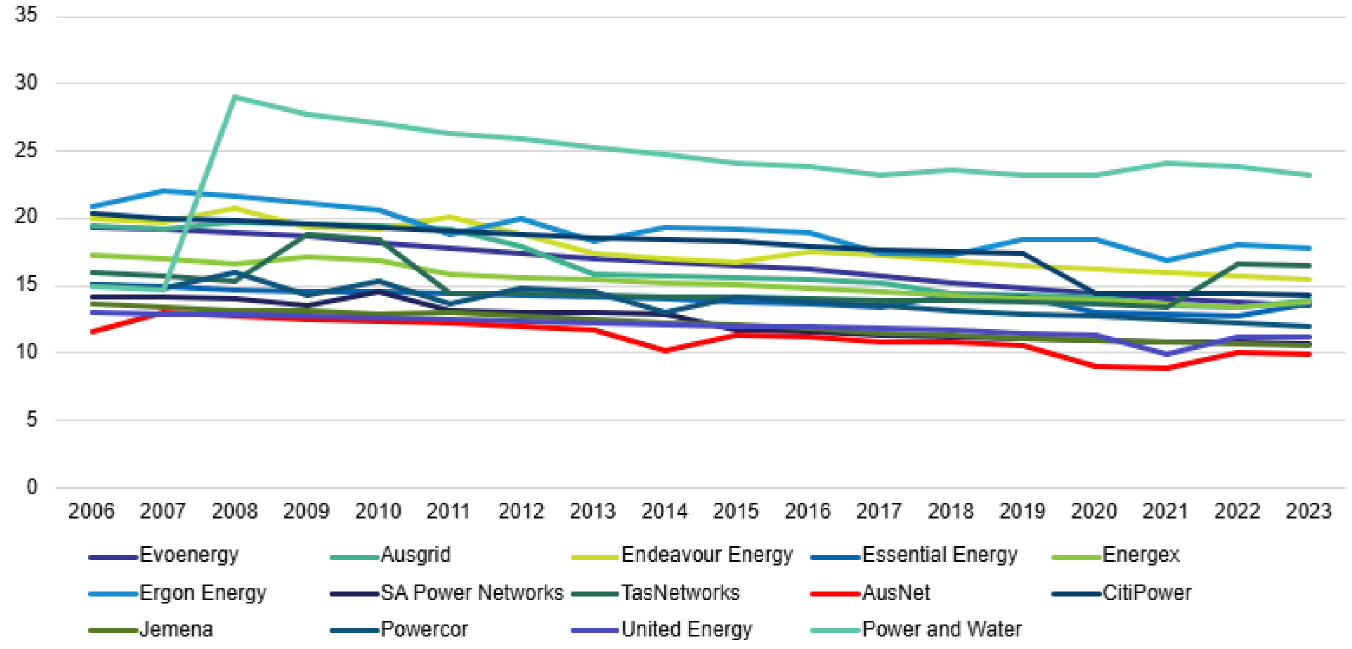
7.8.1. Partial performance indicator benchmarking metrics

While econometric benchmarking is used to directly assess opex efficiency, a range of opex benchmarking approaches can be used to draw insights into the relative productivity of various networks. Some of these other metrics are presented in this section. These show that generally across the range of Partial Performance Indicators AusNet performs well. This is despite many of our opex drivers not being adjusted for, including terrain, vegetation, legislated safety requirements (including bushfire mitigation) and high storm risk.

AusNet appears to be a relatively poor performer on partial performance indicator metrics when expenditure is normalised by peak demand (MW) or consumption, which is because our customer base is skewed towards residential customers who are relatively low users of electricity. In fact, our customers have the lowest average consumption and maximum demand in the NEM. In our view, the number of customers we serve and the physical size of our service area are far bigger drivers of our opex than the amount of energy that flows through the network. Consumption does not have a direct impact on maintenance requirements, or corporate costs (including call centre staffing, finance and human resource support), while asset metrics such as line length, and how many customers we have, impact costs far more directly.

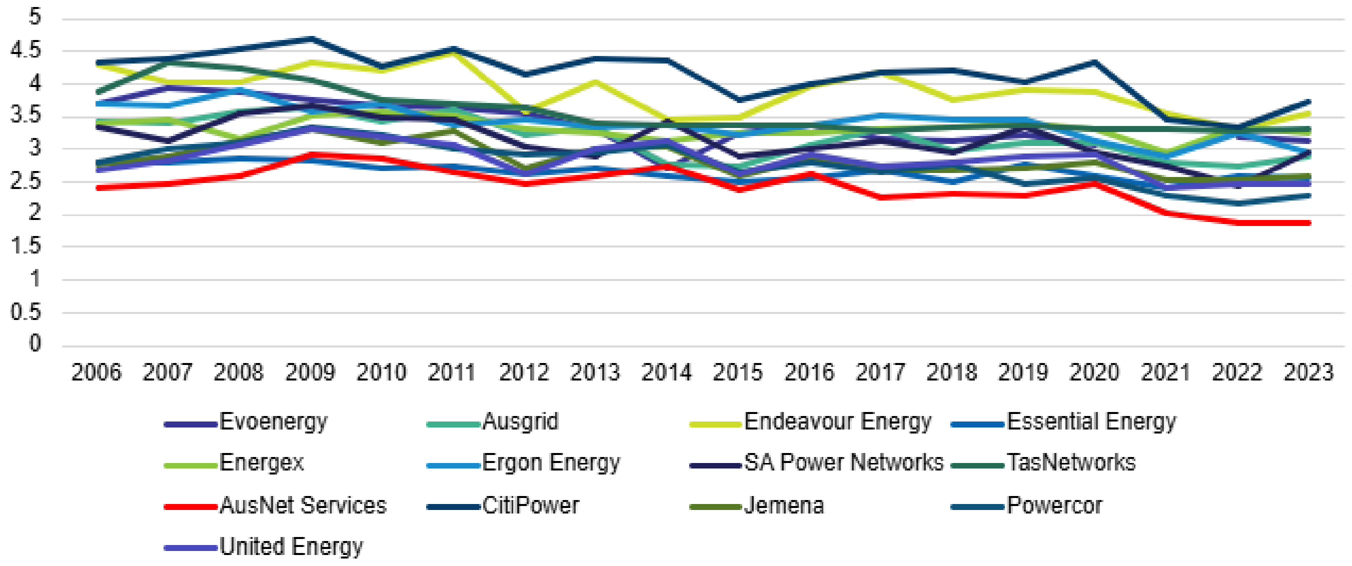
The figures below confirm that our customers have the lowest average consumption and average maximum coincident demand in the NEM. Customer numbers, maximum demand and energy throughput are included as outputs in the AER's benchmarking analysis and have a bearing on our performance.

Figure 7-5: Energy per customer (kwh)



Source: AER RIN data

Figure 7-6: Coincident maximum demand per customer (MW)

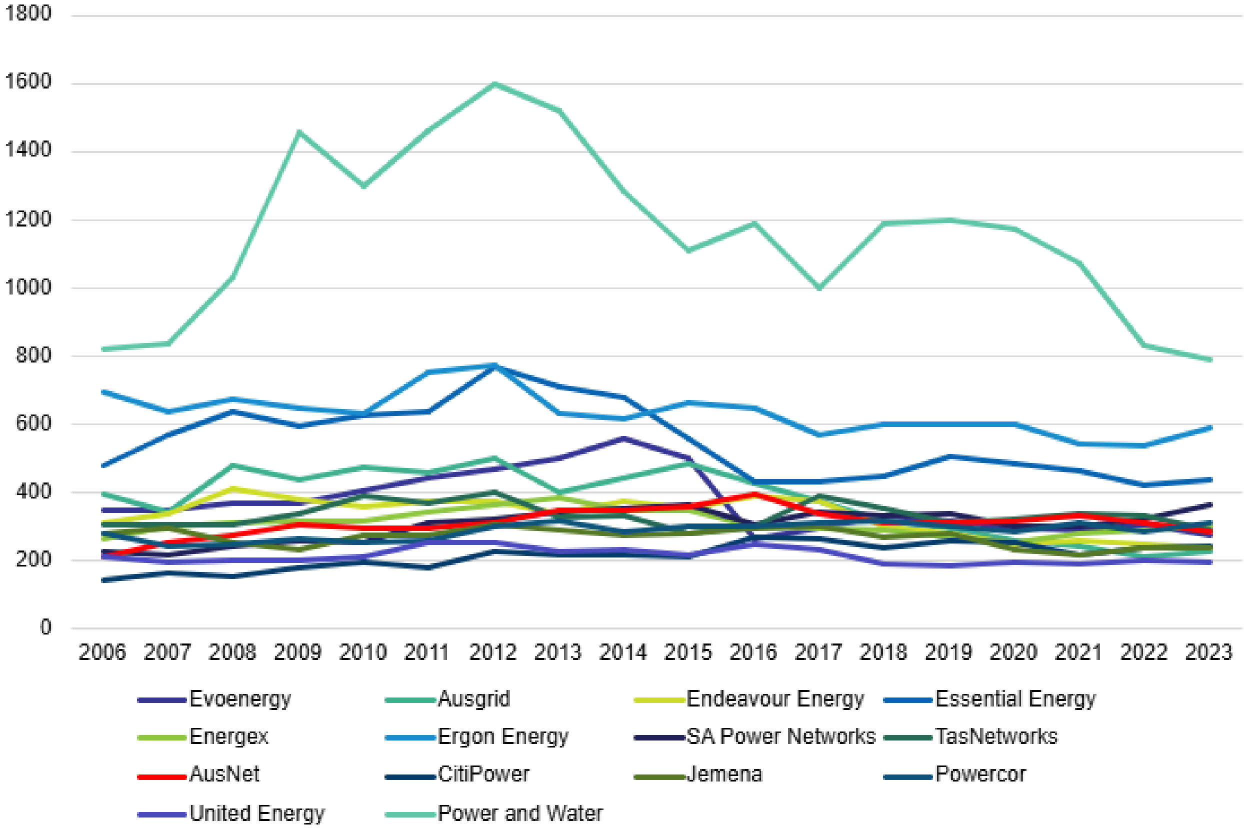


Source: AER RIN data

Opex normalised by customer numbers or circuit length

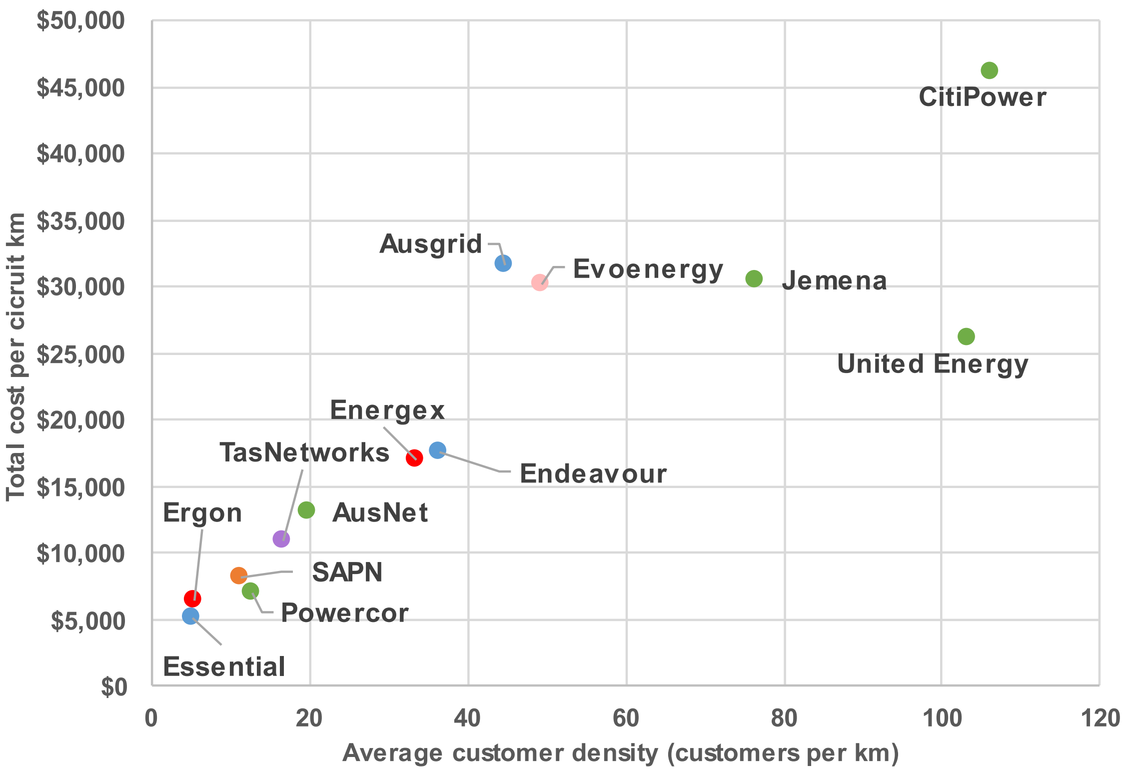
As mentioned above, we perform relatively well when our opex is normalised by customer numbers and circuit length.

Figure 7-7: Opex per customer $m, real 2023



Source: AER RIN data

Figure 7-8: Total cost per km of circuit line length against customer density (average 2019-23), $June 2023

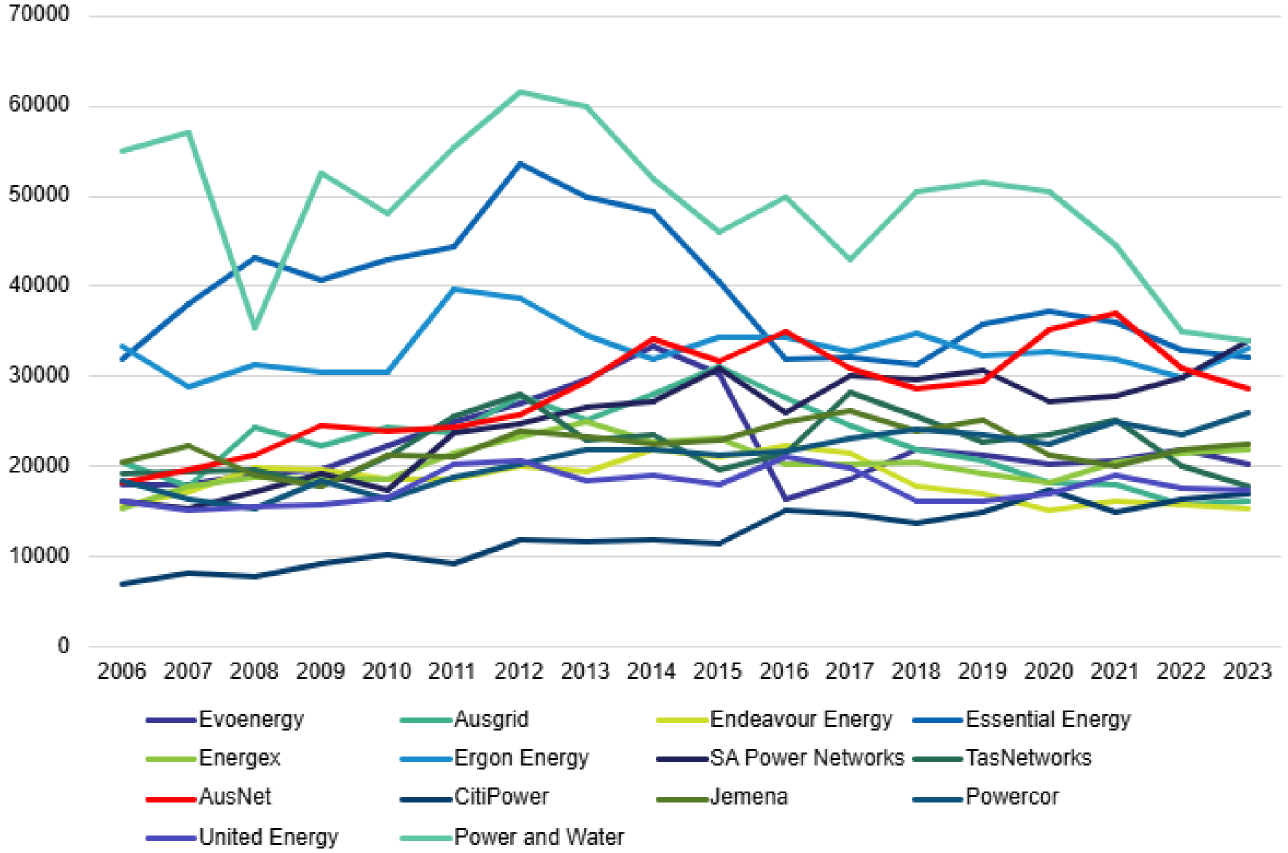


Source: AER 2024 Annual Benchmarking Report

Opex normalised by demand or consumption

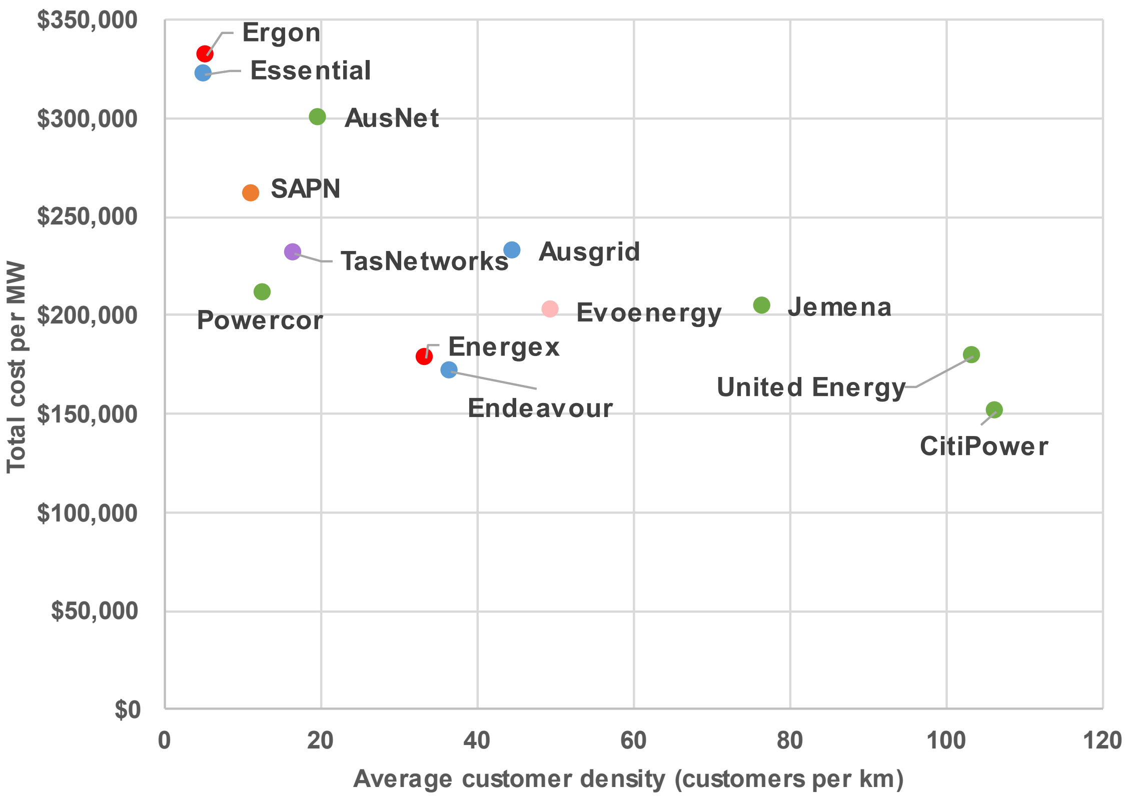
As outlined above, we perform less well on metrics that present cost relative to our consumption and demand.

Figure 7-9: Opex per MWh $m, real 2023



Source: AER RIN data

Figure 7-10: Total cost per MW of maximum demand against customer density



Source: AER 2024 Annual Benchmarking Report

7.9. Step Changes

AusNet proposes 11 (9 positive and 2 negative) step changes relating to new regulatory obligations, capex/opex trade-offs and new initiatives. Additional funding is required to efficiently meet our customer's evolving needs through education and improved communications, uplifting our customer relationship management resources, improving network safety and resilience along with complying with new obligations. Our proposed step changes are outlined in Table 7-6 below.

Offsetting these increases are $62 million of affordability measures we have incorporated in our forecasts to help address our customers' affordability concerns. These measures comprise:

- We have not included additional opex running costs for SAPs ($0.5m).
- Labour cost synergies between flexible exports and emergency backstop ($3m).
- Absorption of the following costs:
    - Additional labour costs due to expected EBA outcomes ($20m).
    - Additional SOCI expenditure to uplift physical security across 70+ distribution sites ($2m).
    - GSLs for controllable services, to increase our accountability to deliver positive customer outcomes ($3m).
    - Digital additional opex associated with higher license costs for existing systems and platforms ($4m)
    - Additional opex associated with out increased fleet requirements ($14m)
- Negative step changes for:
    - Efficiencies resulting from our Digital investments ($4m).
    - Electrification of the AusNet fleet ($0.7m)
- Adjustment to reflect expected avoided GSLs due to reliability investment ($2m).
- Synergies between customer relationship managers and emergency preparedness staff ($9m).

In determining our proposed step changes, we have accounted for costs incurred in the 2022-23 base year – that is, the step change sought is the amount over and above any relevant costs included in base year opex. If AusNet commenced incurring costs after 2022-23, there have been no adjustments made unless explicitly stated. Note any change in base year from 2022-23 would have a consequential impact on many of the step change amounts presented in this section.

The AER's step change criteria from the Better Resets Handbook are presented below; we have carefully considered these criteria when assessing whether step changes are warranted.

New regulatory obligation step change

- It is clearly linked to the new regulatory obligation and represents a major upward step to comply with it which will have an impact on the costs of providing prescribed network services and can be demonstrated that it is not capable of being managed otherwise under forecast opex through in-built provisions under output, price and productivity growth.
- No double counting of costs.

Capex/opex substitution step change

- It is supported by thorough cost-benefit analysis, the avoided capex is estimated accurately and it more than offsets the increase in opex in net present value terms (that is, efficient substitution).
- No double counting of costs.

Step change driven by major external factor(s) outside the control of a business

- It will have an impact on the costs of providing prescribed network services and it can be demonstrated that it is not capable of being managed otherwise under forecast opex, including through inbuilt provisions under output, price and productivity growth and is not being double counted.
- Where it involves incurring costs in complex areas or markets, it is accompanied by an expert report (including analysis of options, market outlook and opinion on the reasonableness of the proposed step change).

Table 7-6: Proposed opex step changes ($m, real 2025-26)

Step change	Driver	Total over 5 years
Emergency Backstop Mechanism	New Regulatory Obligation Capex/Opex trade-off	21.6
ESV direction to conduct more frequent pole inspections	Changed Regulatory Obligation	8.0
Digital (inc. SaaS, licenses etc.)	New initiative and opex associated with capex	39.9
Digital Efficiencies	Capex/Opex trade-off	-3.9
Flexible Services and non-network solutions	Capex/Opex trade-off	8.5
Fleet Electrification	Capex/Opex trade-off	-0.7
Customer relationship management and broad communications	Customer driven initiative	15.7
Early Fault Detection	New initiative and opex associated with capex	7.8
Resilience (Hazard Tree Program)	Capex/Opex trade-off	15.0
Emergency Preparedness and Response	Major External Factor	9.2
Insurance	Major External Factor	10.5
AEMO Fees	New Regulatory Obligation	0 (Placeholder)
Total		**131.7**

Source: AusNet.

As shown above, we have included a step change for an uplift in our hazard tree vegetation management program. However, our opex forecast does not currently incorporate any, potential vegetation management implications of our proposed 3D Lidar model capex project, which is discussed in Chapter 6. This project will also allow us to understand with higher accuracy when vegetation encroaches into our mandated clearance zones and requires rectification. We will consider the implications of this program for our vegetation management requirements and costs in our Revised Proposal, following further engagement with Energy Safe Victoria on our Regulatory Proposal.

C-I-C

7.9.1. Emergency Backstop Mechanism (EBM)

New Regulatory Obligation and capex/opex trade-off

The Victorian Government introduced an Emergency Backstop Mechanism where all new and replacement rooftop solar systems connected to distribution networks can be remotely curtailed in a minimum system load emergency to maintain system security. This obligation was introduced in 2024, within our current period and AusNet applied for a pass through to recover the material increase in costs to comply with the obligation.

The mechanism is designed to address declining minimum system load in Victoria increases the risk that AEMO cannot securely manage the electricity system, and a minimum system load emergency creates the risk of a statewide blackouts. When Victoria's system load drops below 1,600 MW, AEMO must take measures to ensure system security. However, there is a risk that AEMO will exhaust all available options to prevent a minimum system load emergency and introduction of the EBM will provide AEMO with a new last resort measure to manage this risk.

New licence conditions for distribution networks were introduced to implement the Emergency Backstop Mechanism, in two stages:

- **Stage 1:** effective 25 October 2023, for embedded generation above 200kV.
- **Stage 2:** effective 1 July 2024, for embedded generation below 200kV (includes small customers).

Specifically, networks are required to:

- Have capabilities to be able to remotely curtail new solar (up to 30MW). For customers below 200kV, distributors are required to operate a utility server capable of remotely interrupting or curtailing electricity from solar systems
- Curtail solar when directed to do so by AEMO or to test the unit is capable of being curtailed, and
- Ensure compliance of inverters connecting to distribution networks through a commissioning process (about 20,000 new connections p.a.) and an ongoing monitoring. Regular notification of customers for testing of capabilities / compliance.

Investment under the Victorian Emergency Backstop Mechanism creates a foundation for flexible export services. This will allow us to extract more customer benefit from the investment over time, through a smarter management of export services, as well as providing system security services. This mandate also reflects the greater role for customer energy resource management and enablement for distribution networks as part of the energy transition.

The VEBM step change includes:

- On-going operating expenditure already approved by AER in their cost pass through decision96, by extrapolating these costs into the 2026-31 regulatory period (new regulatory obligation), and
- Conversion of a DER Management system (DERMs) licence cost from capex to opex from 2028-29 (capex-opex trade-off).

These are explained below.

7.9.1.1. Ongoing VEBM opex

AusNet applied for a cost pass through in February 2024 to recover the efficient costs associated with the implementation and ongoing operation of the Victorian Emergency Backstop Mechanism, as this was a new regulatory requirement introduced within the current regulatory period, and our determination did not include expenditure to meet this requirement. The AER approved the cost pass through application in August 2024, including efficient ongoing opex of $2.6 million per annum.

As our base year (2022-23) pre-dates the introduction of the VEBM implementation, it does not include any opex associated with the VEBM. We therefore require an opex step change to fund the ongoing opex already approved as efficient by the AER. This step change has been quantified based on the ongoing opex approved in our cost pass through application, as this remains our best estimate of steady state, ongoing opex required to meeting the requirements of the VEBM.

The step change value equals $16.3 million ($2025-26) over the regulatory period. A breakdown of ongoing opex provided in our pass-through application is shown below.

Table 7-7: VEBM ongoing opex ($m, real 2020-21)

$ Jun 2021	Labour	Contracts	Materials	Total
Ongoing Opex 2025-26	$ 1,795,213	$ 456,106	$ 352,023	$ 2,603,342

Source: AER Emergency Backstop Mechanism pass through decision

The costs expected to be incurred in 2025-26 have been used as the basis for the step change as they reflect the ongoing opex required to address our regulatory obligations. In contrast, 2024-25 is not appropriate forecasting basis as it will include implementation costs. Further costings and a breakdown of ongoing opex can be found in AusNet's pass-through application.

[96] Determination AusNet Services Victorian Emergency Backstop Mechanism Cost Pass Through August 2024

7.9.1.2. Expensing DERMs licence

Additionally, there is a capitalised license cost that will transition to being expensed in 2028-29 which relates to DERMs totalling $8.1 million in $2024 over the 2026-31 regulatory period. This cost estimate has been provided by the vendors and reflects the next extension of the DERMS contract. The current contract ends in 2028-29, which capitalised the maintenance costs. In 2028-29 half the regulatory year will reflect the new opex DERMS maintenance contract. Of the total amount going forward, 63% of the cost relates to our compliance under the emergency backstop mechanism regulatory obligation and the other 37% to deliver further customer benefits beyond compliance including flexible exports. This license cost was also approved by the AER in our pass-through application as capital expenditure due to AusNet paying 5 years upfront for licencing and 63% also reflects the AER's decision on the proportion of our DERMS costs which are compliance driven. Below is the split of this cost over the regulatory period:

Table 7-8: Total DERMS cost by compliance related portion (real, $2023-24)

$ Jun 2024	2028-29	2029-30	2030-31	TOTAL
Total Expensing of DERMS	$ 1,609,750	$ 3,156,500	$ 3,314,250	$ 8,080,500
Emergency Backstop Mechanism Compliance	*$ 1,014,142*	*$ 1,988,595*	*$ 2,087,978*	*$ 5,090,715*

Source: AusNet

7.9.1.3. Total VEBM step change

This cost increase, which we consider is material, is consistent with the AER's step change framework as it is driven by a new regulatory obligation and is not funded through any other component of the opex forecast. No adjustment has been made to reflect costs incurred in the base year as AusNet commenced incurring these costs in 2023-24.

Table 7-9: Emergency Backstop Mechanism Step Change forecast ($M, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Emergency Backstop Mechanism	3.3	3.3	4.3	5.4	5.5	**21.6**

Source: AusNet

7.9.2. Energy Safe (ESV) direction to conduct more frequent pole inspections

Changed Regulatory obligation

On 9 June 2023, Energy Safe Victoria issued a direction requiring us to increase scheduled pole inspection frequency from 6 to 5 years. The transition to the new schedule was required to commence on 1 January 2024[97], which is after our proposed base year of 2022-23. The previous version of the Bushfire Mitigation Plan (BFM 21-79), Issue 21 outlined that an inspection cycle was 6 years; this has now been decreased to 5 years.

The new cycle requires AusNet to increase pole inspections by over 17,000 per annum. It is also important to note that a pole can only be classified as "transitioned" once it had been inspected 5 years from the previous inspection date, bringing forward some inspections that were expected to be on 6-year cycles.

This change has led to a material increase in our asset inspection costs, due to the addition of 6 new resources (3 Asset Inspectors and 3 Asset Assessors), along with additional vehicles and equipment required to be acquired to support the new resources from the initial commencement day of 1 January 2024. These vehicle costs are in addition to the fleet increase required due to the change in our service delivery partner, as discussed in section 6.17. As this increased frequency is not captured in our base year, a step change is required to manage the additional costs it will result in.

[97] ASD – ESV request to submit revised bushfire management plan

Table 7-10: Basis for additional resources and cost requirements for labour and contracts

	Previous State (2022-23)	Current State
Working Days	195 Refer to Note 1 below.	**195** Refer to Note 1 below.
Total Ground Inspections p.a.	82,000	**89,000** + 7,000 from base year
Total Aerial Inspections p.a.	34,233	**41,000** + 7,000 from base year
Pole Population	433,042 Assuming this increases at 1.1% p.a. (approx. 4k poles p.a.)	433,042 Assuming this increases at 1.1% p.a. (approx. 4k poles p.a.)
Avg. Poles/Day	14	**14**
# of Inspectors	30 82,000/195/14 = 30	**33** 89,000/195/14 = 33 Increased by 3 inspectors
# of Assessors	10	**13** Increased by 2.5 assessors for increased inspections and 0.5 for increased aerial inspections.

Source: AusNet
Note 1: Working Days calculation (365 days minus 13 public holidays and 105 weekends) => 247 Working Days
247 working days, minus (24 RDO's, 20 days annual leave, 4 days sick leave, 4 days training).

A breakdown of our proposed step change is provided in the table below, including the additional resources explained above and additional, associated costs.

Table 7-11: Composition of pole inspection step change ($'000, real $2023-24)

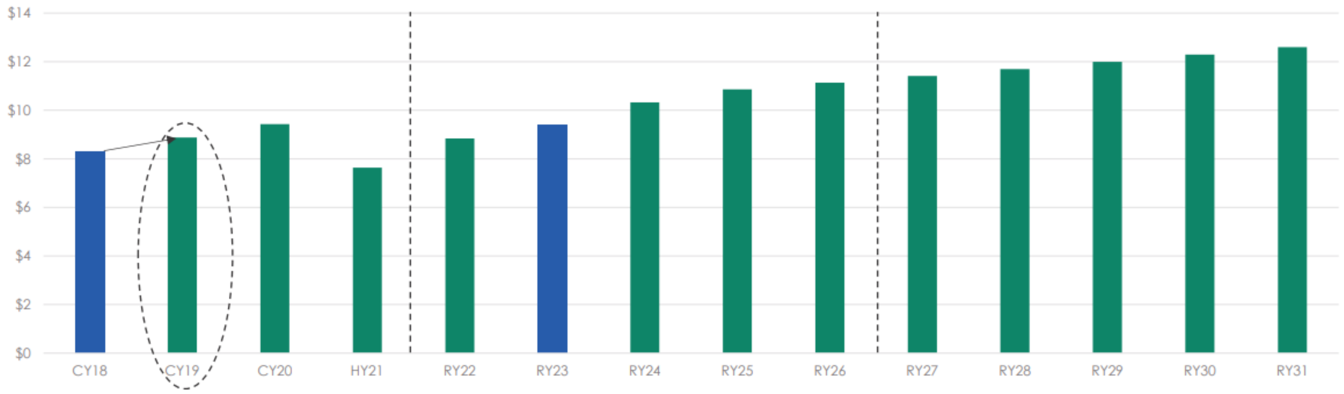
Additional opex costs	$,000
Labour	
6 additional resources	$ 623
Oncosts (33%)	$ 307
Training	$ 15
Subtotal	**$ 945**
Contracts	
C-I-C	C-I-C
C-I-C	C-I-C
Aerial	$ 300
Auditing - Compliance Plus	$ 13
Misc	$ 35
Vehicle	$ 50
Subtotal	**$ 518**
Total	**$ 1,463**

Source: AusNet

A shorter inspection cycle allows AusNet to maintain network risk by allowing for identification of unserviceable poles in which we can address through replacement or reinforcement in a timely manner. As discussed in section 6.7, this change is also contributing to the increase in pole replacement volumes we are forecasting for 2026-31.

As part of our engagement on step changes with them, the Opex and Benchmarking Panel considered that if we had benefited financially from a prior decrease in inspection frequency (from five to six years) that occurred in 2019, then our proposed step change for 2026-31 would prevent customers from sharing in those benefits through the EBSS. We have examined our historical spend and found that, despite this prior change, our inspection costs increased in 2018-19 and, therefore, AusNet did not financially benefit from the previous change. This is because, despite the increased inspection frequency occurring in 2019, our asset inspection costs increased due to a range of other factors. This is demonstrated in the figure below. Accordingly, we have retained a step change in our 2026-31 forecast, to manage the cost increases associated with the 2024 increase in inspection frequency.

Figure 7-11: Actual and forecast Pole Asset Inspection Costs ($m, nominal)



Source: AusNet

This cost increase, which we consider is material, is consistent with the AER's step change framework as it is driven by a change in our regulatory obligations as directed by Energy Safe Victoria and is not funded through any other component of the opex forecast. No adjustment has been made to reflect costs incurred in the base year as AusNet commenced incurring these additional costs from 1 January 2024, after the 2022-23 base year.

Table 7-12: Energy Safe direction to conduct more frequent pole inspections Step Change forecast ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
ESV direction to conduct more frequent pole inspections	1.6	1.6	1.6	1.6	1.6	8.0

Source: AusNet

7.9.3. Digital (inc. SaaS, licences etc.)

New initiative and opex associated with capex

AusNet is proposing a step change of $39.9m (real $2025-26) to manage material, additional Digital opex we are forecasting for 2026-31 as a result of:

- Efficient investment in new capabilities, including new control room capabilities necessary to address evolving customer needs and the findings of several reviews initiated following the February 2024 storms.
- Greater use of cloud solutions to manage increasing data hosting requirements, in line with industry trends.

The key drivers of this proposed step change are shown in table 7-13. Over 60% of the total step change is driven by the spend necessary to maintain new ADMS capabilities, as explained and justified in the supporting ADMS, Field Enablement and TAM Digital business case. The remainder consists of new licenses and subscriptions associated with investments in other, new capabilities – which are explained and justified in the relevant Digital business cases - and additional cloud costs.

The requirements of each project including the necessary capex and opex, quantification of benefits and recurrent and non-recurrent splits can be found in the ICT program briefs listed in each subsection below. The existing expenditure captured in our base year is close to entirely recurrent as such all the amounts are in addition to this.

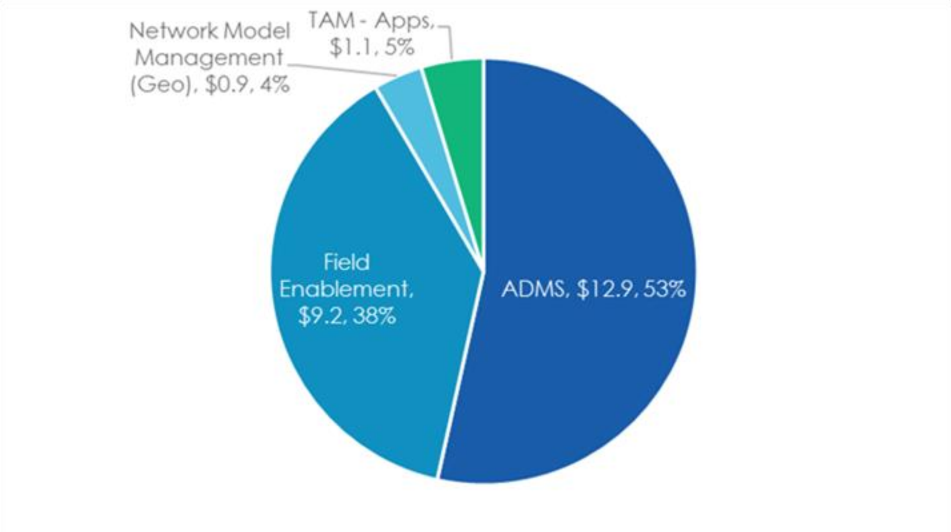
Table 7-13: Opex step change amounts per drivers ($M, real 2023-24)

$ Jun 2024	2026-27	2027-28	2028-29	2029-30	2030-31	TOTAL
ADMS Phases 3 & 4 (L&S) - New	$2.9	$4.7	$5.1	$5.1	$5.1	**$23.0**
ADMS Phases 3 & 4 (Support Labour)	$0.0	$0.3	$0.3	$0.3	$0.3	**$1.2**
Other (L&S) - New	$0	$1.3	$1.9	$3.0	$3.0	**$9.2**
Cloud Migration	$0.5	$0.7	$0.9	$1.0	$1.2	**$4.3**
TOTAL	**$3.4**	**$7.0**	**$8.2**	**$9.5**	**$9.7**	**$37.8**

Source: AusNet

ADMS Phases 3 and 4 ($24.2million, $2023-24)

Figure 7-12: Opex amount and % related to capex business case for ADMS Phase 3 and 4 ($M, real 2023-24)



Source: AusNet.

At AusNet, our Customer and Energy Operations Team (CEOT) is at the core of our operations as a DNSP. As the electricity distribution landscape continues to change, our control room operations must adapt to ensure we can continue to provide an efficient reliable, high-quality power supply service for our customers into the future.

While we have successfully delivered core ADMS capabilities, these capabilities and system functionality are not sufficient to enable AusNet to effectively manage the key issues and challenges facing our network. These include:

- Increasing penetration of renewables on a grid originally designed and built for large scale one-way power flows is creating challenges in keeping energy supply and demand in balance and ensuring frequency and voltage levels remain within operating limits.
- Increased frequency of extreme weather events reduced base load generation, rapid technological change, evolving market players, and changing customer expectations are increasing the complexity in how we must operate and manage our network.
- The lack of integration between our ADMS and SCADA systems is becoming more an emerging issue as the complexity of the network increases and overtime can decrease the responsiveness of our control room and lead to more Human Error Incidents (HEIs).
- Greater workload and therefore stress on our controllers may hinder employee performance and retention and therefore put the continuity of our capabilities and effective operation of the network at risk.

The need to improve outage management and communication capabilities has been identified from recent external and internal reviews including the Victorian Government's Network Resilience Review, the Victorian Government's Network Outage Report and an independent Post Incident Review following the February 2024 storms that was conducted by Nous Group (provided as a supporting document).

In addition, the way field crews are managed and the digital tools available to them that are critical to the way AusNet operates and can materially impact our network performance, customer experience, and maintenance costs. Currently, AusNet's field crews and fault location visibility solutions are primarily outsourced and driven by our current delivery partner, Downer, with additional parties known as field service providers (FSPs) engaged when further support is required (for example, on a major event day). The reviews of the February 2024 storm also highlighted limitations in our field management practices that need to be addressed to improve our outage management capability, reduce restoration timeframes, and improve customer outcomes, as extreme weather events become more severe and larger in magnitude.

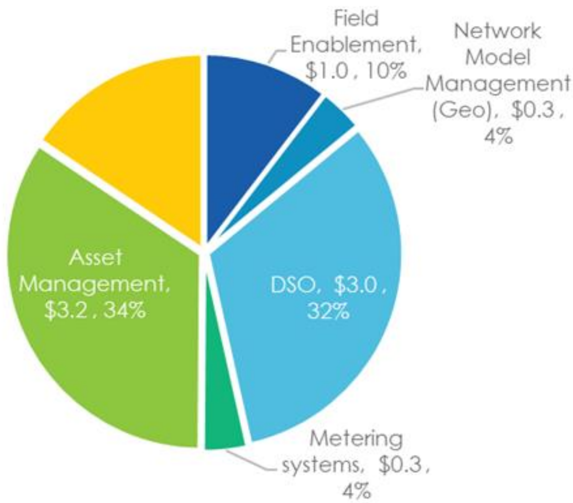
Investing in the recommendations from the Nous report will drive more effective use of planning, scheduling and engagement with delivery partners. Reducing restoration timeframes and providing more accurate estimations for when power will be restored whilst avoiding increased planned and unplanned outages. Ultimately, these investments will enable us to maintain our customer experience into the future whilst being able to adapt to challenges and complexities that our network will come across from the transition to renewables, the increasing uptake of customer energy resources (CER), and the increasing frequency and severity of extreme weather events we experience.

The AER has also acknowledged this in its recent pass-through decision in December 2024 that, "AusNet Services commissioned Nous Group to undertake an independent post incident review of its response to the February 2024 storm events. We expect that AusNet Services will implement recommendations arising from that review to further improve its capacity and operations in responding to this type of event, to ensure customer outage times (and therefore MED GSL payments) are not unnecessarily extended following storm events."[98]

We have commenced implementing these recommendations through our ADMS Phase 3 project, which is currently in-flight. Further information on the justification of the ADMS Phase 3 and 4 costs – including the additional opex driving the need for this step change - can be found in the ADMS, Field Enablement and TAM business cases, which support our Digital capex proposal. The NPV analysis contained in these business cases demonstrates that proposed spend (capex and opex) for the preferred solutions is efficient.

Licencing costs driven by investment in other new capabilities ($9.2 million, $2023-24)

Figure 7-13: Opex amount and % related to capex business case for licences driven by new capabilities ($M, real 2023-24)



Source: AusNet.

This component is linked to investment in new capabilities – separate to ADMS Phase 3 and 4 – which will drive additional opex that is material and not captured in other opex components.

These new capabilities are as follows and described in more detail in business cases on Field enablement, Network model management, DSO, Metering services, Asset management and Customer experience:

- Field Mobility Solution (non-energy)
- Multi-View Demand Forecasting
- Flexible Demand Orchestration (C&I) (L&S)
- Flexible Trading Arrangements (mandatory changes)
- Enhance Maintenance Planning
- Service & Project Delivery Collaboration
- Skills Management
- Unplanned Outage Communication Improvements
- Uplift Planned Outages Comms
- Major Connections Portal

[98] AER Determination - AusNet Services - February 2024 Storm Event - Distribution Cost Pass Through - November 2024 | Australian Energy Regulator (AER) December 2024

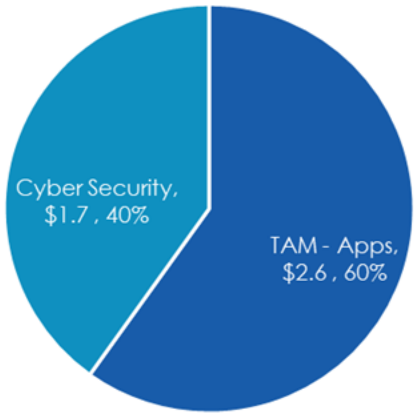
Further information on the justification of these costs can be found in the ICT business cases as part of our proposal. NPV analysis for these new capabilities highlights that the preferred solutions are efficient, refer to the business cases on Field Enablement, Network Model Management, DSO, Metering Systems, Asset Management and Customer Engagement for further detail.

We have not pursued any increases in opex related to the ADMS Phase 2 project that is scheduled for completion by the end of 2024, to moderate the proposed digital step change and improve the affordability of our plans. These costs, which are not captured in the 2022-23 base year, amount to $4m over 2026-31. Expenditure relating to the DERMS licence cost shifting from being capitalised to expensed in 2028-29 has been included in the Emergency Backstop Mechanism step change.

We have not identified any instances of licencing costs for other systems/platforms that are expected to decrease materially in 2026-31. However, as discussed in the next section, we have reduced our opex requirements by $3.9m ($2025-26) to reflect efficiency improvements from investment in new capabilities that are not captured in the opex productivity factor.

Cloud Migration ($4.3 million, $2023-24)

Figure 7-14: Opex amount and % related to capex business case for cloud migration ($M, real 2023-24)



Source: AusNet.

AusNet's IT systems will evolve in line with the industry trend of increased cloud usage and hosting. The quantity of data being collected and stored is growing and will continue to grow over the 2026-31 period. While cloud-based systems require reduced recurrent investment to maintain than on-premises systems, reduce the need to invest in on-premises data centres and provide a range of inherent operational and security advantages, they require a greater amount of opex in the form of cloud hosting costs. The requirement for AusNet to increase its cloud usage is not internally driven but rather a result of not having other credible options to efficiently manage increasing volumes of data.

We have proposed a step change of $4.3m ($2023-24) to manage these additional costs, which relate to the following business cases:

- Technology Asset Management
- Cyber Security

The costs of increasing cloud usage and hosting are partially captured in the trend parameters. However, base opex cloud/SaaS trend of $1.4m is insufficient to fund the additional costs we are forecasting for 2026-31. Therefore, to avoid overlaps between opex components, we have netted off this component from our forecast of cloud usage growth, our expected cloud growth usage estimate represents a compound annual growth of no larger than 5% p.a.. The step change amounts to $4.6m in ($2025-26) from deducting the trended base from the forecast, note rounding of numbers below.

Table 7-14: Cloud migration opex component ($m, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31
Base amount – trended forward	6.9	6.9	7.1	7.2	7.3
Total cloud costs we are forecasting	7.5	7.6	8.0	8.3	8.6
Step change	0.6	0.7	0.9	1.1	1.3

Source: AusNet

As discussed in detail in section 6.13, we have no focused cloud migration program planned for the 2026-31 regulatory period. However, we have noted the trend of vendors shifting their products to the cloud, necessitating migrations to maintain vendor support and service levels. To address this, we have included step change of $3.74 million ($2023-24) in opex in our Technology Asset Management (TAM) submissions to account for these "forced" migrations. Further details can be found in the TAM business cases (See section 6.13 for more details).

By migrating to cloud AusNet is able to adapt to evolving requirements and enhance our flexibility on what customers pay for which focuses on the services they actually need and reduce the need to keep investing in on-premises data centres. We also note the new licenses associated with the growth of cyber services and the increase in cyber cloud service offerings. These offerings will prudently allow us to mitigate possible threats to our critical infrastructure and maintain current levels of reliability, security and safety, consistent with the National Electricity Objective (NEO).

Further information on the justification of these costs can be found in the business cases on Cyber Security and TAM - Apps as part of our ICT proposal.

Table 7-15: Digital (inc. SaaS etc.) Step change forecast ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Digital (inc. SaaS etc.)	3.6	7.4	8.7	10.0	10.2	39.9

Source: AusNet

7.9.4. Digital Efficiencies

Capex/opex trade-off

Our investment in non-recurrent digital capabilities will provide efficiencies which we have proposed to deduct from our opex forecast as a step change. Through this step change we are able to pass on the improvements in operating efficiency directly to customers and ensure customers benefit from these investments in the next regulatory period. The has come as a result of feedback and engagement with the Opex and Benchmarking panel which aided us in identifying productivity that could be given back to customers above the standard approach of 0.5%

The basis of the number is captured through improved opex productivity captured in the digital business case NPV assessment. The negative step change of $3.9m reflects the difference between the following amounts:

- Total efficiency improvements quantified in the NPV analysis underpinning Digital business cases ADMS, Field enablement, Customer experience, Network model management and Asset Management ($25.6m).
- The effects of the 0.5% opex productivity factor ($21.8m).

Importantly, should our proposed Digital capital and operating expenditure not be approved by the AER, we will reduce these estimated efficiencies in our Revised Proposal.

Table 7-16: Digital Efficiencies Negative Step Change forecast ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Digital Efficiencies	-0.8	-0.8	-0.8	-0.8	-0.8	-3.9

Source: AusNet

7.9.5. Flexible services and non-network solutions

Capex/opex trade-off

For the 2026-31 Regulatory Proposal, we have engaged in detail with our Future Networks Panel on emerging customer needs and how we should best invest to unlock more value from all CER on our network, including rooftop solar, batteries and EVs/EV charging units. We have also been engaging directly with the Victorian government and community energy groups on their energy ambitions, particularly through the implementation of the Neighbourhood Battery Initiative. This includes an AER-run phase 2 Low-voltage network visibility data trial between community battery proponents and Victorian distributors. Finally, we engage with our customers every day on their energy needs and pain points, including most recently with customers looking to install public charging stations across our network, or to upgrade existing connections to incorporate EV charging units.

Key themes from the EDPR engagement and our engagement with our customers and community groups directly (among others):

- Strong support to introduce Flexible Exports as an option for all new solar customers from 1 July 2026, with an alternative of a low static limit. Flexible Exports are a new way of managing solar exports, by sending daily export limits to solar systems based on network conditions at the time. By taking this approach, we are only constraining solar exports at the time when they are likely to either cause network constraints or create minimum demand risk. This is a more efficient and more equitable way of managing exports than applying conservative static constraints that are on a 'first come first serve' basis. We engaged on Flexible Exports mostly with our Future Network Panel and the Victorian government.

- Strong demand for flexible connection options for flexible load. This includes having capabilities to send dynamic signals to connecting load around network limits, which allows them to connect at lower cost (for example, not having to pay for a transformer upgrade as part of the connection cost). Battery proponents and EV charging providers are continuously seeking these services from us. This is also summarised in the DCCEEW options paper on Streamlining the connection of Electric Vehicle Supply Equipment (EVSE) and large CER.
- Strong desire to simplify processes and opportunities to be rewarded for flexibility, through 'flexible services'. With more and more CER on our network, including installations of very flexible batteries of any size (including behind and in front of the customer connection point), there is increasing demand on us to reward these customers for their flexibility through network support payments if they are able to provide 'flexible services'. Our engagement has indicated that the process for signing up to non-network solutions or flexible services can be onerous and proponents may not always have sufficient information regarding the potential value of the services they may provide. This deters potential providers of non-network/flexible services.

AEMO is currently designing a national CER Data Exchange, with AusNet as a key participant, through a co-design process with the industry. The Australian Renewable Energy Agency (ARENA) is supporting this initiative through a grant from its Advancing Renewables Program.

In response to customer feedback, we have developed a range of initiatives that deliver customer services and provide optionality to customers in line with changing expectations. A number of those initiatives are operating expenditure solutions that either defer capital expenditure or are necessary to enable a capital expenditure solution.

The capital expenditure solutions are summarised in our Distribution System Operator ICT business case. The operating expenditure solutions are described in more detail below. It is important to note that as a customer affordability measure, we have not proposed $2m in operating expenditure for Flexible Exports, even though we know there will be costs associated with managing a growing number of customers on Flexible Exports in the future.

Our step change includes:

- Personnel to manage the implementation of flexible connections and dynamic management of load customers such as batteries and EV charging stations, providing them with an option of a flexible connection if they allow controls for how they interact with the network ('dynamic connection'). We are already getting requests for this service from batteries and EV charging stations, however we do not have the capability or the personnel to provide the service today. We anticipate the demand for these dynamic load connections to grow over time, with increasing year on year costs during the regulatory period (starting with one FTE in 2026-27 and increasing to 5 in 2030-31).
- Personnel to manage the anticipated AEMO CER Data Exchange, which is currently being co-designed with industry. We anticipate the data exchange will require increasing support in managing the data shared with AEMO and other participants in the data exchange as well as any queries and requests related to the data. This data management cost is associated with the ICT investment for AusNet to integrate with the data exchange, which in itself is expected to deliver significant benefits to the National Electricity Market (NEM) through simplification and synergies in CER exchanges.
- Payments for non-network solutions procurement in the LV network, or payments for 'flexible services' provided by our customers, retailers and aggregators in the LV network (unlikely to be large customers in that case). Our proposal is to streamline the provision of these services to the network through a platform that simplifies the exchange of services and contractual arrangements, increasing the number of customers and responses to requests for flexible service or non-network solutions. We therefore anticipate the provision of these services and our payments of them to grow each year of the regulatory period. The cost of the non-network solutions payments is based on anticipated deferred augmentation, where the price to attract solutions is close to, but not higher than, deferred augmentation.

We do not provide any of these services today and therefore none of the proposed step changes are captured in the base year. We have identified potential synergies with our emergency backstop mechanism step change and community energy support - these include DER optimisation, flexible exports roll out and network data sharing and have not been proposed as part of this step change

Table 7-17: Flexible services and non-network solutions step change break down ($m, real 2023-24)

Component	2026-27	2027-28	2028-29	2029-30	2030-31	Total
DERMS – CER Generation/Load Management	0.1	0.2	0.2	0.4	0.5	**1.5**
CER Open Data Exchange Integration	-	-	0.2	0.2	0.2	**0.5**
Flexibility Services Payments	0.4	0.8	1.2	1.6	2.0	**6.0**

Benefits of the step change

The key benefits of the proposed step change are highlighted below:

- Increased network utilisation and deferred augmentation, reducing long term network cost for all AusNet customers.
- Optionality for customers when connecting to the network (both load and embedded generation).
- Lower cost of connection for flexible loads.
- Lower cost of aggregation of CER and participation in non-network solutions, to the benefit of all AusNet customers and electricity consumers in the National Electricity Market (NEM).

We have assessed the opex / capex trade off efficiency of the flexible service / non-network solutions component of the step change, through our LV augmentation modelling. The model selects augmentation sites where a modest 25% response rate to a flexible service request can deliver an effective augmentation deferral, assuming a reasonable level of response from customers based on previous experiences. The deferral was estimated at $29m, which can be efficiently offset by $6m of additional opex for network support payments. The deferred capex has been excluded from our forecast LV augmentation capex. We do not have sufficient evidence at present on what the efficient price for LV non-network solutions is likely to be (as no networks have this as an established practice yet with reasonable levels of response), however, we anticipate the price would be in the range that is similar to the value of network deferral (which would be the price to beat in future auctions through the proposed flexible service exchange platform).

Table 7-18: Flexible services and non-network solutions break down ($m, real 2023-24)[99]

		2026-27	2027-28	2028-29	2029-30	2030-31	Total
Undiscounted	LV augex deferrals			0.3	8.2	20.7	**29.2**
	Opex for network support payments	0.4	0.9	1.3	1.7	2.2	**6.4**
Discounted (PV)	LV augex deferrals			0.3	6.6	15.8	**22.6**
	Opex for network support payments	0.4	0.8	1.1	1.4	1.7	**5.3**

Source: AusNet

We have not undertaken a detailed quantification of the benefit of the other elements of the step change, however we are confident that flexible load management will lead to lower customer connection costs for those who choose to connect that way. This reduces direct costs to customers (particularly batteries that have approximately 90% customer contributions) and increases network utilisation, which benefits all AusNet customers. We are also supportive of AEMO's assessment of the benefits of the CER data exchange, which is based on the premise of delivering savings to all NEM customers.

[99] There is an extra deferred capex amount of $3.0m in 2031-32 (undiscounted, real, 2023-24) that is not a part of our analysis above.

Customer engagement on the step change

We have engaged with the Future Network Panel extensively on our proposal to introduce Flexible Exports and other forms of flexibility in our network management, including potential for flexible load services and an increased use of non-network. The Future Network Panel is very supportive of these measures, and any flexibility we can introduce to improve network utilisation and reduce network augmentation.

Table 7-19: Flexible services and non-network solutions Step Change forecast ($m, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Flexible services and non-network solutions	0.5	1.1	1.7	2.3	2.9	8.5

Source: AusNet

7.9.6. Fleet Electrification

Capex/opex trade-off

The energy transition allows us to unlock new opportunities, and we intend to transition our fleet of light vehicles to electric vehicles, as part of their lifecycle replacement cycle. This will provide cost savings to our customers by investing in electric vehicles for 70% of our existing fleet vehicle replacements over the 2026-31 regulatory period which was supported by our EDPR Coordination Group. The running costs of our fleet in total would decrease compared to the current period and as such we have proposed a negative step change to ensure our customers benefit from these savings in 2026-31.

The basis of this step change is that 35 vehicles will be replaced per annum with the full savings realised once the whole fleet has transitioned over, given the magnitude of the saving reflects the number of electric vehicles electrified. Further detail provided in the accumulated workbook for opex and step changes.

Due to AusNet's change to a new service delivery partner from August 2025, we have proposed to acquire additional vehicles (as discussed in section 6.16), which may allow us to electrify our fleet above the rate assumed for this step change. Recognising that electrification during 2026-31 may not be viable for many of the vehicles we have proposed to purchase (e.g. heavy vehicles), AusNet is committed to exploring the implications of these additional vehicle purchases for this step change further in our Revised Proposal.

Table 7-20: Fleet Electrification Step Change forecast ($M, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Fleet Electrification	-0.1	-0.1	-0.1	-0.2	-0.2	-0.7

Source: AusNet

7.9.7. Customer relationship management and broad communications campaign

New Initiative

Our customers have supported us in providing a step up in customer experience to strive for customer service excellence, allowing AusNet to be easier to deal with and save customers time and effort when interacting with us. The amount of $15.7 million which will deliver the service improvements explained below.

Dedicated customer service support

We have included 14 new customer relationship managers in the regions dedicated to commercial customers and community engagement across our 3 regions. This is based on feedback received from our commercial and industrial customers through the engagement process, and extensive research, including through our customer satisfaction survey, and engagement with our Customer Experience Panel, on the need for on ground customer support across a range of areas including for planned and unplanned outages, community energy and customer connections.

We have heard strongly from our customers and stakeholders that an area of concern is lack of direct contacts within the business for customers with complex needs, and lack of AusNet presence in the community. Many of our commercial customers, including local councils and community energy groups, have had recent experiences with AusNet that have left them needing more targeted and dedicated support, which is not always available. This results in customer frustration, waste of time in chasing the right contact to resolve and issue, and prolongation of outstanding customer issues. This feedback has been gathered through various channels over the past couple of years, with most notable and detailed feedback obtained through dedicated interviews with commercial customers conducted by our EDPR Research & Engagement Panel. We have heard this feedback clearly and our proposal includes a team of customer relationship managers, who will provide dedicated support to all commercial customers, local government and community energy groups across all the regions of our network. They will be based in the regions and provide the following type of support:

- Community engagement and outreach to identify/escalate customer/community pain points and provide updates on AusNet's programs to the regions—includes proactive engagement with customers and communities on their projects, current jobs with AusNet, future plans etc.
- Dedicated commercial customer engagement and support—depending on size of team, dedicated support can range from ~500 major commercial customers, or it can include smaller commercial customers as well (which typically need less support per customer).
- Reduce impact of planned and unplanned outages on customers and communities—working with commercial customers directly to negotiate best time for planned outages and providing on the ground support to communities during unplanned outages and storms.
- Facilitate customer connections in the context of local community energy projects—being the 'go to' person for all customer project enquiries, providing data to support project development, updates on progress of projects etc.

We engaged on this proposal with our EDPR stakeholders at our 2-day deliberation workshop in August 2024. The proposal was seen as necessary to address the identified gap in customer service for commercial customers and was supported by the stakeholders. However, this support was subject to several conditions, set out in the Coordination Group's report on the Draft Proposal[100], and addressed below:

Table 7-21: Conditions associated with Customer Panel support for this step change

Condition	How we have addressed this
Customers would not pay twice for service improvements through ex-ante funding and the CSIS	This initiative primarily targets C&I customers; the CSIS does not cover this customer cohort. Outcomes from our broad communication campaign are not drivers of satisfaction measured by the CSIS.
Updates on this program should be clearly communicated to a restructured Customer Consultative Committee, to ensure it is effectively representing customers and adheres to a clear set of obligations	Updates will be provided to our restructured CCC. More information on the CCC is provided in supporting document 'Customer Consultative Committee Terms of Reference'.

We have engaged with customers on the risk in funding a team of customer service managers, in recognition that we can decide to use the resources for other purposes, e.g., to manage unforeseen changes in our external environment that require reprioritisation of resources. To alleviate this concern, our proposal is reflected in our commitments to continue to improve customer experience, for which we have agreed with stakeholders a framework for accountability. This includes that if the business decides to cease this type of dedicated customer service, it needs to discuss that with customers first.

Broad customer communications

Through engagement with our panels and our customers in workshops, we have heard that as the energy transition progresses, and with the changing climate, there is an increasing need to keep customers better informed on various topics that they may not have been as engaged on in the past. We engaged on the proposed campaign themes through our Future Network Panel, Tariffs and Pricing panel and the Customer Experience panel. In all three panels we received support and encouragement to play a larger role in customer communications that builds agency and provide trusted information to help customers make decisions.

We have applied this feedback to scope a communication campaign focused topics A key theme is the energy transition; as many customers are, or are considering, investing in Consumer Energy Resources, it is important that they are well informed to make decisions in their best interests.

The campaign includes communications mediums we have not used extensively in the past, including developing explainer videos, customer fact sheets, targeted SMS about specific topics, translated content in various languages, and social media ads. These mediums can deliver various benefits including expanded reach and comprehension across our customer base. Further details on the scope and benefits of the campaign are outlined in our customer relationship manager and broad communication campaign supporting document.

[100] Coordination Group, Independent Report on Draft Revenue Proposal 2026-31, XX 2024

We are also proposing digital capex of $41m to make it easier for customers to engage with us and uplifting customer interactions on our platforms. This program is discussed further in section 6.13.4 and the supporting Digital Business Case - Customer Experience.

Table 7-22: Breakdown of costs per subsection

$ Jun 2024	2026-27	2027-28	2028-29	2029-30	2030-31	TOTAL
Customer Managers	$ 2.1	$ 2.1	$ 2.1	$ 2.1	$ 2.1	**$ 10.4**
Education & Communication	$ 1.0	$ 0.9	$ 0.9	$ 0.9	$ 0.9	**$ 4.5**

Source: AusNet

We have ensured there is no overlap between this program and our base year. We are taking an iterative approach our investment in customer relationship management, with some roles operating since the beginning of the current period and other roles joining over time. We have ensured there is no overlap with our base year so that our step change reflects only the incremental cost of new labour resources to enable a step up in customers being managed by AusNet. In addition, the funding provided through base year communications spend (trended forward) has been deducted to calculate the step change. Therefore, the scope of this step change represents costs to deliver the identified material gaps where AusNet providing further communications to improve understanding would benefit our customers. As such, a step change is needed to fund this cost increase, which we consider is material, driven by our customers' evolving needs and is not funded through any other component of the opex forecast.

For further information and detail on engagement of this step change, refer to supporting document[101]

Table 7-23: Customer relationship management and broad communications campaign step change forecast ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Customer relationship management and broad communications campaign	3.3	3.1	3.1	3.1	3.1	15.7

Source: AusNet

7.9.8. Early Fault Detection (EFD)

As discussed in Chapter 6 – Capital Expenditure, we are proposing $12.7m of capital expenditure to install early fault detection (EFD) devices on our SWER network, as a new bushfire safety program. EFD devices are a relatively new, innovative technology aimed at proactively identifying potential asset failures, triggering field inspection and replacement. AusNet has undertaken three field trials, the most recent of which was part funded by the Victorian Government. The completion of these trials has confirmed the technology can reduce bushfire risk on our network. We are presenting all information relating to our trials, economic modelling and all aspects of our plans to the Victorian safety regulator (Energy Safe Victoria) as formally requested under s 101(1) of the Electricity Safety Act 1998 (Act).

As can be observed from the modelling the benefits are low due to the very low customer density of SWER, limitations in the framework on how safety benefits are quantified and given the Probability of Failure is low due to the strong condition of the network. The potential to detect latent defects through EFD technology that are not detectable through current inspection and monitoring practices, provides an opportunity for AusNet to further manage hazards and risk AFAP in compliance with its legislative obligations.

The program delivers safety benefits that are typically not quantified elsewhere in the framework as the f-factor incentive is relatively weak. It is also consistent with AusNet's obligations to meet safety legislation requirement to innovate and be across new technology.

Units would be installed across the AusNet network at approximately 3.5km spacing. AusNet requires approximately 1,830 units to cover the SWER network of 6,400km. Hardware, configuration and software licensing are all required from a supplier, resulting in additional capex and opex.

The installation of EFDs is expected to increase our opex costs by $7.8m during 2026-31, in the form of additional software and servicing costs. This cost increase is material and consistent with the AER's step change framework as it is not funded through any other component of the opex forecast. An adjustment has been made to reflect costs

[101] ASD – AusNet – Customer relationship manager and broad communication campaign – 31 Jan 2025

incurred in the base year although not material in nature ($0.07m in 2022-23). AusNet will commence incurring material costs in the 2026-31 regulatory period.

Our proposed opex step change costs of $7.8m reflects a quote provided by the technology vendor, IND Technology. This has been provided as a supporting document. The cost of the step change is assumed to be spread equally over the 2026-31 regulatory period.

Benefits of EFD devices

AusNet believes this innovative product will mitigate bushfire danger AFAP as it progresses to a mature state with greater deployment providing opportunity to develop the defects attributes library.

A staged implementation of EFD across the network to build knowledge and process is a prudent approach to operationalising the product. Once operational, the customers who ultimately pay for this innovation will receive the benefits of the technology, not only for bushfire mitigation, but also improved community safety.

Our modelling demonstrates that EFDs will deliver significant benefits to our network and customers in the form of reduced bushfire risk which will serve as a public safety initiative.

The driver and key benefits of EFDs are discussed further in Chapter 6.14 and the supporting document entitled ASD – AusNet – AMS Early Fault Detection - 31012025

While Victoria's rollout of REFCL technology cut the fire-risk of polyphase (multi-wire) powerlines to a fraction of the previous level, there is no similar solution available for SWER powerlines. SWER fire-risk constitutes a gap in Victoria's effort to ensure powerline bushfire safety.

In the final report on the EFD SWER trial between the Victorian Government, IND-T, AusNet, CitiPower and Powercor, potential benefits of further rollout of the technology were significant.

While EFD devices are relatively new and innovative technology, they aim to proactively identify potential asset failures before it occurs, allowing for swift deployment of field personal to remedy before the item can fail and start a fire. AusNet is proposing to install Early Fault Detection (EFD) devices on the network in Codified and High Bushfire Risk Areas (HBRA) as a new bushfire safety program for the 2026-31 following initial trials.

Drivers include:

- Detect latent defects and reducing the probability of a catastrophic fire.
- Most of the steel SWER conductor fleet is over 50 years old and has been subjected to lighting strikes which are known to fracture or break strands of the conductor not easily detected through traditional inspection. If left unchecked will ultimately fail.

Other Considerations

RECOMMENDATION 27

The State amend the Regulations under Victoria's *Electricity Safety Act 1998* and otherwise take such steps as may be required to give effect to the following:

- the progressive replacement of all SWER (single-wire earth return) power lines in Victoria with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk. The replacement program should be completed in the areas of highest bushfire risk within 10 years and should continue in areas of lower bushfire risk as the lines reach the end of their engineering lives
- the progressive replacement of all 22-kilovolt distribution feeders with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk as the feeders reach the end of their engineering lives. Priority should be given to distribution feeders in the areas of highest bushfire risk.

The Victorian Bushfire Royal Commission (VBRC) into the Black Saturday bushfires recommended the replacement of all SWER lines in High Bushfire Risk areas by 2021 (10 years from Powerline Bushfire Safety Taskforce Final Report).

We have proposed 200km of SWER line replacements in Codified areas, across 2026-31, to address the VBRC's recommendation.

For SWER lines outside the codified areas but within the High Bushfire Risk areas, we have proposed EFD devices to complement the SWER line replacement program, because they can be rolled out quickly and immediately begin to protect the community. They can reduce risk at a much lower cost than covering or insulating conductor. The Firesafe Report submitted by IND Technology to the Victorian Government in Nov-2024[102] describes the latest 2-year trial of EFDs on rural powerlines has confirmed their effectiveness in reducing fire risks by continuously monitoring powerlines to detect and address faults before they spark fires.

[102] See https://ind-technology.com/wp-content/uploads/2025/01/FireSafe-SWER-EFD-Trial-Final-Report-November-2024-1.pdf

See ASD - AusNet - Early fault detection - 31 Jan 2025 for further information.

Table 7-24: Early Fault Detection Step Change forecast ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Early Fault Detection	1.6	1.6	1.6	1.6	1.6	7.8

Source: AusNet

7.9.9. Resilience (Hazard tree program)

Capex/opex trade-off

Much of the storm damage on our network since 2021, and subsequent prolonged outages, were caused by hazard trees falling onto lines. Hazard trees are trees with some sort of structural defect outside of the regulated clearance zone that are at risk of failing and causing a power outage. We have estimated the value of the outages caused by hazard trees at approximately $17m p.a. (described further below).

The impacts of dense vegetation on our network and customers were also highlighted in the Nous Post Incident Review of the February 2024 storms:[103]

> *"Areas with dense vegetation also make AusNet's network more prone to storm damage. 24 per cent of AusNet's wires and cables suspended between its poles and towers require vegetation management to reduce these risks."*

Climate change is expected to increase the amount of vegetation-related prolonged outages, as evidenced by the increasing frequency of severe storms on our network. Our aim, therefore, is to reduce climate related vegetation outages through the expansion of the annual hazard tree management program at an additional cost of $3m per annum. As discussed below, this additional expenditure is demonstrated to be efficient, when assessed against the quantified benefits it will deliver to customers through avoided outages.

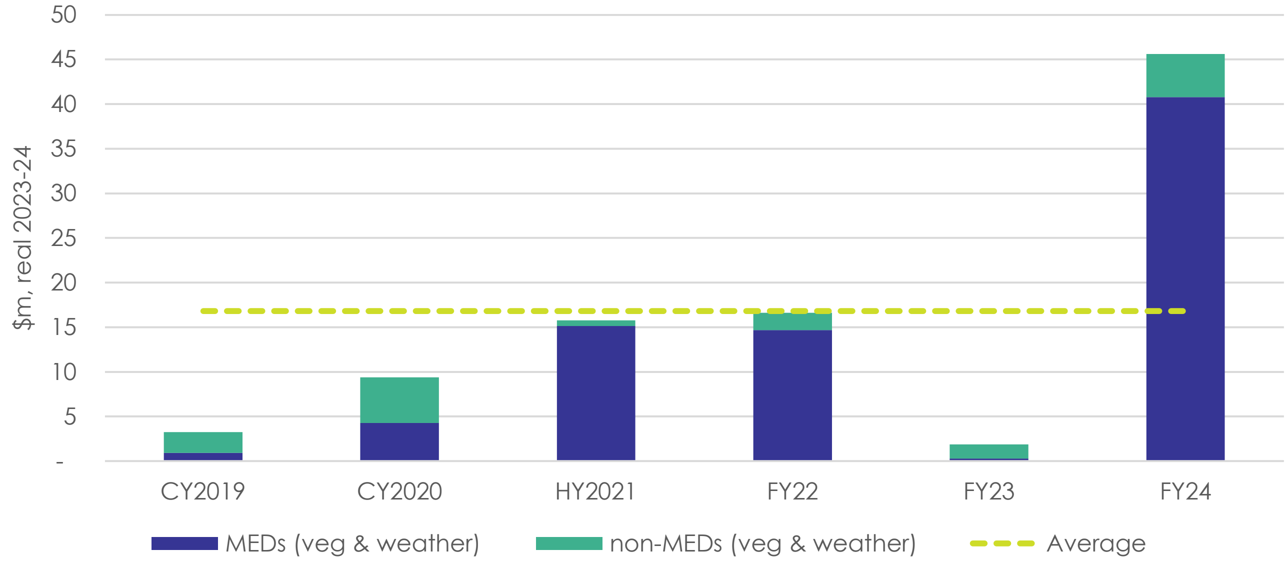
Expanding the hazard tree program is forecast to reduce the value of hazard tree related outages by approximately 45% (a $8m p.a. reduction). From an overall network perspective, this would also avoid the need for further increases in emergency response opex and moderate the need for additional network hardening (over and above the resilience network hardening capex we have proposed, as discussed in Chapter 6).

The figure below shows that the annual average value of hazard tree caused outage is approximately $17m per annum. This has been derived by:

- Analysing our RIN data over 5.5 years, from 2019 to 2023-24 (inclusive).
- Filtering SAIDI for vegetation caused outages (see CA RIN, 6.3 Sustained Interruption, Reason for interruption column).
- Converting SAIDI to CMOS (multiply SAIDI by the number of customers in that year).
- Converting CMOS to hours (divide CMOS by 60).
- Converting hours to unserved energy (multiply hours by an assumed energy consumption rate of 0.71kWh per hour).
- Converting unserved energy to a value of unserved energy (multiply unserved energy by a weighted average VCR of $40 per kWh).
- Converting value of unserved energy (caused by vegetation) to one specific to hazard trees (multiply value of unserved energy by 30% i.e., we have assumed that 30% of all vegetation caused outages are due to hazard trees).

[103] ASD - Nous - Post Incident Review into AusNet's Response to the February 2024 Outage Event – 10072024, p.15

Figure 7-15:36 Estimated value of hazard tree caused outages ($m, real 2023-24)



Source: AusNet

We have estimated that an expansion of the hazard tree program to produce benefits of approximately $8m per year based on a product of the following:

- Estimating how many customers would be affected by the average sized hazard tree caused outage (and for how long)
- Energy consumption rate of 0.71 kWh per hour
- Weighted average VCR of $40 per kWh
- Probability of a hazard tree causing an outage, probability of cutting the right hazard tree, and probability of failure within 12 months (if hazard tree not cut).

That is, the proposed expansion of the hazard tree program will help customers avoid outages to the value of $8m per year and, therefore, is economic when considered against the costs of $3m p.a.

This cost increase, which we consider is material, is consistent with the AER's step change framework as it is driven by a capex/opex trade-off (avoided additional capex to manage climate risk) and is not funded through any other component of the opex forecast. It is also consistent with the NEO as it provides net benefits to customers and, thus, is in their long-term interests.

An adjustment has been made to reflect the costs incurred in the base year.

Table 7-25: Resilience (Hazard tree program) step change forecast ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Resilience (Hazard tree program)	3.0	3.0	3.0	3.0	3.0	**15.0**

Source: AusNet

7.9.10. Emergency preparedness and response

Major externally driven change and/ or (new regulatory obligation)

The opex step change is required to uplift in our operational capability to prepare and respond to extreme events that are expected to become more frequent and severe as the climate changes. This follows several extreme events experienced this regulatory period. These events involved an emergency response by AusNet.

The February 2024 storm was the largest storm event to impact our network and stress-tested many aspects of our operational response.

Following this event, two reviews into our performance were commissioned. These reviews are:

- The Network Outage Review (NOR) commissioned by the Victorian Government[104]; and
- Nous Group's independent Post Incident Review of our operational response.[105]

AusNet must address these recommendations to meet the expectations of our customers given the high impact of prolonged power outages. These expectations are shared by the Victorian Government[106], which supports an independent review of distribution businesses' implementation of the Network Outage Review recommendations following the next event resulting in prolonged power outages.

In addition, the AER has set out its expectation that AusNet will implement recommendations of the Nous PIR as follows:

> *We note that AusNet Services commissioned Nous Group to undertake an independent post incident review of its response to the February 2024 storm events. We expect that AusNet Services will implement recommendations arising from that review to further improve its capacity and operations in responding to this type of event, to ensure customer outage times (and therefore MED GSL payments) are not unnecessarily extended following storm events.*[107]

In June 2024 AusNet's Board of Directors passed a resolution confirming the organisation supports AusNet implementing the Nous PIR recommendations, including five that are the subject of the enforceable undertaking we entered into with the ESC[108]. Regular reporting is being provided to our Board on progress against the implementation of the recommendations.

AusNet is already implementing these recommendations. The expenditure included in this step change is incremental to expenditure occurring in our 2022-23 base year.

We have significant customer feedback that supports uplifting our response to extreme events (see Chapter 2.4), and both the Nous PIR and the Network Outage Review were informed by customer research and engagement, and the recommendations reflect this.

We have considered the interrelationship between operational response and investing in the network to improve resilience to extreme events in developing this step change. Both approaches are essential because it is not possible to prevent all outages and therefore fully displace the need for timely response and recovery. Conversely, allowing for unrestricted growth in outages and diverting all resources to response and recovery would not be an optimal outcome for customers either.

Our benchmarking proposal (Appendix 7C) also highlights the need to clarify the treatment of emergency preparedness costs in future benchmarking assessments.

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104 Network Outage Review
105 Post Incident Review into AusNet's Response to the February 2024 Outage Event. Commissioning this PIR was a requirement of an Enforceable Undertaking we entered into with the ESC.
106 Victorian Government response to the Network Outage Review, available here: Network Outage Review
107 AER, Determination February 2024 storm cost pass through – AusNet Services, November 2024 Report template
108 AusNet enforceable undertaking - AusNet

7.9.10.1. Relevant review recommendations that underpin this step change

Network Outage Review

The relevant recommendations from the Network Outage Review and the Victorian government response are outlined below. While several of these have yet to be formally implemented through regulation, the intent of government to support all recommendations (in part or in full) was clearly set out in their response.

Table 7-26: Network Outage Review Panel recommendations and Victorian government response

No.	Recommendation	Victorian Government response
2	Distribution businesses annually attest to the Minister for Energy and Resources about the currency, completeness, maturity and implementation ability of their emergency risk management practices with regards to maintaining electricity supply, inclusive of assets, people, resources, governance, systems, processes and arrangements with contractors. The attestation should include specific reference to, but not limited to: **Planning and coordination** 1. Participation in Regional Emergency Management Planning Committees and Municipal Emergency Management Planning Committees to support response planning for areas at high risk of prolonged power outages. **Communication and engagement with customers and community** 2. Application of best practice communication and engagement approaches before, during and after prolonged power outages including: a. Inclusive design of customer service systems such as outage trackers and interactive voice response (IVR) systems with regular monitoring, evaluation, and feedback from customers with lived experience of vulnerability. b. Capacity of customer service systems to meet surge demand and back-up continuity plans if these services fail. c. Capability to provide on-the-ground support to communities during emergencies. **Impact assessment and make-safe actions** 3. Adoption and operation of State Emergency Management Priorities including 'make safe'. 4. Ability to undertake rapid impact assessment at a network-wide scale during an event including integration of: a. mutual aid resources and state and regional emergency response teams b. reports of damaged infrastructure by emergency services personnel and community members c. consistent information flow through to the incident response and restoration planning teams 5. Processes to report timely and accurate information about status to restore services and confirm 'safe' infrastructure to emergency services and communities. **Restoration planning, prioritisation and operations** 6. Capability and capacity to achieve effective management of events and timely restoration of customers. 7. Review of emergency management practices including but not limited to review of risks and risk controls and testing of revised controls following all major events and exercises. **Temporary generation for key community assets** 8. Capacity and capability to connect main streets and key community assets in areas at high risk of prolonged power outages to temporary generation within 12 hours of an event. Information on location of temporary generation sites, network connection points and key access routes should be included in Regional Emergency Management Planning Committees and Municipal Emergency Management Planning Committees.	**Support**
5	DEECA work with distribution businesses, emergency service agencies, and peak bodies to integrate prolonged power outage preparedness into existing business and household emergency preparedness plan templates.	**Support**
7	The Victorian Government and energy sector work with The Energy Charter #BetterTogether Life Support Customer Initiative to support and implement in Victoria a national approach to achieve better outcomes for life support customers that meets strong standards of consumer protection.	**Support in principle**

10	Owners and operators of critical infrastructure should participate in Regional Emergency Management Planning Committees and ensure that they have appropriate arrangements for services to stay connected for 72 hours without network power supply.	**Support in principle**[109]
13	To quickly address unreliable power supply to known areas at risk of prolonged power outages, the Minister for Energy should apply a license condition for AusNet to improve reliability of specified feeders and install network connection points to enable rapid installation of temporary generation in key townships.	**Support in part**[110]
16	DEECA in conjunction with distribution businesses formalise mutual aid arrangements between all businesses to support effective management of prolonged power outage events to reduce time to restore outcomes for customers. Arrangements should include early consideration of mutual aid when a prolonged power outage event is likely to last more than 48 hours.	**Support**
17	Distribution businesses to inform DEECA of properties with defect notices to support community recovery planning. DEECA work with peak bodies to ensure coordinated community recovery planning.	**Support**
18	The Minister for Energy and Resources undertake an independent review of distribution businesses response to the next prolonged power outage event(s) against the recommendations and observations of the Network Outage Review with a view to identifying and removing barriers to achieving better outcomes for the community	**Support**

Importantly, the final recommendation confirms the Victorian Government's expectation that distribution businesses will implement these recommendations prior to the next prolonged power outage event.

Nous Post Incident Review

The PIR was commissioned by AusNet and was completed by the Nous Group (Nous). The report is independent and evidence-based of AusNet's operational response to the major unplanned outage event caused by severe weather events in February 2024, which led to the most significant outages in AusNet's history.[111] While most of the Nous recommendations are not formal regulatory requirements on AusNet[112], they reflect the expectations of our customers and stakeholders, including the AER (see above). Therefore, it is reasonable that AusNet has included the costs of implementing these recommendations in our regulatory proposal.

This opex step change supports many of the recommendations made by Nous Group.

A mapping between the expenditure sought through this step change and the recommendations in the Nous PIR and the Network Outage Review is provided in the 'Emergency preparedness and response step change' supporting document.

7.9.10.2. Additional resourcing requirements

Our proposal is focused on uplifting preparedness and response resourcing, given many of the Nous PIR recommendations require additional employee activity. This includes expanding our emergency response procedures (SPIRACs) and implementing regional delivery structures, better utilising AusNet staff and reviewing current training program, reviewing preparedness communications campaigns and being prepared to process Prolonged Power Outage Payments (PPOP) and handle associated customer enquiries.

The components of our proposed step change are described below:

- Additional emergency management specialists – we are in the process of increasing the number of full-time emergency management staff from one in 2022-23 to five. Funding for three of these roles is sought in the step change. Of these three new roles, two have commenced and the third role is currently in the market. The five roles in the team are described as below:
  - A new Group Manager Operations and Emergency Management (costs not included in step change)
  - Emergency Manager (in place in 2022-23) (costs not included in step change)
  - **New role:** Emergency Preparedness and Planning Lead (commenced)
  - **New role:** Business Resilience and Continuity Lead (commenced)
  - **New role:** Training and Exercise Specialist (in the market)

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[109] In principle, rather than full support, is provided by government in recognition that it is not practicable for all critical infrastructure to fully meet this recommendation
[110] Support granted in part as the Dec 2024 timeline was not met due to the need for further cost benefit analysis
[111] Post Incident Review into AusNet's Response to the February 2024 Outage Event
[112] The exceptions to this are five recommendations required to be delivered under the Enforceable Undertaking entered into with the ESC: AusNet enforceable undertaking - AusNet

The role of these specialists will be to:

- Own and maintain SPIRACs and associated policies and procedures;
- Ensure compliance with the annual attestation provided to the Minister for Energy and Resources and implement continuous improvement against the requirements, including the additional requirements contained in Recommendation 2 of the Network Outage Review;
- Coordinate emergency rosters and training, which will be significantly more complex and resource intensive as we increase the number of staff able to assist in emergency response events (including participating in regional committees);
- Raise awareness of emergency management capability across the organization and drive continual improvement;
- Liaise with government, other utilities and other emergency response agencies on preparedness, and coordinate preparedness activities undertaken by customer support staff.

More detailed descriptions of the accountabilities of the three new roles that are the subject of this step change are described in the 'Emergency preparedness and response step change' supporting document. While these roles support all emergency events impacting AusNet, the team capacity is driven by the requirements of the distribution network.

- Ongoing delivery of emergency management training across a larger number of staff who will be trained to assist with emergency management;
- Development and maintenance of emergency management role-specific training material, to align with SPIRACs and uplifted practices; and
- Ongoing licensing and subscription costs to uplift and maintain telecommunication contingencies, including the use of satellite phone subscriptions.
- Some other aspects of the additional funding we require are included in other step changes:
- Additional customer support staff to work with local councils on preparedness planning and support customers and communities (including by staffing emergency resource vehicles) during emergency events are included in the customer relationship management step change; and
- An additional $0.2 million per annum required for emergency management comms and marketing, including the execution of emergency specific preparedness/awareness campaigns, is captured in our broad communications campaign step change.

The uplift commenced in the current regulatory period. In particular, we will have four additional emergency management staff in roles by the end of 2024-25. This demonstrates that AusNet is prioritising the delivery of this uplift as prudent and efficient and required to meet the needs of our customers.

Consistent with the AER's step change framework, and as shown in the Table below, where relevant expenditure has been incurred in our 2022-23 opex base year, this has been netted off the amount included in the step change.

While some of these items are individually small, in aggregate these activities represent a material cost to AusNet. We have provided granular detail to be transparent and assist the AER in its assessment. These are also only a sub-set of additional costs incurred from uplifting emergency response and preparedness activities, which also include significant management oversight and time and integration of emergency preparedness and response activities into BAU roles for a number of employees including customer communications, government affairs, and operational management.

Table 7-27: Estimating incremental costs of emergency preparedness and response uplift ($m, real 2022-23)

Description	Current ('22/'23)	Future	# of NOUS recs. this will support	Gap per year	Assumptions
Additional Emergency Management Specialists	$0.18m	$0.72m	17	**$ 0.54m**	Cost of each FTE is $0.18m. This assumption is conservative as 2/3 of these are at General Manager or Manager level.
Delivery of Emergency Management related training and refreshers, and developing and maintaining training material	$ 0.05m	$ 0.30m	25	**$ 0.30m**	**Current expenditure** supports training of 30-40 people a year through AIMS training led by an external provider. This supports about ~90 staff trained in emergency response. **Future expenditure** will support up to 400 individuals to maintain emergency response training. This also includes the cost of developing and maintaining training materials.
Satellite phone subscriptions	Nil	$1.00 m p.a.	1	**$ 1.00m**	Back up comms capability available across 10 Depots and to serve 400 mobile sites (EMMAs and field trucks). A combination of satellite-related services is used to support back up comms

Source: AusNet

7.9.10.3. Total emergency preparedness and response step change

This cost increase, which we consider is material, is consistent with the AER's step change framework as it is driven by a major external factor and (forthcoming) regulatory requirements. It is not funded through any other component of the opex forecast.

An adjustment has been made to reflect the costs incurred in the base year and synergies across other step changes.

Table 7-28: Preparedness and Response Step Change forecast ($M, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Preparedness and Response	1.8	1.9	1.8	1.8	1.8	9.2

Source: AusNet

7.9.11. Insurance

Material externally driven change

AusNet maintains a comprehensive insurance program across our regulated energy networks. The major policies that contribute to 98% of the current premium are bushfire liability, property and cyber. Costs for these three policies are expected to increase above the opex rate of change.

Lockton, our insurance broker, has provided an expert report and forecast of premium increases during the 2026-31 regulatory period (see Appendix 7D). Based on these forecasts, a step change of $10.5m over five years is required to efficiently manage these costs, which are driven by external factors and market conditions. A step change is consistent with the AER's preferred approach of ensuring networks are funded for their efficient insurance premium costs, as demonstrated by the current determination and other, recent AER decisions (e.g., for SA Power Networks).

We operate an extensive overhead network of assets covering large areas of rural and heavily vegetated land, which carry a high level of bushfire risk. As a result, we are exposed to significant bushfire liability risks and must, therefore, ensure we have adequate insurance coverage. Otherwise, the full costs arising from bushfire-related events will be borne by customers through the Insurance Coverage cost pass through event, which we propose to maintain in the 2026-31 regulatory period. To determine an appropriate level of coverage we obtain independent assessments of our Maximum Foreseeable Loss (MFL).

There are significant changes taking place in the insurance market, at both domestic and international levels, which are reducing the number of insurers who can offer cover on terms and conditions that a prudent network service provider would accept. A number of insurers are increasing their premiums, reducing the scope of the policy's coverage, or exiting the market altogether as the number and severity of bushfire-related events increases the number of claims. One of the key impacts of these changes is that the annual cost of our bushfire liability insurance premiums is increasing markedly year-on-year. Recent events such as the Hawaii fires are contributing to increasing premiums. We have also seen market conditions for bushfire liability insurance, become more volatile and further global developments such as the January 2025 Los Angeles fires may further impact our forecast. As such we are proposing the amount of bushfire liability insurance premium costs above the base year (trended forward by the rate of change) as a step change.

Importantly, we have moderated our forecast of insurance premiums by assuming we can continue to utilise AusNet's Captive Insurer during 2026-31, which helps keep costs down (as demonstrated by the lower of the two forecasts shown in the figure below, which we have adopted). We also increased our deductible from C-I-C to C-I-C at the last reset, further moderating our bushfire liability insurance premiums.

While we have underspent the current regulatory period insurance allowance due to changes in market conditions, customers will share the benefit of this underspend through a lower base year – the impacts on the opex allowance of underspending in the base year far outweigh (-$21.7m over five years) the proposed step change (+$10.5m)

Figure 7-16: Actual and forecast bushfire liability insurance premiums ($m, nominal)

C-I-C

This cost increase, which we consider is material, is consistent with the AER's step change framework as it is driven by a major external factor and is not funded through any other component of the opex forecast. Adjustments have been made to deduct the effects of the trend parameters from the step change.

AusNet is committed to revisiting the need for and magnitude of this step change in our Revised Regulatory Proposal (after the next renewal process which is expected to be in October 2025), given the volatility of market conditions which can materially impact insurance premium forecasts.

For further information on the insurance market and forecast premiums refer to Appendix 7D - Lockton Insurance Report and Forecast.

Table 7-29: Insurance Step Change forecast ($M, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Insurance	1.8	2.0	2.1	2.2	2.4	10.5

7.9.12. AEMO NEM Fees

New Regulatory Obligation

AEMO recovers its costs in full from energy market participants in the form of Participant Fees, the structure of which are set every 5 years, with the next period beginning from 1 July 2026. To date, AEMO has not levied a share of these fees on distribution businesses, but this may change over time. We have not included a step change in this Regulatory Proposal, but we will include one in the Revised Regulatory Proposal if AEMO indicates we will be being charged Participant Fees from 1 July 2026.

Specifically, in relation to the NEM 2025 Reform Project (which is a Declared NEM project for which AEMO is required to consider the fee structure out-of-cycle) AEMO states:

> *AEMO will continue to monitor the progress of the implementation of the NEM2025 Reform Program to identify if there is a need to charge this Participant category in the future in line with the fee structure principles and NEO.*[113]

AEMO has indicated that it will commence consultation on the structure of Participant Fees that will apply for the period 1 July 2026 to 30 June 2031 in early 2025. This timing should allow us to include a reasonable forecast of AEMO fees (if any are assigned to distributors) in our Revised Regulatory Proposal.

Any cost increase would be consistent with the AER's step change framework as it is driven by a new regulatory obligation and is not funded through any other component of the opex forecast.

[113] *AEMO, Structure of Participant Fees for AEMO's NEM2025 Reform Program Draft Report and Determination, June 2023, p.22*

7.10. Bottom-up Forecasts

7.10.1. Guaranteed Service Level (GSL) Payment

AusNet is subject to Guaranteed Service Level (GSL) payments under the Electricity Distribution Code of Practice (EDCOP) which is administered by the Essential Services Commission (ESC) of Victoria. The GSLs establish minimum standards for appointments, new connections, supply restoration, sustained and momentary interruptions, and include a specific payment for Major Event Days. If we do not meet these standards for any customer, the Code mandates that we compensate them with a GSL payment.

We have projected our GSL payments based on the average of actual GSL payments over the past 5.5 years (2019 to 2024), broadly in line with the approach approved by the Australian Energy Regulator (AER) for the 2021-26 electricity distribution price review and the preceding period of 2016-2020. These actual GSL costs are shown in the figure below.

In response to feedback from our Benchmarking & Opex Panel we have committed to covering the costs of GSLs that are within our control such as missed appointments and delays in processing connections from our own bottom line, acknowledging that the actual amount absorbed will depend on our performance, which we expect to improve. In addition, we have made a deduction to GSLs for the benefits of our proposed reliability investments program. This adjustment accounts for the delivery timing of these projects and when the benefits are expected to be realised. By making these commitments, we are absorbing approximately $4.8 million of opex over the 2026-31 regulatory period.

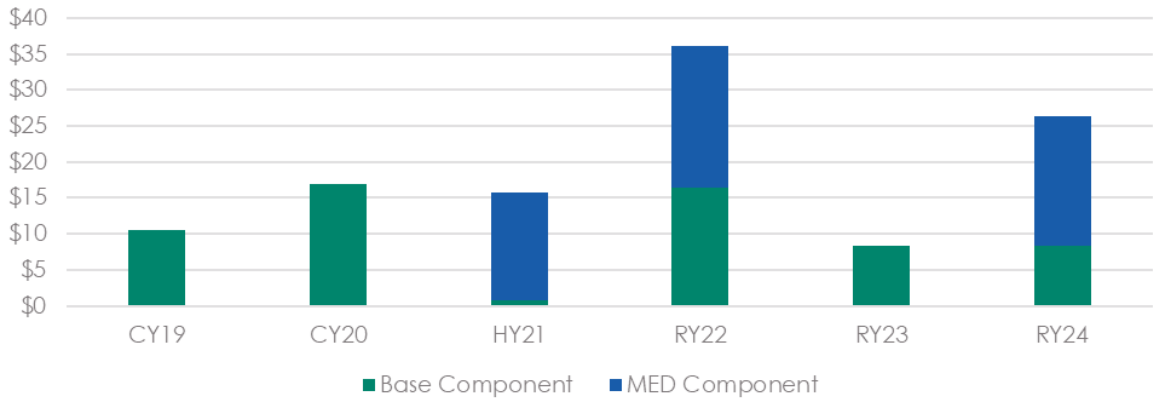
For any months and years preceding the change in the ESC's GSL payment schedule in mid-2021, AusNet has recalculated GSLs using actual outage data, to be consistent with the GSL scheme that applied from July 2021. To avoid a double recovery of costs, we have excluded the amounts recovered via pass through applications for the June 2021, February 2024 and the September 2024 major storm events[114] from the historical costs used to forecast GSLs (noting the September 2024 pass through application is currently being considered by the AER). Consistent with this, we expect the Major Event Day payment associated with potential, future events that meet the cost pass through threshold will be recovered as part of future cost pass through applications.

GSL amounts included in recently approved and submitted pass through applications are as follows:

- June 2021: $22.2 million (nominal).
- February 2024: $18.6 million (nominal).
- September 2024: $7.0 million (nominal).

We also note that the ESC may undertake a review of the current GSL scheme during the remainder of the reset process. If this occurs, we will seek to adjust our forecast GSL expenditure to account for any changes to the scheme.

Figure 7-17: Actuals and recast values of GSLs ($m, real 2025-26)



Source: AusNet

Supporting document 'Accumulated Workbook for Opex and Step changes' outlines the workings of the GSL forecast and recast values used for CY19, CY20 and HY21.

[114] Note that AusNet did not recover October 2021 storm GSLs through a pass-through application. This is a different approach to other recent storm events that have been subject to cost pass throughs. Therefore, we are seeking to recover the MED GSL payments associated with the October 2021 storms through the 2026-31 opex allowance.

Table 7-30: GSL cost forecast ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
GSL cost	11.1	10.8	10.7	10.7	10.7	54.0

Source: AusNet

7.10.2. Debt Raising Costs

AusNet has calculated the debt raising cost allowance based on the AER's standard benchmark approach. The forecast opex is shown in the table below:

Table 7-31: Debt raising cost forecast ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
DRC costs	3.0	3.1	3.3	3.5	3.7	16.6

Source: AusNet

7.10.3. Innovation

Our proposal for innovation involves expenditure of $15 million ($2023-24) over the 2026-31 regulatory period. This consists of $7.7 million ($2025-26) of opex which would fund 7 strategic innovation projects that are expected to deliver significant customer benefits.

The projects are all focused on unlocking potential benefits to customers from the current energy transition, driven by customers' strong take up of consumer energy resources (CER). As the energy transition progresses, we expect customer experience and services will become increasingly complex and will evolve over time. It is important that we are able to test and research possible ways in which we evolve our services, tariffs and ways in which we operate, to ensure we continue to meet customer expectations and that we are able to operate in a way that improves efficiency.

Consistent with the innovation fund for the 2021-26 regulatory period, we are proposing the following funding arrangements for the 2026-31 innovation projects:

- The innovation expenditure will only be available for the 2026-31 regulatory period. This means, for example, that the opex element would not become a permanent part of our base year opex.
- A 'use it or lose it' arrangement will apply, which means that we will return any funds that are not spent during the 2026-31 regulatory period to customers (at the end of the 2026-31 regulatory period). The 'use it or lose it' provision would apply to the total innovation allowance over the 5-year period, rather than operating on an annual basis, to allow smoothing of expenditure from year to year.
- Through the exclusions we have proposed in Chapter 13, the Capital Expenditure Sharing Scheme and the Efficiency Benefit Sharing Scheme will not apply to the innovation expenditure.

Further information can be found in Chapter 8 of our proposal.

Table 7-32: Innovation expenditure forecast ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Innovation expenditure	0.3	1.3	1.8	2.2	2.1	7.7

Source: AusNet

7.11. Trend

7.11.1. Rate of Change

The rate of change applied to the base year opex for each year of the upcoming regulatory control period accounts for anticipated real increases in labor and materials costs, opex increases due to network growth (scale escalation), and expected changes in productivity. Following the AER's Expenditure Forecast Assessment Guideline, we calculate the rate of change using the formula:

Rate of change = output growth + real price growth – productivity growth

The table below presents our proposed rate of change escalators:

Table 7-33: Rate of change forecast in opex model (%)

Component	2026-27	2027-28	2028-29	2029-30	2030-31
Output growth	0.89%	1.12%	1.80%	1.81%	1.79%
Real price growth	0.55%	0.49%	0.61%	0.72%	0.60%
Productivity growth	-0.50%	-0.50%	-0.50%	-0.50%	-0.50%
Rate of change	**0.93%**	**1.11%**	**1.90%**	**2.03%**	**1.89%**

Source: AusNet

7.11.2. Real Price Growth

The real price growth accounts for the expected increases in labour rates along with the escalation in the price of materials. The weighting of each is sourced from 2024 benchmarking report from the AER, which applies weights of 59.2% and 40.8%, respectively, to labour and non-labour inputs.

7.11.2.1. Labour Escalation

We have applied the AER's standard approach to forecasting real wage growth (i.e. wage growth above actual CPI), which involves an average of two WPI growth forecasts for the electricity, gas, water and waste services (EGWWS) – a forecast commissioned by the network (in this case, we have used Oxford Economics Australia – see Appendix 7A) and one commissioned by the AER (recently changed to Deloitte). These will be updated through the reset process, and we expect these forecasts to account for EBA outcomes as they are finalised. However, escalation based on the EGWWS will not be as high as the EBA increases we incur in practice, as other, non-electricity sectors are included which typically experience lower labour cost growth. We have estimated our exposure to EBA-based labour costs increases during 2026-31 at $20m, which we will incur. Under the AER's standard approach, these costs must be funded through productivity savings that are additional to the 0.5% opex productivity factor .

The AER's current approach to real labour escalation has been in practice for almost 10 years. However, DNSPs have seen emerging cost pressures across the country reflecting EBA outcomes. The NSW networks have recently been in EBA negotiations. EQ and SAPN have also recently entered into EBAs higher than the AER's labour escalators.

Table 7-34: Wage Price Index (WPI) forecasts

Component	2026-27	2027-28	2028-29	2029-30	2030-31
Oxford Economics Australia	1.16%	0.97%	1.25%	1.35%	1.20%
Deloitte Utilities Aus Placeholder	0.70%	0.70%	0.80%	1.10%	0.84%
Average	0.93%	0.84%	1.03%	1.22%	1.02%

Source: AusNet

7.11.2.2. Non-Labour Escalation

For the 2026-31 period, we have forecast that non-labour costs, including materials, will increase at the same rate as CPI. Although there is evidence that material costs will continuously increase above inflation, given the demand associated with the energy transition both locally and globally, the outlook to 2031 is uncertain.

Recognising this uncertainty, we have proposed cost pass through that would be triggered by a major disruption to the supply chain necessary to AusNet's operations arising because of, but not limited to, outbreak of war or pandemic, sanctions or trade restriction. We propose when assessing a major supply chain pass through, the AER would have regard to the difference in the forecast inflation used by the AER in its Final Decision and actual inflation, commodity prices and product price indexes (PPIs).

7.11.3. Output Growth

We have applied the AER's standard approach to output growth.

Our strong customer growth will lead to expansion in network assets and network costs. The AER utilises a standardised methodology to calculate incremental opex costs relating to network growth, based on the below measures:

- Customer numbers
- Circuit length, and
- Ratcheted maximum Demand (RMD).

We agree with the methodology set out by the AER and that output growth should be factored into our opex forecasts as an efficient estimate.

Over the 2026-31 regulatory period we are forecasting a 9% increase in customer numbers, 8% in RMD and 3% in circuit length. For internal consistency, our forecast of customers and circuit length excludes any potential customers that transition to Stand Alone Power Systems (SAPS), based on our SAPS proposal (discussed in Chapter 6).

We have adopted the output weights in 2023 benchmarking standards and NSW decisions for the proposal.

Our proposed output growth assumptions are set out below:

Table 7-35: Output parameters rate of change (%) forecasts

Component	2026-27	2027-28	2028-29	2029-30	2030-31
Customer numbers	1.76%	1.73%	1.71%	1.70%	1.68%
Circuit length	0.59%	0.65%	0.65%	0.66%	0.64%
Ratcheted maximum demand	0.00%	0.58%	2.32%	2.36%	2.34%

Source: AusNet

7.11.3.1. Customer Numbers

The customer number forecast is consistent with our connections capex proposal and reflects net customer growth, adjusted for proposed SAPS rollout.

7.11.3.2. Circuit Length

The circuit length is an estimation based on the long-term average growth rate from 2006 -2023, less the SAPS investment circuit length that will be removed. The amounts for each year can be found in the supporting document.[115] We will look to update these lengths for any further expected network augmentation in the revised Regulatory proposal.

7.11.3.3. Ratcheted maximum Demand (RMD)

RMD is the historical high non-coincident summated raw system annual maximum demand on the network from the transmission connection point. The forecast of this output reflects our demand forecasting methodology discussed in Chapter 4. Our RMD forecast reflects a 30%/70% weighting of our Probability of Exceedance 10% and 50% demand forecast. This is consistent with the approach used to calculate forecast peak demand as part of augmentation project economic assessments. In turn, the augmentation planning approach aligns with AEMO's Victorian electricity planning approach:

> *"The probability is determined based on probabilistic market simulations considering the following uncertainties:*
>
> - *Demand forecasts, 50% POE and 10% POE (with a 70% and 30% weighting respectively)."* [116]

Why our RMD approach best meets the opex criteria

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[115] Accumulated Workbook for opex and step changes
[116] victorian-electricity-planning-approach.pdf , June 2016

While we recognise a P50 forecast is typically used to forecast RMD for output growth purposes, we have reassessed this issue and consider that this approach leads to a mismatch between the opex and capex forecasts.

In contrast, our RMD calculation approach is internally consistent with the approach taken in our augex project economic assessments, which reflects industry-best practice for network planning. As this weighting is the basis on which we plan and build the network, it should also be used to estimate incremental opex associated with network growth. will also drive our opex. Proposing an alternative weighting would lead to a mismatch in our forecasting approach and as such do not represent the most appropriate growth rates in the opex required to efficiently operate our network. AEMO also state in their Victorian electricity planning approach that they utilise a probabilistic approach to assess the market impact of network limitations with a demand forecast of POE50 and POE10 which follows the same weighting.[117]

Our weighted approach is also consistent with the opex criteria, which require the opex forecast to reflect "a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the operating expenditure objectives."[118] Given it is based on accepted, good industry practice for network planning to address expected demand growth, our proposed RMD forecast therefore better reflects a realistic expectation of demand forecast during the 2026-31 period than alternative approaches.

7.11.4. Productivity Growth

The AER's standard approach is to commit to a productivity growth factor of 0.5%, which best reflects the opex productivity growth that an electricity distributor should be able to achieve.

We have included a 0.5% productivity growth factor in our proposal, which is equivalent to $21.8m. To respond to feedback from our Benchmarking & Opex Panel that the productivity growth factor should be 1%, and address affordability concerns across our customer base, we have supplemented this with several affordability measures, including:

- Negative step changes associated with Digital capex initiatives and fleet electrification ($5m).
- ADMS phase 2/DERMS opex being absorbed ($4m).
- Applying the 0.5% productivity adjustment ($4m) to capitalised network overheads.
- Adopting the AER's preferred labour escalation approach despite estimating an exposure of around $20m associated with EBA-driven labour cost increases.

Together these adjustments accumulate to approximately $33m of additional costs that we will need to fund through productivity savings during 2026-31.

7.12. Why our opex forecasts satisfy the Rules requirements

We have developed our operating expenditure forecasts based on explicit feedback received through our engagement process and to align with the operating expenditure objectives (NER cl 6.5.6(a)) and criteria (NER cl 6.5.6(c)) and the NEO. We have taken several proactive measures to ensure our forecasts are both prudent and efficient, as outlined below. In summary, our approach to developing our opex forecast has been guided and supported by:

- **AER's preferred forecasting methodology**: Our forecasting approach is consistent with the AER's Base-Step-Trend methodology.
- **Use of an efficient base-year**: We have selected 2022-23 as the base year on the basis that it reflects a stable and efficient level of expenditure in accordance with the operating expenditure criteria under the NER. Benchmarking confirms we are an efficient business relative to peers, even after accounting for unique factors

[118] NER cl. 6.5.6(c)(3)

such as extreme weather events and our lower customer density, which unavoidably influences costs.119 This ensures that our opex forecasts reflect reasonable costs for a network of our size and circumstances.

- **A rate of change using the AER's standard approaches**.120 The rate of change parameters reflect the forecasts underpinning our capex forecast. To ensure our total opex forecast reflects no more than efficient costs, we have netted trend growth from our proposed step changes.
- **Undertaken rigorous engagement and have included step changes supported by our customers or required to meet obligations.** Our positive steps changes are required to manage new regulatory obligations, appropriate capex/ and opex substitutions121, as well as external factors outside our business control. We have also identified a customer-driven initiative in response to customers telling us that they support investment in enhanced customer services to address their concerns regarding the need for targeted and dedicated support systems. Where material, new opex associated with capex also warrants positive step changes.122
- **Proactive pursuit of measures to address affordability concerns**: In addition to incorporating positive step changes, we have also proactively identified two negative step changes, to reflect the efficiency savings our investments in new Digital capabilities and electric vehicles will deliver. In total, we propose to fund $33m of opex that we expect to incur through productivity and efficiency savings, contributing to the prudency and efficiency of our total opex forecast.

7.13. Supporting Documentation

We have included the following documents to support this chapter:

- ASD - Operating Expenditure Model -31 Jan 2025
- ASD - AusNet - Accumulated Workbook for Opex and Step Changes -31 Jan 2025
- ASD - AusNet - Customer relationship manager and broad communication campaign - 31 Jan 2025 - PUBLIC
- ASD - Victorian Government - VEBM Ministerial Order Stage 1 & 2 - 31 Jan 2025 - PUBLIC
- ASD - Energy Safe Victoria - Request to submit revised bushfire management plan - 31 Jan 2025 - PUBLIC
- ASD – AusNet - Emergency preparedness and response step change - 31 Jan 2025 - PUBLIC
- ASD - Labour price growth forecast - 310125
- C-I-C
- ASD - Deloitte Access Economics - Labour price growth forecast - 31 Jan 2025 - PUBLIC
- ASD - AusNet - Hazard tree program BC - 31012025
- ASD - AusNet - Hazard tree program economic model – 31012025
- ASD - Oxford Economics Australia – Labour cost escalation report and forecast - 31 Jan 2025 - PUBLIC
- ASD - AER - AusNet approved Emergency Backstop Mechanism pass through - 31 Jan 2025 - PUBLIC
- ASD - AusNet - Benchmarking Proposal - 31 Jan 2025 - PUBLIC
- ASD - Lockton - Insurance Report and Forecast -31 Jan 2025

[119] NER, cl 6.5.6(e)(5A).
[120] NER, cl 6.5.6(e)(6).
[121] NER, clause 6.5.6(e)(7)
[122] NER, clause 6.5.6(e)(5A).

8. Innovation

8.1. Key points

The key points in this chapter are:

- We are proposing a $15 million ($2024) innovation fund during 2026-31, which is an increase compared to our current $8m ($2024) fund in 2021-26. We are seeking more funding to help us address rapidly arising challenges from the current energy transition and in the goal to achieve Net Zero targets.
- Our 7 innovation projects within the proposed fund fall into two key themes—smarter network management and new customer services and tariffs—all focused on delivering customer benefits such as increased network utilisation (and lower unit cost of electricity), lower network costs in the long term, and enabling customers to maximise the value they can achieve from their investments. Our EDPR stakeholders and Innovation Advisory Committee support our expanded innovation ambition.
- The innovation fund is in addition to the proposed Demand Management Innovation Allowance (DMIA), for which the AER sets the value. Our proposed projects under the DMIA are focused on managing the increasing risk of peak demand during winter, largely driven by electrification.
- We have a strong track record of delivering innovation projects, from inception to scalability, including our Flexible Exports trial delivered during 2021-26. We also have a strong track record of successfully obtaining external funding for industry-leading innovation, including most recently: project EDGE (Energy Demand and Generation Exchange—ARENA funded collaboration between AusNet, the Australian Energy Market Operator (AEMO) and aggregators; and project Electri-fair-cation which has received funding from the Victorian Government.
- We propose to maintain our strong governance arrangements with our Innovation Advisory Committee (IAC), to provide ongoing customer focus and technical expertise, provide input and feedback to inform the prioritisation and delivery of our innovation projects, and to strengthen coordination across the Victorian distribution businesses and systematic sharing of innovation learnings across the industry. It is important IAC have the flexibility to introduce new projects and re-prioritise projects other than those proposed by AusNet as part of our funding proposal, to ensure currency and relevancy throughout the regulatory period.
- Consistent with the current innovation fund, the $15 million ($2024) of innovation fund is a 'use it or lose it' fund, where the funding must be used for innovation projects in the 2026-31 regulatory period or the funds will be returned to customers. This means that the fund will not be reflected in our base opex in the 2021-36 regulatory period. In addition, the proposed innovation expenditure is excluded from the operating and capital expenditure incentive schemes. This is consistent with how the DMIA operates.
- To ensure customers receive value for money, we are proposing to continue to seek external funding to leverage our funding contribution and will continue to ensure learnings from our projects are shared across the sector, to maximise the value of our investment and reduce the risk of redundant or duplicative innovation.

8.2. Chapter structure

This chapter is structured as follows:

- Section 8.3 sets out our innovation expenditure proposal, governance arrangements and industry knowledge sharing plans.
- Section 8.4 outlines our track record in innovation and summarises recent innovation programs.
- Section 8.5 outlines our engagement with customers and stakeholders to determine their views on the appropriate focus of the innovation projects and size of program.
- Section 8.6 summarises supporting documentation for our innovation projects.

8.3. Our innovation proposal

This section of the proposal outlines our $15 million ($2024) innovation expenditure proposal and strong governance arrangements to ensure the actual projects delivered under the innovation program meet customer and stakeholder expectations. This section of the proposal also explains why the innovation projects would not be funded under the existing regulatory framework.

8.3.1. Innovation expenditure proposal

As shown in Table 8-1 below, our proposal for innovation involves expenditure of $15m ($2024) over the 2026-31 regulatory period. This consists of $7.2 million of opex and $7.8 million of capex which would fund 7 strategic innovation projects that are expected to deliver significant customer benefits.

The projects are all focused on unlocking potential benefits to customers from the current energy transition, driven by customers' strong take up of consumer energy resources (CER). As the energy transition progresses, we expect customer experience and services will become increasingly complex and will evolve over time. It is important that we are able to test and research possible ways in which we evolve our services, tariffs and ways in which we operate, to ensure we continue to meet customer expectations and that we are able to operate in a way that improves efficiency.

Table 8-1: Proposed innovation projects for the 2026-31 regulatory period, $m ($2024)

	Innovation project	Capex	Opex	total
Smarter network management				
1	Leading-edge network modelling and data visibility	0.8	0.7	1.5
2	Alternative storage technologies	2.2	0.8	3.0
New customer services and tariffs				
3	Real time sharing of network data	1.0	1.0	2.0
4	CER and electrification toolbox	0.4	0.6	1.0
5	V2G for outage management	1.0	1.5	2.5
6	Tariff trials	1.0	0.5	1.5
7	Flexible demand trials for residential customers	1.3	2.2	3.5
	Total	**7.8**	**7.2**	**15.0**

The innovation projects fall into two key themes:

- **Smarter network management**—these projects are seeking to develop new ways of monitoring our low voltage (LV) network, including better visibility of asset performance and customer behaviours, to help us develop granular and detailed network models that do not exist anywhere in Australia **today**. This includes testing and better understanding different types of storage technologies, which all have different ways of providing network services such as voltage regulation. These initiatives are aimed at improving network utilisation and the efficiency of network operations over time, given we can demonstrate they add value and reduce long term costs for customers.
- **New customers services and tariffs**—includes projects that aim to test new services for customers, including flexible demand services such as managed electric vehicle (EV) charging, and new possible network tariffs, for example tariffs that incentivise dynamic EV control. We need to test these types of new services and tariffs prior to rolling them out at scale, as we do not have any evidence of customer behaviour and response that we can rely on for larger delivery programs at present.

Figure 8-1 summarises the program timelines and when we anticipate to scale up the capabilities following the planned trials.

Figure 8-137: Timeline of proposed innovation projects for the 2026-31 regulatory period

<table>
<tr><th>PROJECT</th><th>2025-26</th><th>2026-27</th><th>2027-28</th><th>2028-29</th><th>2029-31</th></tr>
<tr><td>Leading-edge network modelling and data visibility</td><td colspan="3">Trial</td><td colspan="2">Scaling</td></tr>
<tr><td>Real time sharing of network data</td><td></td><td colspan="3">Trial</td><td>Scaling</td></tr>
<tr><td>Alternative storage technologies</td><td></td><td></td><td></td><td colspan="2">Trial</td></tr>
<tr><td>Flexible demand trials for residential customers</td><td colspan="2">Trial</td><td colspan="3">Scaling</td></tr>
<tr><td>Trialling new network tariffs</td><td colspan="5">Trial</td></tr>
<tr><td>CER and electrification toolbox</td><td></td><td colspan="2">Trial</td><td colspan="2">Scaling</td></tr>
<tr><td>V2G for outage management</td><td></td><td colspan="2">Trial</td><td colspan="2">Scaling</td></tr>
</table>

The proposed expenditure profile in line with the timeline of the projects is summarised in Table 8-2.

Table 8-2: Proposed innovation fund expenditure profile, $m ($2024)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Operating expenditure	0.38	1.22	1.70	1.98	1.97	7.25
Capital expenditure	1.55	1.39	1.87	1.42	1.53	7.75
Total	**1.93**	**2.61**	**3.57**	**3.40**	**3.50**	**15.00**

Source: AusNet

More detailed information on each project is provided in the submitted Innovation Program attachment and the Innovation Program Model, including estimated project cost details.

We are proposing to increase innovation funding in 2026-31 compared to the 2021-26 regulatory period. This is to address new challenges from an energy system that is growing in complexity rapidly as we progress through the current energy transition and aim to meet Net Zero targets. Our EDPR stakeholders have supported us to expand our innovation ambition compared to the current regulatory period, contingent on meeting the innovation criteria discussed in section 8.3.6. We discuss engagement on the innovation fund and the support we have received in section 84.

It is important to note that while we have identified the likely projects we plan to undertake as part of our proposed innovation program, under our governance arrangements (see section 8.3.5) we have received strong feedback from the IAC that we need to maintain flexibility in the program for the IAC to introduce or select different projects during the regulatory period. This is because new priorities for strategic innovation may arise throughout the period without the ability to foresee those today. This is particularly likely given the uncertainty in the pace of the current energy transition. Our experience in the 2021-26 regulatory period shows this flexibility is necessary as we have already seen priorities in innovation change, which has led to very different projects being delivered compared to those identified in 2021. Therefore, we expect there will likely be changes to the final set of projects delivered by June 2031.

8.3.2. Why innovation funding is needed

The current regulatory framework does not reward investment in innovation other than for demand management, through existing expenditure criteria or incentives:

- The benefits of innovation extend to the entire market, not just our network, and to all customers. These wider benefits would not be considered in the economic case for standard network funding. In fact, the current framework actively discourages capex and/or opex that does not produce immediate benefits in terms of lower costs or improved reliability.
- As the benefits of proposed innovation projects accrue over multiple regulatory periods, the expenditure incentive schemes are not capable of properly funding innovation - even though this expenditure is essential to transition the sector to lower cost and higher customer value outcomes.
- The small scale of the innovation projects, which will test solutions in very small scale settings mean that there can be no expectation of meaningful or material impacts on the service reliability outcomes that drive incentive payments under the Service Target Performance Incentive Scheme (STPIS) or the Customer Satisfaction Incentive Scheme (CSIS).

- The DMIA is targeted at innovation related to demand management initiatives. We have allocated demand management projects to utilise the DMIA funding of approximately $4.8 million ($2025-26) in the 2026-31 period that are separate to the innovation projects listed above (see section 8.3.8).

The AER has recognised the need for ex-ante innovation funding for trials and pilots to test and explore new ideas, concepts and technology before committing to solutions and rolling these into business-as-usual activities.[123] Further, there is no explicit section within the National Electricity Rules (NER) that requires a full cost-benefit assessment of all proposed expenditure before it can be deemed efficient or in "the long-term interests of consumers" by the AER. The AER can approve all capital and operating expenditure it considers to be in the long-term interests of consumers and our innovation program would be subject to governance arrangements that would ensure only those projects would proceed.

We therefore consider our innovation funding proposal is necessary and consistent with the NER. Where we are funded to undertake these strategic innovation projects, we will continue to seek external funding to further leverage our proposed funding contribution and reduce the cost impact on our customers.

8.3.3. Funding arrangements for the innovation projects

Consistent with the innovation fund for the 2021-26 regulatory period, we are proposing the following funding arrangements for the 2026-31 innovation projects:

- The innovation expenditure will only be available for the 2026-31 regulatory period. This means, for example, that the opex element would not become a permanent part of our base year opex.
- A 'use it or lose it' arrangement will apply, which means that we will return any funds that are not spent during the 2026-31 regulatory period to customers (at the end of the 2026-31 regulatory period). The 'use it or lose it' provision would apply to the total innovation allowance over the 5-year period, rather than operating on an annual basis, to allow smoothing of expenditure from year to year.
- The Capital Expenditure Sharing Scheme and the Efficiency Benefit Sharing Scheme will not apply to the innovation expenditure.

8.3.4. Expected benefits of the innovation program

Our innovation plans are seeking to provide long-term benefits to all our customers by:

1. Lower long term network costs to customers from:
   - more efficiently managing our LV network, as more and more customers electrify and invest in CER
   - increasing network utilisation of the LV network through smarter network management and more flexible tariffs and services, which reduces the unit cost of electricity
   - use of new storage technologies for effective network support and services.
2. Enabling customers to maximise the value they can achieve from their investments from:
   - improved customer and community groups' visibility of network conditions, allowing them to make more informed decisions about their energy choices
   - having access to an easy-to-use tool that explains and simplifies CER and electrification customer choices, with a view of increasing understanding of how to unlock value while reducing impact on the network
   - better understanding the different use cases of EVs, including V2G to potentially reduce the impact of outages
   - willingness to shift usage and allow network or third party managed devices within the home, to reduce bills and contribute to overall lower costs in the long term.

The expected benefits of each propose innovation project are summarised in Table 8-3. We have not quantified the potential benefits of the projects as we cannot reliably estimate the long-term benefits these projects may deliver, given the novel nature of each project and without the research and development necessary to provide certainty of value. Our projects aim to test the hypothesis of the customer benefits as described in Table 8-3, and as such assist in plans for large scale deployment in the regulatory periods following 2026-31. Further detail on how these benefits can be measured in the future is included in the Innovation Program attachment.

Table 8-3: Expected customer benefits of the proposed innovation projects

Project	Customer benefits

[123] AER, Final Decision Ausgrid Electricity Distribution Determination 2024 to 2029 (1 July 2024 to 30 June 2029), page vi.

Data driven network modelling	**Lower network cost**—Enhanced accuracy of network models as a foundation for a multitude of operational and planning functionalities, facilitating optimal resource allocation and investment decisions. This includes advanced grid management techniques, such as demand response and voltage optimisation, to improve network utilisation and efficiency and asset management optimisation, resulting in improved resilience and reliability.
Alternative storage technologies	**Lower network cost**—reduces need for network augmentation where alternative storage technologies can provide network support and customer services more efficiently.
Real time sharing of network data	**Maximising customer value**—empowering community energy groups and customers to make informed investment and project decisions, by providing real time access to network data and insights.
CER and electrification toolbox	**Maximising customer value**—empowering customers on their CER and electrification journey, by providing easy to use simple tools to help them make informed decisions, including about their interaction with the network and what costs they may experience, e.g., for supply upgrades.
V2G for community resilience	**Maximising customer value and lower network costs**—allowing customers to get the most value out of their EV investment, by being rewarded for the storage and export capabilities of their vehicles and smart chargers, while also allowing networks to utilise this technology to improve customer outcomes during storms and reduce the cost of network and community resilience.
Tariff trials	**Maximising customer value and lower network costs**—allowing customers to reduce bills directly through tariff response, while also improving network utilisation and reducing long term network costs.
Flexible demand trials for residential customers	**Maximising customer value and lower network costs**—allowing customers to earn rewards for the flexibility of their electricity devices such as EVs, while increasing network utilisation and reducing long term network costs.

8.3.5. Governance arrangements

We propose to maintain the existing governance arrangements for our current 2021-26 innovation program into 2026-31. In 2021 AusNet set up an Innovation Advisory Committee (IAC) as a governance body to help ensure customer perspectives help shape the design and prioritisation of our proposed innovation projects, including projects under the innovation fund and the Demand Management Innovation Allowance (DMIA).

IAC's remit, which was refined and agreed with IAC in November 2024, includes:

- Engage on the selection, design and prioritisation of AusNet's electricity distribution innovation program.
- Provide a forum for AusNet to partner and collaborate with consumer advocates and represent customers voices, placing the customer at the centre of investment decisions as we transform our network.
- Inform and shape our innovation program engagement activities to ensure we deliver best practice, fit for purpose engagement.
- Propose additional initiatives for AusNet and the IAC's consideration.
- Ensure that AusNet's innovation plans deliver long-term benefits to customers, and that AusNet's looking for opportunities to maximise ancillary benefits of innovation spending.
- Ensure that all innovation lessons and outcomes for each innovation project are communicated to the broader industry.

IAC's governance is summarised in the Figure below.

Under IAC, customers remain at the heart of the governance process through:

- Customer engagement and research to inform innovation project design and delivery.
- Maintaining a focus on innovation projects delivering customer benefits.
- Enabling customers and community groups to propose projects for the innovation fund.

Figure 8-238: IAC governance

IAC Members
- Dean Lombard, Independent
- Damian Sullivan, Brotherhood of St Laurence
- Jo Witters, Independent
- Scott McKenry, Eastern Alliance for Greenhouse Action
- Heather Smith, Chair Coalition for Community Energy
- Emma Chessell, Independent

Technical advisors
- Nando Ochoa Pizzali, University of Melbourne
- Tom Bakker, Aurecon
- Clean Energy Council

Observers
- CitiPower, Powercor and United Energy
- Jemena

AusNet members
- Charlotte Eddy, General Manager Strategy and Regulation (Distribution)
- Ana Erceg, Manager Grid Evolution
- Engagement specialists

IAC is already well established and has significantly contributed to the delivery and success of our innovation program in 2021-26 (see section 8.4). This includes providing oversight of the innovation project pipeline, funding, knowledge sharing and direct input into design of the projects. While not originally envisaged when the IAC was set up, some members of the IAC put in a proposal for a project to be considered for funding under the innovation fund, with a strong focus on better understanding customer impacts from electrification. This was adopted by AusNet and initiated the Electri-fair-cation project. We have received feedback from IAC since its inception in 2021 that flexibility in project selection is extremely important, to allow them to provide genuine input to shape AusNet's innovation strategy and delivery. We plan to maintain IAC's remit for 2026-31, which means not all projects proposed for the funding may go ahead exactly as set out in our plans.

8.3.6. Innovation project criteria

The projects meet the criteria developed for the 2026-31 regulatory period with IAC. We engaged with IAC to review the criteria that applied in 2021-26 and whether any changes are needed, particularly in light of the energy transition which has accelerated since the criteria were first developed between AusNet and the Customer Forum. The updated criteria directly reflect IAC's input and comments, and are as follows:

1. Seek to deliver benefits and outcomes to customers, driven by equity, needs and expectations
2. Customers see value in outcomes delivered
3. Flexibility and agility to meet network challenges and opportunities posed by the energy transition
4. Projects build on (but do not duplicate) existing trials and learnings
5. Represent strategic innovation
6. Involve collaboration and knowledge sharing with industry and other partners, e.g., industry, academia, community organisations and others
7. Project would not be funded under the incentive schemes.

We outline in the Innovation Program attachment how the projects meet the criteria.

8.3.7. Industry knowledge sharing

We recognise that many networks are investing in innovation and there is a need to coordinate innovation activities to reduce overlap and redundant trials. We have received strong feedback from our Future Network Panel and Coordination Group that our projects should be genuinely innovative and that any learnings should be shared broadly with other distributors and the industry, to reduce the risk of overlapping innovation initiatives.

We already have extensive knowledge sharing practices for our current innovation program, including:

- webinars and presentations, and public case studies and learnings summaries, published on the Innovation page on our website and the Community Hub page
- Energy Network Australia (ENA) annual Future Network Forum, including knowledge sharing sessions and webinars

- specific industry Reference Groups for each innovation project
- industry and distributors road-shows
- presenting at industry conferences
- presenting at universities and research institutions
- presenting directly to other distributors and other interested parties, as requested
- presenting to local councils in areas where the projects are being implemented
- Inviting other Victorian distributors to our IAC meetings as observers.

Our innovation team is also heavily involved and interested in other distributors' knowledge sharing sessions, and opportunities for collaboration. For example, AusNet's Flexible Exports trial funded by the 2021-26 innovation fund started through a knowledge sharing session and collaboration opportunity with SA Power Networks, who carried out a similar trial although with key differences specific to each jurisdiction.

We also contribute to, and have access to, the ENA's online knowledge sharing platform (library), known as Knowledge Bank. This library contains useful research papers, customer benefit analysis and other relevant information. We use the information contained within the online knowledge sharing platform (as do our peers) to access and consider information that has the scope to help us undertake innovative work, including preparing proposals.

We plan to continue to use these channels and explore other knowledge sharing channels, to share learnings from our innovation projects in 2026-31.

8.3.8. DMIA proposal

The AER's final Framework and Approach Paper for Victorian distributors for 2026-31 outlines that they plan to apply the DMIA. We endorse this decision and have proposed the DMIA amount as per AER's approach to setting this allowance for each distributor. The proposed DMIA is shown in Table 8-4.

Table 8-4: Proposed DMIA, $m ($2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
DMIA	0.87	0.92	0.94	0.98	1.05	4.76

Source: AusNet

We plan to include projects under DMIA that are mostly focused on managing peak demand in winter months, which is becoming a new challenge for our network—we forecast to become a winter peaking network by 2027.

While we have not forecast or developed our DMIA projects in advance for the regulatory proposal, as we expect flexibility in choosing projects during the regulatory period to meet emerging needs, we have outlined below where we anticipate more innovation may be required in relation to demand management:

- **Minimum demand management with large customers**—maximising customer value and lower network costs—providing opportunities for large customers (including new types of customers like data centres) to save on energy bills while lowering network costs in managing high solar output during the day and low demand.
- **Critical peak pricing for large customers in winter**—maximising customer value and lower network costs—providing opportunities for large customers (including new types of customers like data centres) to save on energy bills while lowering network costs in managing new winter peaks from electrification.

8.4. Track record in innovation

This section provides information on our track record of success in delivering innovation, including through our 2021-26 innovation fund. This provides strong confidence in our commitment to innovation and our ability to deliver.

Since 2021, we have initiated and participated in several marquee innovation projects, which provide significant industry learnings, have driven policy design and have brought genuine innovation into our operations and services we offer to customers. Figure 8-3 briefly highlights six innovation initiatives that have been completed or are currently under way.

Figure 8-339: Marquee innovation projects delivered since 2021 or currently underway

Flexible Exports

Flexibility through dynamic operating envelopes, dynamic connection agreements and IEEE2030.5 communications standards. Provides constrained customers with a dynamic export option.

The trial was completed in 2023, with customers on the trial continuing to receive Flexible Exports. The learnings will be used in roll-out across our network at scale from 1 July 2026. The trial has also informed AER's Flexible Exports Guideline design and the Victorian Government policy on Emergency Backstop Mechanism and Flexible Exports.

Funded through the innovation fund.

Project EDGE

ARENA-funded trial with AEMO and aggregators, trialling the use of dynamic operating envelopes through a common platform, and the potential for network support services from aggregators to be shared through this platform.

The trial was completed in 2023. Learnings from this trial have been shared broadly with the industry, through various industry forums, conferences and knowledge sharing documents. The next phase is the ARENA-funded CER Data Exchange Industry Co-Design (the platform trialled during EDGE) which is currently run by AEMO with AusNet supporting.

Electri*fair*cation

Trialling the process and impact of electrification of households with vulnerabilities, including understanding impact on local network, for network planning purposes.

The project was suggest by members of our IAC, and initiated in 2023. The trial is located in Morwell, and is anticipated to run until 2026. Knowledge sharing includes presenting at conferences, industry forums and through a diverse set of stakeholders on the project reference group, including government departments leading electrification initiatives.

Funded through the innovation fund with some funding from the Victorian Government, in the form of subsidies for households that are electrifying.

Transformer monitoring

Trialling the feasibility of using smart meter data and advanced analytics as virtual transformer monitor instead of installing monitoring devices on transformers.

The trial was completed in 2024 by successfully demonstrating analytics can be used to displace investment in transformer monitors. The learnings from this trial have been shared through industry forums and will be used in the next phase of trialling leading-edge network modelling, using trialled analytics.

Funded through the innovation fund.

Innovative tariff trials

Several tariff trials with a focus on increasing network utilisation and smoothing out maximum and minimum peaks, including:

* Dynamic electric vehicle tariff for customers with home smart chargers, rewarding charging during the day and dynamic response

* Trialing how industrial customers may respond to moving consumption to times of solar exports

* Four new storage tariffs with rewards for evening exports.

Funded through the innovation fund.

Pole top batteries

Trialling the use of pole top batteries in AusNet's network to manage network constraints, including export constraints and peak demand. The batteries are leased to third party with a ring-fencing waiver.

While pole top storage has been trialled in other jurisdictions, it requires AusNet to trial how the technology interacts with our control systems, as many networks use different controls systems and have network-specific configurations.

Funded through the DMIA, Victorian government funding, lease reveneu and capital expenditure.

All the completed or current innovation projects have a strong focus on improving customer outcomes, whether through new services and tariffs, new opportunities for customers to get value from their behaviour or investment in CER, or through operational improvements that are anticipated to lead to long term savings for customers from higher network utilisation and lower network costs.

For example, our Flexible Exports trial showed that customers on Flexible Exports can export up to 3.5kW on average using this smart technology, when they would otherwise be constrained to zero exports under the static export limit rules. This is a direct benefit to those customers who benefit from a feed in tariff, as well as wider benefits by unlocking renewable energy that would otherwise be inefficiently constrained.

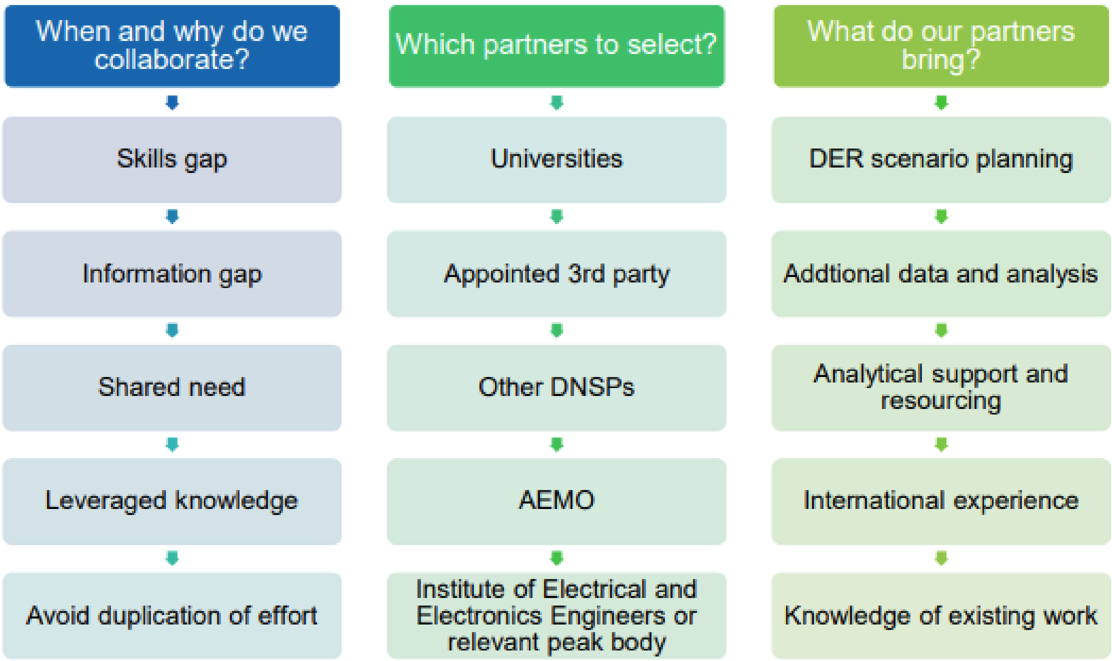
Please refer to our Innovation webpage for more detail on our current or completed projects, including the benefits unlocked.

8.4.1. Industry collaboration and shared funding for projects

Our innovation approach emphasises collaboration with other distributors and across the sector. We will continue to look for opportunities to collaborate on all our initiatives as we recognise this will minimise costs, facilitate knowledge sharing and reduce scope for duplication, maximising the potential for customer benefits to be realised.

We already have established strong collaborative partnerships with a wide range of organisations, universities and research institutions and continue to look for ways we can work with others. The choice of partners to assist with a particular project will vary depending on particular challenges and the "gaps" in our expertise. Figure 8-4 illustrates the drivers for collaboration and the partners that currently work with and support us.

Figure 8-440: Drivers and partner of collaboration



We continuously look for opportunity to get external funding to support our projects—typically external funding covers a portion of the project cost with the funding agencies seeking that all parties contribute to the cost of the project. We have a strong track record of accessing ARENA funding and other sources of funding to offset the costs of network innovation projects. We have been successful in securing external funding from ARENA (the main source of funds for energy system transformation projects) and will continue to do so while this is available. We have also been successful in obtaining Victorian government funding on several projects, including pole top batteries, Electrifaircation and microgrid development.

Using the above approach, we have established a strong and credible record of accomplishment of collaborating with our peers and the broader community to deliver best value expenditure. For example, most recently we worked with other distributors on the following innovation projects:

- In 2021, we participated in an ARENA-funded Dynamic Electric Vehicle Charging Trial, led by Jemena with participation from other Victorian distributors. The trial developed methods to further understand the impact of EV's and the network's ability to shift energy during periods of high renewable energy supply and support the network in low periods.[124]
- In 2021, we launched the industry-leading EDGE trial jointly with AEMO and Mondo (aggregator), which was then joined by other aggregators. The project was ARENA-funded and supported and has received wide attention from across the sector. In 2024, we also joined AEMO in the subsequent CER Data Exchange Industry Co-Design trial, which is currently (at the time of writing) recruiting support and participation from other distributors, retailers and aggregators.
- In 2022, we engaged with SA Power Network to learn from their ARENA-funded Flexible Exports trial, which informed our Flexible Exports trial design with necessary amendments for the Victorian context. This was a very close collaboration with SA Power Networks which included regular meetings, knowledge sharing sessions and joint presentations at industry forums and conferences.
- To ensure customers receive value for money, we are proposing to continue to seek external funding to leverage our funding contribution and will continue to seek opportunity to undertake joint trials with other distributors, to maximise the value of our investment and reduce the risk of redundant innovation.

[124] More details on the trial can be found here: https://arena.gov.au/projects/jemena-dynamic-electric-vehicle-charging-trial/

8.5. Customer engagement

We have undertaken extensive engagement and research to better understand our customers' preferences regarding the focus of innovation activities, innovation program governance and innovation program size.

Our customers have told us that innovation is very important to them, with almost half of our customers rating innovation as a top priority in our Energy Sentiment survey. Many expect innovation to be business-as-usual and want AusNet to drive innovation in all aspects of services, recognising a link between innovation and finding opportunities to cut costs or improve outcomes. We also engaged with our customers on the proposed innovation program at the October 2024 Customer Workshops, where customers supported innovation for networks.

In developing our innovation proposal, we largely engaged with our IAC and Future Networks Panel on the merits of and options for an innovation program in 2026-31, and with customers in our Round 4 workshops. We heard that:

- Customers expect AusNet to be innovating. They know there is a lot of new technology around, and expect AusNet to always be looking for new and better ways to do things.
- Customers expect innovation projects to save them money longer-term. When discussed in the workshops, customers were generally comfortable with the trade-off of spending more up-front to save more later, and with the benefits being somewhat uncertain on a project-by-project basis but ending up better off over time.
- Funding innovation for regulated monopolies is important, as monopolies do not have the same incentives to undertake riskier research and development as competitive businesses.
- Innovation funds should have the flexibility to change projects during the regulatory period. This flexibility is seen to be critical to the success of an innovation program. Several made the comment *"If a project can be decided now for 2031, it's definitely not innovation."*
- Crowdsourcing ideas was very popular especially in our customer workshops. Customers made the great point that good innovation ideas can come from anywhere, and we will be working more channels for customers and stakeholders to suggest projects in the governance model.
- AusNet should be more ambitious in innovation, with support for a larger innovation fund that is focused on genuinely innovative projects that are likely to deliver customer benefits. When considering trade-offs between bill impacts to customers and innovation fund size, our EDPR stakeholders support a larger fund.
- It is important to maintain the current governance arrangements for transparency and trust, particularly as some projects may not be successful and it is important to be transparent around those as well.
- The criteria for innovation projects agreed with the Customer Forum in 2021-26 continues to apply and should drive innovation investment in 2026-31.
- It is important that benefits from innovation are tangible to customers, i.e., the benefits and merits of the program need to be explained in terms that customers can understand and how they would see the benefits.
- Sharing innovation learnings and strategies between distributors will facilitate more innovation, however there was recognition there may need to be diversity in approaches to accommodate differences between the networks.

The Innovation Program attachment summarises the engagement and outcomes in more detail, and how we have taken that engagement into account in shaping our innovation proposal.

8.6. Supporting Documentation

We have included the following documents to support this chapter:

- Innovation Program.
- Innovation Program Model.

9. Regulated Asset Base

9.1. Key points

The key points in this chapter are:

- The Regulatory Asset Base (RAB) has been calculated in accordance with the Rules provisions and the AER's Roll Forward Model (RFM) and Post Tax Revenue Model (version 5) (PTRM).
- Our opening RAB for the forthcoming regulatory period includes a proposed roll-in amount for new asset class 'Critical spares -network assets'.

9.2. Chapter structure

This chapter is structured as follows:

- Section 9.3 discusses our past capital expenditure;
- Section 9.4 explains the methodology for rolling forward the asset base values to 1 July 2026;
- Section 9.5 outlines AusNet's proposed Final Year asset adjustments included in the roll forward model;
- Section 9.6 outlines AusNet's response to several suggested changes in the roll forward model and PTRM as part of the AER's pre-lodgement engagement;
- Section 9.7 explains the derivation of the RAB values for each year of the next regulatory control period (2026-27 to 2030-31); and
- Section 9.8 lists the relevant supporting documentation for this chapter.

9.3. Review of Past Capital Expenditure

Clauses S6.2.2A of the Rules permits the AER to review past capital expenditure in certain circumstances, and exclude capex from the RAB where actual total expenditure over the review period exceeds the AER's allowance (adjusted for approved pass-through amounts), and that capex is deemed inefficient or imprudent. The relevant review period for this Ex-post review is 1 January 2019 to 31 December 2023.

AusNet has not overspent against its approved capital expenditure allowance during the review period and, as such, there is no basis for the AER to exclude capex from the RAB.

Accordingly, all the capital expenditure we incurred during the review period will be included in the RAB.

9.4. Establishing the Opening RAB as at 1 July 2026

AusNet's opening RAB has been calculated in accordance with the AER's standard regulatory approach.

As the actual capital expenditure for the final two years of the current period (2024-25 and 2025-26) is not yet known, our opening RAB estimate in this proposal reflects forecast information. The Revised Regulatory Proposal will take account of the actual data for 2024-25, but not 2025-26. An adjustment to the forecast information will need be made in the subsequent regulatory review. Similarly, the opening RAB for 1 July 2026 includes a true-up to account for actual expenditure incurred from 1 January 2020 to 30 June 2021.

The calculation of the opening RAB for 1 July 2026 therefore involves the following standard steps:

- Adopt the approved opening RAB as at 1 July 2021.
- Add actual and forecast capital expenditure (net of disposals) for the 2021-2026 regulatory period.
- Deduct the annual nominal depreciation forecast for the 2021-2026 regulatory period.
- Add the RAB indexation amount for the 2021-2026 period.
- Make an adjustment to correct for the difference between actual and forecast net capital expenditure incurred in 2020 and January to June 2021, and
- Reflect the forecast final year asset adjustments in the roll forward model, which are explained in section 9.5.

The table below sets out the RAB roll forward calculation for the current period.

Table 9-1: Regulatory Asset Base roll forward to 1 July 2026 ($m nominal)

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26
Opening RAB (1 July)	4,657.5	4,763.6	5,001.3	5,499.4	5,875.9
Plus Capex, net of disposals and contributions	341.4	332.1	385.9	451.8	442.1
Less Nominal Forecast Straight-line Depreciation	-275.4	-261.0	-279.4	-298.1	-306.3
Plus Nominal Actual inflation on opening RAB	40.1	166.6	391.7	222.8	176.3
Difference between Actual and Forecast Net Capex for 2020 and 2021					-35.5
Forgone return on difference					-13.2
Final Year Asset Adjustments					5.6
Closing RAB (30 June)	4,763.6	5,001.3	5,499.4	5,875.9	6,144.9

Source: AusNet Roll Forward Model (2021-26)

In accordance with the above calculation, our proposed opening RAB for 1 July 2026 is $6,144.9 million (nominal). As noted earlier, our opening RAB will be updated in our Revised Regulatory Proposal to reflect actual data for 2024-25.

9.4.1. Actual and forecast net capex, 1 July 2021 to 30 June 2026

The RAB roll forward calculation requires a combination of actual and forecast capital expenditure (net of contributions and disposals), as shown in the table below. Actual costs and disposals information reconcile with the nominal values reported in the Annual Regulatory Accounts. We have sourced our annual Gross Capex values for regulatory years 2021-22, 2022-23 and 2023-24 from the annual RIN data source. Our Amended RINs for years 2021-22 and 2022-23 were provided in response to an AER request as part of its pre-lodgement engagement with us on the RFM model. [125]

125 AER - AusNet Draft Plan Models Review_20241002 - ASD Amended response

Table 9-2: AusNet Net Capex, 1 July 2021 to 30 June 2026

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26
Gross Capex	359.82	347.92	391.47	484.45	489.62
Less Disposals	0.20	1.06	0.08	1.58	1.63
Less Customer Contributions	24.31	24.71	24.82	46.06	56.74
Nominal Net Capex	335.31	322.15	366.57	436.81	431.25
Net Capex recognised in RAB[126]	**341.4**	**332.1**	**385.9**	**451.8**	**442.1**

9.4.2. Regulatory Depreciation

In the current regulatory control period, AusNet applies depreciation on a forecast basis consistent with the approach required under the Capital Efficiency Sharing Scheme (CESS) incentive scheme. Economic depreciation is calculated by determining the nominal depreciation values, and offsetting the CPI indexation for each asset class. The calculation of each of these elements is set out below.

9.4.2.1. Forecast straight line depreciation, 1 July 2022 to 30 June 2026

AusNet has sourced the real $2020-21 straight line depreciation forecasts by asset class from the most recent determination for the current regulatory period, which has been updated to reflect the approved cost pass-through127. The PTRM model containing these forecasts includes the 2024-25 annual cost of debt update. These forecasts are input into the AER's standard RAB roll forward model and adjusted for actual (outturn) inflation. The table below shows the calculation.

Table 9-3: AusNet Nominal Depreciation, 1 January 2016 to 30 June 2021

$M	2021-22	2022-23	2023-24	2024-25	2025-26
Forecast Straight line Depreciation – real $2020-21	273.02	250.06	248.22	254.54	253.86
Actual / Forecast inflation	2.38	10.94	31.18	43.56	52.44
Nominal Depreciation	**275.4**	**261.0**	**279.4**	**298.1**	**306.3**

9.4.2.2. Actual and forecast indexation, 1 July 2022 to 30 June 2026

Clause 6.5.1(e)(3) of the NER requires that the established opening asset base, be adjusted for actual inflation consistently with the indexation method used in the control mechanism. AusNet has applied the definition of CPI to escalate the RAB for the current period in accordance with the approach outlined in the 2021-26 Determination, as follows:

> *"CPI is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from the June quarter in regulatory year t–2 to the June quarter in regulatory year t–1, calculated using the following method:*
>
> *The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the June quarter in regulatory year t–1*
>
> *divided by*
>
> *The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the June quarter in regulatory year t–2*
>
> *minus one."*[128]

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[126] Net Capex recognised in RAB includes a half-nominal WACC allowance

127 AusNet Services Dx PTRM – 2024-25 RoD update (inc storm and VEBM CPT), https://www.aer.gov.au/documents/ausnet-services-dx-ptrm-2024-25-rod-update-inc-storm-and-vebm-cpt

[128] AER - Final decision AusNet distribution determination - Attachment 14 - Control mechanisms – April 2021, p.25.

Figure 9-441: Actual and Forecast Inflation, 1 July 2022 to 30 June 2026

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26
1 Year Lagged Actual CPI	0.86%	3.50%	7.83%	4.05%	3.00%

For roll forward purposes, AusNet applies the 'all-lagged' inflation approach for both opening RAB indexation and converting real $2021-22 to $Nominal forecast straight line depreciation values. This is consistent with the roll forward method used in previous regulatory control periods for AusNet's Distribution RAB.

Table 9-4: AusNet Services' Opening RAB Indexation, 1 January 2016 to 30 June 2021

Nominal, $M	2021-22	2022-23	2023-24	2024-25	2025-26
RAB indexation	40.1	166.6	391.7	222.8	176.3

9.4.2.3. Economic Depreciation

The calculation of economic depreciation (nominal straight line depreciation net of RAB indexation) for the current period is shown in the table below.

Table 9-6: Calculation of economic depreciation

Nominal, $M	2021-22	2022-23	2023-24	2024-25	2025-26
Nominal Depreciation	275.4	261.0	279.4	298.1	306.3
RAB Indexation	-40.1	-166.6	-391.7	-222.8	-176.3
Regulatory Depreciation	235.28	94.39	112.28	75.29	129.98

9.5. Forecast Final Year Asset Adjustments

We are proposing two end of period adjustments, including:

- An opening asset adjustment of $7.61 million ($Nominal) for new asset class 'Critical spares – network assets'. Section 10.5 of the regulatory depreciation chapter describes this adjustment in further detail, including the justification for the proposed adjustment and the method for estimating the 1 July 2026 opening RAB value.
- Total negative adjustment to class 'Non-network Leasehold Land & Buildings – 1 July 2021' of $2.1 million ($Nominal). This adjustment includes two components:
  - The RAB final year adjustment as at 1 July 2021 updated for actual 2020 and HY2021 capex, and
  - Other net capex adjustments, which are consistent with our discussion with the AER during the pre-lodgement engagement.

Table 9-7: Proposed Final Year Asset Adjustments (30 June 2026), $Nominal

RAB Class	Proposed RAB adjustments ($M)	Remaining life of adjustments to RAB (Yrs)
Critical spares – network assets	7.61	n/a
Non-network Leasehold Land & Buildings – 1 July 2021	2.1	3.3

9.6. Pre-lodgement engagement

During pre-lodgement engagement, the AER requested confirmation on whether we agree to include a type 2 capital contribution of $24.1 million in the actual capex amount for 'Distribution system assets' for the period January to June 2021. We do not agree with this approach and have provided a detailed response to the AER as part of the pre-lodgement engagement on 10 October 2024.

While we acknowledge that our proposed approach to type 2 capital contributions has no net impact on the RAB compared to the AER's approach, it does result in a net impact on the TAB. This impact will be explained in detail in section 12.

9.7. Forecast RAB over the 2026-31 Regulatory Period

The opening RAB as at 1 July 2026 is rolled forward during the 2026-31 regulatory control period to reflect our capex forecast, forecast straight line depreciation and the indexation of the RAB. The estimated total value of our RAB increases by $2,879 million (nominal) by the close of 2026-31 regulatory period, which represents an average annual increase of approximately 8.0% over the period.

Table 9-8: Regulatory Asset Base roll forward 1 July 2026 to 30 June 2031 ($m nominal)

Regulatory Year	2026-27	2027-28	2028-29	2029-30	2030-31
Opening RAB	6,144.9	6,607.0	7,162.3	7,764.2	8,381.0
Plus capex, net of contributions and disposals	628.7	734.4	799.6	824.8	857.3
Less straight line depreciation	-320.2	-344.4	-376.8	-402.0	-423.9
Plus nominal forecast inflation on opening RAB	153.6	165.2	179.1	194.1	209.5
Closing RAB	**6,607.0**	**7,162.3**	**7,764.2**	**8,381.0**	**9,024.0**

Source: AusNet Services PTRM 2022-26

The calculations shown above are consistent with the AER's Roll Forward Model and Post Tax Revenue Model (Version 5). In accordance with clause S6.2.1(e)(4) of the Rules, only actual and estimated capital expenditure properly allocated to the provision of standard control services in accordance with our approved CAM is included in the RAB. It should be noted that the nominal capital expenditure in the table above excludes capital contributions. Customer initiated capital expenditure included in the RAB is the gross (total) expenditure minus customer capital contributions.

9.8. Supporting Documentation

The following documentation is provided in support of this chapter:

- Our proposal models, including the PTRM models, Proposal RFM model (2026-31) and Depreciation tracking model (2026-31)
- Our response to the AER's draft plan model review questions: Document entitled 'AER - AusNet Draft Plan Models Review_20241002 - ASD Amended response.pdf' (Previously submitted to the AER)
- Supporting models, including 'ASD - Connections Capex Forecast Model (2026-31) -310125 – PUBLIC', 'ASD - Energy Connections Forecast Model - 310125 – CONFIDENTIAL', 'ASD - EV Public Charging Forecast Model - 310125 – CONFIDENTIAL', 'ASD - SCS capitalised leases – transitional arrangement - 310125 – CONFIDENTIAL', 'ASD - Customer growth driven feeder augmentation - 310125 – CONFIDENTIAL', 'ASD - Critical spares list - Distribution (5-Dec-2024) - 310125 – CONFIDENTIAL', 'ASD - Lease offsetting adjustments_20241118 - 310125 – CONFIDENTIAL', 'ASD - Resubmission 2021-22 RIN A - 8.2 Capex template 030524 - 310125 – CONFIDENTIAL', and 'ASD - Resubmission 2022-23 RIN A - 8.2 Capex template 030524 - 310125 – CONFIDENTIAL'.

10. Depreciation

10.1. Key points

The key points in this chapter are:

- We are using the approach approved at the last reset for depreciating the opening RAB using the year-by-year tracking method.
- We are proposing five new asset classes to ensure our assets are appropriately categorized and depreciated, aligning with their specific characteristics and economic lives.
- Our proposed regulatory depreciation is 7% below the depreciation allowance approved for the 2021-26 Regulatory Period, on a like-for-like basis.

10.2. Chapter structure

This chapter is structured as follows:

- Section 10.3 briefly discusses our depreciation methodology
- Section 10.4 presents our proposed opening RAB depreciation over 2026-31
- Section 10.5 sets out our standard asset lives in the regulatory asset base for 2026-31, including an explanation of our proposed new asset classes
- Section 10.6 outlines AusNet's response to several suggested changes in the depreciation tracking model and PTRM as part of the AER's pre-lodgement engagement
- Section 10.7 presents our proposed depreciation allowance for 2026-31, and
- Section 10.8 lists the supporting documentation for this chapter.

10.3. Depreciation Methodology

Our proposed methodology for the 2026-31 period is consistent with the AER's determination for the 2021-26 regulatory control period. Our approach is briefly summarised as follows:

- Apply straight-line depreciation to assets contained in the opening RAB using the year-by-year tracking approach, and
- Apply straight-line depreciation to new assets that will be added to the RAB over the 2026-31 period according to their standard lives.

10.4. Opening RAB

Straight-line depreciation of the opening RAB is calculated using a disaggregated approach. AusNet has applied the AER's standardised depreciation tracking model, which uses the year-by-year tracking approach to calculate depreciation charges for the forthcoming regulatory control period. The depreciation model sets out the values, inputs and calculations used to determine forecast depreciation of the opening RAB as at 1 July 2026. The outputs from this model are included as inputs to the Post Tax Revenue Model (Version 5) (PTRM), which is submitted alongside this regulatory proposal.

Below are the proposed straight-line depreciation values for the opening RAB for each year of the 2026-31 regulatory control period, as reflected in the PTRM model.

Table 10-1: Proposed Opening RAB depreciation (2026-31), $Jun 2026

Regulatory Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Opening RAB depreciation	312.4	295.1	279.3	258.4	235.1	1,380.4

Source: AusNet PTRM (2026-31)

10.5. Standard Asset Lives

AusNet's proposed standard asset lives for new additions in the forthcoming regulatory control period are presented in Table 10-2 below. This includes standard asset lives for the five new asset classes we have proposed (discussed in the section below).

Table 10-2: Proposed standard asset lives for new additions to the RAB

Asset Classes	Standard life (Yrs)
Subtransmission	45
Distribution system assets	50
SCADA/Network control	10
Non-network general assets - IT	5
Non-network general assets - Other	5
Land	n/a
Non-network Leasehold Land & Buildings – 1 July 2021	n/a
Non-network Leasehold Land & Buildings - 2021-22	n/a
Non-network Leasehold Land & Buildings – 2025-26	n/a
Non-network Leasehold Land & Buildings – short term	5.0
Non-network Leasehold Land & Buildings – long term	20.0
Non-network solutions	15.0
Critical spares – network assets	n/a
Heavy Vehicles and Plant	15.0
Buildings – capital works	40.0
In-house software	5.0
Equity raising costs	n/a

Source: AusNet

10.5.1. New Asset Classes

We have proposed five new asset classes in the PTRM for the 2026-31 period. These new asset classes are listed and explained below.

10.5.1.1. Critical spares – network assets

Critical spares are essential components kept in inventory to ensure the electricity network remains reliable and operational during unexpected faults or emergencies. These spares allow for quick replacement and minimize downtime, which is critical for maintaining service continuity.

In the past, AusNet's electricity distribution business did not earn a return on these critical spares, as they were excluded from the RAB. We are proposing a new "Critical Spares" asset class for the 2026-31 regulatory period. This approach is consistent with the approach approved by the AER for our transmission business.

As critical spares are non-depreciable (until placed into service), we have not proposed a standard asset life for this new asset class.

Our proposed opening RAB of $7.61 million is based on a current inventory listing of Distribution network critical spares, which reflects existing volumes and material unit prices. This approach provides a representative proxy for the typical volume of critical spares held by the business, establishing the opening RAB value as of 1 July 2026. While no forecast capex is included for the 2026-31 period, we anticipate movements between Inventory and work in progress to be captured in the annual reporting RIN process.

Supporting document "Appendix 10A – accounting policy for critical spares" outlines the accounting treatment, detailing how Distribution network critical spares are recorded as Inventory and subsequently transferred to work in progress as incurred. In the RAB, critical spares will be classified as non-depreciable assets until they are transferred to work in progress.

Since these critical spares are non-depreciable, they do not add to our forecast depreciation allowance. However, including them in the RAB means that they earn a return on capital, increasing the overall revenue requirement.

10.5.1.2. Non-network solutions

We are proposing non-network capex programs (totalling $298m of capex in the 2026-31 regulatory period) to enhance network resilience, reliability, and emergency response. These solutions operate outside traditional infrastructure, offering flexible support for evolving energy demands and community needs. This mainly includes the Mobile Generation program within our resilience capex and the Alternative Storage Technologies and Operation Model program within our innovation fund.

The Mobile Generation program focuses on enhancing AusNet's ability to respond swiftly to prolonged outages and extreme weather events by deploying mobile generation assets (see Section 12 for more details). Specific assets associated with this program include:

- Mobile Generation (HV Diesel Generation Replacement): Replacement of aging diesel generators nearing end-of-life with new 1.5 MVA units, ensuring quick deployment to support communities during prolonged outages.
- Mobile Generation (Battery): Deployment of HV battery systems to enhance energy storage, providing flexibility and improved outage management capabilities alongside backup power generation.
- Mobile Generation (Portable Station): Portable stations equipped with transformers and switchgear for rapid deployment during outages, enhancing grid connectivity and supporting quicker restoration efforts.

The Alternative Storage Technologies program focuses on exploring and deploying innovative energy storage technologies to provide network support, improve energy efficiency, and manage peak demand (see Chapter 8 for more details).

Assets associated with these programs have technical asset lives between 10 to 15 years, as detailed in the table below.

Table 10-3: Technical asset lives for mobile generation and alternative storage programs

Programs	Technical Asset Life
Mobile Generation (HV Diesel Generation Replacement)	10 Years
Mobile Generation (Battery)	10 Years
Mobile Generation (Portable Station)	10 Years
Alternative Storage Technologies and Operations Models	10-15 Years

Source: AusNet

As both programs are non-network solutions, and since there is no existing asset class with a standard asset life that aligns with the technical asset lives of the assets associated with these programs, we propose a new asset class, 'Non-Network Solutions', to consolidate these assets for appropriate classification and depreciation. We propose a standard asset life of 15 years, which is set at the higher end of the technical lives of these assets, as detailed in the table above. Setting the standard asset life at the higher end of the technical asset life reduces the annual depreciation expense. In net terms, this approach minimizes the overall addition to our proposed 2026-31 revenue requirement and, therefore, smooths the customer bill impacts over time.

Our proposed 15-year standard asset life aligns with industry benchmarks. For instance, in its most recent proposal, SA Power Networks has split its mobile generation program into three asset classes, resulting in a weighted average standard asset life of 10 years, which was approved by the AER.[129]

We propose an opening asset value of zero for this new asset class 'Non-network solutions' as we are not transferring any existing assets into this class. Although it is technically possible to transfer historical capex that better fits into the new asset class, the value of such assets (which currently sits in existing asset classes with longer lives) is minimal. In addition, the modelling required for such transfers is complex. Given these considerations, we consider it more practical and efficient to not transfer any existing assets into this new asset class.

129 SAPN – 511 –AER Standardised Capex model – January 2024 – Public, https://www.aer.gov.au/documents/sapn-511-aer-standardised-capex-model-january-2024.

10.5.1.3. Heavy vehicles and plant

As discussed in non-network capex fleet section, we have proposed $134m of fleet expenditure in 2026-31 to substantially increase the size of our fleet. This reflects our recent decision to take operational control of our vehicle assets as part of transitioning our Operations and Maintenance Services Agreement to Zinfra from August 2025. Our proposed fleet purchases comprise of cars, light commercial vehicles, heavy commercial vehicles and various plant and equipment.

We propose to depreciate cars and light commercial vehicles using the existing 'Non-network General Assets – Other' asset class, in line with the technical lives of these assets.

However, to ensure our forecast depreciation schedules for the remaining vehicle types accurately reflect their technical lives, we propose to include two types of assets in this asset class:

- Heavy Commercial Vehicles: This includes trucks such as Elevated Work Platforms (EWP), High Voltage (HV) trucks, Medium Voltage (MV) trucks, and Portable Emergency Response Units (PERU). These heavy vehicles typically have a useful life of around 15 years. Unlike the light commercial vehicles, we have owned and categorised under the asset class 'Non-network General Assets – Other', which have a shorter useful life of around 5 years, heavy vehicles typically have significantly longer useful lives. We therefore do not consider it appropriate to continue categorising these assets under the same class as car and light commercial vehicles.
- Plant and Equipment: This asset class also includes plant equipment such as cable reelers, trailers, forklifts, tractors, and cable stands. These items share a useful life similar to heavy commercial vehicles of around 15 years.

As both assets share a similar useful life of 15 years, and there is not an existing asset class with a similar standard asset life, we propose a new asset class '*Heavy vehicles and plant*' to consolidate both assets into this single asset class for depreciation purposes. We propose a standard asset life of 15 years for this asset class, consistent with the useful life of the two assets. Our proposed standard asset life is consistent with the industry benchmark asset life for heavy commercial vehicles and trailers/plant, as shown in the table below.

Table 10-4: Industry benchmark data comparing target fleet replacement age across DNSPs

	Heavy Commercial	Trailers/Plant
Essential Energy	10-15 Years	15 Years
Ausgrid	15 Years	15 Years
Powerlink	8-10 Years	10 Years
Ergon Energy	10-15 Years	15 Years
Energex	10-15 Years	15 Years
SA Power Networks	EWP 10 Years Crane 15 Years	20 Years
Jemena/Zinfra	10 Years	

Source: Essential Energy, Asset Life Cycle Strategy – Towed Vehicles.

We propose an opening asset value of zero for this new asset class 'Heavy Vehicle and Plant,' as we are not transferring any existing assets into this class. Although it is technically possible to transfer historical capex that better fits into the new asset class, the value of such assets would be minimal as, consistent with our existing service delivery arrangements, we currently own very few heavy commercial vehicles or plant. In addition, the modelling required for such transfers is complex. We therefore consider it more practical and efficient to not transfer any existing assets into this new asset class.

10.5.1.4. Non-network Leasehold & Buildings

During the pre-lodgement engagement, the AER noted that our lease-related assets have varying lives, primarily around 5 years and 24 years. The AER has recommended creating two distinct lease-related asset classes 'Non-network Leasehold & Buildings – short term' and 'Non-network Leasehold & Buildings – long term' to streamline modelling and future revenue determinations. We agree with this approach and propose establishing separate asset classes for Leasehold Land & Buildings for short life and longer life accordingly. We propose standard lives of 5 years and 20 years for these asset classes respectively, which reflects the average term of leases in the current regulatory period, including leases expected to be extended and/or established in the next regulatory period. This proposal has been submitted in response to the AER's Draft Plan Models Review questions.[130]

[130] AER – AusNet Draft Plan Models Review_20241002 – ASD response

10.6. Pre-lodgement engagement

During the pre-lodgement process, AusNet engaged with the AER on several key depreciation-related issues to ensure alignment with the AER's standardised tracking models. These discussions focused on addressing timing mismatches in the depreciation tracking model for long-life asset classes and the treatment of accelerated depreciation (AD) for network SCADA assets. The agreed approaches to these issues are summarised below.

10.6.1. Depreciation for Subtransmission and Distribution System assets

AusNet's 'in-house' depreciation model applied a more disaggregated approach to tracking final-year asset adjustments than the AER's standardised model. This resulted in timing mismatches in depreciation outputs for the Subtransmission and Distribution System Assets classes. While these differences were relatively minor in the 2021-26 and 2026-31 periods, they became more material beyond 2030-31, leading to unintended gains or losses across multiple resets.

To address this, the AER proposed updated remaining asset lives of 26.43 years for Subtransmission and 27.40 years for Distribution System Assets to minimise depreciation mismatches. However, this approach did not fully resolve variances in depreciation beyond 2030-31. AusNet initially proposed one-off transitional adjustments in the depreciation tracking model to align annual depreciation profiles with those in its in-house model131.

While the AER preferred to maintain its standardised tracking formulas, an alternative solution was agreed upon: splitting the final-year adjustments across 2020 and HY2021. This approach more closely aligned the tracking model outputs with the intended depreciation profile while ensuring a smoother transition to the AER's standardised approach. These updates are reflected in our depreciation tracking model.

10.6.2. Accelerated Depreciation of Network SCADA Assets

As part of the 2021-26 final determination, the AER approved accelerated depreciation (AD) of network SCADA assets, totalling approximately $196 million (real Jun $2021), to be recovered over two resets (2021-26 and 2026-31).

The approved straight-line depreciation profile in the 2021-26 period for AD class 'Secondary systems (pre 2016)' followed a declining structure, where higher depreciation was applied in the earlier years and reduced over time. For the remaining ~$50 million (real Jun $2026) of AD in the 2026-31 period, the AER proposed an alternative approach of smoothing the depreciation evenly over the five years rather than following the declining profile. Although this change introduced a difference in present value (PV) terms, AusNet agreed to the AER's suggestion for modelling simplicity and consistency with the AER's standardised tracking model. These updates are reflected in our depreciation tracking model.

10.7. Forecast Depreciation

Based on the depreciation methodology described above, AusNet's total forecast economic depreciation for the forthcoming regulatory control period is $894.5 million (real $Jun 2026). This is 7% below the depreciation allowance approved for the current regulatory period. Depreciation amounts for existing and new assets are presented in the table below.

Table 10-5: Forecast Economic depreciation ($m, $Jun 2026)

Regulatory Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Existing assets	312.4	295.1	279.3	258.4	235.1	**1,380.3**
New assets	-	32.7	70.6	105.8	139.6	**348.6**
Less: indexation on opening RAB	-149.9	-157.2	-166.3	-175.8	-185.2	**-834.4**
Total	**162.5**	**170.6**	**183.6**	**188.4**	**189.4**	**894.5**

Source: AusNet PTRM Model (2022-26)

131 AusNet, 'ASD review of 2026-31 reset pre-populated models (19 May 22)', 19 May 2022.

10.8. Supporting Documentation

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following documents are provided in support of this chapter:

- Supporting model entitled "ASD - AusNet EDPR 2026-31 - Depreciation Tracking Model – 310125 - PUBLIC";
- Appendix 10A – Accounting policy for critical spares and supporting model 'ASD - Critical spares list - Distribution (5-Dec-2024) - 310125 – CONFIDENTIAL';
- Document entitled "ASD - Essential Energy, *Asset Life Cycle Strategy – Towed Vehicles*".

11. Return on capital and gamma

11.1. Key points

The key points in this chapter are:

- In February 2023, the AER published its 2022 Rate of Return Instrument and an accompanying explanatory statement, following an extensive review and stakeholder consultation process. This is a binding instrument that sets out the key parameter values and the method that should be applied in estimating the rate of return
- Our cost of equity and debt have been estimated in accordance with the AER's Rate of Return Instrument
- Our debt and equity raising costs have been estimated in accordance with the AER's current practice
- A gamma value of 0.570 has been adopted in accordance with the Rate of Return instrument, and
- Our placeholder inflation forecast is 2.50 per cent for the regulatory period commencing 1 July 2026.

11.2. Chapter structure

This chapter is structured as follows:

- Section 11.3 provides a brief commentary on the AER's Rate of Return Instrument
- Sections 11.4 and 11.5 set out our allowed cost of equity and debt for the 2022-26 regulatory control period
- Section 11.6 summarises our estimated weighted average cost of capital (WACC)
- Sections 11.7 and 11.8 present our estimated equity raising and debt raising costs
- Section 11.9 recaps the role of imputation credits under the post-tax revenue model, and notes the value of gamma adopted for the 2022-26 period
- Section 11.10 explains our approach to forecast inflation, which is consistent with the AER's conclusions following its detailed review in 2020, and
- Section 11.11 lists the supporting documentation for this chapter.

11.3. Rate of Return Instrument

In November 2018, the National Electricity Law was amended to require the AER to make a binding rate of return instrument every four years.[132] As a binding instrument, it must set out the precise value for the rate of return or set out a method for calculating the rate of return that can be applied automatically without exercise of discretion. The AER published its second Rate of Return Instrument and an accompanying explanatory statement in February 2023.[133]

The AER's 2022 Rate of Return Instrument maintains the long-standing regulatory approach of determining a nominal vanilla weighted average return on equity and debt, weighted by the gearing ratio. The AER's Rate of Return Instrument therefore defines the allowed rate of return as follows:

$$k_t = (1\text{-}G) + k_t^d \ x \ G$$

Where:

- k_t is the rate of return in regulatory year t
- k^e is the allowed return on equity for the regulatory control period and is calculated in accordance with clause 4 of the instrument
- k_t^d is the allowed return on debt for the regulatory year t, and is calculated in accordance with clause 9 of the instrument, and
- G is the gearing ratio and is set at a value of 0.6.

In accordance with the Rules[134], this chapter sets out AusNet's calculation of the allowed rate of return for each regulatory year of the 2026-31 period.

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132 National Electricity Law, Part 3, Division 1B.
133 Available at https://www.aer.gov.au/industry/registers/resources/guidelines/rate-return-instrument-2022
134 National Electricity Rules, S6.1.3(9).

11.4. Return on Equity

The AER's explanatory statement adopts the Sharpe-Lintner CAPM (SLCAPM) to calculate the return on equity. Within the SLCAPM formula, the AER set fixed values for market risk premium and equity beta, and establishes a formula for calculating the risk free rate. Clause 4 of the AER's rate of return instrument defines the return on equity as follows:

$$k^e = k^f + \beta \times MRP$$

Where:

- k^f is the allowed risk free rate of return expressed as an effective annual rate percentage;
- β is the allowed equity beta and is set to a value of 0.6; and
- MRP is the allowed market risk premium and is set to a value of 6.2 per cent per annum.

As the values of the equity beta and market risk premium have been set by the AER's rate of return instrument, AusNet has adopted these values for the purpose of this Regulatory Proposal in accordance with the Rules.

The Rate of Return Instrument requires us to estimate the risk free rate using a formula based on yields on 10-year Commonwealth Government Securities (CGS). The formula requires the risk free averaging period to be:

- over a period of between 20 and 60 business days;
- start no earlier than 8 months prior to the commencement of the regulatory control period; and
- finish no later than 4 months prior to the commencement of the regulatory control period.[135]

In accordance with the Rate of Return Instrument, AusNet has nominated its averaging periods in a confidential letter to the AER. For the purpose of this Regulatory Proposal, it is only possible to provide an estimate of the risk free rate that will apply in the respective nominated averaging periods. The AER will update the risk free rate and the resulting cost of equity in its draft and final decisions. In this Regulatory Proposal, we have adopted a risk-free rate of 4.42 percent, based on the implied forward rate on 10-year Commonwealth Government Securities (CGS) for March 2026.

In accordance with the AER's rate of return instrument, our estimated cost of equity for the purpose of this Regulatory Proposal is 7.72 per cent, as presented in the table below.

Table 11-1: Proposed cost of equity parameters

Parameter	Proposed value	Basis of parameter value
Risk free rate (nominal)	4.42%	This is a placeholder value reflecting the yield on ten year Commonwealth bonds measured over the 60 business day period ending 14 Oct 2024. The risk free rate for the AER's final determination will be measured over the nominated periods selected in accordance with clause 8 of the AER's rate of return instrument.
Equity beta	0.6	This value is consistent with clause 4(b) of the AER's rate of return instrument.
Market risk premium	6.2%	This value is consistent with clause 4(c) of the AER's rate of return instrument.
Cost of equity	7.72%	The cost of equity is estimated in accordance with the SLCAPM, as specified in clause 4 of the AER's Rate of Return Instrument.

11.5. Cost of Debt

The AER explains that its approach to estimating the cost of debt comprises the following key elements:

- A benchmarking approach, based on debt yield data from third party data providers and benchmarks for term of debt and credit rating, and
- A 10-year trailing average approach with an annual update, and
- A 10-year transition to the 10-year trailing average approach, noting that where a transition has commenced in a previous determination, the AER will continue that transition.

135 AER, Rate of Return Instrument, clause 8.

In the AER's final decision for our 2016-20 period, the AER adopted an 'on-the-day' approach for the first regulatory year and commenced a 10-year transition to a trailing average approach, which operates as follows:

- For 2016, the estimated cost of debt reflected the prevailing market rates near the commencement of the 2016-20 regulatory control period, and
- For each subsequent year, 10 per cent of the return on debt is updated to reflect the prevailing market conditions in that year.

The transitional period will conclude at the end of the 2021-2026 current regulatory period. In accordance with the AER's Rate of Return Instrument, the transitional approach will not continue for the 2026–31 regulatory period. Instead, we will fully adopt the trailing average approach for calculating the return on debt, meaning the return on debt will reflect the average of market rates over the past 10 years.

The 6-month extension to the 2016-20 regulatory control period required an adjustment to the transitional approach. We continue to apply the simple adjustment guided by the AER, as implemented in the last regulatory control period, to accommodate this extension. In particular, the revised approach is as follows:

- Revenues in the extension period include 10% of the prevailing cost of debt estimated for the 1 January – 30 June 2021 extension period.
- Thereafter, revenues incorporate a trailing average cost of debt over an 11 year period, with a 5% weighting applied to both the debt estimate for the extension period and the first (i.e. least recent) observation.
- This continues until the 2030-31 regulatory period, at which point the trailing average reverts to an equally weighted, 10 year average.

For the purpose of this Regulatory Proposal, we adopt a prevailing cost of debt of 6.45 per cent[136]. The final will be updated in accordance with the AER's Rate of Return Instrument, reflecting the average of data published by Bloomberg, the Reserve Bank of Australia and Thomson Reuters on the annualized yield on ten year BBB rated corporate debt calculated over the nominated averaging period, which will be selected in accordance with paragraphs 11, 12 and 26 of the rate of return instrument.

The table below shows the estimated cost of debt over the 2026-31 regulatory period, in accordance with the AER's trailing average approach. The data shown in the table below will be updated to reflect the prevailing cost of debt each year and for the nominated averaging period for regulatory year 2027.

Table 11-2: Estimated benchmark cost of debt

	2026-27	2027-28	2028-29	2029-30	2030-31
Nominal pre-tax return on debt	4.91%	5.06%	5.24%	5.48%	5.81%

11.6. Nominal Vanilla WACC

The table below summarises the calculation of the nominal vanilla WACC or the 'allowed rate of return', in accordance with clause 3 of the Rate of Return Instrument. The table shows that the application of the AER's approach would result in a WACC of 6.04 per cent for 2026-27, increasing to 6.58 per cent by 2030-31.

Table 11-3: Estimated nominal vanilla WACC

	2026-27	2027-28	2028-29	2029-30	2030-31
Return on equity	7.72%	7.72%	7.72%	7.72%	7.72%
Nominal pre-tax return on debt	4.91%	5.06%	5.24%	5.48%	5.81%
Gearing	60%	60%	60%	60%	60%
Nominal vanilla WACC	6.04%	6.13%	6.24%	6.38%	6.58%

The allowed rate of return will be updated in the AER's draft and final decisions and then annually to reflect movements in the cost of debt.

[136] Based on a placeholder averaging period of 3 to 21 July 2023.

11.7. Equity Raising Costs

Equity raising costs are the transaction costs incurred when network service providers raise new equity in order to fund capital investment. Accordingly, the AER provides a benchmark allowance to reflect the efficient costs of raising equity, if equity raising is required to maintain the benchmark gearing of 60 per cent.

Our equity raising costs are derived from the PTRM and the AER's benchmarking approach, which includes a distribution rate of 0.9, consistent with the Rate of Return Instrument. Our modelling indicates that under the AER's approach no external equity injection is required to maintain the benchmark capital structure over the 2026-31 regulatory control period.

11.8. Debt Raising Costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced. These costs may include arrangement fees, legal fees, company credit rating fees and other transaction costs.

The AER provides a benchmark allowance for debt raising costs as a component of our operating expenditure allowance. The AER's approach is based on a report from the Allen Consulting Group, commissioned by the ACCC in 2004. The AER subsequently updated Allen Consulting Group's analysis to reflect more recent market data provided by PricewaterhouseCoopers during the 2013 rate of return guideline process. The estimates of debt raising costs for a generic NSP have since been updated by Chairmont in 2019 and (in relation to the arrangement fee specifically) by the AER in 2021.

In this Regulatory Proposal, AusNet Services has calculated a debt raising cost allowance based on the AER's recent approach to setting benchmark debt raising costs. The resulting benchmark allowance is provided in our operating expenditure forecasts, which are set out in chapter 7 of this Regulatory Proposal.

11.9. Imputation Credit Value (Gamma)

Under the Australian imputation tax system, investors receive imputation credits for tax paid at the company level. For eligible shareholders, imputation credits offset their Australian income tax liabilities. The AER takes account of the value of imputation credits (known as gamma or 'γ') to recognise that imputation credits benefit equity holders, in addition to any dividends or capital gains they receive.

As the regulatory framework applies a post-tax WACC, the value of imputation credits is not a WACC parameter. Instead, the value of imputation credits is a direct input into the calculation of a network service provider's benchmark tax allowance. In accordance with the AER's rate of return instrument, we have adopted a value for imputation credits of 0.57.

The calculation of our benchmark tax allowance for the 2026-31 regulatory period is provided in Chapter 15 of this Regulatory Proposal.

11.10. Forecast inflation

The AER published its final position on the regulatory treatment of inflation in December 2020, outlining its method for estimating and applying inflation in regulatory determinations for energy networks. The AER's approach to estimating the average annual inflation rate over a five-year period is as follows:

- For years 1 and 2, the Reserve Bank of Australia's (RBA) two-year inflation forecast is used.
- For years 3 to 5, a gradual transition is applied, moving toward the RBA's long-term inflation target midpoint of 2.5% in year 5.

In line with this approach, we propose to follow the AER's methodology for estimating expected inflation, as specified in the PTRM. Currently, the RBA's inflation forecast is available only up to December 2026,[137] so forecasts for the first and second regulatory years – as required by the AER's methodology - are not currently available. For the purposes of this Regulatory Proposal, we are using a placeholder inflation rate of 2.5%, the RBA's long-term target. We will revise our expected inflation input to reflect the latest RBA two-year forecast and apply the glide-path approach accordingly in our Revised Proposal.

We note that applying the latest available RBA forecast (2.5%) to the first year of the regulatory period, followed by a glide path to 2.5% in year 5, would result in the same expected inflation input that has been applied in this Regulatory Proposal.

The AER adopts a post-tax vanilla WACC, so inflation is not directly used to derive or adjust WACC values. However, inflation is a key input in our proposal and financial modelling, as it impacts the indexation of the regulatory asset base (RAB), revenue adjustments, and the calculation of the nominal rate of return. In our modelling, expected inflation is used to adjust the RAB and convert nominal values into real terms to ensure consistency with the real rate of return approach. Additionally, inflation influences the escalation of operating and capital expenditure forecasts, ensuring that cost estimates reflect expected price changes over the regulatory period.

11.11. Supporting Documentation

We have included the following documents to support this chapter:

- PTRM(s);
- Appendix 11A – Rate of Return Averaging Periods; and
- Rate of Return Build up model.

[137] RBA, *Statement of Monetary Policy*, November 2024

12. Corporate Tax Allowance

12.1. Key points

The key points in this chapter are:

- We are forecasting a zero tax allowance over 2026-31 regulatory period.
- AusNet applies the Year-by-Year Tracking Depreciation approach for depreciation of the Opening Tax Asset Base commencing from 1 July 2026.

12.2. Chapter structure

This chapter is structured as follows:

- Section 12.3 explains the method for calculating the tax allowance;
- Section 12.4 calculates the opening Tax Asset Base (TAB) as at 1 July 2026;
- Section 12.5 presents the standard tax lives which are used to calculate tax depreciation;
- Section 12.6 presents AusNet Services' forecast of immediately deductible expenditure for the 2026-31 period;
- Section 12.8 outlines our response to suggested changes in the roll forward model and PTRM as part of the AER's pre-lodgment engagement;
- Section 12.8 sets out the proposed tax allowance; and
- Section 12.9 lists the supporting documentation for this chapter.

12.3. Method for Calculating the Tax Allowance

12.3.1. Overview

The AER's post-tax revenue model (PTRM) calculates a DNSP's tax allowance in accordance with clause 6.5.3 of the National Electricity Rules (NER). Specifically, the PTRM calculates the tax allowance (or the tax building block) by:

1. Deducting tax expenses (opex, interest payments on debt and total tax depreciation for all assets) from required revenue (including income from customer contributions) to arrive at the DNSP's taxable income; and
2. Multiplying taxable income by the corporate income tax rate, then multiplying the result by one minus the utilisation of imputation credits (gamma).

This calculation is represented by the following equation in clause 6.5.3:

$ETC_t = (ETI_t \times r_t)\ (1 - \gamma)$

where:

ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the Distribution Network Service Provider, operated the business of the Distribution Network Service Provider, such estimate being determined in accordance with the post-tax revenue model;

r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and

γ is the value of imputation credits.

12.3.2. Inputs to the calculation of the tax allowance

The method for calculating AusNet's tax allowance for the 2026-31 period requires the following inputs:

- Opening tax asset base (TAB) as at 1 July 2026;
- Standard tax lives;
- The company income tax rate;
- The value of gamma;
- Any accumulated tax losses as at 1 July 2026; and
- A forecast of immediate expensed (for tax purposes) capex for the 2026-31 period.

Each of these inputs is discussed in the following sections.

12.4. Opening Tax Asset Base

The following table shows the roll forward of the TAB using actual and forecast net capex and depreciation. Net capex shown for regulatory years 2024-25 and 2025-26 are forecasts and we will update our 2024-25 net capex with actuals as part of our Revised Regulatory Proposal.

Table 12-1: AusNet's Tax Asset Base roll forward ro 1 July 2026 ($m nominal)

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26
Opening TAB	3,620.4	3,667.5	3,701.7	3,710.3	3,816.4
Plus capex, net of disposals	359.6	346.9	391.4	482.9	488.0
Less straight-line depreciation	-312.5	-312.7	-382.8	-376.8	-388.1
Closing TAB	**3,667.5**	**3,701.7**	**3,710.3**	**3,816.4**	**3,922.3**

Source: AusNet's Proposal Roll Forward Model

For the TAB roll forward from 1 July 2026, AusNet uses the Year-by-Year Tracking Depreciation approach, and consequently, the straight-line depreciation calculations are based on the specific useful lives of each individual assets contained in the SCS depreciation tracking model that is provided with this Regulatory Proposal.

12.4.1. Final Year Asset Adjustments

AusNet is proposing two end of period asset adjustments to both RAB and TAB. These adjustments are described in Chapter 9 – RAB, section 9.5. The corresponding TAB adjustments are shown in the table below.

Table 12-2: AusNet's Proposed Final Year Asset Adjustments (30 June 2026), $Nominal

RAB Class	Proposed TAB adjustments ($M)	Remaining life of adjustments to TAB (Yrs)
*Critical spares – network assets	7.61	n/a
Non-network Leasehold Land & Buildings – 1 July 2021	-1.61	4.3

Source: AusNet Roll Forward Model (2021-26)

** Denotes the new asset classes proposed by AusNet. Further information about these classes is contained in section 10.5 of the Depreciation Chapter.*

12.4.2. Opening TAB Values for critical spares – network assets

We are proposing five new asset classes for the forthcoming Regulatory Period, and we propose an opening tax asset value for one of these new asset classes 'Critical spares – network assets'. Further details on the new asset classes are provided in section 10.5.

AusNet has also undertaken a calculation to estimate the 1 July 2026 opening tax base value for the asset class 'Critical spares – network assets'. As shown in below, we have estimated the opening TAB value to be $7.61m ($Nominal). The opening TAB values were determined by aligning it with the estimated 2026 opening RAB value for the asset class. Section 10.5 of the regulatory depreciation chapter describes the calculation of opening RAB for asset class 'Critical spares – network assets' in details.

The table below shows the opening TAB value for our proposed asset class 'Critical spares – network assets'.

Table 12-3: Estimated Opening TAB for new asset classes as at 1 July 2026

Asset Class	Estimated Opening TAB value ($m)	Average Remaining life (Yrs)	Recalculated Average Remaining life (Yrs)
Critical spares – network assets	7.61	n/a	n/a

12.5. Standard Tax Lives

At the commencement of the 2021-26 regulatory control period, AusNet adopted the standard tax lives set out in ATO Tax Ruling 2018/4 (TR 2018/4) to assign standard lives to each tax asset class. The AER approved the proposed standard tax lives, which are outlined which are outlined below.

Table 12-4: AusNet's Standard Tax Lives for 2021-26 period

Asset Class	Standard life (Yrs)
Sub-transmission	43.0
Distribution system assets	46.0
SCADA/Network control	10.0
Non-network general assets - IT	4.0
Non-network general assets - Other	12.0
Land	n/a
Secondary systems (pre 2016)	n/a
Accelerated depr – Distr assets (contingent project 3)	n/a
Accelerated Distr assets (other)	n/a
Non-network Leasehold Land & Buildings – 1 July 2021	n/a
Non-network Leasehold Land & Buildings – 2021-22	23.7
Non-network Leasehold Land & Buildings – 2025-26	5.0
Buildings - capital works	40.0
In-house software	5.0
Equity raising costs	5.0

Source: AER

12.5.1. Proposed Standard lives

For existing asset classes, AusNet's proposed standard tax lives for new additions in the forthcoming regulatory control period (2026-31) (presented in table 12-5 below) are unchanged from the current period.

For the new asset classes proposed, including critical spares – network assets, non-network solutions, heavy vehicles and plants, and non-network leasehold & land assets—we propose tax lives equal to their RAB standard asset lives. As discussed within section 10.5, our proposed RAB standard asset lives reflect the economic lives of these assets. Therefore, setting tax lives equal to RAB standard asset lives ensures alignment with the economic life of assets. This approach also simplifies modelling and compliance by maintaining consistency between tax and regulatory depreciation calculations.

Table 12-5: AusNet's Proposed Standard Tax Lives for new additions

Asset Class	Standard life (Yrs)	DV rate
Sub-transmission	43.0	4.7%
Distribution system assets	46.0	4.3%
SCADA/Network control	10.0	20.0%
Non-network general assets - IT	4.0	50.0%
Non-network general assets - Other	12.0	16.7%
Land	n/a	n/a
*Non-network Leasehold Land & Buildings – short term	5.0	40.0%
*Non-network Leasehold Land & Buildings – long term	20.0	10.0%
*Non-network solutions	15.0	13.3%
*Critical spares – network assets	n/a	n/a
*Heavy vehicles and plants	15.0	13.3%
Buildings - capital works	40.0	n/a
In-house software	5.0	n/a
Equity raising costs	5.0	n/a

Source: AusNet
** Denotes the new asset classes proposed by AusNet. Further information about these classes is contained in section* 10.5 of the Depreciation Chapter.

12.6. Forecast of immediately deductible expenditure

The table below contains AusNet's forecast of immediate deductible capital expenditure for the 2026–31 regulatory control period as contained in the SCS capex model and PTRM Model (Version 5) that are each submitted as part of this Regulatory Proposal. We have mapped our forecast immediate expensing of capex to forecast capex on an as-incurred basis as contained in the AER's standardised SCS capex model. This approach allows any upwards or downwards capex adjustments to flow through the immediate expensing of capex forecast. Our 2027-31 immediate expensing capex forecast is contained in supporting model 'ASD 2026-31 SCS Capex Model (Public)'. Refer to worksheets 'Capex Immediately Expensed' and 'ASD changes' for further details. We confirm that this forecasting approach reflects AusNet's current practice of immediately expensing replacement capex and capitalised labour and non-labour overheads on an as-commissioned basis.

Table 12-6: Forecast immediately deductible expenditure 1 July 2026 to 30 June 2031 ($m Jun $2026)

Asset Class	2026-27	2027-28	2028-29	2029-30	2030-31
Sub-transmission	37.2	53.8	63.6	61.2	58.5
Distribution system assets	170.5	207.3	241.2	240.4	234.9
SCADA/Network control	20.1	23.1	24.6	30.4	34.2
Non-network solutions	0.2	0.1	0.1	0.1	0.0
Total	**227.9**	**284.3**	**329.4**	**332.1**	**327.7**

AusNet prepares its immediate expensing of capital expenditure (capex) by aligning its regulatory and tax practices while accounting for differences in reporting periods. Immediate expensing applies to capex that is immediately deductible for tax purposes, such as replacement capex and capitalised indirect labour and non-labour overheads.

There are notable differences in how capital expenditure and overheads are treated for tax and regulatory accounting purposes. For tax purposes, certain costs, such as replacement capital expenditure and indirect labour and non-labour overheads, are immediately expensed, meaning they are fully deducted in the year incurred rather than depreciated according to standard tax lives. In contrast, the regulatory accounting approach capitalises these costs, including them in the RAB, where they are depreciated over the asset's life. Additionally, some expenditures and capital contributions are excluded from the AER's model inputs, as these are deemed outside of the revenue cap. We confirmed this with the AER during the 2021-26 Electricity Distribution Price Review in our confidential response138.

AusNet also confirms that it does not intend to change its tax policy on immediate expensing capital expenditure from its current policy for its electricity distribution business.

12.7. Pre-lodgement engagement

During pre-lodgement engagement, the AER requested confirmation on whether we agree to include a type 2 capital contribution of $24.1 million in the actual capex amount for 'Distribution system assets' for the period January to June 2021. We do not agree with this approach and have provided a detailed response to the AER as part of the pre-lodgement engagement on 10 October 2024.

AusNet acknowledges the AER's position on including actual HY2021 type 2 contributions in the RFM. However, we believe this approach does not reflect the unique tax treatment of gifted assets following the Federal Court's 2020 decision in the VPN vs Commissioner of Taxation case139, which determined that gifted assets are no longer assessable for income tax purposes. Consequently, AusNet's company tax return for 1 July 2020 to 30 June 2021 excluded gifted asset-related income and associated tax depreciation. As such, no tax assets were created for the $24.1 million ($nominal) of type 2 capital contributions during this period.

Including these contributions in the regulatory tax asset base would artificially increase it by $24.1 million ($nominal) as of 30 June 2021, creating a disconnect with the actual tax base. This would result in no corresponding tax benefits in the form of future tax depreciation deductions, leading to compounding carried-forward tax losses in AusNet's Proposal PTRM for 2026-31. By 30 June 2031, these losses are projected to grow to $3.5 million ($nominal) and would continue to accumulate in subsequent periods, further distorting the regulatory tax base.

As detailed in our response to the AER, we propose to exclude type 2 capital contributions from both gross capex and customer contributions in the RFM and depreciation tracking module inputs for January to June 2021 to align with the actual tax treatment and ensure consistency. We welcome further engagement with the AER to discuss this approach.

12.8. Proposed Tax Allowance

The table below contains AusNet's forecast TAB roll forward for the forthcoming regulatory control period.

Table 12-7: AusNet's Tax Asset Base roll forward to 30 June 2031 ($m nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Opening TAB	3,922.3	4,148.4	4,387.8	4,606.6	4,825.2
Plus capex, net of disposals and capital contributions	618.1	721.8	785.4	809.6	840.7
Plus capital contributions	69.9	58.2	55.5	55.8	58.5
Less tax depreciation	-461.9	-540.6	-622.1	-646.7	-658.4
Closing TAB	**4,148.4**	**4,387.8**	**4,606.6**	**4,825.2**	**5,066.1**

Our proposed corporate tax is zero for the 2026-31 period, consistent with the previous period, primarily due to the impact of immediately deductible expenses and the ongoing accumulation of carried-forward tax losses.

138 AusNet - ASD - IR019A - Response to IR019A 20200609 - Confidential

139 Available at: https://www.ato.gov.au/law/view/print?DocID=LIT%2FICD%2FVID237-240of2019%2F00001

AusNet assumed a company income tax rate of 30% for the 2026-31 period and applies a diminishing value multiplier of 200% for new additions post 30 June 2026. As already noted, we have used 57.0% for the value of gamma in accordance with the AER's 2022 rate of return instrument[140].

AusNet confirms that, consistent with the information contained in the current period decision PTRM, it will carry forward the accumulated tax loss as at 1 July 2021 of $342.4 million.141

Our forecast of the tax allowance for the 2026-31 period is shown in the table below.

Table 12-8: AusNet's Proposed Tax Allowance 1 July 2026 to 30 June 2031 ($m nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Tax Payable	0	0	0	0	0
Imputation credits	0	0	0	0	0
Tax Allowance	0	0	0	0	0

12.9. Supporting Documentation

We have included the following documents to support this chapter:

- Supporting models 'ASD - AusNet EDPR 2026-31 - Depreciation Tracking Model – 310125 – PUBLIC', 'ASD - AusNet EDPR 2026-31 – RFM – 310125 – PUBLIC', and 'ASD - AusNet EDPR 2026-31 – PTRM Model – 310125 – PUBLIC'.
- Other supporting models, including 'ASD - Lease offsetting adjustments_20241118 - 310125 – CONFIDENTIAL', 'ASD - Resubmission 2021-22 RIN A - 8.2 Capex template 030524 - 310125 – CONFIDENTIAL', and 'ASD - Resubmission 2022-23 RIN A - 8.2 Capex template 030524 - 310125 – CONFIDENTIAL'.

140 AER, 2022 rate of return instrument, February 2023, p.22.

141 AusNet Services Dx PTRM - 2024-25 RoD update (inc storm and VEBM CPT).xlsm, https://www.aer.gov.au/documents/ausnet-services-dx-ptrm-2024-25-rod-update-inc-storm-and-vebm-cpt

13. Incentive schemes

13.1. Key points

This chapter describes our proposed approach to the national and jurisdictional incentive schemes that will apply in Victoria during the forthcoming regulatory period including the:

- Service Target Performance Incentive Scheme (STPIS).
- Customer Service Incentive Scheme (CSIS).
- Efficiency Benefit Sharing Scheme (EBSS).
- Capital Efficiency Sharing Scheme (CESS).
- F Factor scheme.
- Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance (DMIA).
- Export Service Incentive Scheme.

The targets and outcomes from these incentive schemes are fundamentally interlinked to our expenditure proposals as both are an input to and output from the company's asset management strategy and the work programs that underpin this proposal. Our capex and opex proposals are outlined in Chapters 6 and 7 respectively. We have a strong record of responding to incentives. Therefore, the AER's stated intention to apply the full suite of incentives in Victoria is fully supported.

13.2. Chapter structure

The structure of the remainder of this chapter is:

- Section 13.3 provides important background to our current performance and stakeholder views, including the input of our customer panels.
- Section 13.4 explains the proposed customer satisfaction incentive scheme, which has been developed with the input from our customer panels.
- Section 13.5 sets out our STPIS proposal.
- Section 13.6 explains our CESS proposal.
- Section 13.7 presents our EBSS proposal.
- Section 13.8 explains the F-factor scheme.
- Section 13.9 explains our DMIA proposal.
- Section 13.10 explains the Export Service Incentive Scheme.

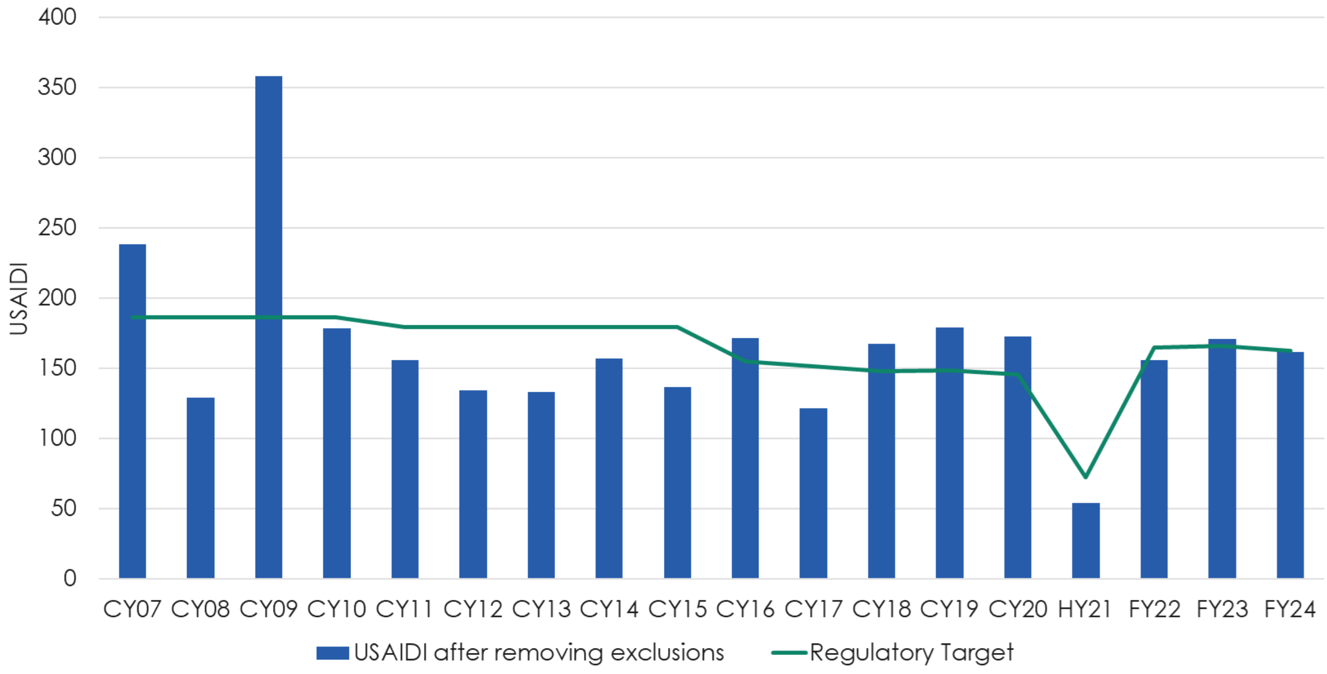
13.3. Recent performance and stakeholder feedback

We strongly support the AER's incentive regime. The framework's constituent schemes align the distributors' incentives to achieve efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO). The objectives and benefits of the incentive framework is demonstrated by our performance under the current period's various incentive schemes.

We have a long-term improving trend of reliability performance, driven by a continued focus on the incentives provided by the STPIS. In recent years, our reliability performance has been mixed.

In 2017, our USAIDI performance was best on record. However, the periods from 2018 to 2020 and 2021-22 to 2023-24 experienced below-average USAIDI performance. As the targets for USAIDI under the STPIS have become successively harder, it is becoming more difficult to outperform these targets year-on-year.

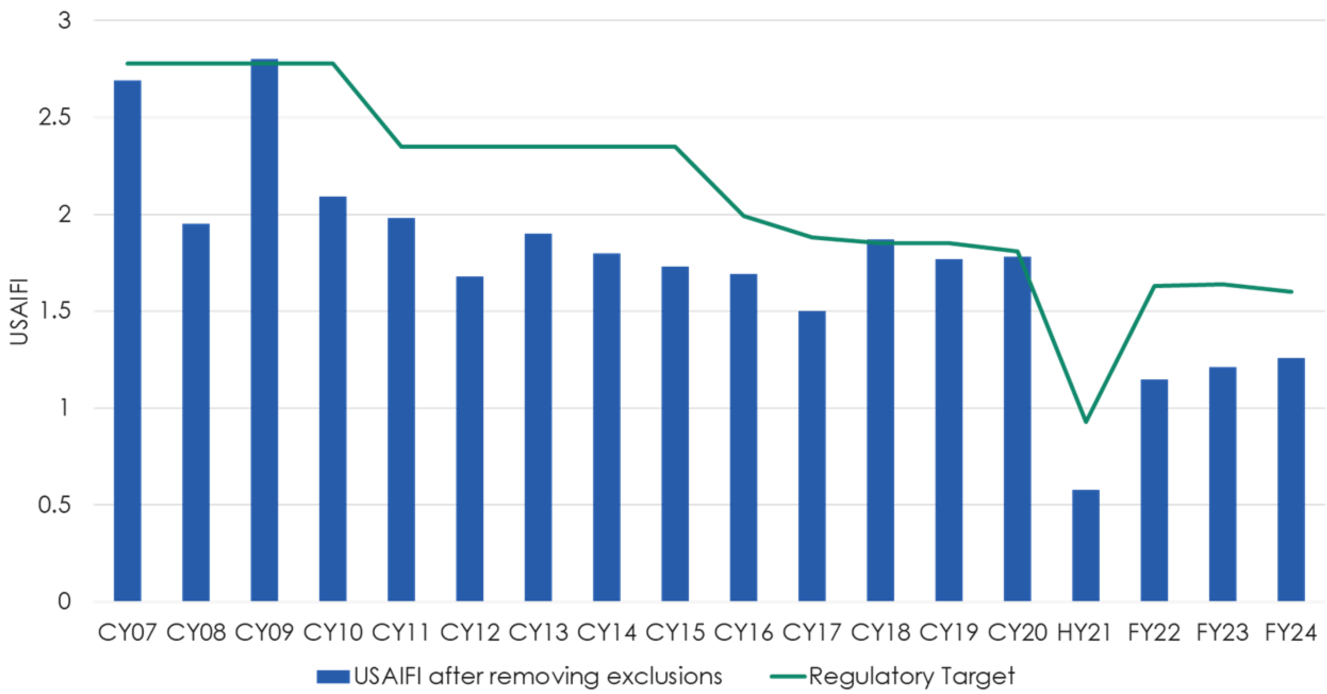
Figure 13-1:42 Average minutes off supply per customer (USAIDI)



Source: AusNet

Our USAIFI performance has been improving in the past. The last regulatory period was our best period on record for reliability performance, with 2021-22 as the best single year on record.

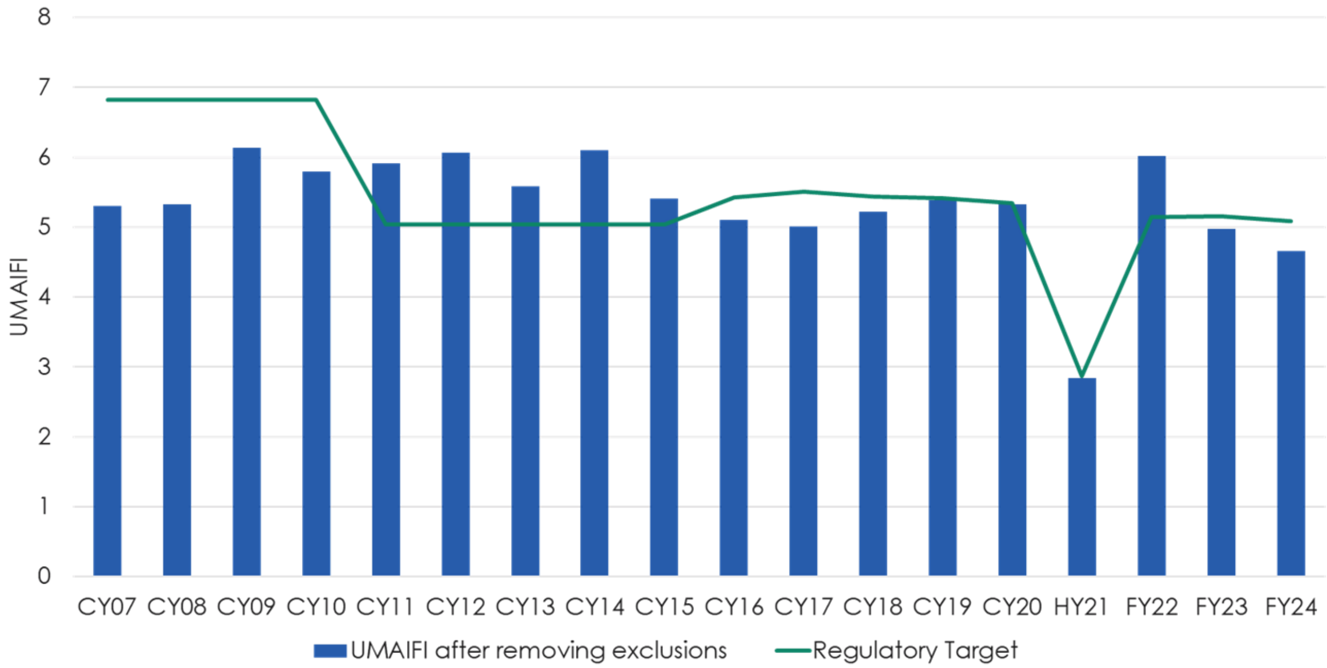
Figure 13-2:43 Average number of unplanned interruptions per customer (USAIFI)



Source: AusNet

Our UMAIFI performance has also been improving in the past, with 2023-24 as the best single year on record.

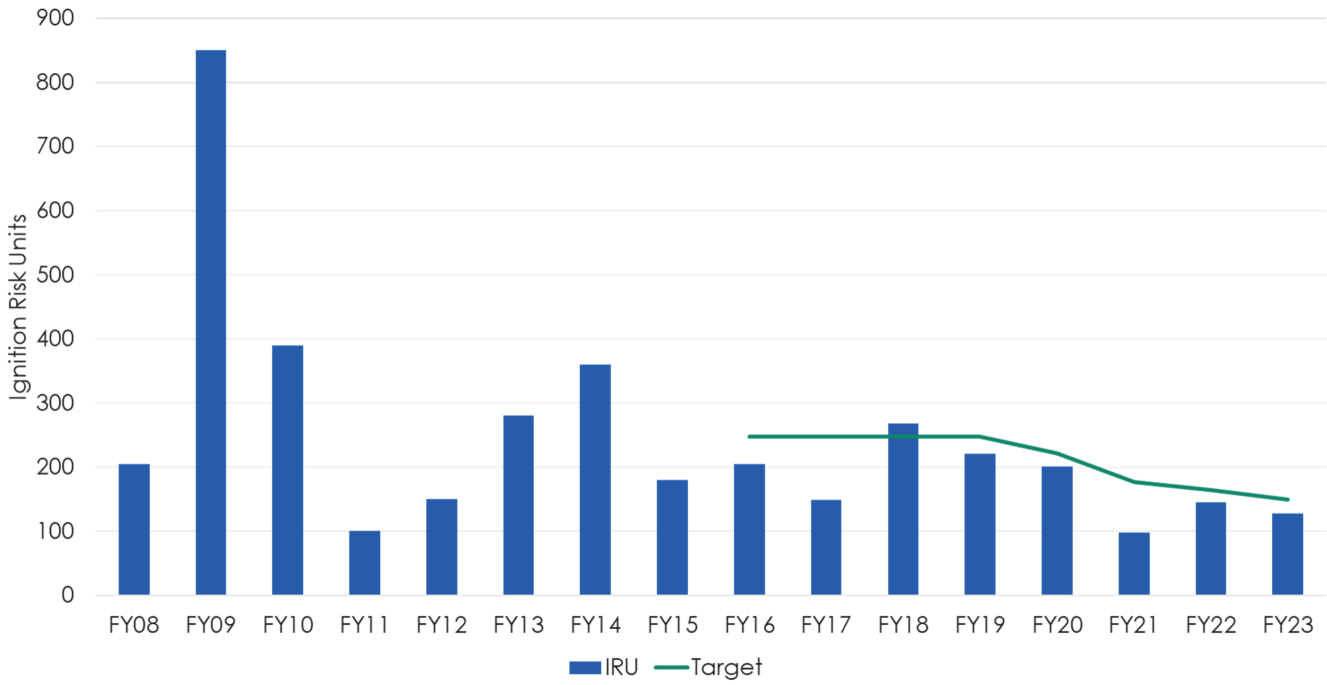
Figure 13-3:44 Average number of momentary interruptions per customer (USAIFI)



Source: AusNet

In relation to the f-factor scheme, we have experienced a considerable fall in its Fire Risk and has outperformed the Ignition Risk Units targets each year since they were incorporated into the F-Factor Scheme except for 2017-18.

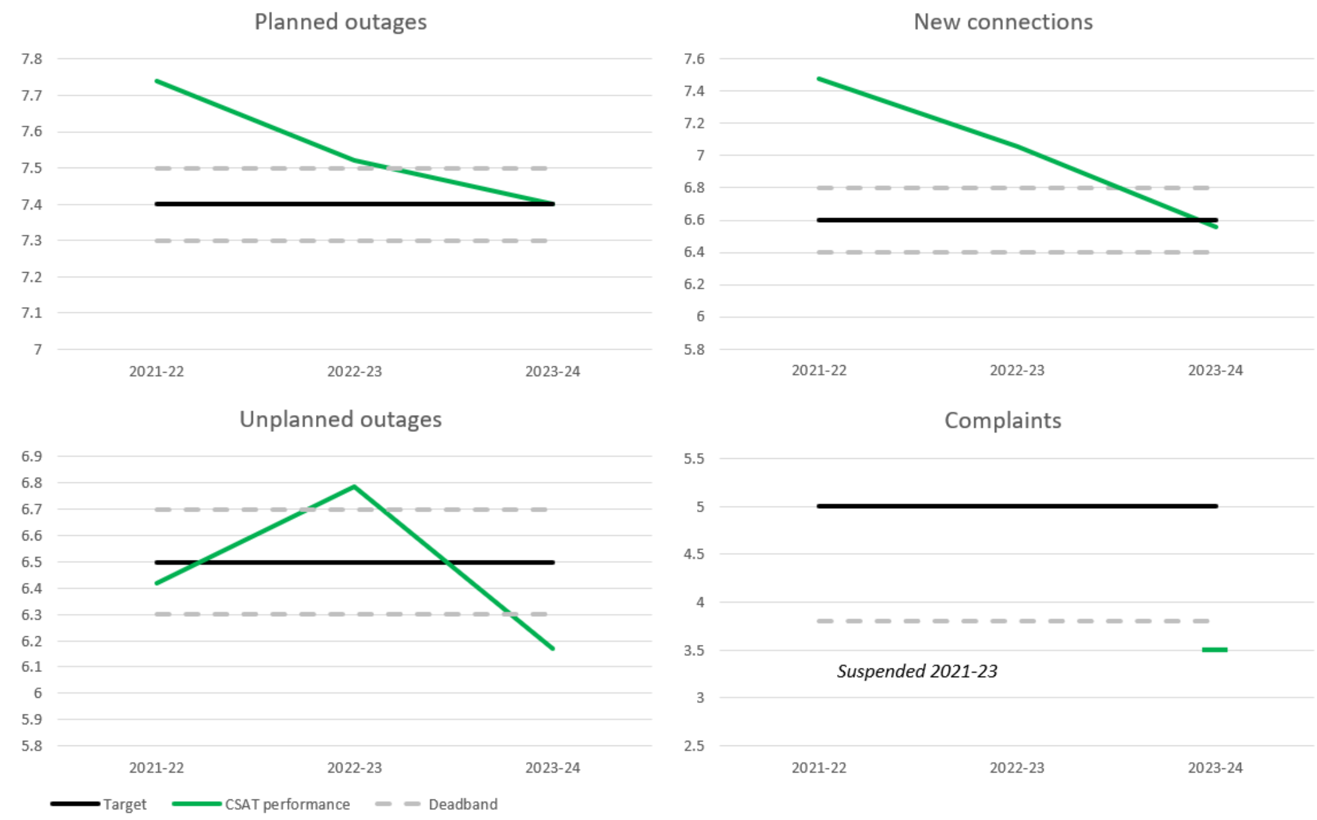
Figure 13-4:45 F-factor IRU's



Source: AusNet

In relation to CSIS, we have implemented targeted improvement programs since 2021, achieving mixed outcomes that provide valuable insights for shaping our future customer satisfaction strategies. Since 2021, we have rolled out targeted improvement programs in unplanned and planned outages and plan to undertake an improvement program in new connections in 2025. Some of the improvements have been reflected in higher C-SAT results compared to historical averages, however, we have also seen declining results in some areas. Prior to the decline in 2023-24, we achieved C-SAT results above our targets or within our deadbands (results in no penalty or reward). Positively, in the second half of 2024, we saw improvements to our planned outage and connections C-SAT from 2023-24 levels. Our new C-SAT research methodology and upcoming customer improvement initiatives aims to target further improvements in the current and upcoming period.

Figure 13-5:46 Current CSIS performance



Source: AusNet

Table 13-1: Current CSIS performance

	2021-22	2022-23	2023-24	Target (Deadband)
Planned outage C-SAT	7.7	7.5	7.4	**7.4 (7.3-7.5)**
Unplanned outage C-SAT	6.4	6.7 (Voluntary suspension)	6.2	**6.5 (6.3-6.7)**
Connections C-SAT	7.5	7.1	6.4	**6.6 (6.4-6.8)**
Complaint C-SAT	Suspended	Suspended	3.5	**3.8 (3.8-5.0)**
Total	**$775k**	**$296k**	**-$291k***	

**Indicative - Final outcome not yet determined by AER.*
Source: AusNet

For the remainder of the current period, we have sought a 2-year suspension from the AER of our 2021-26 CSIS for regulatory years 2024-25 and 2025-26, necessitated by a change in methodology for measuring customer satisfaction (C-Sat) from the current telephone survey to a more modern online survey in line with the clear preferences of our 2026-31 EDPR panel members and AusNet customers. This change will take effect from 2 January 2025.

The change in methodology is required due to factors outside of AusNet's control – largely a sustained declining trend in customer response to telephone surveys for C-Sat under the current methodology. It is taking far longer to reach our monthly quota, few suppliers are willing to offer the program as it is considered outdated, and it is not in line with customers' general preferences for digital channels and is impacting their experience with the C-Sat program.

We consider these proposed arrangements to be in the long-term interest of our customers, as we are proposing a more fit-for-purpose and sustainable method of surveying that is aligned with customers' expectations. It will provide the necessary statistical and data robustness for the CSIS in the long term, and form the baseline for our proposed C-Sat based metrics in our 2026-31 CSIS outlined in section 13.4. It will also make it faster and easier for us to understand customers' experiences and give many more customers an opportunity to provide feedback. To continue holding ourselves to account to customer outcomes during the change-over, we propose to undertake a "paper trial", where we will publish and provide to the AER our annual C-Sat results using the new methodology.

13.4. Customer Service Incentive Scheme

Our proposed incentive design and how it satisfies the incentive design criteria is set out in the following sections in accordance with scheme requirement 3.3.(1)(a).

13.4.1. Regulatory requirements

The Customer Service Incentive Scheme (CSIS) is a *Small Scale Incentive Scheme,* as is the Export Services Incentive Scheme (ESIS), which was introduced by the AER in 2023. Clause 6.6.4 of the NER allows the AER to develop a small scale incentive scheme. It states:

> (a) The AER may, in accordance with the distribution consultation procedures, develop and publish an incentive scheme or schemes (small-scale incentive scheme) that provides Distribution Network Service Providers with incentives to provide standard control services in a manner that contributes to the achievement of the national electricity objective.
>
> (b) In developing and applying a small-scale incentive scheme, the AER must have regard to the following matters:
>
> 1) Distribution Network Service Providers should be rewarded or penalised for efficiency gains or losses in respect of their distribution systems;
> 2) the rewards and penalties should be commensurate with the efficiency gains or efficiency losses in respect of a distribution system, but a reward for efficiency gains need not correspond in amount to a penalty for efficiency losses;
> 3) the benefits to electricity consumers that are likely to result from efficiency gains in respect of a distribution system should warrant the rewards provided under the scheme, and the detriments to electricity consumers that are likely to result from efficiency losses in respect of a distribution system should warrant the penalties provided under the scheme;
> 4) the interaction of the scheme with other incentives that Distribution Network Service Providers may have under the Rules; and
> 5) the capital expenditure objectives and the operating expenditure objectives.

The default revenue at risk for a Small Scale Incentive Scheme is 0.5% in a regulatory year. However, it can be increased to 1% for a CSIS where a DNSP consents and the ESIS is not proposed. For the ESIS, the cap of 0.5% applies.[142]

We have designed our proposed CSIS to satisfy the requirements of the NER and to promote the National Electricity Objective (NEO). Furthermore, our proposed scheme is consistent with the AER's Scheme Objectives with this section of our proposal satisfy requirement 3.3(1)(b)(i) of the scheme. Each of the matters the AER must have regards to as set out in clause 1.4(2), and the reason we consider the proposed scheme satisfies these requirements of the Scheme, is set out below:

- By providing a more holistic incentive to improve customer satisfaction, we consider the proposed scheme is in the long term interest of consumers and satisfies the NEO.
- Customer satisfaction is a measure of the quality of output of our business and so an improvement in customer service represents an increase in our efficiency. The CSIS will provide us an incentive to increase expenditure on customer service when the additional inputs are less that the value of the increased output. This represents an overall gain in the efficiency our network.
- We consider these incentive rates ensure the benefits to electricity consumers that are likely to result from efficiency gains in respect of a distribution system should warrant the rewards provided under the scheme.
- There are limited interactions with the AER's existing STPIS, however these limited interactions are not impediments to implementing this CSIS.
    a) The STPIS provides rewards for reductions in the number and duration of unplanned outages. The CSIS will measure customer's satisfaction with the unplanned outages they experience. However, this does not result in an inappropriate interaction between the two schemes because the two measures should be largely independent.

[142] AER, Export service inventive scheme, Explanatory Statement, pp. 7-8.

b) Clause 6.5.7(a)(3)(iii) of the NER allows that building block proposal must include the capital expenditure to maintain the quality, reliability and security of supply of standard control services. Similarly, Clause 6.5.6(a)(3)(iii) of the NER requires that the building block proposal must include the operating expenditure to maintain the quality, reliability and security of supply of standard control services. The proposed CSIS is the appropriate funding mechanism to drive improvements in customer satisfaction.

13.4.2. Customer engagement and support

The scheme objectives include aligning the incentives of DNSPs with the customer service preferences of their customers and the incentive design criteria require the incentive design to be strongly supported by customers. The following section outlines how we have meet scheme requirement 3.3(1)(b)(ii).

Our proposed design targets areas customers particularly value and want improved, as evidenced by our engagement with our panel and customers.

For the 2021-26 regulatory period, AusNet codesigned the first CSIS in Australia. The CSIS was developed to provide more holistic incentives to improve customer experience, replacing an incentive for time taken to answer the telephone. The Customer Forum at the time and AusNet agreed the CSIS is a significant improvement on the existing incentive arrangements, but that it is only one element of AusNet's commitment to improving customer experience, and that the scheme will need to evolve over time.

As part of that evolution, we have engaged extensively with our Customer Experience Panel on the design of the updated CSIS for 2026-31. Early in the engagement process, we co-designed a set of Focus Questions with the Panel, which were the focus of our engagement. Related to the CSIS, we worked with the Panel to answer the following Focus Question: **"How might we design a CSIS that delivers maximum benefit for customers?"**.

Our engagement with the Customer Experience Panel on the CSIS design and principles included:

- reviewing the current CSIS metrics with a view of whether changes needed to be made for 2026-31
- revenue at risk for the CSIS
- C-Sat methodology
- setting targets for the new CSIS metrics.

Through deliberation over a number of discussions the Customer Experience Panel supported the following guiding principles:

- Continue to include customer experience metrics (i.e. C-SAT), however consider adding service level measures to have a mix of satisfaction and service level parameters.
- Continue to include overarching C-SAT measures (e.g. satisfaction with the overall planned outage experience) rather than specific aspects (e.g. satisfaction with communication on the planned outage).
- Customers should not pay twice for service improvements (i.e. through the CSIS and other expenditure allowances).
- AusNet should be ambitious with their CSIS, setting stretch targets and increasing the revenue at risk of the incentive, up from +/- 0.5% in the 2021-26 period, to reflect AusNet placing a high value on customer satisfaction and experience.

At our EDPR stakeholder offsite in August 2024, we received support from stakeholders on:

- Our proposed performance parameters for the 2026-31 CSIS, which includes removing a claims C-SAT metric that is part of the 2021-26 CSIS due to data issues and introducing a new service level metric for first-call resolution.
- Our proposal to change the C-SAT surveying methodology from telephone to online, due to significant benefits that can be extracted from moving away from an outdated surveying approach using telephone calls.[143]

We also engaged on the CSIS through our Draft Proposal, where we presented the updated CSIS metrics and our proposed methodology for setting targets in 2026-31. Our EDPR Coordination Group wrote in their submission to the Draft Proposal that they support our CSIS proposal, provided that the metrics are sufficiently challenging. We also received some further feedback from other submissions that we outline in section 2.5.4.

[143] On 18 October 2024, AusNet notified the AER of our proposed change in methodology given it's impacts on our current period 2021-26 CSIS.

13.4.3. Proposed CSIS design

13.4.3.1. Performance parameters

We propose the following performance parameters to satisfy scheme requirement 3.3(1)(b)(iii):

1. Customer satisfaction with unplanned outages
2. Customer satisfaction with planned outages
3. Customer satisfaction with new connections
4. First call resolutions (FCR).

This is a change from the CSIS parameters in 2021-26:

- We have removed the customer satisfaction with claims and complaints. This was supported by our panel engagement.
- We added a new metrics for FCR.

We considered a range of different interactions and potential metrics to include in a new CSIS with our Panel. It was determined that out current CSAT measures, excluding the complaint C-SAT, remined fit for purpose. In addition, a first call resolution was prioritised to be included as the call centre remains a key point of interaction our customer have with us. FCR is also seen as a proxy for ease to interact with, as customers are looking for a fast resolution to their queries. The mix of holistic and subjective satisfaction measures and a service level FCR measure aligns with customer feedback that we include a balance of the two types of measures.

In considering the parameters, we adhered to the following criteria (in addition to the Scheme requirements):

- We have evidence of improvements for the parameter being a customer priority to address existing or emerging pain points
- Metrics are largely within AusNet's control to improve
- Metrics can be accurately measured
- Improvements are achievable within the upcoming period, but targets would not be easily met without direct effort from AusNet
- Aiming to limit number of parameters under the scheme so the incentives are not diluted.

13.4.3.2. Measurement methodology

We propose to apply an online surveying methodology for the C-SAT based performance metrics. We have made the switch to the online method as of January 2025 and will no longer be collecting C-SAT using phone surveys, which was agreed to with our Research & Engagement Panel. This section satisfies scheme requirements 3.3(1)(b)(v). Our new method includes:

- Online survey delivered via customers' preferred channel for AusNet communications (SMS/email)
- A survey link at the end of every interaction message (e.g. following restoration of an outage or establishing a connection) which provides a chance for every customer to provide feedback immediately (or almost immediately) after their interaction
- We have made a minor refinement to our question wording to make it more clear and simple for our customers, as suggested by the R&E panel. The survey will ask " On a scale of 0 to 10, how was your recent [INTERACTION]? 0 means "Very Poor" and 10 means "Very Good".?"

We propose the following methodology for the FCR parameter:

- a hybrid approach to generate a robust data sample including:
- **On-call question:** Call centre agent script includes "Before we wrap up, is there anything else I can assist with? And are you clear on what's next?".
- **Post call survey:** following each call, an automated survey will ask "Have we resolved your queries today?".
- The percentage that respond "Yes" to the above questions will represent out FCR performance. Customers who say "No" will be given the opportunity to provide feedback as to how we could help them better.
- Scope includes all general enquiries calls related to the distribution network, excluding calls relating to outages and faults as we will be capturing satisfaction with outages in our C-SAT metrics which provides a more broad and useful metric for us to track for these interaction through the CSIS.

The proposed methodologies are compliant with the CSIS design criteria, including Clause 3.2 of the Scheme which requires that each performance parameter's features be accurately measured and compiled in an objective and reliable manner with results that could be audited.

13.4.3.3. Assessment approach

Our proposal is to set the CSIS metric targets for 2026-31 based on historical performance (historical period discussed below). Historical targets remain appropriate regardless of planned improvements, as:

- Maintaining satisfaction levels requires investment, due to rapidly changing customer expectations and the need to manage an increase in the frequency of extreme weather events and climate impacts.
- Our proposed improvements in customer service are not necessarily linked to our CSIS metrics; for example, we are proposing a large uplift in our commercial customer management, and commercial customers are not surveyed in the C-SAT. Equally, many parts of our C-SAT surveys are not related to expenditure or investment, including for example if our staff are professional.
- There are many other factors that can impact customer satisfaction in the future which we are not taking into account in setting targets; for example, as we progress substantive network investment during 2026-31 we anticipate an increase in planned outages across our customer base. This will likely put downward pressure on our C-SAT results.
- Our 2026-31 expenditure program stretches over five years, with most benefits likely to be fully realised at the end of the regulatory period or in the next period.
- We are proposing deadbands for our new targets, meaning the highest rewards can only be achieved if we make significant improvements.

While we have proposed an approach to setting targets, we have not proposed any targets to comply with scheme requirement 3.3(1)(b)(vi) at this stage as we are in the process of implementing changes to our C-SAT measuring methodology to an online-based approach which will likely have an impact on historical performance and target setting. In addition, we do not currently have a baseline of historical performance for FCR to base our targets on, as this is a new measure we have introduced to drive customer improvements. We propose to submit our data collected since January 2025 in our revised proposal to determine appropriate targets. While the historical period will not be multiple years, the data will be robust due to the expected higher sample size from online methods per month (n=~1000) compared to the phone survey (n=~30).

We will apply performance deadbands again to our assessment approach so that we are only rewarded or penalised for significant improvements or decrements to customer service levels. This approach incentivises genuine improvements in line with the value of the service improvements to our customers.

We have provided a template for annual reporting to satisfies scheme requirement 3.3(1)(b)(iv).

13.4.3.4. Financial component

Our Panel have told us to be ambitious with our new CSIS, and supported increasing the revenue at risk of the incentive, up from +/- 0.5% in the 2021-26 period. The increase in CSIS value is in line with the value that our customers attribute to the level of service improvements or degradations. We have heard the importance of improving customer service and strengthening the incentive to facilitate this was supported by our Panel.

We are not proposing to introduce an Export Service Incentive Scheme (ESIS) in 2026-31, which provides us the flexibility to increase the revenue at risk of the CSIS to 1%. In doing so, we propose that the Service Performance Target Incentive Scheme (STPIS) remains at 4.5%, with the total incentives from STPIS and CSIS equalling 5.5%.

We have proposed an equal weighting and incentive rate for all 4 parameters as the Panel did not express a desire to value one more than another. We do not propose any exclusions. We consider this section satisfies scheme requirement 3.3(1)(b)(vii) and (viii).

13.4.4. Supporting Documentation

We have included the following document to support this chapter:

- AusNet 2026-31 CSAT Data, Targets and Reporting template.

13.5. Service Target Performance Incentive Scheme

The national distribution STPIS provides a financial incentive to distributors to maintain and improve service performance. The STPIS ensures that cost efficiencies encouraged under our expenditure schemes are not achieved at the expense of service quality for customers. Penalties and rewards under the STPIS are calibrated with customers' willingness to pay for service improvements. This aligns with the distributors' incentives promote efficient price and non-price outcomes in accordance with the long-term interests of consumers, consistent with NEO.

In November 2018, the AER reviewed the operation of the STPIS and published its final decision on STPIS version 2.0. We have applied this version of the STPIS for the upcoming 2026-31 regulatory period.

13.5.1. Regulatory Requirements

The STPIS, as it will be applied in Victoria is defined in the following two documents:

- Electricity Distribution Network Service Providers Service Target Performance Scheme Guidelines, released in November 2018 (STPIS Guidelines);
- The AER's Framework and Approach.

NER S6.1.3(4) requires that a regulatory proposal must contain a description of how the DNSP proposes the STPIS should apply for the relevant regulatory control period.

13.5.2. Proposed Application of the STPIS Scheme

AusNet proposes to apply STPIS v2.0 and we have prepared our actual performance data tin accordance with this scheme. This allows us to propose targets consistent with the STPIS requirements.

13.5.2.1. Revenue at Risk

AusNet currently has the default revenue at risk of 4.5% for the network reliability component. We propose that there be no change to this figure.

13.5.2.2. MED Threshold

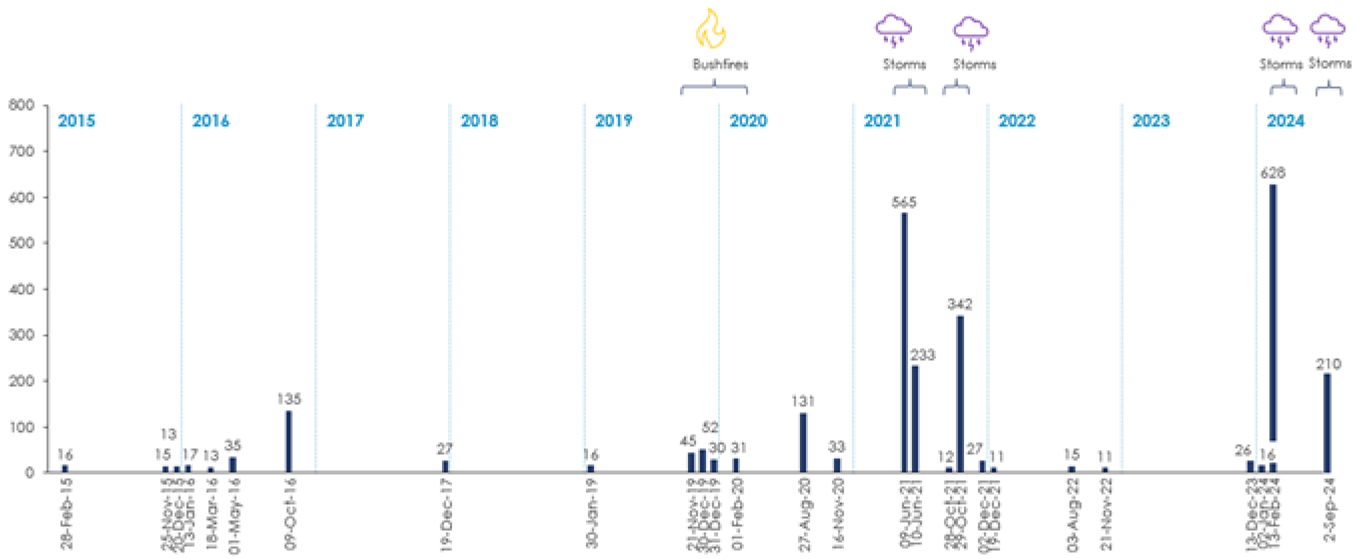
The AER's proposed approach to calculating the exclusion or major event day (MED) threshold is to apply the methodology indicated in the STPIS Guideline. We currently apply a standard deviation of 2.8β when calculating the MED threshold and we propose that the same value applies for the forthcoming regulatory control period.

We also propose to exclude catastrophic events from the calculation of the MED threshold in the 2026-31 regulatory period. This is consistent with current engineering standards, specifically IEEE 1366-2022, which outlines that extremely large daily SAIDI values can skew the distribution of performance (which is assumed to be Gaussian) and, when included in a MED threshold determined using a 5-year average, can cause a relatively minor upward shift in reliability metric trends.

The inclusion of all MED events in setting the threshold during the current period has resulted in the under-identification of MED exclusions. This means more outages have counted towards performance indices, leading to artificially under-performing indices. This is an unreasonable outcome as it penalises us for catastrophic events that are clearly rare and considered outliers, even when compared to other large events.

As an illustration, since 2015 there have been 4 major storm events (and 5 days) where the SAIDI result has been extremely large. These are highlighted in the chart below.

Figure 13-6:47 USAIDI per Major Event Day



AusNet has previously raised this issue with the AER, and specifically has proposed a suspension under section 2.7 of the STPIS for the days deemed catastrophic. This would have meant that the USAIDI results from these days did not impact the calculation of the MED threshold in future years. However, the AER's view was that the scheme did not allow it to exclude catastrophic events from the calculation of the Major Event Day threshold because the AER rejected the application of the 2012 version of the IEEE standard when it last reviewed the STPIS, and it is the 2003 version of the IEEE standard, which does not contain the same discussion of the impact of catastrophic events, which is applicable in the current STPIS.

AusNet considers that this is a critical issue that needs to be addressed, and as the climate changes, is expected to increase in importance over time. We propose that the AER writes into our distribution determination that catastrophic events should be excluded from the calculation of the MED threshold under the applicable STPIS. If the AER does not consider this approach is allowed under the regulatory framework, then we formally propose that the AER reviews the STPIS in line with the distribution consultation procedures to move to a more recent IEEE standard (either the 2012 or 2022 version) which would allow for the exclusion of catastrophic events when calculating the MED threshold.

13.5.2.3. Exclusions

AusNet proposes that the exclusions set-out in clauses 3.3, 5.4 and 6.4 of the STPIS scheme apply to AusNet in the 2026-31 regulatory control period. We are not currently proposing any modification to these exclusions.

13.5.2.4. Measures

The AER has set applicable parameters for reliability of supply (system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI) and momentary average interruption duration index (MAIFI)).

AusNet proposes that the customer service (telephone answering) parameter should not apply to AusNet in the 2026-31 regulatory control period. We have instead proposed that this parameter is replaced by our proposed Customer Satisfaction Incentive Scheme. Clause 5.1(b) of the STPIS states that the telephone answering parameter will apply unless the AER determines otherwise in its distribution determination for a DNSP. We consider the AER should exercise this discretion not to apply the telephone answering parameter because we are proposing a more robust and meaningful measure of customer satisfaction. This is consistent with the AER's determination for the current regulatory period, where it accepted the replacement of the STPIS telephone answering parameter with the Customer Service Incentive Scheme (CSIS).[144]

The AER proposes to set performance targets based on the distributor's average performance over the past five regulatory years. AusNet supports this approach as the basis for calculating targets.

13.5.2.5. Proposed Target

AusNet proposes to calculate the targets using data from the five financial years from 1 July 2020 to 30 June 2025. The actual performance data for FY 2025 is not yet available. For the purposes of this Regulatory Proposal, we have

144 FINAL DECISION AusNet Services Distribution Determination 2021 to 2026 - Attachment 12 Customer service incentive scheme

calculated the average historic performance using actual data from FY 2020 to FY 2024. We will update the average historic performance using the actual performance data for FY 2025 in our revised proposal.

AusNet proposes reliability and resilience programs as part of our capex proposal for the 2026-31 regulatory control period, which are expected to result in improvement in supply reliability. We acknowledge the need to adjust STPIS performance targets to reflect these planned reliability improvements, in accordance with clause 3.2.1(a)(1A) of STPIS v2.0.

However, rather than adjusting the STPIS performance targets, AusNet proposes to remove the expenditure associated with improved reliability (as measured by the STPIS) from our capex forecast. A detailed discussion on the calculation of the expenditure associated with improved reliability to be removed, along with its impact on our capex proposal, is provided in section 6.4.12.

We believe this approach would provide greater financial benefits to our customers compared to an alternative approach of including the full capex amount for reliability-driven projects in our proposal and adjusting STPIS targets. This is because removing the expenditure associated with reliability improvements not only compensates customers for the lower standard of STPIS targets on an equal basis, but also provides additional financial benefits by reducing revenue through lower return on capital and depreciation, as the removed capex will not contribute to the RAB or depreciation allowance. In NPV terms, removing the associated expenditure from capex, as opposed to adjusting STPIS targets, is estimated to deliver a net benefit of $0.26 million (real $2025-26) to our customers.

In addition, this approach also provides the additional benefits below to our customers:

- It keeps up front costs lower for customers than otherwise.
- AusNet, not customers, wear the risk that the project does not deliver the intended outcomes. Customers only pay the full project costs if it is successful.

Therefore, we consider this approach to better satisfy the objectives of the scheme, as outlined in clause 1.5. This approach addresses feedback from our Availability Panel that the forecast reliability benefits of our resilience and reliability programs should be accounted for holistically across our Revenue Proposal.

We outline our method for calculating the amount of capex to be removed and explain why this approach delivers greater benefits to our customers below.

13.5.2.6. Incentive Rates

AusNet proposes to calculate the incentive rates in accordance with the steps outlined in clause 3.2.2 of STPIS v2.0, using the formulas provided in Appendix B of STPIS v2.0.

The VCR is an important input to calculating the incentive rates. It estimates the value different types of customers place on reliable electricity supply. In 2019, the AER separately published its inaugural reports on the VCR methodology and the VCR values. In December 2023, the AER initiated its 2024 VCR review – required every five years – which included reviewing the 2019 VCR methodology by 30 August 2024 and publishing the VCR (for it to take effect) by 18 December 2024.

Due to timing, we have not incorporated the final 2024 VCRs into our Regulatory Proposal given it was published in December 2024. For the purposes of this Regulatory Proposal, we have calculated incentive rates based on AER's latest published VCRs from December 2023 escalated to the start of the 2026-31 regulatory period. We will update the incentive rates using the final 2024 VCRs in our Revised Regulatory Proposal. This is consistent with our approach of incorporating the new VCRs into other aspects of our Regulatory Proposal.

Table 13-2: STPIS Targets and Incentive Rates for 2026-31

Measure	Average Historic Performance	Modification	Proposed Targets	Proposed Incentive Rates
USAIDI				**(%/minute)**
Urban	88.030	0	88.030	0.0202%
Rural Short	184.240	0	184.240	0.0200%
Rural long	295.080	0	295.080	0.0079%
USAIFI				**(%/0.01 Interruptions)**
Urban	0.812	0	0.812	1.4579%
Rural Short	1.506	0	1.506	1.5917%
Rural long	2.146	0	2.146	0.7260%
MAIFI				**(%/0.01 Interruptions)**
Urban	2.941	0	2.941	0.1166%
Rural Short	4.948	0	4.948	0.1273%
Rural long	8.839	0	8.839	0.0581%

Source: AusNet

13.5.2.7. Telephone answering parameter

The STPIS allows that where a DNSP makes a proposal to vary the application of this scheme, that proposal must be in writing and:

(1) include the reasons for and an explanation of the proposed variation

(2) demonstrate how the proposed variation is consistent with the objectives in clause 1.5

(3) if appropriate, include the calculations and/or methodology which differ to that provided for under this scheme.

The STPIS states that the 'telephone answering' parameter referred to in clause 5.1(a)(1) will apply during a regulatory control period except where the AER determines otherwise in its distribution determination for a DNSP.

As discussed above, AusNet proposes that the telephone answering parameter should not apply in the forthcoming regulatory period and that it should be replaced with the CSIS scheme instead. We consider the CSIS will provide a more holistic incentive on improving customer satisfaction and so replacing the telephone answering parameter with this scheme better meets the objective of the STPIS and is in the long-term interests of our customers. We note that the AER accepted the replacement of the STPIS telephone answering parameter with the Customer Service Incentive Scheme (CSIS) for the 2021–26 regulatory period.[145]

13.5.3. Supporting Documentation

We have included the following document to support this section.

- Spreadsheet entitled "STPIS Target Calculation (Full Year)" showing calculation of the STPIS targets.
- Spreadsheet entitled "STPIS Incentive Rates Calculator" showing calculation of the STPIS incentive rates.

13.6. Capital Efficiency Sharing Scheme

This section sets out our proposal with respect to the application of the Capital Expenditure Sharing Scheme (CESS). It sets out:

- The calculation of the current period's efficiency carryover amount, which will be recovered during the forthcoming period.
- Our proposal for the operation of the CESS in the next period.

13.6.1. The current period carryover amount

We have calculated the efficiency carryover amount to be recovered during the forthcoming regulatory period in accordance with the AER's final decision, determination on the application of the CESS for the 2021-26 period and November 2013 CESS guideline. This calculation involved the following steps:

- Calculate the capex applicable to the CESS, by removing customer contributions and asset disposal from total capex.
- Removing excluded costs from actual, expected and approved capex – discussed further below
- Calculate the cumulative underspend amount for the current regulatory period in net present value terms.
- Apply the sharing ratio of 30% to the cumulative underspend amount to work out what our share of the underspend should be.
- Make an adjustment for differences between actual and forecast capex for the final year of the previous regulatory period (CY2020).
- We calculate the CESS payments taking into account the financing benefit of the underspend.

145 FINAL DECISION AusNet Services Distribution Determination 2021 to 2026 - Attachment 12 Customer service incentive scheme

13.6.1.1. Adjustments for material deferral

We have not adjusted our proposed CESS revenue adjustment to reflect material capex deferral from the current regulatory period into the next. Principally, this is because our actual and expected capex in the current regulatory period is 19% above the allowance, reflecting several new drivers and the need to address new, anticipated issues not reflected in the capex allowance. This planned overspend is contributing to a CESS penalty of $117m. Therefore, the criteria in which a CESS adjustment may be warranted, including "the amount of the estimated underspend in capex in the current regulatory control period is material", have not been met.

Furthermore, the amount of capex deferred from the current regulatory period is not considered material.

Through our stakeholder engagement on this issue, our customers did not express concerns with our proposed approach and generally considered it a matter for the AER to assess.[146]

13.6.1.2. Proposed exclusions for 2021-26

In calculating our proposed CESS revenue adjustment, we have excluded the following capex:

- Expenditure associated with the transition to Zinfra as our operations and maintenance service provider (Zinfra transition costs); and
- Innovation expenditure.

While we acknowledge the current CESS guideline applies to total net capex and does not explicitly provide for exclusions, we have outlined below the reasons why our proposed exclusions are consistent with the regulatory framework and/or our current determination and, therefore, should be approved by the AER. We also note that the AER's preference, as stated in the 2026-31 Framework and Approach, is "to apply the CESS to all categories of capex and to make exclusions only in exceptional cases [emphasis added]."147 This indicates the AER has a level of discretion regarding the approval of CESS exclusions, despite the provisions of the existing CESS guideline.

Zinfra transition costs

We consider the costs of transitioning to Zinfra, which are not captured in our current period allowances, should be excluded from the calculation of CESS incentive payment. This approach avoids unreasonably penalising AusNet and discouraging businesses from investing in lower cost arrangements that, ultimately, benefit customers through lower costs.

Accordingly, in calculating our proposed CESS payment, we have excluded $13m of transition costs. As shown in the table below, these costs relate to Digital systems, fleet, property leases and tools and equipment and will mostly be incurred in 2025-26. These costs are not part of our current period revenue allowance but have been included in our forecasts of actual capex in 2024-25 and 2025-26 provided as part of this revenue proposal.

Table 13-3: Zinfra transition costs excluded from the CESS ($'000)

	2024-25	2025-26
ICT	$0.0	$2,700.0
Vehicles	$0.0	$1,816.9
Property leases	$909.6	$69.5
Tools and equipment	$0.0	$7,466.4
Total	$910	$12,052

Source: AusNet

We have not proposed to exclude opex transition costs from the EBSS, due to the opex base-step-trend forecasting methodology and EBSS together providing a continuous incentive, regardless of the year within in a regulatory period additional costs are incurred or savings made. The continuous nature of the EBSS allows networks and customers to share both the costs and benefits of investments to improve efficiency, regardless of which year an investment was made within a regulatory period.

In contrast, the timing of the transition costs (being at the end of the current regulatory period) in conjunction with the capex bottom-up forecasting approach means that, unless excluded, AusNet will incur CESS penalties as a result

146 Coordination Group meeting, 6th December 2024

147 AER, *Framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026–31*, July 2024, p.16

of the transition costs, with little opportunity to benefit by outperforming the capex allowance and earning a corresponding CESS reward. This is because the lower rates enabled by our upfront investment in more efficient arrangements will only impact the final 9 months of the current regulatory period.

By applying Zinfra unit rates to our capex forecast, which are lower than alternative service provider rates, we will pass on the benefits through lower costs to customers from 1 July 2026, and have foregone capex outperformance opportunities during the 2026-31 period. Without this proposed CESS exclusion, we will be penalised for investing in lowering costs for customers.

If the AER is minded to reject this proposed CESS adjustment, the alternative way to ensure the regulatory framework does not penalise networks from making alternative investments that benefit customers would be for our 2026-31 capex forecast to be built up using unit rates assuming we had not changed service provider. In this scenario, we would pay a penalty on the transition costs, but also share in the resulting savings. This approach would increase our repex forecast by approximately $30m over the 2026-31 regulatory period, reflecting the difference between Zinfra's costs and the costs of our current, primary service provider obtained during the RFQ process. While a different forecasting approach applies to opex, the equivalent opex amount is approximately $40m.

Taking account of the revenue that would be recovered over the life of the assets, these amounts significantly exceed the revenue impact of the CESS exclusion of up to $4m (i.e., 30% * $13m).

When considered holistically, our approach of applying Zinfra unit rates to our forecast and excluding transition costs from the CESS, is demonstrated to be in the long- term interests of customers relative to the alternative approach outlined above.

We informed our Coordination Group of our decision to change service delivery partners and intent to exclude transition costs from the CESS. However, the timing and confidentiality of the decision did not allow for meaningful engagement on this issue.

We note that, under the current CESS guideline, differences between actual and forecast capex in 2025-26 will be trued up through a revenue adjustment as part of the determination for the subsequent, 2031-36 regulatory period. However, as noted above, transition costs have been included in our forecasts of expenditure for 2024-25 and 2025-26, which are reflected in the CESS model. Accordingly, while a true-up will ultimately apply to 2025-26 costs, the AER's decision on this exclusion as part of its 2026-31 determination will impact the CESS incentive payment we recover during the 2026-31 regulatory period.

Innovation expenditure

We propose to exclude innovation capex from the calculation of our proposed CESS incentive payment. In applying this exclusion, we have removed $6m from current regulatory period actual and expected capex.

Related to this, we have also:

- Excluded innovation opex from the EBSS.
- Proposed a revenue adjustment to reflect differences between the composition of actual and forecast innovation capex and opex (discussed further in Chapter 5).

We propose to maintain the exclusion of innovation expenditure from the expenditure incentive schemes in the 2026-31 regulatory period, as discussed further below.

Our approach of excluding innovation expenditure from the current period EBSS and CESS calculations is consistent with the AER's Draft Decision for the current regulatory period, where it stated:[148]

> *We also note that innovation was part of the negotiations with AusNet Services' Customer Forum. We understand the projects are focused on unlocking the benefits of the energy system transformation and that there would be an independent Innovation Advisory Committee that will evaluate and prioritise the innovation projects that best reflect customer preferences.* ***We also note that any unspent innovations expenditure will not be a part of the CESS*** [emphasis added].

As noted by the AER in its Draft Decision, we engaged extensively with the Customer Forum as part of preparing our 2021-26 innovation proposal. The Customer Forum wanted to ensure that, were we to receive innovation funding, we could not profit if we didn't deliver any innovation projects and therefore underspent the allowance. As such, we agreed with the Customer Forum that this allowance would be provided on a use-it-or-lose it basis, as documented in the Customer Forum's Final Report:

In 2018, the Customer Forum identified $7.5 million ($2020) as an appropriate allowance. Importantly, the Customer Forum stipulated this figure was a ceiling and AusNet Services agreed to return funding to customers for any nominated projects that did not proceed.149 We have honoured this commitment and we have made a negative adjustment to revenues to forego any financial benefit we would have otherwise received, resulting from differences

148 AER, Attachment 5: Capital expenditure | Draft decision – AusNet Services 2021–26, p.28

149 Customer Forum, Final Engagement Report, 31 January 2020, p.35

in both the timing of expenditure and the mix of capex and opex, relative to the forecast included in our revenue determination.

Under a use-it-or-lose-it arrangement (implemented through a revenue adjustment) with a ceiling it becomes redundant to include innovation capex in the CESS and the EBSS. This would simply increase the complexity of the revenue adjustment calculation given we do not seek to be rewarded for underspends, and any innovation spend exceeding the total allowance over the regulatory period will be subject to the incentive schemes, given we have committed to apply a ceiling to the innovation allowance.

We note that in its recent decisions, the AER has not accepted network proposals to exclude innovation capex from the CESS for a variety of reasons, including consideration of the effects on revenue. However, in these cases the innovation allowance was not received by the network on a use-it-or-lose-it basis. In addition, the exclusion of innovation capex from our proposed CESS calculation has the effect of **decreasing** our proposed revenue requirement, reflecting a small underspend of the approved capex (offset by opex overspending). This demonstrates that we are operating in the best interests of customers by honouring our commitment to the Customer Forum. If this CESS exclusion is rejected, we would need to recalculate this amount.

13.6.1.3. Proposed carryover amount for 2021-26

The table below sets out our proposed CESS carryover amount, calculated in accordance with the steps outlined above.

Table 13-4: Calculation of CESS carryover amount ($m 2026)

	2021-22	2022-23	2023-24	2024-25	2025-26
Capex allowance	346.8	337.98	332.1	280.6	279.6
Actual capex	359.82	347.92	391.47	484.45	489.62
Excluded costs	0.0	0.8	2.3	2.7	13.6
Net capex for CESS purposes	341.4	331.34	383.5	449.0	427.7
Underspend	5.38	6.64	-51.35	-168.4	-148.1
Year 1 benefit		0.15	0.15	0.2	0.1
Year 2 benefit			0.18	0.2	0.2
Year 3 benefit				-1.4	-1.1
Year 4 benefit					-3.5
Year 5 benefit					
NPV underspend	7.1	8.3	-57.7	-177.0	-148.1
NPV financing benefit	0.0	0.2	0.4	-1.1	-4.3
Total underspend (NPV) adjusted for deferrals	-367.4				
Relevant sharing ratio	30%				
Consumer share	-257.2				
NSP share	-110.2				
Total NSP financing benefit (NPV)	-4.8				
NPV of CESS payments (post-adjustment) 30 December 2020	-105.4				
NPV of CESS payments (post-adjustment) 30 June 2021	-$117.0				
CESS Payment Per Year ($2021 million)	-$23.4	-$23.4	-$23.4	-$23.4	-$23.4

Source: AusNet

13.6.2. The 2026-31 regulatory period

In the Framework and Approach, the AER stated that it intends to apply the CESS, as amended in its 2023 review of incentives schemes to implement a tiered arrangement, to the Victorian DNSPs in the 2026–31 regulatory period.[150] We endorse that position, except for several proposed exclusions which are discussed below.

We would welcome engagement with AER on these exclusions and alternative uncertainty mechanisms, as part of both this review process and a potential CESS review that we understand the AER is considering.

13.6.2.1. Proposed exclusions in the 2026-31 regulatory period

We consider the following categories of capex should be excluded from the CESS applying in the 2026-31 regulatory period:

- **Innovation expenditure**, as we are proposing this on a use-it-or-lose-it basis, consistent with the outcomes of our stakeholder engagement and the AER's determination for the current regulatory period.
- **Regional Reliability Allowance (RRA) expenditur**e, as we are proposing this on a use-it-or-lose-it basis, consistent with the outcomes of our stakeholder engagement.
- **Expenditure for new technology connections,** to reflect uncertainty around the pace of the energy transition and the difficulty in accurately forecasting some connection types. The specific connection types proposed for exclusion are:
  - Community batteries.
  - Grid scale battery and renewable generator hybrids.
  - Public EV charging points.
  - Data centres.

Our connections capex forecast for these categories is discussed further in section 6.11.

As discussed in Chapters 7 and 9, we have proposed that the innovation allowance and the RRA would be on a 'use it or lose it' basis and as such, it is appropriate to exclude these categories from the CESS (and the EBSS) to ensure that we do not receive a CESS reward if we underspend these allowances.

We engaged with our customers and stakeholders on the three exclusions outlined above, as part of consultation on the application of incentive arrangements during the next regulatory period.[151]

There was general support from the Coordination Group and Availability Panel for the exclusion of innovation and RRA expenditure, respectively, from the CESS, on the grounds that these allowances should be provided on a 'use it or lose it' basis.[152] However, both panels were generally comfortable leaving these decisions to the AER

In respect of excluding new types of connections, we engaged on the growing level of uncertainty with the Coordination Group, and the possible ways to manage the risk to our customers, including through an exclusion. The Coordination Group acknowledged the risk of uncertainty is growing and that accurately forecasting these types of connections is extremely challenging. In its Interim Report, the Coordination Group supported the need for a new exclusion.

Our proposed exclusion for new types of connections is discussed further in the following section and in capex chapter section 3.11.

Exclusion of new technology connections

We propose to exclude the following specific connection types, which we are referring to as 'new technology connections':

- Community batteries.
- Grid scale battery and renewable generator hybrids.
- Public EV charging points.
- Data centres.

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150 AER, *Framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026–31*, July 2024, p.16

151 Coordination Group meeting, 16 April 2024

152 Coordination Group, Independent Report on Draft Revenue Proposal 2026-31, p. 34

While new customer numbers have been relatively consistent over time, in recent 10 years we either have experienced, or are anticipating, a surge in connections of new technologies including community batteries, solar and battery hybrids, connections of EV charging points and data centres.

Forecasting new technology connections is particularly difficult and there are high levels of uncertainty, due to limited information on the scale of roll-out of these technologies to 2031, lack of sufficient evidence of connection costs and customer contributions (customer contributions are based on anticipated demand impacts, which are also mostly unknown still), with the potential for connections costs to be large and lumpy (in contrast to high volume load connections). For example, unanticipated data centre connections account for a material share of our current period expected overspend. This is associated with a small number of connection enquiries, demonstrating the lumpiness and high cost per connection for this connections category.

In the Framework and Approach, in response to stakeholder submissions, the AER considered the exclusion of connections expenditure from the CESS, coming to the following conclusion:

> *A decision on exclusions is not required as part of this F&A and is best considered in context as part of the broader consultation on regulatory proposals, including forecasts of connections capex, next year. As we have noted in recent decisions for other distributors, our preference is to apply the CESS to all categories of capex and to make exclusions only in exceptional cases. This is because under the ex-ante regulatory framework, we make a decision on total capex and do not approve specific projects or programs. While we consider (amongst other things) the prudency and efficiency of specific projects/programs to inform our view of a total capex forecast, businesses can depart from project and program level forecasts, and/or spend more or less than the total capex forecast as circumstances change throughout the regulatory control period.*

We agree that the exclusion of connections capex should be considered as part of the assessment of, and consultation on, Victorian electricity distribution Regulatory Proposals. We also agree that exclusions should be made in exceptional case and consider that these connection types that are linked to the energy transition and evolving technology should qualify as exceptional. This is because:

- The energy transition is the most significant change in the energy sector since the electrification of the state and while it is having a very significant impact on connections and other expenditure categories today it is unlikely to have this same degree of impact in the longer term.
- The potential magnitude of costs impacted by new technology connections can be very significant, as demonstrated by Jemena applying for a reopener due to data centre connections, using a regulatory mechanism that had never been used by electricity networks since the regulatory framework was established.

For these connection types we cannot rely on departing from project and program level forecasts and/or spending more or less than the total capex forecast to manage this uncertainty, due to our inability to control connections expenditure.

We are required to carry out all requested connections, and the type and volume of connections is fully outside of our control. If our cost estimates are materially higher than actuals, AusNet customers pay for efficiency rewards that were achieved not through efficiencies but through inaccuracy in forecasts. Conversely, if our estimates are materially lower than actuals, AusNet customers pay financial penalties for cost overruns, or they get lower services in other areas if we are required to divert funding to meet connections requirements (in practice, networks have a limited ability to fund cost overruns in particular categories without impacting other capital projects and projects).

Given the significant risk faced by both AusNet and its customers from high uncertainty in connection forecasts during 2026-31, we propose that the connection costs related to new technology connections are excluded from the CESS. This reduces the cost risk borne by AusNet customers related to inaccurate forecasts. While the risk is not completely removed (costs can still overrun or there may be savings), excluding the expenditure from the CESS materially and appropriately reduces the financial impact of either scenario on AusNet customers. importantly, even with a CESS exclusion in place for new technology connections, we will continue to face a strong incentive to minimise all connections expenditure, in order to outperform the total capex allowance and maintain our reputation as a prudent and efficient asset owner and operator.

Our proposal to exclude new technology connections is specific to the 2026-31 regulatory period, when there is significant uncertainty about the volume and cost of these connections. The approach for the 2031-36 regulatory period can be assessed at the next regulatory determination.

Further information on the sources of uncertainty for new technology connections is provided in Chapter 6 – Capital Expenditure.

13.6.2.2. Proposed forecast capex for the CESS

Table 13-5 below sets out the proposed capex for the CESS in the 2026-31 regulatory period.

Table 13-5: Proposed capex for the CESS ($m 2026)

	2026-27	2026-27	2024 (FY)	2025 (FY)	2026 (FY)
Forecast Net Capex	603.1	687.0	729.4	733.5	743.1
Less excluded costs					
Innovation Program	0.5	0.5	0.5	0.5	0.5
RRA	6.2	6.2	6.2	6.2	6.2
New connection types	17.6	16.9	18.5	16.8	15.0
Capex for CESS ($m, 2026)	**578.7**	**663.4**	**704.1**	**710.0**	**721.4**

Source: AusNet

13.6.3. Supporting documentation

We have included the following documents to support this chapter:

- AusNet CESS model.

13.7. Efficiency Benefit Sharing Scheme (EBSS)

13.7.1. Overview

The Efficiency Benefit Sharing Scheme (EBSS) incentivises distribution network service providers (DNSPs) to improve opex efficiency while ensuring that savings are fairly shared with customers. AusNet has calculated a carryover of $40.2 million for the 2026-31 regulatory period.

This section sets out AusNet's proposal with respect to the application of the efficiency benefit sharing scheme (EBSS). It sets out:

- The calculation of the current period's efficiency carryover amount, which will be recovered during the forthcoming period.
- AusNet's proposal for the operation of the EBSS in the next period.

As a result of the change in the regulatory period, the AER has proposed amendments to the operation of the EBSS to ensure that the impact of the period from 1 January 2021 to 30 June 2021 is appropriately factored into the EBSS calculation.

We have adopted the revised RIN template issued by the AER for the purposes of this calculation. Our approach to Opex described in Chapter 7 is linked to the EBSS which uses the same inputs where relevant.

13.7.2. Rule Requirements

The National Electricity Rules (NER) 6.3.2(a)(3) provides the framework for how any Efficiency Benefit Sharing Scheme (EBSS) applies to the building blocks in a revenue determination, primarily focusing on operating expenditure (Opex). The scheme incentivises DNSPs to improve efficiency by allowing them to retain a portion of the savings they achieve. These savings are then reflected in the building blocks for future regulatory periods, benefiting both the DNSP and its customers.

13.7.3. Application in the current regulatory period

AusNet has calculated the efficiency carryover amount to be recovered during the forthcoming regulatory control period in accordance with the AER's final decision and determination on the application of the EBSS for the 2021-2026 period. This calculation involved the following steps:

Determining actual and expected opex for the EBSS in 2018 and 2020 to 2024-25, which is equal to total opex less:

- GSL payments
- Movements in provisions
- Debt raising costs
- Demand Management Innovation Allowance (DMIA), and
- Innovation spend.

The basis of the efficiency carryover amount is calculated by comparing 2021-26 controllable opex with the adjusted regulatory allowances.

The duration of the carry over period for 2026-31 is 5 years which aligns with AusNet's regulatory period.

Table 13-6: Current regulatory period incremental efficiency gains and losses ($m, 2025-26)

Calculation	2020	Jan-Jun 2021	2021-22	2022-23	2023-24	2024-25	2025-26
Total opex (excluding Debt Raising Costs)	275.0	142.3	300.0	252.6	299.1	331.8	282.4
Less: DMIA costs	-0.3	-	-	-0.1	-	-0.9	-
Less: GSL payments	-13.7	-1.4	-43.3	-8.4	-28.4	-7.5	-
Less: Movements in provisions	-5.4	-2.7	23.0	18.2	2.6	-	-
Less: Innovation	-	-	-	-	-0.3	-1.3	-
Opex For EBSS	255.6	138.3	279.6	262.4	273.1	322.0	282.4
Approved allowance for EBSS	315.3	169.8	288.2	285.9	302.7	299.2	305.9
Incremental efficiency gain/loss	24.2	1.7	-19.0	15.0	-6.1	-52.5	46.4

Source: AusNet

Table 13-7: EBSS carryover amounts from the current regulatory period ($m, 2025-26)

Carryover of efficiency gain/loss made in:	2026-27	2027-28	2028-29	2029-30	2030-31	Total
2020 True Up	-12.1					
HY2021True Up	1.7					
2021-22	-19.0					
2022-23	15.0	15.0				
2023-24	6.1	6.1	6.1			
2024-25	-52.5	-52.5	-52.5	-52.5		
2025-26	46.4	46.4	46.4	46.4	46.4	
Efficiency carryover amount	**–15.0**	**15.0**	**0.0**	**-6.1**	**46.4**	**40.2**

Source: AusNet

The calculation of the EBSS carryover for the 2021-26 period is set out in table above and can be found in reset RIN template 7.5 in Workbook 3.

13.7.4. Application in the 2026-31 regulatory period

The application of EBSS for 2026-31 is dependent on the base-trend-step opex forecasting methodology. AusNet has nominated 2022/23 regulatory year as the base year as it will be the most recent year that is not affected by abnormal events and is expected to reflect efficient spend. Further information can be found in Chapter 7 – Operating Expenditure.

AusNet proposes to remove these categories of opex not forecast using a single year revealed cost approach in the following period. This is consistent with the approach applied in the current regulatory period and remains appropriate in the forthcoming regulatory period. Where a revealed cost approach to forecasting the opex allowance is not used, then the EBSS should not be applied to those forecasts.

- GSL payments are one such category, where the amount forecast is based on a five and a half-year average. AusNet considers that GSL payments should be excluded from both the allowance and the actuals when assessing the efficiency benefit under the EBSS Guideline for all GSLs including pass through amounts. GSL payments are effectively an incentive scheme and should not be subject to EBSS, by not excluding this it results in an incentive payment on a jurisdictional incentive payment which were developed after an assessment of customers' willingness to pay and the balance between the service incentives and efficiency incentives generally.
- We accept the AER's approach to setting debt raising costs using its current benchmark methodology, although this embeds a benchmark significantly below actual cost. Debt raising costs should also be excluded from the EBSS calculation.
- As discussed in Chapter 8, we have proposed that the innovation allowance would be on a 'use it or lose it' basis and as such, it is appropriate to exclude it from the EBSS to ensure that we do not receive an EBSS reward if we underspend this allowance.
- As discussed in Chapter 6, we have proposed a regional reliability allowance which would also operate on a 'use it or lose it' basis. We consider that it would be appropriate to exclude the costs of any opex projects which may ultimately be funded through this allowance, should such projects be identified and supported by our stakeholders.
- The DMIA is also specifically designed to be a 'use it or lose it' research allowance and should continue to be excluded from EBSS calculations.

Therefore, excluding these costs better achieves the requirements of clause 6.5.8 of the NER and the NEO.

13.7.5. Supporting Documentation

We have included the following documents to support this chapter:

- ASD – AusNet - EBSS model.

13.8. F-factor Scheme

On 22 December 2016, the Victorian Government published the "f-factor scheme order 2016" (the 2016 Order), which revoked the previous 2011 f-factor scheme Order. The current f-factor scheme targets incentives towards fire ignitions that pose the greatest risk of harm via ignition risk units (IRUs).

The AER's F&A paper set-out that they propose to continue to apply the f-factor scheme to Victorian DNSPs in the forthcoming distribution determinations. We endorse this decision to apply the f-factor scheme.

We submit our annual fire start data, including the IRU amount, to the AER each year. Under the F-factor scheme, we are awarded $15,000 for each unit of IRU below the target and penalised $15,000 for each unit of IRU exceeding the target. DEECA establishes annual IRU Targets for each Victorian distribution business on the following basis:

- IRU Targets will only be published for a single year;
- IRU Targets will be calculated on the basis of the most recent five-year fire start history that is available; and
- IRU Targets will be adjusted to reflect the estimated benefit of bushfire mitigation activities operating throughout the bushfire season, with a particular emphasis on the operation of Rapid Earth Fault Current Limiters (REFCL).

Details of our past performance under the F-factor scheme are provided in section 13.1.

13.9. Demand Management Incentive Scheme and Allowance

The AER's F&A paper set-out that they propose to continue to apply both the demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM) in the forthcoming distribution determinations. We endorse this decision and have proposed the DMIA amount as per AER's approach to setting this allowance for each distributor. Please see section 8.3.8 for details of out DMIA proposal.

13.10. Export Service Incentive Scheme

In 2023, the AER made a decision to allow a new type of Small Scale Incentive Scheme, the Export Service Incentive Scheme (ESIS) which can be designed and proposed through Regulatory Proposals[153]. The regulatory requirements for Small Scale Incentive Schemes are outlined in section 13.4.1.

As outlined in section 2.5.4.2, we engaged with our Future Network panel on the value to proposing an ESIS for 2026-31 and their feedback was to only introduce an ESIS if known pain points can be better addressed through an incentive scheme than through expenditure programs.

Following consideration of the panels feedback and whether our export metrics could be appropriately targeted through an incentive scheme, we do not propose to introduce an ESIS in 2026-31, as our export services, such as solar connection timeframes, are currently performing well on average and we do not have evidence of other customer pain points that would be suitable for this type of incentive.

[153] AER - Final - Export Service Incentive Scheme - June 2023

14. Typical charges for residential and business customers

14.1. Key points

This chapter will explain the differences between network and retail bills, outline the components that make up a retail bill. We also explain how our distribution charges are expected to change over the regulatory period for different types of residential and business customers, noting that residential customers will experience different charges depending on their progress through the electrification journey.

14.2. Chapter structure

This chapter is structured as follows:

- Section 14.3 provides background information on network and retail bills and the breakdown of electricity charges for typical customers.
- Section 14.4 explains how our regulatory proposal will impact the network charges paid by different types of residential and business customers.
- Section 14.5 lists the supporting documents for this chapter.

14.3. Network and retail bills

A network bill consists of costs that end customers pay for using the network to service their energy needs. These network costs typically consist of costs from the entire network system which includes services provided by the 'poles and wires' that bring power to homes and businesses. We also provide meters and transport electricity that customers want to export back into the grid from their solar systems.

As a distribution network business, AusNet does not invoice customers directly, but indirectly via the electricity retail bill issued by the customers' retailers. Our charges are one of several cost components that make up the bill. While the composition of a retail bill varies by customer type, by retailer and by tariff, the costs of providing network services to our residential customers' is approximately 36% of a total electricity retail bill.

14.4. Bill impacts for our typical customers

This section sets out the impact of this proposal on our customers' distribution charges over the regulatory period.

The AER has adopted a standard approach to calculate bill impacts which applies a price path customers' annual bill to estimate the bill impact over the 2026-31 period. This price path is derived from using annual total revenue and energy delivered (consumed).

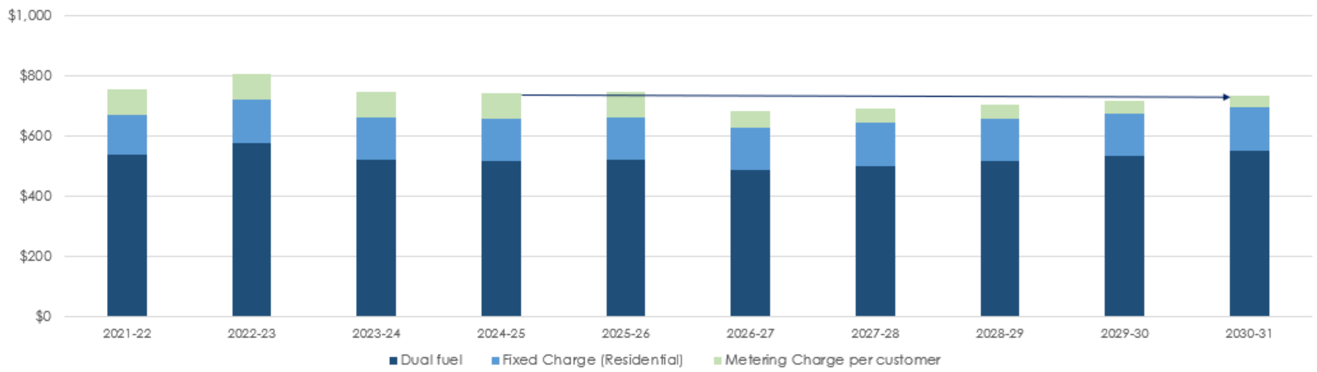
We believe this approach may not accurately reflect the total annual bill and bill impact outcomes for customers during the 2026-31 period. It does not account for changes in customer numbers or change in annual usage due to electrification, such as customers transitioning from gas cooking or heating to electric alternatives, or the increasing adoption of electric vehicles.

As show below, our bill impact calculations have aimed to reflect and incorporate how our customers use electricity in various when determining the price path for both residential and business customers. For instance, some residential customers live in all-electric homes, while others use gas for heating and hot water. Some are in the process of transitioning to all-electric systems or have invested in technologies like solar panels or solar batteries. These diverse usage patterns mean that electricity usage vary significantly from one household to another. Consequently, analysing bill impacts for an average residential customer may not accurately reflect a particular customer's experience.

We have therefore modelled the bill impacts for residential customers at different stages of electrification. The figures below below illustrate the bill impacts for various types of residential customers as they progress through their electrification journey. The analysis shows:

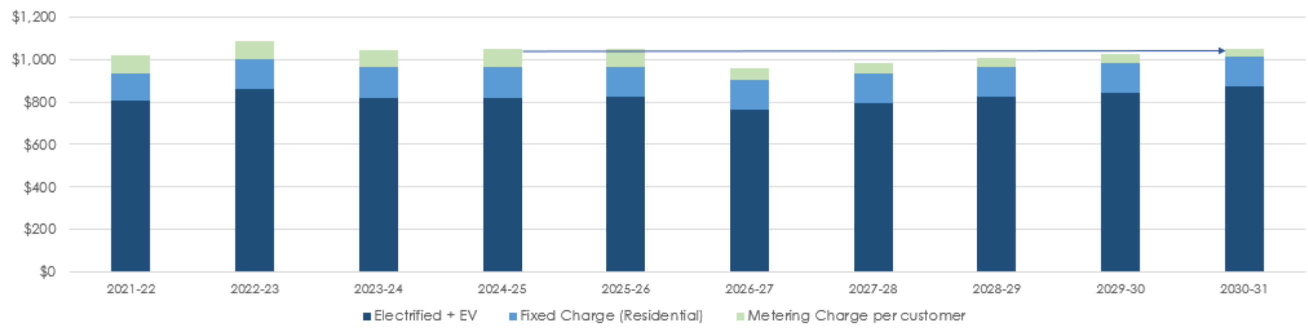
- For residential with gas and no EV, annual distribution costs, including metering costs, are expected to decrease by 1% (including metering and excluding inflation) from today till 2031, and
- For residential customers with all electric appliances and EV, annual distribution costs, including metering costs are expected to stay flat (including metering and excluding inflation) from today till 2031.

Figure 14-1: Residential with gas and no EV – typical distribution charge reductions of 1% (including metering and excluding inflation) from today compared to 2031



Source: AusNet, assumes annual usage of 5.2MWh + incremental increase from today to 2031

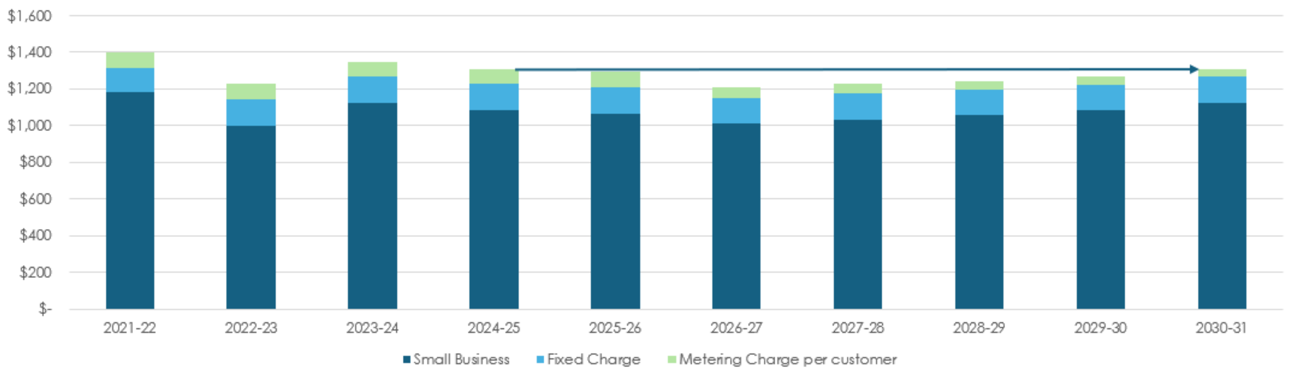
Figure 14-248: Residential with all electric appliances and EV – typical distribution charge flat (including metering and excluding inflation) from today compared to 2031



Source: AusNet, assumes annual usage of 8.3MWh + EV incremental increase to 2031

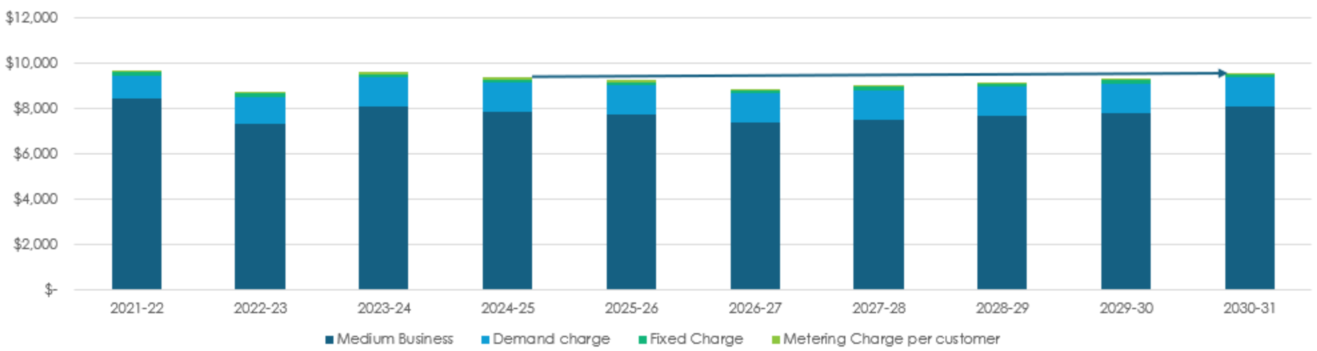
For business customers, particularly larger business customers, electrification trajectories are less clear and more variable. This makes it challenging to analyse network cost impacts for these customers. While we expect some of these customers will electrify over this period, the bill impact analysis presented below assumes usage will remain flat throughout the period. It shows that small, medium and large business customers are expected to experience increases in annual distribution costs, including metering costs of approximately 2%.

Figure 14-349: Small business – typical distribution charge typical distribution charge flat (including metering and excluding inflation) from today compared to 2031



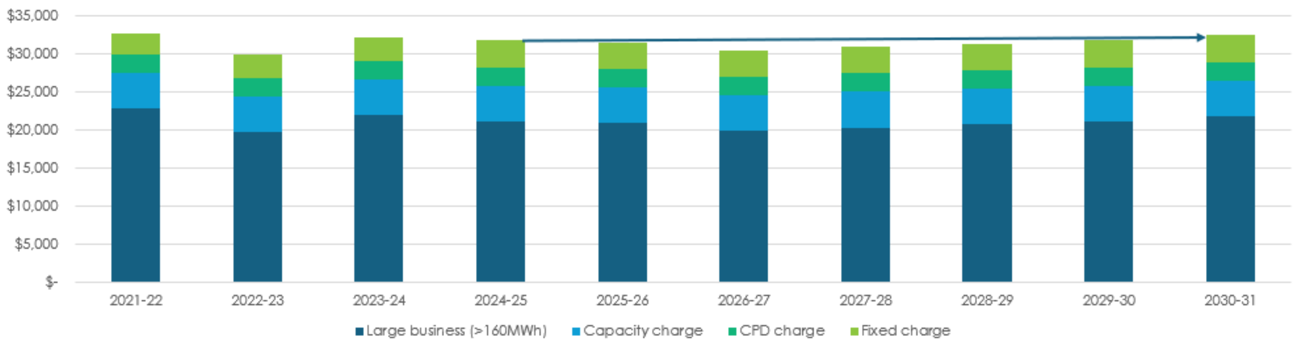
Source: AusNet, assumes annual usage of 11.7MWh

Figure 14-450: Medium (40-160MWh) business – typical distribution charge increases of 2% (including metering and excluding inflation) from today compared to 2031



Source: AusNet, assumes annual usage of 69.5MWh

Figure 14-551: Large (>160MWh) business – typical distribution charge increases of 2% (including metering and excluding inflation) from today compared to 2031



Source: AusNet, assumes annual usage of 240.4MWh

14.5. Supporting documentation

There are no supporting documents available for this chapter.

15. Proposed cost pass through events

15.1. Key points

The key points in this chapter are:

- The pass-through framework provides an efficient mechanism to recover the costs arising from uncertain events that are beyond our control, which may occur during the next regulatory period.
- There is currently significant uncertainty underpinning our proposal. We have re-proposed our existing 5 nominated events and intend to introduce 3 more to manage this uncertainty.
- Our new events are targeted at the significant uncertainty and resulting forecasting risk for costs related to the electricity supply chain, AEMO participant fees and pace and the impact of electrification. We consider a nominated pass through the most appropriate way to fund these events given the likely materiality and given the significant uncertainty in scale and timing of these events, it may not be appropriate to include them in our expenditure forecast. This approach best manages the risk by ensuring customers are not paying for events unless they eventuate. However, we consider there is a reasonable likelihood the proposed new events will occur in the 2026-31 period.
- We support broader reform to the regulatory framework to better manage heightened uncertainty associated with the energy transition, to support optimal customer outcomes.

15.2. Approach to developing cost pass through events

A cost pass through mechanism is an efficient method of managing unpredictable, high cost events that are beyond our control. This cost recovery mechanism ensures that our regulated revenue does not include any amount to insure against these events, either through self- insurance or through commercial insurance, thereby lowering the costs to our customers of operating our network. Instead, we recover only the efficient caused by one or more of these events, subject to the AER's approval, and only if the event occurs.

By allowing DNSPs to pass through material costs associated with events outside of their control, the cost pass through provisions in the NER provide an efficient mechanism to address the cost impact of uncertain events. The cost pass through mechanism ensures:

- DNSPs have a reasonable opportunity to recover at least their efficient costs;
- DNSPs face an incentive to manage risk effectively; and
- Expenditure forecasts and approved allowances best reflect the prudent and efficient costs incurred by DNSPs.

In addition to cost pass through arrangements, DNSPs may address risk through several other mechanisms. These include:

- Including costs directly in opex and capex allowances;
- Utilising third party insurance cover and/or self-insurance; and
- Proposing contingent projects in accordance with rule 6.6A.

Cost pass-through provisions are most appropriate for risks that cannot be dealt with through the above mechanisms. These risks are typically associated with high consequence, low probability events, or where there is substantial uncertainty with respect to the cost impact of an event that is expected to occur during the next regulatory period. The cost impact of these events cannot be predicted with sufficient certainty for it to be included in expenditure allowances, while insurance and self-insurance is not likely to be available on a cost-effective basis.

Without these mechanisms, a DNSP would need to include an allowance to cover the highly uncertain costs arising from an event that may or may not proceed. This alternative approach is less efficient than a pass through mechanism because it is likely to result in revenues not reflecting the DNSP's costs, leading to windfalls loses for the DNSP or customers.

The pass through events prescribed in the NER cover a range of scenarios:

(1) a regulatory change event;

(2) a service standard event;

(3) a tax change event;

(4) a retailer insolvency event; and

(5) any other event specified in a distribution determination as a pass through event for the determination. .

In considering whether to nominate any additional events as a pass through event, we have been guided by the cost pass through considerations, which are the matters that the AER is required to consider in deciding whether to approve a nominated cost pass through. as defined in chapter 10 of the NER. These considerations include whether:

- The event proposed is an event covered by a category of pass through;
- The nature or type of event can be clearly identified at the time the determination is made for the service provider;
- A prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;
- Whether the relevant service provider could insure against the event, having regard to the availability of insurance whether it can be obtained on commercial terms; and
- Whether the event can be self-insured.

Taking the above considerations into account, our approach to identifying cost pass through events has involved:

- Identifying potential changes to our operating environment and regulatory and legislative framework that may create risk over the forthcoming regulatory period; and
- Assessing the certainty, likelihood and consequence of each risk to determine whether risks can be accounted for in expenditure forecasts or in the case of low consequence risks, absorbed internally.

We have also had regard to the nominated pass through events previously approved by the AER, noting that these pass through provisions will continue to be warranted unless the approach described above indicates that they are no longer required.

In assessing potential changes to our operating environment it is clear there is both a higher number and higher magnitude of potential uncertainties in this period of the energy transition than there have been in previous reviews. This tests the boundaries of the cost pass through provisions of the regulatory framework. In particular, we agree with Evoenergy that the existing options under the Australian regulatory framework do not adequately address the real potential for the energy transition to drive rapid demand growth broadly across the entire network[154]. Regulatory frameworks elsewhere have adapted to better manage this uncertainty, including the introduction of reopener provisions for net zero policy changes and high voltage augmentation introduced by Ofgem. While this Revenue Proposal has been prepared under the existing regulatory framework as required by the rules we consider regulatory bodies, government and industry should work to reform the regulatory framework to ensure it is sufficiently flexible to support positive customer outcomes through the energy transition.

[154] Evoenergy, Appendix B Managing uncertainty through the energy transition, November 2023. Available here: Evoenergy-Appendix B Managing uncertainty through the energy transition-November 2023.pdf

15.3. Nominated pass through events

In addition to the prescribed pass through events defined in the NER, we propose seven nominated pass through events for the forthcoming regulatory period. These cost pass through events, which have been developed in accordance with the approach set out in section 15.2, are:

- An insurance coverage event;
- An insurer credit risk event;
- A terrorism event;
- A natural disaster event;
- A retailer insolvency event; and

The AER has previously approved these five nominated events and their definitions.

We are proposing three new events:

- A major supply chain disruption event;
- An AEMO participant fee event;
- An electrification event

Each of these events is discussed below.

15.3.1. Insurance coverage event

15.3.1.1. Background

We maintain a level of insurance cover that is commensurate with the scale and size of our operations, the risks assessed to be associated with our operations, and industry standards and practices. The premiums associated with bushfire insurance cover are incorporated in our proposed opex forecast through our base year opex. Our base year opex also includes actual self-insurance costs incurred that relate to liability losses falling below the deductible for our insurance cover.

We are exposed to the risk that we incur liability losses that exceed our insurance coverage. We therefore consider that nominating an 'insurance coverage event' as a cost pass through event is a prudent and efficient way to mitigate this risk. We consider that our insurance coverage event satisfies the nominated pass through event considerations and that there is a sound basis for the AER to accept it as a nominated pass through event. This is because:

- the insurance coverage event is not covered by any of the prescribed cost pass through events set out in the NER;
- the nature and type of an insurance coverage event can be clearly identified at the time of the AER's final determination;
- our ability to prevent or limit an insurance coverage event on a cost-effective and efficient basis is limited. That being said:
    - the protection of communities within our area of operations is of critical importance to us, and we have developed a sophisticated approach to managing network safety; and
    - the substantial deductible payable on our bushfire liability policy creates a strong financial incentive for us to prevent or mitigate the risk of such events from occurring in the first place; and
- as explained previously, it is not possible to calculate self-insurance premiums for liability losses that exceed the policy coverage with certainty.

We also consider that accepting the insurance coverage event is consistent with the Revenue and Pricing Principles. In particular, section 7A(2) of the NEL requires us to be provided with a reasonable opportunity to recover at least the efficient costs we incur in providing direct control network services. Absent the insurance coverage event, we will be precluded from receiving such an opportunity because the costs of an insurance coverage event have not been allowed for elsewhere in this proposal.

We are re-proposing this event with the definition approved by the AER in our 2021-26 determination.

Proposed definition

An insurance coverage event occurs if:

1. AusNet Services:

   (a) makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy or set of insurance policies; or

   (b) would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances; and

2. AusNet Services incurs costs:

   (a) beyond a relevant policy limit for that policy or set of insurance policies; or

   (b) that are unrecoverable under that policy or set of insurance policies due to changed circumstances; and

3. The costs referred to in paragraph 2 above materially increase the costs to AusNet Services in providing direct control services.

For the purposes of this insurance coverage event: 'changed circumstances' means movements in the relevant insurance liability market that are beyond the control of AusNet Services, where those movements mean that it is no longer possible for AusNet Services to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in paragraph 2 above within the scope of that insurance policy or set of insurance policies.

'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had:

(i) the limit not been exhausted; or

(ii) those costs not been unrecoverable due to changed circumstances.

A relevant insurance policy or set of insurance policies is an insurance policy or set of insurance policies held during the regulatory control period or a previous regulatory control period in which AusNet Services was regulated; and

AusNet Services will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of AusNet Services in relation to any aspect of AusNet Services' network or business; and

AusNet Services will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of AusNet Services in relation to any aspect of AusNet Services' network or business.

Note for the avoidance of doubt, in assessing an insurance coverage event through application under rule 6.6.1(j), the AER will have regard to:

i. the relevant insurance policy or set of insurance policies for the event

ii. the level of insurance that an efficient and prudent DNSP would obtain, or would have sought to obtain, in respect of the event;

iii. any information provided by AusNet Services to the AER about AusNet Services' actions and processes; and

iv. any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event that occurs.

15.3.2. Insurer credit risk event

15.3.2.1. Background

The cost impacts to us of one of our insurers becoming insolvent are potentially significant. We could be subject to higher or lower premiums, or a higher or lower claims limit or deductible.

While the retailer insolvency event (if specified by the AER in its determination) provides a cost recovery mechanism in the event of a retailer becoming insolvent, we consider the need for both the retailer insolvency and insurer credit risk events because we may incur costs that the insolvency event would not ordinarily cover.

For these reasons, we propose an 'insurer credit risk event' as a nominated cost pass through event. Importantly, any pass through amount claimed in association with an insurer credit risk event will be net of any insurance payout made to us or recovered through a retailer insolvency event pass through application.

We consider that our insurer credit risk event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in our costs. This position is consistent with the nominated pass through event considerations:

- the insurer credit risk event is not covered by any of the prescribed cost pass through events set out in the NER and does not duplicate the retailer insolvency event;
- the nature and type of the event can be clearly identified at the time that the AER makes its determination for us;
- the extent to which we can reasonably prevent an insurer credit risk event from occurring and/or can substantially mitigate the cost impacts of such an event is limited. That said, we consider several risk management factors when assessing whether to insure with a particular provider, such as the insurer's track record, size, credit rating and reputation; and
- the relative infrequency and potentially substantial financial impact of insolvent insurer events creates significant practical challenges for self-insuring for such events. A pass through mechanism provides a more appropriate arrangement for managing the cost impacts in the unlikely circumstances that an insurer credit risk event occurs and causes a material increase in our costs. We consider that managing costs through a nominated pass through event is in the long-term interest of consumers.

We are re-proposing this event with the definition approved by the AER in our 2021-26 determination.

Proposed definition

An insurer credit risk event occurs if an insurer of AusNet Services becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, AusNet Services:

(a) is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or

(b) incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.

Note: in assessing an insurer credit risk event pass through application, the AER will have regard to, amongst other things:

i. AusNet Services' attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation; and

ii. in the event that a claim would have been covered by the insolvent insurer's policy, whether AusNet Services had reasonable opportunity to insure the risk with a different provider.

15.3.3. Natural disaster event

15.3.3.1. Background

The cost impact of a natural disaster on our network assets can be potentially significant. Potential natural disasters that could cause significant property damage include, but are not limited to, bushfires, earthquakes, storms and floods. Our insurance coverage provides some protection against property damage caused by natural disasters; however, the cost impact of a natural disaster could materially exceed the coverage provided by these policies.

Further, while the insurance coverage event provides a cost recovery mechanism in the event of a natural disaster, there is a need for both pass through events because the NSP may incur costs that an insurance policy would not ordinarily cover.

For these reasons, we propose a 'natural disaster event' as a nominated cost pass through event. Importantly, any pass through amount claimed in association with a natural disaster event will be net of both insurance and self-insurance cover, and any amounts recovered through an insurance coverage event claim.

We consider that our natural disaster event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event occurs and materially increases our costs. This position is consistent with the nominated pass through event considerations:

- the natural disaster event is not covered by any of the prescribed cost pass through events set out in the NER;
- the nature and type of the event can be clearly identified at the time that the AER makes its determination for us;
- the extent to which we can reasonably prevent a natural disaster event from occurring and/or can substantially mitigate the cost impacts of such an event is limited;
- our insurance coverage, which has been obtained on a cost-effective basis, provides some protection against property damage and other losses associated with a natural disaster. However, the cost impact of a natural

disaster could materially exceed the limits of our insurance cover. Any pass through amount claimed in association with a natural disaster event will be net of payouts made under these policies; and

- the relative infrequency and potentially crippling financial costs of a natural disaster creates significant practical challenges for self-insuring such events. A pass through mechanism provides a more appropriate arrangement for managing the cost impacts in the event that a natural disaster event occurs and causes a material increase in our costs. We consider that managing costs through a nominated pass through event is in the long-term interest of consumers.

We are re-proposing this event with the definition approved by the AER in our 2021-26 determination.

Proposed definition

Natural disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2021–26 regulatory control period that changes the costs to AusNet Services in providing direct control services, provided the cyclone, fire, flood, earthquake or other event was:

(a) a consequence of an act or omission that was necessary for the service provider to comply with a regulatory obligation or requirement or with an applicable regulatory instrument; or

(b) not a consequence of any other act or omission of the service provider.

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

(1) whether AusNet Services has insurance against the event;

(2) the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

15.3.4. Terrorism event

15.3.4.1. Background

The cost impacts of an act of terrorism, such as a cyber-attack on our IT or network operations systems could potentially be significant. Our insurance policies provide some cover against losses caused by terrorism; however, the cost impact of such an event could materially exceed the limits of these policies.

Further, while the insurance coverage event provides a cost recovery mechanism in the event of an act of terrorism, there is a need for both the insurance coverage and terrorism events because the NSP may incur costs that an insurance policy would not ordinarily cover.

For these reasons, we propose a 'terrorism event' as a nominated cost pass through event. Importantly, any pass through amount claimed in a pass through application for a terrorism event will be net of any insurance payout made to us and any amounts recovered through an insurance coverage event pass through application.

We consider that our terrorism event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in our costs. This position is consistent with the nominated pass through event considerations:

- the terrorism event is not covered by any of the prescribed cost pass through events set out in the NER;
- the nature and type of event can be clearly identified at the time that the AER makes its determination for us;
- the extent to which we can reasonably prevent a terrorism event from occurring and/or can substantially mitigate the cost impacts of such an event is limited. That said, we have a range of security and other measures in place which are intended to prevent acts of terrorism, and to mitigate the cost impact of such an event should one occur;
- our insurance coverage, which has been obtained on a cost-effective basis, provides some protection against property damage caused by a terrorism event. However, the cost impact of such an event could materially exceed the coverage provided by this insurance. Any pass through amount claimed in association with a terrorism event will be net of any insurance payout we receive, and any amount recovered through an insurance coverage event pass through application; and
- the relative infrequency and potentially very high costs of a terrorism event creates significant practical challenges for self-insuring such events. A pass through mechanism provides a more efficient arrangement for managing the cost impacts in the unlikely circumstances that a terrorism event occurs and causes a material increase in our costs. We consider that managing costs in this way is prudent and in the long-term interest of consumers.

We are re-proposing this event with the definition approved by the AER in our 2021-26 determination.

Proposed definition

Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which:

from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear); and

changes the costs to AusNet Services in providing direct control services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

- **i.** whether AusNet Services has insurance against the event;
- **ii.** the level of insurance that an efficient and prudent NSP would obtain in respect of the event; and
- **iii.** whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

15.3.5. Retailer insolvency event

15.3.5.1. Background

Retailer insolvency is a category of prescribed pass through event under the NER, which defines it as:

The failure of a retailer during a regulatory control period to pay a DNSP an amount to which the service provider is entitled for the provision of direct control services, if: a. an insolvency official has been appointed in respect of that retailer; and b. the DNSP is not entitled to payment of that amount in full under the terms of any credit support provided in respect of that retailer.

The prescribed pass through event in the NER is effective in all jurisdictions other than Victoria. We therefore rely on consistency with other participating jurisdictions that have started the National Energy Retail Law (NERL) as a relevant matter to be considered by the AER. To ensure we have access to the same protection in the event of a retailer failure as other DNSPS in jurisdictions where the NERL applies, we propose a pass through event for retailer insolvency to manage the risk of retailers defaulting on payment of their network charges.

For these reasons, we propose a ‘retailer insolvency event’ as a nominated cost pass through event. Importantly, any pass through amount claimed in a pass through application for a retailer insolvency event will be net of any insurance payout made to us and any amounts recovered through an insurance coverage event pass through application.

We consider that the retailer insolvency event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in our costs. This position is consistent with the nominated pass through event considerations:

- the retailer insolvency event outlined in the NER does not apply to Victorian DNSPs as the NERL has not been adopted in Victoria;
- the nature and type of event can be clearly identified at the time that the AER makes its determination for us;
- the cost impact of such an event could materially exceed the coverage provided by our insurance coverage; and
- the extent to which we can reasonably prevent a retailer insolvency event from occurring and/or can substantially mitigate the cost impacts of such an event is limited; and
- the relative infrequency and potentially very high costs of a retailer insolvency event creates significant practical challenges for self-insuring such events. A pass through mechanism provides a more efficient arrangement for managing the cost impacts in the unlikely circumstances that a retailer insolvency event occurs and causes a material increase in our costs. We consider that managing costs in this way is prudent and in the long-term interest of consumers.

We are re-proposing this event with the definition approved by the AER in our 2021-26 determination.

Proposed definition

Until such time as the National Energy Retail Law set out in the Schedule to the National Energy Retail Law (South Australia) Act 2011 of South Australia is applied as a law of Victoria, retailer insolvency event has the meaning set out in the NER as in force from time to time, except that:

(a) where used in the definition of 'retailer insolvency event' in the NER, the term 'retailer' means the holder of a licence to sell electricity under the Electricity Industry Act 2000 (Vic); and

(b) other terms used in the definition of retailer insolvency event in the Rules as a consequence of amendments made to that definition from time to time, which would otherwise take their meaning by reference to provisions of the NER or National Energy Retail Law not in force in Victoria, take their ordinary meaning and natural meaning, or their technical meaning (as the case may be).

For the purposes of this definition, the terms 'eligible pass through amount' and 'positive change event' where they appear in the NER (as well as any subordinate terms including, without limitation, 'retailer insolvency costs', 'failed retailer' and 'billed but unpaid charges') are modified in respect of this retailer insolvency event in the same manner as those terms are modified in respect of the retailer insolvency event prescribed in the NER from time to time

Note: This retailer insolvency event will cease to apply as a nominated pass through event on commencement of the National Energy Customer Framework in Victoria.

15.3.6. Major supply chain disruption event

15.3.6.1. Background

The transition could increase pressure on the supply of certain materials, commodities and skilled labour, driving prices higher. Globally energy systems, including Australia's, need to undergo this transformation on similar timelines. The need to quickly manufacture and build the necessary infrastructure to meet local targets will create strong demand for essential materials. Those linked to the construction and maintenance of electricity infrastructure are expected to face especially high demand.

The labour and materials used in Australia's energy transition are a small part of the global build. This will place pressure on the labour and material costs we face in the next regulatory period Moreover, a significant proportion of construction materials are imported into Australia, making them subject to fluctuations in the value of the AUD and high shipping costs

Disruptions to the supply chains AusNet rely on are unforeseeable but can have significant impact on our costs and deliverability of our projects required to deliver distribution services. Our expenditure forecast assumes that these costs will increase at the same rate as CPI. However, historically, there can be substantial discrepancies in the cost growth between material prices (as measured by the PPIs) and the CPI due to major supply chain disruptions. For example, recently following COVID-19 and the war in Ukraine.

We consider that the major supply chain disruption event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in our costs. This position is consistent with the nominated pass through event considerations:

- the major supply disruption chain event is not covered by any of the prescribed cost pass through events set out in the NER;
- the nature and type of event can be clearly identified at the time that the AER makes its determination for us;
- the extent to which we can reasonably prevent a major supply chain disruption event from occurring and/or can substantially mitigate the cost impacts of such an event is limited;
- we cannot obtain insurance for this type of event and the potentially material costs of a major supply chain disruption event creates significant practical challenges for self-insuring such events.

Proposed definition

A Major Supply Chain Disruption Event occurs if it:

1. Involves a major disruption to the supply chain necessary to AusNet's operations arising because of, but not limited to, outbreak of war or pandemic, sanctions or trade restrictions,
2. which falls within no other category of pass through event;
3. that occurs during the regulatory control period; and

In assessing a Major Supply Chain Disruption Event, the AER will have regard to:

(a) whether a declaration has been made by a relevant government authority in respect of an event which is causing or contributing to the major disruption to the supply chain; and

(c) the difference in the forecast inflation used by the AER in its Final Decision and actual inflation, commodity prices and product price indexes (PPIs) reported by the Australian Bureau of Statistics during or following the major supply chain disruption.

15.3.7. An AEMO participant fee event

15.3.7.1. Background

AEMO recovers its costs in full from energy market participants in the form of Participant Fees, the structure of which are set every 5 years, with the next period beginning from 1 July 2026. Under the NER[155], AEMO can charge DNSPs Participant fees. To date, AEMO has not levied a share of these fees on distribution businesses, but this may change over time.

In its latest fee 5 year determination, AEMO considered allocating 3% of fees to DNSPs due to:

> "… an increasing amount of AEMO's activities involve TNSPs and DNSPs in the management of power system security and power system reliability and operations. Correspondingly, the cost allocation survey indicated the level of involvement with both TNSPs (17.5%) and DNSPs (3.0%) has increased since the previous fee determination[156]"

Their final determination was to not charge DNSPs fees, but AEMO noted:

> *"[DNSP] involvement with AEMO's systems and processes will be monitored throughout the next fee period and should there be a material increase in involvement (e.g. as a consequence of regulatory reform), AEMO will consider a declared NEM fee project consultation process to recover those costs[157]"*

Clause 2.11.1.(bb)of the NER allows AEMO to consult on fees and allocate these to DNSP for declared NEM projects, which can occur outside of the 5 year fee structure determination. Specifically, in relation to the NEM 2025 Reform Project (which is a Declared NEM project for which AEMO is required to consider the fee structure out-of-cycle) AEMO states:

> *"AEMO will continue to monitor the progress of the implementation of the NEM2025 Reform Program to identify if there is a need to charge this Participant category in the future in line with the fee structure principles and NEO."[158]*

Major reform, developments or changes can be declared NEM projects and will not be known at the time of the upcoming fee determination and cannot be forecast for our revenue proposal.

AEMO has indicated that it will commence consultation on the structure of Participant Fees that will apply for the period 1 July 2026 to 30 June 2031 in early 2025. If costs are assigned to DNSPs, this timing should allow us to include a reasonable forecast in the form of a step change in our Revised Revenue Proposal. However, this upcoming determination will not cover us if these fees materially increase over time or if there is a declared NEM project which results in an additional participant fee being imposed. Accordingly, the pass through mechanism will still be appropriate in addition to any step change incorporated at the revised proposal stage.

We consider that the AEMO participant fee event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. The AER in its recent determination for TasNetworks concluded the event was consistent with the following nominated pass through event considerations:

- the AEMO participant fees event is not covered by any of the prescribed cost pass through events set out in the NER
- the nature and type of event can be clearly identified at the time that the AER makes its determination for us;
- the extent to which DNSPs can reasonably prevent an AEMOs fee event from occurring and/or can substantially mitigate the cost impacts of such an event is limited.

We consider in absence of certainty around AEMO fees, a nominated pass through represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in our costs. We will propose an opex step change in our Revised Proposal if the AEMO fee consultation for 2026-31 results in more certainty around ongoing participant fee rates for DNSPs. However, we consider the pass through mechanism still remains necessary due to the uncertainty in the level of the fees and as fees associated with Declared NEM events will be excluded from a potential opex step change forecast.

Proposed definition

An AEMO participant fees event occurs if, under clause 2.11.1, including for a Declared NEM Project, AEMO determines a portion of participant fees to be paid by NSPs, which materially increases the costs to AusNet Services in providing direct control services

[155] Clause 2.11.1
[156] AEMO Electricity Fee Structures Final Report and Determination, March 2021, pg. 5
[157] AEMO Electricity Fee Structures Final Report and Determination, March 2021, pg. 16
[158] *AEMO, Structure of Participant Fees for AEMO's NEM2025 Reform Program Draft Report and Determination, June 2023, p.22*

15.3.8. Electrification event

15.3.8.1. Background

The Victorian Government has released its updated Gas Substitution Roadmap and outlined a clear position to electrify residential homes. However, exactly how and when this will unfold is yet to be determined.

The Gas Substitution Roadmap is one area of policy targeted at electrification that has the potential to materially increase electricity demand that is not currently foreseeable. The impact of this electrification is expected to be material and result in a large residential heating load which is not flexible. This may result in peak demand shifting from summer to winter peaking in some areas which may result in asset ratings being exceeded. The timing and coordination of the move away from gas reliance for residential homes in Victoria is uncertain and therefore the materiality of impact on the costs of providing distribution services is difficult to forecast.

One example of a policy change that could result in electrification occurring faster than embedded in our forecasts is the Victorian Government's current Regulatory Impact Statement (RIS), which may conclude that building and planning regulations should be amended or requiring existing gas appliances in homes and relevant commercial buildings be replaced with electric appliances when the current appliance reaches end of life.

In addition to the electrification of gas load, similar programs or policies may be announced which materially affect the uptake of electric vehicles and/or electric vehicle charging infrastructure within the regulatory control period. Such programs may again have a material and unforeseen impact on electricity demand. For example, other jurisdictions, including the ACT and many worldwide, have set a date to ban Internal Combustion Vehicle (ICE) vehicle sales by 2035. Governments may choose to introduce new incentives for EVs and/or EV chargers as we approach 2030 targets. EV sales in Victoria were less than 10% in 2024 and the Victorian government has a 50% target for new car sales to be zero emissions by 2030.

A significant increase in electrification and the consequential demand will have implications for electricity network service providers. The expected material increase in costs resulting from DNSPs augmenting their networks or implement other significant non-network solutions to ensure their networks can enable customers to electrify through safely and reliably meeting the increased demand. These costs could materially exceed those provided for in our revenue determination. There is significant uncertainty with respect to the cost impacts and the degree of demand driven augmentation required which will depend on the pace, coordination and management of electrified appliances.

As noted in section 6.6, our proposed demand driven augex is driven by our demand forecasts, which primarily use the latest inputs and assumptions from AEMO and the Victorian Government's VIF. Otherwise, to avoid over-investment during a period of heightened uncertainty, we have adopted inputs and assumptions on the lower end of expectations. Given the significant uncertainty, it is in the long-term interests of our consumers that we recover the prudent and efficient costs of the electrification event through uncertainty mechanisms in the regulatory framework, such as pass through arrangements, rather than ex-ante expenditure forecasts.

We consider that the electrification event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents an efficient and appropriate means of managing risk if such an event occurs and results in a material increase in our costs. This position is consistent with the nominated pass through event considerations:

- the electrification event is not covered by any of the prescribed cost pass through events set out in the NER. There may be legislative changes or changes to (including the creation of) a regulatory framework for gas electrification that occur during the forthcoming regulatory period in a way that allows us to submit a cost pass through application for a regulatory change event. However, this pass-through event will not be available if:
    - the change to the legal or regulatory obligation does not meet the definition of "regulatory obligation or requirement" in section 2D of the NEL; and
    - the increase in electrification is in response to a policy announcement or other event that is not accompanied by a change in the law or other regulatory instrument, but the change nevertheless results in a material increase in the cost to us of providing direct control network services.
- the nature and type of event can be clearly identified at the time that the AER makes its determination for us;
- the extent to which we can reasonably prevent an electrification event from occurring and/or can substantially mitigate the cost impacts of such an event is limited;
- the full range of costs that could potentially be incurred as a result of the occurrence of this type of event are not insurable;
- the timing and impact of the occurrence of an electrification event is not foreseeable but can result in high consequence or magnitude.
- A pass through mechanism provides the most efficient arrangement for managing the uncertain cost impacts under the current regulatory framework should an electrification event occur and result in a material increase in our costs. We consider that managing costs in this way is prudent and in the long-term interest of consumers.

Proposed definition

An electrification event occurs if:

1. The Commonwealth Government or the Government of Victoria announces a new or amended policy, program, initiative, scheme or other measure, which is directed at accelerating electrification of transport, or gas-powered appliances or processes; and
2. The cost to AusNet to meet or manage the actual or expected demand materially increases as a result of the announcement, relative to the cost set out in AusNet's 2026-2031 regulatory proposal.

In assessing an electrification event, the AER will have regard to whether, as a result of the announcement, there is:

(a) a forecast increase in energy used by customers connected to AusNet's electricity distribution network, when compared to the forecasts set out in our 2026-31 regulatory proposal; or

(b) an increase in the after diversity maximum demand (ADMD) applicable at the date we submit our regulatory proposal to the AER.

15.4. Application of pass through arrangements to direct control services

Our nominated pass through events should apply to all direct control services (i.e. both standard control services and alternative control services) on the basis that the costs of providing alternative control services are also permitted to be considered as part of the cost pass through framework in rule 6.6.1.

16. Alternative Control Services: Metering services

16.1. Key points

The key points in this chapter are:

- We installed our smart meters, as part of a Victorian government mandate, to now 99% of our 840,000 residential and small business customers providing metering data and services in accordance with National and more stringent Victorian regulatory obligations. These mandated services in Victoria now include whole of network voltage compliance monitoring for more than 95% of our customers.
- In our plans for 2026-31, we are centering our customers at the heart of our metering services. Smart meters are now part of the electricity supply systems required to keep prices down, keep people safe, keep the network reliable and enable customers to use as much renewable energy as possible. As requested by our customer representative Coordination Group, this chapter explains and quantifies the benefits that customers obtain from our smart meters.
- Our proposed smart meter investment in pro-active meter replacements starting in 2028-29, smart meter communication network augmentation, and IT system requirements is justified by customer benefits and regulatory compliance imperatives and supported by advice from one of our global technology suppliers.
- For the 2026-31 regulatory period, our proposal delivers a metering fee price reduction from $84 per annum in 2026-27 to $39 per annum in 2030-31. This reduction is driven by the full depreciation of metering assets from our initial rollout and reductions in metering operating expenditure, slightly offset by initiating a long-term targeted meter replacement. This cost saving will be passed on to customers with smart meters. For customers without smart meters, which cost us an additional $156 per year to manually read, we are keeping the price equal to the 2025-26 price in real terms over 2026-31.
- We support the meter service classifications and forms of control proposed by the AER in its Framework and Approach Paper. All our proposed metering fees, metering exit fees and axillary metering service fees align with this decision.
- Our approach to setting exit fees, type 7 metering charges and ancillary metering services is unchanged from the 2021-26 regulatory period. We continue to offer zero-cost move-in move-out services and remote meter reading fee, where those services are performed remotely. For the 2026-31 regulatory period, we are proposing to continue with these zero-cost remote services.

16.2. Chapter structure

This chapter is structured as follows:

- Section 16.3 describes our metering services, customer service commitment to benefiting customers and regulatory obligations to meet minimum performance targets
- Section 16.4 explains our investment plan and why we need make these investments
- Section 16.5 sets out our proposed costs and revenues and examines the impact on our customers, and
- Section 16.6 describes the applicable regulatory arrangements applying to metering services.

16.3. Our metering customer service

16.3.1. Overview of our smart meter roll out and our obligations

In 2008, the Victorian government required electricity distribution businesses to install Advanced Metering Infrastructure (AMI) meters (or smart meters) to every small customer by the end of 2013. [159] Now, our smart meters measure and provide the electricity consumption for 99% of our small customers in accordance with obligations. [160] Our meter services obligations for the delivery of metering data in Victoria remain more stringent and robust than the Service Procedure and Metrology obligations under National Electricity Rules (NER).

Since implementing meters, systems and processes to meet these requirements, we have leveraged this investment to provide additional services to our customers, including:

- identifying safety issues and fixing them before an incident occurs (e.g., fixing a loss of neutral before someone contacts electricity);
- more efficiently identifying supply interruptions; and
- lowering costs customers by offering free remote services, enabling customers to find and switch to the accurate lowest cost retailer offer, and reducing the cost of energy theft.

Additionally, the ESC established changes to the Electricity Distribution Code of Practice, effective on 1 October 2022, that requires us to measure voltages, at least, every 10 minutes for 95% of our small customers and provide quarterly voltage reports to the ESC.[161] This mandatory voltage data enables Victorian Distributors to provide customers with the highest level of voltage assurance in Australia. Compliant voltage levels benefit our customers by increasing appliance performance and enabling more renewable generation from rooftop solar generation.

16.3.2. Focusing smart meter services on our customer needs

In our plans for 2026-31, we are centring our customers at the heart of our metering services. Over the past decade, we have focused on delivering smart meter benefits to our customers. Now that nearly a third of Victorian customers have embraced solar generation, and hundreds of thousands of Victorians are using smart meter data on Vic Energy Compare each year to change retailers, our customers have come to expect and rely on quality smart meter services. Naturally, we are also striving to provide excellence in our provision of every day's essential regulated metering services:

- Accurate, up-to-date customer billing and market settlements with interval metering data (30-minute intervals for pre-2018 meters and 5-minute intervals for newer meters).
- Fast and reliable remote services that are mostly offered free of charge for high volume services.

Our customers now benefit from the smart meters at their premises through lower bills than they would otherwise have been charged and by providing additional services (outlined in detail below). We heard in our previous EDPR's engagement and reiterated by our Customer Panel members in this EDPR engagement process that we need to continue to explain to customers the benefits they receive from smart metering technology and data. We have listened to our customers, discussed these benefits with our customer representatives, and are enhancing these benefits at the core of our 2026-31 plans. Our enhancements will improve service levels and will enable customers to directly connect their appliances to any new smart meters – both important steps realising benefits to customers.

We now extensively use smart metering data, supported by App based processes, to deliver regulated service obligations, improved network performance and customer services. These innovations in smart meters are essential to reducing the price of electricity, keeping people safe and properly managing electricity distribution network in terms of voltage, capacity and supply interruptions. We are continuing to leverage smart meters to benefit customers and plan to offer new capabilities in 2026-31 and with further innovations we intend to make Apps on our meters available directly to customers and their agents.

To assist our customers and stakeholders in their understanding of the value of smart meters, we have summarised the benefits in Table 16-1 below.

[159] Our smart meters were installed as part of the Advanced Metering Infrastructure (AMI) Orders
[160] We must comply with the Minimum AMI Service Levels Specification (Victoria) September 2008 Release 1.1 and the Minimum AMI Functionality Specification (Victoria) September 2013 Release 1.2
[161] Clauses 19.4.1(e), 20.4.2 and 20.4.7(c) of the Electricity Distribution Code of Practice published on 1 October 2022 require us, with civil penalty requirements, to publish voltage data measured at the meter, and comply with AS 61000.3.100.

Table 16-1: Benefits currently provided by our smart meters

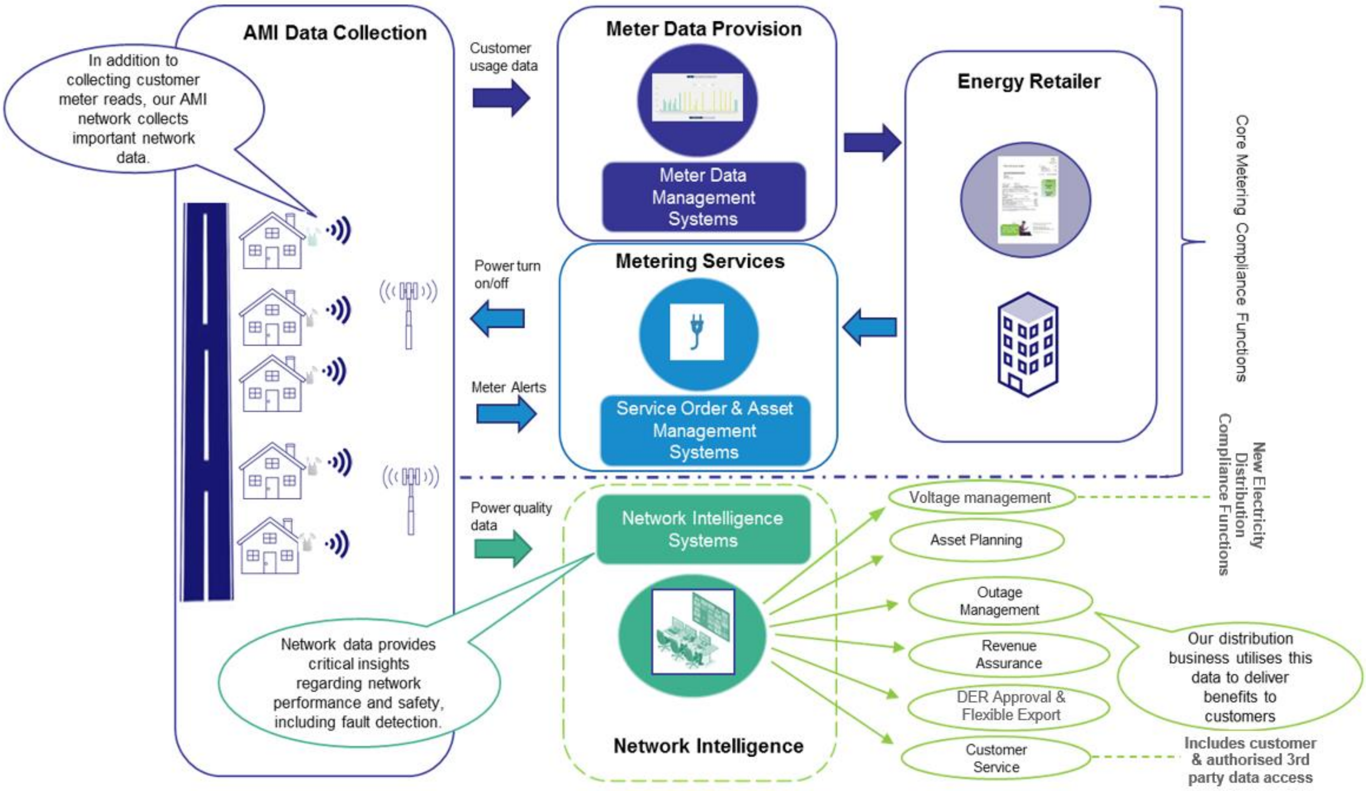
	Benefit type	Benefit	Value
	Keeping energy prices down	**Remote reading and services** - reduced field service costs from manually reading meters and fuse removals.	Over $8 million per year, based on pre-AMI meter roll out staff numbers
		Reducing energy theft – addressing stolen wholesale market and network costs that would otherwise be paid-for by all customers	Avoiding over $2 million per year of stolen energy
		Customer can use their consumption data and make decisions to switch retailers based on their interval data – building confidence in the energy market and benefiting those customers with a more informed switching decision	Enabling customers to find and switch to the lowest cost retailer offer. These benefits can be substantial[162]
	Keeping customers and communities safe	**Pro-actively identifying and fixing faults, before they become safety issues (low voltage service neutral faults) that can lead to electrocution** – reducing electrical shocks per year	Safety benefits
	Customers kept informed in the event of an electricity outage and faster restoration	**Tools to correct network mapping and better understand who is on and off supply** – more accurate outage notifications	Fewer complaints and breaches
		Enabling our call centre staff to view meter supply status in real time – used to verify customer outages are not at the customer's premises	Superior customer experience and some reduction in wasted truck costs
		Detecting customer outages and supply restorations for superior storm management	Not yet still being implemented in operational staff systems (known as ADMS)
	DER uptake and voltage management	**Responding to your solar or battery application quickly and more accurately with our online pre-approval tool, AMDER.**	Next day or earlier response for solar applications
		Publishing aggregated data on network model, GridView, to third parties – to check the available capacity for generation on distribution network assets.	Used by proponents for 100s of generator/hybrids units and public chargers per year (~$2 million per year in lower costs for these proponents)
		Identifying voltage issues and informing corrective switching and augmentation – to maintain compliant supply voltages to our 830,000 LV customers. This includes automated dynamic voltage management system (**DVMS**) switching that we are presently trialling and plan to implement.	More renewable generation and less voltage complaints ~$1 million per year in compliance benefits and much more in avoiding network augmentation

Source: AusNet

Figure 1 below shows the different roles of smart meter technology, systems and data in delivering services that our customers rely on and value. Smart meters and network intelligence are integral to the network functions required to maintain network performance, voltage level compliance and the expectations of external stakeholders to facilitate more DER participation.

[162] On average customers save $340 per year by switching retailer see the Frequently Asked Questions on https://compare.energy.vic.gov.au/ last accessed on 23 October 2024. Using historical interval data, provides the most accurate recommendation for the cheapest offer.

Figure 16-1: The role of our AMI network in delivering value to our customers



Source: AusNet

16.3.3. Delivering compliance and exceeding customer expectations

Throughout the 2021-26 regulatory period, we have improved our meter data delivery performance in line with Victorian and NER regulatory obligations. During this time, we reduced the cost of providing metering services, and we implemented changes to comply with five-minutes settlement National Electricity Rules (**NER**) changes. These required us to convert over 100,000 customer meters from recording 30-minute meter data to 5-minute meter data.

We remain committed to achieving all mandated regulatory performance obligations associated with our AMI meters. The most stringent obligations remain those associated with the Minimum AMI Service Specification (Victoria):[163]

- no less than 95% being actual data, with the remainder substituted, from meters to be available to retailers and AEMO by 6am the following day
- no less than 99% of actual data to be available to retailers and AEMO within 24 hours of the time in previous point, and
- no less than 99.9% of actual data to be available to retailers and AEMO within 10 business days from day the consumption occurred.

AEMO's Service Level Procedure (**SLP**) Meter Data Provider (**MDP**) services requirements under the NER have become more stringent since the Power of Choice rule changes. However, these targets remain less stringent than the above Victorian requirements, as detailed in Table 16-2 below.

[163] first established by the S 286 12 November 2007 Order in Council and amended by subsequent Orders in Council

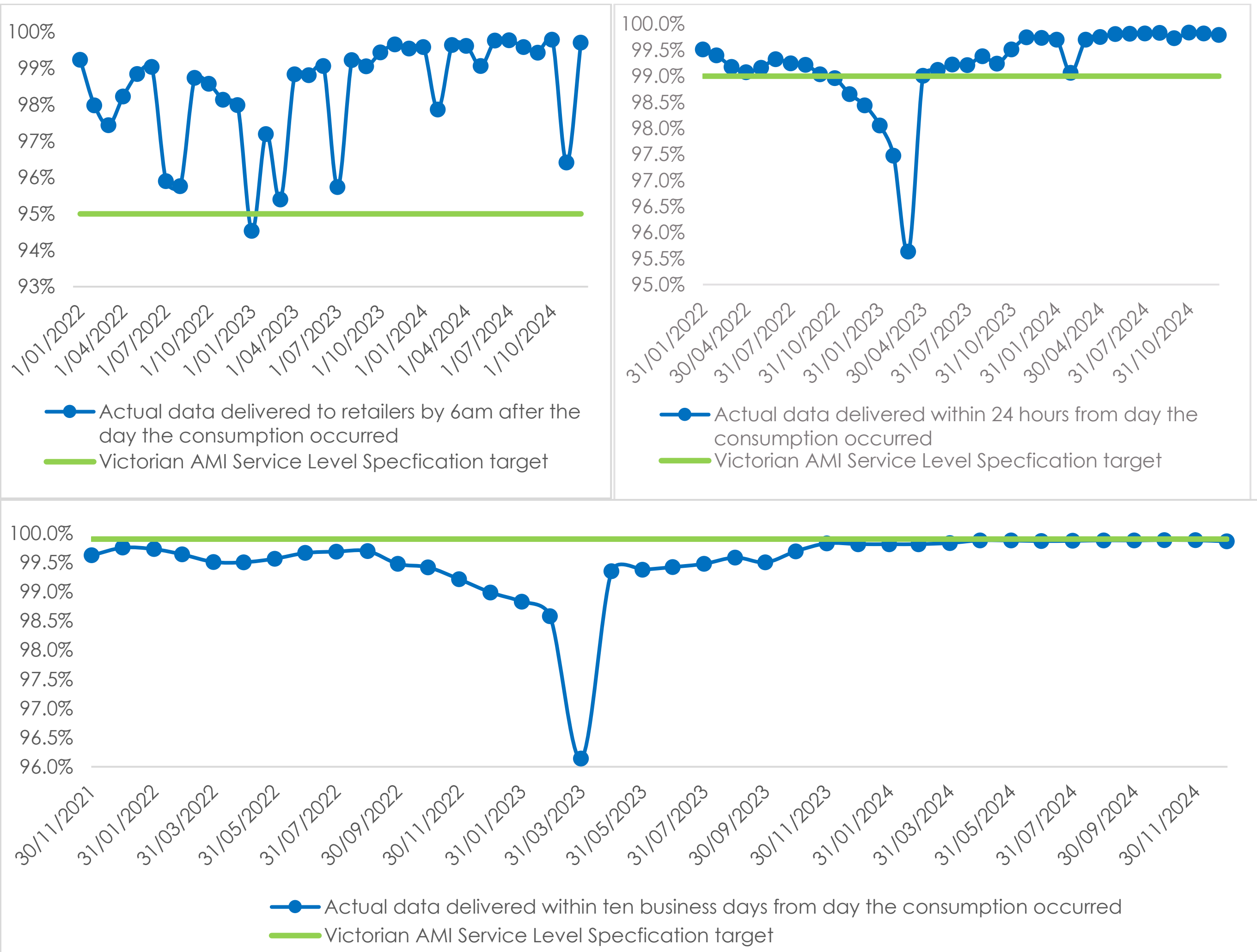
Table 16-2: Comparison of Victorian and NER MDP mandatory service levels

Victorian target	NER MDP SLP	Comparison: Victorian and NER obligations
No less than 99% of actual data to be available to retailers and AEMO within 24 hours of the time in previous point.	By the end of each week, we must provide data to AEMO 98% quality and 95% quantity for the previous week's consumption.[164]	Vic target requires 99% of actual data delivered in 24 hours, while the NER target requires between 93% and 98% of actual or final sub data within a week.
No less than 99.9% of actual data to be available to retailers and AEMO within 10 business days from day the consumption occurred.	Within 6 months from the week the consumption occurred, we must provide data to AEMO 99.9% quality and 99.9% quantity.	Vic target requires 99.9% of actual data delivered in 10 business days, while the NER target requires between 99.9% and 99.8% of actual or final sub data within 6 months.

Source AusNet based on the Victorian AMI Minimum Specification and AEMO's Service Level Procedure: Metering Data Provider Services

The figures below show our actual meter data performance and level of conformance with these targets since 2022. We note, the Victorian requirements allow for 1% hardware and software systems unavailability, and there is a need to provide substituted meter data instead of actual meter data in certain circumstances (e.g., electricity supply interruptions).

Figure 16-2: Actual meter data delivery performance since 2022



Source: AusNet

[164] A minimum 93% of actual data quality can be with 95% quantity and 98% quality.

We will continue to maintain and improve our meter data delivery performance and apply best endeavours to achieve 100% adoption of smart meters across our customer base. Previous performance dips have been subject to the ESC's thematic audits and monitoring by the ESC, we note the dips in 2023 we the result of meter reprogramming to comply with NER 5-minute settlement obligations. In accordance with good asset management practices, we propose efficient investment in our smart meters and associated systems to achieve these requirements. We require the following proposed initiatives to maintain compliance with our actual meter delivery targets.

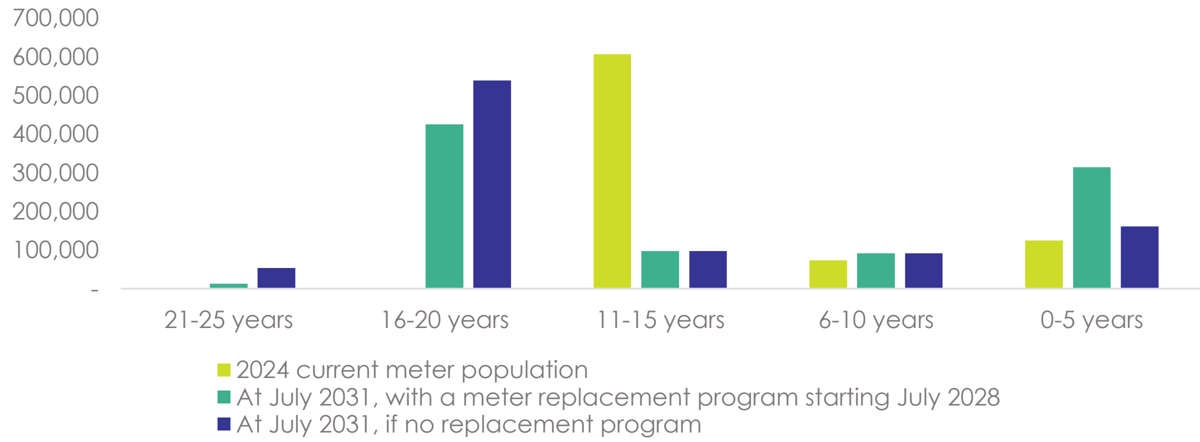
- A 13-year meter replacement commencing in FY2028/29
- IT system upgrades for UIQ and our meter data management system, and
- meter communications replacements and augmentation.

For households who have yet to receive a smart meter we propose other investment in pole mounted or fence-line meter housing solutions directly supports our ability to achieve 100% adoption of AMI meters and our voltage management compliance targets where customer electrical lines do not comply with Australian Standards. These arrangements, where technically applicable, would help us to provide a safe and efficient electricity supply to some vulnerable customer groups with both a medically confirmed health issue and a fear of smart meters is so severe that it is impacting their health.

16.3.4. Further engagement with customer groups on smart meters

In early June, we met with our Future Networks, Tariffs & Pricing Panels to discuss our proposal to commence a 13-year bulk replacement of smart meters. The alternative is to defer meter replacement until smart meters fail, mitigating the risk of a large number of meters failing at once as they age past 20-24 years old. 75% of our smart meters at our customers' premises were installed between 2010-2013 and will be between 18 and 21 years old by July 2031 if not replaced. Figure 3 below shows a projection of this aging populations of smart meters.

Figure 16-3: aging meter populations from 2024 to July 3031 with and without a replacement program



Source AusNet

Our customer representatives asked whether our replacement of smart meters within 2026-31 was warranted, and what are the customer benefits of doing so.

We explained that from our experience with pre-2009 digital meters we know they fail at high rates when they approach their estimated end of life. If the meter lasts to this point, the 5V circuitry in the meter is likely to corrode to the point inhibiting digital circuity and communications interfaces, like a mobile phone. We also discussed other failure modes that were likely to occur earlier in 2026-31 at escalating rates:

- Further escalating meter data recording issues that impact customer billing accuracy, our compliance performance and ability to identifying supply interruptions after a wide-spread supply interruption.
- Rising meter failures impacting the operation of hot water heating (e.g., leaving the customer with cold showers until we replace the meter).

We noted that due to the full depreciation of metering assets from our initial rollout and our reductions in metering operating expenditure during the 2026-31 period, it is possible to re-invest in new meters while still significantly reducing the annual metering charge.

Additionally, we discussed the benefits of new smart meters and communications modules enabling the transition to Distributed Intelligence capabilities. New meters installed from 2027, including replacement program smart meters will deliver these capabilities. This Distributed Intelligence will pave the path to the following benefits, described in Table 16-3 below.

Table 16-3: Distributed Intelligence benefits

Benefit type	Customer benefit	How and when?
Keeping customers and communities safe	Faster resolution of electrical safety issues with meters and identifying of other network safety issues.	Meters that "think" (e.g., analyse network data) and "talk" to each other
Keeping energy prices down through participation	Ease of participation in VPP wholesale markets or forthcoming voluntary scheduled resources incentives by choice of aggregator products	Our vendors expect to allow compatible apps in their smart meters from third party vendors from 2029
	Near real time data access from the smart meter to inform optimal use of appliances and their battery charging	Customer devices can access the smart meter with Wi-Fi to understand their metered consumption and information about the local network from 1st deployments from 2029
Paving the way to micro-grid reliability when the HV network goes down.	Foundation for managing "islanded" low voltage networks that would represent a quantum step in network reliability improvements	Increased visibility of LV network and integration into the DERMS and faster DER envelop implementation to manages voltage from after 2037 when Distributed Intelligence meters are deployed to the majority of our customers

Source AusNet

Our customer representatives discussed with us the following views.

- They support our plans to maintain a modern meter fleet with a progressive replacement of smart meters informed by the need to avoid deteriorating customer service standards and the problems of our last meter roll-out in 2010-2013.
- Reducing metering costs, smoothing the impact and costs of a full meter replacement "seems like a no brainer".
- Asked if there were any possible contentions with other metering businesses in NSW, SA and QLD for the use of qualified meter installation technicians in the years 2026-30.[165]
- We need to explain in plain English what smart metering and meter replacements mean to customers.
- As we develop Distributed Intelligence capability, we need to make choices that allow customers to choose a range of consumer facing applications and service providers from our smart meters.

We agreed to incorporate this feedback into our plans and keep it front of mind as we undertake these exciting developments in 2026-31.

16.4. Our investment plans

Proactive metering replacement program

Our 2026-31 proposal delivers a metering fee price reduction from $83 per annum to $41 per annum with smart meter customers. We achieved this reduction with the full depreciation of metering assets from our initial rollout and reductions in metering operating expenditure, while including plans for undertaking investments in IT system upgrades, communications network augmentation and initiating a long-term targeted meter replacement. This reinvestment is efficient and avoids adverse customer impacts from meters that are likely to fail if not replaced.

As smart meters age their components can deteriorate or fail. From our experience with pre-AMI digital meters, we observed that the very low voltage electronics in meters fail in high numbers between 20 and 25 years of in-service life. We expect our meters would also be subject to this trend.

[165] We discussed that by training the staff we need in 2028 to conduct 13 years of steady meter replacement volumes there is contention for qualified meter installers with other jurisdictions.

This deterioration or failure can impact customers in different ways. The impact to customers is dependent on the type of meter issue and the number of customers affected. We have observed increases in meter issues with meter components. Based on asset life estimate advice from our meter manufacturers, meters are more likely to fail after:

- Meter battery estimated asset life of 10 years;
- Load control switch rated to 10,000 hot-water heating switching instances (or 13.7 years); and
- Overall meter and display screen estimated asset life of 15 years.

In recent years, there has been only a small increase in load control switch and display screen failure related replacements. However, there has been a sharp rise in recorded meter events relating to problems within the meter. These events include:

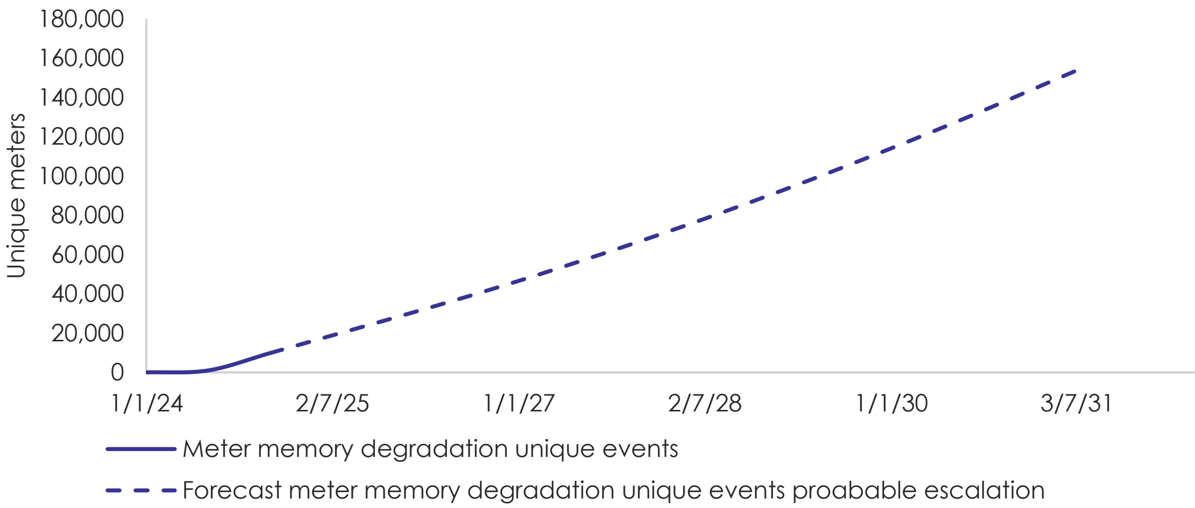
- Failure of automated time synchronisation requiring a meter program; and
- Meter data storage error events – meter detects its data recorded is not accurate in every data interval.

We engaged our global meter technology supplier, Itron, to undertake a technical, performance assessment report of our smart meters and end-to-end systems. This technical assessment identified the above trend of increasing meter memory errors and identified factors other than age associated with meters time synchronisation errors.

The automated time synchronisation error is the result of cascade of problems within the meter. Firstly, there is a reason why the meter clock varied from the set time within the meter by more than 20 seconds. This is most likely due to the meter battery having inadequate stored energy to sustain power supply to the meter during an electricity network supply interruption to the meter (e.g., during a storm event or planned supply interruption). Secondly, it only becomes a problem if the automated, remote time synchronisation fails to correct the error, if the synchronisation takes longer than an interval of recorded data (i.e., 30 minutes or 5 minutes) the meter needs to be reprogramed.

The meter data storage error events are due to the degradation of the meter's flash memory at a steady rate of 1,500 unique meters per month occurring mostly in our oldest smart meters. below shows actual and our forecast growth in the number of these unique meter events recorded.

Figure 16-4: actual and our forecast growth in flash memory degradation based on failure probability



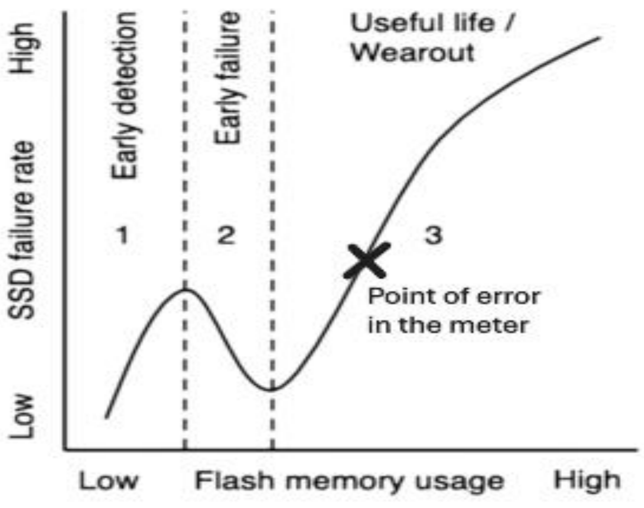
Source AusNet

This occurs in all modern electronic devices depending on the characteristics of flash memory within the device.[166] The speed of degradation is affected by repeated use of memory from daily cycling (e.g., from daily PQ reads) and variations in the supply voltage inside the meter. The memory error rate escalates once flash memory degradation has reached a threshold where programmed data mitigation techniques in the meter that identify and avoid corrupted memory.

The meter records these memory events to identify the issue of the flash memory's bit to error rate exceeding its capacity to identify and mitigate the errors within. The meter recorded memory event enables the meter service provider to replace meters before the flash memory degradation impacts the integrity of the meter and meter data.

[166] Y. Cai, S. Ghose, E. F. Haratsch, Y. Juo, O. Mutlu. "Errors in Flash-Memory-Based Solid-State Drives: Analysis, Mitigation, and Recovery". https://arxiv.org/pdf/1711.11427

Figure 16-5: Pictorial depiction of flash memory usage vs failure rate operating the field with annotation indicating the point where a meter records a memory event



Source: AusNet annotation of diagram based on technical advice. Annotation of original diagram annotation[167]

We expect the error rate generally double every 1,000 memory rewrite cycles or 3 years for an in-service meter that records PQ measurements. Over time memory degradation within a smart meter will escalate to more frequent memory errors and total meter failure, see Figure 16-5 above. To mitigate the risk of meter memory failures from impacting customers and our regulatory obligations we propose to replace meters 3 years after a unique memory event is recorded.

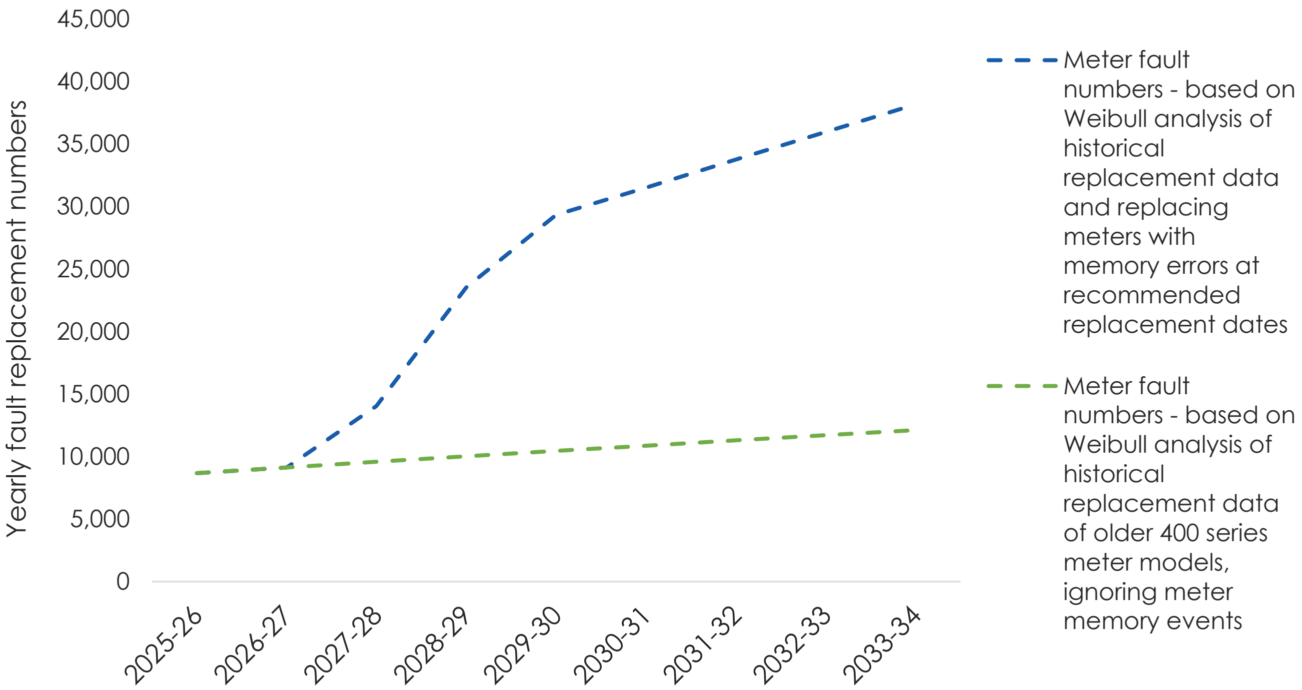
The performance assessment found that most of our time synchronisation meter errors were likely to be associated with recently installed smart meters recording at 5 minutes. The time synchronisation meter errors are caused by the meter responding to our midnight network-wide time check and update instruction. Where time drift has occurred (e.g., due to meter battery and supply interruption issues), the update needs to occur within the current data interval, otherwise the meter registers a time synchronisation meter error causing substituted data until it is reprogramed. Following the performance assessment, we believe the time synchronisation is taking too long for many smart meters configured to record 5-minute interval data. With Itron's recommended communication network augmentation and new access points described later in this section, we should be able to adequately mitigate the issues of time synchronisation meter errors and provide the performance required to meet our service level requirement.

These issues both contribute to meter data quality issues, which will affect customer billing accuracy and our delivery performance of actual meter data to AEMO and our customers' retailers. They exceed the volumes of our other expected forecast meter faults caused by load control switch, display and other meter electronics failures.

Figure 16-6 below shows our meter failure forecasts based on Weibull probabilistic failure rate analysis and the replacement of meter's indicating memory integrity events after 3 years from the date of the meter event.

167 J. Meza, Q. Wu, S. Kumar, and O. Mutla, "A Large-Scale Study of Flash Memory Errors in the Field", in SIGMETRICS, 2015, Page 5

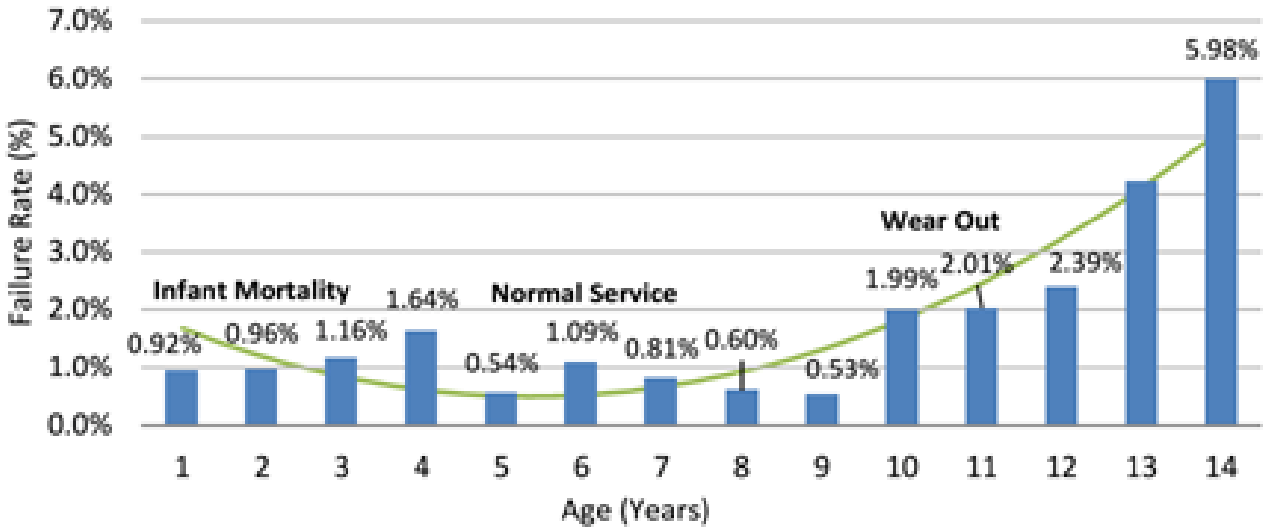
Figure 16-6: AusNet's meter failure forecasts based on Weibull probabilistic failure rate analysis and the recommended replacement of meters indicating compromised memory integrity events



Source AusNet

Our forecast meter failure rates show an escalating meter failure rate as our smart meters age past 17 years. We compare this with analysis from Canada's Hydro One utility smart meter replacement. Hydro One commenced their smart meter roll out in 2007, which was 2 years before Victorian distributors. They are now replacing their legacy smart meter fleet based on an observed escalating meter fault rate at 14 years from component failure, see the figure below.[168] We note that our smart meters are lasting longer than Hydro One smart meters but are likely to exhibit failure rates as our meters age. Based on this comparison and our analysis of escalating meter flash memory issues, our decision to undertake our proposed targeted meter replacement is consistent with comparable smart meter operators.

Figure 16-7: Hydro One's replacement analysis used to justify their smart meter replacement program



Source: Hydro One from their 5-year Distribution System Plan for the 2023 to 2027 period

Based on the Hydo One experience, data of emerging issues and our experience with managing pre-AMI digital meters to their 25-year end of life, we have a realistic expectation that issues with our smart meters will continue to

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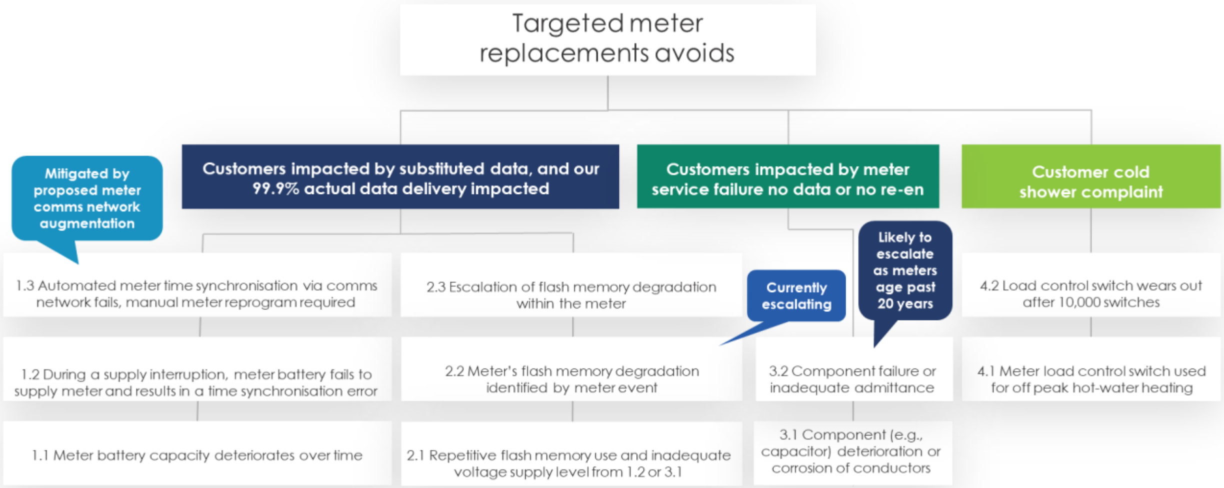
168 Hydro One, 2021, 5-year Distribution System Plan for the 2023 to 2027 period, https://www.hydroone.com/abouthydroone/RegulatoryInformation/JointRateApplications/Documents/HONI_Appl_Exhibit%20B3_DSP_20210805.pdf, page 133

increase and escalate. The escalating issues would likely impact our ability to comply with our 99.9% actual meter delivery obligations by 2030 with more than 30,000 meters likely to have flash memory issues and nearly 5% of meters installed prior to 2014 failing every year. If just 6,000 smart meters per year have significant flash memory deterioration, we will fail this important electricity distribution licence obligation without undertaking additional expenditure to mitigate data delivery quality issues. Other causes of data substitutions typically account for 0.005% of meter data substitutions from intermittent remote comms with Telstra's 4G network, or normal meter reprograming activities.

Consistent with good asset management practices required by Electricity Distribution Code of Practice and requirements of NER 6.5.7(c)(1-3) for undertaking efficient costs and prudent decision making, we plan to undertake a targeted meter replacement program to replace our oldest meters, meters with hot-water load control contractors and meters with memory issues in the forthcoming period based. This replacement program will reduce the incidence of metering issues adversely affecting our customers. Our plans enable us to replace the smart meters most likely to impact customers and our regulatory compliance, see Figure 16-8 below.

Figure 16-8: meter faults and customer impacts mitigated by our targeted meter replacement program



Source AusNet

Following the customer feedback discussed earlier, we undertook a cost benefit assessment of three different meter replacement options (commencing July 2026, July 2028, & July 2031).[169] This assessment incorporated the cost difference of replacing meters on an ad hoc basis compared to less costly bulk meter replacements. The analysis also considered the customer impacts, project management costs and additional measures that could prevent breaching obligations. We concluded that replacing meters in July 2028 leads to $18.6 million in lower costs than the option of replacing meters in July 2026 and commencing the replacement of smart meters after July 2028 would likely breach compliance obligations without costly risk mitigation costs of $17.6 million.[170] Therefore, it produces the best outcome for customers. Initiating this replacement over 13 years in July 2028:

- Deliveries our compliance obligations in an efficient way by replacing those meters that are most likely to fail first;
- Manages the price impact on our customers by spreading our replacement expenditure beyond the 2026-31 regulatory period; and
- Mitigates customer disruptions and higher management costs from a high-volume meter replacement program, like those experienced in the 2010-13 initial smart meter deployment.

Based on this assessment and customer preferences for a meter replacement that deliver cost efficient outcomes for our customers, we are proposing a targeted meter replacement commencing in July 2028 to replace our oldest meters first. In 2026-31, we will continue to monitor the condition of our meters, meter faults and associated data issues to establish our replacement program for 2032-36.

[169] See ASD – AusNet – Business case for smart meter replacement - 31012025

[170] Based on more recent Weibull analysis data and the observed trends in flash memory degradation issues.

Can meters be repaired and refurbished instead?

One question arising from our discussions with customer representatives, is instead of replacing meters can we repair and refurbish the meter. Most of our pre-2018 meters are not capable of 5-minute metering and non-compliant with National Electricity Rules changes introduced in May 2016.171 Therefore, these meters cannot be refurbished for re-use.

Additionally, we note that opening a smart meter to replace a component or battery requires certification testing and does not enhance the longevity of other core components (e.g., already aged meter flash memory). The marginal benefit of re-using a smart meter from expected longevity improvements of less than 10 years is unlikely to cover the additional labour costs, which tends to be prohibitive, especially at relatively low volumes. Therefore, adopting a program of meter repairs and refurbishment would be less efficient than the proposed replacement program.

Metering communications investments

We engaged our global meter technology supplier, Itron, to undertake a technical, performance assessment report of our smart meters and end-to-end systems. This report provided an independent, snapshot investigation of our asset management forecasts, identified current issues with meter systems when compared to international best practice.

The assessment report identified several areas requiring improvement, resulting in 34 recommendations in relation to Mesh augmentation, current system performance, and performance optimisations. Once we implement the performance assessment recommendations, our smart meters, meter communications network and our associated meter systems will be more resilient, fault tolerant and will perform at a higher level and satisfy the requirements associated with the current NEM Reform market changes.

Based on the recommendations in this report and our initial assessment of performance we are planning to expand and augment our meter communications (mesh) network with 307 access points in the 2026-31 period,172 undertake configuration changes and upgrade our metering systems. Our planned mesh augmentation:

addresses current performance issues of high latency, which contributes to meter data delivery issues and to the above-mentioned meter time synchronisation issues; and

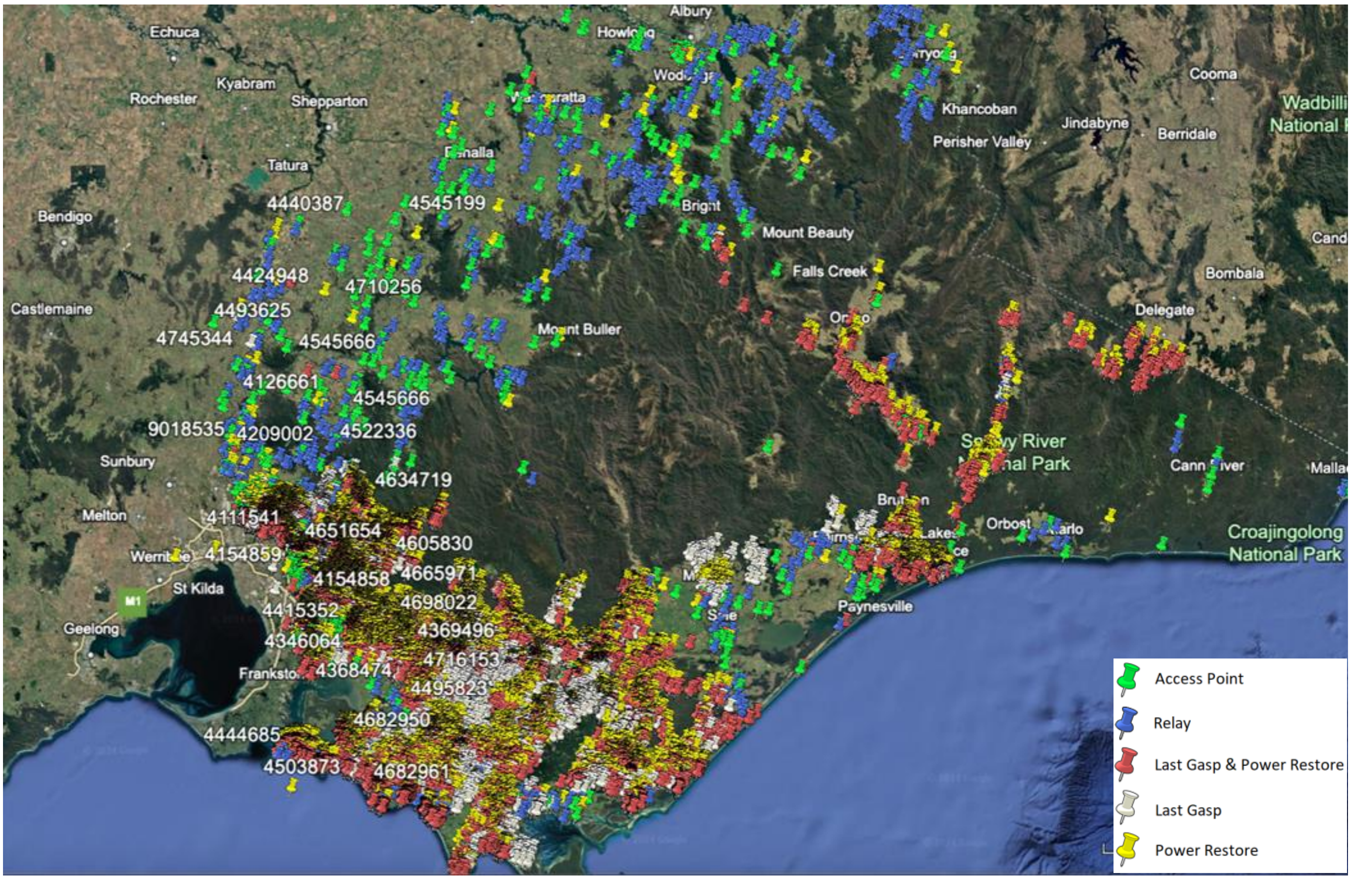
improves the quality of our high frequency collection of network data required to dynamically manage voltage compliance on our network.

Additionally, shown in Figure 16-9 below is analysis of the 2 September storm event identified potential improvements showed that how undertaking mesh augmentation and system improvements will help us manage storm events with better raw data. It observed that lowering our access point ratio will increase our last gasp performance during an outage. With further upgrades our ADMS system will be able to better leverage this raw data, which consequential benefits for our customers in terms of improved service and safety outcomes.

[171] AEMC, 2016. https://www.aemc.gov.au/rule-changes/five-minute-settlement

[172] We plan to increase volumes of access points, the primary backbone of the mesh network, to a total of 965 in July 2031.

Figure 16-9: meter detected outage information from 2 Sept storm event at 3:00 am



Source: Itron

Summary of proposed metering capital expenditure

Our cost benefit assessment of meter replacement options reflects our assessment of the optimal end of life replacement program. The Itron Performance Assessment report also supports our proposed expenditure for key IT system upgrades and meter communications augmentation. Consistent with good asset management, our expenditure is justified as the most efficient level of investment required to manage our meter customer services and obligations to required service levels.

Our proposed capital metering expenditure in 2026-31 comprises of the following initiatives:

- Our proposed meter replacements, including 60,000 per year end of life replacement meters from July 2029 (30,000 in July 2028-29), and 4,700 to 5,600 per year meter replacements for customers requesting a 3-phase supply.
- new meters for new customers and customers with meter faults with 70% of new connections becoming multi-phase by 2031;173
- IT system upgrades and upsizing of UIQ, SIQ and associated metering systems;174
- meter communications replacements and augmentation with 307 new Access Points;175
- an upgrade of our meter data management system to accommodate greater volumes of 5-minute interval and accommodate NEM reform requirements; and
- pole mounted or fence-line meter housing solutions for customers with smart meter objections or with voltage drops between their point of supply and meter.

Table 16-4 below provides a more detailed description of our proposed metering capital expenditure and the estimated customer benefits that the program is expected to deliver.

[173] The approved F&A requires us to fund new smart meters for connecting customers.
[174] As recommended by Itron's Solution and Performance Assessment
[175] As forecast by AusNet for performance enhance and recommended by Itron's Performance Assessment

Table 16-4: metering initiatives and the justification for investing in the initiative (costs and benefits in Real July 2025 $s and determined by a 30-year NPV assessment)

Metering initiatives	Relevant factor	Justification
Our proposed meter replacements – commencing in FY2028-29	Deferring meter replacements from FY2026-27 to FY2028-29	$17.6 million in total expenditure savings[176]
	Efficiencies from replacing many meters in a region rather than replacing individual meters	$12.2 million meter capex reduction compared option 2 to fix on fail alternative
	Avoiding billing customer complaints each complaint costing an estimated $100 per customer complaints and meter data correction time	$1.2 million total cost savings compared option 2 to fix on fail alternative
	Avoiding Project Management Office costs associated with a very high-volume meter replacement from a rapidly escalating individual meter failure	$4.0 million total cost reduction compared option 2 to fix on fail alternative
	Avoiding compliance risk mitigation costs – replacing meter in 2 days at high volumes with no advance planning	$22.8 million in additional meter exchange costs from higher labour rates compared Option 2 to fix on fail alternative [177]
IT system upgrades and upsizing of UIQ & SIQ	Provides future compatibility with NEM2025 Reforms. If we do not invest, systems would not meet essential functions.	Required for compliance with NER and Victorian obligations
	Improved awareness of smart meter communication network performance issues	Improved system and communications reliability
Meter comms. augmentation	Improved remote meter reading, improved meter supply status responsiveness and outage detection	Less customer complaints and superior outage information
	Meter synchronisation at mid-night resulting in less manual meter reprograming and less meter data substitutes	Avoids escalating meter reprograming 10,000s of meter after issues arise
	Improved customer outages and supply restorations for superior storm management	Provides additional benefits to our proposed ADMS Phase 3 upgrade
Pole mounted or fence-line meter housing solutions	Provides potential options for customers that were previously opposed to smart meters and facilitating greater customer engagement on smart meter benefits	$5 million in reduced meter reading costs from replaced meters
	Improved voltage reporting by voltage anomalies caused by AS3000 non-compliant customer premise wiring for hundreds of sites.	More accurate voltage reporting for improved transparency and compliance
	Removing non-smart meters that are no longer compliant with Rules, no longer accurate and becoming less accurate over time.	Avoids significant customer bill inaccuracies and retailer billing disputes

Source AusNet

Each of metering expenditure initiatives directly translate to either compliance requirements or avoided costs that justify our forecast expenditure.

[176] See option 1 compared to the base case in attachment "Business case for smart meter replacement"
[177] It is uncertain to whether replacing meters within 2-3 business days is even possible for large scale meter failures across a large network like our regional network. It is not possible to comply with our obligations for 99.9% data delivery obligation, if 15,000 meters fail in a year, and meters are replaced within 10 days of the meter failure. This mitigation applied to option 2

16.4.1. Customer engagement approach for meter replacements

We understand how important it is for our customers that they pay no more on their energy bills than for their correct energy consumption. The meter at their premises is critical to ensure this outcome. As we continue to maintain, use and replace meters with smart meters, we recognise our customer need for respect and quality metering services. A key goal in providing metering services to our customers is to build confidence that we are working in the best interests of the community. In every interaction with our customers where it relates to their metering, we recognise the importance of this confidence and the need for consistent and helpful communications. We will collaborate with our customers through genuine engagement to effect a safe and respectful meter change. In advance of the meter exchange, we will provide the customer with:

- Clear information on the meter exchange process and the importance of having a new meter.
- Details of a contact person to enable the customer to ask questions and discuss the process further.
- Reasonable time for the customer to consider information on which to base a decision.

Whether it is replacing a smart meter with a new smart meter, or replacing a customer's non-smart meter with their first smart meter, we need to be respectful of our customers' preferences and concerns. Our engagement will benefit from best practice stakeholder engagement training and include mitigation strategies to address underlying concerns.

Smart meters are now part of the electricity supply systems required to keep prices down, keep people safe, keep the network reliable and enable customers to use as much renewable energy as possible.

Our 5,500 active customers with non-smart meters have not yet allowed us to undertake a meter replacement since 2013. Non-smart meters have no failure mechanism that interrupts the electricity supply to the customer, which creates the perception of being fully functional. However, these non-smart meters are now likely to be failing to meet Class 1 energy measurement accuracy standards (i.e. 99% accurate). The accuracy of aged non-smart meters will eventually deteriorate so much the customer's electricity charges could materially differ from their actual consumption.

Initiatives to incentivise smart meter replacements for the remaining less 1% of customers

Over the last decade we have made, at least, 6 attempts to contact each customer with a non-smart meter and organise a replacement. Our non-smart meters are now widely and sparsely distributed throughout our network area and meter reading is a very travel intensive activity. The additional cost of manually reading their meter 4 times a year is $156 per meter per year more than the cost of remotely reading a smart meter.

For customers with a smart meter, their metering fee price will reduce from $84 per annum to an average of $45 per annum. We are proposing to only pass on this cost saving to customers that have smart meters and contributing to those community benefits. For customers with smart meters, we are proposing to charge the same fee as they are currently paying with prices indexed with CPI.

These customers will not receive an average of $38 per year meter charge reduction until we replace their smart meter. This price difference provides an incentive to encourage engagement with us on meter replacements but does not pass on the additional cost of manually reading meters. We acknowledge the price difference and volumes may be insignificant for some retailers and not justify billing changes for their customers. However, where the retailer agrees to not recover this price difference, we expect this will encourage engagement with their customers to discuss the benefits of a meter replacement.

Alternative arrangements for customers

Additionally, to facilitate a replacement of non-smart meter or where the customer's electrical installation does not comply with AS3000 voltage requirements, we plan to offer the establishment of fence-line meter cabinets, or in limited circumstances where the pole is technically suitable, pole-top meter cabinets. If there is a suitable alterative meter location option, we expect this offer will facilitate more meaningful engagement with the customer and overcome their underlying concerns with the smart meter replacement. Our proposed $3 million investment would cover our costs of moving our point of supply, the cost of safe, compliant meter housing, and associated engagement for nearly 2,000 customers. However, the cost of any wiring changes at the premises would be customer funded and not be funded by us. The establishment of this alternative arrangement would also benefit other customers with difficult to read sites.

Feedback from our customer Coordination Group

We discussed these two initiatives with our customer representative Coordination Group overall they were comfortable with these initiatives. They questioned whether other Victorian distribution businesses were undertaking a similar meter charge initiative and what circumstances retailers would pass on the costs. It would be easier to manage customer communications if other Victorian distribution businesses are implementing the same price reduction. We considered that most retailers are unlikely to establish separate pricing (i.e., market offers) for less than 5,000 Victorian customers. Retailers also benefit from most accurate and timely energy data from smart meters. The modest price difference would be another incentive for retailers to encourage customers to allow their meter to be replaced.

16.5. Proposed costs and revenue

In accordance with the building block approach mandated by the Rules, our smart metering charges reflect:

- the return on and of capital associated with the metering RAB and continued capex associated with new customers and replacement of existing meters
- the return on and of capital associated with the Meter Management System RAB and continued capex associated with maintaining and renewing that system
- the opex associated with maintenance, meter reading and metering data services. Metering data services involve the collection, processing, storage, delivery and management of metering data, and
- any tax liability that arises over the period.

Details of these building blocks are set out in the sections below.

16.5.1. Allocation of costs between standard control and smart metering services

In the 2026-31 regulatory period, we propose metering costs are allocated between standard control services and alternative control services based on the principle of cost reflectiveness. For most of our costs including the cost of procuring, installing and maintaining meters, this is the same capitalising operating expenditure methodology applied in the 2021-26 regulatory period final determination.

However, we now use our metering data systems and communications to comply with network obligation in the Victorian Electricity Distribution Code of Practice (EDCoP). We propose to update the 2021-26 allocation of some meter capex is allocation methods to take this requirement, which requires the collection of voltage data from all smart meters. The 2021-26 allocation in the final determination assumed we only needed to collect data from a representative group of smart meters (i.e., 6% of meters) we have now updated this allocation method for capex expenditure to take apply the same reasoning and considers that we must collect energy and power quality (voltage) data from each smart meter. We did not apply this to mesh licencing and system maintenance costs, which we have retained to maintain the integrity of the base, step and trend approach.

The table below outlines our allocation of IT and communication costs based on cost reflective usage between Alternative Control Services and Standard Control Services (ACS:SCS). We propose to allocate system and data costs for capex according to the shared use allocations of IT and communication costs between Alternative Control Services and network Standard Control Services, because we must collect both energy data and power quality (including voltage) data from all smart meters (to achieve compliance with our Victorian regulatory obligations).

Table 16-5: Proposed cost allocations and our reason for amending from the 2021-26 final determination

Allocation to capex	2021-26 final determination	Proposed 2026-31 allocation	Reasoning
Meters assets (ex comms modules), their installation and maintenance	100% ACS	100% ACS	No change, meters remain measurement devices for a range of mandatory data.
Dedicated systems to read energy data from meters without communications	100% ACS	100% ACS	No change, whether communications are available, or not, the data recorded must be collected and provided to retailers and AEMO for customer billing and market settlement purposes.
Mesh (UtilityIQ) licensing opex	94% ACS 6% SCS	Retaining 94% ACS 6% SCS	Retaining opex ACS/SCS split from the current period to ensure consistency with the base, step and trend approach to pass on savings to our customers.
Meter data management system (EnergyIP), reporting and DMACs[178] opex	50% ACS 50% SCS	Retaining 50% ACS 50% SCS	Retaining opex ACS/SCS split from the current period to ensure consistency with the base, step and trend approach to pass on savings to our customers.
4G and data backhaul opex	94% ACS 6% SCS	Retaining 94% ACS 6% SCS	Retaining opex ACS/SCS split from the current period to ensure consistency with the base, step

[178] DMACs are dynamic monitoring and control system services that support

			and trend approach to pass on savings to our customers.
Mesh network assets (capex)	94% ACS 6% SCS	50% ACS 50% SCS	The above reasoning also applies to our smart metering communications assets (e.g., communications modules, access points and relays).
Meter Data Management System (EnergyIP) capex	100% ACS	50% ACS 50% SCS	Our MDMS currently provides validated energy data to AEMO and retailers. In the forthcoming regulatory period, NEM reform regulatory changes are likely to require the provision of energy quality via this system as well.

Source: AusNet

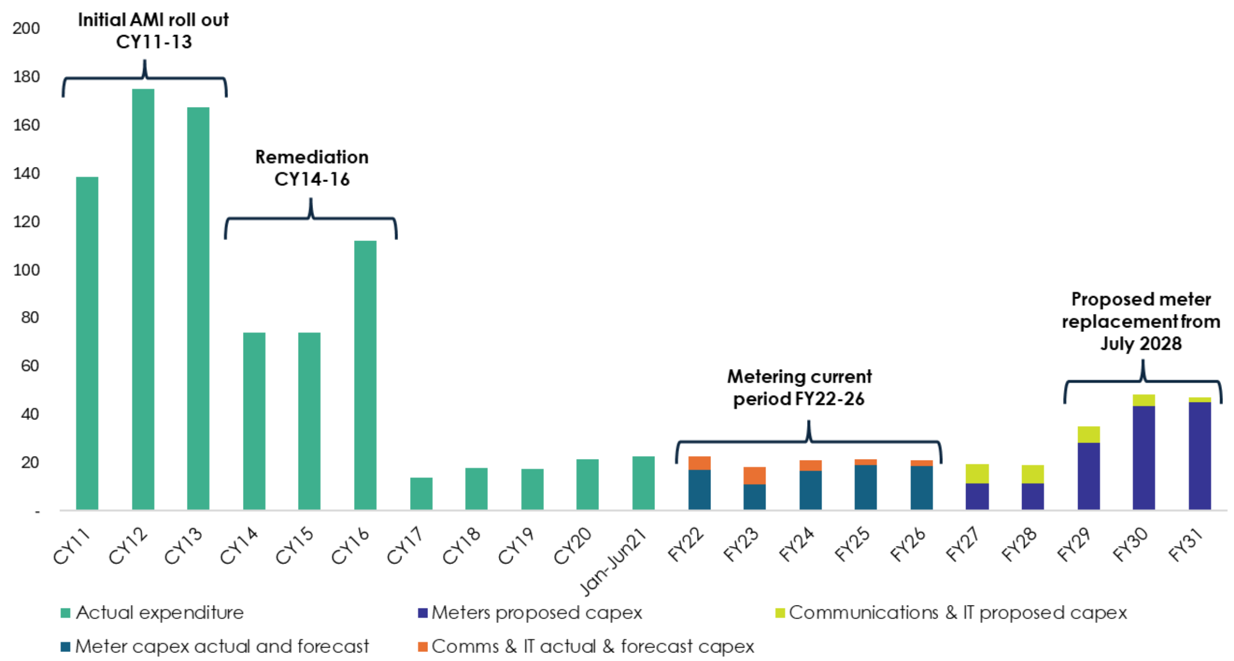
16.5.2. Proposed capex

Our meters require ongoing investment to maintain the provision of reliable metering services to our customers. This investment includes capex to meet customer growth and to maintain the metering service as current technologies become obsolete or technically unsupported over the period. In particular, our capex forecast shown in Figure 16-10 below includes expenditure for:

- new and replacement meters;
- modest investment in solutions to install meters at 100% of small customer premises;
- maintain and augment our smart meter communications network; and
- investment in meter management IT systems.

Metering capex is expected to remain consistent with the current regulatory period in the first two years of the regulatory period because we plan to run down existing meter stock and augment our meter communications network with additional Access Points, and then increase by 43% per annum from 1 July 2028 as we commence the proactive replacement program.

Figure 16-10: Metering ACS Capex – Actuals (2011 to July 2024) & Forecast (2025-31) ($ real $2025-26)



Source: AusNet

The following points should be noted in the figure above:

- We are augmenting our smart meter communications infrastructure in FY27 and FY28; and
- Our 13-year meter replacement commencing in FY29 with a slow ramp-up will avoid rapid price rises for customers and keep prices lower in the long term.

Our proposed metering capex is set out in Table 16-6 below.

Table 16-6: Proposed Type 5 and 6 Metering Capex ($m, real $2026)

	2026-27	2027-28	2028-29	2029-30	2030-31	TOTAL
Meters	11.2	11.6	28.4	43.5	45.1	139.8
IT	3.2	2.9	4.3	2.6	-	13.2
Communications	2.5	2.2	1.1	1.1	1.0	8.0
Total	13.6	14.2	28.2	41.2	41.9	160.1

Source: AusNet

16.5.3. Proposed opex

Our smart meters require continued operating and maintenance expenditure to ensure ongoing compliance with our regulatory obligations. Current period operating expenditure is materially lower than our allowance, due to improvements from our use of mesh-based meter communications provided as compared to our use of a hybrid WiMax and mesh solution in the 2021-25 regulatory period.

Our proposed operating expenditure is based on a base, step and trend approach that ensures operating efficiencies achieved are handed back to customers, through lower metering charges in 2026-31.

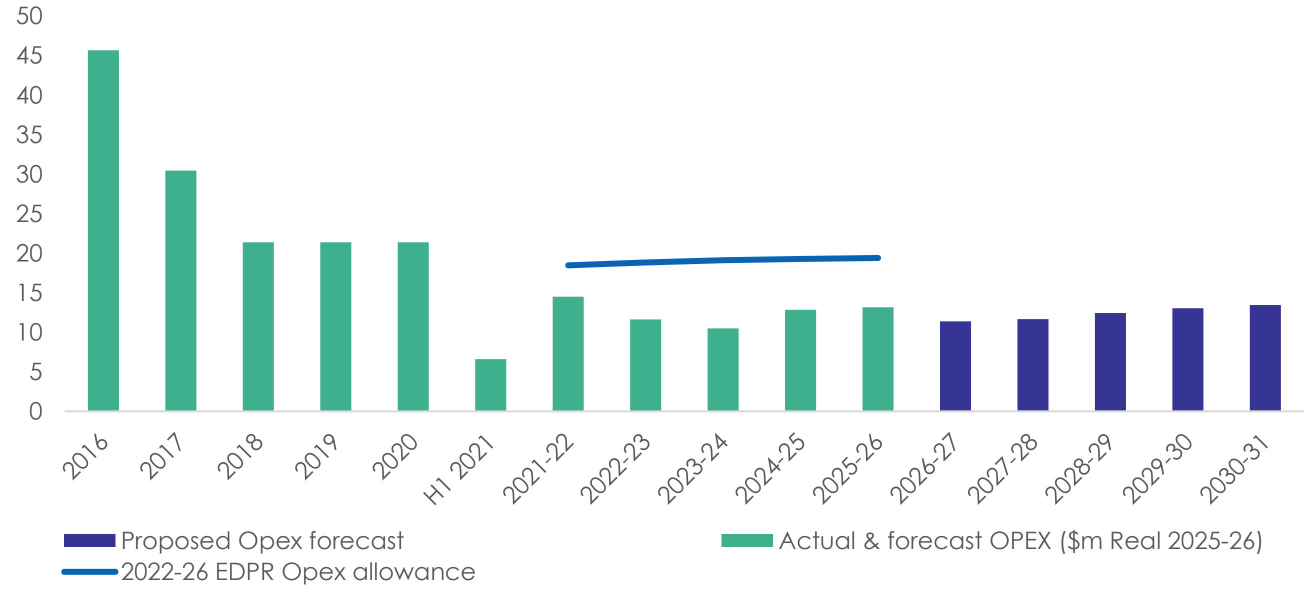
We are forecasting a growing meter population. Each new meter results in additional meter software subscription and telecommunications costs in the new period and higher labour rates.

Additionally, we are forecasting a step increase in meter software licencing costs for new meters to develop Distributed Intelligence capabilities for new smart meters installed from July 2029. This yearly subscription cost only applies to new smart meters enabled to provide these new capabilities and customer meter services, assessable to customers by Wi-Fi.

Our metering forecast shown below in Figure 16-11 includes opex relating to:

- license subscription costs for metering systems in the meter communications card, the meter communications network assets, and at our head-end IT facilities;
- manual reading of meters, where the communications have not been installed due to customer refusals or economic considerations;
- telecommunication charges to operate our backhaul communications and gateway;
- meter data management and ongoing maintenance of the meters; and
- management of the metering business, including asset management of the meters and the meter management IT system.

Figure 16-11: Metering ACS opex from 2016 to July 2031 ($ real $2025-26)



Source: AusNet

Our customers will continue to benefit in the 2026-31 period from the cost savings achieved during current 2021-26 regulatory period through the application of a decline in our base year expenditure. Our proposed operating expenditure is based on a base, step and trend approach that includes substantial achieved operating efficiencies, see the table below.

Table 16-7: Assumptions to our proposed opex

Opex factor	Forecast assumption	Justification
Base year	2023-24 base year for ACS metering opex of $9.78m (nominal)	2023-24 is the most recent regulatory year and therefore the most relevant indication of future metering expenditure. The AER's ACS metering model requires the base year for the initial proposal to be 2023-24. 2023-24 base year for ACS metering opex is a 40% reduction on the 2023-24 current regulatory allowance and represents a substantial cost reduction for our customers.
Trend	Increasing meter numbers	Increasing meter numbers resulting in directly proportional higher opex from higher software licencing costs, increased bandwidth and field resource requirements
Step change	Increases in licensing costs from Distributed Intelligence and WiFi new meter capabilities	We plan to provide new meters from July 2028 with Distributed Intelligence and Wi-Fi capabilities that allow our customers access meter in near real time via a convenient Wi-Fi interface. Distributed Intelligence will also allow us to embed our head-end network analytics of smart meter data in our meters and expand existing meter capabilities to respond in near time. Our proposed step change is based on indicative vendor pricing and subject to a trial and competitive market procurement processes.

Source: AusNet

The cumulative effect of our base, step and trend opex forecasts is substantially reducing opex charges per meter. These reductions are sustainable and represent efficient prices outcomes for our customers. Our proposed metering opex contributions is set out in Table 16-8 below.

Table 16-8: Proposed type 5 and 6 metering opex contributions ($m, real $2026)

	2026-27	2027-28	2028-29	2029-30	2030-31
Metering services	1.85	1.90	1.95	2.01	2.07
Metering maintenance	1.05	1.08	1.11	1.14	1.17
IT and communications	8.22	8.44	9.11	9.61	9.90
Total	11.12	11.42	12.17	12.77	13.14

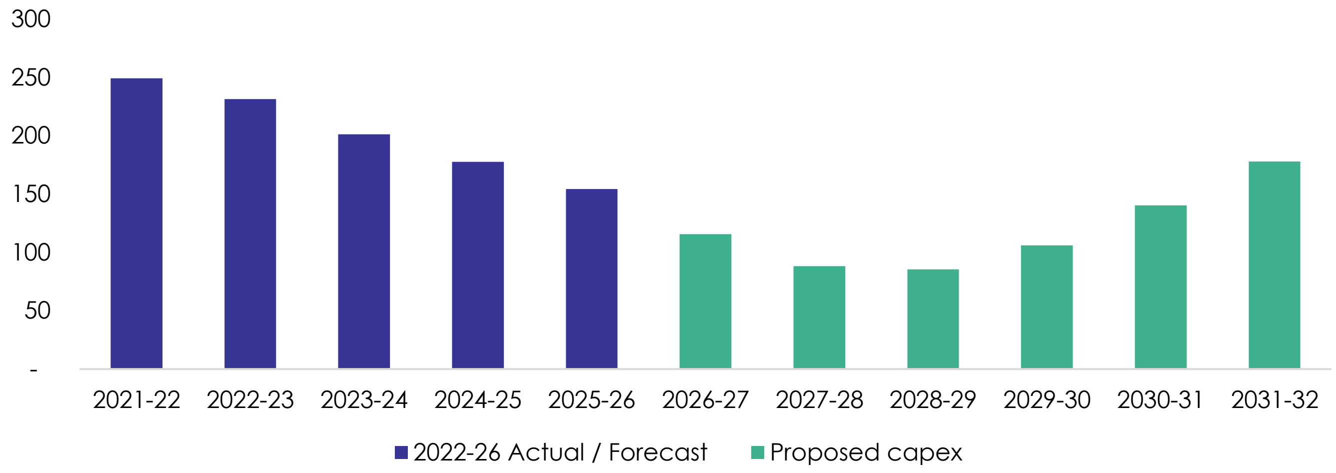
Source: AusNet

16.5.4. RAB

We have not sought to modify the asset lives established under the AMI Cost Recovery Order in Council for depreciation purposes. The RAB is depreciated according to the remaining lives and depreciation profile contained in the tracking module that will be submitted with the proposal.

Our alternative control service metering RAB has declined and is forecast to decline until our meter replacement program commences at full deployment rates in 2030-31, see the figure below.

Figure 16-12: ACS metering opening RAB value actuals and forecast ($m real $2025-26)



Source: AusNet

The proposed metering RAB, including forecast capex and depreciation, is set out in Table 16-9 below.

Table 16-98: Forecast type 5 and 6 metering RAB ($m, real $2026)

	2026-27	2027-28	2028-29	2029-30	2030-31
Meters	73.4	49.8	53.3	77.0	115.8
IT	1.7	4.7	7.0	10.4	11.4
Communications	38.8	30.4	22.1	15.8	10.4
Total	**113.9**	**84.8**	**82.5**	**103.3**	**137.6**

Source: AusNet

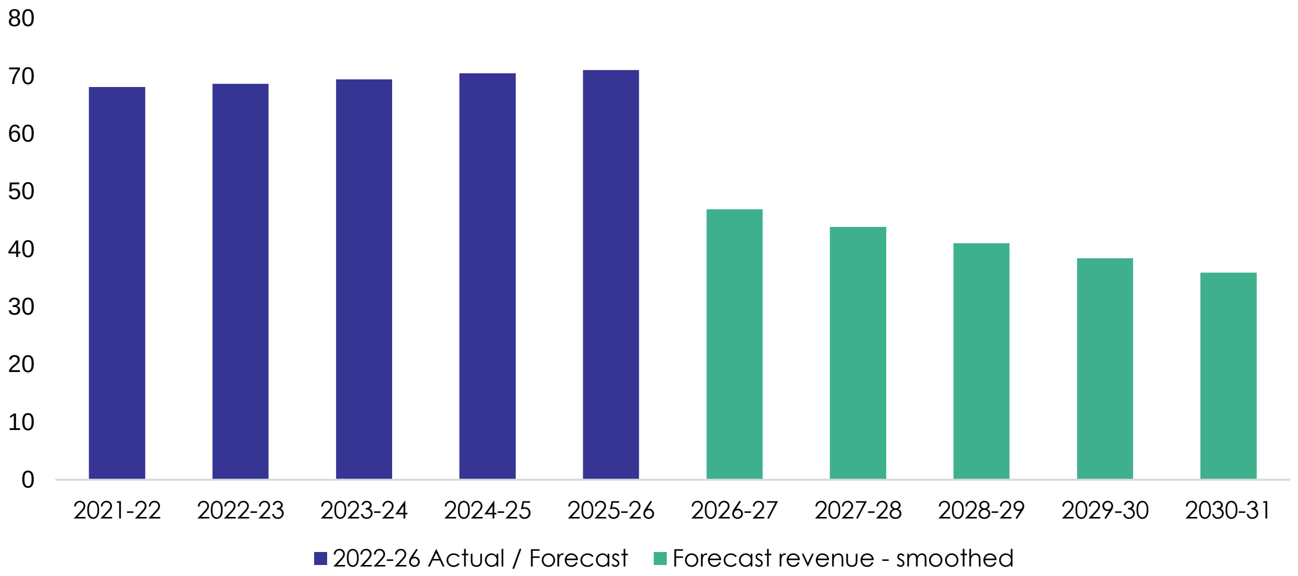
16.5.5. Return on capital

We are proposing the same WACC and gamma values for the metering service as for the standard control services set out in Chapter 11.

16.5.6. Revenue and customer bill impacts

In real $2026 terms, we are proposing $206m of ACS metering revenue over the 2026-31 regulatory period. The figure below shows the actual and forecast yearly smoothed revenue requirement.

Figure 16-13: Forecast/actual total ACS metering smoothed revenue ($m real $2025-26)



Source: AusNet

An average annual metering charge of $46 per customer over the 2026-31 regulatory period, which is a reduction of 45% compared to the average charge of $84 per customer in the 2021-26 regulatory period. As explained above, this reduction has been achieved primarily through efficiency gains in metering operations and the full depreciation of metering assets from our initial rollout. Table 16-10 below shows the contributions to reductions to revenue requirements.

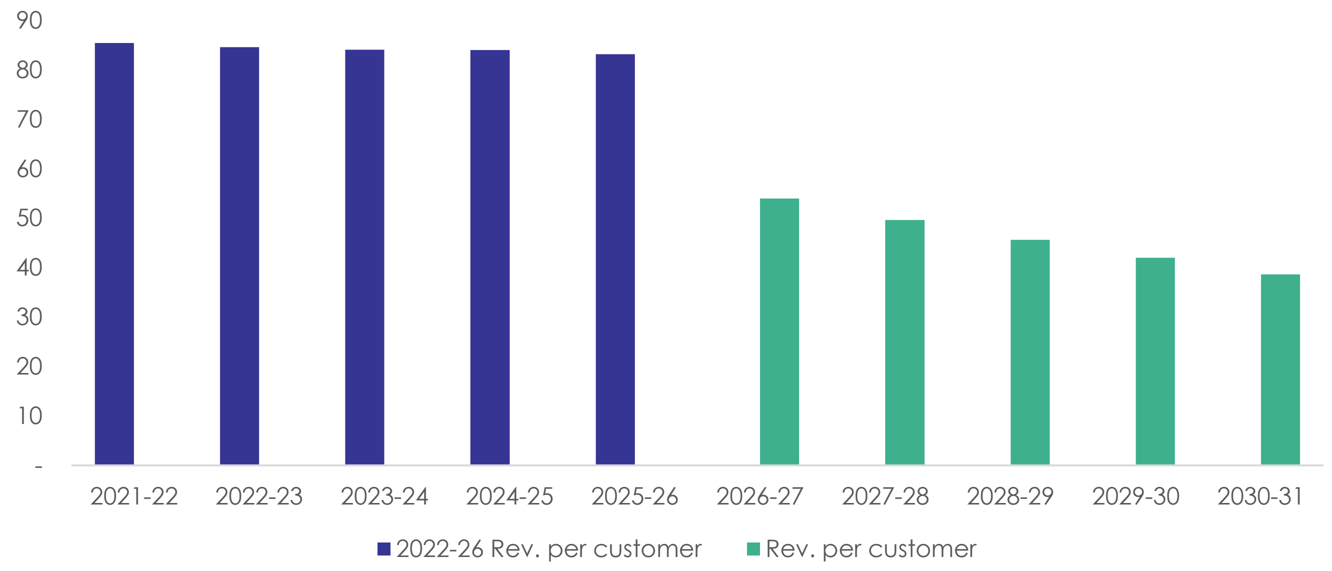
Table 16-10: contributions to price reductions based on revenue requirements

Contribution to price reduction	Value of revenue contribution over 2026-31 in $m real 2025-26	Percentage of price reduction in average prices
Depreciation reduction	80.26	52.40%
Opex reduction	33.19	21.67%
Increase in customer base	19.4	12.67%
Return on Capital - change in WACC	10.44	6.82%
Tax allowance	9.87	6.45%

Source: AusNet

The average annual revenue per customer in real $2026 terms is depicted in the figure below.

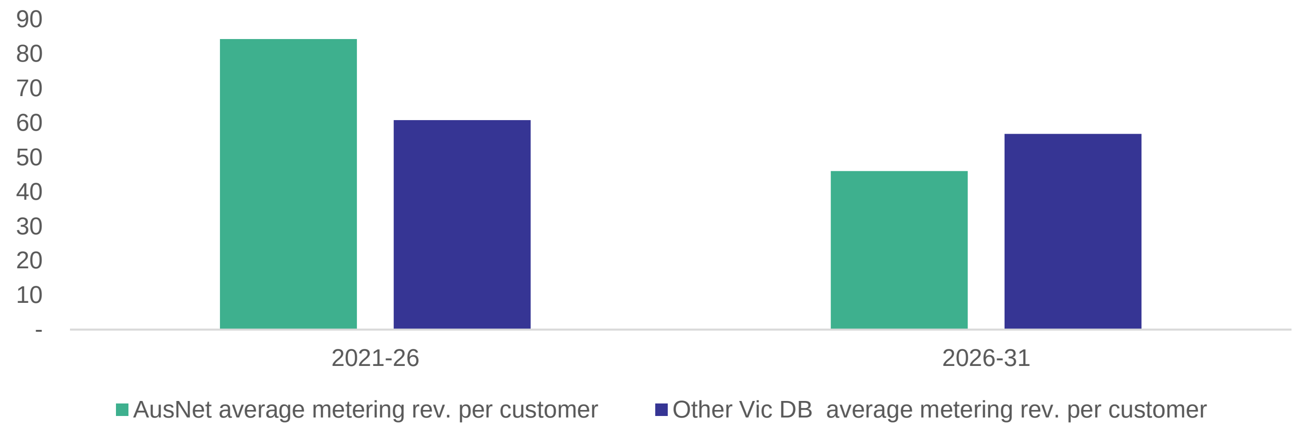
Figure 16-14: Average metering revenue per customer ($m real $2025-26)



Source: AusNet

When compared to the other Victorian distribution businesses' Draft Proposals, our metering revenue per customer at $46 per year is lower the average of the other four Victorian businesses, which is indicated to be $57 per year averaged over FY2026-31 period, see the figure below.[179]

Figure 16-15: AusNet's average metering price compared to the other Victorian distributors indicative average prices



Source: AusNet and other Victorian distributors' draft plans

16.5.7. Indicative metering charges

Based on the forecast annual revenue requirements and meter volumes for the 2026-31 regulatory period and applying consistent price splits from 2025-26, the indicative metering charges are shown in the Table below.

However, for customers with meters not providing smart meter benefits we are proposing to apply the ACS fee-based service price control mechanism and include revenue with our metering revenue.

In this regulatory period, we have introduced separate fees for remaining manually read, non-smart meters. We are required to replace these meters with smart meters. However, these customers have prevented the replacement. Our cost of manually reading these meters is $165 per year per meter, costs that exceed the price for any of our meter products. Therefore, we consider that is reasonable to not pass on the savings to these customers over the period to create an incentive for these customers to allow us to replace these meters.

[179] Based on the 2026-31 draft plans of Jemena, Powercor, Citipower, and United Energy published in August and September 2024

Table 16-10: Indicative alternative control metering services charges ($ nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Single phase single element	48.82	45.76	42.84	40.13	37.51
Single phase two element with contactor	59.02	55.33	51.80	48.52	45.36
Multiphase with and without contactor	74.55	69.89	65.43	61.29	57.29
Multiphase CT connected	78.37	73.46	68.78	64.43	60.22
Single phase single element – not providing smart meter benefits	64.98	66.60	68.27	69.97	71.72
Multiphase with and without contactor – not providing smart meter benefits	78.56	80.52	82.54	84.60	86.72

Source: AusNet

16.5.8. Meter exit fees

Metering exit service fees allow us to recover the written down value of a smart meter and the efficient costs of removing and disposing of the meter, when the meter is no longer required at an existing site. This typically occurs when a brownfield site becomes an embedded networks, necessitating the removal of the existing meters. The AER approved F&A classified metering exit services as an alternative control service.

Our modelling of the metering exit fee is unchanged from the approach adopted in the current regulatory period. In particular, the model that we have used to calculate its proposed exit fee:

- Requires historical and forecast capex (by meter category, and for IT and communications) to be in nominal terms
- Converts these nominal expenditures into real $2026 based on inputted escalation factors that are consistent with those that have been used throughout other parts of this regulatory proposal
- Depreciates this real $2026 capex using the method that underpins the AER's building block model (which provides for no depreciation in the first year, but for capex to be inflated by a half year WACC, with this inflated amount depreciated over the useful life of the asset)
- Calculates the average WDV in each year, by meter category, based on the average of the start and end year WDVs for that meter category, with the end year WDV figure based on the:
  - Starting WDV for that year (in real $2026 terms)
  - Plus the capex incurred in that year (in real $2026 terms, inflated by a half year WACC if that expenditure is forecast to occ from 2027 onwards)
  - Less the depreciation
  - Divides the average WDV of each meter category in each year, by the average number of meters in that meter category that were (or are expected to be) in situ in that year
  - Adds the average WDV of IT and communications based on the same methodology as above
  - Adds the costs of back-office processing, final read and billing activities, and
  - Adds the removal of meter and return of meter to store labour costs.

Our model for calculating exit fees uses the following key inputs.

- **Historical capex (by meter category):** This is based on the opening RAB for the forthcoming regulatory period. However, these costs have been split into meter categories for the purposes of modelling the exit fee, as opposed to the broader capital expenditure category of 'remotely read interval meter'.
- **Forecast capex (by meter category):** This is based on the forecast costs included in other parts of this Regulatory Proposal that have been allocated to the provision of metering services to customers less than 160MWh. Again, these costs have been split out by meter category.
- **Depreciation lives:** These have been sourced from the Metering Post Tax Revenue Model, but generally, the capital and installation costs of the meters have been depreciated over 15 years, while the communications and IT costs have been depreciated over 7 years.

Our exit fee includes reasonable and efficient costs of removing the metering installation for which we are the metering coordinator.

The table below summarises our proposed exit fees for each of our relevant meter categories, for each year of the forthcoming regulatory period and shows the exit fees for the last year.

Table 16-11: proposed exit fee by meter type ($ nominal) with the last year of the current period included

	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
Single phase single element	287.57	210.52	193.62	177.06	187.69	218.87
Single phase two element with contactor	287.57	213.96	196.50	179.50	190.78	223.44
Multiphase with and without contactor	287.57	227.95	208.17	189.40	203.31	241.97
Multiphase CT connected	287.57	309.99	276.65	247.46	276.79	350.65

Source: AusNet

16.5.9. Unmetered installations

We provide meter data services to customers with unmetered supplies including public lighting customers. The charges for the provision of the service are in two parts: a charge in respect of each NMI for which the data stream is calculated, and a charge for each light that is recorded on the Inventory table of lights for each public lighting customer. Consistent with historical practice, we propose that the charges for both parts be adjusted by the CPI and the forecast labour escalation rate for each year. Table 16-3 below sets out the charges for the first year of the forthcoming regulatory period. The price for the remaining years will be calculated with the application of CPI, and X factors as consistent with our AER approved F&A for alternative control services.

Table 16-12: Proposed Type 7 metering charges ($ nominal) with the last year of the current period included

	2025-26 charges per year	2026-27 charges per year
Per NMI	36.90	37.25
Per light	2.17	2.19

Source: AusNet

16.5.10. Auxiliary metering services

We provide auxiliary metering services to customers to meet their needs that arise from time to time. These include the essential services of de-energising/re-energising the customers premise, or reconfiguring their smart meter to record their solar generation exported to the grid, upon the customer's request to their retailer. Consistent with the AER approved Final F&A, our proposed auxiliary metering services are classified as alternative control services.

Our auxiliary metering services activities include:

- requests to test, inspect and investigate, or alter an existing type 5 or 6 metering installation
- testing and maintenance of instrument transformers for type 5 and 6 metering purposes
- non-standard metering services for Type 5 to 7 meters and any other meter types introduced
- works to re-seal a type 5 or 6 meter due to customer or third-party action (e.g., by having electrical work done on site)
- change DNSP load control relay channel on request that is not a part of the initial load control installation, nor part of standard asset maintenance or replacement
- remote de-energisation and re-energisation
- remote meter configuration
- field based special meter read
- office-based special meter read.

In the current regulatory period, our fees for our range of auxiliary metering services are calculated based on cost and volume assumptions. Additionally, we agreed with our customer representatives that our smart meter customers will no longer pay for remote de-energising/re-energising of their premises.

In the 2026-31 regulatory period, we propose to apply the charges for auxiliary metering services based on adjusted by the CPI and the forecast labour escalation rate for each year. The price and volume assumptions used in determining most prices for the current regulatory period have not significantly changed beyond inflation and labour escalation rates.

The only service that we are varying from this approach is non-standard AMI data subscription (per month) from the current regulatory period. There was no substantial interest in this service from customers in the current regulatory period. Further, in accordance with our F&A decision by the AER to separately classify standard and non-standard data services to standard control and quoted alternative control services, our non-standard data subscription is not required in 2026-31.

The table below sets out the charges for the first year of the forthcoming regulatory period. The price for the remaining years will be calculated with the application of CPI, and X factors as consistent with our AER approved F&A for alternative control services.

Table 16-413: Proposed auxiliary metering services charges ($ nominal) with the last year of the current period included

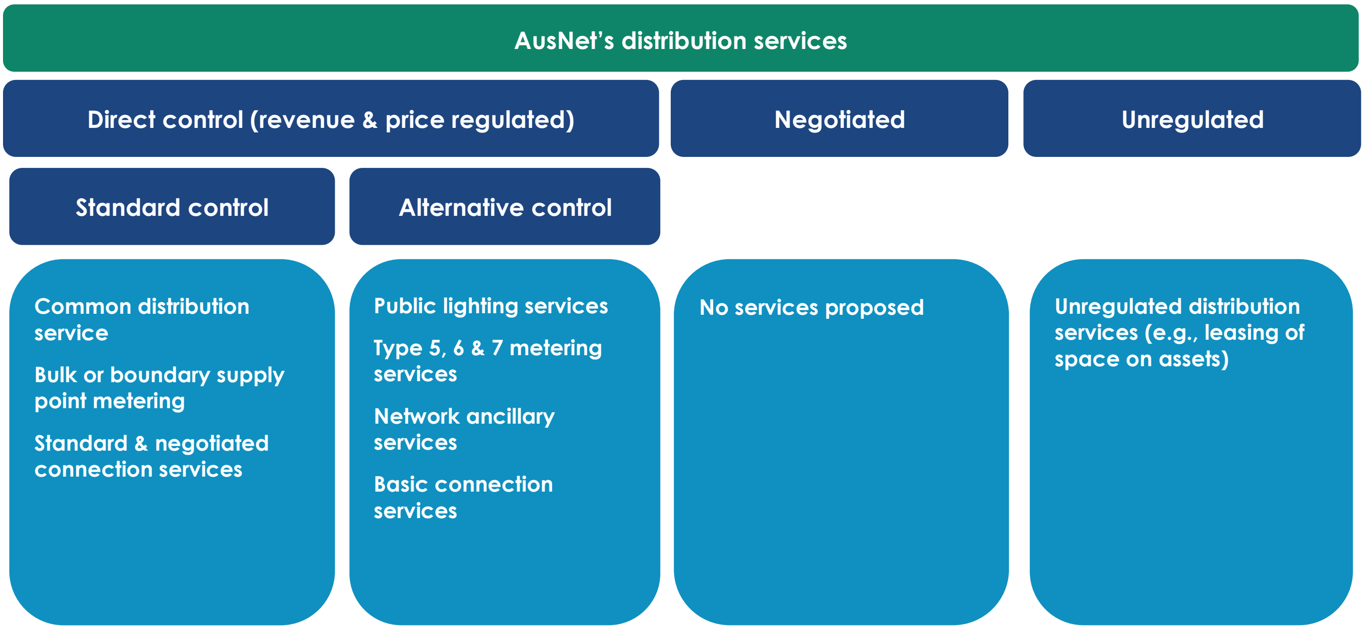
	2025-26	2026-27
Remote special meter read	-	-
Remote re-energisation	-	-
Remote de-energisation	-	-
Remote meter re-configuration	18.59	18.76
Field officer visit - business hours – does not apply for Type 1-4 metering	42.81	43.21
Manual meter reading	42.81	43.21
Priority re-energisation	41.44	41.83
Field officer visit - after hours – does not apply for Type 1-4 metering	74.93	75.62

Source: AusNet

16.6. Regulatory arrangements applying to metering services

The AER's F&A confirms that the classification of metering services will be unchanged from current arrangements, as shown in the figure below.

Figure 16-16: AER's classification of distribution services



We support the AER's service classification and forms of control for metering services and auxiliary metering services. The AER's proposed service classification is:

Type 1 to 4 metering services

Type 1 to 4 meters are not regulated in Victoria (or in most other jurisdictions), and are therefore, classified as unregulated electricity services. However, for bulk or boundary supply point metering we undertake activities relating to monitoring the flow of electricity through the distribution network. These Type 1 to 4 meters are regulated electricity services and classified as Standard Control Services.

Type 5 and 6 metering services

In 2006, the Victorian Government initiated a roll-out of smart meters to all households and small businesses with electricity use of up to 160 MWh per annum under the Advanced Metering Infrastructure (AMI) program. Pursuant to a Victorian government derogation, AMI smart meters are classified as Type 5 and 6 meters. The Power of Choice reforms that introduced metering contestability to residential electricity consumers in other jurisdictions do not apply in Victoria. In 2017, the Victorian Government deferred metering competition in Victoria through an Order-In-Council amending the National Electricity Rules as they apply in Victoria. Consequently, Victorian distributors are the exclusive providers of metering services to residential and small business customers consuming up to 160 MWh of electricity per annum. Activities include:

- recovery of the capital cost metering equipment (including meters with internally integrated load control devices); and
- meter maintenance covers work to inspect, test, maintain and repair metering installations;

Type 7 metering services

Type 7 metering services are unmetered connections with a predictable energy consumption pattern - for example, public lighting connections. Charges associated with Type 7 metering services relate to the process of estimating electricity usage. As there is no potential to develop competition in the provision of Type 7 metering services, these services continue to be classified as Alternative Control Services.

Auxiliary metering services

We also provide a range of metering related services to customers on request, such as meter testing and additional meter reads or equipment alterations. These services are classified as Alternative Control Services.

Metering exit fees

Metering exit fees allow the distributor to recover the written down value of, as well as the efficient costs of removing and disposing of, AMI meters. This currently occurs when brownfield sites become embedded networks, requiring the removal of the existing meters. If competition in the provision of AMI meters was introduced and an existing AMI meter was removed, metering exit charges would also apply. As metering exit fees are related to the provision of metering, the AER classifies these services as auxiliary metering services (rather than metering services). We explain our proposed metering exit fees in section 19.4.10.

16.6.1. Form of control

In addition to classifying metering services as an alternative control service, the F&A determined the form of control that will apply to these services.

For the 2026-31 regulatory period, the AER has decided to apply:

- a revenue cap, including a pass through provision, to the provision of Type 5 and 6 metering services; and
- price caps for all other metering services, including auxiliary metering services.

These forms of control were mostly unchanged from the current arrangements, with minor amendments to remove obsolete true ups and the addition of 4 formulae, which demonstrate the calculation of the B factor (formulae 5 to 8). We generally agree with the positions taken in the AER's F&A. However, the transition to financial year regulatory periods has resulted in the need for adjustments to be made to the form of control formulae.

The price control mechanism for metering is set out in Chapter 19.

16.7. Supporting Documentation

We have included the following documents to support this chapter:

- Electricity Distribution Metering (**EDM**) Asset Management Strategy Part 0
- EDM Asset Management Strategy Part 1 Meters
- EDM Asset Management Strategy Part 2 Comms
- Itron's AMI Performance Assessment
- Business case for smart meter replacement
- Smart meter replacement business case model
- Metering capex and opex model
- Metering charges model
- Metering pricing model
- Metering Post-Tax Revenue model (**PTRM**)
- Metering depreciation model
- Metering roll forward model (**RFM**)

17. Alternative Control Service: Public lighting

17.1. Key points

The key points in this chapter are:

- Over the 2026-31 regulatory period, we will continue to replace each light that fails or requires a globe replacement with efficient LEDs. By 2031, approximately 98% of minor road lights will be LED lights and 75% of major road lights will be LEDs. LED lights are more reliable and need less maintenance, in addition to consuming less electricity and greenhouse gas emissions.
- Councils' total public lighting bill includes their public lighting fees paid to AusNet and an energy consumption charge. Due to the continued move to efficient LEDs, we anticipate Councils, Shires and Road Authorities can expect on average a decrease of 8% in their total public lighting bill to AusNet and a 15% decrease in their energy costs or street lighting. This is despite an increase in AusNet's public lighting charges on a per light basis in the 2026-31 period, of 2% per year (real) for efficient lights and increase by 9% per year (real) for inefficient lights, as a result of the greater capex from the inefficient and obsolete light replacement and for the inefficient RAB to be recovered across a diminishing population of lights.
- We engaged with councils on our public lighting proposal and received no opposition to our proposed approach. We began the discussion with councils on whether we should offer a smart lighting service through a Central Management System. However, further engagement will be required in 2025 if we are to obtain sufficient consideration and support to justify this initiative. While we have not proposed a smart lighting service in our proposal, we will continue to engage closely with councils prior to submitting our Revised Proposal.

17.2. Chapter structure

This chapter is structured as follows:

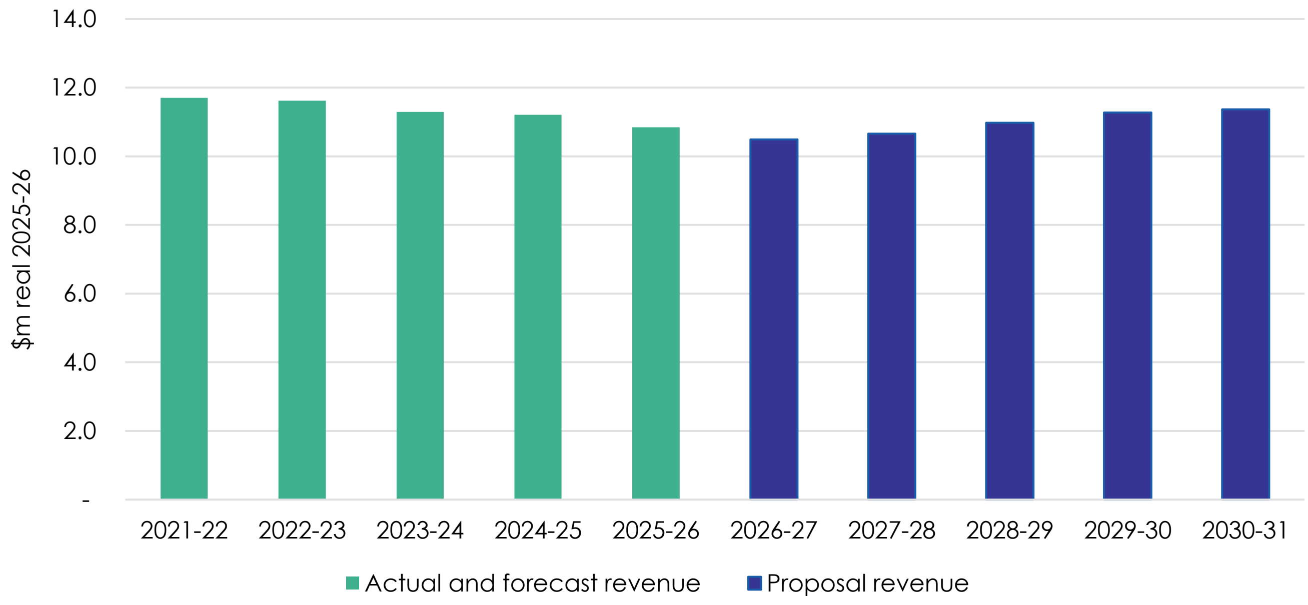
- Section 17.3 provides a summary of our proposal
- Section 17.4 explains the regulatory framework of our public lighting proposal;
- Section 17.5 explains the key drivers for our proposed expenditure;
- Section 17.6 discusses our customers' preferences; the feedback we received and how this feedback has been reflected in our plans in this Regulatory Proposal
- Section 17.7 outlines our proposed prices;
- Section 17.8 lists the supporting documents for this chapter

17.3. Summary of our proposal

In the upcoming period, we will continue to provide public lighting services to our customers consistent with the approach adopted in 2021-26. Most notably, we will continue to replace lights that fail or need a globe replaced with most efficient and suitable LED alternatives. This is due to the continued scarcity in the supply of older light types and in line with our customers' expectations of a rapid move to efficient LEDs.

Figure 17.1 shows our expected public lighting revenue for the 2026-31 regulatory period. The revenue is forecast to decline by 4% in 2026-31 compared to actual revenue in 2021-26.

Figure 17-152: Public lighting revenue ($m, real 2025-26)



Source: AusNet

Councils' total public lighting bill includes their public lighting fees paid to AusNet and an energy consumption charge. Due to the continued move to efficient LEDs, we anticipate Councils, Shires and Road Authorities can expect on average a decrease of 8% in their total public lighting bill per light and a 15% decrease in their energy costs for street lighting. This is despite a per light increase in our public lighting fees, of 2% per year (real) for efficient light and increase by 9% per year (real) for inefficient lights.

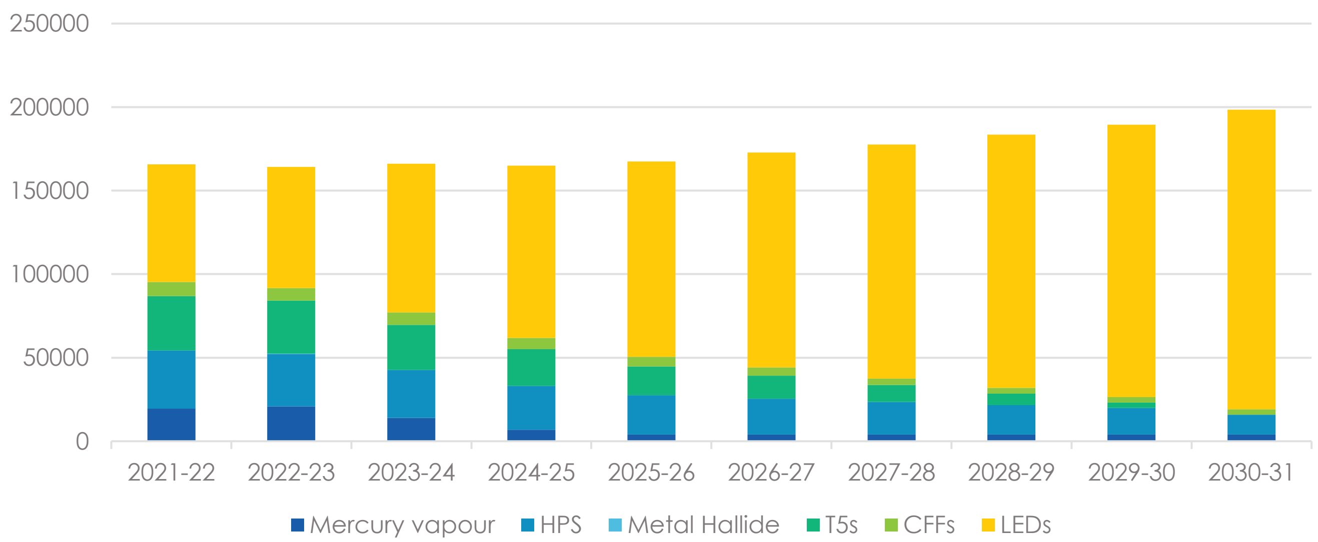
The reduction to councils' total bills is driven by the replacement of inefficient and older technology efficient lights with more energy efficient LED lights. The LED lights are more reliable and need less maintenance, in addition to consuming less electricity.

We expect to replace 70% and 92% of our inefficient and obsolete lights with efficient LED lights respectively during 2026-31. This approach will result in approximately 98% of minor road lights, and 75% of major road lights, having LEDs by 2031, reducing emissions and saving councils on their energy bills.

Specifically, we are proposing to replace:

- Failed High Pressure Sodium (**HPS**) lanterns with equivalent LED lights; and
- T5 and Compact Fluorescent (**CFL**) lights that fail or at 4 years in service, when we run out of globes and lanterns stock.

Figure 17-2: Number of lights per light type, actual and forecast, 2022 to 2031

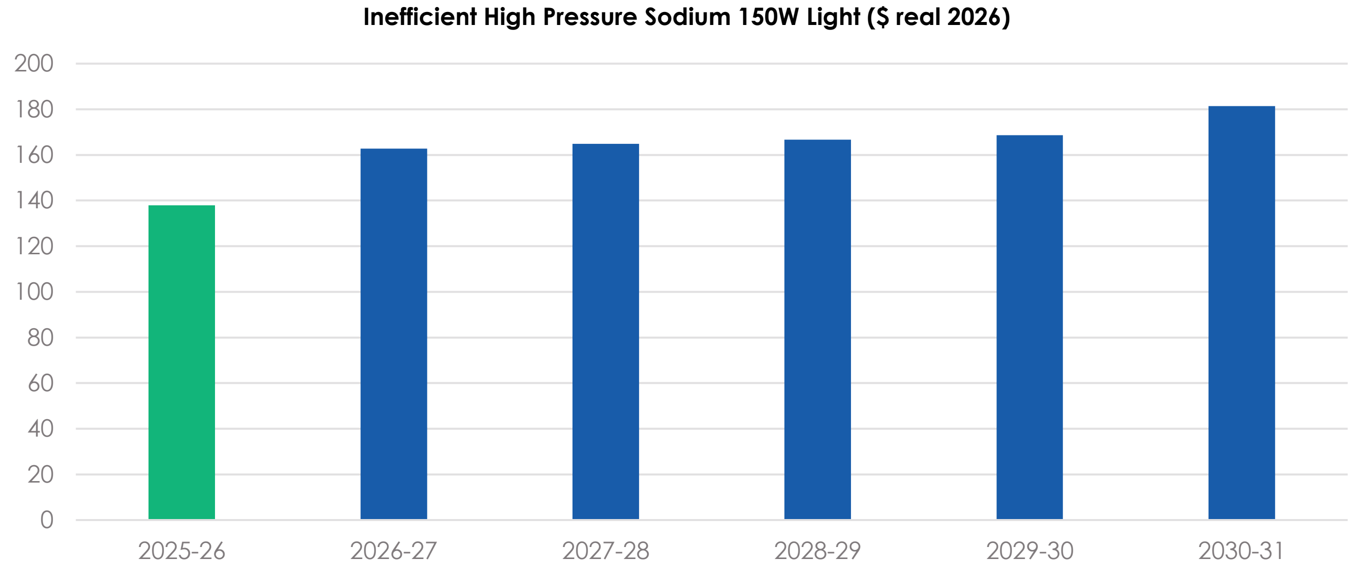


Source: AusNet

Despite the expected decrease in average total bills, the per light public lighting fees for inefficient lights is increasing due to:

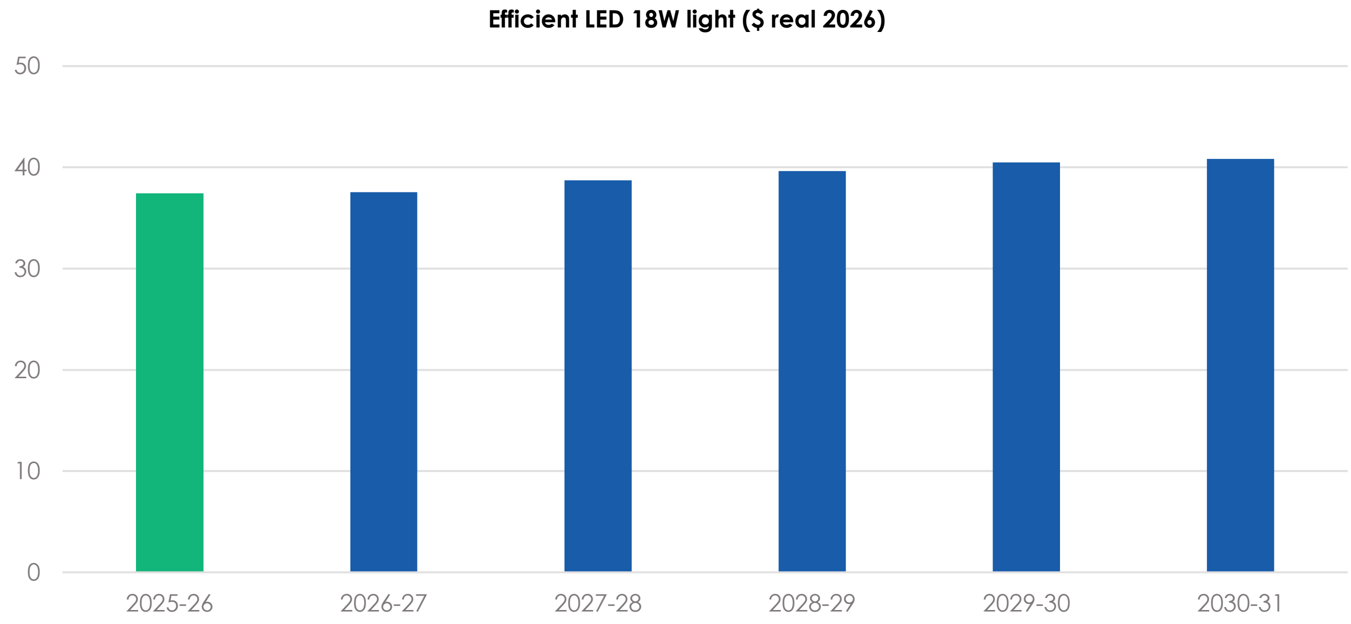
- The Inefficient lighting RAB being shared amongst a diminishing number of lights by the end of the period; and
- For councils who do not replace their Mercury Vapour (**MV**) lights in the current period, we need to replace the globes in our residual MV lights with a "corn cob" LED globe which can be fitted in the lantern. These replacement globes are significantly more costly than MV globes (i.e., $75 as compared to $6), the cost of replacing this globe every 4 years contributes to maintenance costs of MV globes. As the lights will still be classified as MV despite the LED globe, councils will be required to continue to pay for the higher charge until they replace these lights with an LED equivalent associated with the LED globe replacements. This approach applies the higher cost to the Council or Shire with the MV lights that benefits from lower electricity consumption and not other Councils and Shires that have already replaced their MV lights.

Figure 17-3: Average public lighting fees for common lighting types (in real 2026 $s)



Source: AusNet

LED lighting fees are also expected to increase, driven by updated unit rates and the increase in capital expenditure as we replace the inefficient and obsolete lights with LEDs.



Source: AusNet

We have presented our proposal and estimated prices to Councils, Shires and other interested parties, and have not received opposition to the proposal.

17.3.1. Smart lighting service

We do not currently offer a smart lighting service. We started engaging with the Councils and Shires on a proposal to adopt this service which would require upgrading our IT systems and our meter mesh communications network, at additional cost to public lighting customers.

While our proposal received some interested from councils, we consider it important that we obtain additional support from our customers before progressing to service. We recognise we will need to have further engagement with councils throughout 2025 to obtain a consensus and agree to an approach for smart lighting. As such, we have not proposed the new service in our Regulatory Proposal. Rather, we will be continuing to engage on this with our customers during 2025, with a potential to incorporate the new service into our Revised Regulatory Proposal, if sufficient support is obtained.

17.4. Regulatory framework

We provide and maintain public lighting for public lighting customers (i.e., Councils, Shires and roads authorities) in accordance with responsibilities and minimum standards set out in the Public Lighting Code of Practice published by the ESC. [180] These responsibilities include:

- Facilitating the establishment of, and connecting, new lights.
- Keeping the lights on by replacing faulty globes, lanterns and light activated switches (known as PE cells).
- Maintaining our light poles and replacing any that are broken or unsafe.
- Providing access to, and maintaining, public lighting records and associated billing data.
- Effectively communicating with public lighting customers via convenient online portals and when otherwise contacted.

17.4.1. Classification of public lighting services

These following services are provided in accordance with Victorian Public Lighting Code:

- operation, maintenance, repair and replacement of shared public lighting assets
- operation, maintenance and repair – watchman or security lighting[181]
- provision of new public lights (including emerging public lighting technology)
- alteration and relocation of public lighting assets.

Consistent with the classification in the AER's Framework and Approach, the table below outlines our proposed alternative control public lighting services for the forthcoming regulatory period. The classifications allow for the ongoing provision of regulated services including new lights, while still facilitating competition where Councils or road authorities wish to provide and manage their own lights, in accordance with applicable safety and metering requirements.

Table 17-1: Classification of public lighting services

Public lighting service	Classification
Operation, maintenance, repair and replacement public lighting services	Alternative control (fee-based)
Provision, construction and maintenance of emerging public lighting technology.	Alternative control (fee-based)
New public lighting services incl. greenfield sites & new light types (DNSP provided).	Alternative control (quoted)
Alteration and relocation of public lighting assets	Alternative control (quoted)

[180] This is available via the Essential Services Commission's web site: www.esc.vic.gov.au.
[181] We no longer offer security and watchmen lights as a new service. All new security and watchmen lights must be established as part of a metered electrical installation.

17.4.2. AusNet's public lighting customers

We maintain around170,000 streetlights – one streetlight for every five customers – and we're committed to providing the highest standard of service to councils, VicRoads and the local community. The breakdown of these streetlights is provided below:

- **Central ~120,000 lights**

  Local Government areas of: Banyule, Cardinia, Casey, Darebin, Frankston, Greater Dandenong, Hume, Knox, Manningham, Maroondah, Nillumbik, Whittlesea and Yarra Ranges.

- **North and East ~50,000 lights**

  Local Government areas of: Alpine, Bass Coast, Baw Baw, Benalla, Bogong Trading Company, East Gippsland, Falls Creek Resort, Indigo, La Trobe, Mansfield, Mitchell, Moira, Mount Buller Resort, Murrindindi, South Gippsland, Strathbogie, Towong, Wangaratta, Wellington and Wodonga.

17.5. Key drivers of expenditure

17.5.1. Key inputs, assumptions and forecasting approach

Consistent with the other four Victorian distribution businesses, we have used the AER's Public Lighting model to forecast our proposed fee-based charges to apply to our public lighting assets for the 2026-31 regulatory period. These rates apply to all public lighting installations that are owned by us and utilise either wholly or in part the shared distribution network assets in the provision of the lighting service.

We have separate pricing structures for the Central Region and for the North and East Regions. These price structures take account of the higher costs associated with the provision of the services in the latter regions due to the higher costs of servicing lights in lower light density areas and greater distances travelled by contractors and service agents.

In forecasting our proposed fee-based charges, we have used actual contracted unit rates that have been competitively tendered to determine key inputs in the AER's Public Lighting Model.-Additionally, we have updated the material and labour costs to reflect the latest information from our contractors escalated by CPI and adjusted to reflect the forecast replacement volumes.

Table 17-2: Key inputs and assumptions

Input / Assumption	Description
Unit rates	Unit rates based on our recently competitively tendered contracted rates
Replacement rates	LED replacements based on failure rates based on history up to 2023 Obsolete and inefficient lighting populations replaced based on lighting stock and asset life assumptions
Growth rates	Growth in lighting population based on history up 2023 and extrapolated in to LED population in new period
RAB roll forward	As shown in our Amended Depreciation Error version of our 2021-26 Public lighting model, we identified a calculation error in our 2021-26 Final decision public lighting model which resulted in the incorrect depreciation (existing light depreciation in cell R67 of total RAB). This resulted in our current approved prices not reflecting the correct depreciation profile and therefore assumed insufficient recovery of some capex. We have rectified this issue so opening RAB is correct and it does not continue into the 2021-31 period.

Source: AusNet Services

17.5.2. We need to phase out inefficient and obsolete lighting types

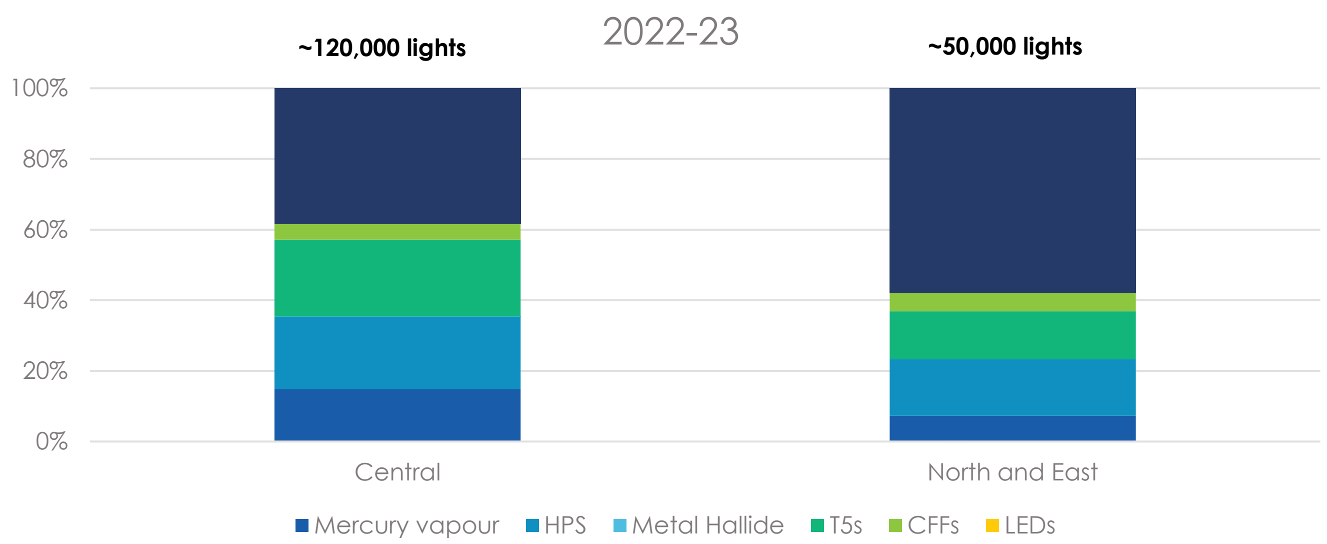
Over the forthcoming regulatory period, we will be reducing the populations of all lighting technologies in the upcoming period, except for LEDs which will grow to replace the other technologies which are inefficient and/ or obsolete.

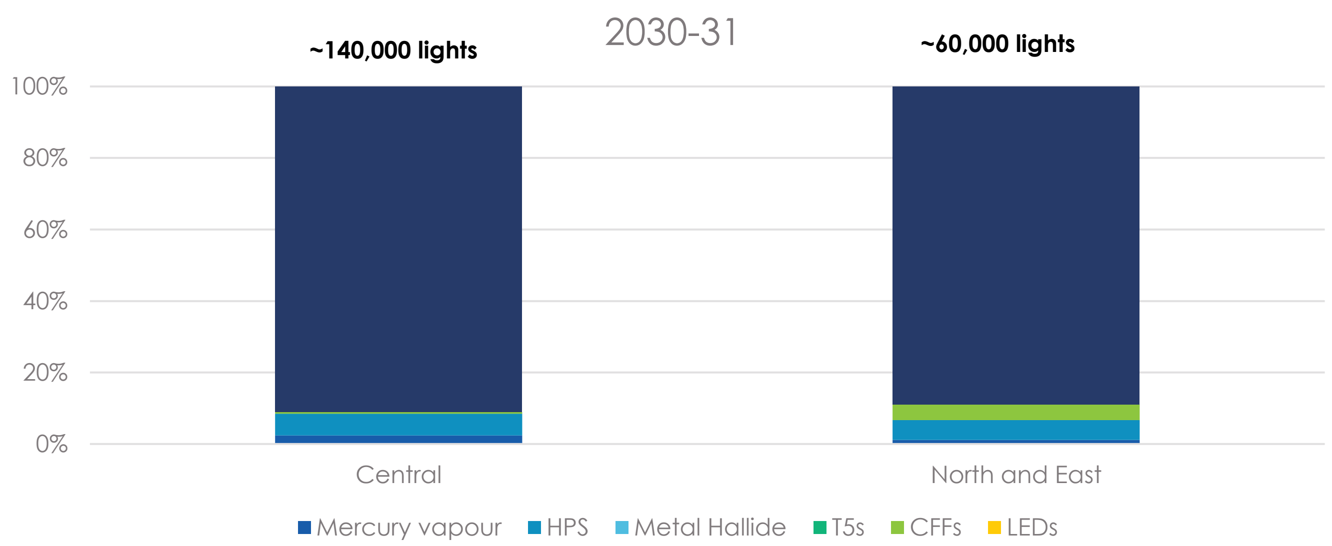
Table 17-3: Lighting technologies in AusNet's public lighting population

Inefficient lighting technologies	Efficient lighting technologies
Mercury Vapour (MV)	Light emitting diode (LED)
High pressure sodium (HPS)	T5 Fluorescent (T5)
Metal Hallide	Compact fluorescent (CF)

Source: AusNet Services

Figure 17-4: Proportion of lighting types per region (2022-23)





Source: AusNet Services

In the current period we have six lighting technologies, including a mix of efficient and inefficient lighting types.

In recent years, we have continued to see a shift to efficient LEDs lights due to the benefits these lights have over the inefficient lights in public lighting populations. These benefits include cheaper running costs due to using less energy and therefore lower greenhouse gas emissions. During the current 2021-26 regulatory period we plan to replace all Metal Halide and Mercury Vapour lights, which would consolidate our current six lighting technologies to four. This will expand to replacing all HPSs in the upcoming 2026-31 period.

In addition to this, we are currently unable to replenish our stocks for some efficient light types. Although CFs and T5s are consider efficient lighting, they are obsolete in the upcoming period.

These drivers will result in our public lighting population converting to LED only, where the bulk of the replacements occurring in the upcoming period. Rationalising the number of lighting technologies on our network will improve our cost efficiency. While the increased replacement activity over the 2026-31 period will lead to higher capital costs in the immediate future, it will also result in future cost savings, particularly in rural and remote areas. The benefits of replacing the inefficient and obsolete lights are summarised below:

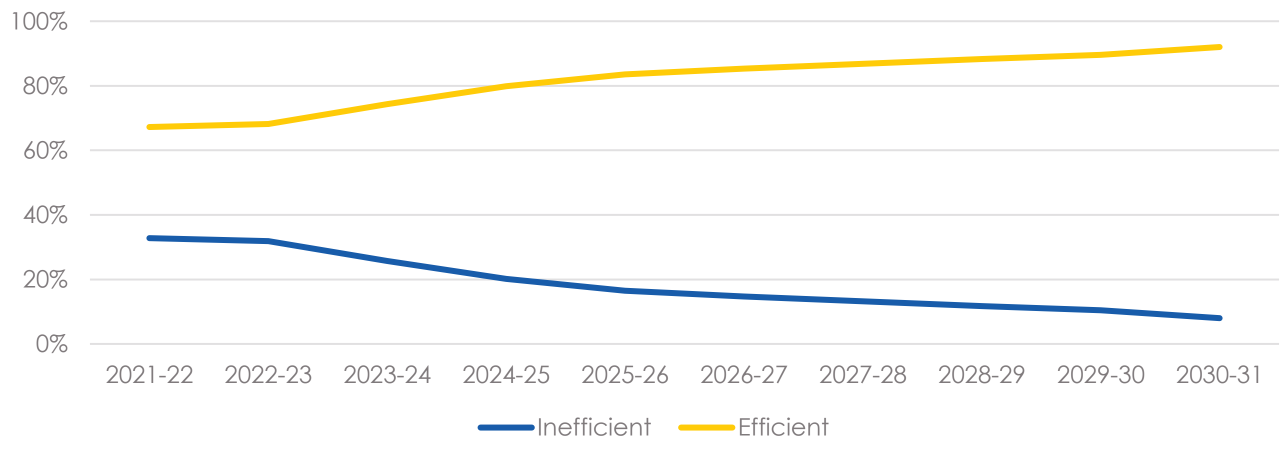
- LEDs have lower maintenance costs. Operating and Maintenance (O&M) costs form part of our public lighting charges and this will reduce as we move to LEDs.
- HPS have high maintenance costs and high failure rates.
- Quality issues with T5 and compact fluorescent light globes have adversely impacted maintenance costs.
- Replacement of inefficient lights with LED lights will provide on-going energy cost savings for customers. The retail portion of customers' bills will be reduced due to uses of less energy per light.

In addition, there are safety and environmental benefits of replacing with efficient LED lights:

- High Pressure Sodium lanterns carry a risk of these lights igniting fires and replacement will minimise the costs and improve safety
- LEDs consume less energy and therefore minimise greenhouse gas emissions from public lighting.

In summary, our proposal to replace inefficient and obsolete technologies will result in a safer and more efficient service.

Figure 17-5: Forecast increase in efficient lighting



Source: AusNet Services

17.5.3. Capital expenditure

Capital expenditure (capex) for public lighting is forecast to increase by 20% from our current $25m allowance in 2021-26 to $30m in 2026-31 (Real 2025- 26$s). Capex is increasing due to a number of factors:

- Increasing unit rates from our service providers. These rates are market tested but have been increasing consistent with our other unit rates.
- due to the replacements of our last inefficient lights (e.g., High Pressure Sodium lights) and older technology, obsolete lights (e.g., fluorescent lights) in 2026-31.

Table 17-4: Capital expenditure for public lighting, $m, $2024

	2026-27	2027-28	2028-29	2029-30	2030-31
Existing inefficient lights	0	0	0	0	0
Energy efficient lights	3.5	3.6	3.6	3.7	3.7
Poles and brackets	2.3	2.3	2.3	2.3	2.3
TOTAL	**5.8**	**5.9**	**5.9**	**6.0**	**6.0**

17.5.4. Operating expenditure

Our public lighting operating expenditure (opex) is forecast at $22m in 2026-31, which is 28% less than our current allowance. This saving is a consequence of reducing the number of less reliable inefficient lights.

Table 17-5: Operating expenditure for public lighting, $m, $2024

	2026-27	2027-28	2028-29	2029-30	2030-31
TOTAL	4.5	4.4	4.4	4.3	4.1

17.6. Council engagement

Our engagement with our public lighting customers (councils and Vic Roads) on our public lighting proposal included a forum in August 2024, direct meetings with councils and another forum in October 2024.

In August 2024, we discussed with councils our draft expenditure plans and prices, including discussion of inefficient and obsolescent lights and the approach to replace them with LED replacement globes. It was posed to the group whether they support this approach. We received very limited feedback on our proposal and no opposition to our proposed plans and prices. We also did not get any requests to replace inefficient or obsolete lights faster than our proposal. As such, we have maintained our public lighting proposal as presented to the councils at the forum.

At our August 2024 forum, the councils requested further discussion on smart lighting service options. In response, we held a forum in October specific to the topic of smart lighting. We presented an option for smart lighting, including costs, and the level of commitment from councils in order for AusNet to offer this service.

To offer a smart lighting service, we would be required to invest in a centralised management system (CMS) and IT software required to manage smart lights. Without a CMS, councils have not taken up smart lighting at scale. Therefore, we considered the cost of AusNet installing and managing a CMS and took this proposal to our councils. Our engagement included discussion on how this will impact the costs paid and the take up required to have sufficient scale to justify rolling out a centralised management system (CMS).

We discussed the benefits of offering smart lighting services. Smart lighting allows public lighting customers to have greater visibility and flexibility of their lighting population in order to make decisions such as optimising use. Benefits of smart lighting include:

- Energy consumption cost savings, due to the ability to control light output e.g. dimming
- lower operation and maintenance costs e.g. due to fewer patrols
- Environmental savings, lower and more accurate energy consumption for emissions reporting.

As already noted, we will continue to engage with Councils on their desire to progress a smart lighting program and revisit this issue in our Revised Regulatory Proposed.

17.7. Proposed prices

Our public lighting fees cover the following:

- the cost of replacing lanterns and poles, which are depreciated over 20 or 35 years, respectively.
- the ongoing cost of operating and maintaining our lights.

The impact of our updated unit rates and replacing inefficient and obsolete lights with LEDs as they fail or reach end of life on prices includes LED public lighting fees increasing on average by ~30% per light by end of period. This is equal to approximately 5% per year. The Inefficient lighting RAB being shared amongst a diminishing number of lights also results in a 50% increase in inefficient lighting prices by the end of the period. In addition, MV lighting O&M costs are increasing due to replacement with most costly LED globes.

However, as councils will be shifting from inefficient light, there will be energy consumption saving costs and expect on average a decrease of 8% in their public lighting cost per light and a 15% decrease in their energy costs for street lighting. While on average, our proposal should benefit councils, we will consider the impact on councils with a greater number of inefficient or efficient lights than the average and if any additional measures are appropriate.

The tables below set out the prices for fee-based services for the 2026 to 2031 regulatory period.

Table 17-6: Central - Public lighting fees (prices quoted in nominal $s)

	30- Jun-26	30-Jun-27	30-Jun-28	30-Jun-29	30-Jun-30	30-Jun-31
Existing lights						
Mercury Vapour 80W	$71.68	132.24	137.51	142.45	147.62	165.10
HP Sodium 150W	$128.25	156.47	162.66	168.64	174.97	193.56
HP Sodium 250W	$131.59	159.68	166.01	172.13	178.61	197.69
Mercury Vapour 50W	$109.68	202.33	210.38	217.94	225.85	252.61
Mercury Vapour 125W	$105.38	194.39	202.13	209.40	216.99	242.70
Mercury Vapour 250W	$138.17	167.66	174.31	180.74	187.54	207.57
Mercury Vapour 400W	$143.44	174.05	180.95	187.62	194.69	215.48
HP Sodium 100W	$137.23	167.42	174.04	180.45	187.22	207.11
HP Sodium 400W	$186.86	226.75	235.74	244.43	253.63	280.72
Metal Halide 70W	$312.91	577.24	600.23	621.79	644.36	720.69
Metal Halide 100W	$306.22	373.59	388.38	402.66	417.78	462.16
Metal Halide 150W	$347.88	424.43	441.23	457.45	474.63	525.05
HP Sodium 50W	$56.86	69.37	72.11	74.77	77.57	85.81
Efficient lights						
T5 2X14W	$61.72	57.85	61.47	66.08	75.21	64.28
T5 2X24W	$65.69	63.87	68.29	74.30	87.30	58.49
LED 18W	$36.28	37.14	39.31	41.29	43.29	44.78
LED 14W	$38.28	44.69	47.65	50.34	53.03	55.01
LED 70W-125W (L1)	$57.03	62.85	67.46	71.67	75.84	78.94
LED 155W-250W (L2)	$58.17	62.85	67.46	71.67	75.84	78.94
LED 275W-400W (L4)	$68.36	86.70	94.38	101.34	108.09	113.00
Compact Fluorescent 32W	$54.29	50.89	54.07	58.13	66.16	56.54
Compact Fluorescent 42W	$54.29	50.89	54.07	58.13	66.16	56.54

Table 17-7: North & East - Public lighting fees (prices quoted in nominal $s)

	30- Jun-26	30-Jun-27	30-Jun-28	30-Jun-29	30-Jun-30	30-Jun-31
Existing lights						
Mercury Vapour 80W	$75.82	136.02	141.41	146.47	151.77	169.38
HP Sodium 150W	$147.34	175.66	182.67	189.56	196.93	216.67
HP Sodium 250W	$147.71	175.99	183.18	190.11	197.53	217.66
Mercury Vapour 50W	$112.22	201.31	209.29	216.78	224.61	250.68
Mercury Vapour 125W	$112.22	201.31	209.29	216.78	224.61	250.68
Mercury Vapour 250W	$153.62	183.03	190.50	197.71	205.43	226.36
Mercury Vapour 400W	$158.05	188.31	196.00	203.42	211.35	232.89
HP Sodium 100W	$157.66	187.96	195.45	202.82	210.71	231.84
HP Sodium 400W	$209.75	249.90	260.11	269.95	280.49	309.07
Metal Halide 70W	$288.46	517.47	537.99	557.24	577.38	644.39
Metal Halide 100W	$312.08	372.06	386.90	401.49	417.10	458.92
Metal Halide 150W	$354.55	422.69	439.55	456.13	473.87	521.37
HP Sodium 50W	$67.00	79.88	83.06	86.20	89.55	98.53
Efficient lights						
T5 2X14W	$68.13	66.33	71.46	78.92	96.31	69.77
T5 2X24W	$72.72	70.87	76.07	83.46	100.26	64.62
LED 18W	$38.58	39.33	41.58	43.63	45.70	47.26
LED 14W	$40.50	46.81	49.85	52.61	55.36	57.41
LED 70W-125W (L1)	$63.48	68.81	73.62	78.03	82.40	85.71
LED 155W-250W (L2)	$64.62	68.81	73.62	78.03	82.40	85.71
LED 275W-400W (L4)	$74.81	92.66	100.54	107.69	114.65	119.76
Compact Fluorescent 32W	$59.92	58.34	62.85	69.42	84.72	61.37
Compact Fluorescent 42W	$59.92	58.34	62.85	69.42	84.72	61.37

Source: AusNet Services.

17.8. Supporting Documentation

We have included the following documents to support this chapter:

- AusNet 2026-2031 - Public Lighting Model;
- 2021-26 Public Lighting Model – amended depreciation
- ASD - AMS 20-73 Public Lighting

18. Alternative Control Services: Ancillary network services

18.1. Key points

The key points in this chapter are:

- Our ancillary network services for fee-based and quoted services are additional to our SCS network services. Our customers expect us to provide these services, such as a simple connection, at reasonable costs where relevant competitive markets are not available.
- These services are classified as Alternative Control Services (ACS) for 2026-31 in line with the AER approved final Framework and Approach Paper (F&A). This classification reflects the nature of these services, as they can be directly attributed to the customer to whom the service is provided.
- We have proposed fee-based costs and quoted service unit rates for ACS services in 2026-31 based on the application of efficient and reasonable factors, e.g., anticipated costs from competitively tendered service providers or by escalating the current approved prices by CPI and benchmark labour escalation rates.
- We have introduced new ACS charges for new enhanced services and a new administration quoted labour rate, consistent with the AER approved F&A.
- We incorporated the formula for the ACS control mechanism specified in our proposed F&A that includes a margin and an allowance for tax. For fee-based ACS charges our calculated tax allowance for ACS is only applied to the margin and is not material.

18.2. Chapter structure

This chapter is structured as follows:

- Section 18.3 outlines our approach to setting ACS prices
- Section 18.4 outlines our proposed fee-based ACS, the basis for developing the fees for those services, and the proposed fees
- Section 18.5 outlines our proposed quoted ACS and labour categories and rates
- Section 18.6 lists the supporting documents for this chapter.

18.3. Approach to setting prices

ACS are services provided by means of, or in connection with, a distribution system that are customer specific or customer requested. A number of these services also have the potential to be provided on a competitive basis, rather than by the local distributor. The cost of providing ACS is not recovered through revenue earned from distribution use of system tariffs. Rather, it is recovered through regulated fees directly from the customer requesting the service.

We endorse the classification of services set out in the AER's F&A, including the service groups established.

ACS services can be fee-based services with fixed charge or quoted services where the charge for the service is determined based on time and effort to deliver the service. As per the final F&A, fee-based services are grouped as:

- Connections services—customer and third party-initiated services related to connecting new customers or amending customer supply.
- Ancillary network services—other customer and third party-initiated services related to common distribution services.

These services are priced based on either a fixed fee or a quote. Our proposed approach to setting these prices is described in this section.

18.3.1. Fee-based services

We provide fee-based connection and ancillary network services to customers across three broad geographic regions. The geographical differences are reflected in different rates for each of these regions:

- Central region: this region covers those predominately urban and semi urban areas in and around our north and east growth corridors (e.g., Beaconsfield and South Morang);
- North Region: this region covers those predominately rural and semi-rural towns and regions in the northern part of our service territory; and
- East Region: this region covers those predominately rural and semi-rural towns and regions in the eastern part of our service territory.

We competitively tender, and periodically go to market, for the provision of most connection services and network ancillary services for all three regions. Competitive tendering, and the active management of outsourced contracts, enables us to ensure that the costs we incur are efficient and that service quality is maintained. We recently undertook a competitive tendering process for a broad range of electricity distribution services, as described in section 6.4.7. The winning bidder's prices are used as an input in our fee-based connection services.

Our competitively tendered contract rates provide direct information about the efficient cost of providing premise connection services and network ancillary services. As these rates are market tested, we consider it reasonable to assume that they represent the efficient cost of providing those services.

A model that sets out our proposed charges for each ACS fee is provided as part of this regulatory proposal. The prices proposed for our most common connections services and network ancillary services will increase significantly from our current rates for the following reasons:

- Significant labour price increases due to the demand for skilled electrical workers growing faster than the market can supply. The responses we received from a recent tender process reflected this high demand for skilled resources and the short delivery timeframe for these services to meet our customers' needs. The tender process resulted in the appointment of a new service provider.
- Recent changes in industrial relations negotiated safety requirements require a team of two qualified persons to undertake all connection related activities. Many connections could previously be undertaken by only one qualified person.
- To manage the high demand for labour and customer services during an energy transition, we no longer have one exclusive service provider for all ACS services. We now engage other qualified service providers to provide us with connection and network ancillary services. This has significantly increased our ability to secure labour to deliver services for our customers on time and to a high standard, however, we no longer have access to lower rates based on contract exclusivity.

Additionally, as established for the current regulatory period, our current service charges reflect that a Licensed Electrical Inspector (**LEI**) is required to confirm a Current Transformer (**CT**) metering or group metering panel meets all applicable Victorian Service Installation rules and Victorian safety standards. The cost of providing a separate LEI visit is additional to the connection costs for connections involving a group metering panel or CT.

Our fee-based connection and ancillary services reflect our total efficient costs of serving the retail customers as required by the pricing principles for direct control services, NER clause 6.18.5(g). The proposed costs used to forecast prices are based on competitive tendering with the allocation of applicable oncosts, overheads and margins, or previously approved prices escalated based on CPI and labour factors.

18.3.2. Quoted services

For quoted services, we apply a regulated labour rate and category. In deriving our proposed quoted labour rates, we use a base-trend approach where:

- actual rates per hour are calculated for each labour category from 2024-25
- the starting 2024-25 year price, real labour cost escalators are forecast for 2026-27 (consistent with the labour escalation rates applicable for standard control services) and applied to the base year prices.

Our proposed quoted service hourly rates are based on our efficient costs of serving the retail customers as required by the pricing principles for direct control services, NER clause 6.18.5(g). Accordingly, we based our proposed quoted service hourly rates on previously approved prices escalated based on CPI and labour factors, or in the case of new labour rates established based on recent historical data, labour oncosts, overheads and margins.

18.4. Proposed fee-based services and fees

18.4.1. Connection services

Consistent with the classification in the F&A for the forthcoming regulatory period, we are proposing fee-based connection services for our routine connection services to customers at a new premise or altering their connection to the network, which include:

- routine connection of new premises that qualify as basic connection services
- temporary connections (e.g. metered connection to a builder's pole)
- connections involving an inspection of CT or group metering installation by a Licensed Electrical Inspector prior to initial energisation
- energisation and de-energisation at the pole or pit
- manual pre-approval of a PV or small generator installation.

Table 18-1 sets out the prices for fee based ACS connection services for 2026-27. Our proposed charges for the remainder of the regulatory period (2026-31) are set each year by escalating the 2026-27 prices by the Consumer Price Index (**CPI**) as per the form of control formula, which is detailed in the final section of this chapter.

While some categories of connection services increase significantly between 2025-26 and 2026-27, the proposed fees are efficient as they:

- are based on competitively tendered contracted rates
- are transparently reported in our RIN for fee-based ACS services in terms of revenue and costs.
- on average, benchmark well relative to our peers' current fees.[182]

Table 18-1: Current and proposed connection services and fees, 2025-26 and 2026-27 (real, $Jun 2026)

Connection services	2025-26	2026-27
Single phase overhead – business hours	613.03	726.03
Single phase overhead – after hours	1,073.70	1,270.54
Single phase underground – business hours	269.41	371.22
Single phase underground with a directly connected meter on group metering panel – business hours	580.90	627.03
Single phase underground with a directly connected meter on group metering panel – after hours	NA	1,097.31
Single phase underground – after hours	471.87	649.63
Multi-phase overhead with a directly connected meter – business hours	426.99	560.88
Multi-phase overhead with a directly connected meter – after hours	1,219.17	1,368.55
Multi-phase overhead with a CT connected meter – business hours	1,060.42	1,200.41
Multi-phase overhead connection with a CT connected meter – after hours	2,241.54	2,487.73
Multi-phase underground with a directly connected meter – business hours	426.99	560.88
Multi-phase underground with a directly connected meter on group metering panel – business hours	743.70	816.69
Multi-phase underground with a directly connected meter on group metering panel – after hours	NA	2,487.73
Multi-phase underground with a directly connected meter – after hours	1,608.12	981.53
Multi-phase underground with a CT connected meter – business hours	1,060.42	1,200.41

[182] Our proposed underground service connection fees are less costly than our peers current service connection fees for equivalent types of connections (e.g., single phase or multiphase). We distinguish between underground and less common overhead connections, while our peers do not. For us, underground service connections during business hours, our lowest cost services, make up the majority of our connection volumes.

Multi-phase underground connection with a CT connected meter – after hours	1,855.73	2,100.72
95mm2 overhead service from LVABC – business hours	1,048.66	809.33
95mm2 overhead service from LVABC – after hours	1,835.17	1,416.33
Establish temporary supply connection – business hours	607.82	726.03
Establish temporary supply connection – after hours	1,063.67	1,270.54
Appointment – inspection of group or CT metering prior to connection – business hours	633.43	639.54
Service truck - disconnect / reconnect at pole or pit or Type 1-4 metered site – business hours	697.98	641.63
Service truck - disconnect / reconnect at pole or pit or Type 1-4 metered site – after hours	quoted[183]	1,122.86

Source: AusNet

18.4.2. Ancillary network services

The table below sets out the prices for network ancillary services classified as fee based Alternative Control Services for 2026-27. Our proposed charges for the remainder of the regulatory period (2026-31) will then be set by escalating the 2026-27 prices by CPI as per the form of control formula. In respect to our proposed network ancillary services we note:

- Meter equipment test fees are charged only if metering equipment is not found to be defective or non-compliant.
- Consistent with our recently updated current basic embedded generation Model Standing Offer (**MSO**), and proposed basic embedded generation MSO, we consolidated our manual assessment of solar PV and small generator installation enquiry services and fees to a single service and fee for that applies to 15kW of export capacity (i.e. 5 kW per phase)

Table 18-2: Current and proposed ancillary network services and fees, 2025-26 and 2026-27 (real, $Jun 2026)

Ancillary network service	2025-26	2026-27
Meter equipment test – single phase	383.70	386.96
Meter equipment test – single phase - each additional meter at same site	88.48	89.23
Meter equipment test – multi phase	383.70	386.96
Meter equipment test – multi phase - each additional meter at same site	88.48	89.23
Wasted truck visit – customer not ready for their requested works	259.81	485.53
Manual assessment of PV & small generator installation enquiry, 4.6kW to 15kW.	401.09	NA
Manual assessment of PV & small generator installation enquiry, 15kW to 30kW.	401.09	NA
Manual assessment of PV & small generator installation enquiry, up to 15kW of export capacity (i.e. 5 kW per phase)	NA	404.49

Source: AusNet

18.5. Proposed quoted services and rates

Quoted services are customer specific or customer requested services for which the labour and materials costs vary from job to job. A customer's final charge consists of a regulated charge per hour for each labour type used plus any materials and any vehicle costs (otherwise reflected in the underlying hourly rate). Our financial systems track the revenues received from quoted services and associated costs. Our proposed quoted Alternative Control Services descriptions are consistent with the AER's F&A.

Table 18- below Table 18-outlines the ACS that we propose to offer as quoted services.

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[183] In the current period, retailers queried whether we could provide an approved price on our website for after-hours service truck requests, instead than a quoted fee for each request. The fee was quoted to cater for unexpected cost variations. However, at the time of responding to an after-hours request with a quotation, we are not aware of cost variations. Therefore, we agree to establish approved fee-based prices for these after-hours services.

Table 4 below Table shows the applicable labour rates for quoted services for 2026-27. Labour rates for the remainder of the regulatory period (2026-31) are then set by incrementing the 2026-27 prices by CPI.

Table 18-3: Proposed quoted ACS

Service group	Further description from AER's F&A	Examples
Access permits, oversight, and facilitation	Activities include: • a DNSP issuing access permits or clearances to work to a person authorised to work on or near distribution systems including high and low voltage • a DNSP issuing confined space entry permits and associated safe entry equipment to a person authorised to enter a confined space • a DNSP providing access to switch rooms, substations, and other network equipment to a non-DNSP party who is accompanied and supervised by a DNSP's staff member. May also include a DNSP providing safe entry equipment (fall-arrest) to enter difficult access areas • specialist services (which may involve design related activities and oversight/inspections of works) where the design or construction is non-standard, technically complex, or environmentally sensitive and any enquiries related to DNSP assets • facilitation of generator connection and operation of the network • facilitation of activities within clearances of DNSP's assets, including physical and electrical isolation of assets	Processing access permit applications; Accompanied access for purposes of metering activities within distributor facilities; and Clearance assessment
Sale of approved materials or equipment	Includes the sale of approved materials/equipment to third parties for connection assets that are gifted back to the DNSP become part of the shared distribution network	Sale of specialist and long-lead time transformers, where we have excess stock
Notices of arrangement and completion notices	Examples include: • Work of an administrative nature where a local council requires evidence in writing from the DNSP that all necessary arrangements have been made to supply electricity to a development. This includes but is not limited to receiving and checking subdivision plans, copying subdivision plans, checking, and recording easement details, site visits, assessing supply availability, liaising with developers if errors or changes are required, and preparing notifications of arrangement • Provision of a completion notice (other than a notice of arrangement). This applies where the DNSP is requested to provide documentation confirming progress of work. Usually associated with discharging contractual arrangements (e.g., progress payments) to meet contractual undertakings.	Negotiations with developers, Councils and Shires regarding potential exemptions from requirements to supply electricity to subdivided land
Network related property services	Activities include: • network related property services such as property tenure services relating to providing advice on, or obtaining deeds of agreement, deeds of indemnity, leases, easements, or other property tenure in relation to property rights associated with a connection or relocation • conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer	Property admin and conveyancing inquiries.
Network safety services	Examples include: • provision of traffic control services by the DNSP or third party where required • fitting of tiger tails, possum guards, and aerial markers • high load escort • site visit relating to location of underground cables/assets • third party request for de-energising wires for safe approach	Provision of safety observer services; Fitting of tiger tails, possum guards, HiVis flags, and aerial markers; High load escorts;
Customer requested network outage or	Examples include:	De-energising shared network lines for safe approach

rescheduling of a planned interruption	• customer initiated network outage (e.g., to allow customer and/or contractor to perform maintenance on the customers assets, work close or for safe approach) • where the customer requests to move a distributor planned interruption and agrees to fund the additional cost of performing this distribution service outside of normal business hours	
Inspection and auditing	Activities include: • inspection and reinspection by a DNSP, of gifted assets or assets that have been installed or relocated by a third party • investigation, review, and implementation of remedial actions that may lead to corrective and disciplinary action of a third party service provider due to unsafe practices or substandard workmanship • auditing and inspection of a third party service provider's work practices in the field • re-test at a customer's installation, where the installation fails the initial test and cannot be connected or has been disconnected for more than 12 months or for safety reasons • customer or third party-requested inspection of privately owned low voltage or high voltage network, infrastructure (i.e., privately owned distribution infrastructure before the meter)	Site inspection required to provide a connection offer; Provision of preliminary or final network audit prior to connection, or the granting of statement of compliance, of a reticulated underground network.
Provision of training to third parties for network related access	Training services provided to third parties that result in a set of learning outcomes that are required to obtain a distribution network access authorisation specific to a distributor's network. Such learning outcomes may include those necessary to demonstrate competency in the distributor's electrical safety rules, to hold an access authority on the distributor's network and to carry out switching on the distributor's network. Examples of training might include high voltage training, protection training or working near power lines training.	Training days to employees of third-party service providers.
Authorisation and approval of third-party service providers design, work, and materials	Activities include: • authorisation or re-authorisation of individual employees and subcontractors of third party service providers and additional authorisations at the request of the third party service providers (excludes training services) • acceptance of third party designs and works, and • assessing an application from a third party to consider approval of alternative material and equipment items that are not specified in the DNSP's approved materials list Security lights Provision, installation.	Authorisation or re-authorisation of individual employees of third-party service providers to become accredited to undertake design, construct, audit or tie in distributor's network assets for customer connections; and Assessing third-party requests for new public lighting assets for use as standard lighting.
Security lights	Provision, installation, operation, and maintenance of equipment mounted on distribution equipment used for security services, e.g., nightwatchman lights. Note: excludes connection services.	Upgrading a security light to an LED light
Provision of non-basic electricity network data	Data requests by customers or third parties for network data beyond the scope of Standard Control Service provision, including: • Data requests by customers or third parties including requests for the provision of electricity distribution network data or consumption data outside of legislative obligations. • Customer or third-party requests for assistance to understand or interpret data, or to identify the data they require to meet their needs.	Request by an EV charger or community battery for a multisite assessment of available connection capacity.
Third party funded network alterations or other improvements	Alterations or other improvements to the shared distribution network to enable third party infrastructure (e.g., telecommunications assets) to be installed on the shared distribution network. This does not relate to undergrounding or upstream distribution network augmentation.	Installing telecommunications to support the connection of an embedded generator or hybrid.
Community network upgrades	Collective customer requested network enhancement. Activities related to community requests to augment the network to enable higher PV exports.	Augmenting shared network to create greater network capacity

Connection application and management services	• Connection application related services • Works initiated by a customer or retailer that are specific to the connection point. This includes, but is not limited to: o field based de-energisation and re-energisation o non basic supply abolishment or reposition non-basic connection o temporary connections (e.g., for builder's supply, fetes etc.) o overhead service line replacement – customer requests the existing overhead service to be replaced (e.g., because of a point of attachment relocation). No material changes to the load o protection and power quality assessment o supply enhancement (e.g., upgrade from single phase to three phase) o customer requested change requiring primary and secondary plant studies for safe operation of the network (e.g., change protection settings) o upgrade from overhead to underground service o rectification of illegal connections or damage to overhead or underground service cables o calculation of a site specific distribution loss factor on request in respect of a generating unit up to 10 MW or a connection point for an end-user with actual or forecast load up to 40 GWh per annum capacity, as per clause 3.6.3(b1) of the NER o calculation of site specific loss factors when required under the NER o power factor correction o embedded network management o assessing connection applications or a request to undertake relocation of network assets as contestable works and preparing offers o processing preliminary enquiries requiring site specific or written responses o undertaking planning studies and associated technical analysis (e.g., power quality investigations) to determine suitable/feasible connection options for further consideration by applicants o liaising with groups representing multiple connecting parties (e.g., community group upgrades) o site inspection in order to determine the nature of the connection service sought by the connection applicant and ongoing co-ordination for large projects o registered participant support services associated with connection arrangements and agreements made under Chapter 5 of the NER	Abolishment of connection with a capacity greater 100A; Establishing premises connection assets with a capacity greater 100A; Manual assessment of PV & small generator installation enquiry greater than 30 kW; Manual assessment of connection applications and preparing offers; Rectification of damage to overhead or underground cables; and Upgrade from a single phase connection to multi-phase connection, where the required multiphase supply isn't available at the point of connection.
Enhanced connection services	• Other or enhanced connection services provided at the request of a customer or third party that include those that are: • provided with different levels of reliability of service or quality of service (where permissible) than required by the NER or any other applicable regulatory instruments. This includes reserve feeder installation and maintenance • in excess of levels of service or plant ratings required to be provided by the DNSP, and • management of export and load at a customer site that provides the customer greater network capacity than they would otherwise be eligible for.	Provision and maintenance of reserve feeder and backup supply; and Provision and maintenance of isolation transformer or harmonic filtering equipment at a customer's premises; Dynamic export and load service management to use available capacity on the network.

Source: AusNet

Where our customers request our staff to undertake quoted work, we use hourly labour rates as a component in the quoted cost to the customer in our offer. The hourly labour rates depend on the labour category.

Our proposed formula for quoted services is explained in the form of control section the table below.

Table 18-4: Current and proposed labour categories and labour rates, 2025-26 and 206-27 (real, $Jun 2026)

Labour category	Service description	Business Hours 2025-26	Business Hours 2026-27	After Hours 2025-26	After Hours 2026-27
Labour—wages	Construction overhead install	149.11	150.49	181.09	263.37
Labour—wages	Construction underground install	145.63	146.98	176.87	257.22
Labour—wages	Construction substation install	145.63	146.98	176.87	257.22
Labour—wages	Electrical tester including vehicle & equipment	214.72	216.72	293.54	379.26
Labour—wages	Planner including vehicle	200.16	202.03	NA	NA
Labour—wages	Supervisor including vehicle	200.16	202.03	NA	NA
Labour—design	Design	170.90	172.49	207.55	301.86
Labour—design	Drafting	131.33	132.55	159.51	231.97
Labour—design	Survey	154.69	156.13	187.89	273.23
Labour—design	Tech officer	154.69	156.13	187.89	273.23
Labour—design	Line inspector	149.11	150.49	181.09	263.37
Labour—design	Contract supervision	154.69	156.13	187.89	273.23
Labour—design	Protection engineer	170.90	172.49	207.55	301.86
Labour—design	Maintenance planner	154.69	156.13	187.89	273.23
Labour—design	Senior Engineer	246.35	248.64	367.82	435.12
Labour—admin	Administration staff	NA	88.15	NA	150.51

Source: AusNet

18.5.1. New services offered during the regulatory period

Where a new service is identified that falls within an existing ACS service group classification, we propose to be able to commence offering that service during the regulatory period. This will provide us with the flexibility to provide new services to our customers without having to wait until the subsequent regulatory period. New quoted services will be provided to the AER for approval as part of our annual pricing proposal.

18.6. Supporting documentation

In addition to relevant parts of the RIN templates the following document is provided in support of this chapter:

- AusNet's connection and ancillary network services charge model.

19. Form of control

19.1. Key points

This chapter outlines how AusNet will adjust its prices for its services for each year of the 2026-31 regulatory control period, and how it complies with the requirements of 6.12.1(13) and 6.8.2(c)(3) in the National Electricity Rules (NER) that relate to compliance with the relevant control mechanism.

19.2. Chapter structure

This chapter is structured as follows:

- Section 19.3 outlines the form of control for standard control services
- Section 19.4 outlines the form of control for metering services, fee-based ancillary network services, public lighting and quoted ancillary network services, and
- Section 19.5 lists the supporting documentation for this chapter.

19.3. Control mechanisms

Standard control services are the primary distribution network service consumed by our customers and involve the provision of continuous connection and availability to the electricity grid.

Alternative control services are services that are either customer specific or customer requested services that are related to the connection to our distribution network. The costs to perform these services are not covered by our network tariffs but are instead recovered through regulated fees paid directly by the customer requesting the service.

To ensure we set prices in accordance with the regulatory regime, the AER's Framework and Approach paper (F&A) outlines mechanisms that determine how standard and alternative control services prices change during the regulatory period. By committing to apply the formulae outlined in this chapter, which are consistent with the F&A, we consider we will meet the requirement of cl. 6.8.2(c)(3) to demonstrate compliance with the relevant control mechanism.

Revenue cap for Standard Control Services

A revenue cap sets our revenue from our tariffs at the AER's total revenue allowance. It prevents us from recovering more or less than the AER's determination allows. Where tariff levels and actual volumes result in an under- or over-recovery of revenue in any year, we adjust it in the next year's tariffs to correct the recovered revenue consistent with the allowance. Below sets out the revenue cap control mechanism for standard control services.

Table 19-1: Revenue cap formulae for standard control services

1	$TAR_t \geq \sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij}\, q_t^{ij}$	i = 1, … , n j = 1, … , m t = 1, 2, 3, 4, 5
2	$TAR_t = AAR_t + I_t + B_t + C_t$	t = 1, 2, 3, 4, 5
3	$AAR_\boldsymbol{t} = AR_t$	t = 1
4	$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) + (1 - X_t)$	t = 2, 3, 4, 5
5	$B_\boldsymbol{t} = b_t + A_t$	t = 1, 2, 3, 4, 5

6	$b_{\boldsymbol{t}} = -O_t \times (1 + WACC_t)^{0.5}$	t = 1, 2, 3, 4, 5
7	$A_{\boldsymbol{t}} = a_t^1 + a_{t-1}^2 \times (1 + WACC_t) + a_{t-2}^3 \times (1 + WACC_{t-1}) \times (1 + WACC_t)$	t = 1, 2, 3, 4, 5
8	$WACC_{\boldsymbol{t}} = (1 + rvWACC_t) \times (1 + CPI_t) - 1$	t = 1, 2, 3, 4, 5

where:

t	the relevant regulatory year, with t = 1 being the 2026–27 financial year.
TAR_t	the total annual revenue for year t, calculated as per formula 2 above.
p_t^{ij}	the price of component 'j' of tariff 'i' for year t.
q_t^{ij}	the forecast quantity of component 'j' of tariff 'i' for year t.
AR_t	the annual smoothed revenue requirement in the Post Tax Revenue Model (PTRM) for year t.
AAR_t	the adjusted annual smoothed revenue requirement for year t, calculated as per formulae 3 and 4 above.
I_t	the sum of incentive scheme adjustments for year t. To be decided in the distribution determination.
B_t	the sum of annual adjustment factors, including any bespoke adjustments the AER deems necessary (through the A factor), to balance the unders and overs account for year t. To be decided in the distribution determination.
C_t	the approved pass-through amounts (positive or negative) for year t, as determined by the AER. It will also include any annual or end of period adjustments for year t. To be decided in the distribution determination.
ΔCPI_t	the annual percentage change in the Australian Bureau of Statistics' (ABS) Consumer Price Index (CPI) All Groups, Weighted Average of Eight Capital Cities[184] from December in year t–2 to December in year t–1. For example, for 2026–27, t–2 is December 2024 and t–1 is December 2025.
X_t	the X factor in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the distribution determination.
b_t	the true-up for the balance of the DUoS unders and overs account in year t, calculated as per formula 6 above.
O_t	the opening balance of the DUoS unders and overs account in year t.
$WACC_t$	the approved weighted average cost of capital (WACC) used in regulatory year t in the DUoS unders and overs account. The WACC is updated annually to apply actual inflation, calculated as per formula 8 above. It is also applied to true-up mechanisms to adjust for the time value of money.
A_t	the sum of bespoke adjustments, including the application of the time value of money where appropriate, calculated as per formula 7 above.
a_t^1	the bespoke adjustment '1' for year t. Formula 7 above demonstrates the application of the time value of money for different bespoke adjustments relating to different regulatory years.
$rvWACC_t$	the real vanilla WACC provided in the annually updated PTRM for year t.

[184] If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

19.4. Control mechanisms for alternative control services

19.4.1. Revenue cap for metering services

Similar to the revenue cap control mechanism for standard control services, we cannot recover more or less than the AER's determination allows. Any under- or over-recovery of revenue resulting from actual metering volumes and tariff levels in any year, will be adjusted in the following year's metering prices to correct the recovered revenue consistent with the allowance. Table 19-219-2 below sets out our revenue cap control mechanism for metering services.

Table 19-2: Metering services revenue cap formulae

1	$TARM_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$	i = 1, … , n j = 1, … , m t = 1, 2, 3, 4, 5
2	$TARM_t = AAR_t + B_t + C_t$	t = 1, 2, 3, 4, 5
3	$AAR_{\boldsymbol{t}} = AR_t$	t = 1
4	$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) + (1 - X_t)$	t = 2, 3, 4, 5
5	$B_{\boldsymbol{t}} = b_t + A_t$	t = 1, 2, 3, 4, 5
6	$b_{\boldsymbol{t}} = -O_t \times (1 + WACC_t)^{0.5}$	t = 1, 2, 3, 4, 5
7	$A_{\boldsymbol{t}} = a_t^1 + a_{t-1}^2 \times (1 + WACC_t) + a_{t-2}^3 \times (1 + WACC_{t-1}) \times (1 + WACC_t)$	t = 1, 2, 3, 4, 5
8	$WACC_{\boldsymbol{t}} = (1 + rvWACC_t) \times (1 + CPI_t) - 1$	t = 1, 2, 3, 4, 5

where:

t	the relevant regulatory year, with t = 1 being the 2026–27 financial year.
$TARM_t$	the total annual revenue for metering services in year t, calculated as per formula 2 above.
p_t^{ij}	the price of component 'j' of tariff 'i' for year t.
q_t^{ij}	the forecast quantity of component 'j' of tariff 'i' for year t.
AR_t	the annual smoothed revenue requirement in the metering Post Tax Revenue Model (PTRM) for year t.
AAR_t	the adjusted annual smoothed revenue requirement for year t, calculated as per formulae 3 and 4 above.
B_t	the sum of annual adjustment factors, including any bespoke adjustments the AER deems necessary (through the A factor), to balance the metering unders and overs account for year t. To be decided in the distribution determination.
C_t	the approved metering pass-through amounts (positive or negative) for year t, as determined by the AER. It will also include any annual or end of period adjustments for year t. To be decided in the distribution determination.

ΔCPI_t	the annual percentage change in the Australian Bureau of Statistics' (ABS) Consumer Price Index (CPI) All Groups, Weighted Average of Eight Capital Cities[185] from December in year t–2 to December in year t–1. For example, for 2026–27, t–2 is December 2024 and t–1 is December 2025.
X_t	the X factor in year t, incorporating annual adjustments to the metering PTRM for the trailing cost of debt where necessary. To be decided in the distribution determination.
b_t	the true-up for the balance of the metering unders and overs account in year t, calculated as per formula 6 above.
O_t	the opening balance of the metering unders and overs account in year t.
$WACC_t$	the approved weighted average cost of capital (WACC) used in regulatory year t in the metering unders and overs account. The WACC is updated annually to apply actual inflation, calculated as per formula 8 above. It is also applied to true-up mechanisms to adjust for the time value of money.
A_t	the sum of bespoke adjustments, including the application of the time value of money where appropriate, calculated as per formula 7 above.
a_t^1	the bespoke adjustment '1' for year t. Formula 7 above demonstrates the application of the time value of money for different bespoke adjustments relating to different regulatory years.
$rvWACC_t$	the real vanilla WACC provided in the annually updated metering PTRM for year t.

19.4.2. Price cap for fee-based ancillary network services and connection services and public lighting

The form and formulae of the control mechanism for fee-based ancillary network service connection services and public lighting applicable for the 2026-31 regulatory control period is listed below.

Table 19-3: Price cap control formulae for fee-based ancillary network services and public lighting

1	$\bar{p}_t^i \geq p_t^i$	i = 1, … , n t = 1, 2, 3, 4, 5
2	$\bar{p}_t^i = \bar{p}_{t-1}^i \times (1 + \Delta CPI_t) \times \left(1 - X_t^i\right) + (1 + A_t^i)$	i = 1, … , n t = 2, 3, 4, 5

where:

t	the regulatory year with t = 1 being the 2026-27 financial year.
$\bar{p}_t^i$	the cap on the price of service 'i' in year t.
p_t^i	the price of service 'i' in year t. The initial value to be decided in the distribution determination.
$\bar{p}_{t-1}^i$	the cap on the price of service 'i' in year t-1.
ΔCPI_t	the annual percentage change in the Australian Bureau of Statistics' (ABS) Consumer Price Index (CPI) All Groups, Weighted Average of Eight Capital Cities[186] from December in year t-2 to December in year t-1. For example, for 2026–27, t-2 is December 2024 and t-1 is December 2025.
X_t^i	the X factor for service 'i' in year t. The X factors are to be decided in the distribution determination.
A_t^i	the sum of any adjustments for service 'i' in year t. The X factors are to be decided in the distribution determination.

19.4.3. Price cap for quoted ancillary network services

The price cap control mechanism for quoted ancillary network services connection services is listed below.

[185] If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.
[186] If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

Table 19-4: Price cap control formulae for quoted ancillary network services

1	$\overline{p_t} = Labour_t + Contractor\ Services_t + Materials_t + Margin_t + Tax_t$	t = 1, 2, 3, 4, 5
2	$Labour_t = Labour_{t-1}(1 + \Delta CPI_t) \times (1 - X_t^i)$	t = 2, 3, 4, 5

where:

t	the regulatory year with t = 1 being the 2026-27 year.
$\overline{p_t}$	the applicable price cap for the requested service.
$Labour$	the labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs and overheads. Labour is escalated annually by CPI-X. The initial values are to be decided in the distribution determination.
ΔCPI_t	the annual percentage change in the Australian Bureau of Statistics' (ABS) Consumer Price Index (CPI) All Groups, Weighted Average of Eight Capital Cities[187] from December in year t-2 to December in year t-1. For example, for 2026–27, t-2 is December 2024 and t-1 is December 2025.
X_t^i	the X factor for labour rate 'i' in year t. The X factors are to be decided in the distribution determination.
$Materials$	the cost of materials directly incurred in the provision of the service, material storage and logistic on-costs and overheads.
$Margin$	is an amount equal to AusNet Services' nominal vanilla WACC applied to the total cost of Labour, Contractor Services and Materials
Tax	is an amount, if any, equal to the tax costs in present value terms arising from the provision of the service to a customer, netting off the net present value of the reverse cash flow resulting from the depreciation of the capital contribution.

19.5. Supporting documentation

There are no supporting documents available for this chapter.

[187] If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

Glossary

Abbreviation	Full Name
AARR	aggregate annual revenue requirement
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMS	asset management system
ASIC	Australian Securities and Investments Commission
BAU	business-as-usual
CAM	cost allocation methodology
capex	capital expenditure
CBD	central business district
CCP	Consumer Challenge Panel
CESS	capital efficiency sharing scheme
CGS	commonwealth government security
CSF	category specific forecast
DGM	dividend growth model
DMIA	demand management innovation allowance
DNSP	distribution network service provider
DRC	debt raising cost
DSO	distribution system operator
EAM	enterprise asset and works management
EBM	emergency backstop mechanism
EBSS	efficiency benefit sharing scheme
EFD	early fault detection
EGWWS	electricity, gas, water and waste services
EPA	environment protection authority
ERP	enterprise resource planning platform
ESC	Essential Services Commission
ESMS	electricity safety management scheme
ESV	Energy Safe Victoria
EUAA	Energy Users Association of Australia
FMECA	failure mode effect criticality analysis
GDP	gross domestic product
GIS	gas insulated switchgear
GSL	guaranteed service levels
GST	goods and services tax
IAP2	International Association of Public Participation
ICT	information and communication technology
IT	information technology
KPIs	key performance indicators
MAR	maximum allowed revenue
MTFP	multilateral total factor productivity
MVA	mega volt amps

NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NGO	non-government organisation
NIST-CSFCI	national institute of standards and technology cyber security framework for critical infrastructure
NPV	net present value
NSP	network service provider
OEA	Oxford Economics Australia
OH&S	occupational health and safety
Opex	operating and maintenance expenditure
PCRs	protection & control requirements
PPIs	partial performance indicators
PTRM	post tax revenue model
PV	present value
RAB	regulatory asset base
RCM	reliability centred maintenance
repex	replacement expenditure
RIN	regulatory information notice
RMD	ratcheted maximum demand
RPP	revenue and pricing principles
SAIP	smart aerial image processing
SAPS	stand alone power systems
SAUR	shared asset unregulated revenues
SCADA	supervisory control and data acquisition
SRG	Stakeholder Reference Group
STPIS	service target performance incentive scheme
VCR	value of customer reliability
WPI	wage price index

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