

AusNet



AusNet Electricity Distribution Price Review

2026-31 Revised Regulatory Proposal

Monday, 1 December 2025

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1. Executive Summary

1.1. Introduction

On 31 January 2025 we submitted our regulatory proposal (Initial Proposal) to the Australian Energy Regulator (AER) setting out our revenue requirements for the 2026-31 regulatory period.

On 30 September 2025, the AER published its Draft Decision. This included significant expenditure cuts relative to the Initial Proposal; 51% for capital expenditure and 12% for operating expenditure; and an invitation from the AER to provide additional, technical supporting evidence to substantiate our case.

This document, together with its accompanying supporting material, constitutes our response to the AER's Draft Decision and is our Revised Proposal for our electricity distribution network for the 2026-31 regulatory period.

Our Revised Proposal responds to the issues raised in the AER's Draft Decision and updates our Initial Proposal to incorporate more recent information.

This Executive Summary provides an overview of our Revised Proposal including required revenues and the price impact, changes that have occurred in our operating environment since we submitted our Initial Proposal and how we have considered stakeholder feedback in developing this Revised Proposal.

The dollars presented below are stated in real \$2025-26 terms unless noted otherwise.

1.2. Chapter structure

This chapter is structured as follows:

- Section 1.3 provides an Overview of the changes in our operating environment since our Initial Proposal and how these have impacted our Revised Proposal;
- It also covers alignment of our Revised Proposal with Victorian Government policy objectives and relevant stakeholder and customer feedback; and
- Section 1.4 lists supporting documentation referred to in this Chapter.

1.3. Overview

This Revised Proposal constitutes our formal response to the AER's Draft Decision. The AER plays a critical role in ensuring the prudence and efficiency of network investments, consistent with the requirements of the regulatory framework and ultimately the National Electricity Objective. We acknowledge the concerns and questions raised by the AER in its Draft Decision and have sought to comprehensively address these in this Revised Proposal.

Our Initial Proposal forecasts were developed over a period of several years and extensively tested with customers in various levels of detail. In total, over 16,000 customers provided input on our plans via our research and engagement program. We reflected their views in developing our Initial Proposal which included a package of service level uplifts for reliability, resilience, customer experience and unlocking more renewable energy while maintaining relatively flat annual costs in real terms.

Since the Initial Proposal was submitted ten months ago we have seen data track in line with, or above, key parts of our forecast. This includes actual demand in the 2024/25 summer (which exceeded our forecast across many key feeders) and energy consumption which has been consistent with the anticipated increase.

As we are preparing this Revised Proposal at a time when the energy transition is well underway, the operating environment is changing far more rapidly than during previous price review processes. The high degree of change has meant that we have made updates to several aspects of our forecasts to account for changes in our operating environment. In its Draft Decision the AER and its consultant, EMCa, raised substantive issues regarding the evidence provided to support our expenditure forecasts in our Initial Proposal. We acknowledge all these concerns and have taken them on board. We have addressed each of these issues in our Revised Proposal forecast and have submitted

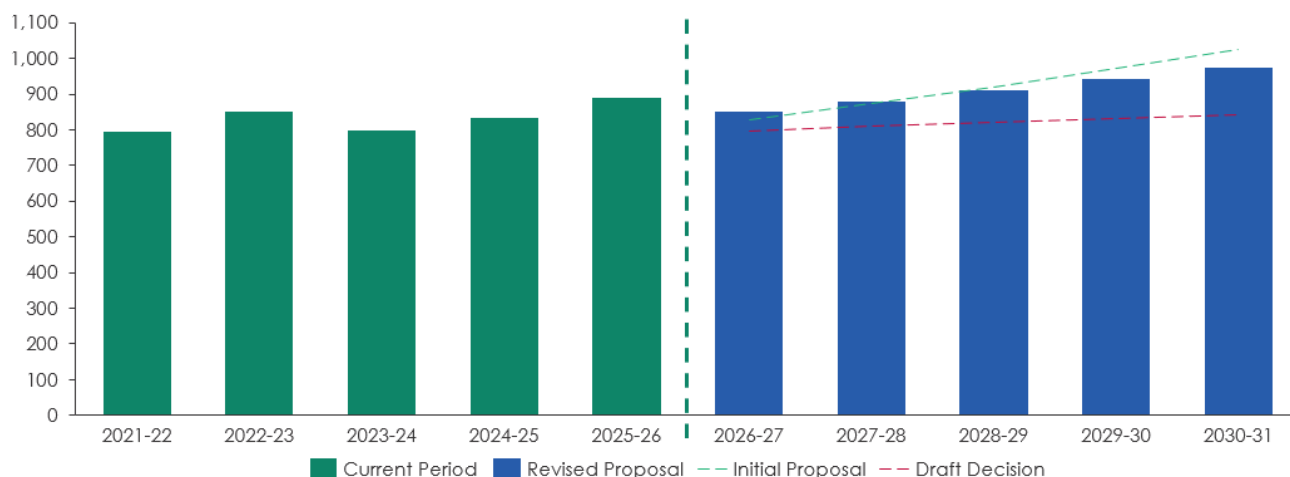
an Issues Register (AER / EMCA Issues Register) listing each of these concerns and referencing where in our proposal documentation these have been addressed. A high level summary of our Revised Proposal is below.

1.3.1. Revenue requirement and price impact

We are proposing a smoothed revenue requirement of \$4,561.9 million for 2026-31 (\$, real 2025-26). Our revised revenue proposal is 11% higher than that proposed by the AER in its Draft Decision and 1% lower than that proposed in our Initial Proposal.

This is shown below.

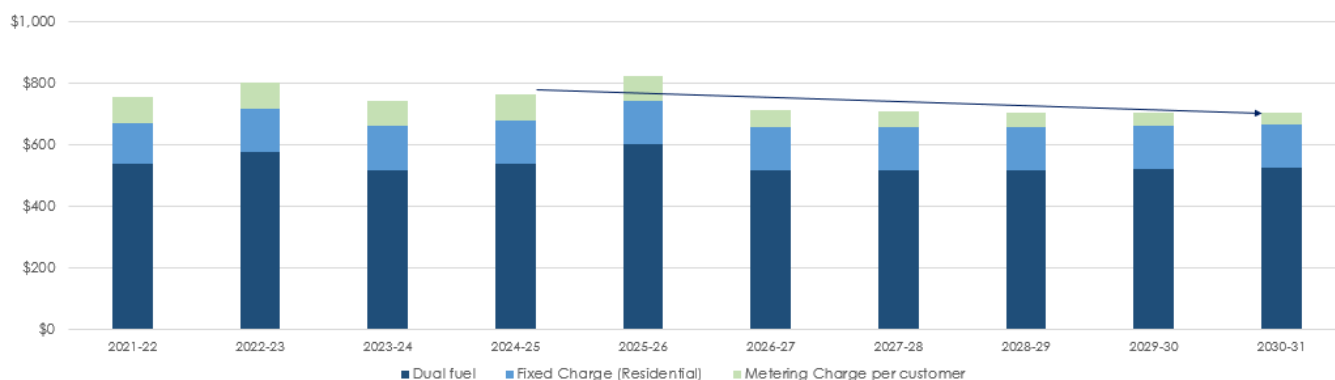
Figure 1-1: Smoothed distribution revenue 2021-26 and 2026-31 period (\$m, real 2025-26)



Source: AusNet

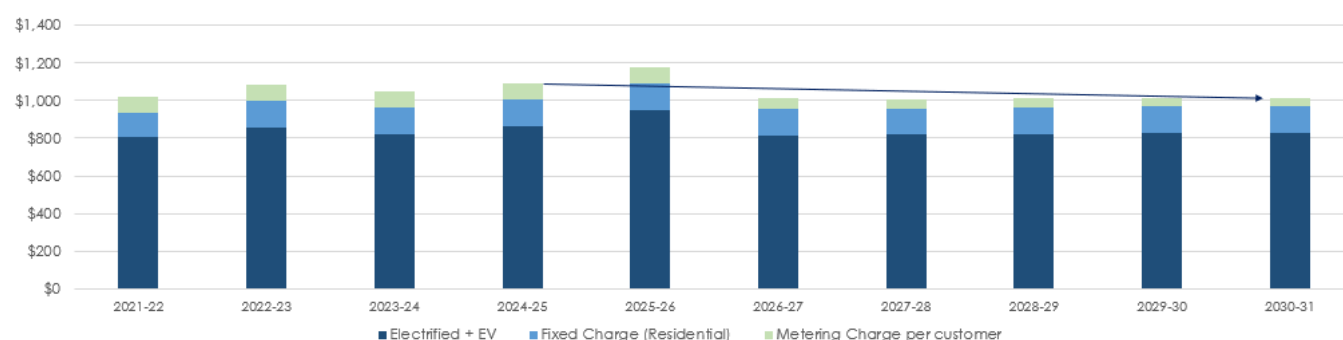
This is expected to have the following bill impacts for residential and business customers:

Figure 1-2: Residential with gas and no EV - typical distribution charge reductions of 8% (including metering and excluding inflation) from today compared to 2031



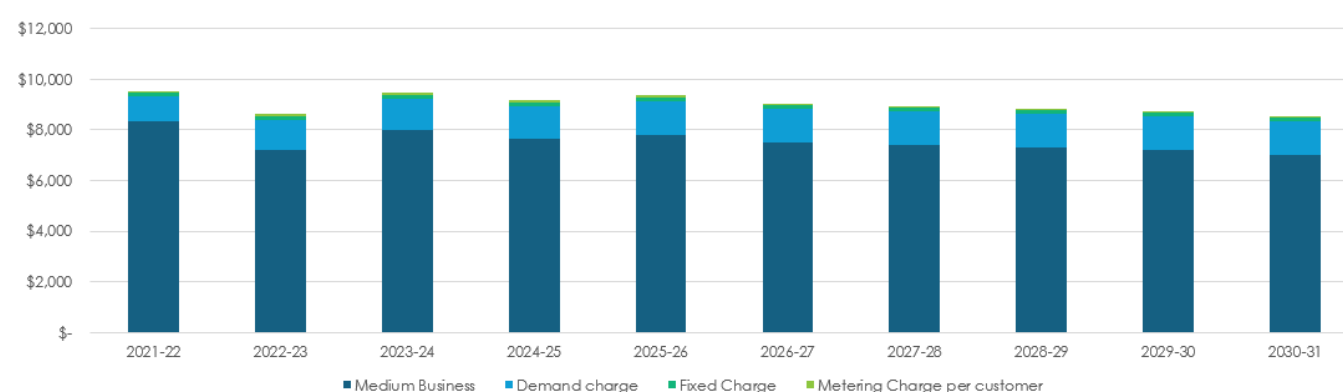
Source: AusNet, assumes annual usage of 5.2MWh + incremental increase from today to 2031

Figure 1-3: Residential with all electric appliances and EV - typical distribution charge reductions of 7% (including metering and excluding inflation) from today compared to 2031



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

Figure 1-4: Medium (40-160MWh) business - typical distribution charge reductions of 9% (including metering and excluding inflation) from today compared to 2031

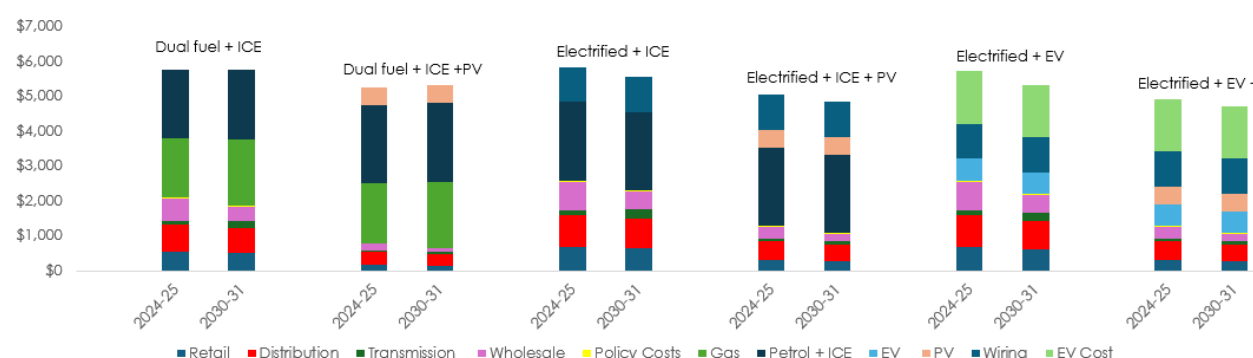


Source: AusNet, assumes annual usage of 69.5MWh

For business customers, particularly larger business customers, electrification pathways remain uncertain and highly variable, making it difficult to assess network cost impacts. While some electrification is expected, our bill impact analysis assumes flat usage over the period. Under this assumption, small businesses (<40MWh) are projected to see a 7% reduction, and large businesses (>160 MWh) a 9% reduction.

We have updated our household energy cost analysis, originally submitted with our Initial Proposal to include our Revised Proposal revenues and more recent assumptions for transmission charges, electric vehicle usage, consumption and customer numbers. Consistent with our Initial Proposal, our Revised Proposal would mean no material change in the overall household running costs for those customers who do not invest in electrification or solar before 2030-31, and confirms substantial savings (of \$1,337, or 22% of total running costs) can be unlocked for those customers who can and do make those investments. We expect over 300,000, or around one-third of our customers, to make investments of this nature over the next regulatory period. It is our role to enable those customers to make the investments so that the savings shown below can be realised, while they receive a safe and reliable electricity service.

Figure 1-5: Household costs by customer type 2024-25 compared to 2030-31



Source: AusNet analysis using various independent data sources. This is based on assumptions that are by nature uncertain, and actual bills may differ from the outlook shown.

The expected impact of electrification has also been modelled by the Grattan Institute, which confirms the very significant household savings to be realised by moving to a single electricity bill, and eliminating gas and petrol bills. This is the trajectory customers and industry are on, and must stick to, to unlock these cost savings. This will require an increase in network capacity and, as evidenced by our customer research and engagement, an uplift in network reliability and resilience. Our Revised Proposal presents additional supporting evidence to demonstrate the technical need for this increase in network capacity and improved network reliability and resilience, amongst other investment drivers.

1.3.2. Changes in our operating environment since submission

Almost a year has passed since we finalised our Initial Proposal. Over this year we have seen:

- The 2024/25 summer being the hottest since 2019/20 and included several hot (close to 40 degree) but overcast days, causing very high demand coinciding with low solar output. This risk was acutely felt in the growth corridors, which are a focus area of our Revised Proposal.
- A relatively mild 2025 winter, but with a record winter peak demand driven by electrification. On our gas network we saw a sharp decline in gas consumption reflecting the same trend.
- Energy consumption volumes tracking in line with our forecasts, which was a 3.4% increase between regulatory year 2023-24 and 2024-25. This is good news for customers as it means increased network investment is spread across a broader base.
- Continued sharp escalations in project costs. AusNet has an outsourced workforce and works closely with several market suppliers to support project delivery. Despite our best-practice tendering approach, market forces have driven efficient costs further upwards. This impacts several capex categories including replacement, augmentation and connections.
- Increased pipeline of data centre and other new technology connections, which has informed our updated connections capital expenditure.
- Continued policy and regulatory changes, due to the current policy focus on meeting net zero targets, which impact many areas of our business in numerous ways. These include supporting the Federal Government residential battery rebate, the Victorian Government's Emergency Backstop (which included changes to the implementation of Stage 2), the Victorian Government's solar subsidies for C&I connected solar, enhanced sustainability reporting requirements, supporting increased demand for Low Voltage network data in line with Victorian Government priorities, changes to REFCL Operating requirements and implementing Flexible Trading Arrangements.

We have also progressed internal changes to:

- Transition our service delivery partner and insourced fleet, depots and tools and equipment. The transition of our field force from Downer to Zinfra took place on 1 August 2025.
- Re-obtain ISO 55001 accreditation, demonstrating the robustness of our asset management system, which underpins our expenditure forecasts.

These changes collectively validate the need for the significant expenditure increases set out in our Initial Proposal and have fed through into detailed updates of our forecasts.

1.3.2.1. Higher peak demand forecasts than in our initial proposal

AusNet is one of the few businesses who has a well-qualified in-house demand forecasting team who have been forecasting demand since 2013. This leverages our network data, smart meter data and independent data sources to get an accurate view of current and expected demand. These forecasts underpin our Distribution Annual Planning Report (DAPR) and are used operationally to underpin our seasonal preparedness program.

In the current period, customer growth is a major driver of peak demand increases. This growth is focused in the northern and southeastern growth corridors located in our network. Our demand forecasts underpin significant augmentation programs, which are urgently required to address high levels of network risk in these areas.

Our demand forecasting methodology has been refined and improved to account for the changes due to the energy transition. We are continuing to build and refine our evidence base as the transition unfolds to monitor changing demand patterns at all levels of the network due to gas and transport electrification and customer energy resources, including residential batteries.

We have responded to all the issues raised on our demand forecasts by the AER and its consultant, Baringa, and where appropriate we have updated our demand forecasts accordingly. This includes changes which make the demand forecasts more conservative (lower) than smart meter data would support. For example, in response to the Draft Decision we have incorporated a downwards adjustment to future demand to take account of future energy efficiency, despite evidence from our network that demand per customer is increasing. We have also incorporated the expected impacts of the residential battery program.

We consider our demand forecasts are robust and should be accepted by the AER in full. Arbitrary adjustments to these which defer augmentation programs risk the reliability of residential and small business customer supply (particularly on very hot and very cold days) and stifling economic development in growth corridors, as we will need to continue to restrict the connection capacity available to Commercial and Industrial (C&I) customers (including supermarkets, large hardware stores and electric vehicle charging operators).

The main changes we have made to our demand forecasts include:

- **Incorporating the latest data** - The revised forecasts use updated historical network data up to the end of March 2025. The past 12 months saw record summer and winter demands, which have directly increased the baseline for future forecasts. This recent surge in demand was not captured in the initial proposal and has led to higher projected peaks from the beginning of the regulatory period.
- **Inclusion of Commercial and Industrial Electrification** - Unlike the initial proposal, the revised forecasts now explicitly include the impact of electrification in the C&I sector. This change reflects new evidence and AEMO's projections that C&I electrification will be a major driver of future demand. Excluding this factor previously kept forecasts conservatively low, but its inclusion now results in a more robust—and higher—peak demand outlook.
- **Adjustment for Block Loads and Other Drivers** - The revised forecasts clarify and update the treatment of block loads (large, discrete new connections) and other post-modelling adjustments. The latest information on block loads, especially in growth corridors, has contributed to the increase in the first-year forecast for both maximum and minimum demand.
- **Balanced Approach to Demand Drivers** – While the revised proposal incorporates downward adjustments for energy efficiency and battery uptake, it also ensures that all significant upward drivers—such as electrification and block loads—are included. This approach results in a balanced forecast that accounts for positive and negative demand drivers.

Further explanation is provided in Chapter 3 – Demand and Energy Forecast.

1.3.2.2. Market cost increases

We have updated our cost estimates to reflect latest market data and project-specific changes since our Initial Proposal. This has resulted in increases in costs for major capital projects, due to:

- the addition of new feeders and associated civil and electrical works for new zone substations
- updated supplier pricing for materials, equipment, and labour
- project-specific constructability requirements identified through more detailed planning.

Due to the materiality of these changes we engaged Worley to provide an independent assessment of whether the revised project costs reflect efficient delivery requirements.

Worley has found that while our revised estimates are higher than those in the January 2025 Proposal, these changes are supported by current market evidence, recent tender outcomes, and benchmarking against industry standards. In some cases they reflect more mature design and delivery assumptions.

The report also highlights that the revised estimates remain consistent with the National Electricity Rules (NER) and the AER's Expenditure Forecast Assessment Guideline.

1.3.2.3. New regulatory developments

Our Revised Proposal accounts for the most recent regulatory developments that have occurred since the Initial Proposal. These include:

- **Flexible Trading Arrangements** – on 15 August 2024 the AEMC made a rule¹ to enable energy service providers to separate and manage 'flexible' CER from passive loads in the energy market with dedicated metering and use in-built measurement capability in technology such as EV chargers and smart streetlights in lieu of meters to

¹ AEMC, *Unlocking CER benefits through flexible trading*, 15 August 2024

facilitate the adoption of innovative products at a lower cost. As the compliance milestones require expenditure in the current regulatory period, on 14 November AusNet submitted a cost pass through application to the AER, seeking to pass through \$12.8m of capex and \$0.1m of opex being incurred in 2025-26. Our Revised Proposal assumes the pass through is approved with the balance of the costs included in the 2026-31 forecasts.

- **Sustainability reporting requirements** – changes to accounting standards (AASB S2) require mandatory climate-related financial disclosures, commencing in 2026 with increasing levels of assurance required to meet disclosure standards over the next few years. We are seeking an opex step change to fund the additional costs of these requirements as set out in Chapter 6 – Operating Expenditure.
- **Energy Consumers Australia's Distribution Strategic Planning rule change** – This rule change will result in reforms to increase the distribution planning time horizon from 5 to 10 or 20 years, informed by scenarios and customer and community consultation. It will also require additional Low Voltage network data to be published to assist customers make more informed decisions around CER investments and connections. AusNet supports the direction of this rule change, which is important to enhance transparency and visibility of the network investment expected to be needed during the transition. We have included a new opex step change (Chapter 6) required to fund the development of the plan required under any of the scenarios contemplated by the AEMC and also re-proposed Digital spend to uplifting LV network data visibility (Chapter 5).

There are several additional reviews underway which will have a more uncertain impact on distribution businesses, including the CER Roadmap (for example, AEMO's CER Data Exchange) and the AEMC's Pricing Review. We would expect these initiatives to impact our network during the 2026-31 regulatory period and potentially drive cost pass throughs or re-open aspects of the decision, such as our Tariff Structure Statement (TSS). There will also be further transition-related changes we are not aware of today that will not qualify for cost pass through and we accept that we will need to manage these cost increases within our ex ante expenditure allowances.

1.3.3. How we have addressed the AER's concerns

The AER and its consultant EMCa raised various issues in the evidence we provided to justify our Initial Proposal forecasts. We have taken this feedback on board and considered it carefully over the last few months. In some cases we have agreed with the AER's concerns and in other cases we have provided further information. In developing our Revised Proposal, we have worked through these issues systematically to make sure our Revised Proposal fully addresses the AER's and EMCa's feedback. This has involved:

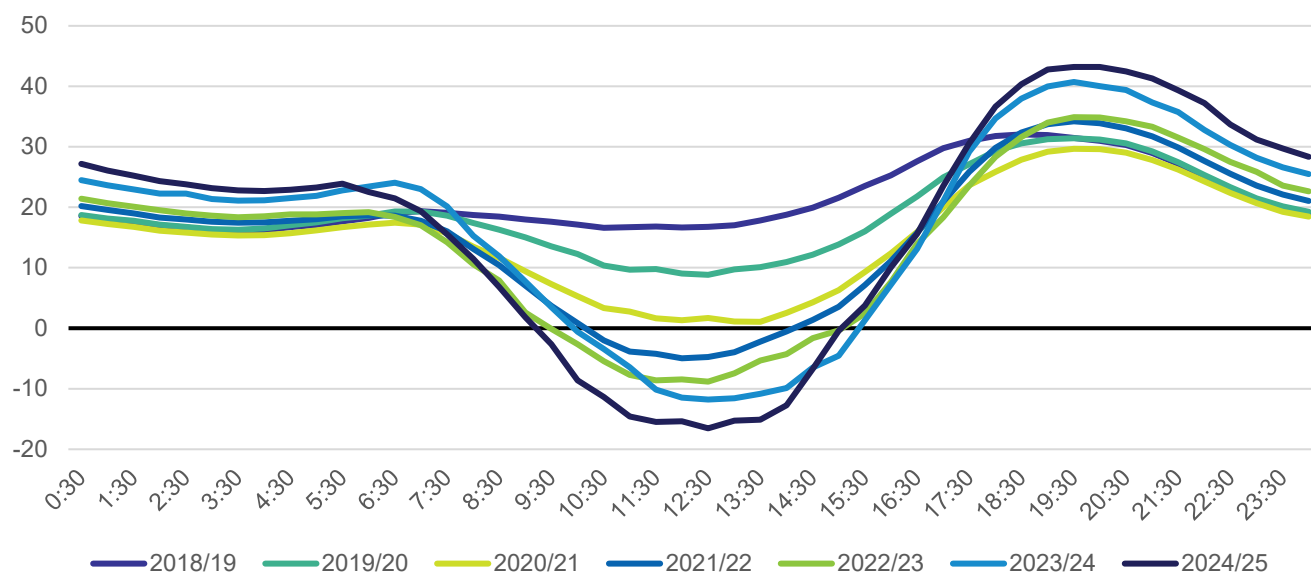
- Rebuilding our repex models to apply a consistent methodology and decision rule, eliminating hard-coding and making sure they are transparent and the assumptions are well-explained.
- Obtaining expert peer review of our repex models which has been documented in a report for the AER (The Mantua Group – Assessment of AusNet AER Compliance)
- Providing a clear mapping between our model outputs and our capex forecast, clearly identifying and explaining any post-model adjustments (AusNet – Capex Project Supporting Document Map)
- Developing new business cases, or new addendums to existing ones, to clearly explain investment drivers, approach and options analysis undertaken to justify each aspect of our expenditure forecasts.
- Applying a consistent and refined risk allowance approach which demonstrably provides unbiased cost estimates.
- Cleansing and updating input data where required.

Other specific concerns have been addressed in the relevant expenditure categories.

1.3.4. Importance of striking the right balance between price and service levels

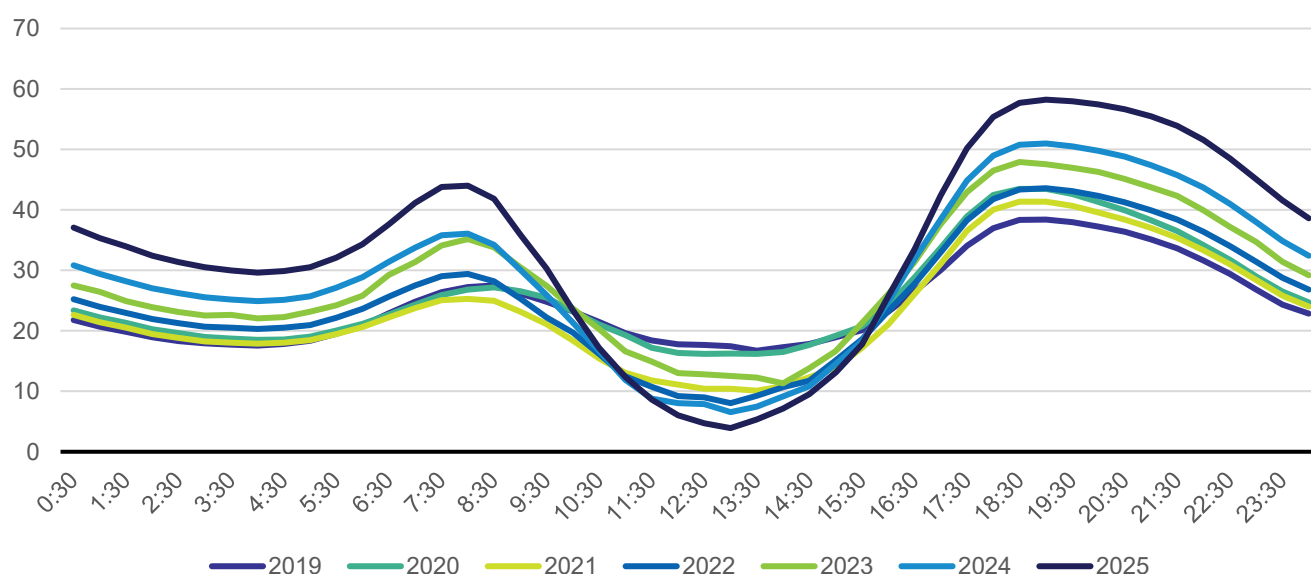
The energy transition is underway. Solar and residential battery uptake continues to grow, propelled by government subsidy programs. We are also seeing evidence of customers electrifying their gas appliances and electric vehicles, with a higher rate of peak demand growth during winter than in summer. These changes are collectively re-shaping customer load profiles to be more peaky; with higher maximum demands and lower minimum demands.

Figure 1-6: Average 30 minute load (MW) during summer at Clyde North zone substation



Source: AusNet

Figure 1-7: Average 30 minute load (MW) during winter at Clyde North zone substation



Source: AusNet. Clyde North is one of AusNet's zone substations in the south-east growth corridor

In addition to investment in required network capacity, this proposal includes measured steps to improve network utilisation via our tariff structures (including a continued roll out of Time of Use tariffs and the optional CER tariff with an export charge and reward) and export and demand management initiatives (including our flexibility services proposal) which smooth load profiles.

In future, as more customers invest in CER and products such as Virtual Power Plants (VPPs), Home Energy Management Systems (HEMS) develop, and customer protections framework issues are resolved, there is potential for greater demand flexibility. In the 2026-31 regulatory period we expect to see increasing evidence of the true potential, and customer appetite for, large scale coordination which will shape network investment required for years to come.

For the 2026-31 period we consider our proposal balances the potential for flexibility (which still needs to be demonstrated at scale) with the need to invest in network capacity to support customer growth and electrification. It

is unrealistic to consider that increases in network capacity can be entirely avoided through load shifting. This is particularly the case given customer growth is the most significant driver of increasing peak demand and therefore our augmentation plans. In addition, without residential batteries operating in a way that is consistent with dynamic network signals, or Vehicle to Grid technologies in use, significant and sustained load shifting cannot be achieved without substantial changes to people's lifestyles. And we know from research that most customers are convenience motivated rather than price motivated².

This is not to say we are not committed to promoting and facilitating more coordination and flexibility – we are, and this is reflected in our flexibility services, strategic customer communications proposal, tariff structure offerings and innovation proposal. But we are also acutely aware of the potential for a loss in customer trust in the energy sector – and specifically the transition – if electrification cannot be smoothly facilitated, or CER investments not integrated efficiently, while providing a level of network availability or service that customers expect and are accustomed to.

1.3.5. Key features of our Revised Proposal

A summary of the key features of our Revised Proposal is below.

1.3.5.1. Capital Expenditure

Our net capex forecast is \$3,408.1³ million. This is an increase of \$1,238.7 million (57%) compared to actual expenditure in the current period and an increase of \$1,706.7m (100%) compared to the Draft Decision. Key aspects of our capital expenditure forecasts are outlined below. For more detail, please refer to Chapter 5 – Capital Expenditure.

- **Replacement and safety capex (\$1,156.1 million)** – The revised repex proposal fully addresses the concerns of the AER and its consultant, EMCa. It includes updated modelling, calibration of asset failure probabilities using historical data, refined consequence-of-failure assumptions, and robust options analysis for each asset class. Detailed business cases and economic models have been provided to support each component. The increase in forecast repex compared to the current period is required to address increasing network risk associated with aged and deteriorating assets, to maintain risk, reliability and safety.

Our approach emphasizes transparency, prudence, efficiency and alignment with good industry practice.

- **Augmentation capex**

Our augmentation program has been updated to address updated demand forecasts (further detail is provided in Chapter 3 – Demand and Energy Forecasts). Our augmentation program has been split by voltage level given the slightly different modelling approaches taken to each voltage level, commensurate with the differences in the physical characteristics of the networks.

- **High and medium voltage (\$533.8 million)** – This focuses on addressing network constraints and supporting demand in high-growth areas, particularly the Northern and South-Eastern Growth Corridors, where new suburbs are being developed in dedicated precincts. Our Growth Corridor Program documents consider the optimal augmentation programs across these areas while also providing project level modelling to illustrate the prudence of each project. Our proposal includes three new zone substations (in Beveridge, Wollert and Pakenham South), associated feeder works, and sub-transmission upgrades to accommodate increased load.

The proposal responds to the AER's draft decision by updating demand forecasts, expanding options analysis, and providing more robust business cases. It justifies the need for a larger program than initially envisaged due to recent demand peaks, cost escalations, and scope changes, while also ensuring that the preferred solutions are both economically justified and strategically targeted to deliver reliable, efficient service to customers.

We are no longer proposing proactive augmentation of the sub-transmission network to unlock large scale renewable generation but encourage consideration by policy makers of how to leverage the sub-transmission network to unlock lower cost capacity for this purpose.

- **Low voltage (\$148.5 million)** – The revised LV augmentation proposal addresses emerging constraints on AusNet's low voltage and single wire earth return (SWER) networks driven by accelerating electrification and CER uptake. It is the first time we have proposed a proactive LV investment program, as historically demand per customer has been relatively stable. Our LV network is highly utilised due to historic planning decisions including the use of probabilistic planning. This has kept network costs low. However as customers electrify

² As identified via our Customer Segmentation Research study, available here: [Customer Segmentation Research | Research | Community Hub](#)

³ After asset disposals

gas and transport, we are seeing peak demand increases at the individual customer level. Low voltage assets benefit least from demand diversity and capacity upgrades are required. If we do not undertake this proactively, our reactive program will grow materially over time, which will increase cost to customers and reduce reliability.

Our program is economically justified through reducing expected unserved energy, with capital expenditure of \$148.5 million, net of \$36 million deferred through the introduction of flexible services as a non-network solution. The proposal responds to AER and EMCa's concerns by applying a more robust method for calculating unserved energy at risk, thoroughly evaluating potential overlaps with other projects, and ensuring that benefits are not overstated. We have removed network upgrades driven by increasing solar exports and plan to utilise smart solutions (Dynamic Voltage Management and flexible exports) to unlock more export instead.

- **Resilience (\$166.2m) and reliability (\$42.2m)** – Our revised resilience and reliability expenditure proposals focus on targeted investments to strengthen the network against climate risks and improve service for the worst-served customers. For resilience, we have updated our network modelling based on the AER's feedback and the Revised Proposal includes \$154.0 million for network hardening (such as undergrounding, covered conductors, hardened poles, and reclosers). We have accepted the AER's draft decision on community support including Stand-Alone Power Systems (SAPS), mobile generation, emergency response vehicles, and are no longer proposing backup power for community hubs. The reliability program, scaled back in response to AER feedback, prioritizes economically justified investments on six worst-served feeders and an additional project (the Benalla to Euroa express feeder), but no longer includes a broad Regional Reliability Allowance.
- **Top down adjustment (-\$16m)**– the overall capex forecast contains a top-down adjustment of \$16m to account for the interactions across programs. The STPIS targets and GSL forecast have been adjusted, consistent with the AER's preferred approach, to account for the benefit for proactive reliability and resilience investments.
- **Connections (\$793.3m)**- The revised connections capex proposal updates the forecasts for new customer connections, reflecting the latest available data on volumes and unit rates. It includes forecasts for business-as-usual residential and commercial connections, as well as large connections such as data centers, EV charging stations, and grid-connected batteries. It also applies a conservative approach to estimating future volumes and costs and aligns with AER guidance on capital contributions.
- **Digital (\$370m)**- The revised digital capex proposal reflects a comprehensive review and refinement of AusNet's digital investment program in response to AER and EMCa feedback. The proposal reduces capital expenditure by 11% and operating expenditure by 35% compared to the Initial Proposal, primarily through program scope reductions. Other key changes include updated cost estimates, more robust cost-benefit analysis, clearer scope definition, improved risk management, and more transparent cost allocation. The digital investments are prudent, efficient, and targeted to support network reliability, customer experience, and cyber security.
- **Non-network (\$323.7m)** - The revised non-network expenditure proposal covers investments in fleet, property, and other non-network assets. The largest components are fleet and plant (\$173.5 million) and property (\$145.7 million), reflecting the need to replace and refurbish depots and acquire additional vehicles following the transition to a new service delivery partner. We have accepted the AER's decision on our strategic depot program and updated our fleet modelling to reflect new, detailed information following the transfer of fleet from our former delivery partner to AusNet. We have also updated our Melbourne office lease costs to reflect current market conditions and support worker demand to return to work.

1.3.5.2. Operating expenditure

Our opex forecast is \$1,606 million excluding debt raising costs. This is an increase of \$122 million (8%) compared to the current period and an increase of \$118m (8%) compared to the Draft Decision. This is 5% lower than the Initial Proposal, reflecting acceptance of aspects of the Draft Decision, removing the Energy Safe Victoria levy, and incorporating updated information including actual opex for Regulatory Year 2025.

We have responded to the AER's feedback by refining cost assumptions, updating demand forecasts, and providing enhanced justification and cost benefit analysis for existing step changes, including those linked to capex programs such as Digital, hazard trees and Early Fault Detection (EFDs). We do not accept the AER's Draft Decision to reject step changes due to low materiality alone. This is of particular concern given the significant opex pressures we are facing as the scope of our role is shifting due to the energy transition, which is not adequately compensated in the current opex forecasting approach.

We also reject the application of a large negative step change to claw back the underspent allowance for insurance premiums in the current period, as including this introduces material bias in the forecast and is not consistent with the National Electricity Rules.

We have also included three additional step changes to address new regulatory obligations that have arisen since the Initial Proposal.

The proposal also includes category-specific forecasts for Guaranteed Service Level payments, innovation, and additional customer engagement and communications.

1.3.5.3. Incentive schemes

Customer Satisfaction Incentive Scheme (CSIS)

We have re-proposed a Customer Service Incentive Scheme (CSIS), with a lower revenue at risk (0.5% instead of 1%). We have carefully considered and addressed the issues the AER raised in the Draft Decision. We have also heard very strong customer sentiment that the alternative metrics for telephone answering and connections timeframes are too narrow and do not reflect current customer expectations. Our CSIS is based on four customer satisfaction parameters: planned outage satisfaction, unplanned outage satisfaction, new connections satisfaction, and first call resolution, and was developed through extensive customer engagement to target outcomes that matter most to customers.

Capital Efficiency Sharing Scheme (CESS)

We propose a CESS penalty of -\$117.2 million for the 2026-31 period. While we have accepted most aspects of the Draft Decision, we reject the decision not to include the Zinfra transition costs (which include Digital, fleet and property costs) as a CESS adjustment because this removes the incentive for networks to make capital investments in the later years of the regulatory period that lower longer term costs. We have also set out our preferred definition of large, bespoke connections in line with AER's updated CESS to apply in 2026-31.

Efficiency Benefit Sharing Scheme (EBSS)

Our revised EBSS proposal seeks a carryover amount of \$38.8 million. We accept all aspects of the Draft Decision, except for the non-recurrent efficiency gain applied for the bushfire liability insurance premium underspend in 2022–23, which we strongly reject.

Service Target Performance Incentive Scheme (STPIS)

We accept the Draft Decision on STPIS, including adjustments to our targets to account for the impact of the resilience and reliability programs. We encourage the AER to undertake a STPIS review before the 2031–36 regulatory period which should address the inclusion of catastrophic events from the Major Event Day (MED) threshold.

1.3.5.4. Managing uncertainty

Cost pass throughs

We have re-proposing an Electrification cost pass through event, which has been re-drafted to reflect the AER's feedback. We have also addressed the issues the AER raised about this event. This is a critical part of the Revised Proposal, which will provide flexibility should gas electrification occur at a pace that differs from that approved in the Final Decision. This is particularly important given the ex post review provisions in the Rules, which require investors to take

Contingent projects

Our Revised Revenue Proposal contains two new contingent projects, that have been included due to developments since the submission of the Initial Proposal. These projects relate to emerging large-load customer connections and are:

- Cranbourne (CRE) Zone Substation (ZSS) third transformer and 22kV distribution feeder
- Wodonga Terminal Station (WOTS) - Barnawartha (BWA) 66kv line augmentation

The expenditure is required to achieve the capital expenditure objectives (subject to the trigger event occurring), exceeds the threshold in the rules, and an appropriate trigger event can be defined to be reasonably specific and capable of objective verification.

1.3.5.5. Tariffs

The revised Tariff Structure Statement (TSS) for 2026–31 reflects customers' feedback, aims to address energy transition challenges, and focuses on simplifying tariffs, improving cost reflectivity, and supporting the integration of new technologies.

Relative to the current period, it introduces several changes, including updating the residential time-of-use (ToU) tariff to include a new "solar soak" period (11am–4pm) and a revised peak period (4pm–9pm) and introducing a new opt-in Consumer Energy Resource (CER) tariff.

We have responded to the feedback in the AER's Draft Decision, including additional information provision on customer impacts and extending the calculation period for Long Run Marginal Cost from 5 to 10 years. We have made the following changes in our Revised Proposal:

- Increased the value of the export reward provided in the CER tariff
- Added a kerbside EV charging tariff trial; and
- Introduced new site-specific and locational tariffs for very large customers.

1.3.5.6. Negotiating Framework

We accept the Draft Decision on Service Classification including regarding the classification of Distribution Asset Rental as a negotiated service. We have updated our Negotiating Framework to support Victorian alignment consistent with the AER's feedback.

1.3.5.7. Metering

We accept the AER's Draft Decision on metering with adjustments for updated connection forecasts and labour escalation rates. We expect the AER to update metering revenues for changes in market parameters including interest rates and inflation prior to the Final Decision.

1.3.5.8. Public lighting

Our revised approach to public lighting services addresses AER feedback, as well as the views raised by the Victorian Greenhouse Alliances (VGA), and Council stakeholders. We have incorporated the following activities based on council feedback:

- an accelerated rollout of LED and smart lighting, with separate pricing models to avoid cross- subsidisation between Councils;
- smart lighting for major roads; and
- warm lighting in designated areas.

While the capital expenditure forecast has increased as a result, overall public lighting bills are expected to fall due to lower energy use.

1.3.6. How our Revised Proposal supports Victorian Government policy objectives

The Victorian Government has an ambitious policy reform agenda focused on facilitating the transition to net zero while supporting customers to lower energy bills and ensuring that the level of service provided by energy networks (as essential services) are appropriate and improving in regional areas. We have found through our customer engagement initiatives that our customers preferences are aligned to the policy objectives of the Victorian Government and we have collected evidence of customer's willingness to pay to uplift services in these areas.

There is some tension between the Victorian Government's policy reform agenda and the current regulatory framework, which tends to apply a more narrowly defined economic test.

In our Revised Proposal we have re-propose parts of our forecasts that we consider are consistent with the parameters of the current regulatory framework and/or the AER has invited more evidence. Where the AER has indicated that policy intervention will be required to address their concerns, this expenditure has not been re-proposed.

While we are providing additional technical detail sought by the AER, and as such do not expect the Draft Decision to be upheld, the impact of the Draft Decision on Victorian Government policy priorities if it were upheld, is shown in the diagram below. This highlights the importance of this Revised Proposal, and AER's Final Decision, in supporting the achievement of policy priorities.

Table 1-1: Impact of the Draft Decision and Revised Proposal on Victorian Government policy priorities

Priority	Draft Decision	Revised Proposal	Policy support needed for
 Achieve committed Victorian Government renewable energy and climate action targets	AT HIGH RISK. AusNet's distribution network is not well-placed to support new generation, electrification or CER.	ON TRACK. Includes investment in network capacity to support electrification. CER unlocked via Dynamic Voltage Management and Flexible Exports.	Leveraging the sub-transmission network to unlock large renewables
 Support the transition of the energy sector and particularly electrification of gas and transport and solar integration	AT HIGH RISK. Network capacity will constrain electrification and impact customer experience.	ON TRACK. Updated demand forecast and associated capex to manage impact of electrification of gas and transport.	Pending Final Decision
 Deliver value to consumers from their investments and investments made on their behalf	AT HIGH RISK. Network utilisation is already high and lack of capacity will constrain electrification and impact customer experience.	ON TRACK. Updated demand forecast and capex plans; increased export reward during peak; more focused customer experience program	Pending Final Decision
 Improve consumer access to reliable energy	AT RISK. Improvements to reliability are unlikely with approved expenditure and modest improvements to resilience.	ON TRACK. Enhanced and justified resilience and reliability improvement programs proposed.	Minimum service levels for reliability and resilience. Already intended by Vic Gov.
 Support improved consumer affordability and prudent network investment	ON TRACK but lowest cost outcomes are being achieved at the expense of value-for-money.	ON TRACK. All network investment.	Planning objectives to be clearly defined to allow holistic, long term planning reflecting customer preferences

1.3.7. Stakeholder and customer feedback on our Revised Proposal

Due to AER feedback on our Initial Proposal being focused on technical supporting evidence, and time constraints at this stage in the process, we developed a targeted customer engagement plan focused on a narrow set of issues where customer support (or otherwise) had the most potential to impact our Revised Proposal or the AER's Final Decision. These issues were discussed with our Coordination Group on 21 October and refined to inform the agenda of a workshop involving a broad range of stakeholders on 6 November.

The outcomes of this workshop and other relevant customer feedback is documented in Chapter 2 – Research and Engagement. It is important to note that we have not relied solely on customer feedback in justifying our Revised Proposal forecasts, but we have sought to address the range of requirements under the regulatory framework, including addressing the AER's concerns.

Where relevant, we have also continued to draw on feedback from our EDPR Customer Engagement Panel during the development of the Initial Proposal and documented in our Coordination Group report that was submitted to the AER on our Initial Proposal⁴.

We have also invited our customers, including members of our Customer Consultative Committee (many of whom were involved in our EDPR engagement) to make submissions on the Draft Decision and Revised Proposal.

1.3.8. Conclusion

We consider our Revised Proposal meets the prudence and efficiency requirements of the AER while delivering more customer value relative to the Draft Decision. This is by enabling electrification, supporting investments in Consumer Energy Resources and offering more rewards for leveraging these at the right times for the grid. Customers also benefit from targeted reliability upgrades and improved network resilience. Our large business customers will also benefit from dedicated account managers to support their more complex requirements.

This will be delivered while keeping bills low, with average residential distribution charges projected to fall by \$66 between today and 2031 and medium business distribution bills to reduce by \$649.⁵

⁴ Coordination Group report submission on AusNet's Initial Proposal, published by the AER here: [AusNet Coordination Group - Submission - Victorian electricity distribution proposals 2026-31 - May 2025 | Australian Energy Regulator \(AER\)](#)

⁵ Refer to Chapter 1.3.1 for graphs on bill impacts for residential customers and medium business, figure is including metering charges and excluding inflation. Average residential customer is average of gas and no EV, electrified household, and electrified household including EV. Medium businesses consumption is >40MWh to 160MWh.

1.4. Supporting Documentation

We have included the following documents to support this chapter:

- ASD – AusNet - AER /EMCa Issues Register – 011225 – PUBLIC;
- ASD – AusNet - Service Classification – 011225 – PUBLIC; and
- ASD – AusNet - Capex Project Supporting Document Map – 011225 – PUBLIC.

2. Research & Engagement

2.1. Summary

- Over 390 hours of engagement with 16,000+ people shaped AusNet's Initial Proposal. Engagement included a Coordination Group and six customer/advocate panels, each focusing on key customer priorities (resilience, reliability, customer service, tariffs and pricing, benchmarking and opex, future networks and research and engagement design), and workshops, forums and research studies.
- The AER did not comment on the overall quality of our engagement in its draft decision but noted that its Consumer Challenge Panel (CCP32) *"observed that AusNet's consumer engagement has met, and in many areas has exceeded the expectations we set out in our Better Resets Handbook"*. Lack of engagement was cited as a reason to reject one inclusion – the Customer Service Incentive Scheme (CSIS), and the AER requested further engagement in one area – the connections tax threshold for data centres.
- Further engagement to support this Revised Proposal focused on the tax threshold for connecting data centres (initiated by the AER) along with public lighting, reliability for worst-served customers, resilience, the CSIS and digital initiatives (initiated by AusNet and/or stakeholders).
- Post-lodgement engagement re-confirmed strong support for reliability and resilience improvements, customer service and customer experience improvements, changes to public lighting (including the introduction of smart lighting and warm lighting options) and re-proposing the CSIS with amendments to address the AER's feedback wherever practical.

2.2. The engagement underpinning our initial Proposal

Our initial Proposal was shaped by more than 390 hours of engagement and the voices of more than 16,000 people. It was the broadest and deepest engagement program AusNet has undertaken for a price review and done to help AusNet design a customer-focussed revenue proposal, meeting the needs of the communities we serve and the AER's expectations as outlined in its Better Resets Handbook.

Table 2-1: A summary of the engagement that underpinned AusNet's initial Proposal

Our Coordination Group and 6 customer and advocate panels spent over 240 hours together engaging on the overall proposal and the best cost vs service level on specific elements important for customers.	Coordination Group	Electricity Availability Customer Panel
	Focused on: • Key proposal elements not captured by panels • Synergies and conflicts between panel streams • Writing an independent report on our draft proposal.	Focused on: • Resilience to climate change • Planned outages • General reliability standards • Improving reliability for worst-served customers • Power quality (voltages).
Customer Experience Customer Panel	Benchmarking & Opex Customer Panel	Future Networks Customer Panel
Focused on: • Customer Service Incentive Scheme (CSIS) • Minimising the impact of planned and unplanned outages on customers • Fit-for-purpose service for all • Communications & customer service channels • Connection processes.	Focused on: • Opex approach, including choice of base year, step changes and trend parameters • Benchmarking methodologies and performance.	Focused on: • Demand forecasts and implications for network investment plans • Community energy • Enabling new generation to connect • Unlocking value for customers (including through their solar and battery investments).

Tariffs & Pricing Customer Panel	Research & Engagement Panel	3 x two-day all-panel forums
Focused on: - Fair revenue allocation - Tariff & customer outcome relationship - Tariffs in the transition to net zero - Building customer agency on tariffs - Principles for good tariff design & pricing objectives.	Focused on: - Collaborating on the Quantifying Customer Values research design - Collaborating on the key design elements of the 20 customer workshops - Interviewing 26 customers to gather their own independent insights to help fill gaps and identify blind-spots in our engagement - Collaborating on our new Customer Satisfaction (C-Sat) tracker design.	At key stages in July 2023, March 2024 and August 2024 to: - Give panel members a whole-of-proposal view, allowing them to make trade-offs between investment areas and understand bill impacts - Connect our Panels with different parts of our distribution area, customers, network infrastructure and staff.

Extensive research and engagement allowed us to hear many voices on a wide variety of topics and informed the Panels' discussions.

We've spent **a further 150 hours** on broad engagement, hearing from more than 16,000 customers.

	20 customer workshops Met four times across five locations - Morwell/Traralgon, Wangaratta, Epping and online. Topics mirrored the Panels' discussions and followed the Proposal planning.	Large customer engagement Via one-on-one meetings and a forum to discuss key aspects of the proposal and implications for large customers.
Council forums 2 forums focusing on the overall proposal and public lighting.	2 x Joint Victorian Networks Framework & Approach Forums Two forums with customer advocates engaging on services Victorian distribution networks will offer in 2026-31, and how services are charged.	Joint Victorian Networks Resilience Forum Held with councils, emergency services, social service organisations and others to help inform state-wide approaches to resilience planning.
3x Joint Victorian Networks Tariffs Forums Held to develop a Victoria-wide approach to tariffs and tariff principles. Customers, their advocates, retailers and other stakeholders with an interest in tariffs attended the forum.	3 x Joint Victorian Networks Vulnerability Forums Held with social service organisations to explore current and emerging issues facing various customers and discuss opportunities for joint network initiatives.	Customer segmentation research Analysed how customers are using electricity to improve our demand forecasts and help us plan the network and investments needed to support our customers' usage with greater accuracy.
Quantifying Customer Values research study Quantified the value customers place on a benefits that are not currently in investment evaluations. Survey of 3,527 customers, and qualitative research with 120 customers to inform the survey design.	Energy Sentiments research Tracks how customers feel about AusNet, a range of energy-related matters, appliance use and purchasing trends. Questions are high-level and designed to monitor general sentiment for changes over time and informed a range of discussions.	Customer Satisfaction (C-Sat) research Tracks customer satisfaction with planned outages, unplanned outages, new connections and complaints. It tells us where we are and are not meeting expectations and helps us prioritise improvements.
Published and engaged on a Draft Proposal More than 16,000 customer's views, 130 hours of broad engagement, plus over 230 hours of deep engagement with our Customer Panels and Coordination Group. Promotion of the draft proposal reached over one million customers. The purpose of this step was to make customers aware of the opportunity to provide feedback, and "stress test" the draft proposal with the feedback received.	And more, including but not limited to: - Engaging with our <i>business-as-usual</i> committees, including the Customer Consultative Committee, Innovation Advisory Committee, Developer Consultative Committee and Strathbogie-Benalla Community Group - Sharing insights from our day-to-day work, including meetings with large customers and community groups - Research studies on: - The distribution generator connections process - Direct costs incurred by customers during long-duration outages - Communications campaigns - Community energy, and	

Source: AusNet

2.3. Reflecting on the AER's Draft Decision

The AER did not comment on the overall quality of our engagement in its draft decision but noted that its Consumer Challenge Panel (CCP32) “observed that AusNet’s consumer engagement has met, and in many areas has exceeded the expectations we set out in our Better Resets Handbook”. Lack of engagement was cited as a reason to reject one inclusion – the Customer Service Incentive Scheme (CSIS), and the AER requested further engagement in one area – the connections tax threshold for data centres.

We appreciate the AER’s primary responsibility is to assess the prudence and efficiency of our proposal, and recognise that this focus is rightfully central to its decision-making. Nevertheless, we observed that the outcomes of our engagement program were not as prominently reflected in the AER’s draft decision and reasoning we anticipated. Stakeholders have expressed disappointment with both AusNet and the AER, highlighting a desire for more assertive advocacy of their interests and clearer technical cases from AusNet, and greater transparency and assurance from the AER regarding how customer feedback is incorporated into its decision-making and how regulatory frameworks are adapting to meet their evolving interests.

Regarding the CSIS, the AER considered that we did not engage sufficiently on the design of the Customer Service Incentive Scheme, which was cited as grounds for its rejection. However, we spent upwards of eight hours formally engaging with our panels on the design of the CSIS, which we and our stakeholders considered to be very reasonable given the value of the scheme and the quality of materials we provided to enable the discussion.

Likewise, we invested very considerably in the Quantifying Customer Values (QCV) study which involved 3,000 AusNet customers. We collaborated with independent advocates on the design, engaged a highly experienced and reputable team of researchers to deliver the research and appointed an independent auditor to review the methodology and findings. We consider the QCV study, which uses AusNet-specific data, actual usage and had a very large relative sample size, accurately represents AusNet’s customers’ views. Indeed, the AER’s 2024 VCR study yielded very similar results to our QCV study for residential customers, and logical differences for other segments. This provided us with comfort that both the QCV and the 2024 VCR study were relatively accurate. We consider this type of research to better understand customer willingness to pay specific to the customer demographics of our network should be encouraged by the AER and we were disappointed that it was not considered more fully.

2.4. Additional engagement underpinning this Revised Proposal

We have undertaken several activities to support the development of this Revised proposal, including on the one matter the AER requested we undertake further engagement on – the connections tax threshold for data centres.

We note the very short timeframe – two months from receipt of the Draft Decision – in which we could plan, deliver and document further engagement to support this Revised Proposal. This meant we needed to engage efficiently, and only on things that would make a meaningful difference to customers and our Revised Proposal.

Our Revised Proposal engagement process comprised:

- **24 September 2025 | Engagement with local government and the Victorian Department of Transport & Planning** on changes to our public lighting proposal, following feedback received via a public submission to the AER on our initial Proposal. We engaged via an online forum and survey of all local governments in our distribution area.
- **21 October 2025 | A meeting with our Coordination Group** to determine the topics and approach for the 6 November “all in” forum.
- **6 November 2025 | An “all in” forum** with members of our seven EDPR panels, outlined in Table 2-1, Customer Consultative Committee and other advocates to update them on the Draft Decision, AusNet’s proposed next steps in key areas, then engage on several areas where they could influence the Revised Proposal approach and that were meaningful for them and customers, being:

- The connections tax threshold for data centres
- Defining “large bespoke connections” in the CESS
- Reliability for worst-served customers
- Resilience
- Customer experience opex, and
- Digital customer experience capex and the Customer Service Incentive Scheme (CSIS).
- **6 November 2025 | A second meeting of our Coordination Group** to debrief on the outcomes of the “all in” forum and to provide the Coordination Group with an opportunity to discuss their independent report.

In addition we have continued to track customers' needs, expectations and priorities via our ongoing research studies – in particular via our **Energy Sentiments** and **Customer Satisfaction trackers**.

These activities are outlined in further detail below.

2.5. Public lighting engagement with local councils

The Victorian Greenhouse Alliances (VGAs), on behalf of their local council members, made a joint submission to the AER on our initial Proposal. This submission showed councils had progressed (i.e. changed) their thinking on public lighting since we engaged with them and prepared our initial Proposal.

In response, we began engaging with VGAs, councils and the Victorian Department of Transport and Planning (DTP) ahead of the AER's Draft Decision on our initial Proposal, with a view to developing a revised public lighting proposal that better met their needs.

On 24 September 2025, we hosted an online forum to discuss and seek feedback on the proposed changes to public lighting in our EDPR Revised Proposal. The forum was attended by 48 representatives from 19 councils, the VGAs, and the Department of Transport and Planning (DTP). Given the direction from councils and the VGAs was clear in the joint submission, we ran this session at the ‘Consult’ level on the IAP2 spectrum of public participation, with the purpose of validating our proposed approach and talking through some more specific implementation considerations including the costs. The forum covered:

- Accelerating the transition to efficient lighting
- Simplifying billing by applying consistent pricing across regions
- Transitioning to smart lighting for major roads, and
- Warm LED lighting for designated areas and councils.

No attendees opposed the changes we proposed, which aligned with the preferences expressed in the joint VGA submission. However, there was extensive discussion on implementation considerations and on clarifying questions.

The meeting summary is provided in Attachment A.

Following the forum, we invited each council and the DTP to complete a survey to validate the forum outcomes and gather council-specific views to help us estimate volumes and shape the Proposal. Eleven councils and DTP submitted responses, which were consistent with the positions put forward in the joint VGA submission:

- All supported our approach to replace all inefficient lighting with efficient lighting and install smart lighting in all major lights.
- 11 of 12 indicated an interest in installing warm lighting. One did not comment
- 11 of 12 supported our approach to establishing designated areas where lights are replaced with warm LED lighting. One did not comment.
- 11 of 12 supported our approach to decorative lighting, where we will move to LED-equivalent globes (i.e. corn-cob) in existing mercury vapor (MV) and compact fluorescent lights (CFL). One did not comment.
- 11 of 12 supported our approach to retain the existing MV lighting type and replacing the globes in a bulk change while reflecting the energy savings by adjusting the energy consumption data for those lights. One did not comment.

- 10 of 12 confirmed their interest in exploring smart lighting for minor lights. One indicated they were not interested and one did not manage any minor lights (so this was not applicable).

The respondent-by-respondent survey results have been provided to the AER on a confidential basis as Attachment B.

2.6. Engagement with our Co-ordination Group

Our Co-ordination Group met twice following the AER's Draft Decision.

Meeting #1 | 21 October 2025

On Tuesday 21 October the Co-ordination Group met for two hours to:

- Debrief on the Draft Decision and its implications for AusNet, and
- Discuss the focuses and format of the “all in” forum on 6 November.

A number of AER staff attended this session and answered questions from AusNet's Co-ordination Group on the AER's Draft Decision.

The Co-ordination Group put reliability, resilience, customer experience opex, CSIS and digital on the agenda given their importance to stakeholders, along with the tax threshold for data centre connections given its importance to the AER.

The Co-ordination Group discussed various formats for the “all in” forum and agreed on a table work-focussed session design.

The Co-ordination Group took its own minutes for this meeting which are provided as Attachment C.

Meeting #2 | 6 November 2025

The Co-ordination Group met for 45 minutes immediately following the 6 November forum to debrief on the day and discuss the format, timing, length and possible contents of its independent report on AusNet's Revised Proposal and the AER's Draft Decision. No formal minutes were taken at this meeting.

2.7. “All in” forum with key stakeholders

Prior to the Co-ordination Group meeting on 21 October 2025, we proactively scheduled a half-day forum on 6 November 2025 with all key EDPR stakeholders. We also extended the invitation to members of AusNet's Customer Consultative Committee (CCC – our business-as-usual customer forum), other advocates and the Victorian Government to enable a diverse and representative group to participate. Although the forum topics had not yet been confirmed at the time of scheduling, securing the date early helped maximise availability and attendance.

Once the Co-ordination Group finalised the topics and format of the forum, we quickly confirmed with attendees and distributed pre-reading materials five days ahead of the session, giving them time to prepare. Some information continued to evolve between the distribution of materials and the forum itself and these updates were acknowledged during the session.

While attendance was optional, we had 22 external stakeholders attend – a high turnout that reflects their strong interest and commitment to the EDPR process.

AusNet provided an overview of the Draft Decision and the approach to be taken in the Revised Proposal for the aspects of the proposal of interest to stakeholders not being covered in more detail today.

The group then engaged on six topics they could meaningfully influence AusNet's approach to the Revised Proposal.

Two topics (the connections tax threshold for data centres and changed to the Capital Efficiency Sharing Scheme (CESS)) were covered briefly as a group, then the remaining four larger topics (reliability for worst-served customers,

resilience, customer experience opex and digital expenditure and the Customer Service Incentive Scheme [CSIS]) were engaged on in detail.

Each topic was introduced by an AusNet expert, followed by 20 minutes of discussion. After each round, the Independent Chair, Peter Eben, facilitated a summarisation session where each table shared their discussion and decisions. Participants worked in table groups of approximately three EDPR panel members, a couple of CCC members, observers from the AER and its Consumer Challenge Panel, and AusNet staff who provided clarification when needed.

Key outcomes included:

- **Connections tax threshold for data centres:** Strong support for large connections to the sub-transmission network (incl. data centres) funding their own tax and opex, avoiding cross-subsidisation across the broader customer base. This extended to support for all commercial customers to fund their own tax and opex associated with their connections.
- **Capital Efficiency Sharing Scheme:** Attendees confirmed that AusNet still has a commercial incentive to deliver connections efficiently, even if they are not included in the CESS, as they are largely subject to commercial negotiation. They noted it is important that the broader customer base does not bear the associated risk and suggested adding electric transport connections (e.g., large-scale electric vehicle charges)
- **Reliability for worst-served customers:** The mood of the group was summarised on the day as “AusNet should repropose the 10WSF program but do more to improve regional reliability – don’t just let it slide. AusNet is better placed to plan value-for-money reliability improvements than the government – needs to keep advocating.”. Broad support for reproposing the 10 Worst-Served Feeders (10WSF) and Euroa–Benalla upgrades, even if they do not meet strict economic efficiency criteria. Participants preferred AusNet’s definition of worst-served feeders, which excludes major event days to avoid overlap with resilience initiatives. Attendees also stressed the reputational risks of unmet community expectations and encouraged advocacy in communications with the AER and government on behalf of the community.
- **Resilience (community hubs):** The mood of the group was summarised on the day as “Drop community hubs for the Revised Proposal but don’t give up longer-term and keep the conversations going with others involved in supporting community resilience”. There was consensus to remove community hubs from the Revised Proposal due to low likelihood of regulatory approval, while continuing to explore longer-term options. Participants strongly supported AusNet playing an active role in ongoing resilience planning in collaboration with local governments and community groups.
- **Customer experience opex (communications and relationship managers):** The mood of the group was summarised on the day as “There’s support for proposing the customer experience opex step change (communications & relationship managers) with a narrower scope but with an expectation that AusNet provides more detailed supporting information to the AER than was provided in the session, beefing up and selling the benefits to customers better”. There was unanimous support for narrowing the scope of the proposed step change, focusing on tariff communications. The vast majority of the group continued to see value in relationship manager roles but a small number thought AusNet should accept the AER’s decision to reject it. Participants agreed clearer justification and evidence of customer benefits is needed in the Revised Proposal.
- **Digital expenditure and CSIS:** The mood of the group was summarised on the day as “Quantify the benefits of your digital programs. Repropose the CSIS and note the AER hasn’t provided any evidence that their alternative STPIS-based program is better-aligned with customers’ interests”. The group strongly endorsed AusNet’s approach to quantifying more digital customer experience benefits. The group also supported AusNet re-proposing the original CSIS proposal using baseline data, acknowledging AusNet cannot address all of the AER’s concerns. The group did not feel the AER’s STPIS-based alternative to the CSIS was better-aligned with customers’ interests and felt very strongly about AusNet re-proposing the original co-designed scheme. It was suggested that AusNet propose delaying the start of the CSIS scheme to address the AER’s desire for more baseline data before it commences.

The session concluded with the Co-ordination Group convening to debrief and discuss their independent report to the AER.

A meeting summary (Attachment D) finalised by our independent facilitator provides more information on the deliberations of the workshop.

2.8. Attachments

A. ASD - Public Lighting Forum Meeting Minutes - 24 Sept 2025 - PUBLIC

- B. ASD - Public Lighting Survey Responses - Oct 2025 - CONFIDENTIAL
- C. ASD - Coordination Group Minutes - 21 October 2025 - PUBLIC
- D. ASD - All-In Workshop 06 Nov 2025 - PUBLIC

3. Demand forecast

3.1. Key points

Forecasts of future customer growth and demand on the network are a crucial input to AusNet's expenditure proposals over the forthcoming regulatory period. AusNet is one of very few distributors with an in-house demand forecasting team, who produces annual demand forecasts for the purposes of network planning. Our forecasting methodology is transparent, sophisticated and explainable and is based on telemetry, smart meter data and independent forecasts. We continuously improve our forecasts over time to improve accuracy. This is particularly important during the energy transition, to make sure we are aware of localised demand growth which will be a result of electrification in addition to customer growth.

AusNet is pleased that the AER's consultant Baringa recognised AusNet's transparency regarding our demand forecast inputs, assumptions and methodology.⁶ However, we also note the areas of concern that both Baringa made in its report and the AER included in the Draft Decision.

AusNet has addressed all of the feedback noted in the Draft Decision. We have:

- updated the demand forecast inputs to reflect AEMO's 2025 *Inputs Assumptions and Scenarios Report (IASR)*
- updated the demand forecasts to reflect historical network data up to 31 March 2025, which have led to increases in the forecasts due to the record summer and winter demands seen in the last 12 months
- clarified the treatment of block loads and other post-modelling adjustments in our forecasting process, including a confirmation that post-modelling adjustments were not made to customer numbers
- incorporated a downwards adjustment to future demand to take account of future energy efficiency, despite evidence from our network that demand per customer is increasing
- clarified our forecasting process for CER (PV and EV), demonstrating that relevant spatial factors are being taken into account when forecasting the impact of CER on our assets
- incorporated the impact of behind-the-meter battery storage, taken from an independent forecast provided by consultants Energeia
- provided a comparison/reconciliation of system to spatial demand, demonstrating that both levels of forecasts are reasonable assessments of future demand.

In addition, AusNet has included the impact of the electrification of the commercial and industrial sector, a key driver of future demand, which AusNet had intentionally omitted from the Initial Proposal forecasts to ensure that demand growth was conservative. The continued exclusion of the electrification of this sector, especially when AEMO is forecasting it to become more prominent, would not result in a forecast that is a reasonable estimate of future demand.

After incorporating the above changes, the revised demand forecasts are higher than the Initial Proposal. Table 3-1 provides an overview of the key forecasts presented in this chapter.

Table 3-1: Demand, energy and customer number forecasts

Customer type	2026-27	2027-28	2028-29	2029-30	2030-31
Customer numbers	860,058	877,208	894,287	911,384	928,464
Energy consumption (GWh)	8,420	8,815	9,228	9,642	10,165
Maximum demand (MW)	2,389	2,425	2,485	2,532	2,615
Minimum demand (MW)	-434	-482	-501	-536	-557

Source: AusNet

⁶ Baringa, *Distribution demand forecast assessment: Review of AusNet Services' 2026-31 regulatory proposal*, p.17.

3.2. Chapter structure

This chapter sets out our response to the AER's Draft Decision on customer numbers, energy consumption and maximum demand forecasts. The chapter is structured as follows:

- Section 3.3 outlines our updated customer number forecasts;
- Section 3.4 outlines our updated energy consumption forecasts;
- Section 3.5 outlines our updated spatial demand forecasts.

3.3. Customer number forecasts

3.3.1. Our Initial Proposal

In our Initial Proposal, we forecast a steady customer growth of approximately 1.8% per annum over the 2027-31 regulatory period. The forecast in our Initial Proposal is reproduced below.

Table 3-2: Forecast customer numbers – Initial Proposal

Customer type	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	Growth rate per annum
Residential	765,418	779,000	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

We explained that our forecast growth in customer numbers is driven by the significant population and development projections in various growth corridors, including:

- 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; and
- within our rural regions, the Shire of Baw Baw.

3.3.2. Draft Decision

The AER did not approve our customer number forecasts, noting that whilst its consultants Baringa considered our approach of using government forecasts for dwelling growth was reasonable, it was concerned with perceived post-modelling adjustments made to the forecasts. Whilst the draft decision did not specify the AER's alternative forecast, it reduced AusNet's connections capital expenditure by 10%.

3.3.3. Revised Proposal

AusNet contends that Baringa's concerns about post-modelling adjustments were based on a misunderstanding of AusNet's forecasts. Whilst AusNet's demand forecasting methodology raises the possibility of applying adjustments where the government's forecasts are not reflecting accurate growth,⁷ AusNet confirmed in responses to two

⁷ AusNet, *Demand Forecasting Methodology*, p.8.

information requests that its Initial Proposal customer forecasts contained no such post-model adjustments to customer numbers.⁸ That is, our forecast customer numbers reflect government forecasts.

Baringa's report highlighted some examples where it could not reconcile AusNet's feeder level forecasts with the SA2-level forecasts reported in *Victoria in Future* (ViF), which AusNet uses as the basis for its forecasts. It is possible that this was the source of Baringa's concern that AusNet was adjusting the forecasts. Rather, these discrepancies have arisen due to changes in SA2 boundaries that occurred between the 2021 and 2023 editions of ViF, usually due to one SA2 region being split into multiple regions. Whilst these changes in boundaries may have made AusNet's forecasts difficult to reconcile to the ViF forecasts, they are not associated with any post-model adjustments.

AusNet has refreshed its customer number forecasts, taking into account the actual growth recorded across AusNet's zone substations and feeders in the last twelve months. Actual growth has been slightly higher than forecast, which has flowed into AusNet's forecasts, resulting in a customer base which is ~1% higher than the Initial Proposal forecasts by the end of the regulatory period. AusNet's revised customer forecasts are set out in Table 3-3.

Our customer number forecast should be accepted in full as they reflect a reasonable estimate for the regulatory period supported by a soundly-based modelling approach. If these forecasts are not accepted, we will not be funded to serve the population growth that Government is expecting and planning for in our distribution area. Such an outcome would be contrary to the NER and NEL requirements which recognise that we should be afforded a reasonable opportunity to recover our efficient costs of providing distribution services.

Table 3-3: Forecast customer numbers – Revised Proposal

Customer type	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	Growth rate per annum
Residential	766,317	782,171	798,040	813,889	829,749	845,614	2.0%
Small business	62,842	63,916	65,008	66,084	67,171	68,243	1.7%
Medium business	9,906	9,985	10,073	10,150	10,234	10,306	0.8%
Large business	3,906	3,986	4,087	4,164	4,230	4,301	1.9%
Total	842,971	860,058	877,208	894,287	911,384	928,464	2.0%

Source: AusNet

3.4. Energy consumption forecasts

3.4.1. Our Initial Proposal

In our Initial Proposal, we forecast increased energy consumption in the 2026-31 period driven principally by:

- Strong customer growth
- Electric vehicle uptake, which is expected to accelerate significantly in the 2026-31 period, and
- The expected increase in residential customers switching from gas to electricity in the 2026-31 period.

3.4.2. Draft Decision

The AER did not comment on AusNet's energy consumption forecasts, other than highlighting stakeholders' concerns that if actual consumption turned out to be lower than forecast, then all other things being equal, the forecast changes in network prices and customer bills would be understated. In acknowledging these concerns, the AER provided a sensitivity analysis of residential and small business bills under a range of energy consumption scenarios.⁹

The AER's analysis suggested that residential bills could be 4.7% higher than AusNet proposed, if future consumption was to grow at just 20% of the growth rate proposed by AusNet. The corresponding small business increase was 6.1%.

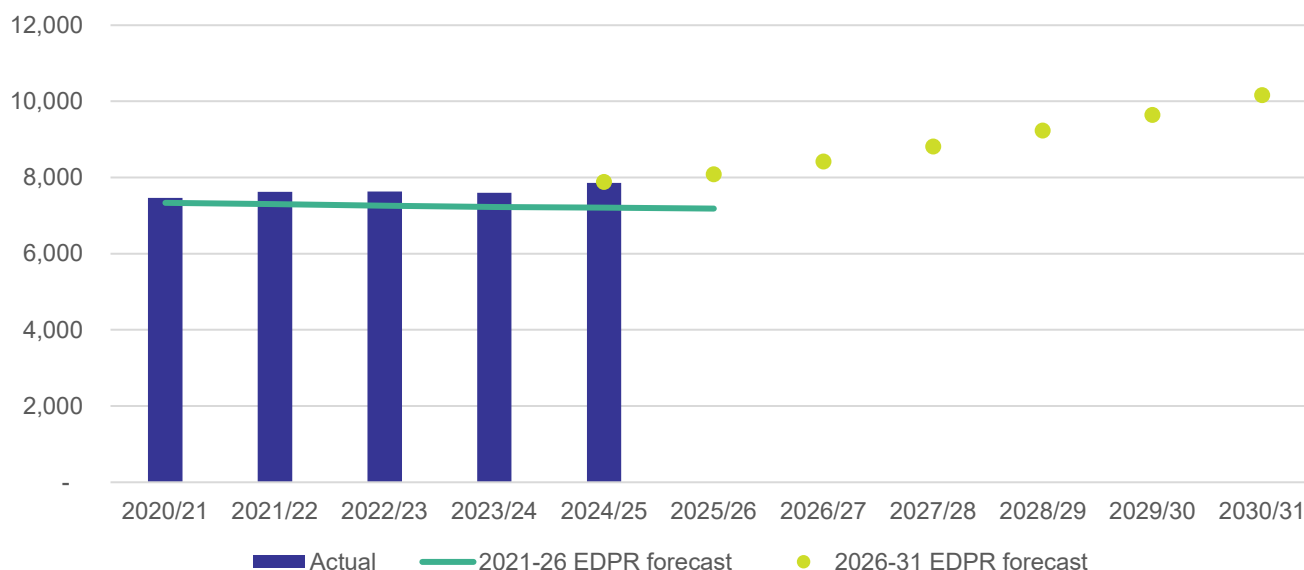
⁸ AusNet, IR#017 – Demand Forecast Response – 20250415 – PUBLIC, question 7 and IR#022 – Demand forecasting – follow up questions response – 20250505 – PUBLIC, question 9.

⁹ AER, Draft Decision – AusNet Services distribution determination 2026-31, Attachment 1 – Building block approach: Annual revenue requirement, Regulatory asset base, Regulatory depreciation and Corporate income tax, pp.12-14.

3.4.3. Revised Proposal

AusNet also acknowledges the views expressed by stakeholders regarding the link between forecast customer bills and forecast energy consumption. AusNet does not have a history of over-forecasting energy consumption, as evidenced by Figure 3-1. Actual consumption over the last five years has exceeded AusNet's approved forecast for the 2021-26 regulatory period. The most recent year (2024/25) was also in line with the energy forecast prepared for that year in the 2026-31 EDPR forecast.

Figure 3-1: Actual v. forecast energy consumption



Source: AusNet

AusNet's strong track record in not over-estimating future energy consumption should provide the AER and stakeholders with confidence regarding its forecast energy consumption.

For the 2026-31 period, AusNet is forecasting strong growth in energy consumption which is driven by emerging drivers of demand such as the electrification of gas and transport, and reflecting the expected growth in AusNet's customer base. As Figure 3-1 above demonstrates, the first year (2024/25) of the 2026-31 energy forecast turned out to be extremely accurate.

Our energy consumption forecasts have been updated to:

- align with the revised proposal customer numbers and
- incorporate the impact of the electrification of the commercial and industrial sectors (see section 3.5.3.3).

AusNet's revised energy consumption forecasts are presented in Table 3-4.

Table 3-4: Forecast energy consumption (GWh)

Customer type	2026-27	2027-28	2028-29	2029-30	2030-31
Residential	3,837	4,008	4,192	4,363	4,545
Small business	709	742	772	810	878
Medium business	667	682	696	715	758
Large business	3,207	3,383	3,568	3,754	3,985
Total	8,420	8,815	9,228	9,642	10,165

Source: AusNet

3.5. Spatial demand forecasts

3.5.1. Our Initial Proposal

AusNet's Initial Proposal forecast growth in maximum demand, driven by strong dwelling growth projections from the Victorian government and the electrification of gas and transport. Table 3-5 sets out maximum demand forecasts included in the Initial Proposal.

Table 3-5: Maximum demand: current and forecast regulatory period (non-coincident, MW, at zone substation level, POE50)

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

Source: AusNet

3.5.1.1. Minimum demand forecasts

As already explained, minimum demand on our network has continued to fall over the last decade and is now routinely negative, driven by higher uptake of rooftop solar. We expect minimum demand to continue to fall sharply across the 2026-31 regulatory period, as shown in Table 3-6 below.

Table 3-6: Minimum demand: current and forecast regulatory period (non-coincident, MW, at zone substation level, POE50)

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

Source: AusNet

3.5.2. Draft Decision

The AER draft decision was to not approve AusNet's demand forecasts. Whilst Baringa noted that our forecasting methodology was reasonable and transparent, it highlighted several areas where the methodology or inputs could be strengthened. Based on Baringa's feedback, the AER required AusNet to incorporate the following changes in its revised demand forecasts:

- update the demand forecast using the latest available data from AEMO's final 2025 IASR, released on 31 July 2025
- update the historical network data up to March 31, 2025
- provide greater transparency and justification for any departures from input data and modelled forecasts – all adjustments need to be independently verifiable.
- incorporate the impact of energy efficiency over time in the demand forecast and if this is not included, AusNet must clearly explain the rationale for its exclusion
- revise the approach for spatially disaggregating EV and PV growth accounting for technological limitations at each zone substation or incorporate relevant demographic data
- include behind the meter battery energy storage systems in the demand forecast and if these are excluded, AusNet must provide a clear justification
- perform a reconciliation between system-level and spatial-level forecasts to demonstrate consistency, rigour and validity of both forecasts.

AusNet has accepted the majority of the AER's feedback and has incorporated several changes to its revised demand forecasts to reflect the AER's expectations. In some instances, the AER's concerns seem to be founded on a

miscommunication or misunderstanding of our approach, rather than due to a shortcoming in our methodology. AusNet's response to the above concerns raised by the AER is outlined in the next section.

3.5.3. Revised Proposal

After incorporating the AER's feedback on the demand forecasts in the Initial Proposal, AusNet's revised demand forecasts are set out in Tables 3-7 and 3-8.

Table 3-7: Maximum demand: current and forecast regulatory period (non-coincident, MW, at zone substation level, POE50)

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
Demand	2,214*	2,324	2,389	2,425	2,485	2,532	2,615
Growth rate		5.0%	2.8%	1.5%	2.5%	1.9%	3.3%

Source: AusNet. 2024/25 value is the raw actual value.

Table 3-8: Minimum demand: current and forecast regulatory period (non-coincident, MW, at zone substation level, POE50)

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
Demand	-377*	-384	-434	-482	-501	-536	-557
Growth rate		1.9%	13.0%	11.0%	3.8%	7.0%	4.0%

Source: AusNet. 2024/25 value is the raw actual value.

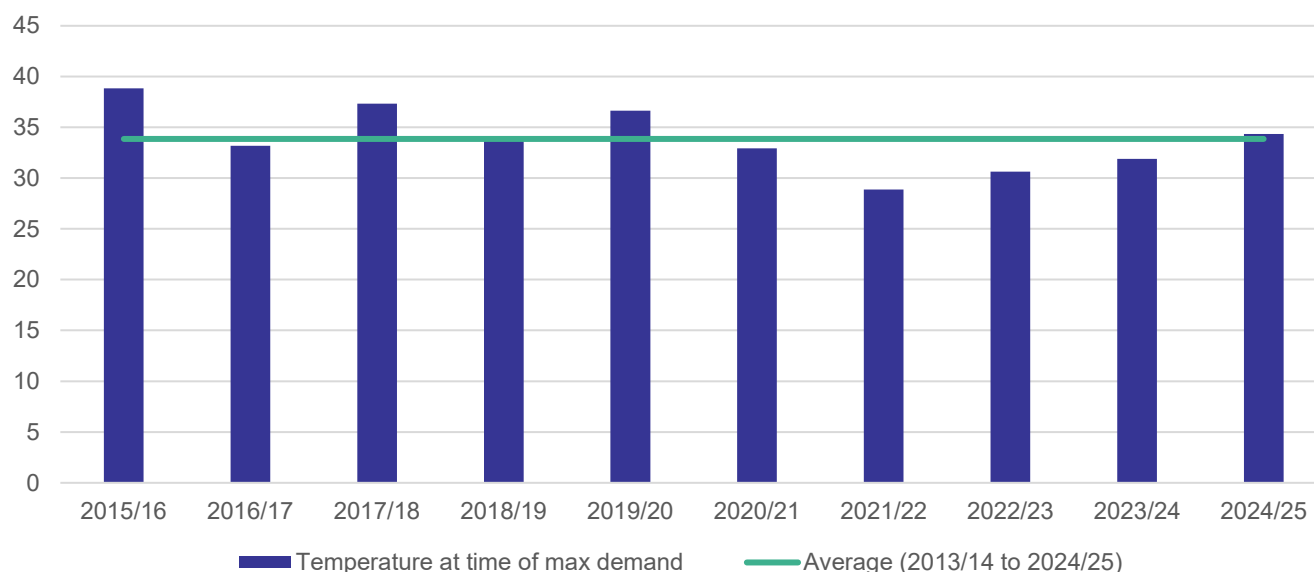
The above forecasts have directly incorporated the impacts of AEMO's 2025 IASR and the actual network data up to the end of March 2025. Regarding maximum demand, whilst the updated IASR has had a minor impact on demand growth, the inclusion of the most recent 12 months of historical network data – all else being equal – has resulted in an increase to the forecasts. This outcome was expected by Baringa¹⁰ and reflects the fact that:

- Summer 2024/25 set a new record for AusNet's coincident peak system demand (1,946MW)
- Non-coincident demand at the zone substation level in 2024/25 was the highest on record (2,214MW) and the second highest on record at the terminal station level (slightly below non-coincident demand recorded in 2020 which was driven by extreme temperatures in summer and COVID impacts in winter).
- AusNet experienced record winter demand in 2024. And although winter 2025 has not been included in the forecasts, it was again a record year for winter demand (exceeding 2024 by 5%).

Whilst the 2024/25 summer broke records for maximum demand, it was not an extremely hot year. Maximum daily temperatures were around the average of the last decade, whether that is measured by the maximum temperature recorded in the summer, or the temperature recorded at the time of maximum demand. Figure 3-2 presents the latter – which shows that the temperature at the time of maximum demand in the most recent summer was in line with the 10 year average.

¹⁰ Baringa, *Distribution demand forecast assessment: Review of AusNet Services' 2026-31 regulatory proposal*, p.47.

Figure 3-2: Average temperature (°C) across AusNet's network at the time of maximum demand



Source: AusNet

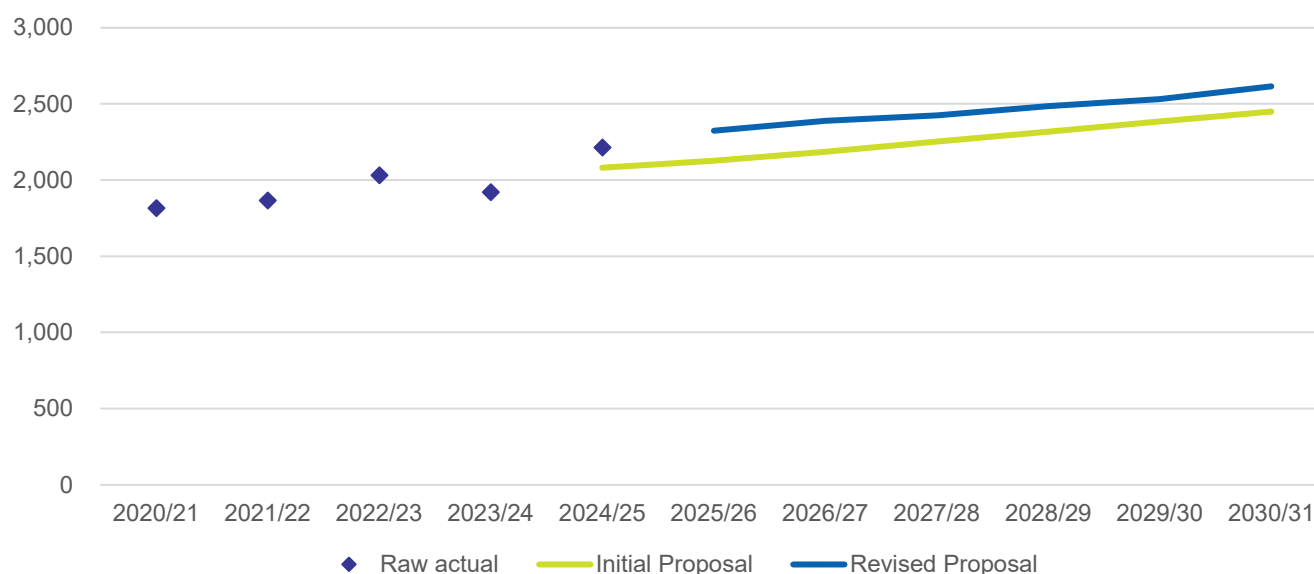
Although temperatures were more or less average last summer, there were a number of hot, but cloudy days. The reduced solar PV output on these days increased demand from the grid – in effect, revealing underlying demand that in previous years was met by customers' solar panels. Solar output is estimated using irradiance data, which suggests 2024/25 was the second lowest solar output in the last 10 years, with the lowest recorded in 2019/20. The combination temperature and solar factors therefore indicates that it was not weather alone which was the cause of the record demand on our network. Instead, our customers' demand is increasing due appliance usage within the home, increased sensitivity to weather, decreased price response, or other factors.

Maximum demand forecasts have also been revised to reflect the latest information on block loads connecting to the network, which have led to increases in the first year of the forecast for both maximum and minimum demand.¹¹ AusNet provides further clarity on the treatment of block loads in section 3.5.3.4.

Our revised maximum demand forecasts, which are driving much of our augmentation capital expenditure, are higher than the Initial Proposal. Figure 3-3 below provides a comparison of the two forecasts and how they compare to the last five years of actual demand. As depicted, actual non-coincident demand in 2024/25 was ~130MW higher than the POE50 forecast in the Initial Proposal and as previously explained, was the highest on record.

¹¹ The first year of the forecast being 2025/26, which is the final year of the current regulatory period.

Figure 3-3: Actual and forecast (POE50) maximum demand (non-coincident, MW, at the zone substation level)



Source: Actuals: Economic benchmarking RINs (DOPSD0107), Forecast: AusNet

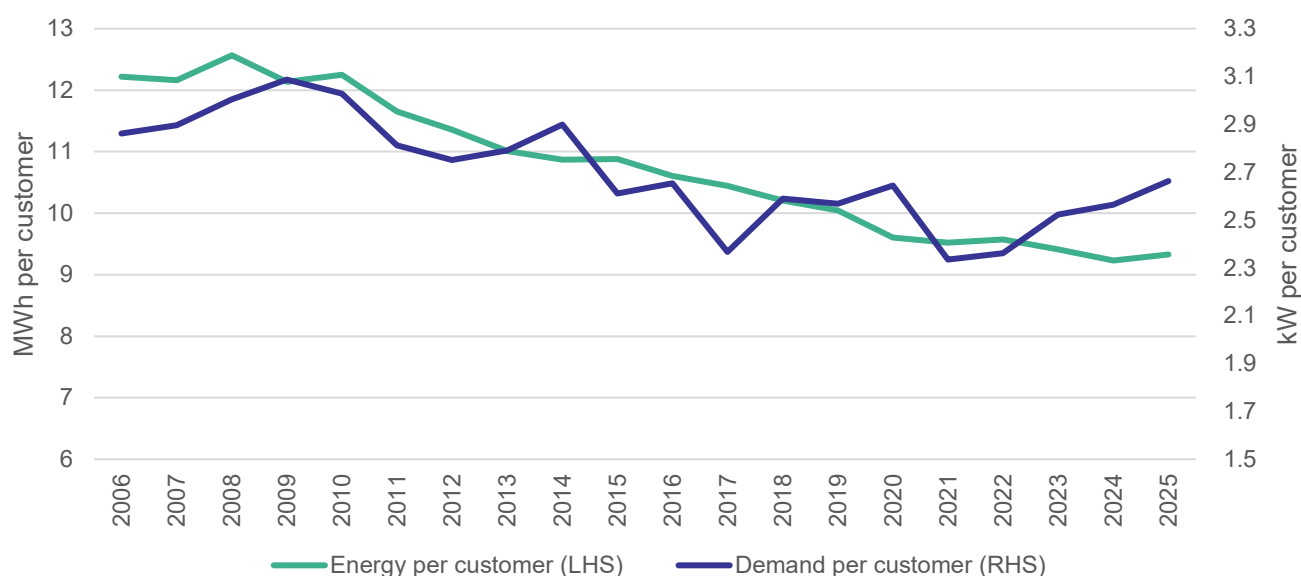
The sections below explain how AusNet has responded to the remainder of the AER's feedback when developing the revised forecasts.

3.5.3.1. Energy efficiency

As explained in AusNet's demand forecasting methodology, AusNet had not explicitly considered the impact of additional energy efficiency (relative to today) in its forecasts, rather, existing levels of energy efficiency were assumed to apply going forward. Whilst we acknowledge the AER's view that this could lead to the forecasts being overstated, other drivers that would be expected to lead to increases in demand, such as the electrification of gas in the commercial and industrial sector, were also not included in our forecasts.

Regarding energy efficiency it is also important to note that data published in AusNet's economic benchmarking RIN shows that demand per customer has increased every year since 2021, at the same time that energy per customer is continuing to fall. These trends are depicted in Figure 3-4 below.

Figure 3-4: Energy density and demand density



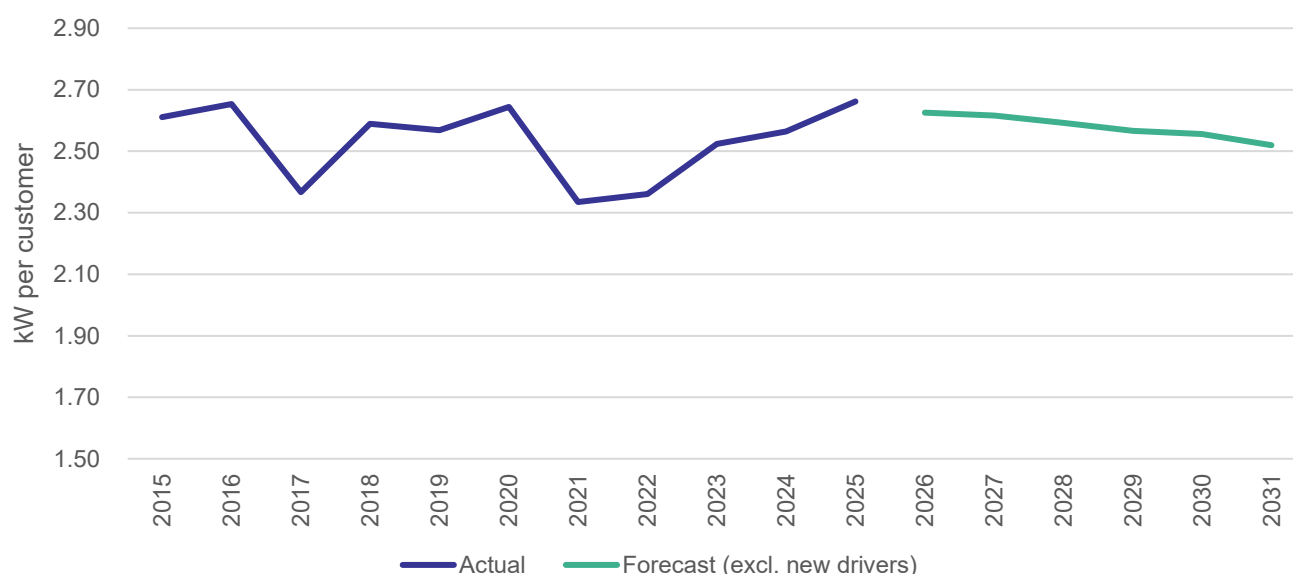
Source: Economic benchmarking RINs (DOEF0102 and DOEF0103)

It should be noted that demand/energy density is not the same thing as energy/demand efficiency. For instance, energy consumption is falling in part, due to the adoption of rooftop solar. There are likely myriad other forces

influencing the above trends, but the key point is that aside from EVs and the electrification of residential gas, AusNet had not included any factors within its forecasts that would continue this trend of increasing demand per customer. And whilst those two forces will have an upward impact on demand, they are unlikely to have played much, if any, role in the above *historical* trend, given the early stages of electrification and – more importantly – the fact that the maximum demand depicted above is mostly summer-driven, negating the current impact we are seeing on our network from electrification of gas in winter.¹² In summary, even though there is evidence of increases in demand per customer not associated with electrification of transport and gas, AusNet did not build in an expectation of this trend increasing in the future.

Despite the evidence of demand per customer increasing on our network, we have accepted the AER's draft decision and applied an explicit assumption about the impact of energy efficiency on maximum demand. To calculate a forecast for the impact of energy efficiency on demand, we have had reference to AEMO's forecasts in the 2025 *Electricity Statement of Opportunities* (ESOO). Specifically, our forecasts have had reference to AEMO's maximum demand per customer in Victoria, which is showing a declining trend over the forecast period, driven to some degree by energy efficiency.¹³ Applying this methodology has reduced our maximum demand by the end of the period by ~85MW and – excluding the impact of new drivers of demand – has reversed the above trend in demand per customer to as depicted below in Figure 3-5.

Figure 3-5: Demand density 2015 - 2031



Source: Actual: Economic benchmarking RINs (DOEF0103), Forecast: AusNet

We consider this energy efficiency adjustment which reverses the recent trend in demand density results in a conservative demand forecast which supports AusNet's position that its demand forecasts should be accepted by the AER without any adjustments.

3.5.3.2. Behind the meter battery storage

To forecast the impact of batteries on our network, AusNet engaged consultants Energeia to prepare battery installation and capacity forecasts for each of our zone substations, as well as the corresponding 30 minute battery load profiles out to 2040. Energeia's report is included as Appendix 3A.¹⁴

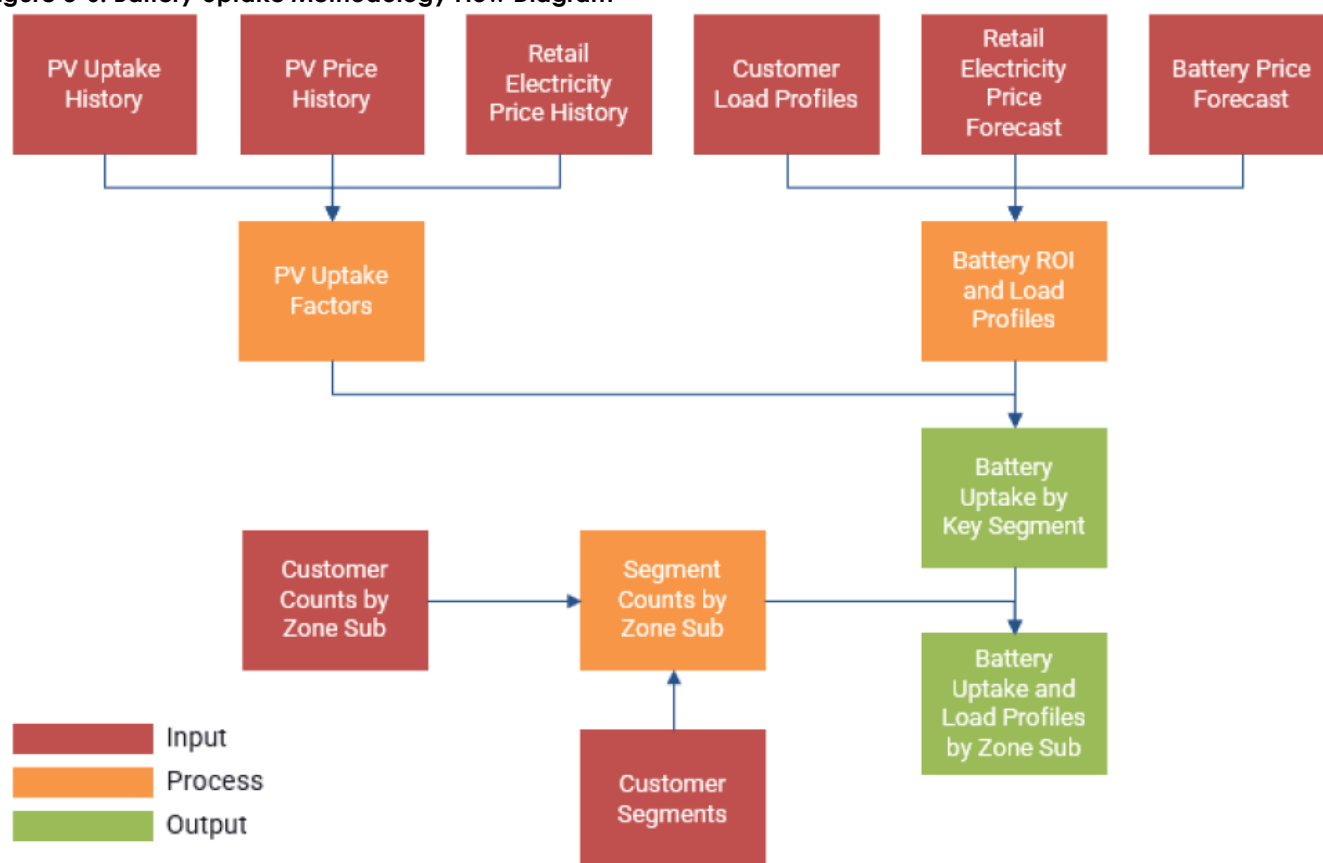
Energeia produced two forecasts – one more aligned with AEMO's *Step Change* ISP forecast (which is the central forecast that AusNet relies on for its forecast) and one more aligned with AEMO's *Progressive Change* forecast, which is more of a downside forecast. Figures 3-6 and 3-7 provide an overview of Energeia's modelling approach and the source of the various drivers used within the model.

¹² This will change in the future as our network increasingly becomes winter peaking, but over the course of the time series in Figure 3-5, AusNet's network was majority summer peaking.

¹³ It is not possible to isolate the impact of energy efficiency on AEMO's overall decline in demand per customer, although it is reasonable to suggest that energy efficiency is a major driver.

¹⁴ ASD – Energeia – Appendix 3A - AusNet Battery Uptake and Impact Forecasting Report

Figure 3-6: Battery Uptake Methodology Flow Diagram



Source: Energeia

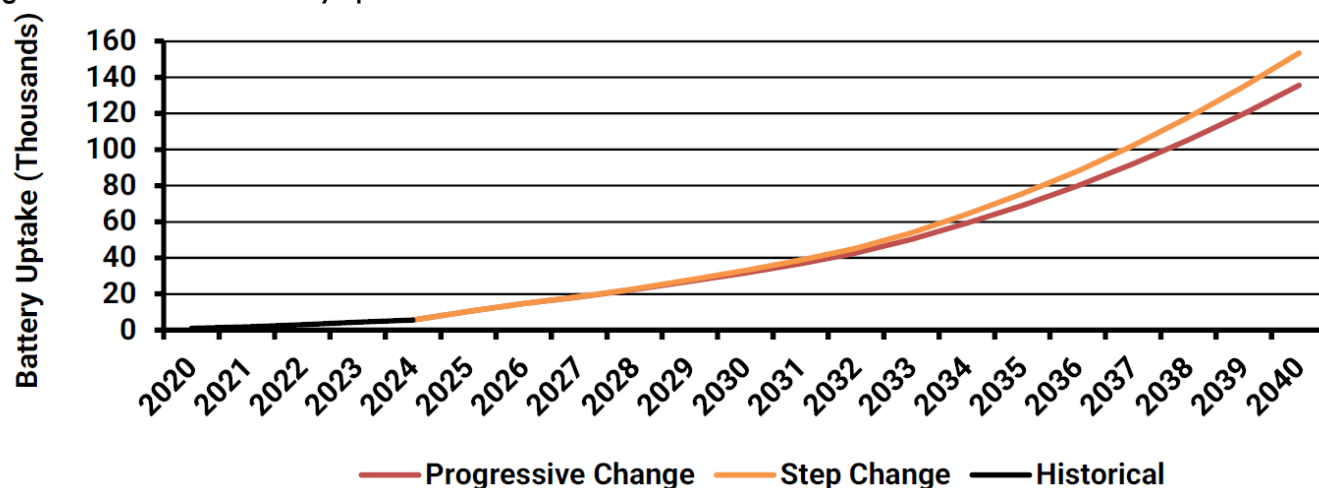
Figure 3-7: Scenario and driver summary

Energeia Model Driver Mapping		Scenarios	
		Progressive Change	Step Change
Demand Drivers	Market Growth	Per Customer Counts	
		Per Customer Counts	
Cost Drivers	Technology Costs	AEMO Progressive Change	AEMO Step Change
	National Electricity Market (NEM) Prices	Energeia	
	Network Revenues	Electricity Distribution Price Review (EDPR)	
	Rebates and Incentives	Cheaper Home Batteries, Solar-battery Loans (Vic)	
Device Drivers	Solar PV Adoption	AEMO Progressive Change	AEMO Step Change
	EV Adoption	AEMO Progressive Change	AEMO Step Change
	Vehicle to Everything (V2x) Adoption	AEMO Progressive Change	AEMO Step Change
Tariff Drivers	Tariff Re-assignment	Energeia	
	Default Tariffs	Using AusNet Provided Tariffs	
	Amber / Wholesale Adoption	Energeia	
VPPs	VPP Participation	AEMO Progressive Change	AEMO Step Change

Source: Energeia

Energeia forecast that AusNet would install approximately 40,000 batteries by the end of the 2026-31 regulatory period in both scenarios, as shown in Figure 3-8.

Figure 3-8: Cumulative Battery Uptake



Source: Energeia

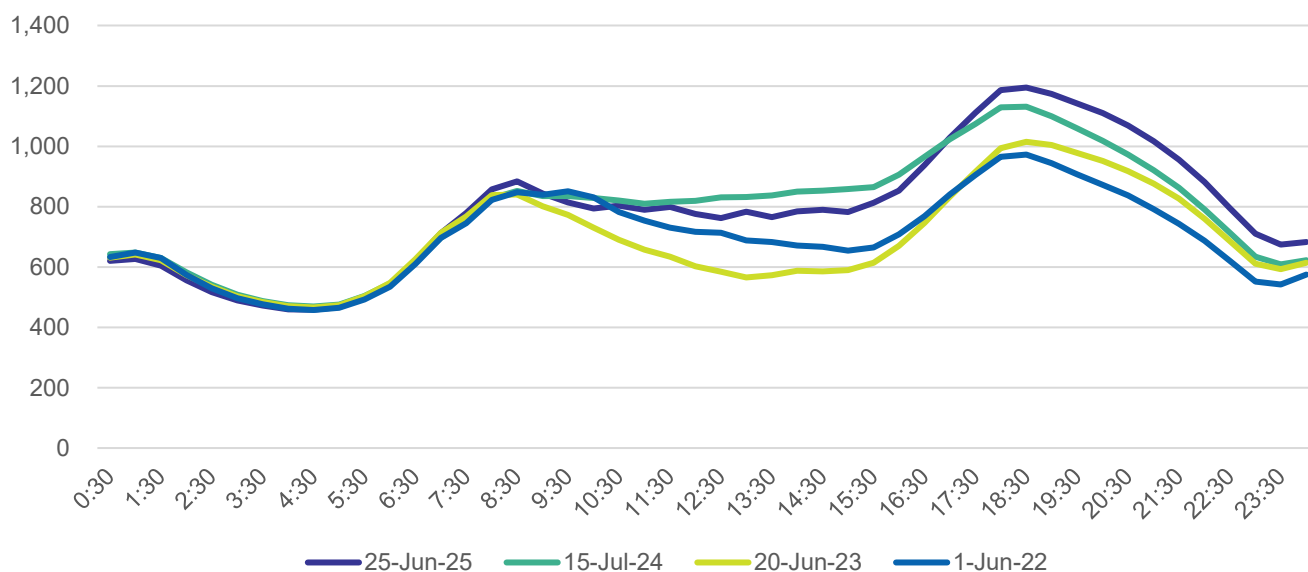
AusNet applied the battery charge/discharge profiles generated by Energeia to the forecast maximum and minimum demands produced by its forecasting model to estimate the decrease (or increase) to demand as a result of customers operating their batteries. This impact differed depending on the date and time of the forecasting simulations that corresponded to the POE10/50 forecasts in a given year for a given asset.

3.5.3.3. Electrification

Recent evidence from AusNet's network and smart meter data highlight the pace of electrification may be accelerating far faster than either our forecasts or AEMO's had predicted. AusNet's network experienced a record winter peak demand in 2025, reaching 1,823MW which exceeded the Initial Proposal's POE10 winter forecast of 1,784MW. Smart meter data supports our hypothesis that electrification is driving large increases in customer demand. Figure 3-9 presents the demand recorded by smart meters on each of AusNet's last four winter peak days. The demand recorded in the most recent winter¹⁵ is 23% higher than the 2022 winter peak, which cannot be explained by customer growth or weather differences between the days.

¹⁵ The difference between the ~1,200 MW peak recorded by smart meters in 2025 as shown in the chart and AusNet's 1,823 MW system load is explained by distribution losses, Type 1-4 meters (i.e. large customers) and non-AusNet distribution loads supplied by AusNet zone substations (e.g. load supplied to Jemena's distribution network by AusNet's Kalkallo zone substation).

Figure 3-9: Smart meter load on AusNet's winter peak days (MW)

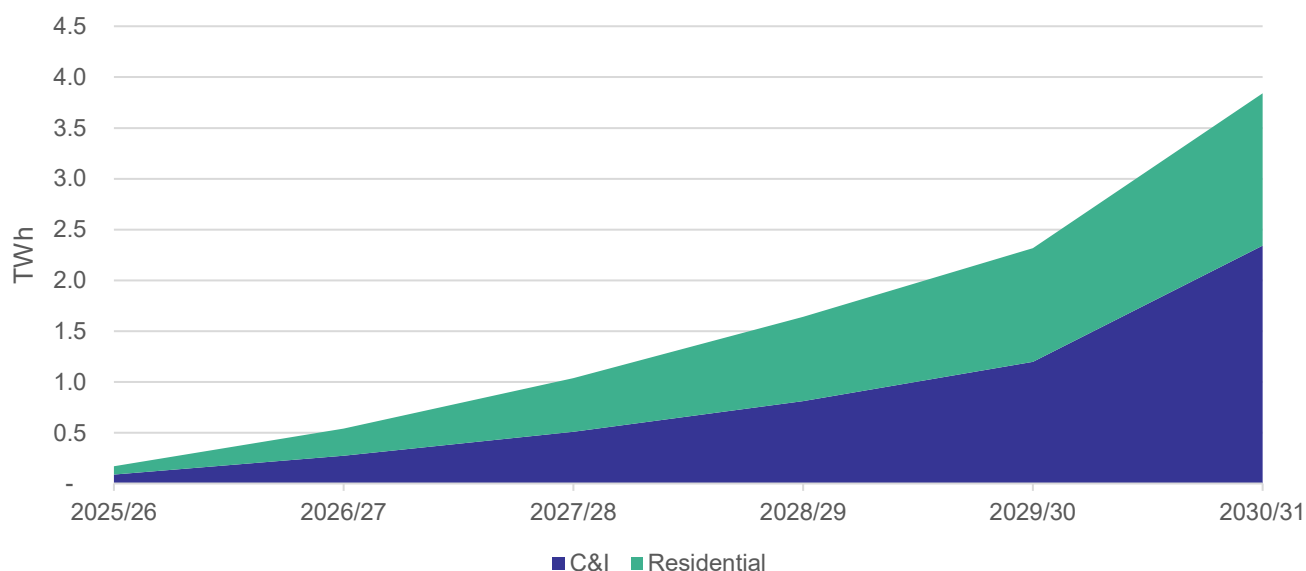


Source: AusNet

However, as noted in the first paragraph of section 3.5.3.1, AusNet had not included the impact of the electrification of the commercial and industrial (C&I) sectors in its demand forecasts in the Initial Proposal. Rather, the electrification component of AusNet's forecasts was based solely on the impacts of switching from gas to electricity at the residential level.

As noted in the Initial Proposal, our electrification assumptions were one of a number of inputs that we considered would be on the lower side of our expectations, resulting in conservative demand forecasts.¹⁶ However, as forecast by AEMO in its 2025 ESOO, by 2030/31, C&I electrification is predicted to account for approximately 60% of load being electrified.

Figure 3-10: AEMO electrification forecast for Victoria (2025 ESOO)



Source: AEMO electricity forecasting data portal

AusNet no longer considers it reasonable to exclude electrification of the C&I sectors from its forecast. Adjusting AusNet's Initial Proposal forecasts to introduce drivers that will reduce demand such as energy efficiency and

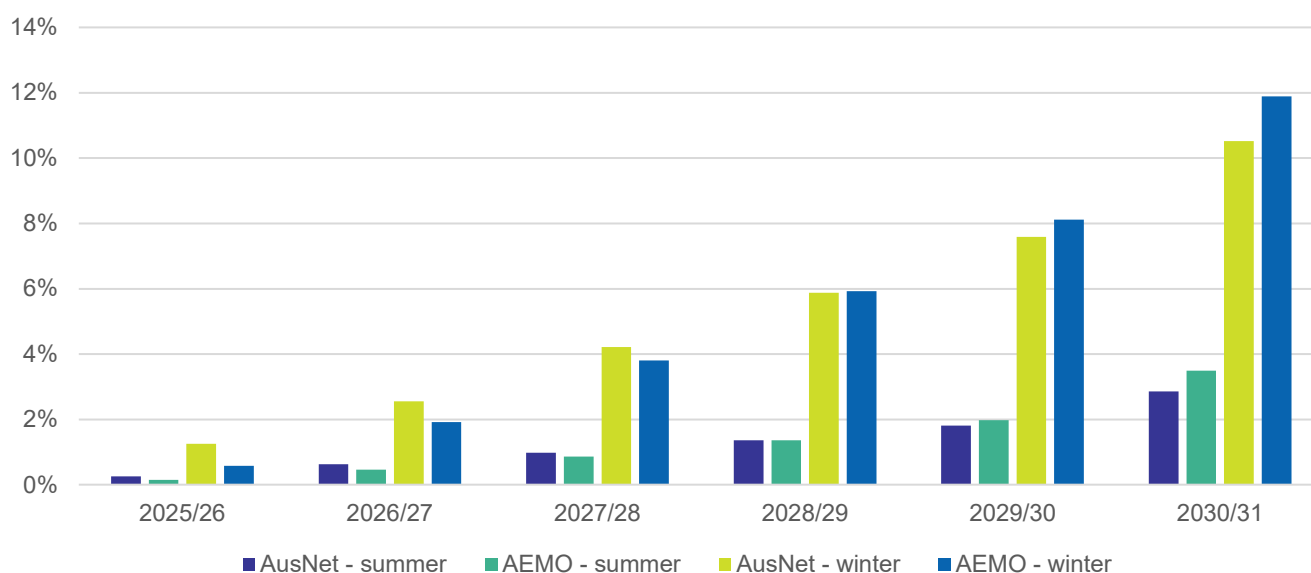
¹⁶ AusNet, *Electricity Distribution Price Review 2026-31 Regulatory Proposal*, p.101.

batteries, whilst ignoring drivers that will increase demand such as C&I electrification, would result in biased forecasts that understates future demand.

Similar to the approach taken to forecasting energy efficiency, AusNet has based its C&I electrification forecasts on AEMO's 2025 ESOO forecasts. Whilst AEMO reports the split between residential and C&I electrification for its consumption forecasts, it only reports the impact of total electrification on its demand forecasts. To estimate the impact of C&I electrification on AusNet's demand forecasts, we have apportioned AEMO's C&I electrification consumption forecast to AusNet's network using AusNet's proportion of Victorian non-residential load (taken from RINs) and then applied AEMO's ratio of electrification demand impact (in MW) to electrification consumption impact (in TWh).

Adding C&I electrification load to our demand forecasts results in a much more robust demand forecast which aligns far better with AEMO's 2025 ESOO. Figure 3-11 shows the percentage impact of electrification on AusNet and AEMO's summer and winter maximum demand forecasts. By 2030/31, AEMO is forecasting that electrification of both the residential and C&I sectors will increase maximum demand by 11.9% in winter and 3.5% in summer. AusNet's corresponding impacts are 10.5% and 2.9%. That is, by the end of the regulatory period, AEMO is forecasting a slightly higher impact than AusNet, however this difference would be more than double if C&I electrification was not included in AusNet's revised forecasts. Hence, continuing to exclude the impact of C&I electrification, especially after reducing the forecasts to incorporate downward drivers of demand such as energy efficiency and batteries, would not result in a forecast that is a reasonable estimate of future demand.

Figure 3-11: Comparison of the impact of electrification on maximum demand forecasts – AEMO v. AusNet



Source: AusNet, AEMO electricity forecasting data portal

The above information confirms that AusNet's approach to forecasting the impact of electrification on maximum demand is reasonable, supporting the acceptance of our demand forecasts in full by the AER.

3.5.3.4. Treatment of block loads

Both Baringa and the AER expressed concerns about how AusNet treats block loads in its forecasting process.

AusNet explained its block load methodology in responses to Information Requests, however there remained some confusion about this treatment. Baringa's report (p. 31) noted concern with 'engineering judgement' being used in AusNet's post-modelling adjustment process. This is in fact, not a feature of AusNet's demand forecasting methodology. Block loads for inclusion in the forecasting model are provided by Network Planners, who apply a framework to assess the probability of the load connecting, but they do not have further input to the process.

AusNet has provided a sample list of block loads, which is a subset of the complete block load list used as an input into the demand forecasts, along with supporting documentary evidence for each block load project stage.¹⁷ The *Distribution Network Planning Standards and Guidelines*¹⁸ describes the various project development stages in the block load sample list and provides explanation on how they are applied by the network planners.

¹⁷ ASD - Ausnet - Block Load List V3 - 1DEC2025 - CONF

¹⁸ ASD - AusNet - Distribution Network Planning Standards and Guidelines_AMS 20-16

As Baringa's report noted, AusNet's model ensures that block loads are not simply 'passed through' to the forecasts, but take account of the organic growth assumed by the model on that asset. If the model has already 'predicted' growth in excess of the block load, then that block load is not included in the forecast.

Taking the Kalkallo (KLO) zone substation as an example. KLO is zone substation in our northern growth corridor that supplies four feeders, several of which have identified potential block loads. By 2030/31, the potential demand associated with these block loads is as high as 22MW, including one major project which is connecting in the later years of the regulatory period. Most of these loads have a high probability of connecting, however our probability weighted assessment brings the total potential load down to 20MW.

However, because KLO is in a growth area, the forecast model is already building in an expectation of future load increases. If this 20MW was added on top of the model, there is likelihood of double counting. This is especially the case in the outer years of the forecast, due to the compounding growth inherent in the model.

Instead, our approach results in no more than 8MW ever being added to the KLO forecast, in 2028/29.¹⁹ By the end of the regulatory period, this is diluted even further to just 2.5MW. That is, from the starting list of 22MW of block loads connecting by 2030/31 (or 20MW on a probability-weighted measure), the KLO model only includes an additional 2.5MW for block loads, because the organic growth in the model has already accounted for the remaining ~18MW of estimated growth from block loads.

The AER described this process as "broadly reasonable",²⁰ but still had concerns that AusNet's methodology could result in forecasts being overstated at higher combined network levels.

These concerns are unfounded. AusNet's methodology for comparing the block load uplift to the overall demand growth on the asset in question captures the broader demand drivers at all network levels and produces an unbiased estimate of the contribution of block loads to the asset's forecast. That is, we believe that our forecasting approach results in exactly the type of scenario that the AER expects to see, namely that block loads have a lower impact at "higher combined network levels, where the larger and more diverse group of customers across a wider area tend to balance out the demand increases from new customers, reducing the overall impact of new large connections."²¹

To demonstrate this, Figure 3-12 focuses on the block loads in AusNet's north and south-east growth corridors, where block loads are driving some of the demand increases in those regions. At the beginning of the forecast horizon, the contribution of block loads at the feeder level is very similar to the block loads being recognised at the zone substations those feeders are supplied by. However, as the forecasting horizon extends, the broader trends being captured at the higher zone substation level are 'diluting' the impact of the block loads in the zone substation forecasts. Furthermore, once the block loads are established, their impact wanes over time, as the underlying forecast model 'picks up' more of the loads that were introduced.

¹⁹ Based on POE10 forecasts

²⁰ AER, *Draft Decision – AusNet Services distribution determination 2026-31, Attachment 2 – Capital expenditure*, p.34.

²¹ Ibid, p.34.

Figure 3-12: Block loads (MW) at the zone substation and feeder level – AusNet growth corridors



Source: AusNet

AusNet therefore considers that its block load forecasting methodology is producing reasonable, reliable and transparent demand impacts of the block loads identified for inclusion in the forecasts and should address the concerns raised by Baringa and the AER.

3.5.3.5. Demand forecast reconciliation

The AER noted that AusNet has not historically included in its demand model a reconciliation of system level demand with its spatial forecasts. This point was also raised by The Centre for International Economics (**The CIE**) in its independent review of our forecasting methodology, as well as Baringa in its report to the AER. It is notable, however, that Baringa agreed with AusNet's substantive points that:

- AusNet's approach to validating our bottom-up spatial forecasts was internally consistent and reasonable
- System level forecasts do not directly inform expenditure forecasts, which are instead derived from the spatial forecasts.²²

Baringa noted that whilst AusNet's approach was reasonable, there was still value in reconciling system level and spatial forecasts. AusNet has taken account of Baringa's feedback and the AER's expectation of a reconciliation between system level forecasts and spatial forecasts. AusNet considers that the terminal station (transmission connection point) forecasts are the most appropriate spatial forecast to use for this purpose, being one level below the system level forecast.

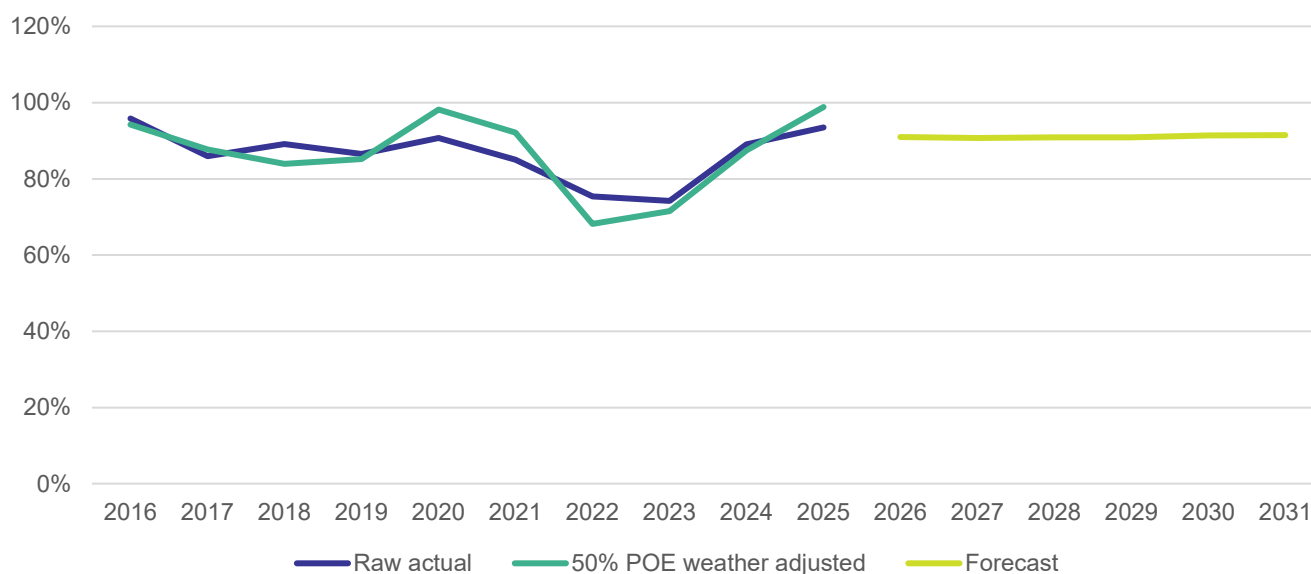
Reconciliations within a forecasting process are primarily used where two levels of forecasts (e.g. system and spatial) produce a demand forecast for a common (i.e. coincident) time. For example, AEMO's forecasting process produces a regional (e.g. Victoria-wide) 30 minute demand trace and a series of sub-regional (e.g. smaller geographic regions within Victoria) 30 minute demand traces. The reconciliation process that AEMO employs ensures that for any given 30 minute period, the sum of the sub-regional traces add up to the regional trace. Thus, there is consistency between coincident spatial (i.e. sub-regional) demand and the system (i.e. regional) demand.

AusNet does not produce spatial forecasts that are coincident with the network forecast, therefore a reconciliation process akin to AEMO's is not valid. However, a different type of reconciliation/comparison can demonstrate that our non-coincident spatial forecasts are consistent with our system forecast when compared with historical actuals. Figure 3-13 below shows how the proportional difference between AusNet's system forecast and the sum of its terminal station spatial forecasts compares to actual outcomes of the same measure. In the chart below, if AusNet's system level demand was 1,800 MW and the sum of the terminal station demands was 2,000MW, the measure would be 90% (1,800/2,000). AusNet's forecast results in this measure being a reasonably consistent 91%. We have

²² Baringa, *Distribution demand forecast assessment: Review of AusNet Services' 2026-31 regulatory proposal*, p.33.

compared this to information historical actuals submitted in our RINs,²³ on both a raw and POE50 basis. As Figure 3-13 shows, our forecast system/spatial relationship is well within the range of historical outcomes.

Figure 3-13: System level demand v. spatial demand (summated terminal stations), actual and forecast



Source: Economic benchmarking RINs, AusNet

We consider the above chart provides strong evidence that AusNet's system level and spatial forecasts have been prepared in a manner that provides for a consistent view of future demand on our network. This also lends credence to our position that block loads have not been modelled inappropriately at both the spatial and system levels.

3.5.3.6. Growth in CER

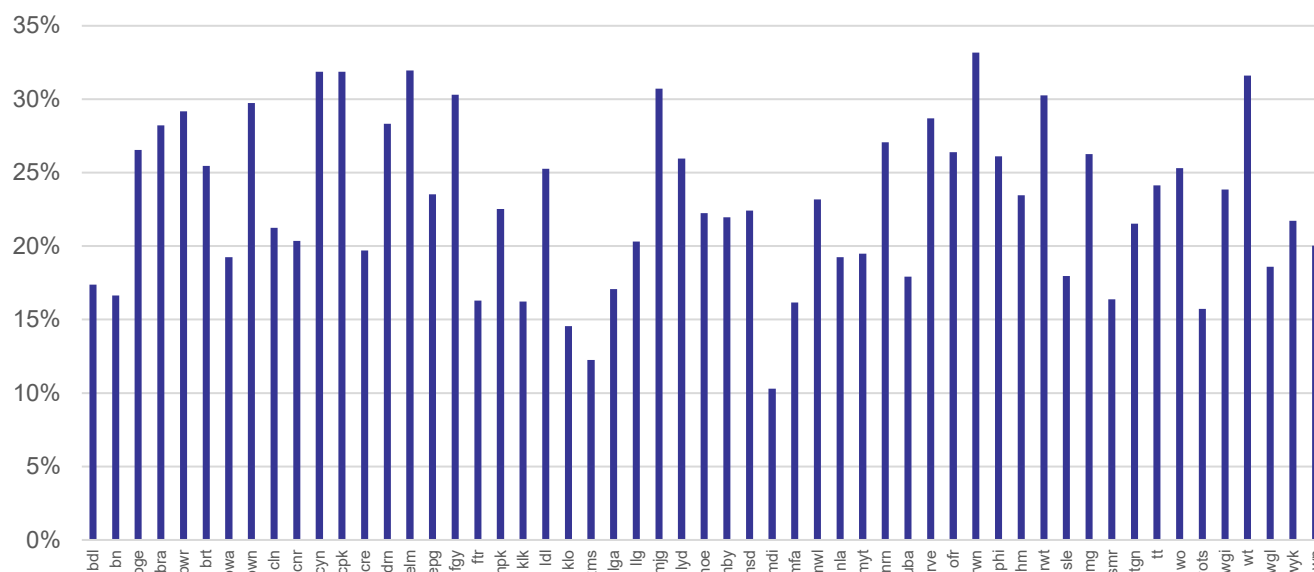
In its Draft Decision, the AER asserted that AusNet's CER forecasts did not consider spatial technological saturation or demographic differences and that our forecast assumed a uniform state-wide growth rate. AusNet disagrees with both of these assertions, which are not an accurate reflection of AusNet's approach to forecast CER.

It is true that AusNet bases its CER forecast (that is, its forecast of solar PV and EVs) on AEMO's forecasts for the uptake of those technologies in Victoria. We consider starting with AEMO's forecast provides a sound and independent basis for our forecasts, however it is not true that we apply AEMO's state-wide growth rates uniformly. AEMO's forecasts are combined with actual data from the growth in CER on AusNet's network and forecast customer growth to arrive at CER forecasts for each of our assets.

The fact that a common growth rate is not applied across AusNet's network is confirmed by Figure 3-14 which shows the change in the proportion of customers who have rooftop PV over the next regulatory period.

²³ Specifically, the RIN data used are [DOPSD0110 / DOPSD0107] for the raw measure and [DOPSD0112 / DOPSD0109] for the POE50 measure.

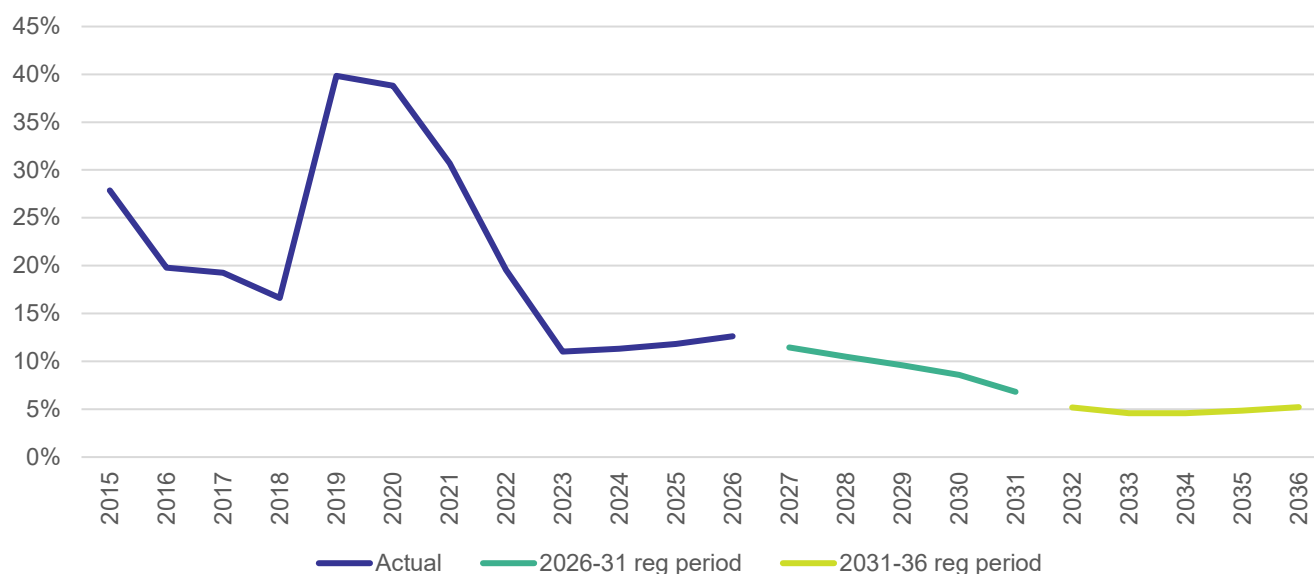
Figure 3-14: Change in proportion of customers with rooftop PV 2026-2031, by zone substation



Source: AusNet

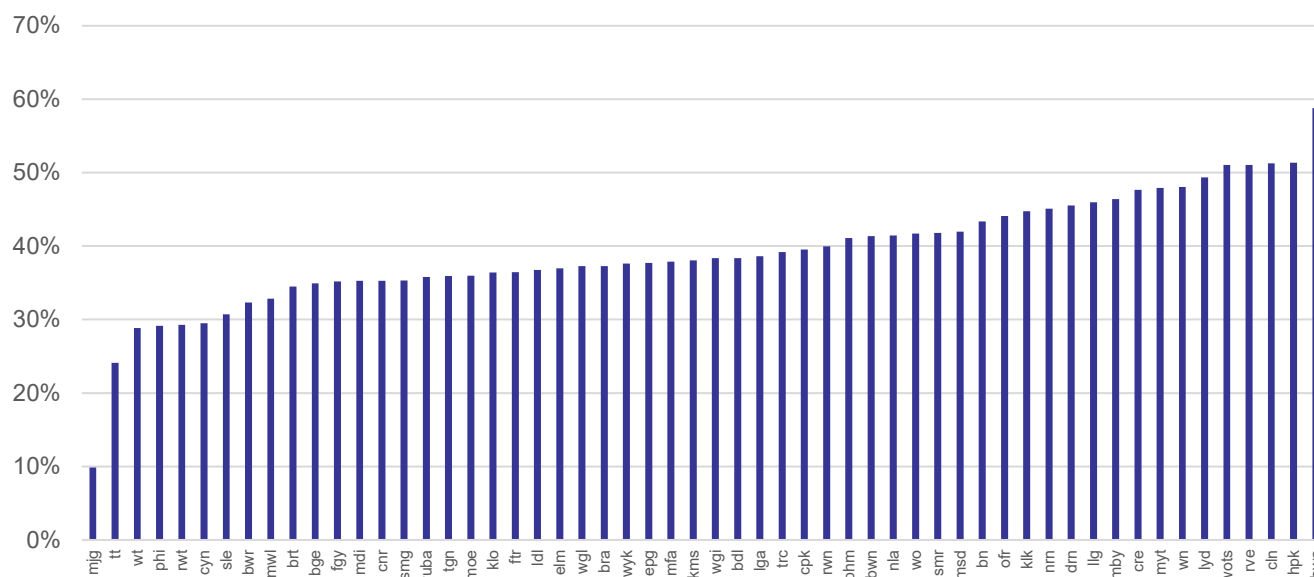
Regarding saturation levels, these are inherently built into AusNet's methodology by combining AEMO's forecasts – which factor in declining growth rates at a regional level due to saturation – with the observed growth rates of the individual assets, which reflect the growth impacts of economic and demographic drivers within that asset's supply area. Figure 3-15 depicts the year-on-year growth rate in residential customers with rooftop PV in one of AusNet's growth zone subs, Clyde North. AusNet is forecasting a slowdown in the rate of solar uptake, whilst Figure 3-16 shows that by 2031, the majority of zone substations are sitting at 50% PV penetration or below. AusNet does not consider this to be an unreasonable forecast of the likely uptake of rooftop PV at a spatial level over the next five years. That is, these penetration rates are not indicative of a model that allows CER growth to 'run away' at unrealistic rates.

Figure 3-15: Year-on-year growth in residential PV customers – Clyde North zone substation



Source: AusNet. Spike in 2019 PV growth due to the introduction of the Victorian Solar Homes program.

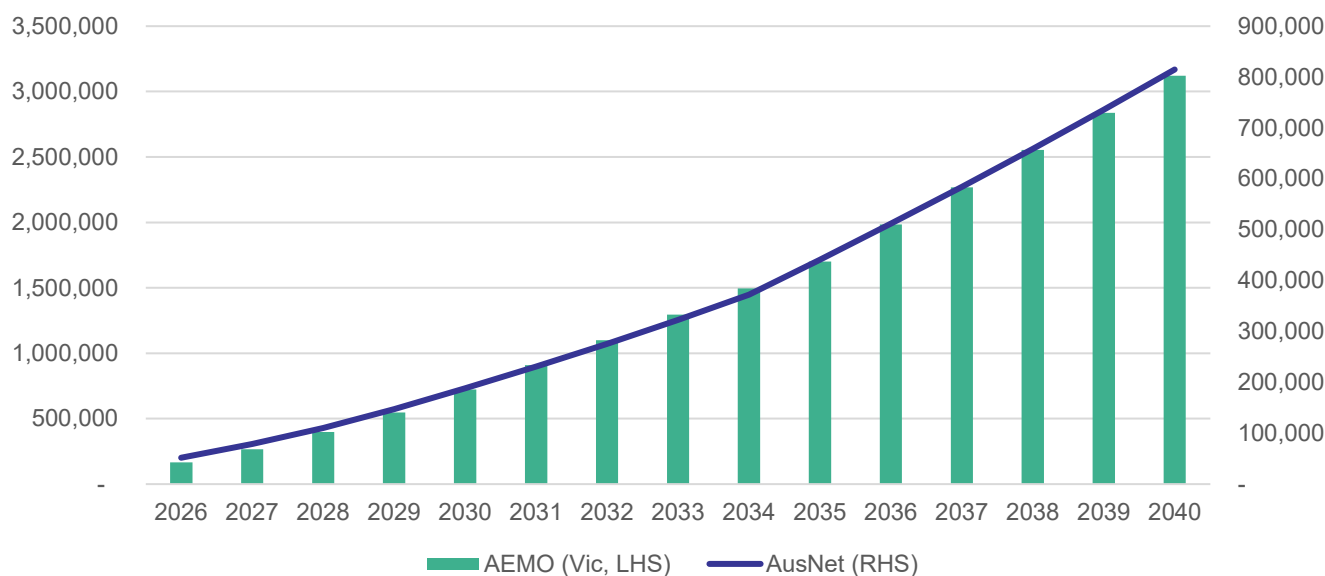
Figure 3-16: Residential PV uptake by the end of the 2026-31 regulatory period, by zone substation



Source: AusNet

The above charts have focused on rooftop PV. Regarding electric vehicles, there is a constraint in the model that doesn't allow more than four EVs per customer to ensure that EV penetration does not reach implausible levels, although this constraint would not be reached in the short to medium term, regardless of AEMO's regional growth rate. EV growth is highest in AusNet's growth zone substations, such as Kalkallo, Clyde North and Eltham where growing populations are more likely to account of more of the EV fleet's growth. At a network level, the differing growth profiles across zone substations are balanced such that AusNet's forecast growth in EVs aligns with AEMO's growth across Victoria.

Figure 3-17: Electric vehicle growth (number of EVs), AusNet and AEMO (Victoria)



Source: AusNet

Baringa observed that AusNet's methodology for forecasting EVs assumes that the areas within the network that have experienced stronger growth in recent years will continue to be the areas that record stronger growth over the forecast horizon. AusNet recognises this feature of the forecasting methodology, but considers that it is a reasonable approach to forecasting what is still an emerging technology within our network. It is still very early in the evolution of EVs within the broader vehicle market and AusNet will continue to monitor ways to spatially forecast EVs. Currently, however, we consider our methodology that uses revealed preferences for EVs as a way of estimating future preferences for EVs is a reasonable approach. We note that Baringa did not suggest alternative methodologies or provide any evidence that those methodologies would be expected to result in a more robust forecast. Forecasts by

their nature are uncertain and we caution the AER against seeking a false level of precision for forecasting what is still a nascent driver of demand.

In summary, we consider that the AER's concerns about our CER forecasts are unfounded. Our methodology blends the statewide forecasts from AEMO with information from our network that captures the demographics and drivers of CER uptake at the asset level. Our CER forecasts do not result in unreasonable levels of CER penetration and can be relied upon as reasonable, valid inputs to the broader demand forecasting process. This supports our demand forecasts being accepted in full by the AER.

3.6. Summary

Customer, energy and demand forecasts are a crucial input to a distribution business's investment plans and we welcome the feedback provided by the AER, informed by Baringa's review of our forecasts. After addressing the AER's expectations set out in its Draft Decision, we consider our revised forecasts provide a robust and realistic view of likely demand during the 2026-31 regulatory period and are the best estimate of future demand on which to base our expenditure forecasts.

Our demand forecasts are based largely on independent data sources and actual characteristics of our network, including most recent smart meter data. Any adjustment to our demand forecasts could compromise our ability to make investments needed by customers, to support the growing population particularly in the northern and southeastern growth corridors, and could compromise our ability to facilitate expected electrification.

3.7. Supporting documentation

We have included the following documents to support this chapter:

- ASD - Energeia - Appendix 3A - AusNet Battery Uptake and Impact Forecasting Report - Aug 2025 - PUBLIC

4. Building Block Revenue Requirement

4.1. Key points

The key points in this chapter are:

- AusNet are proposing a revised revenue requirement of \$4,942.4m in unsmoothed nominal dollar terms. This is a \$53.4m reduction from the Initial Proposal
- In real, smoothed dollar terms, the revised proposed revenue requirement is \$4,561.9m (\$, real 2025-26), or an average of \$912.4 million. This is 10% above the expected revenue in the 2021-26 regulatory period.

4.2. Chapter structure

This chapter is structured as follows:

- Section 4.3 presents our revenue requirement;
- Section 4.4 presents a summary of the building block components of the revenue requirement;
- Section 4.5 presents our smoothed revenue requirement for each year of the forthcoming regulatory period, including a description of the X-factors adopted;
- Section 4.6 sets out the average price path under the proposed revenue cap; and
- Section 4.7 sets out the relevant supporting documents for this chapter.

4.3. Total Revenue

4.3.1. Our Initial Proposal

We proposed a revenue requirement of \$4,995.8 million in unsmoothed nominal dollar terms.

In real, smoothed dollar terms, our proposed revenue requirement was \$4,662.2m (\$, real 2025-26), or an average of \$924.4 million, which was 13% higher than the expected revenue in 2021-26 regulatory period.

4.3.2. Draft Decision

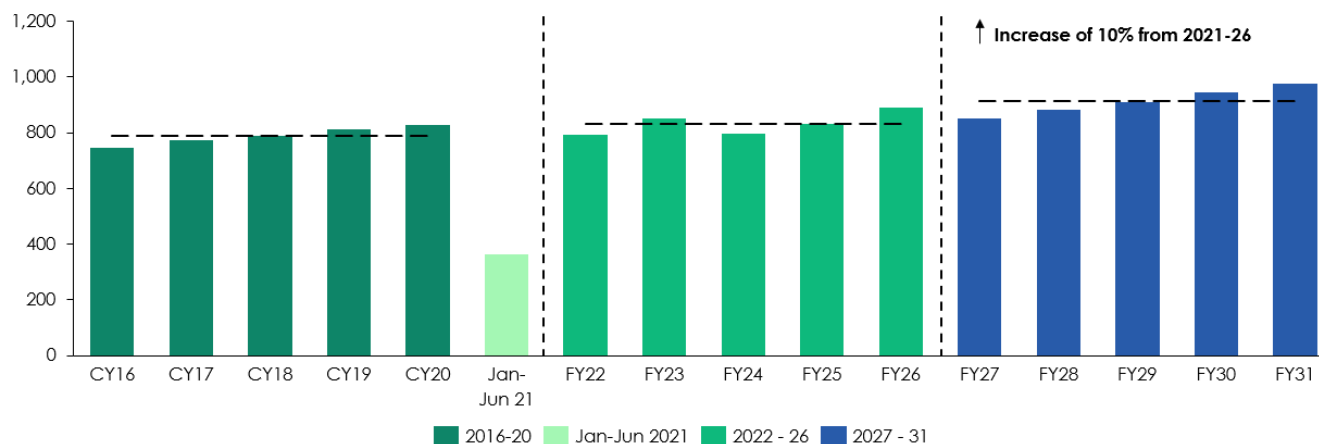
The AER approved \$4,431.1 million (nominal) of the \$4,995.8 million (nominal) of revenue (unsmoothed) forecast in the Initial Proposal. This was a reduction of \$564.7 million or 11.3%. The major cuts to our SCS revenue building blocks proposal included:

- \$239.7 million (nominal) or 10.6% cut to the return on capital (capex);
- \$89.2 million (nominal) or 9.2% cut to the regulatory depreciation allowance; and
- \$209.8 million (nominal) or 11.4% cut to the operating expenditure (opex) allowance.
- \$26.0 million reduction in revenue adjustments, driven by lower EBSS benefits and a higher CESS penalty compared to the initial proposal.

4.3.3. Revised Proposal

Our smoothed revenue requirements for 2027-31 is \$4,561.9m (\$, real 2025-26) or, on average, \$912.4 million per annum (\$, real 2025-26). This is 10% above the expected revenue in the 2021-26 regulatory period.

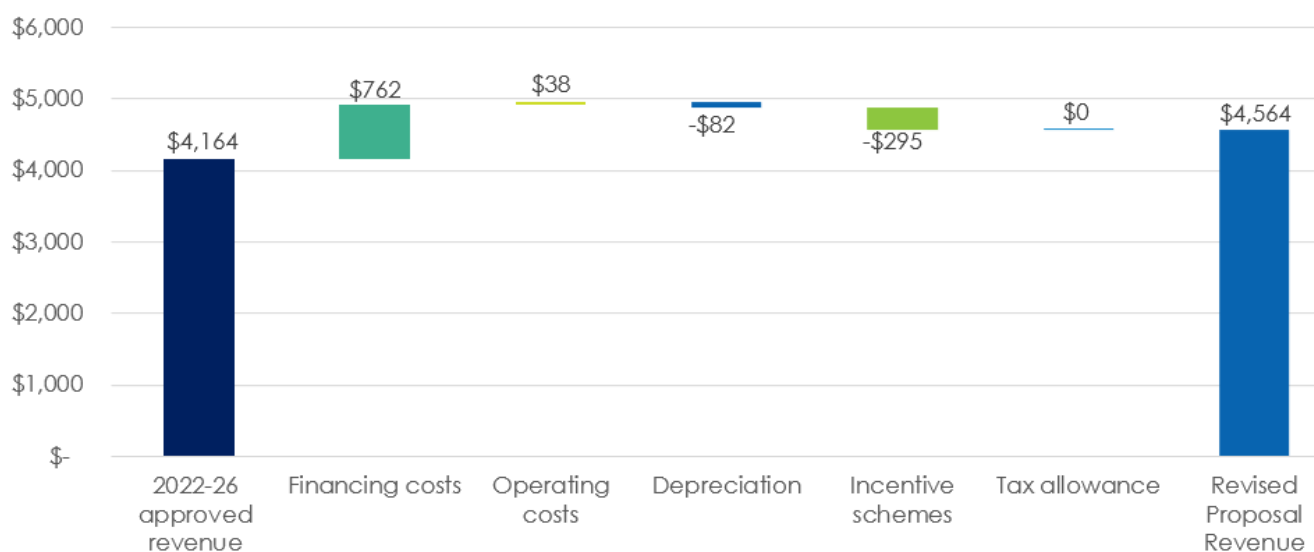
Figure 4-1: Revenue requirement CY 2016 to FY 2031 (\$m, real 2025-26)

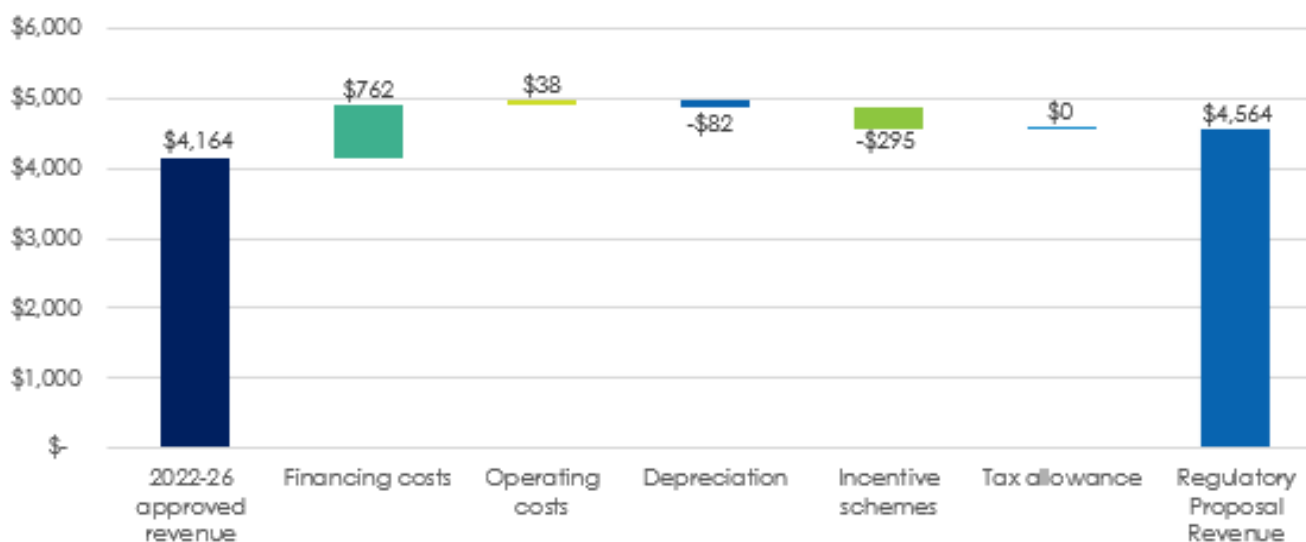


Source: AusNet

Our smoothed revenue requirement for 2026-31 (\$, real 2025-26) revised revenue proposal is 11% higher than that proposed by the AER in its Draft Decision and 1% lower than that proposed in our Initial Proposal.

Figure 4-2: Movement in revenue building blocks, (unsmoothed, \$m, real 2025-26)





Source: AusNet

4.4. Building block components of the revenue requirement

The building block components and our unsmoothed annual revenue requirements for each year of the next regulatory period, under this Revised Proposal, are depicted in the table below.

Table 4-1: Unsmoothed Revenue Requirement (\$m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Return on Capital	380.69	418.22	459.26	504.84	549.45	2,312.45
Regulatory Depreciation	178.66	189.89	204.32	206.98	190.99	970.83
Operating Expenditure	317.74	333.55	350.83	366.83	388.26	1,757.21
Revenue Adjustments	-18.39	-12.71	-28.08	-36.43	-2.45	-98.07
Net Tax Allowance	-	-	-	-	-	-
Unsmoothed revenue requirement	858.70	928.95	986.33	1,042.22	1,126.24	4,942.43

Source: AusNet PTRM

4.4.1. Regulatory Asset Base

Our RAB has been calculated in accordance with the requirements of clause 6.5.1 and Schedule 6.2 of the NER. It reflects the capex forecasts set out in Chapter 5 of this Revised Proposal, the opening RAB based on expenditure in the 2021-2026 regulatory period as detailed in Chapter 8, and depreciation as calculated in Chapter 9. The table below sets out a summary of the derivation of our RAB for the next regulatory period.

Table 4-2: Regulatory Asset Base (\$m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Opening RAB	6,276.0	6,830.7	7,412.5	8,011.7	8,494.9
Net capital expenditure	733.4	771.6	803.6	690.1	742.5

Opening RAB inflation addition	163.2	177.6	192.7	208.3	220.9
Nominal depreciation	-341.8	-367.5	-397.0	-415.3	-411.9
Closing RAB	6,830.7	7,412.5	8,011.7	8,494.9	9,046.4

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.

4.4.2. 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 9.

Table 4-3: Return on capital allowance (\$m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Opening RAB	6,276.0	6,830.7	7,412.5	8,011.7	8,494.9
WACC (% per annum)	6.07%	6.12%	6.20%	6.30%	6.47%
Return on capital	380.69	418.22	459.26	504.84	549.45

Source: AusNet PTRM

4.4.3. 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 8 of this Revised Proposal. 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 4-4: Forecast depreciation (\$m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Nominal depreciation	341.8	367.5	397.0	415.3	411.9
Less: indexation on opening RAB	-163.2	-177.6	-192.7	-208.3	-220.9
Regulatory depreciation	178.7	189.9	204.3	207.0	191.0

Source: AusNet PTRM

4.4.4. 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 6 - Opex, the opex forecast has been prepared in accordance with all applicable requirements of the NER and the RIN.

Table 4-5: Forecast operating expenditure (\$m, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Opex (base, step and trend)	295.52	302.57	310.26	316.28	326.50	1,551.12
Guaranteed Service Levels	9.05	8.81	8.58	8.32	8.10	42.87
Innovation	-	0.16	0.48	0.73	1.07	2.43

Customer relationship managers and comms program	1.95	1.95	1.95	1.95	1.95	9.76
Debt raising costs	3.17	3.37	3.56	3.75	3.88	17.73
Total	309.69	316.86	324.83	331.03	341.50	1,623.91

Source: AusNet PTRM

4.4.5. 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 11 (Incentive Schemes), and the shared assets guidelines.

The CESS increments true-up reflects the true-up of the CESS incentive payment associated with the final regulatory year of the last regulatory period and the 2021 half year extension period.

The FTA cost pass through is the application submitted to the AER on 14 November to recover the costs associated with the Flexible Trading Arrangements Rule Change. The revenue adjustment we have sought in 2026-27 is \$0.17 million.

The building block costs are listed in the table below.

Table 4-6: Revenue adjustments (\$m, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31
Opex efficiencies (EBSS)	7.96	13.95	-	-6.90	23.78
Capex efficiencies (CESS)	-27.48	-27.48	-27.48	-27.48	-27.48
Shared Assets	0.0	0.0	0.0	0.0	0.0
Demand Management Innovation Allowance	0.89	0.92	0.94	0.96	1.00
CESS increments true-up	0.53	0.53	0.53	0.53	0.53
FTA opex cost pass through in 2025-26 year	0.17				
Total	-17.93	-12.07	-26.00	-32.88	-2.16

Source: AusNet PTRM

4.4.6. 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 10 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 4-7: Benchmark tax liability (\$m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Tax payable	-	-	-	-	-	-
Less value of imputation credits	-	-	-	-	-	-
Net corporate income tax allowance	-	-	-	-	-	-

Source: AusNet's Revised Proposal PTRM (2026-31)

4.5. 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'.

We have proposed a flatter revenue profile than would have eventuated under the AER's default smoothing arrangement to mitigate price impacts in the later years of the period and manage cash flows. We request further engagement with the AER on revenue profiling before the Final Decision.

Table 4-8: Annual building block revenue, X factors and maximum allowed revenue (\$m, nominal)

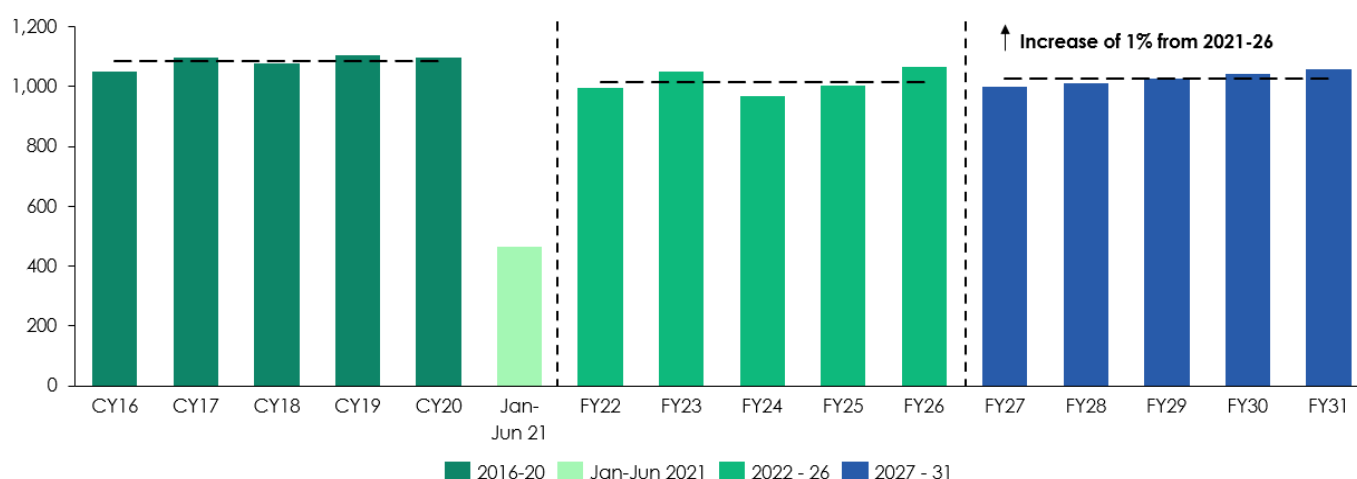
	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Annual building block revenue requirement (unsmoothed)	858.70	928.95	986.33	1,042.22	1,126.24	4,942.43
Annual expected MAR (smoothed)	873.19	927.06	984.25	1,044.97	1,109.44	4,938.92
X factor (%)	4.50%	-3.48%	-3.48%	-3.48%	-3.48%	n/a

Source: AusNet's Revised Proposal PTRM (2026-31)

4.6. Average price path under the Proposed Revenue Cap

In real terms, the average revenue per customer is \$1,028 (\$, real 2025-26), which is 1% higher than the expected revenue per customer in 2021-26 regulatory period.

Figure 4-3: Revenue per customer from CY 2016 to FY 2031 (\$, real 2025-26)



Source: AusNet

4.7. Supporting Documentation

The following model is provided to support this chapter:

- ASD – AusNet – Post Tax Revenue Model – 011225

5. Capital expenditure

Note that, unless specified otherwise, all capex amounts in this chapter are total expenditure (including overheads and escalation) and expressed in real \$2025-26.

Some values and tables have been expressed in real \$2023-24 aligning to the dollar basis of our economic modelling.

5.1. Key points

The key points in this chapter are:

- We proposed gross and net capex forecasts of \$3,812.4 million and \$3,496.0²⁴ million respectively in our Initial Proposal, which the AER's Draft Decision reduced by 47.4% and 51.3%.
- The alternative forecast in the AER's Draft Decision – gross and net capex of \$2,003.6 million and \$1,701.4 million respectively – is significantly below the forecast in our Initial Proposal and approximately \$478.0 million below the expected net capex for the current period. We are expecting to overspend our 2025-26 capex allowance by \$267.5 million or 96.4%, and our total current period allowance by \$459 million (27%), with this overspend driven by the same factors necessitating an increase in investment levels during the 2026-31 regulatory period, such as strong customer and demand growth and the need to replace aged and deteriorated assets.
- Actual expenditure trends in the current period show that the AER's draft forecast for the 2026-31 period manifestly underestimates the efficient level of investment required to meet even current service outcomes.
- We acknowledge the AER has invited us to provide additional, technical supporting evidence to substantiate our case which we have done in this Revised Proposal. Our assessment is that if the AER's Draft Decision forecast is upheld in its Final Decision forecast, this will have serious and harmful ramifications for our customers as we will have insufficient funding to manage demand growth, operate and maintain the network in a safe and reliable manner, and meet our regulatory obligations. Further, we will be unable to deliver the service level outcomes our customers have told us they want and are willing to pay for – including in relation to improved reliability and resilience – or deliver the energy transition in line with Victorian Government policies and objectives. In summary, the proposed cuts will directly compromise our ability to meet mandated safety and reliability outcomes – these are outcomes that our customers tell us they value the most. In addition, the cuts now will have long term impacts. Failure to invest now increases lifecycle costs and elevates risk, potentially resulting in poorer outcomes and higher costs in future period. These outcomes are not in accordance with the NEO.
- As a result, we are unable to accept most of the alternative forecasts. Instead, we have redeveloped a large proportion of our capex forecast (particularly repex, augex and connections) to address the AER's concerns for this Revised Regulatory Proposal:
- Our gross capex forecast is \$3,864.5 million, which is \$52.1 million (1.4%) higher than our Initial Proposal, and \$1,860.9 million higher (92.9%) than the AER's Draft Decision.
- Our net capex forecast is \$3,408.1 million, which is \$87.9 million (2.5%) lower than our Initial Proposal, and \$1,706.7 million higher (100.3%) than the AER's Draft Decision.
- We have been able to accept the AER's (non-zeros) alternative forecast for approximately \$456 million of capex in relation to:
 - \$21 million of augmentation for the Under Frequency Load Shedding (UFLS) project
 - \$214 million of repex and safety programs
 - \$12 million of resilience investment relating to SAPS, emergency response vehicles, and mobile generation
 - \$49 million to fund our strategic depot uplift program
 - \$112 million of non-network primarily for property
 - \$43 million of digital expenditure (the market systems and cyber security programs)

24 After asset disposals

- \$4.0m for our Innovation Fund, which includes 2 of our proposed innovation projects. Further information on our response to the AER's draft decision can be found in section 6.8.3.3.
- **Cost estimates.** Our Initial Proposal proposed new zone substations at Wollert and Pakenham South at \$50.0 million and \$60.6 million respectively. The AER accepted these amounts excluding the risk allowance component. Since then, more detailed engineering analysis has been undertaken, including an increase in feeders, which along with market-driven changes in input costs, has led to an increase in our cost estimates to \$88.4 million and \$77.5 million. We also updated our cost estimates for the Watsonia, Thomastown, Traralgon, Newmerella and Kilmore South zone substation rebuild projects included in our Initial Proposal, increasing the total cost of these projects from \$108.8 million to \$158.6 million. We engaged an independent consultant to assess our updated cost estimates, and they concluded that the cost increases align with the change in scope and industry benchmarks and, therefore, are appropriate cost estimates for use in our Revised Proposal. In this Revised Proposal, therefore, we have updated our cost estimates to reflect on this latest available information.
- **Updated unserved energy calculations and inputs.** Our revised forecast is based on using the AER's 2024 VCRs to quantify expected unserved energy where it is relevant. It is also based on the more mathematically correct gross energy at risk calculation (instead of net energy at risk) by accounting for involuntary load shedding of customers who have rooftop solar generation. The gross energy at risk approach is also mathematically consistent with the AER's VCRs. We note that the use of gross energy at risk is an improvement compared to our Initial Proposal as it values risk more accurately, yet it does not change our capex forecast. That is, our capex forecast for this Revised Regulatory Proposal remains the same whether using gross or net energy at risk, as projects stack up under both methods.
- **Risk allowances.** The AER's alternative forecast excludes risk allowance across the whole portfolio. We disagree with this and have provided additional evidence supporting the need for a risk allowance across our network capex portfolio, to manage inherent and contingent risks that may arise during project delivery and are not accounted for in other elements of our capex estimates or revenue building blocks. Our capex forecast for this Revised Regulatory Proposal includes a P(50) risk allowance that is added to each project's direct cost. Direct cost plus a P(50) risk allowance produces an unbiased, probability weighted cost estimate with an equal likelihood of actual costs exceeding or coming in below the estimates. Our proposed risk allowances are discussed further in section 5.5.2.3.
- **Replacement and safety capex.** The AER's alternative forecast for repx²⁵ is 48.3% less than our Initial Proposal because it could not determine the prudence and efficiency of a significant portion of AusNet's repx forecast based on the information provided. Specifically, the AER had concerns around our risk modelling inputs, optimal timing analysis and unit rates. We have addressed the AER's concerns in this revised proposal by redeveloping the repx forecast based on more robust and consistent modelling across each asset class, with greater transparency of how key probability and consequence of failure inputs have been derived. We have recently re-obtained ISO 55001 certification, demonstrating the robustness of our asset management system, which underpins our expenditure forecasts. We also obtained an independent review of the technical aspects of our updated Weibull analysis, which underpins our probability of failure assumptions. This review found that our approach and parameters are sound and compliant with the AER's published repx guidance across each asset class. Our revised repx and safety forecast²⁶ (excluding REFCL augex) is \$1,156.1 million, which is \$19.6 million (1.7%) lower than our Initial Proposal and \$466.2 million (67.6%) higher than the AER's alternative forecast. Our repx and safety forecast is discussed further in section 5.6.
- **Augmentation.** The AER's alternative forecast for augmentation²⁷ is \$692.2 million less than our Initial Proposal:
 - **Demand driven augex (non-LV).** Some of the AER's reduction (\$162.1 million) relates to demand driven projects (non-LV). Primarily, the AER is concerned that AusNet's demand forecast is too high, which is driving more projects than necessary and that some of these could be deferred to future regulatory periods. The AER also acknowledged the need for AusNet to update its demand forecast to reflect the latest information and noted that level of demand driven augmentation is likely to change as it progresses to its Final Decision. Consistent with the AER's expectations, we have updated our demand forecast (including consideration of the 2025 IASR) and through further analysis, this Revised Regulatory Proposal demonstrates the need for a demand driven program that is larger than envisaged in the Initial Proposal. Our revised forecast is \$533.8 million²⁸ and this is \$252.7 million (89.9%) higher than our Initial Proposal and \$414.8 million (348.5%) higher than the AER's alternative forecast.

²⁵ Based on the AER's preferred categorisation of repx as outlined on worksheet "Output | AER" of its SCS capex model

²⁶ Based on AusNet's preferred categories that among other things, excludes ADMS.

²⁷ Based on the AER's preferred categorisation of repx as outlined on worksheet "Output | AER" of its SCS capex model

²⁸ Excluding construction insurance cost related to augex.

- **Demand driven LV augex.** The AER's Draft Decision adopted a \$0 placeholder for LV augex stating that it lacks adequate justification including insufficient analysis of potential overlaps with other proposed projects and overestimated economic benefits. We have addressed the AER's concerns by updating our modelling approach for more robust input assumptions which has resulted in a revised forecast that is \$128.6 million. Our revised forecast is \$20.0 million (13.4%) lower than our Initial Proposal.
- **Resilience.** The AER fully accepted our customer-related resilience expenditure, being the capex to install 25 units of SAPS and to purchase emergency response vehicles and mobile generation units. We accept the AER's Draft Decision regarding customer-related resilience. The AER did not approve our forecast for providing backup power to community hubs because it is a 'behind the meter' activity and not a network service. We have not challenged the AER on this issue and therefore accept the Draft Decision. In relation to network hardening, the AER's substantially reduced our proposed expenditure from \$255.8 million to \$31.5 million due to concerns around our modelling inputs and methodology. We have addressed the AER's concerns by re-running our resilience model to reflect the correct interpretation of VNR, lower unit rates and lower cost options. The updated resilience model determined that it would be economic to undertake 821km of covered conductors. We have moderated the outcome by proposing half (or 409km) of the covered conductors program over the 2026-31 period, with the other half to be delivered in the 2031-36 period. By halving the covered conductors program, our network hardening investment for the 2026-31 period is \$162.5 million, which further reduces to \$153.9 million after accounting for overlaps between repex/resilience. We accept pole wraps as an alternate network hardening solution to pole replacement in certain locations and our revised proposal includes a lower forecasted pole hardening program as a result.
- **Reliability.** The AER did not accept our Regional Reliability Allowance on the basis that it cannot accept projects without defined scopes. While we maintain that the AER can accept projects without defined scoping, and that its acceptance is in the interest of regional customers who experience far worst reliability compared to urban customers, we nonetheless accept the AER's Draft Decision of zero expenditure. We note that introducing Victorian Minimum Standards (anticipated to be developed by Government following the Victorian Network Outage Review) may help to reduce the disparity in reliability standards, yet exact impacts are still unknown. The AER's Draft Decision also adopted \$0 placeholders for BN11 and 10 worst served feeders on the basis that AusNet has not undertaken a root cause analysis. We have addressed the AER's concerns by undertaking detailed root cause analysis. Our forecast for WSF has reduced from \$25.7 million to \$1.8 million and these projects are NPV positive. Our updated root cause analysis and revised cost estimate for an express overhead feeder between Benalla and Euroa (\$40.5 million) rendered the project being NPV negative. However, the express feeder remains our preferred solution which will deliver reliability outcomes to meet the expectations of the community, despite being NPV negative. At the same time, we have developed an options assessment which shows that reconductoring [C-I-C] of the bare overhead lines is an alternative credible solution that is NPV positive solution.
- **Compliance including REFCLs.** The AER accepted 65.6% of our compliance program, related to accepting our UFLS and quality of supply programs, and accepting a portion of our REFCL augmentation project. Our revised forecast for compliance is now higher at \$207.6 million, and the increase is primarily due to updating our REFCL augmentation cost based on a more mature cost buildup, and the introduction of two REFCL projects at Lilydale and Bairnsdale. We have accepted the AER's draft decision for UFLS. Additionally, we have removed our proactive voltage compliance program and instead proposing to continue to rely on our reactive program to maintain voltage compliance.
- **Large renewables enablement.** The AER did not accept our large renewables enablement program on the basis that it is a broader policy consideration for the Victorian network businesses and that is beyond the scope of the EDPR reset to address. Additionally, the AER had concerns about our market benefits modelling and was not satisfied that the expenditure aligns with the embedded generator connections framework. We disagree that this is outside of the EDPR scope given that we are bound by the NEO which now includes an emissions objective and clause 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 and complying with regulatory obligations or requirements. Nonetheless, we accept the AER's Draft Decision and intend to work with Government on how best to meet its emissions reduction objective.
- **Connections.** The AER's alternative forecast for gross connections is \$503.0 million, which is \$73.4 million less than our Initial Proposal. Our revised forecast is \$793.3 million – \$216.9 million (37.6) higher than our Initial Proposal, and \$290.3 million higher (57.7%) than the AER's Draft Decision – given that the incorporation of more recent data increased our unit rates and our pipeline of connections have increased pushing up our forecast volumes. Additionally, the scope for some of our large energy connection projects have become more certain over the past few months which has allowed for detailed engineering and cost estimates to inform updated cost estimates.

- The AER's alternative forecast for customer contributions at \$263.2 million – that is netted off against gross connections – was lower than our Initial Proposal. We have proposed a customer contribution of \$420.0 million and this is higher than both our Initial Proposal and the AER's alternative forecast.
- **ICT²⁹**. The AER's alternative forecast for digital was 36.6% less than our Initial Proposal explaining that AusNet's business cases lack evidence to justify the need for each initiative, not considered whether initiatives are separable or inter-related, and insufficient options analysis. We have addressed the AER's concerns in this Revised Regulatory Proposal, specifically strengthening the business cases and underlying models to account for the identified gaps and provided further evidence to support the costs. This has resulted in an ICT capex forecast of \$349.8 million.
- **CER Enablement**: The AER's alternative forecast was \$8.4m for CER enablement for voltage management activities. The AER did not accept the remaining \$30.3m for network upgrades to accommodate CER. Our Revised Proposal includes \$38.6m for economically justified voltage management activities. The capex forecast is very similar between the Initial and Revised Proposals. This is the outcome of updating our emissions benefit calculation and removing our proactive voltage compliance program. We have addressed the AER's concerns by incorporating batteries into our demand forecast and ensuring our proposed voltage management investment is net beneficial over a 10-year assessment period.
- **Distribution System Operator (DSO)**: The AER's alternative estimate approved \$16.5 million for flexible exports, and rejected the remaining scope in our \$40m DSO proposal, citing issues in options analysis and overstated benefits. Our revised proposal includes \$33m of capex, focusing on an uplift to enable flexible services, community network data visibility, and a non-network solutions platform. Our revised proposal ensures all investments proposed are individually NPV positive and our overall option represents the most prudent and efficient option in the upcoming period. These capabilities are levers to improve network utilisation, which will become more important over time as the transition continues. Unless we are funded to invest in these capabilities it will be difficult to meet the AER's expectations to improve network utilisation prior to increasing network capacity.
- **Property³⁰**. The AER's alternative forecast accepted parts of our proposal on property, the two main programs which raised concern were the strategic depot reset program and South Morang training centre justifications. As part of the Revised Proposal, we have accepted the strategic depot reset program and re-proposed the South Morang training facility. We have also updated our capitalised leases to reflect our most up to date view whilst incorporating an office project fit out across our CBD office and extra floor space in our head office.
- **Fleet³¹**. The AER did not accept our 'buy over time' option for fleet and reduced our forecast to a lease option. We have taken into consideration the AER's feedback on our modelling and expenditure justification by consolidating all fleet into one model and supporting our program expenditure with a business case and further options analysis.
- **Contingent projects**. Our Initial Proposal did not include any contingent projects. In this Revised Proposal, in response to our updated demand forecasts, we have identified the need for two contingent projects to manage potential demand growth. This is discussed further in section 5.16.

Table 5-1: A comparison of our revised capex forecast compared to Initial Proposal and Draft Decision (\$m, real \$2024)

AER'S preferred categories	Initial Proposal	AER's Draft Decision	Revised Regulatory Proposal
Replacement	1,316.9	681.0	1,218.8
DER capex	89.5	32.5	92.1
Augmentation	911.2	219.0	881.8
Connections	576.5	503.0	793.3

29 Based on the AER's preferred categorisation of repex as outlined on worksheet "Output | AER" of its SCS capex model

30 Based on the AER's preferred categorisation of repex as outlined on worksheet "Output | AER" of its SCS capex model

31 Based on the AER's preferred categorisation of repex as outlined on worksheet "Output | AER" of its SCS capex model

ICT capex	386.7	245.2	349.8
Property capex	173.7	119.7	145.7
Fleet capex	144.2	87.5	173.5
Other non-network capex	4.6	4.5	4.5
Capitalised overheads	209.1	111.1	204.9
Gross capex	3,812.4	2,003.6	3,864.5
Less capcons	277.3	263.2	420.0
Less disposals	39.2	39.0	36.4
Net capex	3,496.0	1,701.4	3,408.1

Source: AusNet

5.2. Chapter structure

This chapter is structured around AusNet's preferred method of categorisation:

- Section 5.3 provides a summary of our revised capital expenditure forecasts.
- Section 5.4 explains our key inputs and assumptions.
- Section 5.5 explains our cost estimates.
- Section 5.6 describes our replacement and safety expenditure proposal.
- Section 5.7 describes our demand driven augmentation expenditure proposal (non-LV).
- Section 5.8 describes our demand driven augmentation expenditure proposal for the LV network.
- Section 5.9 describes our CER enablement expenditure proposal.
- Section 5.10 describes our resilience expenditure proposal.
- Section 5.11 describes our reliability expenditure proposal.
- Section 5.12 describes our connections expenditure proposal.
- Section 5.13 describes our digital expenditure proposal.
- Section 5.14 describes our compliance expenditure proposal.
- Section 5.15 describes our non-network expenditure proposal.
- Section 5.16 describes our contingent projects proposal.
- Section 5.17 lists our supporting documentation.

5.3. Total capex

5.3.1. Our Initial Proposal

Our Initial Proposal included a gross and net capex forecast of \$3,812.4 million and \$3,496.0 million respectively.³² Our net capex forecast represented a 72%³³ increase compared to expected capex in the current regulatory period, where approximately half of the increase was due to new capex drivers being reliability, resilience, and DSO.

Our Initial Proposal forecast comprised the following net capex amounts (based on the AER's standard categorisation):

- \$1,316.9 million of repex
- \$911.22 million of augex
- \$299.1 million of net connections capex
- \$386.7 million of ICT capex
- \$322.5 million of non-network capex including fleet and property
- \$89.5 million of CER capex
- \$209.1 million of capitalised overheads.

5.3.2. Draft Decision

The AER did not accept AusNet's capex forecast. Instead, the AER's alternative forecast for gross capex at \$2,003.6 million, represents a 47.4% reduction. Similarly, its alternative forecast for net capex at \$1,701.4 million, represents a 51.3% reduction.

Key points from the AER's Draft Decision:

- **Consumer engagement.** AusNet has satisfied the capex expectations related to genuine consumer engagement on its capex proposal.
- **Top down testing.** AusNet has not met this expectation as the total capex forecast is 71% above current period actual/estimate spend, and material increases across most categories.
- **Prudent and efficient decision-making.** Some projects did not have cost benefit analysis. The cost benefit analyses for some projects were higher than expected.
- **Alignment with asset and risk management standards.** AusNet has not provided documentation demonstrating alignment of proposal with asset and risk management standards.
- **High unit costs.** Some projects and programs had high unit costs or cost estimates that were difficult for the AER to substantiate based on the information provided. Risks were valued too highly. Additionally, AusNet did not consider the full range of options analysis and optimal timing when developing business cases.
- **Demand forecast.** The AER have not accepted AusNet's demand forecast which has resulted in many demand driven projects being deferred. However, it stated that it recognises that the level of demand drive augmentation expenditure is likely to change as the AER progresses to its Final Decision.

The AER's Draft Decision was also informed by two reports.

- **Baringa report.** Baringa assessed our demand forecast and found our approach to be reasonable and easy to follow. However, Baringa considered that there are several areas where the methodology could be strengthened to improve accuracy and transparency. One key limitation is the exclusion of energy efficiency impacts from the demand forecast with little rationale provided. Additionally, Baringa stated that it is essential that AusNet uses the most up-to-date data available. The AER considered AusNet's demand forecast is likely to be overestimated based on AEMO's draft 2024 ISAR and thus favored the lower demand scenario in its assessment of NPV and optimal timing outcome. This resulted in some projects being deferred beyond the 2026-31 regulatory period.
- **EMCa reports.** EMCa assessed approximately \$828 million of our repex forecast including \$40 million of OT, and \$678 million of our augex forecast. EMCa also reviewed our ICT and cyber security expenditures. EMCa identified instances where the economic benefits and project costs appeared to be overestimated, with the analysis relying heavily on input assumptions that were not always well supported. The AER's Draft Decision generally concurred with EMCa's findings.

³² Based on our Initial Proposal capex forecast submitted on 31st January 2025, which was subsequently updated to \$3,461M on 16th May 2025 in our response to IR#20

³³ Based on our expected capex at the time of Initial Proposal submission.

The table in the next section summarises the AER's key concerns in its Draft Decision by expenditure category and AusNet's response.

5.3.3. Addressing the AER's Draft Decision

We acknowledge the AER has invited us to provide additional, technical supporting evidence to substantiate our case. In the table below we outline the AER's key concerns by capex categories and provide a summary of how AusNet has responded to these in this Revised Proposal. Further detail on our response is provided in later sections of this chapter and the supporting documentation.

Our assessment is that the Draft Decision is significantly below the prudent and efficient investment needs we have identified in the 2026-31 regulatory period, and approximately \$478.0 million below the expected capex for the current period. Accordingly, if the AER's Draft Decision forecast is upheld in its Final Decision forecast, this will have serious and harmful ramifications for our customers as we will have insufficient funding to manage demand growth, operate and maintain the network in a safe and reliable manner, and meet our regulatory obligations. Further, we will be unable to deliver the service level outcomes our customers have told us they want and are willing to pay for – including in relation to improved reliability and resilience – or deliver the energy transition in line with Victorian Government policies and objectives.

Table 5-2: Summary of our response to the AER's draft decision on capex

AusNet's capex categories	AER's key concerns in its Draft Decision	AusNet's response to the Draft Decision
Replacement and safety	- A lack of visibility of volume derivation - Forecast volumes based on failure rate not economic analysis - Alternative volumes not assessed - No explanation of forecast failures and how they've been calibrated against observed experience - No explanation of modelled age - Consequences of failure overstated - AusNet's risk-based modelling (PoF x CoF x CoC) not sufficiently justified - High unit cost - Several programs lacked sufficient supporting evidence to justify the proposed expenditure - Historical service performance data did not support the proposed increase in repex. - Not established a safety obligation - Benefits are unclear - Costs are too high - Weibull parameters unclear & no calibration to observed performance - NPV first positive method will overstate capex	- Comprehensively redeveloped our repex forecast - Developed business cases for key asset classes and asset groups to clearly demonstrate the need - Re-submitted Risk Assessment Methodology, AMS 01-09, to provide greater depth and transparency on the key aspects of our repex forecasting approach - Rebuild economic models using maximum NPV approach - Asset data comprehensively reviewed to ensuring age-based PoF assumptions are calibrated against historical asset replacement activities - Carried out new Weibull analysis which was subject to external verification to ensure alignment with good industry practice and AER guidance.
Demand driven augex (excl LV augex)	- Hardcoded values in economic models - Project timing susceptible to relatively small changes in demand - Lower cost option rejected without sufficient justification - Lack of other typical network alternatives in options analysis - Insufficient consideration of transfer capacity between feeders - Insufficient consideration of demand management - Unit power factor (pf) assumption too conservative - Require evidence-based cost justification	- Comprehensively redeveloped our demand driven augmentation expenditure forecasts - Developed a Northern Growth Corridor plan that clearly explains the constraints in the area and why our proposed package of works addresses the constraints - Similarly, developed a South-Eastern Growth Corridor plan - Refreshed business cases that accounts for the revised demand forecast, and interactions between assets - Single business case and economic model for the Northern Growth Corridor so that interactions between assets are clear - Soft coded models - Tested NPV results at +/- 10% of demand forecast - Adopted more appropriate pf factors - Expanded options analysis

Demand driven avgex (LV avgex only)	- Lacks adequate justification - Insufficient analysis of potential overlaps - Overestimated economic benefits - Inconsistencies between cost benefit analysis assumptions and recorded data - Value of unserved energy is not justified	- Reviewed our approach to calculating unserved energy and have applied a more robust method - Addressed overlaps - Provided further justification to support our proposed unit rates
CER enablement	'Do nothing' is not a credible option - Base case scenario should consider BAU investments such as tap changes and phase balancing - Rooftop solar PV will be receiving flexible exports (or otherwise will be subject to a 1kW static export limit) which lowers the volume of energy at risk - Demand forecast has not accounted for home battery storage leading energy at risk benefits being overestimated	- Validated our do-nothing BAU counterfactual scenario - Considered impact of only assuming only 10 years of benefits and this investment remains prudent and efficient in the current period - Revised demand forecast accounts for home battery storage
Resilience	6–12 hour VCR should be applied when deriving the Value of Unserved Energy for the VNR in the 12–24 hours, 24–72 hours and 72+ hour outages - There are more cost-effective options that also address bushfire risk such as pole wraps - Unit rates for the proposed undergrounding and switchgears and covered conductors are too high	- Adopted 6-12h VCR to derive the VNR (for outages >12h) - Expanded options analysis to include pole wraps and hazard trees within the same model - Updated unit rates are now lower
Reliability	- No root cause analysis - Optimal timing of the investment is unclear - Included a 'solar factor' to this benefit	- Undertaken a comprehensive root cause analysis - We have removed the solar benefit from the reliability benefits calculation - Included optimal timing analysis
Connections	- Concerns with post model adjustment in our customer number forecast - Customer contribution rate adjusted to 85%	- Updated our customer number forecast and gross connection volume forecast using actual data - Accept the capital contribution rate for data centres at around 85%
Digital	- Concerns with allocation between distribution, transmission and gas - Overestimation bias - Business cases lack evidence to justify the need for each initiative - Not considered whether initiatives are separable or inter-related - Not considered whether core vs. optional, and insufficient options analysis	- Produced business case addendums underpinned by updated modelling - Re-examined the scope, assumptions and costs for every program, to rebuild cost estimates from the ground up - Refining scopes to ensure that only essential initiatives remain in our proposal
Compliance including REFCL	Unexplained cost item for REFCL	Updated cost for REFCL with detailed cost build up
Non-network (Fleet)	Fleet – Double counting and lease margin factor and EV transition plan	- Bring all fleet into one model including transition fleet and pre-existing AusNet owned fleet - Option analysis includes three options opposed to two in the Initial Proposal - Business case development as part of Revised Proposal to support NPV model - Removing transition to EVs; we will do where cost neutral.
Non-network (Property, building & land)	- Depot – Concerns regarding the assumptions on land valuation and growth and time savings of each depot - South Morang training facility – Justification for the training facility and option consideration remains unclear	- Accept depot reset strategy program as updating data does not make two rejected depot upgrades economical under AER approach - Repropose South Morang Training Centre supported by strengthened options and risk assessments and VESI letter of support

Source: AusNet

In addition to the concerns outlined above, the draft decision outlined two overarching concerns related to:

- **The inclusion of risk allowances in our cost estimates.** The AER considered that inclusion of a risk allowance overestimates the capex forecast, and that it only accepts risk allowances in limited circumstances that are specific to a particular project or program.

- **AusNet's combined approach to the VCR.** The AER considered that the use of AusNet's combined approach to the VCR – combining our QCV for residential customers with the AER's 2023 VCRs for commercial, industrial and agricultural customers – may bring forward projects earlier than expected compared to using the AER's 2024 VCRs.

We disagree with the AER's Draft Decision on the risk allowance. Section 5.5 explains why cost estimates including a risk allowance is necessary to fund expected costs in the next regulatory period. We have also engaged an independent consultant who concluded that our method for calculating a P(50) risk is appropriate³⁴.

While we agree with the AER's Draft Decision on using the AER's 2024 VCRs and we have updated all models to reflect the 2024 VCRs, we observe that AusNet's QCV for residential customer at \$52.42 per kWh (developed in early 2024) is very similar to the AER's Victorian residential average at \$49.23 per kWh which serves to highlight the robustness of the study that we undertook.

We disagree with the AER's assertions that:

- The AER's VCR study using general climate and remoteness zones is better at reflecting AusNet's residential customers' views than the QCV study which had a greater relative sample size, was co-designed with stakeholders and experts, and is AusNet-specific.
- The QCV study is less relevant because it is older than its latest VCR study. The two studies were conducted 8 months apart which is insignificant (particularly given the AER's 5-yearly cycle for updating VCRs).

5.3.4. Revised Proposal

Our Revised Proposal net capex forecast is \$3,408.1 million, which is \$87.9 million lower than our Initial Proposal forecast, and \$1,706.7 million higher than the AER's alternative capex estimate. The table below outlines our Revised Proposal forecast consistent with AusNet's preferred categorisation.

Table 5-3: Summary of our revised capex forecast by AusNet's preferred categories

AusNet's preferred categories	Initial Proposal	Revised Proposal	\$ change	% change
Replacement	982.4	994.8	12.4	1.3%
Safety & Environmental (excluding REFCLs)	189.8	164.6	-25.2	-13.3%
REFCL	81.7	165.5	83.8	102.5%
Demand driven augex (excl LV augex)	283.0	543.4	260.3	92.0%
Demand driven augex (LV augex only)	148.5	128.6	-20.0	-13.4%
Large renewables enablement	193.6	0.0	-193.6	-100%
Resilience	279.4	166.2	-113.2	-40.5%
Reliability	147.7	42.2	-105.5	-71.4%
Connections	619.3	848.9	229.6	37.1%
CER enablement	84.2	71.6	-12.6	-15.0%
Compliance	60.0	49.2	-10.8	-18.0%
Digital	410.1	362.9	-47.2	-11.5%
Innovation	11.0	3.9	-7.2	-64.9%
Non-network (Fleet)	143.2	172.4	29.3	20.4%
Non-network (Property, building & land)	173.7	145.7	-28.1	-16.2%
Non-network (Other)	4.6	4.5	-0.0	-0.0

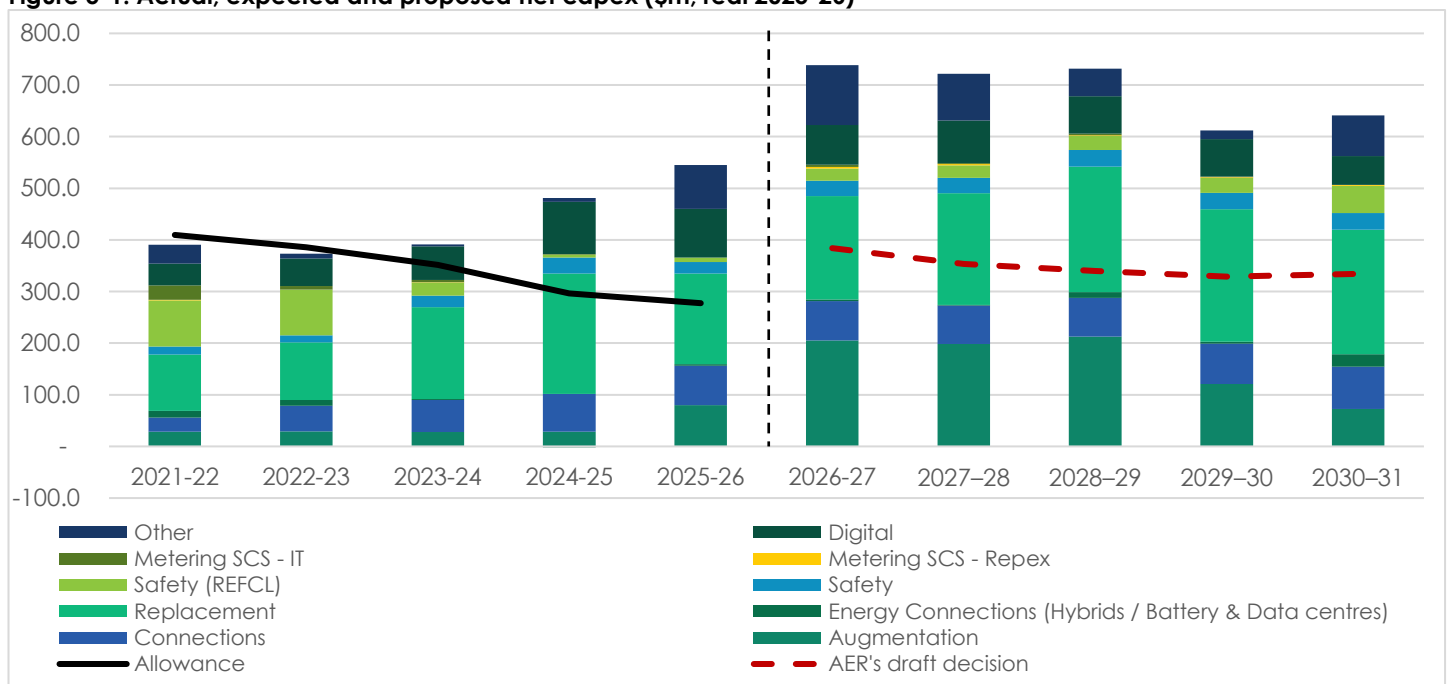
³⁴ ASD - Worley - Review of AusNet Major Project Pricing - 1Dec2025-CONF

Gross capex	3,812.4	3,864.5	52.0	1.4%
Customer contributions	277.3	420.0	142.7	51.5%
Disposals	39.2	36.4	-2.8	-7.1%
Net capex	3,496.0	3,408.1	-87.9	-2.5%

Source: AusNet

The figure below compares our Revised Proposal forecast with current period actual and expected spend, and the draft decision. Our Revised Proposal forecast is 57.1%³⁵ higher than the current regulatory period. Consistent with the higher investment levels required in the next regulatory period, our actual and expected capex has trended upward during the current regulatory period. We are expecting to overspend our 2025-26 total capex allowance by \$267.5 million or 96.4%³⁶, with this overspend driven by the same factors necessitating an increase in investment levels during the 2026-31 regulatory, such as strong customer and demand growth and the need to replace aged and deteriorated assets. On average, proposed annual capex of \$681.6 million³⁷ is 25.5% higher than expected capex in 2025-26 of \$542.95 million³⁸.

Figure 5-1: Actual, expected and proposed net capex (\$m, real 2025-26)



Source: AusNet

5.4. Inputs and assumptions

This section describes the updates we have made to our key capex forecasting input and assumptions as part of preparing our Revised Proposal capex forecast and, where relevant, to address the AER's draft decision concerns. Section 6.4 of our Initial Proposal provides further information on our key capex inputs and assumptions.

5.4.1. Customer engagement findings

³⁵ After asset disposals. Before asset disposals, our revised proposal forecast is 58.0% higher than the current regulatory period.

³⁶ Net capex

³⁷ Net capex, after asset disposals.

³⁸ After asset disposals.

Customer input on our capital expenditure forecasts was sought via two meetings of our EDPR Co-ordination Group and one “all-in” forum with our EDPR panel members and other stakeholders on key elements of our proposal.

In respect of capex, customers at the “all in” forum:

- Re-confirmed strong support for reliability improvements for worst-served customers and supported AusNet addressing the AER’s feedback where possible but refining the case for and re-proposing the worst-served feeder upgrades, and including both the economic and non-economic projects. The group understood AusNet’s decision to accept the AER’s Draft Decision rejecting the Regional Reliability Allowance
- Re-confirmed support for community hubs but agreed with AusNet’s decision to accept the AER’s Draft Decision to reject expenditure on community hubs
- Supported AusNet re-proposing digital expenditure to improve customer experience, quantifying additional customer benefits to economically justify the investment.

5.4.2. Demand forecasting

We have updated our peak demand forecasts to address the AER expectations as set out in the draft decision. This has led to an increase in network-level peak demand forecasts. Further information on our updated demand forecasts is provided in Chapter Three – Demand and Energy Forecasts including:

- How we have addressed the AER’s concerns and expectations
- The improvements we have made to our forecasting methodology and
- The new information we have incorporated into our demand forecasts.

We note that, in our Initial Proposal, our demand forecast was developed for the period from 2025/26 to 2038/39 where the demand year starts 1 April and ends 30 March. This is different to AusNet’s regulatory years which follow Australian financial years starting 1 July and finishing 30 June. As such, there is a mismatch in timing between demand years and regulatory years which we have addressed by:

- Adopting the 1 April 2026 to 30 March 2027 demand forecast as the demand forecast for FY27.
- Adopting the 1 April 2027 to 30 March 2028 demand forecast as the demand forecast for FY28.
- Adopting the 1 April 2028 to 30 March 2029 demand forecast as the demand forecast for FY29.
- Adopting the 1 April 2029 to 30 March 2030 demand forecast as the demand forecast for FY30.
- Adopting the 1 April 2030 to 30 March 2031 demand forecast as the demand forecast for FY31.

Our approach above minimises the timing mismatch between demand years and regulatory years.

The updated energy at risk models provided as supporting documents for our demand driven augex projects provide:

- The specific network element demand forecast inputs used to derive expected unserved energy, and
- The ability for these inputs to be varied to test impacts on project economic timing.

5.4.3. Economic assumptions

Values of customer reliability

Consistent with AER expectations, we have adopted the AER’s 2024 VCRs to quantify expected unserved energy. See table below for the values we have applied in our economic assessments and business cases.

Table 5-4: VCRs used in our Revised Regulatory Proposal (\$ per kWh)

Type	Residential	Commercial	Industrial	Agricultural / farming
Revised regulatory proposal	49.23	34.39	33.49	22.25

Source: AusNet

Notwithstanding this, we continue to consider our Quantifying Customer Values research was robust and provided clear, quantitative evidence regarding customer preferences. We note that the residential value of reliability

determined in the QCV report is very similar in magnitude to the AER's 2024 residential VCR values which gives us comfort the 2024 AER VCR is more closely aligned to our customer's preferences than previous VCR studies.

Discount rate

The Draft Decision did not identify any concerns with the discount rate applied in our Initial Proposal of 5.56%. Accordingly, we have maintained a real discount rate of 5.56% to discount cashflows back to a common starting point. Discount rate based on the average of our regulated WACC at the time of submission (4.11%) and AEMO's ISAR central discount rate (7%). This approach produces a discount rate that is generally higher than the rates used by other network businesses in EDPR submissions which, all else equal, has a moderating effect on our capex forecast because future benefits are more heavily discounted compared to if a lower discount rate had been applied.

Capex inputs

We have used the total cost for each project and program, including overheads and finance charges, when undertaking **economic analysis** to determine whether projects and programs are economically justified. This is a prudent approach as it ensures the identified optimal project timing is reflective of total cost.

At the same time, we have populated the **SCS capex model** using direct cost estimates (including risk allowances), since overheads and contractor support costs are separately added later in the modelling process.

Further discussion on cos estimates is provided in section 5.5.

5.4.4. Capitalised network overheads

Draft Decision

The AER reduced our forecast of capitalised network overheads proportionate to the direct capex approved in the draft decision. This resulted in a 47% reduction to our proposed forecast of \$209.1 million. The AER considered that capitalised overheads are an allocated portion of total forecast capex, requiring a modelling adjustment based on its alternative forecast of total capex.

Addressing the Draft Decision

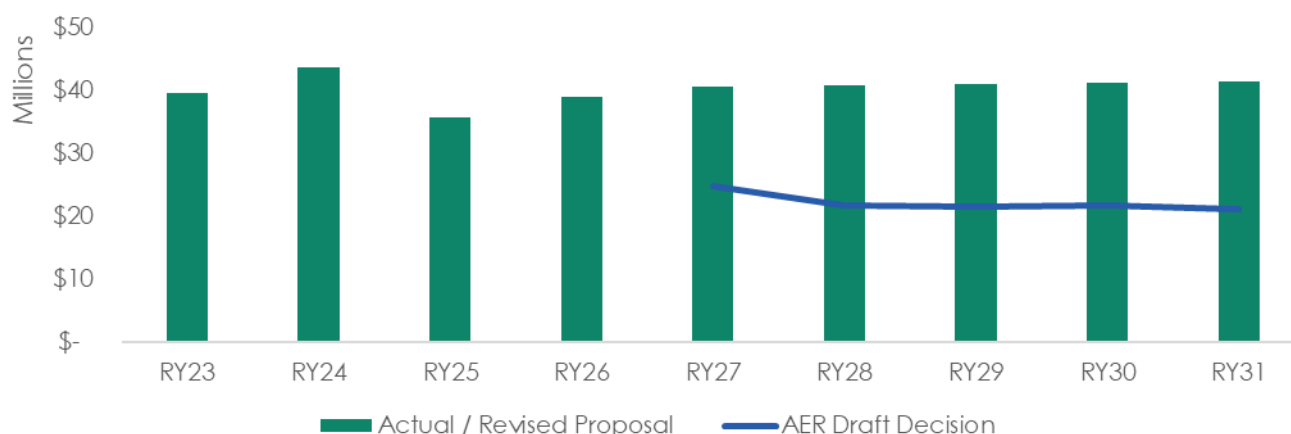
We have updated our forecast to reflect more recent costs which, compared to the Initial Proposal, has decreased our forecast of capitalised network overheads to \$204.9 million. As part of this, we have retained our forecast productivity growth of 0.5% per annum, as an affordability measure.

We disagree with the AER's draft decision to cut overheads proportionally to the direct capex cuts it applied. We have forecast capitalised overheads as a fixed pool, based on historical actual costs incurred. As demonstrated by the chart below:

- Draft Decision capitalised network overheads of \$22 million per annum are materially below our actual, recent levels of capitalised network overheads and, therefore, are not reflective of the prudent and efficient overhead costs we will incur
- Our Revised Proposal forecast of capitalised network overheads is in line with recent, actual levels and, therefore, is a reasonable forecast of the prudent and efficient overhead costs we will incur, given the fixed nature of our overheads pool.

We consider our Revised Proposal forecast of a fixed pool of capitalised network overheads is reflective of prudent and efficient costs we will incur in 2026-31 and should not be adjusted in the event the AER determines a lower level of network capex in its Final Decision compared to our Revised Proposal.

Figure 5-2: Actual, proposed and draft decision capitalised network overheads (\$m, real 2025-26)



Source: AusNet

The inputs and workings for the updated forecast can be found in the SCS Capex Model.

5.4.5. Contractor support costs

Our capex forecast includes two types of contractor support costs:

[C-I-C]

5.4.6. Real cost escalation

5.4.6.1. Draft Decision

The Draft Decision applied zero real cost escalation to the contracted labour cost component of our capex forecast, as part of a modelling adjustment which reduced forecast capex by \$58.5 million. While the Draft Decision did not include any reasoning behind this adjustment in its Draft Decision, it subsequently explained that:³⁹

Modelling adjustments reflect updates to inflation and labour escalation rates compared with those used in AusNet's original proposal. For AusNet, we applied the most recent data for inflation and labour escalation rates and removed the contract labour escalation component.

We have inferred from other AER determinations that the application of zero real cost escalation to contracted labour costs reflects the AER's position that:

³⁹ AER, Response to AusNet requests for further information on capex, opex draft decisions + growth corridor presentation, 20th October 2025

- Contracted services can be adjusted to address changes in the labour market and/or economic climate.
- Forecasting labour price growth for contracted services without accounting for productivity growth would likely overstate the growth in contracted services
- Evidence should be provided to demonstrate that real cost escalation is reflective of the contract provisions or service agreements.

5.4.6.2. Addressing the Draft Decision

In our Revised Proposal, we have updated our real price growth forecasts to reflect the most recent and relevant data available. These updates primarily relate to real labour cost escalation. As discussed in Chapter 6, we have updated our labour escalators to reflect the most recent data available by incorporating:

- The AER's latest labour cost forecasts for Victoria from its September 2025 Draft Decision on opex.
- Updated projections from Oxford Economics, which reflect current expectations for real wage growth

Consistent with our Initial Proposal, we have:

- Applied real labour growth to internal and contracted labour (discussed further below)
- Assumed materials costs increase in line with CPI.

We consider that the AER's proposed treatment of contracted labour costs—limiting escalation to CPI while applying real wage growth only to internal labour—is inconsistent with both market evidence and the principles of incentive regulation.

While we acknowledge the Draft Decision approach is in line with the AER's standard approach to contracted labour escalation, as applied in its recent determinations, we consider that changes to this approach are necessary to:

- Reflect the increasing demand for contracted skilled labour associated with the significant investment required to deliver the energy transition, and the resulting implications for the real price of this labour
- Ensure DNSPs are provided with sufficient opportunity to recover their prudent and efficient costs, in line with the Revenue and Pricing principles.

At our last transmission revenue review in 2021, while we adopted the AER's standard approach in our Revised Proposal, we stated:⁴⁰

"We maintain our view that as several, significant ISP projects move into their delivery phase, there is likely to be upward pressure on external labour costs, and this may well result in a need to apply real cost escalation to external labour costs in future transmission revenue resets. We therefore propose to revisit this issue at the next reset."

And:⁴¹

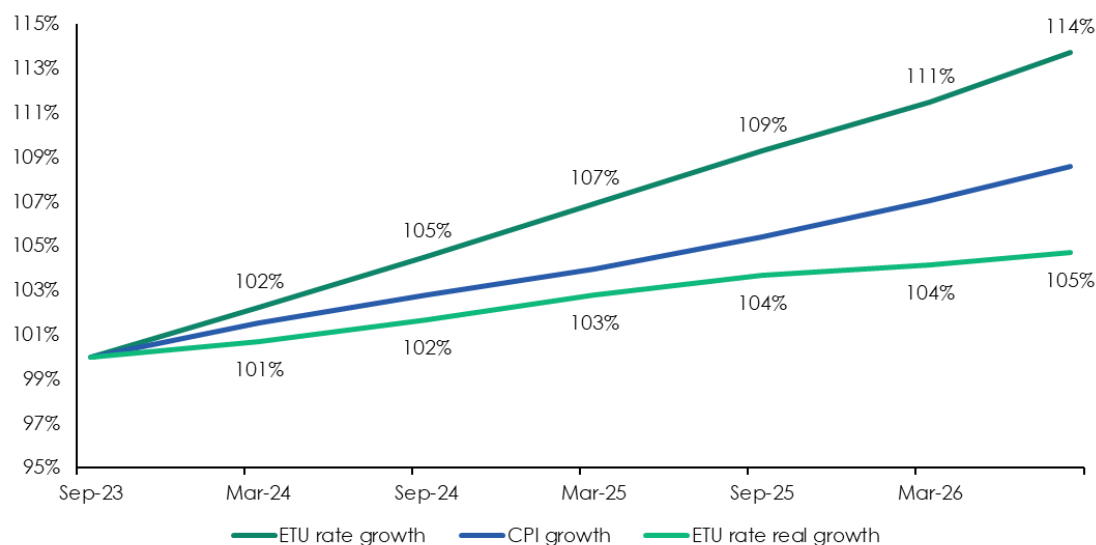
"...we see merit in the application of real cost escalation for external labour. While we appreciate the value the AER may see on precedence with recent decisions, we also see the value and importance of approaches evolving over time to reflect market conditions."

Since that time, the evidence is clear that demand pressures for skilled internal and external labour providing services to the utilities sector have resulted in real cost increases exceeding CPI. As shown in the figure below, the costs of the internal and external labour we rely on to deliver our capital works, which are governed by enterprise bargaining agreements (EBAs), have increased in real terms by around 1–2 per cent per annum, as evidenced by the EBA outcomes applying from 2022–26.

⁴⁰ AusNet, 2023-27 Transmission Revenue Review - Revised Revenue Proposal, 1 September 2021, p.75

⁴¹ AusNet, 2023-27 Transmission Revenue Review - Revised Revenue Proposal, 1 September 2021, p.76

Figure 5-3: Real ETU rate growth, Sep 2023 to Aug 2026



Source: AusNet

The agreements we have in place with our major project and O&M (asset replacement) contractors for the 2026–31 period reference applicable EBA outcomes when adjusting labour rates and the labour component of unit rates. Our exposure to contracted labour cost increases that are in line with EBA outcomes is demonstrated by the service agreement extracts we have provided as a supporting document. This responds directly to the AER's expectation that evidence should be provided to demonstrate that real cost escalation is reflective of the contract provisions or service agreements. As discussed below, consistent with recent experience, these arrangements will continue to result in real increases in contracted labour costs that exceeds CPI.

Our contractor agreements also include mechanisms to reflect reasonably anticipated productivity improvements and technological changes in future labour rate adjustments. However, real productivity gains have not offset observed wage growth, with EBA-linked rates consistently rising faster than CPI since 2022, as shown in Figure 5-4. The continuation of this trend is supported by the OEA forecasts, which show real growth in the Electricity, Gas, Water and Waste Services (EGWWS) wage price index over 2026–31. As the EGWWS measure captures both internal and contracted labour, the same escalation factor should be applied consistently across both components of our capex forecast. The link between real growth in the EGWWS WPI – which the AER accepts as its standard measure of real wage growth – and expected growth in contracted labour costs is confirmed by OEA:⁴²

*The WPI for the EGWWS (Electricity, Gas, Water & Waste Services or 'Utilities') sector in Victoria is used as a proxy for all of Victorian DNSPs electricity network related labour costs. Labour costs includes all internal labour (i.e. all head office staff including professional and admin employees plus field employees) **as well as any external labour hired to provide field services such as 'asset management' services.** Businesses providing these field services are usually classified to the utilities sector.*

The AER's standard approach risks distorting efficient delivery decisions. By applying real wage escalation only to internal labour, the AER effectively penalises networks that have adopted efficient outsourced delivery models, contrary to the principles of incentive regulation. Regulated businesses should be encouraged to choose the most efficient resourcing model, not the one that aligns most favourably with the regulator's escalation assumption.

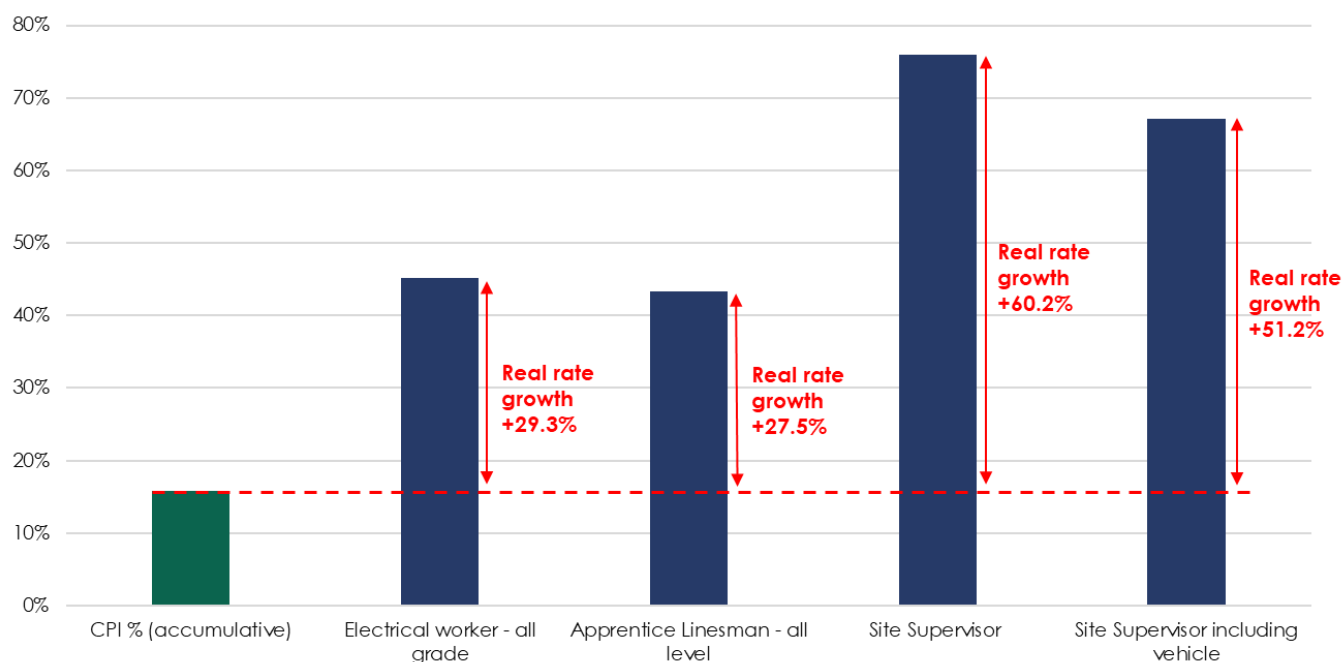
While the AER has considered in its recent determinations on this issue that distributors can manage contractor costs by adjusting contract scope or timing, this is not feasible in practice. Much of our capital and maintenance activity is required to meet reliability and safety obligations and cannot be deferred without unacceptable risk. Moreover, cost pressures in the contracted labour market are unlikely to ease in the short- to medium-term, given the sustained and growing demand for skilled labour to support the energy transition, consistent with the OEA forecast of real increases.

Economic theory and market evidence reinforce this view. Contractor labour operates in a more flexible and market-clearing segment of the labour market. Under tight labour conditions, consistent with those currently being experienced as increased network investment is required to support the energy transition, contractor wages adjust more quickly and sharply than internal wages, consistent with dual labour market and search-and-matching models. Applying CPI-only escalation to contracted labour ignores this dynamic and understates the efficient cost of maintaining delivery capability. Figure shows that the labour rates for contracted electrical workers – which deliver

⁴² Oxford Economics Australia, *Labour Cost Escalation: Forecasts to 2030/31*, September 2025

AusNet's capital works through our construction and design delivery partner contracting arrangements - grew at significantly higher rates than inflation from 2022-23 to 2025-26.

Figure 5-4: Accumulative Growth of Market Rate for Electrical Workers from 2022-23 to 2025-26 vs. Inflation



Source: AusNet

The market rate for contracted electrical workers is expected to continue growing at a rate above inflation, driven by persistent labour market tightness and skill shortages in Australia. According to the Powering Skills Organisation Workforce Plan, shortages in critical occupations such as electricians and energy trades are already evident, compounded by training system inefficiencies and declining apprenticeship rates.⁴³ Similarly, the Nous Group highlights that Australia will require an additional 85,000 workers by 2030 to meet renewable energy infrastructure needs, with over half of these roles in occupations currently experiencing national shortages, including electricians.⁴⁴ These structural constraints mean the labour market pressure is unlikely to ease in the near future, reinforcing upward wage pressures across the sector. While there is clear evidence of labour market tightness, which is placing upward pressure on contracted labour prices, we remain confident in our ability and capacity to deliver the proposed capital program

Finally, the AER's position creates an internal inconsistency between its opex and capex forecasting approaches. In setting opex, the AER escalates the base year by the EGWWS wage price index—which inherently captures both internal and contracted labour. To avoid creating a perverse incentive to shift capex to opex for forecasting purposes, the same principle should apply to the labour components of capital works and outsourced delivery.

For the above reasons, we consider that real labour escalation should be applied to both internal and contracted labour, informed by independent wage forecasts such as the OEA EGWWS index. This approach:

- Reflects real market conditions and the actual costs we expect to incur in delivering our capital program
- Maintains neutrality between capital works delivery models
- Avoids creating perverse incentives between capex and opex

⁴³ "Labour and skills shortages are already present in the energy sector. In 2023, four of the six critical occupations were found to be in shortage nationally by Jobs and Skills Australia. Many of these occupations are considered to be in 'persistent shortage,' with Electricians in shortage 12 times since 2003 and Airconditioning and Refrigeration Mechanics for nearly a quarter of a century."

— Powering Skills Organisation, Workforce Plan 2024, p. 25. Available at: https://poweringskills.com.au/wp-content/uploads/2024/08/Workforce_Plan_Report_2024_Final_15July2024.pdf

⁴⁴ "Australia will need an additional 85,000 workers by 2030 to deliver renewable energy infrastructure. More than half of these roles are in occupations already facing national shortages, including electricians, engineers and plant operators."

— Nous Group, Powering the Future: Securing the Workforce for Australia's Energy Transition, May 2025. Available at: <https://nousgroup.com/insights/powering-the-future?r=ANZ>

- Provides DNSPs are with sufficient opportunity to recover their prudent and efficient costs, in line with the Revenue and Pricing principles.

5.4.7. Gross vs. net energy at risk

Where it is relevant to calculate expected unserved energy, we have quantified it based on gross energy at risk, instead of net energy at risk. This accounts for involuntary load shedding of customers who have rooftop solar generation, and we cannot continue to ignore this segment of unserved energy, given that our network average penetration is 30% and growing, and customers place high value on their ability to self-consume the power that they generate on site. The gross approach is also mathematically consistent with the AER's VCR given that the VCR was developed by taking the value of an outage and dividing it by consumption data for households without PV, because of a lack of verifiable and granular data sources for self-consumption of individual households with PV. This means that the AER's VCR was derived with respect to gross consumption.

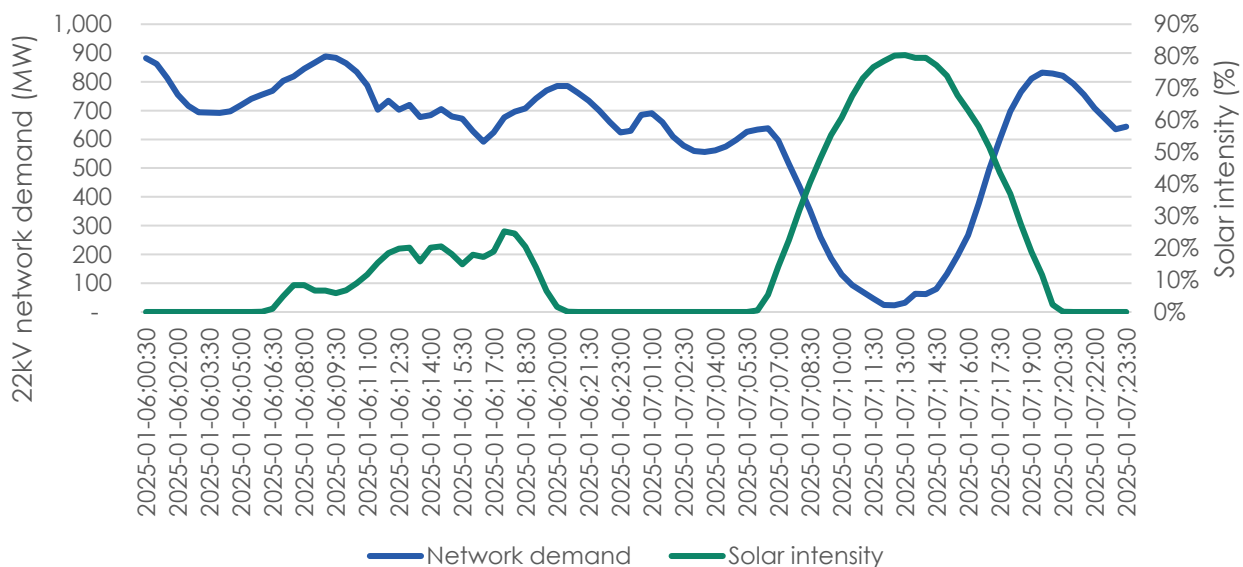
We have adopted the following conversion factors:

- Converting **average** energy at risk from net to gross = 1.22 (this is used when our energy at risk values are not split by season). This is based on 2023 data below, where grid generation as a percentage of underlying demand is 82% across the year, which is equivalent to a conversion factor of 1.22 (100%/82%).
- Converting **summer** energy at risk from net to gross = 1.33. This is based on 2023 data below, where grid generation as a percentage of underlying demand is 75% during summer, which is equivalent to a conversion factor of 1.33 (100%/75%).
- Converting **winter** energy at risk from net to gross = 1.13. This is based on 2023 data below, where grid generation as a percentage of underlying demand is 89% during winter, which is equivalent to a conversion factor of 1.13 (100%/89%).

The use of gross energy at risk is an improvement compared to our Initial Proposal as it places an appropriate value on rooftop solar generation, rather than applying an effective value of zero. Our analysis shows that the capex forecast in this Revised Regulatory Proposal remains the same whether using gross or net energy at risk, as the projects are justified under both methods.

On the 27 January 2025 (a 41 degree day), low solar output pushed up local grid demand by ~17%. The chart below shows network demand on our 22kV network on the 6th and 7th January 2025. The 6th January 2025 was a very low solar day and demand was approximately 700MW at midday, which is significantly higher than the next day which was a high solar day and demand was zero around midday. Both results corroborate with our 2023 data below showing that there is a significant amount of rooftop solar self-consumption that would be affected by load shedding in a similar way to those without rooftop solar.

Figure 5-5: Network demand on our 22kV network on the 6th and 7th January 2025



Source: AusNet. Solar intensity based on solar irradiance measures.

Table 5-5: Demand and generation by season in 2023

Year	Month	Season	Total Underlying Demand (MWh)	Total PV Generation (MWh)	PV generation % of total underlying demand	Grid generation % of total underlying demand
2023	1	Summer	1,366,639	352,875	26%	74%
2023	2	Summer	1,196,086	289,724	24%	76%
2023	3	Summer	1,250,476	246,688	20%	80%
2023	4	Winter	1,184,634	175,757	15%	85%
2023	5	Winter	1,343,855	131,435	10%	90%
2023	6	Winter	1,519,013	101,531	7%	93%
2023	7	Winter	1,561,814	122,714	8%	92%
2023	8	Winter	1,484,346	157,963	11%	89%
2023	9	Winter	1,267,823	241,655	19%	81%
2023	10	Summer	1,293,000	287,917	22%	78%
2023	11	Summer	1,189,677	312,092	26%	74%
2023	12	Summer	1,196,856	353,128	30%	70%

Source: AusNet

5.4.8. Top-down review

Consistent with our Initial Proposal, we have undertaken a top-down review of our network capex forecast, to identify and remove overlaps between projects and programs. This has resulted in the removal of \$209 million from our capex forecast.

This is necessary because we have developed our capex forecast using a bottom-up approach to respond to various drivers such as risk-based asset replacement, network augmentation, resilience and reliability.

Across the network investment proposal, projects address issues at specific geographical locations and may require work on a range of different asset classes. Meanwhile, programs typically address one specific asset class where the individual assets are located across multiple locations.

Each project or program typically identifies a driver for expenditure and estimates the volume and cost of assets required. The identification of assets for some programs is based on asset or fleet specific information and may not initially consider inter-relationships with other works being proposed or conducted. There is therefore the potential for overlap and synergies between programs and projects where two or more bodies of work are undertaken at the same location or propose to replace the same assets.

AusNet has therefore conducted a top-down assessment of its programs and projects to ensure any inter-relationship between elements of these are accounted for in the capex forecast for the 2026-31 regulatory period.

The table below provides a summary of the adjustments made. More information is provided in "ASD - AusNet - Top Down Review - 1Dec2025".

Table 5-6: Adjustments made from the top-down assessment of programs and projects

	Description
Repex / resilience	The resilience scope is to insulate [C-I-C] of bare conductors with covered conductors. The repex conductor program is to replace approximately 950km of bare conductors with bare conductors. The geographical overlap is 27km between the programs. We have removed the 27km overlap from our resilience program. This keeps our capex forecast low because when undertaking these replacements, we will be upgrading from bare to covered to achieve the intend of the resilience program, yet it is included in repex program at the lower unit rate of replacing bare with bare conductors. The resilience scope is to replace [C-I-C] timber poles with concrete poles and it overlaps the repex program by 4%. The repex program is to replace timber poles with timber poles. The 4% overlap is

	equivalent to 66 poles. We have removed the 66 poles overlap from our resilience program. This keeps our capex forecast low because when undertaking these replacements, we will be upgrading from timber to concrete poles to achieve the intend of the resilience program, yet it is included in the capex model at the lower unit rate of replacing timber with timber poles.
Low voltage replex / augmentation	Removed 58 pole top distribution transformers from the distribution transformers program.
Replex / ZSS rebuilds	Removed the following from the replex program: • 41x 22kV circuit breakers • 20x 66kV circuit breakers • 24x current transformers • 33x voltage transformers • 12x power transformers and station regulators • 35x bushing • 112x relays (of protection and control) • 122x HV switches • 18x auxiliary power systems • 6x station surge arresters

Source: AusNet

5.4.9. Capex smoothing

Based on each project/program's costs and benefits, our economic models calculate the optimal year for commissioning (the year it needs available and online). We used the optimal year for commissioning as the starting point in developing our capex profile in the SCS capex model. For example, we have spread the cost of the new Beveridge ZSS across FY27 and FY28 so that the Asset In Service (AIS) date aligns with the optimal year of FY28.

In some cases, we have deferred projects beyond their optimal year because:

- **Some critical projects are already overdue.** In spite of being deferred relative to their optimal timing, they have been prioritised to be delivered as soon as possible.
- **Priorisation.** Some projects have been deferred relative to their optimal timing because other more critical projects have been prioritised so that the overall capex profile is manageable.

To support these projects and timing, we have temporary measures in place to support supply risk over the next 2-3 years while construction is underway. These are temporary measures that can support low levels of energy at risk but cannot provide a cost-effective permanent solution.

Table 5-7: Example of some project deferrals / capex smoothing

	Optimal year for commissioning (being online) based on economic model	Year of commissioning (being online) based on the SCS capex model
Beveridge ZSS	FY28	Cost of station & 2 feeders spread across FY27 and FY28 with an expected Asset In Service (AIS) date of FY28 (matching the optimal year)
Wollert ZSS	FY28	Cost of station & 3 feeders spread across FY27 to FY29 with an expected AIS date of FY29 (deferred one year beyond optimal year).
Pakenham South ZSS	FY28	Cost of station & 3 feeders spread across FY27 to FY29 with an expected AIS date of FY29 (deferred one year beyond optimal year).
Eastern Cranbourne 66kV loop upgrade	FY28	Cost spread across FY27 to FY30 with an expected AIS date of FY30 (deferred two years beyond optimal year)

Source: AusNet

5.4.10. STPIS offsets

In the Initial Proposal we proposed to offset our estimate of STPIS rewards associated with resilience and reliability expenditure against our capex forecast –given that these projects will improve our reliability performance. Other projects are not expected to improve our reliability and therefore not subject to an STPIS offset.

The AER did not accept this approach and requested that we adjust the STPIS targets for these improvements. We accept the draft decision and, therefore, have adjusted our proposed STPIS targets to reflect expected reliability improvements. See section 11.4 on STPIS.

5.5. Cost estimates

5.5.1. Draft Decision

The AER had a number of concerns around our cost estimates which we have addressed in this Revised Proposal:

- **High and unsubstantiated costs.** In a few places, the AER stated that our projects and programs had high unit costs, or cost estimates that were difficult to substantiate, or blanket additional percentages were applied and that these approaches do not demonstrate efficiency.
- **Risk allowances.** The AER rejected the inclusion of general risk allowances because they should only be accepted for specific, identifiable risks that are reasonably likely to occur and beyond the network's control. It also considered that the types of costs covered by the risk allowance were already accounted for elsewhere. We disagree and have addressed the AER's concerns by providing more information and further analysis.

In respect of the risk allowances included in our Initial Proposal, which the AER did not accept, the findings and concerns identified by the AER and EMCa are as follows:

- As a general principle, the AER only approves project specific risk allowances and does not consider that allowances applied broadly to various capex programs and projects are for specific risks that are reasonably likely to arise and are beyond the control of AusNet.
- The AER considered that our proposed risk allowances are to manage overheads, finance charges or the management reserve.
- The AER considered that AusNet has significant control over its capital program and project delivery risks are within AusNet's control.
- The AER considered that AusNet's contract with its service provider Zinfra should already account for project risk.
- EMCa considered that our direct cost components reflect the realised costs of inherent and contingent risks.
- EMCa analysis of data we provided regarding actual vs estimated P(50) costs did not support the application of risk allowances.
- EMCa considered that the risk allowance applied to unit rates based on Zinfra work items is reasonable.

5.5.2. Addressing the Draft Decision

We have addressed the AER's concerns by providing a full suite of bottom-up capex estimates across all our individual and discrete projects, and full suite of our unit rates build up that we rely on for bulk programs. We also engaged an independent consultant to review AusNet's cost estimates for the three new zone substations (Wollert, Beveridge and Pakenham South) and five of our station rebuild projects, who concluded that our costs are aligned to market rates.

We have addressed the AER's concerns with respect to risk allowances by providing an in-depth discussion of why they are appropriate under most circumstances (see section 5.5.2.3). In this Revised Proposal, we propose to continue including a risk allowance in our project cost estimates, for the reasons discussed in section 5.5.2.3. However, not all program cost includes a risk allowance, the table below outlines which programs include risk allowance and which do not. These are explained in detail in this section below.

Table 5-8: Inclusion of Risk Allowance by Program Type

Program types	Inclusion of P(50) risk allowance
Individual and discrete projects delivered by major project delivery partners - with cost estimated using internal estimate	Yes
Bulk programs to be delivered by Zinfra - with cost estimated using contracted rates	Yes
Bulk programs to be delivered by major project delivery partners – with cost estimated using internal estimate	Yes
Bulk programs to be delivered by major project delivery partners – with cost estimated using actual recent project cost	No

Source: AusNet

5.5.2.1. Cost estimates for individual and discrete projects

At AusNet, there are three types of cost estimates for **individual and discrete projects**, each reflecting a different level of known project scope:

- **Planning estimates.** The project definition for Planning estimates is in the range of 1% to 15%. AusNet prepares Planning estimates based on conceptual scopes that are preliminary and high level in nature with broad functional requirements. This type of estimate is used in economic evaluations and options analysis. The level of accuracy of our Planning estimates align approximately with a class 4 estimate as defined by AACE, which is in the range of -30% to +50%, as shown in the table below.
- **Business Case estimates.** A Business Case estimate is considered a more detailed and accurate estimate where the level of the project definition is in the range of 10% to 40%. AusNet prepares Business Case estimates based on more detailed scoping. The key difference between a Planning estimate vs. a Business Case estimate is the certainty of the scope of works, and the amount of detail provided in the scope of works. The level of accuracy of our Business Case estimate aligns approximately with a class 3 estimate, which is in range of -20% to +50%.
- **Control estimates.** A Control estimate is a more mature estimate when the level of the project definition is in the range of 65% to 100%. The level of accuracy of our Control estimates aligns approximately with a class 1 estimate, which is in the range of -10% to +15%.

Consistent with our Initial Proposal and our approach at the last price review, our capex forecast for individual and discrete projects are generally based on Planning or Business case estimates. We note that despite the low level of known project scope at the Planning phase, our sophisticated and experienced estimating process means that we can achieve far higher accuracy than implied (accuracy in the range of -30% to +50%). Importantly our forecast does not have an upward bias as indicated by the range of the accuracy.

We have provided an updated version of our "ASD-AusNet-Project Cost Estimating Methodology-1Dec25-PUBLIC" as supporting documentation. This document contains more information about our cost estimating approach. Additionally, for each project that we have proposed, we have provided a detailed bottom up cost estimate that shows the unit rates, volumes and quantities assumed.

Our capex forecast for individual and discrete projects is made up of two components: a direct cost component and a P(50) risk allowance. Chapter 5.5.2.3 provides more information on why the inclusion of a P(50) risk allowance is appropriate.

Table 5-9: Estimate class based on the Association for the Advancement of Cost Engineering (AACE) classification

Estimate class	Primary Characteristics	Secondary Characteristics		
	Maturity level of project definition deliverables <i>Expressed as % of complete definition</i>	End usage <i>Typical purpose of estimate</i>	Methodology <i>Typical estimating method</i>	Expected accuracy range <i>Typical variation in low and high ranges at an 80% confidence interval</i>
Class 5	0 to 2%	Functional area, or concept screening	SF or m ² factoring, parametric models, judgement, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Or Schematic design or concept study	Parametric models, assembly driven models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Design development, budget authorisation, feasibility	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender, semi-detailed	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or pre bid/tend, change order	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

5.5.2.2. Cost estimates for bulk programs

Project cost estimates for bulk replacement programs—comprising high-volume, low-value assets—are derived by multiplying the nominated replacement volume by a bottom-up unit rate.

In this Revised Proposal, for programs where the AER accepted our proposed unit rate in its Draft Decision, we have retained the unit rates from our Initial Proposal. For programs where the AER raised concerns regarding unit rates, we have updated our unit rate estimates.

For bulk programs with work type (mostly reactive replacement of poles, cross-arms and other lines assets) that are covered by the Zinfra contract and will be delivered by Zinfra, the unit rate is estimated based on the Zinfra contract, and composed of two parts.

- **Direct unit rate estimate:** Based on the target baseline rates specified in the Zinfra contract. As the Zinfra contract excludes material costs, the direct unit rate estimate is calculated as the sum of the target baseline rates and the material cost. Material costs are estimated using actual historical cost data.
- **Risk allowance:** Calculated to account for our contractual exposure to actual costs exceeding the target baseline costs. Further details on this are provided in Section 5.5.2.3 below.

For other programs not covered by the Zinfra contract, which will be outsourced to our major project delivery partners (mostly proactive programs, e.g. conductor replacement) the updated unit rate is estimated using either internal estimates based on historical actual cost of comparable projects or actual recent project cost. If it is based on internal estimates, it is estimated using the same approach for the individual projects. Its unit rate estimates consist of direct unit rate estimate and a risk allowance:

- **Direct unit rate estimate:** Estimated based on expected scope under normal conditions assuming no risk materializing. The estimated cost of cope items are derived from historical actual cost data for comparable projects.
- **Risk allowance:** Calculated using Monte Carlo simulation to account for the inherent and contingent risks of the projects. Further details on this are provided in Section 5.5.2.3 below.

If the project is estimated based on actual recent project, the unit rates estimates only include a direct unit rate estimate and no risk allowance is included:

- **Direct unit rate estimate:** Derived from actual cost data for recently completed comparable projects, covering direct cost components such as labour, materials, design, internal labour, and disposal.
- **No risk allowance:** We do not add risk allowance on top of the direct unit rate estimate for this type of programs.

We have detailed the unit rate estimates for each bulk asset in the spreadsheet 'ASD - Unit Rates - 1 Dec 2025 – CONF', which is provided together with this Revised Proposal. This document also identifies the programs delivered by Zinfra and other programs, details the unit rate calculations for both program types, and specifies the sources of the unit rate data.

5.5.2.3. Risk allowances

The AER rejected our proposed risk allowance and stated that risk allowances should only be accepted for specific, identifiable risks that are reasonably likely to occur and beyond the network's control, not as a general percentage uplift. It also considered that many of the costs AusNet sought to cover through the risk allowance were already accounted for elsewhere, meaning inclusion would result in double counting and customers paying for costs that may not eventuate.

We agree that only program specific risk allowances should be accepted and applying risk allowance as a blanket percentage uplift to direct cost estimates is not reasonable. In this Revised Proposal, for projects where we determine a risk allowance as part of a P(50) cost estimate, we have modelled these risk allowances probabilistically to reflect project-specific risks, rather than a general uplift. We only applied blanket percentage uplift to a minority of projects (5 in total, discussed in more details below).

However, we do not agree with the AER that risk allowances applied to our capex programs and projects are for risks that are unreasonably likely to arise and are within the control of AusNet. The risk allowance included in our project cost estimates account for the inherent risks and contingent risks that are beyond our control. We also do not agree with the AER that direct cost components reflect the realised costs of inherent and contingent risks and including a risk allowance would result in double counting of costs. As explained in detail below, our direct cost estimates assume projects proceed without any risks materialising and only reflect expected costs under normal conditions. Costs associated with inherent and contingent risks are captured exclusively through the risk allowance.

In addition, the AER has incorrectly inferred that our proposed risk allowances are to manage overheads, finance charges or the management reserve. We have explained this in detail in our Cost Estimating Methodology Paper 'ASD - Ausnet - Project Cost Estimating Methodology 1Dec2025', provided together with this Revised Proposal. As discussed above and in more details below in this section, our risk allowances account only for the inherent risks and contingent risks of our programs.

In this revised proposal, we have retained risk allowances in our cost estimates; this is necessary to ensure that our forecasts reflect a realistic expectation of expected, prudent and efficient delivery costs. Below, we explain in detail why a risk allowance is required, the types of risks it addresses, how these risks are identified and quantified, and the empirical evidence supporting our approach.

By adding a P(50) risk allowance to our direct cost estimates, our cost is a probability weighted cost where there is a 50% chance of actual cost coming in less than forecast and 50% chance of actual exceeding forecast.

5.5.2.3.1. The case for risk allowances should be assessed holistically and take account of the cost estimating approach being applied

We acknowledge the AER's general principle of only accepting risk allowances in limited circumstances that are specific to a particular project or program, and its determinations for other networks referred to in the Draft Decision. However, we consider that whether the inclusion of a risk allowance is warranted is inherently linked to the Cost Estimating Methodology applied by each network to develop its regulatory submission cost estimates. There will invariably be differences between networks in how individual project and program cost estimates are built up, the basis for these cost estimates, and how risk is accounted for and quantified.

In the case of the AER's Power and Water Corporation distribution determination 2024–29, the AER rejected PWC's proposed contingency allowances for "construction cost and design development contingencies" associated with its proposed single site consolidation property project. From the publicly available information on this project,⁴⁵ it is not clear whether PWC's inclusion of these allowances is consistent with unbiased, p(50) cost estimates which, as discussed below, is the basis on which our proposed cost estimates have been prepared. For example, the PWC contingency costs may reflect management reserve contingency allowances which, for AusNet, are typically incorporated as part of a P(90) estimates (which are not included in our regulatory submissions). Further, there may be differences in scope maturity between this project and the projects and programs included in this Revised Proposal (discussed in the previous section) which should be considered; there is a stronger case for including risk allowances in cost estimates for projects with relatively low scope maturity, recognising the greater level of uncertainty that applies to outturn costs.

Accordingly, we consider the AER should take a case-by-case approach to assessing whether, holistically, a risk allowance is warranted and necessary to derive robust, unbiased cost estimates, rather than adopt a blanket approach to assessing and rejecting risk allowances in line with its general principle.

5.5.2.3.2. Risk Allowance Covers Risk Costs Not Captured in Direct Cost Estimates for individual programs and projects

For individual programs and projects, our cost estimates comprise two components: a direct cost estimate and a P50 risk allowance. Importantly, the direct cost estimate assumes that the project proceeds without any unforeseen risks materializing. It includes:

- **Materials:** Based on current supplier rates for specific equipment.
- **Labour:** Derived from blended contractor rates and productivity assumptions.
- **Plant and Equipment:** Costs for vehicles and tools required for the scope.
- **Standard Overlays:** Project management, site facilities, and predictable factors such as allowances for inclement weather.

Importantly, these direct costs reflect the expected scope under normal conditions. They do not incorporate additional costs arising from latent or contingent risks. For example, labour hours are calculated assuming a straight run of work without delays or rework. If risks occur, these assumptions no longer hold, and actual costs increase.

For this reason, to derive a robust estimate of expected costs, it is necessary to incorporate a risk allowance that is designed to capture inherent and contingent risks that are not embedded in the direct cost estimate. These risks typically arise during detailed design or delivery and represent real costs that we may incur but cannot reasonably include in the direct cost build-up because they depend on probabilistic events. Specifically, these risks include:

⁴⁵ See <https://www.aer.gov.au/system/files/2023-12/PWC%20-%20Revised%20proposal%20-%203.5%20-%20RBC%20Single%20Site%20Consolidation%20-%2030%20Nov%202023%20-%20PUBLIC.pdf>

- **Inherent Risks:** Uncertainty in scope or quantities due to incomplete information at early stages. The use of Planning and Business Case estimates (as described in the previous section) to develop our regulatory submission capital expenditure forecasts – which rely on a relatively low level of scope maturity compared to control estimates developed closer to project delivery – highlights the need to model and incorporate inherent risks in our cost estimates
- **Contingent Risks:** External or unforeseen factors such as:
 - Project delays (often the largest driver of cost escalation).
 - Market conditions and contractor pricing volatility.
 - Latent site conditions (e.g., contamination, asbestos).
 - Scope creep and design changes.
 - Third-party impacts (e.g., traffic management, customer access constraints).
 - Other contingent risks, such as weather, etc.

These risks are not hypothetical—they occur regularly in project delivery. For example, contamination risk can only be confirmed through site sampling, which is often not completed at the estimating stage. Similarly, market volatility and contractor pricing strategies can lead to significant cost increases through variations or inflated tender responses.

We adopt a probabilistic risk analysis approach, including Monte Carlo simulation, to derive project-specific risk allowances. This process involves:

- Identifying relevant risks for each project.
- Assigning likelihood and impact ranges for each risk.
- Running thousands of simulations to generate a risk profile.

The resulting allowance reflects the P50 expected cost impact of these risks, ensuring that our forecasts are robust and aligned with industry standards. For early-stage estimates with limited scope detail, a flat percentage may be applied, but for the majority of cost estimates in this revised proposal, risk allowances are derived from project-specific analysis. We confirm that blanket percentage uplift has been applied to the five repex projects listed below. This represents a significant improvement over the January submission, where flat rates were used more broadly due to limited scope detail.

Table 5-10: Projects with Risk Allowance as Blanket Percentage Uplift

No.	Capex Category	Project Name
1	Replacement capex	66kv Surge arrestors (Stations)
2	Replacement capex	22kV surge Arrestors (Stations)
3	Replacement capex	HV Switches (Stations)
4	Replacement capex	ACR (Full Replacement): Applied only under the REFCL Policy. For other ACR replacements, our rate is based solely on tank costs derived from actual project data (lines).
5	Replacement capex	Voltage regulators (lines)

Source: AusNet

5.5.2.3.3. Risk Allowance Covers Risk Costs Not Captured in Direct Unit Rate Estimates for bulk programs

For bulk programs where unit rates are estimated based on Zinfra contract, it is necessary to include a risk allowance to account for contractual exposure to actual costs exceeding the target baseline costs. We do not agree with the AER's view that AusNet's contract with its service provider Zinfra should already account for project risk.

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While the AER states that AusNet is best placed to manage 'delivery risk', under these contractual arrangements, where this risk is realised and impacts Zinfra's actual delivery costs, AusNet is exposed to these risks costs. This exposure is not reflected in the TCE contracted rates set out in the contract, i.e. the direct unit rate estimates based on the target baseline do not capture this risk.

To address this, we apply a risk allowance to the bulk programs where unit rates are estimated based on Zinfra contract. Therefore, in this Revised Proposal, we have repropose the risk allowance applied to unit rates based on Zinfra work items, which are calculated and estimated using the same approach in our Initial Proposal. For the reasons set out above, excluding this allowance from our unit rates would fail to provide AusNet with the opportunity to recover its efficient costs and therefore, be inconsistent with the Revenue and Pricing Principles. Finally, we note that EMCa considered that the risk allowance applied to unit rates based on Zinfra work items in our Initial Proposal is reasonable;⁴⁶

"We have reviewed AusNet's full response including an overview of key elements of the design of the commercial model, and consider the approach adopted by AusNet to include a risk allowance for unit rates over the term of the regulatory period is reasonable."

For other programs not covered by the Zinfra contract, which will be outsourced to our major project delivery partners (mostly proactive programs, e.g. conductor replacement) the updated unit rate is estimated using either internal estimates based on historical actual cost of comparable projects or actual recent project cost.

- For projects with costs estimated based on internal estimate, the same methodology applied to individual projects discussed above is used, the unit rate estimate consists of a direct unit rate estimate and a risk allowance. The direct unit rate estimate reflects the expected scope under normal conditions, assuming no risks materialize. Cost estimates for scope items are derived from historical actual costs for comparable projects. Consequently, the direct unit rate estimate does not account for inherent or contingent risks faced by these projects, similar to the risks identified for individual projects above. To address these risks, it is necessary to include a risk allowance. The risk allowance is quantified using the same approach as for individual projects – Monte Carlo simulation.
- For projects with costs estimated based on actual recent project cost. We do not add a risk allowance on top of the direct unit rate estimate to avoid double dipping.

5.5.2.3.4. Our asset replacement project cost estimates broadly align with our actual costs

To demonstrate the robustness of our forecasting approach for asset replacement programs, we compared P50 cost estimates (including a risk allowance) with actual/expected costs for a portfolio of 120 asset replacement projects totalling \$685 million. Both actual and estimated costs are inclusive of overheads.

Table 5-11: P50 Cost Estimate vs. Estimate at Completion for a Sample of Replacement Projects

	P50 cost estimate (incl. risk allowance)	Estimate at completion
\$M, nominal, incl. OHDs	\$685.0	\$748.5
%	100%	109.3%

Source: AusNet

This analysis shows that the total actual cost (including estimated actual costs for works in progress) for delivering a portfolio of approximately 120 asset replacement projects is around 9 percent higher than our P50 cost estimates of \$685.0 million, which include risk allowances. This data demonstrates that the inclusion of the risk allowance is appropriate.

We have provided similar data in response to the AER's information request (Spreadsheet: *P50 vs EAC for sample of Dx projects.xlsx*). That analysis showed the total actual cost for delivering the portfolio of asset replacement projects was around 22 percent higher than our P50 cost estimates. The AER and its consultant EMCa observed that, after excluding bulk replacement programs and outliers, actual costs were 7 percent lower than P50 estimates and concluded this does not justify the inclusion of a risk allowance.

While we agree that outliers should be excluded, we do not consider it reasonable to exclude bulk replacement programs from the analysis. As discussed above, these programs also face the inherent and contingent risks outlined above and their actual costs may exceed estimates where these risks materialize during delivery. Including them

⁴⁶ Energy Market Consulting Associates (EMCa). (2025). Review of Aspects of Proposed Network Related Expenditure and CER: AusNet Services 2026–2031 Regulatory Proposal. Report prepared for the Australian Energy Regulator (AER). Final v1, para 185, page 22.

would not bias the result, and excluding them would ignore a significant portion of real-world risk exposure and understate the empirical evidence. Therefore, the data presented above on the 120 asset replacement projects reflects the same list of projects, but with outliers (projects with actual costs greater than 10 times the P50 estimate) removed. The result still indicates that actual costs are above our P50 estimates – as shown in the table above – reinforcing the need for a risk allowance.

5.5.2.3.5. Specific examples of inherent and contingent risks materialized in our replacement program

To illustrate that the inherent and contingent risks covered by the risk allowance are not uncommon and do impact actual costs in the course of delivering capex projects and programs, we provide specific examples of recent asset replacement projects where actual costs were materially higher than the P50 cost estimates due to these risks materializing during delivery, drawing on the projects included in the above dataset. These are outlined in the table below.

Table 5-12: Examples of Recent Asset Replacement Projects with Actual Costs Higher than P50 Estimates Due to Risks Materializing

Project	P50 Estimate Direct (\$M, nominal, incl, OHD)	Estimate at completion (\$M, nominal, including OHD)	EAC / P50 (%)	Drivers for overspend
YPS-WGL-MOE #2 Groundwire Replacement	\$4.7	\$5.9	125%	1. Weather: Adverse weather conditions required additional allowance in the CDP contract. 2. Contract Variations from CDP: Zinfra's overhead charge increased to 13.5% of direct costs, and a change in construction methodology (from extended outages to daily outages) drove extra operator time and costs. 3. Incomplete Scope: Original estimate missed allowances for delivery partner incentive payments.
High Risk Poor Condition ACRs Replacement	\$3.7	\$4.7	129%	Cost Variations from CDP: Zinfra's construction and variation costs increased significantly, including additional charges for installation/removal of MSI units to minimise outage impacts, replacement of a faulty transformer during an outage, and stranded crew costs due to outage cancellations. These variations, combined with scope changes, drove the direct cost increase
ZSS ENV Upgrade Eight Stations	\$5.5	\$7.2	130%	1. Site Contamination: Disposal costs for contaminated soil were far higher than planned due to EPA regulatory changes, increased landfill charges, and underestimated volumes in the original business case. 2. Incomplete Scope: Original scope and cost estimates from 2016 did not account for updated compliance requirements and actual site conditions, leading to additional work and funding needs.
EDO Fuse Replacement (FY22-FY26)	\$13.5	\$17.9	132%	1. Cost Variations from CDP: Delivery partner costs were much higher than the original business case estimate, with some CDPs charging up to double the expected rate 2. Scope Refinement: Additional requirements emerged, including protection studies for fuse grading and revisiting sites to upgrade incorrectly installed fuses, which were not included in the original scope.
22 kV Dist Net Fusesavers Inst REFCL T2	\$5.0	\$6.8	137%	1. Cost Variations from CDP: Increased Zinfra overheads (from 7% to 15%) and additional civil works, traffic control, and underground works drove costs higher than planned. 2. Scope Creep: Extra tasks emerged, such as installing Bluetooth extender kits, additional BA fuses, and redesign works at LAHA sites. 3. Weather: Wet weather claims added unplanned costs and delays. 4. Defect Rectification: Replacement of inoperable ILJIN switches and addressing fuse saver communication issues required corrective actions.
ILJIN Overhead Manual Switch Replacement	\$12.0	\$16.9	141%	Incomplete Scope: Original plan only covered replacing 480 switches; later, servicing 941 switches and increasing replacements to 520 were added, which were not included in the initial business case. This was necessary to restore operability of additional switches and maintain network reliability while Phase 2 of the program is developed.

Project	P50 Estimate Direct (\$M, nominal, incl, OHD)	Estimate at completion (\$M, nominal, including OHD)	EAC / P50 (%)	Drivers for overspend
Mt Hotham - DPP HV Cable Replacement	\$4.9	\$7.2	146%	1. Scope Refinement: Original business case assumed open trenching, but environmental and cultural constraints required directional boring and additional reinstatement works, increasing complexity and cost. 2. Design Update: Design changes were needed to comply with petrochemical regulations and address reliability gaps not covered in the original scope, including critical cable sections under the Great Alpine Road. 3. Construction Urgency due to Incoming Winter: Stage 1 had to be completed before the winter season to maintain supply to Mt Hotham Snow Village, driving unplanned works and cost escalation.
Warragul ZSS Transformer Replacement and 66kV Rebuild	\$18.7	\$31.0	166%	1. Outdated Cost Estimations for CDP Costs: Significant increase in construction and labour costs since the project was originally estimated 2. Cost Increase for Materials: Increased costs for power transformers, capacitor banks and control building procurement costs compared with original business case estimate
REFCL Augmentation - BGE	\$9.5	\$16.4	173%	1. Scope Refinement: Additional works were required, including installing extra earthing at Belgrave Zone Substation to resolve ghost voltage issues, constructing façade panels, landscaping, and shared driveway works. 2. Cost Variations from CDP: Increased complexity in Downer's underground work for isolation substations, including boring cables and extended generation requirements, drove costs higher than planned.
REFCL T2 ZS WORK - FGY	\$10.9	\$19.1	175%	1. Design Update: Detailed design changes were required for transformer remediation, including raising the plinth, replacing all primary cables, and adding partial discharge testing to meet asset standards. 2. Cost Variations from CDP: Increased construction duration, higher TOMSA labour rates, additional craneage, and LV generation support costs significantly raised the overall estimate.
ZS 66kV Urgent CB CT Replacement	\$4.5	\$8.5	189%	1. Hiring of Security: Security services were required at MOE and FGY substations due to multiple site breaches during construction, adding unplanned costs. 2. Unplanned decommissioning of additional assets: Removal of large amounts of primary equipment at MOE ZSS (including circuit breakers, surge arrestors, VTs, CTs, and isolators) was not initially budgeted,
SLE ZSS 66kV Primary & Secondary Works	\$2.8	\$5.3	190%	1. Project Delays: Late delivery of ABB dead tank circuit breakers due to pandemic-related supply chain disruptions and prioritisation of REFCL works caused a 7-month delay 2. Scope Refinement: Additional works included constructing a temporary 66kV bay for MWTS-SLE line to mitigate outage risks and transferring nine VT replacements from another project 3. Design Update: Changes in earthing standards required redesign and assessment, increasing costs 4. Cost variation from DDP: actual DDP cost higher than original allowance
Maffra ZSS 66kV CB CVT Replacements	\$17.5	\$34.4	197%	1. Outdated Cost Estimations for CDP Costs: Significant increase in construction and labour costs since the project was originally estimated 2. Scope Refinement: additional civils works and associated costs due to complex, brown-field project environment 3. Cost Increase for Materials: Increased costs for capacitor bank and control building procurement costs compared with original business case estimate

Project	P50 Estimate Direct (\$M, nominal, incl, OHD)	Estimate at completion (\$M, nominal, including OHD)	EAC / P50 (%)	Drivers for overspend
Clyde North 3rd Transformer and Switch room	\$12.5	\$25.7	206%	1. Outdated Cost Estimations for CDP Costs: Significant increase in construction and labour costs since the project was originally estimated. 2. Project Delays: local council rejected stormwater discharge design, resulting in site construction delays and resulting storage costs for transformer and control room
74357063 - ZSS 66kV CB- CT replacements	\$3.8	\$9.1	241%	1. Outdated Cost Estimates for Labour: Labour and overhead costs escalated significantly from the original estimate, driven by increased reliance on internal resources during COVID-19 and extended project duration 2. Long lead times: Correct long-lead items had to be repurchased because original equipment was diverted to other urgent projects, delaying construction and increasing costs. 3. Unrecovered Materials: A substantial portion of materials originally funded for this project was used on other projects and could not be replenished, requiring additional procurement and funding.
MDI Supply Modification Works	\$1.8	\$4.3	241%	1. Long lead times: Delivery delays for critical equipment, including spare 66/22kV transformer and regulators, due to prolonged factory acceptance testing and limited availability of 50A units. 2. Issues Materialised: Environmental rehabilitation of the old ZSS site was more extensive than estimated, compounded by poor subsurface conditions requiring additional fill, compaction, and stormwater drainage works. 3. Scope Refinement: Added 66kV circuit breaker, transformer protection, RTU/DIC, underground feeder exit cable, and extra civil works to meet constructability and compliance requirements, along with integration into related feeder projects.

Source: AusNet

In conclusion, based on the reasons outlined in this section, we propose including a risk allowance in project cost estimates to account for inherent and contingent risks, as well as contractual exposure to cost escalation—risks not captured in the direct cost estimates. For most projects, we have estimated program-specific risk allowances at the program level, applying blanket percentage uplifts only to five projects.

5.5.2.4. Cost escalation and broader industry trends

We engaged Worley to undertake an independent cost review of the following projects within our capex forecast:

- Beveridge zone substation
- Wollert zone substation
- Pakenham South zone substation
- Watsonia refurbishment
- Thomastown stage 2 – 22kV
- Traralgon stage 2 – 22kV switchboard upgrade
- Newmerella refurbishment
- Kilmore South ZSS 22kV switch room replacement

Their cost review concluded that the primary drivers of cost increases between our Initial Proposal and Revised Proposal relate to:

- The addition of new feeders and associated civil and electrical works for the new zone substations. We could not find evidence that the costs of feeders were included in the January 2025 submission for Wollert and Pakenham South zone substations.
- More advanced projecting definition and scoping allowing for specificity in cost build-up.

- Updated supplier pricing for materials, equipment, and labour.
- Project-specific constructability requirements identified through more detailed planning.

Worley's assessment considered AusNet's detailed cost build up for each project within scope, AusNet's cost estimating methodology, updated supplier information, AusNet's Construction Delivery Partner (CDP) rates, market cost evidence and Worley's internal pricing datasets. Worley's review tested whether:

- unit rates are aligned with current industry benchmarks and supported by verifiable supplier inputs, and
- AusNet's approach to developing the P50 risk allowance is consistent with its CEM and AER expectations.

Worley concluded that AusNet's updated estimates reflect current market unit costs and demonstrate appropriate application of AusNet's cost estimation methodology.

5.6. Replacement and safety expenditure

This section addresses replacement expenditure with an age, condition or safety driver. The following expenditures that have been classified as repex in the AER's standardised SCS Capex Model, but have different drivers, are discussed in other sections of this Revised Proposal:

- Resilience programs involving asset replacement (discussed in section 5.10);
- The operational technology component of our proposed ADMS investment (discussed in section 5.13).
- The component of our proposed metering communications systems replacement expenditure allocated to distribution (discussed in Chapter 13 – Metering Services).

References to safety expenditure in this chapter exclude REFL augmentation, which is discussed in section 5.14.

5.6.1. Our Initial Proposal

Our Initial Proposal included replacement and safety expenditure of \$1,136.5 million. We considered this expenditure necessary to manage increasing network risk associated with an ageing asset base, meet our regulatory obligations and maintain network reliability and safety during the 2026-31 regulatory period. Further detail on our Initial Proposal forecast is provided further below in Table 5-16.

5.6.2. Draft Decision

The AER accepted \$689.8 million of our repex and safety proposal, which represents a 39% reduction. The AER accepted the following repex projects and programs:

- Civil infrastructure
- Crossarms
- Comms
- Compliance
- Construction insurance.

The key reasons for rejecting the remainder of our repex and safety forecast primarily relate to:

- **Risk modelling and inputs** - The AER considered that AusNet's risk models (used to forecast failures and replacement timing) were not properly calibrated to historical failure data, and that some inputs (e.g. consequence of failure, environmental or safety weights) seemed overstated.
- **Value of customer reliability** – the AER considered that AusNet's hybrid approach using its own "QCV" (Quantifying Customer Value) / VCR (Value of Customer Reliability) framework was not sufficiently justified or compared with standard AER VCR approaches.
- **Lack of detailed project level justification** – the AER observed that in many cases AusNet provided high level modelling but lacked project specific cost benefit analysis, scope or timing justification, overlap between

programs, or explanation of blanket percentage adjustments. The AER flagged that such “blanket” assumptions were not sufficiently supported.

- **Trend / top down checks weak or not reconcilable** - The AER attempted to use top down trend analysis (e.g. network-wide reliability signals, failure trends) and repex modelling to assess the forecast, but found AusNet’s historical data and forecasts could not be reconciled. Because of this, the AER undertook a bottom-up review rather than fully relying on trend analyses.
- **Contingency / “risk allowances” not supported** – the AER observed AusNet had included a general contingency or risk allowance across its capex estimates; the AER did not accept this without project specific support.
- **Timing and volumes adjustments** - The AER adjusted volumes and timing of some replacement programs based on its own view (or where AusNet lacked justification) to determine its alternative forecast. Where AusNet’s proposal lacked support, the AER defaulted more to historical expenditure levels.
- **Insufficient economic justification.** In the case of some programs, e.g., Proactive SWER replacement in Codified Areas, the AER rejected the proposed expenditure as it had not been economically justified by AusNet.

5.6.3. Addressing the AER’s Draft Decision

While we have accepted several components of the draft decision on repex and safety, we do not accept the AER’s draft decision on this investment category overall as the alternative forecast is insufficient to manage increasing network risk associated with an ageing asset base, meet our regulatory obligations and maintain network reliability and safety during the 2026-31 regulatory period.

The projects and programs where we have accepted the draft decision are shown in the table below. In most cases, we have accepted the draft decision where the AER has approved an amount that is not materially different to our Initial Proposal forecast (shaded purple). In the other, following cases:

- **Instrument transformers (VTs & CTS), services, MV switches (air break and ground/indoor), environmental** – for these programs, while we have concerns with level of funding approved in the draft decision, we have adopted the AER’s alternative forecast as it is not materially to our latest, internal forecasts.
- **Distribution poles (street lights)** – the inclusion of street lighting poles in our SCS forecast was an oversight which has been corrected in this Revised Proposal by appropriately including this expenditure in our ACS forecast.
- **Proactive SWER replacement (Codified Areas)** – the Draft Decision provides sufficient funding to maintain the replacement rate of 100km approved for the current regulatory period. We remain concerned that this replacement rate will defer to later regulatory periods the significant volume of Codified Area SWER and bare conductor replacement that is required to meet the VBRC and subsequent PBST’s recommendations. However, the AER’s expectation of economic analysis to justify this program – which is a change in approach to its current determination - cannot be met in and, therefore, we have adopted the draft decision outcome in our Revised Proposal.
- **Early Fault Detection (EFD) devices** – while we have accepted the Draft Decision on the EFD devices program included in our Initial Proposal, we have repropose an alternative, reduced scope EFD devices program as part of our conductor business case, with a revised justification approach demonstrating the net economic benefits of this technology and our proposed investment to deploy it on our network.

We acknowledge there are minor differences between the Draft Decision and our Revised Proposal for the repex programs and projects where we have accepted the Draft Decision. To avoid double counting between the contractor support costs embedded in the repex projects and program costs where we accept the Draft Decision, and the contractor support costs allocated across our Revised Proposal network capex forecast, we have populated the SCS Capex model inputs with:

- The same direct cost unit rates and volumes (prior to contractor support cost allocations) included in the Initial Proposal, where the AER approved our Initial Proposal forecast.
- Direct cost unit rates and volumes (prior to contractor support cost allocations) and volumes that will approximate the Draft Decision outcome, where the AER approved a lower amount than our Initial Proposal.

Contractor support costs are discussed further in section 5.4.5.

Table 5-13: Repex/ safety programs and projected where we have accepted the draft decision (\$M, real 2025-26)

Project or program	Initial Proposal forecast	Draft Decision	Revised Proposal forecast
Replace roofs, doors, window	\$2.7	\$2.6	\$2.7

Project or program	Initial Proposal forecast	Draft Decision	Revised Proposal forecast
Instrument transformers - VTs	\$4.5	\$1.8	\$1.8
Instrument transformers - CTs - 66kV	\$6.8	\$2.7	\$2.7
NERs & NEDs	\$0.5	\$0.2	\$0.2
Distribution poles - street lights 148SIM	\$9.2	\$0.0	\$0.0
Crossarms - HV	\$31.8	\$30.6	\$31.8
Crossarms - LV	\$14.1	\$13.6	\$14.1
Crossarms - Subtransmission	\$4.0	\$3.8	\$3.9
Cables	\$33.6	\$32.3	\$31.7
Services (LV Service Cables)	\$19.3	\$16.5	\$17.1
MV Switches - Air Break	\$4.5	\$2.7	\$2.8
MV Switches - Ground/Indoor	\$20.8	\$12.8	\$13.3
Pole top capacitors	\$0.3	\$0.3	\$1.0
Zone substation lighting	\$2.7	\$2.6	\$2.7
ZSS Fence replacement - general	\$2.1	\$2.0	\$2.1
Line voltage regulator fence replacement	\$0.6	\$0.6	\$0.6
Ground type distribution sub fence replacement	\$0.2	\$0.2	\$0.2
4G Replacements	\$3.3	\$3.2	\$3.4
SDH/PDH and DIC Switch & Serial Server Replacement	\$3.1	\$3.0	\$3.2
Security Enhancement	\$1.3	\$1.3	\$1.3
Upgrade oil control -Distribution Voltage Regulators	\$8.6	\$7.5	\$7.9
Low service compliance	\$18.5	\$17.9	\$18.5
Conductor clearance compliance (3D Model/LiDAR)	\$11.2	\$10.9	\$11.2
Fall arrest systems	\$8.4	\$8.1	\$8.9
SWER Earths	\$1.6	\$1.5	\$1.6
Proactive insulation/undergrounding of SWER (Codified areas)	\$33.6	\$16.1	\$16.8
SWER condition/risk based replacement (Codified Areas)	\$3.4	\$3.2	\$3.4
Bare conductor condition/risk based replacement (Codified Areas)	\$9.4	\$9.0	\$9.0
Early fault detection/broken conductor detection (High consequence areas)	\$15.6	\$0.0	\$0.0
TOTAL	\$275.5	\$206.9	\$213.7

Source: AusNet

For all other projects and programs, we have updated our expenditure forecast to address the AER's concerns. In particular, in response to the draft decision, we have refined key aspects of our repex forecasting methodology to address the AER's concerns and ensure our revised proposal expenditure forecasts are robust and reflective of prudent and efficient expenditure. These refinements and further detail on our revised proposal forecast is provided in the next section.

Our Revised Proposal also includes \$67.9 million of expenditure associated with the following projects and programs that were not included in our Initial Proposal:

- **22kV Circuit Breaker replacement (\$32.4 million).** In preparing the revised proposal, we identified that our initial proposal did not include the 22kV circuit breaker replacements required for the forthcoming regulatory period.

These replacements have now been appropriately reflected in this proposed program. Refer to the 22kV circuit breaker business case for further information of the need for this investment.

- **Bayswater Substation Rebuild (\$18.7 million).** This project was not included in our Initial Proposal as it was expected to be completed during the current regulatory period. It is currently in the construction phase and the Final Project Assessment Report for this project was published in February 2023. Refer to section 5.6.4.10 for further discussion.
- **Fused Overhead Line Connection Boxes (FOLCB) replacements in Codified Areas (\$8.5 million).** This program aims to replace ~9,000 assets in areas of highest bushfire consequence risk, reducing a growing safety risk on the network. FOLCBs ranks third as the cause of fire starts on our network, with an average of 15 fire starts p.a. since 2020. The introduction of this program in our Revised Proposal reflects recent analysis of high-risk assets on our network which. Refer to the FOLCB business case for further information of the need for this investment.
- **Compliance with Energy Safe Victoria's REFCL Operations policy (\$7.1 million).** This program is required to replace legacy ACRs, control boxes, and sectionalisers across REFCL- networks, and recalibration of sensitivity settings, to comply with Energy Safe Victoria's REFCL Operations Policy, which was published by Energy Safe Victoria in March 2025, after lodgement of our Initial Proposal. The program will target only those devices identified as non-compliant or technically deficient, maximising the value of previous investments and minimising costs. Due to timing, we did not include this program in our initial proposal. Refer to the REFCL Operations Policy business case for further information of the need for this investment.
- **Gippsland SDH Comms Replacement (\$1.2 million).** This is an in-flight that has been delayed since lodgement of our Initial proposal.

We acknowledge the AER's repex modelling findings in the Draft Decision, which have led it to undertake a bottom-up assessment of our repex forecast. Accordingly, we have not provided updated repex modelling as part of this Revised Proposal and instead sought to address the bottom-up issues and concerns identified in the Draft Decision relating to individual projects and programs. Given the limitations of the repex model, we consider this is a more meaningful approach to addressing the AER's concerns and demonstrating the prudence and efficiency of our forecast.

5.6.4. Revised Proposal

5.6.4.1. Overview of revised repex forecast

Our Revised Proposal repex and safety forecast is \$1,156.1 million.⁴⁷ This is a 1.7% (\$19.6 million) increase on our Initial Proposal forecast. The increase in our investment needs relative to the Initial Proposal broadly reflects:

- **An updated forecast of replacement volumes for programs**, reflecting the outputs of our redeveloped forecasting methodology and models.
- **Updates we have made to unit rates and discrete project cost estimate**
- **s** to reflect more recent actual cost information, market-driven movements in labour and material costs since the preparation of our initial proposal forecast and, in some cases, more mature cost estimates. While our cost estimates for ZSS rebuilds have increased, in the case of unit rates, some have increased while others have decreased.
- **The inclusion of the several new expenditure items in our forecast**, largely for matters not able to be included in our Initial Proposal, as discussed in the previous section.
- **An updated forecast of in-flight project expenditure**, due to project delays and cost increases since the Initial Proposal, associated with project deferrals to manage current period capital constraints and market-driven movements in cost inputs.

5.6.4.2. An uplift in repex is required to manage network risk

The key drivers of our proposed replacement program continue to be addressing increasing network risk associated with aged and deteriorated assets, to maintain network reliability and minimise safety risk. As shown in the figure below, on a direct cost basis, our proposed repex forecast (excluding safety) is a 27% increase on actual and expected spend in the current regulatory period.

⁴⁷ Excludes \$1.4 million of construction insurance allocated to repex

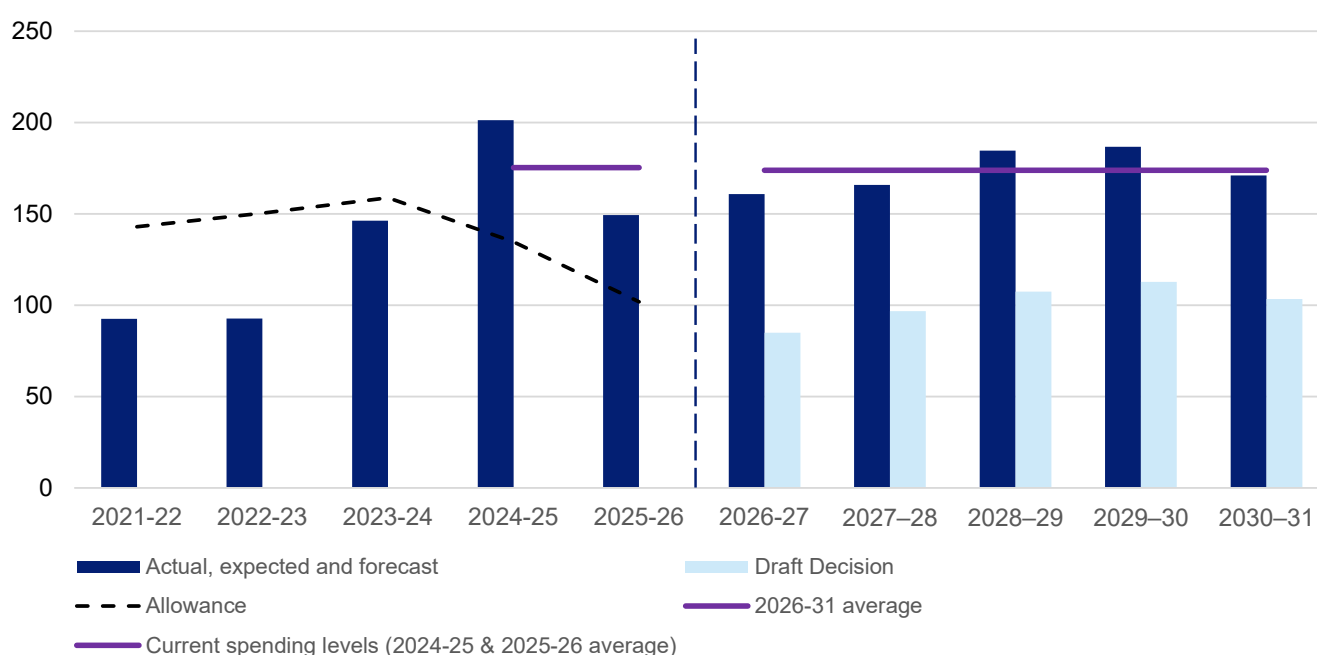
While we have accepted some components of the draft decision on repex and safety, we are concerned that, in aggregate, it provides insufficient funding to address these drivers, ensure a safe and reliable network, and meet our obligations.

In real terms, the repex approved in the draft decision of \$101 million p.a. (direct, \$2024)⁴⁸ is 35% less than average actual/ expected repex in the current regulatory period of \$136.4 million. An examination of more recent spending levels shows that these are in line with our forecast for the next regulatory period; in fact, average actual and planned repex in 2024-25 and 2025-26 of \$175.3 million is slightly above proposed annual average repex of \$173.9 million.

This demonstrates that the same factors driving our proposed 2026-31 investment levels – risk-based replacement of ageing and deteriorated assets – are driving the same levels of investment today. Concerningly, the AER's alternative forecast of \$101 million is 73% below these recent spending levels.

The planned reduction in repex in 2025-26 compared to the prior year reflects a reprioritisation of investment to fund urgent network upgrades required to manage strong demand growth in our northern and south-eastern growth corridors. At a total capex level, we are expecting to overspend our 2025-26 allowance by \$267 million or 96% and our current period allowance by \$459 million (27%).

Figure 5-6: Actual, expected and forecast repex; AER draft decision (\$m, real 2023-24)



Source: AusNet

Note: Direct costs only; excludes safety-driven replacements, resilience, metering and ADMS

Under NER cl. 6.5.7(c), the AER is required to approve a total capex forecast if it is satisfied this forecast reasonably reflects the efficient costs of achieving the capex objectives, which includes, relevantly:⁴⁹

- Maintaining the quality, reliability, security of supply of standard control services;
- Maintaining the reliability and security of the distribution system through the supply of standard control services; and
- Maintain the safety of the distribution system through the supply of standard control services.

Regarding managing safety in the distribution system, under Victorian legislation, namely Section 98 of the Electricity Safety Act 1998 (Vic), AusNet has a General duty as described below:

A major electricity company must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable—

⁴⁸ Excludes safety repex, metering, resilience and ADMS

⁴⁹ NER, cl. 6.5.7(a)

- (a) the hazards and risks to the safety of any person arising from the supply network; and
- (b) the hazards and risks of damage to the property of any person arising from the supply network; and
- (c) the bushfire danger arising from the supply network.

Given the age profile of our asset base and the demonstrated need to increase replacement volumes across major asset classes (e.g. poles, conductors), we consider a 71% reduction in investment compared to recent spending levels is neither reasonable nor consistent with the capex objectives. In particular, such a reduction of this scale would materially constraint our ability to maintain network reliability and safety.

Once assets reach a certain age or a deteriorated condition, higher asset replacements and investment levels are necessary to maintain the reliability and safety of the network. This conclusion is supported by The Mantua Group's (TMG) report which discusses the Bow Wave Phenomenon. While this discussion focusses on the dangers of attempting to calibrate Weibull parameters to reflect historical failure rates, it also highlights the inherent limitations of relying on observed asset failure and performance data alone to infer long-term replacement needs:⁵⁰

"For asset populations with mean age approaching or exceeding the population MTTF, the failure rate is inherently accelerating due to Weibull wear-out characteristics ($\beta > 1$ minimum, typically 3 or higher). Historical replacement counts reflect past population age structure, which differs materially from the forecasted age structure over the next regulatory period and may oscillate dramatically as the initial cycle of a Drenick (1951) phenomenon.

Specifically:

- *Historical Period (Past 5 Years): Asset population was younger on average, with lower cumulative failure probability and consequently lower replacement demand.*
- *Forecast Period (Next 5 Years): Same asset cohort is now 5 years older, entering steeper portion of Weibull hazard curve, with substantially higher annual failure probability.*
- *If this regulatory period forecast is anchored to historical replacement rates without accounting for this population aging dynamic, it will significantly underestimate the emerging bow wave. The Drenick oscillation in the first replacement cycle means past performance is a misleading predictor.*

This creates a "bow wave" of impending replacements where the forward-looking forecast necessarily exceeds historical experience, not due to model error but due to genuine population aging dynamics."

The AER's proposed reduction in replacement capex relative to the levels required to maintain reliability and safety would expose consumers to reliability and safety risks, contrary to our obligations under the Victorian Electricity Distribution Code of Practice, the Electricity Safety Act 1998 (Vic) and the NER capex objectives. Our assessment is that a materially higher level of repex than current regulatory period and the Draft Decision is required to ensure that we manage reliability, security and safety of the distribution network as required under our Victorian legislation and in line with customer expectations.

Based on the draft decision outcomes, AusNet would be required to defer a significant number of justified asset replacement projects and programs. In practice, this will lower the reliability and safety outcomes for our customers contrary to the AER's limited discretion under clause 6.5.7(c). It would also prevent us from addressing clear and consistent feedback we have received from our customers on the importance of maintaining and improving network reliability through the energy transition.

5.6.4.3. Our revised failure rate modelling approach and assumptions have been externally assessed as accurate and consistent with AER repex guidance

As part of reviewing and improving our repex forecasting approach, we engaged TMG to assess the accuracy of the Weibull methodology we have applied to derive our Revised Proposal probability of failure assumptions, and its consistency with the AER's *Industry Practice Guideline for Asset Replacement Planning*. TMG's report is provided as a supporting document.

TMG concluded that the overall methodology and technical aspects of our Weibull analysis are sound and compliant with the AER's guidance. The detailed findings are reproduced in the table below.

Table 5-14: TMG's Assessment of Weibull analysis approach against AER requirements

⁵⁰ The Mantua Group, *AusNet Distribution Weibull Methodology for PoF Analysis Review*, 1 December 2025

AER Requirement	The AusNet Approach	Compliance Evidence (TMG report reference)	Status
Step 1: Collect asset end-of-life failure data	Failure age data from SAP PM notifications (Performance of 60,000+ assets for some asset cohorts).	Master data extract, data dictionary	✓ Compliant
Step 2: Inclusion of asset replacement data	Replacement data used with appropriate statistical treatment for informative censoring.	Sections 1.1-1.2, circularity acknowledged	✓ Compliant
Step 3: Select failure distribution methodology	2-parameter Weibull for wear-out, single-mode failures; Crow-AMSAA determined to not be inappropriate.	Section 2.1-2.2, detailed justification	✓ Compliant
Step 4: Derive probability of failure distribution parameters	Maximum Likelihood Estimation (MLE) per AER recommendation; superior to OLS.	Section 3, Genshel & Meeker (2010)	✓ Compliant
Step 5: Generate probability of failure time series function	Weibull CDF produces F(t) for all ages; individual asset-level PoF calculated.	Section 5, Nelson's conditional probability	✓ Compliant
Step 6: Calibrate probability of failure function to individual assets	Individual asset PoF from age-specific Weibull CDF; row-level calculation.	Section 5.2.2, mathematical equivalence	✓ Compliant
Validation: Test against actual failure data	Weibull plots, 95% confidence bands, goodness-of-fit tests (Anderson-Darling).	Section 4, visual and statistical validation	✓ Compliant
Independent verification	The Mantua Group (TMG) certification using JMP Pro.	Section 3.2.1, exact parameter agreement	✓ Compliant
Sensitivity analysis	Parameter confidence intervals, WACC, CoF, industry benchmarking.	Section 11	✓ Compliant
Transparency and stakeholder accessibility	Full documentation, reproducible methodology, audit trail.	Section 12, reproducibility package	✓ Compliant
Economic justification	NPV analysis with WACC = 5.56%, market-tested costs, AER-compliant CoF.	Section 6, NPV maximization	✓ Compliant
CoF methodology	Event tree analysis per AER guidance, VSL = \$5.4M, VCR values.	Section 6.5, detailed event trees	✓ Compliant

Source: The Mantua Group

5.6.4.4. We have reviewed and comprehensively redeveloped our repex forecasting approach and models

In response to the draft decision and the AER's concerns, we have undertaken a review of our repex forecasting approach and implemented several significant changes to improve its robustness and ensure our revised proposal expenditure forecasts are well-supported and reflective of prudent and efficient expenditure. This review drew on both internal SMEs and suitably qualified, external asset management experts to assess and verify that our revised approach is consistent with good industry practice and fit for purpose.

The aspects of our methodology and forecasting approach we reviewed include:

- Modelling approach, consistency and transparency, including post model adjustments
- Asset data inputs (e.g., historical asset replacement data, asset condition data)

- Probability of failure (PoF) inputs and assumptions
- Consequence of failure (CoF) inputs and assumptions
- The methodology used to determine optimal asset replacement timing
- Options assessment
- Sensitivity analysis
- Unit rates
- Supporting documentation.

In addition to redeveloping our repex forecasting approach and models, we recently re-obtained ISO 55001 certification, demonstrating the robustness of our asset management system, which underpins our expenditure forecasts.

To more clearly demonstrate the need for our proposed repex forecast, we have developed business cases for key asset classes and asset groups. These documents, which complement and build upon the AMS documents submitted with our initial proposal, set out asset age, condition and performance information, the identified need, forecasting approaches, options assessments and sensitivity analysis underpinning each component of our proposed repex forecast

We have also re-submitted our Risk Assessment Methodology, AMS 01-09 to ensure consistency with our models and provides greater transparency on key aspects of our repex forecasting approach, including the values and basis for the Weibull parameters applied in our models.

In addition, the values and basis of each input and assumption used to derive replacement volumes for each asset class are now provided in each economic model. The key refinements and improvements we have made to our repex forecasting methodology, and how these changes address the AER's concerns, are summarised in the table below.

Table 5-15: Key refinements made to repex forecasting methodology compared to Initial Proposal

Aspect of repex forecasting methodology	Key refinement or improvement compared to Initial Proposal	AER concerns addressed
Model consistency and NPV methodology	We have rebuilt the economic models used to forecast asset replacement volume and expenditures for each asset class, to ensure a consistent approach to forecasting methodology, inputs and assumptions is applied to all asset classes. As part of this, we have applied the maximum NPV approach to determine economic timing for proactive asset replacements, in line with the AER's asset replacement guidance note. All else being equal, this defers asset replacement timing relative to the 'first positive' NPV approach applied to some asset classes in our initial proposal, and the alternative 'hurdle rate' approach.	Inconsistent NPV approach applied across different asset classes Setting replacement timing equal to when NPV is first positive will overstate investment needs
Asset data / calibration against observed performance	Asset data (e.g., asset age, installation date, disposal date) has been comprehensively reviewed to ensure accuracy and alignment with our financial and asset management systems. This is a critical step to ensuring age-based PoF assumptions are calibrated against historical asset replacement activities and based on fit for purpose asset data. As discussed above and in TMG's report, with an ageing asset base, attempting to calibrate Weibull parameters to reflect historical failure rates risks understating required future investment levels. We have generally relied on asset data extracted directly from our financial and asset management system, SAP, rather than using asset replacement data reported in the annual RIN. While RIN data is typically also sourced from SAP, the RIN reporting categories do not necessarily align with our asset class-specific economic models, making the RIN less suitable as a direct source of input data.	Lack of calibration of PoF assumptions to observed asset performance or failures. Concerns with unsubstantiated or explained Weibull parameters, including where industry supplied values were applied
Probability of failure assumptions	In some cases, our Initial Proposal forecast reflected industry supplied Weibull parameters. We have carried out new Weibull analysis across all	

Aspect of repex forecasting methodology	Key refinement or improvement compared to Initial Proposal	AER concerns addressed
	asset classes ⁵¹ to derive eta and beta values and ensure our PoF assumptions are robust, reflect historical asset performance and in line with expected industry values. This approach, and our proposed Weibull parameters, have been externally validated and verified through multiple software packages. To improve transparency, where we have used asset data to derive Weibull parameters, this data has been included in our submitted economic model.	
Consequence of failure assumptions	We have reviewed our CoF assumptions to improve transparency and ensure consistency across asset classes. We have incorporated 2024 AER VCRs into our Customer CoF calculations and refined some key Safety and Environmental CoF assumptions (e.g., bushfire probability for conductors). CoF assumptions and their basis / source are documented in each economic model. As much as is practical, formulas have been included in the economic model, replacing previously hardcoded values. We remain of the view that our safety assumptions – such as the Value of a Statistical Life – remain consistent with good industry practice. We have reviewed AMS 01-09 to ensure consistency with the CoF assumptions applied in our models.	• Inconsistencies between models and with AMS 01-09 • Hardcodes in CoF calculations • Conductors – environmental & customer CoFs too high • AusNet QCV applied instead of latest AER VCRs • Insufficient information about cases of realised safety risks to support the values attributed to assets in AusNet's modelling • Voltage transformers – DF not labelled and higher than values in 'overview' document • NERs/ NEDs – basis for environmental CoFs not explained
Options assessment	A minimum of three options has generally been presented in each business case, including: • The "BAU" or do-nothing option • A life extension option, such as refurbishment. This option has been assessed for those asset classes where it is a viable alternative to replacement, e.g. power transformers, circuit breakers etc. • Proactive asset replacement. Reasoning and, where possible, modelling have been provided to illustrate or demonstrate why the chosen option is preferred. In respect of poles, following further technical assessment, we have increased our forecast reinforcement rate (as discussed in section 5.6.4.5 and the poles business case). On conductors, we economically assessed four alternative options, to demonstrate the robustness of our preferred option (as discussed in section 5.6.4.6 and the conductor business case).	Lack of information about options considered that are not simply 'all or nothing' • Poles – consideration of lower replacement volumes and alternative options, e.g. reinforcement • Conductors – assessment of alternative options
Post model adjustments	Consistent with our initial proposal, post model adjustments have been made to remove overlaps between proposed repex programs and: • Current period investment programs; • Proposed station rebuild projects; and • Proposed investments with other drivers, e.g., LV augex, resilience. In addition, to ensure our forecast considers both age- and condition-driven network risk, we have adjusted the output of our economic models to: • Remove assets where, despite the asset's age, maintenance is considered the most cost-effective solution to manage risk, rather than replacement • Include assets where, despite the asset's age, we expect additional proactive replacements will be required due to poor asset condition. The above adjustments have been documented and explained within each economic model and business case, to demonstrate the basis for each adjustment and their effects on proposed replacement volumes.	No specific concerns in respect of post model adjustments.

⁵¹ Except for conductors, distribution transformers, insulators and RTUs, where limitations in our asset data mean we have relied on industry supplied or SME estimates for Weibull parameters

Aspect of replex forecasting methodology	Key refinement or improvement compared to Initial Proposal	AER concerns addressed
Unit rates	We have updated our proposed unit rates to reflect: • More robust and mature estimates than those applied in the initial proposal • Recent data on the actual costs of delivering similar projects and • Market-driven movements in the costs of labour and materials. These updates ensure the robustness of the economic assessments we have carried out for each asset class because, in many cases, economic timing is sensitive to the assumed unit rate. To improve transparency, we have submitted a consolidated file (ASD – Unit Rates) providing the basis and breakdown of all unit rates as a supporting document. Our business cases also include information on our proposed unit rates. Asset class-specific unit rates concerns are discussed in the sections below. We have updated and retained the risk allowances included in our unit rates and cost estimates – including by replacing 'fixed rate' risk allowances with probability weighted risk allowances in the majority of cases - and presented evidence demonstrating that these allowances are necessary to derive a replex forecast that reflects the prudent and efficient costs we expect to incur. This is discussed further in section 5.5.	Various concerns relating to risk allowances, as discussed in section 5.5. Concerns that unit rates for some asset classes are overstated.
Sensitivity analysis	Key variables (e.g., PoF, CoF, demand, VCRs, unit rates and discount rate) have been increased or decreased to demonstrate that our proposed replex projects and volumes are robust. Further information is provided in the supporting business cases and ZSS rebuild planning reports.	For AusNet's revised proposal, the AER would like to understand what sensitivity analysis has taken place for each project where applicable.
Development of business cases	To more clearly demonstrate the need for our proposed replex forecast, we have developed business cases for key asset classes and asset groups setting out asset age, condition and performance information, the identified need, forecasting approaches and options assessments underpinning each component of our proposed replex forecast.	More information sought about AusNet's business cases but found contextual information was not provided.

Source: AusNet; AER Draft Decision

Reflecting the above refinements, our replacement program volumes have generally been determined by applying the following risk-based, probabilistic approach, in line with the AER's industry practice application note for asset replacement planning:

1. **Age as a Proxy for Condition:** Recognising that asset age and condition are correlated, age was used as an indicator of condition. The ages of both in-service and decommissioned assets were analysed to derive Weibull parameters (Eta and Beta) for calculating the Probability of Failure (PoF).
2. **Weibull Failure Forecasting:** Age data was applied to Weibull failure distribution models to forecast POF over time.
3. **Consequence of Failure (CoF):** CoF was determined in accordance with AusNet's Risk and Safety Assessment Document (AMS 01-09), taking account of customer (reliability), safety and environmental consequences. As part of this calculation, AER 2024 VCRs were incorporated into the Customer CoF.
4. **Net Present Value (NPV) Optimization:** In line with good industry practice, the replacement year that yielded the highest NPV was identified as the optimal timing for asset replacement.
5. **Asset Health Assessment:** To incorporate condition into the risk assessment, assets have been evaluated using a Health Index derived from asset inspection and testing. Assets exceeding asset specific Health Index thresholds have been included in proposed replacement volumes, reflecting the elevated failure risk of these assets. Equally, assets found to be economic to replace (based on the above steps) have been removed from the proposed forecast where their condition indicated replacement could be deferred to future regulatory period.
6. **Replacement volume:** Assets identified for proactive replacement must satisfy three criteria; their optimal replacement timing was before the end of the upcoming RCP, they are in poor condition (Health Index above the threshold), they are not included in a Zone Substation rebuild.

7. **On condition replacements.** Assets expected to require on-condition replacement are added to the forecast. This volume is calculated by the summation of PoF Values for all assets which are not included in the proactive replacement volume or ZSS rebuilds.

Our approach to forecasting zone substation rebuilds – which EMCa considered reasonable – is largely unchanged since the initial proposal. However, key inputs (e.g. VCRs, project costs) have been updated to reflect new information and ensure consistency with our repex program models.

The key components of our forecast are summarised in the table below, including where we have accepted the draft decision and, therefore, have not resubmitted economic models or developed new business cases.

We have accepted the Draft Decision for 18% (\$213.7 million) of our forecast repex/safety capex. For the remaining 82% (\$942.3 million), further information on our revised proposal forecast and how we have addressed the AER's concerns is provided in the following sections of this chapter and the business cases referred to in the table below.

Table 5-16: Overview of revised proposal repex and safety forecast (\$m, real 2025-26)

Business case / program / project	Initial Proposal forecast	Draft Decision	Revised Proposal forecast	Change (RP vs IP)	Business case reference
Poles	\$219.1	\$160.8	\$214.1	-\$5.0	ASD – AusNet – Poles – 1Dec2025
Conductors	\$136.5	\$76.8	\$98.9	-\$37.6	ASD – AusNet – Conductors – 1Dec2025
Switchgear	\$81.6	\$36.9	\$71.5	-\$10.1	ASD – AusNet – Medium Voltage Switches, ACRs, and Control Boxes – 1Dec2025
Fuses	\$67.5	\$47.8	\$61.3	-\$6.2	ASD – AusNet – MV Fuse Switch Disconnectors – 1Dec2025
Power transformers & bushings	\$26.8	\$6.7	\$58.5	\$31.7	ASD – AusNet – Power Transformers & Power Transformer Bushings – 1Dec2025
Thomastown Stage 2 - 22kV upgrade	\$35.3	\$28.4	\$56.4	\$21.1	ASD – AusNet – Thomastown Zone Substation Rebuild – 1Dec2025
Watsonia Refurbishment	\$35.7	\$28.5	\$52.3	\$16.7	ASD – AusNet – Watsonia Zone Substation Rebuild – 1Dec2025
Distribution Transformers	\$19.0	\$9.1	\$42.2	\$23.2	ASD – AusNet – Distribution Transformers – 1Dec2025
Protection & Control	\$50.6	\$22.5	\$35.0	-\$15.6	ASD – AusNet – Protection and Control – 1Dec2025
RTUs	\$2.0	\$0.9	\$5.6		ASD – AusNet – RTUs – 1Dec2025
22kV Circuit Breakers	\$0.0	\$0.0	\$32.4	\$32.4	ASD – AusNet – 22kV Circuit Breakers – 1Dec2025
Newmeralla Refurbishment	\$14.7	\$0.0	\$23.7	\$9.0	ASD – AusNet – Newmeralla Zone Substation Rebuild – 1Dec2025
Environmental	\$23.1	\$0.0	\$23.3	\$0.2	ASD – AusNet – Environmental Systems – 1Dec2025
Infrastructure (SOCl)	\$22.5	\$10.9	\$22.5	\$0.0	ASD – AusNet – Infrastructure (SOCl) – 1Dec2025
Bayswater Substation Rebuild	\$0.0	\$0.0	\$18.7	\$18.7	N/A (RIT-D completed)
66kV Circuit Breakers	\$26.0	\$10.4	\$15.8	-\$10.3	ASD – AusNet – 66kV Circuit Breakers – 1Dec2025
Traralgon Stage 2 - 22kV switchboard upgrade	\$14.6	\$11.6	\$15.3	\$0.7	ASD – AusNet – Traralgon Zone Substation Rebuild – 1Dec2025
Line Voltage Regulators	\$4.0	\$2.1	\$15.0	\$11.1	ASD – AusNet – Line Voltage Regulators – 1Dec2025
Kilmore South ZSS 22kV Switchroom Replacement	\$8.6	\$7.0	\$10.9	\$2.3	ASD – AusNet – Kilmore South Zone Substation Rebuild – 1Dec2025
HV Switches	\$17.5	\$7.0	\$10.0	-\$7.6	ASD – AusNet – HV Switches, Disconnectors & Earth Switches – 1Dec2025
Station Surge Arrestors	\$4.0	\$0.7	\$9.8	\$5.8	ASD – AusNet – Station Surge Arrestors – 1Dec2025
REFCL Policy	\$0.0	\$0.0	\$7.1	\$7.1	ASD – AusNet – Compliance with REFCL Operations Policy – 1Dec2025
FOLCBs	\$0.0	\$0.0	\$8.5	\$8.5	ASD – AusNet – FOLCBs – 1Dec2025
Line Surge Arrestors	\$5.2	\$0.0	\$7.2	\$2.0	ASD – AusNet – Line Surge Arrestors – 1Dec2025
Insulators	\$16.5	\$0.2	\$7.1	-\$9.4	ASD – AusNet – Insulators – 1Dec2025

Business case / program / project	Initial Proposal forecast	Draft Decision	Revised Proposal forecast	Change (RP vs IP)	Business case reference
Traralgon ZSS Rebuild Stage 1	\$0.6	\$0.6	\$6.8	\$6.2	N/A (RIT-D completed)
Auxiliary Supplies	\$28.4	\$12.6	\$6.4	-\$22.0	ASD – AusNet – Auxiliary Power Systems – 1Dec2025
Warragul ZSS Rebuild	\$1.2	\$1.2	\$4.8	\$3.6	N/A (RIT-D completed)
Gippsland SDH Comms Replacement	\$0.0	\$0.0	\$1.2	\$1.2	N/A (In-flight project)
Sub total	\$861.0	\$482.9	\$942.3	\$81.3	
Projects and programs where we have accepted the draft decision	\$275.5	\$206.9	\$213.7	-\$61.7	
Total repex	\$1,136.5	\$689.8	\$1,157.8	\$19.6	

Source: AusNet; AER Draft Decision

5.6.4.5. Pole replacement

Our response to the Draft Decision

The AER's Draft Decision and EMCa's review raised a number of concerns regarding our pole replacement program, which are summarised in the table below along with how we have responded to these concerns in this Revised Proposal.

Table 5-17: Our response to the Draft Decision – pole replacement and reinforcement

Summary of AER and EMCa findings	Our Response
Forecast staking rate too low and not reflective of historical and industry standard rates. No visibility of method used to determine staking rate	Forecast staking rate increased from 18% in our Initial Proposal (based on all poles, except for street lighting poles which were erroneously included) to 24%, with calculations included in poles forecasting model and explained in the supporting business case. When considering only those poles where staking or reinforcement is a viable solution (due to pole type and/or reinforcement criteria relating to sound wood measurements), our proposed staking rate is 40%. While EMCa commented on our staking rate being lower than historical levels, our proposed volume of reinforced poles of 761 per annum is 4% higher than the current period average of 731 per annum. We acknowledge that pole staking rates may differ between our peers due to several factors. This may be due to differences in reinforcement criteria, composition of existing pole fleets and historical and current pole management practices. For example, AusNet has used Woodscan technology to accurately defer interventions for some poles, however on their second cyclic inspection Woodscan is forcing them to intervention as WoodScan does not slow rot or pest deterioration but rather provides a more accurate measure of residual strength improving confidence over the traditional destructive wood test method. Equally, other networks may practice proactive reinforcement (e.g. staking before a pole is 'eligible' for reinforcement), which will increase the staking rate and provide a modest life extension (e.g., 2.5-5 years) but may result in higher long-term pole management costs. To keep our poles capex forecast down, we have not proposed a step change to enable a proactive staking volume as it relies on historical find rates consistent with other similar DBs in the NEM. The only way to achieve a higher staking volume (than observed historically) is to employ a proactive program, additional to what has been proposed and would require further consultation with Energy Safe through the ESMS / BMP process. This approach would not provide a benefit in the regulatory period 2026-31 but may reduce some interventions in the following 2032-37 period. Our poles business case provides further information on reinforcement criteria and how we have determined our forecast staking rate.
No visibility of pole volume derivation as undertaken in PowerBI Forecast volumes based on forecast failure rate, not economic analysis	The pole model provided as a supporting document now includes all calculations relating to pole volume forecast in Excel format We have maintained our approach to forecasting pole replacements using failure rates based on Weibull parameters. We consider this forecasting approach is appropriate for poles given the strict inspection and replacement criteria that govern our replacement rates, rather than an economic assessment. A similar approach was applied to forecasting pole replacements at the last price review, which the AER accepted. Our updated poles Weibull parameters have been derived from a refreshed dataset of historical pole replacement rates and externally validated to ensure they are robust and in line with good industry practice and the AER's Replacement Expenditure Industry Guidance Note.
Streetlighting poles erroneously included in SCS forecast	The inclusion of street lighting poles in our SCS forecast was an oversight which has been corrected in this Revised Proposal. This has led to the removal of \$9.2 million of capex from our revised proposal repex forecast.
Alternative replacement volumes have not been assessed	We have revised our forecast staking rate to align more closely with historical levels. The poles business case submitted as a supporting document demonstrates that higher staking rates (e.g., 40% of all poles) are not feasible based on sound wood measurement data. The business case also explores alternative replacement options, e.g., replacement upon failure. However, these options are not consistent with our regulatory obligations regarding pole inspection and replacement and, therefore, have not been proposed.

Summary of AER and EMCa findings	Our Response
Unit rates appear reasonable	We have updated unit rates to reflect more up to date information on contractor and free issue material costs. These rates have been refined since the Initial Proposal – with some rates increasing and some decreasing - but continue to reflect competitively tendered Zinfra (OMSA) unit rates and, therefore, are considered reasonable. All unit rate inputs are provided in the ASD – Unit Rates supporting document.

Source: AusNet; AER Draft Decision; EMCa Network Capex assessment report

Overview of forecast

The pole replacement program remains the largest of our proposed repex programs, although our proposed capex for the 2026-31 regulatory period is lower than the current period.

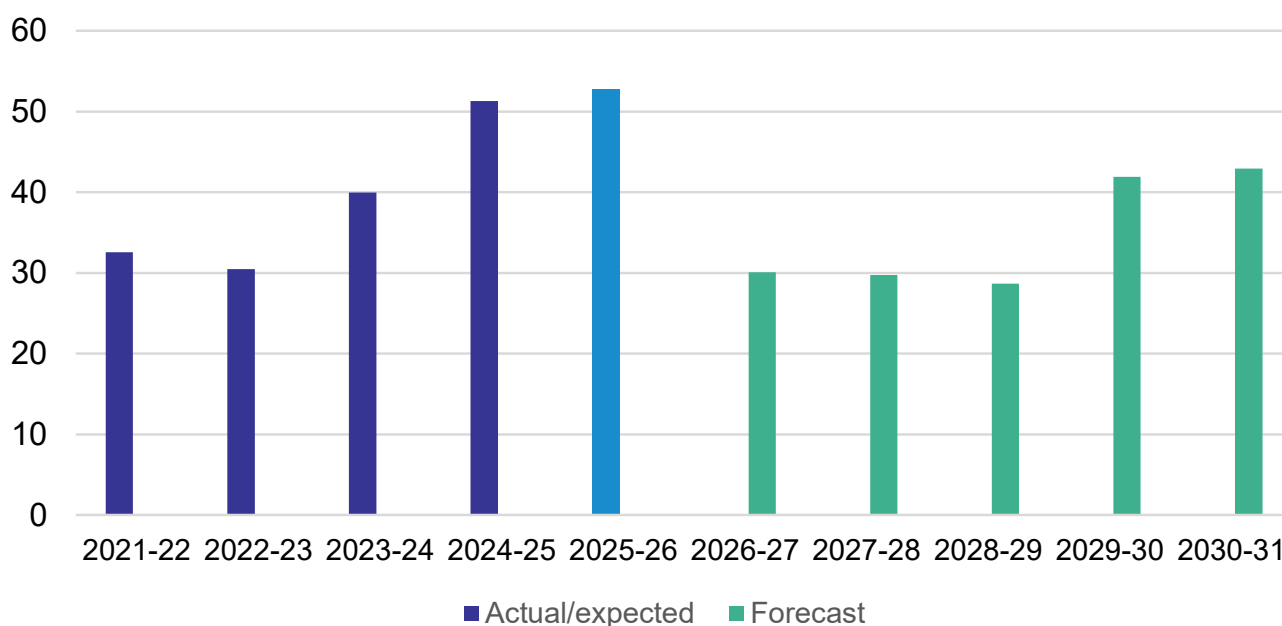
As outlined in our Initial Proposal and poles business case the proactive management of pole application, inspection, maintenance, refurbishment and replacement practice is required to ensure that stakeholder expectations of costs, safety, reliability and environmental performance are met. AusNet's wood pole fleet is ageing, with a significant portion of wood poles exceeding their expected service life. Approximately 64% of timber poles are older than 41 years, and 39.5% are beyond 51 years.

Our Revised Proposal forecast of poles is \$214.1 million, which is 2% below our Initial Proposal forecast of \$219.1 million. Our revised forecast comprises:

- Replacement of approximately 12,102 poles
- Reinforcement of approximately 3,804 poles, reflecting a staking rate of 40% when considering only those poles where staking is a viable solution or 24% when considering all poles.

As shown in the figure below, on a direct cost basis, our revised forecast of pole replacement capex is below actual and expected capex in the current regulatory period.

Figure 5-7: Actual, expected and forecast poles capex – direct costs (\$M, real 2023-24)

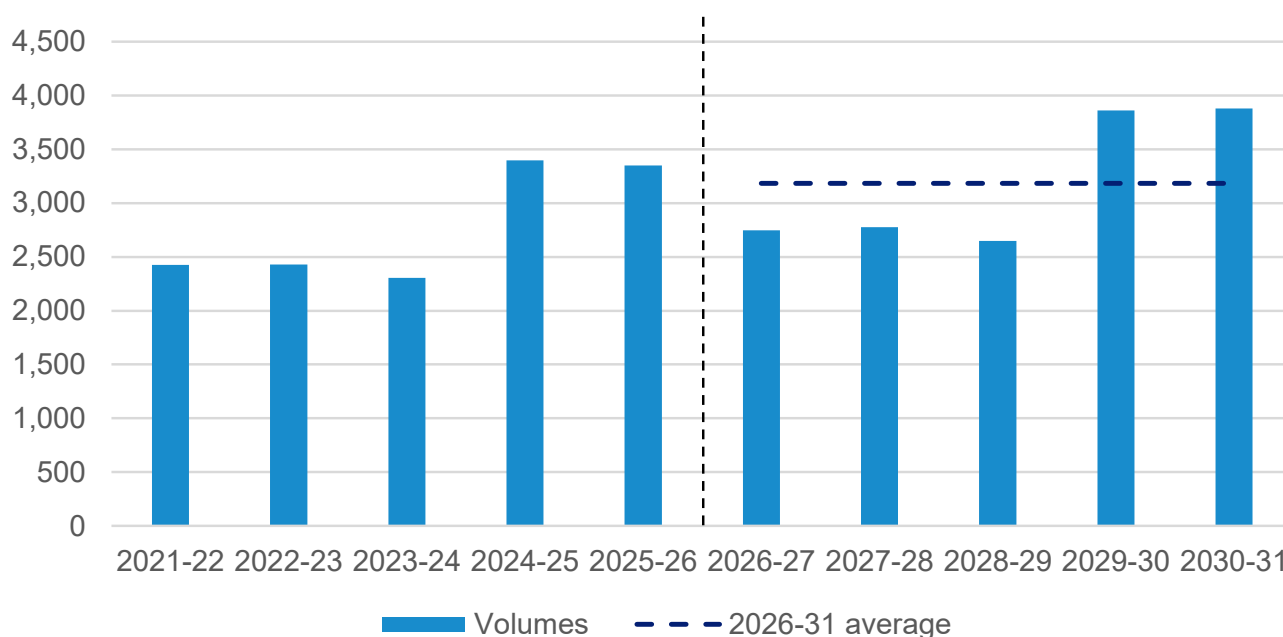


Source: AusNet

Notes: Current period expenditure data includes poles replaced due to major storm events

The figure below shows actual, expected and forecast pole reinforcement and replacement volumes. Proposed pole interventions of 3,359 per annum, on average, in the next regulatory period are broadly in line with the most recent year of actuals in 2024-25 and expected amounts in 2025-26 of 3,400 and 3,350, respectively. The profile of replacements in the next regulatory period has been assumed to be consistent with the current regulatory period. However, in practice, the actual profile will depend on the results of our inspection program.

Figure 5-8: Actual, expected and forecast pole replacements and reinforcements



Source: AusNet

Notes: Current period expenditure data includes poles replaced due to major storm events

We have identified and removed overlaps between our pole replacement program and our resilience network hardening program. These overlaps have been removed from our resilience forecast, rather than from our repex poles forecast, which was the approach we took to removing overlaps in our Initial Proposal. This is discussed further in the Top-Down Review supporting document.

Supporting information

Further information and justification for our conductor forecast is provided in the pole business case and forecast model provided as supporting documents.

5.6.4.6. Conductor replacement

Our response to the Draft Decision

The AER's Draft Decision and EMCa's review raised a number of concerns regarding our conductor replacement program, which are summarised in the table below along with how we have responded to these concerns in this Revised Proposal.

Table 5-18: Our response to the Draft Decision – conductor replacement

Summary of AER and EMCa findings	Our Response
The Weibull parameters set by AusNet did not appear to be based on the asset's natural age or condition. Reasoning for any difference has not been provided Lack of calibration of failure distribution against observed experience in relation to failures	Due to limitations in the available asset installation and disposal data, industry values have been adopted for Weibull parameters. We have reconsidered the most appropriate industry values for conductors and revised our initial proposal's conductor eta value from 50 to 80, and the beta value from 3.5 to 7. This has the effect of deferring replacements beyond the 2026-31 regulatory period, compared to our initial proposal Weibull parameters which, if applied in our updated model, would justify more than 4,000 km of replacement. Our updated Weibull parameters have been verified externally as being in line with industry good practice.
Assumed consequence values are overstated due to: Average demand assumed to be consistent across the feeders for each substation.	We have reviewed all CoF values and adjusted the probability of bushfire start from an estimated static value of 5% to a dynamic value from 0.06% to a maximum of 0.55% depending on the fire area classification. This dynamic value has been calibrated against historical regulatory Fire Reporting which, all else equal, has materially reduced the Safety Environment (Bushfire) CoF values within the conductor model. We have also incorporated the AER's 2024 VCRs and reviewed the application of Customer CoF.

Summary of AER and EMCa findings	Our Response
Assumptions on feeder sectionalisation where a DFA scheme is not in place	We consider our average demand and DFA scheme assumptions are robust and reflective of actual customer and network characteristics. Therefore, we have not modified these aspects of the Customer CoF calculation.
Lack of information about how these inputs fed into the model and further generalisation of conductors at different lengths, contributed to a reduction in the program's forecast	The value and basis for all input assumptions, including PoF and CoF, are set out in the submitted conductor economic model and business case
Lack of further top-down analysis to test robustness	The proposed conductor volumes reflect the need for additional conductor replacements to manage an ageing asset base to maintain network reliability and safety. To test the robustness of our modelling outcomes, we have conducted sensitivity analysis by varying key parameters, such as eta, beta, unit rate. This shows that the preferred option is robust to variation in key inputs and assumptions. Further, as explained in the supporting business case, our proposed conductor replacement volume is less than the economically justified volume, moderating our capex forecast. Considering this moderation, the robustness of our revised model inputs and assumptions and the sensitivity analysis we have undertaken, we do not consider that there is a need for further top-down analysis to determine the prudent and efficient conductor replacements in the next regulatory period.
No analysis of alternative (lower) replacement volumes	The conductor business case provided as a supporting document assesses several options, including reactive conductor replacement which would involve a lower replacement volume than we have proposed. Importantly, our proposed conductor forecast is less than the volume of conductor replacements that can be economically justified. The remaining network risk will be managed through the rollout of Early Fault Detection (EFD) devices, which the business case demonstrates as economic. The EFD technology is comparable to online condition monitoring techniques used for substation assets, such as power transformers.
Inability to verify if proposed volumes are in line with the current period (as stated by AusNet). Proactive SWER/Conductor and replex conductor program should be assessed together.	We confirm that our updated forecast is an increase on current period replacement volumes, reflecting the advanced age of many of our conductor fleet and the reduction in unit rates we have applied compared to the initial proposal. We have accepted the draft decision on the Proactive SWER (Codified Areas) and SWER/Bare conductor condition-based programs. To ensure no overlaps, we have removed the scope of these three programs from our revised proposal conductor forecast as post-model adjustments.
Unit rates are within a reasonable range	We have reduced unit rates to reflect the recent, actual costs of similar projects. While this has resulted in an increase in economic replacement volumes in the next regulatory period, we have proposed less than the economically justified volume to moderate our replex.
Overlaps with other programs have been removed	We have identified and removed 27 km of covered conductor overlaps between this program and our resilience network hardening program. These overlaps have been removed from our resilience forecast, rather than our replex conductor forecast, which was the approach we took to removing overlaps in our Initial Proposal.

Source: AusNet; AER Draft Decision; EMCa Network Capex assessment report

Overview of forecast

The conductor replacement program is the second largest of our proposed replex programs (excluding zone station rebuilds). As outlined in the conductor business case, the ageing and deteriorating condition of conductors exposes customers and the broader community to heightened risks of asset failure, with the potential for significant consequences including bushfires, safety incidents, and unserved energy. The scale of these impacts varies according to the likelihood and location of conductor failure.

Our Revised Proposal forecast of conductor replacement is \$98.9 million (including investment of \$5.3 million in Early Fault Detection devices – explained further below), which is 28% lower than our Initial Proposal forecast of \$136.5 million. As noted above, reductions to our proposed unit rate have led to an increase in economic conductor volumes and overall conductor expenditure, relative to the initial proposal. We now propose to replace 936 km of

conductor during the forthcoming regulatory period, compared to 927km in our Initial Proposal, and defer another 431km of conductor replacement through deployment of EFD devices.

The scope of our conductor business case includes \$5.3 million to install 254 Early Fault Detection (EFD) devices on high-risk parts of our network, as an economic alternative to proactive conductor replacement.

We have considered EMCA's commentary the conductor program should be considered in aggregate, inclusive of all programs targeting the replacement of conductor. Accordingly, to ensure synergies and overlaps are accounted for, our updated conductor economic model and business case holistically assess:

- **Proactive, economically justified and reactive conductor replacement.** These volumes are the focus of our revised proposal conductor program and supporting business case and economic model.
- **Proactive SWER and condition-based bare/ SWER conductor replacement in Codified Areas.** As we have accepted the draft decision for these three programs, to avoid double counting, we have removed their scope from the proposed program, through post model adjustments.
- **EFD devices deployment.** To moderate our conductor replacement forecast, we have identified where economically justified conductor replacements can be deferred, without unacceptable impacts on network risk.

We recognise the EFD devices program submitted with our Initial Proposal was presented as not offering net economic benefits, based on the information available at the time, and therefore, was rejected in the draft decision. Our revised approach to assessing the costs and benefits of EFD devices now appropriately recognises that a key benefit of this technology is that it is expected to be a viable, cost-effective alternative to conductor replacement. This reflects maturation in the effectiveness of EFD device technology since our initial proposal was developed, following more widespread deployment on electricity distribution networks, giving us greater confidence in its condition- and risk-monitoring capabilities.

The following options are assessed in the conductor business case, including:

- **Option 1.** Do nothing, which would give rise to unacceptable reliability and safety risks and therefore, fail to meet our General duty under the *Electricity Safety Act 1998 (Vic)* as described above.
- **Option 2.** Undertake all economically justified replacements. This option would involve the replacement of 1,367 km of conductor, with no EFD device deployment, at a capital cost of \$39 million greater than the below, preferred option.
- **Option 3 (preferred option).** Targeted replacement of 936 km of conductor complemented by deployment of EFD devices to defer economic conductor replacements to future regulatory periods. This option involves 638 km of proactive replacements and 298 km of reactive replacements, consistent with our current reactive replacement rate, and offers the greatest net benefits of all options considered.
- **Option 4.** Replacement of all conductors exceeding 70 years (1,434km total), agnostic to failure consequences.

The table below summarises the options considered, demonstrating that Option 3 provides the greatest net benefits – approximately \$80 million over the assessment period. Sensitivity analysis has been contained in the conductor business case demonstrates that our proposed volume is at the lower end of a range of modelled scenarios and, therefore, our proposal is robust to variations in key input parameters.

Table 5-19: Conductor options assessment

Option Assessment	Forecasted Length (km)	EFD Monitored (km)	Forecasted Cost (\$m)	Forecasted Benefit (\$m)	Benefit / Cost Ratio
Option 1	1,242	-	133	-	-
Option 2	1,367	-	118	186	1.57
Option 3	936	431	80	160	2.00
Option 4	1,434	-	126	39	0.31

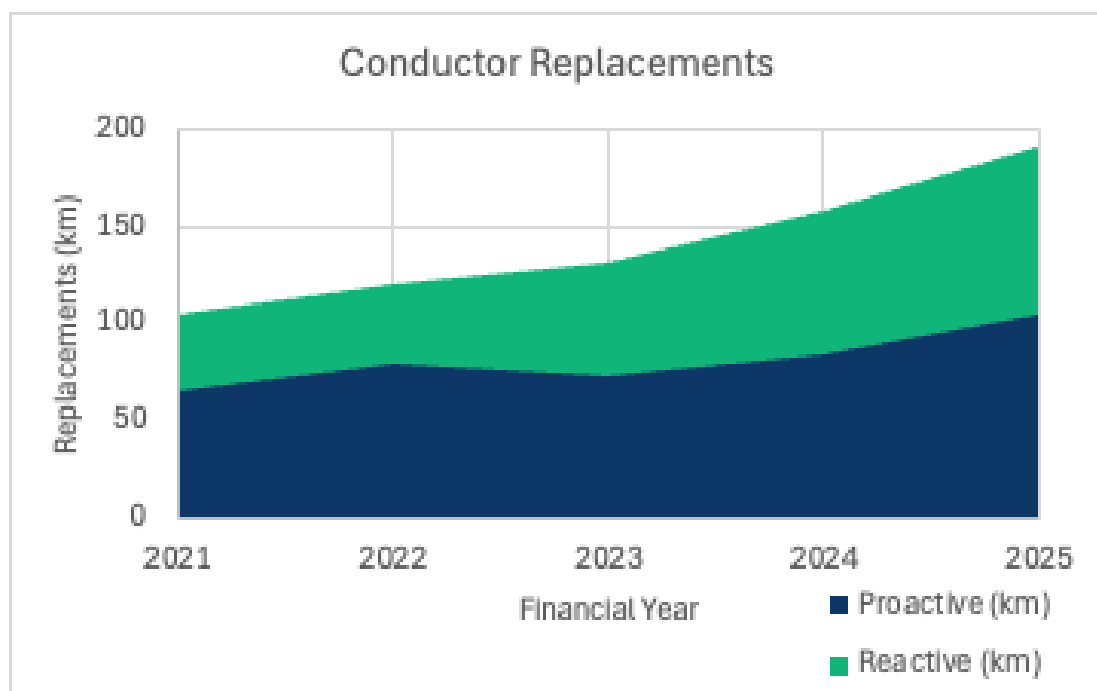
Source: AusNet

We acknowledge proposed conductor replacements of 931 km is a 33% increase on actual and expected replacements during the current regulatory period of approximately 705km. While this is lower than the volume approved for the current regulatory period, as with some other repex projects and programs, conductor replacements have been impacted by the need to reprioritise funding towards critical network upgrade projects in

our growth corridors. As mentioned previously, our actual and expected capex will result in a 23% overspend of our current period capex allowance. However, consistent with further ageing of the conductor fleet since the last price review, increased replacements are necessary during 2026-31 to manage increasing network risk.

This increasing risk is reflected in a rising trend of reactive replacements upon asset inspection or failure, which have increased significantly between 2021 and 2025. Reactive replacements are a combination of fault response and replacements triggered from on-condition asset defects as identified during cyclic inspections or during fault response. During the current period we expect to reactively replace 298km of conductor. Although we anticipate reactive replacements to continue to gradually increase due to the aging conductor population, we have taken a conservatively low approach to estimating our conductor investment needs and proposing the same volume of reactive replacements in the 2026-31 period.

Figure 5-9: Proactive and reactive current period conductor replacement



Source: AusNet

Given the useful life for conductor is estimated at 70 years, the current projection of conductor that will have a service age equal to or exceeding this useful life at the conclusion of the next period is 2,402 km, significantly above our proposed replacement volume. Further, our proposed replacement volume of 936 km accounts for just 2.6% of the total conductor fleet.

Supporting information

Further information and justification for our conductor forecast is provided in the conductor business case and economic model provided as supporting documents.

5.6.4.7. Switchgear replacement

Our response to the Draft Decision

The AER's Draft Decision and EMCa's review raised a number of concerns regarding our switchgear replacement program, which are summarised in the table below along with how we have responded to these concerns in this Revised Proposal.

Table 5-20: Our response to the Draft Decision – switchgear replacement

Summary of AER and EMCa findings	Our Response
Control boxes	
Unit rate of approximately [C-I-C] is at the high end of a reasonable range	We have proposed a lower, updated unit rate of [C-I-C]. This rate is based on the actual cost of recently delivered projects and, therefore, is considered reasonable

Summary of AER and EMCa findings	Our Response
AusNet has been replacing control boxes at a lower rate than is proposed	Our updated forecast of 859 control boxes is 35% lower than our Initial Proposal forecast of 1,331 units ⁵² , reflecting the refinements we have made to our modelling approach, including a lower unit rate.
- Derivation of Weibull parameters, and reasonableness of their application to control boxes has not been demonstrated - The distribution of failure events is wide, but low in number - Not clear whether modelling has been calibrated against failure observations; AusNet has modelled an aggressive failure rate	The increase on actual/ expected replacements in the current regulatory period is necessary to address increasing failures expected due to the age of control box fleet. Approximately half of the control box fleet is more than 10 years old, with Weibull analysis indicating a marked rise in failure likelihood beyond this age. We have used refreshed asset data to derive updated Weibull parameters, which have been externally validated to ensure they are robust and in line with good industry practice and the AER's Replacement Expenditure Industry Guidance Note. The use of historical asset replacement data to derive Weibull parameters, rather than industry values, ensures our assumed failure rates reflect actual asset performance and are not overstated.
Approach to determining economic timing is biased towards including interventions prematurely Absence of root cause analysis, which may indicate a wider array of solutions including repair / replacement of components, improved mechanical / weather / vermin protection and or enhanced maintenance practices In addition to modelling, onsite reports or any other supporting material that reflects an observable increase in failed assets, e.g. investigations of root cause	Consistent with our economic models for other asset classes, we have adopted the maximum NPV method to forecast economic timing of control box replacements. Our Revised Proposal includes 830 GSS100 type control boxes, which represent ~97% of proposed replacements. AusNet's fleet of GSS100 control boxes is exhibiting increasing rates of hardware, firmware, and software failure, resulting in unreliable operation of the Distribution Feeder Automation (DFA)/FLISR schemes and compromising network safety performance. The GSS100 platform is now obsolete, no longer supported by the manufacturer, and suffers from significant functional limitations - including inadequate protection settings, lack of REFCL capability, limited overcurrent detection functions, and no IP-rated enclosure suitable for outdoor installation. Unreliable wireless communications, spurious switching operations, and known toggling issues create material risks to network reliability and customer outage duration. Past attempts to refurbish these units by replacing analogue cards and CPUs have proven ineffective, and replacement components are no longer available. A targeted replacement program is therefore required to address the operational, safety, and obsolescence risks associated with retaining this aging control box fleet. In respect of ILJIN MV switches, we currently have a very high rate of inoperable switches. Across the total fleet of 797 these switches on our network, 577 units (72%) have currently been assessed as inoperable or not fit for safe operational use. We propose to replace all these switches in the 2026-31 regulatory period, in line with current period replacements of 718.
Lack of transparency regarding Customer CoF calculations	Addressed in our updated control box economic model, which provides CoF workings and sets out the basis for all input and assumptions.
Expectation that applying AER 2024 VCRs would reduce the program	Consistent with our broader Revised Proposal capex forecast, our control box forecast reflects AER 2024 VCRs. As noted above, our updated forecast is a significant reduction on our Initial Proposal.
Switches and other⁵³	
The AER does not consider AusNet's switches program efficient and does not have the information needed to approve its prudence	We have provided further justification information in the Switchgear business case provided as a supporting document, as well as refined economic modelling to demonstrate the prudence and efficiency of the forecast.
Require more information about why replacements would need to be completed sooner than what historical replacements would suggest	Our revised Weibull analysis indicates that a rate of replacement higher than historical levels is needed to maintain reliability and safety, given the age and deteriorated condition of the assets. As demonstrated in the business case, there has been a sharp increase in the number of switchgear defects and corrective maintenance items in the last two years compared to the prior years.

⁵² Updated on 16th May 2025 as part of our response to IR#20

⁵³ Includes further information provided by the AER on 20th October in relation to its concerns with our switchgear proposal

Summary of AER and EMCa findings	Our Response
Evidence of actual incidents that support AusNet's inputs, particularly for safety and environment CoF values	In respect of MV ILJIN switches, we have provided several safety incident reports in the Switchgear business case, demonstrating these assets: • Are increasingly unsafe to operate manually, with high risk of mechanical failure. • Exhibit inoperability or unreliable indication, making switching operations unpredictable. • Present significant safety risk due to falling components and compromised tank integrity. These actual incidents and safety risks support the CoF assumptions we have applied in our modelling.

Source: AusNet; AER Draft Decision; EMCa Network Capex assessment report

Overview of forecast

The switchgear replacement program is the third largest of our proposed repex programs and involves the replacement of the following assets:

- Auto-circuit reclosers (ACRs).
- Medium Voltage (MV) switches, including Air Break, Ground/ Indoor and Manual Gas switches
- Control boxes.

As we have accepted the Draft Decision in relation to Air Break and Ground/Indoor MV switches, and all fuse expenditure (i.e. reactive and proactive, safety driven replacements) is discussed in the Fuses business case, the switchgear business case focusses on the need and justification for replacement of:

- 184 ACRs
- 993 Manual Gas switches
- 859 control boxes.

Our Revised Proposal forecast for the above switchgear assets is \$71.5 million, 12% below our Initial Proposal forecast of \$81.6 million. While the forecast is an on current period replacement volumes and expenditure, as outlined in the business case, a targeted replacement program is required in the 2026-31 regulatory period to address the accelerated ageing and increasing failure rates observed in control boxes, oil-insulated ACRs, and ILJIN MV switch units. Condition assessments and Weibull analysis confirm that control boxes beyond ten years of service experience a steep rise in failure likelihood, while oil-filled ACRs and ILJIN switches have demonstrated progressive deterioration, safety concerns, and obsolescence issues, with limited manufacturer support and spare part availability.

Replacement is the preferred option as it provides a long-term, cost-efficient solution to address both condition and reliability risks. The “do nothing” or “defer replacement for 5 years” alternatives would allow asset degradation to continue, increasing the likelihood of in-service failures – with safety risks to employees and customer outages.

Supporting information

Further information and justification for our forecast is provided in the switchgear business case and economic model provided as supporting documents.

5.6.4.8. Fuse replacement

Our response to the Draft Decision

The AER's Draft Decision and EMCa's review raised several concerns regarding our fuse replacement program, which are summarised in the table below along with how we have responded to these concerns in this Revised Proposal.

Table 5-21: Our response to the Draft Decision – fuse replacement

Summary of AER and EMCa findings	Our Response
AER reduced unit rate to historical rates as insufficient information to justify the proposed cost and risk allowance	We have proposed a lower, updated unit rate of approximately [C-I-C], which is 23% lower than our Initial Proposal rate of approximately [C-I-C].
EMCa considered the unit rate is likely to be higher than an efficient level and observed the unit rate is higher than AusNet has included in its proposal for the current RCP	The updated rate is based on competitively tendered Zinfra contracted rates and, therefore, is considered reasonable. We consider this is a more robust and accurate basis for the unitised costs we will incur in the next regulatory period, compared to the rate proposed and approved by the AER for the current regulatory period, which EMCa has referred to in its assessment
AusNet's uplift in fuses volumes was not justified	A breakdown of our proposed unit rate is provided in the fuse business case and in the ASD – Unit Rates supporting document.
Economic modelling is used as basis for increase in replacement volume, and which is likely overstated	Our Revised Proposals forecast of fuse replacements is 19% below actual and expected replacements in the current regulatory period and, therefore, is not an uplift.
The application of standard Weibull parameters without calibration to observed performance may result in overstating the	We have justified our proposed replacement volume through a combination of economic modelling and historical replacement rates.
	Consistent with other asset classes, our updated economic modelling for fuses:
	• Uses refreshed asset data to derive updated Weibull parameters for fuses, rather than relying on industry supplied values, which have been externally

Summary of AER and EMCa findings	Our Response
risk and number of fuse replacements that AusNet will undertake.	validated. The basis for these parameters is set out in the fuse economic model provided as a supporting document
Year of replacement is based on when the investment first becomes positive	Adopted the maximum NPV method to forecast economic timing of fuse replacements. We have also conducted sensitivity analysis demonstrating the proposed volume is robust to variations in key parameters (e.g. PoF, CoF, VCR, discount rate.)
AusNet's claim that fire starts have been decreasing also seems to contradict findings from the Energy Safe Victoria that they are increasing.	Our fuse business case demonstrates an increasing rate of fuse failures, supporting the need for a continuation of our proactive fuse replacement program. AusNet has not changed fire start data provided to Energy Safe, we confirm that it is accurate and shows a broadly stable overall trend for the last five years. However, fire start data is not the only determinant of risk, as the location of fire starts plays a significant role in risk assessment. Equally, fire risk across our network (as measured by Ignition Reduction Units (IRUs)) is increasing, requiring proactive fuse replacement to manage the increasing risk.
Additionally, risk appeared to be unjustified with no link to observed performance	Fuse failures, which have more than tripled over the last decade, represent a significant safety risk to the community. In line with our safety obligations, AusNet must minimise this safety risk which is best achieved through a proactive and reactive replacement of fuses during the next regulatory period.

Source: AusNet; AER Draft Decision; EMCa Network Capex assessment report

Overview of forecast

The fuse replacement program is the fourth largest of our proposed repex programs and involves the proactive replacement of high-risk MV fuses, particularly ageing EDO and Boric Acid (BA) types, to prudently manage safety and bushfire risks in line with our obligations, maintain network reliability, and reduce the likelihood of costly unplanned outages. Fuse candling is the leading cause of fire starts in AusNet's network, with MV fuse failures accounting for the largest proportion of network-initiated fires (41% of all recorded fire incidents since 2012) and contributing to a rising trend in Ignition Risk Units (IRUs) on our network.

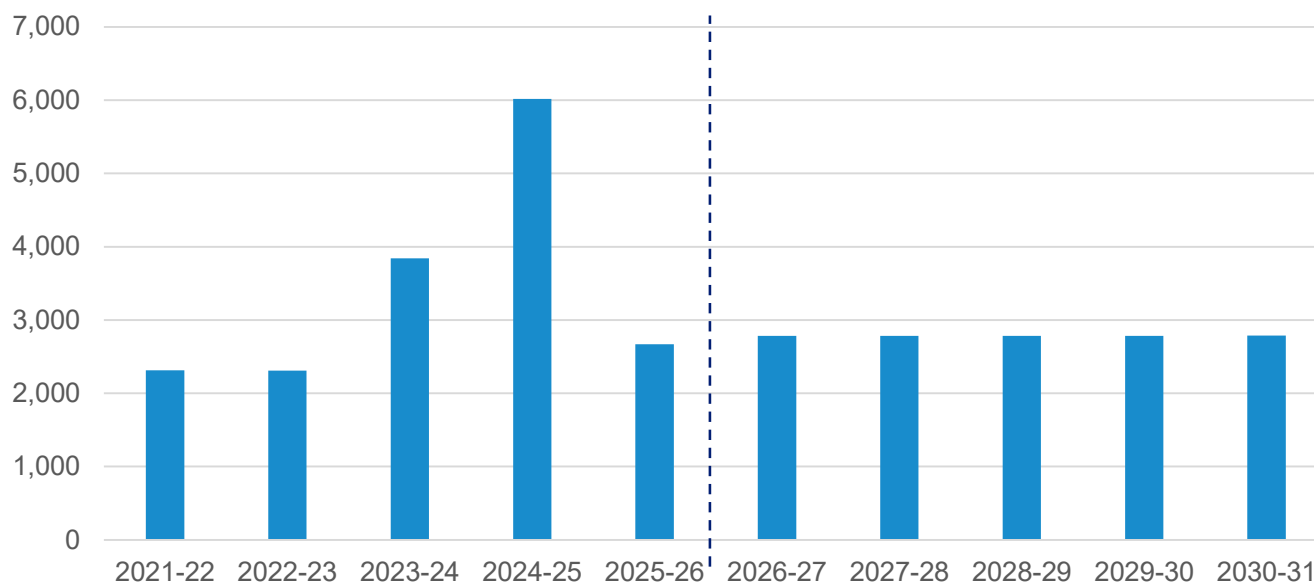
Our Revised Proposal fuse forecast is \$61.3 million, which is \$6.2 million lower than our Initial Proposal forecast of \$67.5 million. This decrease reflects a 23% reduction in our fuse unit rate which has been partly offset by a 14% increase in replacement volumes.

The scope of our proposed fuse replacement program comprises:

- Proactive, economically justified replacements of 11,401; and
- Reactive replacements of 2,526, which are in line with historical fault and replacement rates.

As shown by the figure below, combined total replacements of 13,927 are 19% lower than actual and expected replacements in the current regulatory period of 17,115. Based on trend analysis alone, we consider the forecast is reasonable. This supports the findings of the economic assessment we have undertaken, which demonstrates the proactive replacement program offers material net economic benefits to consumers of \$49 million over the assessment period. These findings, and our proposed replacement volume, have been validated through sensitivity analysis demonstrating the proposed volume is robust to variations in key parameters.

Figure 5-10: Actual, expected and proposed fuse replacements

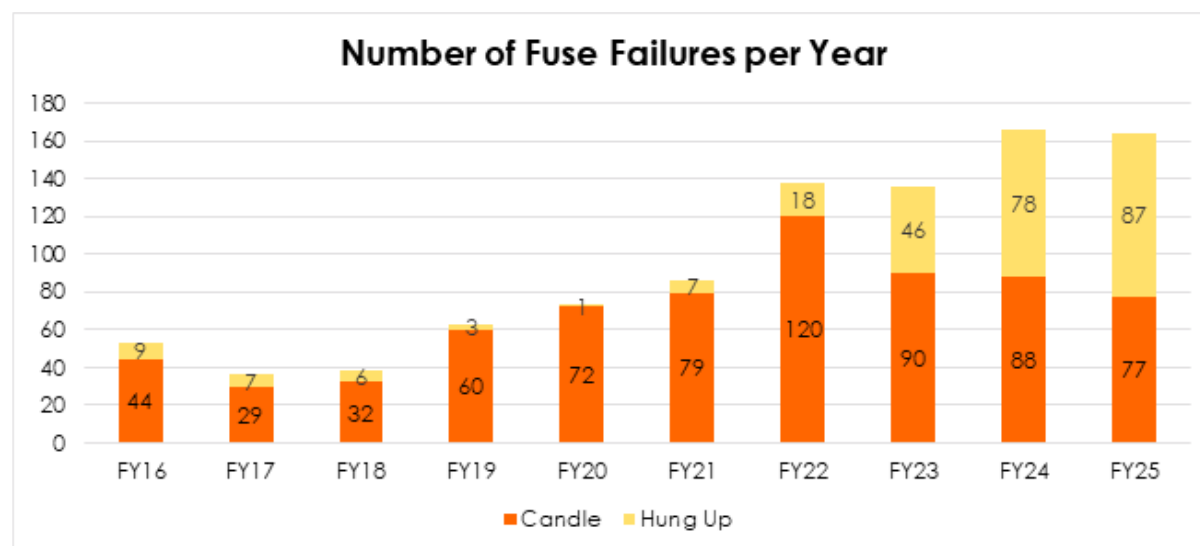


Source: AusNet

To meet its General duty under Section 98 of the Electricity Safety Act 1998 (Vic), AusNet is required to undertake an assessment of whether safety risk can be reduced 'as far as practicable' with a clear presumption of safety. AusNet has undertaken this assessment and found that a proactive fuse replacement program is expected to reduce the safety risks outlined above to as low as practicable levels, while delivering a net benefit to customers based on an NPV analysis.

The need for continued fuse replacements in the next regulatory period is underscored by the rising trend in fuse failures occurring on our network. Fuse candling and hung-up failures predominantly occur in EDO and BA fuse types, with candling incidents in other fuse types being exceptionally rare. The figure below illustrates the number of fuse failures attributed to these two modes, which has increased by over 200% in the last decade.

Figure 5-11: Fuse failures per year



Source: AusNet

AusNet already has a proactive fuse replacement program to reduce the identified safety risk, including new risks such as higher BA failure rates. We provide regular updates to Energy Safe on the progress of the program. We also collaborate with other Victorian distributors to benchmark fuse performance and share best practices.

Supporting information

Further information and justification for our fuse forecast is provided in the fuse business case and economic model provided as supporting documents.

5.6.4.9. Power transformer replacement

Our response to the Draft Decision

Despite EMCa finding our risk methodology for power transformers reasonable, the AER's Draft Decision and EMCa's review raised several concerns regarding our power transformer replacement program. These are summarised in the table below along with how we have responded to these concerns in this Revised Proposal.

Table 5-22: Our response to the Draft Decision – power transformer and bushing replacements

Summary of AER and EMCa findings	Our response
Methodology for the calculation of risk for power transformers and circuit breakers is reasonable	Consistent with other asset classes, we have:
Adopted Weibull are within a reasonable range of values expected. However, greater transparency required for power transformer bushing parameters	Used refreshed asset data to derive updated Weibull parameters for power transformers, which have been externally validated. The basis for these parameters – including for power transformer bushings – is set out in the power transformer economic model provided as a supporting document
The selection of a program in the first year that the analysis is NPV positive is not indicative of the justified economic timing	Adopted the maximum NPV method to forecast economic timing of power transformer replacements.
Projects very sensitive to the input assumptions and adopting AER 2024 VCRs results in deferral of some projects	Consistent with our broader Revised Proposal capex forecast, our updated power transformer forecast reflects AER 2024 VCRs. We did not identify any concerns with other CoF values but have refined and updated key inputs (e.g., demand, T3 load at risk and recovery time) to ensure the values are reasonable.
More reasonable CoF values would defer projects beyond the next regulatory period	We have also undertaken sensitivity analysis to demonstrate our proposed power transformer replacement volumes are robust to variations in key parameters, including demand forecasts and VCR inputs. This analysis is presented in the submitted business case.
Unit rates include a risk allowance	We have retained risk allowances in our proposed unit rates and cost estimates, as discussed in section 5.5. Our unit rates have been updated to reflect more recent actual costs, increasing our capex forecast relative to the Initial Proposal. As demonstrated by the Worley Review of AusNet Major Project Pricing supporting document, our updated unit rates for major plant such as power transformers are considered reasonable and reflective of market rates.

Source: AusNet; AER Draft Decision; EMCa Network Capex assessment report

Overview of forecast

The power transformer replacement program is the fifth largest of our proposed repex programs and involves the replacement of 20MVA and 10MVA power transformers and bushings.

Our Revised Proposal power transformer forecast is \$58.5 million, which is 118% higher than our Initial Proposal forecast of \$26.8 million. This higher investment level reflects updated unit rates, which have been revised to reflect more recent actual costs, as well as increases in the proposed volume of:

- 20MVA power transformer replacements, from two to four;
- 10MVA power transformer replacements, from three to six; and
- Power transformer bushing replacements, from 39 to 46.

These volumes exclude assets that will be replaced as part of zone substation rebuilds, which have been removed through post model adjustments made in the submitted economic model.

The higher volumes compared to the Initial Proposal predominantly reflect the calibration of failure rates to actual asset disposal data and our updated, more accurate Weibull parameters, partly offset by adoption of the maximum NPV method. Our updated Weibull parameters, and the methodology used to derive them, have been externally verified as being in line with good industry practice and compliant with the AER's repex guidance note.

The proposed volume of power transformer replacements exceeds historical replacement volumes, which have averaged approximately one replacement per annum since 2015 (excluding assets replaced as part of station rebuilds). However, an increased level of replacements delivered through a proactive power transformer replacement program is required to maintain network reliability and safety in the 2026-31 regulatory period.

A significant portion of the power transformer fleet is operating beyond its expected life, with 22% aged 41–50 years and a portion exceeding 50 years. These power transformers suffer from age-related degradation, including oil leakage, insulation deterioration, and mechanical wear, resulting in reduced reliability and increased risk of failure. These asset performance issues are reflected in the figure below, which demonstrates a notable and sustained increase in fault notifications since 2015. This upward trend in fault reporting indicates a growing risk profile and asset deterioration, reinforcing the need for a proactive replacement strategy to maintain reliability and safety. The escalation in fault activity provides strong evidence that the current replacement rate is inadequate to maintain network reliability and safety and supports the case for increasing the volume of replacements in the upcoming regulatory cycle.

Figure 5-12: Power transformer notifications



Note: ZA- Condition-based Maintenance (usually as Follow-on Notification after Inspections); ZK – Fault (Notifications are raised as a result of a fault); Y – Axis shows ZA and ZK notifications as a % of total notifications

Source: AusNet

To validate the prudence and efficiency of the proposed power transformer replacement volumes, we assessed the costs and benefits of the following options:

- **Option 1: No proactive asset replacement.** This option involves continuing with the current inspection and maintenance plans, with defects addressed as they arise for ageing zone substation power transformers and bushings postponing their replacement until after the 2026–2031 regulatory period. Replacement would be performed only in response to condition assessment during inspection or upon failure, without proactive intervention, it would leave higher risk on the network and is not the preferred option.
- **Option 2: Refurbishment of power transformers to extend asset life.** This option involves undertaking partial refurbishment or overhaul of ageing zone substation power transformers to restore functionality. It aims to temporarily mitigate failure risks by deferring transformer replacement. While offering a positive NPV (\$9 million over the assessment period) and despite its lower cost, this option would provide lower risk reduction and net economic benefits than a proactive replacement program
- **Option 3: Proactive replacement program (preferred option).** This option involves proactively replacing 10 ageing zone substation power transformers, based on asset age and condition, that exhibit significant deterioration as well as replacing high-risk bushings on some of the transformers, rather than relying on reactive maintenance or refurbishment. This option offers the greatest net benefits to customers, with an NPV of \$120 million over the assessment period.

Supporting information

Further information and justification for our power transformer forecast is provided in the power transformers and bushings business case and economic model provided as supporting documents.

5.6.4.10. Zone substation rebuilds

Our response to the Draft Decision

EMCa found our risk methodology for zone substation rebuilds reasonable, along with the options assessment and sensitivity analysis we undertook. However, the AER's Draft Decision and EMCa's review raised several concerns regarding our ZSS rebuild projects. These are summarised in the table below along with how we have responded to these concerns in this Revised Proposal.

Table 5-23: Our response to the Draft Decision – zone substation rebuilds

Summary of AER and EMCa findings	Our Response
Concerns with the application of risk allowances to the unit rates applied to those projects, and that the same nominal risk allowances are present in the cost estimates for the rebuild projects and have not been adequately justified.	We have updated our ZSS rebuild cost estimate to reflect more mature project scopes and market-driven movements in labour and materials costs. We consider the updated costs are more reflective of the costs we will incur in the next regulatory period, compared to the Initial Proposal estimates. We have maintained the inclusion of a risk allowances in our revised cost estimates. However, the risk allowances included in our updated ZSS rebuild cost estimates have been determined on a probabilistic basis to better reflect project-specific risks and, therefore, are more robust than our initial proposal risk allowances and in line with the AER's expectations. As discussed in section 5.5, we consider a risk allowance is necessary to ensure our P(50) cost estimates are reflective of expected prudent and efficient costs.
EMCa are not convinced by the analysis of optimal timing for all projects	The economic assessment we have applied to determine project economic timing is consistent with good industry practice and the AER's repex guidance note. As demonstrated in the supporting planning reports and economic models we have provided for our proposed ZSS rebuilds, our approach determines optimal timing as when the risk reduction benefits the project will deliver exceed the annualised cost of the project. In some cases (e.g., Newmerella), our proposed expenditure is later than the optimal timing, to accommodate project delivery timeframes. We do not consider this deferral is grounds to reduce or reject the expenditure, given the economic analysis confirms the optimal timing is prior to the proposed investment timing.
AusNet's post modelling adjustments in which it deferred its timing demonstrates it may have issues with deliverability of its station rebuilds in the forecast regulatory period Insufficient information to support deliverability of Newmerella Refurbishment in the 2026–31 regulatory period. In respect of Newmerella, the original deferral in AusNet's post modelling was not sufficient to mitigate further risk mitigation, delays with assessments and additional approvals and so it was deferred further to the following regulatory period.⁵⁴	Except for the limited commentary in the Draft Decision (as summarised in this table), neither the AER nor EMCa identified specific concerns with the deliverability of our proposed network capex program, which was supported by the Strategic Deliverability Plan submitted with our Initial Proposal. In fact, EMCa concluded that "...we consider that AusNet has taken reasonable steps to develop the required capacity to deliver its proposed works program".⁵⁵ We remain of the view that our proposed timing for capex projects and programs – including ZSS rebuilds – is realistic and reasonable. Any post model adjustments made to the spend profile of ZSS rebuilds in our Initial Proposal were done to smooth the capex forecast, rather than due to deliverability issues. As mentioned above, these adjustments are not grounds to reduce or reject the expenditure, given the economic analysis confirms the optimal timing is prior to the proposed investment timing. As discussed in section 5.7, we have developed deliverability plans to demonstrate this in respect of our growth corridor augmentation projects. In respect of the Newmerella ZSS rebuild, we have re-assessed this project's economic timing taking account of updated VCR inputs, cost estimates and demand forecasts. This analysis demonstrates that the economic timing to implement the proposed preferred option is by summer 2025-26. This timing highlights the current, significant levels of network risk associated with the poor condition assets at this station, which pose a threat to reliable and safe supply. As discussed in the planning report, the No.3 transformer is currently out of service

⁵⁴ AER email correspondence, 20th October 2025

⁵⁵ EMCa network capex assessment report

Summary of AER and EMCa findings	Our Response
	and undergoing further investigation, following oil testing, demonstrating the need to deliver the proposed asset replacements in the 2026-31 regulatory period. To reflect a realistic project delivery timeframe and smooth our capex forecast, we have assumed commencement of the Newmerella ZSS rebuild in 2028-29 in our capex forecast, with project completion by 2030-31. We confirm there are no delays with assessment or approvals - as referred to by the AER - associated with this project.
Reductions to proposed capex appear to account for additional scope items included in cost estimates Data is inconsistent with the capex included in the regulatory proposal	We confirm that the costs and project scopes associated with the preferred option identified in the planning reports are consistent with the cost inputs entered in the SCS capex model. For example, the direct cost of the preferred option for Newmerella, which includes replacement of transformers, 22kV switchgear and 66kV VTs, is \$18.9 million (\$2024). This aligns with the SCS capex model inputs (prior to the allocation of contractor support costs, as discussed in section 5.4.5).
AusNet's VCR values are higher than indicated in AER's latest publication, resulting in a 10% capex reduction.⁵⁶	We have incorporated the AER's 2024 VCRs in our revised ZSS rebuild economic assessments, in place of the AusNet QCV residential and AER 2023 non-residential VCRs applied in our Initial Proposal. Despite the reduction in non-residential VCRs and our updated, higher cost estimates, these projects remain economic to deliver in the 2026-31 regulatory period, as demonstrated in the planning reports provided as supporting documents.

Source: AusNet; AER Draft Decision; EMCa Network Capex assessment report

Overview of forecast

Zone substation rebuilds collectively comprise the second largest component of our repex forecast, accounting for \$188.9 million of investment, of which \$301.3 million relates to in-flight projects commenced in the current regulatory period. Proposed rebuild investment of \$188.9 million is 71% higher than our Initial Proposal forecast of \$110.7 million, reflecting updated cost estimates for proposed projects and revised costs and timing for in-flight projects.

Our proposed zone substation rebuild capex comprises the following proposed and in-flight projects:

- Proposed projects:
 - Watsonia refurbishment (\$52.3 million).
 - Thomastown (Stage 2) - 22kV upgrade (\$56.4 million)
 - Traralgon (Stage 2) - 22kV switchboard upgrade (\$15.3 million)
 - Newmerella refurbishment (\$23.7 million)
 - Kilmore South 22kV switch room replacement (\$10.9 million).
- In-flight projects.
 - **Traralgon ZSS Rebuild Stage 1 (\$6.8 million).** This project, which was accepted in the draft decision at a lower cost, is in the construction phase. The Final Project Assessment Report for this project was published in April 2023 as part of the RIT-D process. Our updated forecast capex for this project reflects the latest construction schedule and increasing labour and materials costs to deliver this project.
 - **Warragul ZSS Rebuild (\$4.8 million).** This project, which was accepted in the draft decision at a lower cost, is in the construction phase. The Final Project Assessment Report for this project was published in April 2022 as part of the RIT-D process. Our updated forecast capex for this project reflects the latest construction schedule and increasing labour and materials costs to deliver this project
 - **Bayswater Substation Rebuild (\$18.7 million).** This project is in the construction phases and the Final Project Assessment Report for this project was published in February 2023 as part of the RIT-D process. This project was not included in our Initial Proposal as it was expected to be completed during the current regulatory period. However, its inclusion in our Revised Proposal reflects timing changes associated with reprioritisation of our network capex portfolio. Specifically, the need to re-direct two high voltage (HV) switchboards from

⁵⁶ AER email correspondence, 20th October 2025

the Bayswater ZSS rebuild project to address urgent two network projects; the new Beveridge Zone Substation Development Project and Kilmore South 22kV switchroom replacement project.

For the three in-flight projects described above:

- The preferred option identified in the RIT-D remains economic, despite the cost increases.
- Our Revised Proposal expenditure forecast reflects the preferred option identified in the RIT-D.

We engaged Worley to provide an independent assessment of whether our updated cost estimates for our proposed augex and repex discrete projects – including the proposed ZSS rebuilds discussed above - reflect efficient delivery requirements in current market conditions, and whether we have applied our Cost Estimating Methodology consistently. Worley tested whether unit rates are aligned with current industry benchmarks and supported by verifiable supplier inputs, and AusNet's approach to developing the P50 risk allowance is consistent with its CEM and AER expectations. Worley's conclusion is that the updated estimates reflect current market unit costs and demonstrate appropriate application of AusNet's CEM. Worley's report is provided as a supporting document.

To avoid overlaps, the assets to be replaced in the zone-substation program have been removed from the overall replacement program. The removal of these overlaps has reduced the total repex forecast by approximately \$193 million. Further details are available in the Top-Down Review supporting document.

Supporting documents

Planning reports and economic models for the five proposed ZSS rebuilds listed above are provided as supporting documents.

5.6.4.11. Other repex programs

The table below provides detail for other repex and safety programs that exceed \$20 million over the 2026-31 regulatory period, excluding Infrastructure (SOCl). These programs account for 13% (\$154.3 million) of our proposed repex and safety capex. Business cases have been provided as supporting documents for each program.

Table 5-24: Other repex/safety programs - overview of Revised Proposal forecast

Key drivers and overview of forecast	Summary of Draft Decision	Our Response to the Draft Decision
Distribution transformers (\$42.2 million) AusNet's distribution transformer fleet, comprising 60,642 pole-top units and 5,825 ground-mounted units, is experiencing ageing-related deterioration, including insulation degradation, tank corrosion, bushing defects, and oil leaks. These issues have led to declining reliability, increased operational risk, and safety concerns such as fire, electrocution, and environmental contamination, particularly in corrosive areas. Obsolete HV/LV switchgear in older ground-mounted transformers further compounds these risks. Our proposed reactive and proactive distribution transformers replacement program will address these risks by targeting high-risk assets, reduce unplanned outages, and mitigate safety and environmental risks. Proposed replacement volumes of 1,829 units align with current period replacement rates and optimise lifecycle costs for network reliability and compliance. As discussed in the Top-Down Review document, overlaps with the LV augex program have been identified and removed from this repex program Forecast capex for this program is 123% higher than our Initial Proposal, reflecting refinements we have made to our repex modelling inputs and assumptions. Despite this increase, our revised forecast is broadly in line with 6% higher than actual and expected spend in the current period.	CoF values appeared high for projects, such as distribution substations.	We have incorporated 2024 AER VCRs into our Customer CoF calculations. We consider our other CoF values, the basis for which is set out in the distribution transformers business case, are consistent with good industry practice.
Protection & Control & Remote Terminal Units (\$40.6 million)	• Unit costs appear high • Modelling inputs and optimal timing approach	• While our unit rates for protection relays remains broadly in line our Initial Proposal, we have provided a

Key drivers and overview of forecast	Summary of Draft Decision	Our Response to the Draft Decision
The protection and control program (\$35 million) will replace obsolete electro-mechanical, electronic, and early-generation microprocessor protection and control relays to maintain network reliability, safety, and compliance with regulatory obligations. The program plans to replace 122 relays (72 electro-mechanical, 39 electronic, and 11 microprocessor units). These replacements are needed to manage the risk associated with aging assets—35% of relays are obsolete, unsupported by manufacturers, and lack modern self-monitoring features—posing risks of undetected failures, incorrect operations, and extended outages. The RTU program (\$5.6 million) is required to replace three obsolete [C-I-C] RTUs that are no longer supported, pose IT security risks due to outdated operating systems, and cannot interface with modern protection relays, creating reliability and operational vulnerabilities. The proposed solution is a continuation of our phased strategy to modernise our distribution network. Forecast capex for these two programs is 23% lower than our Initial Proposal forecast of \$52.6 million. This is due to a reduction in our proposed replacement volumes because of modelling refinements (e.g. adoption of maximum NPV methodology), partly offset an increase in unit rates.	are contributing to higher than required replacements Risk allowance removed	detailed cost estimate in our supporting business case, reflecting the actual costs of recently delivered projects. We have retained a risk allowance in our unit rate Consistent with other asset classes, we have calibrated our PoF assumptions against actual asset replacement rates (which have been externally validated) and adopted the maximum NPV method to forecast economic timing.
22kV and 66kV circuit breakers (\$48.2 million) The 22kV and 66kV CB replacement programs are required to maintain network reliability and safety by replacing high-risk circuit breakers with modern units. The proposed 22kV CB program will replace 25 obsolete 6.6–22 kV bulk oil and minimum oil circuit breakers, as these assets are over 40 years old, suffer from oil leakage, insulation breakdown, and mechanical wear, and cannot meet modern operational requirements such as auto-reclosing and REFCL functionality. While refurbishment has been assessed as an alternative option, this option offers lower net economic benefits than the proposed replacement program. The proposed 66kV CB program will replace 11 ageing LG4C bulk oil CBs and minimum oil CB. Forecast capex for this program is 39% lower than our Initial Proposal forecast, reflecting a 50% reduction in replacement volumes because of modelling refinements, partly offset by an updated, higher unit rate reflecting a more detailed estimate and recent, actual costs.	The 22kV CB replacement program was not included in our Initial Proposal and, therefore, not assessed in the Draft Decision. In respect of 66kV CBs, the power transformers section of this chapter provided a summary of the AER and EMCA's findings.	Consistent with the modelling improvements we have made to other plant (e.g., power transformers), our circuit breaker forecast: - Reflects Weibull parameters which have been externally validated. The basis for these parameters is set out in the economic models provided as a supporting document - Reflects the maximum NPV method to forecast economic timing of circuit breaker replacements. - Incorporates 2024 AER VCRs - Is supported by sensitivity analysis. We have retained risk allowances in our updated circuit breaker unit rates.
Environmental systems (\$23.3 million) The primary driver for this program is to address the environmental risks associated with the inadequate containment of insulating oil and the potential for contaminating nearby water bodies, stormwater, or farmland. This program is driven by the need to comply with our environmental protection obligations, which are outlined in the business case. Following an assessment of several options, the proposed solution is to install compliant, modern systems at eight high-risk zone substations. The selection of these sites was informed by a detailed risk assessment.	The AER acknowledges that there is a baseline need for oil control but was unable to accept the program in full due to the absence of supporting information	The environmental systems business case sets out the justification for this program, including the identified need, options assessment and a detailed risk-assessment. The business case focusses on the need to upgrade zone substation assets, e.g., power transformers, as we accepted the draft decision on oil control investment for our distribution voltage regulators.

Source: AusNet; AER Draft Decision; EMCA Network Capex assessment report

For the remaining 8% (\$94.8 million) of forecast repex/ safety capex not shown in the table above or discussed in detail in this chapter, further information and justification is provided in the business cases and economic models provided as supporting documents. These programs are listed below along with the capex we have proposed for the forthcoming regulatory period:

- Infrastructure (SOCl) – \$22.5 million
- Line Voltage Regulators - \$15 million
- HV Switches - \$10 million
- Station Surge Arrestors - \$9.8 million
- FOLCBs - \$8.5 million
- REFCL Operations Policy - \$7.1 million
- Line Surge Arrestors - \$7.2 million
- Insulators - \$7.1 million
- Auxiliary Supplies - \$6.4 million.

5.7. Demand driven augmentation

5.7.1. Our Initial Proposal

We proposed \$281.1 million of demand driven augex (excluding LV augex) in our Initial Proposal, primarily made up of two new zone substations in Wollert and Pakenham South in AusNet's northern and southeastern growth corridors. The table below compares our Initial Proposal to the AER's draft decision.

Our initial proposal was informed by the maximum demand forecast at the time of submission which did not account for the latest 2024/25 summer demand.

5.7.2. Draft Decision

The AER approved \$119.0 million or 42.3% of our Initial Proposal where it primarily relates to AusNet's two zone substations at Wollert and Pakenham South.

The AER did not approve the rest of our projects primarily due to concerns about our demand forecast inputs suggesting that many projects can be deferred by a few years. The AER invited AusNet to update its demand forecast for the revised proposal and acknowledged that this would likely impact our augmentation capex program. Source: AusNet

As a result of this end-to-end review, we have strengthened the prudence, efficiency and robustness of our digital capex proposal. It has enabled us to refine and reduce proposed costs across multiple programs while ensuring we remain able to meet our long-term obligations and deliver lasting value to customers throughout the 2026–31 period. The revised forecast now reflects:

- Only the essential scope required to maintain digital resilience and system supportability;
- Targeted investment to enable increasing DER penetration and operational complexity;
- Improvements to outage response, field operations and customer outcomes; and
- Uplifted asset data, risk and compliance capabilities aligned with evolving regulatory requirements.

Table 5-47 summarises the AER's concerns and feedback, and outlines how we have addressed these in preparing our Revised Proposal through the process discussed above.

Table 2 (in earlier section 5.3.3) outlines the AER's key concerns while the table below outlines the AER's Draft Decision outcomes.

Table 5-25: 0-1⁵⁷ Summary of demand driven augex (\$m, real \$2024)

Type	Name	Initial Proposal	AER's Draft Decision	Rationale
New Zone Substation	New Wollert ZSS	50.0	45.5	Approved except for the risk allowance
New Zone Substation	New Pakenham South ZSS	60.6	51.9	Approved except for the risk allowance
Augment 66kV loop	Augment Eastern Cranbourne 66kV loop	41.6	nil	Deferred under a lower demand scenario
Augment 66kV loop	Augment East Gippsland 66kV loop	32.7	nil	Deferred under a lower demand scenario
New 22kV feeder	New 22kV distribution feeder (WGL31)	20.4	nil	Inadequate options analysis and insufficient optimal timing justification

⁵⁷ We have sourced these values directly from the SCS capex model which includes overheads. These do not reconcile directly to Table A.2 of "Attachment 2 - capital expenditure" of the AER's Draft Decision.

New 22kV feeder	New 22kV distribution feeder (SMR11)	15.3	nil	Inadequate options analysis and insufficient optimal timing justification
New 22kV feeder	New 22kV distribution feeder (WOTS21)	7.8	6.8	Approved except for the risk allowance
New transformer	New transformer at WGI	13.4	11.7	Approved except for the risk allowance
Program	Summer/winter network readiness program	6.5	3.1	Unit rates too high
Customer growth		32.7	nil	
Total		283.0	119.0	

Source: Initial Proposal sourced from worksheet "Calc | Project Costs" of AusNet's submitted SCS capex model; AER's draft decision sourced from worksheet "Calc | Project Costs of AER's Draft Decision SCS capex model.

5.7.3. Addressing the AER's Draft Decision

We have not accepted any aspects of the Draft Decision on demand driven augmentation. We consider the AER's alternative forecast is insufficient to manage increasing network risk associated with strong customer and demand growth expected on our network and maintain reliable supply to our growing customer base.

NER cl. 6.5.7(c) requires the AER to accept a total capex forecast proposed if satisfied that it reasonably reflects the efficient and prudent costs of achieving the capex objectives, which includes expenditure required to meet and manage a realistic expectation of demand on our network. Given the extraordinary demand growth we are seeing on our network – which is driving urgent investment in the current period and contributing to a 96.4% overspend of our 2025-26 capex allowance – which is expected to continue in 2026-31, we do not consider the Draft Decision forecast can satisfy the AER's decision-making criteria. We consider our Revised Proposal demand driven augex forecast reflects the prudent and efficient costs required to meet these objectives, being underpinned by robust, updated demand forecasts, a sound, probabilistic network planning and economic assessment approach and detailed cost estimates.

As part of preparing our Revised Proposal demand driven augex forecast, we have addressed the AER's concerns by:

- Updating for the latest demand forecast which incorporates the latest 2024/25 summer actuals, AEMO's latest PV and EV data, residential batteries, business electrification and energy efficiency (see Chapter 3 – Demand and Energy Forecasts).
- Comprehensively redeveloping our demand driven augmentation expenditure forecasts.
- Developed a Northern Growth Corridor long term network development plan that clearly explains the constraints in the area, interactions between projects in the region, and why our proposed package of works addresses the constraints in a prudent and efficient manner. Similarly, we have developed a South-Eastern Growth Corridor long term network development plan.
- Refreshed business cases that account for the revised demand forecast, include comprehensive options assessment considering all feasible solutions, and provide justifications at the individual project level.
- Where relevant, we have updated our assessment to consider interactions between different assets. Since the various projects within the Northern Growth Corridor inter-relate with each other, we have developed a single business case and single economic model for the whole area. This enables inter-relationships to be clearly assessed, while also providing information required by the AER to assess the efficiency of each individual project.
- Tested NPV results at +/- 10% of demand forecast for all projects, in contrast to our Initial Proposal which applied a +/-5% sensitivity to some projects. This sensitivity analysis demonstrates our proposed project timing is robust to demand uncertainty.
- We have adopted appropriate actual power factors based on summer maximum demand derived for each ZSS and feeder asset that are consistent with our demand forecast.
- Updated our options analysis to not rule out lower cost options early on, and if the lower cost option remains ruled out, we have expanded on the reasoning for this in our business cases.

- Removed hardcoding from our economic model to ensure greater transparency.
- Ensured the updated economic and energy at risk models provided as supporting documentation show the specific network element demand forecast inputs used to derive expected unserved energy, and the ability for these inputs to be varied to test impacts on project economic timing.

5.7.4. Revised Proposal

Consistent with the AER's expectation in the draft decision, we have updated our demand driven augmentation forecast to reflect our revised demand forecasts.

We consider our updated demand forecasts are robust and should be accepted by the AER in full. Arbitrary adjustments to these which defer augmentation programs risk the reliability of residential and small business customer supply, particularly on very hot and very cold days, and stifling economic development in growth corridors, as we will need to continue to restrict the connection capacity available to Commercial and Industrial (C&I) customers, including supermarkets, large hardware stores and electric vehicle charging operators.

As shown in the table below, our Revised Proposal augex forecast of \$533.8⁵⁸ million is 89.8% higher than our Initial Proposal forecast, reflecting the updates and augex forecasting improvements outlined above and in the following sections.

Table 5-26: Summary of demand driven augex projects and programs (\$m, real \$2026)

	Initial Proposal	AER's Draft Decision	Revised Regulatory Proposal
Northern Growth Corridor	50.0	45.5	260.5
South-eastern Growth Corridor	60.6	51.9	127.6
Other areas	164.0	18.5	119.5
Summer/winter readiness	6.5	3.1	7.5
Strategic land purchases	0.0	0.0	18.7
Total	281.1	119.0	533.8

Source: AusNet

Our Revised Proposal focuses on two growth corridor programs, which are our plans to build the electricity infrastructure needed to supply new suburbs in the Northern and Southeastern growth corridors. These growth corridors are subject to planning regimes designated by the Victorian Government to support development and combined are expected to contain around 110,000 new customers (around 13% of today's customer base) over the next 10 years.

In response to the strong customer and demand growth we are seeing in our growth corridors, which our customer and demand forecasts demonstrated will continue in the forthcoming regulatory period, our growth corridor investment plans have increased materially since our Initial Proposal. This reflects the following key developments:

- **Demand is rapidly increasing in these areas.** For example, the KLO14 feeder recorded a 22% load growth over the 1-year period to April 2025. By the end of 2039, KLO ZSS is projected to reach a maximum demand of 291MW representing a 419% increase over 2024 levels, and EPG ZSS is forecast to see a maximum demand of 167 MW by 2039, a 95% increase from 2024
- **High solar penetration increasing the volatility in peak demand**, in line with cloud cover which is a new operational risk that we are managing. For example, on 27 January 2025 (a 41-degree day), low solar output pushed up local grid demand by ~17%.
- **Continued investments in CER** by our customers, including solar PV, batteries and electric vehicles, in line with Victorian Government policies and objectives. This investment does not eliminate the need for network capacity augmentation, as peak generation and peak demand typically occur at different times.
- **Deliverability challenges largely due to factors outside of AusNet's control**, including difficulty securing land as competing with other essential infrastructure e.g., roads

⁵⁸ Excluding construction insurance cost related to augex

To manage the extraordinary demand growth we are experiencing in our growth corridors, we are preparing for the upcoming 2025/26 summer by:

- Temporary diesel generation to secure customer supply: 12 MW of generation for KLO14 and KLO24 feeders (temporary site is under construction at Wallan as shown in Figure 5-13 below), complemented by 1.1 MW on EPG feeders
- Feeder critical watch list established, and network hardening and feeder transfers identified and will be in place for peak demand management
- C&I demand management contracts updated, and new participants sought
- Considering communication to residential customers prior to forecast peak demand events to encourage voluntary reductions (if they are able)
- Annual communications on Critical Peak Demand (CPD) tariff with ability to call 5 events on peak days

To complement the above measures, we are also carefully managing new connecting customers to manage network constraints:

- Interim arrangement for new connecting C&I customers (>120kVA). We are offering options including AusNet-owned generation on site, or financially contributing to on-site generation
- Currently working with 8 large customers including shopping centres, a childcare centre and an EV charging station
- Arrangement in place until the new Beveridge Zone Substation is commissioned.

Figure 5-13: Temporary Generator Site at Wallan (for KLO14 and KLO24)



Source: AusNet

We plan to commence construction of the new Beveridge ZSS project in 2026. We have commenced a RIT-D for this project, which is currently at the Options Screening Stage. We have also developed a deliverability plan for the growth corridors which highlights that AusNet does not anticipate any labour supply constraints over the 2026–31 period. Workforce availability will continue to be monitored, with plans adjusted as needed to ensure delivery continuity. Similarly, material supply risks have been actively mitigated through strategic procurement initiatives, providing confidence in the timely availability of critical materials to support program execution.

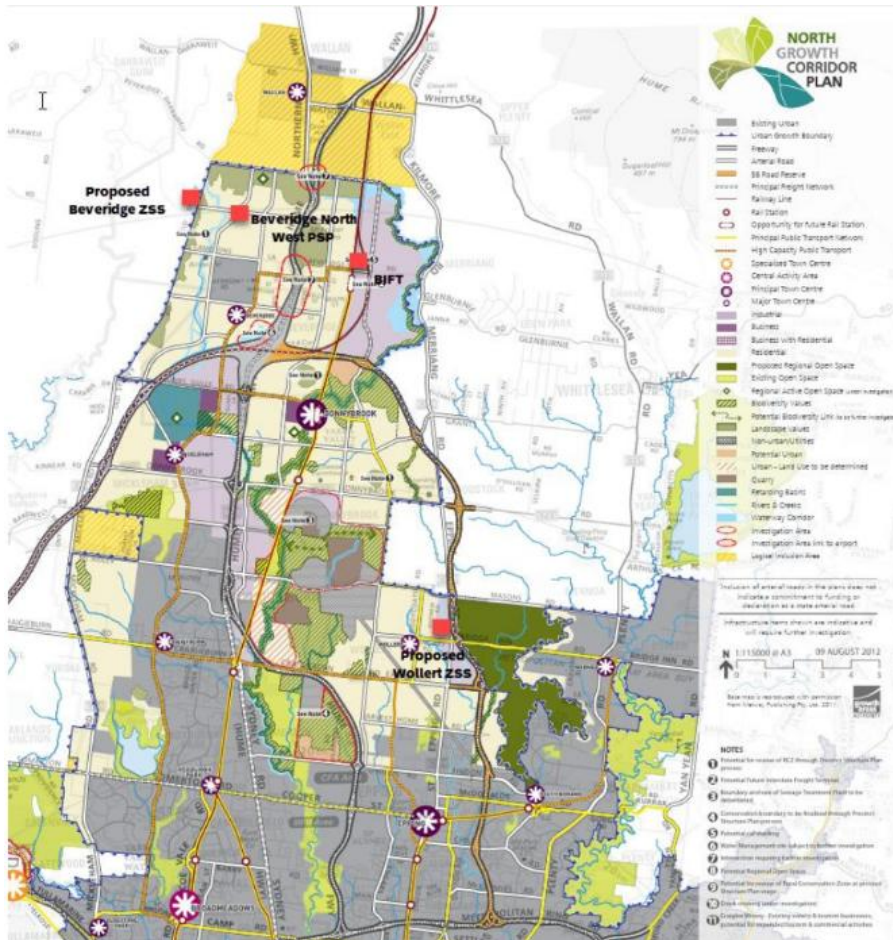
More information in 'ASD - AusNet - Deliverability Plan - Growth Corridors 1Dec2025'.

5.7.4.1. Northern growth corridor

The Northern Growth Corridor is an area approximately 30km north of Melbourne CBD and the corridor can be split into two distinct areas – Wollert and Beveridge - because they serve different geographical areas, and the loads are being supplied by different feeders and zone substations, with different growth rates.

The figure below shows the Northern Growth Corridor development area, relevant PSPs, and our proposed zone substation investments to address the increasing supply requirements in Beveridge and Wollert.

Figure 5-14: Northern Growth Corridor development area

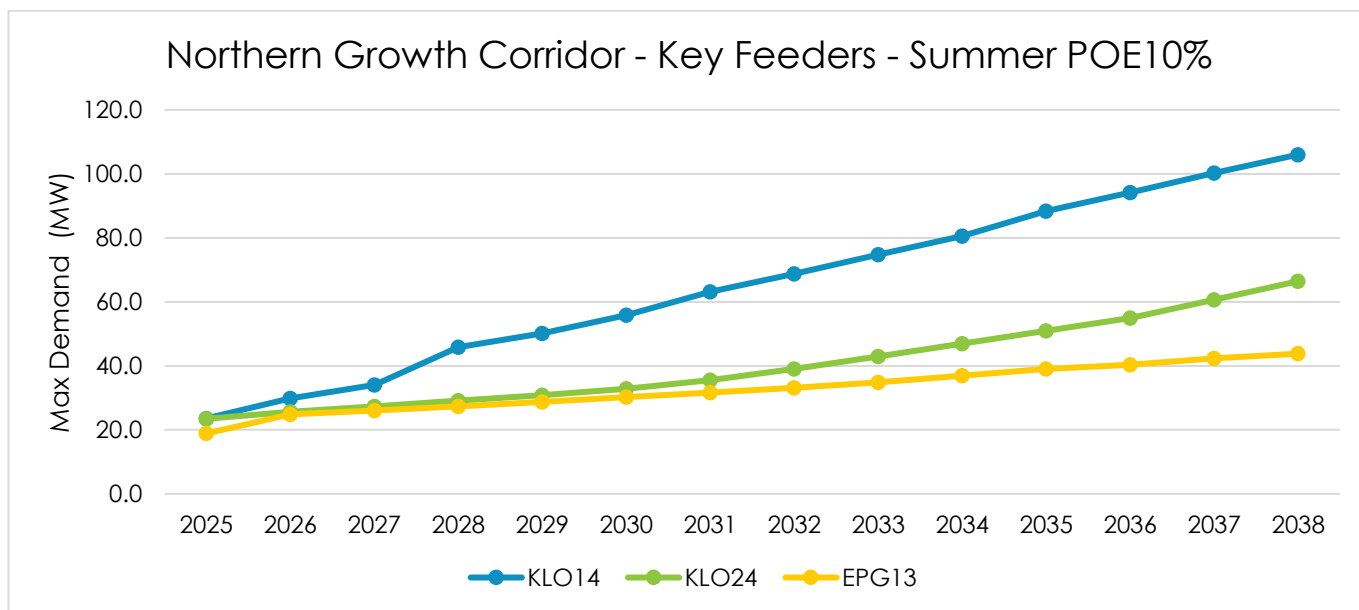


Source: VPA, North Growth Corridor Plan, December 2012 and AusNet additions

The Northern Growth Corridor is a very high growth area, as seen by the demand growth forecasts below. We have experienced this firsthand over the past few years, but growth over the recent 2024/25 summer was particularly pronounced. To manage network demand, we deployed targeted generation during summer 2024/25, including 3.95 MW at the Wallan Sewer Plant (YVW), multiple units at Freeway Enterprise totalling 2.62 MW, and additional capacity at Beveridge (0.9 MW) and Hidden Valley (2.2 MW). These deployments were not without challenges, particularly in finding suitable sites and managing the significant costs of security following repeated copper theft incidents last summer. Despite these efforts, load shedding was required to protect equipment from damage and maintain overall system stability, highlighting the scale of demand pressures. Looking ahead to summer 2025/26, a 12 MW generation site is under construction at Wallan (split evenly between KLO14 and KLO24), complemented by 1.1 MW on EPG feeders. Critical feeders such as KLO14, KLO24, and EPG13 are also being operated at emergency ratings for short durations to provide additional resilience. While these measures have helped mitigate risks in the interim, challenges remain until a permanent solution is in place. This level of network risk is forecast to grow until our proposed network upgrade projects are in service and will be managed during this period using the measures outlined in the above section.

Figure 5-15 illustrates the forecast demand on key feeders within the Northern Growth Corridor and highlights the significant increase in demand and rapid growth rates.

Figure 5-151: Forecast Demand on Key Feeders – Northern Growth Corridor



Source: AusNet

The AER's Draft Decision approved the Wollert zone substation capex forecast in our Initial Proposal except for the risk allowance component. Our Revised Proposal forecast for this project is higher due to recent cost escalation pressures across the industry and a project scope that is now more mature and reflective of the works that will be required in the 2026-31 regulatory period. As explained in section 5.5, we engaged an independent consultant to review AusNet's cost estimates for the three new zone substations projects, who concluded that our costs are aligned to market rates. For the reasons outlined in section 5.5, we have retained a risk allowance in our updated cost estimates for these projects.

The table below summarises our proposed northern growth corridor projects and how they compare with our Initial Proposal forecast and the Draft Decision.

Table 5-27: Summary of Northern Growth Corridor projects (\$m, real \$2026)

Name	Initial Proposal	AER Draft Decision	Revised Proposal	Rationale for revised proposal	Reference
New Wollert ZSS		50.0	45.5	88.4 ⁵⁹ (station \$58.5 & feeders \$29.9)	Demand forecast has increased on feeders KLO14, KLO24, EPG11, EPG12, EPG13, EPG14, EPG21, EPG22, EPG23, EPG24, EPG31 and EPG34. Cost have also increased since Initial Proposal

⁵⁹ The

New Beveridge ZSS	Not included	Not included	127.7 ⁶⁰ (station \$62.6 & feeders \$65.1)	Demand forecast has increased on feeders KLO14, KLO24, EPG11, EPG12, EPG13, EPG14, EPG21, EPG22, EPG23, EPG24, EPG31 and EPG34.
SMTS-BVE-KMS 66kV Line	Not included	Not included	44.5 ⁶¹	Triggered by the Beveridge ZSS
Total	50.0	45.5	260.65	

Source: AusNet

In forming our program for the Northern Growth Corridor, we have analysed the area holistically and considered the interactions between feeders, zone substations, sub-transmission loops and other assets and developed various options. We have also ensured each individual project we have proposed is economically justified.

The identified need assessed in the supporting business case is to address the expected unserved energy risk across feeders KLO14, KLO24, EPG13, EPG21, EPG33, EPG35 and EPG23.

Through analysis of different configurations and permutations at the 22kV network, the preferred option is to address the identified need is to develop two zone substations and run shorter feeders to serve the load centres of Wollert and Beveridge separately.

The table below outlines the different options that we assessed. We have staged the feeder works associated with the zone substations to defer costs where economic to do so. We note that development of a new zone substations with shorter feeders (because they located close to the load centres) is a more prudent and efficient approach relative to alternative solutions involving longer feeders, due to the relatively lower capex afforded by the modular construction of ZSS and the higher capacity afforded by new feeder assets.

The preferred solution at the 22kV network, which includes an additional ZSS at Beveridge, also requires upgrades to the 66kV line. The proposed Beveridge Zone Substation (BVE) is planned to be connected via a cut-in to the adjacent 66 kV SMTS–KMS line (currently rated at 33.72 MVA). Due to its limited capacity, the SMTS–BVE segment is expected to become overloaded by the 2027 summer (based on the POE10 forecast) once the new BVE load is added. This would result in extremely high expected unserved energy and a significant reduction in network reliability. Similarly, the BVE–KMS line is also rated at a low capacity (33.72MVA). If an N-1 contingency occurs on the SMTS–BVE line, the BVE–KMS line will become heavily overloaded, resulting in significant unserved energy. Additionally, the new BVE ZSS will be located in an urban area and must be supplied by lines of 37/3.75 AAC according to AMS 20-16. Our analysis confirms the preferred option – Option 1 in the table below - to reconductor the SMTS-BVE-KMS line is the most economic solution as it will reduce expected unserved energy under N-1 contingencies (despite its higher cost compared to other options).

⁶⁰ The direct cost component of the Beveridge ZSS forecast is lower than our detailed cost build up (see file 'ASD – AusNet - Direct Cost Summary - Beveridge ZSS 22kV Feeder Augmentation (3 Feeders - BVE13, BVE14 & BVE21) - 01122025 - CONF'). Our detailed cost build up was updated following our business case, economic modelling, and EDPR capex forecast development, where it increased by ~\$3.5 million. This does not impact the optimal timing and preferred option of the business case.

⁶¹ The direct cost component of the SMTS-BVE-KMS 66kV forecast is higher than our detailed cost build up (see file 'ASD – AusNet - Direct Cost Summary - Augment SMTS-BVE-KMS 66kV Line - 01122025 – CONF'). Our detailed cost build up was updated following our business case, economic modelling, and EDPR capex forecast development, where it decreased by ~\$2 million. This does not impact the optimal timing and preferred option of the business case.

Table 5-28: Summary of options analysis for the northern growth corridor (\$m, real 2023-24)

	Description	Comment
Option 0	Do nothing	No upfront capital costs, but it exposes customers to the increasing risk and cost of network outages Discounted value of Expected Unserved Energy (EUE) \$279.8 billion
Option 1 (preferred option)	New Beveridge ZSS plus associated feeder works New Wollert ZSS plus associated feeder works Sub-transmission upgrade to SMTS-BVE-KMS line	This is the lowest cost option to address the EUE risk given that zone substations add significant capacity and being more modular, it can be built at a lower cost point compared to the complex task of constructing long feeders as large sections of the NGC region requires undergrounding. By locating the zone substations closer to the load centres, the feeders are shorter. - Discounted total costs (capex & opex) \$248.9 million - Discounted benefits \$217.4 billion - NPV \$217.1 billion
Option 2	Third transformer and bus at existing Doreen ZSS New 22kV feeders from DRN ZSS to Wollert New Beveridge ZSS plus associated feeder works Sub-transmission upgrade to SMTS-BVE-KMS line	This is more expensive than option 1 given it is more expensive to expand DRN ZSS to its full capacity and then run long feeders to the Wollert load centre compared to building a new Wollert ZSS with shorter feeders (DRN ZSS to Wollert is ~9 km, longer than the average feeder length in Option 1). Proposing to underground most of the DRN ZSS to Wollert load centre feeders (instead of overhead) due to factors such as allowing for future road expansions. It also addresses less of the EUE compared to Option 1 because expanding DRN ZSS adds 45 MVA of nameplate capacity compared to a new Wollert ZSS which adds 90 MVA. - Discounted total costs (capex & opex) \$316.8 million - Discounted benefits \$199.9 billion - NPV \$199.5 billion
Option 3	Third transformer and bus at existing Kalkallo ZSS New 22kV feeders from KLO ZSS to Beveridge New Wollert ZSS plus associated feeder works Sub-transmission upgrade to SMTS-WLT line	This option is more costly than Option 1 due to it being more expensive to expand KLO ZSS to its full capacity and then running long feeders to the Beveridge load centre compared to building a new Beveridge ZSS with shorter feeders (KLO ZSS to Beveridge is ~11km, longer than the average feeder length in Option 1). This option also requires additional remote REFCL assets, which are costly but necessary to maintain compliance at KLO ZSS. Proposing to underground most of the KLO ZSS to Beveridge load centre feeders due to overhead infrastructure along the Hume Freeway being declined by the Department of Transport. It also addresses less of the EUE compared to Option 1 because expanding KLO ZSS adds 45 MVA of nameplate capacity compared to a new Wollert ZSS which adds 90 MVA. - Discounted total costs (capex & opex) \$364.6 million - Discounted benefits \$193.2 billion - NPV \$192.9 billion
Option 4	Third transformer and bus at existing Kalkallo zone substation New 22kV feeders from KLO ZSS to Beveridge Third transformer and bus at existing Doreen ZSS New 22kV feeders from DRN ZSS to Wollert	This is the most expensive augmentation option as the cost of expanding existing zone substations and running long feeders to load centres is far more costly than building new zone substations and then running shorter feeders. The additional remote REFCL costs required for option 3 also applies to this option 4. It also addresses less of the EUE compared to Option 1 because expanding DRN ZSS adds 45 MVA of nameplate capacity compared to a new Wollert ZSS which adds 90 MVA. Expanding KLO ZSS adds 45 MVA of nameplate capacity compared to a new Wollert ZSS which adds 90 MVA. - Discounted total costs (capex & opex) \$371.1 million - Discounted benefits \$166.8 billion - NPV \$166.5 billion
Option 5	Contract network support services to defer network investment	This option considers contracting demand management services from agricultural, commercial, and industrial customers. AusNet continues to assess non-network alternatives under RIT-D obligations; however, recent operational experience indicates these options are unlikely to serve as a viable replacement for network augmentation. - Discounted total costs \$56.5 billion - Discounted benefits \$56.5 billion

	Description	Comment
		NPV \$0 billion
Considered but not progressed	Woodstock new zone substation, with new distribution feeders to Beveridge and Wollert	These options were not progressed due to the lengthy feeder runs that are required, crossing several major roads with easement concerns. This would require lengthy underground feeder sections, increasing cost and potentially introducing REFCL concerns and associated costs.
	Wollert new zone substation, with new distribution feeders to Beveridge	
	Beveridge new zone substation, with new distribution feeders to Wollert, and a sub-transmission upgrade to Beveridge	

Source: AusNet

Further information on our Northern Growth Corridor is available in the following:

- **Investment plans:** ASD – AusNet - Supply security of Northern Growth Corridor – 01122025
- **Longterm development strategy:** ASD - AusNet - North Growth Corridor Longterm Network Development Plan – 01122025
- **Investment deliverability:** ASD - AusNet - Deliverability Plan - Growth Corridors 1Dec2025

5.7.4.2. South-eastern growth corridor

The southeastern growth corridor is approximately 40km to the southeast of Melbourne CBD. The figure below shows the Southeastern Growth Corridor development area, relevant PSPs, and our proposed zone substation investment to address the increasing supply requirements in Pakenham South and Officer areas. Beyond these areas, significant growth and associated supply risks are also forecast in the Cranbourne West and Greater Clyde South supply areas.

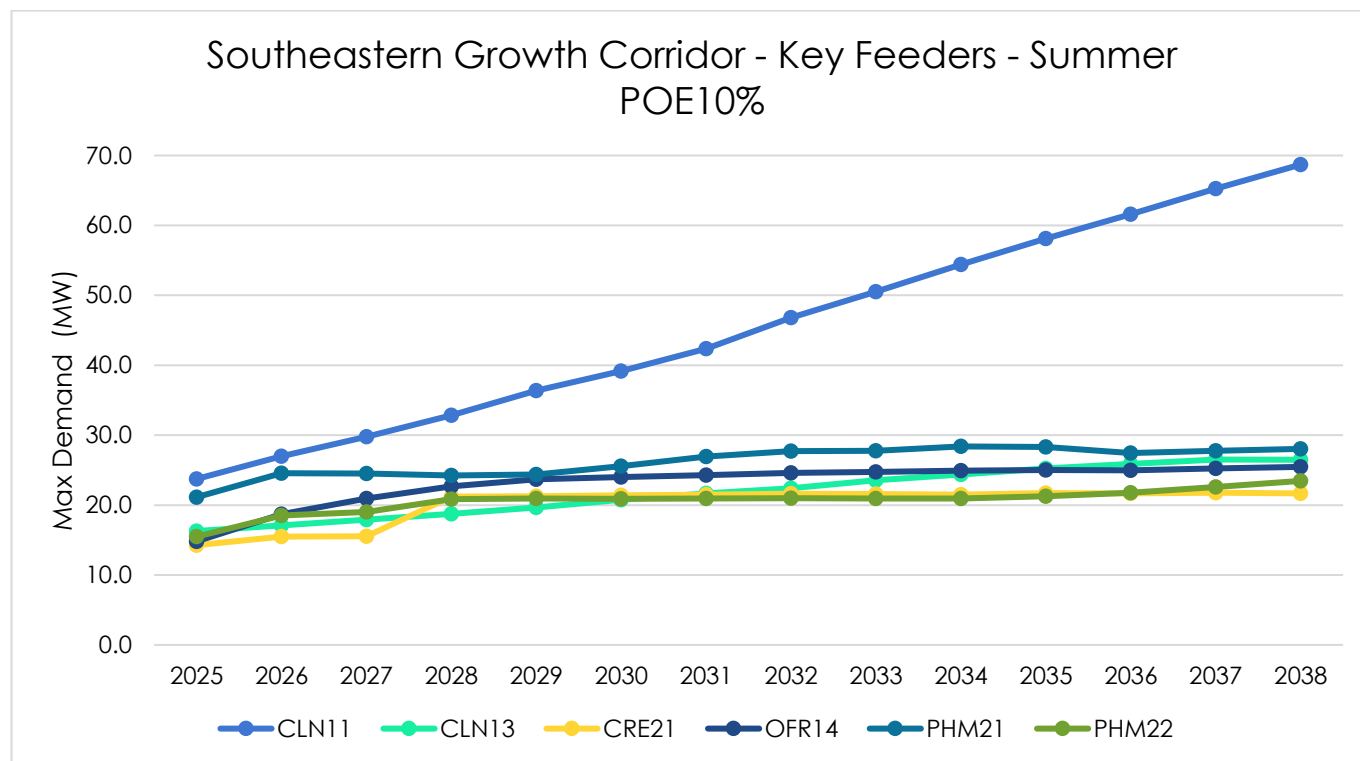
Figure 5-16: Southeastern Growth Corridor development area



Source: VPA, South East Growth Corridor Plan, December 2012 and AusNet additions

The figure below illustrates the forecast demand on key feeders within the Southeastern Growth Corridor and highlights the significant increase in demand.

Figure 5-172: Forecasted Demand on Key Feeders – Southeastern Growth Corridor



Source: AusNet

The table below summarises our proposed south-eastern growth corridor projects and how they compare with our Initial Proposal forecast and the Draft Decision. Proposed investment in this growth corridor \$127.6 million includes \$ 8.2 million associated with an in-flight project that has commenced in the current regulatory period –installation of a third transformer and switchboard at the Clyde North zone substation.

Table 5-29: Summary of Southeastern Growth Corridor projects (\$m)

Name	Initial Proposal	AER Draft Decision	Revised Proposal	Rationale for revised proposal	Reference
New Pakenham South ZSS	60.6	51.9	77.5 (station 59.8 & feeders 17.7)	Demand forecast has increased on feeders CLN22, CLN23, OFR14, OFR21, PHM21, PHM22, PHM24, PHM31, PHM32 and PHM34 as well as CLN and PHM ZSS, increasing supply risk Cost have also increased since Initial Proposal	Chapter 4 of the Southeastern Growth Corridor (SEGC) business case ⁶²
CRE34 new feeder	Not included	Not included	9.3	Demand forecast has increased on feeders CRE21 increasing supply risk	Chapter 6 of the SEGC business case
CLN new feeder (CLN33) Delayed	Not included	Not included	5.9	Demand forecast has increased on feeders CLN11, CLN13 & CRE33 increasing supply risk Originally planned for the current 2021-26 period. Given	Chapter 5 of the SEGC business case

⁶² Refer to: ASD - AusNet - Supply security of Southeastern Growth Corridor - 01122025

				the delay, some costs have carried over (in full or part) to the 2026-31 period.	
CLN 2nd new feeder (CLN32)	Not included	Not included	20.2	Demand forecast has increased on feeders CLN11, CLN13 & CRE33 increasing supply risk	Chapter 5 of the SEGC business case
CBTS 66kV feeder rearrangement	Not included	Not included	6.5	Cranbourne Supply Area RIT-T identified the need for Dx works	CBTS 66kV feeder rearrangement business case
CLN 3rd Tx and switchboard WIP project	Not included	Not included	8.2	Originally planned for the current 2021-26 period. Given the delay, some costs have carried over (in full or part) to the 2026-31 period.	CLN 3 rd transformer and switch room business case and 2x Project Change request documents
Total		60.6	51.9	127.6	

Source: AusNet

The **CBTS 66kV feeder rearrangement** was identified as the preferred option in the Cranbourne Supply Area RIT-T (August 2025)². Specifically, the installation of a fourth 150 MVA 220/66 kV transformer at CBTS was selected to address capacity constraints, maintain supply reliability, and reduce expected unserved energy in Cranbourne. This augmentation will restore adequate firm capacity and N-1 security for the region. The CBTS 66kV feeder rearrangement will simply undertake the required feeder reconfiguration works to enable the connection of the fourth transformer identified under the RIT-T. Until these works are completed, the new transformer will remain installed but only used as a hot spare, and CBTS will continue to operate at its firm capacity limit with N energy at risk persisting.

The purpose of the **CLN 3rd Tx and switchboard** project is to expand the existing CLN zone substation given it has already exceeded its N capacity. This project was originally planned for the current 2021-26 period. Given the delay, some costs will carry over to the 2026-31 period. We have only included the forecast cost expected to be incurred in the 2026-31 period; cost that we have already incurred in the current 2021-26 have been excluded.

The south-eastern growth corridor is split into three distinct supply areas due to its scale, geographical spread of the load growth, and most importantly the independence of existing assets within each area. These three supply areas are:

- **Pakenham South and Officer.** The Pakenham South and Officer area in the east (of the SEGC) serves Clyde North, Clyde, Pakenham South, Officer and Officer South. Loads are transferred to the Pakenham South and Officer supply by feeders CLN22, CLN23, OFR14, OFR21, PHM21, and PHM22 that are connected to CLN, OFR, and PHM zone substations.
- **Greater Clyde South.** The Greater Clyde South area in the middle and south (of the SEGC) serves Clyde, Deavon Meadows, and Five Ways. Loads are transferred to Greater Clyde South by feeders CLN11, CLN13, and CRE33 that are connected to CLN and CRE zone substations.
- **Cranbourne West.** The Cranbourne West area in the west (of the SEGC) serves Cranbourne West. Loads are transferred to Cranbourne West by feeder CRE21 that is connected to the CRE zone substation.

As can be seen from the list above, existing feeders do not overlap the supply areas within the corridor, meaning there are no interdependencies between existing assets that must be accounted for in an assessment. As a result, our analysis for the southeastern growth corridor consists of three standalone assessments – one for each of the supply areas – which differs to our assessment of the northern growth corridor which is a combined assessment.

We assessed each supply area separately:

- **Pakenham South and Officer supply area.**

The Pakenham South and Officer supply area is severely constrained because all six feeders are forecast to be overloaded during the 2026-31 regulatory period, meaning the opportunities and practicalities of feeder transfers, or feeder reconfiguration are limited. Specifically, we have assessed whether it makes sense to install a new Pakenham South ZSS + new feeders, expand the existing Pakenham ZSS + new feeders, expand the existing Officer ZSS + new feeders, or expand the existing Lang Lang ZSS + new feeders.

Our assessment ultimately showed that it is most economical to install a **new Pakenham South ZSS + new feeders (option 1)** because the high cost of a new ZSS is partially offset by being closer to the load centre and therefore

requiring shorter feeders. At the same time, it addresses more of the expected unserved energy risk (compared to BAU and the other options) given it will be a two transformer ZSS. To allow for contingency and planning, AusNet's guideline stipulates that all new ZSS must be built with two transformers at minimum.

The other options are cheaper than a **new Pakenham South ZSS + new feeders (option 1)**. Yet, the other options address less of the expected unserved energy risk because a new transformer and bus – at the existing Pakenham ZSS (**Option 2**), or existing Officer ZSS (**Option 3**) or existing Lang Lang ZSS (**Option 4**) – are restricted in their ability to provide transfer capacity to all feeders in the supply area.

- **Greater Clyde South.**

The Greater Clyde North area is severely constrained because all three feeders are forecast to be overloaded during the 2026-31 regulatory period, meaning the opportunities and practicalities of feeder transfers or feeder reconfiguration are limited. We have assessed whether it makes sense to install one new feeder (**CLN33 – option 1**), two new feeders (**CLN32 and CLN33 – option 2**), a BESS (**option 3**), or contract network services to defer capital investments (**option 4**).

Our assessment showed that the preferred solution is to install new two feeders – **CLN32 and CLN33 under option 2** – given that it addresses the most expected unserved energy risk at a relatively low cost. Under this preferred option, existing and forecast load on feeders CLN11, CLN13, and CRE33 will be distributed across five feeders allowing each to be within its asset rating for several years. This option produced the highest NPV of all options assessed.

While option 1 (**one new feeder CLN33**) is significantly cheaper than option 2 (**the preferred option**), it also addresses far less expected unserved energy risk compared to option 2, rendering it to be less preferred. Under this option, existing and forecast load on feeders CLN11, CLN13, and CRE33 will be distributed across four feeders allowing each feeder to be managed within its asset rating for one year. That is, thermal overloads are expected to occur from FY29 onwards.

- **Cranbourne West.**

The Cranbourne West area is served by CRE21 which is forecast to be overloaded by FY29. This means there are no opportunities for feeder transfers or feeder reconfigurations. We have assessed whether it makes sense to install one new 4.5km long feeder utilising a spare breaker available at existing switchroom in CRE ZSS (**CRE34 – option 1**), construct a new feeder from the existing CRE ZSS following an alternate 5km long route to the west to offload CRE21 (**option 2**), a BESS (**option 3**), or network support services to defer network investment (**option 4**).

Our assessment showed that the preferred option is to install one new feeder (**CRE34 – option 1**) given that it addresses the most expected unserved energy risk at the lowest cost. Under this preferred option, existing and forecast load on CRE21 will be distributed across two feeders allowing each to be within its asset rating for several years. This option produced the highest NPV of all options assessed.

Further information on our Southeastern Growth Corridor is available in the following:

- **Investment plans:** ASD – AusNet - Supply security of Southeastern Growth Corridor – 01122025
- **Longterm development strategy:** ASD - AusNet - Southeastern Growth Corridor Longterm Network Development Plan – 01122025
- **Investment deliverability:** ASD - AusNet - Deliverability Plan - Growth Corridors 1Dec2025

5.7.4.3. Other projects

Consistent with the northern and south-eastern growth corridors, our revised demand forecasts have generally increased at other locations across the network, compared to our Initial proposal, increasing the risk of involuntary load shedding and our ability to connect new customers and maintain reliable supply.

The AER's Draft Decision approved the capex forecast related to **WGI Tx** and **WOTS21** feeder, except for the risk allowance component which the AER removed. Our latest cost estimates have increased slightly based on more mature project scopes and the incorporation of recent data on actual project costs. As such, our capex forecast for these projects in this Revised Proposal are also slightly higher. Our refreshed business cases for these projects demonstrates that they remain prudent to undertake, taking account of the increased cost estimates and updated demand forecast.

The AER's Draft Decision did not accept our capex forecast related to **summer/winter readiness program** on the basis that our proposed unit rates are too high. We have adopted the unit rates from our LV augex program which remains unchanged from our Initial Proposal submission. These rates have been validated as being appropriate to adopt for summer/winter readiness. We have refreshed our summer/winter readiness program business case and economic model.

The AER deferred both the **East Gippsland 66kV loop** and **Eastern Cranbourne 66kV loop** projects based on using a lower demand scenario. We do not accept the AER's assessment approach, as it is inconsistent with the industry's standard practice of using a 70% weighting to 50POE and 30% weighting to 10POE. In addition to this issue, since the Initial Proposal our capex forecast for East Gippsland has increased and we have refreshed our business case to understand whether the project remains economic and therefore prudent to undertake during the 2026-31 regulatory period. Our refreshed business cases (including for East Cranbourne 66kV loop) demonstrates that both projects remain the preferred option with the highest NPV outcome and that the optimal timing remains in the 2026-31 regulatory period.

For **WGL31**, we have incorporated more options analysis, addressing the AER's feedback.

Our updated analysis shows that **SMR11** is no longer economic during the 2026-31 regulatory period, and we have not included it in our Revised Regulatory Proposal.

We have also introduced a new **strategic land purchases** capex forecast that will allow us to purchase five sites in anticipation of load growth. The amount of \$18.7m (\$, real 2025-26) is far less than the expected cost if we delay until such time that it is urgently needed. Our business case shows that there is more value to customers if we purchase the required land in advance compared to purchasing it closer to project delivery, as the cost savings more than outweighs the value of deferment.

The table below summarises our projects outside of the growth corridors.

Table 5-30: Summary of projects outside of the growth corridors

Name	Initial Proposal	AER Draft Decision	Revised Proposal	Rationale for revised proposal	Reference
Augment East Gippsland 66kV loop	32.7	0	38.6 ⁶³	Demand forecast has increased on East Gippsland 66kV loop increasing supply risk. Cost have also increased since Initial Proposal	Augment East Gippsland 66kV Loop Draft Project Assessment Report ⁶⁴
Augment Eastern Cranbourne 66kV loop	41.6	0	29.6	Demand forecast has increased on East Cranbourne 66kV loop increasing supply risk. Cost have also decreased since Initial Proposal	Augment Eastern Cranbourne 66kV Loop CBTS-OFR line Final Project Assessment Report ⁶⁵
New 22kV distribution feeder (WGL31) and switchroom	20.4	0	31.4	Demand forecast has increased on feeders WGL13 increasing supply risk. Cost have also increased since Initial Proposal	Install a new 22kV distribution feeder (WGL31) & New Switchboard at WGL ZSS business case ⁶⁶
New 22kV distribution feeder (SMR11)	15.3	0	0	Demand forecast has decreased on feeder SMR24 which in turn has decreased supply risk to a point that the project is no longer needed during FY26-31 period.	N/A
New 22kV distribution feeder (WOTS21)	7.8	6.8	6.9	Demand forecast has slightly increased for feeder WOTS25 increasing supply risk. Cost have also decreased since Initial Proposal	Install a new 22kV distribution feeder (WOTS21) business case ⁶⁷
New transformer at WGI	13.4	11.7	13.0	Demand forecast has increased at WGI ZSS increasing supply risk.	Install a new 20 33 MVA Transformer at WGI Zone

⁶³ Refer to files 'ASD - AusNet - Direct Cost Summary - MWTS-TGN 66kV Line Augmentation 01122025 - CONF' and 'ASD - AusNet - Direct Cost Summary - Augment East Gippsland 66kV Loop (TGN-MFA lines) 01122025 - CONF'. Two separate documents contain the cost breakdown of separate sections of the lines.

⁶⁴ Refer to: ASD - AusNet - Augment East Gippsland 66kV Loop DPAR - 28112025

⁶⁵ Refer to: ASD - AusNet - FPAR Augment Eastern Cranbourne 66kV Loop CBTS-OFR line - 26112025

⁶⁶ Refer to: ASD - AusNet - Install a new 22kV distribution feeder (WGL31) & New Switchboard at WGL ZSS - 01122025

⁶⁷ Refer to: ASD - AusNet - Install a new 22kV distribution feeder (WOTS21) - 01122025

				Cost have decreased since Initial Proposal	Substation business case ⁶⁸
Customer growth	32.7	0	0	Our revised proposal programs have displaced the need for this	N/A
Summer/winter network readiness program	6.5	3.1	7.5	Identified need has not changed from Initial Proposal. Revised proposal based on updated costs	FY27-31 Summer Winter Network Readiness Program business case ⁶⁹
Strategic land purchases	Not included	Not included	18.7	Land value projections have indicated that it is cheaper to purchase land in advance as this leads to long term savings. Purchasing land just in time is both more expensive and riskier as it could delay construction.	Strategic Land purchases (Wallan, Epping West, Officer South, Cranbourne South & Drouin) business case ⁷⁰
Total	170.4	21.6	145.8		

Source: AusNet

5.7.4.4. Supporting documents

The following table lists the documents and economic models provided in support of our updated demand driven augex forecast.

Table 5-312: Key supporting documents and models

Name	Key Supporting Document	Key Model
General documents	- ASD - AusNet - NPV Model User Guide (Augex) - 01122025 - ASD - AusNet - Deliverability Plan - Growth Corridors 1Dec2025	
Northern Growth Corridor	- ASD - AusNet - Supply security of Northern Growth Corridor – 01122025 - ASD - AusNet - North Growth Corridor Longterm Network Development Plan - 01122025 - PUBLIC	ASD - AusNet - Northern Growth Corridor economic model - 01122025
Southeastern Growth Corridor	- ASD - AusNet - Supply security of Southeastern Growth Corridor – 01122025 - ASD - AusNet - South Eastern Growth Corridor Longterm Network Development Plan - 01122025 - PUBLIC	- ASD - AusNet - New CLN32 & CLN33 feeders economic model - 01122025 - ASD - AusNet - Install a new 22kV distribution feeder (CRE34) economic model - 01122025 - ASD - AusNet - Pakenham South Zone Substation Development Project economic model - 01122025
Augment East Gippsland 66kV loop	ASD - AusNet - Augment East Gippsland 66kV Loop DPAR - 28112025	ASD - AusNet - Augment East Gippsland 66kV Loop economic model - 01122025
Augment Eastern Cranbourne 66kV loop	ASD - AusNet - FPAR Augment Eastern Cranbourne 66kV Loop CBTS-OFR line - 26112025	ASD - AusNet - Augment Eastern Cranbourne 66kV Loop economic model - 01122025
New 22kV distribution feeder (WGL31) and switchroom	ASD - AusNet - Install a new 22kV distribution feeder (WGL31) & New Switchboard - 01122025	ASD - AusNet - Install a new 22kV distribution feeder (WGL31) & New Switchboard at WGL ZSS economic model - 01122025

⁶⁸ Refer to: ASD - AusNet - Install a new 20 33 MVA Transformer at WGI Zone Substation - 01122025

⁶⁹ Refer to: ASD - AusNet - FY27-31 Summer Winter Network Readiness Program - 01122025

⁷⁰ Refer to: ASD - AusNet - Strategic Land purchases (Wallan, Epping West, Officer South, Cranbourne South & Drouin) - 01122025

New 22kV distribution feeder (WOTS21)	ASD - AusNet - Install a new 22kV distribution feeder (WOTS21) - 01122025	ASD - AusNet - Install a new 22kV distribution feeder (WOTS21) economic model - 01122025
New transformer at WGI	ASD - AusNet - Install a new 20 33 MVA Transformer at WGI Zone Substation - 01122025	ASD - AusNet - Install a new 20 33 MVA Transformer at WGI Zone Substation economic model - 01122025 -
Summer/winter network readiness program	ASD - AusNet - FY27-31 Summer Winter Network Readiness Program - 01122025	ASD - AusNet - FY27-31 Summer Winter Network Readiness Program economic model - 01122025
Strategic land purchases	ASD - AusNet - Strategic Land purchases (Wallan, Epping West, Officer South, Cranbourne South & Drouin) - 01122025	ASD - AusNet - Strategic Land purchases (Wallan, Epping West, Officer South, Cranbourne South & Drouin) economic model - 01122025

Source: AusNet

5.8. LV augex

5.8.1. Our Initial Proposal

AusNet's low voltage (LV) network is facing emerging network constraints due to accelerating electrification and we proposed a proactive program to upgrade these assets ahead of the impact of electrification to prevent reliability issues for our customers. Our initial proposal included capital expenditure of \$148.5 million (real 2025–26), to upgrade 995 DSS and 71 SWER lines, net of \$36 million deferred due to flexible services introduced as a non-network solution.

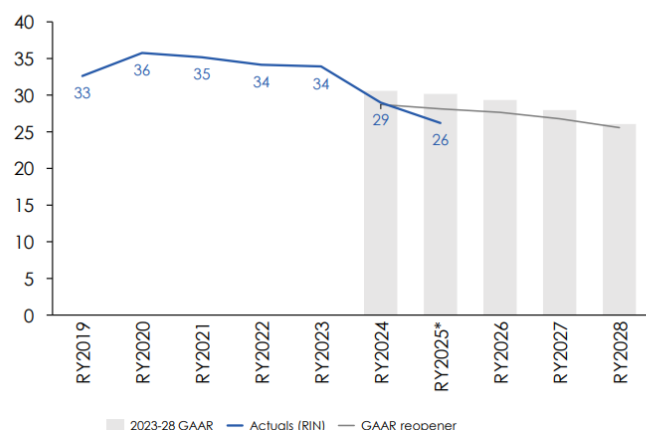
The following section provides further context on the drivers and need for our proposed LV network upgrade program.

5.8.1.1. Electrification is happening now and will accelerate in 2026-31

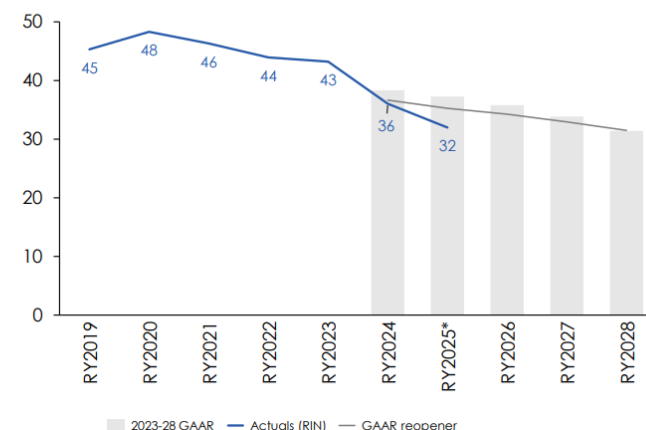
The impact of electrification is already observable on AusNet electricity and gas distribution networks and the scale of these impacts is expected to continue to accelerate in the 2026-31 period. As shown in Figure 5-18 AusNet's gas network has seen decreases in residential gas volumes since 2023, with lower average usage per customer which is clear sign of electrification impacts in the Victoria context.

Figure 5-18: AusNet's gas network – residential usage

Total residential volumes
RY2019 to RY2028*, PJ



Average usage per residential customer
RY2019 to RY2028*, GJ per customer



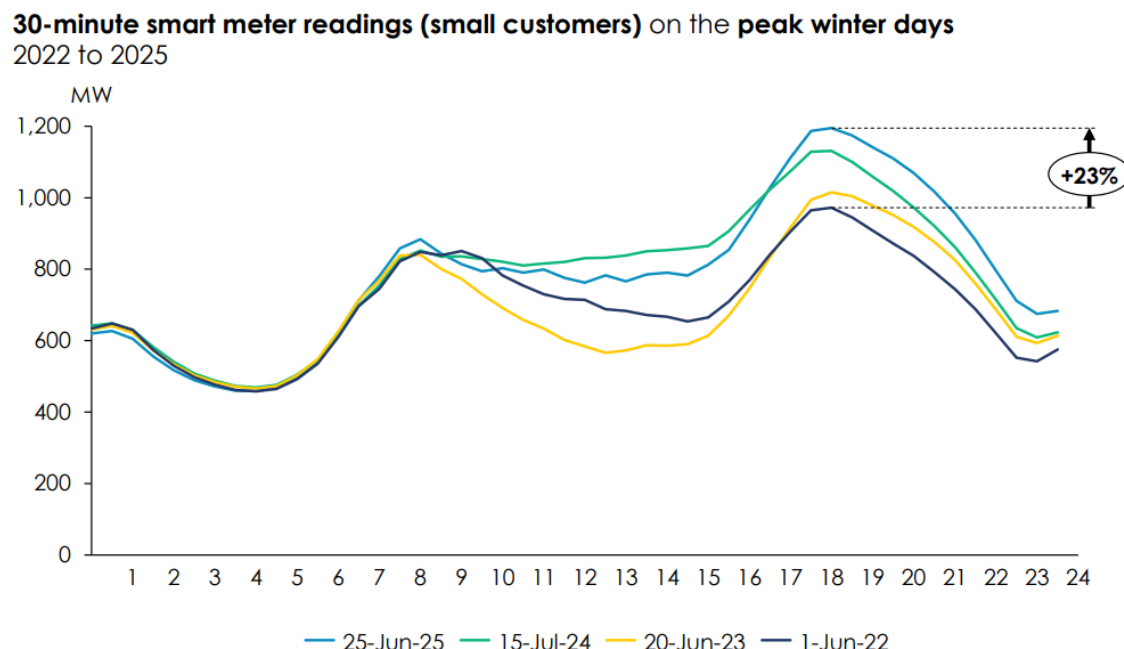
Note AusNet's gas network covers the West Victoria and Melbourne's inner western suburbs.

Source: AusNet

Over the period shown in the charts above, we have also seen increases in peak and average winter electricity demand on our distribution network. The per customer increase in peak electricity demand from gas electrification is

material, as shown in our recent analysis below. Figure 5-19 shows this impact in aggregate, from 2022 to 2025, average small customer nighttime peak load on peak winter days has increased 23% on our network. Figure 5-20 shows an example of impact from full electrification of heating and hot water from a single customer in our Electrification trial. This indicates the expected impact on evening peak in winter, largely driven gas electrification, will be material and likely occur in the near term.

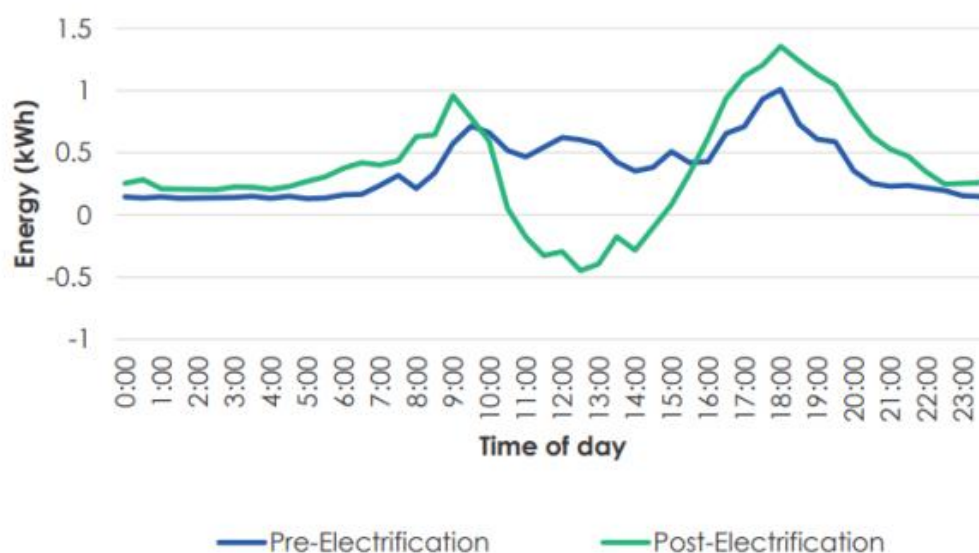
Figure 5-19: 30-minute smart meter readings (small customers) on peak winter days



Source: AusNet

Figure 5-20: Average winter weekday electricity consumption for Customer 6 in the Electrification project

Average winter weekday electricity consumption for Customer 6 in the Electrification project.



This customer electrified their gas heating and hot water systems. They also installed a 6.6 kW solar system

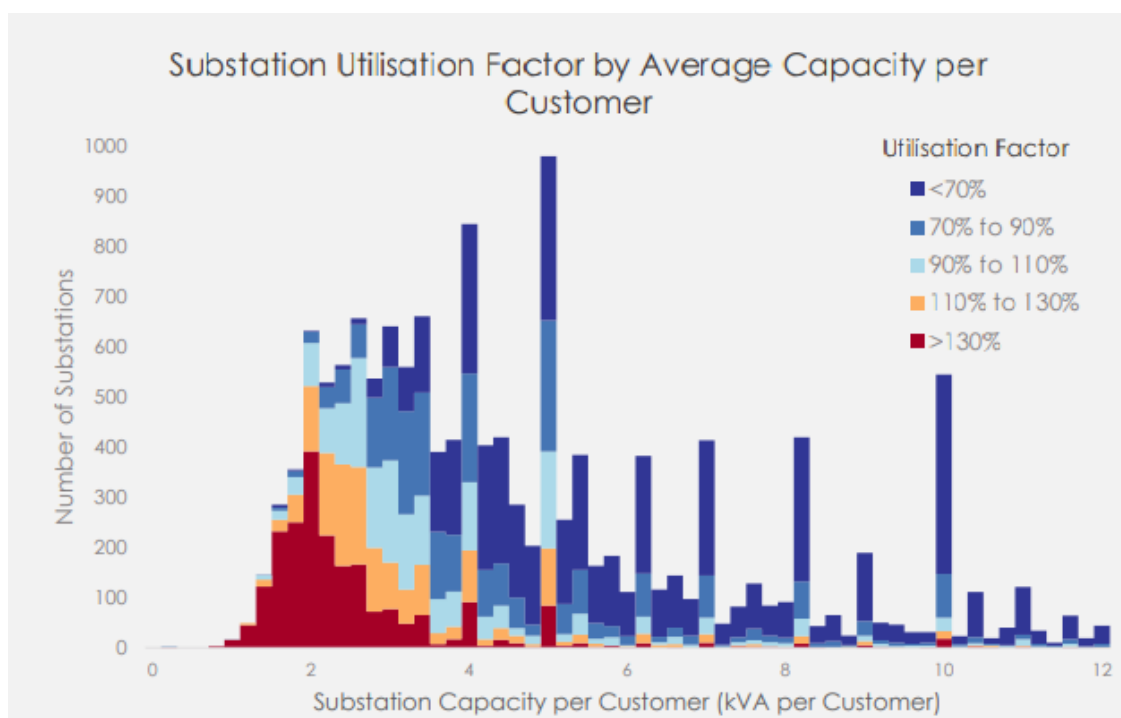
Source: AusNet

Electrification is expected to have an impact across AusNet assets over the 2026-31 period. However, LV distribution substations (DSS) and SWER lines, which serve small numbers of customers, are especially vulnerable to localised

constraints and overload due to their lack of diversity of demand compared to large assets on our network, such as zone substations and high voltage feeders. Given the expected magnitude of the per customer increase in peak demand shown above, the impact of just a modest portion of customers electrifying per DSS or SWER asset would likely result in network constraints during peak periods. This lack of asset diversity in demand and the limited flexibility in customers shifting demand for space heating during evening peaks means that our LV network will be the part of our distribution network that is first and most significantly impacted by widespread capacity constraints from electrification.

Many of our substations are already highly utilised and operate over 110% capacity on peak days, which at times can result in reliability impacts for customers on these highly utilised substations which we currently address largely through reactive works. Without a proactive program to upgrade substations, we will be unable to efficiently manage the impact of electrification as it will become unsustainable, more costly and have much greater reliability impacts on customers electrifying if we were to address emerging constraints through reactive works alone.

Figure 5-21: Substation utilisation factor by average capacity per customer

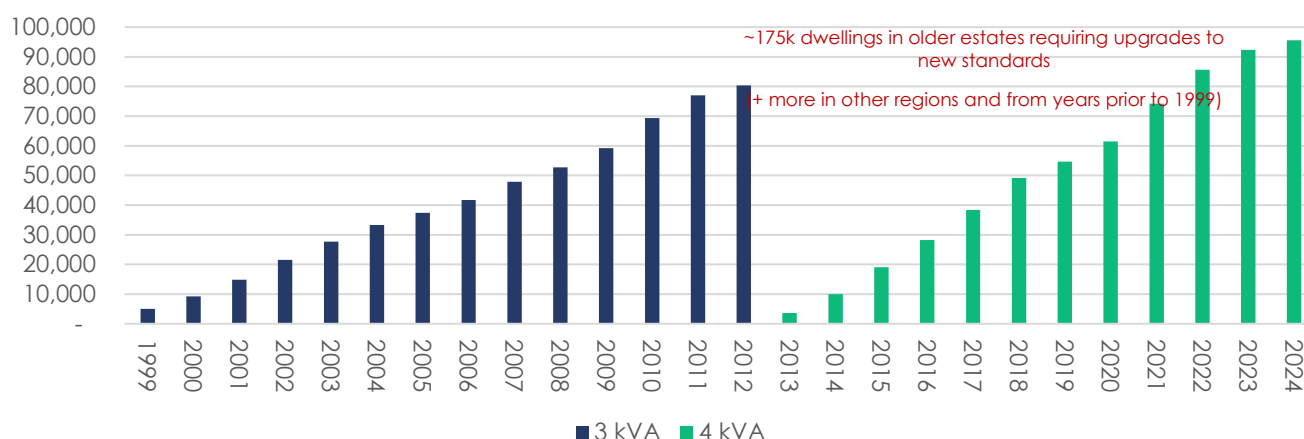


Source: AusNet

The identified need for LV network upgrades is further evident through examining the standards which the network was built to. LV substations were originally designed for stable residential loads with modest diversity, but accelerating electrification has significantly changed consumption levels requiring design standards need to evolve to customer demand and meet electrification. From mid-2024 the standard for new estates changed to 5.25kVA per lot with space allowed to increase to 8kVA per lot, to accommodate the future impacts of electrification of gas and transport.

Figure 5-22 below shows the number of historical lots in one of our three network regions (central) built under 3kVA and 4kVA design standards. The 'angry summer' heatwave which resulted in significant LV failures which led to a change in design standards to 4kVA in 2013. This is significantly below the design standard that will be required under full electrification. The Figure highlights that around 175,000 dwellings in just one of our regions that were built under 3kVA or 4kVA design standards and it can be expected LV upgrades will be needed to meet post-electrification design standards and provide customers with a good level of service once they have fully electrified.

Figure 5-22: Historical lots in estates in Central region connected to old design standards



Source: AusNet

Figure 5-21 also shows the median substation on our network provides 4.8kVA per customer, indicating that our current network is built to accommodate per customer demand below the current design standard of 5.25kVA and well short of the projected 8kVA required to support future electrification. This change will require a significant shift in the distribution of substation capacity shown in Figure 5-20 as our customers progressively electrify.

This shows the scale of impact we are expecting on our LV network from electrification, and the urgency to begin proactive investment. The 66,000 distribution substations on our network were not built to accommodate this increase in per lot demand and as mentioned cannot rely on customer demand diversity. Our initial proposal included proactive LV augmentation to support this growing electricity demand across AusNet's LV and SWER networks, driven by the electrification of transport and gas. Our program has been designed to economically reduce expected unserved energy for customers. Our initial proposal included capital expenditure of \$148.5 million (real 2025–26), to upgrade 995 DSS and 71 SWER lines, net of \$36 million deferred due to flexible services introduced as a non-network solution.

Proactive demand driven augmentation of the LV network is a new category of investment where a standardised approach to economically justify this investment across networks is yet to be established and approved by the AER. Our approach to value unserved energy at risk benefits that economically justify this investment is sound and consistent with other demand driven projects. While there is uncertainty over the post-electrification network capacity required (once the distribution system is fully electrified over subsequent periods), there is a clear identified need for the level of investment we are proposing to deliver in the next regulatory period. Our proposed investment and approach to identify required upgrades represent a no-regrets, modest start to the scale of investment that will be required over the coming years to accommodate electrification on our network.

5.8.2. Draft Decision

The AER did not accept our LV augmentation proposal. The reasons for the decision included overestimation of benefits, including the level of unserved energy at risk and insufficient analysis of potential overlap with other projects. A key concern raised by EMCa was the assumed current baseline for unserved energy was too high and inconsistent with recorded levels in the current period.

5.8.3. Addressing the AER's Draft Decision

We do not accept the Draft Decision in respect of LV augex.

In our Revised Proposal, we have addressed all the concerns raised by EMCa and the AER in their decision. Specifically, we have:

- Thoroughly reviewed our approach to calculating unserved energy at risk in our initial proposal model and have applied a more robust method to apply the forecast demand impact and the resulting energy at risk on our LV assets, ensuring the assumed benefits are not overstated. Our modelled unserved energy at risk in our model at the commencement of the 2026-31 period is now similar to recorded levels observed in the current period.
- Completed an evaluation to identify potential overlaps with other proposed projects where they have included LV asset replacements or upgrades. This assessment resulted in reduction of 58 DSS replacements which has been removed from our proposed repex.

- Provided further justification to support our proposed unit rates for LV augmentation, which are unchanged from our Initial Proposal. We have completed an assessment to validate our assumed unit rate based on information on actual, recent project costs that are in line with the proposed rates.

NER cl. 6.5.7(c) requires the AER to approve a total capex forecast that reflects efficient and prudent costs to achieve the capex objectives, which include expenditure required to meet and manage a realistic expectation of demand on our network. The evidence is clear that electrification is occurring on our network, which is expected to accelerate in the next regulatory period in line with Victorian Government policies, driving network constraints which, if not addressed, will have substantial reliability impacts for our customers.

We do not consider the Draft Decision alternative estimate of zero expenditure is sufficient to meet the capex objectives. We consider our Revised Proposal LV augex forecast is reflective of the prudent and efficient costs required to meet these objectives, being underpinned by robust, updated demand forecasts, a more accurate approach to calculating unserved energy and economic net benefits, a sound, probabilistic network planning and cost estimates which are in line with recent actual project costs. Further information on our Revised Proposal LV augex forecast is provided in the next section.

5.8.4. Revised Proposal

Our Revised Proposal LV augex forecast is \$128.5 million, which is an 13% reduction on our Initial Proposal forecast.

We considered three options in addition to the do-nothing case, which are targeted at mitigating expected unserved energy on the LV distribution substation and SWER networks. These are set out in a Table below with an assessment.

Table 5-32: Considered options to target mitigating expected unserved energy

Option	Description	Comment	Total cost	Total benefit	NPV
Do nothing	No proactive expenditure on addressing network limitations that impact customer reliability.	Without proactive investment, the expected increase in demand will lead to thermal overload on our LV network, which would compromise customer reliability as they electrify. This would also be more costly as upgrading capacity reactively is more expensive than a planned, proactive approach, and so overall costs to customers would be higher. Therefore the do-nothing option is not a prudent or efficient approach as it would involve more costly reactive works whilst leading to poorer reliability outcomes for customers.			
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).	The scope of this program is only to proactively upgrade our network where we have shown it is economic	(115.7)	1,559	1,444
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 2 is the preferred option with a higher NPV compared to Option 1. The scope of this program is only to proactively upgrade our network where we have shown it is economic and use flexible services where economic.	(100.2)	1,558	1,457
Option 3	Deterministic planning approach to remove all expected unserved energy risk from the network using network augmentation project.	This high investment case is also NPV positive and economic on a program level over a 10-year period. However, it represents much larger scope and cost than Options 1 and 2, would be difficult to deliver the scale of upgrades required within a 10 year timeframe and it may not appropriately balance the	(474.9)	2,038	1,563

Source: AusNet

We consider that while Option 3 would be a fundamental change to planning standards, it is not an unreasonable option to consider as part of this assessment. Given the scale of the upgrades that will be needed to the LV network to accommodate full electrification, and the uncertainty over where the localised constraints will emerge over a particular time period, a larger, but still economically justified program, would also be prudent. Nonetheless, given this is the first regulatory period in which we have sought LV augmentation funding we have included Option 2 in our Revised Proposal. We will rely on our nominated electrification pass through event to support additional funding that may be required if electrification happens at a faster pace compared to our forecasts. This adds weight to the importance of the AER's approval of this pass through event.

Option 2 is the preferred option in our Revised Proposal, which includes capital expenditure of \$128.5 million, net of \$21 million (real 2025-26) deferred due to flexible services introduced as a non-network solution.

The scope of this program is only to proactively upgrade our network where we have shown it is economic. We expect there will continue to be a need for reactive investment to manage constraints on our LV network and emphasise our economic analysis has shown that 759 or 1.2% of our DSS should be proactively upgraded but 14% currently operate at over 110%.

Following our proactive program, we do not expect a decrease in average utilisation across our DSS assets, and 14% (equivalent to proportion to current levels) will operate over 110% capacity on peak days, keeping costs low for customers. If we were not to undertake a proactive program the number of DSS operating at over 110% capacity on peak days would be expected to increase to 11.2 by 2031.

To further increase utilisation on our LV network, we have proposed investment to enable AusNet to procure flexible services from our customers with the benefit of deferring augmentation. This will shift load away from peak hours and reduce the risk of overloads on our assets. The cost of flexible services includes \$12m of digital capex and \$3m of opex. This includes upgrades to our processes to ensure we can automate and forecast constraints on our network which will be suitable for demand response to relieve the localised constraints. This will then be signalled to our customers to opt-in to demand response and receive a payment commensurate to their demand response. The costs for flexible services are further explained in section 6.7.3.3.4 and our Distribution System Operator Addendum. Unless we are funded to invest in these capabilities it will be difficult to meet the AER's expectations to improve network utilisation prior to increasing network capacity. In addition, if these capabilities are not funded, we would not be able to rely on flexible services to defer augmentation and therefore Option 1 would become the preferred option.

We have provided further justification of the identified need and cost benefit analysis for this investment in Demand Driven Augmentation in the LV Network & Flexible Services Business case.

5.9. CER enablement

5.9.1. Our Initial Proposal

CER enablement

Our CER Enablement program included investment to support the integration of rooftop solar and battery systems into our distribution network. The proposal was designed to meet growing customer demand for export capacity from our initial forecast 60,000 new solar systems and 30,000 batteries. The preferred investment option was valued at \$40.4 million (real 2025-25) and delivered 264 GWh of additional renewable exports and 16.7 kt/year of CO₂ reductions, with a net benefit of \$427 million over 20 years.

The business case aligned with AER's benefit values (CECV and VER) and reflected strong stakeholder support for efficient, equitable integration of CER. Customers expressed willingness to pay more to avoid wasted solar energy, and our Future Network panel endorsed the economic modelling approach.

We proposed to offer flexible exports from July 2026, which reduced the modelled need for network solutions to enable exports. We proposed \$16.5 million to introduce capability for flexible exports was proposed as a portion of our proposed DSO Digital Business Case.

Distribution System Operator

AusNet's DSO business case proposed \$40.8 million in non-recurrent digital expenditure to uplift capabilities and services to meet the evolving needs of our customer base, through supporting the continued adoption and

integration of CER. The proposed DSO program focussed on transforming the electricity distribution network to create a more flexible, customer-centric energy system. It aims to support expanded integration of CER to enable flexible load and export management, expand opportunities for customers and third parties to participate in non-network solutions, and improve network utilisation while reducing costs and deferring augmentation. Our proposal also included enhance data sharing with customers, communities, third parties and the Australian Energy Market Operator (AEMO) through the Consumer Energy Resources (CER) Data Exchange, delivering direct rewards and optionality for customers.

5.9.2. Draft Decision

The AER included an alternative estimate of \$8.7 million for dynamic voltage management (DVM) and \$16.5m full rollout of flexible exports, noting that network augmentation should be a last resort due to its potential to reduce network utilisation.

CER Enablement

The AER found the program not prudent or efficient, citing flaws in AusNet's options analysis, lack of quantified export service levels, and overestimated benefits. Specifically, the AER criticized the inclusion of a "do nothing" option as non-credible, overstating counterfactual risks, and failing to consider business-as-usual solutions like tap changes and phase balancing. It also flagged that AusNet's demand forecast omitted home battery storage, likely inflating the energy-at-risk estimates. Furthermore, the AER noted that by 2036–37, most customers will have flexible exports or static limits, reducing the volume of energy at risk. The AER also challenged AusNet's benefit modelling, which assumes constant benefits from 2036–46 without accounting for changes in the generation mix, given Victoria's 95% renewable energy target by 2035, reducing the value of avoided curtailment and emissions.

Distribution System Operator

The AER did not accept \$24.5 million for our DSO program scope beyond the \$16.5 million to deliver flexible services. The AER's feedback draft decision on our DSO program included that economic assessment was considered implausible, with unrealistic timing of forecast benefits, and disproportionate avoided generation curtailment and emissions reduction benefits. The options analysis lacks credibility, as the 'do nothing' scenario is not a viable investment option, and other options fail to reflect project scope refinements. Overall, the decision considered AusNet has not adequately justified the proposed scope.

5.9.3. Addressing the AER's Draft Decision

We agree with the AER that maximising exports without network augmentation is preferable. We accept the AER's decision enabling us to roll out flexible exports to all our customers and reduce the need for network options to enable greater exports.

However, we consider this is insufficient to deliver the benefits that our customers and stakeholders value and have therefore re-proposed a CER enablement program. Our program is economically justified based on benefit calculation aligned with AER guidance for CECV and emissions, and we therefore consider this expenditure meets expectations and is economically justified.

We have responded to the specific issues raised by the AER below:

We consider that AusNet's base case scenario is an accurate counterfactual. Our BAU approach for CER enablement should be reflective of current obligation to enable export capacity and therefore does not include investments such as phase balancing, given these are incremental discretionary investments to enable exports where they are preferred over capex investments. Additionally, we note our model is designed to solve for opex based solutions as well as capex, which we would implement and fund within our opex allowance where opex solutions are preferred. Our model has selected phase balancing solutions are economic in 2025-26 for 34 assets and therefore removed constraints prior to our proposed investment in the 2026-31 period which aligns with the AER's expectations of ensuring counterfactual risk incorporate these investments. Furthermore, many of AusNet's legacy transformers are operating at their extreme buck tap and cannot be tapped down any further without a transformer replacement and therefore we have not assumed tap changes alone as a credible option. Therefore, we consider our approach of comparing benefits of investment to a do-nothing BAU scenario is reflective of our BAU investment drivers and costs and does not overstate benefits.

AusNet's revised demand forecast accounts for home battery storage as outlined in Section 3.5.3.2.

- In relation to the AER's additional concerns that our benefits are overstated due to our renewable generation and flexible exports uptake assumptions in the late 2030s being too modest. We have addressed this concern by ensuring the proposed investment is economical over a 10 year period, given our proposal is largely DVM and we have not proposed to include network upgrades. We consider this appropriately balanced the AER's concerns, while also delivering a program with clear benefit to our customers.

Our revised DSO proposal has addressed the identified gaps and strengthened the overall program justification. Our proposal has quantified benefits of each initiative individually to ensure all investments proposed are individually NPV positive and our overall option represents the most prudent and efficient option in the upcoming period. Where our revised submission maintains scope outlined in the initial proposal, we have provided additional evidence to support the scale and maturity of each initiative, along with how each initiative addresses the current limitations of our DSO systems.

5.9.4. Revised Proposal

Our Revised CER Enablement proposal includes \$38.6 million of capex, to undertake economic voltage management activities. This delivers 124 GWh of additional renewable exports and 26.8 kt/year of CO₂ reductions, with a benefit of \$46.5 million over 10 years. We consider this is the preferred option in the current context of CER and appropriately balances minimising augmentation with delivering desired customer benefits.

Most of our assumptions are unchanged from our Initial Proposal. The exceptions to this are the following refinements we have made, which mean our model:

- Accounts for our updated demand forecast, which include the impact of batteries.
- Incorporates more accurate inputs when calculating emissions reduction benefits, based on the half an hour emission intensity values provided by the AER along with the 2025 CECV update. The impact of the updated emissions calculation increases the estimated benefits of the program and ensures these benefits are more accurate

Further information can be found in the supporting document CER Enablement Business Case.

Our Revised DSO proposal includes \$33 million capex and \$1 million opex to deliver the following initiatives:

Distributed Energy Reserves Management System (DERMs) uplift for Flexible exports

- **Community network data upgrades (to our GridView portal).** We propose to expand published network data to meet current stakeholder expectations to improve transparency. Key stakeholders who are calling for distributors in this space include the Victorian Government, community energy groups, local councillors, connection proponents (e.g. EV charging companies) and engaged customers. In addition, the ECA's Distribution Strategic Planning rule change, as described in the Overview, will include requirements to uplift LV data publication.

This funding will support increasing the scope and frequency of data publication and automating our production of these additional datasets. Our proposed scope for the additional data is aligned with known demand for the specific datasets to improve usefulness and informed by our GridView Improvement Group (GIG) which includes community energy groups and local councils to maximise the usefulness of the data we publish.

- **A non-network solutions platform.** We are proposing to streamline the procurement of non-network solutions through a new centralised portal. Currently, opportunities for third-party services such as batteries are identified manually via our website, which is practical and manageable at the current scale but will become inefficient as demand grows. Automating this process where possible will enable AusNet to procure solutions at scale to enable greater potential opportunities to defer augmentation and deliver more benefits to customers while limiting the additional resources we will require to manage this process.
- **DERMs uplift for flexible services.** In addition to procuring third-party non-network solutions, AusNet proposes to enhance our capabilities to elicit demand response directly from customers through flexible services. Our assumed flexible services include opt-in direct load control for C&I customers and opt-in behavioural demand response for CER customers. We consider AusNet's expansion of our DERM capabilities to flexible services is prudent and efficient and will provide a lever to manage the growing impacts of electrification on our network and enable increased network utilisation and defer LV augmentation. It will also provide customers with rewards for their flexibility and therefore provide additional value from their investments in CER.

These capabilities are levers to improve network utilisation, which will become more important over time as the transition continues. During this early transition period it is critical that we start leveraging more demand management to fully understand its potential which will provide a solid foundation to incorporate demand response in planning in future regulatory periods.

Unless we are funded to invest in these capabilities it will be difficult to meet the AER's expectations to improve network utilisation prior to increasing network capacity. In addition, if these capabilities are not funded the \$X million of LV augex should be added back into our LV augex capex proposal (see Section x).

Further Information can be found in the supporting document DSO Digital Business case Addendum.

We have also proposed an opex step change to facilitate deliver of the new services outlined in the DSO. Further information can be found in Section 6.7.3.3.4.

5.10. Resilience expenditure

5.10.1. Our Initial Proposal

We proposed \$279.4 million in resilience-related expenditure over the 2026-31 regulatory period.

Network resilience is an increasingly important network characteristic in the face of climate change. Victoria is experiencing more frequent and severe extreme weather—storms, bushfires, heat events and flooding—that increasingly threaten customer safety, network reliability and asset integrity. Recent events across the state have shown that the scale and duration of outages are growing, communities are more exposed, and recovery is more complex and costly. The network must be strengthened in response to a rapidly changing risk environment.

Traditional maintenance and renewal programs are no longer sufficient on their own. Customers and stakeholders have clearly expressed stronger expectations for preparedness, faster recovery, and better protection of vulnerable communities. Customer preferences were comprehensively sought and considered in the development of our Initial Proposal.

In addition, a Rule Change proposed by the Victorian Energy Minister has introduced resilience into the regulatory framework. Since 3 October 2025, resilience has been embedded in both the capital and operating expenditure factors, meaning there is a requirement for both AusNet and the AER to consider these factors when forming and assessing our expenditure forecasts. We consider both our Initial and Revised Proposal meet this requirement.

Our Initial Proposal comprised several different types of investment associated with network resilience. The largest component (\$255.8 million) related to network hardening investments to address increasing climate change risk. Network hardening consisted of undergrounding our overhead bare conductors or covering and insulating our overhead bare conductors to protect our cables from storms and bushfire risks. It also included replacing timber poles with concrete poles to protect poles from failure during bushfires, and the installation of reclosers to segment the network.

Additionally, we proposed \$11.2 million to provide backup power to 30 community hubs, \$7.7 million to deploy 25 Standalone Power Systems (SAPS), \$3.7 million to purchase 4 diesel generators and associated equipment and \$1.1 million to purchase 4 Emergency Response Vehicles (ERVs).

5.10.2. Draft Decision

In its draft decision, the AER included \$43.7 million. The AER's alternative ("allowed") resilience scope included all 25 standalone power systems, 4 emergency response vehicles and mobile generation that we proposed in our Initial Proposal. The AER's draft decision allowed for some network hardening yet fully removed the 30 community hubs that we proposed. The AER states that it has considered the prolonged outages AusNet has experienced and AusNet's efforts to assess climate risk, in deciding that a certain level of resilience investment is warranted.

Table 5-33: Summary of Resilience Draft Decision

Type	Description	Initial Proposal	AER's Draft Decision
Network hardening	Undergrounding	[C-I-C] of undergrounding (primarily in the Dandenong Ranges) \$115.2 million	nil
	Covered conductors	[C-I-C] of covered conductors \$36.5 million	[C-I-C] of covered conductors \$19.7 million
	Reclosers	[C-I-C] reclosers \$23.2 million	[C-I-C] reclosers \$9 million
	Hardened poles	[C-I-C] hardened poles \$80.8 million	[C-I-C] poles \$2.8 million
Community resilience	Backup for community hubs	30 community hubs \$11.2 million	Nil
	SAPS	25 SAPS \$7.7 million	25 SAPS \$7.5 million
	Mobile generation	\$3.7m	\$3.6 million
	Emergency Response Vehicles	4 vehicles \$1.1 million	4 vehicles \$1.1 million
Opex	Hazard trees	[C-I-C] hazard trees \$15 million opex step change	Nil
Total		Network hardening: \$255.8 million Capex: \$279.4 million	Network hardening: \$31.5 million

5.10.3. Addressing the AER's Draft Decision

We accept the AER's Draft Decision in relation to SAPS, mobile generation and emergency response vehicles.

While we continue to see merit in distribution networks playing a role in providing backup power supply for community hubs, we agree with the AER that the definition of backup power supply for community hubs is uncertain and that it potentially falls outside of standard control services. We will accept the AER's decision to exclude community hubs from our revised proposal.

We agree with the AER's rationale – described in the section above – for updating AusNet's network hardening model. The AER's draft decision volumes and expenditure were developed on the basis of inferring the results based on different scenario runs without running the modelling itself. For the Revised Proposal, we have updated our network hardening model to address the AER's concerns, namely updating the application of the Value of Network Resilience (VNR), broadening our options analysis and incorporating updated unit rates.

5.10.4. Revised Proposal

We are forecasting a resilience augmentation expenditure of \$166.2 million over the 2026-31 regulatory period, primarily made up of network hardening (\$154.0 million). We note that a Victorian compliance framework is under development which will legislate the delivery of the resilience program in line with the AER final decision.

To develop our network hardening investment case, we updated the climate model that was submitted as a part of our Initial Proposal for:

- **Unit rates** – we have adopted the latest unit rates, which are lower than those submitted in our Initial Proposal
- **Options analysis** – as suggested by the AER we have added pole wraps as a lower cost solution to pole hardening, noting the effectiveness is also lower. We have also included hazard trees as an opex option alongside network hardening, to economically optimise across capex and opex solutions
- **VCR** – for residential outages less than 12 hours, we have adopted the AER's 2024 Victorian average residential VCR; this method is consistent with our approach for other investment categories which the AER has accepted. For residential outages greater than 12 hours, we have adopted the 6-12 hour VCR multiplied by the VNR multiple where we have implemented the AER's VNR upper bound by adopting a \$0 VCR for outages greater than 7 days. We have adopted a similar approach for business customers. The table below sets out the inputs used to derive the VNR which has been applied in the network hardening model. While we accept the AER's draft decision that the use of the 6-12h VCR forms the basis of the VNR, it does appear perverse that the resulting VNR for outages 12-24 hours is less than the VCR used to value outages that are shorter than 12 hours, given the strong feedback and willingness to pay scores our customers provided us on the need to prioritise avoiding prolonged outages.

Table 5-34: Derivation of the VNR values applied in the network hardening model

		Base VCR type	Base VCR (\$ per kWh)	VNR multiple	Resulting VNR (\$ per kWh)
Residential customers	<12h	Vic average residential	\$49.23	1	\$49.23
	12-24h	6-12h VCR	\$23.0	2	\$46.1
	24h to 7 days	6-12h VCR	\$23.0	1.5	\$34.6
	>7days	6-12h VCR	\$23.0	0	Nil
Commercial customers	<12h	Commercial overall VCR	\$34.39	1	\$34.39
	12-24h	6-12h VCR	\$12.30	1.5	\$18.45
	24-72h	6-12h VCR	\$12.30	1	\$12.30
	>72h	6-12h VCR	\$12.30	0.5	\$6.15
Industrial customers	<12h	Industrial overall VCR	\$33.49	1	\$33.49
	12-24h	6-12h VCR	\$11.70	1.5	\$17.55
	24-72h	6-12h VCR	\$11.70	1	\$11.70

	>72h	6-12h VCR	\$11.70	0.5	\$5.85
Agriculture customers	<12h	Agriculture overall VCR	\$22.25	1	\$22.25
	12-24h	6-12h VCR	\$9.70	1.5	\$14.55
	24-72h	6-12h VCR	\$9.70	1	\$9.70
	>72h	6-12h VCR	\$9.70	0.5	\$4.85

Source: AusNet

Our updated modelling for network hardening resulted in a slight increase to our capex forecast from \$255.8 million to \$263.4 million based on undertaking 100% of the full program in the 2026-31 period. This is because:

- Reducing the unit rates for covered conductors have resulted in a higher number of volumes becoming economically justified (from [C-I-C]).
- The addition of cheaper options such as pole wraps has resulted in a large program of these becoming economically justified.
- These changes have offset the impact of the reduction in the VNR.

The model has removed undergrounding (given its higher cost compared to other options) and instead replaced it with a significant amount of covered conductors. Our updated modelling results have also replaced some pole hardening with pole wraps in locations where pole wraps may be effective to minimise bushfire risk. Pole wrap is significantly cheaper compared to pole hardening yet is less effective in areas of high vegetation given the flame height would exceed that of the wrap, lowering its ability to protect assets. Despite its higher costs, pole hardening still has a role in network hardening because it is more effective against bushfires in densely vegetated areas.

The results of the updated modelling indicated that [C-I-C] km of covered conductors is needed. To manage the rollout from a deliverability and a customer affordability perspective, we have proposed half over the 2026-31 period, with the rest to be undertaken in the future 2031-36 period.

Table 5-35: Summary of resilience projects and programs (\$m, real \$2026)

Type	Description	Initial Proposal	Revised Proposal
Network hardening	Undergrounding	[C-I-C] of undergrounding (primarily in the Dandenong Ranges) \$115.2 million	Nil ⁷¹
	Covered conductors	[C-I-C] of covered conductors \$36.5 million	[C-I-C] of covered conductors \$93.6 million Updated modelling showed [C-I-C]km being economic to undertake. We have proposed [C-I-C]km ⁷² for the 2026-31 period – being half of the full program – which was further reduced to [C-I-C] after removing overlaps with repex.
	Reclosers	[C-I-C] reclosers \$23.2 million	[C-I-C] reclosers \$13.1 million
	Hardened poles	[C-I-C] hardened poles \$80.8 million	[C-I-C] hardened poles \$44.0 million Updated modelling showed [C-I-C] hardened poles being economic to undertake. This reduced to [C-I-C] after removing overlaps with repex.
	Pole wraps	Not included	[C-I-C] pole wraps \$3.3 million
Community resilience	SAPS	25 units of SAPS \$7.7 million	25 units of SAPS \$7.6 million
	Community hubs	Backup power for 30 established community hubs	Nil

⁷¹ The model showed 10m of undergrounding being economic to undertake. We have instead proposed zero units of undergrounding.

⁷² Our rounding method led to a volume that is close to half, but not exactly half.

	Mobile generation and batteries	Four mobile diesel generators, portable station and HV battery system. \$3.7m	To purchase four mobile diesel generators, portable station and HV battery system. \$3.7m
	Emergency vehicles	To purchase emergency response vehicles \$1.1 million	To purchase emergency response vehicles \$1.1 million
Opex	Hazard trees	[C-I-C] hazard trees \$15 million opex step change	[C-I-C] hazard trees \$6.0 million opex step change

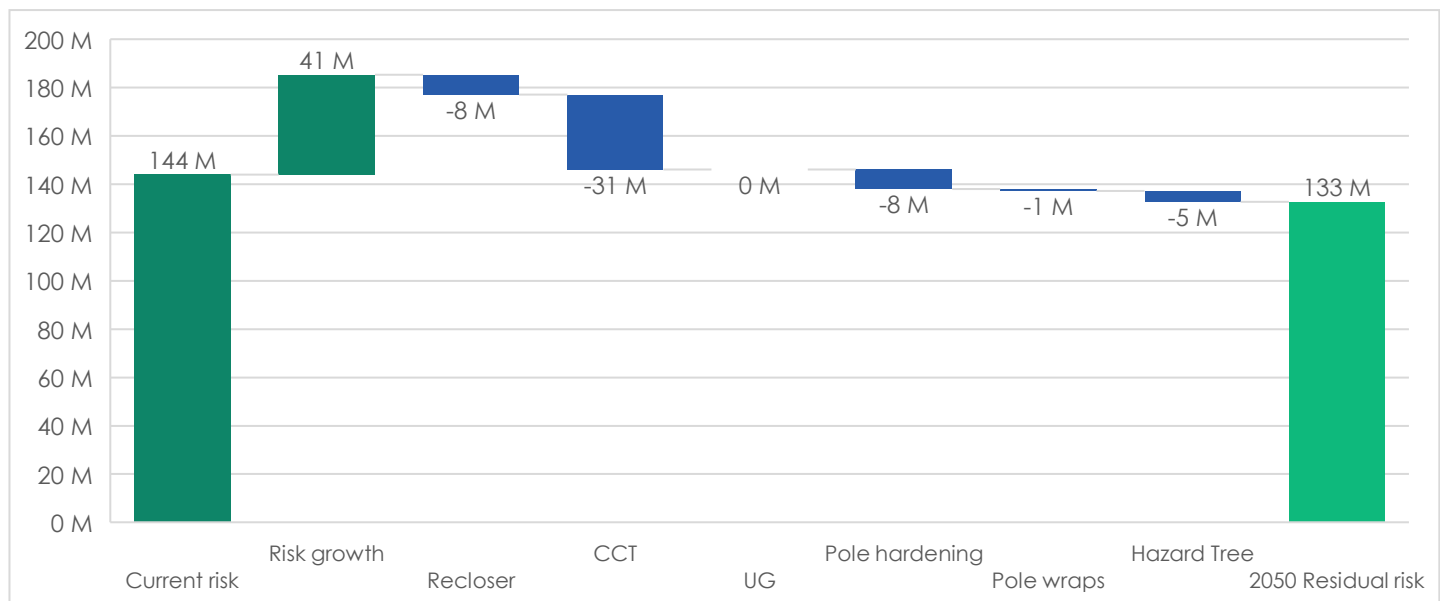
Source: AusNet

Our updated modelling also assessed hazard trees (opex solution) alongside network hardening. The input assumptions include a hazard trees effectiveness at 9.1% at a cost of [C-I-C] per tree. This resulted in \$6.0 million of hazard tree pruning or cuts needed (above BAU) over 2026-31 period, but also every subsequent 5 year period. The effect of adding hazard trees as an option in the resilience modelling allows us to more holistically assess solutions. Hazard tree management is a complementary solution to network hardening, given that it prevents outages caused by hazard trees which cheaper network hardening options are not suited to addressing.

For example, covered conductors cannot prevent large trees from falling onto a powerline and pulling down the line and poles. Without hazard trees included in the model as a potential solution, the network hardening investment increases by \$40.6 million, yet the additional \$40.6 million is not as effective at reducing climate risk. The consistency of the hazard tree opex forecast with the step change framework is described in Chapter 6 – Opex. However, the climate modelling described in this chapter and in the supporting resilience attachments constitute the justification of the hazard tree program and associated opex step change.

The chart below shows the current risk, the 2050 risk without investments, and the risk reduction benefits by the type of solutions. Our mix of solution reduces 2050 risk from \$185 million to \$133 million which is slightly below current levels. It was not our intention to reduce risk below current levels; however, the mechanics did not allow an exact match. It is notable that the hazard tree cost at \$1.2 million p.a. can reduce the 2050 risk by \$5 million.

Figure 5-23: Current risk and risk reduction benefits from various solutions



Source: AusNet

Digital investment programs that will, among other things, support improved network resilience are discussed in section 6.7. Opex step changes for resilience (hazard trees and preparedness and response) are discussed further in section 6.

The table below shows the results under some sensitivity scenarios. When we adopt the 6-12h VCR for outages below 12h, the investment amount decreases by \$15 million (5.5%), and when we remove the hazard tree option, the investment amount decreases by \$46 million.

Table 5-36: Sensitivity testing of resilience network hardening model (\$m, real \$2026)

Type	Description	Base model run	Lower VCR	Higher VCR	Decreasing hazard tree effectiveness to zero
			Use 6-12h VCR for outages less than 12h	Vic average residential VCR	

			and outages greater than 12h	for residential customers & business overall VCR for business customers	
Network hardening	Undergrounding	nil	nil	nil	nil
	Covered conductors	[C-I-C] \$201.2 million	[C-I-C] \$185.3 million	[C-I-C] \$323.5 million	[C-I-C] \$237.2 million
	Reclosers	[C-I-C] \$13.1 million	[C-I-C] \$13.9 million	[C-I-C] \$11.9 million	[C-I-C] \$18.2 million
	Hardened poles	[C-I-C] \$45.8 million	[C-I-C] \$46.1 million	[C-I-C] \$38.3 million	[C-I-C] \$48.4 million
	Pole wraps	[C-I-C] \$3.3 million	[C-I-C] \$3.3 million	[C-I-C] \$2.5 million	[C-I-C] \$5.1 million
Opex	Hazard trees	[C-I-C] \$6.0 million	[C-I-C] \$5.7 million	[C-I-C] \$5.9 million	Nil
Total capex		\$263.3 million	\$248.5 million	\$376.2 million	\$309.0 million

Source: AusNet

5.11. Reliability expenditure

5.11.1. Our Initial Proposal

Supported by strong feedback from our customers AusNet proposed a reliability investment program of \$147.7 million focussing on our worst served customers, during 2026-31, including:

- \$25.7 million to uplift reliability on our top 10 worst served feeders (WSF).
- \$95.2 million for 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.
- \$26.9 million for a new Benalla to Euroa express feeder with a remote REFCL changeover station.

5.11.2. Draft Decision

The AER did not accept any part of AusNet's reliability program for the following reasons:

The AER is cautious about the scale or uplift in reliability spending proposed, questioning whether the underlying evidence supports the magnitude of expenditure.

- The AER expects stronger alignment between reliability interventions and actual network outage / failure data. It looks for disaggregation (by feeder, region) of reliability issues to justify targeted investment rather than whole of feeder perspective.
- The AER also emphasizes that reliability investments should not duplicate replacement or augmentation work. AusNet should clearly separate reliability driven projects from other capex categories.

5.11.3. Addressing the AER's Draft Decision

We are not re-proposing the Regional Reliability Allowance (RRA) as we anticipate that the minimum reliability standards the Victorian Government is developing will provide a mechanism to identify and fund the reliability improvements our customers expect from us. We will work closely with the Government and our customers on the development of these standards.

We have updated our WSF and BN11 analysis in a manner that addresses the AER's concerns and re-proposed this expenditure in our revised proposal.

5.11.4. Revised Proposal

We are proposing total reliability expenditure of \$42.2 million, to address 6 worst served feeders and build a new express feeder to reduce reliability issues in the Euroa area.

The purpose of our demand driven augmentation projects outlined in chapter 5.8 is to address demand constraints, which addresses reliability at the same time. Our demand driven augex projects are geographically different and separate from our worst served feeders and BN11 feeders meaning that the latter can be assessed in a more standalone fashion so long as we are cognisant of the broader augex program.

The lower magnitude of our reliability capex forecast relative to that in our Initial Proposal addresses the AER's concern about the scale of reliability expenditure proposed.

5.11.4.1. Worst Served Feeders (WSF)

For WSF, we have taken on board the AER's feedback and improved our root cause analysis which has resulted in a reduced program of works compared to our Initial Proposal (decrease from \$25.7 million to \$1.8 million). The solutions proposed include extending overhead feeders using covered conductors (WYK13) and replacing manual gas switches for ACRs (MOE13). Comprehensive business cases have been developed for each of these projects and submitted as supporting documents.

We have not proposed projects for four out of the 10 feeders (BM8B31, KLK11, MDI1 and NLA31) as our analysis concluded that investments are not economically justified. Instead, we expect the Victorian Government's minimum reliability standards may drive investment in these four areas.

5.11.4.2. Benalla to Euroa feeder (BN11) reliability improvement project

In our Initial Proposal, we proposed a new Benalla to Euroa express feeder with a remote REFCL changeover station.

The AER did not accept this project in its Draft Decision, citing the following concerns:

- AusNet's demand forecast and demand driven augex program did not present this feeder as facing a demand constraint. As this constraint is caused by temporary tourism demand, the use of temporary generation to address this is appropriate.
- AusNet has not undertaken root cause analysis. The AER analysed 10 years' worth of data and found extreme weather, animals and vegetation as the root cause of outages of BN11. The AER did not consider an express feeder addresses these root causes.
- The AER did not consider the 'solar factor' adjustment was warranted and that AusNet should update the VCRs to reflect the 2024 VCRs rather than the 2023 VCRs.

We have addressed each of the AER's concerns below by:

- undertaking a comprehensive root cause analysis as demonstrated in our updated business cases
- removed the solar factor in our benefits calculation
- performed optimal timing analysis
- updated our approach to forecasting opex
- adopted the AER's 2024 VCRs rather than the 2023 VCRs.

There have been acute reliability issues on the Benalla-Euroa (BN11) feeder, which serves around 4,800 customers, since late 2023. This is when a remote REFCL was commissioned on this feeder, which has significantly reduced bushfire risk but also impacted reliability. The sensitivity of the equipment has led to more frequent outages, and this feeder is the longest on our network (1,216kms), which means that these outages can last for long periods of time, as it takes time to locate these. While AusNet has implemented some operational solutions, a permanent solution is urgently required to improve reliability to an acceptable level that is sustained.

During 2025 BN11 has experienced approximately 76 unplanned sustained outages in 2025. On average, a customer on BN11 has experienced 7 of these outages during the year. There is very strong customer and community support to address these issues, and there has been extensive media coverage and a high degree of political attention. We want to hear this feedback firsthand and set up the Strathbogie Benalla Community Group⁷³ so we can directly hear from local representatives about the impact of outages in the area and communicate our plans to fix these issues.

The Electricity Distribution Code of Practice (EDCOP) states:

"A distributor must use best endeavours to meet targets determined by the AER in the current distribution determination and targets published under clause 13.2.1 and otherwise meet reasonable customer expectations of reliability of supply." (clause 13.3.1)

⁷³ [Strathbogie Benalla Community Group \(SBCG\) - AusNet](#)

We are acutely aware of the reliability expectations of this community and consider these reasonable. To maintain compliance with the EDCOP, we are proposing an Express Feeder which would provide route diversity that will benefit customers in the township of Euroa and surrounding areas.

While we have invested \$10 million on projects and improved operational solutions to reduce the frequency and duration of these outages to date⁷⁴, which have assisted but as explained above acute reliability issues remain today. The Express Feeder solution addresses the following identified drivers of reliability issues associated with the existing BN11 feeder:

- Animal
- Vegetation
- Lightning
- Adverse weather

If any of the factors above cause an outage on BN11 the Express Feeder can continue to supply power. While the solution does not treat the root cause directly, it significantly lowers the customer impact. Through feeder route diversity, the likelihood of a co-incidental incident occurring at the same time is very significantly reduced. We also note that:

- A new 22kV express feeder provides additional capacity to service Euroa and surrounding areas and will address the existing network constraint thereby removing the need to deploy temporary diesel generation annually.
- The new feeder will unlock capacity for future load growth and further economic development of the large area serviced by BN11. The existing feeder is the longest distribution feeder in Victoria and covers a route length of 1,216kms. Demand growth across the coverage area of the feeder is constrained due to insufficient network capacity.

Should the AER be minded to reject this project, we have provided an alternative option to instead insulate sections of bare conductors which are frequently impacted by vegetation. Replacing bare conductor with covered conductor will reduce the probability of vegetation blow-ins impacting the line resulting in either a momentary or sustained outage. This option costs \$2.2 million and is NPV positive. However, it will not lead to the level of reliability improvements that would meet customer expectations because it does not reduce CMOS to the same extent as an overhead express feeder.

Also relevant to the Euroa-Benalla area was an upgrade to SMR11 included in our Initial Proposal. This has not been included in our Revised Proposal because the demand forecast for this feeder has reduced since our Initial Proposal. Notwithstanding this, we will continue to closely monitor network conditions in the area and respond accordingly.

Table 5-37: Summary of our reliability investment program ()

	Description	Initial Proposal	Draft Decision	Revised Proposal
Worst served feeders	Bendoc (BM8B31)	25.7	Nil	Nil
	Cann River (CNR1, CNR2, CNR3)		Nil	0.5
	Kinglake (KLK11)		Nil	Nil
	Murrindindi (MDI1)		Nil	Nil
	Moe (MOE13)		Nil	0.6
	Mansfield (MSD1)		Nil	0.1
	Newmerlla (NLA31)		Nil	Nil
	Woori Yallock (WYK13)		Nil	0.5
BN11	A new Benalla to Euroa express feeder with a remote REFCL changeover station	21.7	Nil	40.5
Regional Reliability Allowance (RRA)	Projects to be identified and defined during regulatory period, in close collaboration with our CCC	76.5	Nil	Nil
Total		118.9	Nil	42.2

⁷⁴ [Euroa region electricity supply - AusNet](#)

5.12. Connections expenditure

5.12.1. Our Initial Proposal

In our initial proposal, we forecast increases in gross and net connections capex to be \$576.5 million and \$342 million over the 2026-31 regulatory period, 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.

Table 5-38 below shows the key connection projects and programs proposed for the 2026-31 regulatory period, showing the proposed gross and net connections capex over the forecast period for each expenditure category. We proposed a single data centre project totaling \$39.6 million in gross capex (\$24.7 million in net capex). We forecasted a 30% capital contribution for this data centre connection.

5.12.2. Draft Decision

The AER's draft decision rejected AusNet's proposed \$576.5 million for connections capex, instead setting an alternative forecast of \$522.8 million—about 9.3% lower—due to concerns over overestimated demand including insufficient justification for post-modelling adjustments. The AER required AusNet to update our demand, connection and energy consumption forecasts, and address the AER's concerns for this category, in the Revised Proposal.

The AER also revised AusNet's capital contribution assumptions for a proposed data centre from 30% to 86.5%, reducing net capex for that project to \$17.5 million.

5.12.3. Addressing the AER's Draft Decision

We do not accept the AER's draft decision to reduce our connection expenditure by 9.3 per cent. The AER's primary reason for reducing our connection capex was its concern that our demand forecast may be too high, particularly due to the post-modelling adjustments applied to our customer number forecast. We have provided a detailed explanation of these adjustments in Chapter 3 – Demand and Energy Forecasts.

In this Revised Proposal, we have:

- Updated our customer number forecast and gross connection volume forecast using actual data; and
- Used these revised forecasts to update our connection capex, as outlined in 5.12.4 below.

We accept the AER's draft decision to set the capital contribution rate for data centres at around 85%. Accordingly, we have recalculated our capital contribution rate based on IC-IR test and applied a revised capital contribution rate of 86% for data centre connections in this Revised Proposal.

5.12.4. Revised Proposal

In this Revised Proposal, we have updated our connection capex forecast to reflect the following key changes:

- Updated customer number forecasts to incorporate actual 2024-25 customer connections data, which was unavailable at the time of our initial proposal.
- Revised unit cost estimates for BAU connections based on actual unit rates incurred in 2024-25.
- Updated forecasts for emerging connection types, including data centres, public EV charging infrastructure, and community batteries.
- Updated forecasts for bespoke large connections, informed by new project information received since January.

Our revised proposal for connection capital expenditure for the 2026-31 Regulatory Period is \$820.8 million for gross capex and \$428.4 million for net capex, which compares to \$576.5 million for gross capex and \$279.1 million for net capex in our Initial Proposal, reflecting the key changes discussed above and explained in more detail below.

Table 5-38 below shows the key connection projects and programs proposed for the 2026-31 regulatory period, and the revised gross and net connections capex forecasts over the forecast period for each expenditure category, and how they compare with our Initial proposal and the AER's Draft Decision.

Table 5-38:3 Connection projects and programs for 2026-31(\$m, 2025-26)

Connection category	Proposal - Gross	Proposal - Net	AER Draft Decision - Gross	AER Draft Decision - Net	Revised Proposal - Gross	Revised Proposal - Net
Medium density housing	95.3	83.9	86.0	75.7	108.7	97.3
Underground service installation	76.2	25.8	68.6	23.2	58.1	21.7
Business supply projects	159.6	114.2	143.9	103.0	244.6	175.4
Complex residential supply projects	57.9	14.9	52.1	13.5	69.0	27.2
Low density housing – subdivision	13.2	3.2	11.9	2.9	12.3	5.4
Private electric line replacement	3.6	3.6	3.3	3.3	3.7	3.7
Hybrid and BESS (1.5MVA or less)	1.8	1.3	1.6	1.2	18.3	4.3
Hybrid and BESS (greater 1.5MVA)	66.1	20.6	59.5	18.6	153.5	30.9
Data centres	40.2	25.7	38.7	5.6	56.8	8.2
Large commercial connection 54MW load	-	-	-	-	8.2	5.4
EV charging stations for public and bus depots	63.4	35.6	57.1	32.1	81.2	42.6
Feeder augmentation	-	-	-	-	6.3	6.3
Total	576.5	328.9	522.8	279.1	820.8	428.4

Source: AusNet

5.12.4.1. We have refined our forecasting methodology and incorporated recent actual data

Our revised BAU connection forecast for the next Regulatory Period is \$496.4 million for gross connection capex and \$330.7 million for net connection capex. This represents an increase of 22.3% for gross connection capex and 34.6% for net connection capex compared with our Initial Proposal.

Key changes include:

- Residential connections: The revised gross connection forecast is 2.3% higher than our Initial Proposal, and the revised net connection forecast is 18.2% lower.
- BAU C&I connections (excluding data centres, community batteries, etc.): The revised gross connection forecast is 53.2% higher than our Initial Proposal, and the revised net connection forecast is 53.2% higher.

These changes primarily reflect the updates we made to the gross connection forecast and revised unit costs, which are explained in further detail below in this section.

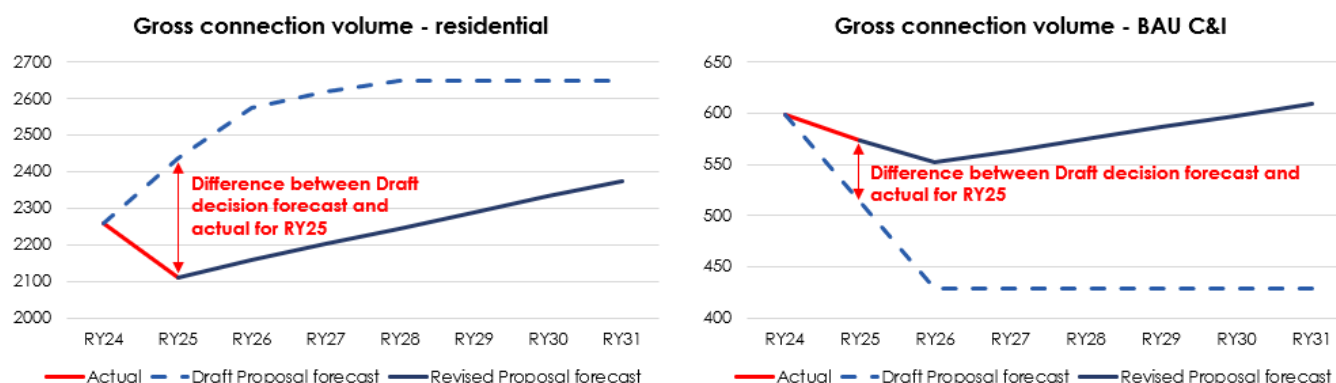
5.12.4.1.1. Revised customer number and gross connection volume forecasts

We have updated our gross connection volume forecasts for business-as-usual (BAU) connections as part of our revised connection capital expenditure (capex) proposal for the 2026–31 regulatory period.

In this Revised Proposal, we forecast gross connection volumes for the upcoming regulatory period by applying the forecast growth rate of net connection volumes to the actual gross connection volume in the most recent year with available data. Specifically, we use RY25 as the base year and the actual connection volume in RY25 as the base volume for each connection category. We then derive separate annual growth rates for net residential and net C&I connections from the forecasted net connection volumes for these categories over the next regulatory period (as discussed in Chapter 3). Finally, we calculate the annual gross connection volumes for each category by applying the corresponding growth rate to its base volume. This method ensures that our gross connection volumes forecasts for BAU connections are properly linked to and consistent with our net connection forecasts in Chapter 3.

Figure 5-25 below shows our revised gross connection volume forecasts for BAU residential and BAU C&I connections and how they compare to the forecasts in our Initial Proposal.

Figure 5-25:3 Gross connection volume (SCS) for BAU connections, RY24 to RY31



Source: AusNet

The revised gross residential connection volume for the 2026-31 regulatory period is 13 per cent lower than that in our Initial Proposal, while the revised BAU commercial and industrial (C&I) connection volume is 37 per cent higher than that in our Initial Proposal. This reflects several key changes:

- Methodology Change:** In our Initial Proposal, we adopted a similar approach to forecasting BAU connections by applying a growth rate to a base volume. However, the method for calculating growth rates and deriving SCS gross connection volume is different. We consider our revised approach more reliable and transparent, as it is directly linked to our customer number (or net connections) forecast.
- Incorporation of latest data:** As discussed above, we have adopted the most recent actual connection data from RY25 as the base volume in this Revised Proposal, which was not available when we submitted our Initial Proposal. In the Initial Proposal, we used the actual connection volume from RY24 as the base. Therefore, the revised forecast incorporates one additional year of actual data, which improves the accuracy of our forecast. This accounts for part of the difference in forecast volumes. Figure illustrates the variance between actual RY25 connections and the RY25 forecast included in our Initial Proposal. In particular, the actual gross connection volume for residential connections is 13% lower than the Draft Decision forecast, while the actual gross connection volume for C&I connections is 12% higher. This partly explains why our revised forecast for residential gross connection volumes is higher, and our revised forecast for BAU C&I gross connections is lower.
- Revised net connection forecast:** Our gross BAU connection forecasts are linked to the net connection forecasts through growth rates. As part of this Revised Proposal, we have updated our net connection forecast, which differs from the forecast presented in the Initial Proposal. This drives part of the difference in forecast gross connection forecasts. Similar to the revised gross connection forecast, the updated net connection forecast incorporates the latest data and information available since January, further details can be found in Chapter 3.

5.12.4.1.2. Revised unit rate forecasts

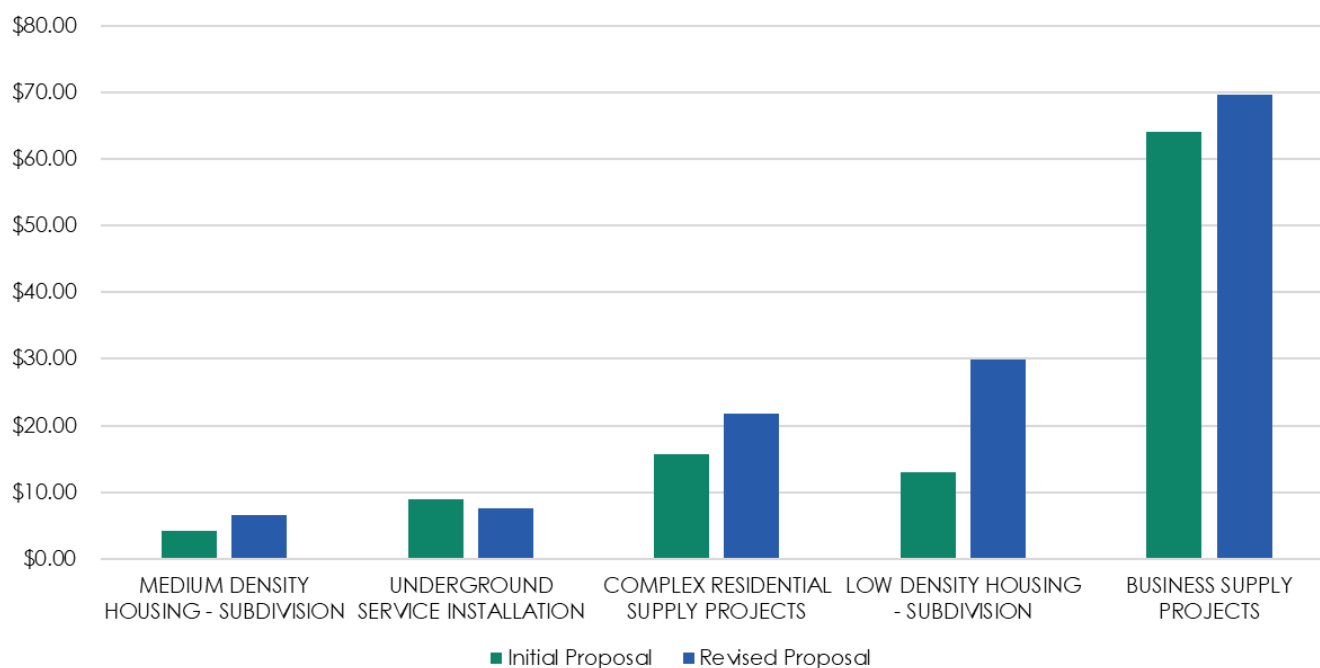
We have updated our unit rate estimates for business-as-usual (BAU) connections as part of our revised connection capital expenditure (capex) proposal for the 2026–31 regulatory period.

In this Revised Proposal, we have retained the same methodology for estimating unit rates for business-as-usual (BAU) connections as used in our Initial Proposal. Specifically, unit rates are calculated by averaging historical actual unit rates over a period of five years (except for medium density housing, the approach of which is detailed in section 5.12.4.13). We note that this methodology aligns with the AER's approach of 'using a longer historical trend', as outlined in the Powercor Draft Decision.⁷⁵ The AER accepted our unit rate estimates in the Draft Proposal.

We have revised our unit rate estimates by rolling forward the averaging period to include the most recent year, Regulatory Year (RY) 2025. At the time of submitting our Draft Proposal, actual unit rate data for RY25 was not yet available, and therefore not reflected in those estimates. In this Revised Proposal, we have incorporated the actual unit rate for RY25. Figure 5-26 below shows our revised unit rate forecasts for business-as-usual (BAU) connections and how they compare to the forecasts in our Initial Proposal.

⁷⁵ 'We consider that using a longer historical trend better reflects forecast unit rates, particularly where volatility is an issue.' AER, Attachment 2 – Capital Expenditure, Draft Decision Powercor electricity distribution determination1 July 2026 – 30 June 2031, p32.

Figure 5-26:4 Unit cost of connection for BAU connections (\$000's, Real June 2024)



Source: AusNet

As shown in Figure 5-26, the revised unit rates are higher than those in our Initial Proposal for most connection categories. This increase is primarily driven by a significant rise in actual unit rates in RY2025. Our delivery partner, Downer, gradually increased its unit rates over the past few years, reflecting market-driven increases in labour and materials costs, with a significant increase in RY2025. During this period, we also began transitioning to a new delivery partner, Zinfra, with some connection work delivered by Zinfra in 2024-25 before a full transition on 1 August 2025. Based on Zinfra's rate card and the actual costs of projects delivered in 2024-25, we consider Zinfra's unit rates to be broadly in line with the 2024-25 actuals. As our revised unit rates are based on a historical average that includes several years of relatively low unit rates, we consider our estimates to be conservatively low, moderating our connections capex forecast.

5.12.4.1.3. Updates in our forecasting approach for each connection category

The table below summarises our forecasting approach for each BAU connection category.

Table 5-39: Updates in our approach to forecasting unit rates and connection volumes for each category

Connection category	Approach to unit rate	Approach to volume forecasts
Medium density housing	Where a third party constructs and developer gifts assets to us: 1) Gifted LV Assets - at agreed unit cost per lot (subject to annual CPI inflation); 2) HV Rebates - at current average unit rate (2024-25) Where we design and construct, we use the 2024-25 financial year historical unit rate.	Apply the net residential connection growth rate to the actual gross connection volumes for RY25
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 RY20-25	Apply the net residential connection growth rate to the actual gross connection volumes for RY25
Business supply projects	5-year historical average direct costs incurred (RY20-RY25). Note that this does not include data centres, community batteries, and other non-BAU C&I connections.	Apply the net C&I connection growth rate to the actual gross connection volumes for RY25

Complex residential supply projects	5-year historical average direct costs incurred (RY20-RY25)	Apply the net residential connection growth rate to the actual gross connection volumes for RY25
Low density housing - subdivisions	5-year historical average direct costs incurred (RY20-RY25)	Apply the net residential connection growth rate to the actual gross connection volumes for RY25
Private electric line replacement	5-year historical average direct costs incurred (RY20-RY25)	Apply the net residential connection growth rate to the actual gross connection volumes for RY25

Source: AusNet

5.12.4.2. New connection types

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.
- 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.

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 have updated our forecast in our Revised Proposal to take account of more recent information.

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.

However, we note that 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.

To mitigate this risk, we propose to manage it through the volumetric adjustment and CESS penalties adjustment for bespoke large connections under the new CESS scheme. We discuss this in detail in section 5.13.5 below.

We note that though the forecasting risk for these connection categories is high, and the new CESS framework de-risks this by applying symmetric incentives, the rewards for underspends and penalties for overspends are still balanced. This means we do not gain from overstating volumes, nor are we disadvantaged by adopting conservatively low forecasts. As discussed above, our forecasts are based on the best available information and reflect our best expectation of demand.

5.12.4.2.1. Data centres

We have adopted the AER's draft decision approach to forecasting data centre connection capex, and updated our forecast to account for more recent information. In the Initial Proposal, we forecast that only one data centre would connect to our distribution network during this period.

In this Revised Proposal, we now forecast two data centres will be connected to our network over the same timeframe. Table 5-40 below outlines the data centres we forecast to connect to our network, along with their project stages as defined by the AER in its Draft Decision for Powercor for the 2026–31 Regulatory Period.

Table 5-40: Forecast Data Centre Connections within AusNet's Distribution Network, RY26 to RY31

Project	Location	Capacity (MVA)	Proposed Year of Energisation	AER Project Stage

[C-I-C]	Barnawartha	[C-I-C]	[C-I-C]	Project is between the connection enquiry and connection offer stage
[C-I-C]	Donnybrook	[C-I-C]	[C-I-C]	Project is between the connection enquiry and connection offer stage

Source: AusNet

As shown in Table 5-40, we forecast a total of two data centres to be connected to our network during the 2026–31 period. In particular:

- [C-I-C]: We have received a connection application for this data centre and have completed a feasibility assessment. The customer has provided proof of land ownership and a development plan. We included this data centre in our connection forecast in our Initial Proposal and the AER accepted the data centre project. Since January, there have been further developments regarding this data centre. Additional projects may be triggered if certain thresholds are met. We have included these as contingent projects. Further details are provided in Section 5.16.2.
- [C-I-C]: We have received a connection application for this data centre, and the customer has provided proof of land ownership and a development plan. We are currently conducting feasibility assessment for this data centre connection and expect to complete within this year. The customer is currently actively engaging with us, and we expect to receive a formal application from the customer once the feasibility assessment is completed.

We did not include the [C-I-C] our Initial Proposal connection forecast, as at the time of submission this project was not at the advanced stage they have reached today. Since January, we have received applications for connection, proof of land ownership, and development plans for this data centre.

Based on these, we consider that these two data centres satisfy the AER's criteria for projects that are "*between the connection enquiry and connection offer stage*," and have strong supporting evidence of a high likelihood to proceed. As outlined in its Draft Decision for Powercor for the 2026–31 regulatory period, the AER supports the inclusion of such projects in connection forecasts.

On this basis, we consider it reasonable to include both projects in our forecast.

To verify our data centre connection forecasts, we engaged Oxford Economics Australia (OEA) to conduct an independent assessment of expected data centre developments within our distribution network. OEA confirmed that the inclusion of the two anticipated projects discussed above is reasonable.

In addition to the two data centres discussed above, the OEA forecasts there will be more data centre connections to our distribution network during the next Regulatory Period, with additional capacity of up to 156 MVA. This figure represents the gap between the combined capacity of the three identified data centres and OEA's total forecast capacity for data centres connecting to our network. The OEA considers the additional data centres will most likely locate in the Northern industrial zone within AusNet's area, e.g. Epping or Donnybrook. The details of OEA's analysis can be found in 'ASD - Oxford Economics Australia - Data Centre Forecast - Nov 2025'.

While we consider the OEA's analysis reasonable [C-I-C], we have conservatively chosen not to include any additional data centres in our connection forecast beyond the three already discussed. This may result in an underestimation of the volume and capacity of data centre connections during the next regulatory period. To mitigate this forecasting risk, we propose managing it through the Capital Expenditure Sharing Scheme (CESS), as discussed in detail in 5.13.5 below.

We have forecasted the gross connection capex for the two data centre projects based on our best expectation, informed by inquiries and applications from data centre operators, and historical costs from comparable connection projects. Each project cost forecast is developed at the individual level, using historical cost data for similar scope items to reflect the specific requirements of each anticipated connection. The cost build-ups for the two data centre projects are included in the energy connection model.

We note that the gross connection capex for the [C-I-C] reflects the best information currently available but remains subject to change as this project matures. A revised project cost estimate will be provided during the information request process if further details become available.

Further detail on our cost estimation approach is provided in 'ASD - Ausnet - Project Cost Estimating Methodology 1Dec2025'. We note that our cost estimating methodology for data centre connections aligns with the requirements set out by the Australian Energy Regulator (AER) in its Draft Decision for Powercor for the 2026–31 regulatory period.

We have estimated capital contribution based on an 86% capital contribution rate, which is derived based on the IC-IR test. Details of the derivation for the 86% capital contribution rate can be found in 'ASD - BWA Data centre contribution calculation - Scenarios (Ver 2.1) - 011225 - CONFIDENTIAL', which is provided together with this Revised

Proposal. We note that the capital contribution is consistent with the AER's Draft Decision. The resulting gross connection capex and net capex forecasts are shown in Table 5-38.

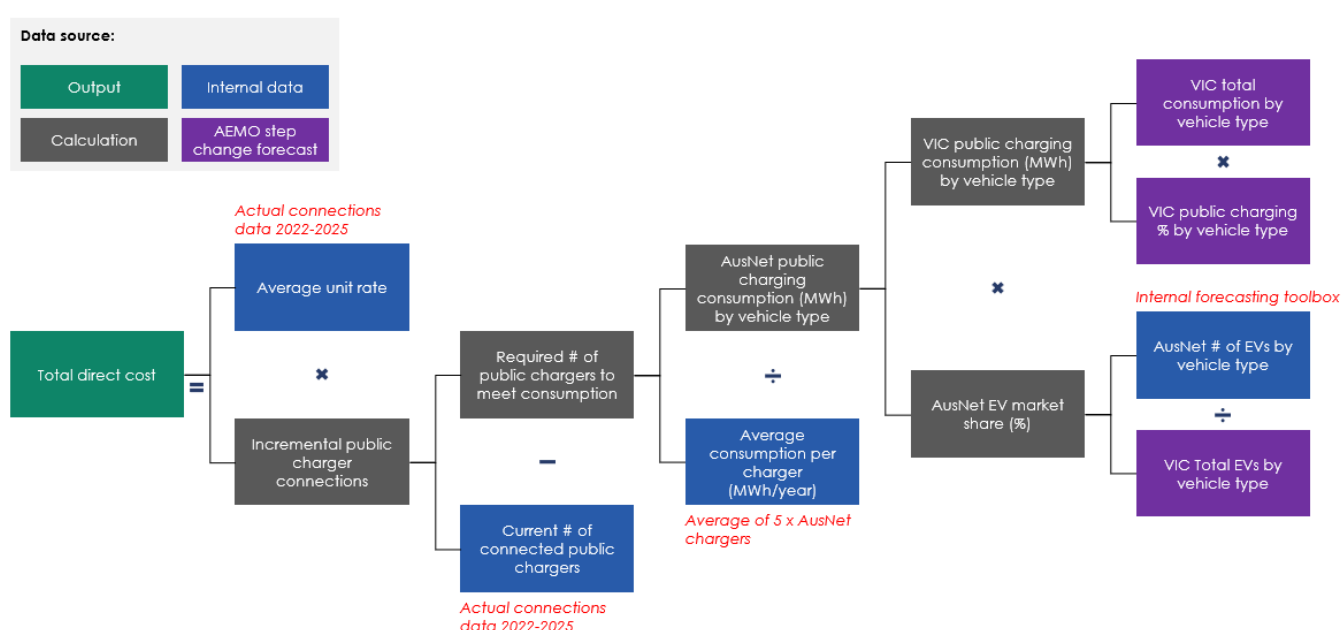
5.12.4.2.2. EV public charging stations

We have updated our connection forecast for EV public charging stations for the upcoming regulatory period in this revised proposal. The revised gross connection capex forecast is 28.1% higher than in our initial proposal, reflecting increases in both forecast connection volume and estimated unit cost of connection for EV public charging stations.

Figure 5-27 below summarises our methodology for forecasting gross connection capex and the underlying data sources. The gross connection capex is calculated by multiplying the forecast unit cost of connection by the forecast connection volumes:

- **Unit cost of connection:** Estimated using actual connection cost data from RY22 to RY25.
- **Connection volume:** Derived by dividing the forecast incremental energy consumption of EV charging stations by the average consumption per charger. The forecast incremental energy consumption is based on AEMO's Step Change forecast and AusNet's projected market share of total Victorian EV public charging consumption.

Figure 5-27:5 Forecasting methodology of EV Public Charging Station Connections



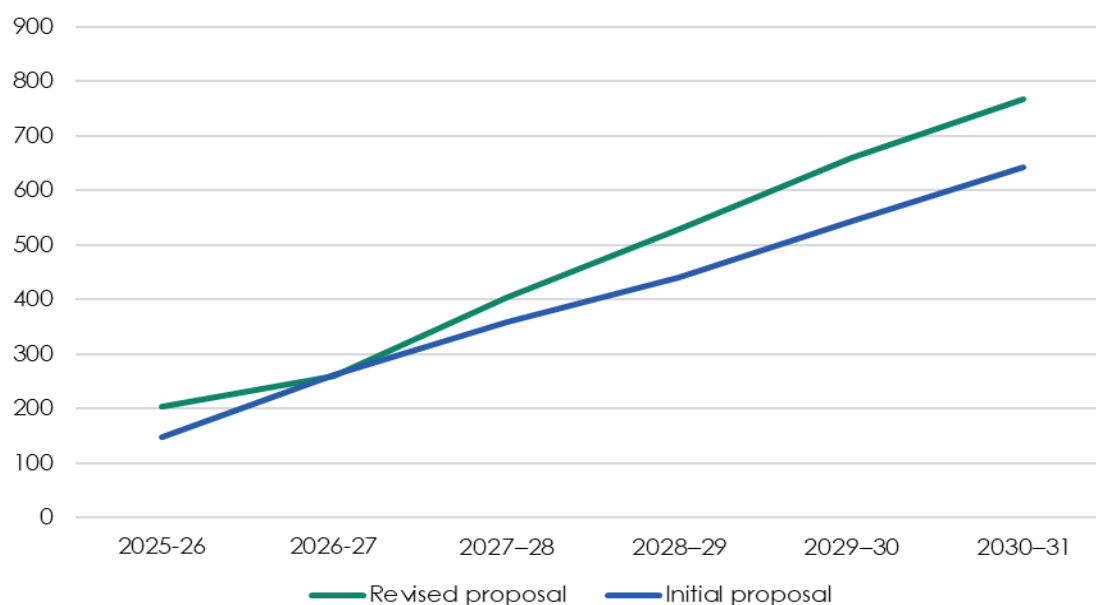
Source: AusNet

Relative to our initial proposal, the change in our forecast connection volume is primarily driven by two key updates:

- **Updated AEMO EV charging forecast (2025 IASR):** The share of residential vehicles using public charging has significantly increased from 8 per cent to 31 per cent, resulting in a higher forecast for total consumption at EV public charging stations in Victoria.
- **Updated AusNet public charging consumption forecast:** We forecast AusNet public charging consumption by multiplying the total consumption in Victoria with AusNet's market share. In our initial proposal, we assumed a fixed market share of 25 per cent. In this revised proposal, we adopt a more granular approach, applying annual market share forecasts by vehicle type, averaging around 15 per cent. This lower market share reduces AusNet's forecast public charging consumption and, consequently, the forecast connection volume.

The net effect of these two changes is an overall increase in the revised connection volume forecast. The revised total connection volume is 17.8% higher than in the initial proposal. Figure 5-28 below illustrates the revised forecast for EV public charging station connections and compares it to our initial proposal.

Figure 5-28: Forecast Connection Volumes for EV Public Charging Stations



Source: AusNet

We have updated our unit cost of connection estimate using the most recent actual connection cost data from 2022 to 2025. The revised unit cost is \$15,300 (real 2025–26), which reflects an upward adjustment from our initial proposal to align with actual costs.

We calculate the forecast gross connection cost by multiplying the forecast connection volume by the unit cost of connection. The forecast capital contribution is then estimated by applying a contribution rate of 65%, consistent with the rate used in our initial proposal. Table 5-38: presents the resulting gross connection cost and net connection capex forecasts.

5.12.4.2.3. Community batteries

In our Initial Proposal, we forecasted that 16 community batteries would be connected to our network during the 2026–31 Regulatory Period. At the time, this forecast was prepared without the key data and information that have since become available from January 2025 onwards. As a result, it significantly underestimated the likely volume of community battery connections. We have now revised our forecast to incorporate the latest available data, including the current pipeline of community battery connection applications submitted to us.

We forecast 155 community batteries will be connected to our network during the 2026–31 Regulatory Period. Table 5-39 below shows the forecast connection volume for community batteries during the 2026–31 Regulatory Period, broken down by forecast type. In particular:

- **35 projects with submitted connection applications under the Victorian Government's 100 Neighbourhood Batteries (NB100) Program.** These projects have secured funding from NB100 and submitted connection applications to us. Under the program's funding conditions, all projects must be connected by August 2027. Accordingly, we have assumed all 35 projects will connect in 2026–27. Notably, this already exceeds the 16 projects we forecasted in our Draft Proposal.
- **27 projects awarded to Mondo under ARENA's Community Battery Funding Program – Round 1.** We have been advised by Mondo regarding the number and expected timing of these projects, and our forecast reflects this information.
- **12 projects anticipated from ARENA's Community Battery Funding Program – Round 2.** This round has now closed, with successful applicants expected to be notified by the end of 2025. We have assumed that 10 per cent of the total awarded projects will connect to our network, resulting in a forecast of 12 connections.
- **48 projects from 2028–29 to 2030–31, from future rounds of state or federal funding.** This forecast assumes that future government funding programs will continue to support community battery deployment. We assume the volume is equivalent to 50 per cent of the combined number of batteries funded under the NB100 and ARENA Round 1 programs.
- **11 market-led projects per year from 2028–29 onwards.** We anticipate that falling battery costs and the continued development of two-way energy markets will create commercial opportunities for neighbourhood

batteries. Based on this, we have assumed that the number of market-led projects will be equivalent to 50 per cent of the total forecast connections in 2027–28.

Table 5-41:5 Forecast connection volume for community batteries, 2026-31 Regulatory Period

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Projects funded by NB100	35					35
Projects from ARENA Round 1	18	9				27
Projects from ARENA Round 2		12				12
Projects from assumed further rounds of funding			16	16	16	48
Future market led connections			11	11	11	33
Total	53	21	27	27	27	155

Source: AusNet

We forecast the gross connection capex for community batteries by multiplying the forecast connection volume by the unit cost of connection. The unit rate applied is the same as the unit rate in our Draft Proposal and is based on the average estimated cost from a sample of community battery projects. Capital contributions have been forecast using a contribution rate of 78%, reflecting the average recovery ratio observed for delivered battery projects in RY25. The resulting forecast gross connection capex and net connection capex are shown on Table 5-38:.

5.12.4.2.4. Bus depot EV connections

We have kept our Bus depot EV connections forecast unchanged. The gross connection capex and net connection capex are shown on Table 5-38:.

5.12.4.2.5. Embedded generations

We have updated our connection forecasts for hybrid generation and grid scale batteries reflecting the revised pipeline of projects using the latest information provided by proponents. In our Initial Proposal, we included 10 embedded generation and hybrid connection projects in our connection forecasts. In this Revised Proposal, we included 15 embedded generation and hybrid connection projects in our connection forecasts, reflecting 5 projects progressing to the application stage since January. We forecast gross connection capex, capital contribution, and net capex at project level. The resulting total gross capex and net capex are shown on Table 5-38:.

5.12.4.2.6. Updates in our forecasting approach for each connection category

Table below summarise our forecasting methodology for new connection types.

Table 5-42:6 Updates in our approach to forecasting unit rates and connection volumes for each category

Connection category	Unit rate	Volume
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, verified by external consultant
EV charging stations for public and EV bus depots	Forecasts of EV charging stations are based on AEMO and Victoria 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)
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, taking into account current pipeline of community batteries connecting to our network as results of government incentive schemes, future government incentives, and market based opportunities.

Hybrid and batteries (1.5MVA or more)

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

Source: AusNet

5.12.5. Other connection projects

5.12.5.1. Feeder Augmentation

In our initial proposal, we proposed a pipeline of 22kV feeder augmentation projects under augmentation capex across the current and upcoming regulatory periods to support network growth, connect new customers, and alleviate local constraints ahead of commissioning new zone substations. These projects were presented as essential investments to maintain reliability and meet community needs, with a forecast of \$30.4 million (real, 2025–26) for the 2026–31 period.

In its draft decision, the AER considered these projects to be predominantly connection-focused rather than demand-driven and indicated they should be included within the connection capex proposal. In response, we have incorporated the feeder augmentation program into our connection capex proposal in this Revised Proposal to align with the AER's position.

These projects primarily involve extending existing feeders or constructing new ones to connect customers in areas where network capacity is insufficient or non-existent, such as greenfield residential developments and industrial clusters. They are distinct from our BAU connection forecast because they require network augmentation rather than standard customer connections. Furthermore, we do not receive customer contributions for these projects, making it critical to secure an allowance for their delivery. For these reasons, we have included these projects within our connection capex proposal for the 2026-2031 regulatory period.

Following a detailed review of proposed feeder augmentation projects, we have revised our forecast down to \$6.3 million (real, 2025–26) for connections after incorporating eligible economic projects in the Augmentation proposal. This revised feeder augmentation program for connections covers additional feeder capacity for new residential housing estates and supply upgrades and/or new feeders for industrial and commercial connections. Further details of this revised forecast are provided in 'ASD – Customer growth driven feeder augmentation – 011225', which accompanies this Revised Proposal.

5.12.5.2. Large commercial connection

We have included one large commercial connection project in our revised connection forecast – The Beveridge Intermodal Freight Terminal (BIFT). This is a major freight and logistics hub planned in Melbourne's northern growth corridor, requiring substantial electrical capacity to support its operations. We have received the application for the connection from the customer. Initially, its load will be supplied from the new Beveridge Zone Substation (BVE) via dedicated 22 kV feeders, which will meet demand until around 2031. The estimated gross capex and net capex of this project is included in Table 5-38.

5.12.6. Reducing uncertainty

The AER has released its final decision on the review of the Capital Expenditure Sharing Scheme (CESS) in August 2025, introducing refinements to address forecasting uncertainty for connections capex. In line with the AER's updated CESS guideline, we propose to apply the volumetric adjustments for business-as-usual (BAU) connections and introduce targeted adjustments to CESS penalties for large bespoke connections.

1. Volumetric Adjustment for Business-as-Usual (BAU) Connections

Consistent with section 2.6.1 of the guidelines, we propose applying a volumetric adjustment mechanism to BAU connection capex. This mechanism will:

- Exclude capex variations driven by changes in BAU connection volumes from CESS calculations.
- Ensure that we are not rewarded or penalised for volume-driven changes beyond our control.
- Apply symmetrically to increases or decreases in BAU volumes, maintaining neutrality in incentives

This approach aligns with the AER's default position to apply the volumetric adjustments to a DNSP's business-as-usual connection capex.

We have identified the following Business-as-Usual (BAU) connection programs below and propose to apply volumetric adjustments to these programs. We confirm that these programs exclude all large bespoke connections and do not overlap with any bespoke connection programs.

Table 5-43:7 Connection programs we propose to apply volumetric adjustments

Connection category	Connection programs
Residential connections	Medium density housing
	Underground service installation
	Complex residential supply projects
	Low density housing
C&I connections (excluding bespoke large connections)	Business supply projects
	EV charging stations
	Dot Bus Depot EV connections

Source: AusNet

We note that, as discussed above, the forecasting risk is especially high for new connection types including EV charging stations for public and EV bus depots. It is especially important to manage the forecasting risk for those connections through the volumetric adjustment.

2. Adjustment of CESS Penalties for Large Bespoke Connections

Consistent with section 2.8.1 of the AER's Capital Expenditure Incentive Guidelines (August 2025), we propose to apply adjustments to CESS penalties for large bespoke connections. This approach reflects the AER's default position to allow reductions in penalties where overspends are driven by efficient increases in bespoke connections—such as data centres—that were not included in forecast capex.

We identify the bespoke large connection programs below and propose to apply the CESS penalties adjustment to these programs. We confirm that these programs do not have overlap with BAU connection programs.

Table 5-44: Connection programs we propose to apply the CESS penalties adjustment for large bespoke connections

Connection category	Connection programs
C&I connections (bespoke large connections)	Data centres
	Other bespoke large commercial connections
Embedded generation	Grid scale batteries and renewable generator hybrids. (Hybrid and batteries (greater than 1.5MVA))
	Community batteries (Hybrid and batteries (1.5MVA or less))

Source: AusNet

These programs mainly relate to the new connection types with high forecasting risk, including data centres, grid scale batteries and community batteries, and renewable generator hybrids. As mentioned above, we forecast these projects at project level and the forecasting risk are not addressed through volumetric adjustment.

The forecasting risk for data centres are especially high for us, as it is likely that we have underestimated the number and capacity of data centres to be connected to our network during the next regulatory period. As discussed above, the OEA forecast that, in addition to the three data centres we included in our connection forecast, there will be more data centre connections to our distribution network during the next Regulatory Period, with additional capacity of up to 38 MVA. In addition, we are currently engaging with customers on a list of proposed data centre projects which are not included in our connection forecast.

These indicate the high likelihood of additional data centre connections beyond what is currently included in our proposal. If these do translate into actual data centre connections, we should not be penalised for overspend given our obligation to connect customers and the progression of these projects are outside our control.

5.12.7. Updates to connection policy

We have updated our Connections Policy to incorporate changes associated with the AER's Export Limit Guidance Note including enabling the implementation of flexible exports. We have also made a change requested in the Draft Decision to enable cost recovery of tax and opex costs directly from large customers, including data centres. This is explained further below.

5.12.7.1. Tax and opex cost recovery from large customers, BESS and hybrids

We have updated our connection policy to charge an upfront tax liability and opex costs as part of the total capital contribution, for data centres and other customers connecting to the subtransmission network.

Charging an upfront tax liability for large customer connections, such as data centres, reduces cross-subsidisation and improves cost-reflectivity. Under the current framework, tax costs arising from capital contributions and opex charges associated with maintaining connection assets are typically recovered through standard control service revenues, which are spread across all customers. This creates a situation where existing customers effectively subsidise the tax burden associated with bespoke, high-value connections that primarily benefit individual applicants. By requiring the connecting customer to pay the tax component upfront, the distributor ensures that costs are allocated to the party driving them, consistent with the AER's principle of limiting cross-subsidies.

Another key rationale is the high degree of uncertainty surrounding the volume and scale of these new customer types, such as data centres and EV charging infrastructure. Forecasting the scale of these connections over a regulatory period is inherently challenging, and errors in these forecasts can lead to either under-recovery or over-recovery, impacting both network businesses and consumers. An upfront approach mitigates this risk by aligning cost recovery with actual connection activity, reducing reliance on speculative forecasts and providing greater transparency and predictability for all stakeholders.

Upfront recovery of tax costs also supports regulatory integrity by ensuring that these costs are not inadvertently recovered twice—once through customer contributions and again through DUoS charges or the post-tax revenue model. By excluding these contributions from the regulatory asset base and associated tax calculations, the approach maintains compliance with the AER's guidelines while delivering a fairer and more efficient outcome for customers and networks alike.

The AER requested that we specify a threshold for applying upfront tax liability in our Revised Proposal. In response, we propose setting this threshold at the sub-transmission level, meaning all sub-transmission connections would be subject to an upfront tax liability. This approach is based on several considerations:

- It avoids discriminatory treatment of specific customer types, such as data centres, by applying a consistent rule across all large connections.
- Sub-transmission and high-voltage connections are inherently difficult to forecast, making upfront recovery a practical solution to manage uncertainty.
- The sub-transmission threshold is clear and objective, whereas alternative thresholds—such as defining a “data centre”—could introduce ambiguity and complexity.
- Customers connecting at sub-transmission and high-voltage levels typically have greater capacity to understand and absorb the net tax liability, ensuring the approach remains equitable and transparent.

We consider the same concerns apply to incremental opex expected to be incurred to maintain connection assets associates with these customer connections. For this reason we have extended the approach to include incremental opex.

In addition, and as foreshadowed in our response to IR#026⁷⁶, we propose to amend our connection policy to enable us to seek recovery of net tax costs and incremental opex from all large load connections >1.5MW where assets are gifted to us. This includes BESS, hybrids and other large load customers who connect to the sub-transmission network and those connecting at lower voltage levels. This is due to the issues outlined above and also the additional issue that connection assets gifted by large customers constitute assessable income for tax purposes but are not able to be imputed into the PTRM, resulting in no tax cost recovery via SCS revenues. Unless this cost can

⁷⁶ ASD, AusNet - EDPR 2026-31 IR#026 - Follow-up response - 20250606 – CONF, p.2.

be recovered directly from the connecting customer, recovery of the net tax cost would not be provided for under the regime which would violate the Revenue and Pricing Principles.

We would welcome further discussion with the AER on this topic. We have raised it through the Q&A process in the context of significant unfunded tax costs associated with gifted assets of large connections (Type 2 contributions) and need to resolve this through this process.

At our 'all in' Revised Proposal forum on 6 November, we engaged on which customers should be charged their tax and opex costs directly as requested by the AER. The consensus from the room was that all commercial customers should bear their own costs. This would represent a major change to the regulatory framework and would need careful consideration, so we have not proposed this approach is taken, but we consider limiting direct recovery of net tax costs and opex from sub-transmission connected customers (including BESS, hybrids and large load customers) is reasonable and consistent with customer preferences to minimise cross-subsidisation.

5.12.8. Key inputs and assumptions

The key inputs and assumptions to our forecasting methodology are summarised in the table below.

Table 5-45: 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 adjustment on connection categories associated with high uncertainty of connection volumes and cost	We propose to apply volumetric adjustments to our Business-as-Usual (BAU) connections and CESS penalties adjustment for large bespoke connections. This is consistent with the AER's default position to apply these adjustments under CESS scheme.
Compliance with laws, codes and standards	We must comply with several regulatory obligations and legislative requirements, including NER 5A ⁷⁷ , 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.
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 - Manage uncertainty of new customer types and emerging technologies through CESS due to uncertainty in forecasting rapidly increasing volumes of EV chargers, battery/hybrids and

⁷⁷ 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)).

Source: AusNet

5.13. Digital expenditure

5.13.1. Our Initial Proposal

AusNet proposed \$386.7 million in digital capital expenditure and \$39.9 million in digital operating expenditure in the Initial Proposal.

5.13.2. Draft Decision

The AER did not accept AusNet's proposed \$386.7 million ICT capital expenditure for the 2026–31 period, instead providing an alternative forecast of \$252.6 million. This represents a 34.7% reduction in our proposed capital expenditure. In addition, the AER accepted our Cyber Security program as prudent with a placeholder of \$27.5 million, subject to AusNet providing detailed risk mapping and link activities to its business drivers.

While the AER acknowledged the need for ongoing digital investment and cyber security uplift, it found that AusNet's proposal did not sufficiently demonstrate prudence and efficiency across several programs. Key concerns of the AER included:

- **Scope and maturity:** initiatives included in the proposed projects have "low maturity" and AusNet should explore new options for a core program of sub-set of initiatives that will likely be NPV positive.
- **Cost estimation:** cost estimates appear overstated for certain areas or unclear scope, without referenceable basis.
- **Benefit justification:** further justification required for certain quantified benefits, and NPVs are negative for some projects.
- **Risk management:** AusNet should review options to assess the necessity of upgrades and identify opportunities for risk-informed deferrals and potential execution synergies.
- **Cost allocation:** all ICT costs were allocated to distribution, ignoring shared services for transmission and gas.

The AER's draft decision and feedback at program level are summarised in Table 5-46 below. The AER expects AusNet's revised proposal to address these issues by providing robust cost-benefit analysis, clearer scope definition, and evidence of distribution network cost allocation

Table 5-46:8 AER draft decision and feedback on digital programs

Program	Proposal (\$m2026)	Draft decision (\$m2026)	AER feedback
Technology Asset Management – Applications	67.3	41.3	Review options to assess the necessity of upgrades and identify opportunities for risk-informed deferrals and potential synergies
Technology Asset Management – Infrastructure	32.7	17.2	AusNet to evaluate alternate risk-adjusted options for extending infrastructure asset lifecycles.
Customer Experience	45.3	11.3	The business case must demonstrate a positive NPV, with AER cost reductions reflecting the quantified benefits outlined in the case.
ADMS (IT portion)	27.9	20.3	- Re-assess maturity of Phase 3 initiatives and overall cost/benefit mapping. - Consider the 2yr lag of the current ADMS project pipeline on EDPR program timelines.

Field Enablement	18.8	17.5	• Program accepted with a \$1.3M allocation adjustment. • Re-submission to include ~\$20M additional spend for ADMS mobility.
Network Model Management	42.7	32.1	• Re-assess validity of benefits modelling and evaluate alternative options to prioritise/defer initiatives.
Asset Management	79.3	47.6	• Identified need demonstrated, however must strengthen the maturity of project scopes and cost estimation.
Cyber security	27.5	27.5	• Costs accepted pending submission of risk mapping to program initiatives.
Metering systems (SCS & ACS)	5.0	4.6	• Reduction related to adjustment in ACS/SCS portioning.

Source: AusNet

5.13.3. Addressing the AER's Draft Decision

We do not accept the AER's Draft Decision to reduce our digital capital expenditure by 34.7%. We have responded to their concerns including the need to re-scope programs, strengthen cost estimates and benefit assessments.

In response to the AER's feedback, we have undertaken a comprehensive review of all digital programs to ensure our revised forecast reflects only prudent, efficient and fully justified expenditure. We re-examined the scope, assumptions and costs for every digital program, working closely with our Strategic Digital Partner, [C-I-C], to rebuild cost estimates from the ground up and refining scopes with distribution business management to ensure that only essential initiatives remain in our proposal. Figure 5-29 details our cost estimation approach for digital programs and the process we undertook to prepare for Revised Proposal.

Figure 5-29: 6 Revised Proposal Cost Estimation Approach for Digital Programs

[C-I-C]

Source: AusNet

In particular, this process began with a structured reassessment of our original EDPR digital business cases, focusing on:

- Validating the stated need for each initiative;
- Confirming the investment rationale and expected benefits; and
- Ensuring all activities were aligned with the digital capabilities AusNet must develop for the 2027–31 period.

Workshops and targeted SME interviews enabled a detailed review of each program, helping to remove or streamline non-critical initiatives, eliminate scope ambiguity, and anchor each initiative to clear evidence and regulatory expectations.

Through this process, we materially refined the scope of our proposed programs. For each program, we revisited the key drivers for investment—such as vendor end-of-support, cyber and SOCI obligations, DER integration challenges, resilience gaps identified during major events, or emerging regulatory settings and compliance needs—and

evaluated scope adjustments that could lower costs while still addressing these drivers. As part of the refinement, we shifted toward leveraging existing platforms, minimised bespoke development, and prioritised initiatives that deliver the strongest customer outcomes and lowest delivery risk.

Following scope revalidation, we rebuilt all cost estimates, in collaboration with [C-I-C], using a rigorous, bottom-up approach. Figure 5-30 below details the approach for bottom-up cost estimating methodologies for TAM programs and capability enhancement programs respectively. Where relevant, initiative costs were subsequently apportioned to the distribution line of business to ensure compliance with regulatory requirements. This was underpinned by a set of overarching cross-initiative assumptions that helped ensure consistency and comparability across all estimates.

Figure 5-30: 7 Bottom-up Cost Estimating Methodologies for Digital Programs

[C-I-C]

Source: AusNet

To ensure the robustness of the revised estimates, [C-I-C] also applied a targeted top-down benchmarking exercise across a selection of initiatives. This benchmark analysis drew on [C-I-C] experience delivering comparable capabilities for DNSPs in Australia, New Zealand and globally. Figure 5-31 details the top-down cost estimating methodologies for digital programs. The benchmarking served as a stress-test to the bottom-up estimates. Where a bottom-up estimate sat significantly outside credible market ranges, the underlying assumptions, scope and delivery effort were revisited and refined to ensure the final forecast was tightly aligned with efficient industry benchmarks.

Figure 5-31: Top-down Cost Estimating Methodologies for Digital Programs

[C-I-C]

Source: AusNet

As a result of this end-to-end review, we have strengthened the prudence, efficiency and robustness of our digital capex proposal. It has enabled us to refine and reduce proposed costs across multiple programs while ensuring we remain able to meet our long-term obligations and deliver lasting value to customers throughout the 2026–31 period. The revised forecast now reflects:

- Only the essential scope required to maintain digital resilience and system supportability;
- Targeted investment to enable increasing DER penetration and operational complexity;
- Improvements to outage response, field operations and customer outcomes; and
- Uplifted asset data, risk and compliance capabilities aligned with evolving regulatory requirements.

Table 5-47 summarises the AER's concerns and feedback, and outlines how we have addressed these in preparing our Revised Proposal through the process discussed above.

Table 5-47: Summary of AER Feedback and AusNet's Response in the Revised Proposal

Topic	AER feedback	AusNet Revised Proposal
Cost Estimates	• Cost estimates appear overstated for certain areas or unclear scope, without referenceable basis	• Cost estimates have been refreshed in collaboration with our delivery partners, [C-I-C] and [C-I-C] to reflect updated delivery assumptions and efficiencies • Formalised delivery partner cost estimates
Scope Maturity	• Several initiatives included in the proposed projects have "low maturity" regarding need or function, technology available, or both • Explore new option for a core program of sub-set of initiatives that will likely be NPV positive	• Comprehensive revalidation of scope with Distribution business stakeholders and leadership, to confirm alignment and strategic priorities and delivery feasibility • Result in adjustments to programs in revised proposal – scope reductions and select increases
Benefit Justification	• Further justification required for assumed scale and benefits; some NPVs negative (e.g. customer experience program)	• Benefit cases re-evaluated and reconfirmed, where needed, with Distribution business stakeholders and aligned with program scope adjustments • Specific benefit quantification completed for customer experience program, aligned with customer consultative committee support
Risk Management	• Review options to assess the necessity of upgrades and identify opportunities for risk-informed deferrals and potential synergies • Provide cybersecurity risk mapping to program initiatives	• Technology Asset Management (recurrent) programs aligned with AusNet's enhanced criticality and risk management framework, together with revalidation of upgrade timing basis • Mapping of cyber security risks, controls and associated investment risk management initiatives will be provided
Cost Allocation	• All costs documented must be documented as distribution-allocated	• All proposal costs were already provided as distribution-allocated. This is clearly documented in each program addendum provided together with this Revised Proposal.

Source: AusNet

5.13.4. Revised Proposal

Our revised proposal for digital expenditure is \$370 million (\$, real 2023-24) for capital expenditure and \$20 million (real, \$2023-24) for operating expenditure. This represents a reduction of 11 per cent for digital capex and a reduction of 35 per cent for operating expenditure, relative to our Draft Proposal.

The reduction mainly reflects reduced scopes and lower cost estimates for most of our proposed programs (as shown in the Table 5-48 below) as a result of the list of actions we took to address the AER's concerns. Our Revised Proposal capital expenditure for each of our proposed programs, and the drivers for change relative to our Initial Proposal are included in Table 5-48 below.

Table 5-48: Digital capex program

Program	Initial Proposal	AER Draft Decision	Revised Proposal	Drivers for change

	(\$m 2024)	(\$m 2024)	(\$m 2024)	
Technology Asset Management – Applications	60.8	39.1	45.7 (-25%)	Scope change and updated cost estimate - Push out ADMS GridOS upgrade to next period - Revised cost estimates from [C-I-C] for SAP and DERMS 20% reduction to lowest criticality Business Operational & Administrative systems
Technology Asset Management – Infrastructure	29.6	16.3	24.5 (-17%)	Scope change and updated cost estimate - Revised cost estimates from [C-I-C] for all infrastructure line items 20% reduction to Data & Analytics and 50% Reduction to User devices (Business Operational Classification)
Customer Experience	41.0	10.7	30.2 (-16%)	Updated cost estimate Scope unchanged, with revised cost estimates from [C-I-C] applied to all line items except Customer Portal Consolidation
ADMS (IT and OT)	60.4	45.6	52.1 (-14%)	Scope change and updated cost estimate - Added Alarm Management & full Wide Area Restoration (schedule) initiatives - Descoped AMI/LV and DERMS ADMS integration initiatives (-\$9m); Assumed Distribution wall board in Control Room project - Decrease in scope of ADMS OT Digital Improvements; assumed SCADA monitoring in SCADA Upgrade - Authorities and workforce management in Field Mobility scope
Field Enablement	17.1	16.6	30.6 (+79%)	Scope change and updated cost estimate: - Additional ADMS Mobility scope moved into this period (+\$13.4m) - Descoped Delegated Switching, and Fault Location Visibility included in ADMS Mobility (-\$4.5m) - Larger scope of Non-energy mobility, with [C-I-C] cost estimate
Network Model Management	38.6	30.4	40.7 (+5%)	Scope change and updated cost estimate - Reflected current scope of ADMS Network Model (inc. LV Mgmt) [C-I-C] estimate for reduced scope of Geospatial capabilities
Asset Management	71.5	45.1	48.9 (-32%)	Scope change and updated cost estimate - Descoped Digital Asset Monitoring and Industry Asset Model initiatives (-\$19m) [C-I-C] cost estimates for remaining items
Distribution System Operator (DSO)	37.0	15.6	29.9 (-19%)	Scope change and updated cost estimate - Initiatives NPV positive when considered individually, not just on a program level - Descoped CER Data exchange. - Updated with [C-I-C] estimate for Flexible Services & AusNet estimate for GridView based on more granular scopes - Some implementation costs shifted to opex
Market systems	18.5	18.5	18.5 (+0%)	No change AER accepted in Draft Decision
Cyber security	24.9	24.9	24.9 (+0%)	No change Document risk mapping for cyber projects as per AER feedback

				Scope change and updated cost estimate
Metering systems (SCS & ACS)	16.3	16.3	22.7 (+39%)	- SCS capex (\$8.6m) includes additional c.\$2m for flex trading meters - New ACS capex for smart public lighting (c.\$6m)
TOTAL	415.7	279.1	368.7	

As shown in Table 5-46, while our revised capex proposals for most programs are lower—reflecting reduced scope and updated cost estimates—three programs have higher updated capex compared to the initial proposal:

- **Field Enablement:** The revised capex is \$13.5 million (+79%) higher than the initial proposal, primarily reflecting scope maturation and newly identified requirements. Since the Initial Proposal, we have completed the detailed design phase for the energy-related Field Crew Mobile Solutions program. This work has delivered a fully defined scope, resulting in the consolidation and de-scoping of initiatives (such as Delegated Switching), revised benefit quantification, and updated cost estimates. In addition, the scope for non-energy-related Field Crew Mobile Solutions has been updated following the migration of field services from Downer to Zinfra, with associated costs and benefits re-quantified to reflect revised business requirements.
- **Network Model Management:** The revised capex is \$2.1 million (+5%) higher than the initial proposal, primarily reflecting scope refinement. In response to concerns around risk assessment and project economics, we have refined our scope to prioritise the highest value-adding components and provide additional evidence on scale and maturity of each initiative. As such, we have adopted a staged approach that accelerates critical capabilities while allowing lower-priority work to be deferred to the next regulatory period. The cost increase, in particular, is mainly driven by scope expansion to integrate LV management with the Network Model (HV and LV) to ensure a holistic and future-ready approach, following the extended scope and benefit review.
- **Metering systems (SCS & ACS):** The revised capex is \$7.3 million (+39%) higher than the initial proposal, primarily reflecting scope change. We have incorporated two compliance-driven programs in addition to the programs in Initial Proposal—Flexible Trading Arrangements (resubmission) and Smart Public Lighting.

Further details on our revised digital programs—including updated scope, benefits, costs, and key changes from the initial proposal—are provided in the Program Addendums accompanying this submission. Details of revised cost-benefit analysis for each program are provided in the Digital CBA model, provided together with this Revised Proposal.

5.14. Compliance expenditure

5.14.1. Our Initial Proposal

AusNet proposed several programs to maintain compliance with our network distribution licence and the regulations that we operate under. These included:

- Network investments of \$81.7 million at four locations – Seymour, Wodonga TS 22kV, Woori Yallock and Kinglake – to maintain REFCL compliance.
- Installing distributed UFLS at all distribution feeders and dynamic blocking to enhance system security \$22.1 million
- Voltage compliance expenditure involving a:
 - **Proactive steady-state voltage compliance program** of works with a capital expenditure requirement of \$28.9 million. This program was designed to address voltage compliance issues where economic. There is no standardised approach or guidance to quantify benefits for investment addressing voltage compliance issues as expenditure in this has historically been solely to meet compliance requirement. Our initial proposal sought to quantify benefits and included safety risk, increased energy consumption and voltage-curtailment of solar PV systems.
 - **Quality of supply program** with a capex requirement of \$9.0 million to continue our Business-as-usual (BAU) response to voltage complaints. This proposed quality of supply program was lower than our current period spend to account for the impacts of proactive program.

5.14.2. Draft Decision

The AER approved:

- \$64.0 million for REFCL augmentation. The reduction relates to the AER removing an unexplained cost item and the risk allowance component.
- \$20.3 million for UFLS installation where the reduction relates to removing the risk allowance component.
- \$8.7 million in reactive supply improvement program.

The AER rejected \$28.9 million in proactive voltage compliance as the underlying assumptions were insufficiently explained.

5.14.3. Addressing the AER's Draft Decision

AusNet has updated its cost estimate to maintain REFCL compliance at Seymour, Wodonga TS 22kV, Woori Yallock and Kinglake, which are now higher⁷⁸. We have provided the detailed cost build up for these REFCL sites to support the higher cost. We have also our updated assessment which shows that it remains the lowest cost option to address our REFCL compliance. We have also introduced two other REFCL compliance projects; REFCL Bairnsdale augmentation (delayed project from current period into the 2026-31 period) and REFCL Lilydale augmentation (WIP with some carryover to 2026-31 period).

AusNet accepts the AER's Draft Decision on UFLS.

We accept the AER's decision that our proposed proactive program was not sufficiently justified. We consider it may be prudent to invest to avoid voltage non-compliance and achieve resulting customer benefit from fewer voltage variation events, but recognise a proactive program requires strong economic justification. Given, there is no established and tested framework to quantify economic cost to customers experiencing voltage variations (or the benefit of minimising these events), the efficient approach is for AusNet to continue to invest through reactive work aligned with maintain compliance within defined limits.

Given we are no longer proposing proactive voltage compliance investment, we have re-assessed our current reactive quality of supply program, including the most recent year of data. We therefore do not accept the AER's Draft Decision on our Quality of Supply Improvement program, as we originally proposed less than our forecast for the current period due to our expectation that our proposed proactive program would reduce the need for reactive works. The Draft Decision of \$8.4 million is much lower than our current forecast spend for our reactive program to respond to voltage complaints (average spend of \$4.0 million per year) and have forecast a consistent level of expenditure will be needed given there are no proactive investment planned. We consider this level of expenditure is required to enable us to maintain function voltage compliance in the upcoming period.

We have refreshed our least cost analysis for REFCL based on updated costs which are higher than our Initial Proposal. We have also explained our costs in our supporting documentation. In short, we have assumed two complex sites and three simple sites, where the detailed cost build up for the complex sites have been provided as a supporting documentation. The unit rate for the simple site is based on removing some cost items from the complex site unit rate.

5.14.4. Revised Proposal

The table below outlines our revised proposal capex forecast related to compliance and REFCLs.

Table 5-50: Summary of compliance augex (\$m, real 2025-26)

Project	Initial Proposal	AER's Draft Decision	Revised Regulatory Proposal	Rationale	Reference
Under Frequency Load Shedding (UFLS)	\$22.1	\$20.3	\$21.3	Accepted the AER's draft decision; minor variations due to escalation	N/A
REFCL augmentation at Seymour, Wodonga TS 22kV, Woori	\$81.7	\$64.0	\$114.9 ⁷⁹	Updated costs; no change in driver	ASD - AusNet - REFCL Driven Augmentation - 01122025

⁷⁸ Five remote REFCLs across four sites

⁷⁹ Refer to file 'ASD - AusNet - Direct Cost Summary - DD-0016722 - REFCL Driven Augmentation Generic Simple Site 01122025 - CONF' & 'ASD - AusNet - Direct Cost Summary - DD-0016722 - REFCL Driven Augmentation Generic Complex Site_01122025 - CONF.' The assumption for this estimate is that the program of works will contain 2 complex sites and 3 standard sites. These estimates do not reconcile with the values in the table because the tabulated values include overhead and escalation.

Yallock and Kinglake					
REFCL Lilydale augmentation	Not included	Not included	20.7	Originally planned for the current 2021-26 period. Given the delay, some costs have carried over (in full or part) to the 2026-31 period.	ASD - AusNet - DD-0014775_REFCL_LD_L Augmentation _Business_Case_Signed - 25112024 - CONF
REFCL Bairnsdale augmentation	Not included	Not included	22.8	Delayed project into the 2026-31 period. Originally planned for the current 2021-26 period. Given the delay, some costs have carried over (in full or part) to the 2026-31 period.	ASD - AusNet - REFCL Bairnsdale (BDL)_Draft Project Assessment Report - 01122025
Voltage compliance program	\$28.9	\$0	\$0	No longer proposing a proactive program	N/A
Quality of supply program	\$9.0	\$8.7	\$24.7	Expanded our reactive program based on historical costs	ASD - AusNet - Quality of Supply Program Business Case - 1Dec2025
Voltage Regulator Relay Replacement	Not included	Not included	\$3.2	Originally planned for the current 2021-26 period. Given the delay, some costs have carried over (in full or part) to the 2026-31 period.	ASD - AusNet - DD-0011611 Voltage Regulator Relay Replacements Business Case (BC) - 21112022 - CONF ASD - AusNet - DD-0011611 Voltage Regulator Relay Replacements PCR01 - 10022025 - CONF ASD - AusNet - DD-0011611 Voltage Regulator Relay Replacements PCR02 - 11092025 - CONF
Total	\$141.7	\$92.9	\$207.6		

Source: AusNet

5.14.4.1. REFCL compliance

Our REFCL projects are:

- **REFCL augmentation at Seymour, Wodonga TS 22kV, Woori Yallock and Kinglake.** The need for these upgrades remain the same as our Initial Proposal being to maintain REFCL compliance at the four sites (5 remote REFCLs across 4 sites). We have updated our costs and refreshed our business case.
- **REFCL Lilydale.** The REFCL network supported by LDL Zone Substation (ZSS) has increasing capacitance growth that requires mitigation to ensure the network remains compliant. Due to Network Dampening and other network characteristics, operating a reliable network at the required capacity at Lilydale demands a capacitive current limit of 192 amperes. The measured capacitance is 232 amperes, which exceeds the 192 amperes limit. This project commenced in the current period and will carry over to the 2026-31 period. We have only proposed the capex amount that will carry over to the 2026-31 period.
- **REFCL Bairnsdale.** The area served by BDL has experienced significant network growth, which is expected to continue. This growth, which includes additional underground networks, means that the capacitive current limits of 144A on Bus 3 and 107A on Bus 4 provided by the existing REFCLs are no longer adequate. As a consequence, future compliance with the Regulations cannot be maintained at BDL in the absence of remedial action. The identified need, therefore, is to maintain compliance with the Regulations at BDL so that bushfire risk is reduced in the affected communities in accordance with the purpose of the Regulations. This is a delayed project that will be undertaken in the 2026-31 period. We have proposed that the full capex amount related to this project be recovered during the 2026-31 period.

5.14.4.2. BAU voltage compliance

Voltage variations can cause significant inconvenience for customers and reflect non-compliance with the Victorian Electricity Distribution Code of Practice (EDCoP), which requires distributors to maintain supply voltage within defined limits to protect customers and ensure reliable service.

In the current period, AusNet's supply improvement program aims to resolve power supply issues, mainly triggered by customer complaints to address quality of supply issues, such as voltage variations, harmonics, flicker, unbalance, sags or swells. Since 2021, AusNet has averaged 360 customer complaints per year at an average total capex cost of \$4.0 million per annum. This program is critical to maintaining compliance, responding to customer-reported issues, and ensuring service quality across the network.

Quality of supply related complaints are commonly caused by:

- High voltages: Often linked to solar PV exports during spring and summer, causing inverter trips or installation delays.
- Low voltages: Increasingly driven by electrification and EV charging, particularly during winter peaks, leading to heating and appliance failures.
- Other quality issues: Flickering, harmonics, phase imbalance, and voltage sags/swells degrade appliance performance and shorten equipment lifespan.

Historically, most voltage complaints were linked to high voltages caused by high solar output during spring and summer, while low-voltage issues often driven by electrification, are becoming more common during winter peaks. This trend is evident in our recent data, which shows high-voltage complaints dominated early years of the current period, peaking at over 600 incidents in 2021. These high-voltage cases have declined, largely due to AusNet's Quality of Supply Programs targeted at resolving recurring localised voltage issues and therefore minimised the number of customers in that area experiencing the impacts of overvoltage. Over the period, the proportion of low-voltage complains has increased and by 2025 low voltage complaint volumes are now more than to high-voltage complaints. This shift highlights a growing risk of undervoltage events as household demand accelerates. As customers transition to electric for their heating, cooking, and transport needs, it will become increasingly important to maintain quality of supply to minimise disruption and inconvenience for our customers.

We have assessed the potential impacts, costs and benefits of two options:

1. Introducing a proactive voltage compliance program – over and above the program discussed in the next section below – and maintaining a smaller reactive works program (as in our Initial Proposal)
2. Continuing with current level of reactive works program to address forecast voltage issues.

There is no credible do-nothing option given this expenditure is required to meet our EDCoP obligations. Aligned with the AERs draft decision, we propose the efficient approach is to continue to invest through reactive work aligned with maintaining functional compliance within defined limits (Option 2). Our capex forecast for option 2 is \$24.7 million.

Given an absence of economically justified proactive programs to address the supply issues driving these complaints, we will need to maintain current levels of annual spend to address forecast complaints in the upcoming period in order to respond to the expected level of quality of supply related customer complaints and maintain functional compliance with the EDCoP limits.

Our Revised Proposal is a continuation of our current BAU program at the current rate after accounting for escalation. We have provided further evidence of recent costs for reactive work – see supporting document Quality of Supply Business Case.

5.14.4.3. Relay replacement for voltage compliance

The voltage regulator relay replacement program is a minor proactive program (as opposed to the BAU reactive program above) aimed at addressing voltage performance issues. We have already received internal approval, and this program is underway. Delays have pushed some of the expenditure into the next 2026-31 program. Our capex forecast of \$3.2 million is the portion that will be carried over to the 2026-31 period.

5.15. Non-network expenditure

5.15.1. Our Initial Proposal

AusNet proposed a gross non-network capex forecast of \$322 million. This increase reflected a strategic program to reset our depot network, upgrade critical facilities, modernise operational infrastructure, and ensure we have the fleet and equipment needed to deliver services efficiently. The uplift in comparison to the current period spend was primarily driven by depot replacements and refurbishments, the transition to Zinfra as our service delivery partner from 1 August 2025, and the planned electrification of 70% of our light vehicle fleet at end of life.

Further detail from our Initial Proposal by program can be found below:

Fleet and plant – \$144 million

- Following the transition to Zinfra as our service delivery partner, we will replace the existing AusNet-owned fleet and acquire additional vehicles and plant to support service delivery. As part of this program, we plan to transition 70% of light vehicles to electric vehicles by 2031, delivering environmental benefits and reducing operating costs over time.

Strategic depot reset program – \$118 million

- A multi-period program to replace and refurbish several depots which underpins our long-term depot strategy. After years of low investment, this initiative is essential to maintain compliance with workplace standards, improve staff safety, and create conditions that encourage retention and are critical for delivering our capital program. Upgraded depots will also strengthen our ability to respond to outages and storm events in regional communities and reduce costly reactive maintenance, generating savings over future regulatory periods.

Business-as-usual building expenditure – \$20 million

- This allocation covers ongoing maintenance and minor upgrades to existing facilities to ensure they remain fit for purpose.

Capitalised leases - \$20 million

- This amount relates to leases renewals for our offices and depots.

South Morang training facility – \$14 million

- Investment in the South Morang training facility to refurbish and modernise our training infrastructure to support workforce capability and compliance. This facility is central to ensuring our teams are equipped with the skills and resources needed to operate safely and efficiently in a changing and growing energy environment.

Tools and general equipment – \$5 million

- This allocation ensures our teams have the tools and equipment required to perform their roles safely and efficiently. While modest compared to other streams, this investment is essential for day-to-day operations and maintaining service quality.

Control room refurbishment – \$2 million

- Modernising our control room is critical to meeting operational and compliance requirements. This investment will improve system reliability, enhance outage management, and support the integration of new technologies, ensuring we can continue to deliver safe and reliable services to customers.

5.15.2. Draft Decision

The AER accepted \$120.5 million of the \$173.7 million proposed for property, which included the full acceptance of:

- Business-as-usual building expenditure (\$20.3 million)
- Capitalised leases (\$19.6 million)
- Control room refurbishment (\$2.4 million)
- Other non-network (\$4.5 million).

The following programs and projects were not accepted in full or rejected:

- **Strategic depot reset program (\$49.2 million)** was only approved for depots that showed as NPV positive for all sensitivity analyses, the AER noted the heavy reliance on speculative future land sale benefits drove a lot of the outcomes. In parallel the AER indicated that land price inputs were based on market prices, not actual sales data and a uniform 3% growth rate was applied across all sites.
- **South Morang Training facility (\$0 million)** was not accepted due to the risk modelling being considered flawed by the overstatement of the delay risk and the timing considered unrealistic. Additionally, the AER noted a limited options analysis (e.g., interstate training alternatives not explored fully or a mix of both). The AER has invited us to provide more detailed modelling regarding the risk of each option, and that we should explore additional options such as interstate training or a mix of interstate and local training in the Revised Proposal.
- **Fleet (\$88 million).** The AER accepted \$88.0 million of the \$144.2 million proposed due to our model assuming a lease cost escalation but no escalation for purchase prices and double counting of some plant and equipment assets. In parallel our fleet electrification program was reduced to reflect a cost neutral approach. The AER

noted it would expect this type of program to have a standalone business case setting out the need and justification, the options considered and the reasoning for the preferred option.

5.15.3. Addressing the AER's Draft Decision

We have accepted the draft decision on the strategic depot reset program; we acknowledge the AER's concerns around the dependency of our land valuation driving outcomes on the two depots that were not accepted by the AER.

We have repropoed the South Morang Training Facility including more robust option analysis to reflect realistic risk and timing assumptions with an economic model. This includes:

- Recalculating the risk modelling based on the FTE shortfall that will occur without the proposed redevelopment option
- Updated modelling to better reflect the costs and benefits of other options, e.g., interstate training
- Providing clearer cost-benefit analysis and timing justification.

We have also accepted the AER's draft decision for control room refurbishment, Flinders St capitalised leases and business-as-usual building expenditure. The FWP lease is being repropoed to reflect a revised floor coverage and expansion of our head office.

We have also updated our fleet capex requirements to reflect more recent and accurate information on fleet requirements and costs, following the Zinfra transition in August 2025. As part of our updated modelling, we have addressed the AER's concerns by:

- Consolidating our fleet economic analysis.
- Ensuring there is no double counting and biases towards certain options.
- Providing a business case for the entire fleet program.
- Adopting electrification only when cost effective to transition.

5.15.4. Revised Proposal

The below table summarises our proposed gross non-network expenditure for the 2026-31 regulatory period. Consistent with our Initial Proposal we are expecting an increase in this capex category compared to the current regulatory period. Increases in our fleet expenditure requirements have been offset by a reduction in our total property costs. As noted above, we have accepted \$121 million of the AER's Draft Decision.

Table 5-51: Non-network expenditure summary (\$m, real 2025-26)

Program	Initial Proposal	Draft Decision	Revised Proposal
Fleet and plant	144.2	88.0	173.5
Property	173.7	120.5	145.7
Other	4.5	4.5	4.5
Total	322.4	213.0	323.7

Note: Fleet includes 4 Emergency Response Vehicles which have been approved as part of the Resilience program totalling \$1.1 million

Source: AusNet

5.15.4.1. Fleet and plant

To support our revised fleet forecast and address the AER's expectations regarding supporting documentation, we have provided a business case to support the model and overall fleet expenditure. This can be found as a supporting document 'ASD – AusNet – Fleet and plant business case – Dec 2025' and the accompanying economic model 'ASD – AusNet – Fleet and plant NPV model – Dec 2025'.

Key changes to our fleet forecasting model include:

- Re-designed our model to ensure we treat buy and lease decisions on a consistent basis. Key model improvements and assumptions are set out in Appendix A in the business case under table 12 in detail and below at a high level.
- Applied a technology agnostic (electric/hybrid/internal combustion) approach to identify the lowest whole-of-life cost for the relevant asset class and duty. We purposefully do not take into account the value of emissions reductions to ensure we identify the lowest cost approach for our customers in this case.
- Draw on more accurate data on fleet running costs, reflecting the actual costs of operating our fleet, which is now available to us following the transition to Zinfra in August 2025.

Further information on the modelling improvements and the basis for key inputs is provided below.

Table 5-52: Key NPV modelling improvements summary

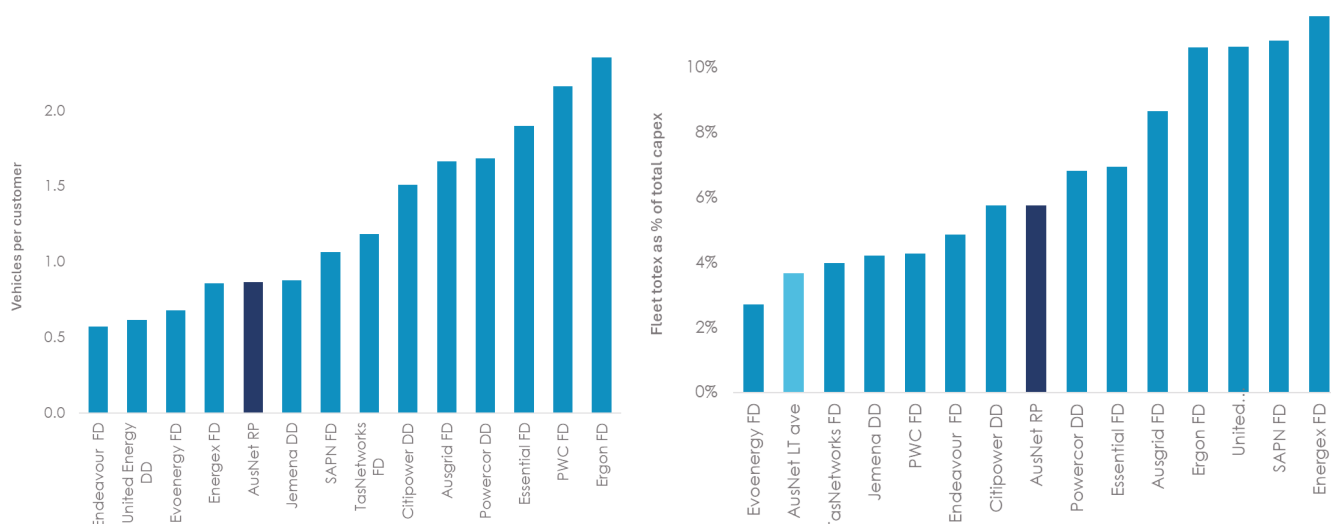
Modelling element	Overview of change in Revised Proposal
Replacement cost	Replacement capex now uses recent supplier quotes for most sub-types, aligning with market prices and eliminating pricing bias
Cost of leases	Lease costs now use current third-party quotes, ensuring consistent buy/lease comparisons with shared cost base and escalation assumptions.
Growth in fleet	Growth is modelled bottom-up using specific additional vehicles by class to meet forecast programs and new 2026–31 requirements.
Scope of fleet modelled	Model now reflects the unified fleet as of 1 July 2025, consolidating Downer assets and updating for actual AusNet ownership
Running costs	Running costs now use AusNet records and lease quote differences, making assumptions more evidence-based and transparent
Lease recognition and regulatory treatment	Leases now treated as ROU assets under AASB 16, ensuring consistent 40-year buy/lease comparisons using regulatory WACC
Terminal values	Terminal values are now included for owned vehicles and ROU balances at year 40, ensuring accurate residual value treatment and cost comparison
Double counting	NPV model rebuilt with checks against unique identifiers (e.g., registration numbers) to eliminate duplicate entries

Source: AusNet

To confirm that our fleet size is reasonable in the context of the work it supports we benchmarked our fleet size and costs against other DNSPs using publicly available data from recent proposals and AER decisions. This analysis seeks to check whether AusNet's fleet is reasonable in terms of size and relative cost.

Whilst our revised proposal fleet expenditure is above current period spend, it is broadly similar with current spending levels of peers, in particularly other rural networks that own their fleet. This is indicative of the reasonableness, prudence and efficiency of our proposed fleet spend. The below highlights two of the metrics where AusNet benchmarks in line or lower than the DNSP average.

Figure 5-32: AusNet benchmarking comparison vehicles per customer and fleet totex as % of total capex



Source: AusNet

5.15.4.1.1. Option analysis

We considered further options as part of our revised proposal these include:

- **Option 1 – Lease only** is simple to implement and with smooth, predictable cash flows, but gives up some control over specs, maintenance and data visibility.
- **Option 2 – Buy over time** gives strong control over specs and standardisation with strong data visibility, but is less flexible, can be complex to implement (partly due to volume) and involves lumpy cash outlays.
- **Option 3 – Hybrid (preferred)** brings the best of both options 1 and 2: control where it matters (heavy, specialised) and flexibility and optionality where it helps (e.g., light fleet & spec control, availability risk).

Our recommended option is Option 3 Hybrid, which delivers the lowest total present value cost over the assessment period, while also scoring strongest on the qualitative assessment as found in our business case.

By adopting a hybrid stance, Option 3 permits optimising the sourcing approach by asset class and duty, where high value and highly customised long-life assets are bought outright for AusNet to own and manage, while lower value and less complex assets can be leased and replaced more regularly as needs change. This includes the option to move to alternative fuel technologies (EV/PHEV/ICE) where it makes economic sense to do so.

We also note that we have absorbed any extra opex requirements from our fleet program and have dropped a step change in relation to this as an affordability measure.

Table 5-53: Fleet and plant costs included in Revised Proposal (\$m, real 2025-26)

(\$m, 2025-26)	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Fleet and plant	35.3	47.4	30.2	10.4	49.1	172.4

Note: above value does not include 4 Emergency Response Vehicles which have been approved as part of the Resilience program totalling \$1.1 million

Source: AusNet

5.15.4.2. Strategic depot reset program

We accept the AER's draft decision on the strategic depot reset program expenditure totalling \$49.2 million.

5.15.4.3. BAU building expenditure

We accept the AER's Draft Decision on BAU building expenditure totalling \$20.3 million.

5.15.4.4. South Morang training facility

Our costs for this project are unchanged from the Initial Proposal. However, we have undertaken further, more robust risk modelling and considered alternative options to address the AER's concerns.

5.15.4.4.1. Risk modelling

We have undertaken revised risk modelling to more accurately model the network risk costs we will face in future regulatory periods, should a shortfall of line workers eventuate.

This analysis shows a growing shortfall in line worker supply from 2032 onwards – our proposed training facility is essential to close this gap and maintain delivery capability for critical programs.

We have taken the following steps to determine line worker requirements and projected shortfall.

Table 5-54: Line worker workforce analysis – key steps

Step	Overview of change in Revised Proposal
Forecast Demand	Mapped deliverability planning data to relevant capex categories. Calculated average cost per FTE and extrapolated demand for 2026–31 and 2031–36 periods.
Assess Current Supply	Used Victorian workforce age profile data. Identified AusNet delivery partner line workers and scaled to reflect actual AusNet workforce.
Model Future Supply	Estimated retirements over the next 10 years based on age profile. Projected remaining workforce after retirements.
Training Capacity Scenarios	Without new facility apprentice intake is capped at 25 per year. With new facility intake this increases to 40 per year from 2031, supporting future demand.
Outcome	Analysis shows a growing shortfall in line worker supply from 2032 onwards. Proposed training facility is essential to close this gap and maintain delivery capability for critical programs.

Source: AusNet

The above allows us to then calculate the amount of shortage we will have in line workers over a 10- year period; we see these shortfalls primarily eventuate over the subsequent, 2031-36 regulatory period:

Table 5-55: Line worker shortfall by year in 2031-36 regulatory period

Year	2031-32	2032-33	2033-34	2034-35	2035-36
Without facility					
Total demand	605	643	658	682	709
Total supply	609	616	626	635	639
FTE shortfall	4	-27	-32	-47	-70

Source: AusNet

We have assumed that the amount of FTE continues at the same amount that is presented in 2035-36 over the assessment period, this is based on the number of FTEs required to deliver augmentation works, the average augmentation program dollar amount per line worker on our network equates to \$1.8 million.

Combined with the shortfall amounts shown above, this translates to the following estimate of augex deferrals we expect to eventuate without the proposed facility – which sums to \$316 million over the 2031-3 regulatory period.

Table 5-56: Estimated capex deferral due to line worker shortfall in 2031-36 regulatory period (\$m, 2025-26)

Year	2031-32	2032-33	2033-34	2034-35	2035-36
Capex not delivered due to shortfall	0	48	57	85	126

Source: AusNet

To quantify the network risk impact of this deferred spend, we determined an average network risk value per million dollars of augmentation capex deferred by dividing the following two amounts:

- The average annual energy-at-risk for all 22kV and 66kV augmentation business case proposed in the 2026-31 regulatory period. This acts as a proxy for the energy at risk we expect that we will need to manage during the 2031-36 regulatory period, through network upgrade project equal to \$109 million.
- The average annual augmentation capex for the same preferred options over the 2026-31 period equal to \$14 million.

Programs relating to REFCL and summer/winter readiness were excluded from both calculations.

Applying the above approach results in average supply risk per \$1 million of deferred augmentation capex of \$7.7 million. Applying this rate to the estimated capex deferral shown above yields total 2031-36 energy at risk of \$2,443 million.

Table 5-57: Network risk impacts of lines worker shortfall in 2031-36 regulatory period (\$m, 2025-26)

Year	2031-32	2032-33	2033-34	2034-35	2035-36
Network impact	0	373	440	658	972

Source: AusNet

We consider the above is a more robust calculation of network risk impacts of lines worker shortages, compared to the Wollert zone substation project deferral included in our initial proposal analysis, as it:

- Is grounded in analysis of lines worker demand and supply, and the link between lines worker availability and augex project delivery
- Relies on the robust network analysis underpinning our 2026-31 augex proposal to determine network risk impacts, which is considered a reasonable proxy for these types of impacts during the subsequent regulatory period

For future years in the assessment period (i.e. post 2036), we have held the 2035-36 value constant across the options that model this as a benefit (interstate training and redevelopment of the facility).

5.15.4.4.2. 3rd party training and other alternative options

We have considered additional options including training in interstate facilities and assessed other options which we deemed unrealistic, cost prohibitive or well outside AusNet's strategic requirements.

We maintain that interstate training is not a viable alternative to redeveloping the South Morang facility. Limited capacity at interstate facilities, combined with rising demand for line workers across the NEM, would lead to delays in training and apprenticeship progression, increasing project delay risk.

Every other state is entering a major growth phase, driving up demand for skilled workers and training resources. NSW training centres are facing capacity constraints and will likely prioritise NSW trainees over interstate candidates such as those from Victoria.

Further, VESI requirements mandate practical training on Victorian assets, adding lead time for interstate or overseas-trained workers which we cannot quantify, these additional risks include:

- **Apprenticeship compliance:** Programs and ETU onboarding requirements are difficult to meet interstate.
- **Scheduling flexibility:** Interstate training limits rescheduling options and increases costs.
- **Course alignment:** Victorian Certificate III requires modified core and elective units not delivered elsewhere.
- **Standards and asset familiarity:** Victorian build standards and AusNet-specific knowledge necessitate local training.

Collectively, these constraints make interstate training a suboptimal and unviable option for meeting AusNet's workforce requirements.

Notwithstanding the above risks associated with interstate training, we have assessed this option in our updated economic model. As such the options considered in the Revised Proposal include:

- **Option BAU** – No investment in training facility;
- **Option 1** – Redevelopment of the South Morang facility to create a modern training facility owned and managed by AusNet;
- **Option 2** - Refurbishment of the current South Morang facility to enable training but no extra capacity; and
- **Option 3** – Interstate training for apprentice line workers

Further detail can be found in the accompanying economic model 'ASD – AusNet - South Morang training facility economic model – Dec 2025 - CONF'.

For the cost of training, we have assumed:

- That the cost of existing workforce training is the same across all options
- For interstate training for apprentices the amount required is assumed to be 125% higher than training undertaken in Victoria. This amount, which has been refined since our initial proposal (15% higher), is due to flights, accommodation and other expenses incurred from such activity.

5.15.4.4.3. Risk assessment

AusNet has also considered the risk and consequences for each relevant option using the following likelihood criteria, risk categories and threat rating matrix which encompasses AusNet's enterprise risk management framework.

Figure 5-33: Risk rating matrix

		Consequence				
		1	2	3	4	5
Likelihood	Almost Certain	C	C	B	A	A
	Likely	D	C	B	B	A
	Possible	E	D	C	B	A
	Unlikely	E	D	D	C	B
	Rare	E	E	D	C	C

Source: AusNet

Action per residual risk rating

- A – Take immediate action to treat risk to acceptable level
- B – Take action to treat risk to aim for acceptable level
- C – Implement cost-effective additional treatments where appropriate
- D – Monitor and review periodically
- E – Manage per identified controls

Risk assessment – BAU

The BAU option involves no capital investment and relies on existing training programs that are already at capacity. This creates significant risks:

- **Workforce shortfall:** Revised modelling shows a growing shortage of line workers from 2032 onwards, with up to 70 FTE shortfall by 2035–36. This would defer critical augmentation programs worth \$316 million and expose the network to an estimated \$2.4 billion in risk impact.
- **Competency:** Limited intake (25 apprentices per year) will delay training and reduce workforce proficiency, increasing reliability and resilience risks.

- **Third-party dependence:** Continued reliance on external providers compromises scheduling flexibility, price predictability, and compliance with VESI standards.

Overall, BAU presents an untenable risk level for AusNet's network and customers.

Table 5-58: Risk assessment - BAU

Outcome	Likelihood	Consequence	Risk category
Safety	Possible	3	C
Environment	Unlikely	1	E
Reputation	Likely	3	B
Customer	Likely	3	B
Regulatory	Likely	3	C
People	Almost certain	4	A
Financial	Likely	3	B
Average	Likely	3	B

Source: AusNet

Risk assessment – Option 1 Redevelop

Redeveloping South Morang addresses these risks by:

- Increasing apprentice intake to 40 per year from 2032, closing the projected workforce gap.
- Providing fit-for-purpose facilities that meet VESI compliance and Victorian Certificate III requirements along with meeting our safety and workplace obligations.
- Reducing reliance on third parties and ensuring long-term capability for critical programs. This option aligns with industry best practice and regulatory precedent (e.g., AER's approval of Powercor's facility as part of the 2026-31 Draft Decision).

This option offers a NPV of **\$10,198 million** over the assessment period.

Table 5-59: Risk assessment – Option 1

Outcome	Likelihood	Consequence	Risk category
Safety	Rare	1	E
Environment	Unlikely	1	E
Reputation	Unlikely	1	E
Customer	Unlikely	1	E
Regulatory	Unlikely	1	E
People	Unlikely	2	D
Financial	Unlikely	1	E
Average	Unlikely	1	E

Source: AusNet

Risk assessment – Option 2 Refurbishment

Refurbishment offers ownership benefits and some flexibility but does not increase capacity beyond current limits. Apprentice intake remains capped at 25 per year, meaning the workforce shortfall and associated risks remain largely unchanged from BAU. While refurbishment reduces reliance on external providers, it does not address the critical gap in training throughput or capability. This option therefore only partially mitigates risk and fails to deliver long-term resilience.

Table 5-60: Risk assessment – Option 2

Outcome	Likelihood	Consequence	Risk category
Safety	Unlikely	3	D
Environment	Unlikely	1	E

Reputation	Likely	3	B
Customer	Likely	3	B
Regulatory	Likely	3	C
People	Almost certain	4	A
Financial	Likely	3	B
Average	Likely	3	B

Source: AusNet

Risk assessment – Option 3 Interstate

Interstate training was assessed in response to AER feedback but is not viable for several reasons:

- **Capacity constraints:** NSW and other states face their own growth pressures and will prioritise local trainees, leaving limited availability for Victorian apprentices.
- **Compliance risks:** VESI requirements mandate practical training on Victorian assets. Interstate programs do not deliver Victorian Certificate III electives or AusNet-specific standards, creating onboarding delays and compliance gaps.
- **Scheduling and cost:** Interstate reliance reduces flexibility for rescheduling and increases travel and accommodation costs, adding complexity to workforce planning.
- **Sector-Wide Demand:** Every state is entering a major growth phase, driving up demand for skilled workers and training resources, making interstate capacity increasingly scarce.

While this option has the same network risk benefits as assumed for Option 1, it introduces new operational and compliance risks, does not provide a sustainable solution and with a NPV of **\$10,195 million** offers lower net economic benefits than Option 1.

Table 5-61: Risk assessment – Option 3

Outcome	Likelihood	Consequence	Risk category
Safety	Rare	1	E
Environment	Unlikely	1	E
Reputation	Unlikely	1	E
Customer	Likely	2	C
Regulatory	Likely	2	C
People	Unlikely	2	D
Financial	Unlikely	2	D
Average	Unlikely	2	D

Source: AusNet

Conclusion

Redevelopment of South Morang is the only option that materially reduces workforce availability, financial, and customer risks while aligning with industry standards and regulatory precedent. As demonstrated in our revised proposal economic model, this option also offers greater net benefits than the other option that may mitigate network risks outlined above, being interstate training.

5.15.4.4.4. VESI Skills and Training Reference Committee (STRC)

We have also received support by the Victorian Electricity Supply Industry (VESI) for the re-development of AusNet's training facility; this is in line with similar facilities proposed in Victoria such as Powercor and CitiPower's training facility for the 2026-31 period.

The below written letter of support highlights the training facilities criticality and support within Victoria:

"We support AusNet recognising the importance of investing in workforce development and infrastructure. This project will not only strengthen AusNet's training capabilities but will also set a precedent for innovation and excellence across the industry. The VESI STRC is confident that this initiative will yield long-term benefits for AusNet, the industry and the broader community"

The full letter can be found at 'ASD – VESI – Letter of support for training facility – Dec 2025 – PUBLIC'.

5.15.4.4.5. Other DNSP facilities and decisions

The re-development of our own training facility will be in line with the practices of other distributors around Australia. These distributors in large do not rely on external spaces to facilitate their training as shown below.

Table 5-62: Owners of each distributor's training facility

Distributor	State	Facility
SA Power Networks	SA	Owned
TasNetworks	TAS	Owned
Western Power	WA	Owned
Power and Water Corporation	NT	Not Owned
Ergon Energy	QLD	Owned
Energex	QLD	Owned
Essential Energy	NSW	Owned
Ausgrid	NSW	Not owned
Endeavour Energy	NSW	Owned
Evoenergy	ACT	Not owned

Source: PAL BUS 8.02 - PUBLIC

Given Victoria's significant position in the electricity sector which is home to over 20% of Australia's electricity distribution workforce, it to date remains as the only state without a functional, distributor-owned training facility across all the Victorian DNSPs. This is particularly concerning given Victoria's unique role as the sole provider of the comprehensive Certificate III VESI apprenticeship program and over-reliance on existing training providers which are at full capacity. As shown in the table above, the majority of regional DNSPs in the NEM have their own training facility and with the AER's approval of Powercor's facility, AusNet risks being one of the only regional DNSPs to be without one unless sufficient funding is approved in the final decision.

As part of the AER's Draft Decision for the Victorian DNSPs for 2026-31 regulatory period the AER accepted Powercor's proposal for capital costs relating to a new training facility, this was justified based on a risk criteria comparison among options which included 'do nothing', build a new facility and thirdly build a premium new facility. This expenditure was approved without supporting economic analysis.

5.15.4.4.6. Preferred option

The initial proposal analysis included total project costs for both Transmission and Distribution but only accounted for Distribution benefits. This understated the net benefits, as Transmission delivery benefits were not quantified.

In our revised proposal, we used a 40-year assessment period to assess the options, consistent with the standard life applying to buildings. Over this assessment period the preferred option remains the redevelopment of the South Morang facility. This option offers adaptable, practical training arrangements to meet long-term network demands and long term lower costs over 40 years. Importantly, no land acquisition is required, reducing cost variability compared to sourcing a new site and relying on interstate training to fulfil training requirements.

Overall, a Victorian purpose-built training facility aligns with industry and workplace standards and is supported by more robust network risk and economic analysis than our initial proposal. The cost estimates below reflect the amount provided in the Initial Proposal and subsequent information requests.

Table 5-63: Training facility expenditure included in Revised Proposal

(\$m, 2025-26)	2026-27	2027-28	2028-29	2029-30	2030-31	Total
South Morang training facility	0.0	0.0	13.5	0.0	0.0	13.5

Source: AusNet

5.15.4.5. CBD and Southbank office costs

The AER's Draft Decision accepted the proposal for our Control Room refurbishment and CBD and Southbank offices lease renewals.

5.15.4.5.1. CBD Office

Lease

We accept the AER's Draft Decision on the CBD office lease renewal totalling \$7.5 million.

Refurbishment

We accept the AER's Draft Decision on the CEOT in-situ refurbishment totalling \$2.4 million.

We have also included an amount of \$3.0 million in refurbishment costs for the CBD offices, required due to current condition. The cost estimate of this work is based on standard industry benchmark of \$1,500/sqm to refurbish existing spaces.

5.15.4.5.2. Southbank Office

Lease

We have obtained an updated quote from our Southbank landlord⁸⁰ for leasing and incorporated the updated cost into our Revised Proposal. To make sure we have access to the most competitive deal we have engaged [C-I-C] the market leading agency to negotiate with our landlords and ensure we are getting the most attractive rates. As [C-I-C] work across many large corporates, landlords have an incentive to offer competitive rates.

We have also:

- Reduced the allocation of the lease to the distribution network from 45% to 35% to reflect current headcount splits across line of business, reducing costs for distribution customers; and
- Sought to expand the Southbank tenancy to include two extra floors. 70% of an additional floor (or 35% of the two floors) is allocated to distribution, taking the distribution businesses' desk allocation in the CBD from 308 to 326 (assuming a reversion to space per desk to 12.5 sqm, consistent with benchmarks for similar firms, which can house the 490 CBD distribution employees 67% of the time).

The net impact of these changes is to increase costs by \$1.8 million (capex) over the regulatory period.

The lease term for the two additional floors will be 8.5 years to align the expiry with the 5 year renewal for the existing floors in the Southbank Office. This provides more flexibility in future to assess alternative accommodation options. Importantly, while a longer lease term increases capex in the 2026-31 regulatory period all else equal, the revenue recovery from customers is smoothed as the lease is depreciated over the 8.5 years. This reduces the annual cost to customers.

We require additional desk space in FWP as current work patterns are challenging the capacity of our offices on peak days. Work patterns have significantly changed over the last 5 years in Melbourne in particular, as the COVID pandemic has had a sustained impact. Prior to COVID it was atypical for CBD located staff members to work from home, whereas after 2 years of on and off enforced lockdowns and a Victorian Government recommendation to work from home, work patterns changed. Due to this change, AusNet introduced a hot desking policy in 2021. This resulted in a reduction in desks from >1 per employee to around 0.63 per employee today.

While customers have benefitted from low costs, our current offices are not fit for purpose, and despite taking steps to maximise utilisation of existing office space we have exhausted all options and the current office space is below industry standard and is negatively impacting staff morale. Over time this will result in retention issues and compromise our ability to provide safe, reliable and secure services for our customers.

There is an increasing number of employees wanting to work from the office for an increasing number of days per week, particularly on Tuesdays, Wednesdays and Thursdays. During these mid-weekdays, occupancy typically exceeds 63% (i.e. more than the number of available desks), resulting on staff working on communal tables without proper monitor set ups on each of these days.

We have taken steps to increase the number of desks available by replacing collaboration areas on the floors with additional desk banks. For example, 49 additional desks were added to the distribution team's desk space across 2024-2025. This has resulted in a high desk density of around 10.9 sqm which is comparable with standard benchmarks for call centres rather than corporate offices. This is lower than our target density of around 12.5 sqm. This can be compared to the Building Code of Australia's recommend minimum of about 10 sqm per person for

⁸⁰ ASD - AusNet - Request for Financial Proposal Southbank lease - Sep 2025 - CONF

office space, with a typical range of around 12 – 14 sqm recommended for most organisations, and higher than this (14 sqm plus) for some professions such as law and consulting.

Results of employee engagement surveys display frustration with the current desk shortage on key days, see supporting document 'ASD - AusNet - Vibe verbatim comments on desk availability - March 2025 – CONF'. We need to ensure that we are providing an office environment that is fit for purpose and does not negatively impact staff retention.

In line with our general Occupational Health & Safety obligations, we have reviewed whether the current office layout provides a safe and appropriate environment for staff. Existing workstation spacing is considered as requiring improvement to minimise the hazards associated with cramped layouts, shared hot desking creating congestion and insufficient break out areas. Increasing the space allocation per desk to be more in line with similar workplaces is a control which helps minimise these risks.

In considering the need for additional floor space we have also had regard to the Victorian Government's election promise to mandate the right to work from home for office workers should they be re-elected in 2026. Even if the Victorian Government election commitment occurs, we consider securing two extra floors is a prudent decision for the following reasons:

- The footprint we are seeking only provides desk capacity 67% of the time, which assumes employees continue to work from home; and
- Consistent with common working patterns, even if all staff do work from home 2 days a week, Tuesday, Wednesday and Thursday are likely to remain the busiest days in which people want to come into the office. Even with the Victorian Government mandate in place we expect demand close to 84% on these days (accounting for annual and personal leave, part time work and the use of non-CBD locations). Therefore, the expansion is conservative.

Our proposal is modest and takes us back in line with industry benchmarks and continues hot desking (with continued expected desk shortages on peak days).

Fitout and refurbishment

We have included \$3.0 million of refurbishment costs and \$2.5 million of fit out costs associated with the new floorspace in our Revised Proposal.

The cost estimate of this work is based on standard industry benchmark of \$1,500/sqm to refurbish existing spaces and \$3,000/ sqm to fit out new spaces.

The full amount of CBD and Southbank costs claimed are below.

Table 5-64: CBD and Southbank office costs

(\$m, 2025-26)	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Leasing costs	4.4	7.5	0.0	0.0	9.2	21.1
Fitout costs	2.8	2.7	0.0	1.5	1.5	8.5

Note: Fitout line item does not include CEOT in-situ refurbishment

Source: AusNet

5.15.4.6. Capitalised leases

We acknowledged the AER's Draft Decision as appropriate for what we proposed in the Initial Proposal, as above we have updated the amount in our capitalised leases to recognise new lease information and additional leases as part of bringing our offices together. This has resulted in a forecast of all capitalised leases for 2026-31 which is \$2.9 million greater than the Draft Decision.

Table 5-65: Total capitalised leases included in Revised Proposal

(\$m, 2025-26)	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Capitalised leases	4.4	7.5	0.0	0.4	10.7	23.2

Source: AusNet

5.15.4.7. Other non-network

We accept the AER's Draft Decision on other non-network expenditure totalling \$4.5 million.

5.15.4.8. Supporting documentation

We have included the following documents to support non-network expenditure:

- ASD - VESI - Letter of support for training facility - Dec 2025 - PUBLIC
- ASD - AusNet - Fleet & plant business case - Dec 2025 - PUBLIC
- ASD - AusNet - Fleet and plant - Lease & replacement quotes – CONF
- ASD - AusNet - South Morang training facility economic model – Dec 2025 - CONF
- ASD - Head Office Lease calculation - 011225 - CONFIDENTIAL
- ASD - AusNet Distribution - Capitalised leases remaining lives - 011225 – CONFIDENTIAL
- ASD - AusNet - Request for Financial Proposal Southbank lease - Sep 2025 - CONF
- ASD - AusNet - Navigating Melbourne's office market, 22 May 2025 - CONF
- ASD - AusNet - Vibe verbatim comments on desk availability - March 2025 - CONF

5.16. Contingent Projects

Since lodging our Initial Proposal, AusNet has continued to monitor customer connection activity, demand growth and network utilisation and capacity constraints across key parts of the distribution network. Through this process, two potential augmentation projects have developed to a point where they meet the threshold for treatment as contingent projects under clause 6.6A.1 of the NER. Updated planning has identified credible scenarios where demand at these two locations could exceed the capacity of the relevant transformer and line assets, driven primarily by the development of current and potential large load connection projects. However, given uncertainty associated with the progress of these projects at these locations it means that there is some uncertainty around whether the relevant investment will become economic in this next regulatory period.

Accordingly, we are proposing two contingent projects in this Revised Proposal to accommodate potential large new loads on separate parts of our distribution network. This ensures that customers are not required to fund speculative capex, while maintaining the ability to efficiently and prudently respond to material load growth and customer-driven investments.

5.16.1. Cranbourne Zone Substation

Cranbourne (**CRE**) zone substation is a summer-peaking ZSS supplying a rapidly growing part of Melbourne's southeast growth corridor. The substation currently consists of two 66/22kV, 20/33 MVA transformers supplying two 22kV buses and six 22kV feeder circuits. Under an existing customer-driven project, an additional 22kV feeder (**CRE24**) is expected to be commissioned by Q1 2026. Once that work is completed, only one spare 22kV feeder circuit breaker will remain. Under our 2026–31 Revised Proposal, this breaker has been allocated to a new, second 22 kV feeder (**CRE34**), scheduled for connection in FY29.

5.16.1.1.1. Background

CRE supplies approximately 26,600 residential, commercial, industrial and agricultural customers and sits within a broader network of high growth suburbs also served by Clyde North (**CLN**), Hampton Park (**HPK**), Berwick North (**BWN**) and Officer (**OFR**) zone substations. Several Precinct Structure Plans (**PSPs**) and Development Plans have been published to guide the development of new urban areas and growth precincts in the Cranbourne supply area:

- Cranbourne East PSP⁸¹ – Mature, fully developed area
- Cranbourne North PSP⁸² – Mature, fully developed area
- Croskell Employment PSP⁸³ – Mixed residential and commercial development, including both brownfield and greenfield sites

⁸¹ Refer: [Cranbourne East Precinct Structure Plan - VPA](#)

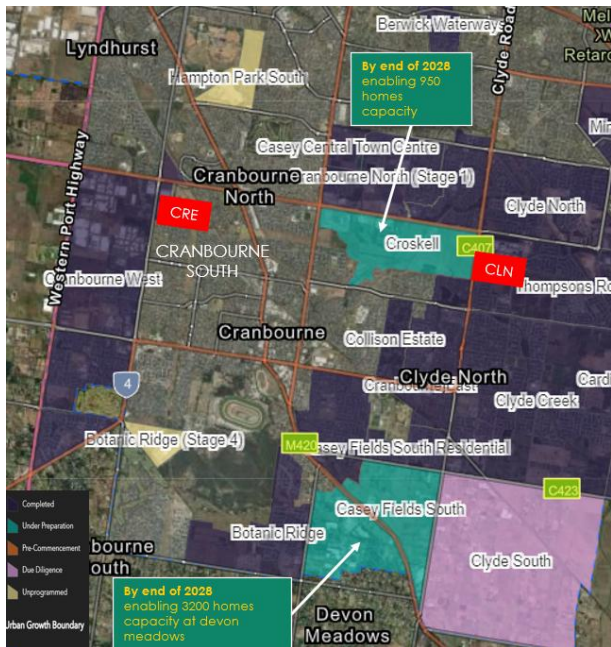
⁸² Refer: [Cranbourne North \(Stage 2\) Precinct Structure Plan - VPA](#)

⁸³ Refer: [Croskell \(Employment\) - VPA](#)

- Botanic Ridge Development Plan (stage 4)⁸⁴ – Rezoned from agricultural to greenfield residential development
- Hampton Park South – Part of the Hampton Park Hill Development Plan Precinct reflects the need of future waste and resource recovery activities, as well as employment.

Figure 5-34 illustrates the scale of development served by the CRE and adjacent CLN zone substation networks.

Figure 5-34: Cranbourne and Clyde North zone substation Supply area



Source: [VPA Green Field Planning](#) edited by AusNet

5.16.1.1.2. Network Constraints and Solutions

CRE's recorded 2024/25 summer maximum demand was 62.2 MVA, and the substation is experiencing an average demand growth rate of around 2% per annum over the next decade. Forecasts indicate that the POE10 demand at CLN ZSS alone may reach 89.6 MVA by 2030, increasing reliance on CRE to offload some CLN feeders as part of balancing load across the local network. Updated forecasts show that CRE's POE10 demand is expected to reach 80 MVA by 2025/26 and 90.7 MVA by 2030/31, which is nearing the summer cycling rating of the existing transformer bank (96.4MVA) under moderate to high probability scenarios.

The constrained 22 kV network in the area, combined with the limited spare circuit breaker capacity and growing industrial demand is increasing the risk of unserved energy and limiting the ability to transfer or offload load to adjacent substations. This potential constraint affects AusNet's ability to maintain capacity and provide reliable supply to customers and will be exacerbated with any new customers requiring connections under the NER.

Currently, 12 large load connections amounting to approximately 23 MVA have applied for connection to CRE zone substation feeders. These loads have been considered in our demand forecast and proposed new CRE34 feeder, however they indicate the scale of current and future large load connections in the network.

To respond to this potential demand need, in the case where the future state of the CRE distribution network differs materially from our forecast, we have identified that a third 20/33 MVA transformer and associated 22kV switchroom may be required at CRE to accommodate load growth. The additional transformer would enable transfer of load from constrained neighbouring substations and maintain supply reliability during peak periods and contingencies.

Accordingly, AusNet is proposing a contingent project which involves installation of a third transformer, switch room and busbar, together with a new 22kV distribution feeder at the CRE zone substation. The estimated cost of the project is \$53.9 million (\$2024) inclusive of direct + P50 risk + indirect costs.

5.16.2. Wodonga-Barnawartha Area Augmentation

[C-I-C]

at
Barnawartha zone substation (**BWA ZSS**), which is currently in the preliminary application stage. BWA is supplied by

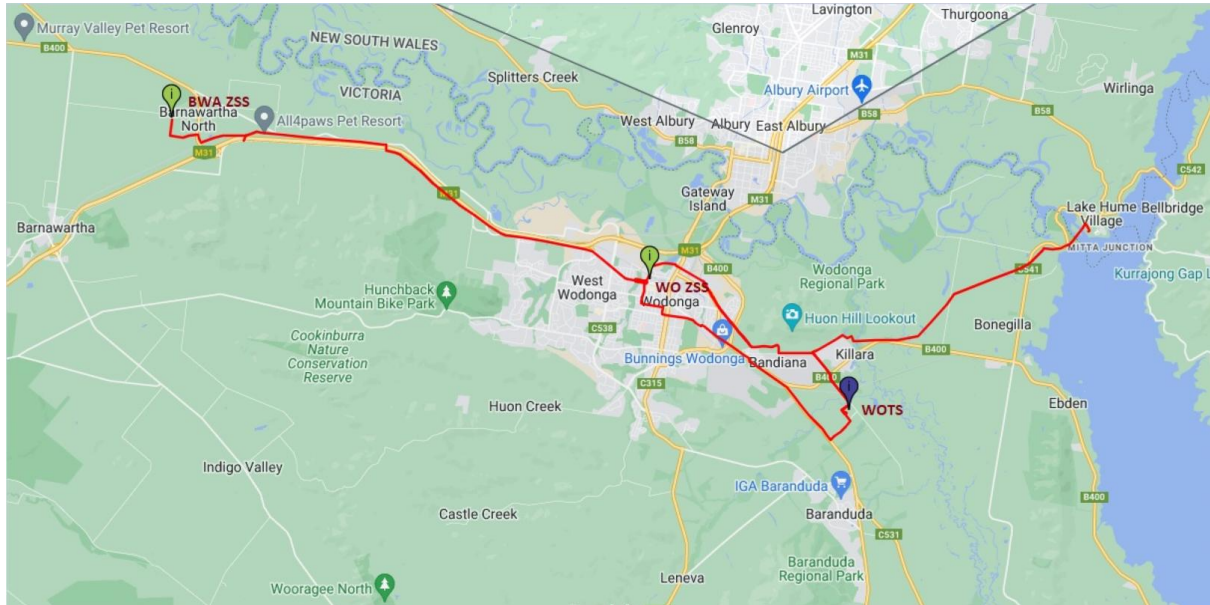
⁸⁴ Refer: [Botanic Ridge Stage 1 and 4 \(Development Plan\)](#) | City of Casey

Wodonga Terminal Station (**WOTS**) sub-transmission (66kV) system. The WOTS sub-transmission system was originally planned, built, and maintained to meet the rural load in that area and is not strong enough to connect this significantly large load.

5.16.2.1.1. Background

WOTS is the main source of supply for a significant part of north-eastern Victoria. The supply is via two 330/66/22 kV three-winding transformers with a nominal rating of 75 MVA each. WOTS supplies Wodonga centrally as well as the area from Rutherglen in the west to Corryong in the east. Wodonga zone substation (**WO ZSS**) is connected to WOTS via two 66 kV feeders connected to 66 kV bus 1 and 2 of WOTS for improved reliability.

Figure 5-35: Map showing the Wodonga - Barnawartha sub-transmission network



Source: AusNet

As shown in the map above, the BWA ZSS is currently connected to WO ZSS via a single 66 kV feeder.

5.16.2.1.2. Network Constraints and Solutions

The WO-BWA 66kV radial feeder is 16.6 km long with a summer rating of 64.0 MVA and has a committed [C-I-C] currently in delivery phase to connect to the line. The BWA maximum load (PoE 50) is around 12 MW. It could accommodate an additional 30 MW of load with no network augmentation, totalling 42 MW of capacity at BWA ZSS, but the reliability will be low as there is only one line supplying BWA.

To accommodate the [C-I-C] the following network augmentations are required:

- 1) A third new 330/66/22 kV 75 MVA transformer at WOTS.
- 2) New 66 kV line between WOTS-BWA with 37/3.75 AAC conductor.

The third, new WOTS transformer, Augmentation (1), is treated as a connection asset as it is at the connection point between the transmission and distribution network. Therefore, should this investment proceed, its costs will be recovered outside of the EDPR process following a RIT process. As a result, the cost associated with this augmentation is excluded from the total cost of the contingent project.

Augmentation (2), new 66 kV line between WOTS-BWA, was included in our initial proposal connections capex forecast and accepted by the AER in its Draft Decision. AusNet accepts the AER's Draft Decision for this project and therefore it remains unchanged in our Revised Regulatory Proposal. The additional available capacity at BWA ZSS after Augmentations (1) and (2) is approximately 80 MW, making the total capacity at BWA ZSS of approximately 92 MW based on the current PoE 50 maximum demand forecast.

The data centre applicant has indicated that they are interested in increasing the capacity of their [C-I-C]. To increase the additional capacity at BWA ZSS beyond ~80 MW to facilitate the expansion of the data centre or any other load connection applicants, the following additional augmentations are required:

- 3) Potentially a fourth new 330/66/22 kV 75 MVA transformer at WOTS. Similar to Augmentation (1) this augmentation will be outside the EDPR process.
- 4) Upgrade low-capacity sections of the two existing 66 kV lines between WOTS-WO with 37/3.75 AAC conductor.
- 5) Second, new 66 kV line between WO-BWA with 37/3.75 AAC conductor.

At the completion of the above five Augmentations, approximately 120 MW of additional capacity will be available at BWA ZSS, totalling 132 MW of capacity, based on the current PoE 50 maximum demand forecast.

In summary, this contingent project includes Augmentations (4) and (5) only. The estimated cost of this contingent project is \$59.3M (2024 dollars, inclusive of Direct + P50 RISK + Indirect costs).

5.16.2.2. Trigger Events for Contingent Project

In developing trigger events for these contingent projects, we have drawn on AER's previous decisions approving contingent projects driven by large customer connections. Accordingly, the triggers proposed are:

- reasonably specific and capable of objective verification;
- tied to events outside of AusNet's control (customer connection process and RIT-D outcomes); and
- directly related to the need for the relevant augmentation.

5.16.2.2.1. CRE third transformer and 22kV distribution feeder

A trigger event will occur when all the following conditions are met:

- AusNet receives a connection application or applications for load(s) at CRE ZSS or it's associated feeders which results in forecast demand exceeding the N-rating (96.4 MVA) at the CRE ZSS during the 2026-31 regulatory control period.
- AusNet completes a RIT-D during the 2026-31 regulatory control period to address the identified need of maintaining a reliable supply of power to customers in the CRE ZSS coverage area where the preferred credible option demonstrates that network investment is required during the 2026-31 regulatory control period.
- The AER is satisfied that the proposed investment meets the requirements of the RIT-D.
- AusNet's Chief Executive Offer provides a commitment to proceed with the Project within the 2026-31 regulatory control period, subject to the AER amending AusNet's 2026-31 distribution determination pursuant to the NER. For verification, a letter from the CEO will be provided to the AER.

5.16.2.2.2. WOTS - BWA 66kv line augmentation

A trigger event will occur when all the following conditions are met:

- AusNet signs a connection agreement with the existing [C-I-C] applicant or any other load applicant(s) at BWA ZSS which results in forecast demand exceeding 92 MW at BWA ZSS during the 2026-31 regulatory control period.
- AusNet completes a RIT during the 2026-31 regulatory control period to address the identified need of maintaining a reliable supply of power to customers in the BWA ZSS coverage area where the preferred credible option demonstrates that network investment is required during the 2026-31 regulatory control period.
- The AER is satisfied that the proposed investment meets the requirements of the RIT.
- AusNet's Chief Executive Offer provides a commitment to proceed with the Project within the 2026-31 regulatory control period, subject to the AER amending AusNet's 2026-31 distribution determination pursuant to the NER. For verification, a letter from the CEO will be provided to the AER.

5.16.2.3. Compliance with NER

The proposed contingent projects satisfy the requirements of clause 6A.6.1 of the NER. The table below sets out our assessment against each element of the rules.

Table 5-66: AusNet assessment against each element of the rules

Requirements		Consideration
(a1)	Proposed contingent capital expenditure that is included in a regulatory proposal of a Distribution Network Service Provider must not	Our proposed contingent project does not include expenditure for restricted assets.

	include expenditure for a restricted asset, unless that Distribution Network Service Provider has submitted an exemption application with the regulatory proposal, which requests an asset exemption under clause 6.4B.1(a)(2) in respect of that asset or class of asset for the contingent project.	
(b)(1)	the proposed contingent project is reasonably required to be undertaken in order to achieve any of the capital expenditure objectives	The proposed contingent projects are required to: • meet or manage the expected demand for standard control services over the next regulatory period; and • maintain the quality, reliability and security of supply of standard control services.
(b)(2)(i)	the proposed contingent capital expenditure is not otherwise provided for (either in part or in whole) in the total of the forecast capital expenditure for the relevant regulatory control period which is accepted in accordance with clause 6.5.7(c) or substituted in accordance with clause 6.12.1(3)(ii) (as the case may be)	No expenditure to deliver the proposed contingent projects has been included in our regulatory proposal. The proposed projects are discrete and do not overlap with the other augmentation programs included in our proposal.
(b)(2)(ii)	the proposed contingent capital expenditure reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors, in the context of the proposed contingent project as described in the regulatory proposal	Our proposed contingent projects reflect the efficient costs (either based on unit rates or detailed estimation methods) to achieve the capital expenditure objectives and represent costs a prudent operator would incur based on realistic demand forecast and cost inputs as required in the capex criteria.
(b)(2)(iii)	the proposed contingent capital expenditure exceeds either \$30 million or 5% of the value of the annual revenue requirement for the relevant Distribution Network Service Provider for the first year of the relevant regulatory control period, whichever is the larger amount	Forecast capital expenditure to deliver the CRE and WOTS/ BWA contingent projects is \$53.9M and \$55M respectively. This exceeds the 5% of our annual revenue requirement in the first year of the next regulatory period which is approximately \$42M (which is more than \$30M).
(b)(3)	the proposed contingent project and the proposed contingent capital expenditure, as described or set out in the regulatory proposal, and the information provided in relation to these matters, complies with the relevant requirements of any relevant regulatory information instrument	There are no applicable requirements for contingent projects in any relevant regulatory information instrument.
(b)(4)	the trigger events in relation to the proposed contingent project which are proposed by the Distribution Network Service Provider in its regulatory proposal are appropriate	The trigger events we have proposed align with Rule 6.6A.1(c) (as outlined above) and are consistent with similar trigger events previously determined by the AER for distribution network services providers in similar circumstances.

Source: AusNet

5.17. Supporting Documentation

In addition to business cases, economic analysis and energy at risk models, we have provided the following documents to support our capex forecast:

- **Capex Project Supporting Document Map** maps each project and program listed in our SCS capex model to a business case, economic model and/or section of this Revised Proposal providing the justification information.
- **Growth corridor deliverability plans** to support our northern and southeastern growth corridor augex forecast.
- **Project cost estimating methodology** that describes our cost estimating approach.
- **Worley's independent review of cost estimates** that supports AusNet's cost estimate for the three new zone substation (Wollert, Beveridge and Pakenham South) and five station rebuilds (Watsonia refurbishment,

Thomastown stage 2 22kV upgrade, Traralgon stage 2 22kV switchboard upgrade, Newmerella refurbishment, and Kilmore South ZSS 22kV switch room replacement).

- **Distribution Network Planning Guidelines and Standards** (AMS 20-16) that supports our augex forecast.
- **Risk Assessment Methodology (AMS 01-09 and AMS 01-09-2)** which sets out our approach to assessing and quantifying risk in our repex economic assessments.
- **A report from The Mantua Group** assessing the accuracy and consistency of the Weibull methodology we have applied to derive our Revised Proposal probability of failure assumptions with the AER's *Industry Practice Guideline for Asset Replacement Planning*.
- **Bottom up cost estimates** for discrete and individual programs
- **Unit rates build up** for bulk programs
- **Top-down review report** that demonstrates how we have accounted for overlaps between programs.
- **Zinfra TOMSA and DOMSA Overhead and Support Costs** calculations underpinning the forecast support costs discussed in section 5.4.5.

6. Operating Expenditure

6.1. Key points

The key points in this chapter are:

- We are proposing operating and maintenance expenditure (opex) excluding debt-raising costs of \$1,606 million for SCS in the 2026-31 regulatory period.
 - 8% higher than that proposed in the AER's draft decision: and
 - 5% lower than that proposed in the Regulatory Proposal
- We have accepted aspects of the AER's draft decision, including the AER's alternative estimates for:
 - innovation fund allowance
 - adjustments to base year opex 2022-23
 - circuit length growth
 - the emergency backstop mechanism step change
- As invited by the AER we have provided more up to date information on other aspects of the draft decision including:
 - updating figures to include RY25 actuals for total opex, movement in provisions, DMIA, SaaS, GSL payments, innovation fund and corporate overheads
 - updated demand forecasts for our network
- We have provided additional information to address the AER's concerns on the following parts of our proposal:
 - Step changes relating to flexible services and non-network solutions, Digital, Early fault detection and Hazard tree program
- New information has led to the following updates to our forecast:
 - Additional step change proposals for three new regulatory requirements that have developed since the Draft Decision, being the rule change for Distribution Strategic Planning requirements, Corporations Act 2001 new sustainability reporting compliance and flexible trading arrangements.
- We consider we have provided the additional information required by the AER in its Draft Decision to justify the step changes we are proposing. Following the revised proposal, we will look to work with the AER to address any information it needs to ensure that we are able to deliver the best outcomes for our customers and:
 - Provide on ground community and customer support including during extreme events and storms
 - Operate and maintain our growing network efficiently
 - Respond appropriately to regulatory obligations imposed on our network.

6.2. Chapter structure

This chapter is structured as follows:

- Section 6.3 introduces our Revised Proposal opex;
- Section 6.4 describes the sufficiency of total opex;
- Section 6.5 considers our proposed base year expenditure;
- Section 6.6 outlines our proposed rate of change;
- Section 6.7 sets out our proposed step changes;
- Section 6.8 outlines category specific forecasts;

- Section 6.9 provides a summary of our Revised Proposal for opex; Section 6.10 outlines benchmarking efficient opex; and
- Section 6.11 sets out our supporting documents for this chapter.

In the event of inconsistency between information contained in this chapter and our Regulatory Proposal, the information contained in this chapter prevails.

6.3. Introduction

6.3.1. Our Initial Proposal

The opex included in our Regulatory Proposal was informed by our extensive engagement with our customer panels. The forecast proposed was \$1,700 million over the next regulatory period. This amount was 6% higher than the opex allowance for 2021-26⁸⁵.

This uplift reflects several key drivers:

- Rising costs in materials and labour.
- Growth in customer numbers and network demand increasing operational and asset maintenance requirements.
- Meeting increased expectations of our customers and government, requiring:
 - Enhancements to our Digital systems to meet evolving customer expectations.
 - Additional on-ground customer engagement staff to provide bespoke support to major customers.
 - Emergency event preparedness and response
 - Enhanced reliability on rural parts of our network and fault response
- New regulatory obligations, including bushfire safety, system security, and improved responsiveness during major events.

To help address customer affordability concerns, and as set out in our Initial Proposal, we also:

- Absorbed \$3 million in expected increases from our non-network solutions step change.
- Identified \$9 million in future synergies to be passed on to customers.
- Lowered opex through planned Digital investments and fleet electrification.

Our proposed opex ensured we could continue to deliver safe, reliable, and responsive network services while managing growth and keeping costs as low as possible for customers.

6.3.2. Draft Decision

The AER approved \$1,504 million of the \$1,700 million in the Regulatory Proposal, representing a reduction of \$196m or 11.5%. This amount is 4.5% lower than the opex allowance approved in 2021-26 final decision.

The key drivers of the AER's reductions were:

- Exclusion of several proposed step changes, including Flexible Services, more frequent pole inspections, Early Fault Detection rollout, Digital efficiencies, Preparedness and response, Hazard tree program, Customer relationship management and broad communications, and Insurance. These exclusions totalled \$70.8 million and were primarily rejected due to insufficient justification, immateriality, or because the costs were considered manageable within base opex or trend.
- Inclusion of lower alternative estimates for two accepted step changes: the Digital program was reduced by \$26.7 million, and the Emergency Backstop Mechanism was reduced by \$16.3 million. The AER proposed these reductions on the basis that it believed costs were overstated, lack of detailed economic analysis, and perceived partial duplication with other forecast components.

⁸⁵ Figures exclude debt raising costs

- Applying a negative step change of -\$58.1m to account for insurance costs that did not increase as much as previously forecast, treating the underspend as a non-recurrent efficiency gain. Additionally, a further non-recurrent efficiency gain of \$23.4m, equal to the insurance premium underspend in the base year, was included to meet the opex criteria and to share the benefit of the underspend with network users through the Efficiency Benefit Sharing Scheme (EBSS).
- Use of a lower maximum demand forecast in the output growth component of the rate of change. The AER applied a more conservative approach to ratcheted maximum demand, resulting in a lower output growth contribution to total opex.

6.3.3. Revised Proposal

We do not accept the Draft Decision opex allowance as it does not fund our efficient costs to provide safe, secure and reliable network services over the 2026-31 regulatory period. In developing our Revised Proposal, we have considered and responded to the AER's concerns and requests for additional information. This has led us to:

Accept the AER's draft decision with respect to:

- Base year adjustments for ESC license fees, non-recurrent SaaS and property management fees
- The output growth forecast with respect to circuit length and the use of a PoE50 forecast
- The productivity growth parameter
- The emergency backstop mechanism and digital efficiencies step change
- Innovation allowance

Update our assumptions or forecasts as invited by the AER regarding:

- Demand forecasts
- Expensing non-recurrent SaaS
- 2024-25 actuals
- Step changes tied to capex

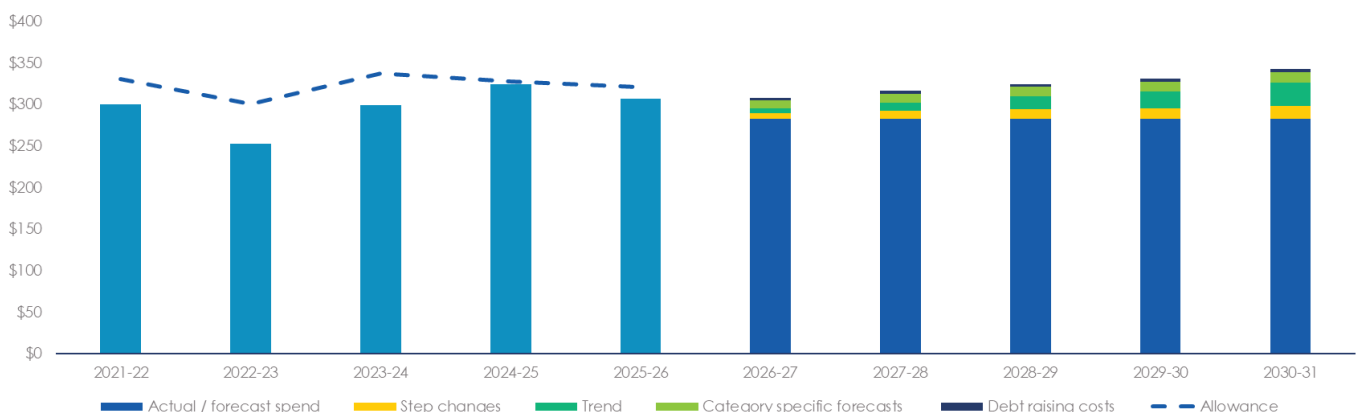
Addressed the AER's concerns and taken an alternative position on:

- Non-recurrent efficiency adjustments
- Rejection of step changes on basis of materiality
- Negative insurance step change

We have also introduced new step changes to fund regulatory obligations that have arisen since our Initial Proposal and we removed the Energy Safe Victoria levy from the base year, which we identified was erroneously included in our Initial Proposal. The Energy Safe Victoria levy adjustment has reduced opex by \$3.5 million in the base year.

Our Revised Proposal for SCS Opex is \$1,606 million excluding debt raising costs for the 2026-31 regulatory period. This is \$122m (8%) higher than actual and expected current period expenditure. Further information on how this Revised Proposal has been built up is outlined below in the figure and table:

Figure 6-18: Actual and forecast operating expenditure 2021 to 2031 (\$m, real 2025-26)



Source: AusNet

Note: Category specific forecast (includes G&Ss, Innovation and customer engagement and communications program)

Table 6-19: Forecast Operating Expenditure (\$m, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Base Opex	282.5	282.5	282.5	282.5	282.5	1,412.6
Step Changes	7.1	9.6	11.7	12.8	15.6	56.7
Trend (Output, labour and productivity)	5.9	10.5	16.1	21.0	28.4	81.8
Bottom-up forecasts (Guaranteed Service Level payments, debt raising costs and innovation)	14.2	14.3	14.6	14.8	15.0	72.8
Total	309.7	316.9	324.8	331.0	341.5	1623.9

Source: AusNet

6.4. Sufficiency of total opex

Since our 2022-23 base year, the scope and scale of activities required to manage the energy transition has accelerated markedly. The step up in operational demands has been far more rapid than in any previous price review process and are not necessarily accommodated within a static base-step-trend allowance.

To meet government expectations, customer needs and system requirements, we have already absorbed volumes of unfunded work. Examples of additional activities that have grown significantly in recent years include:

- onboarding new employees to support solar inverter compliance,
- managing Minimum System Load events,
- engaging customers and communities on LV data visibility,
- responding to increasingly complex DER and electrification enquiries, and
- providing timely data-driven insights for policy development and market participants.

These activities reflect the structural shift in the role distribution networks now must play – including supporting DER participation and integration, maintaining system security and enabling decarbonisation. Because many of these activities evolve incrementally and organically across different parts of the business, we did not include explicit step changes for these activities. Nonetheless, they are essential functions and must be resourced to maintain safe, reliable and accessible network operations. At the same time, we have already absorbed \$62 million in additional opex pressures as ‘affordability measures’, placing further downward pressure on our opex allowance. Further detail on these measures is provided in our initial proposal⁸⁶.

Taken together, the significant volume of unfunded activities we already absorb, and the material cuts applied in the Draft Decision results in an opex allowance that cannot sustain efficient service levels across the 2026-31 period. Despite the evidence that we are increasingly self-funding emerging needs of the network, the Draft Decision does not recognise or account for this when assessing the overall sufficiency of the opex allowance. As a result, the total opex allowance in the Draft Decision is set at a level that does not reflect the real and growing operating needs of our network and customers.

This under-recognition is compounded by the way key elements of the AER’s forecasting methodology have been applied. In several areas, the Draft Decision systematically biases the allowance down – through selective

⁸⁶ [AusNet EDPR 2026-31](#) p.227

adjustments, the rejection of legitimate step changes and the introduction of backward-looking considerations that are inconsistent with the current operating environment.

We summarise these concerns in the following sections:

Selective use of category-specific adjustments

The Draft Decision applies a material downward category-specific adjustment for historical underspend in bushfire liability premiums. However, no symmetrical adjustments were made for categories where historical expenditure was materially above base year allowances (e.g. such as maintenance). This selective application distorts the base year, understates the level of efficient expenditure and results in an artificially low starting point for forecasting. This issue is further discussed in section 6.7.3.

Rejection of valid step changes based on “materiality” concerns

The AER has assumed that step changes of low materiality can be absorbed through the output growth parameter. In particular the Draft Decision states that a “step change must be for material increase in expenditure ... where it can be demonstrated that it is not capable of being managed under forecast opex through trend”. While we acknowledge this is an interpretation of the AER’s step-change framework, this approach does not reflect the operating reality faced by distribution networks as part of the energy transition and increasing demands placed on the network by customers and regulators.

As the pace of energy transition accelerates and the demands on distribution networks become more complex, past performance is not reasonably indicative of future resourcing needs. Reliance on historical circumstances risks is likely to embed outdated cost structures which puts at risk our ability to maintain the safe and reliable operation of the network.

Other international regulators, such as the New Zealand Commerce Commission (NZCC), have already adapted their opex forecasting methods to better capture the structural effects of the energy transition and increasingly varied requirements placed on network businesses. For example, in its DPP4 Final Decision (20 November 2024), the NZCC amended its opex step change decision-making framework moving from a rigid set of criteria that had to be fully satisfied to a framework based on factors that inform judgment.⁸⁷ As a result the NZCC retained the traditional base-step-trend approach, but relaxed the step change test so it can more effectively accommodate emerging categories of opex.

For example, in the context of the materiality or “significance” criterion, the NZCC will assess step changes with proportionate scrutiny. So, a smaller step change with clear drivers and objectively assessable costs may be included:

We clarify that in applying the significance factor, it will be assessed with proportionate scrutiny. In applying that principle, a smaller step change with clear drivers and an objectively assessable cost may be appropriate to include, whereas a change of similar magnitude with less certain drivers and costs that are more difficult to estimate with certainty (without substantial analysis) may not be. Similarly, if the step change is for a significant cost (and therefore impact on consumer bills), then a higher level of scrutiny will be applied to the evidence and information provided against the other factors.

This more flexible, judgment based approach recognises that traditional base-step-trend forecasting methods can become less reliable when networks face incrementally evolving and cumulatively compounding cost pressures. We consider that it is open to the AER to undertake the same flexible approach to avoid the application of a deterministic forecasting method which may render unreliable and unsustainable allowance outcomes in the current operating environment.

In aggregate, the step changes rejected on the basis of low materiality total \$45.9 million (comprising pole inspections, preparedness and response, enhanced customer engagement, flexible services and insurance premiums) representing 2.7% of total opex. This disallowance is clearly not immaterial. These emerging obligations cannot be absorbed in the base year or the rate of change, as neither component captures the structural shift that networks are facing in responding to changed operating conditions.

Introduced backwards-looking considerations into decision-making

In some instances, the AER has relied on historical conditions or historical performance to reject forward looking step changes. For example, efficiencies achieved previously through customer service in the 2016-20 regulatory period were referenced as a basis to reject customer-service related expenditures for this forthcoming period. Similarly, the allowance for pole inspections was reduced by reference to EBSS rewards obtained for outperformance in 2020-2024.

⁸⁷ New Zealand Commerce Commission, Default price quality paths for electricity distribution businesses – Final Decision, Attachment C – Operational Expenditure, 20 November 2024.

In both cases, the implication is that historical savings that may have been achieved should fund future cost increases. This is problematic in a couple of ways. Firstly, it is not consistent with the basis on which a business makes expenditure decisions. The receipt of an EBSS reward in the past will not inform a decision today on whether to under

Expectation to deliver unfunded, customer-supported initiatives

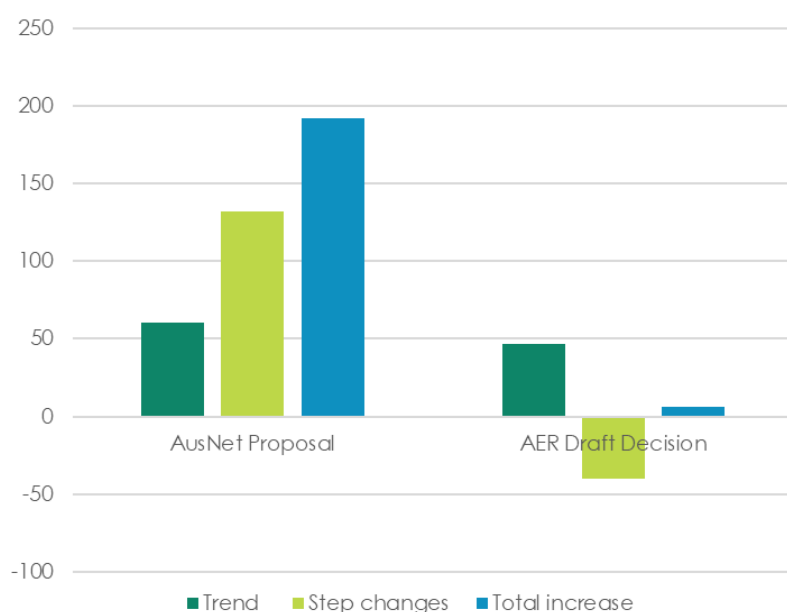
The Draft Decision states that improved communication and coordination “appears to be a discretionary expansion of existing BAU” and therefore does not satisfy the step change criteria. This conclusion overlooks the repeated feedback from customers that the scale, frequency, and detail of engagement expected is vastly different from historical business as usual activities. The step up in customer advisory needs and data support requests is not discretionary work. Rather, it is a structural change in customer expectations because of, principally, the growing uptake of consumer and distributed energy resources. Positioning these activities as business as usual while denying the associated costs implicitly assumes that AusNet should deliver expanded services without an allowance, contrary to the efficient cost recovery principles in the NEL.

These initiatives cannot continue without explicit resourcing, and if they are not funded, they cannot proceed. This would mean we would not be able to meet the expectations of our customers and other stakeholders, including Government.

Collectively, the AER’s approach has resulted in a Draft Decision that provides only an additional \$6 million above trend and step change components of opex across the regulatory period. This uplift is marginal when compared to the scale of structural changes in operating conditions we are facing.

The graph below illustrates the difference in scale between the AER’s Draft Decision allowance and the opex profile from our Initial Proposal. This comparison demonstrates that the Draft Decision allowance is not calibrated to the scale of change in operating conditions and therefore does not provide adequate funding to maintain a safe, reliable and customer-supported network operations.

Figure 6-2: Opex increase over 5 years 2026-31 (\$m, real 2025-26)



Source: AusNet

We encourage the AER to consider the totality of the additional cost pressures affecting our network and to reassess parts of its Draft Decision, accordingly, particularly considering the issues raised above with aspects of its application of the forecasting approach.

We commissioned a report to explore this issue further. Please refer to attachment labelled ‘ASD – HoustonKemp – Operating expenditure step changes and output growth – Nov 2025’.

6.5. Base year expenditure

6.5.1. Our Regulatory Proposal

We nominated the 2022-23 regulatory year as the base year for forecasting opex and outlined the base year adjustments to our actual expenditure to represent efficient costs. These adjustments included:

- Expensing of corporate overheads
- Property management fees

6.5.2. Draft Decision

The AER accepted AusNet's proposed base year of 2022-23 for forecasting operating expenditure, concluding that it was not materially inefficient. We note that the AER found our proposed base year to not be materially inefficient, supported by benchmarking analysis and the absence of abnormal events. We also recognise the AER's adjustments to the base year, including:

- **Corporate overheads:** The AER accepted our proposed reclassification of corporate overheads from capex to opex, with a minor adjustment to reflect updated inflation assumptions.
- **Property management costs:** The removal of \$2.5 million over the period, reflecting the cessation of the Downer contract and associated non-recurrent costs.
- **ESC (Essential Services Commission) license fees:** A downward adjustment of \$4.8 million to reflect the transition of these costs to be recovered under a jurisdictional scheme from 1 July 2025.
- **Insurance:** The AER introduced a negative step change of \$58.1 million and a non-recurrent efficiency gain of \$23.4 million, reflecting underspends in insurance premiums during the 2021-26 period.

6.5.3. Revised Proposal

Our Revised Proposal retains 2022-23 as the base year and accepts the AER's conclusion that this year's opex is efficient. We accept the AER's base year adjustments for:

- Non-recurrent SaaS costs
- ESC license fee
- Property management fees.

We have updated our forecast of capitalised corporate overheads for the purposes of the base year adjustment to reflect more recent information.

We disagree with the AER's base year adjustment for non-recurrent efficiency gain associated with lower bushfire insurance premiums.

We have added an adjustment to remove the ESC levy, which has been identified during this process to have been erroneously included in our opex forecast.

The adjustments made to our base year of 2022-23 to ensure it is representative of efficient costs in the Revised Proposal are listed below:

Table 6-210: Base year breakdown in operating expenditure for Revised Proposal

Component	Draft Decision	Revised Proposal	Changes
Base year opex minus movements in provisions, DMIA and implementation SaaS (\$m, nominal)	238.3	238.3	Accepted
Escalation to 2025-26 (\$2025-26)	29.8	31.4	Accepted with some changes – updated for latest inflation figures and flexible trading arrangement submitted pass through
Trend to 2025-26 (\$2025-26)	19.5	19.8	
Remove estimate final year opex for categories forecast (\$2025-26)	-7.5	-7.6	
Adjustments – Positive - corporate overheads (\$2025-26)	4.0	6.0	Revised amount
Adjustments – Negative - property, ESC license & Energy Safe Victoria levy (\$2025-26)	-1.5	-5.3	Revised amount

Non-recurrent efficiency gain (\$2025-26)	4.7	0.0	Revised amount
Estimated 2025-26 Opex (\$m, real 2025-26)	287.3	282.5	Revised amount

Source: AusNet

Further information on each of these adjustments is explained below.

6.5.3.1. Property management fees

We accept the AER's draft decision on the negative base year adjustment for property management costs.

6.5.3.2. ESC licence fee

We accept the AER's decision to remove the ESC licence fee from base opex. During the Q&A process the AER identified the amounts captured in the base year of 2022-23 include \$0.9 million relating to the Essential Services Commission (ESC) licence fees. However, the ESC licence fees are recovered via the annual pricing proposal process and should not be included in forecast opex.

6.5.3.3. Non-recurrent SaaS

Non-recurrent SaaS costs are excluded from the base opex and not included in the 2026–31 forecast because these costs typically relate to one-off projects. During the 2021–26 period, the AER's guidance required these costs to be treated as capital expenditure for reporting purposes although the accounting rule change to expense these amounts came into effect in 2021. However, in our regulatory accounts we included these costs for 2021-22, 2022-23, 2023-24 and 2024-25 in reported opex. Consistent with the AER's Draft Decision we have excluded these amounts from base opex (\$1.4 million, nominal) and the EBSS calculation for each year to ensure the forecast reflects the AER's preferred treatment in the current period. We have included non-recurrent SaaS costs in our opex forecast for the 2026-31 regulatory period.

6.5.3.4. Expensing of corporate overheads

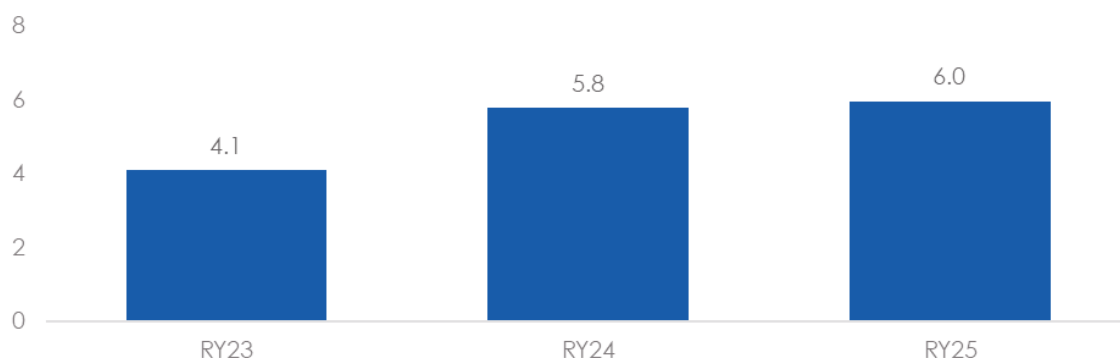
We welcome the AER's Draft Decision to accept our proposal to expense all corporate overheads from 1 July 2026, which results in including these costs in its alternative opex estimate. This approach aligns the treatment of corporate overheads for our electricity distribution network with our gas network, as approved by the AER in the 2023–28 Gas Access Arrangement Review.

In our Initial Proposal, we applied a base year adjustment of \$3.7 million (2022–23), reflecting the actual corporate overheads capitalised in that year, which we considered broadly representative of ongoing costs. In its decision, the AER adjusted base year opex by \$4.0 million (or \$20.0 million over the 2026–31 regulatory period) to reflect the change in capitalisation practices, which it considered reasonable. However, we have now updated this forecast because we no longer consider 2022–23 to reasonably reflect our ongoing level of corporate overheads. More recent actuals indicate a sustained upward trend since the RY23 base year, as shown in the figure below. This trend reflects changes in business operations and cost drivers that were not fully captured in the 2022-23 estimate – in particular:

- Since 2022/23 there has been an expansion within corporate functions of our business such as, legal, health and safety areas, as well as expansion of digital capabilities to support business scalability and efficiency.
- Accounting corrections made since RY23, reversing the outcome of reducing capitalised overheads in that period.
- Labour related impacts, such as incentive programs and updated remuneration settings, have contributed to higher ongoing overhead levels.
- Operational changes to move from functional divisions to a line of business model in 2024, as well as the CAM update in 2025, has improved transparency and consistency in allocating corporate costs across network businesses.

As such we now consider RY25 provides a more appropriate base year adjustment of \$5.7 million (2024-25) representative of our ongoing costs. While transferring these costs from capex to opex increases prices in the short term, it delivers long-term benefits by avoiding growth in the regulated asset base and associated return on and return of capital. This approach remains consistent with accounting standards and our approved CAM.

Figure 6-3: Capitalised corporate overheads actuals 2022-23 to 2024-25 (\$m, real 2025-26)



Source: AusNet

6.5.3.5. Energy Safe Victoria levy

Energy Safe Victoria levy costs of (\$3.5 million, nominal) were erroneously included in our opex base year. These costs are recovered through the annual pricing proposal process (via the B factor). Therefore, in this Revised Proposal we are excluding these amounts from base year opex resulting in approximately \$20.3 million (\$2025-26) decrease to the overall opex forecast over the 2026-31 regulatory period respectively along with an approximate \$3.0 million (\$2025-26) increase to the EBSS carryover amount. This also aligns with the AER's approach for other DNSPs on jurisdictional schemes.

6.5.3.6. Non-recurrent SaaS

Non-recurrent SaaS costs are excluded from the base opex in the 2026–31 forecast because these costs typically relate to one-off projects. During the 2021–26 period, the AER's guidance required these costs to be treated as capital expenditure for reporting purposes although the rule change came into effect in 2021. However, from 2026-31 regulatory period, they will be treated as opex, consistent with the updated framework. Excluding them from the base ensures the forecast reflects a stable and recurrent cost profile, while allowing for their inclusion as additional opex where appropriate.

6.5.3.7. Property management fees

We accept the AER's draft decision on the negative base year adjustment for property.

6.5.3.8. Non-recurrent efficiency gain

The AER has added a non-recurrent efficiency gain to recognise an underspend in our allowance for bushfire liability insurance, which has resulted in an additional \$23.4 million in our opex allowance. However, we do not consider this adjustment to be appropriate and any underspend relative to opex allowances in 2021-26 should be viewed as a reflection of both market conditions and AusNet's strategic risk management and ongoing efficiencies through using a captive. This is discussed further in attachment 'ASD - HoustonKemp - Victorian DNSP insurance premiums - Nov 2025' and section 6.7.3 on the insurance negative step change.

6.5.3.9. Base year vs forecast year comparison

We highlight the adjustments we have made to our base year to best reflect a stable and efficient foundation, in addition to the above adjustments we highlight the emerging cost pressures, regulatory obligations and changes in accounting treatment. We reinforce the need for step changes and trend to ensure our opex forecast accurately reflects the evolving environment and regulatory landscape.

6.6. Rate of change

6.6.1. Regulatory Proposal

In our Regulatory Proposal we outlined our proposed rate of change escalators and the underlying calculations used to derive them, based on the AER's standard methodology and the most up to date information of inputs and

available at the time. AusNet's proposed rate of change contributed \$60.6 million to our total opex forecast, equating to an average annual increase of 1.6%.

A summary of our proposal is below:

Table 6-311: Rate of change forecast in Initial Proposal opex model (%)

Component	2026-27	2027-28	2028-29	2029-30	2030-31
Output growth	0.9	1.1	1.8	1.8	1.8
Real price growth	0.6	0.5	0.6	0.7	0.6
Productivity growth	-0.5	-0.5	-0.5	-0.5	-0.5
Rate of change	0.9	1.1	1.9	2.0	1.9

Source: AusNet

6.6.2. Draft Decision

The AER accepted our output growth parameters, apart from:

- the approach and underlying demand forecasts used to forecast ratcheted maximum demand. The AER:
 - Applied 100% weighting on POE50 forecasts, and rejected our approach to place weight on POE10 forecasts to align with the approach taken for network planning;
 - Reduced our forecast demand reflecting the outcome of its assessment of our demand forecast, specifically it removed some block loads.
- Applied updated output weights to reflect the 2024 Annual Benchmarking Report.
- Accepted real price growth escalators and applied updated labour price forecasts using more recent forecasts from Deloitte Access Economics, which were not available at the time of our Initial Proposal.
- Accepted our application of its standard -0.5% productivity adjustment

The AER's alternative estimate included a lower contribution of \$46.5 million, reflecting average annual increases of 1.2%. The parameters applied in the Draft Decision are shown in the table below:

Table 6-412: AER rate of change forecast in Draft Decision opex model (%)

Component	2026-27	2027-28	2028-29	2029-30	2030-31
Output growth	0.8	0.8	0.8	1.5	1.7
Real price growth	0.5	0.6	0.7	0.7	0.7
Productivity growth	-0.5	-0.5	-0.5	-0.5	-0.5
Rate of change	0.8	0.9	1.0	1.7	1.9
Difference to AusNet Proposal	-0.1	-0.2	-0.9	-0.3	0.0

Source: AusNet

6.6.3. Revised Proposal

We do not accept the AER's Draft Decision regarding the overall rate of change. The principal issue relates to the AER not accepting our demand forecast. In response, we have updated our forecast to directly address the concerns raised in the Draft Decision, ensuring it reflects the most current and robust assumptions available. This extends to updating for the latest labour escalation data, revised output growth parameters and confirmed productivity factor.

Further detail on our revised assumptions for real price growth, output growth, and productivity is provided in the sections below.

6.6.3.1. Real price growth

In our Revised Proposal, we have updated our real price growth forecasts to reflect the most recent and relevant data available. These updates primarily relate to labour cost escalation, which is a key driver of real price growth in our opex forecast. While the focus is on labour, we note that real price growth also interacts with broader inflationary trends and economic conditions that influence input costs across the business.

The total impact of real price growth over the 2026-31 regulatory period is forecast to be:

Table 6-513: Forecast price growth (\$m, real 2025-26)

Rate of change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Price growth	1.4	3.0	4.9	7.0	9.0	25.2

Source: AusNet

6.6.3.1.1. CPI

We have updated our inflation assumptions in line with the latest data published by the Australian Bureau of Statistics (ABS), as well as the Reserve Bank of Australia's (RBA) most recent Statement on Monetary Policy. These updates ensure our forecasts reflect the most current macroeconomic outlook and provide a more accurate basis for estimating real cost changes over the regulatory period.

6.6.3.1.2. Labour Escalation

Labour escalation has been updated to reflect the most recent data available. We have incorporated:

- The AER's latest labour cost forecasts for Victoria from its September 2025 Draft Decision on opex.
- Updated projections from Oxford Economics, which reflect current expectations for real wage growth.

These updates ensure our forecasts are aligned with prevailing labour market conditions and provide a more accurate basis for estimating cost pressures over the regulatory period. Further information can be found in Oxford Economics' report.

6.6.3.2. Output growth

We have updated our output growth forecasts in the Revised Proposal to reflect the latest available benchmarking data and demand forecasts. Specifically, we have revised the output weightings in our opex model using the output elasticities from the 2024 Quantonomics benchmarking report, which are applied to our base year using the AER's four econometric benchmarking models.

As the 2025 AER Annual Benchmarking Report is expected to be released in November 2025, it has not been possible to incorporate updated output weights into the Revised Proposal but acknowledge that the AER will make this update in the Final Decision.

The total output growth forecast is below:

Table 6-614: Forecast output growth (\$m, real 2025-26)

Rate of change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Output growth	5.9	10.3	15.5	19.8	26.5	78.0

Source: AusNet

In Section 6.4 above we raise concerns about the current relevance of the composition of the output growth parameter, as the data that underpins it is not well-aligned to current opex drivers. Notwithstanding this, this section adheres to the current opex forecasting framework.

6.6.3.2.1. Ratcheted maximum demand

We have updated our forecast of ratcheted maximum demand to reflect our updated demand forecasts. We have also applied POE50 values only, rather than the 30% POE10 / 70% POE50 weighting applied in our Initial Proposal, to align with the AER's preferred approach. For further information on maximum demand updates refer to Chapter 3 – Demand and Energy Forecasts.

6.6.3.2.2. Customer numbers

Customer growth has been revised in line with our updated demand forecast. The average annual growth rate has increased slightly from 1.7% p.a. in our Initial Proposal to 1.9% p.a. in our Revised Proposal. This adjustment reflects the most current and robust forecast methodology applied in our demand forecasting process. Importantly, this approach continues to align with the AER's preferred forecasting principle ensuring that our projections remain transparent, evidence-based, and consistent with regulatory expectations. The revised growth rate represents a stable and predictable expansion in our customer base over the regulatory period.

6.6.3.2.3. Circuit length

We accept the AER's draft decision and have made no updates in our Revised Proposal.

6.6.3.3. Productivity growth

We accept the AER's Draft Decision to apply a 0.5% annual productivity growth factor to our opex allowance which is consistent with our Initial Proposal. This reflects the expectation that networks continue to find efficiencies over time and deliver value to customers.

We remain committed to pursuing productivity improvements throughout the 2026–31 regulatory period and will continue to look for opportunities to pass these benefits on to customers. However, we note that achieving sustained productivity gains is increasingly challenging in the current environment. This has been exacerbated by emerging cost pressures including those driven by the energy transition and digitisation which are placing upward pressure on operating costs. At the same time, customer expectations around service quality, reliability, and responsiveness are rising, and regulatory obligations are becoming more complex and resource intensive to manage.

The total productivity impact can be found below:

Table 6-715: Forecast productivity growth (\$m, real 2025-26)

Rate of change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Productivity growth	-1.4	-2.8	-4.3	-5.7	-7.2	-21.4

Source: AusNet

6.6.3.4. Overall rate of change

With the updates outlined above as part of our Revised Proposal the overall rate of change for our Revised Proposal is outlined below:

Table 6-816: AusNet rate of change forecast in Revised Proposal opex model (%)

Component	2026-27	2027-28	2028-29	2029-30	2030-31
Output growth	2.1	1.5	1.7	1.4	2.2
Real price growth	0.5	0.6	0.7	0.7	0.7
Productivity growth	-0.5	-0.5	-0.5	-0.5	-0.5
Rate of change	2.1	1.6	1.9	1.7	2.4

Source: AusNet

6.7. Step changes

6.7.1. Regulatory Proposal

As part of our Regulatory proposal, we put forward several step changes driven by customers, regulatory obligations and capex/opex trade-offs, namely:

Table 6-917: Proposed opex step changes (\$m, real 2025-26)

Step change	Amount 2026-31 (\$m)
Flexible services and non-network solutions	8.5
Energy Safe Victoria pole inspection	8.0
Fleet electrification	-0.7
Digital	39.9
Early Fault Detection	7.8
Digital efficiencies	-3.9
Preparedness and Response	9.2
Resilience (hazard tree program)	15.0
Customer relationship managers and comms	15.7
Emergency Backstop Mechanism	21.6
Insurance	10.5
Total step changes	131.7

Source: AusNet

We also highlighted \$62 million (\$2025-26) of additional cost pressures and step changes we would absorb without a compensating increase in our opex allowance, as a tangible response to the affordability concerns of our customers. We also included a negative step change for digital efficiencies to account for productivity gains. We also included a negative step change to reflect expected savings from electrifying a portion of our fleet.

6.7.2. Draft Decision

6.7.2.1. Step changes fully or partially accepted

6.7.2.1.1. Fleet Electrification

The AER accepted this negative step change of -\$0.7 million, reflecting opex savings from transitioning to electric vehicles. It was considered a prudent opex/capex trade-off consistent with recent determinations and the AER's expenditure forecasting guideline. However, despite the AER accepting this step change, we are no longer proposing additional capex to fund electric vehicles and will transition when there is cost neutrality. Consistent with this updated approach, we have removed the negative opex step change.

6.7.2.1.2. Digital (SaaS, Licenses, etc.)

The AER included a reduced placeholder of \$13.3 million, citing concerns about overstated costs, insufficient economic analysis, and a lack of evidence that the proposed expenditure was prudent and efficient. Several sub-programs were excluded including Field Enablement, Distribution System Operator and Asset Management.

6.7.2.1.3. Emergency Backstop Mechanism

The AER partially accepted this step change, including only the recurrent license fees not already captured in the final year increment. The remainder of the proposed costs were considered to be already accounted for through the final year adjustment.

6.7.2.2. Step changes requiring further justification

6.7.2.2.1. Early Fault Detection

The AER did not accept this step change, noting that AusNet had not demonstrated a clear regulatory obligation or sufficient net benefit to consumers. EMCA also raised concerns about the justification for the program and the robustness of the cost estimates.

6.7.2.2.2. Flexible services and non-network solutions

The AER did not include this step change in its alternative estimate, citing insufficient justification for the proposed costs and a lack of evidence that the services would be procured or required. The AER also considered that the proposed activities could be accommodated within the rate of change component of the opex forecast.

6.7.2.2.3. Resilience (Hazard tree program)

The AER did not accept this step change, citing a lack of evidence for the capex/opex trade-off and concerns about the robustness of the benefit assumptions. EMCa identified shortcomings in the business case, including the absence of avoided capex estimates and potential overstatement of outage-related benefits.

6.7.2.2.4. Insurance

The AER did not accept this step change of \$10.5m, stating that forecast increase in insurance premiums were not material and would be captured through the price growth component of the rate of change. Subsequently, the AER introduced a negative step change to remove the overstated insurance premium component embedded in the final year increment. This adjustment of -\$58.1m was made to reflect the underspend on insurance premiums during the 2021-26 period and to ensure consistency with the opex criteria and the EBSS.

6.7.2.2.5. Preparedness and Response

The AER considered this step change to be relatively immaterial and manageable within the trend component. While the activities were acknowledged as prudent, the AER found that the proposed uplift did not meet the threshold for a step change under its framework.

6.7.2.2.6. Customer relationship management and broad communications

This step change was not included in the AER's alternative estimate. The AER considered the proposed activities to be a discretionary expansion of business-as-usual functions and noted that the forecast increase was relatively immaterial and could be accommodated within base opex and trend.

6.7.2.2.7. Digital Efficiencies

This negative step change of -\$3.9m was excluded from the AER's alternative estimate. The AER noted that the proposed savings were linked to the Digital step change, which had been significantly reduced, and therefore the corresponding efficiency savings were not supported.

6.7.2.2.8. Energy Safe Victoria more frequent pole inspections

This step change was not accepted on the basis that the costs were considered immaterial and could be managed within the trend component. The AER also noted that the change in inspection frequency reversed a previous reduction and that no negative step change had been applied when the frequency was lowered in 2019.

6.7.3. Revised Proposal

Our Revised Proposal for step changes responds to the AER's feedback provided in the Draft Decision. We have addressed the AER's concerns in relation to step changes we are continuing to propose. For those step changes linked to capex programs, we have updated supporting documentation and cost-benefit analyses to demonstrate prudence and efficiency. Where the AER raised concerns about materiality or justification, we have provided further information to demonstrate that these costs are incremental, unavoidable costs driven by the AER's framework.

As part of our Revised Proposal, we propose 10 step changes, including 3 new regulatory obligation step changes due to new regulatory obligations that have arisen since the Initial Proposal. We outline below our proposed opex step changes and, where relevant, address concerns raised by the AER in the Draft Decision.

6.7.3.1. Overview

We propose a total of \$57 million in step changes over the 2026–31 regulatory period, which represents 4% of our total opex forecast. These step changes are prudent, efficient, and not captured within base year or trend parameters. They all meet at least one of the AER's step change criteria.

We have reviewed the AER's Draft Decision and updated our step change forecast to reflect:

- New and emerging obligations imposed on our network
- Customer driven initiatives that support resilience, safety and engagement
- Capex / opex trade-offs that deliver net benefits to customers
- Updated costings and business cases that address the AER's feedback

A summary of our Revised Proposal step changes is below. These have been grouped into common categories which address concerns raised by the AER.

Table 6-1018: Comparison of proposed opex step changes (\$m, real 2025-26)

Step change	Initial Proposal 2026-31	Draft Decision 2026-31	Revised Proposal 2026-31
Accept Draft Decision			
Emergency Backstop Mechanism	21.6	5.4	5.4
Digital Efficiencies	-3.9	0.0	0.0
Prudent and efficient costs that cannot be absorbed			
Emergency preparedness and response	9.2	0.0	9.2
Energy Safe Victoria pole inspection	8.0	0.0	6.0
Customer relationship managers and comms	15.7	0.0	0.0*
Flexible services and non-network solutions	8.5	0.0	1.9
Aligned to capex programs			
Hazard tree program	15.0	0.0	6.2
Early Fault Detection	7.8	0.0	1.0
Digital	39.9	13.3	20.9
Fleet Electrification	-0.7	-0.7	0.0
Oppose regulatory treatment			
Insurance	10.5	-58.1	0.0
New regulatory obligations			
Integrated distribution system planning rule change	-	-	4.0
Sustainability reporting required under Corporations Act 2001	-	-	2.4
Flexible Trading Arrangements	-	-	-0.1
AEMO NEM fees	0.0	0.0	0.0
Total step changes	131.6	-40.1	56.7

Source: AusNet

Note: Integrated distribution system planning rule change and sustainability reporting are marked as (-) as they are new step changes introduced in the revised proposal.

*: CRM and Communications is included as a category specific forecast for the Revised Proposal

We address each of these step changes below.

6.7.3.2. Accepting parts of the AER's Draft Decision

Table 6-11: Proposed step changes accepted from the AER's Draft Decision

Step change	AER step change category	Initial Proposal	Draft Decision	Revised Proposal
Emergency Backstop Mechanism	Capex/opex trade off	21.6	5.4	5.4
Digital efficiencies	Capex/opex trade off	-3.9	0.0	0.0

Source: AusNet

6.7.3.2.1. Emergency Backstop Mechanism

We accept the AER's draft decision to include a \$5.4 million step change in our operating expenditure forecast for the 2026-31 regulatory period. We agree our ongoing opex is captured by the final year increment which reflects the amount accepted in the pass-through application in August 2024. The remaining step change relates to the transition of Distributed Energy Resource Management System (DERMS) licence fee from capital to operating expenditure from mid-2028-29. These costs were capitalised in the current period due to the upfront nature of the license payment but will become recurrent opex in the next contract term.

Table 6-12: Emergency Backstop Mechanism step change forecast (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Emergency Backstop Mechanism	0.0	0.0	1.1	2.1	2.2	5.4

Source: AusNet

6.7.3.2.2. Digital efficiencies

In our Initial Proposal we included this negative step change to account for efficiencies we expect to realise as a result of our Digital capex program. In the Draft Decision the AER rejected this step change as it disallowed Digital opex associated with the specific projects that generate these efficiencies. Our Revised Proposal approach is to accept the removal of this step change and address Digital efficiencies directly by reducing the Digital step change amount to account for these. This is discussed further below.

6.7.3.3. Prudent and efficient costs that cannot be absorbed

The AER cites immateriality as one of its reasons for cutting the following proposed step changes, which in aggregate results in a reduction to our opex allowance of \$41.4 million, namely:

Table 6-13: Proposed step changes that are prudent and efficient costs that cannot be absorbed

Step change	AER step change category	Initial Proposal	Draft Decision	Revised Proposal
Emergency preparedness and response	Major external factor	9.2	0.0	9.2
Energy Safe Victoria pole inspection	Changed regulatory obligation	8.0	0.0	6.0
Customer relationship managers and comms	N/A*	15.7	0.0	0.0*

Flexible services and non-network solutions	Capex/opex trade-off	8.5	0.0	1.9

Source: AusNet

*: CRM and Communications is included as a category specific forecast for the Revised Proposal

While the AER appears to apply a materiality criterion that treats a step change as only allowable where it corresponds to a sizeable proportion of total forecast opex (i.e. 1.0% of total proposed opex), this approach is not supported by the AER's Expenditure Forecast Assessment Guideline nor the opex objectives or criteria in the NER.

First, the AER's Guideline does not establish any materiality threshold for step changes. Rather the Guideline focuses on preventing double-counting and ensuring that efficient and prudent costs are recognised. The AER's Guidelines provides:

We will consider what might constitute a compensable step change at resets, but our starting position is that only exceptional events are likely to require explicit compensation as step changes.

As emphasised above, the Guideline deliberately frames the assessment around the nature of the cost (not its magnitude) – and whether it is exceptional, as in uncontrollable, unavoidable and recurring – to assess whether it should be allowed.

Secondly, the NER requires that total forecast opex reflects the efficient costs a prudent operator would require to meet expected demand, comply with all applicable regulatory obligations and maintain quality, reliability and security of supply as well as contribute to the energy transition. Neither the opex objectives, nor the opex criteria contain any materiality threshold, and there is no discretion for the AER to otherwise reject prudent and efficient expenditure simply based on its relative size. We consider there is no legal basis within the NER for the AER to apply immateriality as a determinative ground for rejecting a step change, and results in the arbitrary exclusion of legitimate unavoidable and externally driven cost increases. Further justification in support of the inclusion of the above step changes based on relevant criteria is set out below.

6.7.3.3.1. Emergency preparedness and response

We do not accept the AER's Draft Decision to exclude our proposed \$9.2 million step change for emergency preparedness and response. The AER's Draft Decision characterises the activities are likely prudent but considered due to materiality the costs proposed can be managed by the business with no step change, and that it is covered by the trend component in the AER's opex forecasting approach.

We consider this assessment does not adequately reflect the nature, scale, and external drivers of the proposed expenditure. Therefore, we have maintained the step change which addresses critical gaps exposed by the February 2024 storm, the most severe in AusNet's history, by implementing time-bound recommendations from government reviews, regulatory expectations, and strong customer feedback. This uplift includes meeting requirements for an annual attestation to the energy minister on emergency risk maturity, enhanced emergency planning, improved surge capacity, faster deployment of temporary generation, and best-practice engagement with vulnerable customers. Key activities include recruiting emergency management specialists, expanding training from 90 to 400 staff, and strengthening backup communications. These measures are essential to meet new obligations and prevent prolonged outages.

While we acknowledge the AER's concern that providing for incremental opex for smaller step changes may risk double counting within a base-step-trend framework, this risk does not arise in relation to our emergency preparedness and response step change. In particular because:

- These incremental resources are not reflected in our 2022-23 base year. Our base year costs did not contemplate the activities required to implement the recommendations from the Network Outage Review and Nour Post-Incident Review recommendations commissioned after the February 2024 storm.
- These functions are also not captured in trend, as suggested by the AER, as they do not arise from general business expansion or ongoing productivity adjustments but instead from new, discrete and externally driven requirements. This step change, in introducing new roles, expanded training reach and new communications capabilities, is driven by resilience needs which is divorced from the drivers of the opex trend parameter, being productivity savings, real price escalation, maximum demand growth, customer growth and circuit length. As such, we do not agree that this prudent and efficient cost can be absorbed within our trend opex allowance.

Accordingly, the AER should accept the proposed step change here as representing a genuine, incremental increase necessary to meet new obligations and expectations, necessary so as to not repeat the impacts of the February 2024 storm.

Alignment with Stakeholder Expectations

While the AER notes the absence of submissions directly addressing this step change, broader stakeholder feedback strongly supports enhanced network resilience and emergency response. Our proposal is grounded in extensive customer engagement and aligns with the Victorian Government's policy direction and the AER's own expectations.

We urge the AER to reconsider its Draft Decision considering the clear evidence of externally imposed obligations, customer expectations, and the materiality of the proposed uplift in capability. This step change is essential to ensure AusNet can meet its responsibilities and deliver improved outcomes for customers during future extreme events.

Table 6-14: Emergency preparedness and response step change forecast (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Emergency preparedness and response	1.8	1.9	1.9	1.8	1.8	9.2

Source: AusNet

6.7.3.3.2. Energy Safe Victoria pole inspection

We do not accept the AER's draft decision on the Energy Safe Victoria pole inspection step change and have maintained the step change to our base year of 2022-23. The step change reflects the requirement change from a 6-year inspection cycle to a 5-year cycle, noting that we incurred these additional costs in the most recent regulatory year of 2024-25.

The EMCa report also states that these additional costs arising from this regulatory obligation are prudent in response to the uplift in pole inspection frequency and are not captured in our base year of 2022-23.

We agree with this assessment as the step change amount is:

- Driven by a regulatory obligation; and
- Not captured in our base year of 2022-23

The updated values below reflect the amount presented at the EMCa offsite and communicated to the AER through IR 9⁸⁸. This refines the FTE amount to explicitly relate to the uplift driven by the regulatory obligation. This is \$2 million in total lower than the Initial Proposal. This ensures customers are only funding the efficient cost of meeting the new inspection standard.

We acknowledge the AER's concerns on the EBSS rewards. However, the previous efficiency saving from lengthening inspection cycles was more than offset by market rate increases affecting the total cost of the pole inspection program. At a headline opex level, numerous variances emerged between forecast and actual opex, with outturn costs often higher or lower than expected. In this context, the AER's emphasis on historical efficiency saving, rather than the underlying base year costs, and in doing so, dismissing a regulatory-driven step change is inconsistent with the AER's opex forecasting framework. On this basis, disallowing the efficient opex required to meet the new inspection requirement due to an efficiency saving that occurred 6 years ago is not supported by the AER's own expenditure assessment framework.

Table 6-15: Energy Safe Victoria pole inspection (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Energy Safe Victoria pole inspection	1.2	1.2	1.2	1.2	1.2	6.0

Source: AusNet

6.7.3.3.3. Customer relationship managers and communications

We do not accept the AER's Draft Decision to reject in full the \$15.7m opex step change for customer relationship management and broad communications on the basis that the step change has not been justified against the AER's step change criteria.

With the support of our customers (per our 6 November "all in" forum) we are addressing the AER's feedback and have refined and are re-proposing this step change at a lower cost of \$10.3m.

⁸⁸ IR#009 – EMCa questions, Q38-42 - CONF

At the 6 November forum, the mood of the group was summarised on the day by our independent facilitator as “There’s support for proposing the customer experience opex step change (communications & relationship managers) with a narrower scope but with an expectation that AusNet provides more detailed supporting information to the AER than was provided in the session, beefing up and selling the benefits to customers better”. There was unanimous support for narrowing the scope of the proposed step change, focusing on tariff communications. The vast majority of the group continued to see value in relationship manager roles but a small number thought AusNet should accept the AER’s decision to reject it. Participants agreed clearer justification and evidence of customer benefits is needed in the Revised Proposal.

This program was originally designed with and strongly supported by our EDPR panels (in particular the Customer Experience Panel) and strongly supported by customers when it was tested at our five customer workshops held across the networks in October 2024, who also confirmed their willingness to pay for this step change.

The Co-ordination Group in its report to the AER on our Proposal noted it “supports the appointment of customer relationship managers across the network” and noted this step change had “strong customer support” (page 26).

Additionally, submissions received on the Draft Proposal backed greater customer support:

- Sandy Point Community Power’s submission, representing 54 community members, highlighted a perceived gap between AusNet’s customer service objectives and customers’ experience on the ground, and called for closer collaboration with councils, emergency services, and other utilities to support coordinated responses to major weather events.
- An anonymous survey respondent confirmed the value of customer relationship managers for commercial customers, and
- Written submissions from customers and community groups reinforced the importance of dedicated engagement and unbiased, on-demand information on energy transition and resilience.

Figure 6-4: Feedback from our Round 4 customer workshops completed in October 2025 showed strong support and willingness to pay for AusNet’s customer relationship management and communications step-change, which was tested explicitly and discussed in detail. Excerpts from the report from consultants SenateSHJ capture this feedback

Customers see on-the-ground support as critical because it enables important local knowledge and relationships and vital outage support

How important do you think it is to have engagement staff on the ground in regional areas? What should they be focused on?	
Customers supported commitments to improve community presence.	What customers said
• Local presence and accessibility: Customers emphasised the importance of having regional engagement staff accessible in specific areas. They noted that having staff locally stationed would help foster direct communication and build relationships, enabling a deeper understanding of regional issues and quicker response times. Some customers expressed frustration about the number of Emergency Response Vehicles proposed (four vehicles) being too low.	• “Make sure these new roles don’t just disappear into the ether of AusNet. If I’m thinking of AusNet, I should know that, say, Sue is down at Latrobe every month, on a set day, as the visible face of the company. I think that’s important. But I don’t know if 14 is the right number. If one person is expected to cover all of Gippsland—from Phillip Island up to the Murray—you might need two people for that. So maybe 14 isn’t enough; it’s something for you to explore.” • “The four people to cover 800,000 people is absolutely absurd. I think that’s a bit of an insult. We’re in the high country and were completely cut off...”
• People with customised regional knowledge: Regional staff are expected to have strong local knowledge and an understanding of community-specific challenges, especially those unique to rural or isolated communities. Participants felt that engagement staff should be familiar with local infrastructure and population needs to better address region-specific outages and support requirements.	• “I think it’s a good idea to have them positioned locally. They’ll understand the local market better, especially in rural areas, and will be more equipped to assist with the specific challenges those communities face.”
• Emergency and outage support: It was agreed there’s a need for engagement staff to be involved during emergencies, especially prolonged outages. This includes providing regular updates, offering on-the-ground support, and coordinating with local emergency response teams to ensure critical needs are met promptly.	• “In our area, we have a bushfire point of last resort, and every small community in the mountains has one. Maybe that should be a focal point for people to gather during emergencies since everyone in these communities knows where they are.”
• Coordination with local authorities: Participants suggested that engagement staff should work closely with local councils and MPs, particularly during times of crisis, to provide consistent information and support to the community. They believed that this collaboration could enhance communication and trust within the community.	• “Have you ever considered connecting with our local Member of Parliament to keep them directly informed during emergencies? They could serve as a community voice, sharing updates from AusNet and letting people know what’s happening on the ground. It seems like a natural role for them, being part of the government.”
• Relationship managers for business: Business customers would like to have a relationship manager who is knowledgeable about local businesses and the area.	• “And the relationship manager also understands larger to medium businesses. That’s a godsend. That works well in other business models. And I’d like to see that in this case as well, especially when something goes wrong.”

Source: SenateSHJ, Business and residential customer workshops round four report, November 2024

Figure 6-5: Excerpts from the report from consultants SenateSHJ on tariff communication

Communication on tariffs needs to be clear and simple

How should we communicate the benefits of our changed tariff structures to residential customers?	
	What customers said
• A call to emphasise simplicity and provide real-time guidance: Participants emphasised the need for clear, straightforward information, potentially through an app, to inform optimal times to use energy and save costs.	• "Provide clear, real-time information, so customers know when they're saving."
• The message is changing and customers feel conflicted: Participants recalled earlier campaigns that encouraged night-time use, which now conflicts with the solar soak tariff messaging. They expressed a need for consistent and straightforward communication that adjusts outdated messaging and influences behaviour change.	• "Just tell us which way to go. We've had 30-40 years of 'don't use during the day,' and now we're told the opposite."
• Support for a communications campaign: It is critical that the tariff structure is communicated in easy-to-understand language as many people are confused.	• "After years of 'use it at night' it's confusing to now shift to day usage."

Source: SenateSHJ, Business and residential customer workshops round four report, November 2024

In its Draft Decision the AER acknowledged the proposal had customer support but expressed the following concerns:

- AusNet has not justified how the proposal meets the step change criteria and cannot be managed under forecast opex through trend
- The proposal appears to be an expansion of business as usual (BAU) activities
- AusNet reduced customer service-related expenditure over the last two regulatory periods
- The proposal (totalling 0.9% of total forecast opex) is not material.

Externally driven change in AusNet's social obligations

As the energy landscape becomes more complex, climate change impacts start to be felt and households and businesses are being moved to decarbonise and electrify, it is no longer acceptable for AusNet to stay stepped back from the people who rely on our network every day and leave supporting customers to government and retailers. We have a social obligation to provide our customers with fit-for-purpose customer service.

The volume of engagement and advice our customers need has increased significantly in recent times as we collectively progress through the energy transition. An efficient, fair and equitable transition *requires* customer participation. At present, customers do not have the support and access to the information and advice they need to take control of their energy futures and are asking and expect AusNet to do more, particularly when it relates to how they interact with the AusNet network. No other party is filling this gap.

On communications, AusNet is currently under pressure from the AER and customer advocates to do more to promote the benefits of engaging with pricing signals to customers. With the change in peak and off-peak usage times and strong uptake of rooftop solar, the importance of time-of-use tariffs for customers and keeping network costs down has emerged as a new priority.

The trend parameter accounts for changes in output, real prices and productivity. It does not account for major changes in customer or government and regulator expectations. As explained above the trend parameter cannot be assumed to fund step changes that have been rejected by the AER based on low materiality. If these are not explicitly funded, we will not be able to provide the expansion in services foreseen in the initial proposal.

The proposal is not an expansion of BAU activities

AusNet has maintained a customer relationship management team consistently since 2020, with ad-hoc support provided prior to this. The team was small and highly reactive, responding to council, MP and complex enquiries. This team has now increased to five in November 2025 and provides proactive and reactive support to 250 of AusNet's largest commercial, industrial and farming customers from 1GWh/y to 200GWh/y.

We have absorbed the costs of other urgent customer service improvements in response to increasing customer expectations where we have been able, including creating a team in 2024 to engage with community on distribution works (now three people), appointing a community energy relationship manager (one person) and expanding our customer communications team (from two people to five people in the past five years).

We are proud of this work but growing needs and expectations of several key customer groups providing important community services – supporting those experience vulnerability, schools, essential services and connecting parties (incl. developers and EV charging connections) – are not being met. The revised step change proposes establishing capability in these areas and addresses the AER's concerns by making clearer the distinction between AusNet's existing engagement functions ("BAU") and the functions we are seeking to create.

Our current period communications campaigns are limited to bushfire preparedness, safety and outage tips. We do not have any regular campaigns on encouraging uptake of tariffs or to shift load which has generally been seen to be a responsibility of retailers in the past.

Finding efficiencies in the past should not be used as grounds to reject future expenditure

In its Draft Decision the AER correctly noted that AusNet reduced customer service-related expenditure in the past two regulatory periods, consolidating and outsourcing call centre operations and outsourcing IT services and business back-office functions driven by a range of factors including cost cutting, managing fluctuating workloads (and the ability to scale up/down) and service level improvements. Our relationship management and communications functions were not affected by these changes.

The regulatory regime is designed to incentivise networks finding efficiencies, from which customers and networks both benefit (70-30) via the CESS and the EBSS. Customers benefitted financially from AusNet finding areas to save via the EBSS and, at the same time, benefitted from improved customer service. Since the transition to our outsourced call centre operations model, customer service has improved. These outsourced arrangements for customer service have been maintained and are not proposed to change in EDPR 2026-31, and we consider them to be in customers' interests.

Cumulatively, step changes total a material amount

Pressures on AusNet are increasing on many fronts, and it is not possible to fund meeting new expectations without explicit opex funding. The AER has deemed the initial step change proposal as immaterial at 0.9% of total opex but as outlined in section 6.4, cumulatively AusNet's proposed step changes total a material amount.

Our updated customer relationship management and communications step change

We have updated our plan for engaging with our customers and communities from our initial proposal "Customer relationship manager and broad communication campaign" step change. The revised scope addresses the AER's feedback and is narrower (more targeted). This change was supported in principle by customer representatives at our 6 November "all in" forum, noting attendees thought AusNet best-placed to determine the overall composition of the step change. The revised step change totals \$10.3m – down 34% on the initial step change proposal.

The customer relationship management component will service four key customer segments who do not receive any consistent relationship management support. When support is occasionally provided to these customer segments, it is done so by AusNet staff going above and beyond in their current roles and is unfunded, but this support is inconsistent across customers, and the volume and complexity of requests (across all customer cohorts including large customers and community energy groups) means this approach is no longer manageable.

The four segments, their unique needs, and the focuses of their relationship managers is outlined below.

Table 6-16: Four key customer segments without consistent relationship management support, their needs and the services to be provided.

1. Communities experiencing vulnerability

This segment is included in response to strong support from stakeholders and a clear expectation that AusNet do more to support those helping our customers, building partnerships to streamline activities and maximise impact. Our stakeholders have been clear that AusNet should not single out vulnerable customers, and instead focus on uplifting all customers and consistency across the state. FTE: 3 Direct beneficiaries: We expect to partner with ~120 organisations supporting our customers per year including community groups, social service organisations, CALD and First Nations groups. Segment includes: • Social service groups • Community groups • First Nations people	Issues faced by segment: Lack of information on energy matters: We are seeing increasing requests for attendance at community events to provide information and advice on energy matters. Power outages: Severe weather (e.g. storms, heatwaves) can significantly impact the community safety, access to facilities, transport and agency. Resilience-ready facilities: Need for greater resilience-ready infrastructure with right-sized assets to support impact of severe weather events and power outages. Resilience coordination across sectors: Resilience projects can be negatively impacted by a lack of collaboration between developers, energy, transportation and climate sectors. CALD community climate-change agency: Low energy awareness and engagement with traditional communications channels. Financially and socially vulnerable: Proportionally higher financial impact of electrification (from gas) as well as low energy awareness and difficulty access communication materials. First Nation vulnerability: Proportionally higher financial impact of electrification (from gas) as well as low energy awareness and barriers to engaging through mainstream methods.	Services to be provided by relationship managers: • Partnerships: Build partnership with key agencies that support these communities to further understand their needs, specialist requirements, channels for engagement and opportunities for participation. • Community events: Attend local governments and local community groups events and festivals (with EMMA vehicles) to build power prepared awareness and community agency. • Work with local CALD program providers, leveraging AusNet's research insights to develop and align CALD engagement strategies and materials with key communities. • Build relationships with community and welfare groups that support financially and socially vulnerable communities and develop a tailored approach to engagement. • First Nations Advisor: Identify and connect with First Nation communities most impacted by severe weather events in alignment with AusNet's Reflect RAP and organisational programs.
2. The education sector		
This segment is included in response to state government policy and growth agendas including: • The Victorian Government's Education and Training Climate Change Adaptation Action Plan 2022-2026 • The Victoria Government's Victoria's Climate Change Strategy FTE: 2 Direct beneficiaries: 667 NMIs primary and secondary schools on the AusNet network Segment includes: • New builds and upgrades • Schools prioritised for resilience upgrades • Schools prioritised for electrification or energy efficiency upgrades	Issues faced by segment: • New builds & major upgrades: Schools being constructed or significantly upgraded (e.g., VSBA projects, new campuses, major refurbishments). • Renewables & electrification initiatives: Projects focused on integrating solar, batteries, or electrification (e.g., SEC programs, sustainability upgrades). • Power outages: Severe weather (e.g. storms, heatwaves) can significantly impact school infrastructure and disrupt student learning and access to school. • Resilience-ready learning facilities: Need for resilience-ready infrastructure to support education continuity (eg unplanned outages can disrupt learning, exams and school operations). • Right-sizing assets: Risk of over-sizing grid assets based on consultant/engineering advice, leading to high tariff assignments and ongoing demand charges that don't match actual usage. • Tariff complexity: Some schools facing high ongoing costs due to tariff structures not being aligned with their consumption patterns. • Resilience coordination across sectors: School projects can be negatively impacted by a lack of collaboration between developers, energy, transportation and climate sectors. • Students' climate-change agency: Support government education programs to promote student agency uplift re: climate change adaptation.	Services to be provided by relationship managers: • Early pipeline engagement: Engage early with education sector stakeholders at the pipeline planning stage to anticipate upcoming projects and share network capacity insights. • Preliminary network assessments: Provide early advice on potential grid constraints, required augmentations, and tariff impacts to inform project planning and avoid costly oversizing. • Dedicated liaison & escalation: Serve as a single point of contact for problem-solving and escalation, maintaining oversight and ensuring timely resolution of operational issues. • Access to data: Build awareness and access to energy-related datasets that enable stronger and more informed decision making (eg locations). • Resilience partnerships: Collaborate with authorities to identify and prioritise vulnerable schools, sharing outage data, energy-related datasets to support resilience planning and effective decision making. • Integrative schools program: Promote activities that build energy awareness and uplift student agency.
3. Housing and electric vehicle (EV) charging for developers		
This segment is included in response to strong growth in	Issues faced by segment:	Services to be provided by relationship managers:

developer interest and a desire for advice, including in response to state government policy and growth agendas including: • The Victoria Government's Victoria's Climate Change Strategy • The Victorian Government's Victoria's Housing Statement: The Decade Ahead 2024-2034 • The Victorian Government's Zero Emissions Vehicle Roadmap • The Victorian Government's Destination Charging Across Victoria program FTE: 1 Direct beneficiaries: Approximately 120 businesses (70 housing developers, 50 EV charging developers noting this space is evolving rapidly) Segment includes: • Land developers • Residential builders • Estate Managers/Project Managers • Civil contractors • Planning consultants/surveyors • Local councils • Electrical consultants/designers • Embedded network operators • Public charging networks incl. fast-charging corridors and urban hubs • Fleet and depot charging • Residential and workplace charging • Destination charging • Pole-mounted and kerbside charging	• Ad-hoc support: Connections treated individually, no opportunity to partner on strategic ambitions. • Site and connection assessment: Challenges in locating suitable locations, facilitating network growth and support for initiatives. • Lack of resilience coordination across sectors: Developments can be negatively impacted by a lack of collaboration between housing, energy, transportation and climate sectors. • Limited knowledge and capacity: Developers can lack access to the latest data, tools, and expertise needed to design resilient housing. • Community impact: Projects can impact community sentiment due to outages, property access and noise/dust. • Tariff complexity and cost: High demand charges, uncertainty around optimal tariff structures. • Limited grid capacity: Some regions lack the electrical grid capacity to support widespread EV charging, especially during peak demand or extreme weather events. • Fragmented EV charging market & technology: Multiple providers, evolving standards, and lack of consistent approach to technology or business models. • EV charging land use & permitting: Approval issues for land/asset use, especially for pole-mounted and kerbside charging.	• Early pipeline engagement: Engage early with operators, councils, and developers to understand demand, share network insights and inform site selection. • Preliminary network assessments: Provide upfront advice on grid capacity, constraints, and augmentation needs for proposed sites. • Dedicated liaison & escalation: Serve as a single point of contact for issue resolution and escalation, maintaining oversight across projects. • Innovation & regulatory partnerships: Collaborate on trials (e.g., pole-mounted charging), support regulatory reform, and share learnings to shape sector standards. • Access to data: Build awareness and access to energy-related datasets that enable stronger and more decision making (e.g. locations). • Local insights: Share in-depth community knowledge to support planning and risk minimisation (e.g. opposition to projects due to local priorities). • Tariff insights & support: Uplift knowledge on tariff structures and opportunities to leverage AusNet infrastructure (e.g. poles) to support EV charging. • Policy alignment: Facilitate dialogue between developers/EV chargers and regulators and/or councils to help them stay ahead of evolving climate and energy policies, zoning laws, and incentive programs.

4. Utilities and essential services

This segment is included in response to strong growth in utility and essential service demand for support including in response to government and industry decarbonisation and climate preparedness agendas including: • The Victoria Government's Victoria's Climate Change Strategy	Issues faced by segment: • Resilience-ready facilities: Need for greater resilience-ready infrastructure with right-sized assets to support impact of severe weather events and power outages. • Resilience coordination across sectors: Resilience projects can be negatively impacted by a lack of collaboration between developers, energy, transportation, essential services and climate sectors.	Services to be provided by relationship managers: • Partnerships: Build partnership with utilities, essential services and local government that support agency-related community engagement. • Community events: Collaboratively organise and attend events with utility, essential services and local government partners to build community energy resilience and agency. • Dedicated liaison and escalation: Serve as a single point of contact for problem-solving and

- The Victorian Government's Victoria's Housing Statement: The Decade Ahead 2024-2034 - Water corporations' commitment to net zero by 2030. FTE: 2 Est. beneficiaries: 54 orgs, 11,525 NMs Servicing: - Water authorities (10 orgs, 1728 NMs) - Telecommunications (6 orgs, 5495 NMs) - Essential services (4 orgs [Police, Ambulance Country Fire Authority, Fire Rescue Victoria], 752 NMs) - Local government (34 orgs, 3550 NMs)	Low community resilience planning awareness: Communities in highly-affected areas with low resilience literacy including recent 'tree' and 'sea changers' with metro energy expectations now living in regional or rural communities.	escalation, maintaining oversight and ensuring timely resolution of operational issues. - Innovation programs: Collaborate on trials and share learnings to shape sector standards. Access to data: Build awareness and access to energy-related datasets that enable stronger and more decision making (e.g. where to locate investments). Local insights: Share in-depth community knowledge to support planning and risk minimisation (e.g. opposition to projects due to local priorities).

Source: AusNet

We also propose a more targeted communication program, focussed on communication campaigns designed to influence customer behaviour in response to price signals. The intent is to deliver tangible benefits such as deferring network augmentation by reducing peak demand and unlocking greater PV exports.

This approach aligns with the clear direction from the AER to do more on tariffs. In its draft decision the AER commented *"It is imperative for AusNet to use all the levers available to it, particularly tariffs, to optimise network utilisation. We consider that AusNet should engage further with stakeholders, including with retailers, to encourage take up of cost reflective tariffs and improve understanding of how tariff reform can complement (or mitigate) its proposed expenditure"*⁸⁹. The fact that cost-reflective tariffs exist does not lead to higher network utilisation – the response to tariffs does. Our communications proposal directly addresses the current gap in customer awareness of and engagement with pricing signals, which is limiting the effectiveness of tariff signals today. This gap is evidence by our Segmentation study ([here](#)). Targeted communications are needed to explore whether lifting awareness and understanding results in widespread behaviour changes. Only then can customers respond to pricing signals. This is consistent with the AERs and government expectations for DNSPs and we received support from our stakeholders in our November 2025 "all-in" engagement session.

It is important to note that we do not expect tariff campaigns to be self-funding, as the benefits flow directly to customers and any capex savings would not be realised until subsequent regulatory periods. Therefore, unless a specific allowance is approved for this activity, we will not deliver tariff campaigns in the next regulatory period.

The value of this program

Without dedicated funding, we will be unable to meet growing customer demands for support, information and advice, leaving them disempowered and lacking agency in the energy transition. These customer cohorts are asking AusNet for this support and expect us to provide it, noting no other parties including government or retailers are filling this gap. The refined program is consistent in objective and intent of the program in our initial Proposal, which was strongly supported, and customers indicated a willingness to pay for. This more targeted program is prudent, supported by our customer engagement and consistent with the expectations of customers and the Victorian Government and therefore we propose its inclusion in the 2026–31 allowance is a necessary investment.

This opex step change is fundamentally in the interests of all customers because it directly addresses the evolving needs and expectations of our diverse customer base during the energy transition. While it does not fit neatly in the traditional step-change criteria (being a regulatory obligation or capex/opex trade-off), the proposed investment is a targeted response to a significant expansion in expectations of AusNet. It responds to clear and repeated feedback from customers, stakeholders, and government that AusNet must do more to support, inform, and empower communities, including and especially those outlined above.

The value of this program is demonstrated by:

⁸⁹ Overview | AER Draft decision – AusNet Services distribution determination 2026-31, page viii

- **Strong customer support:** Extensive engagement, including our November 2025 workshop and five customer forums in late 2024 confirmed broad willingness to pay for enhanced engagement and communications. Customers and representatives consistently indicated that AusNet is best placed to fill critical information and support gaps, and that these services are not being provided by other parties.
- **Clear outcomes for customers:** The revised program is sharply focused on meeting social obligations and delivering benefits to customers and communities, including improved resilience for communities, helping customers respond to price signals and lower their bills, knowledge building, improved decision-making, and time and cost savings. The benefits of this investment will be further amplified across the communities and customers the beneficiaries serve. The outcomes being delivered will be monitored and reported to our Customer Consultative Committee.
- **Alignment with regulatory and policy expectations:** The program is designed to meet the clear direction from the AER and government for DNSPs to play a more active role in customer engagement, particularly as the energy system becomes more complex and customer participation is essential for a successful transition. The precedent set in Citipower, Powercor and United Energy's draft decisions to approve expenditure for energy care (partnerships with organisations supporting customers), a vulnerable customer assistance program and a First Peoples program demonstrates the value seen in improving customer support and acknowledges that these types of activities are not business as usual for networks. Social service organisations have repeatedly and over many years expressed the importance of consistency in networks' approach to support across the state, and approving this more targeted step change would lead to more equitable outcomes for communities across Victoria.
- **Efficient and prudent investment in response to immediate pressures:** By proposing this as a category-specific forecast, AusNet ensures transparency and avoids embedding costs into ongoing base opex, allowing for periodic review and adjustment as customer needs evolve. This approach is consistent with regulatory precedent and ensures customers only pay for services that deliver proven value. Proposing it as a category-specific forecast aligns with the precedent set in Powercor's draft decision on its First Peoples program. We consider it highly likely the new resources identified will be required on an ongoing basis in upcoming regulatory periods. However, we recognise the level of demand for these services may evolve from period to period during the energy transition. We also recognise our targeted communication campaigns may not need to be a recurring uplift and may be more appropriate as a category specific forecast. Therefore, we have aligned our proposal with the AER preferred approach as applied for Powercor to include programs of this nature as a category-specific forecast in the 2026-31 period.

In summary, this step change is a necessary and efficient investment that will enable AusNet to deliver the level of customer support, information, and engagement that customers expect and deserve. Without it, critical customer cohorts would remain underserved, and the broader objectives of the energy transition—affordability, reliability, and customer empowerment—would be at risk.

Table 6-17: Customer relationship management and broad communications step change forecast (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Customer relationship managers	1.5	1.5	1.5	1.5	1.5	7.3
Communications	0.5	0.5	0.5	0.5	0.5	2.4
Total opex	2.0	2.0	2.0	2.0	2.0	9.8

Source: AusNet

6.7.3.3.4. Flexible services and non-network solutions

We do not accept the AER's Draft Decision on this step change. As requested by the AER we have provided further information and updates on this program, including refining costs and more clearly defining the scope. This step change is related to our Demand Driven Augmentation in the LV network & Flexible services and Distribution System Operator (DSO) business cases. These business cases set out the basis of the prudence and efficiency of flexible services and is a key part of our efforts to improve network utilisation, keeping long run customer costs low.

This step change meets the AER's step change framework because it represents incremental costs not captured in the base year or trend, is prudent and efficient, and delivers net benefits to customers. It is driven by a capex/opex trade off, because procuring flexible services and non-network solutions avoids or defers LV augmentation and other

network upgrades. These costs enable dynamic management of DER and CER connections, supporting customer exports and reducing augmentation costs.

We outline the two components of this opex step change below:

Table 6-18: Flexible services and non-network solutions step change cost breakdown (\$m, real 2025-26)

	Total	Changes from Initial Proposal
New resources	1.6	No change, scope of expanded service offering unchanged
Flexible services payments	0.2	Updated to reflect the latest forecast energy at risk (KWh), reduced flexible services within the 'DDA in the LV network and flexible services Business Case'. Updated approach to calculate the value of payments (\$/KWh) based on AusNet's existing demand management customer payments.
Flexible services & non-network solutions	1.9	Reduced step change cost by 78%

Source: AusNet; numbers may not add up to total due to rounding.

The AER recognises it is prudent for networks to expand their dynamic management capabilities and that the costs associated with this uplift is not principally for business-as-usual activities but represents continued growth and adaptation of our business. However, we do not agree with the AER's Draft Decision that these costs are captured via growth in total opex.

- As stated in our Regulatory Proposal, we have absorbed \$3.0 million as an affordability measure for expected increases as part of this program, leaving these amounts included in the step change as amounts that are new emerging costs that will be prudently incurred.
- The activities included in this step change are material adaptations of our business activities and service offering and cannot be funded within our base or trend. Specifically, these new arrangements represent a significantly expanded scope beyond the growth in activities associated with traditional connections, which we consider our base year and trend parameters are designed to cover. This expanded scope includes:
 - Managing our new flexible export arrangements for all new solar customers. We receive approximately 20,000 new solar connections per year on average, and we have forecast the majority (70%) will opt-in for flexible exports. In addition, we intend to proactively support existing customers to transition to flexible export limits, where this would increase their potential to export.
 - The forecast step change in battery connections on our network is also significant. Under the Commonwealth Government's Cheaper Home Battery scheme, customers are expected to increase their network support participation by importing and exporting to the grid during constrained periods. This will likely be achieved through AusNet procuring non-network solutions from aggregators. This represents a new stakeholder group with whom AusNet will need to increase its resourcing in order to effectively establish and maintain relationships.
 - The forecast step change in other CER, such as community scale batteries and EV chargers, will also drive increased activity on our network. Our connection forecast includes 155 community battery connections. Due to the size and capability of these technologies, these new connection types represent material opportunities for customers to provide flexible services *if* AusNet has established the capability and resources to manage and respond to these requests from CER customers.

Therefore, we have re-proposed additional resources to manage the anticipated demand for flexible services and non-network opportunities in the upcoming period. The resources will be required to administer support for customers who opt-in to provide these services, including responding to prospective enquiries, guiding customers to opt in to flexible services, fielding ongoing operational enquiries and managing the volumes of customer interactions expected. Our DSO capex proposal has assumed partial automation which allows us to limit this step change to customer-facing functions only. Engineering resources for demand forecasting, location-specific impact assessment and customer demand response modelling are separately funded through capex and therefore not included.

This FTE uplift is justified by our observed resourcing in supporting customers in the connection process during this current period, after the implementation of the emergency backstop mechanism.

Consistent with our capex proposal, we have accepted the AER's decision not to include new resources to manage the upcoming regulatory obligation for the AEMO CER Data Exchange.

We recognise our initial proposal did not sufficiently demonstrate the benefits or justify the amount of flexible services assumed and how this linked to our payments. Our Revised Proposal approach strengthens this justification by showing that it:

- **represents a more realistic level of flexible services payments that is likely to be available in the upcoming period.** Further analysis done since the Draft Decision, allowed us to refine the expected \$/MWh that would be appropriate for customers to opt-in and respond, which has brought down our proposed costs. This \$/MWh has been based on our assessment of recent trials and our current arrangement to procure demand management. We consider this addresses the concerns from EMCa around the robustness of calculation method and provides evidence that these payments are reasonable.
- **demonstrates that this investment is prudent and efficient** due to the deferred augmentation benefit in our Demand Driven Augmentation in the LV network & Flexible services business case. This step change and associated cost benefit analysis includes the value of payments to procure demand response where it relates to our assumed deferred LV augmentation. We anticipate the scope and scale of services we can procure is likely to expand over the forthcoming regulatory period, but have not assumed a step change for payments beyond this program and will assess the capex-opex trade-offs associated with other non-network solutions at the time of investment. This approach ensures we have not double counted for capex and opex solutions to address our network constraints in our proposal. However, we reiterate our proposed Flexible Services capability is NPV positive.

This updated step-change is consistent with the step change criteria and represents a capex-opex trade-off. The value of the totex for flexible services, including this step change is lower than the deferred augmentation benefit which indicate it will be in our customer's best interest to expand our services to capture this additional value. If the AER does not accept this step change, we would be unable to provide flexible services in a meaningful way to improve network utilisation and avoid additional augmentation cost from traditional network upgrades, and we therefore would consider Option 1 (augmentation only) in our business case the only viable preferred option.

Table 6-19: Flexible services and non-network solutions step change forecast (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Flexible services & non-network solutions	0.1	0.2	0.3	0.5	0.7	1.9

Source: AusNet

6.7.3.4. Aligned to capex programs

These step changes are directly linked to capital programs and represent prudent capex/opex trade-offs that deliver net benefits to customers. They involve incremental and unavoidable costs not captured in the base year or trend and meet the requirements of the AER's step change framework.

Each initiative, hazard tree removal, flexible services, early fault detection, and digital transformation – addresses critical drivers such as bushfire safety, network resilience, DER integration, SWER reliability, and ICT modernisation. Updated business cases demonstrate these programs are cost-effective, NPV positive, and aligned with the National Electricity Objective, enabling customers to benefit from improved safety, reliability, and efficiency while avoiding or deferring significant future capital expenditure.

Table 6-20: Proposed step changes aligned to capex programs

Step change	AER step change category	Initial Proposal 2026-31 (\$m)	Draft Decision 2026-31 (\$m)	Revised Proposal 2026-31 (\$m)
Hazard tree program	Capex/Opex trade off	15.0	0.0	6.2
Early Fault Detection	New initiative and opex associated with capex	7.8	0.0	1.0
Digital	New initiative, capex/opex trade-off and opex associated with capex	39.9	13.3	20.9

Source: AusNet

6.7.3.4.1. Hazard tree program

We do not accept the AER's Draft Decision and have provided further information as requested by the AER. This step change is a necessary, efficient and targeted measure, reflecting incremental costs that are not captured in our base year or trend.

This step change aligns with the AER's step change framework because:

- it represents a capex/opex trade off, where targeted operating expenditure on hazard tree removal reduces the need for network hardening investments;
- It is supported by the NER requirement – namely the obligation for the AER to consider the extent to which a forecast "efficiently reduces the risk and impact on consumers of power outages caused by severe weather events." under clause 6.5.6(e)(e)(4). That is, if the AER doesn't consider it meets the criteria of a capex/opex trade-off, then it does meet the step change criteria of a new regulatory obligation; and
- it materially improves resilience by reducing the likelihood and consequences of outages during storms and climate-related events.

Hazard tree removal is a direct and effective lever for meeting resilience objectives. In our Revised Proposal, we have added hazard tree removal into our resilience modelling that underpins our resilience program. This model optimises the mix of various resilience solutions, including various network hardening solutions. The model takes into account their various effectiveness rates and determines an economically optimised program across a range of capex and opex (hazard tree) solutions. This step change is to fund the economically optimal increase in hazard tree removal which has been determined by the model.

Our resilience modelling shows that it is NPV positive to prune or remove [C-I-C] hazard trees on top of our BAU program, at a cost of \$6.2 million over the 2026-31 period – or \$1.2 million p.a. – where this reduces our 2050 risk by \$5 million. As a result, we have updated our hazard tree opex step change to reflect the outcomes of the updated resilience modelling.

The effect of adding the hazard tree program as an option in the resilience modelling allows us to optimise the mix of hazard tree removal and network hardening. These are related and complementary measures given that hazard tree removal prevents outage risk caused by trees that cheaper network hardening options cannot address. For example, covered conductors cannot prevent large trees from falling onto a powerline causing outage. Without a hazard tree program in the mix to mitigate storms-related outages, the network hardening investment increases by \$45.6 million, yet the additional \$45.6 million is inferior in addressing these issues.

We have updated our hazard tree effectiveness to 9.1% and this is based on the product of the following:

- the number of hazard tree impacts per year as a portion of vegetation outages 20.1%
- the ability for a trained arborist to detect all hazard trees is 90%
- the ability to be able to detect a hazard tree which could impact the network was taken as 50%

See chapter 5.10 for more information on our resilience modelling.

Table 6-21-19: Hazard tree program step change forecast (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Hazard tree program	1.2	1.2	1.2	1.2	1.2	6.2

Source: AusNet

6.7.3.4.2. Early Fault Detection

We do not accept the AER's Draft Decision on this given its safety implications on the SWER network. The Single Wire Earth Return (SWER) network comprises of long-stretches of single-wire conductors serving remote and bushfire prone areas, many of which are over 50 years old and vulnerable to defects caused by lightning strikes and environmental wear. Traditional inspection methods are unable to detect these hidden faults, which, if left unaddressed, can result in catastrophic failures and bushfires. Early Fault Detection (EFD) technology offers a proactive solution by continuously monitoring the network and identifying faults before they escalate, thereby significantly reducing bushfire risk and improving community safety.

EFD devices provide continuous monitoring for up to 3.5km of conductors per unit, enabling targeted oversight where risk is greatest. This approach has been successfully operationalised on other Australian networks and documented internationally, demonstrating its ability to defer conductor replacements while maintaining

compliance with safety obligations. By leveraging EFD, AusNet achieves a higher level of intervention efficiency, avoiding unnecessary capital expenditure and optimising lifecycle management.

This step change meets the AER's step change framework because it represents incremental costs not captured in the base year or trend, is prudent and efficient, and delivers net benefits to customers. It is primarily driven by a capex/opex trade off, where targeted operational expenditure on EFD technology prevents failures on SWER lines, reducing bushfire risk and avoiding costly replacements. This investment addresses critical safety obligations and improves reliability, consistent with the NEO and the AER's criteria for step changes.

Since submitting our Regulatory Proposal, we have received further insights from IND-T's rollout across North America, including deployments by Fortis and Ederson in Canada in the US. These utilities invest up to \$1 billion annually in vegetation management, enabling a targeted inspection approach. This scale of investment supports program efficiencies and builds confidence in prioritised risk-based responses.

Similarly, AusNet's approach integrates EFD into its asset strategy to compliment cyclic inspections and proactive replacement, enabling that latent defects on long SWER lines are detected before failure. This is particularly critical in bushfire-prone regions where the consequences of failure are severe.

We recognise the EFD devices program submitted with our Initial Proposal was presented as not offering net economic benefits, based on the information available at the time, and therefore, was rejected in the draft decision. Our revised approach to assessing the costs and benefits of EFD devices now appropriately recognises that a key benefit of this technology is that it is expected to be a viable, cost-effective alternative to conductor replacement. This reflects maturation in the effectiveness of EFD device technology since our initial proposal was developed, following more widespread deployment on electricity distribution networks, giving us greater confidence in its condition- and risk-monitoring capabilities.

Responding to the AER's concerns

The AER did not accept EFD because it did not see a clear regulatory obligation or sufficiently demonstrated net benefits; EMCA raised concerns about cost estimate robustness. AusNet is responding by making the driver of EFD clearer, as a SWER safety and a bushfire-risk mitigation program, clarifying that traditional inspection methods can miss latent conductor defects on too long, remote SWER spans. The expenditure is incremental to base and focused on the defect prevention that avoids catastrophic failures and downstream asset replacement.

We acknowledge the AER's feedback on this step change and have provided a strengthened justification and technical evidence summarised below and included in ASD – AusNet – Conductors – 1 Dec 2025.

- **Clarifying the driver:** EFD is a targeted SWER safety and bushfire-risk mitigation program, addressing latent defects on long, remote spans where traditional inspection methods fail. These defects pose catastrophic failure and ignition risks that cannot be economically managed through visual inspections alone
- **Regulatory obligation and risk context:** The Electricity Safety Act requires risks to be managed "as far as practicable." EFD enables AusNet to meet these obligations by providing continuous monitoring of high-risk conductors, reducing bushfire ignition potential and improving public safety.
- **Economic justification:** The revised analysis demonstrates that EFD is a cost-effective alternative to conductor replacement, delivering positive NPV outcomes when combined with target replacements.
- **Technology maturity:** Since the initial proposal, EFD has been successfully operationalised on other Australian networks and internationally, with documented performance improvements. This maturation gives AusNet confidence in its ability to deliver risk-based interventions and defer replacements without increasing network risk.
- **Cost robustness:** Detailed cost breakdowns for device procurement, installation, and supporting infrastructure have been provided, supported by competitive market testing and sensitivity analysis across discount rates, unit costs, and demand scenarios.
- **Stakeholder engagement:** Energy Safe Victoria has been briefed on the proposed expenditure and its alignment with bushfire mitigation obligations, reinforcing the program's compliance and safety credentials.

Table 6-22: Early Fault Detection step change forecast (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Early Fault Detection	0.2	0.2	0.2	0.2	0.2	1.0

Source: AusNet

6.7.3.4.3. Digital

We have revised the digital opex step change to reflect updated program scope and costings. The revised step change totals \$20.9 million (\$m, real 2025-26) over the 2026–31 regulatory period and relates to costs not captured in the 2022–23 base year opex.

This step change meets the AER's criteria because it:

- Represents incremental costs not captured in the base year or trend.
- Is prudent and efficient, supported by business cases and NPV analysis.
- Delivers outcomes to consumers through improved network reliability, customer engagement, and operational efficiency, consistent with the NEO.

The primary driver is a capex/opex trade-off and opex tied to efficient capex, this also includes SaaS implementation program costs which have shifted from capex to opex due to an accounting rule change. This classification is purely due to the International Financial Reporting Interpretations Committee (IFRIC) prescriptive guidance change introduced in early 2021, which applies to the implementation and configuration of software-as-a-service (SaaS) platforms. Prior to this, these costs were treated as capital expenditure. The nature of the investment has not changed, only the accounting treatment has. The costs are non-recurrent and will only be incurred if we proceed with the associated projects. Overall, this step change supports AusNet's digital transformation strategy.

Responding to the AER's concerns

The AER has a number of concerns about the Digital step change, leading EMCa to conclude it was overstated by around 50-60%. These concerns were:

- Not satisfied with prudence and efficiency. These concerns include overstatement of justified level of scope, overestimated costings, unconvincing evidence of ability to deliver program and lack of allocation of forecast project costs.
- Additional opex would be offset by business savings.

Regarding prudence and efficiency, these concerns reflect concerns about the programs as a whole (not just the opex component), and are substantively addressed in the Capex chapter, Section 5.14. In summary, we have:

- Revalidated and refined digital programs to highest value initiative scope
- Updated cost profiles, with delivery partner estimates, with annual phasing and total amounts for each ICT initiative.
- Revised business cases with NPV analysis and options assessment to demonstrate prudence and efficiency.

Regarding expected offsets to opex, the Revised Proposal addresses this directly by refining the scope and costings of the step change to remove any elements that deliver offsetting efficiencies or are self-funding. To address this, we have:

- Undertaken a program-by-program assessment of opex efficiencies that form part of the business case;
- Removed or reduced opex amounts associated with licensing and ongoing support opex where there is evidence that these could be funded via productivity benefits.

We also clarify the treatment of SaaS costs by separating non-recurrent implementation costs (per revised accounting guidance) from recurrent licensing and support costs. We have removed reported non-recurrent SaaS costs of \$1.4 million from the base year. This provides transparency and aligns with the AER's expectations.

Applying the correct accounting treatment of SaaS implementation costs results in a \$9.1 million (\$, real 2023-24) increase in the opex step change, relative to our Initial Proposal.

Changes from Initial Proposal

AusNet is proposing an opex step change of \$20.9 million (\$, real 2025-26) for project implementation and ongoing software licensing and support costs associated with the forecast 2026-31 ICT program. There are 11 ICT programs proposed in the upcoming regulatory period and this step change reflects the opex associated with these programs. A brief description of each program is provided in the table below, alongside the opex associated with each program.

For clarity we have split the opex associated with each program into two categories:

- Implementation opex costs for SaaS applications (non-recurrent opex)
- Ongoing licensing and support opex costs (recurrent opex)

The justification for the opex associated with each of these programs is provided in the relevant ICT business cases provided in this Revised Proposal. This includes details on the requirements of each project, the options considered, and NPV analysis to demonstrate the preferred solution and proposed spend (capex and opex) is efficient and in the long-term interest of customers.

Programs with an offsetting business cost benefit

The licensing and ongoing vendor support opex costs for our ICT program are \$20.2 million (\$, real 2023-24) which are recurrent in nature. These are additional, new recurrent costs associated with new ICT programs proposed for the 2026-31 period. Therefore, this expenditure is incremental to existing recurrent expenditure embedded in our opex base year.

As part of our response to the AER's draft decision we have made updates to best reflect a more refined and updated outlook of our Digital expenditure in 2026-31. For clarity we are **not** proposing the amounts relating to licensing and ongoing support opex where there is an opex offset, this is in response to the AER's concerns where programs are self-funding to exclude them. In our Initial Proposal we had included a negative Digital efficiencies step change (-\$3.9 million) to account for expected productivity benefits. We are not reproposing this step change but instead are foregoing claiming recurrent licencing and ongoing vendor support opex associated with specific programs to reflect these efficiencies. The amount of opex we are foregoing is \$8.7 million (\$, real 2023-24), higher than the \$3.9m (\$, real 2025-26) Digital efficiencies negative step change included in our Initial Proposal. This is in direct response to the AER's and EMCA's concerns.

The total costs and the adjustments made to account for expected business benefits are shown in the table below.

Note that these reductions have been applied in addition to the AER's productivity factor, which reduces our opex forecast by \$21.4m (\$, real 2025-26). The aggregate impact of the AER's productivity adjustment and the opex reduction due to the expected business cost benefit reduces our opex by \$8.7 million. This highlights the conservative nature of the forecasts, and the need for the AER to carefully consider the sufficiency of total opex in making the Final Decision so as to ensure they reflect prudent and efficient costs and do not include downward bias.

Table 6-23: Adjustments made to Digital opex step changes to account for business benefits (\$, real 2023-24)

Item	\$s
Total recurrent licencing and support costs associated with new 2026-31 programs	\$20.2 million
Deductions made for anticipated business benefits	
Customer engagement platform	\$1.3 million
Field Enablement ERP	\$6.1 million
Network model management geospatial and asset model tools	\$0.6 million
Asset Risk Management	\$0.6 million
Recurrent licencing and support costs associated with new 2026-31 programs claimed in Digital step change	\$11.5 million

Source: AusNet. Totals may differ due to rounding.

Step change is not captured in base or trend

To validate the prudence of our revised step change, we undertook analysis comparing, base year costs (RY23 actuals), RY25 actuals and expected RY26 amounts for ongoing Digital costs. This analysis assessed what digital opex would look like if these amounts were rolled forward. The findings show that the current period digital opex is approximately \$3 million per year above our FY2023 baseline.

We have not included this amount in our step changes, as these costs are already embedded in current operations and do not form part of the incremental step change associated with new programs in the 2026-31 period. Notwithstanding this, if the AER's adjustment to claw back current period bushfire liability insurance underspends is upheld, there should be a similar adjustment made to account for the overspend relative to allowance of Digital opex in the same period.

For avoidance of doubt, the proposed step change only covers additional costs for new ICT programs and SaaS implementation in the 2026-31 period.

Non-recurrent Software as a service (SaaS)

The AER noted they did not have enough time to assess the addition of SaaS to our opex forecast from capex. As noted in IR#15⁹⁰ our Revised Proposal includes new non-recurrent SaaS costs as operating expenditure in 2026-31. This classification is purely due to an accounting rule change introduced in early 2021, which applies to the implementation and configuration of software-as-a-service (SaaS) platforms. Prior to this, these costs were treated as capital expenditure. We highlight that the nature of the investment has not changed, only the accounting treatment. The costs total \$9.1 million (\$, real 2023-24) and form part of our forecast.

As explained above, to avoid double counting, we have excluded non-recurrent SaaS expenditure from our base year totalling \$1.4 million (\$, nominal), so the SaaS implementation and configuration costs that form part of our step change forecast do not overlap with costs included in our base opex.

Program-by-program breakdown

In the below table we have distinguished project implementation opex from licensing and supporting costs and highlighting the programs that are self-funding.

Note more detailed descriptions of the various programs are provided in the Capex chapter, Section 5.14.

Table 6-24: Breakdown of opex step change by program and type (\$m, real 2023-24)

Program	Description of program	Project Implementation opex (non-recurrent)	Licensing & support (recurrent and no opex offset)	Licensing & support (recurrent with an offsetting business benefit) [NOT REQUESTED]	Total step change
04 – Business systems (TAM – systems)	Recurrent investment to maintain the resilience and existing capabilities of our digital applications. Opex represents refresh costs for existing SaaS applications and anticipated forced migration to SaaS solutions.	0.7	1.3	-	2.0
06 – Asset risk management	Non-recurrent expenditure to asset management data, risk analytics, and decision-making capabilities. Incremental licensing and support opex assessed as self-funding through maintenance cost efficiencies.	-	-	0.6	Self-funding
07 – Customer engagement platform	Non-recurrent expenditure to uplift AusNet's customer engagement systems to meet the growing needs of our customer base. Project opex represents configuration of AusNet's SaaS CRM. Licensing and support opex assessed as self-funding through contact centre and business process efficiencies.	7.6	-	1.3	7.6
08 – Cyber security	Program incorporates recurrent and non-recurrent expenditure to advance AusNet's cyber security maturity to Security Profile 3 under the Australian Energy Sector Cyber Security Framework (AESCSF). Incremental recurrent opex required for the associated new digital processes, systems and tools.	-	1.7	-	1.7
10 – ADMS energy management (IT long life)	Non-recurrent expenditure for continuation of our ADMS implementation program by delivering enhanced network operations and grid optimisation capabilities. Incremental licensing and support opex required for new capabilities improving customer outcomes.	-	7.1	-	7.1

⁹⁰ IR015 – Allocation of Opex SaaS costs

10 – ADMS energy management (SCADA/OT portion)	As above; non-recurrent for our ADMS implementation program with incremental licensing and support opex required for new capabilities improving customer outcomes.	-	0.2	-	0.2
11 – Field Enablement ERP	Non-recurrent expenditure to enhance the digital tools used to coordinate and execute work by AusNet and delivery partners. Incremental licensing and support opex assessed as self-funding through field execution productivity improvements.	-	-	6.1	Self-funding
12 – Network model management geospatial and asset model tools	Non-recurrent investment to enhance our network models and geospatial capabilities to enable more effective real-time operation and management of the HV/LV network. Incremental licensing and support opex is assessed as self-funding through productivity efficiencies.	0.2	-	0.1	0.2
12 – Network model management geospatial and asset model tools (IT long life)	As above; investment to enhance our network models and geospatial capabilities, with incremental licensing and support opex is assessed as self-funding through productivity efficiencies.	-	-	0.5	Self-funding
14 – DSO/Future service provider hub	AusNet's expenditure to uplift capabilities to meet the evolving needs of our customer base, through supporting continued adoption of Distributed Energy Resources (DERs). Opex represents configuration of AusNet's SaaS portal and incremental licensing and support to enable flexibility services for our customers.	0.2	0.8	-	1.0
17 – Metering systems SCS	Program consists of recurrent expenditure to maintain the reliability and security AusNet's metering systems, and non-recurrent investments meet new regulatory requirements including increasing volumes of 5-minute settlement data and the Flexible Trading Arrangements (FTA) Rule change requirements. Opex for FTA implementation and incremental licensing and support are included in AusNet's cost pass through application.	0.4	0.4	-	0.8 Covered through Flexible Trading Arrangements pass through (FTA)
Total		9.1	11.5	8.7	19.8

Note: In relation to our ICT program, all of the licensing and ongoing support opex costs are recurrent in nature. The implementation opex costs of our program are non-recurrent. Last column is equal to 19.8 as 0.8 has been deducted off the total amount to ensure FTA is not double counted.

Source: AusNet

The annual breakdown of the total step change can be found below:

Table 6-25: Total digital step change forecast (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Digital	1.9	3.1	4.6	4.3	6.9	20.9

Source: AusNet

6.7.3.4.4. Fleet electrification

We do not accept the AER's draft decision on our fleet electrification step change as we are no longer proposing to include electric vehicle costs in our fleet capex forecast. Consistent with the AER's draft capex decision, we will look for opportunities within the 2026-31 regulatory period to electrify our fleet where there is cost neutrality with ICE

vehicles. As such, fleet electrification will only occur when it is self-funding, and we have removed additional capex of approximately \$6 million and the negative opex step change (-\$0.7m) from our forecasts.

6.7.3.5. Oppose regulatory treatment

This category addresses situations where AusNet does not agree with the AER's proposed adjustments because they do not align with the opex forecasting framework or National Electricity Rules. Opposing the regulatory treatment means challenging decisions that apply retrospective adjustments, mischaracterising cost drivers, or introduce mechanisms that distort efficient cost recovery.

In this case, it relates to the AER's approach of applying a negative step change and a non-recurrent efficiency gain for bushfire liability insurance based on historical underspends. These adjustments assume past conditions will persist and treat risk management outcomes as repeatable efficiencies, which is inconsistent with forward-looking principles. The section explains why the treatment is inappropriate.

6.7.3.5.1. Bushfire liability insurance

In our 2021 – 2026 distribution determination, the AER included a step change of \$45.1 million (\$2020-21), based on an anticipated material increase in premiums from the previous regulatory period. The AER noted that it considered the long-term interests of consumers is better served if the appropriate incentives remain with the businesses to actively work to moderate expected increases in insurance premiums over the next regulatory control period.⁹¹

Our actual spend on insurance premiums over the 2021 – 2026 period has been lower than the forecast allowance reflected in our 2021 - 2026 distribution determination (-\$21.7m over five years) as a result of changes in market conditions and our use of a captive insurance arrangement which seeks to manage volatility in global insurance markets and optimise the cost of insuring operational risk.

In our Initial Proposal, we proposed a \$10.5 million (\$2025/26) step change for insurance premiums-related opex in our Initial Proposal.

In its draft decision, the AER did not accept our proposed step change for insurance premiums. Additionally, the AER proposed three adjustments relating to our insurance premiums, as follows:

- a non-recurrent efficiency gain of \$23.4 million (\$2025/26) is included in base year opex, which increases our opex allowance in each year of the 2026 – 2031 regulatory period in an amount equal to our underspend on insurance premiums in the base year (i.e. actual insurance premiums less the premium allowance in the base year);
- a negative step change adjustment of -\$58.1 million (\$2025/26), calculated as the difference between the premium allowance and actual premium in the final year of the current regulatory period, that decreases our opex allowance in each year of the next regulatory period; and
- an adjustment to the calculation of the EBSS carryover amounts (of -\$23.4 million (\$2025/26)) arising from the application of the EBSS during the 2021 – 2026 RCP to reflect the non-recurrent efficiency gain adjustment made to base opex.

The AER stated (at page 34 of its opex draft decision):

To remove the insurance premium component of the final year increment, our alternative estimate for the draft decision includes a combination of a negative insurance step change and a non-recurrent efficiency gain. This ensures our alternative estimate of total forecast opex meets the opex criteria and the EBSS that provides a fair sharing of efficiency gains and losses between NSPs and network users.

The negative step change, calculated as the difference between the final year premium allowance and the actual premium, removes the expected over forecasting of insurance premiums in 2025 – 2026, thus ensuring this over forecasting doesn't continue into the 2026 – 2031 period. It then sets the non-recurrent efficiency gain in the base year equal to the insurance underspend in the base year. Together, this results in:

- *Forecast opex equal to that required by a prudent operator*
- *NSPs returning all the 2021 – 2026 insurance premium underspends through EBSS decrements 6 years later (treating the underspends as non-recurrent efficiency gains).*

Since we submitted our Regulatory Proposal, we re-visited our step change for bushfire liability insurance due to the volatility of market conditions which can materially impact insurance premium forecasts, this has also been accompanied by the recent renewal of our premium in October 2025.

⁹¹ AER, Final Decision, AusNet Distribution Determination 2021 to 2026, Attachment 6 Operating Expenditure, April 2021, at p. 53.

Lockton, our insurance broker has provided an updated expert report and forecast of premium increases during the 2026-31 regulatory period (see ASD – AusNet - Insurance Report and Forecast – Nov 2025 - CONF). Based on these forecasts, we have decided to remove this step change.

Other than the matter above, our revised proposal does not accept the AER's draft decision in respect of insurance premiums – including the negative step change as well as the adjustments to base year and calculation of the EBSS carryover amounts.

Along with the other Victorian DNSPs, we engaged legal and economic experts DLA Piper and Houston Kemp to provide further detailed information which supports why the AER should reconsider its Draft Decision in relation to these issues. These reports are provided as attachments: ASD - DLA Piper - John Middleton Legal Opinion - Nov 2025 - PUBLIC and ASD - HoustonKemp - Victorian DNSP insurance premiums - Nov 2025 - CONF.

The expert legal and economic analysis identifies several fundamental errors in the AER's draft decision. The key points from these reports have been summarised below:

- The AER's draft decision seeks to reclassify the 2021-26 insurance outperformance as a temporary or one-off efficiency gain. The AER has applied this approach without any underlying general principle in support, noting that the Draft Decision does not, in a like way, review overspends, such as AusNet's condition-based maintenance costs, which is also driven by market conditions outside of AusNet's control, partially offset by efficient cost management, as potential efficiency losses. As a result, the AER's approach means that any underestimation of actual costs remains subject to higher EBSS penalties, whilst effectively lowering the EBSS rewards for outperformance. There is no reasonable basis for this downward bias in EBSS outcomes.
- The AER has also misapplied the non-recurrent efficiency gain mechanism by adding the underspend back into base year opex and then immediately offsetting this positive adjustment, with a negative step change. In doing so, the AER produces an overall revenue reduction that the EBSS and NER do not permit. The non-recurrent efficiency gain is intended to correct one-off anomalies in base year costs by adding them back into the base year. The AER has applied this concept to a multi-year insurance underspend by adding that outperformance back to the 2022-2023 base year opex. This positive adjustment is then immediately offset with a negative adjustment in the EBSS. In doing so, the AER cancels both the base year adjustment and the EBSS reward that would normally follow the underspend, using the mechanisms together to unwind an approved allowance and reduce total revenues.
- The AER's approach above undermines the integrity of incentive based, ex ante regulatory framework – in that by clawing back the underspend (without any equivalent compensatory treatment or recognition of overspends), the AER removes the fundamental incentive for DNSPs to seek cost efficiencies. For example, networks should be confident that they will retain the benefits of efficient cost reductions. Instead, the effect of the AER's decision is to distort incentives to pursue cost mitigation strategies with the risk that gains will be confiscated at the next reset.
- Finally, the AER has effectively isolated insurance premiums as a stand-alone category for ex post adjustment, which is inconsistent with the top-down total opex forecasting process. This well-understood framework recognises that while underspends may occur in certain categories, they are often offset by overspends in others. For example, within the 2021–26 regulatory period, there are several areas where actual expenditure has exceeded forecasts such as maintenance expenditure. For example, we overspent our maintenance allowance by \$44m in the current regulatory year, compared to a \$10m underspend in the insurance allowance. However, neither the AER (nor ourselves) have proposed a positive adjustment to reflect unexpected market movements in this category which we have not been fully funded for. Adjusting for one category with actual costs lower than the allowance but ignoring other cost categories (including those with a more material impact than the one the AER has picked to adjust for) introduces clear negative bias into the opex forecast.

By intervening in this way, the AER removes the incentive to manage trade-offs across operating costs and amounts to a "cost-of-service" regulation for a single cost category inconsistent with the NER. Taken together, the expert economic and legal analysis demonstrate that the AER's insurance related adjustments, including both the negative step change and non-recurrent efficiency gain adjustment are economically and legally flawed and inconsistent with the ex-ante framework. The decision distorts incentives, reopens settled decisions, misapplies the EBSS and undermines the total opex framework, leading to a materially lower allowance that does not reflect the efficient, ongoing costs of an efficient and prudent operator.

A more detailed explanation of our concerns is included in ASD - AusNet - Insurance submission - 011225 - CONF.

6.7.3.6. New regulatory obligations

Since we submitted our Initial Proposal in January 2025 several new and emerging regulatory obligations have been introduced that materially affect AusNet. The regulatory reform environment continues to evolve, reflecting

accelerating actions taken by Governments and regulators to support the transition to net zero. We expect this high degree of regulatory change to continue throughout the 2026-31 regulatory period.

These new obligations discussed below were not embedded in historical practices or costs. They introduce new and mandatory requirements, including extended planning horizons, adhering to AASB legislative mandates and flexible trading arrangements. As these obligations have been developed after preparation of our Initial Proposal, AusNet could not have reasonably anticipated, costed or incorporated these changes as part of our Initial Proposal. It is therefore appropriate that we raise these matters as part of our Revised Proposal.

We consider the following step changes adhere to the AER's opex assessment framework, demonstrating that they reflect efficient and prudent costs required to comply with new regulatory obligations. We have also reviewed our 2022/23 base year to confirm that these obligations are not already captured in historical expenditure.

Table 6-26: Proposed step changes that are new regulatory obligations (\$m, real 2025-26)

Step change	AER step change category	Initial Proposal 2026-31	Draft Decision 2026-31	Revised Proposal 2026-31
Integrated distribution system planning rule change	Regulatory obligation	N/A	N/A	4.0
Sustainability reporting	Regulatory obligation	N/A	N/A	2.4
Flexible trading arrangements	Regulatory obligation	N/A	N/A	-0.1

Source: AusNet

6.7.3.6.1. Integrated distribution system planning rule change

Energy Consumers Australia (ECA) submitted a significant rule change request⁹² to the Australian Energy Market Commission (AEMC) aimed at reforming how DNSPs plan their networks. This proposal is known as the Integrated Distribution System Planning (IDSP) rule change.

This rule change has been initiated to improve transparency for distribution network users, including those considering investing in Consumer Energy Resources (CER) like rooftop solar, batteries, and EVs. ECA also want to see better alignment with the Integrated System Plan and proactive engagement with communities. We support the intent of this rule change and have actively participated in the AEMC's consultation process.

The proposed IDSP process would replace the current DAPR with a biennial Integrated Distribution System Plan, alternating with the ISP.

This would require DNSPs to:

- Publish network data and insights roadmaps.
- Provide granular data on network hosting capacity and constraints.
- Engage more meaningfully with stakeholders.
- Align local planning with broader system planning (ISP).

The AEMC published a Directions paper on 16 October 2025 which provides clear direction that significant new strategic planning requirements will be put in place as all options being considered by the AEMC require:

- Distribution planning timeline extended beyond 5 years, to either 10 or 20 years.
- Scenario analysis, requiring a significant step up in demand forecasting capability and effort
- Require earlier, more frequent and more meaningful customer and stakeholder engagement
- Increases coordination obligations across the system – for example, improved coordination with AEMO, transmission networks, local governments, developers and new energy participants

⁹² AEMC, Integrated Distribution System Planning (IDSP) rule change, accessed [here](#).

- Shift the planning framework toward an iterative, year-round process. Rather than one annual document, the options push planning toward a continuous process: maintaining up-to-date inputs, engaging iteratively, and reassessing options as conditions change. This transforms planning from a seasonal reporting exercise into a sustained operational function.

The draft Rule will be published in March 2026, providing greater clarity on the scope and timing of new requirements ahead of the AER's Final EDPR decision in April 2026.

Although the AEMC's Directions Paper notes that some distributors already undertake elements of this work, we confirm that the proposed obligations represent a material uplift for AusNet and are not reflected in our 2022-23 base year costs.

Even with potential refinements to the DAPR framework, the extended planning horizon and scenario analysis will require substantial additional effort to maintain and update planning outputs on an annual basis.

The DAPR changes may remove some reporting and template obligations, but they do **not** reduce the underlying planning, analysis, or customer engagement work that distributors must perform under the new framework. In fact, the ECA-driven obligations require deeper and more iterative engagement, more robust options assessment, additional data and model validation, and expanded documentation for regulatory and customer scrutiny. These activities substitute for *neither the quantum nor the complexity* of the tasks removed from the DAPR. The reductions are largely administrative and do not materially lower opex.

These obligations must be complied with in full and on an ongoing basis. They are not discretionary, nor can they be absorbed within existing resourcing.

Even after accounting for DAPR streamlining, the uplift from the ECA rule change is materially higher and enduring. Victorian distributors must still produce annual planning outputs, maintain the same level of network risk assessment, and comply with explicit new requirements around customer engagement, transparency and non-network assessments. These are new, rule-driven responsibilities that expand the scope of planning rather than simply repackaging it. Therefore, any reductions in administrative reporting cannot reasonably be expected to offset the substantive additional work required, nor do they remove the need for a step change to fund efficient, mandated activities.

The expected additional cost associated with the strategic planning element of this rule change are set out below. The rule change will also include increased requirements to provide more LV network visibility. To this end, we have also re-proposed digital capex to uplift LV data visibility, as explained in Chapter 5.

Table 6-27: Cost build-up of step change by line item (\$m, real 2025-26)

Cost build up	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Strategic planning engineering lead	-	0.2	0.2	0.2	0.2	0.8
Strategic planning engineer	-	0.2	0.2	0.2	0.2	0.6
Strategic planning engineer	-	0.2	0.2	0.2	0.2	0.6
Engagement specialist	-	0.2	0.2	0.2	0.2	0.6
Forecasting resource (0.5 FTE)	-	0.1	0.1	0.1	0.1	0.4
Forecasting tool (licence)	0.1	0.1	0.1	0.1	0.1	0.5
Forecasting tool (set up)	0.2	-	-	-	-	0.2
Forecasting tool (support)	-	0.1	0.1	0.1	0.1	0.2
Total	0.3	1.0	1.0	1.0	1.0	4.0

Source: AusNet

Table 6-28: Integrated distribution system planning rule change step change forecast (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Integrated distribution system planning rule change	0.3	1.0	1.0	1.0	1.0	4.0

6.7.3.6.2. Sustainability reporting required under the Corporations Act 2001

AusNet is proposing a new opex step change of \$2.4 million over the regulatory period to meet mandatory sustainability and climate reporting requirements under Australian legislation. The sustainability reporting regime was not included in AusNet's Initial Proposal, because at the time we finalised scope and forecasts for that submission, the obligations and their costs impacts on AusNet were not sufficiently settled to enable accurate costing. These regulatory changes include:

- Legislative change: Treasury Laws Amendment (Financial Market Infrastructure and Other Measures) Act 2024.

Impact: This Act introduces mandatory climate-related financial disclosures for large entities under the Corporations Act 2001. It empowers the AASB to issue sustainability reporting standards and requires companies like AusNet to prepare annual sustainability reports starting from 1 January 2025. Compliance is no longer optional, and we must disclose climate risks, opportunities, and transition plans in line with legislated standards. This creates a new compliance obligation, requiring governance structures, scenario analysis, and data systems that AusNet currently does not have.

- ASIC enforcement under RG280 issued March 2025.

Impact: This enforcement sets out how the regulator will supervise and enforce compliance with sustainability reporting obligations. While ASIC promises a "pragmatic" approach initially, it will focus on serious or reckless non-compliance, including failure to prepare reports or misleading disclosures. This framework means AusNet faces legal and reputational risk if it does not meet disclosure requirements. RG280 also clarifies expectations around Scope 3 emissions, scenario analysis, and governance, which require specialist capability and robust processes.

- AASB S2 Climate-related Disclosures standard effective from 1 January 2025.

Impact: AASB S2 is the mandatory reporting standard aligned with IFRS S2. It requires disclosure of climate-related risks and opportunities that could affect cash flows, access to finance, or cost of capital. Key elements include scenario analysis, emissions data (Scope 1, 2, and later Scope 3), and governance disclosures. Meeting AASB S2 demands new data collection systems, analytical capability, and governance processes. It also requires integration of climate risk into financial modelling.

AASB S2 Climate-related Disclosures standard effective from 1 January 2025.

Impact: The AUASB has approved a phased assurance model under ASSA 5000 and ASSA 5010 which was issued in September 2025. Initially, disclosures will be subject to limited assurance, escalating to reasonable assurance by FY30. Scope 3 emissions and scenario analysis will also require assurance over time. Assurance obligations significantly increase compliance complexity and cost. AusNet must ensure its disclosures are audit-ready, which means investing in robust data systems, internal controls, and external advisory support from the outset.

The first annual sustainability report is for the year ending 31 December 2025 is due at the end of March 2026, with external audit obligations commencing in 2025 and expanding to include Scope 3 emissions reporting by 2027, followed by reasonable assurance in 2029. These obligations cannot be met with existing resourcing and require incremental resources to enable compliance with AASB S2 standards and evolving regulatory expectations, based on external advice received by the current auditor.

The proposed step change covers the cost of additional specialist capability, including two dedicated FTEs, a manager to oversee evolving reporting and compliance activities and a data analyst to prepare Scope 3 emissions data and disclosures. It also includes external audit and assurance costs as reporting requirements scale up. This investment enables AusNet to deliver accurate, transparent sustainability reporting aligned with legislated mandates and stakeholder expectations, while mitigating compliance risk and supporting the transition to enhanced climate-related financial disclosures. A more detailed breakdown can be found below:

Table 6-29: Cost build-up of step change by line item (\$m, real 2025-26)

Cost build up	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Implementation costs including external advice for reporting and assurance step changes	0.1	0.3	0.1	0.1	0.1	0.8
System cost – incremental modules	0.1	0.1	0.1	0.1	0.1	0.5
Governance	0.1	0.1	0.1	0.1	0.1	0.5
Strategy	0.1	0.1	0.1	0.1	0.1	0.7

Risks, opportunities, metrics and targets	0.1	0.2	0.2	0.2	0.2	0.8
External audit and assurance	0.2	0.3	0.4	0.4	0.4	1.6
Report publication	0.1	0.1	0.1	0.1	0.1	0.4

Note: Assumption that AusNet Distribution takes on 50% of these costs

Source: AusNet

Table 6-30: Sustainability reporting step change forecast (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Sustainability reporting	0.3	0.5	0.5	0.5	0.5	2.4

Source: AusNet

6.7.3.6.3. Flexible trading arrangements (FTA) pass through

The Australian Energy Market Commission's 2024 Flexible Trading Arrangements (FTA) Rule requires AusNet to implement significant system and process changes to support new metering types (8A, 8B, and 9) and enable flexible Consumer Energy Resources (CER) trading.

These changes include upgrades to customer, asset, billing, and data management systems, integration with AEMO's MSATS and B2B procedures, and compliance with Victorian regulatory obligations. To meet these requirements by May and November 2026, AusNet will incur approximately \$20.3 million (nominal) in incremental costs, with \$15.2 million in 2025–26 and \$5.1 million in 2026–27. On 15 November 2025 we submitted a cost pass-through application seeking AER approval for recovery of these efficient costs. We have adjusted our opex allowances in RY26 to account for these pass through amounts in that year.

We have also included a negative step change to make sure that only the incremental opex forecast to be incurrent as a result of this requirement (and stated in our pass through application as part of the eligible pass through amount) is included in our forecast opex. This negative adjustment is proposed to ensure the opex allowance reflected the eligible pass through amount claimed in the pass through. Without this adjustment, the final year increment would embed a higher opex value in our 2026-31 allowance.

We expect the AER will adjust the opex allowances in our Final Decision to reflect the outcome of the pass through application.

Table 6-31: Eligible pass through amount proposed in FTA pass through application (\$m, real 2020-21)

\$ JUN 2021	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Capital expenditure	12.8	3.6	-	-	-	-	16.5
Operating expenditure	0.1	0.1	0.3	0.1	0.1	0.1	0.8
Total	13.0	3.7	0.3	0.1	0.1	0.1	17.3

Source: AusNet

Table 6-32: Flexible Trading Arrangements step change forecast (\$m, real 2025-26)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
FTA	-0.0	0.2	-0.1	-0.1	-0.1	-0.1

Source: AusNet

6.7.3.7. Other matters

6.7.3.7.1. AEMO NEM Fees

As stated in our Regulatory Proposal, 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 commencing from 1 July 2026.

AEMO released their draft determination⁹³ on 30 September 2025 which stated that their position is to not charge Participant Fees to distributors. As a result of this draft determination, we have held the placeholder of zero for this step change. Should AEMO's final decision on 12 February 2025 does allocate NEM fees to distributors we will formally request a step change to account for this cost. However, this is not expected.

6.8. Category specific forecasts

6.8.1. Regulatory Proposal

We forecast several categories of costs using a category specific forecast, consistent with the approach taken in the 2021-26 regulatory proposal. These included:

- GSL payments (\$54.0 million, \$2025-26), using a five-year averaging approach.
- Debt raising costs (\$16.6 million, \$2025-26); and
- Innovation expenditure (\$7.7 million, \$2025-26).

In our initial proposal, we sought to build on the success of our 2021–26 innovation program by proposing a \$18 million innovation fund. This represented an uplift from the \$8 million allocated in the current period, reflecting the growing complexity of the energy transition and the need to support customer-centric innovation. We proposed seven projects which were grouped under two key themes: smarter network management and new customer services and tariffs.

6.8.2. Draft Decision

6.8.2.1. Innovation expenditure

The AER declined our overall proposal for innovation which consisted of \$7.7 million (\$2025-26) of opex which would fund seven strategic innovation projects that are expected to deliver significant customer benefits. The alternative estimate value is \$2.4 million over the 2026-31 regulatory period. As a placeholder, the AER approved funding for two of the seven proposed innovation projects but considered that further work was required to justify the remainder of the program.

6.8.2.2. Guaranteed Service Levels (GSLs)

The AER accepted \$43.5 million (\$2025-26) in GSL payments, this was \$10.5 million less than the Initial Proposal. The difference has arisen from the AER using a 3-year averaging approach, rather than the 5-year averaging approach we proposed, including regulatory years 2021-22 to 2023-24. The AER excluded amounts relating to reliability improvements not yet approved, Major Event Day payments that have been recovered in cost pass through events, all RY24 major event days, and missed appointments and connection delays. The AER also noted that the ESC may review the GSL scheme and payment rates, but as no changes had been confirmed, the current scheme was used for forecasting.

6.8.2.3. Debt raising costs (DRC)

The AER accepted \$15.7 million (\$2025-26) in debt raising costs, this was \$1 million less than we proposed in the Initial Proposal as a result of the changes to the size of the RAB. The AER continued to apply its standard benchmarking results rather than relying on actual or forecast costs, to maintain consistency with the rate of return building block.

6.8.3. Revised Proposal

As part of the Revised Proposal, we are forecasting category specific forecasts in line with the categories we set out in our Initial Proposal, as further set out below. We have also re-scoped the customer service-related step change to be considered as a category specific forecast.

- GSL payments (\$42.9 million, \$2025-26)
- Debt raising costs (\$17.7 million, \$2025-26)

⁹³ AEMO draft report and determination, 30 September 2025: [nem-participant-fee-structure-review-draft-report-and-determination.pdf](#)

- Innovation expenditure (\$2.4 million, \$2025-26); and
- Customer engagement and communications programs (\$9.8 million, \$2025-26).

Table 6-3320: Comparison of proposed category specific forecasts (\$m, real 2025-26)

Category specific forecasts	Initial Proposal 2026-31	Draft Decision 2026-31	Revised Proposal 2026-31
Guaranteed Service Levels (GSLs)	54.0	43.5	42.9
Debt Raising Costs (DRC)	16.6	15.7	17.7
Innovation Expenditure	7.7	2.4	2.4
Customer engagement and communication programs	-	-	9.8
Total category specific forecasts	78.3	61.6	72.8

Source: AusNet

Note: Customer engagement and communication programs was proposed as a step change in the initial proposal

6.8.3.1. Guaranteed Service Levels (GSLs)

Guaranteed Service Level payments are an efficient cost reflecting a transfer of funds from the broader customer base to those with the poorest reliability. The GSL scheme included in the Victorian Essential Service Commission's Electricity Distribution Code of Practice (EDCOP) applies to AusNet.

We do not accept the AER's use of a three-year averaging approach for forecasting GSL payments.

The objectives of the GSL forecast are:

- to provide an estimate of efficient GSL payments, and to
- allow 'the business to get back and overspends (or 'pay back' under spends) in the five years of the following control period'⁹⁴.

Both must be met for the forecast to be consistent with the Revenue and Pricing Principles.

These objectives can only be achieved if a consistent forecasting period is applied that remains stable over the long term. Without clear objectives, the choice of averaging period becomes arbitrary and risks bias based on known historical outcomes. The arbitrary nature of the averaging period is clear from the inconsistency in the draft decisions across distributors, with Powercor's being a 3-year average, and Jemena's a 4-year average. This variation highlights the need for clear guiding objectives.

Previous Decisions and Industry Practice

In the current (2021-26 regulatory period), AusNet proposed a five-year average to forecast GSL payments, consistent with the forecast used for the 2016-20 and the 2011-15 regulatory periods. While the AER confirmed that 'To forecast GSL payments for the current regulatory control period our standard approach is to use a five-year historic average of GSL payments'⁹⁵, which the AER rejected in favour of a 10-year average. It linked this decision to the significant changes that had occurred to the GSL scheme, following the Essential Services Commission's review of the scheme which was finalised in November 2020. The AER stated⁹⁶:

"We consider a ten-year time series more appropriate as it smooths out the impact of abnormal events in the current period"

"Using a longer-term average reduces the impact of abnormal, or outlier events and is more likely to reflect the likely costs involved".

⁹⁴ AER, Final Decision - AusNet Services distribution determination – Attachment 6 – Operating expenditure , April 2021, p.57 accessed [here](#).

⁹⁵ AER, Final Decision - AusNet Services distribution determination – Attachment 6 – Operating expenditure , April 2021, p.57 accessed [here](#).

⁹⁶ AER, Final Decision - AusNet Services distribution determination – Attachment 6 – Operating expenditure , April 2021, accessed [here](#).

Consistent with the AER's statement that a 5 year averaging period is its standard approach to forecasting GSLs, other determinations have also applied a 5 year averaging period, including TasNetworks recent determination (2024-29 regulatory period)⁹⁷:

"This is because we have forecast GSL payments as the average of GSL payments made by TasNetworks over the most recent five years for which we have actual data, consistent with how we forecast GSL payments in the 2019–24 regulatory control period."

Our Position

We rejected the Draft Decision to apply a three- year average to forecast GSL payments. We maintain that a five- year averaging approach used over time provides both a forecast of efficient GSL payments and provides cost recovery over time. Therefore, we propose the period from 1 July 2020 to 30 June 2025.

This provides an efficient forecast that is consistent with the Revenue and Pricing Principles. This is because it:

- Smooths annual fluctuations over the period
- Reflects current scheme settings
- Is consistent with the averaging period used in historical decisions (albeit not for the current regulatory period) and therefore provides a fair recovery of GSL costs.

If the AER does not accept a five-year period, consistent with its previous decision, then it should apply a ten-year average to meet the Revenue and Pricing Principles.

To calculate our average, we have removed costs associated with Major Event Day (MED) payments from historical years that have been recovered via cost pass through applications⁹⁸.

Specific feedback on the Draft Decision calculation

We note the following minor inconsistencies in the AER's modelling as part of the Draft Decision. Specifically:

- Our RY23 GSL value included a transcription error in the AER's model equalling a revised value of \$3.9 million opposed to \$6.9 million
- For the MED GSL payment category, the AER applied a two-year average instead of the intended three-year average, which inflated the result.

Nevertheless, as noted in our initial proposal, we have applied an average using RY21 to RY25, incorporating:

- Latest audited date for RY25
- A recast value for RY21 as if the current GSL scheme had been effective.

This update results in a GSL forecast for the 2026-31 period of \$42.9m. This is a decrease of \$0.6 million compared to the Draft Decision and a reduction of \$11.1million compared to our Initial Proposal. Full workings are provided in the GSL tab of the Revised Proposal opex model.

GSL improvement from proposed expenditure

We have deducted expected GSL reductions from our forecast to reflect benefits of our proposed reliability and resilience investments. These deductions account for project delivery timing and expected benefit realisation. This reduces our forecast by \$0.2 million of opex over the regulatory period.

Table 6-34: GSL deductions over the 2026-31 regulatory period (\$, real 2025-26)

Program	2026-27	2027-28	2028-29	2029-30	2030-31
BN11, Worst Served Feeder program and Resilience	\$ 0	\$ 8,855	\$ 20,261	\$ 60,168	\$ 73,816

Source: AusNet

Table 6-3521: Actuals and recast values of GSLs (\$m, nominal)

Year	Amount (\$m)

⁹⁷ AER, Draft Decision - TasNetworks distribution determination – Attachment 6 – Operating expenditure, September 2023, accessed [here](#).

⁹⁸ Namely June 2021 storm pass through, Feb 2024 storm pass through and the September 2024 pass through.

2020-21	10.1
2021-22	13.1
2022-23	6.9
2023-24	7.7
2024-25	8.5
Average	9.3

Source: AusNet

We are currently not aware of any forthcoming reviews by the ESC of the GSL scheme but if a change were to be made, we expect to collaborate with the AER to update this prior to the final decision.

Table 6-36: Guaranteed Service Levels forecast (\$m, real 2025-26)

Category specific forecast	2026-27	2027-28	2028-29	2029-30	2030-31	Total
GSLs	9.1	8.8	8.6	8.3	8.1	42.9

Source: AusNet

6.8.3.2. Debt raising costs (DRC)

We accept the AER's standard approach on debt raising costs as per the AER's Draft Decision. The forecast value for opex has been updated in line with our updated capex forecast in our Revised Proposal. This has increased debt raising costs by \$2 million relative to the Draft Decision.

Table 6-37: Debt raising costs forecast (\$m, real 2025-26)

Category specific forecast	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Debt raising costs	3.2	3.4	3.6	3.8	3.9	17.7

Source: AusNet

6.8.3.3. Innovation expenditure

We accept the AER's Draft Decision of \$2.4 million in regard to innovation expenditure. While this falls short of to fund our ambition in our original proposal, we will seek to instead use more grant funding to meet the ambition of our Innovation Advisory Council (IAC) where possible. We also intend on continuing to utilise our DMIA to gather important insights related to demand management.

We note it is difficult to quantify the potential benefits of innovative 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.

It is also 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 (explained in the Innovation Chapter in our Regulatory Proposal) we have received strong feedback from our IAC that we should maintain flexibility in the program so we can work with 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 note that we expect there to be changes to the final set of projects delivered by June 2031.

However, we have undertaken analysis to indicate the potential quantum of some benefits which could be achieved by delivering these projects, as requested by the AER. Our projects aim to test the hypothesis of some of customer benefits as described in the table below, and as such assist in plans for large scale deployment in the regulatory periods following 2026-31 where proven to be beneficial.

Table 6-38: Expected benefits for innovation projects approved as a placeholder in the Draft decision

Project	Expected customer benefits	Estimated quantitative benefit
Alternative storage technologies	Lower implementation cost (both CAPEX and OPEX), by working closely with OEMs to shape the development of storage technologies that deliver enduring value to customers. Benefits include: • Deferred replacement cost, as thermal energy storage has a life cycle of 20-30 years (compared to 10-15 years for Lithium batteries) • Saving in implementation cost, as flow batteries are potentially 30-50% lower cost per cycle over 20 years compared to lithium To quantify benefits, we have assumed per battery benefits consistent with our current pole-top battery project over this longer assumed life. Benefits include reduce energy at risk, deferred augmentation, reduced export curtailment and emissions benefits.	\$2.3m + <i>Expected Cost benefit ratio: 1.0-3.0</i>
V2G for resilience	AusNet has identified 15 vulnerable communities and critical infrastructure customers who face significant challenges due to factors such as remoteness, geographical constraints, socioeconomic disadvantage, and a history of exposure to major events. To quantify customer benefits, the following metrics were considered: • Resilience benefit was quantified using: ◦ Average outage duration based on historical events ◦ Average energy loss during outages ◦ The value of enhanced network resilience • Lower costs for customers associated with power outages, including reduced reliance on diesel generation, saving approximately \$12,500 per critical site in prolonged power disruptions. • Reduced safety risk due to injury or loss of life resulting from prolonged power outages causing loss of supply for essential services. This project offers additional qualitative benefits, including: • Maximizing customer value on their investments. 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 network and community resilience. • Other reduced health and safety risks from loss of supply to essential services, including electricity, water and telecommunications. Currently there is no clear framework to support strengthening power supply reliability and resilience for critical infrastructure customers, as it does not consider the cascading impacts, such as loss of water, telco, and other essential services when power supply is lost. During a prolonged power outage, communities experience not only financial loss but also significant impacts on health, safety, and mental well-being.	\$12.1m + <i>Expected cost benefit ratio: 5.0</i>

Source: AusNet

We note there are further benefits which cannot be quantified associated with innovative projects, such as the value of learning and knowledge sharing with industry. We emphasis the standard metrics which we have quantified are not the main driver or the key outcome for delivering innovative projects. The near-term value to our customers is the learnings and improvements that can be implemented as a result of the trials and due to their broader strategic value, each project proposed is prudent as an innovation initiative.

Further information on Innovation can be found in ASD - AusNet - Innovation Program Benefits – 1Dec25 - CONF.

Table 6-39: Innovation forecast (\$m, real 2025-26)

Category specific forecast	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Innovation	0.0	0.2	0.5	0.7	1.1	2.4

Source: AusNet

6.8.3.4. Customer engagement and communications programs

Refer to step change discussed above at section 6.7.3.

Table 6-4022: Customer engagement and communications program forecast (\$m, real 2025-26)

Category specific forecast	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Customer engagement and communications program	2.0	2.0	2.0	2.0	2.0	9.8

Source: AusNet

6.9. Total opex forecast

Our revised total opex forecast is \$1,606 million excluding debt raising costs (\$2025-26) or \$1,624 million including debt raising costs (\$2025-26) for the 2026-31 regulatory period.

Table 6-4123: Forecast operating expenditure (\$m, real 2025-26)

Component	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Base opex	282.5	282.5	282.5	282.5	282.5	1,412.6
Real price change	1.4	3.0	4.9	7.0	9.0	25.2
Output growth	5.9	10.3	15.5	19.8	26.5	78.0
Productivity change	-1.4	-2.8	-4.3	-5.7	-7.2	-21.4
Step changes	7.1	9.6	11.7	12.8	15.6	56.7
GSL	9.1	8.8	8.6	8.3	8.1	42.9
Innovation	0.0	0.2	0.5	0.7	1.1	2.4
Customer	2.0	2.0	2.0	2.0	2.0	9.8
Total exc. DRC	306.5	313.5	321.3	327.3	337.6	1,606.2
DRC	3.2	3.4	3.6	3.8	3.9	17.7
Total	309.7	316.9	324.8	331.0	341.5	1,623.9

Note: numbers may not reconcile due to rounding

Source: AusNet

6.10. Benchmarking efficient opex

As noted in section 6.4, the AER provided commentary on our benchmarking performance. This section provides some comments in response to the AER's observations.

6.10.1. Draft Decision

The AER provided detailed analysis on our benchmarking efficiency performance and found:

- We perform well compared to other networks, ranking 6th out of 13 distribution businesses in the AER's 2024 Annual Benchmarking Report, with efficiency scores of 0.80 (2006-23) and 0.76 (2012-23) – both above the benchmark threshold of 0.75, qualifying AusNet as a benchmark comparator business.
- Our 2022-23 base year opex is not materially inefficient, with actual opex of \$270.7 million, which is 15% below the approved forecast for that year.

The AER noted AusNet's opex over the 2021-26 period is \$110.7 million (7%) below the AER's forecast, and that our average annual opex over 2021-24 is only \$2.6 million higher than the 2016-20 average, indicating sustained cost discipline. While our benchmarking score is slightly more borderline than other comparators, the AER concluded that our revealed costs are suitable for base opex forecasting.

6.10.2. Revised Proposal

We agree with the AER's conclusion on the efficiency of our base year opex. As this Revised Proposal maintains the 2022-23 base year, there is no need to formally propose any matters related to benchmarking.

We are disappointed that the AER has neither acknowledged nor considered our detailed proposals to improve the robustness of its benchmarking approach. These were summarised in our Initial Proposal and several issues have been raised consistently over several years with the AER, including via a 'Proposal for updating the AER's benchmarking models' submitted to the AER in April 2023.

This lack of engagement with these issues creates uncertainty for us. The AER's Draft Decision repeatedly highlights we may want to consider changing base years from 2022-23⁹⁹. However, we are unable to confidently make this change as we are unclear about how the AER would assess the efficiency of these years under its benchmarking framework, given the material issues we have raised with the AER have a greater impact on the later years of the regulatory period compared to the current base year.

6.11. Supporting Documentation

We have included the following documents to support this chapter:

- ASD - AusNet Distribution – Opex Model - 011225 - PUBLIC;
 - GSL calculation
 - Ratcheted maximum demand information
 - Step change workings
- ASD – Oxford Economics Australia – Labour escalation report and forecast – Sep 2025 - PUBLIC;
- ASD – Deloitte Access Economics – Labour price growth forecast - Jul 2025 - PUBLIC;
- ASD – AusNet - Insurance Report and Forecast – Dec 2025 - CONF;
- ASD – AusNet – Insurance Submission – 011225 - CONF;
- ASD - DLA Piper - John Middleton Legal Opinion - Nov 2025 – PUBLIC;
- ASD - HoustonKemp - Victorian DNSP insurance premiums - Nov 2025 – CONF; and
- ASD – HoustonKemp – Operating expenditure step changes and output growth – Nov 2025 - PUBLIC;

⁹⁹ For example, Attachment 3 – Operating expenditure, page 20, paragraph 5

7. Regulated Asset Base

7.1. Key points

The key points are:

- Our Initial Proposal set out our estimate of the opening Regulatory Asset Base (**RAB**) as at 1 July 2026, and the forecast RAB for the remainder of the 2026-2031 regulatory period. Our calculations followed the standard approach to calculating the RAB, in accordance with the NER and Roll Forward Model.
- The AER's Draft Decision accepted our approach to calculating the opening and forecast RAB for the 2026-2031 regulatory period.
- The AER updated the RAB estimates to reflect the latest inflation data and the impact of other aspects of its Draft Decision, notably its reduction in our forecast capital expenditure and the consequential reduction in the regulatory depreciation allowance.

In this Revised Proposal, we have updated the RAB calculations to reflect the latest input data, including our revised forecast capital expenditure and regulatory depreciation. Our proposed opening RAB also includes several final year asset adjustments which are outlined in further detail in this chapter.

7.2. Chapter structure

This chapter is structured as follows:

- Section 7.3 explains how our opening RAB accounts for past capital expenditure;
- Section 7.4 sets out our updated estimates for the Opening RAB as at 1 July 2026;
- Section 7.5 details the forecast RAB for each year of the 2026-2031 regulatory period, taking into account the revised forecasts in the Revised Proposal; and

Section 7.6 lists the supporting documents.

7.3. Review of past capital expenditure

Clause S6A.2.2A of the NER permits the AER to review past capital expenditure (capex) and, in specific circumstances, exclude some capex from the RAB. For the purposes of this capex review, the relevant review period is 1 January 2020 to 30 June 2024.

Under clause S6A.2.2A(b)(1), the AER is permitted to review past capex if the actual total expenditure over the review period exceeds the AER's allowance (adjusted for approved pass-through amounts), and the AER is not satisfied that part or all of the capex overspend reasonably reflects the capital expenditure criteria.

For this review period, clause S6A.2.2A(b)(1) is not satisfied because we have not overspent against our approved capex allowance (adjusted for approved pass-through amounts). This is supported by the AER's draft decision which confirms that AusNet's actual capex was below the forecast for this review window, so no efficiency review was triggered.¹⁰⁰ No other circumstance in which the AER is permitted to review past capex is satisfied. As such, all the capex we incurred during the review period is automatically included in the RAB.

We have also included our actual and forecast capex for the period 1 July 2024 to 30 June 2026 in the RAB. We note that capex for these years will form part of the Ex-post review period at the next reset.

¹⁰⁰ AER, Overview | Draft decision – AusNet Services distribution determination 2026-31 – 30 September 2025, pp.16-17.

7.4. Opening RAB

7.4.1. Initial Proposal

We proposed an opening RAB as at 1 July 2026 of \$6,144.9 million (nominal), which reflect actual and forecast capital expenditure, nominal depreciation, and RAB indexation for the 2021-26 period. Adjustments were also made for differences in actual and forecast net capex for 2020 and the 2021 half year extension.

We also proposed a final year total RAB adjustment of \$5.6 million, comprising –\$2.0 million for capitalised leases and \$7.6 million for critical spares. The adjustment for capitalised leases primarily accounts for extensions and terminations of leases that occurred in the 2021–26 period for lease arrangements that were established prior to 1 July 2021. The adjustment for critical spares establishes an opening asset value that reflects the existing stock of critical spares that had not previously been included in the RAB. We also proposed a new asset class for 'Critical spares' to record stock movements in the RAB.

In accordance with standard regulatory practice, we also explained that our estimate of the opening RAB would be updated in our Revised Proposal to reflect actual data for 2024-25.

7.4.2. Draft Decision

The AER's Draft Decision accepted our approach for determining the opening RAB, and accepted the calculations subject to making minor adjustments in the RFM¹⁰¹, including:

- **Lower CPI.** Updated the 2025–26 inflation rate from our estimate of 3.00% for December quarter (1-year lagged) to the actual CPI of 2.42% (8 cities), reducing the opening RAB by \$32.9 million.
- **Capex Adjustments.** Minor corrections to 2021-22 and 2023-24 capex to align with the annual RINs.
- **Capex Reallocation:** Reallocation of 2023-24 capex between asset classes to correct an error in the allocation between the 'Distribution system assets' and 'Land' asset classes, in line with our response to an information request.¹⁰²
- **Treatment of Software-as-a-Service (SaaS) expenditure:** For the purposes of RAB roll-forward, the AER explained that actual SaaS expenditure should be reported as capex to be consistent with how the capex forecast was treated in the 2021–26 determination.
- **Gifted assets for the 2021 half year period:** Using reported 2021 half-year capex information by asset class, the AER added gifted assets of \$24.1m (\$Nominal) to both gross capex and customer contributions inputs in the RFM, which has a net zero effect in the RAB. In doing so, this created \$24.1m (\$Nominal) of tax assets in the Tax Asset Base (TAB) which we discuss further in Chapter 10 – Corporate Tax, ss.10.4.1.

These adjustments resulted in a revised opening RAB of \$6,129.0 million (\$Nominal), which is \$16.0 million (0.3%) lower than our estimate in the Initial Proposal.

7.4.3. Revised Proposal

In this Revised Proposal, we accept the adjustments set out in the AER's Draft Decision except for the 2021 half year gross capex and customer contribution adjustments (totalling \$24.1m, \$Nominal). The data below shows the updated calculation for our opening RAB, which also reflects actual 2024-25 capex and the latest forecasts in relation to 2025-26. The summary calculation is shown in the table below, which is explained in further detail in the sub-sections below.

As shown in Table 7-1 below, our revised opening RAB calculation for 1 July 2026 is \$6,276.0 million (\$Nominal) which is \$131.1m (2.1%) higher than our estimate in the Initial Proposal and \$147m (2.4%) higher than the AER's Draft Decision.

Table 7-124: 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)	4,657.4	4,766.2	5,005.5	5,505.6	5,923.8

¹⁰¹ AER, AER - RFM - Draft decision - AusNet distribution determination 2026-31 - September 2025.

¹⁰² ASD, Response to information request – IR#037 – General modelling clarifications – 23 June 2025, pp.2-3.

Plus Capex, net of disposals and contributions	344.0	333.6	387.5	493.2	557.5
Less Nominal Forecast Straight-line Depreciation	-235.3	-94.3	112.6	-75.0	-161.1
Plus Nominal Actual inflation on opening RAB	40.1	166.7	392.0	223.1	143.6
Difference between Actual and Forecast Net Capex for 2020 and HY2021					-35.5
Forgone return on difference					-13.3
Final Year Asset Adjustments					4.7
Closing RAB (30 June)	4,766.2	5,005.5	5,505.6	5,923.8	6,276.0

Source: AusNet Services' Revised Proposal RFM Model (2021-26)

7.4.4. Actual and forecast net capex, 1 July 2021 to 30 June 2026

At the time of lodging our Initial Proposal in January 2025, we included placeholder forecasts for both 2024-25 and 2025-26 net capex. Table 7-2 below presents our updated estimates for net capex, which includes actual expenditure for 2024-25 and our latest forecasts for 2025-26.

Table 7-225: AusNet Net Capex, 1 July 2021 to 30 June 2026, \$m, \$Nominal

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26
Gross Capex	362.4	349.4	393.1	517.6	593.3
Less Disposals	0.2	1.1	0.1	0.6	1.6
Less Customer Contributions	24.3	24.7	24.8	40.2	48.4
Nominal Net Capex	337.9	323.6	368.2	476.9	543.2
Net Capex recognised in RAB¹⁰³	344.0	333.6	387.5	493.2	557.5

Source: AusNet Services' Revised Proposal RFM Model (2021-26)

Our Net capex forecast for 2025-26 has increased by \$115.1 million (30.0%) (\$Nominal) from our Initial Proposal, before overheads and SaaS expenditure adjustments. The main drivers for this increase in Net capex include:

- (1) Augmentation expenditure (+\$17.4 million, Direct cost);
- (2) Digital program expenditure (+\$21.3 million, Direct cost) including \$3.2m of additional service provider transition costs;
- (3) New land purchase for Wollert Zone Substation (+\$13.4 million, Direct cost);
- (4) Fleet and Plant expenditure associated with service provider transition (+\$52.8 million, Direct cost);
- (5) Property leases novated to AusNet associated with service provider transition (+\$8.3 million, Direct cost); and
- (6) Lower forecast Type 1 customer contributions associated with large energy connections (+8.3 million).

These forecast changes are partially offset by:

- Lower forecast SaaS expenditure (-\$3.9 million, Direct cost). Our updated forecast for SaaS Propex of \$1.1 million has reduced compared with our placeholder forecast for 2025-26 of \$5.0 million confirmed with the AER via an information request.¹⁰⁴

We discuss service provider transition related expenditures (items 4 and 5 above) further in section 7.4.6 - Forecast final year asset adjustments.

7.4.5. Regulatory Depreciation

¹⁰³ Net Capex recognised in RAB includes a half-nominal WACC allowance.

¹⁰⁴ ASD, AusNet's response to information request IR#037 (AER - AusNet - IR#037 - Q4 template - SaaS - Populated), 23 June 2025.

The tables below show our updated calculations for our nominal straight-line depreciation and regulatory depreciation for the period 2021-2026.

Table 7-326: AusNet Nominal Depreciation

\$M	2021-22	2022-23	2023-24	2024-25	2025-26
Forecast Straight line Depreciation – real \$2020-21	273.0	250.1	248.2	254.5	254.0
Actual / Forecast inflation	2.3	11.0	31.2	43.6	50.7
Nominal Depreciation	275.4	261.0	279.4	298.1	304.8

Source: AusNet Services' Revised Proposal RFM Model (2021-26)

Table 7-427: 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	166.7	392.0	223.1	143.6

Source: AusNet Services' Revised Proposal RFM Model (2021-26)

Indexation of the RAB was updated based on available ABS data for the current regulatory period. These updates are reflected in Table 7-5 below and are based on December quarter CPI (8 cities), in accordance with the control mechanism.¹⁰⁵

Table 7-528: Inflation inputs

	2021-22	2022-23	2023-24	2024-25	2025-26
Inflation – 1-year lagged	0.86%	3.50%	7.83%	4.05%	2.42%

Source: AusNet Services' Revised Proposal RFM Model (2021-26)

The calculation of economic depreciation (nominal straight line depreciation net of RAB indexation) for the current regulatory period is shown in the table below.

Table 7-629: 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	304.8
RAB Indexation	-40.1	-166.7	-392.0	-223.1	-143.6
Regulatory Depreciation	235.3	94.3	-112.6	75.0	161.1

Source: AusNet Services' Revised Proposal RFM Model (2021-26)

7.4.6. Forecast final year asset adjustments

Table 7-7 below shows the final year adjustments which have been accepted by the AER in its Draft Decision.

Table 7-7: Proposed Final Year Asset Adjustments (30 June 2026), \$m, \$Nominal

RAB Class	Proposed RAB adjustments (\$M)	Remaining life of adjustments to RAB (Yrs)
Critical spares – network assets	7.6	n/a
Non-network Leasehold Land & Buildings – 1 July 2021	-2.0	3.3

Source: AusNet Services' Initial Proposal RFM Model (2021-26)

In this Revised Proposal, we have included several final year asset adjustments, including:

¹⁰⁵ AER, AER – Final decision – AusNet Services distribution determination 2021–26 – Attachment 14 – Control mechanisms – April 2021, p.20.

- Reallocation of 2025-26 capex incurred for service provider transition related expenditure of \$57.3 million (\$Nominal) including short-term motor vehicle leases, vehicle running costs, and heavy vehicle and plant purchases. This is discussed further in ss.7.4.6.1 below.
- Reallocation of 2025-26 capex incurred for service provider transition related expenditure of \$8.6 million (\$Nominal) for property leases that have transitioned from Downer Engineering to AusNet. We discuss this further in ss.7.4.6.2 below.
- An update for approved asset class 'Critical spares' to account for the current value of stock of critical spares for Distribution, being \$7.93 million (\$Nominal) or an increase of \$0.32 million (\$Nominal) from the AER's Draft Decision. We have included supporting documentation for our proposed update with this Regulatory Proposal.
- An update for existing asset class 'Non-network leasehold land & buildings - 1 July 2021' from our Initial Proposal of -\$2.0 million to -\$3.3 million (\$Nominal) based on 2024-25 actual capex inputs.

7.4.6.1. Fleet and Plant - Leases and Acquisitions

As part of our transition to a new service provider on 1 August 2025, in 2025-26 we are leasing vehicles previously leased by our former network maintenance delivery partner (Downer Engineering) and purchasing heavy vehicles for additional operational requirements. Previously, AusNet has expensed its motor vehicle leases in line with existing accounting policy and has not forecast this type of lease expenditure for the 2022-2026 regulatory period. Starting from 2025-26, AusNet proposes to capitalise its motor vehicle lease costs under accounting standard AASB16 and depreciate them in the opening RAB.

Table 7-8 below contains our forecast expenditures including the calculated Right-of-Use (ROU) lease asset value of \$49.0 million (\$Nominal) for short-term vehicle leases, comprising both light vehicles and heavy vehicles. Table 7-8 also shows our proposed RAB class allocations for these investments in 2025-26 including vehicle running costs. We have provided supporting documentation for these expenditures with this Revised Proposal.

Table 7-830: Final Year Capex Forecast – Fleet and Plant (Leases & Acquisitions), \$m, \$Nominal

Expenditure Type	2025-26	RAB Class allocation		
		Subtransmission	Distribution system assets	Motor Vehicle and plant Leases - short term Heavy vehicles and plant
Motor vehicle leases – short-term (ROU assets)	49.0			100%
Heavy vehicle purchases	3.8			100%
Running costs	3.0	5%	95%	
Total	55.9			

Source: AusNet Services' Revised Proposal RFM Model (2021-26)

Table 7-9 below shows our proposed final year asset adjustments to reallocate \$57.3 million¹⁰⁶ (\$Nominal) of 2025-26 capex into the appropriate asset classes. This includes allocations for two new asset classes for the 2026-2031 regulatory period, including approved class 'Heavy vehicles and plant' from the AER's Draft Decision¹⁰⁷ and our new proposed class 'Motor Vehicle and plant Leases - short term' reflected in this Revised Proposal. These two asset classes including their remaining lives are discussed further in Chapter 8 – Depreciation.

Our proposed final year RAB adjustments are shown in Table 7-9 below.

Table 7-931: Proposed Final Year Asset Adjustments – Fleet and Plant (Leases & Acquisitions), \$m, \$Nominal

RAB Class	Proposed RAB adjustments (\$m)	Remaining life of adjustments to RAB (Yrs)
Subtransmission	0.2	45
Distribution system assets	2.9	50

¹⁰⁶ Net Capex recognised in RAB includes a half-nominal WACC allowance.

¹⁰⁷ AER, AER - Attachment 1 - Annual revenue requirement - Draft decision - AusNet Services distribution determination 2026-31 - September 2025, pp.28-29.

Non- Network Leasehold Land & Buildings - 2021-22	-57.3	n/a
Heavy vehicles and plant	3.9	14.5
Motor Vehicle and plant Leases - short term	50.3	3.9
Total	-	

Source: AusNet Services' Revised Proposal RFM Model (2021-26)

7.4.6.2. Property leases novated to AusNet

In our Initial Proposal, we included \$1.1 million (\$Nominal) of forecast capex across 2024-25 and 2025-26 associated with novated property leases from our former network maintenance delivery partner (Downer Engineering).

Table 7-10 and Table 7-11 below compares our forecast expenditures for 2024-25 and 2025-26 at the Initial Proposal stage with our updated 2024-25 actual capex and latest forecasts for 2025-26 that form part of this Revised Proposal.

Table 7-1032: Initial Proposal - Novated Property Lease capex – Forecast, \$m, \$Nominal

RAB Class	2024-25	2025-26
Non- Network Leasehold Land & Buildings - 2025-26	0.9	0.1
Total	0.9	0.1

Source: AusNet Services' Initial Proposal RFM Model (2021-26)

Table 7-1133: Revised Proposal - Novated Property Lease capex – Actual / Forecast, \$m, \$Nominal

RAB Class	2024-25	2025-26
Non- Network Leasehold Land & Buildings - 2025-26	0.4	8.3
Total	0.4	8.3

Source: AusNet Services' Revised Proposal RFM Model (2021-26)

At the Initial Proposal stage, it was expected that most leases would transfer to AusNet during 2024-25. Only one of these leases transferred in 2024-25 for \$0.4 million (\$Nominal). We are satisfied that this capitalised lease is captured in existing class 'Non- Network Leasehold Land & Buildings - 2025-26' as it has a 5-year lease term that matches the standard life at the asset class level. As shown in Table 7-11 above, the forecast for 2025-26 has been revised to \$8.3 million (\$Nominal) in this Revised Proposal, reflecting a more comprehensive lease payment schedule and underlying assumptions. We have provided supporting documentation for our revised forecast with this Revised Proposal.

Table 7-12 below shows our proposed reallocation of 2025-26 lease capex of \$8.6 million¹⁰⁸ (\$Nominal) to approved class 'Non-Network Leasehold Land & Buildings – short term'. The AER's Draft Decision approved this new asset class for use in the forthcoming 2026-2031 regulatory period¹⁰⁹. We have therefore allocated our forecast lease capex of \$8.6 million (\$Nominal) to this approved class given the short-term nature and our ability to set the weighted average remaining life of 7.6 years in the opening RAB. We consider our approach conforms with NER cl.6.5.5(b)(1), which requires that "the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets."¹¹⁰

In addition, we have proposed forecast expenditure in the 2026-2031 regulatory period in the same asset class for leases commencing in 2025-26 that are expected to renew upon lease expiry. This forecast is discussed further in Chapter 5 – Capital Expenditure.

Table 7-1234: Proposed Final Year Asset Adjustments – Property Leases, \$m, \$Nominal

RAB Class	Proposed RAB adjustments (\$M)	Remaining life of adjustments to RAB (Yrs)

¹⁰⁸ Net Capex recognised in RAB includes a half-nominal WACC allowance.

¹⁰⁹ AER, AER - Attachment 1 - Annual revenue requirement - Draft decision - AusNet Services distribution determination 2026-31 - September 2025, pp.28-29.

¹¹⁰ Available at: <https://energy-rules.aemc.gov.au/ner/674/658460>

Non- Network Leasehold Land & Buildings - 2025-26	-8.6	n/a
Non-Network Leasehold Land & Buildings – short term	8.6	7.6
Total	-	

Source: AusNet Services' Revised Proposal RFM Model (2021-26)

7.5. Forecast RAB over the 2026-31 Regulatory Period

7.5.1. Our Initial Proposal

Our Initial Proposal explained how the opening RAB as of 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. We noted that:

- Our approach is 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 has been included in the RAB.
- The nominal capital expenditure excludes Type 1 capital contributions and asset disposals.

Our forecast closing RAB as of 30 June 2031 was \$9,024.0 million (\$Nominal).

7.5.2. Draft Decision

The AER's Draft Decision forecast a closing RAB value of \$7,119.5 million (\$Nominal) for 30 June 2031, which is a reduction of \$1,904.5 million (21.1%) compared to our Initial Proposal. The key driver of the lower forecast closing RAB is the AER's lower capital expenditure allowance for the 2026-2031 regulatory period. In particular, the AER noted that it reduced AusNet's proposed forecast capex for the 2026–31 period by \$1,977.7 million (\$Nominal) or 51.4%. The AER's Draft Decision also included an update to the expected inflation rate (from 2.50% to 2.55%), which had the effect of increasing the indexation of the RAB component for the 2026–31 period by \$19.0 million (\$Nominal) or 0.2% from the Initial Proposal.

7.5.3. Revised Proposal

In this Revised Proposal, we have updated our forecast RAB for the 2026-2031 regulatory period to reflect the updated inputs presented in this Revised Proposal, including our revised forecast capital expenditure. The updated forecast RAB is presented in Table 7-1335 below, noting that our capital expenditure forecasts in this Revised Proposal are substantially higher than the Draft Decision, which increases the RAB over the 2026-2031 regulatory period. We have updated the expected inflation rate from 2.55% to 2.60% based on the latest RBA forecast inflation data¹¹¹. This has the effect of increasing the RAB indexation component by \$37.9 million (0.4%) from the Initial Proposal or \$17.1 million (0.4%) from the Draft Decision.

Table 7-1335: 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	6,276.0	6,830.7	7,412.5	8,011.7	8,494.9
Plus capex, net of contributions and disposals	733.4	771.6	803.6	690.1	742.5
Less straight-line depreciation	-341.8	-367.5	-397.0	-415.3	-411.9

¹¹¹ Based on published RBA forecast inflation data sourced from Statement on Monetary Policy - November 2025. Available at: <https://www.rba.gov.au/publications/smp/2025/nov/overview.html>

Plus nominal forecast inflation on opening RAB	163.2	177.6	192.7	208.3	220.9
Closing RAB	6,830.7	7,412.5	8,011.7	8,494.9	9,046.4

Source: AusNet's Revised Proposal PTRM (2026-31)

As noted in our Initial Proposal, the calculations shown above are consistent with the AER's Roll Forward Model and Post Tax Revenue Model (Version 5), and our approved CAM.

7.6. Supporting Documentation

The following documentation is provided in support of this chapter:

- ASD - AusNet Distribution - PTRM Model - 011225 – PUBLIC;
- ASD - AusNet Distribution - RFM Model - 011225 – PUBLIC;
- ASD - AusNet Distribution - Depreciation Tracking Model – 011225 – PUBLIC;
- ASD - Head Office Lease calculation - 011225 – CONFIDENTIAL;
- ASD - AusNet Distribution - Capitalised leases forecast (2025-2031) - 011225 - CONFIDENTIAL;
- ASD - AusNet Distribution - Critical spares list (10-Oct-2025) – CONFIDENTIAL;
- ASD - AusNet - Fleet & plant NPV model - Dec 2025 – CONF; and
- ASD - AusNet - Fleet & plant Business Case - Dec 2025 – PUBLIC.

8. Depreciation

8.1. Key points

The key points in this chapter are:

- We continue to apply the year-by-year tracking methodology for straight-line depreciation, which the AER accepted in its Draft Decision.
- Our pre-lodgement engagement with the AER resolved several issues, including the approach to accelerating depreciation for SCADA/Network control assets and the treatment of critical spares.
- The AER's Draft Decision accepted our proposed asset classes and asset lives, apart from our proposed lives for Concrete and Glass Reinforced (GRC) Poles and non-network IT (long-life) assets. In this Revised Proposal, we accept parts of the AER's Draft Decision and propose a new asset class which is discussed further in this chapter.
- The AER reduced our depreciation allowance for the 2026-2031 regulatory period compared to our Initial Proposal, principally as a result of the AER's lower capital expenditure allowance in its Draft Decision. Our Revised Proposal updates our depreciation allowance to reflect our revised capital expenditure forecasts, our updated opening RAB and the latest inflation data.

8.2. Chapter structure

This chapter is structured as follows:

- Section 8.3 summarises our Initial Proposal;
- Section 8.4 provides an overview of the AER's Draft Decision;
- Section 8.5 sets out our Revised Proposal; and
- Section 8.6 lists the supporting material provided in relation to our forecast depreciation for the 2026-2031 regulatory period.

8.3. Initial proposal

Our Initial Proposal adopted the AER's year-by-year tracking approach to calculate the straight-line depreciation allowance for our existing assets and forecast capex. This approach resulted in a total forecast regulatory depreciation of \$965.8 million (\$Nominal) for the 2026–31 regulatory period.

In addition to maintaining the asset classes and standard asset lives for the existing asset classes, we proposed 5 new asset classes with the following standard asset lives:

- Non-network solutions: Standard asset life of 15 years.
- Heavy vehicles and plant: Standard asset life of 15 years.
- Critical spares – network assets: Non-depreciable until placed into service.
- Non-network leasehold land & buildings – short term: Standard asset life of 5 years.
- Non-network leasehold land & buildings – long term: Standard asset life of 20 years.

In our Initial Proposal, we explained that these new asset classes would:

- Improve transparency and granularity in depreciation calculations for stakeholders.
- Support efficient investment by aligning depreciation profiles with the economic life of assets.

- Align with the AER's tracking model for smoother regulatory assessments and compliance.
- Enhance cost reflectivity by ensuring costs are closely tied to the specific assets being used.

For most new asset classes, we proposed an opening asset value of zero, as simplicity considerations at that time indicated that existing assets should not be transferred into these new asset classes. We have revised our approach for these new asset classes in this Revised Proposal to include our proposed final year asset adjustments, discussed further in Chapter 7 – Opening RAB, s.7.4.6.

8.4. Draft Decision

The AER's Draft Decision reduced our total forecast regulatory depreciation by 9.2% to \$876.6 million (\$Nominal). This reduction was primarily due to the AER's proposed reductions in our forecast capex, minor adjustments to the opening RAB, the introduction of new longer-lived asset classes and the AER's increase in expected inflation (which reduces regulatory depreciation).

The AER accepted our proposed straight-line depreciation method, year-by-year tracking approach, and standard asset lives for existing asset classes. The AER also accepted our proposed new asset classes including their standard asset lives, except for the concrete poles and glass-reinforced concrete poles, which were combined into a single asset class with an 80-year standard life. The AER also introduced a new asset class for non-network IT assets (Long life), which has a standard asset life of 10 years.

8.5. Revised proposal

Our Revised Proposal accepts the AER's Draft Decision methodology for calculating the depreciation allowance, and we propose a new asset class 'Motor Vehicle and plant Leases - short term' that features in our proposed final year asset adjustments in the RFM model. We have reallocated our forecast 2025-26 capex into this new asset class with a remaining life of 3.9 years, as outlined in s.7.4.6 of the opening RAB chapter. These updates, along with reallocations from existing classes into approved asset classes from the AER's Draft Decision are reflected in our proposed depreciation allowance for the 2026-2031 regulatory period. These inputs including our revised capital expenditure forecasts (discussed in Chapter 5), opening RAB and inflation data (discussed in Chapter 7), are set out below.

8.5.1. Opening RAB

In our Revised Proposal, we continue to apply straight-line depreciation of the opening RAB using the year-by-year tracking approach. The table below shows our 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 8-1: Proposed Opening RAB depreciation (2026-31), \$m, \$Jun 2026

Regulatory Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Opening RAB depreciation	333.2	315.7	299.7	277.6	237.8	1,464.0

Source: AusNet's Revised Proposal PTRM (2026-31)

8.5.2. Standard Asset Lives

As already noted, the AER has accepted all new asset classes and associated standard lives proposed in our Initial Proposal. In addition, the AER introduced two new asset classes which we have accepted in this Revised Proposal. Table 8-2 outlines the standard asset lives for new additions to the RAB, including the five new asset classes along with our proposed new asset class 'Motor Vehicle and plant Leases - short term'.

Table 8-2: Proposed standard asset lives for new additions to the RAB

Asset Classes	Standard life (Yrs)
Subtransmission	45.0

Distribution system assets	50.0
Concrete poles	80.0
SCADA/Network control	10.0
Non-network general assets - IT	5.0
Non-network IT assets – long life	10.0
Non-network general assets - Other	5.0
Land	n/a
Secondary systems (pre 2016)	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	5.5
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
Motor Vehicle and plant Leases - short term	5.0
<i>Buildings – capital works</i>	40.0
<i>In-house software</i>	5.0
Equity raising costs	n/a

Source: AusNet

8.5.2.1. Fleet and Plant Asset classes

To efficiently manage costs in the RAB associated with fleet and plant leases and acquisitions, we have utilised the following approved asset classes from the AER Draft Decision and proposed a new asset class:

- **Approved class:** 'Non-network general assets – Other' – 5-year standard life
- **Approved class:** 'Heavy Vehicles and Plant' – 15-year standard life
- **Proposed class:** 'Motor Vehicle and plant Leases - short term' – 5-year standard life

As part of transitioning to a new service provider, we are leasing vehicles and plant that were previously managed by our former network maintenance partner (Downer Engineering). AusNet has not previously proposed to capitalise motor vehicle and plant leases in the 2022-26 regulatory period. We have updated our 2025-26 forecast capex for fleet and plant leases of \$49.0 million (\$Nominal), as set out in Table 7-830 in ss.7.4.6.1 of this Revised Proposal. AusNet proposes to depreciate these lease costs under accounting standard AASB16 in the opening RAB according to their average remaining life of 3.9 years. The leases are of short-term nature and includes a mix of light vehicles and heavy vehicles that would be renewed on a 5-year lease term in the 2026-2031 regulatory period, unless replaced by a company-owned vehicle.

For fleet and plant acquisitions, we will utilise the two approved classes (noted above) which have varying standard lives of 5 years and 15 years. For purchases of light vehicles, we will continue to forecast and report RAB additions and disposals in 'Non-network general assets – Other' class which has a 5-year life. For heavy vehicle and plant acquisitions in the 2026-2031 regulatory period, we will forecast and report RAB additions and disposals in 'Heavy Vehicles and Plant' class which has a 15-year life. Accordingly, we have updated our asset disposal forecast for the 2026-2031 regulatory period in the SCS capex model, based on expected number of disposals by class. We have included supporting documentation for our proposed expenditures with this Revised Proposal.

8.5.2.2. Short-term Property leases

In this Revised Proposal, we have amended the standard life for approved class 'Non-network Leasehold Land & Buildings – short term' from 5.0 years to 5.54 years. This is based on our updated forecast of capitalised property leases for the 2026-2031 regulatory period, including revised forecasts for one of our head office sites and other leases associated with transitioning to a new service provider. The result of these changes is a new weighted average standard life of 5.54 years. We have provided supporting documentation for these updates with our Revised Proposal.

8.5.3. Forecast depreciation

Based on the depreciation methodology described above, AusNet's total forecast economic depreciation for the forthcoming regulatory control period is \$898.5 million (real \$Jun 2026). This is 7.7% below the depreciation allowance approved for the current regulatory period on a like-for-like basis (including approved cost passthrough amounts). Depreciation amounts for existing and new assets are presented in the table below.

Table 8-3: Forecast Economic depreciation (2026-31), \$m, \$Jun 2026

Regulatory Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Existing assets	333.2	315.7	299.7	277.6	237.8	1,464.0
New assets	-	33.4	67.9	97.2	124.4	322.9
Less: indexation on opening RAB	-159.0	-168.7	-178.4	-188.0	-194.3	-888.4
Total	174.1	180.4	189.2	186.8	168.0	898.5

Source: AusNet's Revised Proposal PTRM Model (2026-31)

8.6. Supporting Documentation

The following documents are provided in support of this chapter:

- ASD - AusNet Distribution - PTRM Model - 011225 – PUBLIC;
- ASD - AusNet Distribution - RFM Model - 011225 - PUBLIC;
- ASD - AusNet Distribution - Depreciation Tracking Model – 011225 – PUBLIC;
- ASD - AusNet Distribution – SCS Capex Model - 011225 – CONFIDENTIAL;
- ASD - AusNet Distribution - Critical spares list (10-Oct-2025) – CONFIDENTIAL;
- ASD - Head Office Lease calculation - 011225 – CONFIDENTIAL;
- ASD - AusNet Distribution - Capitalised leases forecast (2025-2031) - 011225 – CONFIDENTIAL;
- ASD - AusNet - Fleet & plant NPV model - Dec 2025 – CONF; and
- ASD - AusNet - Fleet & plant Business Case - Dec 2025 – PUBLIC.

9. Return on Capital

9.1. Key points

- Our Revised Proposal in relation to the return on capital has been prepared in accordance with the 2022 Rate of Return Instrument (RORI).
- In our Initial Proposal, we adopted a placeholder nominal vanilla WACC of 6.04%, for the first regulatory year 2026-27, with subsequent years to be updated annually. The AER's Draft Decision updated the placeholder value to 6.06% for the first regulatory year and subsequent years. In this Revised Proposal, we have adopted the Draft Decision placeholder with a slight difference due to rounding (6.07%).
- The AER's Draft Decision accepted our estimate for gamma, which is consistent with the 2022 RORI. We continue to adopt a gamma value of 0.57.
- In our Initial Proposal, we adopted the AER's preferred approach to estimating expected inflation to derive an estimate of 2.5% per annum for the 2026-2031 regulatory period. In this Revised Proposal, we have applied our updated estimate of 2.60% per annum for expected inflation as described in this chapter.
- In our Initial Proposal, we adopted the AER's standard approach for estimating debt and equity raising costs. In this Revised Proposal, we continue to apply the AER's standard approach, noting that the cost of debt allowance is included in our opex allowance.

9.2. Chapter structure

This chapter is structured as follows:

- Section 9.3 addresses the rate of return;
- Section 9.4 explains our approach to estimating equity raising costs;
- Section 9.5 described the approach to estimating debt raising costs;
- Section 9.6 sets out the estimated value for gamma;
- Section 9.7 explains the approach to estimating expected inflation; and
- Section 9.8 lists the relevant supporting documents.

9.3. Rate of Return

9.3.1. Overview

In our Initial Proposal, we estimated a rate of return placeholder of 6.04%. In its Draft Decision, the AER updated this estimate to 6.06% as shown in Table 9-1 below. For this Revised Proposal, we have updated this estimate to 6.07% as a result of a rounding difference. This is reflected in our rate of return build up model submitted with this Revised Proposal. This placeholder estimate will be updated in the AER's Final Decision to reflect our final rate of return averaging periods.

Table 9-1 Proposed placeholder Rate of Return

	Initial Proposal	Draft Decision	Revised Proposal
Return on equity	7.72%	7.97%	7.97%
Return on debt (yr 1)	4.91%	4.79%	4.79%
Inflation	2.50%	2.55%	2.60%

Gearing	60%	60%	60%
Gamma	0.57	0.57	0.57
Nominal vanilla WACC	6.04%	6.06%	6.07%

Source: AusNet

Our estimate in this Revised Proposal for the rate of return for each year of the regulatory period is set out in the table below.

Table 9-2: Rate of return by year

	2026-27	2027-28	2028-29	2029-30	2030-31
Return on equity	7.97%	7.97%	7.97%	7.97%	7.97%
Nominal pre-tax return on debt	4.79%	4.89%	5.01%	5.19%	5.46%
Gearing	60%	60%	60%	60%	60%
Nominal vanilla WACC	6.07%	6.12%	6.20%	6.30%	6.47%

Source: AusNet

9.3.2. Return on equity

Our Initial Proposal calculated the return on equity of 7.72% using a placeholder estimate of 4.00% for the risk-free rate. In the AER's Draft Decision, updated this placeholder estimate to 4.25% using an averaging period of 20 business days ending 30 June 2025. In this Revised Proposal, we have adopted the return on equity estimate in the Draft Decision, as summarised in the table below. The cost of equity will be updated in the AER's Final Decision.

Table 9-3: Proposed cost of equity parameters

Parameter	Proposed value	Basis of parameter value
Risk free rate (nominal)	4.25%	This is a placeholder value reflecting the yield on ten-year Commonwealth bonds measured over the 20 business day period ending 30 June 2025. 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	7.97%	The cost of equity is estimated in accordance with the SLCAPM, as specified in clause 4 of the AER's Rate of Return Instrument.

Source: AusNet

9.3.3. Cost of debt

Our Initial Proposal, we adopted a cost of debt of 4.91% using the trailing average approach in accordance with the RORI. We explained that the cost of debt will be updated in the AER's Final Decision in accordance with the AER's Rate of Return Instrument. In particular, the cost of debt will reflect the average of data published by Bloomberg and London Stock Exchange Group plc (LSEG), formerly known as Refinitiv, on the annualised 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 2022 RORI.

This Revised Proposal adopts the placeholder cost of debt of 4.79% set out in the AER's Draft Decision, calculated using an annual cost of debt of 5.87% within the trailing average methodology and an averaging period of 13 business days ending on 26 February 2025. The table below shows the estimated cost of debt for each year of the 2026-2031 regulatory period.

Table 9-4: Estimated benchmark cost of debt

	2026-27	2027-28	2028-29	2029-30	2030-31
Nominal pre-tax return on debt	4.79%	4.89%	5.01%	5.19%	5.46%

Source: AusNet

The benchmark cost of debt will be updated in the AER's Final Decision and annually in accordance with the 2022 RORI.

9.4. Equity Raising Costs

Equity raising costs are the transaction costs incurred when network service providers raise new equity in order to fund capital investment. 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.

In our Initial Proposal, we explained that 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 2022 RORI. Our modelling indicated that under the AER's approach no external equity injection is required to maintain the benchmark capital structure over the 2026-2031 regulatory control period. The AER's Draft Decision confirmed that no equity raising costs are required.

In this Revised Proposal, we have updated the modelling using the latest capital expenditure forecasts. This analysis confirms that no equity raising costs are required for the 2026-2031 regulatory period,

9.5. 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.

In our Initial Proposal, we proposed debt raising costs of \$16.6 million (real \$Jun 2026) for the 2026-2031 regulatory period, which are included as part of the operating expenditure forecast. In this Revised Proposal, we have updated the benchmark allowance, as explained in Chapter 6 – Operating Expenditure with an updated value of \$17.7 million (real \$Jun 2026).

9.6. Imputation Credit Value (Gamma)

In our Initial Proposal, we explained that 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 2022 RORI, we adopted a value for imputation credits of 0.57.

The AER's Draft Decision confirmed an estimated value for gamma of 0.57. In this Revised Proposal, we have continued to apply a gamma value of 0.57. The calculation of our tax allowance, using this gamma value, is provided in Chapter 11, which addresses our corporate tax allowance.

9.7. Forecast inflation

In our Initial Proposal, we explained that the AER revised its approach to estimating expected inflation in December 2020 in which the AER estimates the average annual inflation rate over a five-year period 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 2.50% in year 5.

In line with this approach, we proposed to follow the AER's methodology for estimating expected inflation and proposed a placeholder inflation rate of 2.50%. In the AER's Draft Decision, the AER updated the placeholder estimate for expected inflation to 2.55%. In this Revised Proposal, we have incorporated the RBA's November Statement of Monetary Policy update in our expected inflation estimate and apply a placeholder inflation rate of 2.60%.

This will be updated in the AER's Final Decision to incorporate the release of the RBA's Monetary Policy Statement in February 2026.

9.8. Averaging periods

We accept the Draft Decision's approval of our nominated equity and debt averaging periods.

9.9. Supporting Documentation

We have included the following documents to support this chapter:

- ASD - AusNet Distribution - PTRM Model - 011225 - PUBLIC; and
- ASD - AusNet Distribution - Rate of Return Build Up - 011225 – PUBLIC.

10. Corporate Tax Allowance

10.1. Key points

The key points in this chapter are:

- In our Initial Proposal, we explained that the estimated cost of corporate income tax for the 2026-2031 period will be zero as AusNet forecasts that it will incur tax losses during the period, so no positive tax cost needs to be included within the building-block revenue allowance.
- The AER's Draft Decision included various adjustments to the tax inputs, including the tax asset base (TAB), forecast capex and tax depreciation. The AER also proposed new asset classes with proposed standard tax lives for concrete poles (45 yrs) and non-network IT (5 years) long-lived assets. The net result of these changes confirmed that no tax allowance should be included in our revenue allowance for the 2026-2031 regulatory period.
- The AER's Draft Decision also suggested that we should amend our connection policy which would increase the tax liability that is recovered from large customer connections and reduce the tax costs that are borne by the broader customer base. Our Revised Proposal incorporates this change.
- In this Revised Proposal, we have adopted the AER's Draft Decision in relation to the 1 July 2026 opening TAB that includes gifted assets for the 2021 half year extension period of \$24.1 million (\$Nominal). Notwithstanding this, we consider this overstates gifted assets for reasons explained further in this chapter.
- We also propose a new asset class for capitalised fleet lease costs for the 2026-2031 regulatory period, and we present our updated forecast closing TAB as of 30 June 2026 that includes our updated capex forecasts in accordance with this Revised Proposal.

10.2. Chapter structure

This chapter is structured as follows:

- Section 10.3 discusses the method for calculating the tax allowance, including the approach adopted in the Initial Proposal, the AER's assessment in its Draft Decision, and our Revised Proposal;
- Section 10.4 sets out our Revised Proposal in relation to the opening TAB as at 1 July 2026;
- Section 10.5 sets out our Revised Proposal in relation to standard asset lives for tax purposes;
- Section 10.6 sets out our Revised Proposal in relation to immediately deductible expenses;
- Section 10.7 sets out our Revised Proposal in relation to the roll forward of the TAB and the calculation of our proposed tax allowance; and
- Section 10.8 lists the supporting documentation in relation to the tax allowance.

10.3. Method for Calculating the Tax Allowance

10.3.1. Our Initial Proposal

Our initial Proposal explained that our estimated of the tax allowance for the 2026-2031 regulatory period followed the AER's standard approach, which includes the following steps:

- **Taxable Income Calculation:** Taxable income was calculated by subtracting tax expenses (opex, tax depreciation, and interest expenses) from taxable revenue, which included income from customer contributions.

- **Tax Payable Calculation:** The corporate tax rate of 30% was applied to the taxable income to calculate the tax payable.
- **Adjustment for Imputation Credits (Gamma):** The tax payable was adjusted by multiplying it by one minus the value of imputation credits (gamma). AusNet applied a gamma value of 0.57, consistent with the AER's 2022 RORI
- **Tax Asset Base (TAB):** The opening tax asset base was rolled forward using actual and forecast net capital expenditure and depreciation, reflecting the tax treatment of capital expenditure and depreciation.
- **Standard Tax Lives:** Standard tax lives were applied based on the ATO Tax Ruling 2018/4 (TR 2018/4) and aligned with the economic lives of assets.
- **Tax Depreciation:** Tax depreciation was calculated using the diminishing value method, which applies a higher rate of depreciation in the earlier years of an asset's life.
- **Interest Expense Deduction:** Interest expenses were calculated based on the benchmark gearing ratio of 60% and the cost of debt determined by the AER.
- **Immediately Deductible Expenditure:** Certain expenditures, such as replacement capex, capitalised overheads, and large customer connections, were treated as immediately deductible for tax purposes.
- **Accumulated Tax Losses:** Accumulated tax losses from the previous regulatory period were carried forward and offset against taxable income.

Our Initial Proposal showed that the net outcome from the above calculation resulted in a zero tax allowance for the 2026-2031 regulatory period, primarily due to the impact of immediately deductible expenses and the ongoing accumulation of carried-forward tax losses.

10.3.2. Draft Decision

In its Draft Decision, the AER accepted our proposed approach to estimating the tax allowance subject to the following change:

- **Tax Losses:** The AER calculated that AusNet will carry forward \$77.9 million in tax losses as of 30 June 2031, which can be used to offset future tax liabilities in the 2031–2036 period. This significant reduction in carried forward tax losses compared to our Initial Proposal of \$894.4m by 30 June 2031 primarily reflects the AER's reduced forecast of immediately expensed capex for 2026–31 period and other minor changes as noted below.
- **Opening TAB:** The AER determined an opening TAB value of \$3,954.1 million as of 1 July 2026, which is \$31.9 million higher than our Initial Proposal. This adjustment was mainly due to the inclusion of capital contributions for gifted assets in the 2021 half-year of \$24.1 million (\$Nominal).¹¹²
- **Forecast Immediately Expensed Capex:** The AER reduced our proposed forecast immediately expensed capex from \$1,501.4 million to \$697.5 million, reflecting the AER's lower capex allowance for the 2026–31 period as detailed in its Draft Decision.
- **Tax Depreciation:** The AER accepted AusNet's proposal to use the year-by-year tracking approach for tax depreciation of existing assets, and the application of the diminishing value tax depreciation method.
- **Standard Tax Asset Lives:** The AER accepted our proposed standard tax asset lives for existing and new asset classes. Additionally, the AER introduced two new asset classes, with the following asset lives for tax purposes
 - Concrete poles: 45 years.
 - Non-network IT assets – long life: 5 years.¹¹³
- **Tax Treatment of Capital Contributions:** The AER suggested that we should consider amending our connection policy to remove the cross-subsidy of tax costs associated with large customer connections. This change would transfer the tax liability from the broader customer base to the connecting customers.¹¹⁴

The net result of the AER's adjustments to our tax inputs was to confirm that the tax allowance for the 2026-2031 regulatory period should be zero.

¹¹² AER, AER - Attachment 1 - Annual revenue requirement - Draft decision - AusNet Services distribution determination 2026-31 - September 2025, p.37.

¹¹³ Ibid, p.34.

¹¹⁴ Ibid, p.41.

10.3.3. Revised Proposal

In this Revised Proposal, we accept the AER's Draft Decision subject to updating the estimates to reflect the capex forecasts in accordance with this Revised Proposal. We expect the net result of these changes, which are explained in detail below, to confirm that the tax allowance for the 2026-2031 regulatory period should be zero.

10.4. Opening Tax Asset Base

Our Revised Proposal in relation to the opening TAB is set out in the table below, which reflects our amended 1 July 2021 opening TAB, actual and forecast net capex and depreciation, using the latest available data.

Table 10-1: AusNet's Tax Asset Base roll forward to 1 July 2026 (\$m, \$Nominal)

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26
Opening TAB	3,644.4	3,693.5	3,727.9	3,736.5	3,810.5
Plus capex, net of disposals	362.2	348.3	393.0	517.1	591.7
Less straight-line depreciation	-313.1	-313.9	-384.3	-443.1	-390.5
Closing TAB	3,693.5	3,727.9	3,736.5	3,810.5	4,016.8

Source: AusNet's Revised Proposal RFM

10.4.1. Gifted asset contributions for 2021 half-year extension period

For this Revised Proposal, we have adopted the Draft Decision 1 July 2021 opening TAB of \$3,644.4 million that includes capital contributions for gifted assets in the 2021 half-year of \$24.1 million (\$Nominal). Notwithstanding this, we consider that this overstates the 1 July 2021 opening tax base by \$24.1 million for two reasons:

- Current tax treatment:** As mentioned in our Initial Proposal, gifted assets received by Distribution networks are no longer treated as assessable income (for most types of connections) following the 2020 Full Federal court ruling for VPN vs Commissioner of Taxation.¹¹⁵ The AER agreed with this statement in the Draft Decision¹¹⁶.
- Regulatory consistency principle:** The capital contributions allowance approved in the AER's Final Determination for the 2016–20 period did not include any material value of gifted assets. This aligns with the methodology applied by AusNet in its 2016–20 Connections Capex Forecast model¹¹⁷ for estimating customer contributions. Consequently, the 2021 half-year forecasts for gross capex and customer contributions are not directly comparable to the AER's approach in the Draft Decision RFM, which incorporates gifted assets into both gross capex and customer contributions¹¹⁸.

Considering the above, we respectfully request that the AER reconsider the inclusion of gifted asset contributions in the 2021 half-year opening tax base for AusNet. Retaining the Draft Decision approach would overstate the tax asset base by \$24.1 million, which is inconsistent with the forecasts developed by AusNet for the 2016–20 period (notwithstanding gifted assets were treated as assessable income at that time) and with the current tax treatment following the 2020 Full Federal Court ruling. Aligning the Final Decision for the 2021 half-year inputs with these principles would promote regulatory consistency and prevent unintended distortions in AusNet's regulated tax base calculation.

¹¹⁵ Available at: <https://www.ato.gov.au/law/view/print?DocID=LIT%2FICD%2FVID237-240of2019%2F00001>

¹¹⁶ AER, AER - Attachment 1 - Annual revenue requirement - Draft decision - AusNet Services distribution determination 2026-31 - September 2025, p.37.

¹¹⁷ ASD, AST Distribution Connections Capex Forecast Model (Public), 30 April 2015.

¹¹⁸ AER, AER - RFM - Draft decision - AusNet distribution determination 2026-31 - September 2025.

10.5. Standard Tax Lives

In this Revised Proposal, we largely accept the AER's standard tax lives which reflect our existing and proposed new assets, together with the two new asset classes introduced by the AER in its Draft Decision. We have amended the standard tax life for class 'Non-Network Leasehold Land & Buildings – short term' and proposed a new asset class, as discussed further below. The standard tax lives and diminishing value rates for this Revised Proposal are set out in the table below.

Table 10-2: Proposed standard tax asset lives

Asset Classes	Standard life (Yrs)	DV rate
Sub-transmission	43.0	4.7%
Distribution system assets	46.0	4.3%
Concrete Poles	45.0	4.4%
SCADA/Network control	10.0	20.0%
Non-network general assets - IT	4.0	50.0%
Non-network IT assets – long life	5.0	40.0%
Non-network general assets - Other	12.0	16.7%
Land	n/a	n/a
Secondary systems (pre 2016)	n/a	n/a
Non-network Leasehold Land & Buildings - 1 July 2021	n/a	n/a
Non-network Leasehold Land & Buildings – 2021-22	n/a	n/a
Non-network Leasehold Land & Buildings – 2025-26	n/a	n/a
Non-Network Leasehold Land & Buildings – short term	5.5	36.1%
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 Plant	15.0	13.3%
Motor Vehicle and plant Leases - short term	5.0	40.0%
Buildings – capital works	40.0	n/a
In-house software	5.0	n/a
Equity raising costs	5.0	n/a

Source: AusNet

In line with our proposed RAB standard lives described in Chapter 8 of this Revised Proposal, we propose two changes to standard tax lives as follows:

- (7) We have amended the standard tax life for approved class 'Non-Network Leasehold Land & Buildings – short term' from 5.0 years in the Draft Decision to 5.54 years based on our updated forecast of capitalised property leases for the 2026-2031 regulatory period. We provide supporting documentation for these updates with our Revised Proposal.
- (8) A new asset class 'Motor Vehicle and plant Leases - short term' with a standard tax life of 5.0 years. We consider that the standard tax life of these assets should align with the economic life in the RAB of 5.0 years.

10.6. Forecast of immediately deductible expenditure

Our Revised Proposal in relation to forecast immediate deductible capital expenditure for the 2026–2031 regulatory control period is set out in the table below. The approach is consistent with the Draft Decision, updated to reflect the forecast capex in this Revised Proposal.

Table 10-3: Forecast immediately deductible expenditure 1 July 2026 to 30 June 2031 (\$m, \$Nominal)

Regulatory Year	2026-27	2027-28	2028-29	2029-30	2030-31
Sub-transmission	69.0	74.8	85.6	91.4	70.0
Distribution system assets	165.7	175.1	190.3	184.3	184.5
Concrete Poles	0.5	0.6	0.7	0.8	0.8
SCADA/Network control	11.9	9.5	11.2	21.1	27.1
Non-network general assets - IT	-	-	-	-	-
Non-Network Leasehold Land & Buildings – short term	-	-	-	-	-
Non-Network Leasehold Land & Buildings – long term	-	-	-	-	-
Non-network solutions	0.1	0.0	0.0	0.1	0.1
Critical spares – network assets	-	-	-	-	-
Heavy Vehicles and Plant	-	-	-	-	-
Motor Vehicle and plant Leases - short term	-	-	-	-	-
Buildings – capital works	-	-	-	-	-
In-house software	-	-	-	-	-
Total	247.2	260.1	287.8	297.7	282.6

Source: AusNet

10.7. Proposed Tax Allowance

Our updated calculation of roll-forward of the TAB for this Revised Proposal is shown in the table below.

Table 10-4: AusNet's Tax Asset Base roll forward to 30 June 2031 (\$m, \$Nominal)

Regulatory Year	2026-27	2027-28	2028-29	2029-30	2030-31
Opening TAB	4,016.8	4,344.8	4,640.5	4,921.5	5,067.7
Plus capex, net of disposals and capital contributions	721.3	758.7	789.9	678.0	728.9
Plus capital contributions	64.5	85.6	99.0	105.8	100.8
Less tax depreciation	-457.9	-548.6	-607.8	-637.5	-628.7
Closing TAB	4,344.8	4,640.5	4,921.5	5,067.7	5,268.8

Source: AusNet

Our proposed corporate tax is zero for the 2026-31 period, consistent with our Initial Proposal and the AER's Draft Decision, primarily due to the impact of immediately deductible expenses and the ongoing accumulation of carried-

forward tax losses. In calculating the corporate tax allowance, we have continued to apply the same approach, which 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; and
- An estimate of 0.57 for the value of gamma in accordance with the AER's 2022 RORI.

Our proposed tax allowance for this Revised Proposal for each year of the 2026-2031 regulatory period is shown in the table below.

Table 10-5: AusNet's proposed tax allowance calculation 1 July 2026 to 30 June 2031 (\$m nominal)

Regulatory Year	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

Source: AusNet

10.8. Supporting Documentation

We have included the following documents to support this chapter:

- ASD - AusNet Distribution - PTRM Model - 011225 – PUBLIC;
- ASD - AusNet Distribution - RFM Model - 011225 - PUBLIC;
- ASD - AusNet Distribution - Depreciation Tracking Model – 011225 – PUBLIC;
- ASD - AusNet Distribution – SCS Capex Model - 011225 – CONFIDENTIAL;
- ASD - AusNet Distribution - Critical spares list (10-Oct-2025) – CONFIDENTIAL;
- ASD - Head Office Lease calculation - 011225 – CONFIDENTIAL; and
- ASD - AusNet Distribution - Capitalised leases forecast (2025-2031) - 011225 – CONFIDENTIAL.

11. Incentive Schemes

11.1. Key points

The key points in this chapter are:

- We are re-proposing our CSIS design from our Initial proposal, applying targets from a 9 month baseline. We have carefully considered the AER's draft decision not to accept our CSIS and have addressed their concerns to the extent we are able to do so. We also acknowledge the very strong customer feedback on the CSIS design.
- In case the AER concludes that we have not fully addressed its concerns in relation to CSIS, we have set out an alternative proposal to re-apply the telephone answering parameter of the STPIS.
- We accept the Draft Decision on the STPIS, including adjustments to our targets to account for the impact of the resilience and reliability programs. We encourage the AER to undertake a STPIS review before the 2031-36 regulatory period which should address the inclusion of catastrophic events from the Major Event Day (MED) threshold.
- AusNet's revised CESS proposal seeks a carryover amount of -\$137.4 million. While we have accepted most aspects of the Draft Decision, we reject the decision not to include the Zinfra transition costs as a CESS adjustment, given this removes the incentive for networks to make capital investments that lower longer term costs in the later years of the regulatory period. We have also set out our preferred definition of large, bespoke connections in line with the AER's updated CESS.
- AusNet's revised EBSS proposal seeks a carryover amount of \$38.8 million. We accept all aspects of the Draft Decision, except for the non-recurrent efficiency gain applied for the bushfire liability insurance premium underspend in 2022-23, which we strongly reject. Our EBSS proposal for the 2026-31 period aligns with the AER's Draft Decision and proposes a further exclusion for customer relationship managers and communications program, which we have proposed as a category-specific forecast (see Chapter 6 – Opex, section 6.7.3.3.3).
- We accept the continued application of the f factor and Demand Management Incentive Scheme.

11.2. Chapter structure

This chapter is structured as follows:

- Section 11.3 provides an overview of our Customer Satisfaction Incentive Scheme (CSIS) proposal;
- Section 11.4 explains our Service Target Performance Incentive Scheme (STPIS) proposal;
- Section 11.5 sets out our Capital Efficiency Sharing Scheme (CESS) proposal; and
- Section 11.6 describes our Efficiency Benefit Sharing Scheme (EBSS) proposal.

11.3. CSIS

11.3.1. Our Initial Proposal

We initially proposed a Customer Service Incentive Scheme (CSIS) designed to improve customer experience through holistic measures. This built on the CSIS that has applied during the current regulatory period. The proposal attached one percent of revenue to performance against four customer satisfaction parameters:

- Planned outage customer satisfaction (C-Sat).
- Unplanned outage C-Sat.
- New connections C-Sat.

- % of matters resolved during customer's first call.

These measures were developed through customer engagement and aimed to reflect outcomes that customers value. We considered our design to be consistent with the Scheme guidelines, although we did not propose targets as we did not yet have a baseline available. This was because in January 2025 we changed our survey methodology from telephone calls to email surveys due to very lower customer response rates to telephone calls. This is an industry wide issue and we needed to change the surveying approach to continue to get statistically significant samples.

11.3.2. Draft Decision

The AER rejected the design of our proposed CSIS and instead proposed the value of one percent of revenue (in aggregate) apply to the following two Service Target Performance Incentive Scheme (STPIS) metrics:

- Time taken to connect a property.
- % of calls answered in 30 seconds.

The AER concluded that our proposed CSIS did not meet the incentive design criteria set out in the CSIS framework and therefore could not be accepted. These criteria require that the design achieves the scheme's objectives, is based on robust data, and provides incentives that are commensurate with the value of service improvements to customers. The AER's identified three key issues:

1. **Lack of Baseline Data and Targets**
AusNet did not provide sufficient historical performance data to establish credible baselines for its proposed measures. Without robust baselines, the AER could not assess whether the proposed targets were achievable or meaningful.
2. **Revenue at Risk**
The proposal to apply a $\pm 1\%$ revenue at risk was considered inconsistent with the principles of the CSIS.
3. **Risk of Overlap with STPIS for our unplanned outage parameter**
The AER highlighted potential interrelationships between AusNet's proposed CSIS and the existing STPIS. Specifically, some proposed measures could duplicate incentives already provided under STPIS, creating inefficiencies and complexity in the regulatory arrangements.

We address each of these concerns below.

11.3.3. Revised Proposal

We have not adopted the AER's Draft Decision on the CSIS and have tried to address the AER's concerns set out in its Draft Decision. CSIS benefits are currently quantified in business cases at AusNet and adopted as business performance KPIs, which means that moving away from a CSIS would impact those investment decisions. In our view, this incentive scheme would appropriately drive investment that is aligned to prioritising customer satisfaction.

In addition, our customers strongly support the application of a CSIS compared to the telephone answering metric, and we consider the AER's concerns, while valid, are outweighed by the benefits of a more meaningful incentive scheme applying.

However, if the AER's concerns remain, we propose the STPIS customer call centre metric should apply rather than having no customer-focused incentive in the 2026-2031 regulatory period. Our proposal as to how this would apply is outlined in Section 11.3.4.

Notwithstanding this alternative proposal, our preference is to apply our CSIS for the below reasons:

- We do not believe that the current STPIS metrics serves our customers best interests in the upcoming period. The proposed metrics were designed in an operating environment which is different to today's, and the metrics are too narrow, inflexible, and do not align with the interactions and outcomes that customers value most. Our CSIS also measures call centre and connection performance to the extent these impact customer satisfaction, and includes more holistic and meaningful measures that have been tested and validated through extensive engagement to make sure they drive meaningful improvements that align with the priorities and preferences of our customers.
- Our customers and stakeholders strongly oppose applying STPIS metrics. During our November workshop, attendees expressed strong and unanimous support for AusNet to persist with our original CSIS proposal. Participants noted a lack of compelling evidence to demonstrate that its alternative, STPIS metrics, would deliver superior or more relevant outcomes for customers. The feedback from this engagement was unequivocal that AusNet's original CSIS, with its design directly informed by customers, is the preferred approach to drive improvements in service areas that matter most to them.

Further, recognising the AER's concerns about the sufficiency of historical data, some participants suggested delayed commencement of the CSIS if necessary to establish targets as the additional time will ensure robust benchmarking data, ultimately satisfying the AER's requirements while ensuring that the scheme can be approved for the majority of the 2026-2031 regulatory period. We would be open to exploring this option with the AER.

Our proposed CSIS design, consistent with our Initial Proposal, and including our proposed targets, are set out in the Table below.

Table 11-1: Proposed CSIS design

AusNet 2026-31 CSIS			
Performance parameter	Target	Incentive rate/Revenue at risk	Deadbands
Planned outage C-Sat	6.87	0.125%	6.77-6.96
Unplanned outage C-Sat	5.41	0.125%	5.23-5.58
New Connections C-Sat	5.78	0.125%	5.17-6.39
First Call Resolution	80.9%	0.125%	N/a

Source: AusNet

In response to the AERs specific concerns raised in their draft decision:

- **Baseline data and targets:** We re-propose the CSIS design with targets based on the last 11 months of results presented in the above table as this is the maximum baseline available under our proposed methodology. We engaged with our R&E panel and the AER when the decision to change methodology and suspend our current period CSIS was made at the end of 2024.

While the new targets are lower than our current period average, these results should not be interpreted as a decline in services. As previously raised¹¹⁹, we were expecting this to decrease our average score for each parameter because behavioural evidence suggests that people are typically more critical when responding to online surveys compared to providing feedback directly to another person on the telephone. The change in methodology is also providing us with a much more representative sample of our customers and therefore more meaningful results.

Alternatively, there is the opportunity for the AER to apply a longer baseline through the information request process, or a 1-year delayed start to our CSIS scheme to commence in 2027-28, with a January 2025-June 2027 baseline. This additional time would allow for further data to be collected to inform the target.

We have an opportunity to engage on CSIS targets with our next Customer Consultative Committee (CCC) to be scheduled for February 2026, prior to the 30 April 2026 Final Decision. We welcome early feedback from the AER on whether the Final CSIS Decision will turn on this engagement being undertaken, as we have numerous other agenda items we could prioritise.

1. **Revenue at risk:** We accept the AERs decision to apply a maximum of 0.5% revenue at risk to the CSIS if approved.
2. **Overlap with STPIS:** As outlined in our response to AER requests for further information, AusNet's position is that unplanned C-Sat and STPIS metrics serve distinct but complementary purposes: the former drives improvements in customer experience, while the latter focuses on operational reliability.

There is a clear distinction between the CSIS and the existing STPIS unplanned outage metrics. While the STPIS incentivises reductions in the frequency and duration of outages focusing on objective operational metrics, the CSIS is designed to improve the subjective and qualitative aspects of customer experience during unplanned outages. Customer satisfaction captures perceptions of communication, professionalism and responsiveness during outage events.

Although outage duration is one factor in customer satisfaction, our analysis shows that communication and service quality are stronger drivers of satisfaction than duration alone. Our regression analysis of survey data demonstrates that customers' perceptions of how an outage was managed, including the clarity, timeliness, and usefulness of

¹¹⁹ AusNet Proposed CSIS Methodology change and transitional arrangement submission to AER - 18 October 2024

information provided have an influence on customer satisfaction. The CSIS thus targets areas not directly incentivised by the STPIS, ensuring the two schemes are complementary rather than duplicative.

Further, given the lower financial materiality of the CSIS incentive relative to the STPIS, the proposed CSIS is not designed to reward avoidance of outages, but rather how well customers are supported when outages do occur.

In addition, specific initiatives incentivised under the CSIS, such as enhancements to real-time outage communications and improvements in crew training, are not captured by the STPIS.

Despite both being related to outages, the very different drivers of performance under each incentive scheme, lead us to consider this is not a material concern that would warrant not applying the CSIS. We also note that both the unplanned outage component of the CSIS and the STPIS have applied in the current period and so this perceived overlap has been previously accepted by the AER.

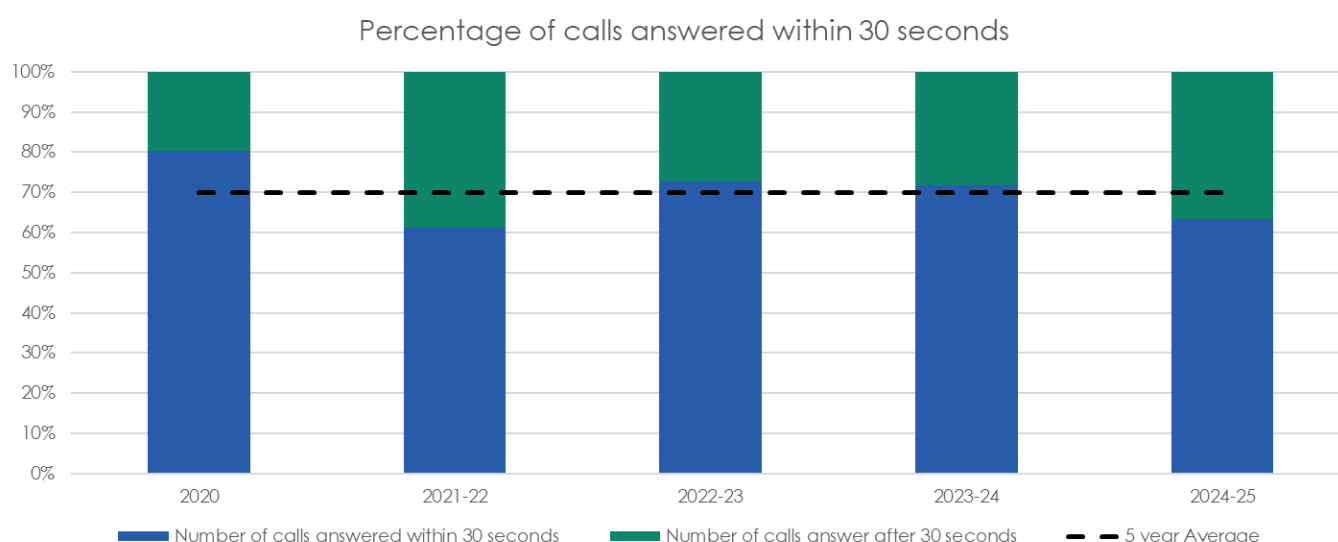
11.3.4. Alternative approach

If the AER does not consider we have fully addressed its concerns, we are open to the re-application of the customer service aspect of the STPIS. In this case, we would propose to apply 0.5% revenue at risk to the call answering metric and not apply the proposed CSIS.

11.3.4.1. Telephone answering parameter

We propose the standard application of the telephone answering parameter. Our data reported in the RINs shows a target of 70% based on the last 5 years of performance.

Figure 11-1: AusNet historical performance on STPIS telephone answering



Source: Table 6.6.1 of AusNet Annual RIN (2020, 2021-22, 2022-23, 2023-24), Table 6.7 of AusNet Annual Order 2024-25

Table 11-2: AusNet historical performance

Source: AusNet

11.3.4.2. Connections parameter

STPIS is designed to incentivise improvements in activities classified as standard control services (SCS) consistent with 5.1.9(e) of the scheme. Victorian DNSPs classify connections the majority of our connection activities Alternative Control and therefore the connection parameter could only apply to standard control service connections, but our basic connections (which are the vast majority of our connections and are classified as ACS) would not be captured. Additionally, we consider the overlap with the GSLs scheme applicable to Victorian DNSPs and the connections parameter in the STPIS, may not be appropriate.

If the CSIS cannot be applied the AER should consider a review of the STPIS customer metrics in the guideline to improve the metric options for future periods. We would welcome engagement with the AER on evolving the STPIS guideline for future regulatory periods, and we remain flexible to transition to a new incentive as soon as practical, even if it is within the 2026–31 period.

11.4. Service Target Performance Incentive Scheme

11.4.1. Initial Proposal

We proposed to apply version 2.0 of the STPIS in the 2026–31 period, but with several clarifications:

- Major Event Day (MED) boundary: We proposed to exclude catastrophic events from the calculation of the MED boundary in the 2026–31 regulatory control period.
- Customer service component (telephone answering parameter): We proposed that the telephone answering parameter should not apply in the forthcoming regulatory period and that it should be replaced with the CSIS.
- Revenue at risk: We proposed to apply revenue at risk of $\pm 4.5\%$ for the STPIS, which is 0.5% lower than the default revenue at risk due to the proposed CSIS replacing the Customer Service Component.
- Performance targets: We proposed the standard target setting approach. However, we included reliability and resilience programs as part of our capex proposal, which we expect to result in improvement in supply reliability.

	2020	2021-22	2022-23	2023-24	2024-25
Number of calls received (After removing excluded events)	87,772	95,269	68,075	74,611	100,964
Number of calls answered within 30 seconds	70,585	58,375	49,448	53,567	64,012
Percentage of calls answered within 30 seconds	80%	61%	73%	72%	63%

Rather than adjusting the STPIS performance targets, we proposed to remove the expenditure associated with improved reliability from its proposed capex allowance.

11.4.2. Draft Decision

In its draft decision, the AER stated that it will apply version 2.0 of the STPIS for the 2026–31 regulatory period, with SAIDI, SAIFI, MAIFI and customer service (telephone answering and new connections) as the applicable parameters. The AER rejected our proposed Customer Service Incentive Scheme (CSIS) and instead confirmed that it will apply the STPIS telephone answering and new connections parameters. Consequently, the AER also rejected our proposed revenue at risk of ± 4.5 per cent, which CSIS, and retained the default ± 5 per cent.

For our proposed STPIS performance targets and incentive rates, the AER:

- Requires us to update performance targets and incentive rates by incorporating actual data from RY2025 in our Revised Proposal;
- Rejected our approach to reducing reliability-related capex to account for expected STPIS reward, instead of adjusting STPIS targets. The AER found our approach to be inconsistent with the scheme, and instead required us to adjust targets accordingly;

- Accepted our proposal to apply a MED threshold of 2.8 for exclusions but rejected our proposal to exclude catastrophic events from the STPIS.

11.4.3. Revised Proposal

11.4.3.1. Customer Service Component

As explained in section 11.3, we do not accept the AER's draft decision to apply the telephone answering and new connections parameters in place of our proposed CSIS for the customer service component. We have repropose our CSIS. In addition, if the Customer Service Component of the STPIS is to apply, we propose this is limited to the telephone answering parameter. This is discussed in detail i

11.4.3.2. Revenue at Risk

As discussed, we have repropose our CSIS and propose that it replaces the telephone answering and new connections parameters under the STPIS customer service component. Accordingly, we continue to propose a revenue at risk of ± 4.5 per cent for the STPIS, reflecting the inclusion of the CSIS within the overall incentive framework.

11.4.3.3. Exclusions

We accept the AER's draft decision not to exclude catastrophic events from STPIS. We acknowledge the AER's draft decision to retain the current approach under STPIS version 2.0, which requires the application of the IEEE 1366-2003 standard and does not permit the exclusion of catastrophic events from the calculation of the MED threshold. The AER has confirmed that any change to allow such exclusions would require an amendment to the STPIS. While the AER acknowledged our formal request to review the STPIS, the AER has decided not to conduct a review at this time.

However, while we accept this draft decision, we note that this is a material issue for AusNet Services. Catastrophic events can significantly distort reliability performance metrics and, in turn, the operation of the STPIS. The IEEE 1366-2012 and 2022 standards contemplate the exclusion of catastrophic events to avoid skewing reliability trends and provide a more accurate reflection of underlying network performance.

The AER has indicated that it will continue to monitor developments in the IEEE standard and consider whether these warrant a future review of the STPIS. We strongly support a review and expect this to occur in time to apply in the 2031-36 regulatory period. This will ensure that the STPIS remains fit for purpose and reflects contemporary best practice in reliability measurement.

11.4.3.4. Performance targets and incentive rates

We have revised our STPIS performance targets using data from the five years from 1 July 2020 to 30 June 2025. This includes actual performance data for regulatory year 2024-2025, which was not available at the time of submitting our initial proposal.

In addition, we have adjusted the performance targets to reflect the expected impact on STPIS performance of our proposed reliability and resilience related programs. We accept the AER's draft decision requiring us to adjust these targets rather than remove the associated expenditure from our capex forecast. The estimated performance improvements have been derived from historical performance data and assumptions regarding program effectiveness and ramp-up profiles. These assumptions are consistent with those adopted in the cost-benefit analyses and business cases for these programs.

The calculation of estimated performance improvements is detailed in 'ASD-AusNet STPIS performance Target – 2Dec2025.xlsx'

We have also revised our proposed incentive rates based on revised performance targets, most recent VCR values, and other updated data since January. Table 1-3 below outlines our proposed incentive rates. The calculation of incentive rates is detailed in 'ASD - AusNet - STPIS Incentive Rates Calculator - 2Dec2025.xlsm'.

Table 11-3: STPIS Targets and Incentive Rates for 2026-31

Measure	Average Historic Performance	Adjustment for Reliability and Resilience Programs	Proposed Targets	Proposed Incentive rates
USAIDI				(%/minute)
Urban	82.815	1.429	81.387	0.0210%
Rural short	196.603	4.052	192.551	0.0209%

Rural long	313.902	3.660	310.242	0.0082%
USAIFI				(%/0.01 Interruptions)
Urban	0.743	0.015	0.728	1.5658%
Rural short	1.481	0.033	1.448	1.8649%
Rural long	2.105	0.023	2.082	0.7720%
MAIFI				(%/0.01 Interruptions)
Urban	2.867	0.090	2.777	0.1253%
Rural short	4.793	0.090	4.703	0.1492%
Rural long	8.695	0.025	8.670	0.0618%

Source: AusNet

We note that the performance targets and incentive rates outlined above assume the AER accepts our proposed BN11 option of overhead express feeders. As an alternative, we have also provided an option for [C-I-C] of covered conductors for BN11. Should the AER approve the covered conductor option instead of overhead express feeder, the expected performance improvements for BN11 will need to be revised accordingly. Consequently, the STPIS performance targets and incentive rates will be updated as shown in the table below. Calculations of STPIS performance targets and incentive rates for this alternative scenario are detailed in 'ASD - AusNet STPIS Performance Target - Alternative - 2Dec2025' and 'ASD - AusNet - STPIS Incentive Rates Calculator - Alternative - 2Dec2025'.

Table 11-4: STPIS Targets and Incentive Rates for 2026-31, Alternative Scenario (10 km Covered Conductors for BN11)

Measure	Average Historic Performance	Adjustment for Reliability and Resilience Programs	Proposed Targets	Proposed Incentive rates
USAIDI				(%/minute)
Urban	82.815	1.429	81.387	0.0210%
Rural short	196.603	4.052	192.551	0.0209%
Rural long	313.902	3.092	310.810	0.0082%
USAIFI				(%/0.01 Interruptions)
Urban	0.743	0.015	0.728	1.5658%
Rural short	1.481	0.033	1.448	1.8649%
Rural long	2.105	0.019	2.086	0.7719%
MAIFI				(%/0.01 Interruptions)
Urban	2.867	0.090	2.777	0.1253%
Rural short	4.793	0.090	4.703	0.1492%
Rural long	8.695	0.025	8.670	0.0618%

Source: AusNet

We note that should the AER reject components of our reliability or resilience capex program, the proposed target adjustments should be updated accordingly.

11.5. Capital Efficiency Sharing Scheme

11.5.1. Our Initial Proposal

In our initial proposal, we proposed a CESS revenue decrement of \$117.2 million (real \$2025-26) due to an overspend against the AER's approved capex allowance for the 2021-26 period. We proposed two exclusions from the CESS calculation:

- Costs associated with the transition to Zinfra as our operations and maintenance service provider.

- Innovation expenditure.

We also proposed a true-up increment of \$2.1 million, later updated to \$2.7 million in response to IR10, to reflect actual capex for 2020-21.

For the 2026-31 period, we proposed to apply CESS but with specific exclusions, including:

- Innovation expenditure.
- Regional reliability allowance expenditure.
- Expenditure for new technology connections.

11.5.2. Draft Decision

The AER did not accept our proposed decrement of \$117.2 million. Instead, it applied a larger decrement of \$122.1 million (2025-26 dollars) across the 2026-31 period. The difference reflects updated CPI and WACC inputs and the removal of our proposed exclusions for Zinfra transition costs and innovation expenditure.

The AER also included a \$0.6 million adjustment for updated actual capex, compared to the \$2.7 million we proposed.

For the 2026-31 period, the AER will apply the updated CESS (version 4 of the Capital Expenditure Incentive Guidelines), which includes:

- An ex-ante volumetric adjustment for business-as-usual connections to address forecasting uncertainty.
- The ability to adjust penalties after an ex-post review for large bespoke connections (e.g., data centres, batteries).

The AER does not allow category-specific exclusions for innovation or regional reliability allowance but notes that we may voluntarily forgo CESS rewards for these categories.

11.5.3. Revised Proposal

We do not accept the AER's Draft Decision on the revenue adjustment for each year of the 2026-31 regulatory period arising from the application of the CESS during the 2021-26 regulatory period.

In particular, we do not accept the AER's Draft Decision on removing our proposed exclusions for Zinfra transition costs and innovation expenditure, which we discuss in detail below. We accept the AER's Draft Decision on adjusting our proposed true-up increment of \$2.7 million to \$0.6 million.

Incorporating these, we have revised our proposed CESS carry over amount, to a total of -\$137.4 million, which is outlined in the table below.

Table 11-5: Calculation of CESS carryover amount (\$M, real June 2026)

	2021-22	2022-23	2023-24	2024-25	2025-26
Capex allowance	346.75	337.98	332.12	291.11	294.75
Net capex for CESS purposes	343.97	332.69	385.14	487.55	478.29
Underspend	2.78	5.30	-53.02	-196.44	-183.54
Year 1 benefit		0.07	0.08	0.09	0.09
Year 2 benefit			0.15	0.16	0.17
Year 3 benefit				-1.49	-1.56
Year 4 benefit					-5.55
Year 5 benefit					
NPV underspend	3.68	6.61	-59.73	-206.88	-183.54
NPV financing benefit	0.00	0.09	0.25	-1.31	-6.85
Total underspend (NPV) adjusted for deferrals	-439.86				
Relevant sharing ratio	30%				
Consumer share	-307.90				

NSP share	-131.96				
Total NSP financing benefit (NPV)	-7.80				
NPV of CESS payments (post-adjustment) 30 December 2020	-124.15				
NPV of CESS payments (post-adjustment) 30 June 2021	-137.38				
CESS Payment Per Year	-\$27.48	-\$27.48	-\$27.48	-\$27.48	-\$27.48

Source: AusNet

We accept the AER's Draft Decision to apply the updated CESS for the 2026-31 regulatory period. We have included details on how we propose to apply the volumetric adjustment and penalties adjustment for bespoke large connections in Chapter 5 – Capex, section 5.12. We also accept the Draft Decision to not include category-specific exclusions for innovation and the regional reliability allowance (which has been rejected in full).

11.5.3.1. Proposed Exclusions of Zinfra Transition Costs

The AER removed our proposed exclusion for Zinfra transition costs because exclusions were not part of the CESS design for the 2021–26 period. No other issues were raised in the Draft Decision regarding this exclusion.

While we acknowledge the current CESS guideline applies to total net capex and does not explicitly provide for exclusions, we 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]"*.¹²⁰ This indicates the AER has a level of discretion regarding the approval of CESS exclusions, despite the provisions of the existing CESS guideline. This is confirmed by the AER's acceptance of our voluntary reduction in the CESS for innovation expenditure because it is reasonable and in the long-term interests of consumers.

We consider the proposed exclusion of Zinfra transition costs is also reasonable and in the long-term interests of consumers, for the reasons set out below. While these reasons were also raised in our Initial Proposal the AER did not engage with these reasons in its Draft Decision so we repeat them in our Revised Proposal.

Unlike the opex framework, the capex framework does not provide a continuous incentive for networks to invest in capital solutions intended to reduce costs over the long-term. This is because:

- Capital allowances are reset based on a bottom-up forecast every 5 years, meaning efficiencies expected from year 1 of the regulatory period after the investment is been made are fully reflected in capex allowances from that time; and
- The CESS rewards are calculated with respect to the 5 year regulatory period capex allowance only, with no regard for future efficiencies that may have been achieved due to capital investments within the 5 year period.

In the case of our Zinfra transition costs, we incurred costs related to digital systems, fleet, property leases, and tools and equipment in the final two years of the current regulatory period on the basis that the change to Zinfra from our previous service provider was expected to lower ongoing costs to customers. Customers will benefit from these lower ongoing costs from the 1 July 2026 as our capex forecast has been built up using Zinfra rates. This also means that, from 1 July 2026, AusNet will not retain any benefit from its decision to transition to a new, lower cost, service provider.

However, unless the proposed exclusion is accepted, AusNet will be penalised around \$24 million under the CESS as a direct result of this investment. This is not consistent with incentive-based regulation and will set a precedent that prevents networks investing in cost savings initiatives in the latter years of the regulatory framework. This would provide a perverse incentive to wait until the start of the next regulatory period to make efficiency investments, delaying the customer benefit for 5 additional years, rather than investing at the optimal time. Contrary to the National Electricity Objective this would not be in the long term interests of consumers.

In addition, rejecting this exclusion violates the Revenue and Pricing Principle to provide AusNet with a reasonable opportunity to recover our efficient costs. We consider these costs to be efficient but are unfunded because they were not anticipated at the time of the 2021-26 EDPR. Including these costs in the calculation of our CESS penalty means that AusNet will be penalised around \$24 million for incurring these efficient costs.

The problem set out above, and potential consequential impacts for customers, is one reason why the EBSS and opex forecasting framework is designed to provide a continuous incentive so networks can invest in efficiency improvements that deliver customer benefits with confidence. As the AER has recognised and addressed this issue in the opex framework, it follows this should also be addressed in the capex framework.

¹²⁰ AER, Framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026–31, July 2024, p.16

We also note that the impact of the accounting standard which recognises future fleet lease payments in the year in which the lease is entered into worsens this issue. The annual vehicle costs faced by customers is spread over the term of the lease via revenues but the entire lease cost is recognised as capex in 2025-26. This means that a CESS penalty is incurred on the entire amount. Under the previous accounting treatment where leases were opex this issue would not have been as severe. This point generally applies to leases for both property and fleet and the interactions with the CESS, which disincentivises networks from entering into longer-term leases even where they are better value for money for customers.

For the reasons set out above, AusNet continues to propose the costs included in the table below should be excluded from the CESS.

Table 11-6: Zinfra transition costs excluded from the CESS (\$'000)

	2024-25	2025-26
ICT	\$4,464	\$6,322
Vehicles		\$55,864
Property leases		\$8,346
Tools and equipments		\$4,973
Total	\$4,464	\$75,505

Source: AusNet

11.5.3.2. Proposed Exclusion of Innovation Expenditure

We acknowledge the AER's decision not to accept our proposed exclusions for innovation expenditure. Nevertheless, we continue to exclude innovation expenditure from the CESS. This is because innovation funding was provided on a use-it-or-lose-it basis, with a ceiling agreed upon through extensive engagement with the Customer Forum. Including innovation expenditure in the CESS would create unnecessary complexity and contradict the principle that we should not profit from underspending this allowance.

We welcome further engagement with the AER on this proposed exclusion prior to the final decision.

11.5.3.3. Correction to CESS Model for Capital Contributions

We propose an amendment to the Capital Expenditure Sharing Scheme (CESS) model for Standard Control Services to address an error in forecasting capital contributions for the 2021–26 regulatory control period. This adjustment of \$3.6 million was identified during model validation and communicated to the AER capex team on 11 July 2023, following email correspondence with the AER regarding “reset pre-populated models – AusNet Services.”

On 12 July 2023, the AER confirmed that, after reviewing the adjustment, it appeared reasonable for the purpose of recalculating the CESS payment. While the AER's draft decision for the 2026–31 period removed this adjustment from its published CESS model, AusNet notes the AER's agreement in principle and seeks to reinstate the correction in the revised proposal to ensure accurate incentive outcomes, and consistency with the agreed approach.

The timing of identifying this error meant that the AER Final Decision PTRM (2021–26) for AusNet could not be amended. Accordingly, we consulted the AER on the proposed adjustment to the CESS payment as part of the 2026–31 revenue reset during the pre-lodgement engagement process. We have included our original calculations supporting these proposed adjustments in the CESS model. Refer to worksheet 'CESS Adj 1 - Cap Cons' for further details.

This amendment:

- Aligns with the intent of the CESS to reward efficient capital expenditure.
- Corrects a known error in the pre-populated model, ensuring fairness in incentive calculations.
- Reflects prior engagement and agreement with the AER on the reasonableness of the adjustment.

11.5.3.4. Large, bespoke connections

Consistent with the AER's default position, we propose to:

- Apply volumetric adjustment for Business-as-Usual (BAU) connections; and
- Apply the penalties adjustment for bespoke large connections.

We have included the details of our proposal, outlining our approach to identifying BAU connections as well as bespoke large connections in section 5.12.

11.6. Efficiency Benefit Sharing Scheme (EBSS)

11.6.1. Our Initial Proposal

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. We proposed an EBSS carryover amount of \$40.2 million (\$2025-26) in our Regulatory Proposal.

In proposing this carryover amount we noted that:

- We would update values reported in our 2024-25 regulatory accounts to reflect audited actuals.
- We would update our allowances in line with the outcome of the September 2024 storms pass through.

For the 2026-31 regulatory period we proposed the following categories of expenditure should be excluded from allowances for EBSS purposes.

- Costs forecast on a bottom up basis including GSL payments and debt raising costs;
- Expenditure associated with programs proposed on a 'use it or lose it' basis, including innovation and the Regional Reliability allowance; and
- Demand Management Incentive Allowance (DMIA).

11.6.2. Draft Decision

The AER overall rejected our proposal and approved a carryover amount of \$24.7 million (\$2025-26) from the application of the EBSS for the 2021-26 regulatory period. Key changes made by the AER included:

- Updating inflation and WACC inputs to the latest number
- Including a non-recurrent efficiency gain for our base year, associated with bushfire liability premiums
- Removing non-recurrent SaaS costs from actual opex.

The AER's Draft Decision accepts our proposal to exclude innovation opex from the application of the EBSS for the 2026-31 period but rejected the proposed Regional Reliability allowance because it did not accept this proposed expenditure.

The AER's draft decision is reflected in the table below:

Table 11-7: EBSS carryover amount – AER Draft Decision (\$m, 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
EBSS carryover amount	-0.7	9.3	-4.7	-11.6	32.4	24.7

Source: AER

11.6.3. Revised Proposal

We have re-proposed an updated EBSS carryover figure of \$38.8 million in our Revised Proposal to reflect:

- Audited actuals reported for regulatory year 2024-25 from our annual regulatory accounts, including reported opex, GSLs, Innovation, DMIA and movement in provisions.
- Adjusted reported opex to exclude the Energy Safe Victoria levy for years 2021-22, 2022-23 and 2023-24 as this levy was incorrectly included within those years opex. The opex reported for Regulatory year 2024-25 excludes the Energy Safe Victoria levy hence no exclusion has been made for this year.

- Updated opex allowances to reflect the approved pass through amounts in relation to the February and September 2024 storm events and include the impact of Flexible Trading Arrangements pass through application submitted to the AER on 15 November.
- Reflecting the AER's preferred approach, excluded non-recurrent SaaS from all actuals within the 2021-26 regulatory period and updating the 2024-25 amount.
- Updated actual and expected inflation to reflect latest ABS and RBA data.

We accept all aspects of the AER's Draft Decision except for the AER's non-recurrent efficiency gain for our base year of 2022-23, which we strongly reject. The impact of correcting this change is to increase the carryover amount by \$23.4m compared to the Draft Decision. This is further discussed in section 6.7 on Opex – Insurance.

The tables below reflect the EBSS calculation and carryover amounts proposed in the Revised Proposal for 2026-31. The following true-ups have been applied which are consistent with the AER's Draft Decision:

- 2020 true-up = -\$6.4 million
- HY2021 true-up = \$1.5 million

Table 11-8: EBSS calculation – Revised Proposal (\$m, 2025-26)

	2021-22	2022-23	2023-24	2024-25	2025-26
Adjusted EBSS Opex allowance	287.9	286.5	302.3	305.7	306.7
Actual EBSS Opex	273.0	257.6	266.6	300.7	277.9
Incremental efficiency	-0.9	14.0	6.9	-30.7	23.8
Carry over year	2026-27	2027-28	2028-29	2029-30	2030-31

Source: AusNet

Table 11-9: EBSS carryover amount – Revised Proposal (\$m, 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
EBSS carryover amount	8.0	14.0	0.0	-6.9	23.8	38.8

Source: AusNet

11.6.3.1. Excluded cost categories in 2026-31 regulatory period

In relation to excluded cost categories for the 2026-31 period we:

- Accept the Draft Decision to exclude innovation opex;
- Accept the Draft Decision that the Regional Reliability Allowance will not be excluded, given the AER has rejected this program and we have not re-proposed it.

Our Revised Proposal includes a new category-specific opex forecast namely customer engagement and communications program. Further information can be found in section 6.8 on Opex – Category Specific Forecasts.

Consistent with the application of the EBSS for category-specific opex forecasts (like GSLs and debt raising costs), if this program is accepted as a category-specific opex forecast rather than a step change, we propose to exclude these costs from the application of the EBSS over the 2026-31 regulatory period.

11.7. Supporting Documentation

We have included the following documents to support this chapter:

- ASD - AusNet Distribution – EBSS Model - 011225 - PUBLIC;

- ASD - AusNet STPIS Performance Target - 2Dec2025;
- ASD - AusNet STPIS Performance Target - Alternative - 2Dec2025;
- ASD - AusNet - STPIS Incentive Rates Calculator - 2Dec2025;
- ASD - AusNet - STPIS Incentive Rates Calculator - Alternative - 2Dec2025;
- ASD – AusNet - AusNet EDPR 2026-31 - SCS CESS Model
- ASD – AusNet –2026-31 – CSIS Data and Reporting Template

12. Pass through events

12.1. Key points

- In our January 2025 proposal, we nominated a set of pass through events comprising five long-standing events (terrorism, insurance coverage, insurer credit risk, natural disaster and retailer insolvency events, as previously approved in our 2021–26 determination) and three new events aimed at emerging sources of risk.
- We accept the AER's Draft Decision to include the five standard nominated pass through events (natural disaster, insurer's credit risk, insurance coverage, terrorism, retailer insolvency events) including the drafting proposed for these events which aligned with our 2021-26 determination and AER's recent determinations.
- We acknowledge the AER's decision to not approve our proposed major Supply Chain Disruption event and AEMO participant fees event. We have not repropoed these events in this Revised Proposal.
- However, we do not accept the AER's Draft Decision in relation to our proposed Electrification pass through event. As further explained in this Revised Proposal, accelerated electrification poses a credible risk of unexpected, near-term cost impacts on our network that meets the NER criteria for a pass through event. Accordingly, we have refined our definition of this pass through event to address the AER's concerns regarding measurability and likelihood.

12.2. Electrification Event

12.2.1. Our Initial Proposal

In our Initial Proposal, we proposed an electrification pass through event, because although there is strong evidence that electrification will materially increase electricity demand during the 2026-21 period, the timing, scale and scope of this impact remains uncertain.

Several Victorian Government policy directions – including the Gas Substitution Roadmap, emerging regulatory impact statements and potential amendments to building and applicable standards – suggest a credible risk of accelerated electrification, but which because of uncertain timing cannot be directly included in our forecasts with specific references to predicted impacts of each policy and when they will occur. We specifically noted that the assumptions and inputs relevant to our augex proposal accommodated for this uncertainty to produce a more conservative forecast, and instead relied on the cost pass through mechanism as the most appropriate and efficient mechanism for managing this cost risk.

12.2.2. Draft Decision

The AER rejected the electrification event based on three key grounds.

First, the AER relied upon the fact that similar events had been rejected previously, relying upon precedent in other cases – such as EvoEnergy, CitiPower and AusNet, as well as AusNet Gas, for various reasons including that electrification related changes are difficult to isolate from wider trends and therefore unsuitable for a pass through. The AER specifically considered that the announcement of a program, initiative or scheme is not clearly defined or measurable (and in any case could be reversed or amended) and therefore too indirect to constitute a discrete measurable event.

Second, that the electrification impacts are expected to be gradual and immaterial in the short to medium term. The AER's view is that electrification is expected to occur gradually over many years, which would likely result in a small uptick in demand growth that may bring forward planned augmentation at different network locations with varying timings. In particular, the AER considers that electrification will occur slowly over the next 5 to 10 years as consumers replace gas appliances, given the high cost of conversion. As a result, network impacts would be incremental and dispersed, requiring localized and staged augmentation rather than large-scale, immediate works.

Third, the AER argues that electrification impacts can be managed through existing tools – including joint planning with Government, demand forecasts and normal augmentation expenditure – making a pass-through event unnecessary.

12.2.3. Revised proposal

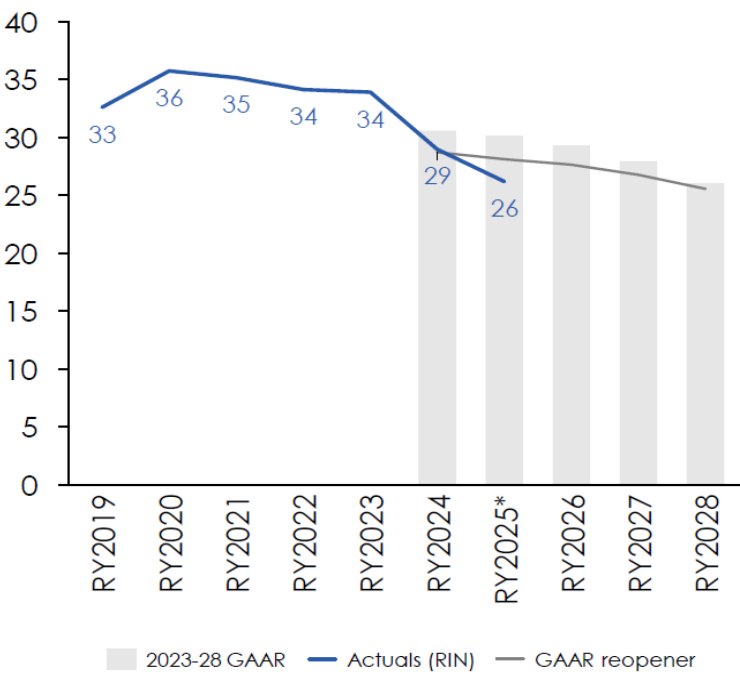
12.2.3.1. Response to the AER’s views around progress of electrification and mitigation measures

AusNet considers that the AER’s reasoning is flawed in several important respects. In particular, the AER’s view that electrification will unfold slowly over 5-10 years and that associated demand impacts will be small and manageable through joint planning, augex allowances or feeder rearrangement is not consistent with observable behaviour, current policy directions and the physical set up of the LV network.

Several data points and emerging trends demonstrate that electrification is already occurring faster and less predictably than the AER assumes and in ways that cannot be fully mitigated through existing planning tools. In particular:

- **Gas consumption is already declining sharply**, with the severe drops we have seen expected to continue. This is supported by the sharp drop in residential usage we have seen on our gas network. This demonstrates that customers are moving away from gas faster than the AER’s assumed 5-10 years trajectory indicating electrification is not occurring slowly or in a linear way. Gas volumes have declined even more rapidly than was estimated in AusNet’s application to re-open the 2023-2028 Gas Access Arrangement Review (GAAR), as shown in the figure below.

Figure 12-1: Total residential volumes RY2019 to RY2028, PJ



Source: AusNet

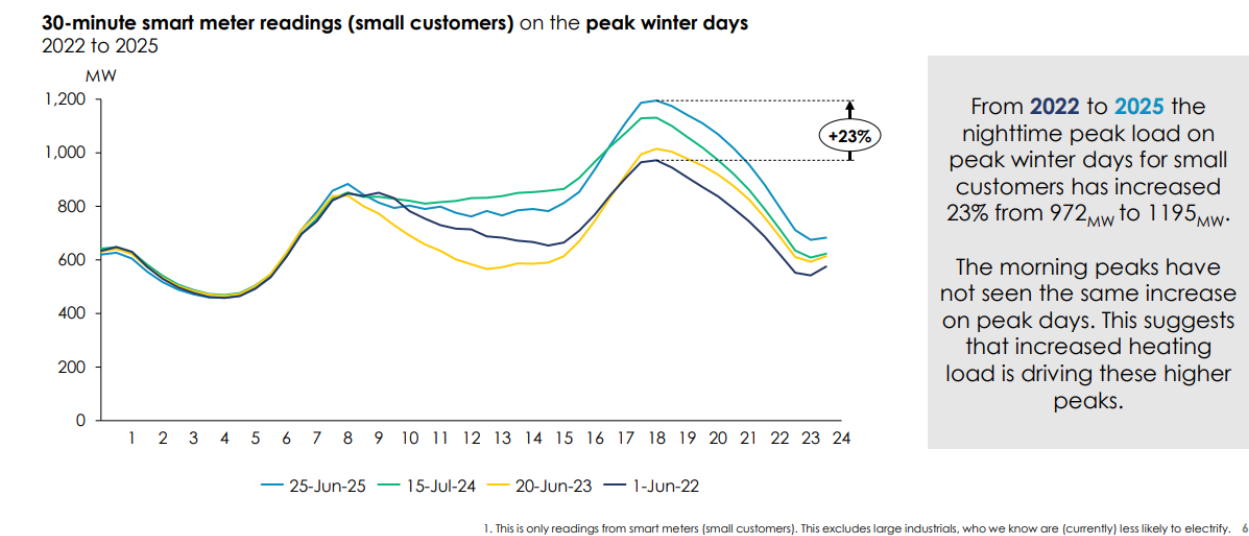
Winter nighttime electricity peaks have risen materially in the last three years, with smart meter data showing a 23% increase in peak winter night-time load for small customers (from 925kW to 1,195kW). See the figure below, with further discussion on these observations set out in Chapter 3 - Demand and Energy Forecasting.

This uplift is occurring now, not gradually over a decade, and is consistent with earlier adoption of electric heating. Our forecasts did not include 2025 winter data because it was not available at the time the forecasts were being prepared for the Revised Proposal, and the emerging trend of higher winter night time loads suggests that our demand forecasts and associated augex spend have the potential to be conservative.

Figure 12-2: 30-minute smart meter readings (small customers) on peak winter days in 2022 to 2025

Electricity | The higher winter peak days are being driven by increases in nighttime load

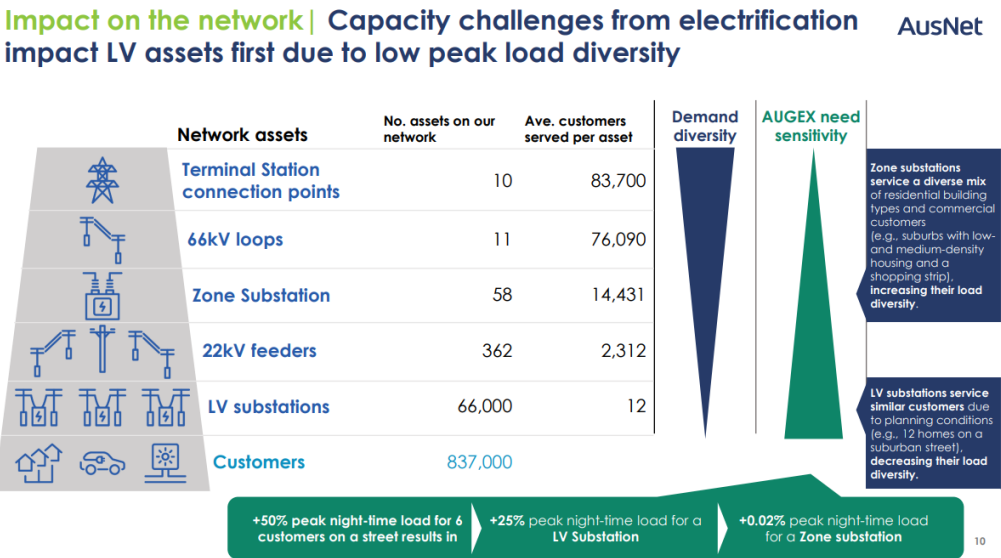
AusNet



Source: AusNet

- Further, electrification pressures will first manifest on the lower voltage network, where diversity is lowest - approximately an average of 12 customers per LV substations, compared with over 14,000 average customers at a zone substation (see Figure below). Electrification of even a handful of households on a single street can increase peak loading to significantly increase creating immediate augmentation needs to maintain reliability and security of supply. We have more than 60,000 LV substations which are exposed to this electrification risk, and with the scale and location of required LV upgrades depending entirely on the pace and clustering of customer electrification adopters – these factors cannot be planned with precision.

Figure 12-3: Impact on the network



Source: AusNet

- Further joint planning cannot anticipate household-led clustering impacting these localised areas on the network. Electrification behaviour will be driven by household decisions, local incentives and market conditions, none of which can be predicted through long term planning or regional scale forecasting.

- Feeder rearrangement is not a viable mitigation tool, particularly on LV or SWER networks, where options to redistribute load are extremely limited. As outlined above, LV substations have an average of 12 connected customers and there is not flexibility to find alternative supply pathways in this part of the network. Electrification-driven increases in peak load will require direct augmentation, not reconfiguration.

Given these issues above, the AER's conclusion that electrification will be slow, smooth and manageable within existing augex allowances underestimates the speed, concentration and operational significance of electrification impacts emerging across our LV network.

12.2.3.2. Response to the AER's views around directness and measurability of the electrification event

The AER rejects the electrification event on the basis that policy announcements may be "indirect" or "too broad" and that the event is insufficiently defined or measurable. AusNet consider that this reasoning does not align with the NER and applies a higher standard than required.

A nominated pass through event must be clearly described, outside the DNSP's control, not already compensated for, and capable of resulting in a material increase in costs.

We consider that the event proposed met the required standard for a pass through, and wish to further reiterate that:

- The AER's view that the impacts of government policy announcements are indirect is presumably because they operate through consumer decisions. However, we consider this overlooks the fact that policy-driven behavioral changes are already legitimate triggers for pass through events such as a regulatory change event.
- We consider that the event, being the cost impact of government policy change is measurable as it can be demonstrated through observed and unexpected increases in electricity demand which are matched by decreases in gas demand, which are objective, and quantifiable measures capable of being assessed through evidence.

To address the AER's concerns and improve definitional clarity, we propose refining the drafting of the event, to make it better supported by objective metrics for materiality which we have included under paragraph 3 a) and b) of the event.

We have also changed the focus of the event to target not only government policy announcements but refined to broaden the event to also capture material non-government actions that have the practical effect of accelerating electrification. Recent developments in Victoria demonstrate that significant substitution away from gas can arise from industry or market driven changes, independent of Government policy. A clear example is the closure of Solstice Energy compressed natural gas (CNG) network, which will occur from 2026, and which will materially reduce the availability of gas supply options for commercial transport users and accelerated their shift to electricity. Including such potential market-driven developments ensures that the event captures all material drivers of gas-to-electricity substitution, not just those initiated by Government. In either case, the directness and measurability of the event is linked to objective, observable and quantifiable changes in energy demand.

The updated drafting is as follows:

An electrification event occurs if:

- **A material driver of gas-to-electricity substitution arises, due to:**
 - a) **The Commonwealth Government or the Government of Victoria introduces, amends or announces a policy, program, initiative, scheme or other measure, which is expressly directed at accelerating electrification of gas-powered appliances, processes or end-uses; and/or**
 - b) **a material market or industry development occurs – including the withdrawal, closure or substantial reduction in availability of gas supply options, or other private enterprise action that has the practical effect of accelerating customer substitution away from gas towards electricity.**
- **As a result of that announcement, AusNet incurs or will incur a material increase in costs to meet or manage the actual or expected demand, relative to the assumptions 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:**
 - a) **AusNet records two consecutive years of system-level maximum demand above the POE10 (10% probability of exceedance) winter maximum demand forecasts approved in the 2026-31 distribution determination, which suggests a sudden and unexpected increase in electricity demand (since POE10 forecasts should only be exceeded once every ten years on average); and**

b) Victorian Tariff V gas consumption volumes (such data is available from AEMO) has experienced year-on-year declines in the corresponding years referred to in 3(a).

The above criteria in (b) will address the risk or concern that the increases in demand referred to in (a) are driven by atypically cold weather, as even in the event of gradual electrification of the gas network, an atypically cold winter would still be expected to result in increases in gas demand.

We consider that the combination of (a) and (b) will be strong evidence that an electrification event has occurred as a result of the government intervention or private enterprise action referred to in (1). In summary, this trigger requires:

- the announcement of a government policy (or similar) or other industry action, followed by,
- two consecutive years of electricity demand above a level that should only be exceeded once every ten years, whilst; and
- at the same time seeing declines in gas demand, which is the fuel source that the government policy is intending to reduce.

If the AER has a different view regarding appropriate guiding criteria, we are happy to work with the AER on an alternative trigger definition. Building in flexibility to be able to respond to differences in electrification trends relative to our forecasts is important to ensure we can respond to customer needs in a variety of circumstances.

Without greater at flexibility in the pass through framework, a sustained and rapid uplift in electrification above forecast levels could leave us unable to fund the timely augmentation needed to maintain existing reliability standards. While we will continue to use joint planning, operational measures and incremental upgrades to manage emerging constraints, these tools may not fully address structural increases in peak demand caused by customers shifting their appliances and processes from gas to electricity. If augmentation is required but cannot be recovered under the ex ante allowance, customers may experience avoidable quality of supply issues including poorer reliability outcomes and undervoltage. This risk is inconsistent with the NER requirements that we meet expected demand and maintain service standards, and it would ultimately undermine customer confidence in the energy transition.

The ex post review provisions under the NER compound this risk. Where electrification trends deviate materially from AER approved forecasts, we may face a situation where augmentation is necessary to meet service obligations, yet later judged as imprudent because demand growth was not captured in the original forecast. This places a materially high level of financial risk on investors than the regulatory regime contemplates, and may discourage prudent, timely, investment to support electrification objectives. That outcome is not in the long term interests of customers as it increases the likelihood of reactive high cost investment, exposes customers to service quality degradation and undermines customer trust in the networks ability to accommodate the energy transition.

12.3. Supporting Documentation

No supporting documents have been provided for this Chapter.

13. Metering services

13.1. Key points

The key points in this chapter are:

- We accept most aspects of the AER's Draft Decision for metering services for the next regulatory period. There are no new projects in this Revised Proposal for metering services. However, we have updated our meter volume forecasts to reflect the updated new connections forecast, which has the effect of increasing our capex forecast.
- We have submitted a revised capex and opex forecast to reflect the AER's Draft Decision on the ACS and SCS allocations, which means that all meter installations and replacements capex are recovered through metering services.
- We have updated our indicative metering services fees in accordance with the AER's Draft Decision and the updates to forecast connection volumes and labour escalation rates.
- We have updated our exit fees to reflect the Draft Decision's substitutions in the metering model, including inflation, rate of return inputs, pricing escalation values and revised smoothing recommendations.

13.2. Chapter structure

This chapter is structured as follows:

- Section 13.3 provides our metering customer service and investment plans in the context of our initial proposal and the AER's draft decision
- Section 13.4 4.4.2 explains proposed costs, allocation methods and forecast RAB;
- Section 13.5 sets out our proposed revenue requirements and prices for metering services and related metering specific Ancillary Network Services (ANS); and
- Section 13.6 describes our supporting documentation.

13.3. Metering customer service, engagement and investment plans

13.3.1. Our Initial Proposal

- In our Initial Proposal, we proposed smart meter investment in pro-active meter replacements starting in 2028-29, smart meter communication network augmentation, and explained that IT system requirements are justified by customer benefits and regulatory compliance imperatives and supported by advice from one of our global technology suppliers.
- We described our customer stakeholder engagement that guided our proposed plans, and highlighted that 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. In this engagement with our customer representative Coordination Group, they requested that we explain and quantify the benefits that customers obtain from our smart meters in our plans.
- For the 2026-31 regulatory period, our Initial Proposal explained that it would our metering fee price would reduced 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. We further explained that this cost saving would 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 proposed to keep the price equal to the 2025-26 price in real terms over 2026-31.

- Our Initial Proposal adopted 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 aligned with that decision.

13.3.2. Draft Decision

The AER's Draft Decision proposed changes in the metering model substituted our total ARR and smoothing profile to reflect updates to forecast inflation and inputs related to the 2022 rate of return instrument and WACC, and updates to:

- Forecast metering capex, including revisions to labour costs for the proposed proactive replacement of meters, removal of components of proposed IT capex, revisions to allocations of expenditure to SCS and to apply updates to forecast inflation and labour cost escalation.
- The RAB roll forward values for historical inputs for capex expenditure consistent with RIN data, while accepting our RAB roll forward and calculation method.
- Forecast metering opex to apply updates to forecast inflation and labour cost escalation.

In amending our proposed metering capex, the AER highlighted several modelling issues relating to our proactive meter replacement approach, which is selective in nature. In light of these issues, the AER proposed benchmark meter unit installation rates instead of AusNet's unit installation rates that were based on replacing meters indicating memory degradation, which is the main fault experienced in aging smart meters.

The AER's Draft decision accepted AusNet's proposed recovery of costs from legacy meter customers at a higher price point than smart meter customers. However, the AER amended our metering exit fee price caps to apply updates to forecast inflation and inputs related to the 2022 rate of return instrument and WACC, as well as substituted capex and opex forecasts.

The AER's Draft decision also expressed concerns that the price paths for our exit fees, as the expected increases over the coming 2026–31 period and beyond may incentivise exiting activities, and asked us to consider this as part of its revised proposal.

13.3.3. Revised Proposal

The key points in this Revised Proposal are:

- We will deliver a metering fee price reduction from \$83 per annum in 2026-27 to \$39 per annum in 2030-31. These average metering fees and all individual prices have not changed by more than 1% from our Initial Proposal to our revised proposal.
- We have amended our expenditure and revenue requirements to reflect the updated new connection forecasts and labour escalation rates.
- We have accepted the AER's Draft Decision substitution of the labour component of the pro-active replacement unit rates for single phase meters, single phase 2-element meters and 3-phase directly connected meters. In accepting the AER's Draft Decision, we note the AER's comments on our modelling approach in relation to selective meter replacement. Given the complexities involved, we regard the AER's approach in its Draft Decision to be a pragmatic resolution of those issues.
- We have accepted changes to Draft Decision's RAB roll forward values for historical inputs for capex expenditure, except where actual and more detailed information has become available, such as meter replacement volumes in 2024-25.
- We have accepted the AER's Draft Decision's ACS/SCS allocation of metering expenditure and clarified the allocation of interchangeable meter communications modules and supporting metering systems.
- We considered the price path for exit fees, and concluded that the exit fees should not be subject to price smoothing.

13.4. Proposed costs

13.4.1. Revised proposal allocation of costs between standard control services and alternative control services

We accept the AER's draft decisions on the allocation of costs between standard control services and alternative control services in our revised proposal. Significantly, our revised proposal no longer seeks to treat meters communications module assets in our meters as 50% ACS & 50% SCS as mesh communications network asset, rather we accept the draft decision allocation that of meter assets with 100% ACS, which means that all meter installations and replacements capex is recovered through metering services.

Table 13-1 below summaries all metering capex and opex cost allocations between ACS and SCS from the 2021-26 final determination to our revised proposal.

Table 13-1: Revised proposal cost allocation and earlier cost allocations

Metering expenditure	2021-26 final determination	Proposed 2026-31 allocation	Draft Decision 2026-31 allocation	Rev. Proposal 2026-31 allocation
Metering Capex:				
Meters assets (ex comms modules), their installation and maintenance	100% ACS	100% ACS	100% ACS	100% ACS
Meters comms module assets, their installation and maintenance	100% ACS	50% ACS 50% SCS	100% ACS	100% ACS
Mesh communications network assets, including Access Points and Relays (capex)	94% ACS 6% SCS	50% ACS 50% SCS	50% ACS 50% SCS	50% ACS 50% SCS
Meter Data Management System (EnergyIP) capex	Not allocated	100% ACS for data delivery performance; Otherwise 50% ACS 50% SCS	100% ACS	100% ACS
UIQ & SIQ upgrades or replacement	100% SCS	50% ACS 50% SCS	50% ACS 50% SCS	50% ACS 50% SCS
Dedicated systems to read energy data from meters without communications	100% ACS	100% ACS	100% ACS	100% ACS
Flexible Trading Arrangement Rule implementation costs in 2026-31	Not allocated	100% ACS	100% SCS	100% SCS
Metering Opex:				
Meter data management system (EnergyIP), reporting and DMACs ¹²¹ opex	50% ACS 50% SCS	Retaining 50% ACS 50% SCS	50% ACS 50% SCS	50% ACS 50% SCS
4G and data backhaul opex	94% ACS 6% SCS	Retaining 94% ACS 6% SCS	94% ACS 6% SCS	94% ACS 6% SCS
Mesh (UtilityIQ) licensing opex	94% ACS	Retaining 94% ACS	94% ACS	94% ACS

¹²¹ DMACs are dynamic monitoring and control system services that support

6% SCS	6% SCS	6% SCS	6% SCS

Source: AusNet

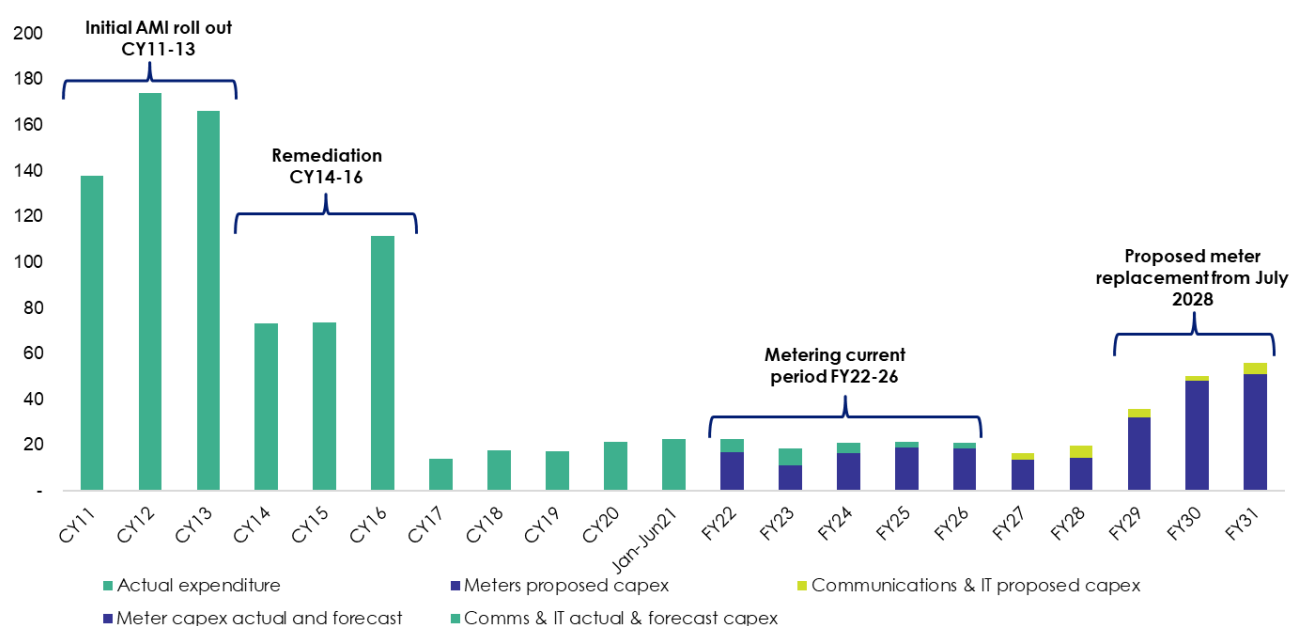
13.4.2. Revised proposed capex

Subject to an update to new connection meter volumes, we accept the AER's draft decisions on our plans for 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 metering technologies. In particular, our capex forecast shown in the Figure 13-1 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.

Our revised proposal metering capex is only marginally different to our initial proposal due to cost allocation and connection volumes differences.

Figure 13-1: Metering ACS Capex - Actuals & Revised Proposal forecast - \$m, real \$2025-26



Source: AusNet

The following points should be noted in relation to the figure above and the accompanying tables set out below:

- 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 Revised Proposal includes updated new metered connection forecasts.

The below tables detail our Revised Proposal capex forecasts for ACS and SCS metering.

Table 13-2: Revised proposal ACS Type 5 and 6 Metering capex (\$m, real \$2026)

2026-27	2027-28	2028-29	2029-30	2030-31	TOTAL

Meters	13.8	14.5	31.9	48.1	51.1	159.5
IT	0.0	3.0	2.7	0.9	3.8	10.5
Communications	2.6	2.3	1.2	1.2	1.2	8.4
Total	16.3	19.8	35.8	50.3	56.1	178.4

Source: AusNet

Proposed SCS Type 5 and 6 Metering capex (\$m, real \$2026)

Table 13-3: Revised Proposal SCS Type 5 and 6 Metering Capex (\$m, real \$2026)

	2026-27	2027-28	2028-29	2029-30	2030-31	TOTAL
IT	0.0	1.8	2.7	0.9	0.0	0.0
Communications	2.6	2.3	1.2	1.2	1.2	2.6
Total	2.6	4.0	3.9	2.1	1.2	2.6

Source: AusNet

Our Revised Proposal metering capex are significantly higher than our 2021-26 capex allowance mainly due our proactive meter replacement program. Table 13-4 below shows the comparison from Initial Proposal, Draft Decisions and Revised Proposal.

Table 13-4: Summary of metering capex forecasts (\$m, real \$2026) & % change from our 2021-26 capex allowance

	ACS metering	% change from allowance	SCS metering	% change from allowance
Capex allowance 2021-26	101.8	-	15.8	-
Initial Proposal capex	172.5	70%	33.7	113%
Draft Decision metering capex	174.6	72%	13.7	-13%
Revised Proposal capex	178.4	75%	13.7 (excluding FTA capex)	-13%

Source: AusNet

13.4.3. Revised proposal opex

In our revised proposal, we accept the AER's Draft Decision in relation to metering opex which included minor amendments to our Initial Proposal. As noted in related to capex, we have also updated our forecast opex to reflect the latest forecasts for labour rates and meter volumes having regard to the most recent data. The net impact of these changes to our forecast opex, which is shown in Figure 13-2 below, is less than 1%.

Figure 13-29: Metering ACS Opex - \$m, real \$2025-26



Source: AusNet

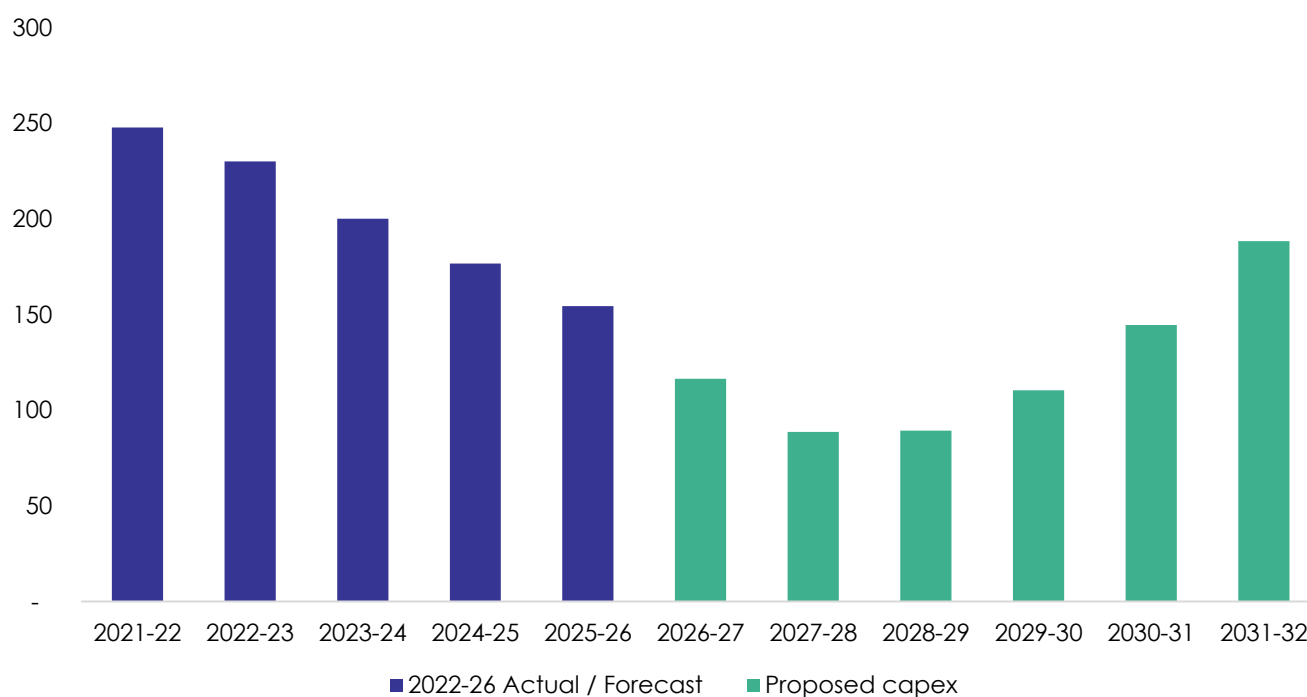
13.4.4. Revised proposal forecast RAB

Consistent with our Initial Proposal and the AER's Draft Decision, we are using the same 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 this Revised Proposal.

We have accepted changes to Draft Decision's RAB roll forward values for historical inputs for capex expenditure, except where actual and more detailed information has become available, such as meter replacement volumes in 2024-25.

Our Revised Proposal 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, as shown in Figure 13-3 below.

Figure 13-3: ACS opening RAB value forecast - \$m, real \$2025-26



Source: AusNet

Table 13-5: Revised proposal forecast type 5 and 6 metering RAB (\$m, real \$2026-27)

	2026-27	2027-28	2028-29	2029-30	2030-31
Meters	81.2	59.9	65.6	90.9	130.5
IT	1.0	0.9	3.8	5.9	5.9
Communications	32.5	25.0	17.5	12.2	7.7
Total	114.7	85.8	86.9	108.9	144.1

Source: AusNet

13.4.5. Revised proposal return on capital

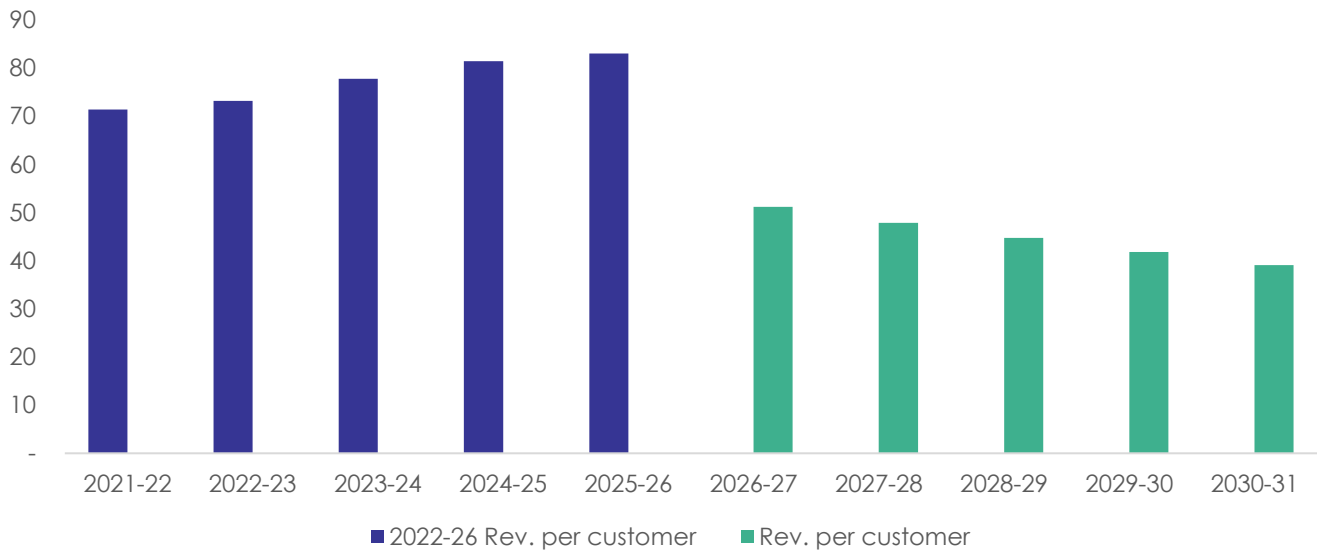
We are proposing the same WACC and gamma values for the metering service as for the standard control services set out in Chapter 9.

13.5. Our proposed revenue and prices

13.5.1. Revised proposal 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. Our indicative average prices are shown in Figure 13-4 below, which have not materially changed from our Initial Proposal.

Figure 13-4: Average metering revenue per customer (\$m real \$2025-26)



Source: AusNet

An average annual metering charge reduces to \$45 per customer over the 2026-31 regulatory period, which is a reduction of 42% compared to the average charge of \$77 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. The differences between average annual metering charges from our Initial Proposal to the AER's Draft Decision and our Revised Proposal are less than 1%.

13.5.2. Revised proposal indicative metering charges

As a result of our revised connection forecasts and other minor updates, we propose a revenue requirement of \$206 million (\$2026), with \$178 million (\$2026) in metering capex and \$62 million (\$2026) in metering opex. In our Revised Proposal, we submit the following indicative metering charges for the next regulatory period.

Table 13-6: Revised proposal indicative alternative control metering services charges (\$ nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Single phase single element	46.43	44.30	42.24	40.25	38.32
Single phase two element with contactor	56.14	53.56	51.08	48.67	46.33
Multiphase with and without contactor	70.91	67.66	64.52	61.47	58.52
Multiphase CT connected	74.54	71.12	67.81	64.62	61.51
Single phase single element – not providing smart meter benefits	65.01	66.67	68.37	70.11	71.90

Multiphase with and without contactor – not providing smart meter benefits	78.60	80.60	82.66	84.77	86.93

Source: AusNet

It should be noted in the above table that the changes in all prices from our initial proposal to our revised proposal have changed by less than 1%.

13.5.3. Revised proposal meter exit fees

Our metering exit fees allow us to recover the written down value, as well as the efficient costs of removing and disposing, of meters. Our exit fee includes reasonable and efficient costs of removing the metering installation for which we are the metering coordinator.

We accept the AER's Draft Decision for metering exit fee price caps substituted forecast inflation and inputs related to the 2022 rate of return instrument and WACC, as well as template changes.

The AER's expressed concerns that the price paths for exit fees, where there is expected increases over the coming 2026–31 period and beyond, may incentivise exiting activities. It asked us to consider this issue as part of our Revised Proposal.

However, the Victorian AML orders do not allow small customers to replace a relevant metering installation with a contestable meter in most circumstances. Therefore, we consider the risk of unsmoothed exit fees incentivising exiting activities will not eventuate unless there is a Victorian policy change. Additionally, smoothing exit fees in the 2026–31 regulatory period would likely result in a greater increase from 2031–32 than we have in 2028–29, because our meter replacements are likely to continue in the 2031–36 regulatory period driving expected exit fees higher. Therefore, we consider the application or price smoothing of exit fees would be counterproductive. Our revised proposal exit fees are not subject to price smoothing.

Table 13-7 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 13-7: revised proposal exit fee by meter type year 1 price caps (\$ nominal) and year 2–5 X factors

	2026–27 price cap	2027–28 X factor	2028–29 X factor	2029–30 X factor	2030–31 X factor
Single phase single element	208.39	10.08%	-3.87%	-12.32%	-14.30%
Single phase two element with contactor	214.15	10.11%	-4.09%	-12.69%	-14.60%
Multiphase with and without contactor	237.60	10.22%	-4.87%	-14.02%	-15.67%
Multiphase CT connected	387.83	11.04%	-7.10%	-17.96%	-18.52%

Source: AusNet

13.5.4. 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

The table below sets out our Revised Proposal charges for auxiliary metering services for the first year of the forthcoming regulatory period, which have been updated for the latest information on inflation, labour escalation rates, margin and actual 2024-25 network overhead rate, and the application of the applicable tax rate. We note the network overhead rate increased from 3.0% to 9.7%, resulting in price increases that reflects our actual costs.

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 and Draft Decision for alternative control services.

Table 13-8: Current, Draft Decision, and Revised Proposal auxiliary metering services charges (\$ nominal) with the last year of the current period included

	Current 2025-26	Draft Decision 2026-27	Revised Proposal 2026-27
Remote special meter read	-	-	-
Remote re-energisation	-	-	-
Remote de-energisation	-	-	-
Remote meter re-configuration	19.12	18.99	20.53
Field officer visit - business hours – does not apply for Type 1-4 metering	44.04	43.72	47.27
Manual meter reading	44.04	43.72	47.27
Priority re-energisation	42.63	44.30	47.90
Field officer visit - after hours – does not apply for Type 1-4 metering	77.07	76.53	82.75

Source: AusNet

13.6. Supporting documentation

We have included the following documents to support this chapter:

- Metering capex and opex model
- Metering charges model
- Metering pricing model
- Metering PTRM
- Metering depreciation model
- Metering RFM

14. Alternative Control Service: Public lighting

14.1. Key points

The key points in this chapter are:

- We have submitted a revised Capex and Opex forecast incorporating the AER's Draft Decision proposed amendments, which we accept all but one. For the one contractor unit rate we do not accept, we have applied the cost from a recently tender service contract. We have also updated the lighting volumes based on recent data and included the expected costs of implementing smart lighting.
- These changes (in real \$ 2026) have resulted in:
 - \$54.1m (173%) increase in capex compared to the Initial Proposal, or \$55.0m (181%) increase to the Draft Decision.
 - \$1.0m (5%) decrease in opex compared to the Initial Proposal, or \$1.0m (5%) increase to the Draft Decision.
 - \$10.0m (18%) increase in revenue compared to the Initial Proposal, or \$12.0m (23%) increase to the Draft Decision.
 - 1.7% increase in average, per light, applied prices compared to the 2021-26 prices, noting that average applied prices declined in the 2021-26 regulatory period as lights with higher prices were changed for lights with lower prices.
 - 1.6% decrease in year on year, per light, public lighting customer bills (for ACS fees and retailer energy bills) from 2025-26 average applied prices.
- Consistent with the Victorian Greenhouse Alliances (**VGA**) submission to the AER's issues paper on the 2026–31 proposals and recent Council engagement in September, we:
 - Will accelerate LED rollouts;
 - Will provide smart lighting services, the extra cost of which will be outweighed by cost savings;
 - Have adopted a new public lighting model with separate prices between lights replaced as part of a Council funded replacement, and those replaced by AusNet with a dedicated new RAB to remove cross-subsidisation between Councils.
- Additionally, we will offer warm lighting replacements in areas nominated by Councils, as requested by Councils. Warm lighting will be supported by changes to our systems and processes to inform our field service contractors, whether replace a light with a normal LED light or warm LED light.

14.2. Chapter structure

This chapter is structured as follows:

- Section 14.3 provides our public lighting engagement and investment plans;
- Section 14.4 explains key drivers of expenditure;
- Section 14.5 details our capital expenditure
- Section 14.6 describe operating expenditure
- Section 14.7 explains RAB, depreciation, and accelerated depreciation
- Section 14.8 sets out revised proposal prices; and
- Section 14.9 describes our supporting documentation.

14.3. Public lighting engagement and investment plans

14.3.1. Our Initial Proposal: engagement and investment plans

In our Initial Proposal of 2026-31 public lighting plans, we proposed to continue to replace each light that fails or requires a globe replacement with efficient LEDs. Our proposed plans would mean that 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. Included in our initial plans was replacing more energy-efficient lights across our network with initiatives to:

- replace failed High-Pressure Sodium (**HPS**) lanterns with equivalent LED lights;
- replace T5 and Compact Fluorescent (**CFL**) lights that fail, or at 4 years in service run out of globes and lanterns stock; and
- replace MV globes with more expensive 'corn cob' LED globes that can be fitted in the lantern.

In the Initial Proposal, we analysed the impact of our Initial Proposal light replacement forecasts on the total Public Lighting bill to Councils, including the public lighting fees paid to AusNet and the total energy consumption costs. The results of this analysis confirmed due to the continued move to efficient LEDs, we anticipate Councils, Shires and Department of Transport and Planning (**DTP**) could expect an average decrease of 8% in their public lighting bill paid to AusNet, and a 15% decrease in their wholesale energy costs for street lighting.

The net savings in total cost is expected to be achieved 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 lighting RAB to be recovered across a diminishing population of lights.

In preparing our Initial Proposal, we engaged with Councils on our public lighting proposal and received no opposition to our proposed approach. Our discussion with Councils also included whether we should offer a smart lighting service through a Central Management System (**CMS**) and smart lighting controllers to enable a smart lighting rollout. However, we concluded that further engagement would be required during 2025 if we were to obtain sufficient support to justify a smart lighting rollout. While we did not include a smart lighting service in our Initial Proposal, we explained that we would continue to engage closely with Councils on this topic prior to submitting our Revised Proposal.

14.3.2. Draft Decision: engagement and investment plans

The AER's Draft Decision did not accept our initial public lighting proposal although the AER considered it to be largely reasonable. The Draft Decision changes to the public lighting reduced our revenue over 2026-31 by 3.4%. We were encouraged to consult further with stakeholders to inform our Revised Proposal on matters such as an accelerated LED rollout, smart lighting services and funding options for each.

Additionally, the Draft Decision updated our initial proposal to change:

- Photo electric (**PE**) cell replacement cycle to 10 years for all five light types
- Lamp replacement cycles for Mercury Vapour (**MV**) lights to 5 years
- Labour rates to incorporate updates on inflation and labour escalators
- Hourly patrol vehicle rate based on benchmark costs across Victorian distribution businesses.

The Victorian Greenhouse Alliances (**VGA**) response to the AER's issues paper on the 2026-31 proposals recommended the above changes and called for accelerated LED rollout with separate prices for customer-funded and DNSP funded replacements. It also called for the installation of smart lighting for all major roads and for additional lighting assets nominated by individual local governments.

14.3.3. Revised Proposal: engagement and investment plans

In the intervening period between our Initial Proposal and Revised Proposal, we heard the views expressed by the VGA and pursued further engagement with Councils and other public lighting stakeholders on further accelerating

LED rollouts and offering new smart lighting services. In response to this and the draft decision, we held an engagement forum on 24 September attended by more than 35 representatives from more than half of the Councils in our distribution area, conducted a survey which received 12 formal responses from our public lighting customers, and amended our revised proposal plans to reflect this valuable feedback. We provide a full summary of our survey and our engagement slide pack. This further engagement addresses the AER's Draft Decision in which it encouraged us to consult further with stakeholders on accelerating the LED rollout and on the introduction of smart lighting.

Table 14-1 below shows the summary of survey responses. These survey responses and attendees at the meeting confirmed their support for AusNet to accelerate our accelerating LED rollouts and adopt smart lighting services, given the energy cost savings, which more than offset the cost of the rollout and smart lighting services, and the community support for these changes. Smart lighting not only reduces energy costs and excess light issues, but according to the VGA submission it improves road safety outcomes.

Table 14-1: Response summary from 11 Councils and DTP to our survey

Do you support our approach for efficient lighting replacements:	Is your council interested in installing warm lighting:	Do you support the establishment of designated areas for warm lighting:	Do you support our approach to decorative lighting:	Smart lighting for minor lights:
All Councils are supportive of this approach.	All Councils have indicated an interest in installing warm lighting.	All Councils are supportive of this approach.	All Councils are supportive of this approach.	Most Councils are interested in exploring smart lighting for minor lights.
DTP is supportive of this approach.	DTP did not comment.	DTP did not comment.	DTP did not comment.	Indigo Shire Council and DTP do not support smart lighting for minor lights.

Source: AusNet

There was also strong support for our approach to replace the globe on decorative MV and CFL lights with LED corn-cob globes to achieve some energy and greenhouse gas emissions savings while the Council develops a longer-term replacement plan for the decorative pole or fitting. Our new tendered lighting service provider prepared a viable option for MV and CFL LED corn-cob conversions for existing decorative poles or fittings.

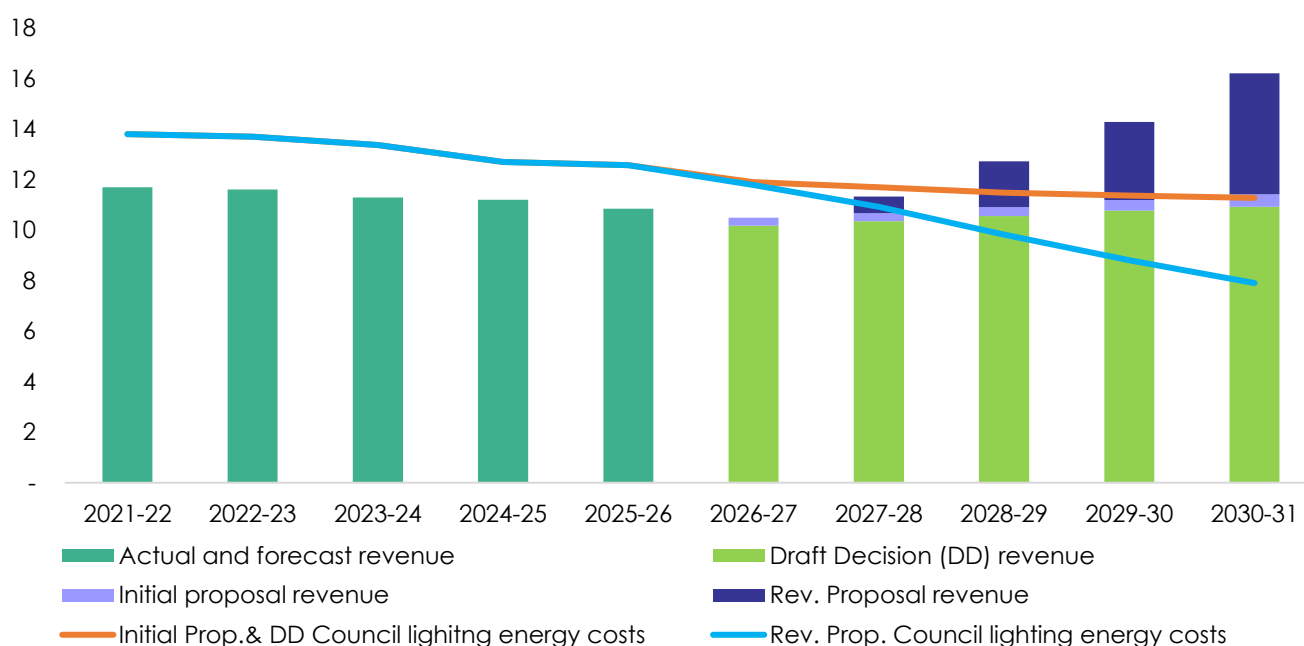
In this engagement, Councils were strongly supportive of warm lighting in areas that they designated. We are working on plans to include new data elements for our lights and arrangements to ensure the light is replaced on failure. Councils have told us that warm lighting on local street environments and close to natural environments would be greatly welcomed.

Additionally, we have commenced two trials of smart lighting with smart lighting vendors in Manningham Council and Bass Coast Shire Council with two different smart lighting vendors (i.e. Itron and Signify). These trials provide an opportunity for us develop installation, commissioning, asset management processes and data sharing arrangements with Councils. The Bass Coast Shire Council trial on Phillip Island includes warm lighting LED replacements and some lights with active dimming. 60%-70% of residents surveyed expressed views that energy savings and protecting native wildlife were very important to respondents. These trials are still in their early stages and will inform our decision making and implementation of our Revised Proposal plans.

We will continue to provide public lighting services to our customers, however, with the forementioned initiatives we will be providing consistent with the approach adopted in 2021-26. Most notably, we will continue to replace lights that fail or need a globe replaced with the most efficient and suitable LED alternatives. Our approach reflects 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 14-1 below shows our Revised Proposal public lighting revenue and public lighting energy costs for the 2026-31 regulatory period, along with revenue and public lighting energy costs for the Initial Proposal and Draft Decision. The revenue is forecast to increase by 14% from 2021-26 to 2030-31 in real terms. In the context of increasing light volumes, the real average price per light will only increase on average by 1.7% from 2021-26 to 2026-31 with a decrease in the first year 2026-27. However, the net cost to public lighting customers (Councils and DTP) is forecast to decline by 1.6% per year in real terms from 2025-26 to 2030-31.

Figure 14-110: public lighting forecast revenue and Council energy consumption costs (\$m real 2025-26)



Source: AusNet

The significant key drivers of this increase in revenue are:

- Once off implementation and deployment costs for smart lighting, including substantial software implementation costs and the deployment of smart lighting controllers to all major road streetlights.
- Increasing the proposed number of inefficient and other obsolete lights replacement with LED lights to 66,720 light replacements from our initial proposal plans of replacing 23,359 lights – a 186% increase from our initial proposal.

These significant drivers for investment and revenue increases were requested by Councils in the VGA submission and supported by our September forum and survey results. The once off smart lighting implementation investments will be made and will be largely depreciated in the 2026-31 period, while their benefits are expected to persist into future periods.

14.4. Key drivers of expenditure

14.4.1. Revised Proposal: 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 revised proposal 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.

In our Initial Proposal, we had separate pricing structures for the Central Region and for the North and East Regions. This provided marginally higher prices for 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.

However, in our Revised Proposal we have adopted a pricing structure, and new public lighting model, that no longer makes this distinction between the Central Region and for the North and East Regions. Our suppliers generally no longer provide us with different prices for different regions for lighting. Therefore, it is simpler and more cost reflective to align the prices across regions in the new public lighting model.

Additionally, the energy saving benefits from smart lighting dimming allow for greater energy savings in urban areas (\$30 per L2 light per year) and rural/remote areas (\$20 per L2 light per year).¹²² Rural Councils typically have more major streetlights that benefit less from smart lighting than urban Councils due to different lighting standards preventing more dimming in rural areas. In providing smart lighting to all Councils, we determined the additional marginal benefit provided for major streetlights adequately compensates urban Councils for the averaging of prices across regions (e.g., a difference of \$4 per light for most lights).

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, and the AER's Draft Decision, escalated by CPI and adjusted to reflect the forecast replacement volumes.

Table 14-2: Key inputs and assumptions

Input / Assumption	Description
Unit rates	Unit rates based on our recently competitively tendered contracted rates, including: • Tender of a service agreement that included public lighting services in Q3 2024; and • Tender of a dedicated service agreement solely for public lighting services in Q3 2025.
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.
Smart lighting costs	Estimated based on publicly available information ¹²³ and based on a range of confidential information sources. We are currently in a Request for Proposal (RFP) process with smart lighting vendors – one that aims to contract for smart lighting services.
In-house software costs	Estimated based on offers from the IT suppliers that provide primary support and augmentation for existing Digital systems, and bottom-up estimates of additional staff/contractor resources.
Additional staff for smart lighting operations	Smart lighting drives energy efficiency gains, more transparent billing, improved traffic safety, and will ultimately result in lower patrol costs for major road streetlights (with less frequent patrols). However, we will need additional staff to install, maintain programs/configurations, and data updates. These additional forecast costs are based on the incremental changes to our existing smart metering operations.
Growth rates	Growth in lighting population based on history up 2023 and extrapolated in to LED population in new period.
RAB roll forward	Having amended the opening RAB and depreciation in our initial proposal, we apply the draft decision opening RAB in our Revised Proposal.

Source: AusNet

14.4.2. Revised Proposal: Further accelerating our LED replacements of inefficient and obsolete lighting on all but decorative lights

As discussed in our Initial Proposal, we will be replacing non-LED technologies lights in the upcoming period with LED lights. In response to the AER's issues paper, the VGA submission representing the majority of our Councils supported the replacement of these lights. However, it raised concerns of inequality between Councils between:

- Councils that have already replaced most non-LED lights, and
- Councils that have large volumes of LED lights.

¹²²

Ironbark informed AusNet that these energy savings were used in modelling for Ironbark's Smart Public Lighting Strategy, Nov 2023, that is available on www.aer.gov.au/system/files/2024-02/Ergon%20-%2011.10%20-%20Ironbark%20Smart%20Public%20Lighting%20Strategy%20-%20November%202023%20-%20public.pdf

¹²³ See the other Victorian distributors initial proposal and the AER's draft decision

The VGA submission recommended the adoption of a public lighting model with separate prices between lights replaced as part of a Council funded replacement, and those replaced by AusNet with a dedicated new RAB to ensure no substantial cross-subsidisation between Councils.

In our Revised Proposal, consistent with the VGA submission, and our recent stakeholder feedback, we will be accelerating the light replacement of inefficient and/ or obsolete with LED lights. We will also be replacing all non-LED lights, except for non-standard lights. Additionally consistent with the VGA submission, our Revised Proposal establishes new public lighting regulatory models with separate prices between lights replaced as part of a Council funded replacement, and those replaced by AusNet with a dedicated new RAB.

Table 14-3: Lighting technologies in AusNet's public lighting population

Inefficient (or legacy) lighting technologies	Efficient lighting technologies
MV	Light emitting diode (LED)
HPS	T5 Fluorescent
Metal Hallide	CFL

Source: AusNet

In the current period, we have six lighting technologies, including a mix of efficient and inefficient (or legacy) lighting types.

In recent years, we have continued to observe a shift to efficient LEDs lights due to the benefits these lights have over legacy 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 planned to replace Mercury Vapour lights with LED lights by offering capital contributions to Councils – resulting in the replacement of over 80% of MV lights.

In our Revised Proposal, we are accelerating our planned replacement of lights consistent with the VGA submission. We note that MV, Metal Hallide, HPS, CFL and T5 lighting are now obsolete technologies.

These drivers will result in our public lighting population converting to LED only, with 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:

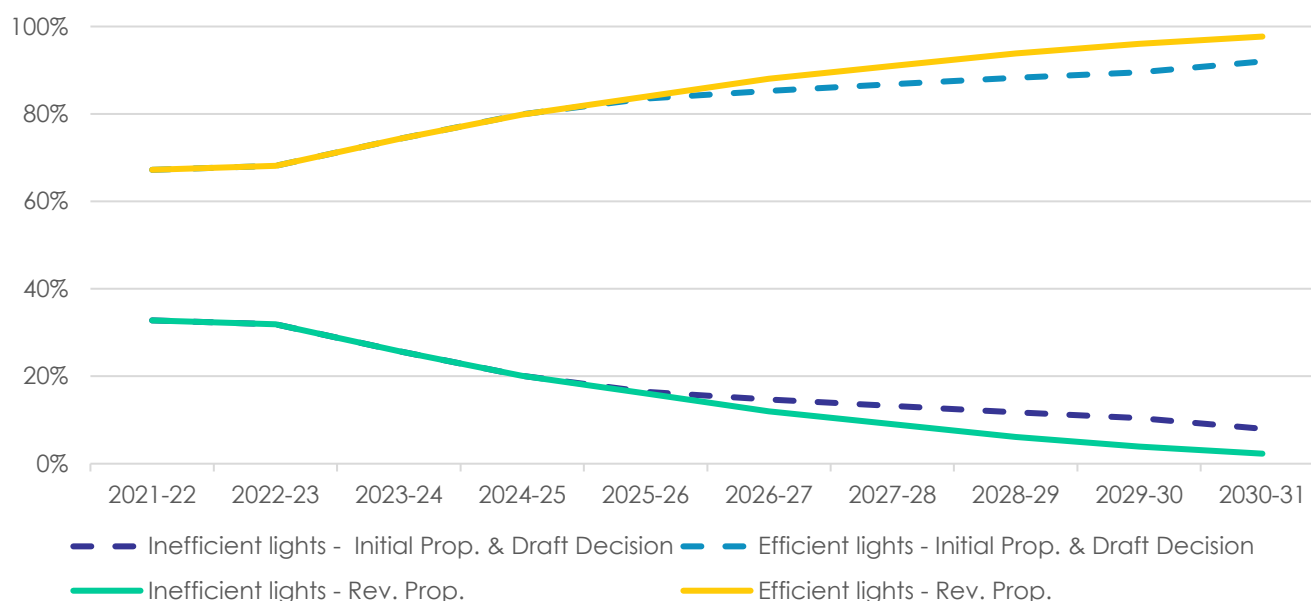
- LEDs have lower maintenance costs. Operating and Maintenance (O&M) costs form part of our public lighting charges and this will reduce as we move to LEDs.
- HPS have high maintenance costs and high failure rates.
- Quality issues with T5 and CFL globes have adversely impacted maintenance costs.
- Replacement 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:

- HPS 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 revised proposal to replace inefficient and obsolete technologies will result in a safer and more efficient service compared to our Initial Proposal, which has already proposed substantial improvements compared to the current period. Figure 14-2 below shows the acceleration of efficient light replacements in our Revised Proposal as compared to our Initial Proposal and the AER's Draft Decision forecasts.

Figure 14-2: Increase in efficient lighting in our revised proposal from Initial Proposal and Draft Decision volumes



Source: AusNet

14.5. Capital expenditure

14.5.1. Initial Proposal

Our Initial Proposal developed capex related inputs based on:

- historical data and escalated previously approved inputs;
- service provider unit costs;
- replacements of dedicated light poles and light brackets based on historical expenditure;
- failure replacements for lights; and
- efficient lighting replacements of inefficient lighting types.

Our Initial Proposal plan forecasted \$31.2 million (Real 2025-26\$s) to fund the replacement of 23,359 lights, 4,086 dedicated poles and 6,618 light brackets. These plans leave 15,865 inefficient lights in service at the end of the forthcoming period or 30 June 2031.

14.5.2. Draft Decision

The AER's Draft Decision is not to accept our public lighting Initial Proposal. In relation to capex, the Draft Decision updated the following capex expenditure inputs in our Initial Proposal public lighting model, including substituted:

- dedicated light pole equipment cost (not the labour costs);
- lighting bracket equipment cost (not the labour costs); and

It also updated the capex forecast to reflect updated CPI and labour escalators.

No changes were made to forecast replacement volumes in the Draft Decision.

The impact of these changes resulted in a 2.9% reduction from our Initial Proposal capex, to include total capex of \$30.3 million (Real 2025-26\$s) in the Draft Decision.

14.5.3. Revised proposal

Our Revised Proposal capital expenditure (capex) for public lighting is forecast to increase by 191% from our current \$29.4m allowance in 2021-26 to \$80.7m in 2026-31 (Real 2025-26\$). Capex is increasing due to the below factors:

- Increasing the proposed number of inefficient and other obsolete lights replacement with LED lights to 66,720 light replacements from our Initial Proposal plans of replacing 23,359 lights. This account for the majority of the increase \$56.8m,¹²⁴ and will reduce other components of the public lighting bills.
- Once-off implementation and deployment costs of \$25.7m for smart lighting, including software implementation costs and the deployment of smart lighting controllers to all major road streetlights.
- The inclusion of 4.0% of network overheads for capital expenditure in the public lighting input model, which contributes to \$3.3m in capital expenditure over the 2026-31 regulatory period. However, this is minor compared to the above factors

With these increases, we have accepted the AER's substitution:

- dedicated light pole equipment cost, which did not the labour costs; and
- lighting bracket equipment cost, which did not include the labour costs.

However, in our Revised Proposal we provide further updates to the draft decision inputs and modelling factors:

- Replacement costs for LED 14W and 18W lights based on new contract unit rates from a 2025 tender for a new service provider to provide smart lighting services. [C-I-C]
- Updated pole replacement numbers based on recent pole replacement modelling, part of our broader pole replacement program and documented in Asset Management Strategy 20-70 for poles.¹²⁵ Our Revised Proposal pole replacement volumes of 362 per year are significantly lower from the Draft Decision volumes of 817 per year. This decrease is the result of our new strategy of retrofitting LED corn-cobb globes to all remaining non-standard poles with CFL and MV lights, instead of offering a standard pole replacement.
- Unit rate increases for pole replacement labour costs as per our tendered contract, noting the above volume changes.
- As outlined in Chapter 5, we have provided new labour escalators and forecast CPI updates for our capex forecasts, while we acknowledge the CPI and labour escalators updates represented data at the time.

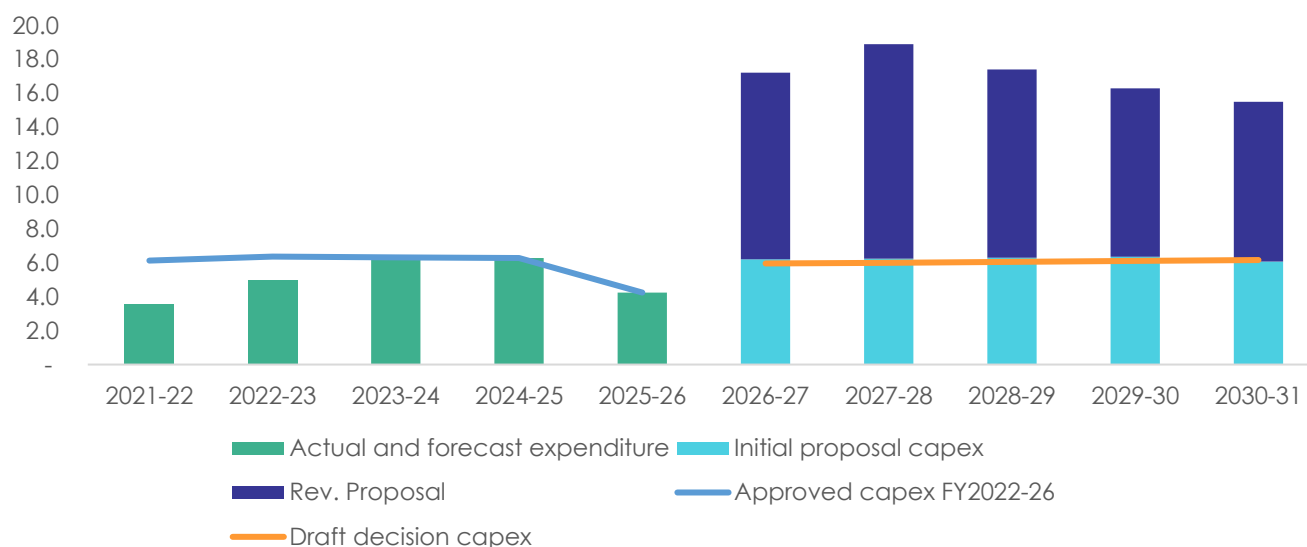
The Revised Proposal capex forecasts and significantly higher than the Initial Proposal and Draft Decision capex forecasts, as shown in see Figure 14-3 below. These increases are driven by the smart lighting, warm lighting and energy efficiency savings that Councils supported in our engagement with them.

We note that we did not share exact price impacts of the smart lighting program with Councils when we engaged. We will offer an engagement session during December to talk the Councils through the final impact on charges, to inform any submission they are intending to make to the AER on this matter.

¹²⁴ All lights will be replaced with LED lights, except for non-standard lights, including 3,287 MV and 3,705 CFL lights. These lights will be fitted with LED corn cobb replacement globes, including replacing the lighting base in the case of CFL lights.

¹²⁵ See supporting document "ASD – AusNet – Poles – 1 Dec2025"

Figure 14-3: Public lighting ACS capex - Actuals, forecast, draft decision, initial and rev. proposal - \$m, real \$2025-26



Source: AusNet

Our Revised Proposal capital expenditure forecasts include new 3 categories for 4 new ACS RABs, as discussed in section 14.7.1 below. Table 14-4 shows our Revised Proposal capital expenditure forecasts in the 3 existing and 4 new ACS categories.

Table 14-4: Revised Proposal capital expenditure for public lighting, \$m, real \$2025-26

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Poles and brackets	1.3	1.3	1.3	1.3	1.3	6.4
Existing lights – luminaires	0.0	0.0	0.0	0.0	0.0	0.0
Energy efficient lights - partially funded	0.0	0.0	0.0	0.0	0.0	0.0
Energy efficient lights - ASD funded	10.9	13.3	11.8	10.8	10.0	56.8
CMS once-off implementation costs	0.0	0.0	0.0	0.0	0.0	0.0
Smart lighting controller costs	0.0	5.1	5.0	4.9	4.9	19.9
In-house software	5.7	0.0	0.0	0.0	0.0	5.7
TOTAL	17.9	19.7	18.1	17.0	16.1	88.9

Source: AusNet

Need for In-house software for smart lighting explained

AusNet reasonably expects to be required to provide Type 9 metering to our Public Lighting customers upon their request. The Responsible Minister for the Electricity Industry Act 2000 is expected to revoke the existing ministerial order of 12 October 2017 Order and issue a new order, see attached confidential draft orders. Amongst other changes to give effect to the Flexible Trading Arrangements (FTA) rule change in Victoria, Clause 5 of these orders are expected to introduce an obligation on AusNet to provide type 9 metering. The type 9 meters on public lights are smart lighting controllers. Hence, we describe a public light with a Type 9 meter a smart light.

We plan to commence a project to deliver the required changes for functional, compliant and efficient smart lighting. This project is planned to commence after the completion of our FTA compliance obligation project. To do so, we assessed the requirements to determine the high-level design for the smart lighting system and process

changes, including the implementation of a Central Management System (**CMS**) and the identification of warm lighting requirements. These requirements were developed and confirmed in workshops with business subject matter experts (**SMEs**) and functional leads/managers. The outcome of these meetings was a documented list of Workflows, Reports, Interface, Conversion, Enhancements, and Forms (**WRICEF**) that are additional to the WRICEFs for our FTA compliance project.

Our two IT Vendors that support our digital systems provided estimates and quotations to deliver the documented WRICEFs requirements. However, our two IT Vendors that support our existing digital systems do not provide smart lighting technology or CMS. Therefore, we have undertaken to Request for Proposal (**RFP**) to establish to establish a contract with a smart lighting and CMS provider that provides the best service and value for our customers. This commercial process is still underway at the time of submitting our Revised Proposal. Responses from 3 potential Vendors to our RFP have informed our cost estimate, subject to confidentiality concerns.

Following the delivery of our FTA compliance obligation project, we will need significant changes our existing digital systems to make the following very high-level changes:

- Establishing changes to our metering data management system to request and receive meter data from the CMS;
- Developing meter data substitution processes, exception management, form changes and reports in our metering data management system;
- Inclusion of fields interface changes to our asset management systems to uniquely identify each of our smart controllers (i.e. that match to the QR code on the lighting controller device) and warm lighting requirement identification;
- Provision of this information to field resources that attend and repair faulty lights;
- Incorporate in our customer information management systems a one National Metering Identifier (NMI) to many assets association suitable for smart lighting, to include the unique asset information from our asset management system;
- An interface to the CMS from our asset management system or our customer management system to CMS to ensure we correctly match interval from devices to customers and identify exceptions (such as unexpected communicating devices);
- Presenting new smart lighting and warm lighting information to customers via portals; and
- System integration changes to undertake data transfers and requests between systems.

These system changes are likely to impact the following of our business processes:

- Asset management
- Connections
- Operations & Works management
- Finance & Billing
- Metering
- Customer Engagement
- Market management (AEMO & Retailers)

Additionally, our digital management and change management team estimated the resources needed for governance, successful delivery, training, change management and communications. These five components form the basis for the incremental costs included in our software development costs.

Our two IT Vendors provided detailed estimates for the documented WRICEFs of their costs using their standard methodologies. Additionally, our change management team also estimated the resources for training and change management. Digital change projects like this are often costly, for example we are currently completing a similar Digital change project for billing compliance to our public lighting asset management, customer information management and billing that is forecast to cost over \$5 m (real 2025-26). Likewise, our smart lighting digital change project is warranted to facilitate better public lighting outcomes, compliance to new obligations and energy savings.

The work for smart lighting is required for 1 July 2027 to enable us to deploy smart lighting as early as possible, in accordance with Council expectation. These estimates are provided in the confidential attachment ASD - Costing of Smart lighting Digital solutions and CMS.

14.6. Operating expenditure

14.6.1. Initial Proposal

Our Initial Proposal developed opex related inputs based on:

- historical data and escalated previously approved inputs;
- service provider unit costs escalated for CPI and labour escalation factors;
- current equipment pricing from suppliers;
- repair and failure rates of relevant light types; and
- updates to daily volumes for repairs and patrols.

Our Initial Proposal plan forecasted \$21.8 million (real 2025-26\$s) to maintain our lights and lighting poles and brackets.

14.6.2. Draft Decision

The AER's Draft Decision is to not accept our public lighting Initial Proposal. In relation to opex, the Draft Decision updated the following opex expenditure inputs in Initial Proposal public lighting model, including substitutes of:

- replacement unit rate for LED 14W lights as they relate to opex;
- lamp replacement cycles for MV lights to 5 years
- labour rates to reflect its decision on our operating expenditure, including updates on inflation and labour escalators
- Hourly patrol vehicle rate based on benchmark costs across Victorian distribution businesses.

These adjustments were made on the basis of benchmark information, stakeholder feedback and the ESCV's views on 'industry best practice'.

These changes resulted in total opex of \$30.3 million (Real 2025-26\$s) or a 8.7% reduction in our Initial Proposal opex.

14.6.3. Revised Proposal

Our Revised Proposal public lighting opex is forecast at \$20.7m in 2026-31, which is:

- 31.3% less than our current allowance;
- 4.6% less than our initial proposal opex; and
- 4.8% higher than the draft decision opex.

Our Revised Proposal opex is decreasing in aggregate due to a number of factors:

- Reductions in the number of less reliable inefficient lights, hence less repair costs;
- Reductions from changes to input costs substituted in the draft decision; and
- Increases from additional FTE required for smart metering data management and smart lighting licence fees.

Table 14-5 below shows our revised proposal opex alongside the initial proposal and draft decision opex.

Table 14-5: operating expenditure for our initial proposal, draft decision and rev. proposal, \$m real \$2025-26

	2026-27	2027-28	2028-29	2029-30	2030-31
Total public lighting opex – Initial Proposal	4.5	4.4	4.4	4.4	4.1

Total public lighting opex – Draft Decision	4.2	4.1	4.0	3.9	3.7
Total public lighting opex – Revised Proposal	4.6	4.2	4.1	3.9	3.9

Source: AusNet

14.7. RAB and Depreciation

14.7.1. Revised proposal includes new RABs

Our revised proposal introduces 4 new RABs to facilitate our investment in smart lighting and accelerate the replacement of all remaining inefficient standard lights. These new RABs were not contemplated in our initial proposal or included in the AER's draft decision model. However, these new types of regulated assets were recommended by the VGA submission to the AER's issues paper that recommended all DNSP:

- “replace all streetlights with LEDs by the end of the period”;
- “install smart lighting in all major road lights...” and
- “to replicate the approach of Jemena to ensure councils who have fully funded capital replacements are not subsidising DNSP funded roll outs.”

As discussed earlier after further engagement with our Councils and a survey, we have established there is substantial support from our public lighting customers for these views. Accordingly, our revised proposal RAB now includes these new assets categories.

The RAB is forecasted to grow by 94% to an opening RAB of 2031-32, see Table 14-6 below. However, this RAB will decline after 2031-32, and by 2036-37 the opening RAB likely decline by \$20m (real \$2025-26).

Table 14-6: Revised proposal public lighting RABs, \$m real \$2025-26)

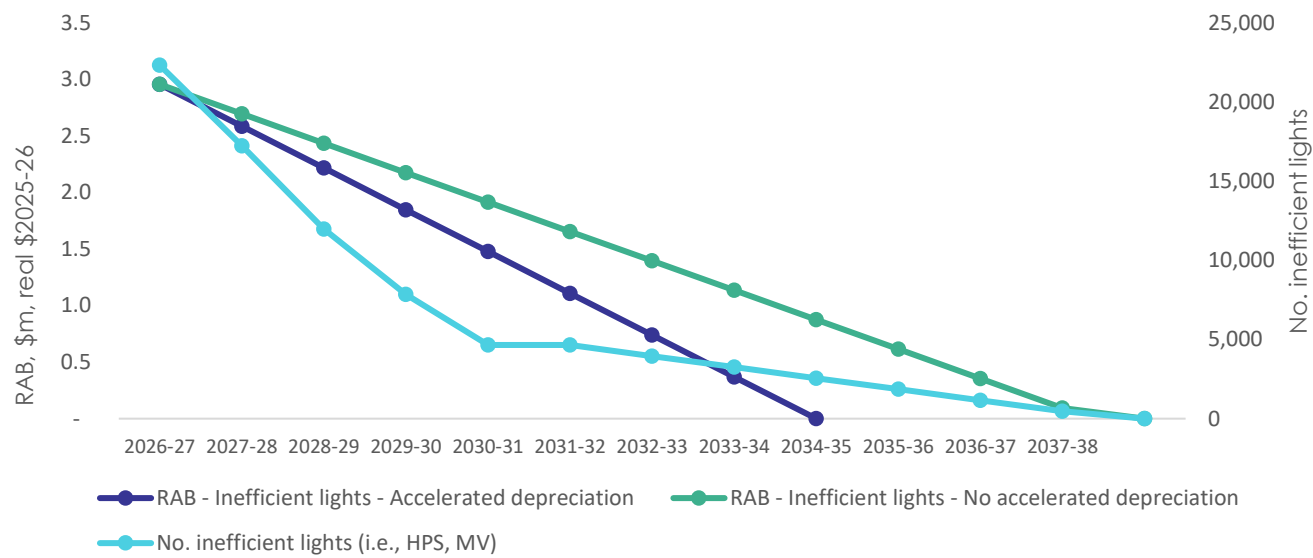
	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Poles and brackets	22.8	23.2	23.6	24.0	24.3	24.5
Existing lights - luminaires	3.0	2.6	2.2	1.8	1.5	1.1
Energy efficient lights - partially funded	32.2	30.4	28.6	26.7	24.9	23.1
Energy efficient lights - ASD funded	0.0	11.1	24.1	34.9	44.0	51.8
CMS once-off implementation costs	0.0	0.0	0.0	0.0	0.0	0.0
Smart lighting controller costs	0.0	0.0	5.2	10.0	14.3	18.2
In-house software for smart lighting	0	5.8	4.7	3.5	2.3	1.2
Total public lighting RAB	58.0	73.2	88.3	100.9	111.3	119.9

Source: AusNet

14.7.2. Accelerated depreciation of inefficient lights

In our Revised Proposal, AusNet is proposing an accelerated depreciation of remaining inefficient lights of a 2.9 year reduction in remaining asset life (i.e., 10.9 years to 8 years), see Figure 14-4. This accelerated depreciation of inefficient lights is needed to mitigate the stranded asset risk. This accelerated depreciation of inefficient lights brings forward \$547,000 over the 2026-31 regulatory period, where the average light volume is over 12,000 lights as compared to the 2031-36 regulatory period with less than 4,000 lights. If the replacement rate of the remaining inefficient lights after July 2031 is higher than 15% per year, we would have stranded assets. Asset replacements of inefficient lights could occur due to luminaire failure or a Council choice to replace the light before failure. In either case, the Council is responsible for funding the cost of replacing non-standard lights. Without this accelerated depreciation, Councils would have a strong incentive to bring forward their replacement of non-standard lights.

Figure 14-411: RAB for inefficient lights with and without accelerated depreciation and forecast volume



Source: AusNet

14.8. 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 provision of smart lighting services.
- the ongoing cost of operating and maintaining our lights.

Table 14-7 below set out our Revised Proposal prices for fee-based public lighting services for the 2026 to 2031 regulatory period. These prices are different to our Initial Proposal and included separate prices for fully AusNet funded lights, optional smart lighting lights, no longer include regional price difference. These prices are substantially different from our Initial Proposal and the calculated prices in the AER's Draft Decision model.

Table 14-7: Indicative 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
Legacy lights						
Mercury Vapour 80W	104.11	88.44	98.52	109.75	122.26	136.19
HP Sodium 150W	173.62	153.88	171.42	190.96	212.73	236.98
HP Sodium 250W	180.17	159.88	178.10	198.40	221.02	246.21
Mercury Vapour 50W	158.90	135.30	150.72	167.90	187.04	208.35
Mercury Vapour 125W	152.21	129.20	143.93	160.34	178.61	198.97
Mercury Vapour 250W	186.26	165.12	183.94	204.90	228.26	254.28
Mercury Vapour 400W	194.95	173.01	192.73	214.70	239.18	266.44
HP Sodium 100W	182.56	161.58	180.00	200.51	223.37	248.83
HP Sodium 400W	260.61	231.60	258.00	287.41	320.17	356.67
Metal Halide 70W	450.69	382.45	426.04	474.61	528.71	588.97
Metal Halide 150W	104.11	355.24	395.73	440.84	491.09	547.07
Efficient lights - funded by Councils or Developers						
T5 2X14W - Partially-funded	63.44	58.35	65.00	72.41	80.67	89.86
T5 2X24W - Partially-funded	68.77	63.42	70.64	78.70	87.67	97.66
LED 18W - Partially-funded	35.73	31.79	35.41	39.44	43.94	48.95
LED 14W - Partially-funded	37.72	33.70	37.54	41.82	46.58	51.89
LED 18W Opt-in Smart Lighting - Partially-funded	NA	38.14	42.49	47.33	52.73	58.74
LED 14W Opt-in Smart Lighting - Partially-funded	NA	40.44	45.05	50.18	55.90	62.27
LED 70W-125W (L1) - Partially-funded	56.41	51.34	57.19	63.71	70.97	79.06
LED 155W-250W (L2) - Partially-funded	58.24	52.99	59.03	65.76	73.25	81.60
LED 275W-400W (L4) - Partially-funded	67.45	61.23	68.21	75.98	84.64	94.29
Compact Fluorescent 32W	55.44	50.99	56.80	63.28	70.49	78.52
Compact Fluorescent 42W	57.88	53.23	59.30	66.06	73.59	81.98
Efficient lights - fully funded by AusNet						
LED 18W - ASD-funded	NA	94.59	105.37	117.38	130.76	145.67
LED 14W - ASD-funded	NA	100.28	111.71	124.45	138.63	154.43
LED 18W Opt-in Smart Lighting - ASD-funded	NA	113.51	126.45	140.86	156.92	174.80
LED 14W Opt-in Smart Lighting - ASD-funded	NA	120.34	134.06	149.34	166.36	185.32
LED 70W-125W (L1) - ASD-funded	NA	152.78	170.19	189.59	211.20	235.28
LED 155W-250W (L2) - ASD-funded	NA	157.69	175.67	195.69	218.00	242.84
LED 275W-400W (L4) - ASD-funded	NA	182.21	202.98	226.11	251.89	280.60

Source: AusNet

14.8.1. Consolidating pricing for all our public lighting customers

We maintain around 180,000 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. In the current and previous regulatory periods, we have charged different prices for lights in the North and East regions to the Central region.

As discussed in section 14.3.3 above in our revised proposal, we are consolidating our customer pricing arrangements to simplify our pricing structure and balance the effect of smart lighting arrangements saving more energy in urban areas than rural areas.

14.8.2. Implications of Council funding projects during the period

Councils can choose to self-fund their remaining inefficient light replacements with a MAV project. In these circumstances, the Council would benefit from the “partially funded” equivalent price and not the “fully funded by AusNet” price. Our public charges are subject to a price cap, meaning we will recalculate our prices for the next regulatory period to recover the revenue. The relative benefits to all parties are listed below.

- Proponent Council: receive price cap differential benefit for the remaining years of the period and the following periods – that will diminish as lights fail and reallocated to AusNet funded.
- AusNet: losses revenue for the remaining years of the period but does not incur capex to fund the replacements.
- Other Councils prices do not change during the period and are no worse off in the forthcoming period.

The cost difference in the regulatory period is between 5.5% and 7% per year of our hypothetical replacement costs (depending on the year of the period), which is generally equivalent to our depreciation. Therefore, there is no substantial cross-subsidy between Councils from this pricing approach and offering Councils to self-fund projects.

14.9. Supporting documentation

We have included the following documents to support this chapter:

- ASD - AusNet 2026-2031 - Public Lighting Model;
- ASD - AusNet 2026-2031 - Public Lighting Inputs Model;
- ASD - Costing of Smart lighting Digital solutions and CMS;

ASD - Public Lighting Service Supplier - Smart Lighting Prices – 011225;

ASD - Summary of Council responses Public lighting - 011225;

ASD – AusNet – Poles - 1 Dec 2025

ASD - DEECA Draft s 16BA NEVA Ministerial Order - minor changes to enable AEMC FTA

ASD - DEECA Draft AMI Obligation to install Order

15. Alternative Control Services: Ancillary network services

15.1. 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 ancillary services to connect to the network, alter their network connection, and obtain additional services, such as meter testing or maintain security lighting.
- The AER's Draft Decision largely accepted our proposed services and proposed charges (with the exception of the wasted truck visits fee), with relatively minor changes to the calculation method including a modification to the tax allowance.
- The AER adjusted labour inputs, tax rates, and contractor rates, resulting in an average price increase of 1.7% compared to our Initial Proposal.
- In this Revised Proposal, we have accepted the changes to our modelling approach, tax allowance and all quoted service labour rates proposed in the AER's Draft Decision.
- However, we have updated all fee-based service prices to reflect the latest CPI, labour rates, margin and overhead rates. We have also revised the contract unit rate for wasted truck visits to ensure cost recovery and added a new fee-based service for Type 9 meter data services arising from recent changes to the NER and expected new Victorian obligations.
- Our Revised Proposal prices are, on average, 9.7% higher than our Initial Proposal driven by recent increases in our actual costs.

15.2. Chapter structure

This chapter is structured as follows:

- Section 15.3 summarises our Initial Proposal;
- Section 15.4 summarises the key findings in the AER's Draft Decision;
- Section 15.5 sets out our Revised Proposal updated fee-based service charges
- Section 15.6 provides our Revised Proposal quoted services
- Section 15.7 lists the supporting documents.

15.3. Our Initial Proposal

- Our Initial Proposal explained that 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.
- Ancillary network 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. They are priced on a fee-based or quoted basis.
- In our Initial Proposal, explained that our fee-based costs and quoted service unit rates for ACS services in 2026-31 are 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 proposed new ACS charges for 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 the F&A that includes a margin and an allowance for tax. For fee-based ACS charges, we explained that our tax allowance for ACS is only applied to the margin and not to materials costs.

15.4. Draft Decision

The AER's Draft Decision:

- Accepted our proposed fee-based and quoted services labour rates for all the labour categories as they are below our maximum efficient benchmark.
- Did not accept our proposed method of applying tax to all our fee-based services and substituted a diminishing value tax method to our connection fee-based services.
- Did not accept our proposed price for fee-based service 'wasted truck visit – customer not ready for works on the basis that the price increase was very significant. The AER also noted that AusNet's proposed price was significantly higher than other distributors.
- Adjusted labour inputs, tax rates, and contractor rates, resulting in an average price increase of 1.7% compared to our Initial Proposal.
- Accepted our proposed margin of 4% applied on all fee-based services, noting that it is below the AER's benchmark margin allowance of 6% (for quoted services).
- Accepted our proposed corporate and network overhead rates as they are below the AER's benchmark of 61%.
- Substituted our proposed price cap and year one (2026–27) prices for fee-based services with the AER's draft decision price caps and prices for 2026–27.
- Substituted our proposed X factors for years two to five with our draft decision X factors, based on labour price growth forecasts.

15.5. Revised Proposal – fee-based services

In this Revised Proposal, we have accepted the changes to our modelling approach, tax allowance and approach to all quoted service labour rates proposed by the AER in its Draft Decision, as described above. The remainder of this section sets out our Revised Proposal for:

- Fee-based connection services
- Ancillary network services; and
- Quoted services and rates.

We have accepted the AER's Draft Decision unit rates for all fee-based services except wasted truck visits.

In our Revised Proposal, we have updated the prices to reflect the latest CPI, and forecast and labour rates, consistent. Additionally, we have:

- Proposed an increase in our network overhead rate from 3.00% to 9.70%. Our actual cost network overheads for ACS fee based increased in 2024-25 as reflected in RIN data. Our Initial Proposal network overheads was based on a 5-year average, however this data that is unlikely to represent a forecast including -0.17% in 2021-22 and 0.02% in 2022-23. While is possible to have near zero and negative network overheads, we consider that it is unlikely to occur again after refining our processes to more accurately account for fee-based ACS costs. The 9.70% is still well below the Draft Decision's corporate and network overhead benchmark rate of 61%. Therefore,

we consider the network overhead better represents our forecast costs and revenue requirement in the forthcoming period.

- Proposed a new price for wasted truck visits based on further negotiations with our supplier. A wasted truck visit service is not a standalone service for which we can appoint a separate supplier. However, we have negotiated with our supplier to lower the price to provide better value for our customers. Our revised wasted truck visit rate is a 27% increase on the Draft Decision and a 18% decrease on our Initial Proposal unit rate. This provides a lower cost for customers while ensuring we are not required to undertake services at a loss. This would violate the Revenue and Pricing Principle.
- Updated our margin to reflect our nominal vanilla WACC of 6%. This provides state-wide consistency across distribution businesses.
- Added a new ACS service "Type 9 meter data services - Per light Per Year" for the provision of meter data substitution and exemption management services. Recent changes to the NER introducing Flexible Trading Arrangements and expected changes Victorian obligations will require us to provide Type 9 meter data management services. This new fee is similar to our existing Type 7 meter data service fee and compensates us for exception management and compliance reporting associated with our Type 7 unmetered lights. The fee covers an incremental staff increase of 5.3% to support interval meters installed on public lights. This service mirrors our existing "Type 9 metering services charge – per light" with "time on task" estimates based on our existing metering data service operations.

Our Revised Proposal prices are, on average, 11.6% higher than our Initial Proposal and 9.1% higher than the AER's Draft Decision average prices. This price increase mainly reflects recent cost increases in actual network overheads in 2024-25. These network overhead rates better reflect our expected costs in 2026-31 regulatory period.

15.5.1. Fee-based connection services

Consistent with the classification in the F&A for the forthcoming regulatory period and our Initial Proposal, 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 15-1 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).

While some categories of connection services increase significantly between 2025-26 and 2026-27, the Revised Proposal fees are efficient as they:

- are based on competitively tendered contracted rates and any negotiated improvements to those 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.

Table 15-1: Current, Draft Decision and revised proposal connection services fees, 2025-26 and 2026-27 (real, \$ 2026-27)

Connection services	Current 2025-26	Draft Decision 2026-27	Revised Proposal 2026-27
Single-phase overhead - business hours	630.61	764.71	832.52
Single-phase underground - business hours	277.13	391.00	425.41
Single-phase underground with a directly connected meter on group metering panel - business hours	597.55	660.45	718.56
Multi-phase overhead with a directly connected meter - business hours	716.64	823.70	896.18
Multi-phase overhead with a CT connected meter - business hours	1,368.23	1,497.31	1,629.07

Multi-phase underground with a directly connected meter - business hours	439.23	590.76	642.75
Multi-phase underground with a directly connected meter on group metering panel - business hours	765.02	860.21	935.91
Multi-phase underground with a CT connected meter - business hours	1,090.82	1,264.38	1,375.64
95mm2 overhead service from LVABC - business hours	1,078.72	852.46	927.48
Establish temporary supply connection - business hours	625.23	764.71	832.01
Appointment - inspection of group or CT metering prior to connection - business hours	651.59	673.61	732.89
Service truck - Disconnect/Reconnect at pole or pit - business hours	718.00	675.83	735.30
Single-phase overhead - after hours	1,103.57	1,338.25	1,456.01
Single-phase underground - after hours	484.99	684.25	744.46
Single-phase underground with a directly connected meter on group metering panel - after hours	quoted	1,155.78	1,257.49
Multi-phase overhead with a directly connected meter - after hours	1,254.12	1,441.47	1,568.32
Multi-phase underground with a directly connected meter on group metering panel - after hours	quoted	2,212.66	2,407.37
Multi-phase overhead with a CT connected meter - after hours	2,305.80	2,620.30	2,850.88
Multi-phase underground with a directly connected meter - after hours	1,654.23	1,033.84	1,124.81
Multi-phase underground with a CT connected meter - after hours	1,908.92	2,212.66	2,407.37
95mm2 overhead service from LVABC - after hours	1,887.78	1,491.81	1,623.08
Establish temporary supply connection - after hours	1,094.16	1,338.25	1,456.01
Service truck - Disconnect / Reconnect at pole or pit - after hours	quoted	1,182.69	1,286.77

Source: AusNet

15.5.2. Ancillary network services

The table below sets out our Revised Proposed prices for network ancillary services, which are 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 15-2: Current, Draft Decision and Revised Proposal ancillary network services and fees, 2025-26 and 2026-27 (real, \$ 2026-27)

Ancillary network service	Current 2025-26	Draft Decision 2026-27	Revised Proposal 2026-27
Meter equipment test – single phase	90.93	391.52	423.35
Meter equipment test – single phase - each additional meter at same site	394.38	90.28	97.62
Meter equipment test – multi phase	90.93	0.00	423.35
Meter equipment test – multi phase - each additional meter at same site	267.04	0.00	97.62
Wasted truck visit – customer not ready for their requested works	412.25	271.66	398.69
Manual assessment of PV & small generator installation enquiry, 4.6kW to 15kW.	412.25	409.26	NA
Manual assessment of PV & small generator installation enquiry, 15kW to 30kW.	412.25	409.26	NA

Manual assessment of PV & small generator installation enquiry, up to 15kW of export capacity (i.e. 5 kW per phase)	37.96	409.26	442.53
Type 7 metering services - Per NMI	2.23	37.69	40.75
Type 7 metering services - Per light	77.07	2.22	2.40
Security and watchmen lights	90.93	136.74	148.87
Type 9 meter data services - Per light Per Year	NA	NA	6.05

Source: AusNet

15.6. Revised Proposal 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 15-3 below outlines the ACS that we propose to offer as quoted services, which are unchanged from our Initial Proposal.

Table 15-3: Proposed quoted ACS

Service group	Further description from AER's F&A	Examples
Access permits, oversight, and facilitation	Activities include:	
	• DNSP issuing access permits or clearances to work to a person authorised to work on or near distribution systems including high and low voltage	
	• DNSP issuing confined space entry permits and associated safe entry equipment to a person authorised to enter a confined space	Processing access permit applications;
	• 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	Accompanied access for purposes of metering activities within distributor facilities; and
	• 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	Clearance assessment
	• 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	
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,	Negotiations with developers, Councils and Shires regarding potential exemptions from requirements to supply electricity to subdivided land

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.

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 rescheduling of a planned interruption	Examples include: • 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	De-energising shared network lines for safe approach
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	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)	Authorisation or re-authorisation of individual employees of third-party service providers to become accredited to undertake design, construct, audit or tie

design, work, and materials	• 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.	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: ◦ field based de-energisation and re-energisation ◦ non basic supply abolishment or reposition non-basic connection ◦ temporary connections (e.g., for builder's supply, fetes etc.) ◦ 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 ◦ protection and power quality assessment ◦ supply enhancement (e.g., upgrade from single phase to three phase) ◦ customer requested change requiring primary and secondary plant studies for safe operation of the network (e.g., change protection settings) ◦ upgrade from overhead to underground service ◦ rectification of illegal connections or damage to overhead or underground service cables ◦ 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 ◦ calculation of site specific loss factors when required under the NER ◦ power factor correction ◦ embedded network management	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.

	- 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	
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, which are set out in Table 15-4 below for 2026-27 compared to 2025-26.

Table 15-4: Current and revised proposal labour categories and labour rates, 2025-26 and 2026-27 (real, \$Jun 2025-26)

Labour category	Service description	Current Business Hours 2025-26	Rev. Proposal Business Hours 2026-27	Current After Hours 2025-26	Rev. Proposal After Hours 2026-27
Labour—wages	Construction overhead install	148.48	155.14	180.33	271.50
Labour—wages	Construction underground install	145.02	151.52	176.13	265.16
Labour—wages	Construction substation install	145.02	151.52	176.13	265.16
Labour—wages	Electrical tester including vehicle & equipment	213.82	223.20	292.31	283.56
Labour—wages	Planner including vehicle	199.32	208.10	NA	NA
Labour—wages	Supervisor including vehicle	199.32	208.10	NA	NA
Labour—design	Design	170.18	189.38	206.68	331.42
Labour—design	Drafting	130.78	145.53	158.84	254.68
Labour—design	Survey	154.04	171.42	187.10	299.99
Labour—design	Tech officer	154.04	171.42	187.10	299.99
Labour—design	Line inspector	148.48	165.23	180.33	289.15
Labour—design	Contract supervision	154.04	171.42	187.10	299.99
Labour—design	Protection engineer	170.18	189.38	206.68	331.42
Labour—design	Maintenance planner	154.04	217.75	187.10	299.99
Labour—design	Senior Engineer	245.31	272.99	366.28	477.73
Labour—admin	Administration staff	NA	88.66	NA	155.15

Source: AusNet

Our proposed formula for quoted services, which uses the above rates is set out below.

1	$\bar{p}_t = Labour_t + Contractor\ Services_t + Materials_t + Margin_t + Tax_t$	$t = 1, 2, 3, 4, 5$
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.

$\bar{p}_t$ the applicable price cap for the requested service.

<i>Labour</i>	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 ¹²⁶ 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.
<i>Materials</i>	the cost of materials directly incurred in the provision of the service, material storage and logistic on-costs and overheads.
<i>Margin</i>	is an amount equal to AusNet Services' nominal vanilla WACC applied to the total cost of Labour, Contractor Services and Materials
<i>Tax</i>	is an amount, if any, equal to the tax costs in present value terms arising from the provision of connection service to a customer, netting off the net present value of the reverse cash flow resulting from the depreciation of the capital contribution.

15.6.1. 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.

15.7. Supporting documentation

In addition to relevant parts of the RIN templates the following document is provided in support of this chapter:

- AER – Standardised ANS model - Revised Proposal - AusNet Services distribution determination 2026-31

¹²⁶ 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.

16. Form of control

16.1. Key points

Our Initial Proposal adopted the forms of control in accordance with the AER's Framework and Approach (F&A) paper. The AER's Draft Decision accepted our approach, with the exception of the calculation of the margin component and the tax allowance for fee based services. In this Revised Proposal, we accept the AER's Draft Decision, including the margin component and tax definitions for quoted services.

16.2. Chapter structure

This chapter is structured as follows:

- Section 16.3 discusses the form of control for standard control services.
- Section 16.4 discusses the form of control for metering services, fee-based ancillary network services, public lighting and quoted ancillary network services.
- Section 16.5 lists the supporting documentation for this chapter.

16.3. Control mechanism for standard control services

16.3.1. Our Initial Proposal

Standard control services are essential network services that are shared by all customers and provided in accordance with distribution network tariffs. The NER require that the control mechanism for standard control services is subject to CPI-X regulation.

In our Initial Proposal, we proposed a revenue cap formulae for standard control services that was consistent with the control mechanism set out in the AER's Framework and Approach paper (F&A paper).

16.3.2. Draft Decision

The AER's Draft Decision accepted our proposed the revenue cap formulae for standard control services.

16.3.3. Revised Proposal

This Revised Proposal adopts the revenue cap formulae for standard control services as set out in our Initial Proposal, which was accepted by the AER in its Draft Decision.

16.4. Control mechanism for alternative control services

16.4.1. Our Initial Proposal

Alternative control services (**ACS**) are a type of direct control service, but unlike standard control services, ACS are customer-specific services. As such, these services are provided to individual customers or groups of customers who request or require them, rather than being provided to all customers.

In our Initial Proposal, we outlined the following control mechanisms for each type of ACS:

- a revenue cap formulae for metering services;
- a price cap control formula for fee-based ancillary network services, connection services and public lighting; and
- a price cap control formula for quoted ancillary network services

These proposed control mechanisms are consistent with the mechanisms set out in AER's FF&A paper. We committed to apply the same formulae to meet the requirement of clause 6.8.2(c)(3) of the NER to demonstrate compliance with the relevant control mechanism.

16.4.2. Draft Decision

The AER's Draft Decision accepted our proposed control mechanisms for alternative control services. The AER did not accept our proposed margin component and tax component used in the calculation of quoted services. The AER explained that:

- The margin component should be calculated as 6% of labour, contractor services, and material costs only. The AER considered that a flat rate (rather than the WACC) to be transparent and easy to apply and allows a return commensurate with the regulatory and commercial risks involved in providing quoted services.

The tax component should be calculated as 30% (the company tax rate) on the capital component of expenditure that incurs a tax liability, as this approach aligns with the application of tax for other services provided by distributors.

16.4.3. Revised Proposal

We accept AER's Draft Decision for the control mechanisms for alternative control services, including the margin and tax definitions for quoted services.

16.5. Supporting Documentation

There are no supporting documents available for this chapter.

17. Negotiating Framework

17.1. Key points

The key points in this chapter are:

- The AER accepted AusNet's proposed negotiating framework for the 2026-31 period, while recommending enhancements to improve consistency across Victorian DNSPs.
- Specific recommendations for AusNet included:
 - A clearer and more structured approach to publishing negotiation outcomes, aligned with Jemena's practices.
 - A more comprehensive dispute resolution process, incorporating internal procedures and references to external standards such as the Essential Services Commission's Electricity Distribution Code of Practice (EDCoP).
- The negotiating criteria were revised to:
 - Promote fair, timely, and transparent negotiations.
 - Ensure pricing reflects actual, unrecovered costs.
 - Support emerging markets (e.g. EV infrastructure) while maintaining regulatory flexibility.
- We have incorporated these recommendations into the revised proposal and have no objections to the updated criteria.

17.2. Chapter structure

This chapter is structured as follows:

- Section 17.3 outlines changes in negotiating framework and criteria; and
- Section 17.4 sets out our supporting documents for this chapter.

In the event of inconsistency between information contained in this chapter and our Regulatory Proposal, the information contained in this chapter prevails.

17.3. Negotiating Framework

17.3.1. Our Initial Proposal

In the initial proposal, AusNet did not make any changes to the negotiating framework from the previous regulatory period. Formatting was changed, but document details remained the same.

17.3.2. Draft Decision

In its Draft Decision, the AER accepted AusNet's proposed negotiating framework and introduced a new negotiated distribution service for the 2026-31 regulatory period:

- **Distribution Asset Rental** – the rental of distribution assets (e.g. poles) to third parties for the installation of electric vehicle chargers or associated hardware

The AER also encouraged greater consistency across Victorian DNSP's negotiating frameworks stating:

“Consistency in negotiating frameworks within Victoria is something we consider would benefit those seeking access to negotiated distribution services”

To support this goal, the AER recommended the following improvements for AusNet:

- **Publication of Negotiation Outcomes:** Enhance transparency by clearly outlining how and when negotiation results will be published, aligning with Jemena's approach.
- **Dispute Resolution Process:** Expand the framework to include internal dispute resolution procedures and reference external standards such as the Essential Services Commission's Electricity Distribution Code of Practice (EDCoP).

The AER also revised the **Negotiated Distribution Service Criteria** to reflect practical considerations, given that no negotiated services were classified in the previous period. Key updates included:

- Strengthening expectations for good faith and timely negotiations.
- Clarifying that “price” encompasses all fees and charges, including application processing costs.
- Ensuring prices are based on costs not already recovered through other regulated or unregulated services.
- Avoiding overly prescriptive rules to maintain flexibility in the evolving EV infrastructure market.
- Encouraging DNSPs to publish negotiation outcomes to support future guidance and transparency.

17.3.3. Revised Proposal

AusNet's Revised Proposal retains the core structure of the existing negotiating framework, with targeted updates to reflect the AER's recommendations for greater alignment across Victorian DNSP's.

Key enhancements include:

- **Publication of Negotiation Outcomes:** AusNet has committed to publishing a quarterly summary of negotiation results on its website. These summaries will be prepared in accordance with applicable confidentiality requirements to enable transparency without compromising sensitive information.
- **Dispute Resolution Process:** Clause 7 of the framework has been updated to:
 - Detail AusNet's internal dispute resolution procedures, demonstrating compliance with relevant Australian standards and the Essential Services Commission's Electricity Distribution Code of Practice (EDCoP).
 - Clearly reference the applicable access dispute laws and rules under the National Electricity Law and National Electricity Rules, improving accessibility and clarity for stakeholders.

AusNet supports the changes made to the Negotiated Distribution Service Criteria and has no objections to their inclusion in the final framework.

17.4. Supporting Documentation

We have included the following document to support this chapter:

- ASD - AusNet - Negotiating Framework – 011225

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
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
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

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