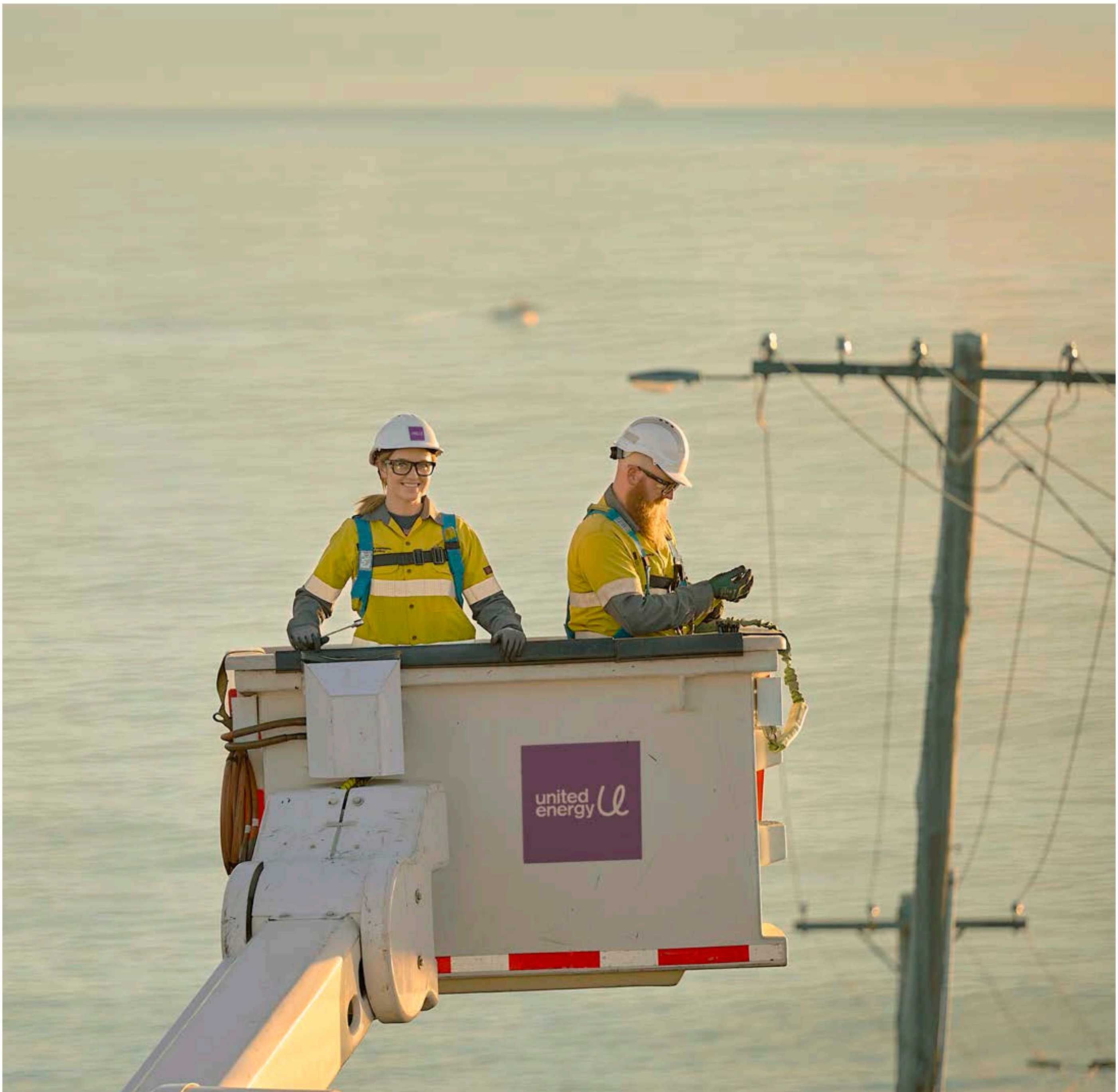

Revised proposal 2026-31

Revenue and expenditure forecasts

united energy

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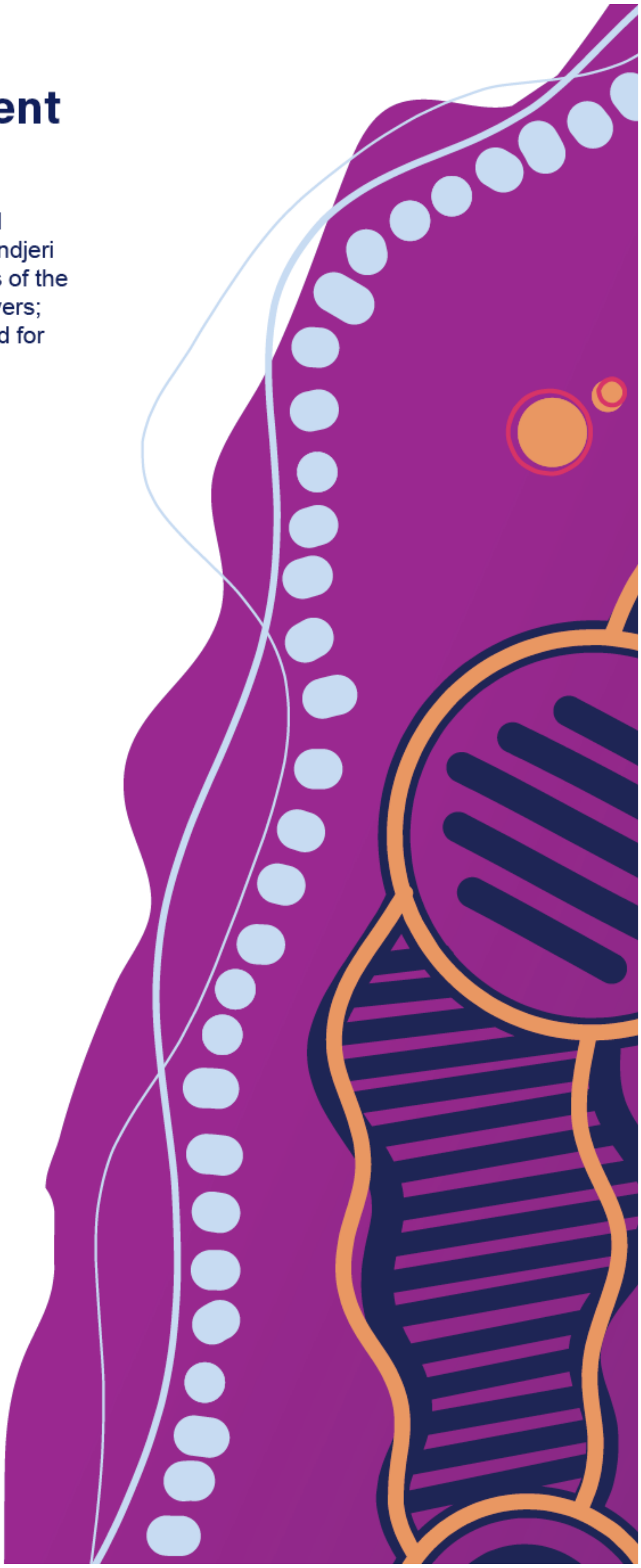
Acknowledgement of Country

United Energy acknowledges and respects the Bunurong and Wurundjeri People as the original Custodians of the lands and waters our network covers; lands First Peoples have occupied for tens of thousands of years.

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



A message from our CEO
Tim Rourke

In January 2025, we submitted our regulatory proposal setting out our plans to meet our customers' service level expectations and priorities over the 2026–31 regulatory period. These plans followed extensive stakeholder engagement – we heard from 8,715 individual customers and approximately 145 stakeholders and incorporated their views into our proposal.

The expectations of our customers reflect our industry leading performance today. With an average of just 35 minutes off supply in FY25 (around 90 minutes lower than the national average), **United Energy is the second most reliable distribution network in Australia**.

We also operate the **most highly utilised urban network**, using technology to maximise the use of our existing assets before we build more. This has been one of the main drivers in keeping bills low.

Since submitting our proposal, we have worked with our customers to further understand their lived experience on critical issues.

The AER published its draft decision on 30 September 2025. This endorsed $1.0 billion of capital expenditure that will help us to deliver the essential services that our customers rely on every day. The decision, however, represents funding that was 25 per cent lower than our original proposal.

We have now updated our forecasts using more recent data, resulting in a 10 per cent reduction in our revised capital expenditure needs for 2026–31. We have also reduced our operating expenditure forecasts, with efficiencies in our vegetation management program in 2025 helping us to lower our funding requirements by $33 million over five years. Despite reducing our forecasts, there remains a gap between what was provided in the draft decision and what customers both want and require. This shortfall will impact our ability to meet several of the key challenges our customers have told us they would like addressed, such as strengthening our low voltage network to support electrification, where our revised proposal would unlock over $237 million of customer benefits.

By 2031, the electrification of everything from homes to transport, along with ongoing population growth, will require our energy system to evolve. We are seeing these impacts now, with near system-wide peak demand in FY25. Weather adjusted residential consumption also grew by over eight per cent in the previous two years and analysis of customers who have electrified their household load shows their average monthly consumption jumping by almost 300 per cent throughout winter.

In total, our revised proposal plans to invest $1.3 billion between 2026 and 2031. This includes key initiatives to enable more electrification, manage seasonal demand on the Mornington Peninsula and support community resilience to extreme weather.

We are also committed to remaining one of Australia's most affordable distribution networks, providing safe and reliable electricity across Victoria's south-east. We'll deliver this for an **average yearly reduction of $6 over the next five years**, along with no increases in our metering charges.

We're about more than maintaining our infrastructure; it's about ensuring that United Energy continues to meet the evolving needs of our customers and enabling Victoria's energy transition.

Tim Rourke
Chief Executive Officer

Responding to the AER's draft decision

In our revised proposal we have accepted much of the AER's draft decision. However, we have re-proposed key projects and programs that deliver critical customer outcomes.

Demand forecasts

Since our regulatory proposal we have experienced a hotter summer and are seeing the impacts of rapid electrification. This includes growing winter consumption as customers transition from gas appliances, particularly heating loads. Our revised forecasts reflect this information, and updated AEMO assumptions.

Electrification

Under-voltage impacts are expected to become increasingly pervasive, impacting customers daily appliance use and limiting access to low-cost retail offers. The draft decision is based on historical reactive expenditure only. Our forecasts allow for an efficient mix of reactive and proactive responses.

Network capital expenditure

The draft decision provides an allowance for network capex lower than current period spend. This is insufficient to properly support customers through the energy transition and increasing climate impacts. We have provided additional information, as requested by the AER, to further support our forecasts.

Data centre forecasts

The AER's draft decision provided detailed guidance on its preferred forecasting methodology for data centres. We have applied this approach in our revised proposal. We have assumed data centre proponents will contribute 85% of the cost of these works, minimising the impact on all customers.

Non-network expenditure

Our non-network expenditure includes ICT (including cyber security), property, fleet and other equipment that supports the modernisation and continued delivery of efficient, safe and reliable services to our customers. The AER has substantively accepted these forecasts, and we have reflected this decision in our revised proposal.

Vegetation management

In its draft decision the AER acknowledged the compliance obligation for vegetation management, however sought further information to substantiate the forecasts. Our revised proposal incorporates updated volumes and efficiencies in the cutting program from 2024 and 2025, resulting in a materially lower step change.

Delivering for our customers

Our revised proposal further refines the cost to deliver the services our customers value.
We will deliver these services with bill reductions for both residential and business customers.

Bill impacts

Annual distribution bills ($, 2026)	Regulatory proposal	AER draft decision	Revised proposal
Residential customer	$348	$295	$316
Small business customer	$927	$786	$842

Residential bill based on annual consumption of 4,000 kWh, small business customer bill based on annual consumption of 10,000 kWh

Revenue, capital expenditure and operating expenditure

2026–31 revenue and expenditure ($, 2026)	Regulatory proposal	AER draft decision	Revised proposal
Revenue	$2,780M	$2,582M	$2,691M
Capital expenditure	$1,399M	$1,046M	$1,258M
Operating expenditure	$991M	$862M	$955M

About this document

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

In January 2025, we published a regulatory proposal setting out our plans for the 2026–31 regulatory period. In September 2025, the AER published a draft determination.

Our revised proposal sets out our revised plans for the 2026–31 regulatory period. It reflects our response to the AER’s draft determination, incorporating stakeholder feedback on our regulatory proposal.

Our revised proposal also encompasses our revised tariff structure statement, as well as supporting business case addendums, model and general attachments.

You can submit feedback on our revised proposal through the contact form provided on our engagement website, or directly via email to community@ue.com.au.

The AER is also seeking feedback on our revised proposal through their engagement links, available on their website.

Table of contents

1. Overview

Our regulatory proposal was initially submitted in January 2025. It was a product of significant engagement and consultation, as well as detailed planning, analysis and testing of our proposed investment program.

Since then, we have responded to over 615 individual questions from the Australian Energy Regulator (AER) on our proposal, across 50 separate information requests. These responses were considered in the AER's draft decision, which was published on 30 September 2025.

Our revised proposal has benefitted from this feedback and further scrutiny. It has challenged us to refine our investment needs and ensure that we provide value for our customers as our energy system continues to change.

1.1 Ongoing stakeholder engagement

Engagement with our customers and communities is a core business-as-usual activity. It enables us to continually improve our understanding of their needs and preferences now and in the future.

For the purposes of developing our revised proposal, we have undertaken additional bespoke engagement focused on areas where it was identified that further insight would ensure our revised proposal truly meets our customers future expectations. This engagement also provided an opportunity to assist us in responding to issues raised by stakeholder submissions and the feedback identified by the AER in its draft decision.

We commenced our additional engagement in early 2025, recognising that meaningful and well-considered engagement requires adequate time to be undertaken effectively. These bespoke engagements built on our previous engagement phases, namely our 'broad and wide', 'deep and narrow', and 'test and validate' phases.

Across all engagements, customers' expectations and their priorities remained consistent. In addition to delivering safe, reliable, resilient and affordable electricity, customers expected us to proactively ensure service levels were maintained throughout the energy transition and tackle the many equity challenges facing our customers (such as for those experiencing vulnerable circumstances).

Additional research and engagement for our revised proposal

The additional research and engagement we completed across 2025 is summarised below. Further detail on the outcomes of these engagements is set out within the relevant expenditure sections, including how this feedback is reflected in our investment cases to ensure the 'golden thread' remains between the voice of the customer and our revised proposal:

- **understanding the impacts of undervoltage**: between May and October 2025, we surveyed 85 customers across our networks who contacted us with an undervoltage complaint. Customers shared feedback on the impact of undervoltage relative to an unplanned outage and described how the experience impacted their everyday life or their business
- **vulnerability strategy engagement**: the Customer Advisory Panel (CAP) challenged us to provide greater clarity on our implementation and delivery plans for supporting customers in vulnerable circumstances. In response, we developed a customer vulnerability strategy to identify our unique role in tackling vulnerability, how we will execute our role and how we will identify and reach customers in vulnerable circumstances[1]

[1] UE RRP ATT 4.05 – Customer vulnerability strategy – Dec2025 – Public

- **public lighting**: in response to feedback from the Victorian Greenhouse Alliance, we engaged with 25 councils and informed stakeholders to understand their feedback on our public lighting package and ensure it is aligned with the future needs and preferences of our public lighting customers[2]
- **kerbside electric vehicle (EV) trial tariffs**: we engaged with 19 informed stakeholders, including retailers and charging infrastructure providers, to shape our EV tariff offering[3]
- **customer commitments development**: we have collaborated with the CAP over the past 18 months to shape a package of customer commitments aligned with our revised proposal. These commitments have been tested with customers, including 23 residential and small-medium business participants. This process has assisted us simplify language and ensure commitments—to be finalised following the AER's final decision—are meaningful and relevant to our customers and communities.

More broadly, our engagement program, including design and outcomes, were also tested with the CAP. Between the submission of our original proposal and the development of our revised proposal, we have met with the CAP on seven separate occasions (including four full-day sessions).

1.2 Our energy system continues to evolve

In addition to further stakeholder engagement, our revised proposal has considered the continuing evidence of the pace and scale of electrification across our network. This rapid change is reflected in our updated demand forecasts that incorporate more recent AEMO inputs and assumptions, and another 12-months of network and customer smart meter demand data.

1.2.1 Our recent summer unearthed latent temperature-dependent demand

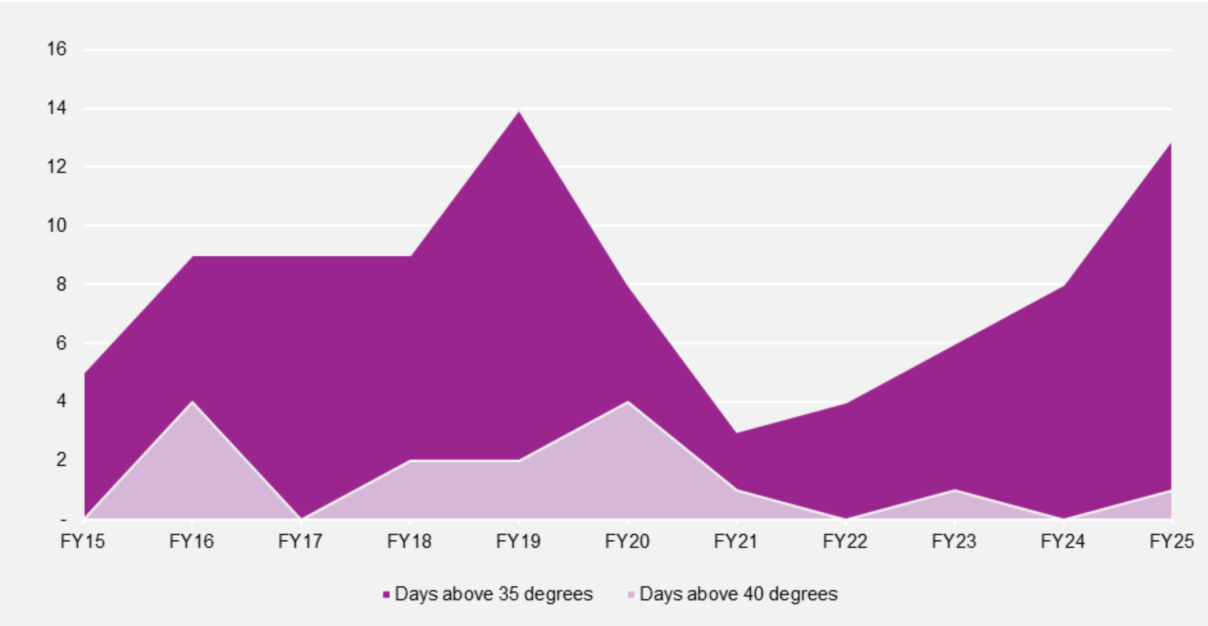
The most recent summer (2024/25) was hotter than those we experienced in recent history, with south-eastern Melbourne, for example, experiencing more than double the number of days above 35 degrees compared to the previous five-year average. This is shown in figure 1.1 below.

This weather trend is generally consistent with that across our entire network area and marked a return to historical norms after a period of cooler summers driven by repeated La Niña events.

This hotter weather had the impact of unearthing latent temperature-dependant demand on our network that was not previously evident in our forecasts due to the milder prevailing conditions. In these conditions (which remain mild relative to future expectations), our network reached near its all-time high maximum demand. This near-record occurred when temperatures were around 39 degrees for less than one day and on a weekend (where demand is typically lower).

[2] UE RRP ATT 6.01 – Public lighting – Dec2025 – Public
[3] UE RRP ATT SE 03 – Kerbside EV charging trial network tariff – Dec2025 – Public

FIGURE 1.1 SOUTH-EASTERN MELBOURNE HISTORICAL TEMPERATURE: HOT DAYS



1.2.2 Network-wide and customer data corroborates increasing electrification impacts

Complementing the observed increases in peak demand is a growing customer trend towards electrification that is supported by Government policies. This includes the substitution of gas, where Victoria is more dependent on gas than any other jurisdiction in Australia—around triple the average annual consumption of New South Wales and South Australia customers, and almost seven-times the usage of Queensland.

The extent of this electrification is being seen today and has strengthened since our original proposal. This is triangulated by network-wide and individual consumption data, as well as uptake in Victorian and national upgrade programs.

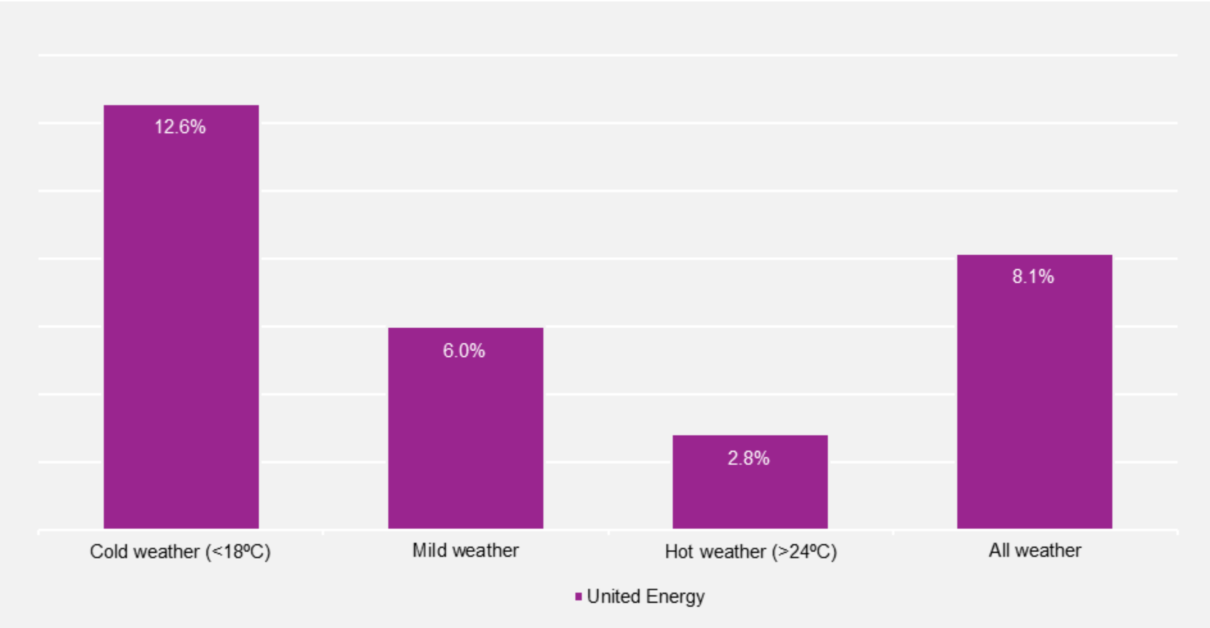
We are observing significant consumption increases today

Figure 1.2 shows the change in household consumption for customers across our network from 2023–2025. Consumption growth in this period compares to historical consumption growth of less than one per cent per annum.

Our analysis is normalised for weather differences between these years and excludes the impacts of new connections and new solar installations. In aggregate, it suggests the paradigm shift in electricity consumption is here and now.

The change in consumption is shown to be most evident in colder temperatures, suggesting the impacts of gas substitution, particularly space heating loads, is significant.

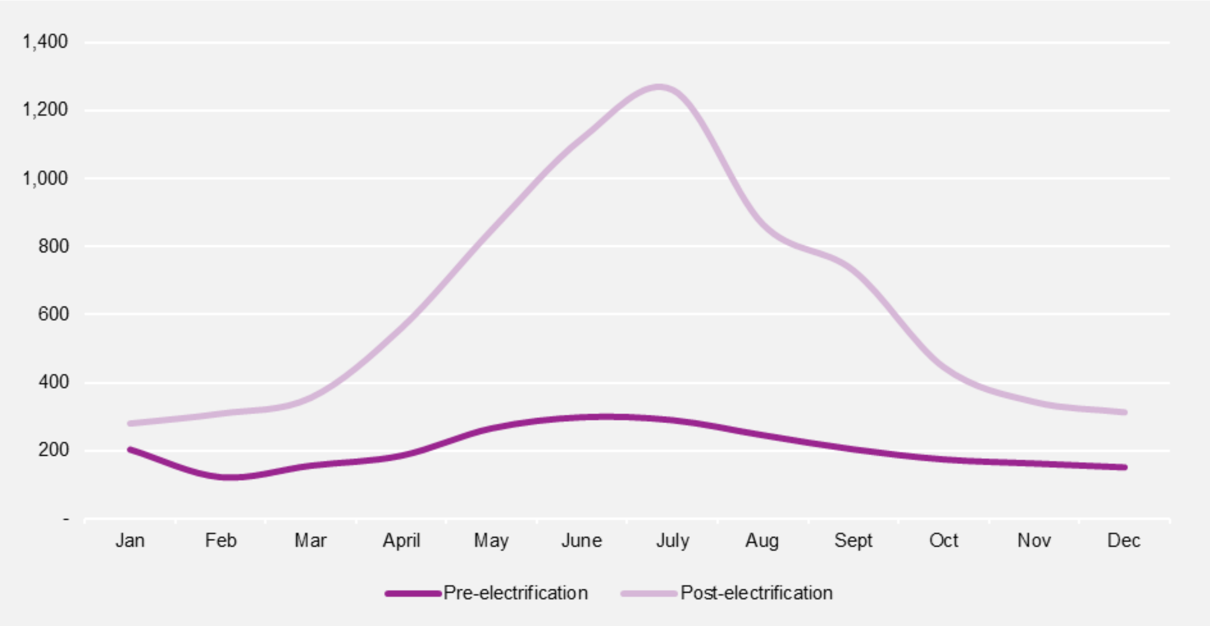
FIGURE 1.2 CHANGE IN HOUSEHOLD CONSUMPTION: 2023–2025



We are also seeing the impacts of electrification at a customer level. Figure 1.3 shows the difference in average load profiles for a sample of our customers who we have identified as having electrified their households.[4] For these customers, average consumption has more than doubled in each month after electrification (other than January). Again, this growth in consumption is particularly pronounced during winter.

Once these profiles are observed at scale, the impacts of this growth will be significant.

FIGURE 1.3 AVERAGE MONTHLY CONSUMPTION PRE & POST ELECTRIFICATION (kWh)



[4] Our analysis is based on the average load profiles for a sample of 1,101 customers; we are expanding this analysis across our network, but this is not yet available. In any event, we expect the observed trends to hold. Further, for our sample, in addition to being the same connections, we have also confirmed that they are the same customer.

1.2.3 We have limited headroom to absorb additional growth

We expect the above trends to accelerate under continued policy direction from both Victorian and federal governments. For example, all new Victorian residential and commercial buildings are now required to be fully electric, and gas hot water systems must be replaced with electric hot water upon failure in existing buildings. The Victorian Government has also mandated that all rental properties must have electric cooling installed by July 2030.[5]

These policies are supported by the Victorian Energy Upgrades (VEU) program, which expanded support for electrified water and space heating in May 2023.[6]

Collectively, the above analysis all points to significant increases in network-wide and localised growth across the 2026–31 regulatory period. In total, we are forecasting peak demand growth of 7.5 per cent by the end of 2031.

Given we are seeing these impacts with growing levels of electrification today, the analysis further highlights the challenge we face with our network being the second most utilised in Australia. Many of our assets are already operating close to capacity or voltage limits, with limited headroom to absorb additional growth or risk without diminishing service level outcomes for customers. We are also operating an aging asset base, with increasingly large populations of high-volume assets at or approaching the end of their expected service life.

In this context, the AER's draft decision to provide an allowance for network capital expenditure that is lower than historical levels is incongruent with the demands we will face with an energy transition that is visible already. The impact of not addressing this growth in network demand and utilisation will be significant and the cost of remedying network requirements too late will be far greater than addressing it with urgency now.

1.3 Our revised proposal

Overall, we have accepted much of the AER's draft decision in our revised proposal. This includes capital expenditure forecasts for the flexible services component of our CER integration forecasts, ICT and non-network investments, as well as step changes related to CER integration, network and community resilience, and ICT modernisation.

Consistent with the AER's guidance on its preferred methodology, we have also re-forecast the impact of data centres in the 2026–31 regulatory period.

We do not, however, consider the entire draft decision is in the long-term interests of our customers, particularly given the rapid electrification of Victoria and the limited headroom for increased demand with our high levels of network utilisation. To put this into context, the AER's draft decision provides an allowance for network capital expenditure in the 2026–31 regulatory period that is below what we will invest in the current regulatory period.

Fundamentally, the draft decision does not sufficiently address the evolving requirements of our network and will constrain our ability to maintain reliable and resilient services as electrification accelerates. For example, for our customer-driven electrification proposal, the AER's draft decision removed $58 million of proposed investments that we forecast would unlock over $237 million of customer value. Further, without funding for these investments, customers will be limited in their participation in the energy transition at a time where their participation is required most.

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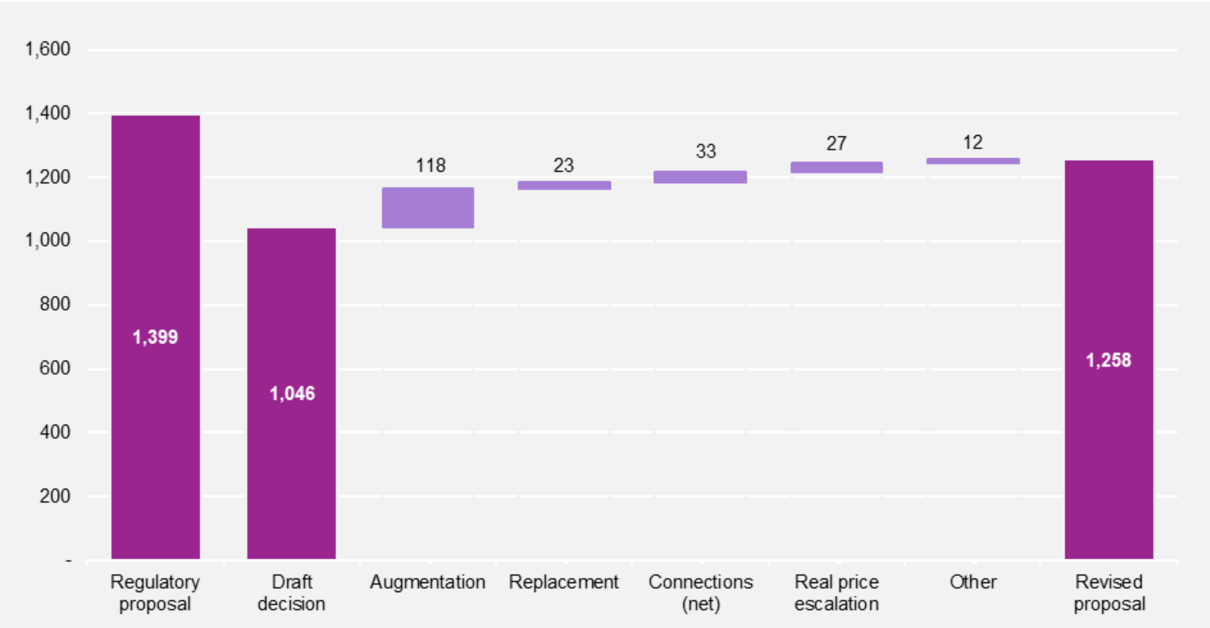
5 DEECA, www.energy.vic.gov.au/households/electric-and-efficiency-standards-for-buildings, accessed 30 November 2025

6 Under the VEU program, our customers have replaced gas space heating with electric space heating at approximately 15,600 locations to September 2025, and registered approximately 12,000 electric vehicles. VEU program eligibility, however, is not available for new builds (that must now be all-electric).

We have carefully reconsidered specific areas in our revised proposal to ensure we continue to meet customer needs now and into the future. This includes the AER's reductions to significant aspects of our network capital expenditure forecasts, our operating expenditure step changes for vegetation management and cloud services, and modelling adjustments related to historical insurance costs and contract labour escalation.

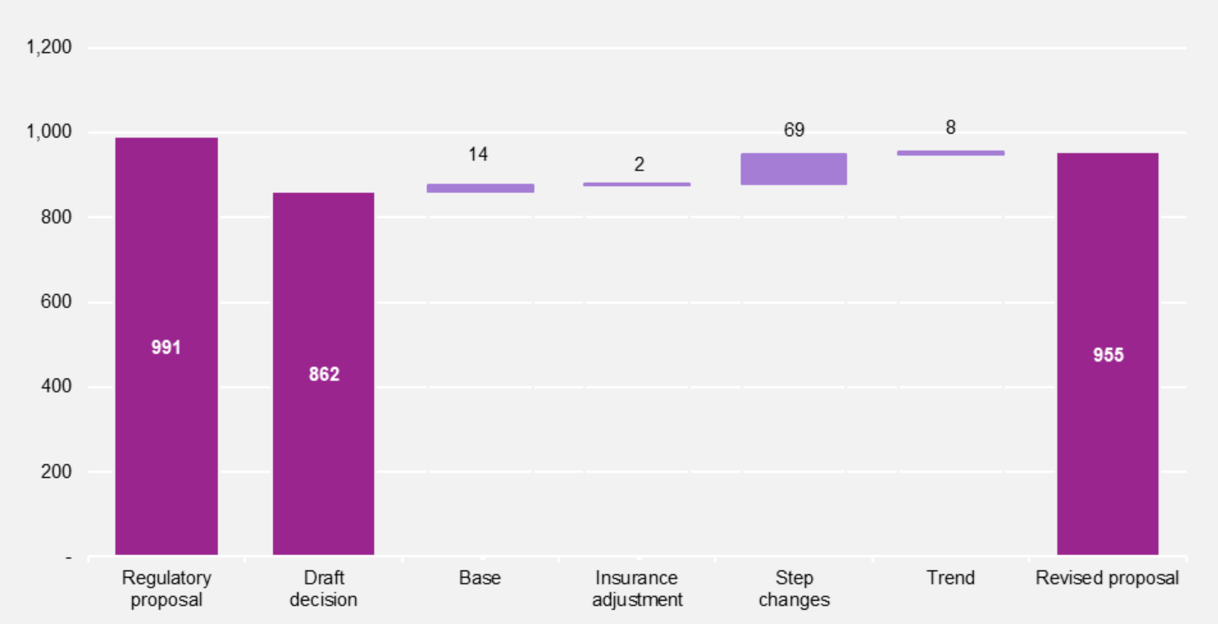
We provide a summary of our revised capital and operating expenditure forecasts below. In total, our revised proposal represents a $173 million reduction on our original expenditure forecasts. Collectively, this results in an annual reduction in network bills for residential and small business customers, on average, over the 2026–31 regulatory period.

FIGURE 1.4 REVISED CAPITAL EXPENDITURE FORECASTS: 2026–31 ($M, 2026)



Note: Our 'other' category above includes CER integration, minor updates to non-network expenditure, overheads and disposals

FIGURE 1.5 REVISED OPERATING EXPENDITURE FORECASTS: 2026–31 ($M, 2026)



Note: Our 'base' includes updates for actual base year data and category specific adjustments; and the 'insurance adjustment' includes the reversal of the AER's base year non-recurrent efficiency gain and step change

1.3.1 Customer bill impacts

Affordability was a key theme throughout our original engagement program, recognising the prevailing cost of living challenges. In the context of the energy transition, however, customer sentiment was also focused on how our network can enable and unlock customer 'value' now and in the future—as noted by the CAP, the big message on affordability from most, though not all customers, is about value rather than cost.[7]

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

For our revised proposal, our forecasts will result in reductions to customer bills, for both residential and small business customers.

The nominal average annual estimated distribution bill impact from our investments over the 2026–31 regulatory period, compared to 2025–26, is outlined in table 1.1 (calculated in accordance with the AER's bill impact template).[8] At the same time, our customers will receive flat nominal metering charges.

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[7] UE ATT SE.30 – CAP – Report on Draft Proposal – Nov2024 – Public
[8] For the purpose of this analysis, we used the same energy forecasts that were used by the AER in its draft decision

TABLE 1.1 REVISED PROPOSAL: ANNUAL NOMINAL AVERAGE ESTIMATED BILL IMPACT

CUSTOMER TYPE	DISTRIBUTION CHARGES[1]	METERING CHARGES[2]
Residential	-$6	$0
Small business	-$17	$0

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

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

2. Annual revenue requirement

Consistent with the National Electricity Rules (the Rules) and our original proposal, we have forecast our revised revenue requirement using a revenue building block approach.

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

As outlined below, we have mostly accepted the AER’s draft decision methodology, with differences in underlying expenditure forecasts and to incorporate updated data for FY25 (that was not available at the time of our proposal or the AER’s draft decision).

We have also revised our approach to corporate income tax, following direction from the AER and subsequent consultation with key stakeholders and customer representatives.

2.1 Annual revenue requirement

Our revised proposed annual revenue requirements and revenue X-factors for standard control services are shown in table 2.1. These forecasts have been calculated in the attached PTRM.[9]

TABLE 2.1 REVISED PROPOSAL: REVENUE REQUIREMENT ($M, NOMINAL)

BUILDING BLOCK	FY27	FY28	FY29	FY30	FY31
Return on assets	179.9	187.9	195.9	206.3	219.3
Regulatory depreciation	147.9	158.4	170.5	179.9	188.7
Operating expenditure	183.6	196.1	211.4	220.4	220.4
Total adjustments	21.0	0.8	-1.3	6.4	0.3
Corporate income tax	1.5	2.2	2.9	5.2	5.1
Unsmoothed revenue requirement	533.8	545.3	579.4	618.1	633.8
Smoothed revenue requirement	547.5	563.7	580.4	597.6	615.2
Forecast CPI (%)	2.55%	2.55%	2.55%	2.55%	2.55%
REVENUE X FACTOR (%)	**0.83%**	**-0.40%**	**-0.40%**	**-0.40%**	**-0.40%**

Consistent with the draft decision, the X-factors from 2027–28 to 2030–31 are equal and have been set such that smoothed revenue in the final year of the regulatory control period is within three per cent of unsmoothed revenue.

9 UE RRP MOD 2.01 – SCS PTRM – Dec2025 – Public

2.2 Regulatory asset base

We are required to roll forward our regulatory asset base (RAB) to 1 July 2026, which is calculated in the attached RFM and summarised in table 2.2.[10] The only change that we have made to the AER's draft decision roll forward is to substitute FY25 estimated capital expenditure, customers contributions and disposals with actual FY25 data.

TABLE 2.2 REVISED PROPOSAL: RAB ROLL FORWARD TO JULY 2026 ($M, NOMINAL)

RAB ROLL FORWARD	TOTAL
1 July 2021 opening RAB from previous determination	2,392.9
Add: True-up for 2020 and 1H 2021 capital expenditure	22.5
Add: Actual/estimated net capital expenditure for 2021–26 (incl. half-year WACC)	1,023.1
Less: Forecast straight-line depreciation for 2021–26	897.2
Add: Adjustment for actual inflation for 2021–26	488.7
1 JULY 2026 OPENING RAB	**3,030.0**

The subsequent roll forward of our RAB over the 2026–31 regulatory period is set out in table 2.3, and based on the AER's PTRM. We have accepted the AER's draft decision asset classes and asset lives, with forecast regulatory depreciation also calculated in accordance with the draft decision but updated for FY25 actuals.

The AER's draft decision, however, misaligned some of the opening RAB inputs in its PTRM. We have amended this in our revised proposal.

10 UE RRP MOD 2.02 – SCS RFM – Dec2025 – Public

TABLE 2.3 REVISED PROPOSAL: RAB ROLL FORWARD OVER 2026–31 ($M, NOMINAL)

RAB ROLL FORWARD	FY27	FY28	FY29	FY30	FY31
Opening RAB	3,030.0	3,131.7	3,233.8	3,344.7	3,458.8
Forecast net capital expenditure	249.5	260.5	281.4	294.1	296.6
Forecast regulatory depreciation	147.9	158.4	170.5	179.9	188.7
CLOSING RAB	**3,131.7**	**3,233.8**	**3,344.7**	**3,458.8**	**3,566.7**

2.3 Rate of return and forecast inflation

Our revised proposal uses the rate of return set out in the AER's draft decision. The AER will update this rate of return in its final determination using observations from the agreed debt and equity measurement periods.

Our revised proposal also uses the draft decision forecast inflation. Similarly, the AER will update forecast inflation in its final determination for the most recent Reserve Bank of Australia inflation forecasts.

2.4 Corporate income tax

Tax costs associated with standard control services connection projects have historically been included in the calculation of total allowable revenue. This is recoverable from all standard control services customers.

In undertaking its assessment of our regulatory proposal, the AER requested us to re-consider this approach. That is, the AER asked to consult with our customers on whether the recovery of economic tax costs for newly connecting sub-transmission and high voltage (HV) connections would be better collected from the connection proponent rather than all customers.

In response, we engaged with the CAP, Department of Energy, Environment and Climate Action (DEECA), Energy Users Association of Australia (EUAA) and Energy Consumers Australia (ECA). Their feedback was:

- most CAP members supported the recovery of tax costs associated with large customer connections from the connection proponent and agreed that this should include all large customer connections rather than specific industries, such as data centres. The later consideration is consistent with principles in the Rules that in assigning customers to tariff classes, customers with a similar connection and distribution service usage profile should be treated on an equal basis[11]
- DEECA supported our proposal to charge tax costs directly to new HV and sub-transmission connections
- the EUAA position is that the economic tax costs for newly connecting sub-transmission and high voltage connections should be paid by the connection proponent. The sentiment was that C&I customers don't want to pay for this tax via their network bills

11 For instance, NER clause 6.18.4(a)(2)

- the ECA did not have a firm position on who should pay, but there was no disagreement with our position.

In considering this issue further, we have balanced the feedback received from the stakeholders with the following factors:

- the principle in AER's Connection Guidelines to limit cross subsidies
- managing the affordability priority of our residential and small business customers
- ensuring our connection policy remains fair and equitable through classifying decision based on connection or electricity usage characteristics, rather than the type of service or industry provided by a new connection.

We propose that the threshold for being liable for tax costs be determined based on the connection voltage on our network. That is, connections that are either HV or sub-transmission will be liable for their own tax costs.

As shown in table 2.4, we expect this decision will impact a relatively small number of connections. For example, over the last three years across CitiPower, Powercor and United Energy there were 88 connection projects that would have been liable for tax costs. About half of these are renewable energy projects which would have been liable for tax under AusNet's current connection policy which has a 1.5 MW threshold for tax liability.

TABLE 2.4 HV AND SUB-TRANSMISSION CONNECTION PROJECTS SINCE 2023

NETWORK	GENERATOR (HV)	NON-GEN (HV)	GENERATOR (SUB-T)	NON-GEN (SUB-T)
CitiPower	-	5	-	-
Powercor	31	30	9	3
United Energy	-	10	-	-

To implement this change in the PTRM, we have removed forecast gross capital expenditure and customer contributions for HV and sub-transmission connections from the PTRM inputs. Net capital expenditure for the RAB is unaffected by this change, only the tax liability calculation if the AER does not accept our proposal to charge tax costs to HV and sub-transmission new connections, or decides on an alternative threshold, then the AER will need to adjust the forecast gross capital expenditure and customer contributions PTRM inputs accordingly.

2.5 Control mechanisms

We accept the control mechanisms for standard control services in the AER's draft decision.

3. Capital expenditure

Today, our customers experience some of the highest performance standards in the National Electricity Market (NEM), in terms of reliability, price and network utilisation. These performance standards provide a strong platform on which to meet the future service challenges and demands on our network.

Ongoing capital investment is critical to ensure we continue to meet these service level expectations.

In its draft decision, the AER recognised many of the specific drivers of our proposed investment needs in the 2026–31 regulatory period. This included accepting the majority of our capital expenditure forecast for CER integration, information and communications technology (ICT), cyber security, and property, fleet and other non-network investments. Except for CER integration, our revised proposal reflects the AER's draft decision in full for these categories.

We have also accepted parts of the AER's draft decision for components of our replacement and augmentation forecasts, and adopted the AER's preferred methodology for forecasting net capital expenditure associated with new data centres.

The AER's draft decision, however, did not accept critical programs required to support the level of electrification expected on our network. Similarly, the AER rejected or reduced key replacement programs and resilience investments that were strongly supported by customer feedback.

Our revised proposal includes additional information to demonstrate the enduring need for these investments and how they will deliver ongoing value for customers in the long-term. In doing so, we have updated our forecasts for new information, such as additional asset data, new demand forecasts and the AER's 2024 values of customer reliability (VCRs), which were not available at the time of our original proposal.

Our revised proposal also responds to criticism from the AER's technical consultant, EMCa, that our economic analysis overstated benefits due to a misalignment in the timing of modelled costs and benefits. This criticism was central to EMCa's recommendations to reject multiple projects, which were accepted by the AER. As set out in section 3.1.1 below, EMCa's analysis is manifestly flawed and inconsistent with well-accepted economic principles for financial valuations (including previous AER decisions).

In total, our revised forecasts represent an increase on the AER's draft decision, but a reduction on our original regulatory proposal.

A summary of our revised capital expenditure forecasts is set out in table 3.1.

TABLE 3.1 REVISED PROPOSAL: CAPITAL EXPENDITURE SUMMARY ($M, 2026)

ASSET CATEGORY	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Electrification and CER integration	17.6	13.6	16.4
Augmentation	148.6	41.2	161.2
Replacement	520.5	414.1	450.3
Resilience	30.7	11.9	12.2
Connections	424.4	357.8	387.0
Information and communications technology	287.4	224.8	224.2
Cyber security	19.4	18.1	18.1
Property, fleet, and other non-network	83.2	80.3	81.5
Innovation	9.8	1.9	5.9
Capitalised overheads	187.0	159.8	171.7
Gross capital expenditure	1,728.5	1,323.5	1,528.4
Customer contributions	327.4	276.0	268.8
Disposals	1.8	1.8	1.8
NET CAPITAL EXPENDITURE	**1,399.3**	**1,045.7**	**1,257.8**

Note: Numbers above include real escalation

3.1 Our economic assessment approach

In the development of our revised proposal, we considered two issues raised by the AER that apply across our capital expenditure portfolio. These include the use of our annualised modelling approach and the application of real escalation to contract labour, which we discuss separately below.

3.1.1 Annualised modelling approach

In developing our regulatory (and revised) proposals, we undertook detailed economic analysis that compared the annualised cost of a project and/or project options to the present value of benefits. The optimal timing for a given project was considered the point where the present value of the benefits exceeded the annualised costs.

In its draft decision, the AER stated that this NPV modelling approach assessed the costs and benefits over different time periods, resulting in an overestimation of the net present value of our investments.

This decision drew from statements made by EMCa in its review of our proposed expenditure, namely that:

- we have commonly applied an approach in which capital expenditure is first annualised, and then the NPV for the project is assessed taking account of this annualised value as a proxy for capital expenditure, rather than the capital expenditure itself
- where the life of the relevant asset is longer than the analysis period this results in a systemic overstatement of the net economic benefit.[12]

We do not agree with the conclusions made by EMCa and the AER, and demonstrate below that when applied correctly, a discounted cash flow (DCF) approach (as suggested by EMCa) is commensurate with our annualised capital expenditure approach.

Specifically, EMCa claims that where the asset life is longer than the assessment period, the annualised capital expenditure method will result in a higher NPV than the standard DCF method. They illustrate this with an example of a capital expenditure investment with a life of 50 years, assessed over 20 years, which we replicate in the table 3.2 below.

EMCa's claim is fundamentally flawed because their DCF analysis compares the present value of capital expenditure over 50 years with the present value of benefits over 20 years. If an asset is assigned an economic life of 50 years, it would be reasonably expected that the asset will deliver benefits over 50 years. Where the expected life of an asset exceeds the modelling period, then a terminal value needs to be assigned to the capital expenditure beyond the modelling period (e.g. in the EMCa example, from year 21 to year 50). The assumption that the asset would deliver no benefits over this period, as is implied by EMCa, would result in the widespread under-forecasting of benefits.

Consistent with our view, Frontier Economics, when engaged by the AER to independently assess the economic analysis and modelling undertaken by ElectraNet in support of its South Australian Energy Transformation RIT-T application, supported the approach to include a terminal value. That is, Frontier Economics stated that omitting a terminal value assumes that there are no benefits beyond the modelling period which they consider to be a 'very conservative assumption'.[13]

ElectraNet's terminal value assumed the remaining benefits reflected the depreciated cost of the proposed interconnector at the end of the modelling period. The AER accepted this approach in its RIT-T determination:[14]

> *[t]he inclusion of a terminal value in the analysis is reasonable given the modelling period is only 21 years and benefits will extend beyond the end of the modelling period given the proposed interconnector is assumed to have an asset life in excess of 40 years.*

Similarly, HoustonKemp addressed the same concerns raised by EMCa for Transgrid.[15] Like the AER and Frontier Economics previously, HoustonKemp also raised the need to assume a terminal value for the DCF method where the asset life is longer than the assessment period. In its report, HoustonKemp recognised the annualised expenditure approach as a valid alternative approach, which is also used by AEMO for its Integrated System Plan assessment.

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[12] EMCa, *United Energy: Review of aspects of proposed expenditure on augex and vegetation management*, August 2025, pp. 63–64

[13] Frontier Economics, *RIT-T assessment: South Australian Energy Transformation; a final report prepared for the AER*, December 2019

[14] AER, *Decision: South Australian Energy Transformation; determination that the preferred option satisfies the regulatory investment test for transmission*, January 2020, p. 82

[15] HoustonKemp, *Transgrid repex and augex business cases review*, October 2022

Applying a terminal value to the EMCa example, and assuming a depreciation profile consistent with constant real asset cost over the life of the asset, results in the same net present value under either a DCF method or annualised capital expenditure method. The following table compares the different methods of assessment with a corrected DCF method, with these results provided in the attached model.[16]

TABLE 3.2 COMPARISON OF ALTERNATIVE MODELLING APPROACHES

METHOD	DCF: EMCa	DCF: CORRECT	ANNUALISED
PV capex	-$25.00	-$25.00	n/a
Annualised capex	n/a	n/a	-$1.07
PV annualised capex	n/a	n/a	-$15.15
PV benefits	$21.31	$21.31	$21.32
Terminal value	n/a	$9.85	n/a
NPV	**-$3.68**	**$6.17**	**$6.17**

For the above reasons we have retained our annualised capital expenditure assessment approach in our revised proposal, and consider the AER decision to reject projects on the basis of EMCa's flawed analysis to be invalidated.

3.1.2 Real cost escalation for contract labour

Our regulatory proposal included real cost escalation for our network capital investment for both internal labour and contract labour. We applied the wage price index (WPI) for the electricity, gas, water and waste services (EGWWS) industry to both internal and contract labour because we consider this is the most representative index for the activities undertaken.

The AER's draft decision allowed real cost escalation for internal labour but applied zero real cost escalation for contract labour (that is, the escalation applied is equal only to the consumer price index (CPI)). The AER also shifted the internal labour we apportioned for our network capital investment to contract labour because this better reflected how we deliver field services and network capital investment.

The AER, however, has not adequately supported the reasons for its position to not apply real cost escalation to contract labour, nor has it supported why CPI is the appropriate measure for escalating contract labour. For example, the AER simply stated that 'given we do not apply real cost escalation to contract labour, we also applied zero real cost escalation for this cost component'.[17]

In contrast, our enterprise agreements and contract provisions for the field and network services provided by external contractors means that we face growth in labour costs beyond CPI, which are prudent and efficient. By not including this real escalation, the AER's draft decision infers that we should absorb these additional costs, and therefore not recover our efficient costs. This is inconsistent

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[16] UE RRP ATT 3.1.02 – Annualised capex comparison to DCF – Dec2025 – Public

[17] AER, *Draft decision, United Energy electricity distribution determination, Attachment 2 – capital expenditure*, September 2025, p. 13

with the requirement that the AER must determine a capital expenditure forecast that reasonably reflect prudent and efficient costs as well as a realistic expectation of cost inputs (in this case, labour inputs).[18]

We engaged HoustonKemp to provide independent expert economic advice on the appropriate rate at which contract labour should escalate to reasonably reflect a realistic expectation of labour cost inputs.[19] This advice considered the AER's rationale contained across previous historical decisions (noting that as above, the AER did not provide any reasoning in its draft decision for our network). Importantly, while the AER indicates that its 'standard' approach is to apply zero real cost escalation to contract labour, the evidence and reasons provided in previous decisions indicates there has been mixed application of real cost escalation. In several cases, the AER has applied escalation in line with a WPI, typically for the EGWWS industry.

In our revised proposal, we have considered HoustonKemp's economic advice, which establishes that:

- the AER's reasoning for limiting escalation to CPI, as described in its decision for SA Power Networks' 2020–25 determination, is predicated on unreasonable assumptions that are not supported by economic principles and depart from commercial realities.[20] The AER's proposition that contract labour rates can be limited to CPI by using short-term contracting assumes that we are somehow able to sustain lower levels of unit labour costs than the electricity industry, which is unrealistic
- internal and external labour are sourced from the same labour market for providing electricity services, so it is not feasible that there would be a material divergence between the labour rates obtained by distributors and contractors
- the rate of change in unit labour costs has generally exceeded the rate of inflation (CPI), which indicates that a WPI that reflects the relevant industry in the relevant jurisdiction is a more appropriate measure to escalate forecast labour costs, rather than CPI. Further, electricity industry skill shortages heighten competition for relevant labour between distributors, contractor firms, and other relevant electricity industry participants, placing further pressure on wage growth. These shortages are expected to worsen as infrastructure pipelines continue to expand[21]
- the escalation for both our internal labour and contract labour is aligned because the enterprise agreement with our employees, as well as the contracts with our contractors, require us to escalate labour rates as set out in our enterprise agreement
- given that internal and contract labour is sourced from the same labour market, any reasons for applying the EGWWS WPI to internal labour for capital expenditure and labour for operating expenditure, would equally apply to contract labour.

We acknowledge some of the AER's previous arguments around escalating labour based on enterprise agreements, which can have the impact of limiting incentives to efficiently incur labour costs. While we consider the escalation rates within our enterprise agreements reflect our expected internal and contract labour escalation over the next regulatory period, we consider the next best escalation rate to apply is the EGWWS WPI, which is consistent with the rates applied to labour in operating expenditure and internal labour for capital expenditure. For these reasons, consistent with our regulatory proposal, our revised proposal applies the EGWWS WPI to the contract labour in our capital expenditure forecasts as this is a realistic expectation of the labour cost inputs (including contract labour).

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[18] NER, cl. 6.5.7(c)
[19] UE RRP ATT 3.1.01 – HoustonKemp – Contract labour escalation – Dec2025 – Public
[20] AER, *Final Decision: SA Power Networks distribution determination 2020–25 – Attachment 5: Capital expenditure*, June 2020, pp. 65–66
[21] See, for example: Infrastructure Australia, *2025 Infrastructure market capacity report*, November 2025, pp. 5–7

3.2 CER integration

Customers are continuing to connect consumer energy resources (CER) to our networks to take advantage of the benefits they offer, such as reduced electricity costs, environmental benefits and more choices when it comes to their energy supply.

Our regulatory proposal included a CER integration and electrification strategy that outlined our approach to ensure all customers benefit from electrification through lower prices. Our strategy involved maximising utilisation and exhausting all possible low-cost solutions, while optimising required augmentation to deliver value for customers.

As part of our CER integration and electrification strategy, we proposed three non-network initiatives including introducing flexible services, provision of enhanced data visibility and automation of our existing manual non-network marketplace platform. The AER's draft decision accepted our flexible services program but rejected our data visibility and non-network marketplace platform investments on the basis that they were not economically justified.

Our revised proposal accepts the AER's draft decision on flexible services. However, the AER's draft decision would not allow us to meet customer and stakeholder expectations to publish sufficiently granular data in a timely manner (to inform their decision making) or to promote market maturity of non-network services by publishing all of our constraints.

A core principle of our CER integration program is to exhaust all possible low-cost options before resorting to network investment. We have already improved CER outcomes for customers through optimising the operating voltages of our network, supporting 40,000 customers to rectify non-compliant inverter settings, implemented automatic solar connection pre-approval and implementing cost-reflective tariffs.

Enhancing data visibility for our customers and establishing life-cycle management of non-network solutions to create a true marketplace are our next steps as we transition towards delivering distribution system operator (DSO) services for our customers.

Given this, we have re-proposed our enhanced data visibility and our non-network marketplace platform, and have responded to the AER's feedback in a targeted business case addendum.[22]

Our revised proposal for CER integration is set out in table 3.3 below

TABLE 3.3 REVISED PROPOSAL: CER INTEGRATION INVESTMENT ($M, 2026)

PROJECT	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Flexible services	13.0	13.0	13.0
Non-network procurement platform	1.8	-	1.8
Enhanced data visibility	1.0	-	1.0
TOTAL	**15.8**	**13.0**	**15.8**

Note: Numbers above exclude real escalation

[22] UE RRP BUS 3.2.01 – CER integration – Dec2025 – Public

3.2.1 DSO vision

While we shared our plans for the 2026–31 regulatory period in our regulatory proposal, we did not present a long-term vision that outlined how our DSO services would deliver on the needs of our customers beyond 2031.

We have since developed a DSO vision that builds on our existing achievements and plans over the 2026–31 regulatory period to guide our future decision making. This vision is intended to be a 'live' document, and we are seeking further customer and stakeholder input (having first discussed this vision with the CAP).

Using customer-first perspectives, our DSO vision highlights how the current needs of our customers will be met through our proposed 2026–31 investments and how these near-term actions place us on a path to enable customer's future energy choices and maximise their investment value.

Our DSO vision also highlights the new challenges we have seen emerge since the submission of our regulatory proposal. For example, we are now seeing innovative retail electricity plans that provide customers with free or low-cost electricity during midday windows. The electricity system as a whole benefits from these retail offerings, which seek to make use of abundant, low-cost renewable electricity when it is available. This reduces wholesale market costs and supports the achievement of net-zero targets.

These plans, however, are leading to undervoltage events on our network in the middle of the day (where we would have historically seen overvoltage issues) because our LV networks are not strong enough to support this load. Our LV networks were typically built to design standards prior to electrification of gas and electric vehicles—recognising Victoria is more dependent on gas than any other jurisdiction—and rely on diversity among customer usage rather than targeted coordination of usage.

This example suggests that investment in the LV network is a complement for flexible services implementation, rather than a substitute. Even with increasing orchestration of CER, such as rooftop solar, batteries and electric vehicles, ongoing investment remains essential.

That is, orchestration can optimise existing infrastructure and reduce peak demand but it cannot eliminate the need for a robust LV network. The network must deliver energy reliability to all consumers, including those without CER, and support growing electrification and renewable generation (which presents greater challenges given our high utilisation and Victorian customer's gas dependency). We expect both CER orchestration and augmentation investment are required in a future optimised energy system.

Our DSO vision also highlights how customers opting-in their CER and other flexible loads can effectively deliver system-level value. However, customers will need to trust that the energy system (e.g. aggregators, networks and other third-parties) will act in their best interests before participating. This trust must be earned through delivering positive outcomes for customers today rather than assumed as a given.

Our full DSO vision is attached to our revised regulatory proposal.[23]

3.3 Augmentation

Augmentation ensures that our networks' capacity can accommodate our customers' growing electricity needs. This is increasingly critical in the context of the energy transition, as our economy seeks to decarbonise on the pathway towards net-zero.

[23] UE RRP ATT 3.2.01 – DSO vision – Dec2025 – Public

Stated alternatively, augmentation ensures that our network has sufficient capacity to avoid customers experiencing load related outages on peak load days, delays in restoring supply when and/or where there is an inability to transfer load, and subsequent constraints on economic development.

Our augmentation forecasts also include the communications system and associated assets we use to operate the network.

In its draft decision, the AER agreed with some of our original regulatory proposal, including all of our non-demand related expenditure for system security and communications. Our revised proposal accepts the AER's draft decision for over $40 million of our augmentation investment.

However, the AER has accepted less than 10 per cent of our proposed demand-driven expenditure and provided an overall augmentation allowance below historical spend. This is challenging given the strong growth in consumption and peak demand, as discussed in section 1.2.

We do not consider the AER's draft decision would allow us to meet customer expectations for several critical programs, including for customer-driven electrification and the lower Mornington Peninsula sub-transmission line. For these works, we have responded to the AER's feedback in targeted business case addendums.

A summary of our revised proposal augmentation forecast is shown in table 3.4.

TABLE 3.4 REVISED PROPOSAL: AUGMENTATION INVESTMENT ($M, 2026)

PROJECT	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Customer-driven electrification	65.7	7.8	85.5
Lower Mornington Peninsula supply	38.2	-	38.0
Other augmentation	35.2	33.0	33.8
TOTAL	**139.2**	**40.8**	**157.4**

Note: Numbers above exclude real escalation

3.3.1 We have updated our demand forecasts

Most of our augmentation proposal is demand-driven, where the prudency of augmentation investment is influenced by forecast growth in localised demand. Our demand forecasting methodology is industry leading and leverages the significant investment from customers in our network of advanced metering infrastructure.

As part of its draft decision, the AER engaged a technical consultant to review our demand forecasts and underlying methodology. While this review provided some feedback on our demand forecasts, the AER did not consider that these had a material impact on their conclusions on our proposed augmentation.[24] Therefore, we have not changed the methodology of our demand forecasts between our regulatory and revised proposal.

In the development of our revised proposal, however, we have updated our demand forecasts for new information. These new forecasts include more recent AEMO inputs and assumptions, and another 12 months of network and customer smart meter data from the 2024/25 summer period. We have also

[24] AER, *Draft decision: United Energy electricity distribution determination, Attachment 2 – capital expenditure*, September 2025, p. 26

included additional forecast load from the electrification of gas, which was inadvertently omitted from our original regulatory proposal due to a process error.

Further detail on changes in demand and consumption on our network was set out in section 1.2. This showed that we are observing significant impacts today, including during winter periods, that are likely to accelerate materially through the 2026–31 regulatory period.

3.3.2 Customer-driven electrification

For most customers, the demand for and supply of electricity starts and ends with our LV network. The strength of our LV network, therefore, is a fundamental enabler of increasing electrification. As our customers continue to further electrify their homes and businesses, a key challenge is ensuring we manage growing undervoltage impacts.

In our regulatory proposal, we outlined a program of proactive and reactive augmentation to maintain undervoltage service levels as they are today and remediate non-compliant voltage supplies to customers who complain to us about receiving poor quality services. This is consistent with our two jurisdictional obligations:

- we must maintain voltage levels between 216 and 253 volts at least 99 per cent of the time, with functional compliance met if these limits are maintained for at least 95 per cent of our customers
- if an individual customer complains to us, we are obligated to reactively remediate non-compliant voltage levels as soon as practicable.

The AER did not accept our proposal, based on its view that we overstated the impacts of undervoltage (including through the number of complaints we received and the economic measure used to value undervoltage). The AER also stated that in the absence of intervention, we will not become non-compliant until FY31. As a result, the AER provided a draft allowance based on historical expenditure levels.

Overall, we consider the AER’s allowance to be insufficient to meet the pace of change or the expectations of our customers in the 2026–31 regulatory period. Given the extent of electrification reflected in our demand and consumption forecasts, history is no longer a prudent or efficient response.

In response to the AER’s draft decision, we have since undertaken more research and revised our modelling. For example, we have sought to further understand the impact of undervoltage directly from customers who have experienced it:

- additional engagement has corroborated existing evidence that undervoltage impacts are real and tangible for our customers—72 per cent of customers in our survey reported undervoltage issues as equal to or more disruptive than a typical outage
- additional analysis has identified how undervoltage impacts are limiting the value customers can derive from retail offers with ‘free’ electricity windows in the middle-of-the-day. At scale, this will limit wholesale market benefits and the achievement of net-zero targets
- we have incorporated updated demand forecasts into our modelling and validated these increases with our own smart meters and external data. This analysis demonstrates that electrification is increasing consumption and demand, and that history is not a predictor of the future.

We have also included additional options to value the benefits of remediating undervoltage constraints. Specifically, we have included alternative methodologies that use 10 per cent of the AER’s VCR to determine an economic level of proactive investment. This is consistent with the approach used by the AER to determine an alternative substitute estimate for our Powercor network’s regional and rural program (which similarly addresses undervoltage levels).

On balance, we have relied on the AER's approach in developing our preferred option—a mix of proactive investments valued using 10 per cent of the VCR, and reactive investments consistent with our compliance obligations to rectify undervoltage levels once identified by customers. While this approach differs from our original proposal, it results in a similar level of proposed investment. Relative to our base-case, it will also unlock benefits (e.g. supply additional compliant voltages to customers) valued at $237 million.

As our preferred option now relies on a direct economic evaluation, it does not require consideration of forecast compliance for proactive investments. That is, forecasts justified on a (proportional) VCR-basis are economic in their own right and unlock value for customers.

We briefly discuss each of the AER's primary concerns with our customer-driven electrification program below, with further detail set out in our attached customer-driven electrification addendum.[25]

Our complaints data is consistent with our regulatory obligations

Our regulatory proposal outlined that we had received 143 undervoltage complaints in FY24. The AER's draft decision instead observed that we had only reported four complaints in our RINs and that there was misalignment between our complaints forecast and our historical actual complaints.

Under the EDCoP, we are obligated to remediate voltage non-compliance when we become aware of it. This typically occurs when a customer contacts us to report non-compliance, after which that customer is engaged in our voltage remediation process. We then investigate, design, schedule and implement a reactive resolution to their complaint.

Where a customer engaged in our voltage remediation process is not satisfied with our response, they can request their case be escalated internally or to the Energy and Water Ombudsman of Victoria (EWOV).[26] The four quality of supply complaints in the FY24 RIN are where customers have requested to have their compliant escalated internally or to EWOV and therefore underrepresents the amount of complaints we receive.

We have attached de-identified records of each customer complaint made to our business to ensure the AER has visibility of all undervoltage-driven customer complaints.[27]

Customers have told us that undervoltage impacts are persistent and highly disruptive

The AER's draft decision found that using the VCR to determine the customer impact of undervoltage supplied to customers is not consistent with the AER's intended application of it. Further, the AER and its technical consultant, EMCa, stated that using the VCR results in a 'significant overestimation of the economic cost of undervoltage supply'.[28]

We consider that the AER and EMCa have misrepresented how we used the VCR within our regulatory proposal. We address this in further detail in our customer-driven electrification addendum. Notwithstanding this, we accept that an alternative to the VCR would be preferable to value undervoltage constraints; however, there is no standard value measure that we could apply.

To manage this regulatory gap, we sought to better understand how undervoltage is disrupting the lives and livelihoods of our customers and how impactful undervoltage is relative to the VCR. For our regulatory proposal, this included engagement through our trade-off evaluation forums. For our revised proposal, we supplemented this with targeted surveys of customers who have experienced undervoltage issues.

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25 UE RRP BUS 3.3.01 – Customer-driven electrification – Dec2025 – Public
26 United Energy 2023-24 Annual Reporting – Basis of Preparation - ANPAL3.6BOP5, 3.6
27 UE RRP ATT 3.3.01 – Undervoltage complaints register – Dec2025 – Public
28 AER, *Draft decision: United Energy electricity distribution determination, Attachment 2 – capital expenditure*, September 2025, p. 28

Customer surveys

Between May and October 2025, we surveyed all customers who complained about non-compliant voltage levels and were engaged in our remediation process. In total across our three networks, we surveyed 85 customers, which is a representative sample of all customers who contacted us with an undervoltage complaint during that period.

Our survey captured the types of impacts on various appliances and asked customers to identify how impactful the disruption was relative to an outage, while also seeking qualitative responses to highlight key areas of concern. We aligned our survey language with the language used in the AER's VCR survey so customers could compare undervoltage disruption with the baseline VCR.

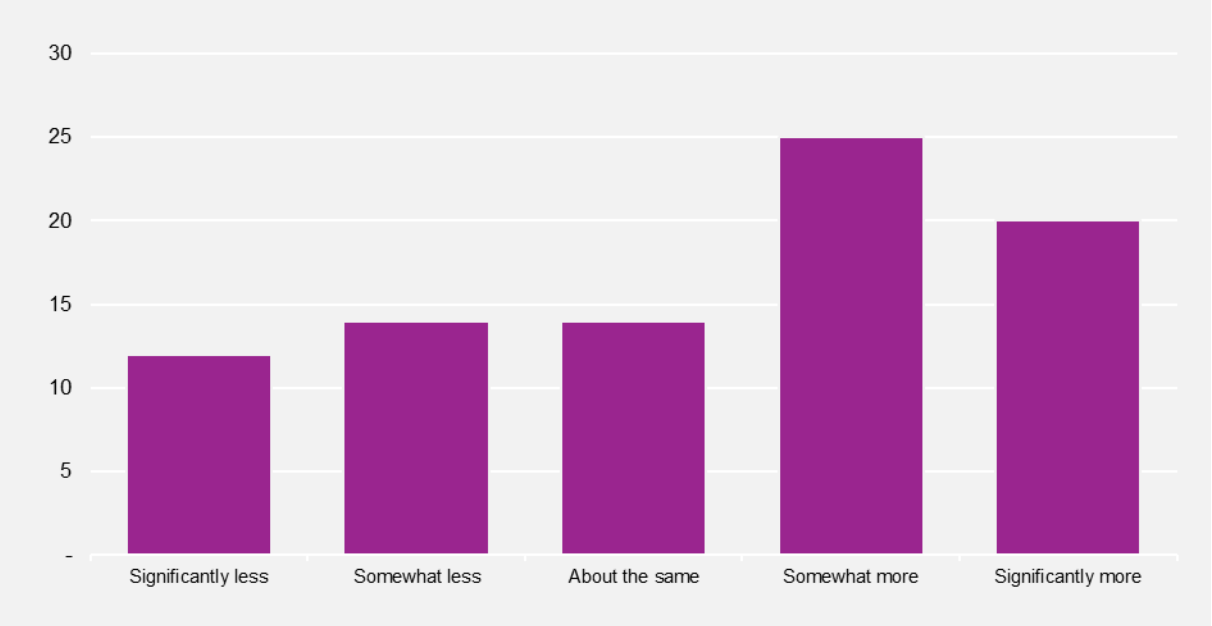
Most customers surveyed were residential and their responses affirmed that undervoltage is highly disruptive:

- 26 customers reported being unable to heat or cool their home
- 14 customers reported being unable to charge their EVs
- 18 customers reported broken or malfunctioning appliances
- eight customers reported losing income as a result of undervoltage levels
- seven customers reported their family's health being impacted.

As shown in figure 3.1, 70 per cent of residential customers responded that their issue was about the same or more disruptive than the baseline VCR.

As more homes, businesses and transport electrify, we expect these trends to continue. This will be particularly challenging for our customers, who live in poorly insulated houses in the coldest climates across mainland Australia and further for customers with malfunctioning space heating (which is expected to be a predominant driver of increasing undervoltage complaints through the 2026–31 regulatory period).

FIGURE 3.1 DISRUPTION OF UNDERVOLTAGE COMPARED TO AN OUTAGE



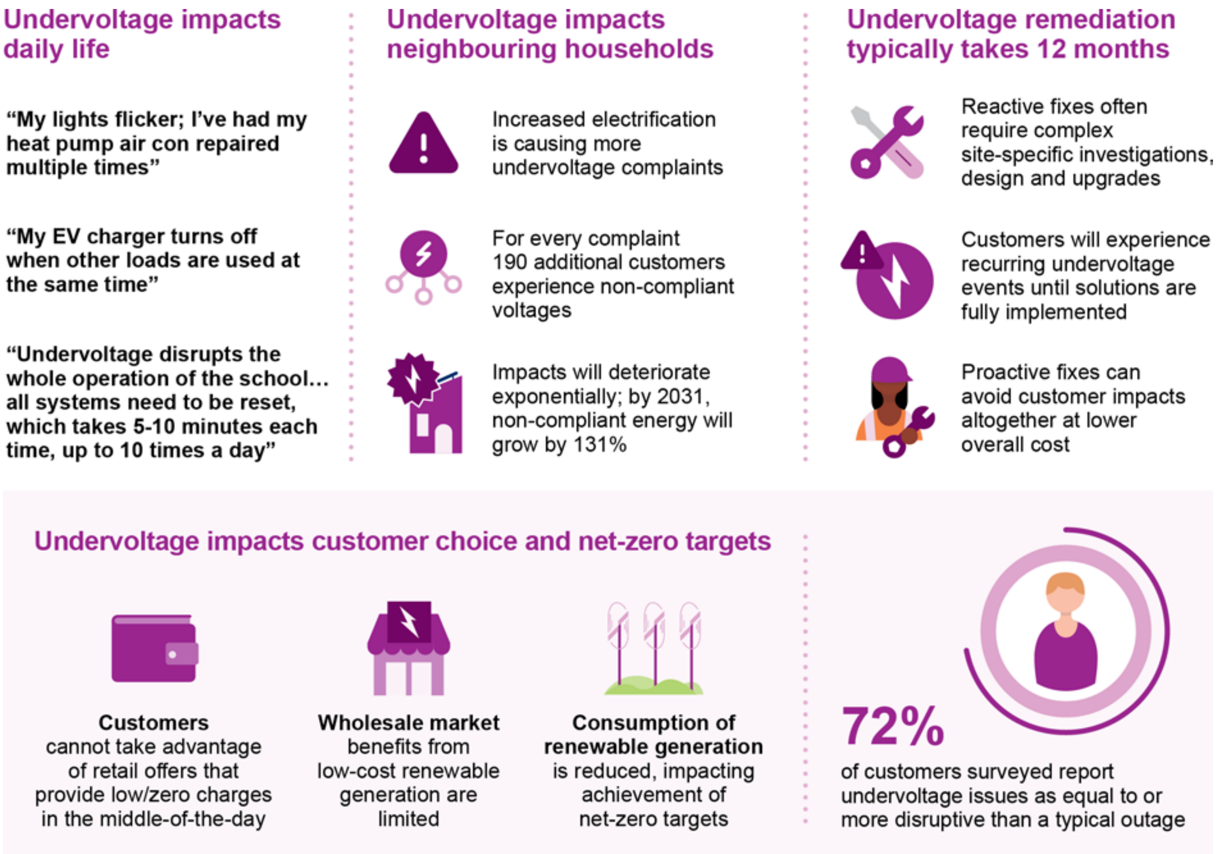
Undervoltage will increasingly limit wholesale market benefits and net-zero targets

As highlighted in the context of our DSO vision (in section 3.2.1), we are now seeing innovative retail electricity plans that provide customers with free or low-cost electricity during midday windows. The Australian Government's recent 'Solar Sharer Offer' is an example of this.[29]

While the electricity system as a whole benefits from these retail offerings—which seek to make use of abundant, low-cost renewable electricity when it is available—these plans are leading to undervoltage non-compliance on our LV network in the middle of the day. The impacts of undervoltage, therefore, present a barrier to the delivery of wholesale market benefits and net-zero targets, and highlights how investment in the LV network is a complement to the energy transition.

A holistic summary of customer and system impacts from undervoltage are summarised below in figure 3.2.

FIGURE 3.2 CUSTOMER AND SYSTEM IMPACTS OF UNDERVOLTAGE NON-COMPLIANCE



We have proposed an alternative methodology, based on a direct economic assessment using a 10 per cent weighting of the VCR

In developing our revised proposal, we considered maintaining our service level approach because of its comparative advantage in prioritising sites to optimise service levels for the greatest number of customers. However, we recognise the AER concerns with this approach and have instead forecast our investment needs using a valuation approach based on a weighting of the VCR.

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29 While this does not immediately affect Victoria, the Government committed to further consultation to support a potential roll out in other jurisdictions in 2027

Specifically, we have valued the benefits of remediating undervoltage constraints using 10 per cent of the VCR.[30] While the AER's draft decision did not propose a specific alternative in its assessment of our customer-driven electrification proposal, it applied 10 per cent of the VCR in determining its substitute estimate for our Powercor network's regional and rural program.

For the avoidance of doubt, however, we remain of the view that the balance of available evidence suggests customers place a materially higher value on these constraints. It is informative in this regard that the AER has not presented any quantitative or customer-centric evidence to substantiate its position. This contrasts to a growing body of corroborative research from multiple, independent engagement forums.

In total, our revised proposal forecast based on a proportional VCR methodology remains consistent with the value of our original regulatory proposal. This reflects updated modelling based on our revised demand forecasts, and recognises that a level of reactive upgrades will still be required in line with our obligations to remediate sites following a customer complaint.

We have also maintained our forecast reduction in capital expenditure assumed to be achieved from non-network services deferring some LV augmentation projects (despite the AER not accepting our non-network marketplace proposal in its draft decision).

Our revised proposal is summarised below in table 3.5.

TABLE 3.5 REVISED PROPOSAL: CUSTOMER-DRIVEN ELECTRIFICATION ($M, 2026)

PROJECT	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Reactive upgrades	25.0	7.8	30.2
Proactive upgrades	41.6	-	56.2
Deferred investment: non-network solutions	-0.8	-	-
TOTAL	**65.7**	**7.8**	**86.4**

Note: Numbers above exclude real escalation

3.3.3 Lower Mornington Peninsula

To avoid the risk of voltage collapse and widespread outages in the lower Mornington Peninsula, our regulatory proposal included the construction of a new, 54km 66kV sub-transmission line from Hastings (HGS) zone substation to Rosebud (RBD) zone substation. This line would be 'over-built' along an existing line route for our 22kV network

Building the sub-transmission line is economic today, however, we have been deferring these works with a non-network solution consisting of 9MW of diesel generation and 1MW of battery storage.

The AER did not accept our proposal to build the HGS to RBD sub-transmission line and instead assessed that the current non-network solution be continued or expanded. The AER stated that this option was not appropriately considered in the regulatory proposal, and the cost did not appear to be derived from the market.

30 That is, we have used 10 per cent of the VCR to value undervoltage energy at risk by applying zero per cent of the VCR at 216V and 10 per cent of the VCR at 207V, with a linear ramping rate between 216V and 207V

To improve the clarity of our modelled options, we have adjusted our revised proposal model so that the base case is now a true ‘do nothing’ scenario. That is, continuing with our existing non-network solution is now assessed as a stand-alone option (in line with the AER’s draft decision). This has improved the ease with which the costs and benefits of our modelled options can be compared.

Our revised options analysis, therefore, comprises the following five options:

- do nothing, meaning cessation of the existing non-network solution and load shedding to keep below the voltage collapse limit
- maintaining the existing non-network solution without expansion
- maintaining the existing non-network solution and then building the sub-transmission line when the benefits exceed the costs
- expanding the existing non-network solution to maintain current levels of energy at risk
- expanding the existing non-network solution to maintain current levels of energy at risk and then building the sub-transmission line when the benefits exceed the costs.

In response to the AER’s draft decision, we have also sought quotes from our existing service provider and an alternative service provider for the expansion of the non-network solution.

After considering more recent cost estimation for the non-network solutions, new demand forecasts and the AER’s revised 2024 VCR, the most economic option for customers is maintaining the existing non-network solution and then building the sub-transmission line by FY31. This option is reflected in our revised proposal forecasts.

If, however, the AER does not accept our preferred option—which we consider is sufficiently certain in the 2026–31 regulatory period—we note the proposed sub-transmission line would meet the contingent project criteria set out in the Rules. We discuss this in section 7.2.

Our proposed expenditure is set out in table 3.6 and detailed in our revised business case addendum and cost model.[31]

TABLE 3.6 REVISED PROPOSAL: LOWER MORNINGTON PENINSULA ($M, 2026)

PROJECT	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
HGS–RBD 66kV sub-transmission line	38.2	-	38.0

Note: Numbers above exclude real escalation

3.4 Replacement

Our asset replacement program includes investments required to ensure we continue to meet our network safety, reliability and environmental obligations as the condition of our network infrastructure deteriorates over time. This investment represents the largest component of our total capital requirements for the 2026–31 regulatory period.

In its draft decision, the AER made significant reductions to our proposed replacement expenditure. Generally, the AER considered we did not provide sufficient supporting evidence for volumes above our historical trend.

31 UE RRP BUS 3.3.02 – Lower Mornington Peninsula – Dec2025 – Public

We have accepted the AER's draft decision for almost all the replacement expenditure categories, except poles and zone substation transformers. For the reasons discussed further in this chapter, our revised forecasts better represent the investment required to continue to deliver the level of service and compliance that our customers expect.

Consistent with the AER's draft decision, we have also included a STPIS adjustment to account for the improved reliability that it expects will eventuate from our risk-based overhead conductor program.

As shown in table 3.7, our revised asset replacement forecast is lower than that included in our original proposal, but higher than the AER's draft determination.

TABLE 3.7 REVISED PROPOSAL: REPLACEMENT INVESTMENT ($M, 2026)

ASSET CATEGORY	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Poles	120.4	85.5	105.1
Pole-top structures	101.5	101.5	101.5
Overhead conductors	62.7	62.7	62.7
Underground cable	45.3	38.5	38.5
Service lines	20.9	20.9	20.9
Distribution transformers	40.8	28.0	28.0
Substation transformers	7.7	6.6	7.7
Distribution switchgear	46.1	40.9	40.9
Substation switchgear	5.7	5.7	5.7
SCADA and protection	12.9	12.9	12.9
Other	11.4	10.9	10.9
TOTAL	**475.4**	**414.1**	**434.8**

Note: Consistent with the AER's presentation in its draft decision, we have removed 'innovation' investment from the 'other' category above. Innovation funding is now specified in its own separate category. Numbers above exclude real escalation.

3.4.1 Poles

Our regulatory proposal used sophisticated decay rate modelling to forecast our pole intervention volumes for the 2026–31 regulatory period. Based on the results of this modelling, and noting an increasing defect trend, we proposed an increase in pole intervention volumes to maintain the reliability of the network.

The AER did not accept our proposed capital expenditure for our poles program and instead included a materially lower substitute estimate based on historical expenditure.

Specifically, the AER considered that we did not provide sufficient evidence to justify our proposed increase in pole replacement volumes, noting that we were proposing uplifts in our pole replacement program where we already have strong historical performance in relation to failures, and that there seemed to be a mismatch between our reported defects and intervention volumes.

Our pole intervention volumes, however, are forward looking, based on current condition of our poles and observed decay rates over time. We consider this a more robust method for forecasting future volumes, noting the depth of the underlying data set and that failure trends are a lagging indicator.

We have also updated this modelling using the latest inspection data, intervention ratios and failure records. Critically, we have also tested the forecasting accuracy of our model by comparing what it would have predicted for the 2021–26 regulatory period to our revealed actuals. The results of this exercise, as shown in table 3.8, support the accuracy of our forecast method, with forecast and actual interventions within three per cent of each other.

TABLE 3.8 ACTUAL VERSUS MODELLED INTERVENTIONS: FY21–FY25

CATEGORY	TOTAL INTERVENTIONS
Forecast interventions	9,287
Actual interventions	9,581

After including the latest updates to our model (e.g. to incorporate FY25 data), we are forecasting minor reductions in our pole replacement volumes compared to our original proposal. This results in a small decrease in our proposed expenditure.

The cost of our revised pole program is set out in table 3.9. Further discussion on our poles program is included in our revised poles asset class addendum.[32]

TABLE 3.9 REVISED PROPOSAL: POLE INVESTMENT ($M, 2026)

INVESTMENT NEED	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
LV pole replacement	55.5	39.4	49.9
HV pole replacement	57.0	40.5	49.6
Pole reinforcement	7.9	5.6	5.6
TOTAL	**120.4**	**85.5**	**105.1**

Note: Numbers above exclude real escalation

32 UE RRP BUS 3.4.01 – Poles – Dec2025 – Public

3.4.2 Overhead conductor

Our regulatory proposal included both a corrective and risk based overhead conductor program. We proposed an increase in our overhead conductor volumes driven by an increasing defect and failure trend since 2019, and the need to move towards more sustainable intervention volumes.

The AER accepted our proposed capital expenditure for our overhead conductor category, however, requested that we include a STPIS adjustment to account for the improved reliability that it expects will eventuate from our risk-based overhead conductor program.

We acknowledge that the successful implementation of our risk-based program may lead to minor improvements in reliability for our customers. As such, we have included an adjustment to our STPIS targets to reflect this.

The calculation of the STPIS adjustment is included in our attached model.[33]

3.4.3 Zone substation transformers

Our regulatory proposal included three separate zone substation transformer programs, including:

- one transformer replacement under our risk-based forecasting approach
- continuing our transformer refurbishment program to address environmental harm from oil leaks to meet obligations under the Victorian Environment Protection Act
- minor station works for unplanned reactive works based on historical defect and failure data.

The AER accepted most of our proposed capital expenditure for our zone substation transformers category, except our transformer refurbishment program. The AER applied a 50 per cent reduction to our transformer refurbishment program because it did not consider our quantification of environmental risk cost was correct. This was based on advice from EMCa for similar environmental refurbishment programs proposed by CitiPower and Powercor.

Our revised proposal maintains our original forecast for zone substation transformers. We contend that the environmental risk framework and risk cost quantification in our original proposal was appropriate and aligned with industry approaches, such as those used by the UK's Office of Gas and Electricity Markets (Ofgem). We clarify that the risk cost is based on the environmental harm from a transformer oil spill, rather than the interpretation by the AER and EMCa that the oil risk costs represent an operational cost associated with replacing the lost oil.

The cost of our revised zone substation transformer programs is set out in table 3.10.

33 UE RRP MOD 3.4.03 – HV conductor STPIS adjustment – Dec2025 – Public

TABLE 3.10 REVISED PROPOSAL: ZONE SUBSTATION TRANSFORMERS ($M, 2026)

INVESTMENT NEED	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Elwood transformer replacement	4.6	4.6	4.6
Minor station works (transformer)	0.9	0.9	0.9
Transformer refurbishment	2.2	1.1	2.2
Total	**7.7**	**6.6**	**7.7**

Note: Numbers above exclude real escalation

3.5 Resilience

Our resilience investments are targeted at improving our network's ability to withstand and recover from the effects of a natural hazard or disaster. This includes both proactive measures to minimise outages due to major events or through reactive measures to minimise the time taken to recover when an outage does occur.

Throughout the development of our regulatory proposal, our customers and stakeholders repeatedly identified that improving network and community resilience was a critical role for distribution networks and a high priority for local communities.

We consider the AER's draft decision is not consistent with the extent of this stakeholder feedback. As outlined below, this is reflected in the AER's approach to applying its value of network resilience (VNR), which implies that customers value the imposition of prolonged events less than a typical outage.

Notwithstanding this, we have accepted the AER's draft decision for our proposed resilience investments. In considering our proposed new Shoreham zone substation, the AER provided an alternative solution, being the purchase and deployment of six 1.5MVA mobile generators. These generators are expected to be deployed across some of our longest and least resilient feeders in the lower Mornington Peninsula supply area.

TABLE 3.11 REVISED PROPOSAL: RESILIENCE INVESTMENTS ($M, 2026)

PROJECT	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Shoreham zone substation	25.0	8.4	8.4
IT situational awareness (capex and opex)	5.9	3.1	3.1
Mobile emergency response vehicle	0.3	0.3	0.3
Community support officers (opex)	1.6	-	-
TOTAL	**32.8**	**11.8**	**11.8**

Note: Numbers above exclude real escalation

3.5.1 The AER's value of network resilience does not reflect customer or industry feedback

In 2024, following direction from the Energy and Climate Change Ministerial Council (ECMC), the AER commenced a review to develop a value of network resilience (VNR). In the AER's draft decision on the VNR, the AER acknowledged that:

> *given the insights from network business customer engagement on resilience and prolonged outages, many customers place a higher value on avoiding prolonged outages compared to standard outages.*[34]

In the draft VNR decision, the AER also suggested that the VCR be used as the base for developing the VNR, with multiples of the VCR deployed over different time periods to reflect the additional value that customers attribute to avoiding prolonged power outages. This initial analysis, which identified that the VNR should be greater than the VCR, concurred with our own customer engagement, where our own customers demonstrated a willingness to pay for a range of network and community resilience investments. On a $/kWh basis, the values that our customers were willing to pay far exceeded the VCR.

In its final decision on the VNR, however, the AER set out an updated methodology for calculating the VNR that we consider materially undervalues resilience investments. Specifically, the AER adapted its draft methodology to only capture the 6–12 hour VCR value as the base for the VNR. Based on the AER's VCR methodology, the $/kWh associated with 6–12 hour outages are materially lower than the standard VCR. By using this subset of the VCR, the VNR was therefore materially decreased.

The AER's final decision document included no explanation related to this change in approach, which appears to contradict entirely the feedback the AER has received from customers and network providers.

To contextualise the magnitude of this change, the average VCR values based on 2024 updates across our network are provided in the table below. When applying the 6–12 hour VCR the value is substantially lower. Even with the multiples applied to the base value (ranging from 0.5 to 2 depending on the type of customer and duration of outage), the VNR remains below the full VCR in all circumstances. The AER has made clear that the VNR is not intended to be additive to the VCR,

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34 AER, *Value of Network Resilience 2024 – Draft decision*, July 2024, p. 44

therefore applying the VNR leads to a lower benefit than continuing to provide the standard VCR for the full extent of an outage.

TABLE 3.12 AVERAGE VCR VALUES ACROSS THE UNITED ENERGY NETWORK

VCR TYPE	$/kWh
Standard VCR	42.23
6–12 hour VCR	17.97

3.6 Connections

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

In its draft decision, the AER made several amendments to our connection forecasts. The AER split its amendments into those applied to business-as-usual (BAU) connections and those applied to large bespoke connections (which focused on data centres).

The AER encouraged us to respond to the issues raised in the draft decision. It welcomed further supporting information including actual expenditure for FY25, connection policy changes and updated economic and demographic statistics which may materially impact its forecasts.

The AER also stated its expectation that we re-forecast data centre connections in line with the guidance provided in its draft decision.

A summary of our revised net connection forecasts is shown in table 3.13, with these largely based on the AER's preferred methodologies.

TABLE 3.13 REVISED PROPOSAL: NET CONNECTION INVESTMENT ($M, 2026)

CATEGORY	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
BAU connections	82.1	74.5	89.7
Large bespoke connections	-	-	17.4
Other major connections	7.3	7.3	7.3
TOTAL	**89.4**	**81.8**	**114.4**

Note: Numbers above exclude real escalation

3.6.1 Business-as-usual connections

The draft decision accepted our forecast volumes for BAU connection types. These volume forecasts were prepared based on FY23 data representing base year volumes, and then applying growth assumptions based on an independent analysis prepared by Macromonitor.

The revised proposal maintains the same methodology, updating the base year to FY25 to incorporate the latest audited volume information and applying growth assumptions based on an updated Macromonitor analysis.[35]

The draft decision requested we provide greater transparency of the intermediary steps in developing our volume forecasts. We have therefore updated the model supporting our connection forecasts in the revised proposal to provide greater visibility of how the growth rates apply to base year volumes.

The AER, however, did not accept our unit rates. These were also based on audited FY23 RIN data (to avoid the impact of the COVID pandemic in previous years). The draft decision replaced these with averaged unit rates over the period FY21–FY24 on the basis averaged unit rates are more robust.

Whilst the inclusion of earlier years clearly distorts the forecast unit rates (particularly where clear, non-recurrent events have occurred within the averaging period), we have accepted the AER's methodology and calculated unit rates for our revised proposal using the last four years of audited RIN data.

Our proposed capital contribution rates were accepted in the draft decision and hence, remain unamended in the revised proposal.

3.6.2 Large bespoke connections (data centres)

The AER's draft decision provided no allowance for data centre connections, but acknowledged that demand for data centres will likely increase in the future. Before any allowance is provided, the AER must be satisfied that the forecasts accurately reflect demand for data centre connections in the forecast period.

Extensive guidance was provided in the draft decision on what would be acceptable evidence to support a data centre connection allowance. This included a structured forecast based primarily on committed works or project enquiries and a requirement to demonstrate the aggregate data centre forecast aligns with forecasts prepared by AEMO.

Given the above, we have applied both a bottom-up and top-down approach for our revised proposal, based on our existing pipeline of data centre connection applications. We provide a summary of this approach below, with full detail set out in our attached business case addendum.[36]

We engaged an expert, independent consultancy, Mandala Partners, to assist in this task. Mandala are economic specialists in data centres and have worked with some of the largest data centres in Australia, including a number already operational or under construction across our networks.

As set out in their review (attached with our revised proposal), Mandala reduced the overall capacity being requested, relative to our existing enquiry pipeline, by 44 per cent.[37]

Bottom-up assessment

Today, our network catchments (CitiPower, Powercor and United Energy) contain 85 per cent of all operational data centres in Victoria. This includes 83 per cent of Melbourne's operational data centres.

For additional context, less than 1.5 per cent of Victoria's data centres are connected to the transmission network.

[35] UE RRP ATT 3.6.02 – Macromonitor – Forecasts by Region – Dec2025 – Public
[36] UE RRP BUS 3.6.01 – Data centre connections – Dec2025 – Public
[37] UE RRP ATT 3.6.03 – Mandala – Forecasting CPU's data centre capacity requests – Dec2025 – Public

Committed and in-flight projects

Where a contract has been executed with the customer, or a firm offer made, the AER's guidance is for these values to be included in the underlying expenditure forecast. We do not have any data centres in this category.

Connection enquiry and offer stage

If no agreement is in place with a connection proponent, a weighted probability assessment for each project is required by the AER.

Assessing the probability of a project proceeding requires an expert knowledge of data centre economics. This includes site identification and feasibility, planning permits building permits, access to water and access to finance.

As noted above, we engaged Mandala Partners (Mandala) to provide this probability analysis. This included the development of a data centre likelihood framework and its application to each data centre connection application. Further detail on this framework is summarised in table 3.14 below.

Mandala also conducted a sensitivity analysis of their probability assessment using a Monte Carlo simulation. This approach conducted 100,000 scenarios, each with different project success probabilities sampled around their estimates, to model the range of possible outcomes.

TABLE 3.14 MANDALA ASSESSMENT FRAMEWORK

METRIC	DESCRIPTION
Distribution connection	Data centres >100MW and that have not signed a SDEC face a 20 per cent chance they will connect directly to the transmission network
Proponent track record	Data centres with a strong track record will have a greater likelihood of proceeding regardless of progress due to experience and expertise in navigating regulatory, financial and other challenges
Connection request complexity	Data centre connection requests where existing networks have limited capacity to expand, or will have complex impacts on surrounding networks, are less likely to proceed
Site identification and feasibility	Ownership or options on land is a key and significant obstacle facing data centre proponents
Utility assessment	Paying for a utility assessment is a clear indication of a proponents' commitment to development
Planning and building permit	Securing a planning and building permit represents the progression through a common hurdle for data centres
Grid connection and firm offer	Data centres that have reached to the point of making a firm offer are very likely to proceed
In construction	Data centres are very likely, though not guaranteed to proceed once they reach the construction phase

While Mandala provided relevant capacity forecasts, project expenditure estimates were prepared by the business. These were prepared internally given no other party has the relevant expertise or network understanding to perform the task.

Consistent with the AER's preferred approach:

- wherever a contract for works existed, or a firm offer had been issued, expenditure was forecast based on these values (as noted above, we did not have any projects in this category)
- where a project is not subject to a contract or firm offer, the project cost was estimated considering projects with similar scopes.

<u>Future projects</u>

Our current connection enquiry pipeline only extends to 2029. It is not expected that applications will cease at this time; rather, we just do not yet have visibility of what these projects may be.

To provide a forecast, therefore, we requested Mandala provide a projection of capacity forecasts for the remainder of the forecast period. Mandala applied a regression-based analysis to estimate data centre demand over the remaining years, with further detail available in Mandala's report.

<u>Customer contributions</u>

In its draft decision, the AER accepted our assumed contribution rate of 85 per cent. Our revised proposal has maintained this assumption.

Top-down assessment

The draft decision required our data centre connection capacity forecast to be reconciled with that of AEMO. For the following reasons, however, aligning with AEMO's forecasts needs to be considered with caution:

- AEMO's data centre capacity forecasts are largely informed by distributors. This is because only a very small proportion of data centres are connected to the transmission network (e.g. just 1.5 per cent today) and AEMO has limited visibility of connections to the distribution network
- the information AEMO possesses from distributors is not current. AEMO's latest Inputs Assumptions and Scenarios Report (IASR) was published in August 2025, but based on a report prepared by Oxford Economics that uses data collected from us in November 2024.[38] Since this time, in aggregate our networks have received almost 1,700MW of additional data centre connection applications
- AEMO forecasts actual demand rather than installed capacity. We are obligated to provide the capacity requested by proponents. Capacity requests are usually higher than the capacity utilised by the data centre proponent, at least in the early years of their connection. AEMO does not forecast installed capacity; rather, its forecasts are intended to capture utilised capacity to assist it manage the wholesale market and the security of the transmission network
- AEMO's forecasts are provided at a state level only. Translating them therefore requires assumptions as to how data centre demand is distributed.

Notwithstanding the above, Mandala conducted a reconciliation with AEMO forecasts for the purposes of the revised proposal. The reconciliation requires many assumptions, which are all explicitly identified, however the temporal differences and different forecast needs make a fulsome reconciliation impossible.

[38] Oxford Economics, *Data Centre Energy Demand*, July 2025

3.6.3 Other major connections

The AER's draft decision accepted our forecast of grid connected batteries. Our revised proposal forecast is therefore consistent with the AER's draft decision.

3.6.4 Connection policy

The draft decision did not accept our proposed connection policy, with amendments proposed by the AER tracked into an amended version of our connection policy.[39] The amendments have been reviewed and accepted in full in our revised proposal.

One unresolved matter, however, related to the proposal to levy large connections the tax liability associated with their contribution. This tax liability is currently collected across all network users.

Further details of our consideration of this issue are included in section 2.4. In summary we have amended the AER's version of our connection policy to include a new provision for the collection of the tax liability associated with customer contributions from all large customers connecting to the high voltage or sub-transmission network.

3.7 Information communications and technology

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

Our original proposal forecast a step up in capital expenditure reflecting the following:

- an uplift in our recurrent investment program linked to infrastructure and system refreshes
- an uplift in our non-recurrent ICT investment program, which includes upgrading our cyber-security position and the replacement of two of our core ICT systems that are critical to the energy transition
- new compliance requirements related to AEMO's NEM reform program.

In its draft decision, the AER supported the prudency of our proposed ICT investments, with the exception of our IT facilities program. The AER, however, considered that our proposed expenditure for some projects was above efficient costs. As such the AER proposed total capital expenditure that was 15 per cent lower than our original forecast.

We have accepted the AER's draft decision in relation to capital expenditure for our ICT program.

The AER also rejected our proposed operating expenditure step change relating to the replacement of our Enterprise Resource Management (ERP) and billing systems. We discuss our reasoning for maintaining this operating expenditure step change further in section 4.2.1 of our revised proposal.

A summary of our revised proposal for ICT investments is set out in table 3.15.

[39] AER, *Draft decision: United Energy electricity distribution determination, Attachment 16, Appendix A Connection Policy*, September 2025

TABLE 3.15 REVISED PROPOSAL: ICT INVESTMENT ($M, 2026)

CATEGORY	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Recurrent	169.8	159.7	159.7
Non-recurrent	63.2	64.5	64.5
AEMO NEM reforms	40.8	23.9	22.6
TOTAL	**273.9**	**248.1**	**246.8**

Note: We recently submitted a cost pass through application to meet AEMO compliance obligations for flexible trading arrangements (FTA). We have not included the updated expenditure for FTA in our expenditure build up, given this cost pass through application has already been submitted. Should the AER determine that a cost pass through is not the correct mechanism to recover these costs, then expenditure related to FTA will need to be re-included in our proposed expenditure build up. Numbers above exclude real escalation.

3.8 Property, fleet and other non-network

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

In its draft decision, the AER accepted our proposed capital expenditure related to these categories. As shown below, our revised proposal is consistent with the draft decision.

TABLE 3.16 REVISED PROPOSAL: PROPERTY, FLEET & OTHER NON-NETWORK ($M, 2026)

CATEGORY	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Property	16.9	16.9	16.9
Fleet	62.4	62.4	62.4
Tools and equipment	1.0	1.0	1.0
TOTAL	**80.3**	**80.3**	**80.3**

Note: Numbers above exclude real escalation

3.9 Innovation

Our innovation has historically been targeted at internal productivity improvements or limited to specific areas such as demand management, given the incentives provided by the regulatory framework. However, in an environment of rapid change, expanding innovation to areas not traditionally invested in by distribution networks has the potential to reduce the long-term costs of the energy transition.

In our regulatory proposal, we proposed an innovation allowance focused on delivering research, pilots and trials. This included specific projects across the first two years of the regulatory period, with expenditure extrapolated across the remainder of the period at a reduced rate. This approach reflects the typical innovation cycle we face in practice.

The AER acknowledged, in its draft decision, the inherent uncertainty with forecasting innovation expenditure. However, the AER did not allow for uncertainty with regards to innovation projects; the draft decision provided no expenditure for projects beyond the initial two years of the 2026–31 regulatory period.

In response to the AER's feedback, we have undertaken additional efforts to provide details for a full suite of innovation projects for the entire 2026–31 regulatory period. While we consider this need remains at odds with the dynamic nature of innovation, we recognise further detail is required to allay the AER's concerns.

Overall, our revised innovation allowance is lower than our original proposal. The key changes in our revised proposal include the following:

- additional detail specific to the AER's assessment criteria for each project
- we have provided cost build-ups of projects across the full 2026–31 regulatory period, with new projects added and reviewed by the CAP
- the complete governance framework for our innovation allowance has been developed in collaboration with the CAP.

Further detail on our revised innovation proposal is set out in our attached innovation addendum, with a summary of proposed expenditure shown in table 3.17.[40] Consistent with our original proposal, our innovation proposal includes a combination of operating and capital expenditure.

TABLE 3.17 REVISED PROPOSAL: INNOVATION INVESTMENT ($M, 2026)

CATEGORY	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Capital expenditure	9.1	1.9	5.7
Operating expenditure	6.0	1.7	3.9
TOTAL	**15.0**	**3.7**	**9.6**

Note: Numbers above exclude real escalation

[40] UE RRP BUS 3.9.01 – Innovation allowance – Dec2025 – Public

4. Operating expenditure

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

As discussed further in this section, we have accepted large components of the AER's draft decision. This includes revisions in our operating expenditure model for updated FY25 data.

Our revised proposal, therefore, is targeted to a limited set of issues, including the AER's base adjustment for insurance and the treatment of our proposed step changes related to vegetation management, CER integration and cloud services.

A summary of our revised proposal forecast is shown in table 4.1.

TABLE 4.1 REVISED PROPOSAL: OPERATING EXPENDITURE SUMMARY ($M, 2026)

CATEGORY	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Base	779.2	775.2	789.2
Base year: insurance efficiency gain	-	20.7	-
Base year: increment to FY26	14.8	14.8	14.8
Base year: remove category specific	-12.9	-9.1	-9.1
Trend	20.4	10.5	18.1
Step changes: excl. insurance	166.1	46.1	115.4
Step changes: insurance	-	-22.6	-
Category specific (incl. debt raising costs)	23.2	26.2	26.6
TOTAL	**990.8**	**861.8**	**955.0**

4.1 Base year

In its draft decision, the AER accepted our proposed base year of FY25. We have since updated our base year modelling to incorporate actual FY25 values from our annual RIOs and applied the latest inflation figures.

We do not accept, however, the AER's base year non-recurrent efficiency gain adjustment relating to the insurance premium step change in the current regulatory period.

4.1.1 Base adjustment for insurance

In its draft decision, the AER applied the following three adjustments relating to our insurance premiums:

- a non-recurrent efficiency gain is included in base year operating expenditure, which increases our operating expenditure allowance in each year of the 2026–31 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, calculated as the difference between the premium allowance and actual premium in the final year, that decreases our operating expenditure allowance in each year of the 2026–31 regulatory period
- an adjustment to the calculation of the efficiency benefit sharing scheme (EBSS) carryover amounts arising from the application of the EBSS during the 2021–26 regulatory period to reflect the non-recurrent efficiency gain adjustment made to base operating expenditure.

We understand that these adjustments are intended by the AER to:

- ensure the AER's alternative estimate of total forecast operating expenditure satisfies the operating expenditure criteria set out in clause 6.5.6(c) of the Rules, by setting a forecast operating expenditure allowance equal to that required by a prudent operator
- remove the expected over forecasting of insurance premiums in the final year, so ensuring this over forecasting does not impact forecast operating expenditure for the 2026–31 regulatory period
- return all the 2021–26 regulatory period insurance premium underspends to customers through EBSS decrements six years later, in a manner consistent with all insurance underspends in 2021–26 being non-recurrent efficiency gains, while ensuring we retain our share of insurance premiums underspends in the form of the time value of holding the underspends for six years.

Our revised proposal does not accept the AER's draft decision in respect of insurance premiums. We consider that a standard base-step-trend approach should be used without the AER's proposed adjustments outlined above.

Specifically, the approach set out in the AER's draft decision is unlawful. We refer to a legal opinion provided by the Honourable John Middleton AM KC (attached with our revised proposal), in which he observes:[41]

- the AER's draft decision, which treats our underspend on insurance premiums as a non-recurrent efficiency gain, is not authorised by any statutory provision. In other words, the AER does not have the power to make the adjustments set out in its draft decision
- the AER's draft decision, which effects a clawback of our underspend on insurance premiums in the 2021–26 regulatory period, is contrary to the scheme of chapter six of the Rules
- the AER's draft decision contravenes section 16(1) of the National Electricity Law (NEL). The AER is not exercising its economic regulatory function or power in a manner that will or is likely to contribute to the achievement of the National Electricity Objective
- the reasoning of, and rationale for, the AER's draft decisions are unreasonable.

The approach set out in the AER's draft decision also creates perverse incentives for distributors and undermines the objectives and intent of the economic regulatory regime. To support this, we refer to an independent report from HoustonKemp, in which they set out their expert opinion that:[42]

- the approach taken in the draft decision undermines the objectives and intent of the total operating expenditure regime, the EBSS and the economic regulatory regime in the NEL and Rules

[41] UE RRP ATT 4.02 – Hon. Judge John Middleton AM KC – legal opinion – Dec2025 – Public
[42] UE RRP ATT 4.04 – HoustonKemp – report on insurance premiums – Dec2025 – Public

- aside from the merits and legality of the AER's approach, the revenue outcomes that occur under the AER's draft decision are not consistent with its stated intention in the draft decision.

Our detailed response to the AER's draft decision on insurance premiums is set out in our insurance addendum, which is provided alongside the above legal opinion from the Honourable John Middleton AM KC, the independent expert report from HoustonKemp and a report from our insurance broker, Marsh.[43]

4.2 Trend

Our revised proposal largely accepts the trend component of the AER's draft decision, but consistent with standard AER practice, we have updated relevant values to reflect more current data.

Specifically, our revised proposal applies the rate of change, comprising the following:

- **price growth**: our revised proposal has been updated to include the more recent labour price growth forecast from the AER's consultant Deloitte Access Economics and updated wage price index (WPI) from our consultant BIS Oxford Economics.[44] We have also removed the superannuation increase in FY27 in the labour price growth rates, consistent with AER feedback
- **output growth**: we have updated the forecast growth rates for ratcheted maximum demand as per our most recent demand forecasts (incorporating recent AEMO data) and discuss this briefly below. Customer numbers and circuit length are unchanged, as per the AER's draft decision
- **productivity growth**: the AER accepted our proposed productivity adjustment, and our revised proposed is consistent with the AER's draft decision.

4.2.1 Ratched maximum demand growth

In its draft decision, the AER expressed concern with our system-level maximum demand forecasts as non-data centre block loads may be double-counting loads otherwise captured in the trend, and other components of our modelling appeared inconsistent with our RINs. The AER's draft decision also noted the following conclusions from its technical consultant, Baringa:

- our approach of only including data centres that are committed and contracted in the maximum demand forecasts is reasonable
- data centres that are yet to be contracted should be excluded from the forecasts
- it was unclear how block loads at the spatial level compared to the system level.

Consistent with the above, our revised proposal uses system-level maximum demand forecasts for ratcheted maximum demand which:

- updates the demand forecast that was used for the reset RIN
- excludes data centres that are yet to be contracted
- sums the forecast maximum demand at each connection point, where the maximum demand at each transmission connection point is the coincident demand of all network assets downstream of that transmission connection point.

Further, regarding the AER's concern at potential overlaps between trend growth and non-data centre block loads, the composition of system-level maximum demand growth from FY26 to FY31 is shown below in table 4.2. By definition, the maximum potential overlap can only be equal to the lower of the

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43 UE RRP ATT 4.01 – Insurance premiums – Dec2025 – Public; and UE RRP ATT 4.03 – Marsh – report on insurance premiums – Dec2025 – Public

44 UE RRP ATT 4.06 – Oxford Economics – Labour cost escalation forecasts to 2030-31 – Dec2025 – Public

trend growth component and the non-data centre block load growth component. That is, as shown below, the potential overlap between trend growth (1.9 per cent) and non-data centre block load growth (2.1 per cent) can only be up to 2.1 per cent.

TABLE 4.2 COMPOSITION OF SYSTEM-LEVEL MAXIMUM DEMAND GROWTH (MW)

COMPONENT	FY26	FY31	GROWTH (%)
Trend growth	2,076	2,115	1.9%
Block load growth: non-data centre	47	92	2.1%
Block load growth: contracted data centres	-	-	-
TOTAL GROWTH	**2,123**	**2,207**	**4.0%**

Note: Due to our forecast system-level maximum demand in FY26 being lower than United Energy's ratcheted demand of 2,143MW, our proposed ratcheted maximum demand growth is 3.1 per cent.

In addition, we have likely under-estimated demand growth given we have not sought to include uncontracted data centres as block loads within our demand forecast (section 3.6 explains how we have forecast new data centre connections). To illustrate this, the potential impact of uncontracted data centre loads on system-level maximum demand is illustrated in table 4.3, based on alternative capacity take-up assumptions. It is evident that even with a low take-up of uncontracted data centre loads, adding these to our system-level maximum demand forecasts supports our view that our forecast output growth is conservative.

TABLE 4.3 POTENTIAL CONTRIBUTION OF NEW DATA CENTRES TO DEMAND GROWTH

UNCONTRACTED DATA CENTRE UPTAKE RATE (%)	DEMAND (MW)	PROPORTION OF FY26 SYSTEM-LEVEL MAXIMUM DEMAND (%)
20%	77	4%
30%	116	5%
40%	154	7%
50%	193	9%
60%	231	11%

4.3 Step changes

Our revised proposal included a limited set of step changes driven primarily by external factors and changes in our regulatory obligations or environment.

As shown in table 4.4, we have accepted the AER's alternative estimates for ICT modernisation and network and community resilience. While we do not agree with the AER's reasons, we have accepted its decision nonetheless.

We do not accept, however, the AER's draft decision regarding vegetation management, CER integration or cloud services. We discuss these below, including the material downward revision to our vegetation management step change, which follows strong performance in the most recent two-years driven by the maturation of our contract model and highly favourable operating conditions.

As outlined previously, we also do not accept the AER's draft decision to apply a negative insurance step change.

TABLE 4.4 REVISED PROPOSAL: OPERATING EXPENDITURE STEP CHANGES ($M, 2026)

CATEGORY	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Vegetation management	72.3	-	44.2
CER integration	18.9	13.5	18.8
Cloud services	24.3	3.9	3.9
ICT modernisation	31.6	28.9	48.7
Network and community resilience	4.4	-	-
Fleet electrification	-0.2	-0.2	-0.2
Insurance	-	-22.6	-
TOTAL	**151.4**	**23.5**	**115.4**

Note: Our regulatory proposal included a step change for our customer assistance package. The AER instead assessed this as a category specific forecast; we have applied this classification in our revised proposal and hence, have excluded these costs in this table.

4.3.1 Vegetation management

Since 2021, we have been on a journey towards reliance on light detection and ranging (LiDAR) technology to identify vegetation spans across our network that are or will become non-compliant without further intervention. The use of LIDAR has increased the standard of compliance possible under the Electricity Safety (Electric Line Clearance) Regulations (the Code), which governs how we inspect and manage vegetation.

In its draft decision, the AER recognised that the adoption of new technology had increased the standard of compliance which can be achieved, and that we need to be funded to meet all our compliance obligations. However, the AER questioned whether our estimates for vegetation management activities were prudent and efficient.

Its draft decision did not include any step change allowance.

We have carefully considered the AER's draft decision and made significant updates to our forecasts. These updates include incorporating additional data (now available) from CY24 and CY25, which reflect the achievement of material efficiencies through the maturation our program over the past two years. We have also accepted areas where the AER considered the 'trend' component of its forecast methodology would provide sufficient funding.

As a result, our revised step change has materially reduced from our original proposal.

We also note that our recent years of cutting volumes, as identified by LiDAR, reflect comparatively benign weather conditions, with abnormally low rainfall (e.g. rainfall in CY24 was in the lowest 10 per cent of all years since 1900). To the extent that actual weather in the 2026–31 regulatory period varies from recent weather patterns, we will bear the risk of any outworkings on our actual vegetation management activities and associated costs incurred.

Further detail on our revised forecast vegetation management operating expenditure step change for the 2026–31 regulatory period is set out in our attached addendum and revised cost model.[45]

4.3.2 Cloud services

Our cloud services step change relates to the SaaS implementation costs required for our ERP and billing system replacement and cyber security. In its draft decision, the AER approved the component of this step change associated with cyber security, but rejected the component associated with our ERP and billing system replacement.

In April 2021, the International Financial Reporting Standards Foundation (IFRSF) determined that SaaS implementation costs should more accurately be expensed as opposed to being capitalised.[46] The AER recognised this in its draft decision, but considered a step change was not required due to the trend component of its base-step-trend approach.

We set out below our responses to each of the specific points raised by the AER in its draft decision.

The trend (output growth) component of the operating expenditure framework will not account for the SaaS implementation costs

The AER considered that the trend component of operating expenditure framework should account for the incremental operating expenditure required.

We do not agree with the AER that our proposed SaaS implementation costs will be accounted for in the trend component of the operating expenditure framework. The AER has previously considered operating step changes associated with SaaS implementation costs (see decisions for Electranet, Transgrid and Ausgrid). We note that in these decisions, the AER approved SaaS implementation step changes and did not suggest that the trend component of the operating expenditure framework would account for these costs as it has claimed in our draft decision.

For example, the trend component is expected to capture the growth of operating expenditure incurred in our base year (FY25). However, we have not incurred material SaaS implementation costs in our base year, and as such it is unclear why the AER has considered that Saas implementation expenditure will be accounted for. We consider regulatory consistency in decisions across networks is important and would encourage the AER to ensure that’s its final decision matches previous decisions in relation to SaaS implementation step changes.

Existing resources assigned to the current platform will not be sufficient to manage the replacements

The AER suggested that our existing resources would be able to manage the ERP and billing system replacements. We again disagree with the AER and refer the AER back to our information request where we set out a labour analysis of hours required to implement the portfolio of IT works. In that response we noted:

> *to meet the additional labour effort required to deliver our ERP and billing system replacement project, we will utilise external and contract labour to flex up our*

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45 UE RRP BUS 4.01 – Vegetation management – Dec2025 – Public; and UE RRP MOD 4.01 – Vegetation management – Dec2025 – Confidential

46 IFRS, *AP12A: Finalization of agenda decision*, April 2021, pp. 5–6.

> *workforce, as we have previously for the successfully implemented five minute settlement project.*
>
> *Given the size and duration of the program, we will establish a new IT business unit to focus solely on the ERP and billing system upgrade. The delivery resources will largely be fixed term contractors and vendor system integrators who have strong experience in delivering S/4HANA upgrades.*
>
> *The existing IT teams would remain separate, focusing on the remainder of IT projects, lifecycle upgrades and operations.*[47]

The labour analysis highlighted the uplift in labour hours that will be required to deliver the ERP and billing system replacement (~563,000 labour hours across the 2026-31 period). We also explained that the majority of this workforce will be specialist external contract labour, as our existing resources have neither the capacity nor specialist knowledge to deliver the ERP and billing system replacements. Our existing workforce will remain responsible for operating the existing platforms.

We have prudently deferred the replacement of our ERP system

The AER noted its concern with the prudency of providing an allowance for a program which has previously received specific forecast expenditure. However, the AER acknowledged the basis of our deferral, and as part of our response to an AER information request, we provided an explanation regarding the substitution of these works with other unforeseen expenditure that was not in our regulatory allowance (e.g. upgrades to our advanced management distribution system).[48]

As set out in our regulatory proposal business case, SAP, the vendor for our ERP system, had provided information to us that they would cease to support our instance of SAP during the 2021–26 period. As such, we proposed to replace our system during the 2021–26 period.

During this period though, SAP extended its support for our current instance of our ERP system into the 2026–31 regulatory period. This allowed us to continue to operate our system with vendor support and deferred capital costs into the future.

Given the original ERP system replacement project was predominately made up of capital expenditure, it is unclear why the AER would have concern with providing a step change for a project that has been prudently deferred.

The replacement of our systems is not an efficiency-based project

The AER considered the converging of CitiPower, Powercor and United Energy systems will produce efficiencies that will be captured under the EBSS, and that AER should not provide step changes for efficiency improving initiatives.

We disagree that our proposed investment is an efficiency-based project. As stated in our business case, the identified need for this project is the cessation of vendor support for our current ERP and billing systems (noting these systems are amongst the oldest of their type still in operation). Without vendor support for these aged systems, the potential for large scale outages are exponentially increased.

In our business case we set out a number of potential upgrade solutions, including a full convergence option (i.e. option four) that would have seen CitiPower, Powercor and United Energy share a single instance of SAP and converge all of their business processes. However, we have not proposed the full convergence option, and would consider that even the efficiencies associated with this option would in

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[47] United Energy, Response to AER information request IR013, 28 April 2025, pp. 4–5
[48] See, for example: United Energy, ICT presentation to EMCa, 26 March 2025

no way equate to the full SaaS implementation costs associated with this project. Rather, we note that the full convergence option was significantly more expensive than our preferred option, with the additional cost outweighing any efficiency gains. Under our chosen option United Energy retains separate business processes that does not create significant operating expenditure efficiencies, with benefits relating predominately to risk reductions and avoided future capital expenditure. These outcomes were reflected in our modelling.

We have accounted for billing system efficiencies in our revised step change

The AER has identified billing system efficiencies in the final two years of the 2026–31 period that have not been accounted for in our step change.

We acknowledge the potential for small efficiency gains toward the end of the 2026–31 regulatory period following the completion of our billing system replacement, which is forecast to be completed in FY30. In line with recommendations from EMCa, we have not re-proposed the recurrent portion of the step change relating to our ERP and billing system to offset any efficiencies from our billing system replacement. As noted by EMCa, the efficiencies in the 2026–31 regulatory period associated with our billing system upgrade are likely proportional to our proposed recurrent ERP and billing system replacement step change. The recurrent component of this step change was included in our ICT modernisation step change, and as such we have accepted the AER's draft decision for that step change (which proposed to exclude the component related to our ERP and billing system replacement).

4.4 Category specific forecasts

The AER's draft decision included category specific forecasts in its draft decision, whereby incurred costs will not be automatically rolled into base operating expenditure in future periods. This included the operating expenditure component of our innovation allowance, GSL payments and debt raising costs.

The AER also reclassified our proposed customer assistance package as a category specific forecast.

As set out in table 4.5, we have accepted the AER's draft decision for each of the category specific forecasts, except our innovation allowance. The AER encouraged us to provide further information on our innovation allowance, with this set out in our revised innovation addendum and summarised above in section 3.9.[49]

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[49] UE RRP BUS 3.9.01 – Innovation allowance – Dec2025 – Public

TABLE 4.5 REVISED PROPOSAL: CATEGORY SPECIFIC FORECASTS ($M, 2026)

CATEGORY	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Innovation allowance	6.0	1.7	3.9
GSL payments	9.2	8.1	6.1
Customer assistance package	14.7	8.7	8.7
Debt raising costs	8.0	7.7	7.9
TOTAL	**37.9**	**26.2**	**26.6**

Note: Our regulatory proposal included a step change for our customer assistance package. The AER instead assessed this as a category specific forecast; we have applied this classification in our revised proposal and hence, have included these costs in this table.

4.4.1 Guaranteed service level (GSL) payments

Our regulatory proposal forecast GSL payments using volumes based on the average of the last three financial years (FY22–FY24) and a placeholder increase of 15 per cent on the GSL payment rate. The AER have removed the increase in its draft decision and will update the final decision to reflect any amendments the ESC makes to the scheme.

For our revised proposal, we have removed the 15 per cent increase to GSL payments as per the AER's draft decision and updated actual outage data to incorporate FY25.

4.4.2 Customer assistance package

Our regulatory proposal included a step change for our customer assistance package, which as noted above, was reclassified as a category specific forecast in the AER's draft decision. We have accepted the AER's draft decision.

We have, however, included our Community Energy Fund initiative as an innovation project (included in our revised innovation allowance). This is to support meeting the needs of customers in vulnerable circumstances, within our innovation framework.

TABLE 4.2 REVISED PROPOSAL: CUSTOMER ASSISTANCE PACKAGE ($M, 2026)

CATEGORY	REGULATORY PROPOSAL	DRAFT DECISION	REVISED PROPOSAL
Energy care	1.4	0.4	0.4
Community energy fund	3.5	-	-
Vulnerable customer assistance package	4.3	4.3	4.3
Energy advisory service	1.5	-	-
First Peoples program	4.0	4.0	4.0
TOTAL	**14.7**	**8.7**	**8.7**

4.4.3 Debt raising costs

Our forecast debt raising costs are aligned with the AER's preferred approach to forecast debt raising costs, using a benchmarking approach. For our revised proposal, we have applied the latest inflation and debt raising rates as reflected in the AER's draft decision, to updated asset values.

5. Incentives

For the 2026–31 regulatory period, our regulatory proposal set out our plan to continue the same incentives schemes as currently in place, with the addition of a new innovation allowance.

In its draft decision, the AER accepted our proposed approach for several of these incentive schemes. However, it did not accept our proposed customer service incentive scheme (CSIS) and consequently the service target performance incentive scheme (STPIS) incentives, or our proposed innovation scheme (for which it provided a direct expenditure allowance instead).

The AER also provided the option for us to opt-out of its more recent changes to the capital expenditure sharing scheme (CESS) regarding connections.

We have considered the AER's feedback and discuss this in further detail below. A summary of our revised proposal is set out in table 5.1.

TABLE 5.1 REVISED PROPOSAL: INCENTIVE SCHEMES

INCENTIVE SCHEME	REVISED PROPOSAL
Capital expenditure sharing scheme (CESS)	Accept scheme, but opt-out of the AER's recent changes regarding connections
Efficiency benefit sharing scheme (EBSS)	Accept scheme, but not the AER's adjustment for insurance
Service target performance incentive scheme (STPIS)	Do not accept the AER's draft decision to include a timeliness of connection parameter
Customer service incentive scheme (CSIS)	Accept the AER's draft decision to reject our CSIS
Demand management incentive scheme (DMIS)	Accept
Demand management innovation allowance mechanism (DMIAM)	Accept
F-factor scheme	Accept
Innovation allowance	Accept AER's direct expenditure allowance approach with revised forecasts

5.1.1 Efficiency benefit sharing scheme

We accept the AER's proposed EBSS for the 2026–31 regulatory period.

The draft decision, however, has applied a base year non-recurrent adjustment for insurance. For the avoidance doubt, as discussed in detail in section 4.1.1 and corresponding attachments, we do not accept the AER's draft decision in respect of insurance premiums.

5.1.2 Capital efficiency sharing scheme

In its draft decision, the AER stated that it will apply the CESS as set out in the capital expenditure incentives guidelines (version four) for the 2026–31 regulatory period.

However, the AER permits Victorian distributors to opt out of the connections volumetric adjustment and/or large bespoke connections adjustment in version four of the AER's capital expenditure incentive guideline.[50] The draft decision offers this choice to opt-out because the amended guideline was published after the submission of our regulatory proposal.

For the 2026–31 regulatory period, we elect to opt out of the connections volumetric adjustment and the bespoke connections adjustment set out in sections 2.6.1 and 2.6.2 of the capital expenditure incentives guidelines (version four).

5.1.3 Customer service incentive scheme

The AER's draft decision abolished the CSIS and instead proposed a reversion to a STPIS inclusive of a customer service component.

In its public forum in October 2025, the AER's approach to the CSIS was criticised by customers and their representatives. The abolishment of the CSIS was considered indicative of growing stakeholder frustration at the practical diminishment of the voice of the customer in the AER's decision making.

We have reflected on the AER's feedback and accept that our proposed CSIS could have benefitted from further consultation with end use customers and from being more explicit in our engagement that what is at issue is an incentive framework (as opposed to a base level of customer service).

We have since considered a revised CSIS engagement plan, but alongside the CAP have determined to accept the AER's draft decision to reject our CSIS. Fundamentally, we did not consider that we could genuinely and robustly engage with customers within the available timeframes.

We do not, however, consider the AER's substitute approach to the STPIS will deliver benefits for customers. Our alternative STPIS proposal is outlined in section 5.1.4.

5.1.4 Service target performance incentive scheme

Consistent with its draft decision regarding our proposed CSIS, the AER specified an alternative STPIS scheme that included a customer service component alongside its typical reliability parameters.

Specifically, the AER's proposed customer service component included two parameters—a telephone answering service (faults only) and a timeliness of connections parameter. Together the customer service parameters comprise one per cent of the revenue at risk and individually 0.5 per cent.

For the reasons outlined below, we do not consider the AER's connections parameter is appropriate for inclusion in an incentive scheme:

- connection timeliness was not identified by our customers as a priority nor was it identified through our internal reviews as a 'pain point' for customers. This is not surprising given we achieve close to 100 per cent of connections before or at the time agreed with the customer
- as there is no scope to improve connections timeliness, we would propose to only maintain performance. Funding to maintain performance is included in our revealed operating expenditure and any incremental investment to achieve minor additional improvements does not represent value for customers

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[50] AER, *Draft decision: United Energy electricity distribution determination, Attachment 6 - Capital expenditure sharing scheme*, section 6.1.2, pp. 2–3

- there is an opportunity cost for customers of including a connection timeliness parameter in a STPIS for the 2026–31 regulatory period. That is, including parameters with very limited scope for improvement (or customer support) means we cannot include other parameters or strengthen incentives where genuine improvement would almost certainly provide more material benefits in line with our customers current and future expectations.

Our alternative STPIS proposal

Our alternative proposal is a STPIS based on the following:

- reliability parameters (SAIFI, SAIDI and MAIFIe) with 4.5 per cent revenue at risk
- telephone answering service (faults only) with 0.5 per cent revenue at risk.

Regarding the telephone answering service component, the current STPIS benchmark and maximum uplift combine to set an effective maximum target. This is shown in table 5.2 below.

TABLE 5.2 TELEPHONE ANSWERING SERVICE PERFORMANCE: 2021–26

MEASURE	PERFORMANCE
Benchmark	75.24
Maximum uplift	5.00
Maximum effective target	**80.24**

We have exceeded the above maximum target in every year of the current regulatory period (noting that rewards under the STPIS are capped under the allowable revenue at risk).

For the 2026–31 regulatory period, our baseline faults telephone answering service performance heading into the next regulatory period is proposed to be 80.24 per cent.

Further detail on the corresponding metrics, targets and weights, updated to include audited data for FY25, are set out in our attached STPIS model.[51]

[51] UE RRP MOD 5.01 – STPIS model – Dec2025 – Public

6. Alternative control and negotiated services

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

We accept the control mechanisms for alternative control services in the AER's draft decision.

6.1 Metering

In its draft decision, the AER substantively accepted our proposed metering program. We have accepted the AER's draft decision in our revised proposal, subject to minor updates for historical capital expenditure.

In updating the roll forward model (RFM) for actual capital expenditure, the AER could not reconcile the values reported in our regulatory proposal with the values reported in CA RIN table 4.2.2. We have revised the draft decision RFM with the corrected capital expenditure values.

We have also updated the FY25 operating and capital expenditure in the metering expenditure model with values reported in the FY25 RIO, in accordance with the draft decision.

We have made no other changes to the draft decision metering models, with table 6.1 below comparing the draft decision revenue with the revised proposal revenue.

TABLE 6.1 REVISED PROPOSAL: METERING TOTAL ARR ($M, NOMINAL)

DESCRIPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Draft decision: unsmoothed	44.5	51.4	59.9	69.5	81.9	307.2
Draft decision: smoothed	57.5	59.0	60.5	62.0	63.6	302.6
Draft decision: X-factors	16.2	-	-	-	-	
Revised proposal: unsmoothed	44.2	51.1	59.5	68.8	81.5	305.1
Revised proposal: smoothed	57.1	58.6	60.1	61.6	63.2	300.6
Revised proposal: X-factors	16.7	-	-	-	-	

We believe that increase in meter exit fees in line with RAB increase is appropriate.

We expect the AER in their final decision to update the models where appropriate for actual inflation, final decision forecast inflation, labour cost escalation and rate of return.

6.2 Public lighting

Our public lighting proposal was not accepted by the AER in its draft decision. The draft decision instead made several amendments to the inputs of our public lighting models and encouraged us to consult further on a submission from the Victorian Greenhouse Alliances.

Following consultation with councils, the Department of Transport and Planning, and the Victorian Greenhouse Alliances, we have made the following changes to the draft decision:

- included an accelerated replacement of non-LED lights over the next regulatory period, with incremental costs recovered from replacement lights over the remainder of the regulatory period. In our consultation we demonstrated that the additional charge for an accelerated replacement light would be roughly offset by the lower operation, maintenance, repair and replacement (OM&R) charge for the LED light and the energy savings from the replacement LED light
- included infill replacement of PE cells with smart PE cells on all major road lights by the end of the regulatory period
- included a separate charge for non-standard LED lamps (corncobs).

Our response to the draft decision is further set out in our public lighting addendum.[52]

6.3 Ancillary network services

In its draft decision, the AER did not accept several components of our proposed ancillary network services. These areas, and our corresponding response, are set out in table 6.2 below.

Our revised standardised ANS model is also attached with our revised proposal.[53]

TABLE 6.2 OUR RESPONSE TO DRAFT DECISION: ANCILLARY NETWORK SERVICES

AER DRAFT DECISION	REVISED PROPOSAL RESPONSE
The following labour rates were not accepted due to being above the AER's benchmark: • administrative officer (business hours) • field worker (business hours) • technical specialist (business hours) • engineering manager (business hours)	Accept draft decision
Did not accept reclassification of reserve feeder maintenance from a quoted service to a fee-based service due the rates being based on only one year of RIN data	We have used four-year average RIN rates to re-calculate reserve feeder maintenance costs to address the AER suggestion that an historical average would be more appropriate
Did not accept the effective tax rate to be applied to routine maintenance costs	Accept the draft decision tax rate
Substituted our proposed X-factors for years two to five with X-factors based on an update of labour price growth forecasts	We have provided updated labour price growth forecasts

In addition to the above, the AER did not accept the reclassification of our connection application service from a quoted service to a fee-based service due to further information being sought.

52 UE RRP ATT 6.01 – Public lighting – Dec2025 – Public
53 UE RRP MOD 6.08 – Standardised ANS model – Dec2025 – Public

6.3.1 Connection application service

We are automating the application process for embedded generation connections below 200 kVA and will therefore withdraw the following two connection application services:

- embedded generation <30kVA
- embedded generation 30kVA to 200kVA.

Further, in response to AER questions regarding cross subsidisation, we have added the following two connection application services:

- embedded generation >1MVA
- moving our equipment.

We have also made some minor wording changes to service labels, with these proposed revisions set out in table 6.3 below.

TABLE 6.3 CONNECTION APPLICATION SERVICE LABELS

REGULATORY PROPOSAL	REVISED PROPOSAL
< 63kVA or < 5 lots	< 63kVA or ≤ 5 lots
63kVA to 200kVA	63kVA to 200kVA or > 5 lots
200kVA to 500kVA	200kVA to 500kVA
> 500kVA	> 500kVA or high voltage
Embedded generation < 30kVA	Removed
Embedded generation 30kVA to 200kVA	Removed
Embedded generation > 200kVA	Embedded generation 200kVA–1MVA
	Embedded generation > 1MVA
Public lighting	Public lighting
Abolishment	Abolishment
	Moving our equipment

Regarding the additional information being sought by the AER, this is provided in our response below:

- the nine services listed above have been categorised into the functional connection categories used internally by the business over at least the last decade for capturing and reporting connection information such as costs and customer contributions. These categories were selected by the business to group connection services into connection projects with similar characteristics such as the capacity and/or nature of the connection. Because the connection capacity and/or nature of each category is similar, the connection application service is also likely to be similar.

Since we do not capture the actual times for each connection application, we are unable to provide a distribution of actual times to perform the service for each of the nine categories

- in our attached connection application service model, we provide a bottom-up estimate of the tasks and average times to perform each task for each connection application service. The total time to perform the task for each of administrative and technical labour, reconciles to the times in our regulatory proposal[54]
- the AER encouraged us to provide NEM wide benchmarking analysis in relation to our proposed service prices that demonstrates the reasonableness of our proposal, however, we are not aware of other distributors providing a fixed fee connection application service
- as we are not proposing any change to current practice from a customer perspective, we did not undertake dedicated customer engagement for the re-classification of connection application services from ACS quoted to ACS fixed fee
- to streamline the connection process and reduce administrative cost, we have been applying the nine different pre-calculated fees. We proposed to reclassify these services in our regulatory proposal for the next regulatory period because the AER informed us that these pre-calculated charges would be more appropriately classified as ACS fixed fee services.

6.4 Negotiated services

Since the Framework and Approach paper was published in July 2024, the AER has identified a material change in circumstances relevant to developments in EV kerbside charging. The opportunity looks to utilise distributors kerbside poles as host infrastructure for commercially provided EV charging networks. The market for asset-rental access for EV hardware has warranted regulatory attention.

The response from the AER is to include a new negotiated distribution service for distribution asset rental. The AER specifies this service as ‘rental of distribution assets (e.g. poles) to third parties for the installation of EV chargers or associated hardware.’ This is to support third party access to distributors poles for the purpose of kerbside charging and support terms that are fair, reasonable, and cost reflective.

We have responded to AER’s feedback by updating our existing negotiating framework to provide clearer timelines to the applicant and updated the publication of successful applicants through this framework.

We have also introduced a new negotiated distribution service classification document which clarifies the service and alignment to the terms of a negotiated service.

In addition, we have identified two new negotiated services.

- the first is identified as an emerging market need for hot water flexibility as a service. There is emerging demand from retailers and aggregators who recognise the existing capability and opportunity of shifting hot water during periods of low wholesale prices. The service benefits the contracting party only, and any wider network benefits are incidental. Pricing should therefore be established through negotiation rather than by regulation
- the second service is related to the recent flexible trading arrangements rule change for type nine metering for public lighting which considers this type of metering as contestable. For this metering service, Councils or lighting owners may appoint us as a preferred provider for specific works. The service benefits only the contracting party and is not required by most customers, so costs should

54 UE RRP MOD 6.10 - Connection application service - Public

be recovered directly from the applicant rather than from all customers and considered a negotiated service.

Consistent with the above, we have attached a revised cost allocation method to accommodate negotiated services.[55]

[55] To assist the AER, we have submitted both clean and marked-up versions; UE RRP ATT 6.04 – Cost allocation method – Dec2025 – Public, and UE RRP ATT 6.05 – Cost allocation method (marked up) – Dec2025 – Public

7. Uncertainty framework

The regulatory framework recognises the inherent uncertainty in longer-term forecasts, and the potential implications on networks and customers where circumstances change within a regulatory period.

This section sets out our revised approach to managing this uncertainty, including our response to the AER's concerns regarding our proposed pass-through events and contingent projects.

7.1 Pass-through events

In its draft decision, the AER did not accept our nominated pass-through events for faults levels, electrification or AEMO participant fees. However, it did accept pass-through events related to insurer credit risk, insurance coverage, natural disaster, terrorism and retailer insolvency.

We accept the AER's draft decision on our nominated pass-throughs for electrification and AEMO participant fees, but not its rejection of our nominated fault level event.

7.1.1 Fault level event

As part of our network planning responsibility, we are required to ensure that short circuit levels at all zone substations, and the 66kV buses of the connection assets, remain within specified fault level limits. If network fault levels are exceeded, it can lead to catastrophic equipment failure, serious safety hazards like arc flashes and widespread power outages.

Consistent with these responsibilities, we specified a nominated fault level pass through event in our regulatory proposal.[56]

In its draft decision, the AER determined there was no need for a nominated fault level event pass-through, including due to the following:

- it is very unlikely a transmission project would have the effect of raising fault levels above their specified limits for our network, and that, if such a project were to arise, the cost impact of the increase could be mitigated through joint planning and would be modest and immaterial
- the availability of contractual solutions and the expected immateriality of costs to address fault levels.

The basis of the AER's above reasons was its interpretation of responses provided to it by AEMO, following specific questions from the AER.

In considering the AER's draft decision, we have spoken with AEMO. As set out in detail in our fault level event addendum, the AER's draft decision misrepresents AEMO's advice (which we consider supports the need for a nominated pass-through event). For example:

- transmission network and connection point fault levels are increasing over time as more generation is connected to the transmission network, and this is occurring in proximity to parts of the grid that do not have equipment capable of withstanding fault levels at the limits specified in the Rules or use of service agreements
- some transmission connection projects may increase fault levels above the distribution network's actual fault level limits, including in circumstances where those fault levels do not exceed the specified limits

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56 UE ATT 11.01 – Managing uncertainty, January 2025

- AEMO does not have visibility of the ratings of plant downstream of the connection point, and accordingly, AEMO is not in a position to identify that our network's actual fault level limits may be exceeded or to plan the transmission network in a way that mitigates the risk of this occurring.

Our revised proposal, therefore, re-proposes our original nominated fault-level pass through event. Further detail is provided in our fault level event attachment.[57]

7.2 Contingent projects

Our regulatory proposal did not include any contingent projects for the 2026–31 regulatory period. While this position is maintained in our revised proposal, in the event the AER does not accept our revised augmentation project to construct a new 66kV sub-transmission in the lower Mornington Peninsula (as detailed in section 3.3.3), then the alternative solution determined by the AER should include the sub-transmission line as a contingent project.

In these circumstances, we note the proposed sub-transmission line would meet the contingent project criteria set out in the Rules because:[58]

- the expenditure would not otherwise be provided for in the total of the forecast capital expenditure for the 2026–31 regulatory period
- the expenditure would reasonably reflect the capital expenditure criteria in clause 6.5.7(c) taking into account the capital expenditure factors in clause 6.5.7(e)
- the expenditure would exceed $30 million or 5 per cent of the value of our proposed annual revenue requirement for the first year of the relevant regulatory period, whichever is greater
- there are no relevant regulatory information instrument requirements, other than the requirement that we include our contingent projects in our reset regulatory information notice.

To the extent required, the proposed triggers are set out in table 7.1 below.

57 UE RRP ATT 7.01 – Fault level event – Dec2025 – Public
58 Clause 6.6A31(b)(2) of the Rules

TABLE 7.1 PROPOSED CONTINGENT PROJECT TRIGGER: LMP SUPPLY

DESCRIPTION	EXPENDITURE	TRIGGER
Lower Mornington Peninsula: new HGS-RBD 66kV line	$38 million	1. United Energy has completed a Regulatory Investment Test for Distribution (RIT-D) that determines the preferred credible option to address the voltage collapse constraint in the lower Mornington Peninsula is the construction of the proposed sub-transmission line, pursuant to the NER; and 2. United Energy commits to proceed with the preferred credible option from the RIT-D, subject to the AER amending United Energy 2026–31 regulatory determination pursuant to the NER. To provide objective verification of this trigger, a letter from the Chief Executive Officer of United Energy will be sent to the AER to confirm such commitment. For the purposes of this trigger: • 'Regulatory investment test for distribution' has the meaning given to that term in the NER.

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