NETWORK AND COMMUNITY RESILIENCE

PAL BUS 5.01 – PUBLIC

2026–31 REGULATORY PROPOSAL

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1. Overview

Resilience is the ability to withstand and recover from the effects of a natural hazard or disaster. It is about planning for, operating through and recovering from a major event. This can be through taking proactive measures to minimise outages due to major events or through a combination of proactive and reactive measures to minimise the time taken to recover when an outage does occur.

In contrast, reliability is about continuous supply of electricity. It generally focuses on average network performance and seeks to minimise outage time during normal conditions. It is typically measured by normalised outages per customer or normalised average outage duration per customer, excluding 'major events'.

The main distinction between resilience and reliability is that reliability excludes major outage events, while resilience focuses on these. When these major events occur, they are classified as major event days (MEDs) and represent days where the network experiences stresses beyond what is normally expected. This predominately occurs when the network is hit by extreme weather.

1.1 The impact from extreme weather events on our assets is likely to continue to grow

Extreme weather events that cause impacts at scale are now occurring in Victoria nearly every year.[1]

For our customers, these events include flooding (in late 2022, 2023 and early 2024), and multiple wind and lighting storm fronts (in 2021, 2022, mid and late 2023, and early 2024). In total, over 923,000 sustained outages due to extreme weather have occurred in the 2021-26 regulatory period.

More recently, in February 2024, more than one million Victorian customers were off supply after a major storm front crossed Victoria. This storm was significant enough to damage transmission infrastructure, as well as distribution assets. The direct cost of this event on Victoria (excluding compensation payments) was estimated at $770 million.[2]

Consistent with climate modelling, it is widely accepted that these sorts of extreme weather events will become more frequent and more severe in the future. Modelling undertaken by the Department of Environmental, Land, Water and Planning in 2019 estimates that by 2050 under a high emissions scenario, Victoria will experience:[3]

- an average annual temperature increase up to 2.4 degrees higher
- up to 60 per cent more very high fire danger days
- double the number of very hot days
- an increase in the number of extreme rainfall events.

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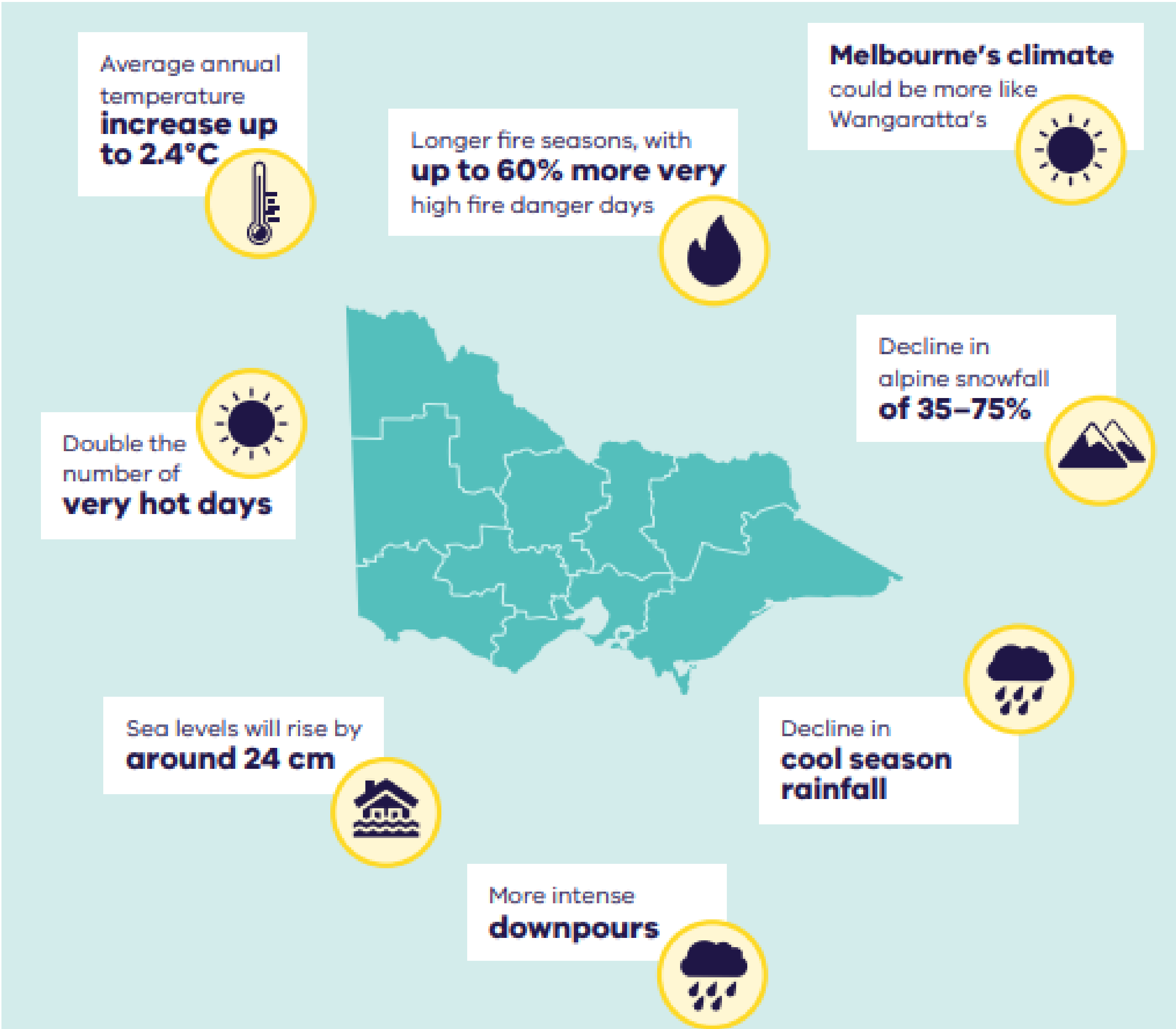
1 DEECA, Network Outage Review, Interim Report, 2024, p. 5
2 DEECA, Network Outage Review Interim Report, 2024, p. 17
3 DELWP, Climate Science for Victoria, 2019, p. 9

FIGURE 1 VICTORIAN CLIMATE IN 2050

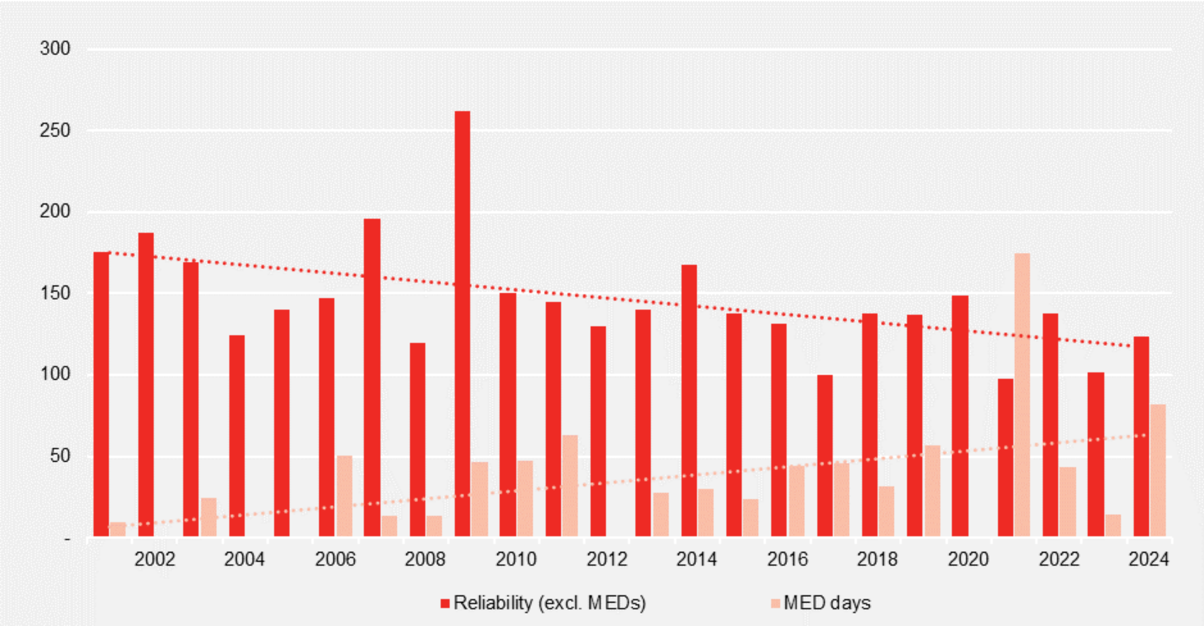


Source: Victoria's Climate Science Report 2019

The changing climate is already impacting our distribution network. As shown in figure 2, while general reliability has been improving over time, customer minutes off supply from MEDs have increased (including several significant spikes in recent years).

As the frequency and severity of these events has increased, so too has the impact to customer's supply. Without investment in our network to make it more resilient to extreme weather it is likely that customer service standards will continue to decline.

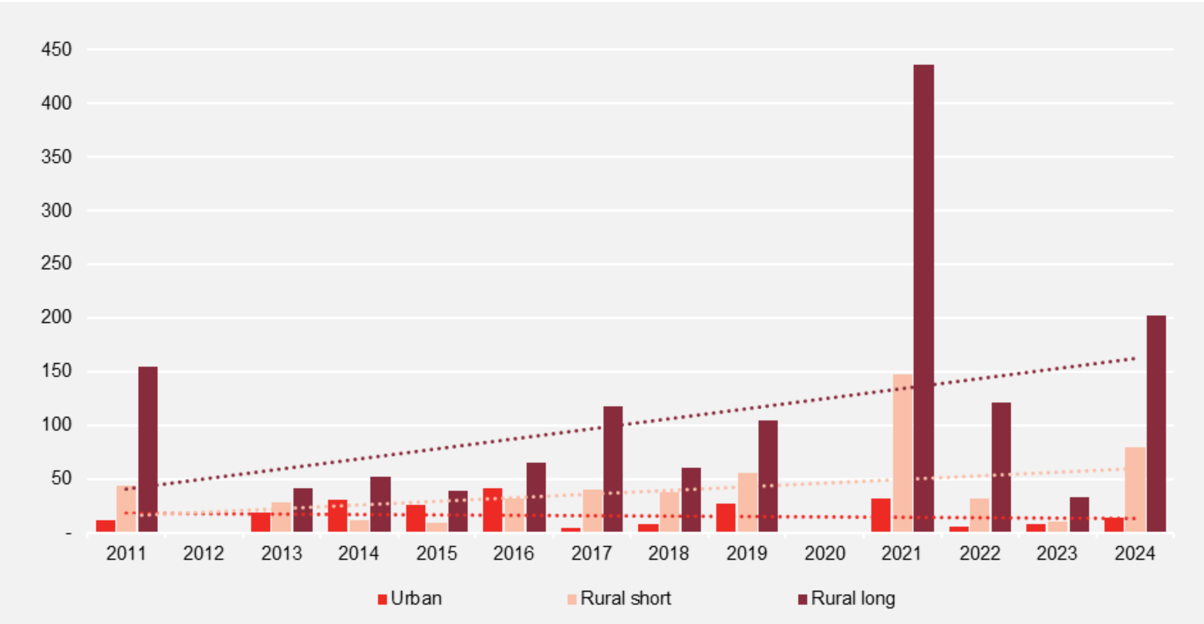
FIGURE 2 CUSTOMER MINUTES OFF SUPPLY



Note: Customer minutes off supply are based on system average interruption duration index (SAIDI)

Further, the impact of these extreme weather events is falling disproportionality on our regional and rural customers. Figure 3 breaks down SAIDI attached to MED days for each of our three feeder types; urban, rural short and rural long. SAIDI associated with our urban feeders has remained relatively constant over time, while SAIDI associated with our rural feeders is increasing as a result of more frequent and severe weather events.

FIGURE 3 CUSTOMER MINUTES OFF SUPPLY DURING MED DAYS BY FEEDER TYPE



1.2 Customers are becoming more dependent on electricity than ever before

At the same time as our climate is changing, rapid electrification and changing behaviour preferences are increasing community dependence on a resilient electricity supply. This dependence is likely to accentuate the impact communities face when they experience a loss of supply—for example:

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

Figure 4 summarises some of these inter-relationships between electricity and other critical goods and services—namely, these goods and services are all dependent on electricity.

FIGURE 4 INTER-RELATIONSHIP BETWEEN ELECTRICITY AND OTHER CRITICAL GOODS AND SERVICES

This increasing dependency on electricity will mean that any future unplanned outages linked to extreme weather events are likely to have greater impacts on customers than historical outages. A greater impact of outages, coupled with a growing number of extreme weather events due to further changes in the climate, will result in larger risks to all communities.

1.3 The Victorian government expects distribution businesses to improve network resilience

Following extreme storm events in 2021, the Victorian Government engaged an expert panel to undertake an Electricity Distribution Network Resilience Review.[4]

The expert panel consulted broadly with local communities and stakeholders impacted by the extreme storms. It found loss of power caused 'considerable distress' and devastating consequences on peoples lives.[5] Customers told the panel of their reliance on power in all aspects of their lives including food, water, access to funds, caring for themselves and their family and their ability to work and communicate. The panel highlighted the significant risk vulnerable and life support customers are exposed to during prolonged outages.[6]

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

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

Aa a result of the review, the Department of Energy, Environment and Climate Action (DEECA) has proposed a rule change to the AEMC to enshrine resilience objectives explicitly in the National Electricity Rules. Within this proposed rule change DEECA has highlighted the increasing threat of major event days and the need for proactive resilience investments to reduce the overall costs to customers.[7]

This review has since been followed by a Network Outage Review into the February 2024 storm event.[8] The outage review highlighted that distribution businesses no longer operate in an environment which is 'steady state'; we are now operating with real potential for frequent weather events that cause impacts at scale. As a result, the Victorian government expects a change in distribution businesses preparedness, response, and recovery from these events to protect the power Victorians value and the ecosystem of essential services that electricity distribution networks sustain.[9]

The outage review concluded in August 2024 with expectations that distribution businesses robustly plan for major events, align restoration with the Victorian Preparedness Framework and proactively

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4 More information can be found at: https://www.energy.vic.gov.au/about-energy/legislation/regulatory-reviews/electricity-distribution-network-resilience-review
5 DEECA, Electricity Distribution Network Resilience Review, Final recommendations report, pp. 4–5
6 DEECA, Electricity Distribution Network Resilience Review, Final recommendations report, p. 9
7 DEECA, AEMC Rule Change Request submission, 30 July 2024, p. 7
8 More information can be found at: https://www.energy.vic.gov.au/about-energy/safety/network-outage-review
9 DEECA, Network Outage Review, Final report, p. 14

address worst performing feeders to reduce the number and impact of outages.[10] It also highlighted the critical need for us to provide customers accurate and timely information and immediate local presence and support. The review emphasised the importance of alternative solutions on the ground, such as community hubs and alternative generation to support communities.[11]

The outage review also included a recommendation that distribution businesses annually attest to the currency, completeness, maturity and implementation ability of their emergency risk management practices.[12]

1.4 Our customers expect us to do more to prevent the impacts of extreme weather events

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

Through these engagements customers provided a number of insights that have helped guide our resilience investment approach:

- resilience is a vital element of energy systems, particularly in light of rising climate-related disruptions
- improving network resilience involves adapting to changing environmental and operating conditions
- customers believe that distributors play a critical role in proactive and reactive disaster management and need to develop network resilience plans tailored to community needs
- regional communities place value on support services such as MERVs that provide a point of both practical (temporary power supply) and psychological support (a gathering point for the community)
- transparent communication and education are critical, especially during emergencies, to stay informed about outage causes, recovery times and preparedness measures.

At our trade-off forums we presented customers with a variety of options to better understand customer's willingness to pay for key resilience measures. The majority of customers were willing to pay to improve network resilience through network hardening and community support, with over 70 per cent of customers willing to invest more. This included over 30 per cent of customers who were willing to pay for investments of at least $75 million over the 2026–31 regulatory period.

Lastly, we undertook the test and validate phase of our customer engagement program following the release of our draft proposal. During this engagement customers:

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

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10 More information can be found at: Victorian Preparedness Framework | Emergency Management Victoria; and DEECA, Network Outage Review, Final report, pp. 7-12
11 DEECA, Network Outage Review, Final report, pp. 26-27
12 DEECA, Network Outage Review, Final report, p. 12

- considered that investment should be targeted to areas that are prone to bushfire and flood. This is because customers viewed regions prone to these extreme weather events as the most vulnerable regions in the network.

2. Our proposed approach to resilience

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

TABLE 1 OUR APPROACH TO RESILIENCE

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

2.1 We have used robust climate modelling to identify areas exposed to extreme weather

To understand how extreme weather events are likely to impact our network and communities over the next regulatory period (and beyond), we engaged AECOM to undertake a climate impact assessment. This assessment used existing independent literature, including the Victorian Government's Climate Science Report and the Electricity Sector Climate Information, to identify and map climate risks and hazards.[13]

AECOM's report highlighted that our network's area is particularly exposed to extreme rainfall, bushfires and wind.

As a second phase of work, we also engaged AECOM to develop a methodology to measure how these climate hazard will impact our network in the future. This included the variable that should be used to represent each climate hazard and how that variable should be projected forward using climate science.[14]

The majority of this modelling has focused on bushfire and flood as modelling related to these types of extreme events has a greater level of maturity. This also corresponds with customer feedback regarding the type of resilience events we should protect against.

Modelling around storm events, specifically around extreme wind gusts which can damage our network assets, continues to prove to be challenging, and we consider that at this stage there is still more work required before wind modelling can be used with the level of certainty required to justify large levels of resilience investment. We will further our wind modelling capabilities during the 2026–31 regulatory period to better understand how our network will be impacted by wind. Expenditure related to improving our climate modelling has been included as part of our innovation allowance.[15]

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[13] More information can be found at:https://www.climatechange.vic.gov.au/victorias-changing-climate
[14] See: PAL ATT 5.01 - AECOM - Methodology report - Jan2025 - Public.
[15] PAL BUS 10.01 - Innovation allowance - Jan2025 - Public

2.1.1 We have taken a conservative approach to our climate forecasts

We have used a moderate climate forecast scenario and timeframe to ensure customers pay no more than they should for safe and resilient electricity supply.

The Intergovernmental Panel on Climate Change (IPCC) has outlined four climate scenarios to explore potential future concentrations of greenhouse gases in the atmosphere, referred to as representative concentration pathways (RCPs). These range from high concentrations (RCP 8.5) to very low concentrations (RCP 2.6)—namely RCP 8.5, RCP 6.0, RCP 4.5 and RCP 2.6. Each RCP reflects a different concentration of global greenhouse gas emissions, based on assumptions of combinations of possible future economic, technological, demographic, policy, and institutional trajectories.

The use of RCP 8.5 allows for the identification of hotspots that may be exposed to more significant climate risks. It is also important to consider RCP 8.5, particularly for near-term climate projections as using a lower emissions scenario (e.g. RCP 4.5) assumes a level of mitigation over the last 15 years that did not occur.

While some of the literature suggests that we are tracking more closely to RCP 4.5, RCP 6.0 is also plausible as emissions would need to peak in 2040 and then decline reasonably rapidly to stay in line with RCP 4.5. However, downscaled Victorian climate projections are not available for RCP 6.0.

RCP 2.6 was not selected as it requires emissions to peak in 2020 and decline through to 2100 which is considered highly unlikely.

It is generally recommended in the literature, including by the Electricity Sector Climate Information (ESCI) Project and the Victorian Climate Projections 2019 (VCP19) guidance that both RCP 8.5 and RCP 4.5 be used to identify the exposure of assets to climate change.

However, as a conservative assumption we have used the emission scenario RCP 4.5 in modelling. We consider this is the least regrets path because:

- RCP 4.5 is a conservative emission scenario
- the use of RCP 4.5 is aligned with the AER's previous decisions for NSW distribution businesses

Climate forecasts are provided for the years 2050 and 2070. As we evaluate our investment initiatives over a 20-year assessment window, all investments for our 2026–31 regulatory proposal will be assessed up to 2050–51. Hence, we have used the 2050 climate forecast in assessing our resilience investments as it is within the 20-year assessment window.

We consider this is again a conservative approach that may underestimate the impact of climate change for some of our longer life assets. However, we consider using the 2050 forecasts instead of the longer term 2070 forecasts is prudent, as the 2070 forecasts inherently contain greater uncertainty due to their long-term nature.

2.1.2 We have focused our investments where we consider climate modelling is most robust

Table 2 sets out the most probable high impact future weather events that we have assessed for our 2026–31 regulatory proposal. We will continue to review climate change and assess its impacts to inform our future regulatory proposals.

TABLE 2 SELECTED WEATHER EVENTS

WEATHER EVENT	SELECTED	REASONS
Bushfire	✓	We have assessed investment options considering these weather events for our 2026–31 regulatory proposal (relative to a do-nothing base case) as we consider these events will have the most material impact on communities and our assets based on historic weather events in Victoria. However, we have focused predominately on bushfire and flood due to the challenges of robustly modelling wind data
Flood	✓	
Storm with high wind	✓	
Heatwave	×	While heatwaves are a probable future weather event that impacts communities and our assets, its impact is less sudden and destructive because heat needs to build up over days before it has a material impact. Due to this gradual nature, we currently consider the most prudent and efficient way to prepare for future heatwaves is though incremental adaptation of network assets and processes
Drought	×	We have not considered drought, earthquakes, tsunami, coastal erosion from sea level rise or storm surge, geomagnetic storms from solar flares and lightning storms in our 2026–31 regulatory proposal assessments because these weather events are significantly harder to predict
Earthquakes	×	
Tsunami, coastal erosion from sea level rise or storm surge	×	
Geomagnetic storms from solar flares	×	
Lightning storms	×	

2.1.3 Annual climate forecasts

We used linear interpolation to project the annual climate escalation to 2050 based on historical, 2030 (where available) and 2050 climate forecasts. This annual climate escalation is used to forecast the annual likelihood of a weather event related to bushfires, floods and storms.

The annual climate escalation is consistent with the methodology developed by AECOM:

- bushfire – forecast and historic number of days per year the Forest Fire Danger Index (FFDI) exceeds 50 (where FFDI greater than 50 represents severe fire risk)
- flood – forecast and historic 24h rainfall volume
- storm – forecast and historic number of days with maximum wind gusts above 100km/h.

2.2 Our resilience investments reflect values for network resilience and worst served customers

In assessing potential resilience investments we have included the AER's recently released value of network resilience as well as our own value for worst served customers.

2.2.1 Our value for worst served customers

We have included a worst-served customer value for customers and communities that are particularly exposed to extreme weather events and who have experienced significantly more minutes off supply than our average customer.

On average, between 2015 and 2023, 22,572 customers experienced more than 500 minutes of power outages annually (approximately 2.5 per cent of our total customer base). This outage duration is 3.7 times greater than that of our average customer.

Given there is a sub-set of our customers who are experiencing consistently lower service standards, we applied a worst-served customer value to our resilience investments where the average annual minutes off supply is greater than 500. The value, which was developed with our customers, is set at $22.30/kWh.

The interaction of the value of customer reliability (VCR), worse served customer value and value of network resilience (VNR) is as follows:

- 0 - 500 minutes off supply – VCR is applied
- 500 - 720 minutes off supply – VCR and worst served customer values are applied
- 720+ minutes off supply – VNR is applied.

Development of our customer values

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

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

At the recommendation of the Customer Advisory Panel (CAP), these values were re-tested and updated in 2023 to ensure they remain reflective of our customer's views. This was undertaken given the economic environment had changed materially, and there was a question of whether customer's preferences had evolved as well. Values produced during this re-testing were very similar to the initial values produced in 2021, demonstrating that customer's continued to value these services.

Table 3 below describes each of our customer values.

TABLE 3 CUSTOMER VALUES

VALUE MEASURE	DESCRIPTION
Reliability in worst-served areas	Customer value of enhancing reliability in worst-served areas of our network, based on kWh of avoided outages
Enabling solar exports	Customer value of avoided rooftop solar constraints
Community resilience	Customer value of enhancing community support during long-duration outages caused by extreme weather. This includes emergency response vehicles and community liaison officers
Customer time	Customer value of time saved by customers on a per-minute basis
Battery storage in local community	Customer value of local battery energy storage systems to optimise the use of locally generated clean energy resources

AER's value of network resilience

The AER released its final decision on an interim value for network resilience on 30 September 2024. The interim VNR was developed to help inform networks and stakeholders about the appropriate investments to enhance network and community resilience against extreme weather events. The AER has timetabled a longer-term VNR that will supersede the interim VNR for 2026.

We have applied the interim VNR for our resilience investments in place of our own values of network and community resilience. The VNR uses multiples of the VCR to account for the additional costs borne by customers during prolonged outages. The VNR has been applied as follows:

- for residential customers:
  - the standard VCR for the first 12 hours of a prolonged outage
  - a multiple of 2x the standard VCR for the period of 12-24 hours
  - a multiple of 1.5x the standard VCR for the duration of the outage that extends beyond 24 hours, until the upper bound is reached (the upper bound for an average customer is expected to be reached after approximately seven days)
- for business customers:
  - the standard VCR for the first 12 hours of a prolonged outage
  - a multiple of 1.5x the standard VCR for the period of 12-24 hours
  - a multiple of 1.0x the standard VCR for the period of 24-72 hours (1-3 days)
  - a multiple of 0.5x the standard VCR for the duration of the outage that extends beyond 72 hours.

3. Our proposed resilience expenditure

Our proposed resilience investments, based on our climate modelling, are summarised in figure 5. These investments have been driven by the outcomes from recent Victorian Government reviews, and strongly supported by stakeholder and customer feedback.

We have split our resilience investments into two main categories; network hardening and community support.

Our proposed network hardening investments are focused on making network assets more resilient. More resilient network assets and supply routes will reduce the likelihood and impact of extreme weather events on customer supply. There are two types of investments we can make to limit customer outages. The first involves upgrading or replacing our assets so that they are less likely to suffer damage during extreme weather events, such as replacing wood poles with concrete poles in high bushfire risk areas. Where we are unable to prevent the extreme weather event from damaging our assets we seek to establish alternative supply routes (such as community microgrids) that allow customers to remain on supply even when certain network assets are damaged.

Customers were very supportive of hardening our network assets during our customer engagement sessions, but wanted us to make sure we were investing in the highest risk areas. The extensive climate modelling we have undertaken around bushfire and flood ensures that our proposed expenditure is targeted at the areas most at risk.

Our community support investments are focused less on our network assets and more on ensuring communities are able to plan for and quickly recover from the impacts of extreme weather events. These investments focus both on ensuring communities are prepared prior to extreme weather events, by having the necessary emergency planning in place, and that communities are supported to recover when these events do occur. The need for increased community investment was a clear outcome of the Victorian Government's 2021 and 2024 outage reviews, which recounted many of the lived experiences of communities during significant storm events.

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

FIGURE 5 OUR PROPOSED RESILIENCE INVESTMENTS

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

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

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

Creating more resilient communities and networks by:

Strengthening and adapting our network to avoid time off supply

Reducing the impact of extreme weather events

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

The remainder of this document sets out the business cases that make up our proposed resilience investments. These business cases should be read with consideration of the material included in the initial sections of this document.

Table 4 provides a summary of our investments including the identified need and associated costs.

TABLE 4 SUMMARY OF RESILIENCE INVESTMENTS ($M, 2026)

PROGRAM	IDENTIFIED NEED	CAPEX	OPEX
Bushfire resilience program	Maintain supply in regional areas during bushfires as bushfires become more frequent and severe	49.3	-
Flood resilience program	Minimise as far as reasonably practicable safety risks under flood conditions	19.6	-
Radio site resilience program	Maintain access to communications during and after extreme weather events	1.4	-
Apollo Bay supply area	Maintain service levels in the Apollo Bay supply area as the severity and frequency of extreme weather events increase	3.1	-
Ballan supply area	Maintain service levels in the Ballan supply area as the severity and frequency of extreme weather events increase	3.2	-
Donald supply area	Maintain service levels in the Donald supply area as the severity and frequency of extreme weather events increase	3.2	-
Lancefield supply area	Maintain service levels in the Lancefield supply area as the severity and frequency of extreme weather events increase	3.2	-
Community support	Provide additional community support in preparing for and recovering from extreme weather events	1.0	3.8
IT situational awareness	Improving the prioritisation and visualisation of outages during large scale outage events	3.1	2.7
Total		**87.1**	**6.5**

3.1 Evaluated credible options using cost-benefit assessment

We undertook the following steps to identify and assess options for our proposed resilience projects and programs:

- identified areas of our network that are exposed to risks associated with the increasing frequency and severity of climate extremes
- short-listed technically and commercially credible solutions to address the identified need
- undertook cost-benefit analysis to identify the preferred solution (relative to our base case).

For options that we considered were both technically and commercially credible, we evaluated the economic efficiency based on a quantitative cost-benefit assessment. This assessment compared the cost of credible options against the risks and impacts of the extreme weather event(s) on our assets and the community.

The credible option that yielded the highest positive net present value (NPV) of costs and risks/benefits to the community formed the preferred option for the resilience program. This ensured we invested in projects that provided the highest benefit to the community and ensured that the cost of the program exceeded the total risk value.

This cost and risk/benefit assessment was underpinned by the risk monetisation approach shown in figure 6. This approach is consistent with the AER's industry practice planning note for asset replacement planning.

FIGURE 6 RISK MONETISATION ANALYSIS

Annual risk cost = **Annual likelihood of weather event** ✖ **Annual climate escalation** ✖ **Annual likelihood of event impacting network** ✖ **Cost of consequence**

We consider this process, in conjunction with our customer engagement, aligns with the requirements outlined by the AER in its network resilience note on key issues.[16] The AER consider evidence to support ex-ante resilience funding should demonstrate that:

- there is a causal relationship between the proposed resilience expenditure and the expected increase in the extreme weather events
- the proposed expenditure is required to maintain service levels and is based on the option that likely achieves the greatest net benefit of the feasible options considered
- consumers have been fully informed of different resilience expenditure options, including the implications stemming from these options, and that they are supportive of the proposed expenditure.[17]

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[16] AER, Network resilience – A note on key issues, April 2022
[17] AER, Network resilience – A note on key issues, April 2022, pp. 11-14

A

BUSHFIRE RESILIENCE

A Bushfire resilience

Our bushfire resilience program focuses on bushfires that are not started by our assets but impact our assets. This is separate from our bushfire mitigation programs, which are aimed at preventing bushfires started by our assets.

Our most vulnerable asset to bushfires is wood poles. Wood poles are susceptible to being burnt by bushfires, which can cause the wood poles to collapse, resulting in an outage of the overhead line and disruption to customers supplied by the line. This is evidenced by the recent 2024 bushfires at Pomonal, which destroyed 12 of our high voltage (HV) and sub-transmission wood poles on long rural overhead lines and caused significant outages.

We currently manage the bushfire risk to our wood poles reactively by replacing destroyed poles after a bushfire. We replace wood poles with concrete poles in the northern region of our network (north of the dividing ranges) but continue to install wood poles in the southern region as per our current asset management practice. While concrete poles are more costly than wood poles, it is used in the northern region as it has a lower lifecycle cost compared to wood poles due to termite issues in the northern region.

A.1 Identified need

A section of overhead line is vulnerable to bushfire outages if it has any wood poles. If a bushfire destroys a wood pole, it will likely lead to a loss of supply to all customers supplied by that section of line.

A section or segment of a line is the part of the line between automatic remote switching devices. We rely on these automatic remote switching devices to isolate the part of the line affected by bushfire, as it is not safe to dispatch our field crews to operate devices in bushfire-affected areas until it is declared safe by the Country Fire Authority. The use of these switching devices limits the loss of supply to customers between these devices rather than the loss of supply to the entire feeder.

The identified need, therefore, is to manage our wood pole assets that are exposed to the impacts of bushfires to maintain reliability and network and community resilience, particularly as climate extremes become more frequent and severe, and our customers become more dependent on electricity.

A.2 Options considered

The focus of this business case is on HV overhead lines because:

- HV overhead lines are typically radial (unlike sub-transmission lines which are typically looped), meaning alternate supply routes do not usually exist
- HV overhead lines are more vulnerable to bushfire outages as they generally traverse rural areas for long distances and supply customers across large geographical areas
- loss of low voltage overhead lines has a lower impact because it provides only localised supply. We anticipate that during a bushfire most people will be evacuated from bushfire affected areas and will not require electricity supply from the low voltage lines.

At the start of the 2026–31 regulatory period, we will have over 350,000 HV wood poles at risk of bushfires across 2,249 sections of lines from 421 feeders.

Our options analysis considers a number of potential options to meet the identified need for these poles (relative to a do-nothing base case). Credible options are those that we consider are able to meet the identified need, meaning the solution is both technically and economically feasible.

A.2.1 Option one: base case

This option maintains the existing reactive approach to bushfire, whereby we replace burnt wood poles after the bushfire. We would continue to replace burnt wood poles with concrete poles in the northern region of our network (north of the dividing ranges) but continue to install wood poles in the southern region as per our current asset management practice.

A.2.2 Option two: replace wood poles with concrete poles

If a section of line has any wood poles, we would proactively replace all the wood poles with concrete poles. Based on our experience with our existing concrete poles in the network, concrete poles are more resilient to bushfires than wood poles (as no concrete poles to date has been destroyed by bushfires).

A.2.3 Option three: replace wood poles with fibre reinforced cement poles[18]

If a section of line has any wood poles, we would proactively replace all the wood poles with fibre reinforced cement poles. While we anticipate fibre reinforced cement poles will have similar fire resistance properties as concrete poles, we currently do not have lived experience of fibre reinforced cement poles surviving bushfires.

This is similar to option two, however, fibre reinforced cement poles have limited pole lengths and strength sizes and are yet to be widely deployed on our network.

There is also only one fibre reinforced cement pole supplier, meaning this option carries greater supply chain risks.

Given these limitations on supply, we have not considered this option as commercially feasible.

A.2.4 Option four: wrap wood poles with fire mesh

This option would entail wrapping the base of the wood poles with a fire retardant mesh. The fire mesh is to be wrapped from slightly below ground level and up the pole to typically a few metres above ground. Wrapping the base of wood poles with fire mesh is intended to protect the poles from grass fires that burn at a lower height but will not prevent canopy fires with embers at height or flying embers from burning wood poles.

Should the fire mesh experience a bushfire, it will activate and swell up to form a protective barrier around the pole to protect it from the fire. However, the fire mesh needs to be replaced once it is activated (i.e. one time use only).

While fire mesh is a potential cost effective technology to protect our wood poles from bushfire, it has not been trialled on our network to test its suitability for our network, terrain and operating conditions prior to network wide deployment. Fire mesh is currently being trialled by networks in NSW and Queensland, however, none of these trial locations have yet experienced a large scale bushfire.

We are proposing to trial this technology through our innovation allowance in the 2026–31 regulatory period. Given the lack of basis on which to assess or model the effectiveness of this technology to our environment, we have only considered this option qualitatively.

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18 Other alternative pole types, such as fibre reinforced polymer poles, were also discounted for similar reasons.

A.2.5 Option five: replicate or underground line

This option would entail replicating the line by building a new duplicated line located along a different route to the existing line. It will provide an alternate supply route should one of the lines be affected by a bushfire.

Similarly, we could underground our existing assets, which will require removing all overhead conductors and poles and replacing them with underground cables. It will also require replacing pole mounted distribution transformers with kiosk transformers.

While these are technically feasible, they are not considered commercially credible given the significant associated costs.

A.3 Options analysis

The credible options were evaluated individually for each of the identified line sections using cost-benefit analysis. The analysis compares the cost of the option against the quantified risk reduction benefits.

A.3.1 Cost-benefit analysis

The benefits associated with each option are reduced unplanned replacement risk and avoided energy at risk. However, we conservatively only included energy at risk as a benefit in the assessment.

The energy at risk was calculated based on the following:

- annual probability of a fire destroying a pole(s) in a section and/or downstream of the section, resulting in an outage. This probability changes over time to account for climate change
- number of customers affected by the resulting outage
- weighted average of forecast demand per customer on a feeder
- historic average bushfire outage durations
- the AER's value of network resilience.

The sub-sections below outline the methodology used to generate this benefit, which were independently modelled by the CSIRO and Blunomy.

We modelled all potential bushfires that can burn our poles

We used the Commonwealth Scientific and Industrial Research Organisation's (CSIRO) Spark fire simulation model to simulate 4.5 million bushfires across our network and areas bordering our network (such as the area across the South Australian border), which could spread into our network area and impact our poles. The model also simulated the potential fire intensities of these bushfires based on fuel load, terrain and weather data.

The probability of a fire burning a pole(s) in a section of line was based on a bottom up assessment of simulated fire experienced at each pole. Our pole locations were overlaid over these fire simulation results to determine the fire experienced by each pole. We calculated the daily probability of each pole experiencing a specific fire intensity for a particular fire danger rating. Fire danger rating classifies potential fire danger based on the Forest Fire Danger Index (FFDI) into categories such as low-moderate, high, severe and catastrophic.[19]

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[19] CSIRO, Forest Fire Danger Index – Bushfire best practice guide (csiro.au)

We adjusted our modelling to incorporate independent future climate projections

The impact of climate change was also included in the probability of a fire burning a pole(s). We used the climate projections from the Electricity Sector Climate Information (ESCI) project for severe fire risk, which is represented by days of FFDI 50 or higher. We consider this is a conservative assumption and representative of the types of destructive bushfires we are seeking to harden our network against. We then scaled and linearly interpolated the probability of a fire burning a pole(s) in a section of line based on the climate projections from the ESCI project to obtain an annual probability for every year from 2026 to 2050.

We then aggregated daily pole fire probability into sections of lines by mapping poles to line sections using our network topology. This also considers a fire may impact both a line section and downstream sections. We converted this daily fire probability for a line section to an annual probability based on the number of days per year allocated to a given fire danger rating and the distribution of fire danger ratings. We also calculated the annual average number of poles in a line section which will experience a fire.

We further overlayed the consequence of a burnt pole based on recent bushfire data

The probability of consequence is the probability the burnt pole(s) in a section of line results in an outage. This was based on the survivability of a wood pole to a fire, which was derived from real world experience of the destruction of our wood poles. This means only wood poles were considered in the consequence calculation.

We also included the potential impact of an outage of a line section on downstream line sections by mapping dependencies between line sections using our network topology. This was to avoid inflating the consequence by double counting the impact of large fires which could destroy multiple sections.

A.3.2 Results summary

Table 5 shows the results of the quantitative option evaluation against our base case.[20]

TABLE 5 OPTION EVALUATION RESULT ($M, 2026)

OPTION	PV COST	PV BENEFITS	NET BENEFITS
Option two: replace with concrete poles	(159.2)	288.8	129.6

In addition to testing the options under a central scenario, we undertook sensitivity analysis, including for higher costs and lower benefits (including removing benefits associated with the VNR). Option two remained economic under all sensitivity scenarios.

A.3.3 Preferred option

Replacing wood poles with concrete poles based on identified risks (option two) is the preferred option.

Replacing wood poles with concrete poles produces a positive NPV for 48 line sections. Within these line sections we identified 8,022 wood poles that would need to be replaced to deliver the associated reduction in bushfire risk. This is a highly targeted investment representing only two per cent of wood poles we have in our network.

[20] Further details are provided in PAL MOD 5.01 - bushfire resilience - Jan2025 - Public

To replace all these poles would require capital expenditure of almost $250 million. However, we consider it unrealistic to replace such a large number of poles within the 2026–31 regulatory period, both from a customer affordability perspective and from a resourcing perspective.

Instead, we are planning to deliver the bushfire resilience program over multiple regulatory periods. For the 2026–31 regulatory period we are proposing to replace poles in only the highest value locations. By undertaking investment on only the highest NPV sections on the network we can deliver the greatest bushfire risk reduction to customers for a given level of expenditure.

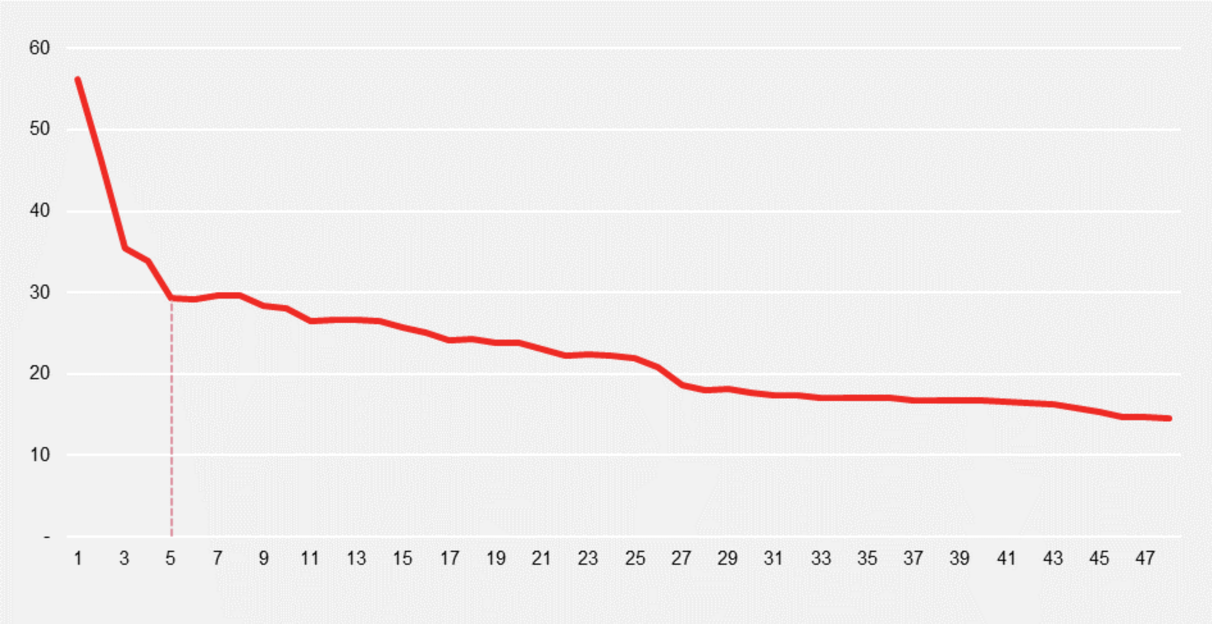
We consider that this investment will help maintain service levels for customers in the identified line sections during major events days. As set out in section 1.1, regional and rural customers have been experiencing deteriorating levels of service due to the increasing frequency and severity of extreme weather events.

Selecting line sections which provide the greatest net benefit

To ensure a no regrets investment, we are proposing to undertake investment on only the highest ranked NPV sections of our network.

Figure 7 shows the cumulative NPV per pole for the 48 NPV positive line sections in descending order. While replacement of wood poles in all of these sections is economic, we used the principle of diminishing returns to select the line sections that provide the greatest net benefit to form the 2026–31 bushfire resilience program. We consider there is a knee point in the curve after the first five sections. Based on this analysis we consider these five line sections provide the greatest net benefit and can be considered no regret investments.

FIGURE 7 CUMULATIVE NPV PER POLE ($'000s, 2026)



As shown in table 6, by selecting only the top five sections, our proposed bushfire resilience program significantly reduces the number of poles and corresponding costs to customers in the 2026–31 regulatory period. By focusing on a limited set of the highest risk poles only, this also supports the prudency of our proposal relative to alternative options, such as the potential for fire mesh in the future to become part of a viable management approach. Overall, we consider that our proposed approach strikes an appropriate balance between customer affordability, resource availability and risk mitigation.

TABLE 6 WOOD POLE REPLACEMENT PROGRAM: ALTERNATIVE APPROACHES

APPROACH	VOLUMES	COSTS ($M)
Replace all economic poles	8,002	246.7
Replace top five line sections only	1,670	51.4

Portfolio review to remove overlaps

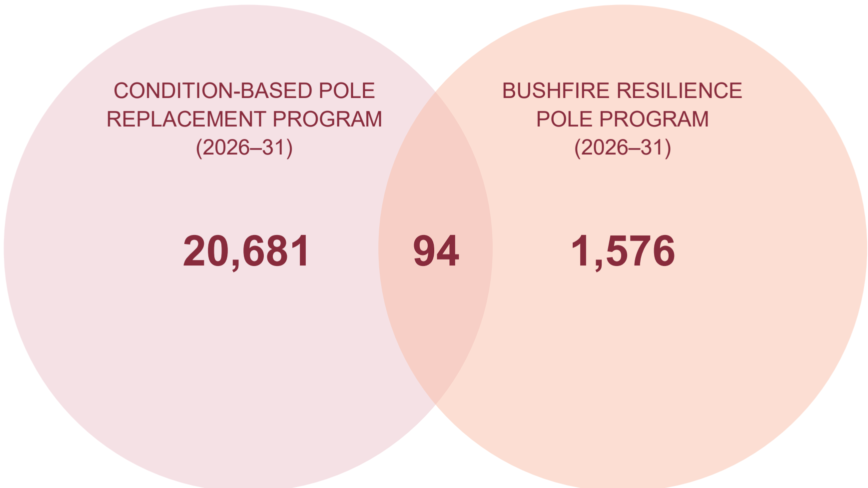
To further challenge our proposed option, we reviewed our bushfire resilience program to remove potential overlaps (e.g. the replacement of poles under this bushfire resilience program has the potential to overlap with our business-as-usual condition-based pole replacement program, which reinforces or replaces end-of-life poles based on deteriorated pole condition).

Figure 8 shows limited overlap of poles in our bushfire resilience program. Under our condition-based pole replacement program we would replace these poles with concrete poles in the northern region (north of the dividing ranges) and wood poles in the southern region. Under the bushfire resilience program we would replace all identified poles with concrete poles. To avoid any double counting of poles under our two separate programs:

- where a wood pole was expected to be installed under our condition-based pole replacement program we only include the incremental cost to upgrade to a concrete pole under our bushfire resilience program
- where a concrete pole was expected to be installed under our condition-based pole replacement program we remove this pole from our bushfire resilience program.

Removing the overlaps between our bushfire resilience program and our condition-based replacement program results in a further $2.0 million reduction in the bushfire resilience program.

FIGURE 8 BUSHFIRE RESILIENCE AND CONDITION- BASED REPLACEMENT OVERLAPS



A summary of the reduced bushfire resilience program capex profile over the 2026–31 regulatory period is shown in table 7. Further detail on our cost-benefit analysis is also provided in our attached model.[21]

TABLE 7 BUSHFIRE RESILIENCE PROGRAM: CAPITAL EXPENDITURE ($M, 2026)

OPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Bushfire resilience: concrete poles	9.9	9.9	9.9	9.9	9.9	49.3

[21] PAL MOD 5.01 - bushfire resilience - Jan2025 - Public

B

FLOOD RESILIENCE

B Flood resilience

Overhead lines are designed and constructed to achieve minimum standard electrical clearances between the ground and conductors for reliability, network safety and public safety purposes.[22] These ground-to-conductor clearance requirements are established at the time of construction.

Flood waters under our overhead lines, however, reduce the effective clearance level. During such an event there is an increased likelihood that a person—for example, emergency service workers—breach safe clearances to our live conductors, which could result in injury or death.

B.1 Identified need

During major flood events, our low voltage (LV) lines supplying a flooded area are typically de-energised due to tripping of flooded residential or commercial switchboards or fuses. Hence, during a significant flood event, our LV lines are less likely to pose safety risks associated with low clearances.

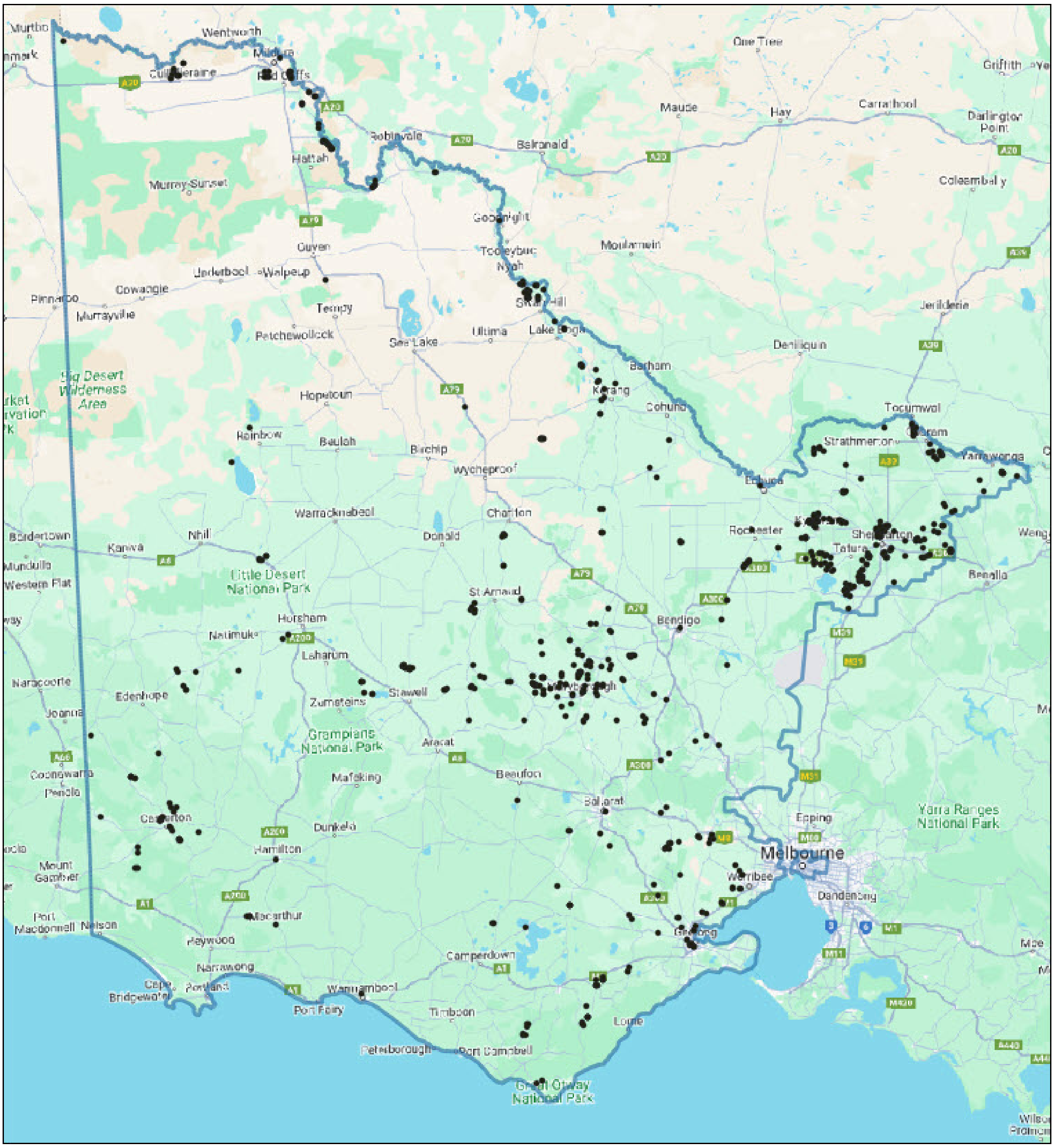
However, high voltage (HV) and sub-transmission lines, which cover a larger geographical area, would otherwise remain energised. We therefore manage this safety risk by de-energising the line until flood waters sufficiently recede. While this approach mitigates the safety risk, de-energising the line results in loss of electricity supply to the wider community.

Our analysis, discussed in more detail below, has identified over 700 HV and sub-transmission conductor spans that present a potential safety risk. These comprise over 1,200 poles across our network. The wide geographic dispersion of these assets is shown in figure 9.

In this context, the identified need is to minimise as far as practicable the potential safety risk under flood conditions whilst also ensuring minimal supply disruption to customers.

[22] The current industry standard for electrical clearances is set out in Australian standard AS 7000:2016 - Design of Overhead Lines.

FIGURE 9 SPANS WITH CONDUCTOR CLEARANCE RISK DUE TO FLOODING



B.2 Options considered

We considered a number of potential options to meet the identified need (relative to a do-nothing base case). Credible options are those that we consider are able to meet the identified need, meaning the solution is both technically and economically feasible.

B.2.1 Option one: base case

This option maintains the existing reactive approach to floods, which is to de-energise lines under flood situations. This will result in extensive supply interruptions to customers, recognising that flood waters can be slow to recede.

B.2.2 Option two: replace with taller poles

This option would involve raising the height of the lines by replacing existing poles with taller poles to achieve safe clearances under flood conditions. As poles lengths are manufactured in incremental steps, the next higher incremental pole length, that is greater than the lifting height required, will be chosen.

B.2.3 Option three: install raiser brackets

This option would raise existing lines by installing raiser brackets at the pole top. Based on initial suitability assessments, we consider there is limited potential application of raiser brackets based on lifting height required and pole design (i.e. whether a raiser bracket can be installed at the top of the pole, and the impact on pole loading requirements).

Given the limited suitability of raiser brackets, we consider this option is not technically feasible.

B.2.4 Option four: re-tension lines

This option would involve restringing lines at a higher tension to reduce sag and increase clearances. However, re-tensioning often provides limited lift to lines based due to the limited ability of existing poles to withstand the increased line tension. If the existing poles are not able to withstand the increased line tension, it will result in the pole leaning and require future pole reinforcement or replacement with a stronger pole.

Given the limited suitability of re-tensioning, we have considered this option as not technically feasible.

B.2.5 Option five: install a covered conductor

This option would replace bare conductors with covered conductors. While covered conductors provide insulation cover around a bare conductor, they do not have an earth screen (i.e. a screen designed to ensure that when the conductor is cut or damaged the electricity will automatically ground to earth) and are therefore not fully insulated and may not prevent injury or death upon contact. Thus, covered conductor requires the same clearances as a bare conductor. Further, there is no covered conductor for sub-transmission conductors.

We consider this option not technically feasible as it is unlikely to reduce the safety risk.

B.2.6 Option six: load transfers, re-locating lines or undergrounding

These options would each require significant augmentation to our network to enable all loads to be transferred to other lines and substations, to enable the de-energisation of flooded lines and substations whilst minimising supply interruption. It may involve building new tie lines to existing lines or entire new lines with corresponding easements and decommissioning.

We consider these options are not commercially feasible due to the significant costs involved in augmenting the network.

B.3 Options analysis

The credible options were evaluated individually for each of the feeders with at-risk spans, using cost-benefit analysis. The analysis was undertaken at a feeder level (instead of per span) to prevent double counting of poles, where a pole is shared by two spans. The cost-benefit analysis compares the cost of the option against the quantified risk reduction benefits.

B.3.1 Cost-benefit assessment

The benefits associated with each option are reduced safety risk and avoided energy at risk. These were calculated based on the following:

- the annual likelihood of a flood event – based on a 1-in-100 year flood event
- annual climate escalation (as detailed below)
- annual likelihood of the flood event impacting the network – based on historical flood events and the likelihood of a person contacting overhead lines
- the cost of the consequence – calculated using the statistical value of a human life and disproportionate factors for safety risks.

We have also applied the AER's value of network resilience where flood durations exceed 12 hours.

Identifying at-risk conductor spans

To identify HV and sub-transmission conductor spans where safe clearances could potentially be breached, we undertook the following:

- modelled flood water height above ground based on existing 1-in-100 year flood zone and terrain elevation profile from the Federal and Victorian government[23]
- determined the existing conductor height above ground based on the most recent LiDAR survey of our conductors
- compared the vertical distance between the conductor and water for each span under flood conditions, based on safe approach distances and typical height of a person.

The results of this identification process are summarised in table 8. These results exclude spans that are part of sub-transmission loops where alternative supply pathways exist, as we are able to de-energise the section of line impacted by flooding without causing loss of supply.

TABLE 8 ASSETS WITH GROUND-TO-CLEARANCE RISK DURING FLOODS

ASSET	VOLUME
HV and sub-transmission spans	709
Feeders	1,208
Poles	100

Flood forecasting

Flood forecasting was undertaken up to 2050 for each span based on the independent advice from our climate specialist, AECOM. AECOM's flood forecasting method compares historic and forecast 24-hour rainfall volumes to forecast the annual exceedance probability at a location, as follows:[24]

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23 Australian government, Victoria - 1 in 100 Year Flood Extent - Victoria - 1 in 100 Year Flood Extent - data.gov.au; and Victorian government, Vicmap Elevation DEM 10m - Dataset - Victorian Government Data Directory

24 PAL ATT 5.01 - AECOM - Methodology report - Jan2025 - Public

- climate change factors representing the percentage increase in the intensity (i.e. volume) of rainfall events for the RCP 4.5 climate scenario were sourced from the Australian Rainfall and Runoff Data hub[25]
- historic 24-hour rainfall volumes for one and two per cent annual exceedance probability events were sourced from the Bureau of Meteorology
- the volume from climate change factors were added to the historic 24-hour rainfall volumes (i.e. summing the numbers obtained from the above two steps) to forecast the 2050 RCP 4.5 rainfall volume
- the 2050 RCP 4.5 forecast rainfall volume was compared to the historic 1-in-100 year volume to determine an approximate equivalent annual exceedance probability volume, and therefore an increase in frequency.

B.3.2 Results summary

Table 9 shows the results of the quantitative option evaluation against our base case.[26]

TABLE 9 OPTION EVALUATION RESULT ($M, 2026)

OPTION	PV COST	PV BENEFITS	NET BENEFITS
Option two: replace with taller poles	(13.4)	90.7	77.3

In addition to testing the options under a central scenario, we undertook sensitivity analysis, including for higher costs and lower benefits. Option two remained economic under all sensitivity scenarios.

B.3.3 Preferred option

Replacing existing poles with taller equivalents (option two) is the preferred option, with only feeders that individually yielded a positive NPV included in the flood resilience program, as shown below.

TABLE 10 ECONOMIC ASSESSMENT OF AT-RISK VOLUMES

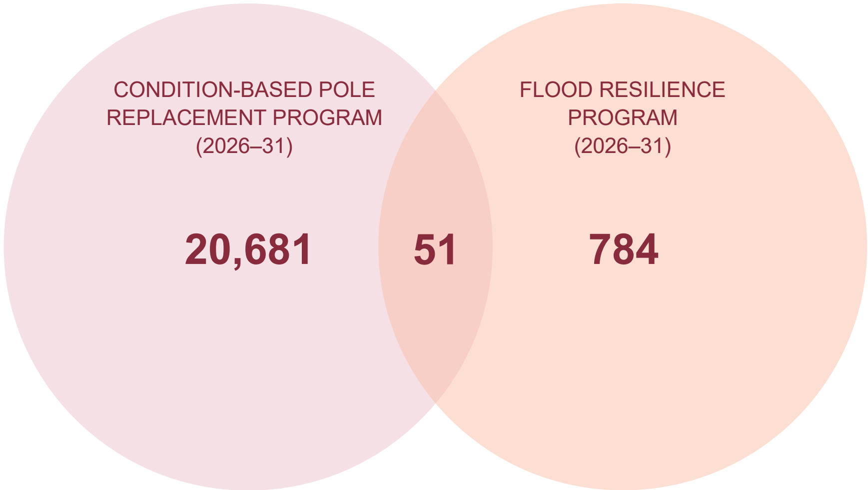
ASSET	AT-RISK	ECONOMIC
HV and sub-transmission spans	709	483
Poles	1,208	835

Portfolio review to remove overlaps

To further challenge our preferred option, we reviewed our flood resilience program to remove potential overlaps (e.g. the replacement of poles under this flood resilience program has the potential to overlap with our business-as-usual condition-based pole replacement program, which reinforces or replaces end-of-life poles based on deteriorated pole condition). Figure 10 shows the limited overlap of poles in the flood resilience program.

25 Home | ARR Data Hub
26 Further details are provided in PAL MOD 5.02 - flood resilience - Jan2025 - Public

FIGURE 10 FLOOD RESILIENCE AND CONDITION BASED REPLACEMENT OVERLAPS



Reduced program expenditure

For simplicity, and as an additional step to maintain affordability for our customers, our regulatory proposal absorbs the incremental costs of installing a taller pole where there is overlap between our condition-based and flood resilience programs (i.e. for the 51 poles identified above). This has resulted in a $1.1m reduction in the flood resilience program.

Table 11 shows the reduced flood resilience program capex profile for taller poles over the 2026–31 regulatory period.

TABLE 11 FLOOD RESILIENCE PROGRAM: CAPITAL EXPENDITURE ($M, 2026)

OPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Flood resilience: taller poles	3.9	3.9	3.9	3.9	3.9	19.6

C

APOLLO BAY SUPPLY AREA

C Apollo Bay supply area

Apollo Bay is a coastal town, located within the Barwon region of Victoria. The township of Apollo Bay is supplied by two feeders, both of which traverse heavily forested areas and are vulnerable to tree falls, bushfires, and extreme weather events.

Our CLC003 feeder supplies customers on the western side of Apollo Bay with an auto changeover scheme with our CLC013 feeder to the east. The CLC003 feeder consists of over 390km of overhead 22KV HV line with 3,000 poles and 14km of underground 22KV HV cable. Due to the long sections of powerlines which travel through this terrain, there can also be accessibility issues when responding to both reliability and resilience events.

The feeders connecting to and within the Apollo Bay supply area are shown in Figure 11.

FIGURE 11 APOLLO BAY SUPPLY AREA

C.1 Identified need

Over the last five years, the CLC003 feeder supplying Apollo Bay has experienced on average 877 minutes of unplanned outages per annum. This is significantly higher than the average across our network.

Faults on CLC003 occur over the full length of the feeder, particularly in the areas surrounded by trees in the Otway Ranges area. The two main causes of outages are vegetation and weather. Vegetation related outages occur due to trees falling onto the line because of tree clearing activities (pine plantations) and windblown bark and branches. Weather related outages occur due to wind damage, lighting strikes and other storm related damage.

Despite being supplied by two feeders, the township is still susceptible to outages from heavy storm events as both feeders pass through heavily vegetated land. This has occurred previously where tree damage due to heavy storms caused outages on both the main CLC003 and backup CLC013 feeders at approximately the same time.

Given the duration and frequency of outages in the Apollo Bay supply area are already well above the averages experienced across our network, the identified need is to maintain service levels as the frequency and severity of extreme weather increases.

C.2 Options considered

We have considered a number of potential options to address the supply risk to the Apollo Bay area from outages of the incoming HV feeders. Credible options are assessed relative to our base case.

C.2.1 Option one: base case

This option assumes that there is no additional investment into the resilience of our network in the Apollo Bay supply area.

As the frequency and severity of extreme weather events increases over time due to climate change, the frequency and duration of supply outages is anticipated to worsen.

C.2.2 Option two: install diesel generator microgrid

This option is to procure and install a diesel-powered generator in the Apollo Bay township which will provide the township with an alternative supply source during outage events. The generator will be located at a suitable area within the township and connected to the HV network. The generator is sized at 2MW so that it can cover the peak demand of the selected microgrid area. Fuel storage has been sized to allow for 48-hours of running time before a refuel is required.

In the event of an outage of the CLC003 feeder, the automatic circuit recloser (ACR) upstream of the township will open and isolate the township from the main electrical grid. The diesel generator is able to be started within minutes to supply the township with electricity in the event of an outage.

On the conclusion of the outage, the generator can be powered down, the ACR closed and the township reverted to power from the grid.

C.2.3 Option three: install diesel generator and BESS microgrid

This option is to procure and install a battery energy storage system (BESS) as well as a diesel-powered generator in the Apollo Bay township. Both assets will be installed at a suitable area within the township and connected to the HV network.

The battery is sized at 2MWh which can power the township for an average of 4.5 hours assuming it is fully charged.

The generator is sized at 2MW so that it can cover the peak demand of the selected microgrid area. Fuel storage has been sized to allow for 48 hours of running time before a refuel is required.

The microgrid would operate in two different modes. During an outage, the township is ‘islanded’ from the electricity grid as the ACR upstream of the town opens. The microgrid would then provide an alternative supply source to customers primarily through the BESS in shorter outages. The diesel generator would be utilised in extended outages and when the demand in the township exceeds what the BESS can supply.

In the absence of a feeder outage, the BESS has the potential to operate in grid connected mode where it provides additional benefit streams through participating in energy markets, as well as storing excess solar exports of customers for use during non-generating hours. Future revenue from energy markets is difficult to predict, and there are also regulatory limitations on the provision of these market services. However, we have sought to include quantified benefits related to BESS, in the form of expected lease values to third parties, to ensure the additional functions of a BESS microgrid are considered.

C.2.4 Option four: high voltage tie line

Apollo bay is currently supplied by two high voltage feeders (CLC003 and CLC013) from the Colac zone substation. These feeders traverse hilly and inaccessible terrain of the Otway Ranges south of Colac. Key sections of each feeder have already been placed underground.

This option considers installing a third feeder to Apollo Bay.

Any new feeder, however, would need to have extensive sections installed underground to avoid being exposed to faults from weather and vegetation. Finding an alternative route into Apollo Bay would also be difficult as there are only two main access roads and these are already the routes for the existing supplies. Installing a large length of additional high voltage underground cable would also cause technical compliance issues with the Colac REFCL and would result in the need to upgrade the REFCL protection at our Colac zone substation.

The cost of this option would not be economical, and accordingly, it is not considered credible.

C.2.5 Option five: undergrounding

To significantly improve the resilience of the CLC003 feeder against storm and bushfire events, over 17km of overhead conductor which passes through dense vegetation would need to be undergrounded. Undergrounding such a large segment of the feeder would have a substantial capital cost making this option uneconomic.

Undergrounding only small sections of feeder would not significantly improve the resilience and reliability of the feeder, as any faults on the remaining overhead sections of the lines will still be exposed to the same outage risk during extreme weather events.

The cost of this option would not be economical, and accordingly, it is not considered credible.

C.3 Options analysis

A summary of the costs for each credible option is shown below. These options have been evaluated using cost-benefit analysis that compares the cost of the options against the quantified benefits.

TABLE 12 SUMMARY OF CREDIBLE OPTIONS: CAPITAL EXPENDITURE ($M, 2026)

OPTION		CAPEX
1	Base case: no investment	-
2	Install diesel generator microgrid	3.1
3	Install diesel generator and BESS microgrid	7.0

The main quantified benefit relates to the reduction in the energy at risk for customers in the supply area. Energy at risk has been calculated using historical outage data specific to the Apollo Bay township over the past five years. We consider using just energy at risk is a conservative representation of the full benefits of each option.

The values of network resilience and worst served customers have been considered in conjunction with the standard VCR to quantify this benefit.[27] We have ensured that there is no overlap between our worst served customer value and the AER's VNR by prioritising the use of the VNR when

[27] See section 12.2 for further details on the values included in our resilience business cases

applicable. By selecting a point within the Apollo Bay township we have been able to calculate the exact number of outages and minutes off supply across the last five years. We have then:

- applied the standard VCR for the first 500 minutes of an outage
- applied both our worst served customer value and the VCR from 500 minutes up to 720 minutes (12 hours)
- applied the VNR from 720 minutes onwards.

The benefit streams associated with BESS market participation have been included based on the estimated value of leasing the BESS to a retailer, given regulatory constraints around distribution networks operating in BESS related markets.

We have applied wind escalation to historical outages to project the impact of climate change. This is based on the methodology developed by AECOM, which estimates changes in the number of days with wind gusts above 100km/h.[28] Gusts above 100km/h are most likely to cause damage to our network assets and result in customer being taken off supply.

The analysis was undertaken over a 20-year time period to align with the expected life of the assets

C.3.1 Results summary

Table 13 shows the results of the option evaluation against our base case.[29] While options two and three generated similar benefits, option two has a lower capital cost.

TABLE 13 OPTION EVALUATION RESULT ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
1	Base case: no investment	-	-	-
2	Install diesel generator microgrid	4.0	5.5	1.5
3	Install diesel generator and BESS microgrid	8.8	5.6	-3.2

In addition to testing the options under a central scenario, we undertook sensitivity analysis relating to capital expenditure and wind escalation. Wind escalation sensitivity was included as wind is a key cause of outages during extreme weather events. Wind is notoriously hard to model, and this inherent uncertainty is only increasing as the climate changes. While we have included our best available wind estimates, we have also included sensitivities that account for no wind escalation and additional wind escalation.

Option two remained economic under all sensitivity scenarios.

C.3.2 Preferred option

The preferred option is to install a 2MW diesel generator microgrid in the Apollo Bay township.

A proposed low voltage network boundary for the microgrid is shown in figure 12. This extent is based on suitable islanding points in the HV network.

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28 PAL ATT 5.01 - AECOM - Methodology report - Jan2025 - Public
29 Further details are provided in PAL MOD 5.04 - Apollo bay microgrid - Jan2025 - Public

The proposed microgrid area has not had any faults occurring within the boundary in the past three years. This indicates that it is less likely for weather related faults to occur within the proposed solution area and that a resilience solution will be more likely to provide a backup supply during a resilience event.

The proposed area will service 428 customers and contains the following critical infrastructure;

- surf life saving club
- grocery store
- Barwon Water sewer pump station
- NBN/Telstra exchange
- proposed EV charging station.

FIGURE 12 PROPOSED APOLLO BAY MICROGRID AREA

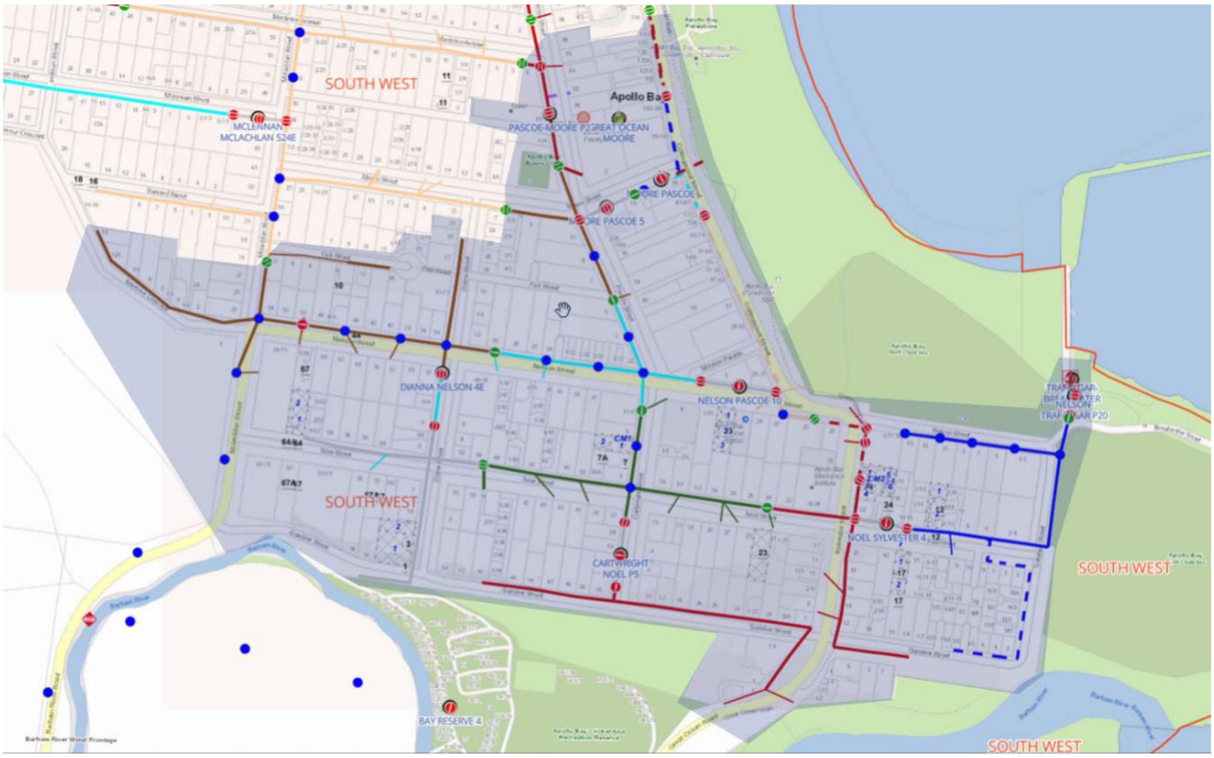


Table 14 outlines the proposed capital expenditure of the microgrid over the next regulatory period.

TABLE 14 INSTALLATION OF DIESEL GENERATOR MICROGRID ($M, 2026)

PREFERRED OPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	-	-	-	3.1	-	3.1

D

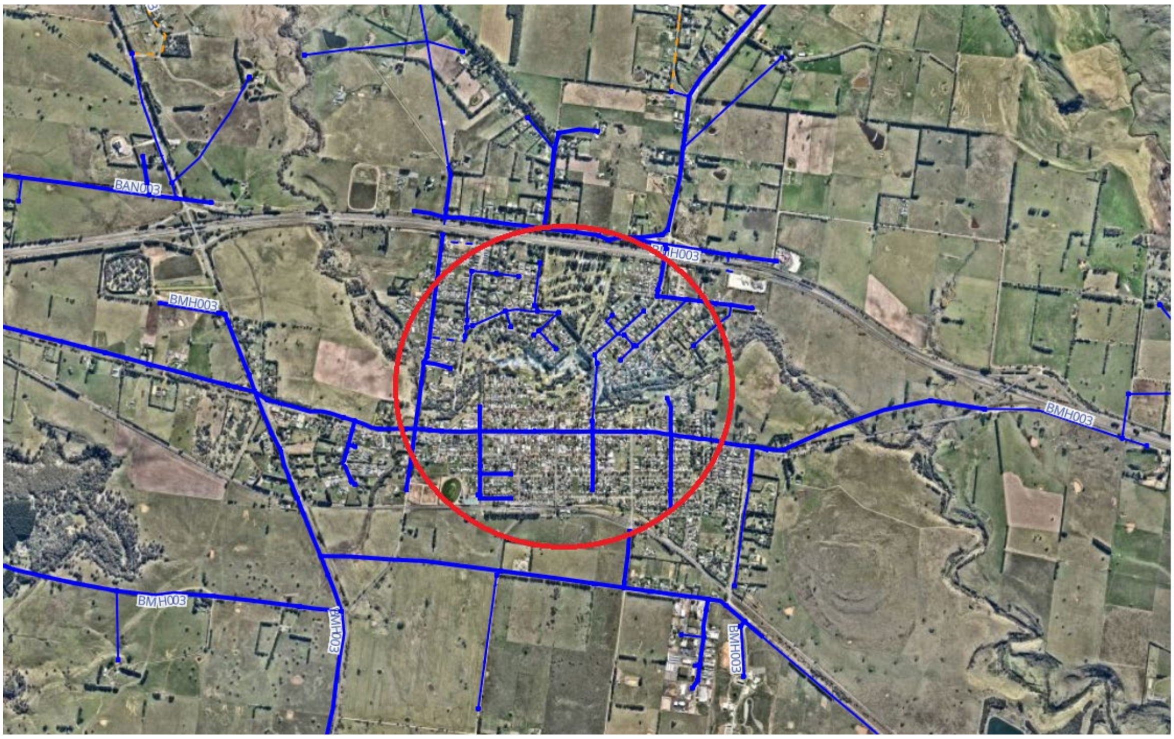
BALLAN SUPPLY AREA

D Ballan supply area

Ballan is small town 80 kms north-west of Melbourne, supplied by a single feeder BMH003. It serves as the administrative centre for Moorabool Shire Council. Our BMH003 feeder runs from Bacchus Marsh west towards Ballan along an alignment approximately parallel to the Western Highway. BMH003 consists of over 198km of overhead 22KV HV line and 6.7km of underground 22KV HV cable. There is one HV tie with our adjacent BAN003 feeder from Ballarat North, but this tie only provides limited transfer capability for Ballan town and its effectiveness is dependent on the locations of the fault affecting Ballan.

The feeders connecting to and within the Apollo Bay supply area are shown in Figure 13.

FIGURE 13 BALLAN SUPPLY AREA



D.1 Identified need

Over the last five years, the BMH003 feeder supplying Ballan has experienced an average of 4 unplanned outage events per year, with average annual unplanned outages totalling 1,292 minutes per year. This is significantly higher than the average across our network.

Faults on the BMH003 feeder occur over the full length of the feeder. Causes include equipment failure, weather, vegetation, third party & animal incidents. Vegetation related outages occur due to trees falling onto the line because of tree clearing activities (pine plantations) and windblown bark and branches. Weather related outages occur due to wind damage, lighting strikes and other storm related damage. This has occurred previously where storms have caused outages in the Ballan supply area.

Given the duration and frequency of outages in the Ballan supply area are already well above the averages experienced across our network, the identified need is to maintain service levels as the frequency and severity of extreme weather increases.

D.2 Options considered

We have considered a number of potential options to address the supply risk to the Ballan area from outages of the incoming HV feeder. Credible options are assessed relative to our base case.

D.2.1 Option one: base case

This option assumes that there is no additional investment into the resilience of our network in the Ballan supply area.

As the frequency and severity of extreme weather events increases over time due to climate change, the frequency and duration of electricity outages is anticipated to worsen.

D.2.2 Option two: install diesel generator microgrid

This option is install a diesel-powered generator in the Ballan township which will provide the township with an alternative supply source during outage events.

The generator will be located at a suitable area within the township and connected to the HV network. The generator is sized at 2MW so that it can cover the peak demand of the selected microgrid area. Fuel storage has been sized to allow for 48 hours of running time before a refuel is required.

In the event of an outage of the BMH003 feeder, the automatic circuit recloser (ACR) upstream of the township will open and isolate the township from the main electrical grid. The diesel generator is able to be started within minutes to supply the township with electricity in the event of an outage.

On the conclusion of the outage, the generator can be powered down, the ACR closed and the township reverted to power from the grid.

D.2.3 Option three: install diesel generator and BESS microgrid

This option is install a battery energy storage system (BESS) as well as a diesel-powered generator in the Ballan township. Both assets will be installed at a suitable area within the township and connected to the HV network.

The battery is sized at 2MWh which can power the township for an average of 3 hours assuming it is fully charged.

The generator is sized at 2MW so that it can cover the peak demand of the selected microgrid area. Fuel storage has been sized to allow for 48 hours of running time before a refuel is required.

The microgrid would operate in two different modes. During an outage, the township is "islanded" from the electricity grid as the ACR upstream of the town opens. The microgrid would then provide an alternative supply source to customers primarily through the BESS in shorter outages. The diesel generator would be utilised in extended outages and when the demand in the township exceeds what the BESS can supply.

In the absence of a feeder outage, the BESS has the potential to operate in grid connected mode where it provides additional benefit streams through participating in energy markets, as well as storing excess solar exports of customers for use during non-generating hours. Future revenue from energy markets is difficult to predict, and there are also regulatory limitations on the provision of these market services. However, we have sought to include quantified benefits related to BESS, in the form of expected lease values to third parties, to ensure the additional functions of a BESS microgrid are considered.

D.2.4 Option four: high voltage tie line

This option would install a tie line between two feeders to allow supply to continue to flow in the event one feeder suffers an outage.

Ballan is currently supplied via one high voltage feeder (BMH003) from the Bacchus Marsh zone substation and there is limited transfer capability to (BAN003) the Ballarat North zone substation due to network capacity and REFCL protection constraints. Installing an additional feeder to ballan would involve the installation of over 30km of high voltage line from Bacchus Marsh or Ballarat. Adding additional high voltage feeder to Ballarat North zone substation would cause technical compliance issues with the Ballarat North REFCL and would trigger significant upgrade works at Ballarat North.

The length of the tie line would also result in the tie line itself being exposed to similar storm/weather conditions as the existing feeders. Being exposed to similar outage events may that there is unlikely to be a significant reduction in the duration or frequency of outages.

The cost of this option would not be economical, and accordingly, it is not considered credible.

D.2.5 Option five: undergrounding

This option would remove overhead HV conductors that are susceptible to outage events and install them underground.

To significantly improve the resilience of the BMH003 feeder against storm and bushfire events, over 25km of overhead conductor would need to be undergrounded. Undergrounding such a large segment of the feeder would have a substantial capital cost making this option uneconomic.

Undergrounding only small sections of feeder would not significantly improve the resilience and reliability of the feeder, as any faults on the remaining overhead sections of the lines will still be exposed to the same outage risk during extreme weather events.

The cost of this option would not be economical, and accordingly, it is not considered credible.

D.3 Options analysis

A summary of the costs for each credible option is shown below. These options have been evaluated using cost-benefit analysis that compares the cost of the options against the quantified benefits.

TABLE 15 SUMMARY OF CREDIBLE OPTIONS: CAPITAL EXPENDITURE ($M, 2026)

OPTION		CAPEX
1	Base case: no investment	-
2	Install diesel generator microgrid	3.2
3	Install diesel generator and BESS microgrid	7.2

The main quantified benefit relates to the reduction in the energy at risk for customers in the supply area. Energy at risk has been calculated using historical outage data specific to the Ballan township over the past five years. We consider using just energy at risk is a conservative representation of the full benefits of each option.

The value of network resilience (VNR) and worst served customers have been considered in conjunction with the standard VCR to quantify this benefit.[30] We have ensured that there is no overlap between our worst served customer value and the AER's VNR by prioritising the use of the VNR when applicable. By selecting a point within the Ballan township we have been able to calculate the exact number of outages and minutes off supply across the last five years. We have then:

- applied the standard VCR for the first 500 minutes of an outage
- applied both our worst served customer value and the VCR from 500 minutes up to 720 minutes (12 hours)
- applied the VNR from 720 minutes onwards

The benefit streams associated with BESS market participation have been included based on the estimated value of leasing the BESS to a retailer, given regulatory constraints around distribution networks operating in BESS related markets.

We have applied wind escalation to historical outages to project the impact of climate change. This is based on the methodology developed by AECOM, which estimates changes in the number of days with wind gusts above 100km/h.[31] Gusts above 100km/h are most likely to cause damage to our network assets and result in customer being taken off supply.

The analysis was undertaken over a 20-year time period to align with the expected life of the assets.

D.3.1 Results summary

Table 16 shows the results of the option evaluation against our base case.[32] While options two and three generated similar benefits, option two has a lower capital cost.

TABLE 16 OPTION EVALUATION RESULT ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
1	Base case: no investment	-	-	-
2	Install diesel generator microgrid	4.2	5.1	0.9
3	Install diesel generator and BESS microgrid	9.3	5.3	-4.1

In addition to testing the options under a central scenario, we undertook sensitivity analysis relating to capital expenditure and wind escalation. Wind escalation sensitivity was included as wind is a key cause of outages during extreme weather events. Wind is notoriously hard to model, and this inherent uncertainty is only increasing as the climate changes. While we have included our best available wind estimates, we have also included sensitivities that account for no wind escalation and additional wind escalation.

Option two remained economic under all sensitivity scenarios.

30 See section 12.2 for further details on the values included in our resilience business cases
31 PAL ATT 5.01 - AECOM - Methodology report - Jan2025 - Public
32 Further details are provided in PAL MOD 5.05 - Ballan microgrid - Jan2025 - Public

D.3.2 Preferred option

The preferred option is to install a diesel generator microgrid in the Ballan township.

A proposed low voltage network boundary for the microgrid is shown in figure 14. This extent is based on suitable islanding points in the HV network. The proposed microgrid area has only had 2 faults occurring within the area in the past three years, and these faults were not due to a weather-related incident. This indicates that it is less likely for weather related faults to occur within the proposed solution area and that a resilience solution will be more likely to provide a backup supply during a resilience event.

The proposed area that will be covered by the microgrid in the event of an outage services 959 customers and contains the following critical infrastructure:

- police station
- grocery store
- Central Highlands Water sewer pump station
- Telstra exchange
- medical centre
- recreation reserve
- Ballan Mechanics Institute.

FIGURE 14 PROPOSED BALLAN MICROGRID AREA

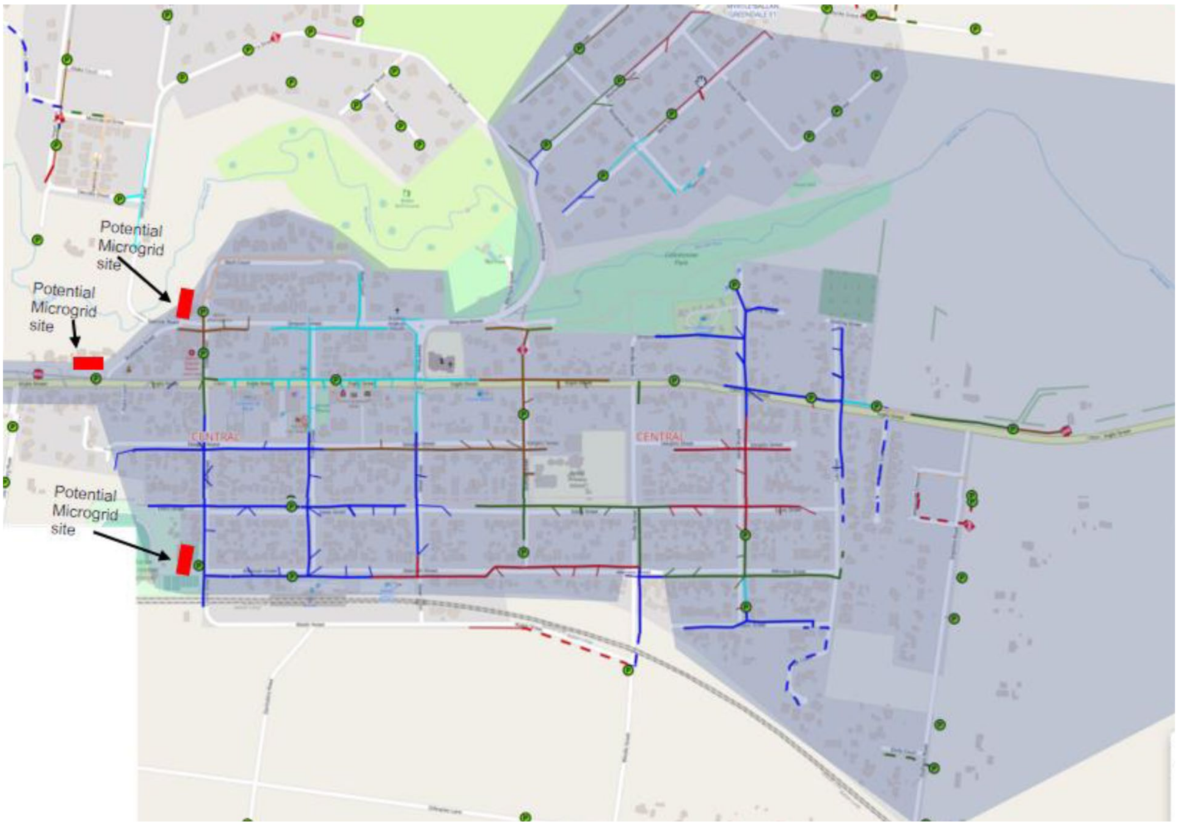


Table 17 outlines the proposed capital expenditure for the microgrid over the next regulatory period.

TABLE 17 INSTALLATION OF DIESEL GENERATOR MICROGRID ($M, 2026)

PREFERRED OPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	-	-	3.2	-	-	3.2

E

DONALD SUPPLY AREA

E Donald supply area

The Donald supply area focuses on customers in and around the township of Donald. Donald is an inland town, located within the Shire of Buloke, 280km North-West of Melbourne. It is supplied by a single feeder CTN006 which runs west from Charlton to Donald along the Borung Hwy. Our CTN006 feeder consists of over 300km of overhead 22kV HV line and 1km of underground 22kV HV cable. Outages in the Donald supply area can often be prolonged as there is no backup feeder which supply can be switched to in the event of an outage.

The feeders connecting to and within the Donald supply area are shown in Figure 15.

FIGURE 15 DONALD SUPPLY AREA

E.1 Identified need

Over the last five years, the CTN006 Feeder supplying Donald has experienced an average of 5 unplanned outage events per year, with average annual unplanned outages totalling 922 minutes per year. This is significantly higher than the average across our network.

Faults on CTN006 occur over the full length of the feeder. The two main causes of outages are weather and equipment failure. Weather related outages occur due to wind damage, lighting strikes and other storm related damage. This has occurred previously where significant storm activity caused an outage totalling 1,356 minutes in the Donald supply area.

Given the duration and frequency of outages in the Donald supply area are already well above the averages experienced across our network, the identified need is to maintain service levels as the frequency and severity of extreme weather increases.

E.2 Options considered

We have considered a number of potential options to address the supply risk to the Donald supply area from outages of the incoming HV feeder. Credible options are assessed relative to our base case.

E.2.1 Option one: base case

This option assumes that there is no additional investment into the resilience of our network in the Donald supply area.

As the frequency and severity of extreme weather events increases over time due to climate change, the frequency and duration of supply outages is anticipated to worsen.

E.2.2 Option two: install diesel generator microgrid

This option is to install a diesel-powered generator in the Donald township which will provide the township with resilience during outage events. The generator will be located at a suitable area within the township and connected to the HV network.

The generator is sized at 2MW so that it can cover the peak demand of the selected microgrid area. Fuel storage has been sized to allow for 48 hours of running time before a refuel is required.

In the event of an outage of the CTN006 feeder, the automatic circuit recloser (ACR) upstream of the township will open and isolate the township from the main electrical grid. The diesel generator is able to be started within minutes to supply the township with electricity in the event of an outage.

On the conclusion of the outage, the generator can be powered down, the ACR closed and the township reverted to power from the grid.

E.2.3 Option three: install diesel generator and BESS microgrid

This option is to install a battery energy storage system (BESS) as well as a diesel powered generator in the Donald township. Both assets will be installed at a suitable area within the township and connected to the HV network.

The battery is sized at 2MWh which can power the township for an average of 3 hours assuming it is fully charged.

The generator is sized at 2MW so that it can cover the peak demand of the selected microgrid area. Fuel storage has been sized to allow for 48 hours of running time before a refuel is required.

The microgrid would operate in two different modes. During an outage, the township is 'islanded' from the electricity grid as the ACR upstream of the town opens. The microgrid would then provide an alternative supply source to customers primarily through the BESS in shorter outages. The diesel generator would be utilised in extended outages and when the demand in the township exceeds what the BESS can supply.

In the absence of a feeder outage, the BESS has the potential to operate in grid connected mode where it provides additional benefit streams through participating in energy markets, as well as storing excess solar exports of customers for use during non-generating hours. Future revenue from energy markets is difficult to predict, and there are also regulatory limitations on the provision of these market services. However, we have sought to include quantified benefits related to BESS, in the form of expected lease values to third parties, to ensure the additional functions of a BESS microgrid are considered.

E.2.4 Option four: high voltage tie line

This option would install a tie line between two feeders to allow supply to continue to flow in the event one feeder suffers an outage.

The option of installing a tie line to supply Donald was discounted due to the distances involved in constructing a tie from an adjacent feeder/zone substation. Donald is approximately 35km from the closest 22kV line supplied from Stawell zone substation or Horsham zone substation. Significant upgrades would be required to convert the existing single phase 22kV and single wire earth return lines to three phase 22kV lines which would be suitable to supply the customers in the Donald supply area.

The length of the tie line would also result in the tie line itself being exposed to similar storm/weather conditions as the CTN006 feeder. Being exposed to similar outage events may that there is unlikely to be a significant reduction in the duration or frequency of outages.

The cost of this option would not be economical, and accordingly, it is not considered credible.

E.2.5 Option five: undergrounding

This option would remove overhead HV conductors that are susceptible to outage events and install them underground.

To significantly improve the resilience of the CTN006 feeder against storm and bushfire events, over 30km of overhead conductor which passes through dense vegetation would need to be undergrounded. Undergrounding such a large segment of the feeder would have a substantial capital cost making this option uneconomic.

Undergrounding only small sections of feeder would not significantly improve the resilience and reliability of the feeder, as any faults on the remaining overhead sections of the lines will still be likely to cause outages during extreme weather events.

The cost of this option would not be economical, and accordingly, it is not considered credible.

E.3 Options analysis

A summary of the costs for each credible option is shown below. These options have been evaluated using cost-benefit analysis that compares the cost of the options against the quantified benefits.

TABLE 18 SUMMARY OF CREDIBLE OPTIONS: CAPITAL EXPENDITURE ($M, 2026)

OPTION		CAPEX
1	Base case: no investment	-
2	Install diesel generator microgrid	3.2
3	Install diesel generator and BESS microgrid	7.1

.

The main quantified benefit relates to the reduction in the energy at risk for customers in the supply area. Energy at risk has been calculated using historical outage data specific to the Apollo Bay township over the past five years. We consider using just energy at risk is a conservative representation of the full benefits of each option.

The values of network resilience and worst served customers have been considered in conjunction with the standard VCR to quantify this benefit.[33] We have ensured that there is no overlap between our worst served customer value and the AER's VNR by prioritising the use of the VNR when applicable. By selecting a point within the Donald township we have been able to calculate the exact number of outages and minutes off supply across the last five years. We have then:

- applied the standard VCR for the first 500 minutes of an outage
- applied both our worst served customer value and the VCR from 500 minutes up to 720 minutes (12 hours)
- applied the VNR from 720 minutes onwards.

The benefit streams associated with BESS market participation have been included based on the estimated value of leasing the BESS to a retailer, given regulatory constraints around distribution networks operating in BESS related markets.

We have applied wind escalation to historical outages to project the impact of climate change. This is based on the methodology developed by AECOM, which estimates changes in the number of days with wind gusts above 100km/h.[34] Gusts above 100km/h are most likely to cause damage to our network assets and result in customer being taken off supply.

The analysis was undertaken over a 20-year time period to align with the expected life of the assets.

E.3.1 Results summary

Table 19 shows the results of the option evaluation against our base case.[35] While options two and three generated similar benefits, option two has a lower capital cost.

TABLE 19 OPTION EVALUATION RESULT ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
1	Base case: no investment	-	-	-
2	Install diesel generator microgrid	4.3	8.6	4.3
3	Install diesel generator and BESS microgrid	9.6	8.7	-0.9

In addition to testing the options under a central scenario, we undertook sensitivity analysis relating to capital expenditure and wind escalation. Wind escalation sensitivity was included as wind is a key cause of outages during extreme weather events. Wind is notoriously hard to model, and this inherent uncertainty is only increasing as the climate changes. While we have included our best available wind estimates, we have also included sensitivities that account for no wind escalation and additional wind escalation.

Option two remained economic under all sensitivity scenarios.

33 See section 12.2 for further details on the values included in our resilience business cases
34 PAL ATT 5.01 - AECOM - Methodology report - Jan2025 - Public
35 Further details are provided in PAL MOD 5.06 - Donald microgrid - Jan2025 - Public

E.3.2 Preferred option

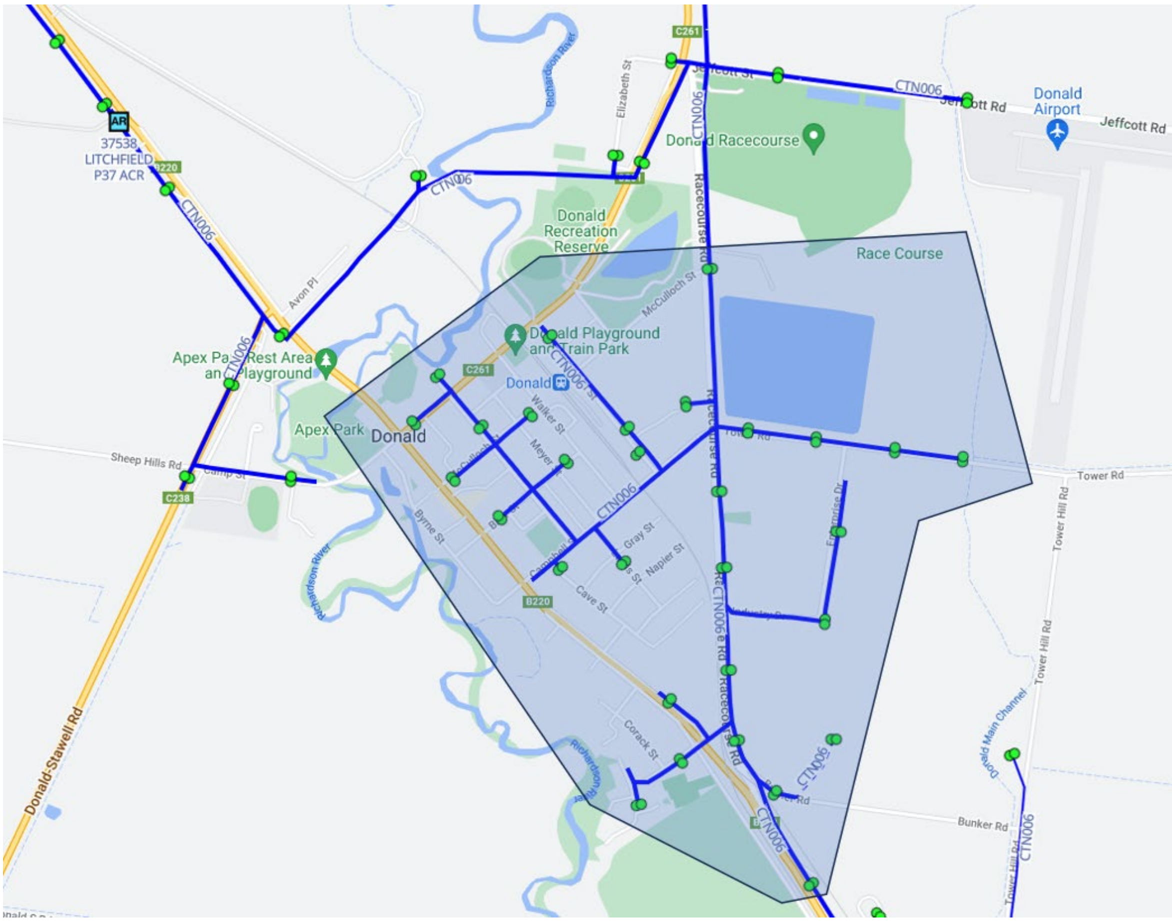
The preferred option is to install a 2MW diesel generator microgrid in the Donald township, as well as a new ACR to enable the town to be islanded from the electricity grid.

A proposed low voltage network boundary for the microgrid is shown in figure 16. This extent is based on suitable islanding points in the HV network. The proposed microgrid area has only had 1 fault occurring within the area in the past 3 years. This indicates that it is less likely for weather related faults to occur within the proposed solution area and that a resilience solution will be more likely to provide a backup supply during a resilience event.

The proposed area that will be covered by the microgrid in the event of an outage services 433 customers and contains the following critical infrastructure:

- Donald police station
- supermarket
- pharmacy
- GWMWater pump station
- train station.

FIGURE 16 PROPOSED DONALD MICROGRID AREA



Source: Energy Resilience Design Studies. CitiPower, Powercor and United Energy

Table 20 outlines the proposed capital expenditure for the preferred option over the next regulatory period.

TABLE 20 INSTALLATION OF A DIESEL GENERATOR MICROGRID ($M, 2026)

PREFERRED OPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	-	3.2	-	3.1	-	3.2

F

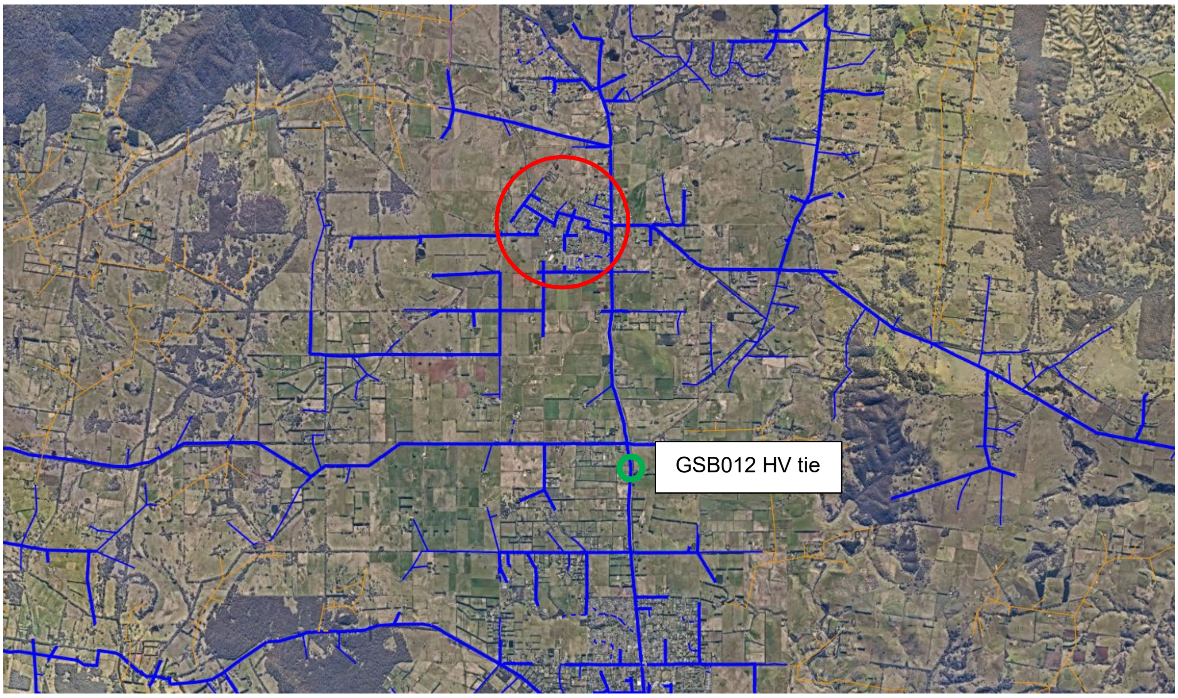
LANCEFIELD SUPPLY AREA

F Lancefield supply area

Lancefield is a town in the Shire of Macedon Ranges located 70km North of Melbourne. The town is supplied by one high voltage feeder (WND013) which runs from Woodend east towards Lancefield via Hanging Rock and Newham. The WND013 feeder consists of over 295km of overhead 22KV HV line and 8.6km of underground 22KV HV cable. There is one HV tie with the adjacent GSB012 feeder which allows for back feeding into Lancefield for any faults in the first part of the feeder.

The feeders connecting to and within the Lancefield supply area are shown in Figure 17.

FIGURE 17 LANCEFIELD SUPPLY AREA



F.1 Identified need

Over the last five years, the WND013 feeder supplying Lancefield has experienced an average of 9 unplanned outage events per year, with average annual unplanned outages totalling 1,292 minutes per year. This is significantly higher than the average across our network.

Faults on the WND013 occur over the full length of the feeder. Causes for these faults include weather, vegetation and equipment failure. However, weather events are the primary driver of outages and accounted for over 85 per cent of all unplanned outage minutes with known causes.

The area supplied by the WND013 feeder is exposed to adverse weather conditions on a regular basis. This has occurred previously where a storm event caused an outage in the Lancefield supply area totalling 2,907 minutes.

With the introduction of the REFCL at Woodend, faults anywhere on the WND013 22KV network may cause the WND013 feeder to trip. This may further impact the frequency and duration of outages.

Given the duration and frequency of outages in the Apollo Bay supply area are already well above the averages experienced across our network, the identified need is to maintain service levels as the frequency and severity of extreme weather increases.

F.2 Options considered

We have considered a number of potential options to address the supply risk to the Lancefield area from outages of the incoming HV feeder. Credible options are assessed relative to our base case.

F.2.1 Option one: base case

This option assumes that there is no additional investment into improving the network resilience and reliability of the Lancefield area.

As the frequency and severity of extreme weather events increases over time due to climate change, the frequency and duration of supply outages is anticipated to worsen.

F.2.2 Option two: install diesel generator microgrid

This option is to install a diesel-powered generator in the Lancefield township which will provide the township with resilience during outage events.

The generator will be located at a suitable area within the township and connected to the HV network. The generator is sized a 2MW so that it can cover the peak demand of the selected microgrid area. Fuel storage has been sized to allow for 48 hours of running time before a refuel is required.

In the event of an outage of the WND013 feeder, the automatic circuit recloser (ACR) upstream of the township will open and isolate the township from the main electrical grid. The diesel generator is able to be started within minutes to supply the township with electricity in the event of an outage.

On the conclusion of the outage, the generator can be powered down, the ACR closed and the township reverted to power from the grid.

F.2.3 Option three: install diesel generator and BESS microgrid

This option is to install a battery energy storage system (BESS) as well as a diesel-powered generator in the Lancefield township. Both assets will be installed at a suitable area within the township and connected to the HV network.

The battery is sized at 2MWh which can power the township for an average of 6 hours assuming it is fully charged.

The generator is sized at 2MW so that it can cover the peak demand of the selected microgrid area. Fuel storage has been sized to allow for 48 hours of running time before a refuel is required.

The microgrid would operate in two different modes. During an outage, the township is ‘islanded’ from the electricity grid as the ACR upstream of the town opens. The microgrid would then provide an alternative supply source to customers primarily through the BESS in shorter outages. The diesel generator would be utilised in extended outages and when the demand in the township exceeds what the BESS can supply.

In the absence of a feeder outage, the BESS has the potential to operate in grid connected mode where it provides additional benefit streams through participating in energy markets, as well as storing excess solar exports of customers for use during non-generating hours. Future revenue from energy markets is difficult to predict, and there are also regulatory limitations on the provision of these market services. However, we have sought to include quantified benefits related to BESS, in the form of expected lease values to third parties, to ensure the additional functions of a BESS microgrid are considered.

F.2.4 Option four: high voltage tie line

This option would install a tie line between two feeders to allow supply to continue to flow in the event one feeder suffers an outage.

There is already one high voltage tie (between feeders GSB012 and WND013) in the vicinity of Lancefield with the tie occurring before Lancefield town. Due to the tie occurring prior to the town, Lancefield is effectively radial from this point onwards. To supply an alternative feed into Lancefield would require the construction of a new section of feeder into Lancefield. The new sections of feeder would run parallel to WND013 and tie into the GSB012 or the WND012 feeder. Whilst providing alternative feed for Lancefield, the GSB012 and WND012 feeders run through similar terrain and are exposed to similar storm/weather conditions as the WND013 feeder. This would result in the alternative feeder being susceptible to the same vegetation and storm/weather events as the current tie, and there is unlikely to result in a significant reduction in the duration or frequency of outages.

A second option would be to bring in a tie from the north from Bendigo. This option was discounted due to the distance the tie would be required to cover, which would expose the tie to additional weather and vegetation related outages as well as having significant costs.

The cost of this option would not be economical, and accordingly, it is not considered credible.

F.2.5 Option five: undergrounding

This option would remove overhead HV conductors that are susceptible to outage events and install them underground.

To significantly improve the resilience of the WND013 feeder against storm and bushfire events, over 25km of overhead conductor would need to be undergrounded. Undergrounding such a large segment of the feeder would have a substantial capital cost.

Undergrounding only small sections of feeder would not significantly improve the resilience and reliability of the feeder, as any faults on the remaining overhead sections of the lines will still be likely to cause outages during extreme weather events.

The cost of this option would not be economical, and accordingly, it is not considered credible.

F.3 Options analysis

A summary of the costs for each credible option is shown below. These options have been evaluated using cost-benefit analysis that compares the cost of the options against the quantified benefits.

TABLE 21 SUMMARY OF CREDIBLE OPTIONS: CAPITAL EXPENDITURE ($M, 2026)

OPTION		CAPEX
1	Base case: no investment	-
2	Install diesel generator microgrid	3.2
3	Install diesel generator and BESS microgrid	7.1

.

The main quantified benefit relates to the reduction in the energy at risk for customers in the supply area. Energy at risk has been calculated using historical outage data specific to the Lancefield township over the past five years. We consider using just energy at risk is a conservative representation of the full benefits of each option.

The values of VNR and worst served customers have been considered in conjunction with the standard (VCR to quantify this benefit.[36] We have ensured that there is no overlap between our worst served customer value and the AER's VNR, prioritising the use of the VNR when applicable. By selecting a point within the Lancefield township we have been able to calculate the exact number of outages and minutes off supply across the last five years. We have then:

- applied the standard VCR for the first 500 minutes of an outage
- applied both our worst served customer value and the VCR from 500 minutes up to 720 minutes (12 hours)
- applied the VNR from 720 minutes onwards

The benefit streams associated with BESS market participation have been included based on the estimated value of leasing the BESS to a retailer, given regulatory constraints around distribution networks operating in BESS related markets.

We have applied wind escalation to historical outages to project the impact of climate change. This is based on the methodology developed by AECOM[37], which estimates changes in the number of days with wind gusts above 100km/h. Gusts above 100km/h are most likely to cause damage to our network assets and result in customer being taken off supply.

The analysis was undertaken over a 20-year time period to align with the expected life of the assets.

F.3.1 Results summary

Table 22 shows the results of the option evaluation against Option 1 base case.[38] While options two and three generated similar benefits, option two has a lower capital cost.

TABLE 22 OPTION EVALUATION RESULT ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
1	Base case: no investment	-	-	-
2	Install diesel generator microgrid	3.9	3.9	0.0
3	Install diesel generator and BESS microgrid	8.6	4.0	-4.6

In addition to testing the options under a central scenario, we undertook sensitivity analysis relating to capital expenditure and wind escalation. Wind escalation sensitivity was included as wind is a key cause of outages during extreme weather events. Wind is notoriously hard to model, and this inherent uncertainty is only increasing as the climate changes. While we have included our best available wind estimates, we have also included sensitivities that account for no wind escalation and additional wind escalation.

Option two remains economic under some but not all sensitivity scenarios.

36 See section 12.2 for further details on the values included in our resilience business cases
37 PAL ATT 5.01 - AECOM - Methodology report - Jan2025 - Public
38 Further details are provided in PAL MOD 5.07 - Lancefield microgrid - Jan2025 - Public

F.3.2 Preferred option

The preferred option is install a 2MW diesel generator microgrid in the Lancefield township

A proposed low voltage network boundary for the microgrid is shown in figure 18. This extent is based on suitable islanding points in the HV network.

The proposed microgrid area has only had 1 fault occurring within the area in the past three years. This indicates that it is less likely for weather related faults to occur within the proposed solution area and that a resilience solution will be more likely to provide a backup supply during a resilience event.

The proposed area that will be covered by the microgrid in the event of an outage services 433 customers and contains the following critical infrastructure:

- Lancefield neighbourhood house
- grocery store
- Lancefield Water filtration plant
- Telstra asset
- medical centre
- fire station.

FIGURE 18 PROPOSED LANCEFIELD MICROGRID AREA

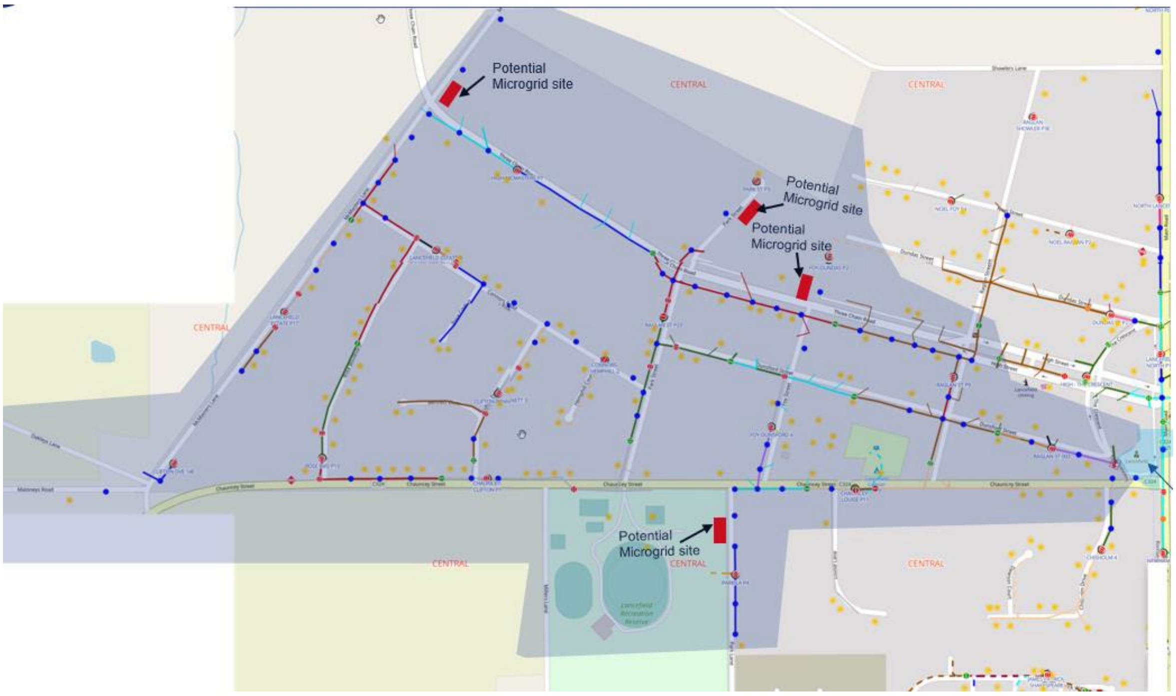


Table 23 outlines the proposed capital expenditure for the preferred option over the 2026–31 regulatory period.

TABLE 23 INSTALLATION OF A DIESEL GENERATOR MICROGRID ($M, 2026)

PREFERRED OPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	-	-	-	-	3.2	3.2

G

RADIO SITE BATTERIES

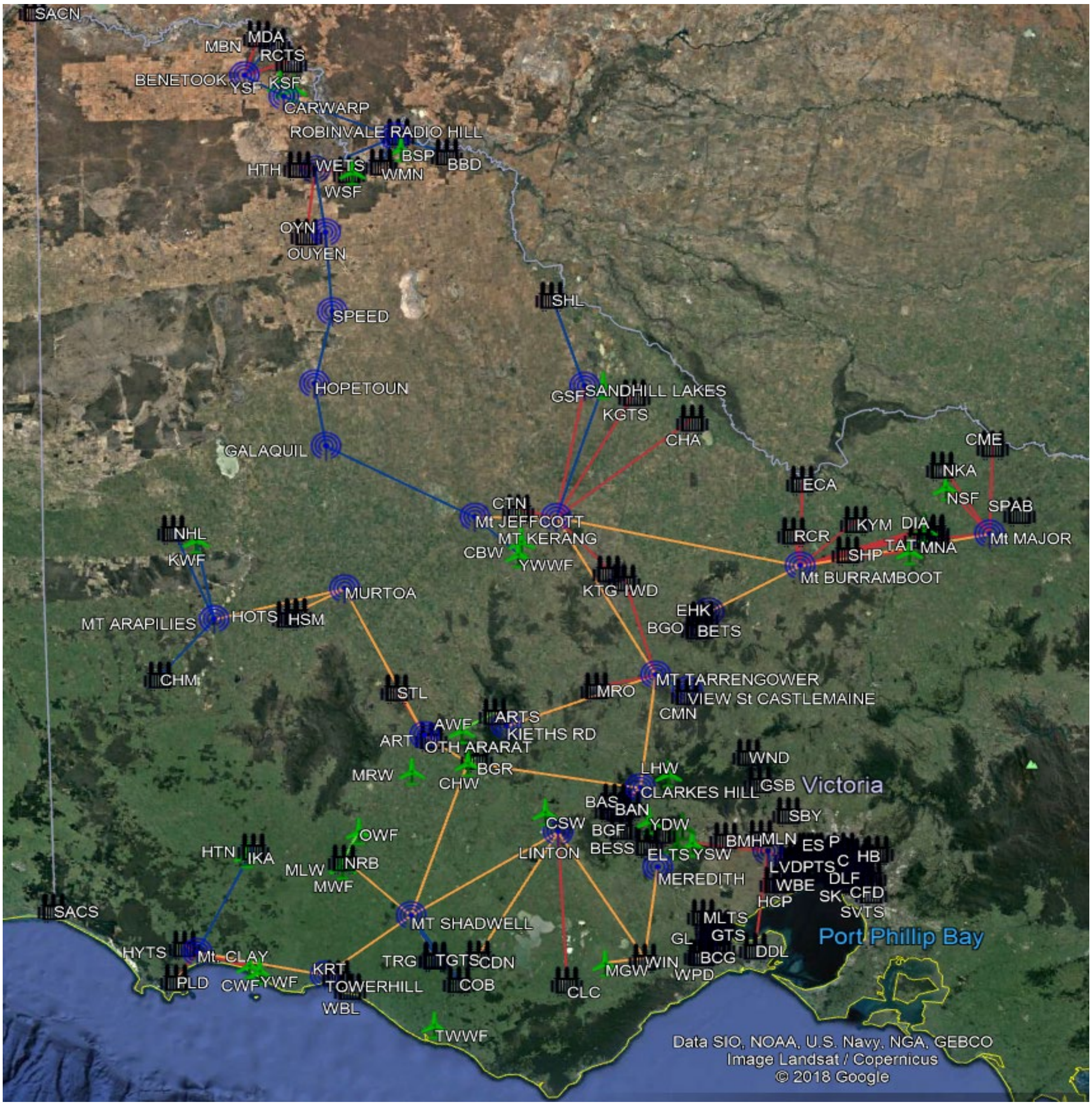
G Radio site batteries

Our radio network was established to support reliability in rural areas. It is primarily used for terminal station and zone substation communications and supporting the integration of large-scale renewable energy generation (wind, solar, battery storage).

In higher density areas it is economic to deploy physical communication mediums such as optical fibre. However, in rural areas long haul radio networks have been implemented as they are far more economical.

In total, we have 27 radio sites across our network, with the extent and remoteness of these sites shown in figure 19.

FIGURE 19 POWERCOR RADIO NETWORK



G.1 Identified need

The performance of our radio network impacts our network service levels as failures may lead to delayed response to a loss of customer supply and pose safety risks to our personnel and the public, particularly in rural areas.

The identified need, therefore, is to manage our radio network to maintain reliability and minimise safety risks as far as practicable, consistent with our regulatory and legislative obligations and as the frequency and severity of extreme weather increases.

G.1.1 Compliance obligations

In accordance with the National Electricity Rules (Rules), the Australian Energy Market Operator (AEMO) requires specific communications links to uphold market reliability. Specifically: [39]

> *each Network Service Provider must provide and maintain…the necessary primary and, where nominated by AEMO, back-up communications facilities for control, operational metering, and indication from the relevant local sites to the appropriate interfacing termination as nominated by AEMO.*
>
> *…AEMO may, by notice in writing, require a Network Service Provider, a Generator or a Market Network Service Provider to: (1) install remote monitoring equipment which, in AEMO's reasonable opinion, is adequate to enable AEMO to remotely monitor the performance of a transmission system or distribution system...*

Our radio communications infrastructure is used to meet these obligations, specifically by underpinning the operation of the following:

- runback schemes – to allow the integration of large-scale wind and solar power generators, power flow must be managed through 'runback' schemes. These schemes protect the electricity network by informing generators to reduce, or runback, their output when the distribution network is nearing capacity. Without runback schemes, there is a material risk our assets and terminal stations would become overloaded, causing wide scale outages and the risk of fire starts
- inter-trip systems – when network protection operates due to a fault, large generators must also be disconnected. AEMO requires inter-trip systems to ensure mass blackouts do not occur. If generators do not quickly disconnect in a fault situation, then a system black outage can occur due to protection equipment tripping at the transmission level (e.g. such as like the blackout event that occurred in South Australia in 2016)
- inter-control centre communications protocol (ICCP) – ICCP links to zone substations and generators are required by AEMO, with ICCP links allowing data exchange to provide AEMO visibility of power flows through the electricity network.

The above applications and schemes all require high reliability and speed of the communications network. AEMO and AusNet (transmission) requires greater than 99 per cent reliability as well as low latency due to the risks involved. AEMO's power system data communication standard outlines that we must transmit data as per standards shown in table 24.[40]

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[39] National Electricity Rules, 4.11.2 (a), (d) and (e).
[40] AEMO, Power System Data Communication Standard, December 2017, p. 9-10.

TABLE 24 AEMO PERFORMANCE REQUIREMENTS OVER 12 MONTHS

CATEGORY OF RME AND RCE	PERIOD OF CRITICAL OUTAGES
Dispatch data where there is no agreed substitute data	6 hours
Dispatch data where there is agreed substitute	12 hours
Remote control equipment	24 hours

Source: AEMO, Power system data communication standard

Most of our substations and the generators connected to our network—for which we must operate a runback scheme—are defined as both remote monitoring equipment (RME) and remote-control equipment (RCE). RCEs are required to have less than 24 hours of outages in 12 months, which equates to 99.73 per cent availability. In the case of dispatch data (generators) greater than 99.9 per cent availability is required. This availability cannot be achieved through public telecommunication networks as they offer, at best, around 95 per cent availability and up to 8-hour battery backup.

In the context of increasing frequency and severity of extreme weather events, it is prudent to consider how we ensure ongoing compliance with these standards.

3.1.1 Government expectations

In addition to direct expectations on electricity distributors, the Victorian Government's network outage review made recommendations on business continuity planning for other essential service providers. Specifically, recommendation 10 requires owners and operators of critical infrastructure to ensure that they have appropriate arrangements for services to stay connected for 72 hours without network power supply.

Our radio network supports our response to customer outages through operation of protection equipment, fault location identification and remote field switching. For this reason, remote communication is vital for managing faults effectively.

Across our network, 23 of our radio communication sites do not have capability to provide 72-hours of operation with mains power.

From a network resilience perspective, the risk of prolonged outages at these sites is compounded by the following:

- our radio communication equipment is typically installed on remote hill tops that have mains supply that itself is inherently vulnerable to extreme weather (i.e. radio equipment is often supplied by a single radial SWER line)
- the remote nature of these sites means restoration timeframes are extended by long travel times, with additional risks associated with potential restrictions due to ongoing weather conditions (e.g. ongoing bushfire risks, flooded and/or blocked roads)
- our radio network is designed to be connected via links that hop from one site to another, rather connecting in 'star' fashion (as this is far more costly and sometimes impractical to implement due to the vast distances involved). This means impacts from an outage at one site may have broader impacts to our communication network
- during a widespread outage, restoring supply to our own communications infrastructure would impose further pressure on scarce resources that would otherwise focus on restoring customers.

G.1.2 Maintaining reliability

The ability for our network control systems (e.g. SCADA) and associated or independent protection schemes to isolate faults quickly is dependent on our communication network.

For example, when a fault occurs at a zone substation or terminal station, the initial notification is received over a communications link in the control centre via SCADA and then passed to our distribution management system (DMS). The network controller reviews the data and dispatches crews to investigate.

In some situations, the network controller is able to restore healthy sections of the affected feeder using remote switching equipment before the field crew arrives onsite. This is achieved through remotely opening and closing circuit breakers, automatic circuit reclosers and remote-control gas switches. They utilise the field crews to further refine outage areas using manual switching devices.

If the radio network failed to function or was shutdown, the information currently received for many zone substations and terminal stations via SCADA and DMS would have to be completed by crews in the field. Given the length of many of our rural feeders, this additional time off supply for customers could be significant.

G.1.3 Maintaining safety

Zone substations are entered by employees that are specifically trained and entry is generally avoided due to the inherent risks of electricity. If protection has tripped inside a zone substation, upon re-energisation, the asset can fail explosively. Therefore, to reduce the risk of injury this is conducted remotely—this would not be possible without the radio network.

Electricity feeders are also remotely de-energised if there is a public safety risk. A key example of this is if a pole is leaning dangerously after a strong wind event, the feeder will be isolated to mitigate the risk of live powerlines coming into contact with a member of the public.

Remote control and monitoring of our distribution network enables us to operate and maintain safety of its assets, customer equipment, customers and the public.

G.2 Options considered

Our options analysis considers a number of potential credible options to meet the identified need (relative to a do-nothing base case). Credible options are those that we consider are able to meet the identified need, meaning the solution is both technically and economically feasible.

G.2.1 Option one: do-nothing different

Under this option, we would continue to maintain our existing batteries at our radio sites, subject to their typical seven-year replacement cycle. Our existing sites typically have 48-hour battery capability.

This option, therefore, would not meet the recommendation set out in network outage review.

Further, since 2021, the average duration of our major widespread outages has been a little over three days, meaning without intervention, our radio sites (and therefore customers) would be exposed to the potential reliability and safety impacts associated with prolonged periods without power.

G.2.2 Option two: extend battery capability at radio sites with solar back-up for high-risk sites

Option two would extend the battery capacity at 23 of our radio sites to 72-hours, with additional solar back-up supply for six high-risk sites. Our four low-risk sites would maintain their existing capacity.

Specifically, this option would replace current lead acid batteries and associated chargers, upgrade the switchboard and wiring for 72-hour battery capacity, and provide a port for diesel generator connection.

This option would meet the recommendation of the network outage review, and better prepare us to maintain communication when mains supply is lost to our radio sites for extended periods. The additional battery capacity provides more time during widespread events to switch the network safely, and if needed, have more time to reach the sites and connect a diesel generator prior to the communication battery reaching the cut-off value where the radio communication equipment fails. The use of solar would extend this timeframe at our six highest risk sites.

G.2.3 Option three: extend battery capability at radio sites with solar back-up for medium and high-risk sites

This option is the same as option two above, but would further supplement our battery supply with solar at all medium and high-risk sites.

Option three, therefore, would equally meet the recommendation from the network outage review. The costs associated with additional solar, however, will be greater.

G.2.4 Other non-credible options

Several additional options and scenarios were not considered credible—for example:

- utilising cellular 4G in place of radio communications has been discounted because it would not comply with AEMO's availability requirements and in any event, the battery survivability of these networks is less than 8-hours. The cellular 4G network also has significant reliability issues during extreme weather events
- options that utilise optical fibre, such as services from the NBN or extending our own optical fibre network, have been discounted due to significantly high costs due to long distances involved.

G.3 Options analysis

As outlined above, only options two and three meet the recommendation from the Victorian Government's network outage review for owners and operators of critical infrastructure to ensure they have appropriate arrangements for services to stay connected for 72 hours without network power supply. Further, the benefits of options two and three are likely to be similar—that is, although additional solar back-up will prolong storage capability, the benefits of doing so at our medium risk sites is likely low.

Accordingly, our options analysis is based on a least-cost to compliance approach.

For options two and three, a summary of the corresponding costs is set out in table 25.

TABLE 25 SUMMARY OF CREDIBLE OPTIONS: CAPITAL EXPENDITURE ($M, 2026)

OPTION		COST
2	Extend battery capacity at radio sites with solar back-up for high-risk sites	1.5
3	Extend battery capacity at radio sites with solar back-up for medium and high-risk sites	3.1

G.3.1 Preferred option

The preferred option is to extend battery capability at radio sites with additional solar back-up at our high-risk sites only (i.e. option two). A summary of the costs of this option are shown in table 26.

TABLE 26 RADIO BATTERIES: CAPITAL EXPENDITURE ($M, 2026)

PREFERRED OPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Extend battery capacity at radio sites with solar for high-risk sites	0.3	0.3	0.3	0.3	0.3	1.5

H

COMMUNITY SUPPORT

H Community support

When they occur, extreme climate events have widespread impacts across our communities. Historically, our primary focus during these outages has been to restore supply quickly and safely to as many customers as possible, while also keeping customers informed through a variety of channels.

We are proud of our track record in responding to these events, which in the major storms in February 2024 for example, included a whole-of-business effort to restore supply to 96 per cent of customers within 16 hours. These restoration efforts are underpinned by significant preparation efforts, including scheduling additional crews and support staff (ahead of predicted weather patterns) to ensure we are ready to respond to multiple outages. As these events progress, our established escalation processes respond to safety issues and restoration priorities.

Our experience during these and other more recent events, however, is that our customers and communities are also seeking a local presence to support them on-the-ground—before, during and after events—to share information and help them make more informed decisions. Today, we are only able to provide this localised support on an ad-hoc and as-available basis (which we discuss in more detail in our options analysis section below).

H.1 Identified need

The identified need is to establish and/or strengthen ongoing partnerships with our communities to provide support before, during and after extreme weather events. This need is consistent with community expectations outlined during our stakeholder engagement program, as well the clear direction from the Victorian Government's resilience reviews.

H.1.1 Community expectations

Our understanding of the expectations of our customers as to how we can best support them to improve the resilience of their communities to extreme weather has grown through our shared experiences since 2021. Over the three-year period since major storm events in 2021, a recurring theme for communities across our network has been the strong desire for improved support with resilience planning and greater on-the-ground engagement with a permanent local presence (before, during and after events).

Planning for extreme weather

Our customers believe their distributor must play a critical, proactive role in disaster management through planning for climate-related extremes:

> *"You can't plan for every scenario but you can prepare for worst-case and make sure you have the bare essentials running"*
>
> Community roundtable participant
>
> *"A resilient society doesn't wait until it's on its knees—they move before that"*
>
> Community roundtable participant

At our community engagement workshop and in our regional and rural summits, we were told that a permanent presence with deep local knowledge is seen as foundational to a balanced approach to community resilience (i.e. combining infrastructure improvements with community-focused initiatives). There was also strong consensus from participants on the importance of embedding representation from our network in strategic planning processes for local government and councils to ensure the needs of each individual community are met.

The need for permanent, localised support was echoed in our First Peoples engagement. We operate across the traditional lands of 11 Registered Aboriginal Parties (RAPs). Feedback from this engagement highlighted that our existing ad-hoc approach has resulted in a lack of understanding among communities as to the responsibilities and roles of emergency response organisations, including Powercor. This has prevented communities from seeking assistance:

> *"(Powercor) needs a First Peoples liaison to help with questions and/or medically vulnerable customers and emergencies"*
>
> First Peoples Powercor customer
>
> *"We didn't see (anyone) and couldn't leave our house. We were just stuck at home"*
>
> Yorta Yorta community member
>
> *"(During a flood event) we couldn't check on Elders. We lit the fire up somewhere different every night because there was water everywhere. Our house was like an island"*
>
> *Yorta Yorta community member*

Supporting communities during extreme weather

During extreme weather events, our stakeholders expect us to provide accurate and timely information, countering the confusion and misinformation that often arises during emergencies.[41] Community Roundtable participants further expressed concern that vulnerable groups, such as elderly residents, families with young children and First Peoples are disproportionately affected during outages, such that we should prioritise communication efforts for these cohorts.

Today, our presence in communities during extreme weather events is supported by two mobile emergency response vehicles (MERVs). These vehicles were introduced following extreme weather events across our network in 2021 and 2022.

MERVs are viewed as a hub for vital services while connection is restored, with stakeholders at our community resilience workshop seeing these as a safe space to meet, access information and seek assurance.

On-the-ground feedback during extreme weather events also highlighted the preference for MERVs to maintain a permanent presence throughout extreme weather. In particular, customers with lived experience told us that it can be distressing to see MERVs move on, especially when power has not yet been restored. This is often required where multiple areas are impacted by prolonged outages (i.e. given limited capacity, our MERVs will move across multiple sites, limiting their ability to stay in a centralised location for a prolonged period).

During major events, community feedback provided at the sites of MERVs has guided our restoration efforts, such as where to place mobile generators to maximise the benefit for the community.

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[41] For the avoidance of doubt, this is beyond, for example, the safe and timely restoration of supply.

Mobile emergency response vehicles

MERVs provide operational and psychological support during major weather events. They are a recognition of feedback we have heard from our communities—we cannot be everywhere, but we can be present where our presence is needed the most. The capability of our MERVs include the following:

- 68-inch TV monitor with remote access capability to our IT and spatial systems, allowing us to display critical safety messages and outage information
- multiple communication platform connectivity including satellite phone, UHF and TMR radio functionality to provide feedback and insights to our EMT in our control rooms
- portable PA system to support community briefings and town hall sessions
- 5-metre light mast to safely illuminate community hub areas and a retractable wrap-around awning for all weather cover
- multiple phone charging lockers to support people recharge their devices including, iPads and laptop computers, safely and securely
- mobile satellite WiFi connectivity to provide a local area hotspot for customers to access basic internet services such as banking, emergency services and social media networks
- in-built fresh and grey water tanks for hot water, coffee machine, and drinks fridge to provide refreshments for affected community members
- defibrillator, first aid kit and fire extinguisher
- fully integrated 7.5kVA onboard generator, providing 240 volts to power features of the vehicle and provide external power support to community hubs if required
- 550 watts of fixed rooftop solar, supported by a 300 Amp-hour deep cycle lithium battery.

H.1.2 Government recommendations

As outlined earlier in this document, following extreme storm events in 2021, the Victorian Government engaged an expert panel to undertake an Electricity Distribution Network Resilience Review. The Government's response to this review made clear its expectations, including the requirement that we partner with communities and local councils in emergency planning and response, and that we communicate with customers before and during prolonged power outages.

Recommendation four: partnering with communities and local councils in emergency planning and response

Current emergency planning arrangements do not explicitly outline that involvement with communities in emergency planning and management at both the municipal and regional level is a responsibility for electricity distribution businesses. In response, the expert panel recommended that electricity distribution businesses have more responsibility to engage with communities and local councils.

This recommendation also included the need for distributors to be available to attend relief centres, community hubs or a community meetings to provide information about incident and response activities.

The Government supported this recommendation in full to require electricity distribution businesses to partner with communities in emergency planning, response, and recovery.

Recommendation six: communication with customers before and during prolonged power outages

The expert panel found that additional information requirements and improved communication channels between electricity distributors, communities and local councils helps to empower affected communities to make informed decisions regarding their safety during a prolonged power outage. Further, the panel noted that a lack of communication access during an outage can be partly addressed by preparing customers at high-risk locations, with this being particularly important in rural communities where door-to-door knocking is not feasible owing to the sparsely distributed customer population.

While recognising the roles of multiple parties in effective communication, the Government accepted this recommendation in full.

This review was followed by a Network Outage Review into the February 2024 storm event. In response, the Victorian government expects that we change our preparedness, response, and recovery from these events to protect the power Victorians value and the ecosystem of essential services that electricity distribution networks sustain.

Recommendation two: distribution businesses annually attest to the currency, completeness, maturity and implementation ability of their emergency risk management practices

To support better outcomes for Victorian customers from prolonged power outages, it is important for Victorian distributors to proactively improve emergency management planning arrangements. This includes the application of best practice communication and engagement approaches before, during and after prolonged power outages (including the ability to provide on-the-ground support to communities during emergencies and information on temporary generation for key community assets to regional and municipal planning committees).

Recommendation ten: owners and operators of critical infrastructure should participate in regional planning committees

The Victorian Government acknowledges the important role critical infrastructure providers can play in the planning and delivery of relief activities, ensuring that appropriate support is being provided to customers experiencing prolonged power outages, and appropriate consequence management processes are in place.

Appropriate representation of critical infrastructure providers and sector leads at Regional Emergency Management Planning Committees would support better preparation for power outages and could include testing of planning arrangements through exercises. It is important that this representation is flexible to the needs of different regional and municipal planning committees, and the nature of different critical infrastructure sectors. Importantly, this builds on the recommendation supported by the Victorian Government in the earlier resilience review for electricity distribution businesses to partner with communities in emergency planning, response, and recovery.

Collectively, these reviews make clear that there are new expectations for how distribution businesses should support community resilience which we are not currently resourced to meet.

H.2 Options analysis

In response to stakeholder and government expectations, we have considered three options to establish and/or strengthen ongoing partnerships with our communities to provide support before, during and after extreme events. These options are outlined below.

We have undertaken a qualitative assessment of these options, recognising the value associated with supporting localised planning and ongoing support for communities is challenging to quantify. On this basis, we have given weight to the strong recommendations of the Victorian Government (noting these were themselves informed by a comprehensive, independent and public engagement process) and the consistent and corroborating feedback from our own customers and stakeholders.

TABLE 27 SUMMARY OF OPTION COSTS ($M, 2026)

OPTION		CAPEX	OPEX
1	Base case: maintain existing response support capabilities	-	-
2	Engage five community support officers and three additional MERVs	1.2	4.0
3	Engage seven community support officers and three additional MERVs	1.2	5.6

H.2.1 Base case: maintain existing response support capabilities

Our base case scenario involves the continuation of our current approach to engaging communities, whereby we maintain a presence in regional cities or towns experiencing extreme weather events only when an event occurs. Outside of extreme weather events, our physical presence within communities across our network will be limited to a targeted, temporary presence in response to an identified priority.

This business-as-usual approach is unlikely to meet the expectations of communities, or allow us to deliver on the recommendations from the Victorian Government. For example, our ability to support emergency management and resilience planning is currently focused at a state-wide level only. Our network, however, spans five separate emergency management areas and 37 separate municipalities. Within these areas are different customer and community groups. The geographic coverage and need for localised knowledge and presence means that our centralised and as-available approach would not be effective in meeting the expectations of our customers and the recommendations from the Victorian Government.

Similarly, our MERVs would continue to be allocated according to priority status across our entire network, which is unlikely to be effective during widespread events. For example, during the 2022 bushfires, our MERV moved from Lara to Pomonal despite the ongoing impact of weather in the Lara area. At the same time, we received requests from customers in other locations for a community presence, which we were unable to meet.

As noted previously, we received strong feedback from our community that seeing our MERVs relocate during outages is distressing for customers and community when they are most vulnerable. There is always likely to be some need for this, however, community preference is for these circumstances to be as limited as practicable.

As the frequency and severity of extreme weather increases, and our dependence on electricity grows, the limitations of our existing capabilities will be tested further.

H.2.2 Option two: five community support officers and three additional MERVs

Research in best-practice community resilience building has established the importance of maintaining a sustained presence with deep understanding of local communities as a crucial first step to community-led resilience to natural hazards.[42] Community involvement in planning develops a plans efficacy, disaster response skillsets within the community, and increases risk perception.[43]

Under option two, we would employ five community support officers (CSOs) and embed their roles across the five emergency management regions within our network. Additionally, we would procure three additional MERVs to supplement our existing fleet.

Community support officers

CSOs will have year-round, full-time responsibilities in both business-as-usual time periods and during major weather events.

In its response to the first network resilience review in 2021, the Victorian Government set an expectation that distributors work with communities to develop and execute resilience plans. Development and delivering on resilience plans will be the primary responsibility of each CSO. Consistent with identified best practice and Government expectations, as part of establishing the plan, the CSO will:

- participate in regional and municipal planning committees to support response planning
- coordinate with other utility service providers to understand their vulnerabilities, particularly essential/critical services
- form relationships with local community leaders to understand and include perspectives, needs and vulnerabilities in resilience planning
- feed local insights back to the business to support informed major event planning
- maintain a presence at community events to distribute key information, electrical safety advice and energy literacy information
- support energy literacy, including tailored sessions with groups to understand electricity bills and local electrification opportunities.

CSOs will also be prominent figures in the community during and after extreme weather. They will be a direct presence and contact for our on-the-ground response during escalation events, including the communication of outage information, conduit of information to support localised response prioritisation and resolutions, and operate our mobile emergency response vehicles. Their role within our networks is visually demonstrated in figure 20.

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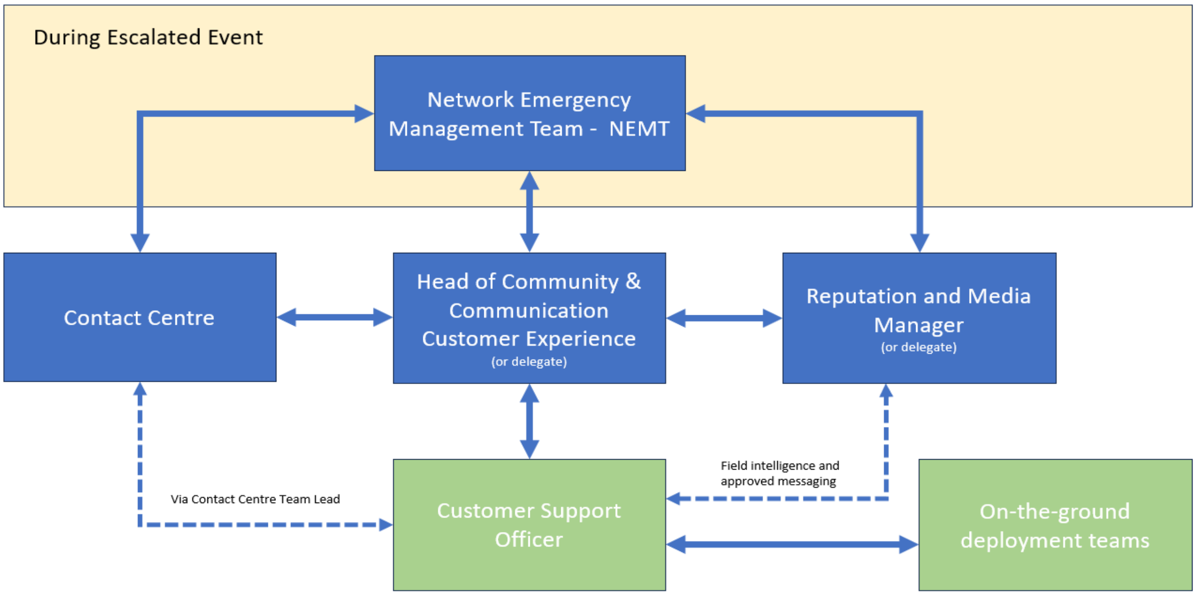
42 Johnston, K.A., Taylor, M. & Ryan, B. Engaging communities to prepare for natural hazards: a conceptual model. *Nat Hazards* 112, 2831–2851 (2022). https://doi.org/10.1007/s11069-022-05290-2

43 Karanci, A.N., Ikizer, G., Doğulu, C. (2024). Community Education and Preparedness for Disaster Risk Reduction. In: Yildiz, A., Shaw, R. (eds) Disaster and Climate Risk Education. Disaster Risk Reduction. Springer, Singapore. https://doi.org/10.1007/978-981-97-5987-3_9

FIGURE 20 ESCALATION PROCESS DURING MAJOR WEATHER EVENTS



To deliver on this role, the CSO will deliver on many responsibilities. Examples of some of these are captured at table 28.

TABLE 28 CSO COMMUNITY RESILIENCE RESPONSIBILITIES

TIMEFRAME	RESPONSIBILITY
Preparation phase	• Test resilience through leading trial exercises of steps established in local community resilience plans • Scenario and response modelling with emergency agencies to establish shared understanding of priorities and pathways to an optimal response • Expectation setting with community members, including the presence of MERVs, energy literacy and contact options for communities • Engage with groups experiencing or at-risk of experiencing vulnerability, to ensure understanding of contact options, local of priority households/individuals • Relationship management with large customers to better understand their capacity and limitations to support community operations before, during and after extreme events

Response phase	•	Maintain consistent engagement with relevant local community leaders and emergency response agencies
	•	Distribute support materials, messaging or localised causes and timeframes, overviews of the fault response/reconnection process, electrical safety advice and future claims processes
	•	Key point of contact for providing on-the-ground feedback and local insights to the Network Emergency Management Team, including insights into groups experiencing heightened vulnerability
	•	Work with our internal subject matter experts as required to share information on topics including repair complexity, completion timeframes, local configuration and capabilities of the business
	•	Work with other impacted utilities to understand their active vulnerabilities and feed this information back to mutual aid resourcing teams
Recovery phase	•	Work with local leads from emergency response agencies to identify groups who need immediate help, are displaced, or are experience heightened vulnerability
	•	Ongoing coordination with impacted utilities and emergency agencies to identify mutual aid resourcing opportunities
	•	Refer impacted customers on for claims processes

Role of additional MERVs

The capability to deploy up to five MERVs simultaneously will limit instances where MERVs are operationally required to depart regional towns or cities to support other communities that have been assessed as higher priority. MERVs are a core component of our on-the-ground operational capabilities during extreme weather, and communities have communicated clear support for investment to ensure MERVs are a permanent presence during events impacting their region.

However, with only five MERVs across a geographic area than spans 145,000km^2, prioritisation decisions will still be required.

Expenditure summary

The costs associated with option two include capital expenditure for the procurement of MERVs and an operating expenditure step change for the labour costs of our CSOs. Forecasts are based on remuneration expectations consistent with the seniority and experience required for the CSO role, and MERV costs reflect our experience with similar fleet.[44]

Costs will also be incurred to operate our MERV fleet, including servicing, petrol and other maintenance. However, these costs are expected to be minimal and have not been included in our proposal.

Expenditure under option two is shown in table 29.

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44 MERV costs reflect the purchase of the vehicle, vehicle fit out, and associated labour.

TABLE 29 OPTION TWO: EXPENDITURE ($M, 2026)

OPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
CSOs: operating expenditure	0.8	0.8	0.8	0.8	0.8	3.8
MERVs: capital expenditure	1.1	-	-	-	-	1.1

H.2.3 Option three: seven CSOs and three additional MERVs

This is similar to option two, however, an additional two CSOs would be engaged. These additional CSOs would supplement the coverage of each emergency area as required, but also play a stronger role for targeted community groups or social advocacy bodies.

This option is consistent with feedback provided during the test and validate phase of our engagement, where stakeholders questioned whether five CSOs could sufficiently cover the geographically broad and diverse needs of local communities (particularly as the frequency and severity of extreme weather increases).

The costs associated with this option are summarised in table 30.

TABLE 30 OPTION THREE: EXPENDITURE ($M, 2026)

OPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
CSOs: operating expenditure	1.1	1.1	1.1	1.1	1.1	5.3
MERVs: capital expenditure	1.1	-	-	-	-	1.1

H.3 Preferred option

Option two is preferred as it addresses the identified need of providing best-practice support to communities on our network to improve their resilience to major weather events. In consultation, our customers have maintained clear support for a permanent presence with deep local knowledge to partner with them to plan for their response to extreme weather events, and support them during and after.

Sections of communities experiencing vulnerability have also identified a specific need for tailored engagement built on trust to ensure all members of their community can experience the same resilience outcomes.

Customers further expressed ongoing support for the deployment of MERVs during major weather events, both for the vehicle's response coordination capabilities and their psychological support. Customers have reported distress when MERVs move on, which is an outcome that is increasingly common as weather events become more severe.

Option three was not considered prudent at this stage given operating step changes have a more immediate impact on customer bills. We also consider that establishing a program and structure for our CSOs is best undertaken incrementally, allowing for the integration of learnings over time.

As noted in the option discussion itself, we consider option one would not meet the identified need as it is inconsistent with the sustained and consistent feedback from customers and Government across multiple engagements and independent reviews.

IT
SITUATIONAL AWARENESS

I Situational awareness

It is not possible to harden our network to avoid all outages, and with the frequency and severity of extreme weather increasing, so too are major ‘escalation’ events. At the same time, ongoing electrification and behavioural change is increasing dependency on electricity, meaning the impacts of outages are becoming more acute and the restoration process more complex.

When there is an outage, our primary function is to restore supply safely and quickly to as many customers as possible. All else equal, we prioritise making assets safe and restoring our feeder ‘backbone’ before addressing single customer outages.

Within this approach we maintain operational flexibility to address safety issues, or to target restoration of critical infrastructure and/or specific customers where practicable (or where directed). Our processes need to be dynamic given changing conditions and priorities during extreme weather events.

We also have critical responsibilities in providing accurate and relevant information to customers and key stakeholders throughout the restoration process, including emergency management personnel.

I.1 Identified need

The way in which we prioritise faults, visualise our network and communicate with stakeholders during major events is complex. Conditions evolve quickly, information is often incomplete and constantly changing, and emergency management priorities vary for every event. Further, the sheer scale and scope of information is substantial.

Today, our response to widespread outages is heavily dependent on our IT systems. Our response, however, still requires significant use of manual processes that are challenged when the scale of outages increase (as occurs during a major event day).

Recent government reviews and corresponding stakeholder engagement have focused heavily on restoration processes, and expectations on distributors are increasing.

The identified need, therefore, is to ensure we best support a coordinated response to major weather events across our network that meets government and community expectations on the safe and efficient restoration of supply and accounts for the increasing complexity in restoration priorities as our economy and lifestyles rely more heavily on electricity.

I.1.1 Our situational capabilities to support a coordinated response

Our approach to managing restoration is supported by our IT systems. For example, we use near-real time information to support emergency management processes, dispatch crews based on level of priority, support our contact centre to report estimated time of restoration to customers and empower communities through a web-based map of outages.

However, there are limitations within these systems and processes that impact our capability to best support the emergency management process. These reflect the significant reliance on manual processes, the lack of systemised data and limitations in our visualisation tools.

Reliance on manual processes

The prioritisation of faults during a major event day is based on information gathered in near real-time from sources including our contact centre, network information systems and AMI data.

The control room uses this information to manually prioritise faults. This process is repeated for all faults during a major event, with crews dispatched via the control room based on priority.

Notably, this process differs from our typical business-as-usual process, where our fault simulation tool models fault resolutions and is used to test and optimise how our systems and processes prioritise and respond to faults. These tools are designed for optimising steady state operations. They are not designed to be used for major event days as they are not 'trained' on these events, which means they do not consider the wide range of conditions a major outage event entails.

Lack of data systemisation

During a major outage event, the volume of data and its evolving nature represents a significant challenge. The ability to process this information quickly in a systematic manner is fundamental to the ability to make informed decisions.

Our limited capacity to systematise and store datasets in a single location, driven by legacy systems, has led us to store information across disparate systems. This has created challenges to sharing a comprehensive view of our network. Reports containing different datasets can be created and shared, but an iterative, repetitive extraction process would be required to create a comprehensive view of how major weather events are impacting our network.

The flow-on impacts of this are that again, manual extraction processes are required. In particular, the data we store is not immediately accessible by external parties (e.g. emergency response agencies), which undermines or delays our ability to support decision-making during major event days. The rate at which information changes during major events can outstrip our ability to manually extract data in a timely manner for both internal and external needs.

Further, the use of disparate systems means that different internal functions may receive and visualise information differently during major weather events. This can lead to conflicting information.

Limited public visualisation capabilities

The public can access information as to how our network is being impacted during major events by using our outage map. However, information is limited to the broad location of an outage, the number of customers impacted, and an estimated time for restoration, once known.

I.1.2 Government recommendations

The Victorian Government's two reviews into network and community resilience, summarised in section 1.3, have set out clear expectations for distributors around the prioritisation, restoration and coordination of our response efforts.

The 2021 Electricity Distribution Network Resilience Review set expectations that distributors should be more proactive when responding to damage caused by extreme weather and improve communication with customers and local councils during prolonged power outages.

The Victorian Government's response to recommendations of the 2024 Network Outage Review considers distributors should be lead response support agencies for electricity emergencies and committed to driving improved coordination and response.

The government further supported clarifying roles and responsibilities of distributors to establish a stronger understanding amongst emergency services and communities during events. It also committed to increasing the accountability on distributors to be better prepared and to prevent and respond to major weather events.

Recommendation two of the network outage review set out the attestation we will be required to make annually on our emergency management capabilities. These are shown in figure 21, and form the basis of our options assessment (with a particular focus on communication, impact assessments and restoration prioritisation).

FIGURE 21 NETWORK OUTAGE REVIEW: RECOMMENDATION TWO

Recommendation 2:

Distribution businesses annually attest to the Minister for Energy and Resources as to the currency, completeness, maturity and implementation ability of their emergency risk management practices with regard to maintaining electricity supply, inclusive of assets, people, resources, governance, systems, processes and arrangements with contractors.

The attestation should include specific reference, but not limited to:

Planning and coordination

1. Participation in Regional Emergency Management Planning Committees and Municipal Emergency Management Planning Committees to support response planning for areas at high risk of prolonged power outages.

Communication and engagement with customers and community

2. Application of best practice communication and engagement approaches before, during and after prolonged power outages including:
    a. Inclusive design of customer service systems such as outage trackers and interactive voice response (IVR) systems with regular monitoring, evaluation, and feedback from customers with lived experience of vulnerability.
    b. Capacity of customer service systems to meet surge demand and back-up continuity plans if these services fail.
    c. Capability to provide on-the-ground support to communities during emergencies.

Impact assessment and make-safe actions

3. Adoption and operation of State Emergency Management Priorities including 'make safe'.
4. Ability to undertake rapid impact assessment at a network-wide scale during an event including integration of:
    a. mutual aid resources and state and regional emergency response teams
    b. reports of damaged infrastructure by emergency services personnel and community members
    c. consistent information flow through to the incident response and restoration planning teams
5. Processes to report timely and accurate information about status to restore services and confirm 'safe' infrastructure to emergency services and communities.

Restoration planning, prioritisation and operations

6. Capability and capacity to achieve effective management of events and timely restoration of customers.
7. Review of emergency management practices including but not limited to review of risks and risk controls and testing of revised controls following all major events and exercises.

Temporary generation for key community assets

8. Capacity and capability to connect main streets and key community assets in areas at high risk of prolonged power outages to temporary generation within 12 hours of an event. Information on location of temporary generation sites, network connection points and key access routes should be included in Regional Emergency Management Plans, and Municipal Emergency Management Plans.

I.1.3 Customer expectations

Customers at our 2024 community workshop told us they see more timely and accurate information during extreme weather as key to enhancing resilience. Participants supported investment in our IT systems to support visualisation and prioritisation during widescale outages. They valued the development of visualisation layers that become a single source of truth, finding that it would alleviate bottlenecks created by customers contacting multiple emergency agencies to obtain information:

> *"To have a single source of truth is invaluable in making decisions. Because so many (emergency response organisations) have their own source, and it doesn't match other organisations"*
>
> *– Community workshop participant*

Participants saw the ability to publicly share information with the community and emergency response agencies as empowering, finding that it would allow individuals to make more informed decisions during an emergency event.

Customers stressed the importance of transparent communication during weather events to allow communities to stay informed on outage causes, expected recovery times and preparedness measures.

I.2 Options considered

Three options have been considered to address how we can best support a coordinated and optimised response to outages across our network during major weather events. Each option represents a sequential progression of investment in our existing capability, with a summary of the costs of each option shown in table 31.

TABLE 31 SUMMARY OF OPTION COSTS ($M, 2026)

OPTION		CAPEX	OPEX
1	Base case (no investment)	-	-
2	Enhance our current capability	1.6	0.6
3	Enhanced capability and visualisation	3.1	2.6

I.2.1 Option one: base case (no investment)

As outlined earlier, under recommendation two of the Victorian Government's network outage review, we must attest to our emergency response capabilities on an annual basis.

In the absence of investment, significant manual prioritisation will continue and data will remain stored across disparate systems, challenging our ability to undertake rapid scale assessments of our network, as the complexity of widespread outages increase with electrification and changing weather patterns. This will inhibit our ability to progress beyond manual processing and responses to faults during escalation events.

The Victorian Government expects a timely flow of information to restoration and response parties. Our current approach to data curation means that extraction upon request from third parties requires significant time and resources. It also constrains the flow of information to incident response and restoration teams. As weather events become more frequent and severe and datasets more complex, we will experience challenges sharing information in a timely manner.

The absence of automated fault simulation and prioritisation capabilities at the scale required for escalation events will also forego opportunities to review, test and learn from previous events.

I.2.2 Option two: enhanced capability

Option two enhances our existing capabilities to better visualise and communicate major weather events, and our capability to prepare for and respond to widespread outages.

Investment under option two improves our ability to meet Victorian Government expectations to support a coordinated response to network outages. However, ongoing requirements to manually extract and share data will still challenge our ability to support constant information flow to incident response and restoration teams.

While upgraded, our fault simulation capabilities will not have the sophistication to support detailed revision and testing of fault restoration policies and procedures.

Visualisation and data provision

Under option two, our GIS software will be upgraded to store datasets that can be manually extracted to meet information requests from external parties. Datasets will be curated and stored in consistent formats for shared use and understanding.

In practice, this means that stakeholders will receive information more quickly than under the base case. However, manual extraction is a resource intensive process. Under option two we will continue to face challenges sharing information at a pace that matches the rate of change during major weather events, particularly as datasets become more complex. This could mean that by the time we have prepared the information to be shared with third parties it is already out of date.

Our upgraded GIS software will also contain new visualisation layers, such as the location of community assets, restoration priorities, and high-risk locations. This will facilitate better oversight of where priorities and vulnerabilities lie within communities, ensuring that we can better identify those that need help the most.

Optimised fault response

Developments in machine learning have created an opportunity to provide improved decision-support to our dispatch teams. This can be achieved by using simulations of fault response scenarios during widescale outages to choose optimal fault response pathways. Option two would leverage this opportunity to enhance our existing simulation capabilities, allowing us to better capture how major weather events will impact our network.

Our existing fault simulation capabilities will be upgraded to allow us to model outcomes that may occur during a major outage event. These outcomes will provide decision support to our control room when prioritising fault restoration. While improved compared to option one, we would still have limited capabilities as to the number of scenarios we are able to model and limited ability to use new information gathered from recent major events to review and configure our fault prioritisation approach.

I.2.3 Option three: further enhanced capability and public view

Option three prioritises further collaboration with emergency response agencies and our communities in recognition that electrification and the increasing frequency and severity of weather events across our network is necessitating an increasingly complex, coordinated response.

Option three will automate data extraction processes, creating opportunities for two-way sharing of information that doesn’t exist today. In this way, option three creates a more informed, shared understanding of how weather events are impacting the network that keeps pace with changing circumstances.

It is also responsive to the expectations that communities have communicated to us through consultation since 2021. With communities seeking to access more in-depth, real-time data, to aid in their own decision-making processes during extreme weather events.

Visualisation

Relative to option two, option three prioritises investment in our ability to support a shared understanding of major outage events. Under option three, our GIS software is upgraded to create a visualisation layer that acts as a near real-time single source of truth for all stakeholders. It would enable:

- complete datasets to be stored, updated and shared in near real time

- emergency response agencies to self-service data extraction needs, meaning external stakeholders can access critical information in near real time
- better collaboration with external parties through the ability for emergency agencies to upload information into our system
- integration of datasets with bushfire and flood overlays, live weather and storm cells.

Optimised fault response

Relative to option two, option three further enhances our fault simulation capabilities to consider outcomes with increased sophistication. In practice, this means that more informed scenario analysis can be undertaken to assess the efficacy of different restoration strategies.

During major events, the outcomes of our fault simulation will provide improved decision-support to our network control centre. Post event, fault simulation will enable us to consistently review and update fault restoration policies utilising significant amounts of data from recent major events.

I.3 Option analysis

Improved coordination between agencies, more informed customer decision-making and an optimised fault response is expected to lead to reduced minutes off supply for many customers and/or an improved customer experience (relative to the status quo). However, the impact of each major event day is different, and the challenges communities face vary greatly, influenced by factors such as location, topography and size. Quantifying the impact of investment at a network level, therefore, risks mischaracterising how communities may be impacted.

Accordingly, much of the analysis of our preferred option is qualitative, with a focus on assessing each option against how it would enable us to meet the expectations set by the Victorian Government in response to increasingly frequent and severe weather events.

Notwithstanding this, the quantifiable benefits of each option, including reduced customer minutes off supply and energy at risk, and the corresponding costs for each option are set out in further detail in our attached IT situational awareness cost and risk models.[45] A summary of the quantifiable present value of costs and benefits is set out in table 32.[46]

45 PAL MOD 5.08 - IT situational awareness cost - Jan2025 - Public; PAL MOD 5.09 - IT situational awareness risk - Jan2025 - Public

46 This includes costs and benefits associated with both Powercor and United Energy. Enhancing our capabilities for one network would make the technology available to the other, we have therefore split the costs of the enhanced capabilities equally between the two networks. However, for the purposes of modelling we have considered the full cost of the enhanced capabilities and the full benefits together.

TABLE 32 OPTIONS ANALYSIS: SUMMARY ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFIT
1	Base case (no investment)	-	-	
2	Enhance our current capability	(6.7)	6.4	(0.3)
3	Enhanced capability and visualisation	(21.7)	24.3	2.6

I.4 Preferred option

Option three, enhanced capability and visualisation, is preferred as it is the most responsive option to both customer and government expectations while also delivering the highest economic benefit.

Through both its network resilience and outage reviews, the Victorian Government has set clear expectations that we must improve how we prioritise restoration and support a coordinated, optimised response during major events through the 2026–31 regulatory period. Our customers have consistently expressed strong support for investments to enhance resilience and have told us that a key component of this is access to transparent, timely and accurate information.

Investing to enhance our current capabilities and establish more in-depth view of major weather events across our network is a direct response to these expectations. Table 33 maps proposed investments against the emergency risk management practices that we are expected to attest to under recommendation two of the network outage review.

TABLE 33 MAPPING OUR PROPOSED INVESTMENT AGAINST EMERGENCY RISK MANAGEMENT PRACTICES

EMERGENCY RISK MANAGEMENT PRACTICE	PROPOSED INVESTMENT
Application of best practice communication and engagement approaches before, during and after prolonged outages.	• Upgraded GIS capabilities enable us to create a more in-depth, community specific, visualisation of a major event.
Ability to undertake a rapid assessment at a network-wide scale during an event including integration of: • Mutual aid resources and state and regional emergency response teams. • Reports of damaged infrastructure by emergency services personnel and community members • Consistent information flow through to the incident response and restoration planning teams	• A visualisation layer becomes the single source for extraction of data, where emergency response agencies are able to access this visualisation, download and upload their own information for collaboration. • Data is systematised within the visualisation layer, meaning all parties are informed by consistent datasets. • Upgrading our fault simulation capabilities to better model the range of possible outcomes present at major event day-scale. • Provide decision support to our network control centre by informing our fault prioritisation process with fault simulation outcomes.
Review of emergency management practices, including review and testing of risk and risk controls, and testing of revised controls following major event days.	• Upgraded fault simulation capabilities are utilised to model fault restoration priorities ahead of major events, and review against outcomes post events.

The expenditure required to deliver option three is set out in table 34.

TABLE 34 PREFERRED OPTION EXPENDITURE FORECAST ($M, 2026)

OPTION THREE	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	2.9	0.2	-	-	-	3.1
Operating expenditure	0.5	0.5	0.5	0.5	0.5	2.7

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