ASSET CLASS OVERVIEW

ZONE SUBSTATION TRANSFORMERS

PAL BUS 4.08 – PUBLIC

2026–31 REGULATORY PROPOSAL

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1. Overview

The management of our zone substation transformers is critical to our ability to maintain network reliability and minimise safety risk as far as practicable. We manage these critical assets on a least lifecycle cost basis, underpinned by the continuous refinement of our risk analysis and understanding of the asset condition and performance. We adjust our asset replacement and maintenance timing as inputs to our risk evaluation changes such as asset cost, reliability, failure consequence such as loss of supply.

Our zone substation transformer forecast is similarly based on detailed risk analysis. It enables the identification of the highest net benefit solution to manage the substation, based on the identified failure modes of the transformer and the corresponding probabilities, likelihoods, and consequences of failures.

Our approach is consistent with the AER's asset replacement planning application note, and our modelling was accepted by the AER in previous regulatory decisions.

In total, our zone substation transformer forecast represents an increase in expenditure from the 2021–26 regulatory period. This forecast comprises the replacement of several transformers, as well as the continuation of an environmental refurbishment program to manage transformer oil leaks in accordance with regulatory requirements.

Our plan aims to maintain network reliability and minimise environmental risks. However, our proposal will still result in overall risk levels in FY31 being higher than corresponding levels at the start of the regulatory period. That is, we require other works such as switchgear replacements and transformer augmentation to maintain our overall zone substation network risk and hence, network reliability.

A summary of our forecast projects and corresponding capital expenditure is shown in table 1.

TABLE 1 ZONE SUBSTATION TRANSFORMER EXPENDITURE ($M, 2026)

EXPENDITURE	FY27	FY28	FY29	FY30	FY31	TOTAL
Cohuna replacement	5.4	2.7	-	-	-	**8.0**
Mooroopna replacement	-	2.8	5.5	-	-	**8.3**
Shepparton North replacement	-	-	-	5.0	2.5	**7.5**
Transformer environmental refurbishment program	1.8	1.8	1.8	1.8	1.8	**8.8**
Minor station works	0.6	0.7	0.7	0.7	0.7	**3.4**
Total	**7.7**	**7.9**	**8.0**	**7.5**	**5.0**	**36.2**

Note: Expenditure reported in this category in our Reset RIN is lower than this amount, as major plant replacement works (such as transformer replacements) are allocated across multiple RIN categories to reflect the nature of the work undertaken.

2. Background

The function of our zone substation transformers is to transform electricity from higher voltages (such as 66kV or 22kV) to a lower voltage (such as 22kV or lower), to enable electricity to be transported to customers.

This section provides an overview of our zone substation transformer asset class, including a high-level summary of our compliance obligations, asset population and age profile.

2.1 Compliance obligations

We operate under a combination of national and state legislation which establish our obligations and the regulatory framework under which we operate.

The National Electricity Rules sets out reliability and safety obligations and the Electricity Distribution Code of Practice include performance requirements. We must also manage our network assets in accordance with the Electricity Safety Act 1998, the Electricity Safety (Management) Regulations 2019, the Electricity Safety (Bushfire Mitigation) Regulations 2023 and the Victorian Environment Protection Act 2017.

These obligations can be summarised as follows:

- Electricity Safety Act 1998 – requires us to minimise safety risk 'as far as practicable' including bushfire danger
- Electricity Distribution Code of Practice – requires us to manage our assets in accordance with principles of good asset management and to minimise the risks associated with the failure or reduced performance of assets
- National Electricity Rules – requires us to forecast expenditure to maintain the quality, reliability and security of supply of our networks and maintain the safety of the distribution system
- Victorian Environment Protection Act (2017) – requires us to reduce the risk of harm from our activities to human health and the environment and from pollution or waste.

In short, we must maintain reliability, minimise safety risk 'as far as practicable' including bushfire danger arising from our network, and reduce the risk of harm to the environment.

2.2 Asset population

Our zone substation transformer asset class includes power transformers across 63 zone substations. Our zone substation transformers are installed either outdoors or indoors within an enclosure or walled environment. They are oil filled and comprise of discrete components, including the transformer core and coils, oil cooling system, on-load tap changer (OLTC) and bushings.

As shown in table 2, most of our transformers are 66/22kV transformers.

TABLE 2 ZONE SUBSTATION TRANSFORMER POPULATION

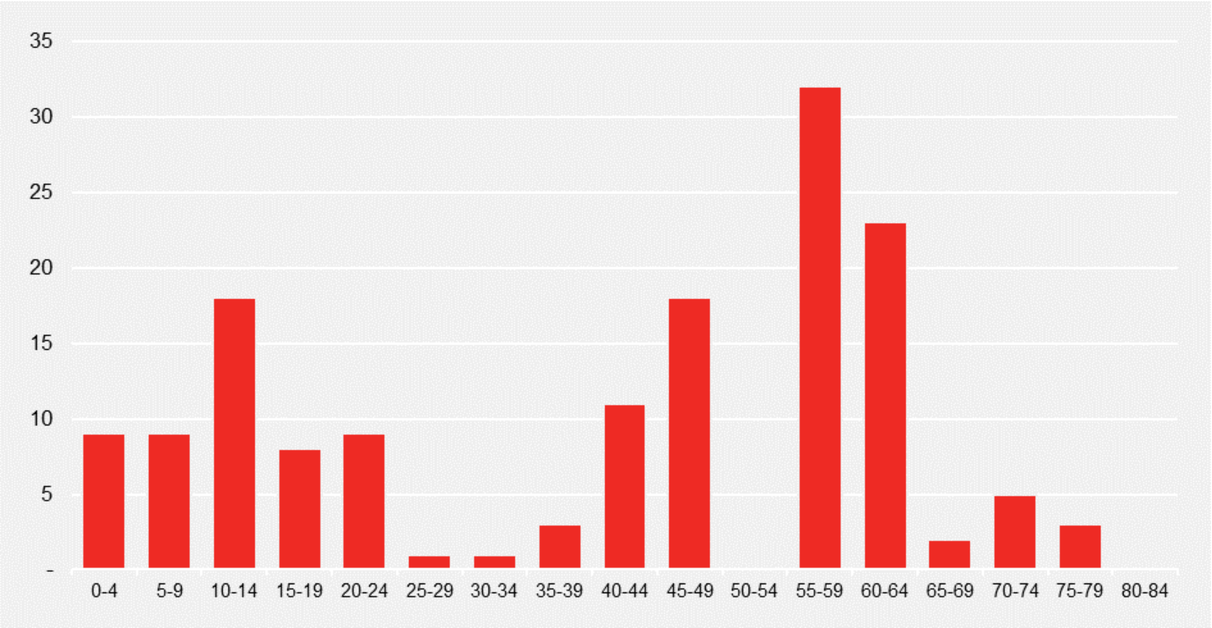
TRANSFORMER TYPE	VOLUME
66/22kV transformer	**147**
66/11kV transformer	**4**
Total	**151**

2.3 Asset age profile

Our zone substation transformers have an average life of 65 years. Average life refers to the average life span of a transformer, after which the asset is likely to be less reliable and require replacement. However, some transformers require replacement before the average life due to type issues, environmental issues or deteriorated condition.

Figure 1 shows the age profile of our zone substation transformers, with eight having exceeded their average life today. Without intervention, this will increase to 35 transformers by the end of the 2026–31 regulatory period.

FIGURE 1 NUMBER OF ZONE SUBSTATION TRANSFORMERS BY AGE (YEARS)



3. Identified need

The performance of our zone substation transformers may impact our network service level, as failure may lead to a loss of supply for customers, pose safety risks to our personnel and the public and potentially catch on fire. This may also result in significant unplanned expenditure to restore supply to our customers.

The identified need, therefore, is to manage our zone substation transformer asset class to maintain reliability and minimise safety risks as far as practicable, consistent with our regulatory and legislative obligations.

This section outlines the historical performance of our zone substation transformers, which has informed how we assess (and respond, as required to) to this identified need.

3.1 Historical asset performance

We monitor the following two key indicators to inform our approach to meet the identified need:

- failures, which are functional failures that occur while the asset is in service
- high priority defects, which indicate deteriorating condition and are leading indicators of future failures.

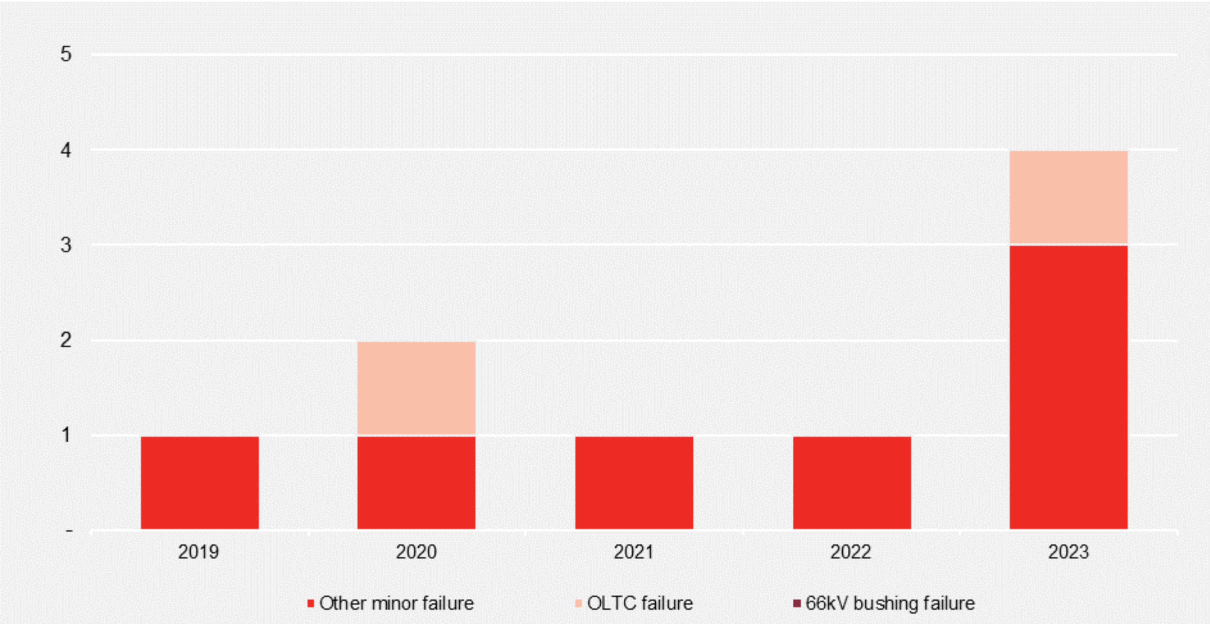
We use our historic asset performance, substation particulars and consequence information to inform and refine our risk evaluation for this asset class.

3.1.1 Historical asset failures

Zone substation transformers are traditionally very reliable as evidenced by the low annual number of failures. However, we have experienced transformer failures annually since 2019 as shown in figure 2.

A component failure will result in the functional failure of the transformer, and may be repairable or require replacement.

FIGURE 2 ZONE SUBSTATION TRANSFORMER: FAILED COMPONENTS



3.1.2 Historical asset defects

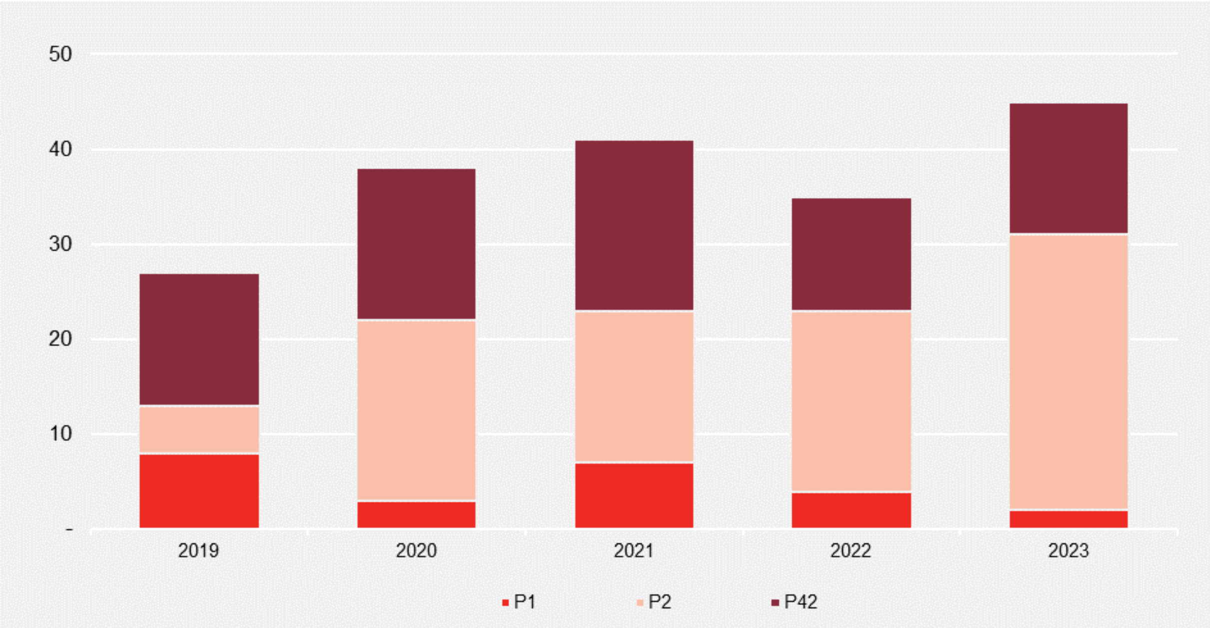
Defects are identified during cyclic asset inspections. Our response to identified defects depends on the nature and severity of the defect and may include more frequent re-inspections. High priority defects that result in intervention are shown in table 3.

TABLE 3 RESPONSE TIMEFRAME FOR HIGH PRIORITY DEFECTS

PRIORITY	TIMEFRAME FOR INTERVENTION
P1	Make safe within 24 hours of identification (replacements or repairs can occur beyond the initial 24 hours)
P42	Addressed within 42 days of identification
P2	Addressed within 32 weeks of identification

As shown in figure 3, our high priority defects have been increasing from 2019 to 2023, driven by increasing P2 defects. This is indicative of the deteriorating condition of our transformers.

FIGURE 3 NUMBER OF HIGH PRIORITY DEFECTS



3.2 Demand growth

By 2031, the electrification of everything from homes to transport, along with ongoing population growth, will require our energy system to evolve.

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

Growth in demand increases the energy that would not be supplied to customers if our distribution switchgear failed.

We forecast demand at an asset level. Our risk modelling uses these asset level demand forecasts to accurately evaluate the energy at risk of not being supplied to customers downstream of specific assets.

4. Forecast interventions

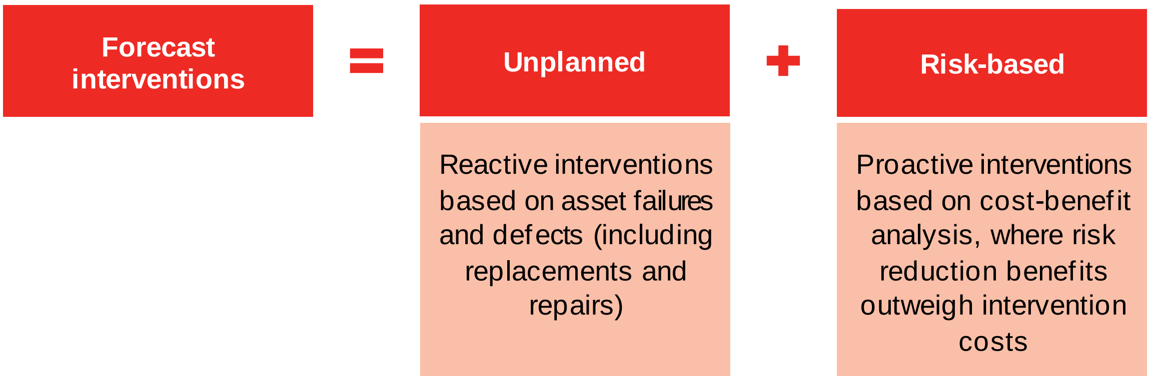
Our current asset management approach for transformers includes multiple options to meet our required service levels, consistent with our compliance obligations. Specifically, these options include the following:

- ongoing planned, preventative maintenance
- targeted replacement of specific components where technically feasible
- defer replacement of transformers through online monitoring systems or other mitigation controls, including asset refurbishment
- asset replacement based on condition and risk assessments, including the impact of common-cause failures.

We constantly revise our plans based on the latest information regarding cost, reliability and risk of these assets to ensure that we are meeting our obligations. As these inputs and understandings change, our forecast will fluctuate accordingly. Our forecast is based on the two categories, as shown in figure 4.

- unplanned interventions are responses to asset failures and defects, which include replacements and repairs of transformer components. These repairs are considered capital expenditure as the repairs will extend the life of the asset
- risk-based interventions are determined by a cost benefit analysis, where risk reduction benefits outweigh the intervention costs.

FIGURE 4 FORECAST CATEGORIES



4.1 Unplanned interventions

We forecast our unplanned interventions predominately based on historical average of the previous five years. These typically comprise minor station works.

4.2 Risk-based interventions

Our risk-based interventions comprise two separate programs—our typical risk-based transformer replacements, as well as an ongoing environmental refurbishment program in response to oil leaks. The section focuses on our typical risk-based transformer replacement methodology, with site specific assessments set out in appendix A.

These forecasts are developed based on sophisticated risk modelling, consistent with the AER's asset replacement planning note and modelling that was accepted by the AER in previous regulatory decisions.[1] This modelling is attached with our regulatory proposal and supported by our asset risk quantification guide.[2]

The methodology and corresponding forecasts for our environmental program are discussed in appendix B.

4.2.1 Forecast methodology

Our risk evaluation method assesses risk at the zone substation level instead of the individual transformer. Assessing risks at zone substation level recognises the unique characteristic of transformers and its impact on the network and customers. It considers the following:

- probability of transformer failure
- joint and conditional probability based on similarity of transformers at the zone substation
- available redundancy and load transfer capability at the zone substation
- zone substation load forecast, including the energy facilitated by the network
- length of outage caused by transformer failure
- increased station risk until transformer is replaced or repaired.

Our risk assessment is underpinned by a risk monetisation approach summarised in figure 5. This approach ensures we invest only when the cost of replacing existing infrastructure exceeds the total value of the underlying risks.

FIGURE 5 RISK MONETISATION APPROACH

Annual risk cost = **Annual probability of failure** × **Likelihood of consequence** × **Cost of consequence**

Probability of failure

Several factors contribute to the deterioration and subsequent failure of transformers. These factors typically include mechanical, insulation or thermal failures of the transformer windings, bushings and/or on-load tap changers (or other components).

In the first instance, we have used our historical asset failure data to determine the probability of failure. Where required, this data is supplemented by failure type ratios from relevant industry surveys (e.g. such as those published by Ofgem).

Consequence of failure

Our approach to monetising risk compares the total cost (including risk) of technically feasible options. The preferred option(s) is that which provides the maximum benefit compared to costs.

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1 See, for example, the AER's final decision for our United Energy network; AER, United Energy distribution determination 2021 to 2026, Attachment 5, April 2021. This modelling approach has since been incorporated to support the asset management of our zone substation program across our three networks, including Powercor.

2 PAL MOD 4.06 - Parallel risk model - Jan2025 - Public; and PAL ATT 4.01 - Asset risk quantification guide - Jan2025 - Public

Figure 6 shows an overview of how we determine the total cost of each option. It identifies the most beneficial solution to manage the substation, based on the identified failure modes for an asset, and the corresponding probabilities, likelihoods and consequences of failures.

FIGURE 6 CONSEQUENCE OF FAILURE

Consequence of failure = Network performance risk + Safety risk + Financial risk + Environmental risk

The determination of these consequences is summarised below:

- network performance risk (energy at risk) – we quantify transformer failure risk-based on the overall risk at the zone substation. That is, we use a joint and conditional probability model to calculate the energy at risk cost for the substation. This considers available redundancy, load transfer capability at the substation, response times for different investments and the cost of multiple interventions that affect overall system reliability, rather than focusing on the condition of a singular asset. This is particularly important in zone substations as they are redundant systems, and the consequence of failure can vary throughout the year. The value of energy at risk is based on the AER's determined value of customer reliability
- safety risks to our staff are determined based on the likelihood of a person present when the failure occurs, and the likelihood of an injury or death as a result. The value of safety risks are based on the value of a statistical life from the Australian Government and injury values informed by Safe Work Australia
- financial risks comprise unplanned replacement and unplanned repair impacts respectively. For the purpose of monetising the risk of transformer failures, we categorise these failures as either significant or major (or both, with a likelihood ratio assigned based on experience). Significant failures are those that are repairable, whereas major failures require the replacement of the asset. The corresponding costs are based on observed history
- environmental risk quantifies the potential impact of a transformer oil leak on the environment. Our oil leak risk assessment is based on the type of pollutant or contaminant, magnitude of possible environmental impact, asset information (e.g. transformer size), type of oil containment (if any), distance of the transformer to groundwater sources and the depth of groundwater sources.

4.2.2 Options considered

Table 4 lists all the potential credible zone substation transformer intervention options. The suitability of these options, however, depends on the zone substation.

TABLE 4 RISK-BASED INTERVENTION OPTIONS

OPTION	DESCRIPTION
Do-nothing different	No change to existing practices and no planned transformer replacement
Online monitoring	Install online monitoring on the transformer
Revised maintenance program	This option updates our maintenance practices and timing on each transformer at the zone substation
Refurbish transformer	Refurbish the transformer if the transformer has not been recently refurbished. This may entail oil treatment, painting/repairs to the main tank, and other minor component replacement as required but does not include any OLTC or oil replacement.
Replace transformer	Replace one transformer at the zone substation

We also considered the following intervention options, but these have been assessed as not credible and thus not subject to economic assessment:

- asset de-rating – we have management practices in place to de-rate assets where required because of acute limitations. Applying this in a general sense is not expected to alter the probability of transformer failure
- non-network solutions – we are not aware of non-network solutions that will be able to replace the functionality of a zone substation transformer. Our zone substation transformer replacements are listed in our annual distribution asset planning report (DAPR) and to date, we have not received any non-network proposals for transformer asset replacement.

4.2.3 Forecast risk-based interventions

Based on the risk monetisation approach summarised above, we assessed individual zone substations for potential interventions in the 2026–31 regulatory period. This identified six zone substations where transformer replacements were the preferred option.

A further review of this portfolio across our broader network planning needs, however, identified an overlap between our augmentation and replacement forecasts. Specifically, the following three zone substation transformer replacements had the potential to overlap with other augmentation projects:

- Bacchus Marsh (BMH)
- Drysdale (DDL)
- Eaglehawk (EHK).

Further economic assessments determined that augmentation options were the most prudent and economic solution at these sites and hence, we have removed these zone substations from our transformer replacement forecast. We will otherwise propose transformer replacements at these zone substations if the corresponding augmentation works are not included in the AER's determination.

A summary of our proposed zone substation transformer replacements is set out in table 5. Further site-specific assessments are provided in appendix A.

TABLE 5 ZONE SUBSTATION TRANSFORMERS: FORECAST EXPENDITURE ($M, 2026)

EXPENDITURE	FY27	FY28	FY29	FY30	FY31	TOTAL
Cohuna replacement	5.4	2.7	-	-	-	**8.0**
Mooroopna replacement	-	2.8	5.5	-	-	**8.3**
Shepparton North replacement	-	-	-	5.0	2.5	**7.5**
Total	**5.4**	**5.5**	**5.5**	**5.0**	**2.5**	**23.9**

Note: Corresponding transformer volumes are reported in our Reset RIN on an as-commissioned basis (i.e. in the last year of expenditure)

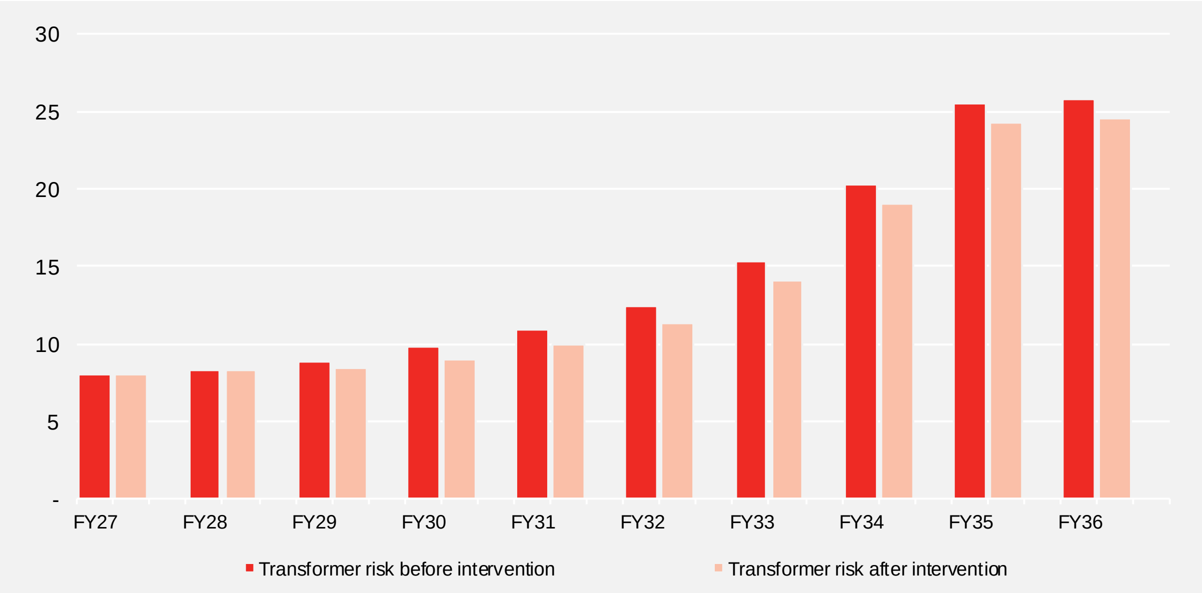
Top-down portfolio review

In addition to the review of overlaps between our replacement and augmentation programs, we also considered the overall change in zone substation risk between the start and end of the 2026–31 regulatory period. This is to inform the impacts of our program on maintaining reliability.

A central theme of our stakeholder engagement program was reliability, with customers consistently highlighting the importance of a maintaining a reliable energy supply. This view was explored in the context of our customers' increasing dependence on electricity given forecast electrification. Our replacement program and asset management practices are critical to ensure reliability outcomes for customers as well as maintaining trust throughout the energy transition for our customers to electrify.

As shown in figure 7, our zone substation transformer risk will increase over time without any intervention. While our proposed forecast will constrain this increase in risk over the 2026–31 regulatory period, the value of risk by FY31 after our proposed interventions will still be higher than at the start of the regulatory period.

FIGURE 7 ZONE SUBSTATION RISK: TRANSFORMERS ($M, 2026)



A Transformer replacements: site-based assessments

This appendix provides a summary of site-based assessments for our proposed risk-based zone substation transformer replacements.

For each site, a full cost benefit analysis has been undertaken and is provided in the attached models. The options considered are consistent with those outlined in the body of this asset class overview and are presented relative to the base case (i.e. a do nothing different option).

A.1 CHA zone substation

Cohuna (CHA) zone substation is supplied by sub-transmission 66kV lines connected to Kerang terminal station (KGTS). It supplies approximately 4,400 customers.

A.1.1 Identified need

CHA zone substation currently consists of two identical 10 MVA 66/22kV transformers, which were both installed in 1962. These transformers are 62 years old and are at the end of life, with key components past their design life and showing signs of deterioration. The main tank transformer seals are failing due to their age and will require significant investment at the site as a minimum to comply with our obligations under the Environmental Protection Act.

The identified need is to address risks associated with failure to supply the area from the substation.[3]

A.1.2 Option analysis

Despite the risk management techniques employed to date, risk analysis of the site identified intervention options that are prudent and efficient in the 2026–31 regulatory period. This risk analysis focuses on the substation as a whole, rather than any individual asset.

Of the transformers at the zone substation, the number two transformer was identified as being in worse condition and was therefore the unit assessed for replacement.

Online monitoring and revised maintenance program options were not considered credible options at this site due to the age and condition of the transformer, meaning they would not address the identified need.

The results of our analysis, relative to a do-nothing base case, are shown in table 6.

[3] PAL MOD 4.06 - Parallel risk model - Jan2025 - Public; and PAL MOD 4.02 - CHA transformer - Jan2025 - Public

TABLE 6 OPTIONS EVALUATION RELATIVE TO BASE CASE ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
2	Replace T2 transformer	(4.6)	5.6	1.0
3	Refurbish T2 transformer	(0.5)	1.3	0.8

Preferred option

The preferred option is to replace the number two transformer at our CHA zone substation (option two), recognising this is the most economic option under our central scenario. This replacement forms part of our overall plan that will defer the replacement of other ageing assets at the site for the foreseeable future

Sensitivity analysis was also used to test the robustness of the central scenario result to potential variations in costs and benefits. The preferred option remained economic under all scenarios.

A.2 MNA zone substation

Mooroopna (MNA) zone substation is supplied by sub-transmission 66kV lines from Shepparton (STN) zone substation and Shepparton terminal station (SHTS). It supplies approximately 10,840 customers.

A.2.1 Identified need

MNA zone substation currently consists of two identical 33MVA 66/22kV transformers, which were both installed in the late 1970s. These transformers are near 50 years old and are approaching the end of their useful life, with key components past their design life and showing signs of deterioration. For example, the main tank transformer seals are failing due to their age and will require significant investment at the site as a minimum to comply with our obligations under the Environmental Protection Act.

The identified need is to address risks associated with failure to supply the area from the substation.[4]

A.2.2 Option analysis

Despite the risk management techniques employed to date, risk analysis of the site identified intervention options that are prudent and efficient in the 2026–31 regulatory period. This risk analysis focuses on the substation as a whole, rather than any individual asset.

Of the transformers at the zone substation, the number one transformer was identified as being in worse condition and was therefore the unit assessed for replacement.

Online monitoring and revised maintenance program options were not considered credible options at this site due to the age and condition of the transformer, meaning they would not address the identified need.

The results of our analysis, relative to a do-nothing base case, are shown in table 7.

[4] PAL MOD 4.06 - Parallel risk model - Jan2025 - Public; and PAL MOD 4.01 - MNA transformer - Jan2025 - Public

TABLE 7 OPTIONS EVALUATION RELATIVE TO BASE CASE ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
2	Replace T1 transformer	(4.3)	5.3	1.0
3	Refurbish T1 transformer	(0.5)	0.8	0.3

Preferred option

The preferred option is to replace the number one transformer at our MNA zone substation (option two), recognising this is the most economic option under our central scenario. This replacement forms part of our overall plan that will defer the replacement of other ageing assets at the site for the foreseeable future

Sensitivity analysis was also used to test the robustness of the central scenario result to potential variations in costs and benefits. The preferred option remained economic under all scenarios.

A.3 SHN zone substation

Shepparton North (SHN) zone substation is supplied by sub-transmission 66kV lines from Shepparton terminal station (SHTS). It supplies approximately 11,200 customers.

A.3.1 Identified need

SHN zone substation currently consists of two 33MVA 66/22kV transformers, which were both installed in 1982. These transformers are 42 years old and their condition is close to end of life.

The identified need is to address risks associated with failure to supply the area from the substation.[5]

A.3.2 Option analysis

Despite the risk management techniques employed to date, risk analysis of the site identified intervention options that are prudent and efficient in the 2026–31 regulatory period. This risk analysis focuses on the substation as a whole, rather than any individual asset.

Of the transformers at the zone substation, the number two transformer was identified as being in worse condition and was therefore the unit assessed for replacement.

Online monitoring and revised maintenance program options were not considered credible options at this site due to the age and condition of the transformer, meaning they would not address the identified need.

The results of our analysis, relative to a do-nothing base case, are shown in table 7.

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[5] PAL MOD 4.06 - Parallel risk model - Jan2025 - Public; and PAL MOD 4.03 - SHN transformer - Jan2025 - Public

TABLE 8 OPTIONS EVALUATION RELATIVE TO BASE CASE ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
2	Replace T2 transformer	(3.7)	4.5	0.7
3	Refurbish T2 transformer	(0.5)	0.3	(0.2)

Preferred option

The preferred option is to replace the number two transformer at our SHN zone substation (option two), recognising this is the most economic option under our central scenario. This replacement forms part of our overall plan that will defer the replacement of other ageing assets at the site for the foreseeable future

Sensitivity analysis was also used to test the robustness of the central scenario result to potential variations in costs and benefits. The preferred option remained economic under all scenarios.

B Environmental management program

Changes to the Victorian Environmental Protection Act (2017) that came into effect in July 2021 introduced requirements to proactively minimise risks so far as reasonably practicable, of risks of harm to human health and the environment.

B.1.1 Identified need

In response to these changes, we have taken a risk-based approach to complying with the Environmental Act and have significantly increased our investment in this area across a range of network-related activities. This includes targeted refurbishments of large transformers in the current 2021–26 regulatory period to manage oil leaks.

Our assessment of the risk includes a risk-monetisation approach to determine which control(s) are deemed reasonably practicable, considering asset and substation data as well as the cost of different interventions. This approach has been shared with the Environmental Protection Agency.

Our existing program, detailed below, forms part of our ongoing plan which will continue to manage these risks in the 2026–31 regulatory period. The plan is a continuation on the extent of our current works which includes managing network constraints while work takes place, engagement of specialist contractors and our current resource capabilities, and considers overlaps with other forecast works.

B.1.2 Options considered

Table 9 lists all the credible options considered to address transformer oil leaks. To evaluate these options we developed an oil risk model to assess and prioritise transformers based on their underlying oil risks. Our model has been benchmarked against practices from other regions, locally and internationally to ensure our model is robust and the assumptions reasonable.

TABLE 9 CREDIBLE OPTIONS

OPTION		DESCRIPTION
1	Base case	Continue existing maintenance of minor short-term fixes and no planned capital works
2	Transformer refurbishment	Refurbish transformers where leaks are significant and minor short-term fixes are inadequate
3	Transformer replacement	Replace transformers, noting however, that this option is typically not credible due to the cost of replacement relative to the value of the risk

B.1.3 Preferred option

Based on our risk evaluation and performance data, we identified 25 transformers where the cost to address the risk is lower than the risk valuation. The highest risk transformers will be refurbished in the remainder of the current regulatory period, with a further 15 transformers proposed in the 2026–31 regulatory period. This will maintain our existing refurbishment rate of around three transformers per annum, and manage planning and deliverability considerations.

A summary of the transformers proposed in the 2026–31 regulatory period is set out in table 10, with further detail in our risk model.[6] Option two is preferred for all sites.

TABLE 10 OPTION EVALUATION RESULT

ZONE SUBSTATION	BENEFITS-COST RATIO OPTION 2	BENEFITS-COST RATIO OPTION 3
Koroit (KRT) T1	5.37	1.14
Ballarat North (BAN) T3	4.39	0.93
Ouyen (OYN) T2	3.26	0.69
Ford North Shore (FNS) T3	2.93	0.62
Cobram East (CME) T2	2.49	0.53
Cobram East (CME) T1	2.47	0.52
Altona (AL) T2	2.34	0.50
Ouyen (OYN) T1	1.73	0.37
Echuca (ECA) T1	1.47	0.31
Numurkah (NKA) T3	1.46	0.31
Drysdale (DDL) T1	1.46	0.31
Numurkah (NKA) T2	1.46	0.31
Charlton (CHA) T3	1.46	0.31
Drysdale (DDL) T2	1.46	0.31
Kyabram (KYM) T3	1.32	0.28

Expenditure associated with this program is shown in table 11.

6 PAL MOD 4.04 - Transformer refurbishment - Jan2025 - Public

TABLE 11 ZONE SUBSTATION TRANSFORMER REFURBISHMENTS ($M, 2026)

EXPENDITURE	FY27	FY28	FY29	FY30	FY31	TOTAL
Transformer environmental refurbishment program	1.8	1.8	1.8	1.8	1.8	**8.8**

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