
# REPLACEMENT

## ZONE SUBSTATION TRANSFORMERS ADDENDUM

PAL RRP BUS 3.4.04 – PUBLIC
2026–31 REVISED PROPOSAL

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# 1. Overview

This business case addendum sets out our response to the AER's draft decision and describes the further work we have undertaken since our regulatory proposal. It should be read in conjunction with the following documents:

- our regulatory proposal business case[1]
- our revised economic models.[2]

Our revised proposal addresses the AER’s draft decision feedback on our economic modelling and provides further information to support our investments. We have provided further detail to:

- clarify our key modelling inputs and assumptions
- demonstrate how we assessed options for transformer refurbishment and making substations ready for emergency spare transformers to test the prudency and efficiency of transformer replacements.
- support our unit cost estimates with more granular information on the scopes of work and costs to demonstrate the prudency and efficiency of the proposed investments.

As shown in table 1 below, our revised proposal is lower than our regulatory proposal, but higher than the AER’s draft decision. As accepted in the AER’s draft decision, we have retained our proposed transformer replacement at Cohuna (CHA) zone substation as it is prudent and efficient even after accounting for updates to our modelling. This includes a reduction in expenditure based on updated cost estimates.

In addition to the accepted transformer replacement, our revised transformer forecast also includes interventions at four zone substations that were not included in our regulatory proposal due to updates to the VCR, our demand forecasts and options analysis. This includes a transformer replacement at Stawell (STL), a transformer refurbishment at Kyabram (KYM) zone substation, and making Camperdown (CDN) and Maryborough (MRO) zone substations ready for an emergency spare transformer to ensure the impact to customers is minimised in the case of transformer failure.

We have also re-proposed our transformer environmental refurbishment program with updated costs.

However, we have not re-proposed the transformer replacements at Mooroopna (MNA) and Shepparton North (SHN) zone substations, which have been deferred primarily due to updating the value of customer reliability (VCR) to latest values.

[1] PAL BUS 4.08 – Zone substation transformers, January 2025
[2] PAL RRP MOD 3.4.03 – 3.4.09, December 2025

**TABLE 1 REVISED PROPOSAL: ZONE SUBSTATION TRANSFORMERS ($M, 2026)**

| CATEGORY | REGULATORY PROPOSAL | DRAFT DECISION | REVISED PROPOSAL |
|---|---|---|---|
| MNA replacement | 8.3 | - | - |
| SHN replacement | 7.5 | - | - |
| CHA replacement | 8.0 | 7.9 | 6.8 |
| STL replacement | - | - | 7.0 |
| KYM refurbishment | - | - | 0.7 |
| CDN emergency spare ready | - | - | 2.2 |
| MRO emergency spare ready | - | - | 2.2 |
| Environmental refurbishment program | 8.8 | 4.4 | 10.6 |
| Minor station works | 4.2 | 4.2 | 4.2 |
| **TOTAL** | **37.0** | **16.5** | **33.7** |

# 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 included in our regulatory proposal and the AER's draft decision.

## 2.1 Our regulatory proposal

Our forecasting approach for zone substation transformers in the 2026–31 regulatory period is based on a risk-based asset management framework. This methodology aligns with the AER's asset replacement planning note and builds on models previously accepted by the AER in regulatory decisions.

For example, we assess risk at the zone substation level, considering failure probabilities, conditional risks, redundancy, load forecasts and outage durations. This enables us to identify the most economically beneficial interventions, balancing cost against the monetised value of risks.

Our risk assessment is underpinned by a risk monetisation approach summarised in figure 1. We monetise risk when assessing investment decisions by determining the annual asset risk cost. This approach is applied to all identified failure modes for an asset, and the sum of the annual asset risk cost for all of failure modes is compared to the annualised cost of the preferred option to determine the economic timing for any intervention.

Our approach to risk monetisation uses the probability of failure informed by our historical asset failure data supplemented by failure type ratios from relevant industry surveys (such as those published by Ofgem), and cost and likelihood of consequence modelling to provide a robust approach for the preparation and application of the required input information. Our risk monetisation modelling is a comprehensive approach, which is aligned with the AER's risk monetisation process.

FIGURE 1 RISK MONETISATION APPROACH


Our regulatory proposal included the following investments for zone substation transformers over the 2026−31 regulatory period. This included:

- replacing transformers at CHA, MNA and SHN zone substations
- continuing our environmental refurbishment program, targeting oil leaks in transformers to meet obligations under the Victorian Environment Protection Act
- minor station works and unplanned interventions based on historical defect and failure data.

Overall, our proposed investments sought to maintain network reliability and minimise environmental risks. However, our proposal still resulted in overall risk levels in FY31 being higher than corresponding levels at the start of the regulatory period.

## 2.2 AER's draft determination

The AER's draft decision did not accept our proposed capital expenditure and instead allowed a materially lower substitute estimate (as shown in table 1 above).

In making its draft decision, the AER had regard to EMCa's advice to determine that:[3]

- our transformer replacement program targeting three zone substations was likely overstated due to our modelling assumptions. These assumptions included using 2023 VCRs, overstating environmental risk costs, and applying different analysis periods to costs and benefits. After making these adjustments, the AER determined that two out of three transformer replacements should be deferred beyond the 2026–31 period
- our transformer unit cost estimates appear high when compared to peers and have not been sufficiently supported
- we incorrectly quantified environmental risk costs for our transformer refurbishment program. The AER applied a 50 per cent reduction to this program to align with the expected capital expenditure in the 2021–26 period
- our proposed capital expenditure for minor station works is reasonable.

Based on the above feedback, the AER determined that the transformer replacements at MNA and SHN should be deferred beyond the 2026–31 period. Further, the AER reduced the capital expenditure for the transformer environmental management program. The AER accepted the proposed capital expenditure for the transformer replacement at CHA and minor station works.

[3] AER, Draft decision – Powercor 2026–31 distribution determination – Attachment 2 – Capital expenditure, September 2025, pp. 27–28

# 3. Revised proposal

We maintain that the CHA zone substation transformer replacement included in our regulatory proposal will be required in the 2026–31 regulatory period. We have also updated modelling to account for updates to key inputs for VCR and demand, as well as options analysis, which has revised our transformer intervention program. Notwithstanding this, we accept that further information was required to support our forecast.

In our revised proposal we demonstrate the following:

- after updating and providing further support for modelling inputs and assumptions, our revised proposal transformer replacement for CHA remains economically justified, but the transformer replacements at MNA and SHN have been deferred
- our updated modelling, cost estimation and options analysis since submitting our regulatory proposal demonstrates that further zone substation interventions are prudent and efficient, including a transformer replacement at STL, a transformer refurbishment at KYM, and making CDN and MRO zone substations emergency spare ready
- our unit cost estimates are prudent, efficient and based on a realistic expectation of cost inputs informed by detailed scopes and cost estimates in appendix A for the various activities and components involved in transformer replacements, as well as site specific conditions.

In response to the AER's feedback regarding modelling issues, insufficient justification of environmental risk cost quantification, and high unit costs, we have re-estimated our transformer replacement cost estimates based on our latest available data and have attached the corresponding functional scopes and estimates in appendix A. We have also clarified the inputs around our environmental risk which were misunderstood by EMCa and the AER.

We do not, however, accept the AER's feedback on the inconsistencies in our modelling regarding the timing of costs and benefits.

## 3.1 Response to AER draft determination

We have considered the AER's draft decision and respond to the feedback below for areas where we have not accepted the AER's draft decision.

### 3.1.1 Applying alternative and updated input assumptions

The AER and EMCa considered that applying alternative and updated input assumptions would likely lead to the deferral of two out of the three transformer replacements we included in our regulatory proposal. Our revised proposal addresses each of the issues raised by updating VCR to latest values, clarifying how we quantify environmental risk costs, and justifying how our approach to modelling costs and benefits is appropriate.

#### Updated VCR and demand forecasts

Across our transformer models, we have updated the VCR to reflect the latest 2024 values, which was not available to us at the time of developing our regulatory proposal.

We also updated our demand forecasts to incorporate more recent AEMO assumptions and the most recently completed summer period. Further detail on our demand forecast updates is provided in our main revised proposal document.

### Clarifying our environmental risk cost inputs

The AER's draft decision stated that our environmental risk cost inputs were overstated due to issues identified by EMCa. These concerns were for incorrect quantification of the base risk costs, not appropriately applying risk modifiers, and not sufficiently quantifying the consequences.

For the environmental risk cost inputs, we clarify that this risk relates to the harm valuation of potential environmental damage costs associated with oil pollution into the environment from events such as oil leaks—not the value of replacing lost oil, as EMCa and the AER appear to have misinterpreted.

In response, our updated models better specify the basis of these input assumptions and emphasise that this approach is aligned with established industry estimation practices. For the environmental risk quantification, we also clarify that:

- we have corrected some minor inconsistencies in cost estimates, as identified by EMCa. These have no impact on our proposed program
- the risk modifiers we applied in our original modelling are aligned with Ofgem's approach to quantifying environmental risk and we have corrected the modifier for distances of less than five metres to groundwater as noted by EMCa
- our revised parallel risk model provides further information to explain the inputs, assumptions and calculations to derive the hardcoded environmental risk costs.[4]

We have also provided further clarification regarding this risk monetisation in appendix B.

In relation to our environmental refurbishment program, we note that the AER reduced our program by 50 per cent to better align with the 2021–26 period. Given this is a risk-based program we do not consider that alignment with the 2021–26 period should be a consideration of the size of our program. Our proposed volumes are based on the environment risk at each of our zone substations, it is this risk that dictates the required interventions in the 2026–31 regulatory period. In addition to this, we also consider our full program better aligns with our historical refurbishments where we have delivered an average of 2.5 refurbishments over the last four years. We have also updated the costs associated with a transformer refurbishment. Following these updates, we are proposing a small increase in expenditure compared to our regulatory proposal.

### Alignment of costs and benefits

As discussed in section 3.1 of our revised regulatory proposal, we do not agree with the feedback regarding the misaligned timing of costs and benefits in our modelling approach. We consider that the approach suggested by EMCa, rather than our methodology, is what creates a misalignment of costs and benefits.

The discounted cash flow method proposed by EMCa is a valid approach. However, EMCa failed to include a terminal value in its example to account for the value of the investment beyond the modelling period. Once a terminal value is included, the difference in net present value between the discounted cashflow method and the annuity method is minimal.

[4] PAL RRP MOD 3.4.09 - Parallel risk model, December 2025, tab 'Environment'

As such, we have retained our annuitised approach to calculating the net present value of our investments and optimal timing as per AER's asset replacement planning application note.[5] This method is also consistent with previous AER decisions, as well as the multiple reports provided to the AER on this issue (including reports from expert economic consultants engaged by the AER).

### 3.1.2 Application of additional options to our modelling

In addition to updating our input assumptions, we also reviewed the options considered for intervention in our risk modelling. This includes the potential benefits from making a number of zone substations emergency spare ready.

As described in table 2 below, we applied this option to all zone substations with 10MVA transformers and found that this is the preferred option at our CDN and MRO zone substations to prudently and efficiently meet the identified need.

**TABLE 2 RISK-BASED INTERVENTION OPTIONS**

| OPTION | DESCRIPTION |
|---|---|
| Do-nothing different | No change to existing practices and no planned transformer replacement |
| Make emergency spare ready | Install a hard standing area with connection infrastructure to allow for trucking in and quickly connecting an emergency spare transformer in the event of one transformer failure. This quickly restores the substation operating capability to reduce unserved energy and reduces the risk of simultaneous transformer failure by minimising overloading of remaining transformers. This is predominately a short-term measure before more permanent fixes (such as replacement) are implemented. |
| 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 on load tap changer (OLTC) or material oil replacement. |
| Replace transformer | Replace one transformer at the zone substation |

We provide further details on the updated options analysis, scope and cost breakdowns in appendix A.

### 3.1.3 Unit cost estimates

The AER's draft decision did not make any adjustments to our proposed transformer replacement unit costs. Rather, the draft decision was based on deferring two of the three replacement projects.

[5] AER, Asset replacement planning industry practice application note, July 2024, p. 36

The AER stated in its draft decision that our 'cost estimates also appear higher than other comparable DNSPs'.[6] To the extent the AER has relied on benchmarked unit costs in arriving at its alternative estimate, our revised proposal supplements our regulatory proposal with further detailed cost breakdowns and scopes of work involved in our transformer replacements for specific sites in appendix A. We have assessed the cost estimates for a transformer replacement project using our established estimating process. We highlight that the cost estimate to replace a transformer represents the total expenditure required to implement the project, and not just the cost of the transformer itself. We also note that based on updated cost estimates we have reduced the total expenditure required for the transformer replacement at our CHA zone substation.

## 3.2 Revised proposal forecasts

Our revised expenditure forecast maintains our regulatory proposal for the transformer replacement at our CHA zone substation, but we have not re-proposed the transformer replacements at SHN and MNA zone substations. We have also included capital expenditure for additional zone substation transformer interventions based on the latest VCR and load inputs.

For our transformer environmental refurbishment program, we have included a minor increase in expenditure compared to our regulatory proposal based on updated refurbishment costs.

Table 3 sets out our revised proposal forecast expenditure. Overall, our program expenditure has reduced from our regulatory proposal.

6 AER, Draft decision – Powercor 2026–31 distribution determination – Attachment 2 – Capital expenditure, September 2025, p. 28

## TABLE 3 REVISED FORECAST EXPENDITURE ($M, 2026)

| EXPENDITURE | FY27 | FY28 | FY29 | FY30 | FY31 | TOTAL |
|---|---|---|---|---|---|---|
| CHA replacement | 4.5 | 2.3 | - | - | - | **6.8** |
| STL replacement | - | - | - | 4.7 | 2.3 | **7.0** |
| KYM refurbishment | - | 0.7 | - | - | - | **0.7** |
| CDN emergency spare ready | - | - | 2.2 | - | - | **2.2** |
| MRO emergency spare ready | - | - | - | 2.2 | - | **2.2** |
| Environmental refurbishment program | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | **10.6** |
| Minor station works | 0.8 | 1.0 | 0.7 | 1.0 | 0.7 | **4.2** |
| **Total** | **7.4** | **6.0** | **5.0** | **10.0** | **5.2** | **33.7** |

# A

# SITE-BASED ASSESSMENTS

# A Site-based assessments

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

For each site, a full cost benefit analysis has been undertaken and is provided in the attached models.[7] 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).

In each of our proposed investments, the preferred option is selected based on the option that is expected to generate the highest net benefit for customers. We also consider the optimal timing for investments consistent with the AER's guidance on asset replacement planning, where our modelling has identified that the avoided risk costs are greater than the annualised cost prior to or within the 2026–31 period.[8]

We also use sensitivity analysis to test the robustness of the central scenario result to potential variations in costs and benefits.

## A.1 Cohuna (CHA) zone substation transformer replacement

We included the CHA transformer replacement in our regulatory proposal. This section presents the updated options analysis, scopes of work for the preferred option, and updated cost estimates since the regulatory proposal. Further information about the CHA zone substation can be found in our regulatory proposal and information request responses.[9]

### A.1.1 Updated options analysis from regulatory proposal

Our regulatory proposal model conservatively assumed that all zone substations are currently emergency spare ready and included this as part of the base case.

However, analysis of our spare transformer fleet revealed we do not stock a spare 10MVA transformer. Hence, we have removed the spare ready option from the base case and added an explicit emergency spare ready option (option four) in the option analysis.

The results of our updated options analysis, relative to a do-nothing base case, are shown in table 4.

7 PAL RRP MOD 3.4.03 – 3.4.07
8 AER, Asset replacement planning industry practice application note, July 2024, p. 36
9 PAL BUS 4.08 – Zone substation transformers, January 2025, pp. 13–14; and Powercor, Response to AER information request 042 – question 28, June 2025

TABLE 4 CHA: OPTIONS EVALUATION RELATIVE TO BASE CASE ($M, 2026)

| OPTION | | PV COSTS | PV BENEFITS | NET BENEFITS |
|---|---|---|---|---|
| 1 | Base case | - | - | - |
| 2 | Replace T2 transformer | (3.8) | 5.9 | 2.1 |
| 3 | Refurbish T2 transformer | (0.7) | 1.7 | 1.0 |
| 4 | Make emergency spare ready | (2.1) | 4.0 | 1.9 |

#### Preferred option

The preferred option is to replace the number two transformer at CHA zone substation (option two). The optimal timing for replacing the transformer is in the 2026–31 regulatory period to avoid growing risk costs.

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 and the preferred option under all scenarios.

### A.1.2 Preferred option scope

The preferred option is to replace the number two transformer with a standard modern equivalent. It entails installing a new transformer in the spare transformer position and removing the existing number two transformer as shown in the site layout in figure 2 below.

The scopes of work will include:

- installing a new transformer bund in the spare transformer bay next to number two transformer
- installing new oil containment tank
- installing drainage pipes from the new bund to the new oil containment tank
- installing outdoor 66/22kV transformer with attached radiator including current transformers and surge arrestors
- installing number one 66kV strung bus, including bus support structures and foundations
- installing new outdoor switchgear:
    - one 66kV bus disconnect switch, including new foundation, switch structure
    - one 66kV transformer disconnect switch, including new foundation, switch structure and extension arm for conductor support over transformer access track
    - one 22kV transformer disconnect switch, including new foundation and structure
- installing new 66kV conductor support structure and foundation to number one 66kV bus

- installing 66kV and 22kV overhead connections
- installing one new panel for new transformer protection relays in existing control building, assuming sufficient space in existing control building. Modify existing protection, control and communication schemes to interface with the new equipment
- after the commissioning and energisation of the new transformer, decommission and remove the existing number two transformer and associated switchgear, protection and control equipment.

FIGURE 2 CHA: ZONE SUBSTATION SITE LAYOUT

### A.1.3 Cost breakdown

To address the AER's commentary regarding our unit costs, we provide a detailed cost breakdown in our revised proposal to demonstrate to the AER that the build-up of our proposed costs is efficient.[10]

We reaffirm that the estimated cost to replace a transformer represents the total expenditure required to implement the project (as described by the abovementioned scope) and not just the cost of the transformer itself. We provide these cost breakdowns to the AER (in the attached model) as commercial in confidence due to the granularity of the cost estimates and the contents containing costs from contractual agreements.

## A.2 Stawell (STL) zone substation transformer replacement

STL zone substation is supplied by sub-transmission 66kV lines connected to Horsham terminal station and Ararat zone substation. It supplies approximately 6,600 customers.

### A.2.1 Identified need

STL zone substation consists of two identical 10MVA 66/22kV transformers, which were both installed in 1967. These transformers are 58 years old and are at the end of life, with key components past their design life and showing signs of deterioration. The number one transformer recently overheated due to the radiator valve being closed, which will reduce the transformer lifespan.

STL is forecast to have a significant increase in load, which has driven up the energy at risk in the event of a transformer failure at the zone substation. The increase in the 2025 demand forecast for STL is driven by new commercial and industrial connections with expected load growth over the 2026−31 regulatory period.

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

### A.2.2 Options 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 three transformer was identified as being in worse condition and was therefore assessed for replacement.

The results of our analysis, relative to a do nothing different base case, are shown in table 5.

10 PAL RRP MOD 3.4.10 – Transformer cost breakdown – Confidential, December 2025

**TABLE 5 STL: OPTIONS EVALUATION RELATIVE TO BASE CASE ($M, 2026)**

| OPTION | | PV COSTS | PV BENEFITS | NET BENEFITS |
|---|---|---|---|---|
| 1 | Base case | - | - | - |
| 2 | Replace T3 transformer | (3.5) | 8.0 | 4.4 |
| 3 | Refurbish T3 transformer | (0.6) | 1.4 | 0.8 |
| 4 | Make emergency spare ready | (1.9) | 6.1 | 4.2 |

#### Preferred option

The preferred option is to replace the number three transformer at STL zone substation (option two). The optimal timing for replacing the transformer in the 2026–31 regulatory period to avoid growing risk costs.

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 and the preferred option under all scenarios.

### A.2.3 Preferred option scope

The preferred option is to replace the number three transformer with a standard modern equivalent. It entails installing a new transformer in the spare number two transformer position and removing the existing number three transformer as shown in the site layout in figure 3 below.

The scopes of work will include:

- installing a new transformer bund in the spare transformer bay next to transformer number one
- installing oil containment tank
- installing drainage pipes from the new bund to the new oil containment tank
- installing outdoor 66/22kV transformer with attached radiator including current transformers and surge arrestors
- installing new outdoor switchgear:
    - one 66kV transformer disconnect switch, including new foundation, switch structure and extension arm for conductor support over transformer access track
    - one 22kV transformer disconnect switch, including new foundation and structure
    - one 22kV transformer dead tank circuit breaker, including new foundation and structure
    - two neutral isolator switches as neutral bus isolator and neutral direct ground isolator, including new foundation and structure

- installing new 66kV conductor support structure and foundation to the number two 66kV bus
- installing 66kV and 22kV overhead connections
- installing new 22kV 1C 185m2 Al cable from the number two transformer neutral isolator structure to the number one neutral bus switchgear. Note that this neutral connection shall replace the neutral connection of the transformer to be decommissioned at the number one neutral bus switchgear
- installing one new panel for the new transformer protection relays in the existing control building, assuming sufficient space in existing control building. Modify existing protection, control and communication schemes to interface with the new equipment
- after the commissioning and energisation of new number two transformer, decommission and remove the existing number three transformer and associated switchgear, protection and control equipment.

FIGURE 3 STL: ZONE SUBSTATION SITE LAYOUT


### A.2.4 Cost breakdown

To address the AER's commentary regarding our unit costs, we provide a detailed cost breakdown in our revised proposal to demonstrate to the AER that the build-up of our proposed costs is efficient.[11]

We reaffirm that the estimated cost to replace a transformer represents the total expenditure required to implement the project (as described by the abovementioned scope) and not just the cost of the transformer itself. We provide these cost breakdowns to the AER (in the attached model) as commercial in confidence due to the granularity of the cost estimates and the contents containing costs from contractual agreements.

11 PAL RRP MOD 3.4.10 – Transformer cost breakdown – Confidential, December 2025

## A.3 Kyabram (KYM) zone substation transformer refurbishment

KYM zone substation is supplied by sub-transmission 66kV lines connected to Shepparton terminal station, Echuca zone substation and Stanhope zone substation. It supplies approximately 6,870 customers.

### A.3.1 Identified need

KYM zone substation consists of three 10MVA 66/22kV transformers, which were installed in 1963. 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. Both the number one and three transformers are leaking oil and require significant investment to comply with our obligations under the Environment Protection Act.

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

### A.3.2 Options 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 with higher leak rate than the number three transformer and therefore the number one transformer was assessed for replacement. The refurbishment of the number three transformer was submitted as part of our transformer environmental refurbishment program, which is discussed in our regulatory proposal.[12]

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

12 PAL BUS 4.08 – Zone substation transformers, January 2025, pp. 17–19

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

| OPTION | | PV COSTS | PV BENEFITS | NET BENEFITS |
|---|---|---|---|---|
| 1 | Base case | - | - | - |
| 2 | Replace T1 transformer | (3.7) | 5.2 | 1.5 |
| 3 | Refurbish T1 transformer | (0.6) | 4.1 | 3.5 |
| 4 | Make emergency spare ready | (2.0) | 0.4 | (1.6) |

#### Preferred option

The preferred option is to refurbish the number one transformer at KYM zone substation (option three). The optimal timing for refurbishing the transformer is in the 2026–31 regulatory period to avoid growing risk costs.

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 and the preferred option under all scenarios.

### A.3.3 Preferred option scope

The preferred option is to refurbish the number one transformer to prevent oil leaks. The scope entails:

- partially drain the transformer of oil
- replacing leaking seals and gaskets, including main tank lid seal
- painting any rusty transformer exterior
- repairing any damaged fans or radiator fins
- cleaning the transformer area to remove and dispose of any oil
- refilling the transformer with new oil.

## A.4 Camperdown (CDN) zone substation transformer emergency spare ready

CDN zone substation is supplied by sub-transmission 66kV lines connected to Terang terminal station, Cobden zone substation and Colac zone substation. It supplies approximately 5,870 customers.

### A.4.1 Identified need

CDN zone substation consists of two identical 10MVA 66/22kV transformers, which were both installed in 1962. These transformers are 63 years old and are at the end of life, with key components past their design life and showing signs of deterioration.

Further, there is minimal transfer capacity to other zone substations around CDN in the event of a transformer failure. This can increase the risk of losing the remaining transformer due to overloading of this transformer.

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

### A.4.2 Options 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 the worst condition and was therefore assessed for replacement.

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

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

| OPTION | | PV COSTS | PV BENEFITS | NET BENEFITS |
|---|---|---|---|---|
| 1 | Base case | - | - | - |
| 2 | Replace T1 transformer | (3.4) | 4.7 | 1.3 |
| 3 | Refurbish T1 transformer | (0.6) | 0.7 | 0.1 |
| 4 | Make emergency spare ready | (1.9) | 4.0 | 2.1 |

#### Preferred option

The preferred option is to make the CDN zone substation emergency spare ready (option four). The optimal timing for the preferred option is in the 2026–31 regulatory period to avoid growing risk costs.

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 and the preferred option under all scenarios.

### A.4.3 Preferred option scope

The preferred option is to make the CDN zone substation emergency spare ready to minimise the risk of another transformer failure due to overloading. The scope entails:

- designing and constructing hard stand area for spare transformer

- designing and constructing bund arrangement for spare transformer
- designing and constructing mobile interface cubicle for the protection schemes for the spare transformer to plug into
- designing 22kV supply/connection for the spare transformer connection to either transformer circuit breaker
- designing 66kV connection to the mobile transformer
- standing poles ready for 66kV conductor connection if required.

## A.5 Maryborough (MRO) zone substation transformer emergency spare ready

MRO zone substation is supplied by sub-transmission 66kV lines connected to Bendigo terminal station and Castlemaine zone substation. It supplies approximately 9,950 customers.

### A.5.1 Identified need

MRO zone substation consists of two identical 10MVA 66/22kV transformers, which were both installed in 1965. These transformers are 60 years old and are at the end of life, with key components past their design life and showing signs of deterioration. Both transformers are leaking oil and will require significant investment at the site as a minimum to comply with our obligations under the Environment Protection Act.

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

### A.5.2 Options 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 three transformer was identified as being in the worst condition with higher leak rate and was therefore assessed for replacement.

The results of our analysis, relative to a do nothing different base case, are shown in table 8.

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

| OPTION | | PV COSTS | PV BENEFITS | NET BENEFITS |
|---|---|---|---|---|
| 1 | Base case | - | - | - |
| 2 | Replace T3 transformer | (3.5) | 5.5 | 1.9 |
| 3 | Refurbish T3 transformer | (0.6) | 1.7 | 1.1 |
| 4 | Make emergency spare ready | (2.0) | 4.0 | 2.1 |

#### Preferred option

The preferred option is to make the MRO zone substation emergency spare ready (option four). The optimal timing for the preferred option is in the 2026–31 regulatory period to avoid growing risk costs.

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 and the preferred option under all scenarios.

### A.5.3 Preferred option scope

The preferred option is to make the MRO zone substation emergency spare ready to minimise the risk of another transformer failure due to overloading. The scope entails:

- designing and constructing hard stand area for spare transformer
- designing and constructing bund arrangement for spare transformer
- designing and constructing mobile interface cubicle for the protection schemes for the spare transformer to plug into
- designing 22kV supply/connection for the spare transformer connection to either transformer circuit breaker
- designing 66kV connection to the mobile transformer
- standing poles ready for 66kV conductor connection if required.

# B

# ENVIRONMENTAL RISK MONETISATION

# B Environmental risk monetisation

This appendix summarises our approach to monetising the risk associated with environmental pollution in the form of an oil leak, in accordance with our obligations under the *Environment Protection Act 2017* (Vic) (the EP Act). The EP Act was amended in 2017 and came into effect from 2021, introducing a significant change for the alignment of obligations on duty holders is to minimise harm to the environment as far as reasonably practicable. As a result of the changes, the management of environmental issues in Victoria now aligns with the obligations for safety risk management under section 20 of the *Occupational Health and Safety Act 2004* (Vic) (the OH&S Act).

## B.1 Our approach in evaluation environmental risks

The Environment Protection Authority Victoria (EPA) has not provided further guidance on the management of environmental issues aligning with safety risk management obligations mentioned above. In the absence of formal guidance for implementing the EP Act and the values we should apply in our jurisdiction, we have developed an approach and framework that is aligned with that used for safety decision making.

This is used to test if investment to manage the risk meets the reasonably practicable test, which we consider is appropriate given the expectations of the legislation.

### Our approach considers environmental risk consistent with safety risk

Table 9 illustrates the valuation approaches we apply for environmental risks. We note that this uses a similar structure to how we currently assess safety risks. Our approach adapts the Ofgem Common Network Asset Indices Methodology (CNAIM) approach of applying modifiers to the base risk value to account for proximity to waterways, bunding factors and transformer size factor for our zone substation transformers.

**TABLE 9 VALUATION APPROACH FOR SAFETY AND ENVIRONMENTAL RISKS**

| RISK TYPE | HARM / WTP VALUATION | MODIFIERS | OTHER COSTS | TOTAL CONSEQUENCE VALUATION |
|---|---|---|---|---|
| Environment (Oil pollution) | Valuation of oil harm (per litre entering the environment) | Location / distance to groundwater / bunding | Clean up costs | **Value of oil harm × modifiers + other costs** |
| Safety | Value of a statistical life-year (VSLY) | Disability Factors | Medical bills | **VSLY × modifiers + other costs** |

### Our framework and values have been provided to the EPA

For estimating environmental risk costs from oil leaks, we have developed a framework that utilises the value of a statistical life (similar to our safety risk). This framework has been provided to the EPA as part of a recent improvement notice that was issued in the United Energy network. As part of our response to the notice we provided the following explanation:

> *To determine if investment is reasonably practicable, United Energy have assigned a valuation for the harm caused to the environment by oil. The approach is based on that which is used for safety assessment and is linked to the value of a statistical life-year (VSLY), published by the Office of Impact Analysis.[13] In this analysis, the base value of a volume of 2,000 litres of oil is equivalent to 1 VSLY. This equates to $117.50 per litre, which is multiplied by 7.5 due to the proximity and impact to the nearby waterway. This valuation is consistent with published numbers in other jurisdictions (NSW, as well as the UK) used for similar purposes.[14]*

Following our response, the EPA revoked its improvement notice as it considered compliance with the EP Act had been achieved. In the absence of an alternative published value or methodology, we have continued to apply this approach in our assessment of risk costs given we have achieved compliance following this approach with the EPA.

### Our environmental risk cost is conservative

Our estimate of the environmental risk cost is connected to the personal injury and loss of livelihood associated with oil leaks that would arise from oil entering waterways. This is one risk type identified in the AER's industry practice application note for asset replacement planning, which comprises environmental costs for:[15]

- property loss
- damages for personal injury or loss of livelihood
- deemed loss to the natural environment
- clean-up or remediation
- any other related costs (which must be reasonably likely to be incurred and adequately justified).

We have sense checked our value against the environmental risk cost from oil leaks used in Ofgem's CNAIM and Ausgrid's environmental remediation estimate. Figure 4 compares our estimated environmental risk cost (in terms of dollars per litre of leaked oil) with each of the methodologies listed above. The figure demonstrates that our estimate is broadly in line with Ofgem's and below that of Ausgrid's.

We consider alignment with Ofgem leads to a conservative estimate, as there are additional risks related to oil leaks in our network that could justify a higher consequence value. For example, given the rural nature of our network there is significantly larger amounts of bore water that is being used directly by the population. Oil leaking into groundwater and waterways is therefore likely to have a much larger health consequence compared to the UK.

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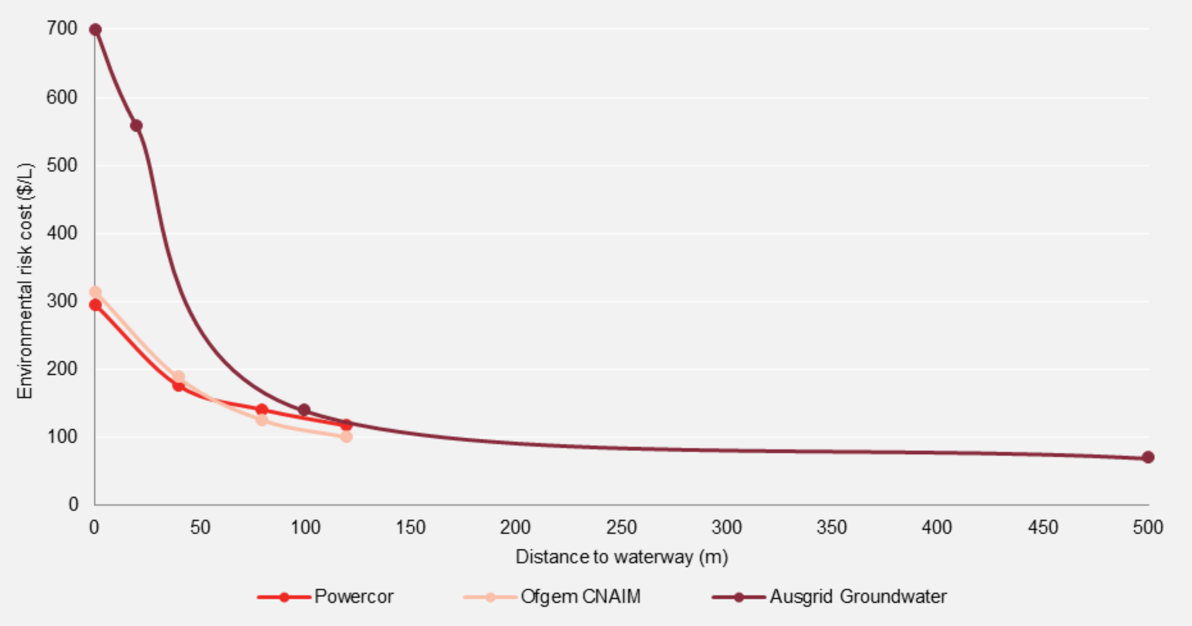
13 Australian Government Department of the Prime Minister and Cabinet, Value of statistical life, November 2024
14 Ausgrid, 2024–29 Regulatory Proposal – Attachment 5.2.c, January 2023, pp. 15–16; and UK Office of Gas and Electricity Markets, Distribution network operators Common Network Asset Indices Methodology, April 2021, Appendix D.3
15 AER, Asset replacement planning industry practice application note, July 2024, pp. 40–41

FIGURE 4 COMPARISON OF ENVIRONMENTAL RISK COSTS ($/L)




## B.2 Application of our environmental risk framework

Our environmental risk cost is a function of both likelihood and consequence, as follows:

- for active oil leaks that are uncontained, the likelihood of oil entering the ground is 100 per cent—that is, the likelihood is a certainty. In this case, the risk value is the same as the consequence value
- when considering a transformer failure, we use additional probabilities to account for the likelihood of a transformer failing which also leads to a rupturing of the oil containment. In this situation while the consequence of event is significantly higher, the likelihood is very low, leading to a smaller risk value.

We present the quantification of two different worked examples below:

- table 10 shows the annual risk value of a zone substation transformer leaking at a rate of 50L/year
- table 11 shows the annual risk value of a zone substation transformer failing, resulting in complete oil loss.

TABLE 10 EXAMPLE OF ANNUAL RISK VALUE FOR LEAKING TRANSFORMER

| PARAMETER | VALUE / CALCULATION |
|---|---|
| Likelihood of a ZSS transformer leak | 100% |
| Consequence value = volume of oil x harm value of oil (uncontained ground) | 50L × $117.5 = $5,875 |
| **OVERALL RISK (L × C)** | **100% × $5,875 = $5,875** |

TABLE 11 EXAMPLE OF ANNUAL RISK VALUE FOR COMPLETE OIL LOSS

| PARAMETER | VALUE / CALCULATION |
|---|---|
| Likelihood of a ZSS transformer failure | 1% |
| Likelihood that the failure results in a rupture | 1% |
| Likelihood of a rupture event | 1% × 1% = 0.01% |
| Consequence value = volume of oil x harm value of oil (uncontained ground) | 20,000L × $117.5 = $2,350,000 |
| **OVERALL RISK (L × C)** | **0.01% × $2,350,000 = $235** |

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