Zone substation transformer replacements: forecast method overview

BUS 4.03

Regulatory proposal 2021–2026

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Contents

1 Overview

The aim of this document is to provide an overview of how we have developed prudent and efficient forecasts for zone substation transformer replacements over the 2021–2026 regulatory period. In particular, we outline our asset management approach for zone substation transformers, and the risk monetisation process used to develop our forecast.

Our risk monetisation approach identifies the least-cost solution to manage the substation, based on the identified failure modes for an asset, and the corresponding probabilities, likelihoods and consequences of failures. This approach is consistent with the AER's recent asset replacement practice note.[1]

For the reasons set out in this document, we will increase the volume of transformer replacements over the 2021–2026 regulatory period. This reflects the rising risk of failure, based on our network experience, as our transformer population continues to deteriorate over time. It also reflects the increased consequence of failure due to higher zone substation demand. When the load at risk and growth rate, age or the cost of required site works change, asset replacements may increasingly become the most efficient option.

A summary of our forecast capital expenditure requirements is shown in table 1.1. These forecasts were modelled in calendar year terms, and converted to financial year estimates following changes to our regulatory period (as required by the Victorian Government and the Australian Energy Regulator).

Table 1.1 Capital expenditure forecasts: zone substation transformer replacements ($ million, 2021)

Expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capital expenditure	5.1	5.8	7.0	7.5	6.8	32.1

Source: United Energy

1 UE ATT099: AER, *Industry practice application note: asset replacement planning*, January 2019.

2 Background

Zone substation transformers are major network assets that transform electricity from higher to lower voltages. This allows electricity to be distributed efficiently over long distances. Our transformers comprise a number of discrete components, including the core and coils, cooling system, on-load tap changers and high voltage bushings.

This section provides an overview of the population and age profile of zone substation transformers in our network.

2.1 Asset population

The quantity and voltage of zone substation transformers installed in our network is set out in table 2.1. Most of these transformers operate at a primary (high) voltage of 66kV and secondary (low) voltages of 11kV or 22kV. There remains a small number of transformers that operate at alternative voltages (6.6kV), reflecting the older age of these assets.

Table 2.1 Transformer population

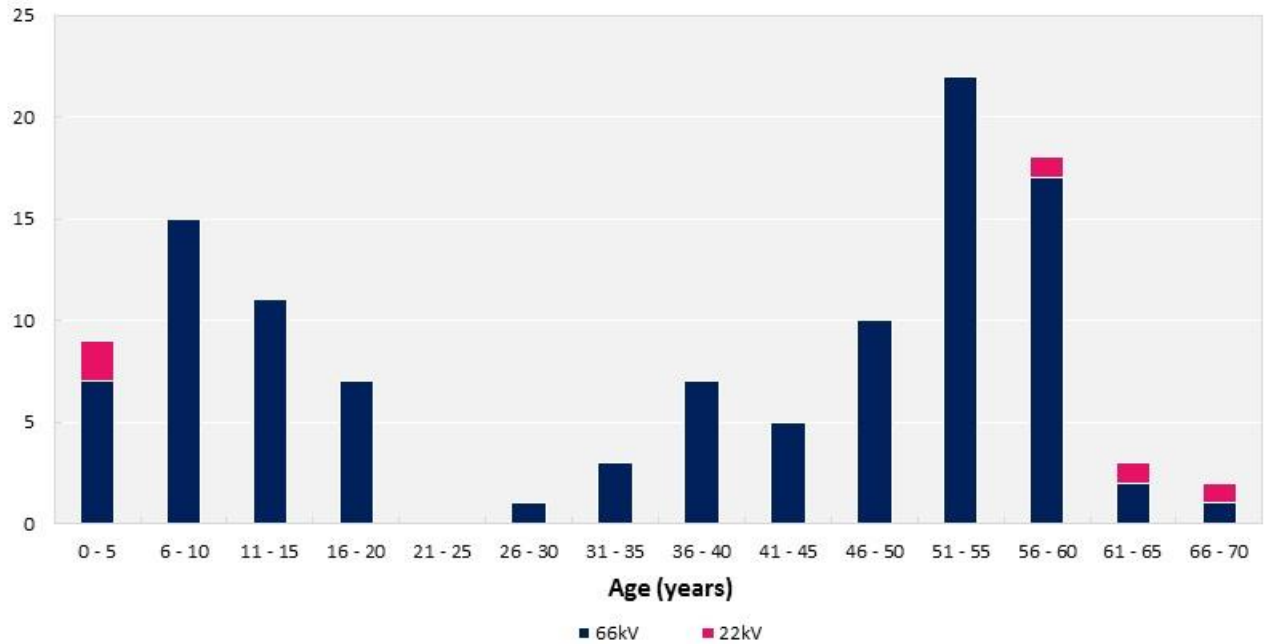
Transformer type	Volume
66kV / 11kV	36
66kV / 22kV	72
22kV / 11kV	3
22kV / 6.6kV	2
11kV / 6.6kV	2
Total	**115**

Source: United Energy

2.2 Asset age profile

As shown in figure 2.1, the age of our zone substation transformer population varies from recent installations to assets installed over 65 years ago. Of this population, over half were commissioned more than 40 years ago, and one-third are older than 50 years.

Figure 2.1 Zone substation transformer age profile (volume)



Source: United Energy

On average, the typical design life of a zone substation transformer is around 40 years. In practice, transformer windings may have an operating life of up to 60 years, whereas external components such as bushings will typically deteriorate at around 45 years of age. Accordingly, once a transformer reaches around 45–50 years of age, they are commonly subject to an overhaul (excluding the winding) to ensure the asset continues to function until the winding reaches its end of life.

For the reasons set out in this document, several of our zone substation transformers are approaching or are at the end of their economic life and will soon require replacement (or alternative interventions).

3 Identified need

We manage transformers on our network, including replacement, to ensure we maintain network service levels in accordance with our regulatory and compliance obligations (listed in appendix A). Our approach to meeting these needs is based on an assessment of the risk and consequence associated with each zone substation.

3.1 Asset management approach

Our asset management approach for zone substation transformers includes multiple options for meeting our required service levels. Specifically, these options include the following:

- ongoing planned, preventative maintenance
- targeted replacement of specific components where technically feasible (e.g. replacement of bushings, refurbishment of on-load tap changers and oil, and minor refurbishments of external, easily accessible transformer components such as the paint, pumps, and gaskets, as these components reach end of life prior to the transformer winding)
- efficient deferral of replacement of transformers through online monitoring systems or other mitigation controls, such as the use of relocatable transformers (as discussed below)
- efficient deferral of replacement of transformers where intervention is not supported by risk quantification (i.e. even where assets are in poor condition, the assessed risk may be insufficient to justify replacement)
- asset replacement or retirement based on assessed risk, including the impact of common-cause failures.

The prudent and efficient option for any given asset is assessed on a case-by-case basis, using the risk monetisation approach outline in section 3.2. This may include running assets towards failure, where the safety and reliability consequences can be managed appropriately.

Relocatable transformers

We currently own two mobile 66/22kV power transformers, and one mobile 66/11kV transformer. These transformers act as risk mitigation measures (i.e. reduce duration of customer outages following major failure) and allow us to efficiently manage energy-at-risk across multiple sites with a single asset.

By managing the consequence of failure, our relocatable transformers also allow us to make prudent investment decisions. For example, where a zone substation has multiple transformers with poor condition history, or high conditional and joint probability failure risk, a relocatable transformer may allow us to replace just one or two transformers (and manage the other towards failure).

To support the use of relocatable transformers, preparation works must be undertaken at at-risk zone substations. We have, and continue to prepare many of our zone substations to readily receive a relocatable transformer. As discussed in the context of our forecast volumes for the 2021–2026 regulatory period (refer to section 4.1), mobile preparation works were undertaken in the current regulatory period that allowed us to efficiently defer some transformer replacements.

The deferral possible with a relocatable transformer varies based on, for example, the load at risk and growth rate, age and the cost of the required site works. As these factors change, asset replacement or other intervention may become the more efficient option.

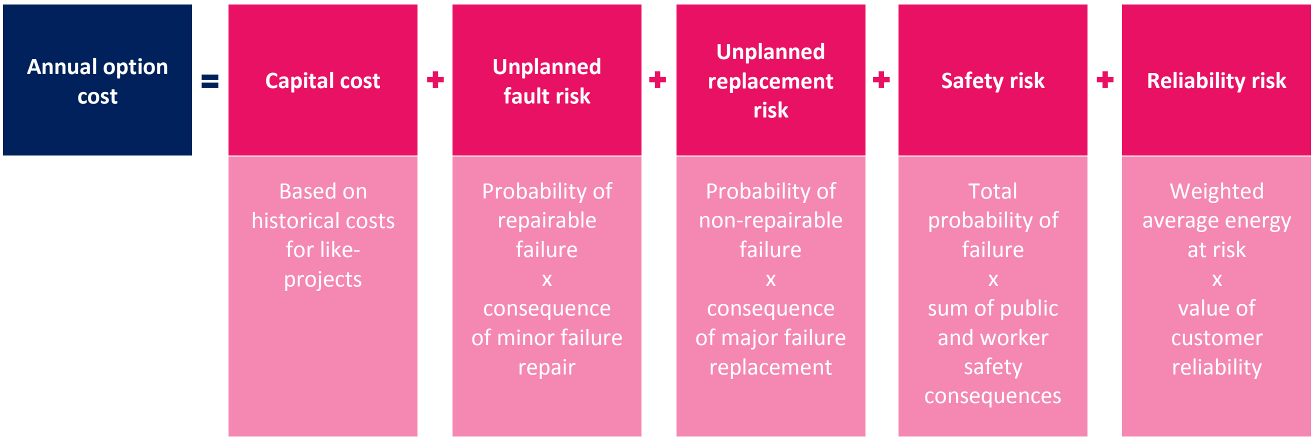
3.2 Risk monetisation

Our asset management interventions for transformers are supported by risk monetisation analysis. This analysis ensures we invest only when the cost of replacing existing infrastructure exceeds the total value of the underlying risks.

As outlined in our regulatory proposal, our approach to monetising risk compares the total cost (including risk) of technically feasible options. The preferred option(s) is that which minimises costs in any given year.

An overview of how we determine the total cost of each option is shown in figure 3.1. This approach identifies the least-cost solution to manage the substation, based on the identified failure modes for an asset, and the corresponding probabilities, likelihoods and consequences of failures. This approach is consistent with the AER's recent asset replacement practice note.[2]

Figure 3.1 Calculation of annual asset-risk option costs



Source: United Energy

3.2.1 Failure modes

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

For the purpose of monetising the risk of transformer failures, we categorise these failures as either minor or major (or both, with a likelihood ratio assigned based on experience). Minor failures are those that are repairable, whereas major failures require the replacement of the asset.

3.2.2 Probability of failure

The probability of failure is a key input assumption in any risk monetisation model.

Since 2018, we have quantified 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 risk-cost for the substation. Rather than focussing on asset replacement, this model considers the available redundancy and load transfer capability at the substation, response times for different investments, and the cost of multiple interventions that affect overall system reliability.[3]

The probabilities of failure derived for our assessments are based on Kaplan-Meier analysis, and our actual observed failure data. Our approach considers failures and replacements as two different data sets in deriving the probability of failure function.[4]

2 UE ATT099: AER, *Industry practice application note: asset replacement planning*, January 2019.

3 Our approach is consistent with the principles set out in section 6.5 of the AER's asset replacement practice note; AER, *Industry practice application note: asset replacement planning*, January 2019 (UE ATT099).

4 This is consistent with the AER's asset replacement practice note; UE ATT099: AER, *Industry practice application note, Asset replacement planning*, January 2019, p. 47.

Table 3.1 lists significant failure events on our network that have occurred since 2012. As shown, significant failure events are rare (i.e. where the transformer is no longer fit for service for an extended period, or until repairs are made, or the transformer is replaced). Where required, this data is supplemented by failure type ratios from relevant industry surveys (e.g. such as those published by Ofgem).[5]

Table 3.1 Significant transformer fault or failure events

Zone substation transformer	Failure mode	Date	Days out-of-service
STO #1	On-load tap changer	Nov 2012	7
STO #2	On-load tap changer	Nov 2012	7
HGS #3	Winding	Feb 2013	18
FSH #1	Current transformer	Aug 2013	45
NW #2	Winding	Aug 2015	180
SR #3	On-load tap changer	Apr 2016	16
NW #1	Winding	Sep 2016	125
CDA #1	Current transformer	Jan 2017	28
CDA #2	Cooling system	Jan 2017	1
NO #1	Surge arrester	Sep 2017	2
NO #2	Surge arrester	Nov 2017	2
HGS #1	On-load tap changer	Feb 2019	30[6]
HGS #3	On-load tap changer	Mar 2019	44
CM #2	Bushing	Jun 2019	9

Source: United Energy

Although the number of zone substation transformer failures shown above is relatively low, our experience shows that several of these failure events have occurred in assets of the same make, model and manufacturer, and had the same failure mode. Such failure events reflect a conditional probability of failure, and are typically referred to as 'common-cause' failures. The AER recognises these events in its asset replacement planning note.[7]

5 UE ATT100: Ofgem, *DNO common network asset indices methodology, version 1.1*, January 2017.

6 The transformer was offline for three days while emergency repairs we made, but was without functional voltage regulation for 30 days.

7 UE ATT099: AER, *Industry practice application note, Asset replacement planning*, January 2019, p. 64.

Joint and conditional probability events

In 2012, we undertook concurrent emergency rebuilds of two tap changers at our Sorrento (**STO**) zone substation. Following this, in 2013, we experienced a switchboard failure at our STO zone substation resulting in multiple outages.

Our initial response to these failures was that the timing was largely 'bad luck'.

In 2015, a transformer at our Nunawading (**NW**) zone substation failed and required replacement. In 2016, the other NW zone substation transformer failed and also required replacement. These transformers were both the same make, model and manufacturer, and had the same failure mode.

Similarly, we have also experienced concurrent, independent transformer faults at our Clarinda (**CDA**) zone substation, and prevented a second fault after a switchboard failure at North Brighton (**NB**) zone substation.

Our response to this experience (i.e. the observed number of failures affecting substation functionality, such as those outlined, was at a much higher frequency than existing expectations) was a broader review of the causes of these failures against our asset management approach. As a result, we now assess the functionality of the entire zone substation rather than the condition of individual assets in isolation, and consider joint and conditional probability events when assessing risk using a multiple Greek letter (**MGL**) model.

Further detail on some of the failures identified in table 3.1 is provided in our attached failure assessment review document.[8]

For highly reliable systems with low failure rates (such as our transformer population), joint and conditional probability events can represent the predominant failure risk.

3.2.3 Consequence of failure

We typically consider the likely consequence of failures on reliability, safety and environmental outcomes. These consequences are calculated based on the method set out in table 3.2. The likelihood of a consequence of failure is based our failure experience.

[8] UE ATT198 - K-BIK Power Substation failures review - Jan2020 - Public.

Table 3.2 Failure consequences: zone substation transformers

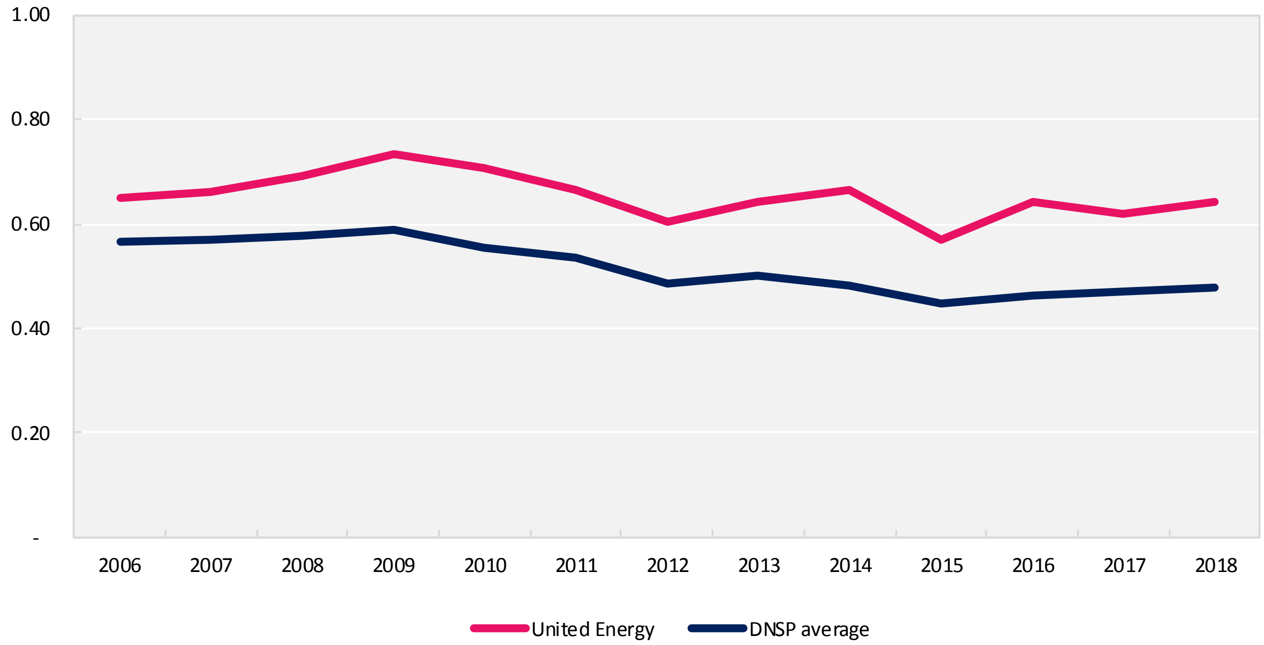
Failure consequence	Approach
Safety: public	Public safety impacts are determined using the value of a statistical life from the Australian Government's guidance note, multiplied by a disproportionality factor and the likelihood of the public safety consequence. The likelihood of consequence is based on Ofgem's common network asset indices methodology.[9]
Safety: worker	Worker safety impacts are calculated as per the public safety consequences. The likelihood of consequence is higher due to the greater frequency and proximity of our workers to our assets. Our worker safety consequences also monetise failures leading to lost-time injuries.
Reliability	The value of energy at risk is calculated based on independent demand forecasts (weighted based on a 30:70 ratio of the 10% and 50% probabilities of exceedance). These are probability adjusted to reflect the likelihood of a major or minor outage, and multiplied by the published value of customer reliability (**VCR**).
Unplanned expenditure	The value of unplanned failure risk (both repairable and irreparable) is calculated based on asset failure modes, derived from our observed failure data combined with available industry figures.
Environmental	Environmental impacts for zone substation transformers have not been calculated, as these are not expected to be a major driver of zone substation transformer replacements in the 2021–2026 regulatory period.

Source: United Energy

The failure consequence for reliability impacts is particularly high due to the high energy at risk at many of our zone substations. As shown in figure 3.2, our network is the second most highly utilised in Australia.

9 UE ATT100: Ofgem, *DNO common network asset indices methodology, version 1.1*, January 2017.

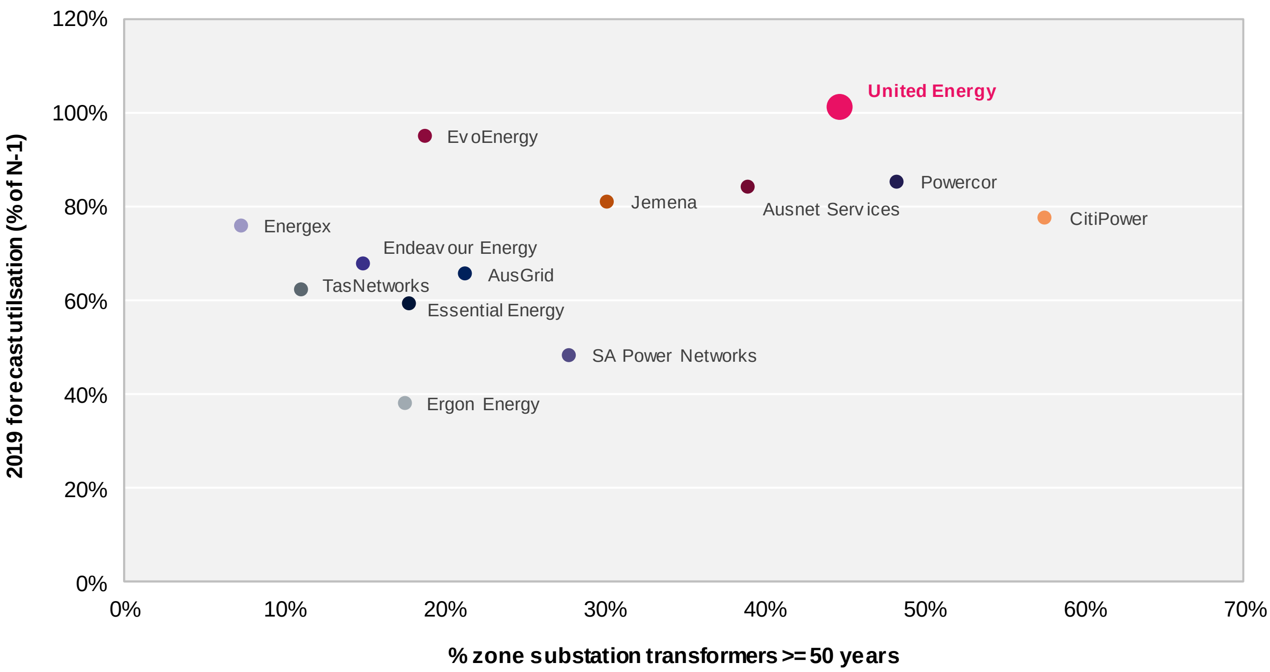
Figure 3.2 Network utilisation



Source: UE ATT107: AER, *Electricity distribution network service provider data report*, August 2019.

Figure 3.3 also highlights our forecast utilisation of zone substation transformers as the percentage of N-1 capacity against the percentage of transformers older than 50 years. Our network has both a high proportion of older transformers, and those transformers are very highly utilised. Although we are currently managing this risk through non-replacement options, the likelihood and consequence of failure are increasing.

Figure 3.3 Transformer utilisation



Source: AER, Regulatory Information Notices, Category Analysis, 2019 (2018 data).

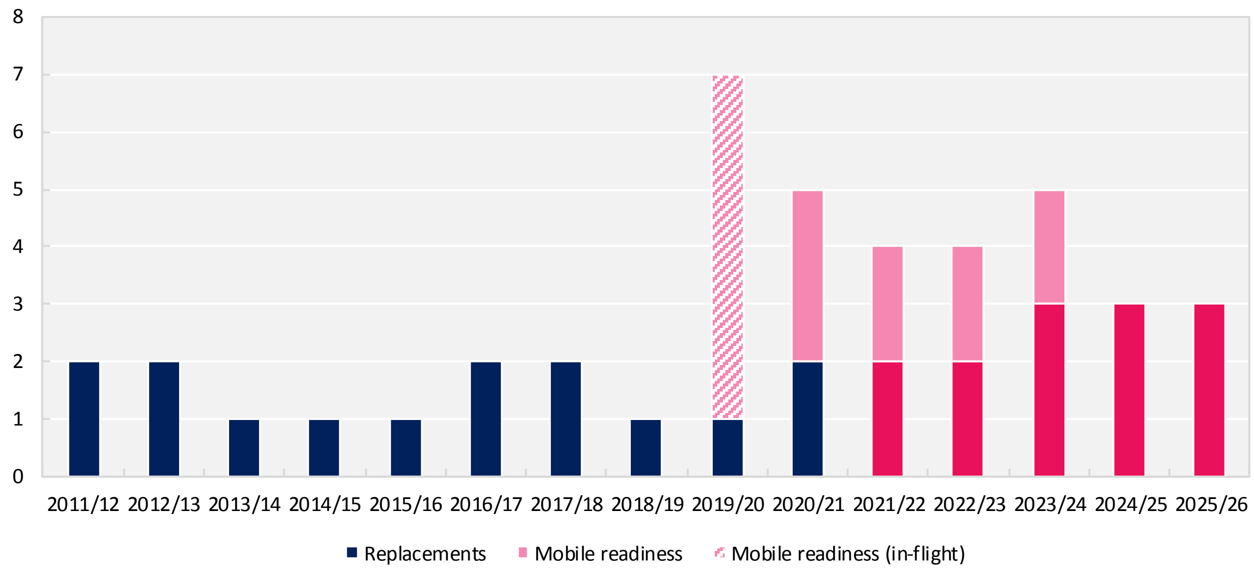
4 Replacement forecast

This section details our zone substation transformer replacement forecast for the 2021–2026 regulatory period to meet the identified need. These forecasts are included in our plant, station and lines replacement model, and the individual monetisation model for each transformer has been provided as part of our regulatory proposal.[10]

4.1 Replacement volumes

We forecast replacement volumes using the risk monetisation approach outlined in section 3.1. A summary of our historical and forecast transformer replacement volumes, including our mobile-readiness program, is shown in figure 4.1.

Figure 4.1 Zone substation transformer replacement volumes



Source: United Energy

Our recent and forecast replacement volumes reflect refinements to our risk quantification method since 2018. Specifically, we have formalised our risk quantification and transformer life-cycle management practices as our observed failure experience has provided a more robust understanding of the probability and consequence of failure.

By assessing the functionality of the entire zone substation, rather than the condition of individual assets in isolation, our asset management approach now includes diversifying plant and equipment to reduce outage response times, and managing transformers towards failure (where safe). This approach, including our investment to prepare sites to accommodate a relocatable transformer, has allowed us to efficiently defer some transformer replacements in the current regulatory period.

An example of the application of our asset management approach is set out below, for our Cheltenham (**CM**) zone substation.

10 UE MOD 4.03 - Plant, stations and lines replacement - Jan2020 - Public; UE MOD 4.04 - Switchgear and transformer risk - Jan2020 - Public.

Cheltenham zone substation

Our CM zone substation was commissioned around 1961, as a two-transformer station to provide capacity to the Cheltenham area of our network. The zone substation has experienced steady growth in maximum demand, and under peak load conditions, emergency load transfer capability to adjacent stations is limited (i.e. CM zone substation has no connectivity to neighbouring Heatherton zone substation due to voltage incompatibility).

The two CM zone substation transformers are both the same make, design, age and possess identical characteristics. This increases the risk of common-cause failure as the condition of these transformers deteriorate at the same rate. Risk at the zone substation is further increased as the transformers are well past their useful life (i.e. both are 58 years old), and in poor condition.

However, rather than replacing both poor condition transformers immediately, the least-cost intervention option that we are implementing is to replace one transformer in 2019/20, and prepare the site to accommodate a relocatable transformer. The second transformer will remain in service.

The forecast increases in our transformer replacement volumes over the 2021–2026 regulatory period, therefore, reflects the rising risk of failure based on our experience as our transformer population continues to deteriorate over time. It also reflects the increased consequence of failure due to higher zone substation demand. As outlined previously, when the load at risk and growth rate, age or the cost of required site works change, asset replacements may increasingly become the most efficient option.

A summary of the outcomes of our risk monetisation assessments for those zone substations where replacement of a single transformer in the 2021–2026 regulatory period maximises the net economic benefits to customers is shown in table 4.1. The application of our risk monetisation approach to a representative transformer is also set out in section 4.3.

For some zone substations, our risk monetisation model indicates an efficient replacement year that is earlier than our proposed commissioning date. From a resourcing perspective, it may not be practicable to perform works immediately. In particular, we seek to align major plant works with the timing of other asset interventions (to ensure efficiencies in project management and build costs). Where possible, we also seek to efficiently manage resources through a smoothed workload over the forecast period.

Table 4.1 Timing of forecast zone substation transformer replacements

Zone substation	Economic replacement	Proposed commissioning	Deferral reason
Ormond (**OR**)	<2021	2021	Relocatable transformer ready
Elsternwick (**EL**)	<2021	2021	N/A (site cannot accommodate relocatable transformer)
East Malvern (**EM**)	<2021	2022	Relocatable transformer ready
Elwood (**EW**)	<2021	2022	Relocatable transformer ready (2020)
Gardiner (**K**)	<2021	2023	Relocatable transformer ready
Sandringham (**SR**)	<2021	2023	Relocatable transformer ready (2020)
Bentleigh (**BT**)	<2021	2024	Relocatable transformer ready
Hastings (**HGS**)	<2021	2024	Relocatable transformer ready
West Doncaster (**WD**)	<2021	2024	Relocatable transformer ready (2022)
Doncaster (**DC**)	<2021	See note 1	Augmentation works to manage risk
Oakleigh East (**OE**)	<2021	2025	Relocatable transformer ready (2021)
Bulleen (**BU**)	<2021	2025	Relocatable transformer ready (2022)
Glen Waverley (**GW**)	2023	2025	N/A (site cannot accommodate relocatable transformer)
Beaumaris (**BR**)	2024	2026	Relocatable transformer ready (2023)
Mordialloc (**MC**)	2024	2026	Relocatable transformer ready
Carrum (**CRM**)	2027	2026 (see note 2)	Relocatable transformer ready
Springvale South (**SS**)	2024	2027	Relocatable transformer ready (2023)

Source: United Energy

Note 1: Our risk quantification model supports the replacement of transformers at our DC zone substation. Our augmentation works at this zone substation, however, will address overall system reliability at the site at the least-cost.

Note 2: Our plans are adjusted to take into account project deliverability; replacement at CRM is recommended prior to replacement at MC to assist in managing load transfers and risk during project works.

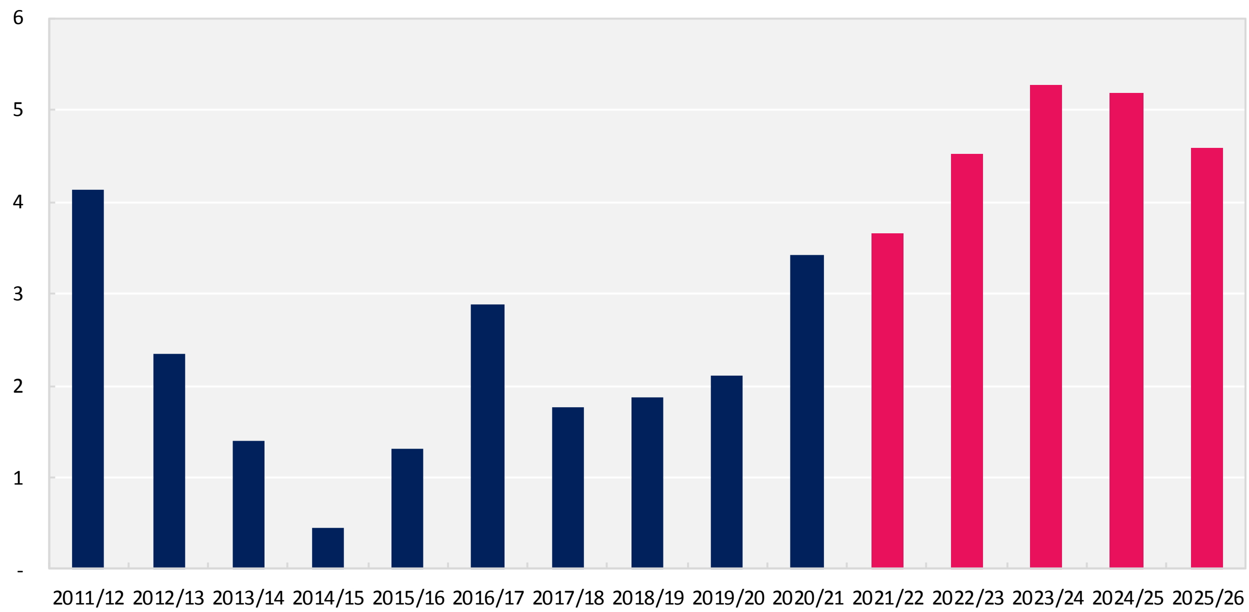
4.2 Replacement expenditure

We have forecast replacement expenditure for zone substation transformers based on the volumes set out in section 4.1. The scope of works for each individual site has been considered, and historical unit costs for like projects over the period 2015–2018 have been used.

A summary of our total historical and forecast transformer replacement expenditure is shown in figure 4.2. As noted in section 4.1, our forecast replacement expenditure reflects refinements to our risk quantification method, where previously unquantified risks were not well understood.

Figure 4.2 also shows that expenditure in some years is low (e.g. 2018). This reflects the impact of relocatable transformers to temporarily defer some works, and internal financial settlement rules that may not correlate exactly to the timing of historical volumes (as expenditure may span multiple years).

Figure 4.2 Zone substation transformer replacement expenditure ($ million, 2019)



Note: Excludes mobile-readiness expenditure
Source: United Energy

4.3 Case study: West Doncaster supply area

Our West Doncaster (**WD**) zone substation supplies the areas of Doncaster and Bulleen, including the Westfield Doncaster shopping centre. The zone substation comprises three power transformers, two of which are identical, that were commissioned during the 1960s. The site has not been made-ready to accept a relocatable transformer.

Our risk model assesses the ability of our WD zone substation to supply electricity, rather than focusing on the probability of failure of a single asset. As our WD zone substation is a three-transformer system with two common-type transformers, a joint and conditional probability assessment was undertaken. This approach is consistent with the AER's asset replacement practice note.[11]

4.3.1 Option analysis

Table 4.2 sets out the intervention options considered for our WD zone substation.

[11] UE ATT099: AER, *Industry practice application note, Asset replacement planning*, January 2019, pp. 64–65.

Table 4.2 WD zone substation: intervention options

Number	Option
Do-nothing	Maintain the status quo (i.e. continue our existing maintenance program, but undertake no major capital works)
1	Prepare the site to allow the relocatable power transformer to be deployed within one month of a failure
2	Install online monitoring systems to identify and prevent some failure modes
3	Prepare the site to allow the relocatable power transformer, and install online monitoring (i.e. combination of both option two and three)
4	Replace one of the common-type transformers
5	Replace both common-type transformers

Source: United Energy

We also considered the following options, but for the reasons stated, have not modelled these costs:

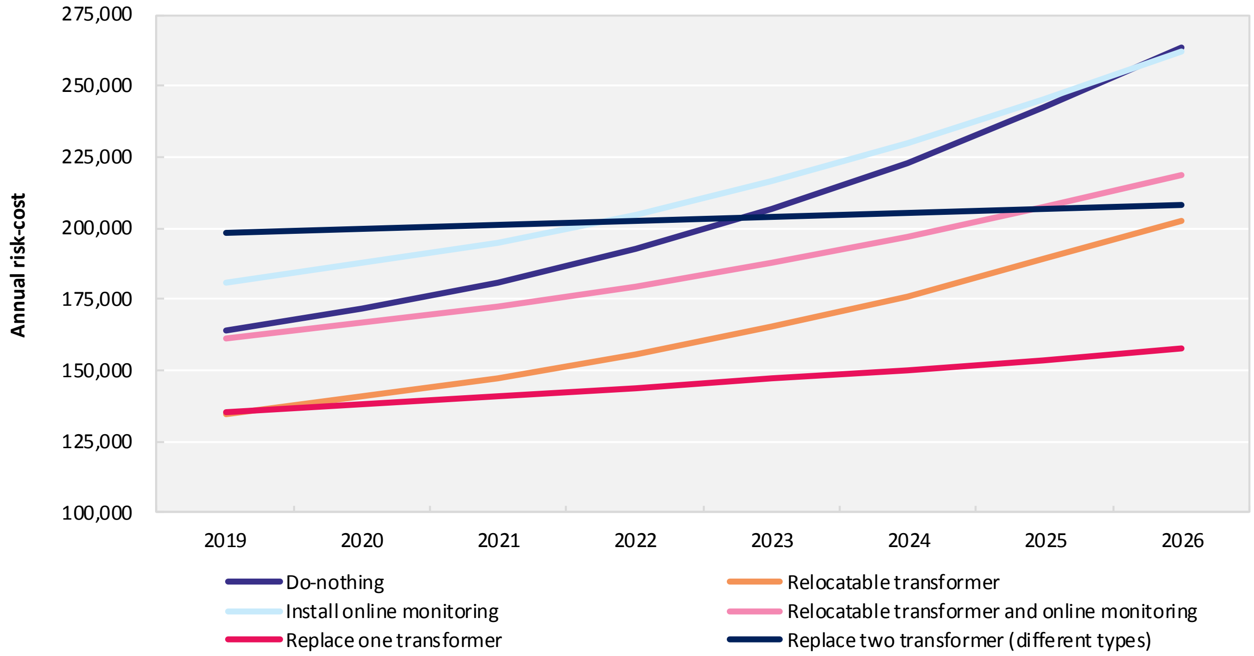
- de-rating—a suitable rating has been applied based on the transformers' condition, and any change to this rating is not expected to alter the probability of failure of this asset
- non-network options—this asset replacement is listed in our distribution asset planning report, and to date, we have not received any non-network proposals for this proposed asset replacement
- refurbishment—no further modification of the probability of failure is expected if this occurs
- change in components—consideration was given to changing the 66kV bushings and on-load tap changers to reduce single and multiple failure risk, however, given the incremental risk reduction relative to the high retro-fit cost, this option is not considered economic.

4.3.2 Preferred option

Figure 4.3 shows our assessment of the whole-of-life costs for the WD zone substation. The lowest curve in any given year indicates the least-cost intervention option. The current preferred option, therefore, is to ready the zone substation to receive a relocatable transformer. The preferred option then changes to replace one of the two common-type transformers around 2020 (i.e. this where the 'replace one transformer' curve intersects the 'relocatable transformer' curve).

As per table 4.1, when considering our broader capital program, we propose to commission this transformer replacement in 2024.

Figure 4.3 Annual risk-costs for WD zone substation options ($, 2019)



Source: United Energy

A Compliance obligations

An overview of the relevant compliance obligations for our transformer asset group is provided below.

A.1 National Electricity Rules

The National Electricity Rules (**the Rules**) set out the capital and operational expenditure objectives, factors and criteria.[12] The key requirements are to prudently and efficiently manage the network to maintain safety, maintain reliability and comply with all applicable regulatory obligations.

A.2 Victorian Electricity Distribution Code

Clause 3.1 of the Victorian Electricity Distribution Code (**the Code**) requires us to manage our assets in accordance with principles of good asset management. Under this provision, we must, among other things, develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets:

- to comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in the Code
- to minimise the risks associated with the failure or reduced performance of assets
- in a way which minimises costs to customers taking into account distribution losses.

A.3 Electricity Safety Act 1998

The Electricity Safety Act 1998 (**the Act**) makes provisions relating to:

- the safety of electricity supply and use
- the reliability and security of electricity supply
- the efficiency of electrical equipment.

Under section 98 of the Act, we (as a major electricity company) must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable:

- the hazards and risks to the safety of any person arising from the supply network
- the hazards and risks of damage to the property of any person arising from the supply network
- the bushfire danger arising from the supply network.

Section 99 of the Act requires that we prepare and implement an electricity safety management scheme, which specifies our safety management system for complying with obligations under section 98.

A.4 Electricity Safety (Management) Regulations 2009

Electricity Safety (Management) Regulations 2009 (made under section 150 of the Act) set out the requirements for an Electricity Safety Management Scheme (**ESMS**), including an electrical safety management system. An ESMS is compulsory, and effectively covers all documentation, procedures, accreditation, monitoring and reporting of work on or for designing, installing, operating, maintaining and decommissioning network assets. The ESMS must be submitted to Energy Safe Victoria (**ESV**) every five years for acceptance, and is audited by ESV.

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12 NER, clauses 6.5.6 and 6.5.7.

The Safety Management System incorporates all network asset policies, procedures, systems, standards and controls in place to manage network safety.

A.5 Electricity Safety (Bushfire) Regulations 2013

Clause 7(1)(i) requires major electricity companies to inspect electricity assets located in hazardous bushfire risk areas at intervals not exceeding 37 months and inspect electricity assets located in other areas at intervals not exceeding 61 months.

Clause 7(2) clarifies that the assets that must be inspected under the schedule specified in clause 7(1)(i) do not include assets located in a terminal station, a zone substation or any part of the major electricity company's underground supply network that is below the surface of the land.