Zone substation switchgear replacements: forecast method overview

UE BUS 4.04

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 circuit breaker replacements over the 2021–2026 regulatory period. In particular, we outline our asset management approach for zone substation circuit breakers, and the risk monetisation process used to develop our forecast.

Our risk monetisation 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 circuit breaker replacements over the 2021–2026 regulatory period. This reflects the rising risk of failure, based on our network experience, as our zone substation circuit breaker population continues to deteriorate over time. It also reflects the increased consequence of failure due to higher zone substation demand.

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 reporting period (as required by the Victorian Government and the Australian Energy Regulator).

Table 1.1 Capital expenditure forecasts: zone substation circuit breaker replacements ($ million, 2019)

Expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capital expenditure	3.0	3.8	4.2	3.8	3.8	18.7

Source: United Energy

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

2 Background

Circuit breakers perform critical functions throughout our network, including stopping power flows during network faults, and facilitating network switching functions. Circuit breakers can be remotely switched from the control centre to enable network rearrangements.

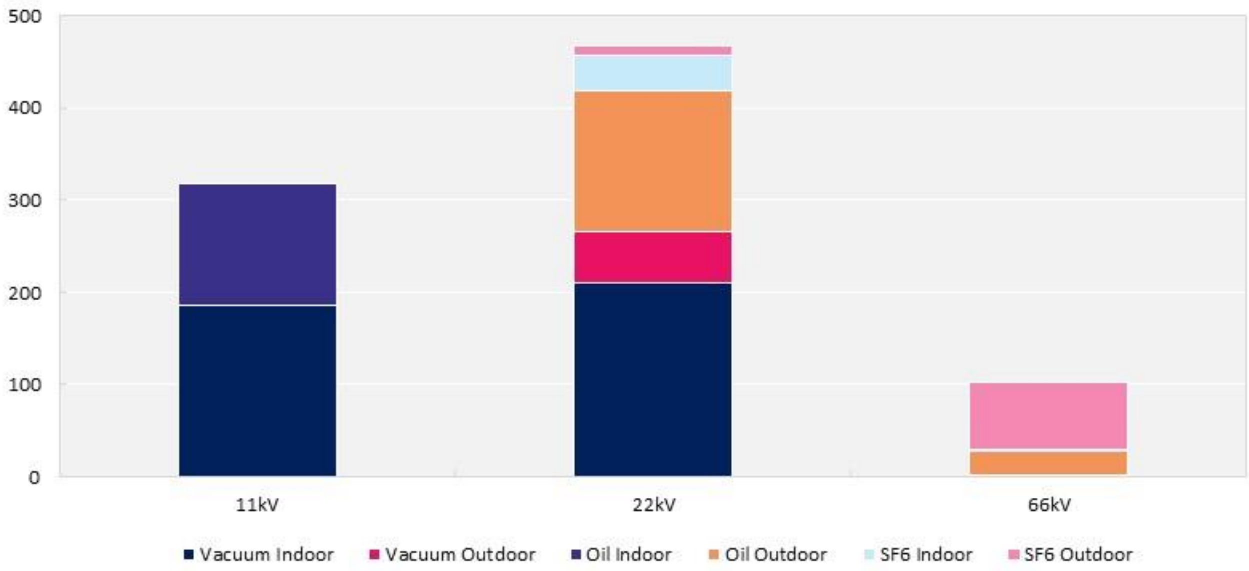
This section provides a snapshot of the types, population, age profile and historic performance of circuit breakers in our network.

2.1 Asset population

Zone substation circuit breakers are installed at both sub-transmission and distribution voltage levels (i.e. 11kV to 66kV). These include outdoor circuit breakers, as well as indoor circuit breakers that form part of a switchboard.

The quantity, insulation type and voltage level of zone substation circuit breakers installed in our network is shown in figure 2.1. Most of these circuit breakers are indoor vacuum insulated, and this is the current standard for new distribution installations and planned asset replacements.

Figure 2.1 Circuit breaker population (volumes)

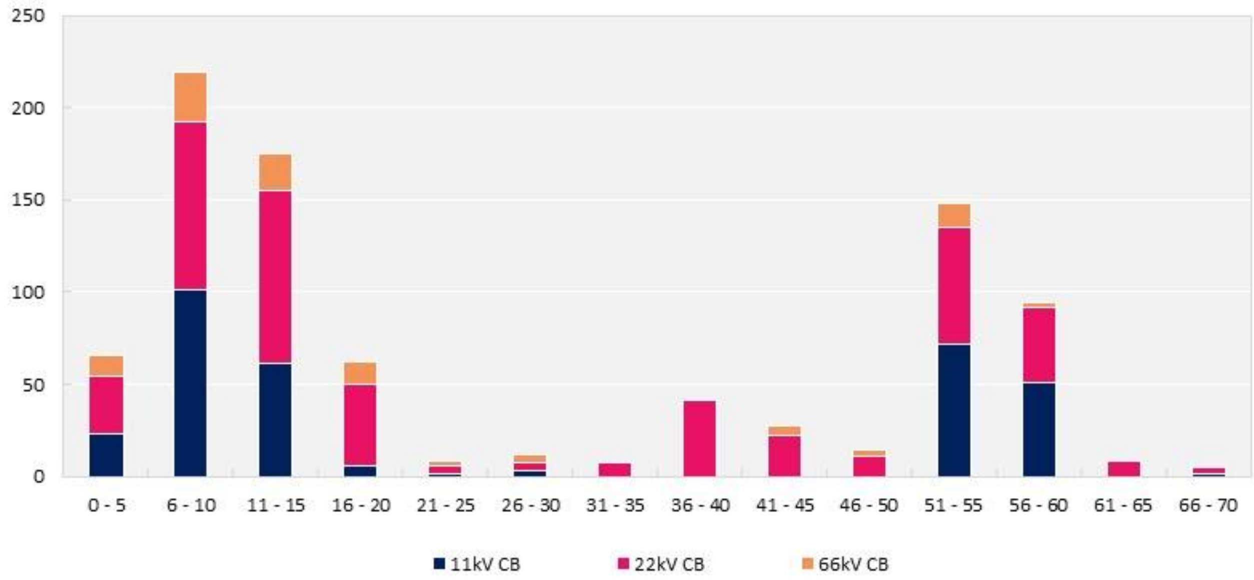


Source: United Energy

2.2 Asset age profile

As shown in figure 2.2, the age of our zone substation circuit breaker population varies from recent installations to assets installed over 65 years ago. The impact of our recent investment program is shown in the population of circuit breakers under 20 years of age. However, almost 30% of our circuit breakers were installed more than 50 years ago (compared to a typical design life of around 40 years).

Figure 2.2 Zone substation circuit breaker age profile (volumes)



Source: United Energy

2.3 Historic asset performance

Our history of circuit breaker and switchboard failures is shown in table 2.1. This experience, combined with our historic replacement program, has informed the probability of failures used in our risk monetisation assessments (as outlined in section 3.2).[2]

Table 2.1 Significant circuit breaker fault or failure events

Type	2013	2014	2015	2016	2017	2018
Outdoor circuit breaker	1	-	-	-	-	-
Indoor circuit breaker (cubicle)	2	-	1	-	-	1
Indoor switchboard (bus)	1	-	-	-	1	-
Indoor switchboard (other)	1	-	-	1	-	-
Total	**5**	**-**	**1**	**1**	**1**	**1**

Source: United Energy

Our experience has found that outdoor circuit breakers have a lower failure rate than indoor circuit breakers (and associated components). This is due to the inherent engineering designs and operating conditions of the

[2] Consistent with the AER's asset replacement practice note, UE ATT099: AER, *Industry practice application note: asset replacement planning,* January 2019, we consider failures and replacements as two different data sets in deriving the probability of failure function.

oldest circuit breakers in service. Further, when a switchboard approaches end-of-life conditions, various components will fail at an accelerating rate within a short period.

We have also found that a number of the significant failures have been common-cause failures. Common-cause failures are those were the defect conditions have been observed with multiple, similar assets at the same zone substation. For highly reliable systems with low failure rates (such as our circuit breaker population), common-cause failures can represent the predominant failure risk.

As a result, our proposed replacement program focusses on replacing assets where risk has been quantified, based on our direct failure experience.

3 Asset management overview

We manage circuit breakers 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 current asset management approach for circuit breakers includes multiple options for meeting our required service levels (consistent with our compliance obligations, as set out in appendix A). Specifically, these options include the following:

- ongoing planned, preventative maintenance
- targeted replacement of specific components where technically feasible
- defer replacement of circuit breakers 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.

The targeted replacement of specific or single components is typically only technically feasible for outdoor switchgear (e.g. for outdoor switchgear, circuit breakers can be replaced but associated disconnector and earth switches retained; the replacement of specific components is more challenging for indoor switchgear due to their inherent design). In any event, the prudent and efficient option for any given asset is assessed on a case-by-case basis, using our risk monetisation approach (discussed below).

3.2 Risk monetisation

Our asset management interventions for major circuit breaker or switchboards 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 has regard to 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 guidance practice note.[3]

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

Figure 3.1 Calculation of annual asset-risk option costs

Annual option cost	=	Capital cost	+	Unplanned fault risk	+	Unplanned replacement risk	+	Safety risk	+	Reliability risk
		Based on historical costs for like-projects		Probability of repairable failure x consequence of minor failure repair		Probability of non-repairable failure x consequence of major failure replacement		Total probability of failure x sum of public and worker safety consequences		Weighted average energy at risk x value of customer reliability

Source: United Energy

3.2.1 Failure modes

Several factors contribute to the deterioration and subsequent failure of circuit breakers or switchboards. These factors typically include the number of operations and accumulated electrical stress, and exposure to elements and any corresponding moisture or pollutant ingress.

For the purpose of monetising the risk of circuit breaker or switchboards failures, we categorise failures as either minor or major. 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. In the first instance, we use historical asset failure rates based on our own internal data. Where required, this data is supplemented by failure type ratios from relevant industry surveys (e.g. such as those published by Ofgem).[4]

We also quantify circuit breakers or switchboard 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. 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 focussing on asset replacement.[5] The probabilities of failure derived for these assessments are based on Kaplan-Meier analysis, and ratios of independent and common-cause failures from our actual observed failure data.

3.2.3 Consequence of failure

We typically consider the likely consequence of failures on reliability and safety outcomes.[6] These consequences are calculated based on the method set out in table 3.1.

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

5 This is consistent with the AER's asset replacement practice note (UE ATT099).

6 Environmental impacts for zone substation circuit breakers have not been calculated, as these are not expected to be a major driver of zone substation circuit breakers replacements in the 2021–2026 regulatory period.

Table 3.1 Failure consequences: zone substation circuit breakers or switchboards

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.[7]
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**). For feeder circuit breakers, a failure can result in either a bus outage or circuit breaker trip lockout. Our failure consequences assume a feeder panel fault will take two hours to restore, whereas a circuit breaker failing to trip only requires one hour of restoration time. For transformer and bus circuit breakers, it is assumed restoration will take four months. Full load transfers to adjacent zone substations are applied, such that only the remaining load that cannot be transferred away is considered.
Unplanned capital and operating expenditure	The value of unplanned failure risk (repairable or irreparable) is calculated based on asset failure modes, and derived from our failure data.

Source: United Energy

[7] UE ATT100: Ofgem, *DNO common network asset indices methodology, Version 1.1*, January 2017.

4 Replacement forecast

The identified need for managing circuit breakers on our network is to ensure we maintain service levels in accordance with our regulatory and compliance obligations (listed in appendix A).

This section details our circuit breaker replacement forecast for the 2021–2026 regulatory period to meet this identified need. These forecasts are supported by our circuit breakers risk monetisation model, and included in our plant, station and lines model.[8]

4.1 Replacement volumes

We forecast replacement volumes based on the risk monetisation approach outlined in section 3.2. A summary of our historical and forecast circuit breaker replacement volumes is shown in figure 4.1. This includes a moving average (over three years), as the completion of zone substation circuit breaker works may span multiple years.

Figure 4.1 Zone substation circuit breaker replacement volumes

Source: United Energy

The majority of our circuit breaker replacements are for 11kV assets. These represent the highest risk category of circuit breakers due to their design, condition, age and failure history.

The outcome of our risk monetisation assessment indicates that during the 2021–2026 regulatory period it will be economic to replace the circuit breakers and switchboards listed in table 4.1. The application of this risk monetisation approach to two representative circuit breaker examples is set out in section 4.3 and 4.4.

8 UE MOD 4.04 - Switchgear and transformer risk - Jan2020 - Public.

Table 4.1 Timing of forecast zone substation circuit breaker replacements

Zone substation	Circuit breaker volumes	Economic replacement year	Proposed replacement year
SR: 11kV indoor	16	<2021	2021
BT: 11kV indoor	15	<2021	2022
EM: 11kV indoor	16	<2021	2023[9]
HT: 22Kv outdoor	4	(one bus) 2022	(one bus) 2023
DC: 22Kv outdoor[10]	7	(two busses) 2021	(one bus) 2024
EW: 11kV indoor	14	<2021	2024
GW: 22Kv outdoor	4	(two busses) 2023	(one bus) 2024
BR: 11kV indoor	15	2022	2025
BU: 11kV indoor	16	2024	2026
OE : 11kV indoor	15	2023	2026

Source: United Energy

Our forecast replacement volumes reflect refinements to our risk quantification method, where previously unquantified risks were not well understood. This approach (as outlined in section 3.2), has already driven the replacement of circuit breakers at our Carrum, Mordialloc and Elsternwick zone substations in 2019.

As a result, our proposed replacement year includes circuit breakers that our monetisation approach indicates may already be economic to replace. Our proposed replacement year has regard to the deliverability of our overall capital works program across the entire 2021–2026 regulatory period, including alignment with other projects to realise capital expenditure synergies. These synergies are included in the proposed forecast.

4.2 Replacement expenditure

We have forecast replacement expenditure for zone substation circuit breakers 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 circuit breakers replacement expenditure is shown in figure 4.2.

9 The modelling and proposed timing for this project assumes EM third 11kV bus augmentation project takes place in 2023 as forecast.

10 The forecast to replace one of two outdoor 22kV busses at DC assumes the DC fourth transformer and additional 22kV bus will occur in 2024. If this does not occur, then replacement of the entire outdoor switchyard at DC is the least-cost option from 2022.

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

Source: United Energy

4.3 Case study: Bulleen zone substation indoor switchboard

Our Bulleen (**BU**) zone substation supplies the areas of Doncaster, Bulleen and Templestowe. It comprises a single 11kV switchboard, with two busses containing 16 panels housing J18 oil-filled switchgear. These assets were commissioned in the mid-1960s.

4.3.1 Option analysis

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

Table 4.2 BU zone substation: intervention options

Number	Option
Do-nothing	Maintain the status quo (i.e. continue our existing maintenance program, but no major capital works)
1	Install online monitoring systems to identify and prevent some failure modes
2	Replace entire 11kV switchboard (same type)
3	Replace entire 11kV switchboard (different type)

Source: United Energy

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

- partial replacement—replacement of only one bus of the switchboard will not reduce the probability of failure on the remaining buses and associated circuit breakers, and given the different physical arrangement of the switchgear and technologies, this option is not considered practical for this switchboard
- 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

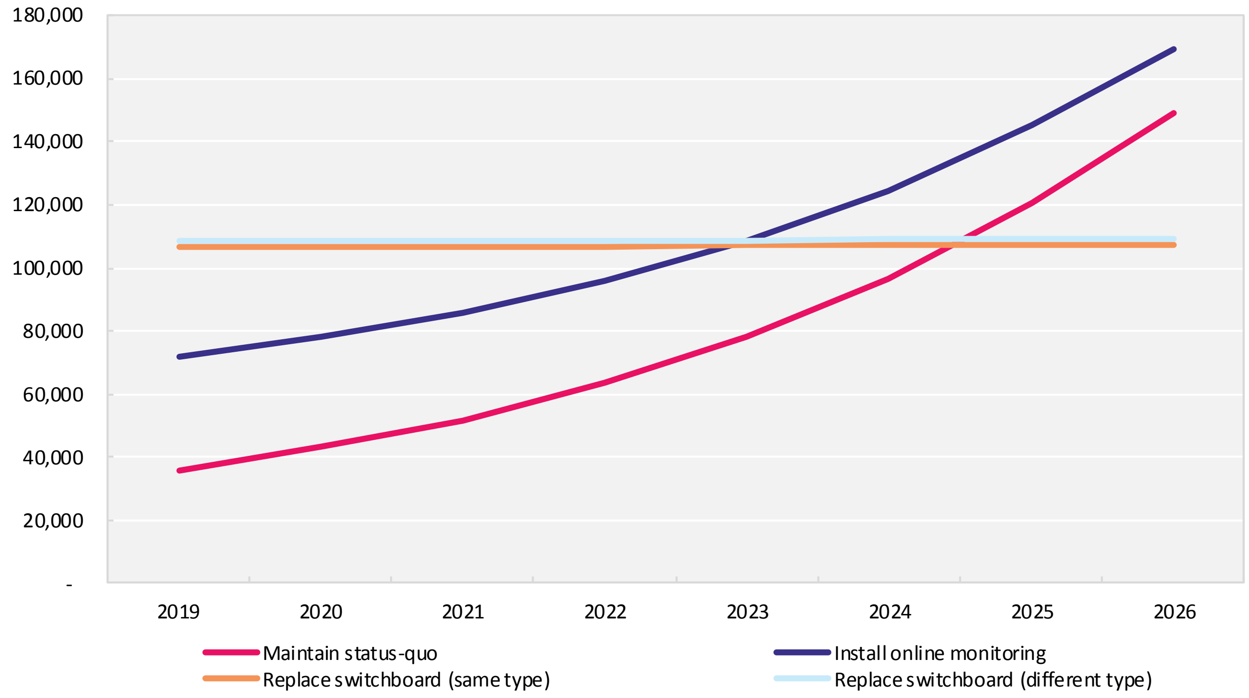
- refurbishment—no further modification of the probability of failure is expected if this occurs.

4.3.2 Preferred option

As shown in figure 4.3, our assessment of the whole-of-life costs for the BU zone substation indicates it is efficient to maintain the status-quo until around 2025. Under this approach, we would continue our existing maintenance program, but undertake no major capital works. Any failures will be managed by using available spares.

After 2025, it becomes economic to replace the existing switchboard. We considered replacement options comprising both the same and different manufacturers to ensure we have regard to common-cause failures.[11] In this example, the difference between the two options is negligible (and we have included the lowest cost option in our forecasts).

Figure 4.3 Option analysis: BU switchboard replacement ($, 2019)



Source: United Energy

Consistent with table 4.1, our forecast implementation of the preferred BU switchboard replacement option needs to be considered in the broader context of our overall capital program. This includes the priority of other sites based on risk. As such, the preferred timing for the BU 11kV switchboard replacement has been deferred from 2025 to 2026.

11 Replacing a switchboard with two different manufacturers involves joining two modern products together. This is common practice where space permits, and has been performed at a number of locations across our network, most recently at our Dromana and Carrum zone substations.

4.4 Case study: Heatherton zone substation outdoor switchyard

Our Heatherton (**HT**) zone substation is a fully developed three-transformer station, supplying the suburbs of Heatherton and Moorabbin. The existing 22kV outdoor switchgear is aged, and warrants further investigation for risk analysis.

4.4.1 Option analysis

Table 4.2 sets out the intervention options considered for our HT zone substation. As outdoor circuit breakers and switchyards offer the benefit of singular asset replacement (compared to complete replacement, as necessary with indoor switchboards), partial replacements of outdoor assets have been included.

Table 4.3 HT zone substation: intervention options

Number	Option
Do-nothing	Maintain the status quo (i.e. continue our existing maintenance program, but no major capital works)
1	Replace single bus
2	Replace two buses (with same-type circuit breakers)
3	Replace two buses (with different-type circuit breakers)

Source: United Energy

For options two and three above, the replacement of circuit breakers would be based on those that pose the highest risk due to condition, lack of redundancy and inability to transfer load. For HT zone substation, the replacement of multiple circuit breakers would include the bus circuit breaker (as there is no redundancy), and those on the worst feeders based on load transfer ability.

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

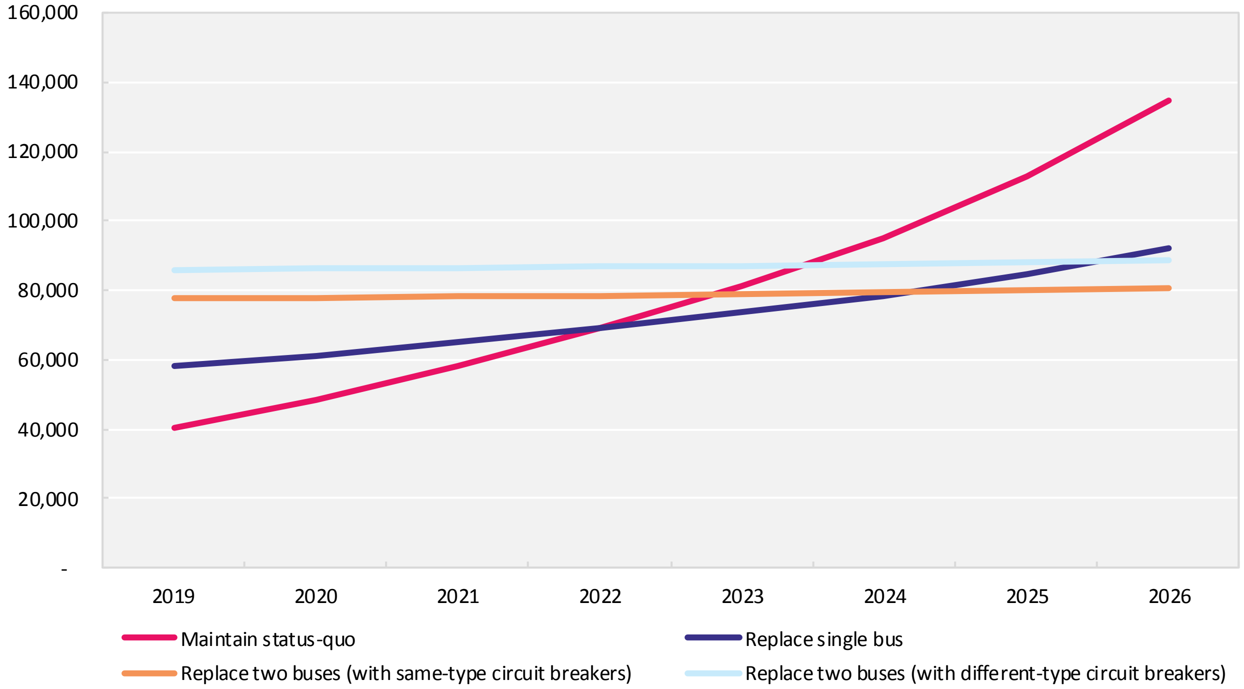
- install online monitoring equipment—because of the segregated, dispersed nature of outdoor switchyards, the installation of online monitoring equipment is not cost effective or practical
- non-network options—this asset replacement is listed in our distribution asset planning report, and to date, we 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.

4.4.2 Preferred option

As shown in figure 4.4, our assessment of the whole-of-life costs for the HT zone substation indicates it is efficient to maintain the status-quo until around 2022. Under this approach, we would continue our existing maintenance program, but undertake no major capital works. Any failures will be managed by using available spares.

After 2023, it becomes economic to replace part of the existing switchyard. This coincides with our proposed relay and control building replacement works.

Figure 4.4 Option analysis: HT switchyard replacement ($, 2019)



Source: United Energy

A Compliance obligations

An overview of the relevant compliance obligations for service line 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 (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.

12 NER, clauses 6.5.6 and 6.5.7.

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.

A.5 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.

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