Addressing reliability requirements in the Tarro load area

FINAL PROJECT ASSESSMENT REPORT

04 November 2022

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Addressing reliability requirements in the Tarro load area

Final Project Assessment Report – November 2022

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Executive Summary

This report represents the application of the RIT-D to options for ensuring reliable electricity supply to the Tarro load area

The Tarro Zone Substation (ZS) is located at the eastern end of the Maitland network area and was commissioned in 1957. It is supplied by two 33kV feeders from Beresfield Sub-Transmission Substation (STS) and is equipped with two groups of 11 kV compound insulated switchgear in a double busbar arrangement. It currently supplies approximately 4,000 customers, including one large industrial customer with a significant load.

The existing 11 kV switchgear at the Tarro 33/11kV ZS has increasing condition, reliability and safety concerns. If action is not taken, our planning studies expect that there will be substantial unserved energy to loads in this area of our network when the switchgear fails, as well as significant reactive maintenance costs associated with having to repair and restore service together with safety risks for Ausgrid personnel and the public. If action is not taken, we expect that our electricity distribution license reliability and performance standards will be breached.

Ausgrid is therefore undertaking a Regulatory Investment Test for Distribution (**RIT-D**) to assess options for addressing the risk that the existing ageing 11 kV switchgear poses, and to ensure we continue to satisfy our reliability and performance standards. This Final Project Assessment Report (**FPAR**) represents the final step in the application of the RIT-D to options for ensuring reliable electricity supply to the Tarro load area and follows publication of the Options Screening Notice.

A Draft Project Assessment Report (DPAR) has not been prepared for this RIT-D as permitted under clause 5.17.4(n) of the National Electricity Rules (NER), i.e., since there are not expected to be any non-network or stand-alone power system (SAPS) solutions and the capital cost of the preferred option is less than the $12 million threshold.[1]

The 'identified need' for this RIT-D is to maintain the required level of reliability for customers connected to the Tarro ZS

Ausgrid is obliged to comply with reliability and performance standards as part of its distribution license granted by the Minister for Industry, Resources and Energy under the *Electricity Supply Act 1995 (NSW)*. Under its license, reliability and performance standards are expressed in two measures:

- SAIDI[2] – which means the average derived from the sum of the durations of each sustained customer interruption (measured in minutes), divided by the total number of customers (averaged over the financial year); and
- SAIFI[3] – which means the average derived from the total number of sustained customer interruptions divided by the total number of customers (averaged over the financial year).

These two reliability measures capture two key sources of inconvenience to electricity customers from supply disruptions, i.e. how long their electricity supply is off for as well as how often their electricity supply is off. Customers experience less inconvenience (i.e. a better level of supply reliability), the lower each of these measures are. Reliability standards applied to distribution networks typically set maximums in relation to each of these two measures.

Our analysis shows that if action is not taken to address the deteriorating condition of the 11 kV switchgear at this site, then the unserved energy modelled will lead to a breach of these standards going forward.

Two network options have been identified and assessed

We have identified and assessed two different network options as part of this FPAR.

Table E.1 – Credible network options assessed, $2021/22

Option	Capital cost	Expected commissioning
Option 1 – Replace the 11 kV switchgear at the Tarro ZS	$11.3 million	2024/25
Option 2 – Build a new ZS to replace the Tarro ZS	$20.4 million	2025/26

[1] AER, *Final Determination – 2021 RIT and APR cost thresholds review,* 19 November 2021, p 5.
[2] System Average Interruption Duration Index.
[3] System Average Interruption Frequency Index.

Non-network options and SAPS solutions are not considered viable for this RIT-D

Ausgrid has considered the ability of any non-network or stand-alone power system (SAPS) solutions to assist in meeting the identified need. An assessment into reducing the risk of unserved energy has shown that these alternatives are unlikely to cost-effectively address the risk, compared to the two network options outlined above. This result is driven primarily by the significant amount of unserved energy that each network option allows to be avoided, compared to the base case, and the cost of non-network or SAPS solutions. This is detailed further in the separate notice released in accordance with clause 5.17.4(d) of the NER.

Three different 'scenarios' have been modelled to deal with uncertainty

Ausgrid has assessed three alternative future scenarios for this RIT-D – namely:

- low benefit scenario – Ausgrid has adopted a number of assumptions that give rise to a lower bound NPV estimate for each credible option, in order to represent a conservative future state of the world with respect to potential market benefits that could be realised under the credible option;
- central scenario – the baseline scenario consists of assumptions that reflect Ausgrid's central set of variable estimates which, in Ausgrid's opinion, provides the most likely scenario; and
- high benefit scenario – this scenario reflects an optimistic set of assumptions, which have been selected to investigate an upper bound on reasonably expected market benefits.

A summary of the key variables in each scenario is provided in the table below.

Table E.2 – Summary of the three scenarios investigated

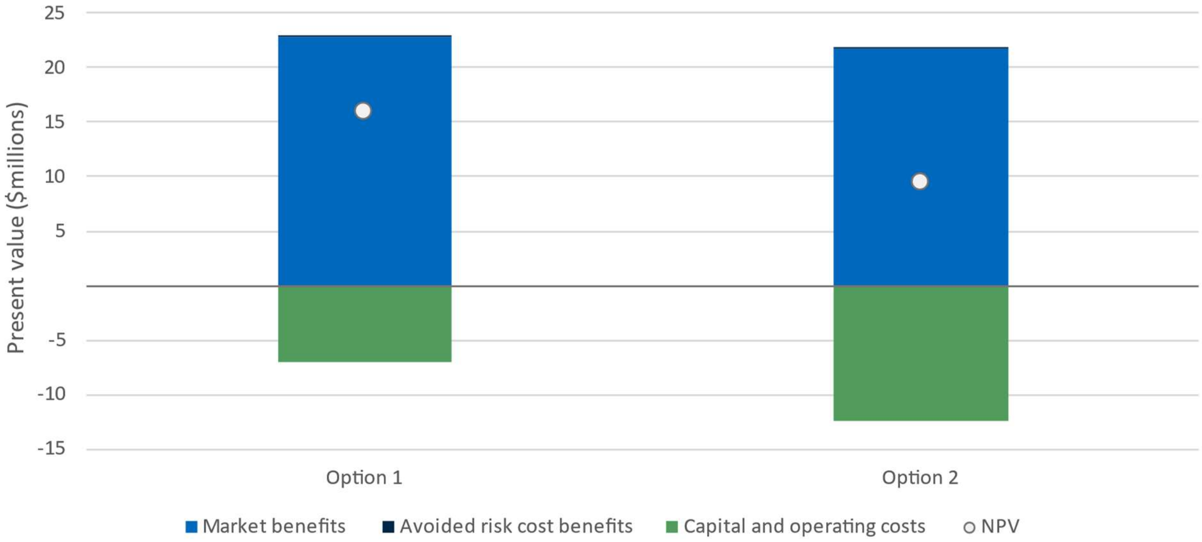
Variable	Scenario 1 – central	Scenario 2 – low benefits	Scenario 3 – high benefits
Demand	POE50	POE90	POE10
VCR	$56.15/kWh	$39.31/kWh	$73.00/kWh
Unplanned corrective maintenance cost	Central estimates	70 per cent of the central estimates	130 per cent of the central estimates
Safety risk costs	Central estimates	70 per cent of the central estimates	130 per cent of the central estimates
Capital costs	Capital cost central estimates	125 per cent of capital cost estimate	75 per cent of capital cost estimate
Planned routine maintenance new assets	Central estimates	125 per cent of the central estimates	75 per cent of the central estimates
Planned routine maintenance existing assets	Central estimates	75 per cent of capital cost estimate	125 per cent of capital cost estimate
Decommissioning costs	Central estimates	125 per cent of capital cost estimate	75 per cent of the central estimate
Discount Rate	3.44%	5.50%	2.34%

Option 1 has the highest expected net market benefits, under all scenarios

Expected benefits are driven primarily by reduced involuntary load shedding and avoided corrective maintenance and safety risk costs that would otherwise be incurred under the base case.

Of the two options, Option 1 is found to have the highest net market benefit under all scenarios as it has significantly lower capital costs and an earlier commissioning date. The earlier commissioning of Option 1 allows for additional years to accumulate benefits compared to Option 2.

Figure E.1: NPV assessment of the credible network options (weighted outcome)



Option 1 is the preferred option for this RIT-D

Ausgrid considers that Option 1 is the preferred option that satisfies the RIT-D. It involves the replacement of the existing 11 kV double bus switchgear at Tarro ZS with modern equivalent switchgear in a single bus arrangement.

The estimated capital cost of this option is $11.3 million.

Ausgrid assumes that the necessary construction to replace the existing switchgear would commence as soon as practicable after this RIT-D and end in 2024/25. After that, ongoing operating costs are expected to average $23,000 per annum (around 0.2 per cent of capital expenditure). A one-off decommissioning cost of approximately $200,000 in 2026 is incurred to remove redundant switchgear equipment after new switchgear has been commissioned.

Next steps and contact details for queries in relation to this RIT-D

This FPAR represents the final step in the application of the RIT-D to options for ensuring reliable electricity supply to the Tarro load area.

Under the NER, parties have 30 days from the date of this report to dispute the application of the RIT-D. Disputes are only able to be made on the grounds that Ausgrid has not applied the RIT-D in accordance with the NER, or that Ausgrid preformed a manifest calculation error in applying the RIT-D. Disputing parties cannot dispute issues in this FPAR that the RIT-D treats as externalities, or relate to an individual's personal detriment or property rights. Clause 5.17.5 of the NER sets out the full process and requirements regarding a dispute of how the RIT-D has been applied.

Any queries in relation to this RIT-D should be addressed to:

Matthew Webb
Head of Asset Investment
Ausgrid
GPO Box 4009
Sydney 2001

Or

email to: assetinvestment@ausgrid.com.au

1 Introduction

This Final Project Assessment Report (F**PAR**) has been prepared by Ausgrid and represents the final step in the application of the Regulatory Investment Test for Distribution (**RIT-D**) to options for ensuring reliable electricity supply to the Tarro load area. It follows publication of the Options Screening Notice for this RIT-D.

The Tarro Zone Substation (ZS) is located at the eastern end of the Maitland network area and was commissioned in 1957. It is supplied by two 33kV feeders from Beresfield Sub-Transmission Substation (STS) and is equipped with two groups of 11 kV compound insulated switchgear in a double busbar arrangement. It currently supplies approximately 4,000 customers, including one large industrial customer with a significant load.

The existing 11 kV switchgear at the Tarro 33/11kV ZS has increasing condition, reliability and safety concerns. If action is not taken, our planning studies show that substantial unserved energy to loads is expected if the switchgear fails, as well as significant reactive repair costs to restore service, together with safety risks for Ausgrid personnel and the public. If action is not taken, we expect that our electricity distribution license reliability and performance standards will be breached.

Ausgrid is therefore undertaking a RIT-D to assess options for addressing the risk that the existing ageing 11 kV switchgear poses and to ensure we continue to satisfy our reliability and performance standards.

Ausgrid has determined that non-network and stand-alone power system (SAPS) solutions are unlikely to form standalone credible options, or form a significant part of a credible option, as set out in the separate notice released in accordance with clause 5.17.4(d) of the National Electricity Rules (NER).

1.1 Role of this report

Ausgrid has prepared this FPAR in accordance with the requirements of the NER under clause 5.17.4. It is the final stage of the RIT-D process set out in the NER in relation to the application of the RIT-D.

The purpose of the FPAR is to:

- describe the identified need Ausgrid is seeking to address, including the assumptions used in identifying this need;
- provide a description of each credible option assessed;
- quantify relevant costs and market benefits for each credible option;
- describe the methodologies used in quantifying each class of cost and market benefit;
- explain why Ausgrid has determined that classes of market benefits or costs do not apply to the options considered;
- present the results of a net present value (NPV) analysis of each credible option, explain these results; and
- identify the preferred option.

A Draft Project Assessment Report (DPAR) has not been prepared for this RIT-D as permitted under clause 5.17.4(n) of the NER, i.e., since there are not expected to be any non-network or SAPS solutions and the capital cost of the preferred option is less than the $12 million threshold.[4] The RIT-D process is detailed in Appendix B.

1.2 Next steps and contact details for queries in relation to this RIT-D

This FPAR represents the final step in the application of the RIT-D to options for ensuring reliable electricity supply to the Tarro load area. Under the NER, parties have 30 days from the date of this report to dispute the application of the RIT-D. Disputes are only able to be made on the grounds that Ausgrid has not applied the RIT-D in accordance with the NER, or that Ausgrid preformed a manifest calculation error in applying the RIT-D. Disputing parties cannot dispute issues in this FPAR that the RIT-D treats as externalities, or relate to an individual's personal detriment or property rights. Clause 5.17.5 of the NER sets out the full process and requirements regarding a dispute of how the RIT-D has been applied.

Any queries in relation to this RIT-D should be addressed to:

Matthew Webb
Head of Asset Investment
Ausgrid
GPO Box 4009
Sydney 2001

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email to: assetinvestment@ausgrid.com.au

[4] AER, *Final Determination – 2021 RIT and APR cost thresholds review,* 19 November 2021, p 5.

2 Description of the identified need

This section provides a description of the network area and the 'identified need' for this RIT-D, before presenting a number of key assumptions underlying the identified need.

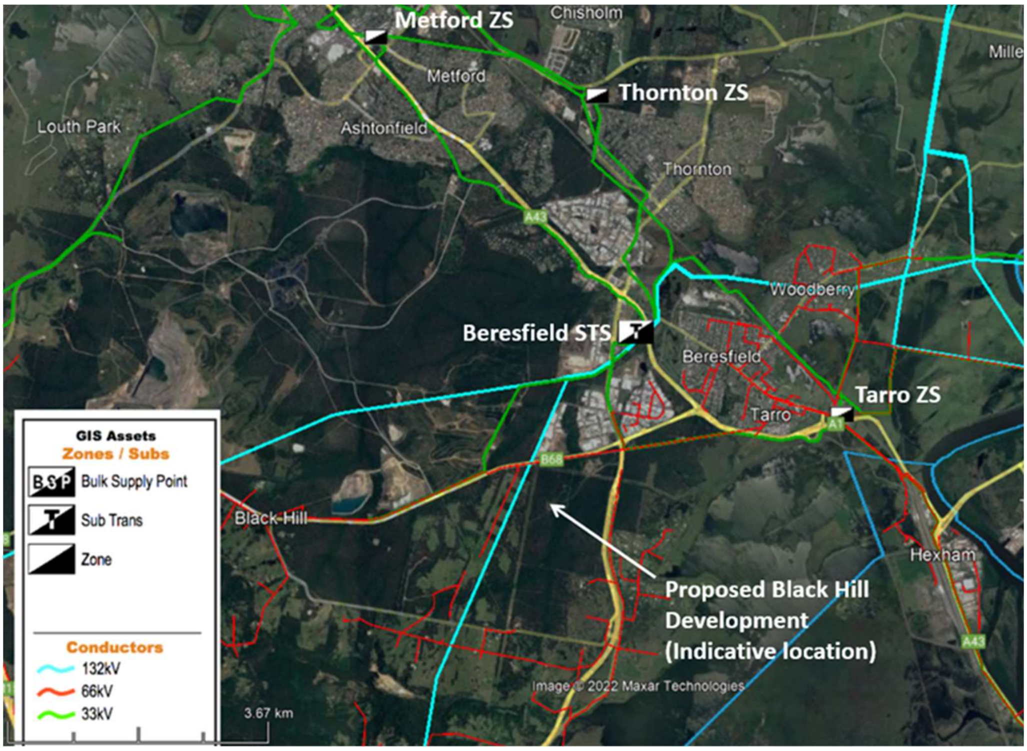
2.1 Overview of the Tarro ZS and the existing supply arrangements for the load area

The Tarro 33/11kV ZS is located on the eastern end of the Maitland region and supplies approximately 4,000 customers including residential, light commercial and industrial developments. Tarro ZS is supplied by the 33 kV network from Beresfield STS.

The 11 kV distribution network supplies nearby residential areas (in Tarro, Woodberry and Beresfield), light industrial and commercial developments (in Beresfield) and one large industrial customer that currently makes up approximately 50 per cent of total demand (and whose details are kept confidential in this FPAR). There has been recent growth in the Beresfield region as a result of new transport infrastructure in the area, with direct access to Sydney, Tamworth (inland) and Brisbane (coast) provided by the intersection of the M1 Motorway, New England Highway and Pacific Highway.

Figure 2-1 below presents the location of Tarro ZS in relation to neighbouring substations and existing/potential large customers.

Figure 2-1: Location of Tarro ZS



Tarro ZS is a summer peaking substation with a current peak load of 17.6 MVA (FY21 summer) and a long term 25 years forecast load of about 17.9 MVA (based on currently connected loads).

The Tarro ZS was first commissioned in 1957 and has two 33/11kV 25 MVA transformers and two groups of 11 kV compound insulated switchgear in a double bus arrangement. Our routine monitoring has identified that the existing 11 kV switchgear at the Tarro ZS has increasing condition, reliability and safety concerns. If not remediated, the existing switchgear is expected to fail at an increasing rate going forward, which will result in significant unserved energy to customers in the area as well as safety risks and unplanned corrective maintenance costs.

In the event of a significant failure, a proportion of the load can be transferred away by switching to adjacent ZS (Thornton, Maryland, Tomago and Mayfield West), but the remaining load would have to be supplied using mobile substations and power generation sets with a non-firm supply until repairs are completed. Whilst there is a major customer in the area with embedded generation, the capacity of this generation is not able to cover the customer's entire load and there are no alternative 11 kV supply connections to adjacent ZS in place for this customer.

We note that there are also potential new industrial developments in the Black Hill area, approximately 4 km west of Tarro ZS (and shown in the figure above), that have the potential to add considerable load that would exceed the existing capacity of Tarro ZS. The identified Black Hill development has been around since 2018 and has aggregate long-term load of up to 30 MVA based on developer estimates. While some loads have already connected to the development, from previous Ausgrid experience with similar developments, we anticipate that it will take considerable time for the Black Hill development to reach the full 30 MVA (if at all) and so we have assumed a gradual ramp up for this load over time (as outlined in section 4.3.1).

2.2 Summary of the 'identified need'

Ausgrid is obliged to comply with reliability and performance standards as part of its distribution license granted by the Minister for Industry, Resources and Energy under the *Electricity Supply Act 1995 (NSW)*. Under its license, reliability and performance standards are expressed in two measures:

- SAIDI[5] – which means the average derived from the sum of the durations of each sustained customer interruption (measured in minutes), divided by the total number of customers (averaged over the financial year); and
- SAIFI[6] – which means the average derived from the total number of sustained customer interruptions divided by the total number of customers (averaged over the financial year).

These two reliability measures capture two key sources of inconvenience to electricity customers from supply disruptions, i.e. how long their electricity supply is off for as well as how often their electricity supply is off. Customers experience less inconvenience (i.e. a better level of supply reliability), the lower each of these measures are. Reliability standards applied to distribution networks typically set maximums in relation to each of these two measures.

The main concern relates to increasing customer supply, maintenance and safety risks derived from the condition of the 11kV switchgear. If action is not taken to address the deteriorating condition of the 11 kV switchgear at the Tarro ZS, then the analysis shows that the unserved energy modelled will lead to a breach of these standards going forward.

2.3 Key assumptions underpinning the identified need

Ausgrid installed compound insulated 11 kV switchgear from the late 1930s until the early 1970s. This type of switchgear is characterised by bituminous compound in the busbar chamber. This bituminous compound electrically insulates the 11 kV busbar during normal operation but can also act as a fuel source in the event of a fire.

Much of this type of equipment has already been retired from Ausgrid's network, and the remaining equipment is approaching end of life, with continued service resulting in further deterioration and an increasing number of failures.

The ability to support this switchgear technology into the future is also becoming more costly. Manufacturers no longer produce this type of equipment, Ausgrid's inventory of spares is limited and the expertise to perform required repairs is specialised and increasingly rare. Repair for failures requires bespoke engineering solutions specific to an individual switchboard installation. Repair is also heavily dependent on the nature and extent of damage to both the switchgear and the switch room, with the realistic outcome in some cases being that it cannot be repaired but only replaced.

While our tests undertaken at Tarro ZS in 2011 indicated the 11 kV switchboard was in reasonable condition for continued service, as the probability of failure increases with age and the compound switchboard approaches 65 years of service, Ausgrid's probabilistic model anticipates increasing deterioration of the asset condition and significant levels of involuntary load shedding.

A sign of deterioration took place in February 2019, when a failure occurred in one 11 kV panel at Tarro ZS. Following this, incident supply was restored but with the panel in question left unrepaired. A solution involving a new interconnection outside Tarro ZS with two switching cubicles was implemented, as it was lower in costs than undertaking repairs. This method is scalable and therefore not suitable for addressing further addressing further risks associated with the Tarro 11kV switchboard.

No additional tests have been conducted, because arrangements to transfer the load away to enable another test are complex and compounded by the fact that a large industrial customer connected at Tarro ZS cannot be supplied from other substations in the area.

[5] System Average Interruption Duration Index.

[6] System Average Interruption Frequency Index.

The need to undertake action is predicated on the deteriorating condition of the existing 11 kV switchgear at the Tarro ZS and the consequences of any resultant outages. This section summarises the key assumption underpinning the identified need for this RIT-D. Appendix D provides additional detail on assumptions used, and methodologies applied, to estimate the costs and market benefits as part of this RIT-D.

2.3.1 Ageing 11 kV switchgear is expected to increase the risk of involuntary load shedding

A critical assumption underpinning the identified need is that retaining the existing 11 kV switchgear is expected to increase the risk of involuntary load shedding. The major factor contributing to the risk of involuntary load shedding is that the switchgear is reaching the end of its technical life and is expected to fail at an increasing rate going forward if action is not taken. The technology used by the switchgear is also obsolete and requires specialist skills to repair and maintain and so, consequently, outage times can be lengthy and spares are not readily available since manufacturers no longer produce the switchgear.

2.3.2 Probability of assets failing increases with age

A range of models have been used to forecast the availability of equipment. These models utilise Ausgrid's historical outage records to determine the likelihood of failure and are combined with estimates for repair or supply restoration time to determine the availability of equipment.

Failures of 11 kV switchboards are assumed to be non-repairable because typically the board is no longer functional following a failure (and hence is replaced or removed from service). Weibull analysis has been used to derive a probability distribution function for the asset's age at time of failure and the parameters of the function are derived by considering the following information:

- the age of Ausgrid's in service 11 kV switchboards;
- the age of functional failure for Ausgrid's failed switchboards; and
- the age of retirement for Ausgrid's switchboards that were retired before the point of functional failure.

The model has been created to distinguish between 11 kV switchboards that are of differing condition. This assessment was performed using a group of Ausgrid subject matter experts based upon their specialist knowledge of the asset(s) and a review of the available conditional information (i.e. test results).

Additional detail on the modelling approach and assumptions is provided in Appendix D.

2.3.3 The capacity to undertake load transfers is limited

In the event of a significant failure, a proportion of the load can be transferred away from the Tarro ZS by switching to adjacent ZS, but the remaining load would have to be supplied using mobile substations and power generation sets with a non-firm supply until repairs are completed.

In addition, while there is a major customer in the area with embedded generation, the capacity available is not able to cover the customer's entire load and no alternative 11 kV supply connections to adjacent ZS are in place for this customer.

The expected unserved energy presented in this FPAR takes account of the limited ability to transfer load when failures occur.

2.3.4 Reactive maintenance costs and safety risk

In addition to the expected unserved energy, the 11 kV switchgear failure model also quantifies unplanned repairs and safety risks associated with the existing 11 kV switchgear. The safety risk arises primarily from the compound insulation in the existing 11 kV switchgear catching fire as its condition deteriorates going forward.

The 11 kV switchgear used at the Tarro ZS is compound insulated and all the original 11 kV Oil Circuit Breakers (OCBs) were replaced with vacuum circuit breakers (VCBs) approximately ten years ago. The compound insulated switchboards can have high fire risks (due to them being a fuel source), which may compromise the safety and reliability of supply. Advances in technology since the 1970s have provided superior/safer alternatives to compound switchboards.

Whilst the removal of OCBs significantly mitigates fire risks, it does not eliminate the risk as the key parts of the original switchboard remain in service. The only practical way to fully eliminate the risk is to retire and replaced the aged switchboard with modern equivalent equipment.

The benefits of avoiding these costs and risks are minor relative to the avoided expected unserved energy benefits (together, making up approximately 1 per cent of the present value of the expected benefits under the central scenario in this FPAR).

3 Two credible options have been assessed

This section provides details of the two credible options that Ausgrid has identified as part of its network planning activities to date. All costs in this section are in $2021/22, unless otherwise stated.

3.1 Option 1 – Replace the 11 kV switchgear at the Tarro ZS

This option involves the replacement of the 11 kV switchgear in a new switch room, as well as enabling works to add a third 11 kV switch group in future to meet future load. This option involves the replacement of the existing 11 kV double bus switchgear at Tarro ZS with modern equivalent switchgear in a single bus arrangement.

Specifically, the scope of this option includes:

- installation of a Modular Equipment Room (MER) adjacent to the 33 kV switchgear;
- installation of a new 11 kV switchboard including two sections of single bus switchgear and 13x11 kV circuit breakers;
- installation of 11 kV connections to connect both existing main power transformers to the MER and transfer seven existing 11 kV feeders to the new switchboard;
- construction of firewalls between transformer bays and on the western boundary to protect a residential property;
- rearrangement of the 33 kV feeder connections and structures within the site to achieve safety clearances required for internal 11 kV cable work;
- secondary systems upgrades; and
- disconnect, dismantle and remove the existing 11 kV switchgear from the site.

Commissioning of all new assets is expected by November 2024. While the optimal timing assessment in section 5.4.1 finds July 2024 as the optimal timing, we consider that November 2024 is the earliest realistic time that we can commission the assets due to deliverability challenges. Decommissioning of the existing 11kV switchgear is targeted for May 2025.

The estimated capital cost of this option is $11.3 million with approximately $200,000 in decommissioning costs incurred in 2026 to decommission existing switchgear. Annual operating costs are expected to be approximately $23,000 per annum (0.2 per cent of capital expenditure).

Under the high demand forecast, Option 1 will also involve a new 11 kV 3rd busbar section (involving 5x11kV panels) at an additional cost of $3.5 million. Under this forecast, this element is assumed to be commissioned in 2033 (however, we note that the specific timing of this element is considered immaterial to the assessment given the overall cost differences between the options).

Figure 3-1 shows the network line diagram for Option 1 upon commissioning.

Figure 3-1 – Network line diagram for Option 1 upon commissioning

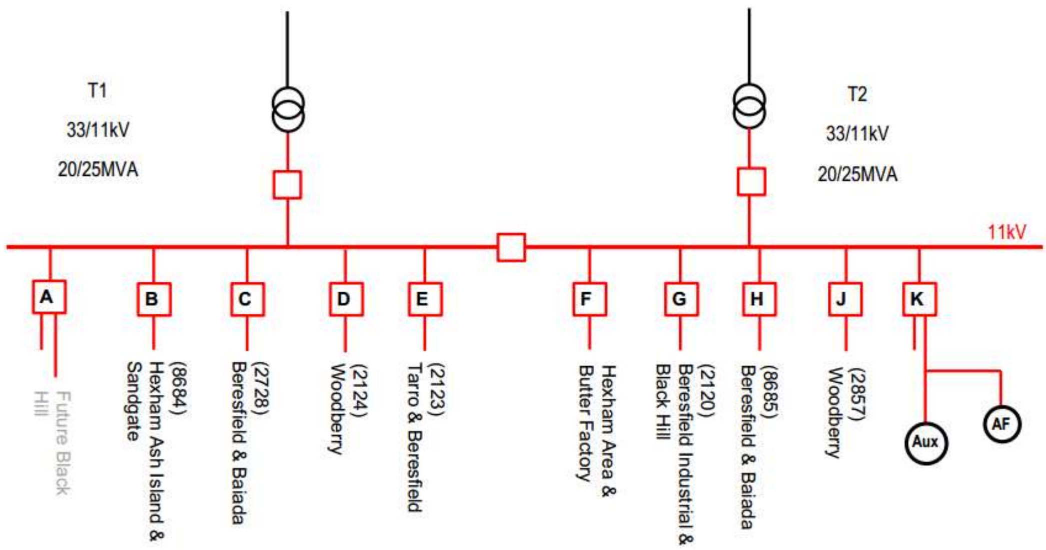
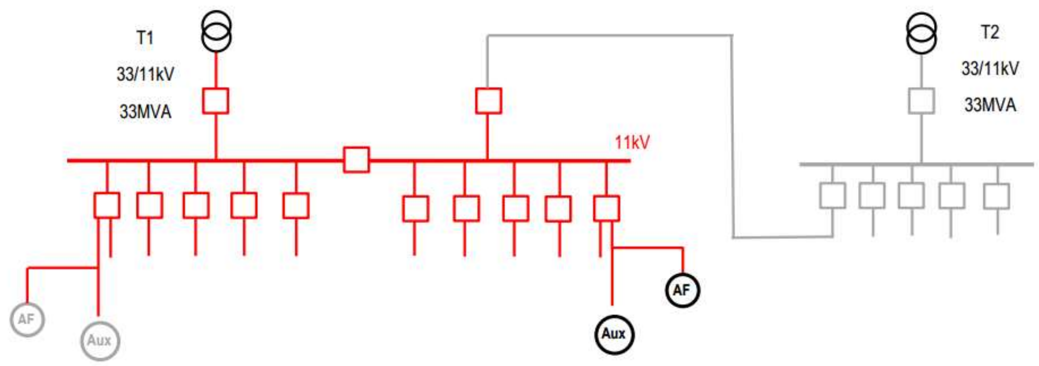


Figure 3-2 shows the network diagram for Option 1 if the third 11 kV bus section is commissioned (which is shown in grey).

Figure 3-2 – Network line diagram for Option 1 once the third 11 kV bus section is commissioned



3.2 Option 2 – Build a new ZS to replace the Tarro ZS

This option involves building a new 33/11kV zone substation next to Beresfield STS to replace the existing Tarro ZS.

Specifically, the scope of this option involves:

- installing two 33/11 kV transformer units;
- installing an equivalent 11 kV switch room with the same configuration proposed under Option 1;
- installing control and protection equipment (secondary systems) to integrate the new ZS to the network;
- installing two 33 kV underground short cable connections (approximately 200 metres long);
- transferring 11 kV load from the existing Tarro ZS to the new ZS;
- transferring the large industrial customer to the 33 kV network (by installing a 10 MVA transformer unit with reclosers and 11 kV circuit breakers to connect to the customer's own substation); and
- decommissioning the existing Tarro ZS)

Commissioning of all new assets is expected by July 2025**,** based on the optimal timing assessment in section 5.4.1. Decommissioning of the existing Tarro ZS is expected a year after commissioning the new assets.

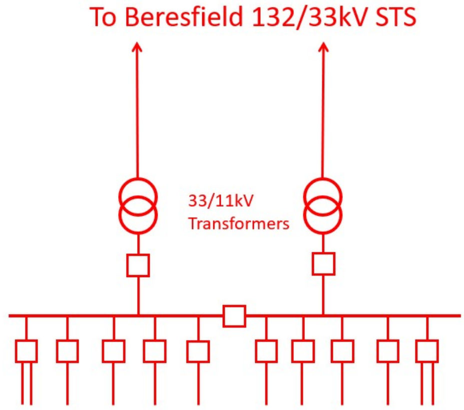
Given that the development and subsequent delivery of a project to establish a new ZS typically takes approximately four to five years from project initiation to commissioning, the feasible commissioning date of July 2025 is consistent with the optimal timing assessment for Option 2.

The estimated capital cost of this option is $20.4 million with decommissioning costs of $2.1 million incurred in 2027. Annual operating costs are expected to be approximately $41,000 per annum (0.2 per cent of capital expenditure).

The new ZS under Option 2 is a 'tail-ended' substation given its proximity to the existing Beresfield STS. While we have included +/- 25 per cent cost uncertainty for both options in the NPV assessment in this FPAR, we consider that the cost uncertainty in Option 2 is likely to be greater than this given it is a non-standard substation.

Figure 3-3 shows the network line diagram for Option 2.

Figure 3-3 – Network line diagram for Option 2



3.3 Options considered but not progressed

Ausgrid also considered several other options that have not been progressed. In general, these options were not progressed because they were found to be technically infeasible or economically infeasible.

The table below summarises Ausgrid's consideration and position on each of these potential options.

Table 3-1 – Options considered but not progressed

Option	Description	Reason why option was not progressed
Transferring the large customer load to the 33 kV network	Transferring the customer load to the 33 kV network (at a capital cost of $5.6 million) so that it is no longer supplied by the Tarro ZS.	While this option is lower cost than Option 1, and reduces the expected unserved energy for the customer since it is no longer supplied from the Tarro ZS, there still remains significant unserved energy (from the remaining load connected to the Tarro ZS), while not addressing reactive maintenance costs and safety risks. This option is therefore not considered economically feasible.
Non-network options	Using non-network solutions either in combination with, or in-place of, a network option.	Ausgrid has considered the ability of non-network solutions to assist in meeting the identified need. Specifically, an analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. An assessment of demand management options has shown that non-network alternatives would not be cost effective due to the magnitude of the load reduction required. This result is driven primarily by the significant amount of unserved energy that the identified network option allows to be avoided, compared to base case, and the cost of demand management solutions. This is detailed further in the separate Options Screening Notice released in accordance with clause 5.17.4(d) of the NER.
SAPS options	Transferring and/or connecting customers to SAPS	Ausgrid has considered the feasibility of SAPS, informed by its trial of SAPS with selected customers living in living in fringe-of-grid areas of Ausgrid's network. Based on Ausgrid's trial, cost of SAPS would limit the number of customers available to reduce demand given the deferral funds available and consequently, the reduction in demand would not be sufficient to defer or postpone the network solution. This is detailed further in the separate Options Screening Notice released in accordance with clause 5.17.4(d) of the NER.

4 How the options have been assessed

This section outlines the methodology that Ausgrid has applied in assessing market benefits and costs associated with the credible option considered in this RIT-D. Appendix D presents additional detail on the assumptions and methodologies employed to assess the option.

4.1 General overview of the assessment framework

All costs and benefits for each credible option have been measured against a 'business as usual' base case. Under this base case, Ausgrid will continue to maintain the existing 11 kV switchgear in service (i.e. no change). This involves escalating regular and reactive maintenance activates as the probability of failure and outages increases over time in the absence of an asset replacement program, as well as consequent escalating unserved energy and safety risks.

The RIT-D analysis has been undertaken over a 20-year period, from 2021-22 to 2040-41. Ausgrid considers that a 20-year period takes into account the size, complexity and expected life of the relevant credible option to provide a reasonable indication of the market benefits and costs of the option.

Where the capital components of the credible option have asset lives greater than 20 years, Ausgrid has taken a terminal value approach to incorporate capital costs in the assessment, which ensures that the capital cost of long-lived options is appropriately captured in the 20-year assessment period. This ensures that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values have been calculated as the undepreciated value of capital costs at the end of the analysis period and can be interpreted as a conservative estimate for benefits (net of operating costs) arising after the analysis period.

Ausgrid has adopted a real, pre-tax discount rate of 3.44% as the central assumption for the NPV analysis. This represents Ausgrid's opportunity cost for its capital investments, based on the guidelines provided in the AER rate of return instrument. As no non-network options have been found to be viable, Ausgrid considers that appropriate discount rate is the regulated cost of capital.

To test the sensitivity of the results against changes in the discount rate, a value of 2.34% has been adopted for the lower bound discount rate, to reflect the average of the latest AER Final Decision for a DNSP's regulated weighted average cost of capital (WACC) at the time of preparing this FPAR[7]. This is approximately 32% lower than the central discount rate assumption. For the upper bound discount rate, the value of 5.50% is adopted to consider the scenario prepared by AEMO for the 2022 Integrated System Plan (ISP). Whilst the use of a symmetrical upward adjustment of the discount rate (in this case 4.48%) may also be a reasonable representation, the adoption of 5.50% is deemed a more appropriate contemporary representation of a boundary value.

4.2 Ausgrid's approach to estimating project costs

Ausgrid has estimated capital costs by considering the scope of works necessary under each credible option together with costing experience from previous projects of a similar nature. Where possible, Ausgrid has also estimated capital costs using supplier quotes or other pricing information.

Operating and maintenance costs have been determined for each option by comparing the operating and maintenance costs with the option in place to the operating and maintenance costs without the option in place. These costs are included for each year in the planning period. If operating and maintenance costs are reduced with an option in place, the cost savings are effectively treated as a benefit in the assessment.

Operating costs have been estimated for the credible options and the base case by taking into account:

- the probability and expected level of network asset faults, which translates to the level of corrective maintenance costs; and
- the level of regular maintenance required to maintain network assets in good working order, including planned refurbishment costs.

Both options reduce the incidence of asset failures relative to the base case, and hence the expected operating and maintenance costs associated with restoring supply.

[7] Specifically, we take a straight average of the real, pre-tax WACCs for the Victorian DNSPs (since they represent the latest Final Decision(s) by the AER).

Ausgrid has also included the costs associated with corrective maintenance that are assumed to be avoided under each of the options, relative to the base case. These costs are based on internal Ausgrid estimates and are immaterial in the analysis, both in terms of absolute values as well as being the same across the options, as illustrated in section 5.1. Details of the assumptions and methodologies adopted to estimate these avoided costs are presented in Appendix D.

4.3 Market benefits are expected from reduced involuntary load shedding

Ausgrid considers that the only relevant category of market benefits prescribed under the NER for this RIT-D relate to changes in involuntary load shedding.

The approach Ausgrid has adopted to estimating reductions in involuntary load shedding are outlined in section 4.3.1 below. Further details on the assumptions and methodology considered are presented in Appendix D.

In addition, Appendix C summarises the market benefit categories that Ausgrid considers are not material for this RIT-D.

4.3.1 Reduced involuntary load shedding

Involuntary load shedding occurs when a customer's load is interrupted from the network without their agreement or prior warning. This relates to the availability of network connectivity and design configuration at the substation. It also arises from the unavailability of network elements and the resulting reduction in network capacity to supply the load.

The expected unserved energy is the probability weighted average amount of load that customers request to utilise but would need to be involuntarily curtailed due to loss of network connectivity or a network capacity limitation.

Ausgrid has forecast load over the assessment period and has quantified the expected unserved energy by comparing forecast load to network capabilities under system normal and network outage conditions. A reduction in involuntary load shedding expected from an option, relative to the base case, results in a positive contribution to market benefits of the credible option being assessed.

The market benefit that results from reducing the involuntary load shedding with a network solution is estimated by multiplying the quantity of expected unserved energy in MWh by the Value of Customer Reliability (VCR). The VCR is measured in dollars per MWh and is used as proxy to evaluate the economic impact of unserved energy on customers under the RIT-D.

Ausgrid has applied a central VCR estimate of $56.15/kWh, reflecting a load weighted value for the affected load at Tarro ZS calculated using the NSW and ACT VCR estimates (for residential, commercial and industrial load) derived by the AER in its VCR Final Report[8], adjusted by the Consumer Price Index (CPI) to be in 2021/22 dollars. A breakdown of how the central load weighted VCR has been calculated is provided in Appendix D.

We have also reflected VCR estimates in the scenarios that are 30 per cent lower and 30 per cent higher than the central rate, consistent with the AER's specified +/- 30 per cent confidence interval.[9]

In addition, Ausgrid has investigated how assuming different load forecasts going forward changes expected market benefits under each option. In particular, three future load forecasts for the area in question have been investigated – namely a central forecast using our 50 per cent probability of exceedance ('POE50'), as well as a low forecast using the POE90 and a high forecast using the POE10 forecasts.

Ausgrid is currently in the process of developing an updated set of load forecasts that draw on the latest Integrated System Plan (ISP) released by the Australian Energy Market Operator (AEMO) on 30 June 2022. These forecasts consider an increased uptake of energy efficiency and electrification to account for an accelerated decarbonisation to meet net zero by 2050, as well as an electric vehicle forecast that is much higher in the earlier years compared to our current forecast and a rapid conversion of residential gas to electricity. As a result, we consider that the load forecasts used in this FPAR are conservative, relative to those under development, but they provide a reasonable representation of what can be expected in the Tarro ZS network area.

The figure below shows the assumed levels of expected unserved energy, under each of the three underlying demand forecasts investigated over the next twenty years. For clarity, this figure illustrates the MWh of unserved energy prior to any replacement of the 11 kV switchgear, taking into consideration the underlying demand forecasts and the assumed failure rates associated with keeping the existing network assets in service.

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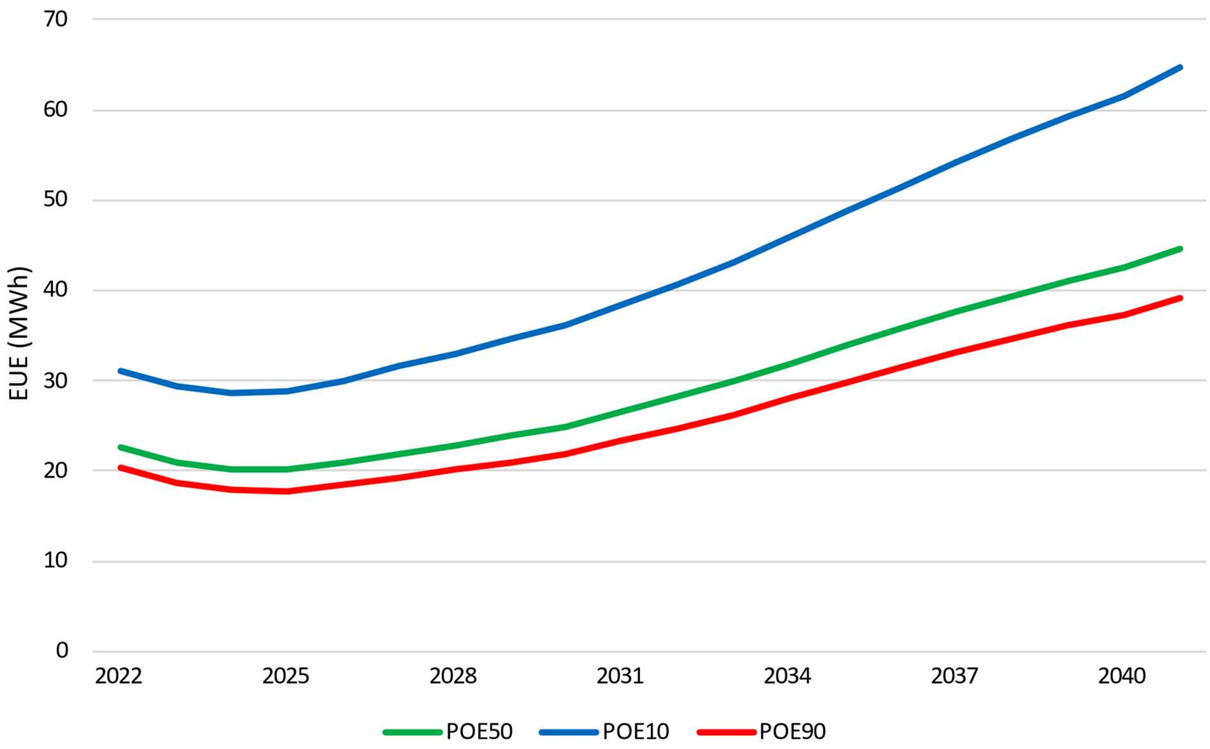
[8] AER, *Values of Customer Reliability Review* – Final Report on VCR values – December 2019. https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf

[9] AER, *Values of Customer Reliability – Final Report on VCR values*, December 2019, p. 84.

Figure 4-1 – Assumed expected unserved energy (EUE) under each of the three demand forecasts



Each of the three demand forecasts above assume a gradual ramp up of the Black Hill development load going forward. Specifically, each demand forecast above assumes a gradual ramp-up to the full 30 MVA over the next 25 year, with 5-10 MVA connecting over the next 10-15 years. However, we note that the timing and ramp-up of the Black Hill load is not ultimately material to the outcome of this FPAR due to the outright cost differences between the two options, i.e., the preferred option in this FPAR is not affected even if the Black Hill development is assumed to come online in full at the start of the period, or not at all over the period.

4.4 Three different 'scenarios' have been modelled to address uncertainty

RIT-D assessments are required to be based on cost-benefit analysis that includes an assessment of 'reasonable scenarios', which are designed to test alternate sets of key assumptions and whether they affect identification of the preferred option.

Ausgrid has elected to assess three alternative future scenarios – namely:

- low benefit scenario – Ausgrid has adopted a number of assumptions that give rise to a lower bound NPV estimate for each credible option, in order to represent a conservative future state of the world with respect to potential market benefits that could be realised under the credible option;
- central scenario – the baseline scenario consists of assumptions that reflect Ausgrid's central set of variable estimates which, in Ausgrid's opinion, provides the most likely scenario; and
- high benefit scenario – this scenario reflects an optimistic set of assumptions, which have been selected to investigate an upper bound on reasonably expected market benefits.

A summary of the key variables in each scenario is provided in the table below.

Table 4-1 – Summary of the three scenarios investigated

Variable	Scenario 1 - central	Scenario 2 – low benefits	Scenario 3 – high benefits
Demand	POE50	POE90	POE10
VCR	$56.15/kWh	$39.31/kWh	$73.00/kWh
Unplanned corrective maintenance cost	Central estimates	70 per cent of the central estimates	130 per cent of the central estimates
Safety risk costs	Central estimates	70 per cent of the central estimates	130 per cent of the central estimates
Capital costs	Capital cost central estimates	125 per cent of capital cost estimate	75 per cent of capital cost estimate
Planned routine maintenance for new assets	Central estimates	125 per cent of the central estimates	75 per cent of the central estimates
Planned routine maintenance for existing assets	Central estimates	75 per cent of capital cost estimate	125 per cent of capital cost estimate
Decommissioning costs	Central estimates	125 per cent of capital cost estimate	75 per cent of the central estimate
Discount Rate	3.44%	5.50%	2.34%

Ausgrid considers that the central scenario is the most likely, since it is based primarily on a set of expected/central assumptions. Ausgrid has therefore assigned this scenario a weighting of 50 per cent, with the other two scenarios being weighted equally with 25 per cent each. However, Ausgrid notes that the identification of the preferred option is the same across all three scenarios (i.e. the result is insensitive to the assumed scenario weights). This implies that even if a much lower weighting was given to the low and high scenarios (e.g., 5 per cent), the preferred option identified in this FPAR would not change.

5 Assessment of the credible option

This section provides the assessment of the credible network options Ausgrid has identified as part of its network planning activities to date. The options are compared against the base case 'do nothing' option.

5.1 Gross market benefits estimated for the credible option

The table below summarises the gross market benefit of the credible option relative to the base case in present value terms. The gross market benefit for each option has been calculated for each of the three reasonable scenarios outlined in the section above.

Option 1 is found to have greater benefits than Option 2 in all three of the scenarios investigated, which is driven by the fact that Option 1 can be commissioned ahead of Option 2, and therefore it can avoid expected unserved energy, safety risk costs and reactive maintenance costs earlier. Option 2 has a later commissioning date compared to Option 1 owing to the additional lead time required to facilitate load transfers and construct a new substation.

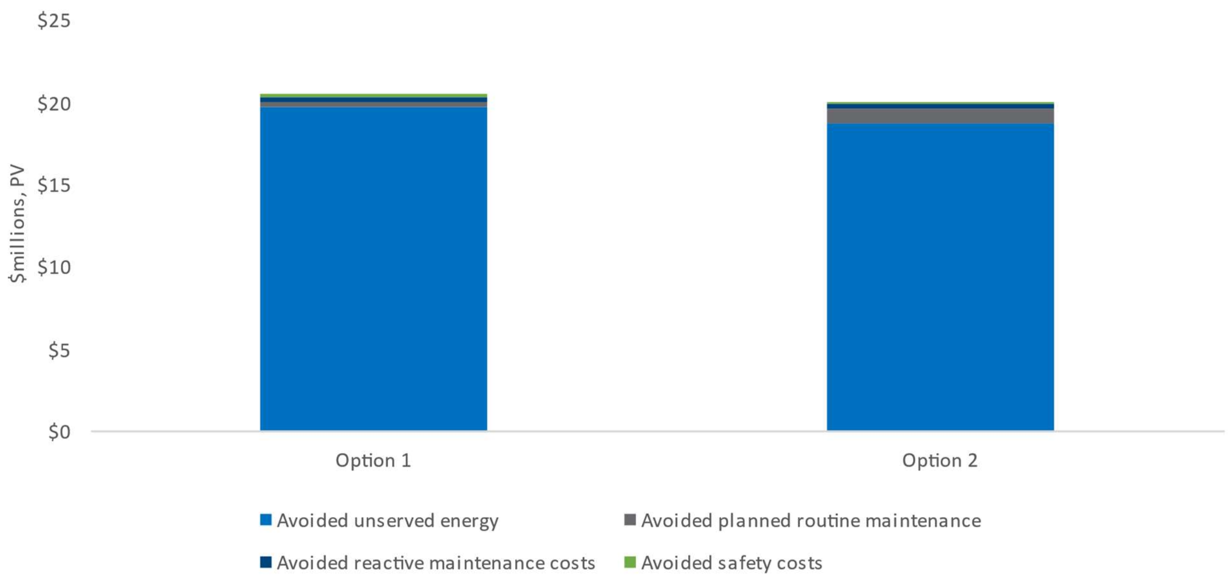
Table 5-1 – Present value of gross benefits of credible options relative to the base case, $m 2021/22

Option	Baseline scenario	Low benefit scenario	High benefit scenario	Weighted benefits
Scenario weighting	50%	25%	25%	
Option 1	20.5	10.2	43.0	23.6
Option 2	20.1	10.0	41.9	23.0

The figure below provides a breakdown of the present value of all benefits relating to the credible options. For clarity, we have combined in this chart the category of 'market benefit' estimated (i.e. reduced involuntary load shedding or unserved energy) with avoided corrective maintenance cost benefits (i.e. reduced unplanned corrective maintenance when assets fail), avoided planned routine maintenance and reduced operating costs associated with safety risk costs given they also inherently reflect benefits (i.e., avoided costs).

The primary benefit is estimated to be avoided unserved energy for both options on account of the increasing likelihood of failure of the assets in question, which are nearing the end of their technical lives. Secondary benefits such as avoided planned and unplanned maintenance (corrective maintenance) and avoided safety costs reflect only a small proportion of the benefits for each proposed option.

Figure 5-1 – Breakdown of gross benefits of the credible options relative to the base case under the central scenario, $m 2021/22



5.2 Estimated costs for the credible option

The table below summarises the costs of the credible options relative to the base case in present value terms. The cost is the sum of the project capital costs and the operating costs associated with each option.

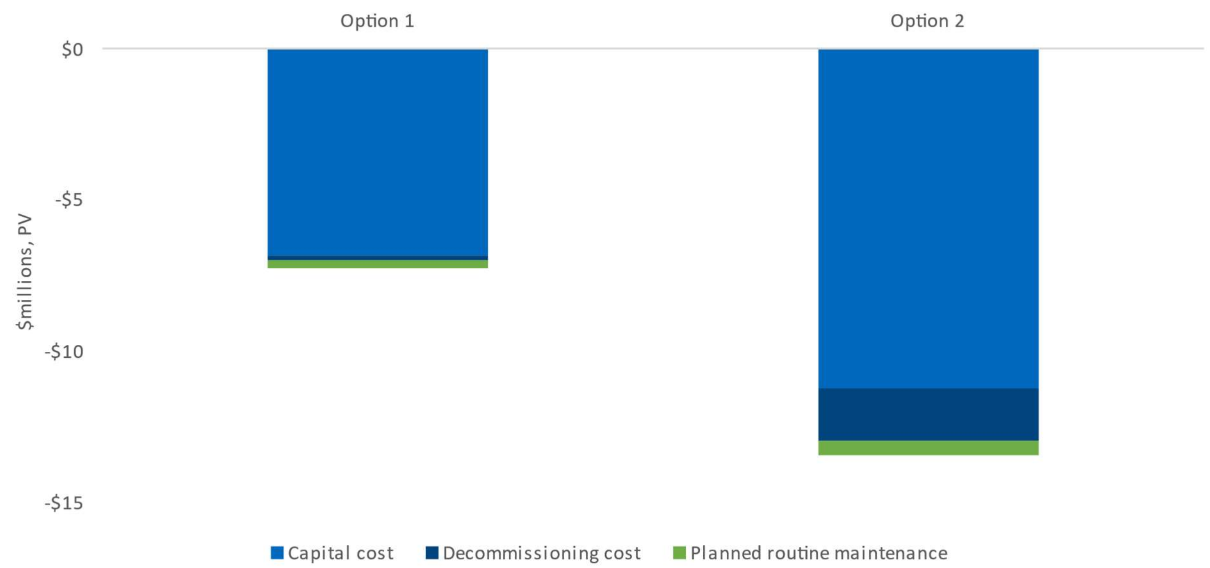
The cost of each option has been calculated for each of the three reasonable scenarios, in accordance with the approaches set out in Section 4. Option 1 has a significantly lower total cost, in present value terms, than Option 2 in all three scenarios.

Table 5-2 – Present value of costs of the credible options relative to the base case, NPV $m 2021/22

Option	Baseline scenario	Low benefit scenario	High benefit scenario	Weighted costs
Scenario weighting	50%	25%	25%	
Option 1	-7.3	-10.1	-5.7	-7.6
Option 2	-13.4	-18.0	-9.4	-13.6

The figure below provides a breakdown of costs relating to each credible option. Capital costs are one of the key determining factors for the ranking of the credible option considered, with the capital costs of Option 2 being substantially higher than the capital costs for Option 1. The costs associated with Option 2 are approximately 79 per cent higher than the costs for Option 1 for the weighted scenario (on a present value basis).

Figure 5-2 – Breakdown of costs of each credible option relative to the base case under the central scenario, $m 2021/22



5.3 Net present value assessment outcomes

The table below summarises the net market benefit in NPV terms for the credible option under each scenario. The net market benefit is the gross market benefit (as set out in Table 5-1) minus the cost of the option (as set out in Table 5-2), all in present value terms.

Overall, Option 1 exhibits the highest estimated net market benefit on a weighted basis (and under each of the three individual scenarios). While Option 1 has marginally negative net benefits under the low benefits scenario, we note that this reflects an extreme combination of conservative assumptions (and also that the preferred option is permitted to have negative net benefits for this RIT-D since it is a reliability corrective action).

Table 5-3 – Present value of weighted net benefits relative to the base case, $m 2021/22

Option	Central scenario	Low benefits scenario	High benefits scenario	Weighted	Ranking
Option 1	13.2	0.1	37.3	16.0	1
Option 2	6.7	-8.0	32.5	9.5	2

Ausgrid notes that the identification of the preferred option is the same across all three scenarios (i.e. the result is insensitive to the assumed scenario weights). This implies that even if a much lower weighting was given to the low and high scenarios (e.g., 5 per cent), the preferred option identified in this FPAR would not change.

5.4 Sensitivity analysis results

Ausgrid has undertaken a thorough sensitivity testing exercise to understand the robustness of the RIT-D assessment to underlying assumptions about key variables.

In particular, we have undertaken two tranches of sensitivity testing – namely:

- step 1 – testing the sensitivity of the optimal timing of the project ('trigger year') to different assumptions in relation to key variables; and
- step 2 – once a trigger year has been determined, testing the sensitivity of the total NPV benefit associated with the investment proceeding in that year, in the event that actual circumstances turn out to be different.

That is, Ausgrid has undertaken sensitivity analysis to first determine the optimal timing of the project, to conclude that a particular year represents the 'most likely' date at which the project will be needed.

Having assumed to have committed to the project by this date, Ausgrid has also looked at the consequences of 'getting it wrong' under step 2 of the sensitivity testing. That is, if demand turns out to be lower than expected, for example, what would be the impact on the net market benefit associated with the project continuing to go ahead on that date.

We outline how each of these two steps has been applied to test the sensitivity of the key findings.

5.4.1 Step 1 – Sensitivity testing of the assumed optimal timing for the credible option

Ausgrid has estimated the optimal timing for each option according to when the expected annual benefit from the proposed option exceeds its annualised cost, consistent with the AER guidance on how to determine the economically prudent and efficient timing for asset retirement.[10] This process was undertaken for both the central set of assumptions (ie, the central scenario) as well as a range of alternative assumptions for key variables.

This section outlines the sensitivity of the identification of the commissioning year to changes in the underlying assumptions. In particular, the optimal timing of the options is found to be invariant to the assumptions of:

- a 25 per cent increase/decrease in the assumed network capital costs;
- alternative forecasts of maximum demand growth, based on POE10 (high) and POE90 (low);
- a higher VCR ($73.0/kWh);
- lower and higher assumed avoided reactive maintenance costs (+/- 30 per cent);
- lower and higher assumed safety risk costs (+/- 30 per cent); and
- a higher/lower discount rate.

Timing analysis indicates the optimal commissioning year is consistent between all the sensitivities modelled, with the optimal commissioning year for each option being invariant to changes in a single assumption (i.e. discount rate).

The figures below outline the impact on the optimal commissioning year for each option, under a range of alternative assumptions. The first figure illustrates that for Option 1, the optimal commissioning date is found to be in 2024/25 for all sensitivities. The second figure illustrates that for Option 2, the optimal commissioning date is found to be in 2025/26 for all sensitivities.

[10] AER, *Industry practice application note – Asset replacement planning*, January 2019, p. 37.

Figure 5-3 – Option 1's distribution of optimal project commissioning years under each sensitivity

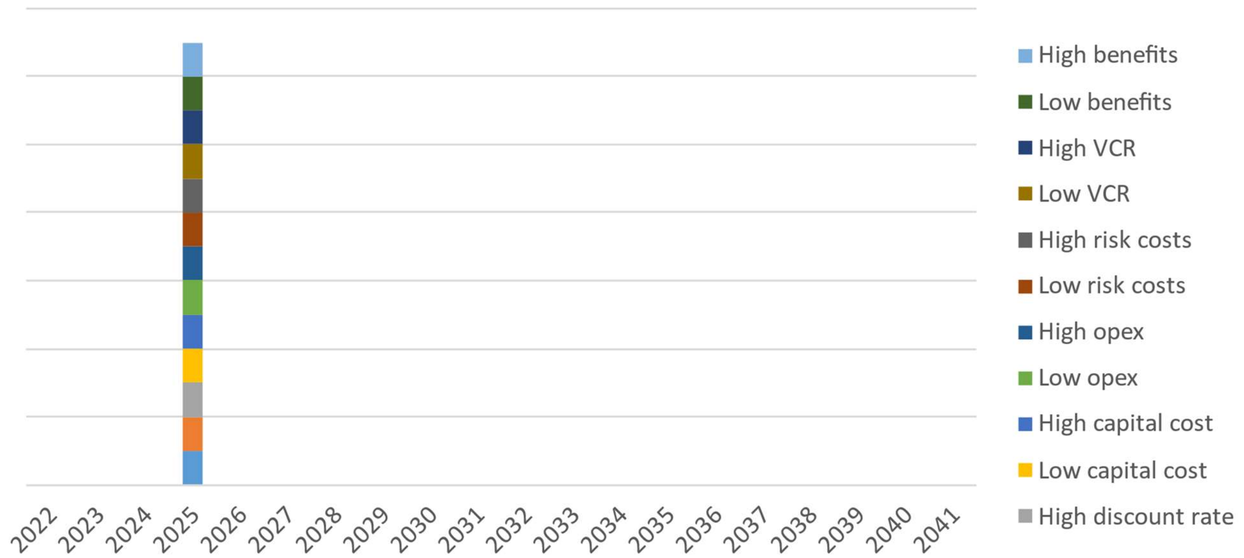
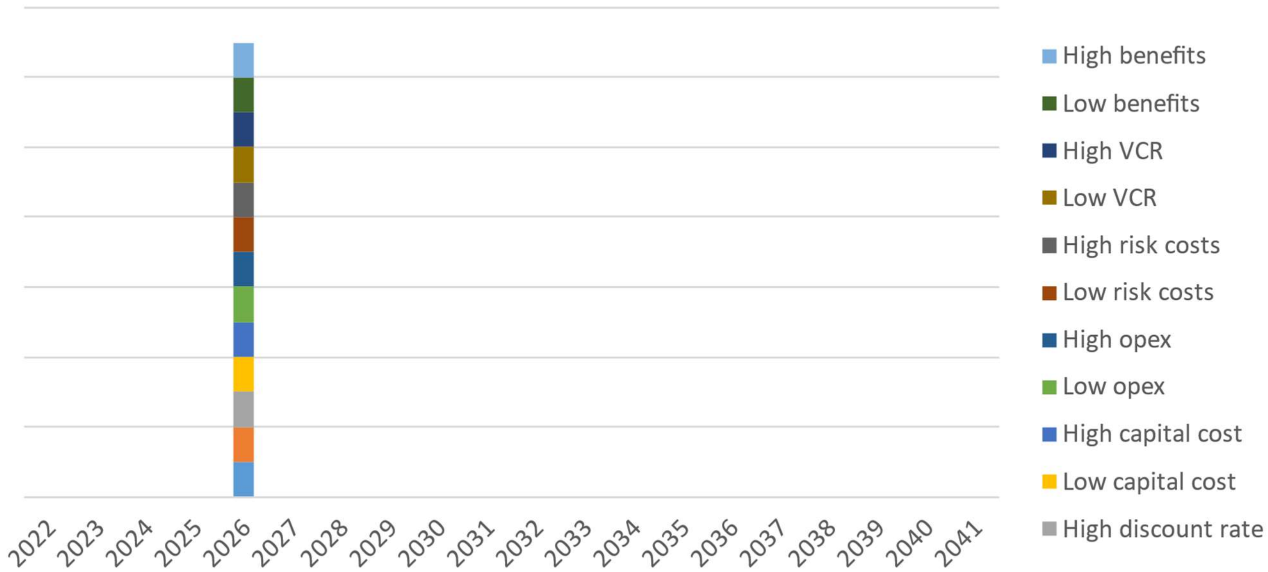


Figure 5-4 – Option 2's distribution of optimal project commissioning years under each sensitivity



5.4.2 Step 2 – Sensitivity of the overall net market benefit

Ausgrid has also conducted sensitivity analysis on overall net market benefits, based on the assumed option timing established in step 1.

Specifically, Ausgrid has investigated the same sensitivities under this second step as in the first step, i.e.:

- a 25 per cent increase/decrease in the assumed network capital costs;
- at 25 per cent increase/decrease in the assumed planned maintenance costs for existing ZS assets;
- alternative forecasts of maximum demand growth, based on POE10 (high) and POE90 (low;
- a lower VCR ($39.3/kWh) and a higher VCR ($73.0/kWh);
- lower and higher assumed avoided unplanned corrective maintenance costs (+/- 30 per cent);
- lower and higher assumed safety risk costs (+/- 30 per cent); and
- a higher/lower discount rate.

The results of the sensitivity test are presented in the table below, showing that Option 1 has positive net market benefits, and greater net market benefits than Option 2, across all variables investigated.

Table 54 – Weighted outcomes of sensitivity tests, $m PV 2021/22

Sensitivity	Option 1	Option 2
Baseline	16.0	9.5
25 per cent higher capital cost	14.2	6.8
25 per cent lower capital cost	17.8	12.4
Unserved energy under POE10 conditions	21.9	15.1
Unserved energy under POE 90 conditions	10.7	4.4
VCR $73/kWh	21.0	14.3
VCR $39.3/kWh	8.2	2.0
Lower discount rate	19.1	12.9
Higher discount rate	10.1	3.4
Higher safety risk costs	16.0	9.5
Lower safety risk costs	15.9	9.4
Higher unplanned corrective maintenance	16.1	9.5
Lower unplanned corrective maintenance	15.9	9.4

6 Proposed preferred option

Ausgrid considers that Option 1 is the preferred option that satisfies the RIT-D. It involves the replacement of the existing 11 kV double bus switchgear at Tarro ZS with modern equivalent switchgear in a single bus arrangement.

The estimated capital cost of this option is $11.3 million and decommissioning costs of approximately $0.2 million.

Ausgrid assumes that the necessary construction to replace the existing switchgear would commence as soon as practicable after this RIT-T and end in June 2024. Once the new installation is complete, ongoing operating costs are expected to be approximately $23,000 per annum (around 0.2 per cent of capital expenditure).

Ausgrid considers that this FPAR, and the accompanying detailed analysis, identify Option 1 as the preferred option and that this satisfies the RIT-D. Ausgrid is the proponent for Option 1.

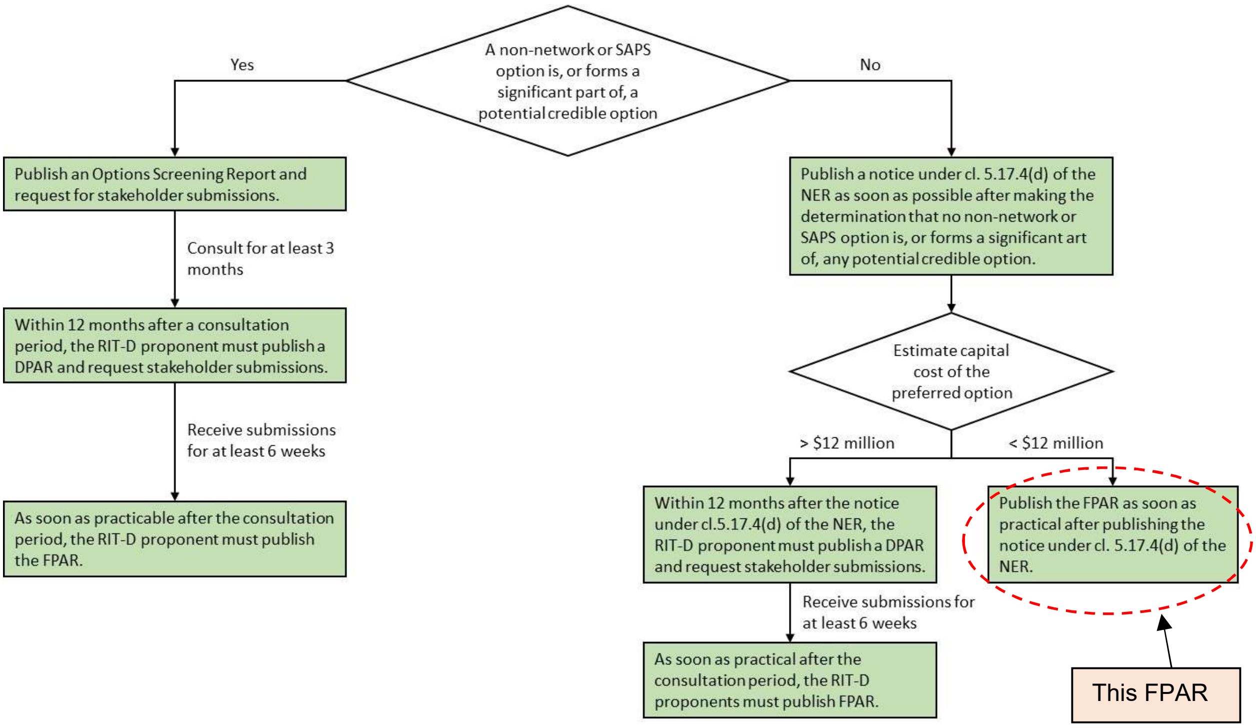
Appendix A – Checklist of compliance clauses

This section sets out a compliance checklist that demonstrates the compliance of this FPAR with the requirements of clause 5.17.4(r) of the National Electricity Rules version 186.

Clause	Summary of requirements	Section in the FPAR
5.17.4(r)	The matters specified as requirements for the draft project assessment report, as outlined below in clause 5.17.4(j).	See below
5.17.4(r)	A summary of any submissions received on the draft project assessment report and the RIT-D proponent's response to each such submission	NA
5.17.4(j)	(1) a description of the identified need for the investment	2
	(2) the assumptions used in identifying the identified need	2.3
	(3) if applicable, a summary of, and commentary on, the submissions on the non-network options report	NA
	(4) a description of each credible option assessed	3
	(5) where a DNSP has quantified market benefits, a quantification of each applicable market benefit for each credible option	5.1
	(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	5.2
	(7) a detailed description of the methodologies used in quantifying each class of cost and market benefit	4
	(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	Appendix C
	(9) The results of a net present value analysis of each of credible option and accompanying explanatory statements regarding the results	5
	(10) the identification of the proposed preferred option	6
	(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (iii) the indicative capital and operating cost (where relevant); (iv) a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	6
	(12) Contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	1.2

Appendix B – Process for implementing the RIT-D

For the purposes of applying the RIT-D, the NER establishes a three-stage process: (1) the Non-Network Options Report (or notice circumventing this step); (2) the DPAR; and (3) the FPAR. This process is summarised in the figure below.



Appendix C – Market benefit classes considered not relevent

The market benefits that Ausgrid considers will not materially affect the outcome of this RIT-D assessment include:

- changes in the timing of unrelated expenditure;
- changes in voluntary load curtailment;
- changes in costs to other parties;
- changes in load transfer capability and capacity of embedded generators to take up load;
- Option value; and
- changes in electrical energy losses.

The reasons why Ausgrid considers that each of these categories of market benefit is not expected to be material for this RIT-D are outlined in the table below.

Table C.1 – Market benefit categories under the RIT-D not expected to be material

Market benefits	Reason for excluding from this RIT-D
Timing of unrelated expenditure	Ausgrid does not expect the project will have any effect on unrelated expenditures in other parts of the network. Accordingly, Ausgrid considers the market benefit from changes in timing of unrelated expenditure is not material.
Changes in voluntary load curtailment	Ausgrid notes that the level of voluntary load curtailment currently present in the National Electricity Market (NEM) is limited. Where the implementation of a credible option affects pool price outcomes, and in particular results in pool prices reaching higher levels on some occasions than in the base case, this may have an impact on the extent of voluntary load curtailment. Ausgrid notes that none of the options are expected to affect the pool price and so there is not expected to be any changes in voluntary load curtailment.
Costs to other parties	This category of market benefit typically relates to impacts on generation investment from the options. Ausgrid notes that none of the options will affect the wholesale market and so we have not estimated this category of market benefit.
Changes in load transfer capacity and embedded generators	Load transfer capacity between substations is predominantly limited by the high voltage feeders that connect substations. Credible options under consideration do not affect high voltage feeders and therefore are unlikely to materially change load transfer capacity. Further, credible options are unlikely to enable embedded generators in Ausgrid's network to be able to take up load given the size and profile of the load serviced by network assets currently considered for replacement. Consequently, Ausgrid has not attempted to estimate any benefits from changes in load transfer capacity and embedded generators.
Option value	Option values arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered have sufficiently flexible to respond to that change. Ausgrid notes that the credible option assessed does not involve stages or any other flexibility and so we do not consider that option value is relevant.
Changes in electrical energy losses	Ausgrid does not expect that any of the credible options considered would lead to significant changes in network losses and so have not estimated this category of market benefits.

Appendix D – Additional detail on the assessment methodology and assumptions

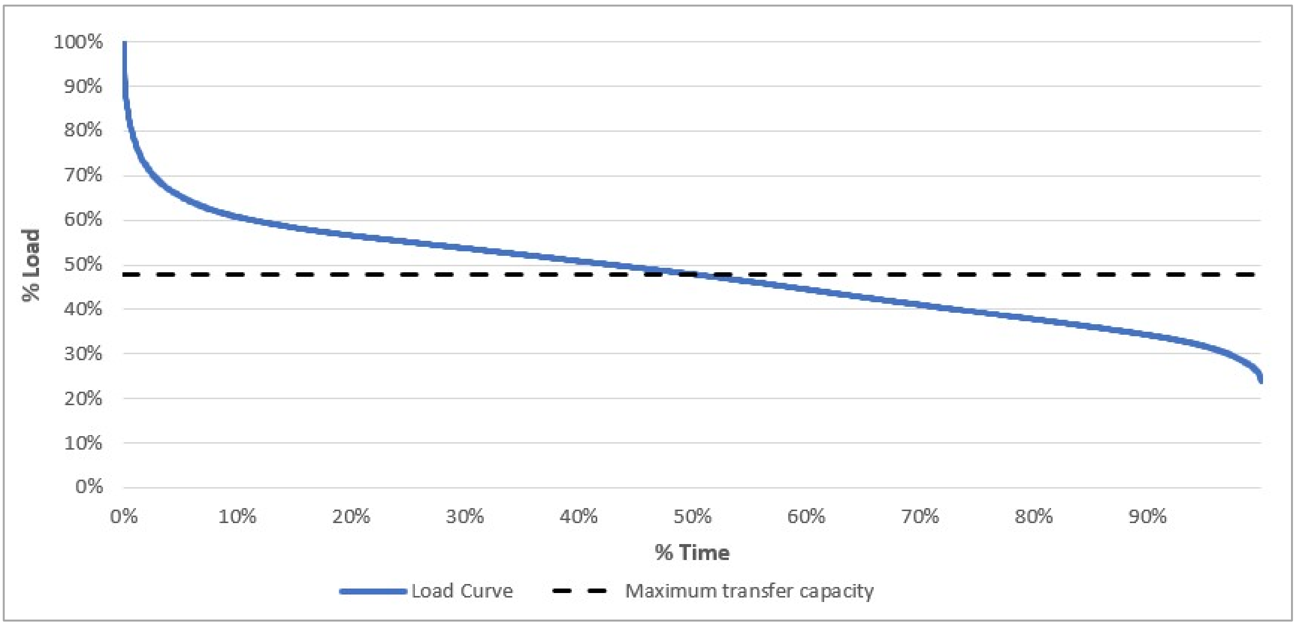
This appendix provides additional detail on key input assumptions that are used in the evaluation of the base case and the credible option.

D.1 Characteric load duration curves

The load duration curve for Tarro ZS is presented in Figure D.1-1 below.

It is assumed that the load types supplied by the substation will not change substantially into the future and therefore the load duration curve will maintain their characteristic shape regardless of the zone substation supplying the existing load at Tarro.

Figure D.1-1 – Load duration curve for Tarro Zone Substation



D.2 Load transfer capacity and supply restoration

Tarro zone substation load area is classified as urban and has potential 11 kV interconnection with Thornton, Maryland, Tomago and Mayfield West zone substations. In the event of a total loss of supply to Tarro zone substation, approximately 47.8 per cent of peak load can be recovered within days via the load transfer capacity of the existing network.

In the event of an equipment outage, the network may be returned to a normal configuration by one of the following actions:

- repairing the failed equipment
- initiating a contingency plan
- replacing the failed equipment with spares.

The assumed supply restoration actions and the time taken to implement the action are detailed in the table below. These actions are the most likely actions for the contingencies considered in this planning study.

Table D.1: Equipment outage assumptions

Equipment outage	Action	Outage duration (Days)
Transformer/Feeder Panel	Time between failure and access	1
	Time to undertake causal analysis	1
	Time to engineer solution (T&D Engineering)	1
	Time to manufacturer/repair engineered solution	6
	Time to implement engineered solution	6
	Ancillary Work - testing etc.	2
	Total - MAJOR FAILURE	**17**
	Total - MINOR FAILURE	**8.5**

D.3 Forecast availability of equipment

A range of models have been used to forecast the availability of equipment relevant to this RIT-D. These models utilise Ausgrid's historical outage records to determine the likelihood of failure. These models are combined with the estimates for repair or supply restoration time to determine the availability of equipment. The assumptions used to obtain the availability forecasts are provided in this section.

C.3.1 Availability of 11 kV switchboards

For the purposes of this analysis, failures of 11 kV switchboards are assumed to be non-repairable because typically the board is no longer functional following a failure (and hence is replaced or removed from service). Weibull analysis is used to derive a probability distribution function for the asset's age at time of failure. This function is denoted as f(t), where 't' is expressed in years. The parameters of the function are derived by considering the following information:

- the age of Ausgrid's in service 11 kV switchboards;
- the age of functional failure for Ausgrid's failed switchboards; and
- the age of retirement for Ausgrid's switchboards that were retired before the point of functional failure.

The model has been created to distinguish between 11 kV switchboards that are of differing condition. This assessment was performed using a group of Ausgrid subject matter experts based upon their specialist knowledge of the asset(s) and a review of the available conditional information (i.e. test results). This review assigned switchboards into three specific condition bands: 'Good', 'Average' and Poor'. The Tarro zone substation compound 11 kV switchboard are assigned a condition band of Average.

The resultant Weibull parameters are given in the table below.

Table D.2: Switchboard parameters for the Weibull analysis

Equipment	Condition	Shape	Scale
Compound insulated 11kV switchboard	Average	5.84	106.2

The concept of conditional probability is used to evaluate the probability of failure (Pf) for each year in the planning period. The probability a switchboard failure occurring each year, given that the board has survived to the current age (T) is calculated by applying the Equation 1:

$$P_f = \frac{\int_t^{t+1} f(t)dt}{\int_T^{\infty} f(t)dt} \qquad (1)$$

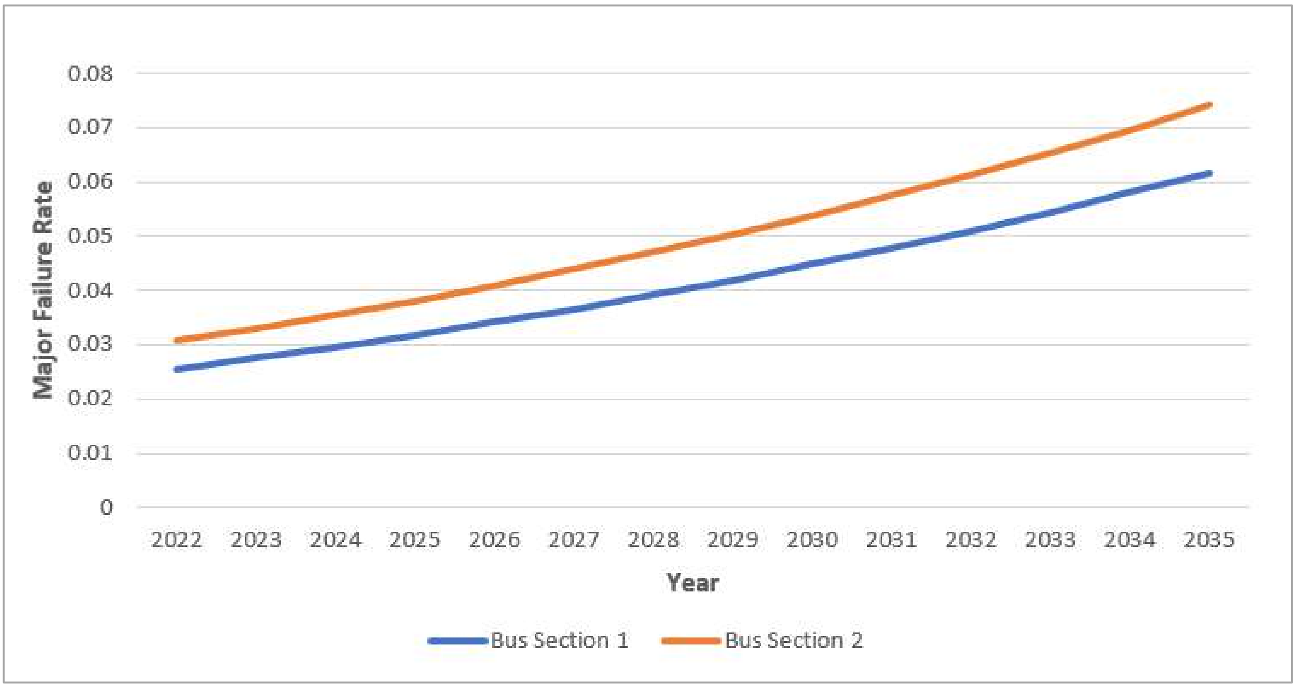
Unavailability is calculated by using a restore time, so the unavailability represents the percentage of time that a particular busbar is not available to supply load. The unavailability (U) of a switchboard is calculated for each year by applying Equation 2:

$$U = \frac{P_f\,.\,Outage\ Duration}{365} \qquad (2)$$

This model is based on the assumption that the condition of a switchboard is dependent upon its age. In order to explore the possibility that each board is in better or worse condition than the population average, lower and upper bounds for U are calculated by either adding or subtracting ten years from the age of each board.

Figure D.2 shows cumulative probability of failure for the 11 kV switchboards at Tarro ZS.

Figure D.2: Cumulative probability of failure – 11 kV switchboards



D.5 Direct costs of equipment failures

For the purposes of evaluating safety impacts, it is assumed that equipment outages have direct costs as per the table below. All costs are in 2019/20 real dollars and have been escalated to 2021/22 real dollars for the purposes of this RIT-D.

For switchboard failures, these costs are based on the estimated cost of implementing the contingency plans described above. This cost includes 11 kV feeder connections, protection and earthing designs, delivery costs and labour rates.

Transformer replacement costs are based on planning estimates for capital replacements. 33 kV reactor, 132 kV circuit switch and 132 kV gas-insulated switchgear replacement costs are based on high level estimates.

Table D.3: Direct costs of equipment outages

Equipment outage		Direct cost ($)
Transformer/Feeder Panel	Time between failure and access	2,320
	Time to undertake causal analysis	8,000
	Time to engineer solution (T&D Engineering)	8,640
	Time to manufacturer/repair engineered solution	16,800
	Time to implement engineered solution	71,040
	Ancillary Work - testing etc.	70,000
	Return to Service (RTS)	5,120
	Total - MAJOR FAILURE	**181,920**
	Total - MINOR FAILURE	**90,960**

D.5 Calculation of central VCR estimate for Tarro ZS

Table D.3: Breakdown of the central VCR estimate for the Tarro ZS

	Unit	Residential	Small non-residential	Large non-residential (LV)	Large non-residential (HV)
Annual consumption	MWh	22,906	7,142	12,107	42,271
Per cent of annual consumption	%	27.1%	8.5%	14.3%	50.1%
2021 AER VCR estimate	$/kWh	$30.37	$70.84	$41.41	66.16
2021/22 AER VCR estimate using CPI	$/kWh	$31.99	$74.63	$43.62	$69.70
2022 load-weighted VCR for Tarro	$/kWh	$56.15			

The underpinning assumptions for the calculation of the VCR for Tarro ZS are:

- For residential loads, the VCR is determined by using the postcode of the area (i.e. Tarro, NSW, 2322), which is located under Climate Zone 5 CBD & Suburban NSW, as determined by the AER[11] and adjusted by CPI.
- Small non-residential loads are considered to be small businesses, for which the VCR determined by the AER[12] for commercial small-medium businesses is applied, adjusted by CPI.
- Large non-residential loads (LV) are considered to be commercial businesses, for which the VCR determined by the AER[12] for large commercial businesses is applied, adjusted by CPI.
- Large non-residential loads (HV) are predominantly industrial loads. For this reason, the VCR determined by the AER[12] for average industrial loads is applied, adjusted by CPI.

[11] See AER, Annual update – VCR review final decision – Appendix F – Residential VCR by postcode, December 2021.

[12] See AER, Annual update – VCR review final decision – Appendices A-E – Final decision – Adjusted values, December 2021.

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