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Maintaining safe and reliable operation of Buronga substation

RIT-T Project Specification Consultation Report

Issue date: 15 August 2024

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Executive summary

Buronga substation is a fundamental part of the 220 kV NSW Transmission Network and Victorian Interconnector, and is being expanded as part of Project EnergyConnect, a new high voltage interconnector between New South Wales and South Australia.

Buronga substation connects several renewable energy sources to the National Electricity Market (NEM) and has been declared part of the access rights network for the South West REZ Access Scheme by the NSW Government.

It is anticipated that the site will remain a crucial energy hub in the transmission network into the foreseeable future.

The purpose of this PSCR is to examine and consult on options to address the deteriorating condition of the identified end of life assets at Buronga substation to ensure the safe and secure operation of our network.

Identified need: Ensure the safe and reliable operation of our transmission network by managing the risk of end of life assets

The identified need for this project is to ensure the safe and reliable operation of our transmission network by addressing the risk of failure of assets that are approaching the end of their technical life.

The X2 transmission line (from Buronga to Broken Hill) is a radial feed to Broken Hill substation so maintaining a reliable supply to the area when Line X2 is out of service requires significant planning and coordination with Broken Hill loads in addition to running the gas turbine generators to supply the Broken Hill 22 kV load.

During asset replacement planning of Buronga X2 feeder circuit breaker (CB), it was identified that the condition of the bus disconnector, line disconnector and bypass disconnector prevent outage access for the CB replacement. Due to the disconnector functional failure a X2 transmission line, outage is required to access the CB.

Based on findings from our assessment, all 10 220 kV ASEA disconnectors at Buronga substation are in similar condition, being at risk of operational challenges or functional failure. Currently an X2 transmission line outage is required maintenance, defect or replacement works access to disconnectors and associated CBs attached to Buronga 220 kV B2 Bus Section. We have also identified 1 Live Head Circuit Breaker (LHCB) that have reached or be approaching the end of their technical life by 2027/28. A full list of assets in scope are in Appendix C below.

We have classified this RIT-T as a 'market benefits' driven RIT-T as the economic assessment is not being progressed specifically to meet a mandated reliability standard but by the net benefits that are expected to be generated for end-customers. Given the quantity of CBs that have been identified for replacement, we consider it prudent and cost effective to manage this risk through a single asset replacement program. This replacement will help limit the amount of in-service failures that occur (along with the associated interruptions to customer load, and safety and environmental consequences).

Credible options considered

We consider that there are three credible network options that can meet the identified need.

These options are summarised in Table E-1.

Table E-1: Summary of the credible options

Option	Description	Capital costs ($m +/- 25%, $2024/25)
Option 1	In-situ like-for-like replacements through Asset Renewal Strategies[1]	6.86 (±25%)
Option 2	Like-for-like replacement in alternate bay location	5.92(±25%)
Option 3	Replacement with double bus selectable feeder bays	8.44 (±25%)

Non-network options are not expected to be able to assist in this RIT-T

We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need for this RIT-T. Non-network options are not able to mitigate the increasing risks of failure of ageing assets.

Draft Conclusion

This PSCR finds that implementation of Option 3 is the preferred option at this draft stage of the RIT-T process. This option includes the re-construction of the current X2 feeder bay and the 0X1 feeder bay, providing X2 feeder supply availability from both A and B bus.

The capital cost of this option is approximately $8.44 million (in $2024/25). The works are expected to be undertaken between 2023/24 and 2025/26. Planning, design, development and procurement (including completion of the RIT-T) will occur between 2023/24 and 2024/25, while project delivery and construction will occur in 2024/25. All works are expected to be completed by 2025/26. Routine operating and maintenance costs are estimated at approximately $64,858 per annum (in $2024/25).[2] All works will be completed in accordance with the relevant standards and components shall be replaced to have minimal modification to the wider transmission network. Necessary outages of relevant assets in service will be planned appropriately to complete the works with minimal network impact.

Exemption from preparing a Project Assessment Draft Report

Subject to the identification of additional credible options during the consultation period, publication of a Project Assessment Draft Report (PADR) is not required for this RIT-T as we consider that the conditions in clause 5.16.4(z1) of the NER exempting RIT-T proponents from providing a PADR have been met.

Specifically, production of a PADR is not required because:

- the estimated capital cost of the proposed preferred option being less than $46 million[3];

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1 Renewal and maintenance strategies for transmission line assets are defined in Transgrid's Renewal and Maintenance Strategy 2021/22.

2 Average operating costs over the period 2024/25 to 2051/52.

3 Varied from $43m to $46m based on the AER Final Determination: Cost threshold review November 2021.

- the PSCR states:
  - > the proposed preferred option, together with the reasons for the proposed preferred option;
  - > the RIT-T is exempt from producing a PADR; and
  - > the proposed preferred option and any other credible option will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding;
- the RIT-T proponent considers that there were no PSCR submissions identifying additional credible options that could deliver a material market benefit; and
- the PACR must address any issues raised in relation to the proposed preferred option during the PSCR consultation.

If an additional credible option that could deliver a material market benefit is identified during the consultation period, then we will produce a PADR that includes an assessment of the net economic benefit of each additional credible option.

If no additional credible options with material market benefits are identified during the consultation period, then the next step in this RIT-T will be the publication of a Project Assessment Conclusions Report (PACR) that addresses all submissions received, including any issues in relation to the proposed preferred option raised during the consultation period.[4]

Submissions and next steps

We welcome written submissions on materials contained in this PSCR.

Submissions are due on 14 November 2024[5] and should be emailed to our Regulation team via regulatory.consultation@Transgrid.com.au.[6] In the subject field, please reference 'Buronga substation PSCR.' At the conclusion of the consultation process, all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

Should we consider that no additional credible options were identified during the consultation period, we intend to produce a PACR that addresses all submissions received including any issues in relation to the proposed preferred option raised during the consultation period. Subject to additional credible options being identified, we anticipate publication of a PACR by January 2025.

4 In accordance with NER clause 5.16.4(z2).
5 Consultation period is for 12 weeks, additional days have been added to cover public holidays
6 Transgrid is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, Transgrid will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.

Contents

1. Introduction

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for ensuring the safe and reliable operation of our transmission network by addressing the risk of failure of assets that will have reached or be approaching the end of their technical life. Publication of this Project Specification Consultation Report (PSCR) is the first step in the RIT-T process.

The purpose of this PSCR is to examine and consult on options to address the deterioration in condition of the identified assets to ensure the safe and secure operation of our network.

1.1 Purpose of this report

The purpose of this PSCR[7] is to:

- set out the reasons why we propose that action be taken (the 'identified need')
- present the options that we currently consider to address the identified need
- outline the technical characteristics that non-network options would need to provide[8]
- summarise how we have assessed the options for addressing the identified need
- present the cost benefit assessment of all options for meeting the identified need
- identify the preferred option under the RIT-T assessment, and
- allow interested parties to make submissions and provide input to the RIT-T assessment.

1.2 Exemption from producing a Project Assessment Draft Report

Subject to the identification of additional credible options during the consultation period, publication of a Project Assessment Draft Report (PADR) is not required for this RIT-T as we consider that the conditions in clause 5.16.4(z1) of the NER exempting RIT-T proponents from providing a PADR have been met.

Specifically, production of a PADR is not required because:

- the estimated capital cost of the proposed preferred option being less than $46 million[9];
- the PSCR states:
  > the proposed preferred option, together with the reasons for the proposed preferred option;
  > the RIT-T is exempt from producing a PADR; and
  > the proposed preferred option and any other credible option will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding;
- the RIT-T proponent considers that there were no PSCR submissions identifying additional credible options that could deliver a material market benefit; and
- the PACR must address any issues raised in relation to the proposed preferred option during the PSCR consultation.

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7 See Appendix A for the National Electricity Rules requirements.
8 Although we note that non-network options are considered unlikely to be able to contribute to meeting the identified need for this RIT-T.
9 Varied from $43m to $46m based on the AER Final Determination: Cost threshold review November 2021.

If an additional credible option that could deliver a material market benefit is identified during the consultation period, then we will produce a PADR that includes an NPV assessment of the net economic benefit of each additional credible option.

If no additional credible options with material market benefits are identified during the consultation period, then the next step in this RIT-T will be the publication of a PACR that addresses all submissions received, including any issues in relation to the proposed preferred option raised during the consultation period.[10]

1.3 Submissions and next steps

We welcome written submissions on materials contained in this PSCR.

Submissions are due on 14 November 2024[11] and should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[12] In the subject field, please reference 'Buronga substation PSCR.' At the conclusion of the consultation process, all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

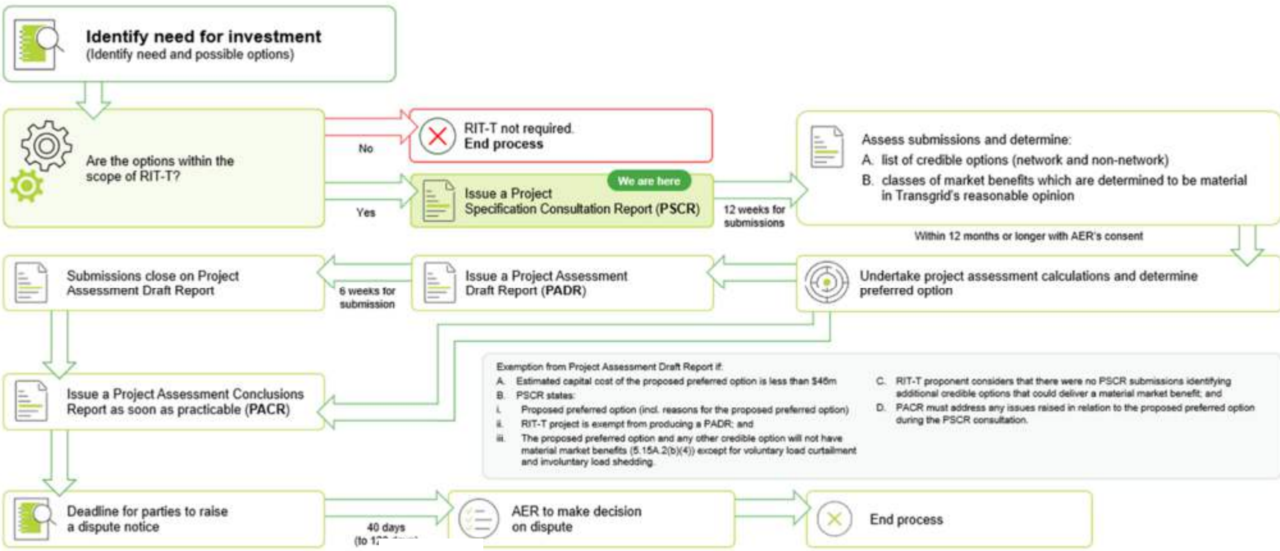
Should we consider that no additional credible options were identified during the consultation period, we intend to produce a PACR that addresses all submissions received including any issues in relation to the proposed preferred option raised during the consultation period. Subject to additional credible options being identified, we anticipate publication of a PACR by January 2025.

10 In accordance with NER clause 5.16.4(z2).

11 Consultation period is for 12 weeks, additional days have been added to cover public holidays

12 Transgrid is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, Transgrid will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.

Figure 1-1 This PSCR is the first stage of the RIT-T process



2. The identified need

2.1 Background to the identified need

Buronga substation is an integral part of the 220 kV NSW Transmission Network and Victorian Interconnector and connects several renewable energy sources to the National Electricity Market (NEM). Buronga also supplies Broken Hill by a single 220 kV transmission line, Line X2, that is around 260 km long. The site comprises of three 220 kV transmission line feeders, two 220 kV reactors and two 11 kV connected synchronous condensers. The site was established in 1988 and assets have install dates between 1988 and 2019. The site will remain a crucial part of the transmission network into the foreseeable future, and is being expanded as a part of Project EnergyConnect, a new high voltage interconnector between New South Wales and South Australia

A map showing the location of Buronga substation in our Southwestern NSW network is shown in Figure 2-1.

Figure 2-1 Location of Buronga substation

2.2 Description of the identified need

The identified need for this project is to ensure the safe and reliable operation of our transmission network by addressing the risk of failure of switchgear that are approaching the end of their technical life.

During asset replacement planning of Buronga X2 feeder circuit breaker (CB) under N2345, it was identified that the condition of the bus disconnector, line disconnector and bypass disconnector prevent outage access for the CB replacement. Due to the disconnector functional failure a X2 transmission line outage is required to access the CB.

Disconnectors are required for the isolation of network elements to perform required routine and corrective maintenance. Ageing, along with a corrosive atmosphere, has resulted in disconnectors often failing or having difficulty in performing their required function of opening and closing. The failure of a disconnector is expected to result in additional equipment outages to isolate the failed disconnector for repair. In case of bus disconnectors this additional outage is significant due to the isolation of all other services from the affective bus bar. The potential outages are expected to disrupt customer and distributor supplies and increase corrective maintenance costs.

We have confirmed that all 10 220 kV ASEA disconnectors at Buronga substation are in similar condition, being either very difficult and unreliable to operation or unable to operate (functionally failed). Currently an X2 transmission line outage is required for maintenance, defect or replacement works, including access to disconnectors and associated CBs attached to Buronga 220 kV B2 Bus Section.

The majority of the 220 kV switchgear at Buronga substation will reach or have exceeded their nominal asset life by the end of RP3 and represent a high failure risk. Many of these assets cause or require an X2 outage in the event of a functional failure.

We have also identified CBs that will have reached or be approaching the end of their technical life by 2027/28. A full list of assets in scope is available in Appendix C below.

The X2 transmission line (from Buronga to Broken Hill) is a radial feed to Broken Hill substation so maintaining a reliable supply to Broken Hill when Line X2 is out of service requires significant planning and coordination with Broken Hill loads[13] in addition to running the 22 kV gas turbine generators to supply the Broken Hill 22 kV load. Transgrid's diesel-fired gas turbines currently provide the backup supply for the Broken Hill area, ensuring compliance with our reliability obligations. However, Transgrid has identified a proposed advanced compressed air energy storage (A-CAES) system as the long-term solution.[14]

Work scope being completed at the site and in conjunction with Project Energy Connect will also result in some equipment being decommissioned or functionally redundant.

We have classified this RIT-T as a 'market benefits' driven RIT-T as the economic assessment is not being progressed specifically to meet a mandated reliability standard but by the net benefits that are expected to be generated for end-customers.

However, the options considered in this PSCR will also ensure compliance with a range of obligations under the NER and jurisdictional instruments (which is not expected under the base case).

[13] The maximum load for Broken Hill substation is forecasted to be approximately 42 MW in 2028 and is currently a mix of residential and commercial

[14] Transgrid, *Maintaining reliable supply to Broken Hill, RIT-T Project Assessment Conclusions Report,* May 2022, pp. 54

Given the volume of assets that have been identified for replacement, we consider it prudent and cost effective to manage this risk through a single asset replacement program. This replacement will help limit the number of in-service failures that occur (along with the associated interruptions to customer load, and safety and environmental consequences).

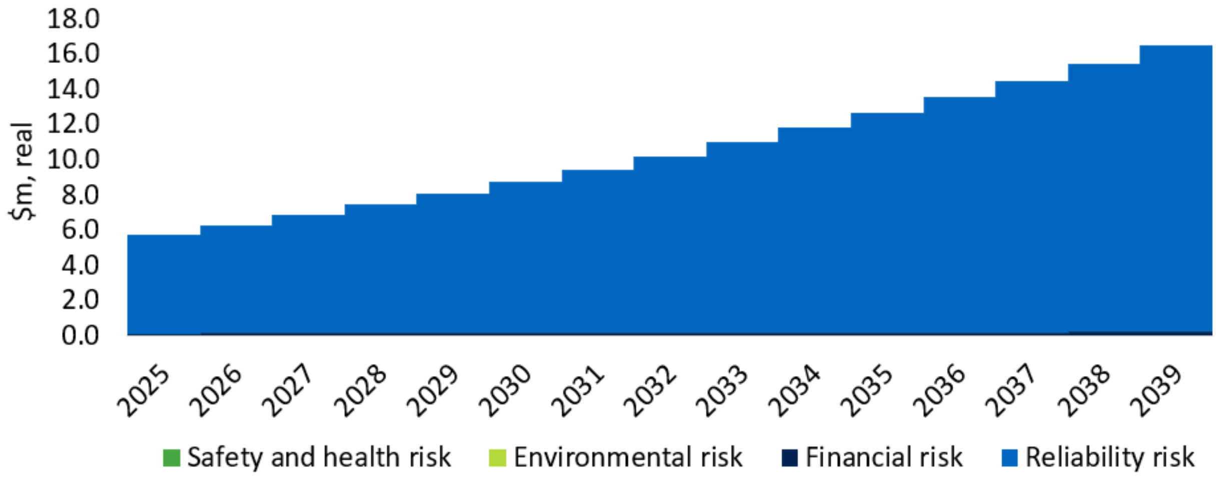
2.3 Assumptions underpinning the identified need

We adopt a risk cost framework to quantify and evaluate the risks and consequences of increased failure rates. Appendix B provides an overview of our Risk Assessment Methodology.

We note that the risk cost estimating methodology aligns with that used in our recently submitted Revised Revenue Proposal for the 2023-28 period. It reflects feedback from the Australian Energy Regulator (AER) on the methodology initially proposed in our initial Revenue Proposal.

Figure 2-2 summarises the increasing risk costs over the assessment period under the base case and our central scenario of asset failure risk.

Figure 2-2 Estimated risk costs under the base case (central scenario)



This section describes the assumptions underpinning our assessment of the risk costs, i.e., the value of the risk avoided by undertaking each of the credible options. The aggregate risk cost under the base case is currently estimated at around $5.75 million in 2024/25, and it is expected to increase going forward if action is not taken (reaching approximately $9.44 million by 2030/31 and $22.16 million by the end of the 20-year assessment period).

2.3.1 Assessment of asset health

2.3.1.1 Circuit breakers

The failure of a CB to operate during a network fault will result in an uncleared fault that must be cleared with a larger outage (via a CB failure back up protection operation), leading to greater unserved energy. The impact of each CB failure on lost load varies according to where it is located in the network. Asset failure may also increase the risk of safety and environment issues associated with catastrophic asset failure, and the potential costs of emergency repair and replacements.

We note that CBs at the Buronga substation have previously been considered under our 'Managing the risk of circuit breaker failure' RIT-T process as part of a network wide CB replacement program. We have therefore not considered the impact of a failure of the CBs at the Buronga substation in this PSCR. This avoids any potential double counting of the benefits related to the replacement of the CBs. The full list of CBs considered in this RIT-T are in Appendix C below.

2.3.1.2 Disconnectors

High voltage disconnectors and associated earth switches (referred to as 'disconnectors') play an important role in providing visible isolation as well as to earth a section of high voltage network for switching and isolation purposes. Disconnectors are required to facilitate maintenance of other HV equipment by isolating (without causing outages) different elements of the substation such as transformers and CBs.

We have identified disconnectors at Buronga substation experiencing condition deterioration with limited spare equipment available in the event of a failure in Appendix C below.

The identified disconnectors will be 52 years old by the year 2027/28. This is greater than their expected economic life, which is 40 years. Refurbishment of disconnectors is unlikely to provide more than 10 years of life extension, and so is not a viable option for disconnectors that have an asset life in excess of 50 years. Based on the age of the assets, and ongoing exposure to corrosive atmospheric elements, the identified disconnectors have a high risk of failure which will significantly increase as the assets continue to age. Technological obsolescence means that access to spares and manufacturer support is limited. When spare components are not available, a new disconnector will have to be retro fitted to the old position incurring significantly increased costs and longer outages.

The failure of these disconnectors are expected to result in additional equipment outages to isolate the failed disconnector for repair. In the case of bus disconnectors (like the ones identified in this RIT-T), this results in additional significant outages due to isolation of all other services from the affected bus bar. The associated outages are expected to disrupt customer and distributor electricity supply and increase corrective maintenance for repairs of the disconnector. On the basis of this assessment, we consider that proactively replacing the identified disconnectors would be expected to result in economic benefits for consumers associated with a reduction in expected unserved energy, and avoided operating expenditure related to corrective maintenance.

2.3.2 Reliability risk

We have considered the risk of unserved energy for customers following a failure of the assets identified in this PSCR. The likelihood of a consequence considers the likelihood of contingent planned/unplanned outages, the anticipated load restoration time (based on the expected time to undertake repair), and the load at risk (based on forecast demand). The monetary value is based on an assessment of the value of lost load, which measures the economic impact to affected customers of a disruption to their electricity supply.

Reliability risk makes up 98.4 per cent of the total estimated risk cost in present value terms. As the assets continue to age the probability of one or more failing increases. This increased probability of failure combined with a long load restoration time and large industrial loads, means that there is likely to be significant amounts of unserved energy over the assessment period without replacement of the assets.

Hence, the impact of an asset failure is mostly comprised of loss of service arising from higher reliability risk.

2.3.3 Financial risk

This refers to the financial consequence of an asset failure. The likelihood of a consequence considers any compliance and regulatory factors which are not covered by the other categories. The monetary value takes into account the associated cost with disruption to business operations, third party liabilities, and the cost of replacement or repair of the asset, including any temporary measures.

Financial risk makes up 1.5 per cent of the total estimated risk cost in present value terms.

2.3.4 Safety risk

This refers to the safety consequence to staff, contractors and/or members of the public of an asset failure. The likelihood of a consequence considers the frequency of workers on-site, duration of maintenance and capital work on-site, and the probability and area of effect of an explosive asset failure. The monetary value considers the cost associated with fatality or injury compensation, loss of productivity, litigation fees, fines and any other related costs.

We manage and mitigate safety risk to ensure they are below risk tolerance levels or ‘As Low As Reasonably Practicable’ (‘ALARP’), in accordance with our obligations under the New South Wales Electricity Supply (Safety and Network Management) Regulation 2014 and our Electricity Network Safety Management System (ENSMS). Consistent with our ALARP obligations, we apply a disproportionality factor of ‘six’ to the public safety component and ‘three’ to the worker safety component of safety risk.

Safety risk makes up less than 1 per cent of the total estimated risk cost in present value terms.

2.3.5 Environmental risk

This refers to the environmental consequence (including bushfire risk) to the surrounding community, ecology, flora and fauna of an asset failure. The likelihood of a consequence considers the location of the site and sensitivity of surrounding areas, the volume and type of contaminant, the effectiveness of control mechanisms, and the likelihood and impact of bushfire. The monetary value considers the cost associated with damage to the environment including compensation, clean-up costs, litigation fees, fines and any other related costs.

Environmental risk makes up less than 1 per cent of the total estimated risk cost in present value terms.

3. Options that meet the identified need

This section describes the option(s) that we have explored to address the identified need, including the scope of each option and the associated costs.

We consider that there are three credible network options that can meet the identified need. These options are summarised in Table 0-1. We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need for this RIT-T.

Table 0-1: Summary of the credible options

Option	Description	Direct capital cost ($2024/25 m)
Option 1	In-situ like-for-like replacements through Asset Renewal Strategies	6.86
Option 2	Like-for-like replacement in alternate bay location	5.92
Option 3	Replacement with double bus selectable feeder bays	8.44

3.1 Base case

Consistent with the RIT-T requirements, the assessment undertaken in this PSCR compares the costs and benefits of each credible option to a 'do nothing' base case. The base case is the (hypothetical) projected case if no action is taken, i.e:[15]

> "*The base case is where the RIT-T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. 'BAU activities' are ongoing, economically prudent activities that occur in absence of a credible option being implemented*"

Under the base case, there is no consideration for replacement of the assets evaluated under this need. This is a 'run to fail' scenario and will lead to an increase in the identified risks under this need, the eventual failure of the assets and the materialisation of the expected consequences. This case shall only be considered a last resort should no option be deemed viable through the economic evaluation process.

Increased operating and maintenance costs are included as an opex cost against the assets under this scenario. The increased cost is modelled based on historical breakdown (corrective) repair costs and represents an operating cost benefit when mitigated through an asset replacement. The annual routine operating and maintenance cost under base case is forecast at approximately $25,000 per annum ($FY 2023/24).

The aggregate risk cost under the base case is currently estimated at around $5.75 million in 2024/25, and it is expected to increase going forward if action is not taken (reaching approximately $9.44 million by 2030/31 and $22.16 million by the end of the 20-year assessment period).

While this is not a situation we plan to encounter, and this RIT-T has been initiated specifically to avoid it, the assessment is required to use this base case as a common point of reference when estimating the net benefits of each credible option.

[15] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, p. 22.

3.2 Option 1 – In-situ like-for-like replacements through Asset Renewal Strategies

Under Option 1, all assets identified in this RIT-T that will reach the end of their technical life by 2027/28, will be replaced through Asset Renewal Strategies[16]. This option is based on a like-for-like approach, whereby the existing bay design and location are retained while the assets are replaced by their modern equivalent.

The works are expected to be undertaken between 2023/24 and 2025/26. Planning, design, development and procurement (including completion of the RIT-T) will occur between 2023/24 and 2024/25, while project delivery and construction will occur in 2024/25. All works are expected to be completed by 2025/26.

The capital cost of this option is approximately $6.86 million (in $2024/25). In addition, routine operating and maintenance costs are estimated at approximately $32,160 per annum (in $2024/25).[17] The table below provides a breakdown of the estimated capital and operating cost. We expect that the CBs and disconnectors will have an asset life of 40 years.

Table 0-2 Option 1 Capital and Operating Cost ($2024/25)

Year	Capital Cost	Operating Cost
2024/25	$6,857,461	$0.00
2025/26	-	$25,186.75
2026/27	-	$25,731.98
2027/28	-	$26,414.63
2028/29	-	$27,060.99
2029/30	-	$27,679.37
2030/31	-	$28,274.61
2031/32	-	$28,850.00
2032/33	-	$29,407.94
2033/34	-	$29,950.27
2034/35	-	$30,478.48
2035/36	-	$30,993.79
2036/37	-	$31,497.21
2037/38	-	$31,989.61
2038/39	-	$32,471.75
2039/40	-	$32,944.27
2040/41	-	$33,407.76
2041/42	-	$33,862.74
2042/43	-	$34,309.65
2043/44	-	$34,748.92

[16] Renewal and maintenance strategies for transmission line assets are defined in Transgrid's Renewal and Maintenance Strategy 2021/22.

[17] Average operating costs over the period 2024/25 to 2051/52.

Total	$6,857,461	$575,260.73

All works will be completed in accordance with the relevant standards and components shall be replaced to have minimal modification to the wider transmission network. Necessary outages of relevant assets in service will be planned appropriately to complete the works with minimal network impact.

Following the implementation of Option 1, the costs associated with reliability, safety, environmental and financial risks are significantly reduced. A reduction in the rate of failure will reduce expected unserved energy and the costs of emergency repair and replacements. A reduction in the risk of explosive failure will reduce the risk of injury to nearby people and infrastructure.

Transgrid has estimated that total risk cost reductions from the base case under a central scenario for Option 1 will be approximately $109,066, after all identified CBs and disconnectors have been replaced (in $2024/25).

3.3 Option 2 – Like-for-like replacement in alternate bay location

This option considers the replacement of all end-of-life assets on a functionally like-for-like basis, utilising the redundant bay location of the ex 0X1 feeder bay for construction staging of X2. Under this option the X2 feeder bay is relocated to the A Bus.

The works are expected to be undertaken between 2023/24 and 2025/26. Planning, design, development and procurement (including completion of the RIT-T) will occur between 2023/24 and 2024/25, while project delivery and construction will occur in 2024/25. All works are expected to be completed by 2025/26.

The capital cost of this option is approximately $5.92 million (in $2024/25). Routine operating and maintenance costs are estimated to be the same as Option 1 at approximately $32,160 per annum (in $2024/25).[18] The table below provides a breakdown of the estimated capital and operating cost.

Table 0-3 Option 2 Capital and Operating Cost ($2024/25)

Year	Capital Cost	Operating Cost
2024/25	$5,917,688	$0.00
2025/26	-	$25,186.75
2026/27	-	$25,731.98
2027/28	-	$26,414.63
2028/29	-	$27,060.99
2029/30	-	$27,679.37
2030/31	-	$28,274.61
2031/32	-	$28,850.00
2032/33	-	$29,407.94
2033/34	-	$29,950.27
2034/35	-	$30,478.48
2035/36	-	$30,993.79

18 Average operating costs over the period 2028/29 to 2049/50.

2036/37	-	$31,497.21
2037/38	-	$31,989.61
2038/39	-	$32,471.75
2039/40	-	$32,944.27
2040/41	-	$33,407.76
2041/42	-	$33,862.74
2042/43	-	$34,309.65
2043/44	-	$34,748.92
Total	$5,917,668	$575,260.73

All works will be completed in accordance with the relevant standards and components shall be replaced to have minimal modification to the wider transmission network. Necessary outages of relevant assets in service will be planned appropriately to complete the works with minimal network impact.

Transgrid has estimated that total risk cost reductions from the base case under a central scenario for Option 2 will be approximately $109,091, after all identified CBs and disconnectors have been replaced (in $2024/25).

3.4 Option 3 – Replacement with double bus selectable feeder bays

This option considers the re-construction of the current X2 feeder bay and the 0X1 feeder bay, providing X2 feeder supply availability from both A and B bus. Concept scoping drawings that provide an overview of work scope are in Appendix D below.

The works are expected to be undertaken between 2023/24 and 2025/26. Planning, design, development and procurement (including completion of the RIT-T) will occur between 2023/24 and 2024/25, while project delivery and construction will occur in 2024/25. All works are expected to be completed by 2025/26.

The capital cost of this option is approximately $8.44 million (in $2024/25). The difference with Option 3 is primarily due to the decommissioning of the redundant X2 bay equipment, and construction of overhead conductors allowing connection of X2 transmission line to the newly constructed bay. Routine operating and maintenance costs are estimated at approximately $64,858 per annum (in $2024/25).[19] The increase in operating costs compared to Option 1 and 2 can be attributed to the provision of more equipment under this option. The table below provides a breakdown of the estimated capital and operating cost.

Table 0-4 Option 3 Capital and Operating Cost ($2024/25)

Year	Capital Cost	Operating Cost
2024/25	$8,439,201	$0.00
2025/26	-	$61,607.20
2026/27	-	$62,061.17
2027/28	-	$62,705.00
2028/29	-	$63,299.70
2029/30	-	$63,855.78

[19] Average operating costs over the period 2024/25 to 2051/52.

2030/31	-	$64,379.41
2031/32	-	$64,874.74
2032/33	-	$65,344.85
2033/34	-	$65,792.11
2034/35	-	$66,218.43
2035/36	-	$66,625.35
2036/37	-	$67,014.22
2037/38	-	$67,386.14
2038/39	-	$67,742.11
2039/40	-	$68,082.97
2041/42	-	$68,409.48
2042/43	-	$68,722.31
2043/44	-	$69,022.08
2043/44	-	$69,309.33
Total	$4,974,455	$1,252,452.39

All works will be completed in accordance with the relevant standards and components shall be replaced to have minimal modification to the wider transmission network. Necessary outages of relevant assets in service will be planned appropriately to complete the works with minimal network impact.

Following the implementation of Option 3, the costs associated with reliability, safety, environmental and financial risks are significantly reduced. A reduction in the rate of failure of the relevant CBs and removal of failure risk for relevant associated current transformers will reduce expected unserved energy and the costs of emergency repair and replacements. A reduction in the risk of explosive failure will reduce the risk of injury to nearby people and infrastructure.

Transgrid has estimated that total risk cost reductions from the base case under a central scenario for Option 3 will be approximately $118,934, after all identified CBs and disconnectors have been replaced (in $2024/25).

3.5 Options considered but not progressed

We have also considered whether other options could meet the identified need. Reasons these options were not progressed are summarised in Table 0-5.

Table 0-5: Options considered but not progressed

Option	Reason(s) for not progressing
Refurbishment and overhaul	Circuit Breakers: The refurbishment/overhaul scope of work involves renewing all deteriorating components of a CB that is typically >30 years old. In Transgrid's experience, the cost of such overhauls is a substantial portion of replacement works considered under other options while presenting the following additional risks: • Outdated and suboptimal component design may be retained in the overhaul. • Parts and technician support is expected to be limited or unavailable. • Continuous current and fault level ratings may not be suitable. • Local overhaul is expected to result in higher defect and failure rates to factory manufacturing processes. • With consideration the potential for life extension is expected to be no more than10 years. Disconnectors: The refurbishment option for the ASEA model disconnectors has also been investigated and eliminated for the following reasons: • Feedback from field staff indicates that the design of the disconnectors is inherently poor and unreliable. • Corrective maintenance activities have been ineffective in providing a lasting improvement to disconnector operation. • Manufacturer parts support is no longer available. The option has not been progressed as it is considered not economically feasible.
Increased maintenance or inspections	The condition issues have already been identified and cannot be rectified through increased maintenance or inspections, and therefore is not technically feasible to address the need.
Elimination of all associated risk	This can only be achieved by retiring the assets, which is not technically feasible due to the requirement to maintain the existing network reliability.
Non-network solutions	It is not technically feasible for non-network solutions to provide the functionality of the equipment under this need. Non-network options are not able to mitigate the increasing risks of failure of ageing assets.

3.6 No material inter-network impact is expected

We have considered whether the credible options listed above is expected to have material inter-regional impact[20]. A 'material inter-network impact' is defined in the NER as:

> "*A material impact on another Transmission Network Service Provider's network, which impact may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network.*"

[20] As per clause 5.16.4(b)(6)(ii) of the NER.

By reference to AEMO's screening test for an inter-network impact,[21] a material inter-regional impact may arise if a credible option:

- is expected to change power transfer capability between transmission networks or in another TNSP's network by more than the minimum of 3 per cent of the maximum transfer capability and 50 MW
- is expected to result in an increase in fault level by more than 10 MVA at any substation in another TNSP's network; or
- involves either a series capacitor or modification in the vicinity of an existing series capacitor.

As none of these criteria are satisfied for this RIT-T, we consider that there are no material inter-network impacts associated with any of the credible options considered.

[21] Inter-Regional Planning Committee. "*Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentations*." Melbourne: Australian Energy Market Operator, 2004. Appendix 2 and 3. Accessed 23 June 2021. https://aemo.com.au/-/media/files/electricity/nem/network_connections/transmission-and-distribution/170-0035-pdf.pdf

4. Technical characteristics for non-network options

We do not consider non-network options to be commercial or technically feasible to assist with meeting the identified need for this RIT-T. The objective of this identified need is to avoid the increasing risks of failure of ageing assets.

For non-network options to assist, they would need to provide greater net economic benefits than the network options. That is, non-network options would need to reduce the reliability, safety and financial risk related costs (which in practice are not expected to be affected by non-network solutions due to the nature of CBs and disconnectors).

We do not expect that non-network options are able to meet the identified need, irrespective of their type, size, operating profile and location. Any non-network solution for this need is expected to only add to the costs of this option without providing any net benefits.

5. Materiality of market benefits

This section outlines the categories of market benefits prescribed in the National Electricity Rules (NER) and whether they are considered material for this RIT-T.[22]

Many of the expected benefits associated with the credible options are captured in the expected costs avoided by the options (i.e., the avoided expected costs compared to the base case). These include avoided costs associated with routine maintenance and avoided risk costs. Of these avoided costs, only unserved energy through involuntary load shedding is considered a market benefit category under the NER, as discussed further below.

5.1 Avoided unserved energy is material

We consider that changes in involuntary load shedding are expected to be material for the credible options outlined in this RIT-T assessment. In the base case, involuntary load shedding would be expected to occur following a failure assets on our network. The probability of asset failure is expected to increase over time as the condition of the assets continue to deteriorate.

We have estimated expected load shedding under the base case and each option. These forecasts are based on probabilistic planning studies of failure rates and repair times. The avoided unserved energy for each credible option is calculated as the difference between the expected load shedding under the base case and the expected load shedding under each option.

5.2 Wholesale electricity market benefits are not material

The AER has recognised that if the credible options will not have an impact on the wholesale electricity market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.

We determine that the credible options in this RIT-T will not affect network constraints between competing generating centres and are therefore not expected to result in any change in dispatch outcomes and wholesale market prices. We therefore consider that the following classes of market benefits are not material for this RIT-T assessment:

- changes in fuel consumption arising through different patterns of generation dispatch
- changes in voluntary load curtailment (since there is no impact on pool price)
- changes in costs for parties other than Transgrid
- changes in ancillary services costs
- changes in greenhouse gas emissions specific to the wholesale electricity market
- competition benefits

[22] The NER requires that all classes of market benefits identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific class (or classes) is unlikely to be material in relation to the RIT-T assessment for a specific option – 5.15A.2(5). See Appendix A for requirements applicable to this document.

5.3 No other classes of market benefits are material

In addition to the classes of market benefits listed above, NER clause 5.15A.2(b)(4) requires us to consider the following classes of market benefits, listed in Table 5-1, arising from each credible option. We consider that none of the classes of market benefits listed are material for this RIT-T assessment for the reasons in Table 5-1.

Table 5-1: Reasons non-wholesale electricity market benefits categories are considered not material

Market benefits	Reason
Differences in the timing of unrelated network expenditure	The credible options considered are unlikely to affect decisions to undertake unrelated expenditure in the network. Consequently, material market benefits will neither be gained nor lost due to changes in the timing of expenditure from any of the options considered.
Option value	We note the AER's view that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change. We also note the AER's view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T. We do not consider there to be any option value with the options considered in this RIT-T. Additionally, a significant modelling assessment would be required to estimate the option value benefits but it would be disproportionate to potential additional benefits for this RIT-T. Therefore, we have not estimated additional option value benefit.
Changes in network losses	We do not expect any material difference in transmission losses between options.
Changes in Australian greenhouse gas emissions	Neither option is expected to induce a material change in Australia's greenhouse gas emissions.

6. Overview of the assessment approach

This section outlines the approach that we have applied in assessing the net benefits associated with each of the credible options against the base case.

6.1 Description of the base case

The costs and benefits of each option in this document are compared against a ‘do nothing’ base case. Under this base case, no investment is undertaken to replace existing CBs or disconnectors which are run until they fail.

The deteriorating condition of the CBs and disconnectors that have been identified for replacement in Appendix C will lead to an increase in unplanned outages as the assets continue to deteriorate and age. Their failure will also impact primary assets, such as lines and transformers, as they will be out of service for longer periods. It will also lead to higher safety, environmental and financial related risk costs that are caused by the failure of secondary systems to operate when required. In addition, there would be higher routine operating and maintenance costs in the base case compared to the options developed.

We note that this course of action is not expected in practice. However, this approach has been adopted since it is consistent with AER guidance on the base case for RIT-T applications.[23]

6.2 Assessment period and discount rate

A 20-year assessment period from 2024/25 to 2043/44 has been adopted for this RIT-T analysis. This period takes into account the size, complexity and expected asset life of the options.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values are calculated as the undepreciated value of capital costs at the end of the analysis period.

A real, pre-tax discount rate of 7 per cent has been adopted as the central assumption for the NPV analysis presented in this PSCR, consistent with AEMO’s Inputs, Assumptions and Scenarios Consultation Report and the assumptions adopted in AEMO’s 2024 Integrated System Plan (ISP). The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 3.63 per cent. We have also adopted an upper bound discount rate of 10.5 per cent (ie, AEMO’s 2023 Inputs, Assumptions and Scenarios Report).

[23] The AER RIT-T Guidelines state that the base case is where the RIT–T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. The AER define 'BAU activities' as ongoing, economically prudent activities that occur in the absence of a credible option being implemented. (See: AER, *Application guidelines Regulatory Investment Test for Transmission,* October 2023)

6.3 Approach to estimating option costs

We have estimated the capital costs of the options based on the scope of works necessary together with costing experience from previous projects of a similar nature.

The cost estimates are developed using our 'MTWO' cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a 'P50' portfolio value for a total program of works (i.e., there is an equal likelihood of over- or under-spending the estimate total).

We estimate the majority of structures will be replaced in normal soil. As work is to replace structures on an existing line, minor access track upgrade works have been allowed for.

We estimate that actual costs will be within +/- 25 per cent of the central capital cost estimate. An accuracy of +/-25 per cent for cost estimates is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the Association for the Cost Engineering classification system.

All cost estimates are prepared in 2024/25 dollars based on the information and pricing history available at the time that they were estimated. The cost estimates do not include or forecast any real cost escalation for materials.

Routine operating and maintenance costs are based on works of similar nature. Given that there is an incremental routine operating and maintenance costs saving in the options compared to the base case, this is a net benefit in the assessment.

6.4 Value of customer reliability

We have applied a NSW-wide VCR value based on the estimates developed and consulted on by the AER.[24] The options considered involve the replacement of assets across our network. As a result, we consider that a state-wide VCR is likely to reflect the weighted mix of customers that will be affected by these options.

6.5 The options have been assessed against three reasonable scenarios

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options have been assessed under three scenarios as part of this PSCR assessment, which differ in terms of the key drivers of the estimated net market benefits (ie, the estimated risk costs avoided).

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios implicitly assume the most likely scenario from the 2024 ISP (ie, the 'Step Change' scenario). The scenarios differ by the

[24] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 124.

assumed level of risk costs and unserved energy, given that these are key parameters that may affect the ranking of the credible options. Risk cost assumptions do not form part of AEMO's ISP assumptions, and have been based on Transgrid's analysis, as discussed in section 2.

We developed the Central Scenario around a static model of demand scenarios, described further in Section A.3 of our Network Asset Criticality Framework. We consider that this approach is appropriate since it materially reduces the computational effort required, and since differences in demand forecasts will not materially affect the ranking of the credible options.

How the NPV results are affected by changes to other variables (including the discount rate and capital costs) has been investigated in the sensitivity analysis. We consider this is consistent with the latest AER guidance for RIT-Ts of this type (ie, where wholesale market benefits are not expected to be material).

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

Table 6-1 Summary of scenarios

Variable / Scenario	Central	Low asset failure risk scenario	High asset failure risk scenario
Scenario weighting	1/3	1/3	1/3
Discount rate	7%	7%	7%
VCR ($2023/24 m)[25]	$54.95/kWh	$54.95/kWh	$54.95/kWh
Network capital costs	Base estimate	Base estimate	Base estimate
Avoided unserved energy	Base estimate	Base estimate - 25%	Base estimate + 25%
Safety, environmental and financial risk benefit	Base estimate	Base estimate - 25%	Base estimate + 25%
Avoided routine operating and maintenance costs	Base estimate	Base estimate	Base estimate

We have weighted the three scenarios equally given there is nothing to suggest an alternate weighting would be more appropriate.

6.6 Sensitivity analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking various sensitivity testing.

The range of factors tested as part of the sensitivity analysis in this PSCR are:

- lower and higher assumed capital costs;
- lower and higher estimated safety, environmental, and financial risk benefits; and
- alternate commercial discount rate assumptions.

The above list of sensitivities focuses on the key variables that could impact the identified preferred option. The results of the sensitivity tests are set out in section 7.4.

[25] This VCR is equal to the $49,216 within AEMO's July 2023 2023 Inputs, Assumptions and Scenarios Report inflated to March 2024.

In addition, we have also sought to identify the ‘boundary value’ for key variables beyond which the outcome of the analysis would change, including the amount by which capital costs would need to increase for the preferred option to no longer be preferred.

7. Assessment of credible options

This section outlines the assessment we have undertaken of the credible options. The assessment compares the costs and benefits of the option to the base case. The benefits of each credible option are represented by reduction in costs or risks compared to the base case.

7.1 Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. The results have been presented separately for each reasonable scenario, and on a weighted basis.

The benefits included in this assessment are:

- avoided involuntary load shedding;
- reduction in safety, environmental and financial risks; and
- avoided routine operating and maintenance costs.

Table 7-1: NPV of gross economic benefits relative to the base case ($2024/25 m)

Option	Central	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*33%*	*33%*	*33%*	
Option 1	109.07	81.80	136.33	109.07
Option 2	109.09	81.82	136.36	109.09
Option 3	118.93	89.20	148.67	118.93

The results show that under all four scenarios, the estimated gross benefits are higher for Option 3 than Option 1 and 2 (in NPV terms). On a weighted basis, the estimated gross benefit for Option 2 is approximately $259m, which is $53m or 22% higher than Option 1 ($2024/25m).

7.2 Estimated costs

The table below summarises the present value of capital costs of each credible option relative to the base case. The results have been presented separately for each reasonable scenario, and on a weighted basis.

Table 7-2: NPV of capital relative to the base case ($2024/25 m)

Option	Central	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*33%*	*33%*	*33%*	
Option 1	6.21	6.21	6.21	6.21
Option 2	5.40	5.40	5.40	5.40
Option 3	7.94	7.94	7.94	7.94

The results show that the estimated cost of implementing Option 2 is higher than Option 1 (in NPV terms). This is due to the higher unit cost of purchasing and installing a Dead Tank Circuit Breaker (DTCB) under Option 2.

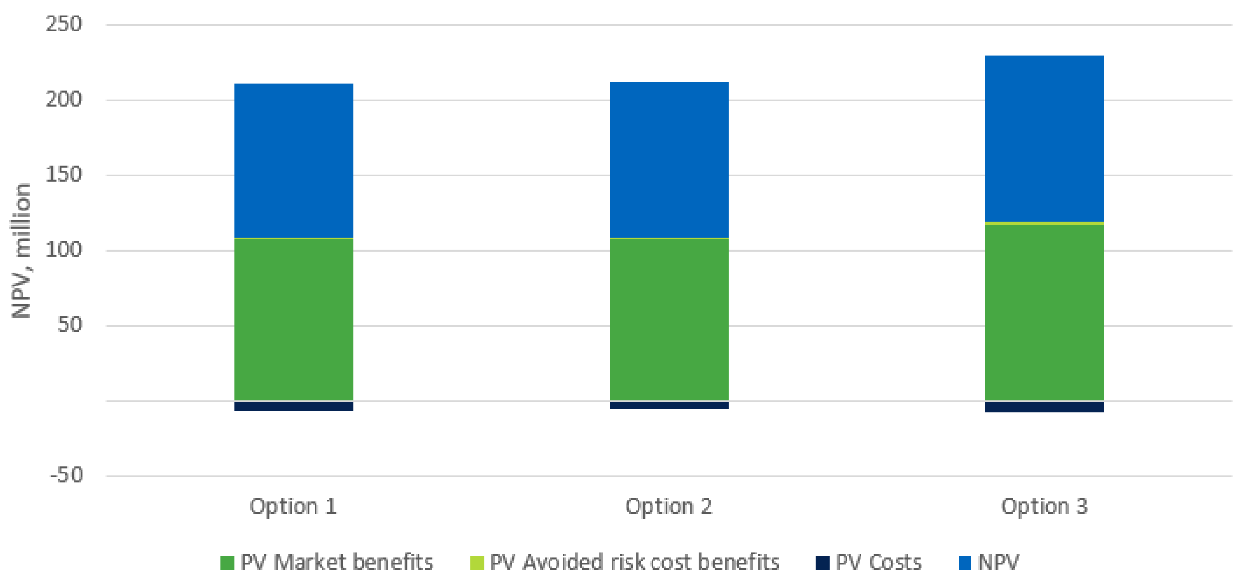
7.3 Estimated net economic benefits

The net economic benefits calculated as the estimated gross benefits less the estimated costs plus the terminal value. The table below summarises the present value of the net economic benefits for each credible option relative to the base case. The results have been presented separately for each reasonable scenario, and on a weighted basis. The table also shows a ranking of the options, where options with a higher net economic benefit under the weighted scenario are accorded a higher rank.

Table 7-3: NPV of net economic benefits relative to the base case ($2024/25 m)

Option	Central	Low risk costs scenario	High risk costs scenario	Weighted scenario	Ranking
Scenario weighting	*33%*	*33%*	*33%*		
Option 1	102.85	75.59	130.12	102.85	3
Option 2	103.69	76.42	130.96	103.69	2
Option 3	110.99	81.26	140.72	110.99	1

Figure 7-1 NPV of net economic benefits ($2024/25 m)



Overall, the results show that Option 3 is ranked higher than Option 2 and 1 in every scenario.

7.4 Sensitivity testing

We have considered the robustness of the RIT-T assessment by undertaking a range of sensitivity testing. The purpose of this testing is to examine how the net economic benefit of the credible options changes with respect to changes in key modelling assumptions. The factors tested as part of the sensitivity analysis for this PSCR are:

- Optimal timing of the project
- Scenario weights
- Higher or lower VCRs
- Higher or lower network capital costs of the credible options
- Alternate commercial discount rate assumptions.

The sensitivity testing was undertaken as against the central scenario. Specifically, we individually varied each factor identified above and estimated the net economic benefit in that scenario relative to the base case while holding all other assumptions under the central scenario constant. The results of the sensitivity tests are set out in the sections below.

In addition, we have also sought to identify the ‘boundary value’ for key variables beyond which the outcome of the analysis would change.

7.4.1 Optimal timing of the project

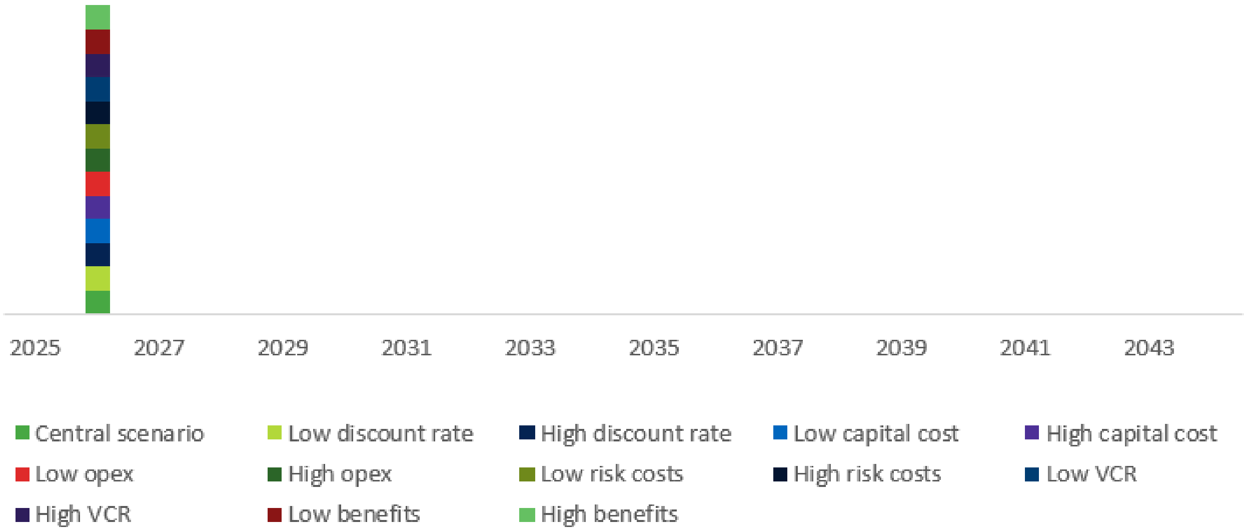
We have estimated the optimal timing for the preferred option. The optimal timing of an investment is the year when the annual benefits (avoided risk costs) from implementing the option become greater than the annualised investment costs. The analysis was undertaken under the central set of assumptions and a range of alternative assumptions for key variables. The purpose of the analysis is to examine the sensitivity of the commissioning year to changes in the underlying assumptions.

The sensitivities we considered are:

- lower and higher assumed capital costs;
- lower and higher estimated safety, environmental, and financial risk benefits; and
- alternate commercial discount rate assumptions.

The results of this analysis are presented in the figure below. In all cases, the optimal timing for the preferred option is 2025/26.

Figure 7-2 Distribution of optimal timing under a range of different key assumptions



7.4.2 Scenario weights

We have estimated that Option 3 is preferred under all three reasonable scenarios. As such, there is no alternative scenario weights that will change the RIT-T outcome (i.e., lead to the identification of a different preferred option, or no preferred option).

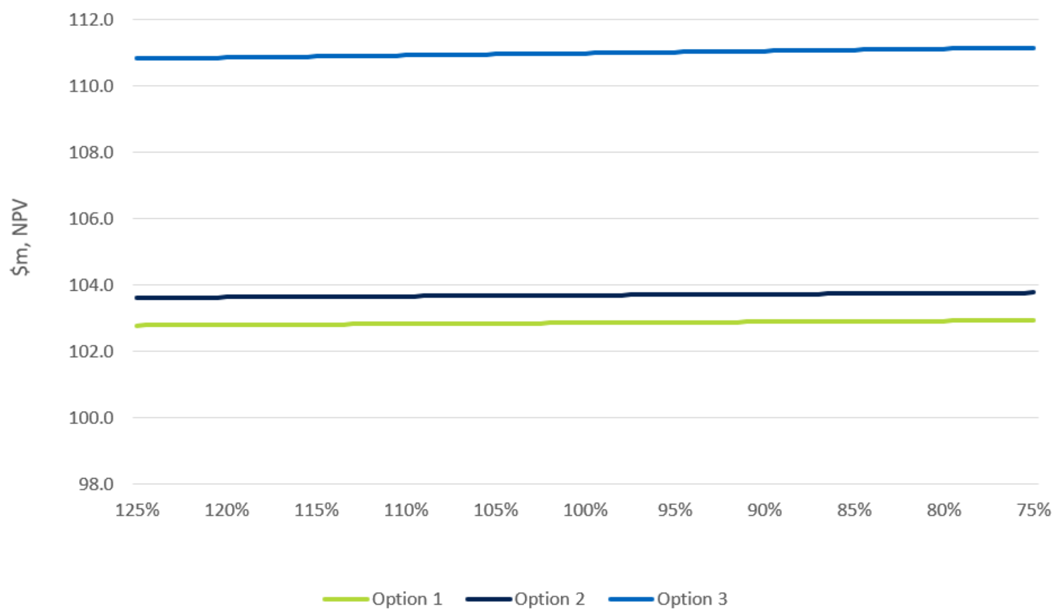
7.4.3 Sensitivity analysis on the VCR

We estimated the net economic benefit of each option by adopting a VCR that is 30% higher (the 'High VCR' scenario) and 30% lower (the 'Low VCR' scenario) than the estimate of VCR adopted in our central scenario. The results of this analysis are presented in the table and figure below.

Table 7-4: NPV of net economic benefits relative to the base case under a lower and higher VCR ($2024/25 m)

Option/scenario	Low VCR	High VCR	Ranking
Sensitivity	*Central estimate - 30%*	*Central estimate + 30%*	
Option 1	102.78	102.93	3
Option 2	103.61	103.77	2
Option 3	110.82	111.16	1

Figure 7-3 NPV of net economic benefits relative to the base case under a lower and higher VCR ($2024/25 m)



Option 3 remains the preferred option under both a low and high VCR scenario.

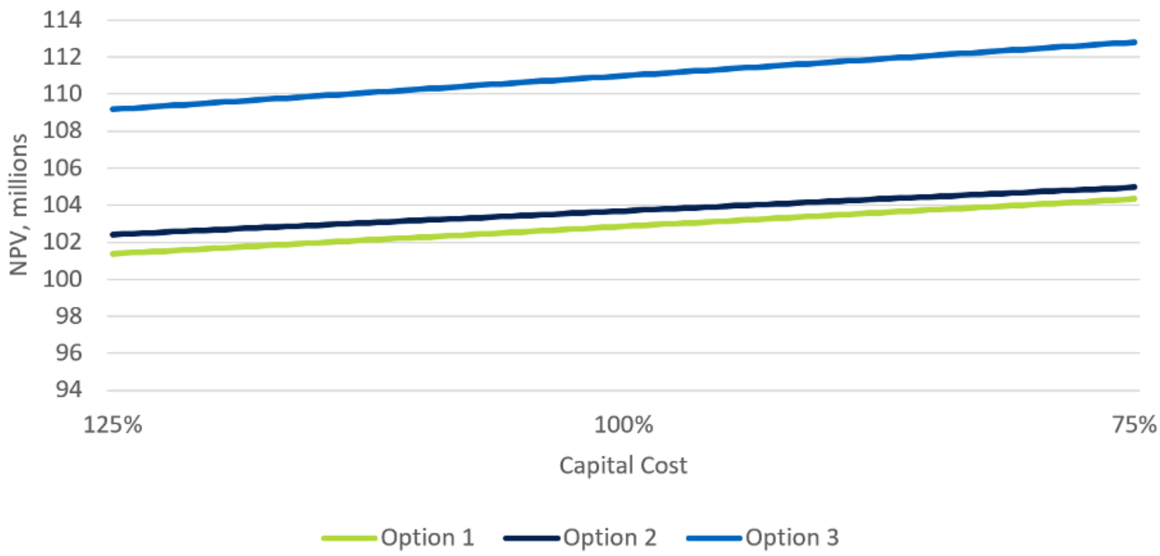
7.4.4 Sensitivity analysis on network capital costs

We estimated the net economic benefit of each option by adopting capital costs for each option that are 25% higher (the ‘High capex’ scenario) and 25% lower (the ‘Low capex’ scenario) than the capital cost estimates in our central scenario. The results of this analysis are presented in the table and figure below.

Table 7-5: NPV of net economic benefits relative to the base case under lower and higher capital costs ($2024/25 m)

Option/scenario	Low capex	High capex	Ranking
Sensitivity	*Central estimate - 25%*	*Central estimate + 25%*	
Option 1	101.38	104.33	3
Option 2	102.41	104.96	2
Option 3	109.17	112.81	1

Figure 7-4: NPV of net economic benefits relative to the base case under lower and higher capital costs ($2024/25 m)



We have also undertaken a threshold analysis to identify whether a change in capital cost estimates would change the RIT-T outcome. Specifically, we considered whether an increase or decrease in the capital costs of one option (while holding the capital costs of the other options constant) would change the RIT-T outcome. Our findings show that Option 3's capex would need to increase by more than 336% of its current baseline capex estimates in order to change the RIT-T outcome i.e., for Option 3's NPV net economic benefit to be less than Option 2's. Such a change in capital costs is outside the expected range of costs and, as such, this result of Option 3 being the preferred options is robust to reasonable capital cost sensitivities.

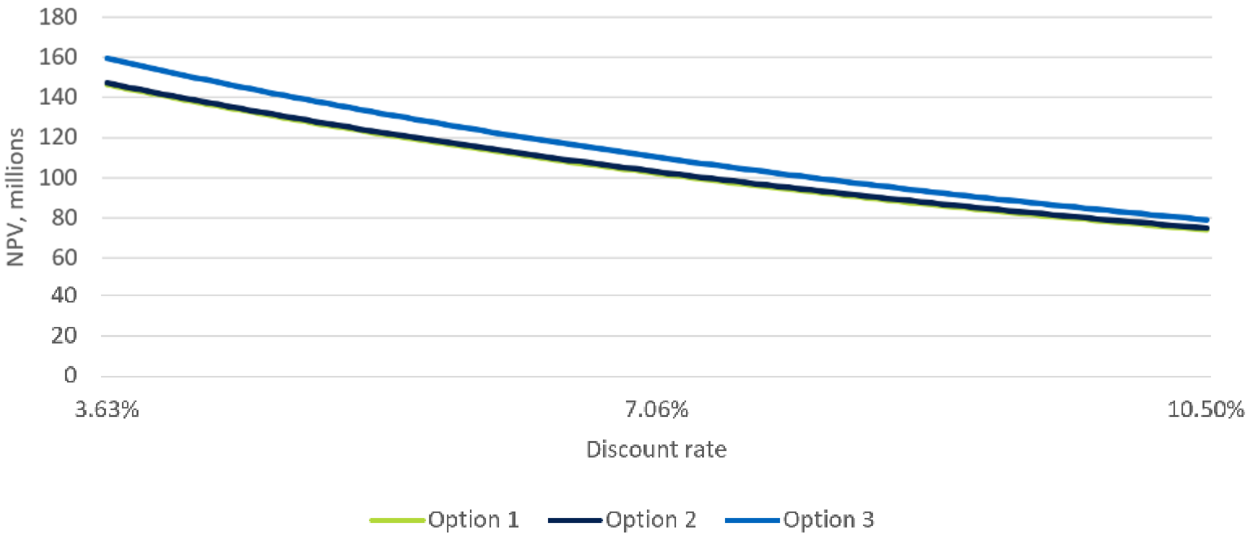
7.4.5 Sensitivity on the discount rate

We estimated the net economic benefit of each option by adopting a low discount rate of 3.63% (the 'Low discount rate' scenario) and a high discount rate of 10.5% (the 'High discount rate' scenario). The results of this analysis are presented in the table and figure below.

Table 7-6: NPV of net economic benefits relative to the base case under a lower and higher discount rates ($2024/25 m)

Option/scenario	Low discount rate	High discount rate	Ranking
Sensitivity	*3.63%*	*10.5%*	
Option 1	73.96	146.44	3
Option 2	74.84	147.18	2
Option 3	79.02	159.41	1

Figure 7-5 Net economic benefits relative to the base case under a lower and higher discount rates ($2024/25 m)



We have also undertaken a threshold analysis to identify whether a change in the discount rate would change the RIT-T outcome. Our approach involved identifying the discount rate that would result in Option 3 not being the preferred option. Our results suggest that there is no reasonable discount rate that would change the RIT-T outcome.

8. Draft conclusion and exemption from preparing a PADR

This PSCR finds that implementation of Option 3 is the preferred option at this draft stage of the RIT-T process. Under Option 3, assets will be replaced with double bus selectable feeder bays.

The capital cost of this option is approximately $8.44 million (in $2024/25). The works are expected to be undertaken between 2023/24 and 2025/26. Planning, design, development and procurement (including completion of the RIT-T) will occur between 2023/24 and 2024/25, while project delivery and construction will occur in 2024/25. All works are expected to be completed by 2025/26. Routine operating and maintenance costs are estimated at approximately $64,858 per annum (in $2024/25).

Subject to the identification of additional credible options during the consultation period, publication of a Project Assessment Draft Report (PADR) is not required for this RIT-T as we consider that the conditions in clause 5.16.4(z1) of the NER exempting RIT-T proponents from providing a PADR have been met.

Specifically, production of a PADR is not required because:

- the estimated capital cost of the proposed preferred option being less than $46 million[26];
- the PSCR states:
  - the proposed preferred option, together with the reasons for the proposed preferred option;
  - the RIT-T is exempt from producing a PADR; and
  - the proposed preferred option and any other credible option will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding;
- the RIT-T proponent considers that there were no PSCR submissions identifying additional credible options that could deliver a material market benefit; and
- the PACR must address any issues raised in relation to the proposed preferred option during the PSCR consultation.

If an additional credible option that could deliver a material market benefit is identified during the consultation period, then we will produce a PADR that includes an NPV assessment of the net economic benefit of each additional credible option.

If no additional credible options with material market benefits are identified during the consultation period, then the next step in this RIT-T will be the publication of a PACR that addresses all submissions received, including any issues in relation to the proposed preferred option raised during the consultation period.[27]

26 Varied from $43m to $46m based on the AER Final Determination: Cost threshold review November 2021.
27 In accordance with NER clause 5.16.4(z2).

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PSCR with the requirements of the National Electricity Rules version 214.

Rules clause	Summary of requirements	Relevant section
5.16.4 (b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	–
	(1) a description of the identified need;	2
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	2
	(3) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction of additional supply; (ii) location; and (iii) operating profile;	4
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent National Transmission Network Development Plan;	NA
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alterative transmission options, interconnectors, generation, demand side management, market network services or other network options;	3
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.16.1(c)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefit are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	3 & 5

5.16.4(z1)	A RIT-T proponent is exempt from [preparing a PADR] (paragraphs (j) to (s)) if: 1. the estimated capital cost of the proposed preferred option is less than $35 million[28] (as varied in accordance with a cost threshold determination); 2. the relevant Network Service Provider has identified in its project specification consultation report: (i) its proposed preferred option; (ii) its reasons for the proposed preferred option; and (iii) that its RIT-T project has the benefit of this exemption; 3. the RIT-T proponent considers, in accordance with clause 5.16.1(c)(6), that the proposed preferred option and any other credible option in respect of the identified need will not have a material market benefit for the classes of market benefit specified in clause 5.16.1(c)(4) except those classes specified in clauses 5.16.1(c)(4)(ii) and (iii), and has stated this in its project specification consultation report; and 4. the RIT-T proponent forms the view that no submissions were received on the project specification consultation report which identified additional credible options that could deliver a material market benefit.	8

[28] Varied to $46m based on the AER Final Determination: Cost threshold review November 2021.

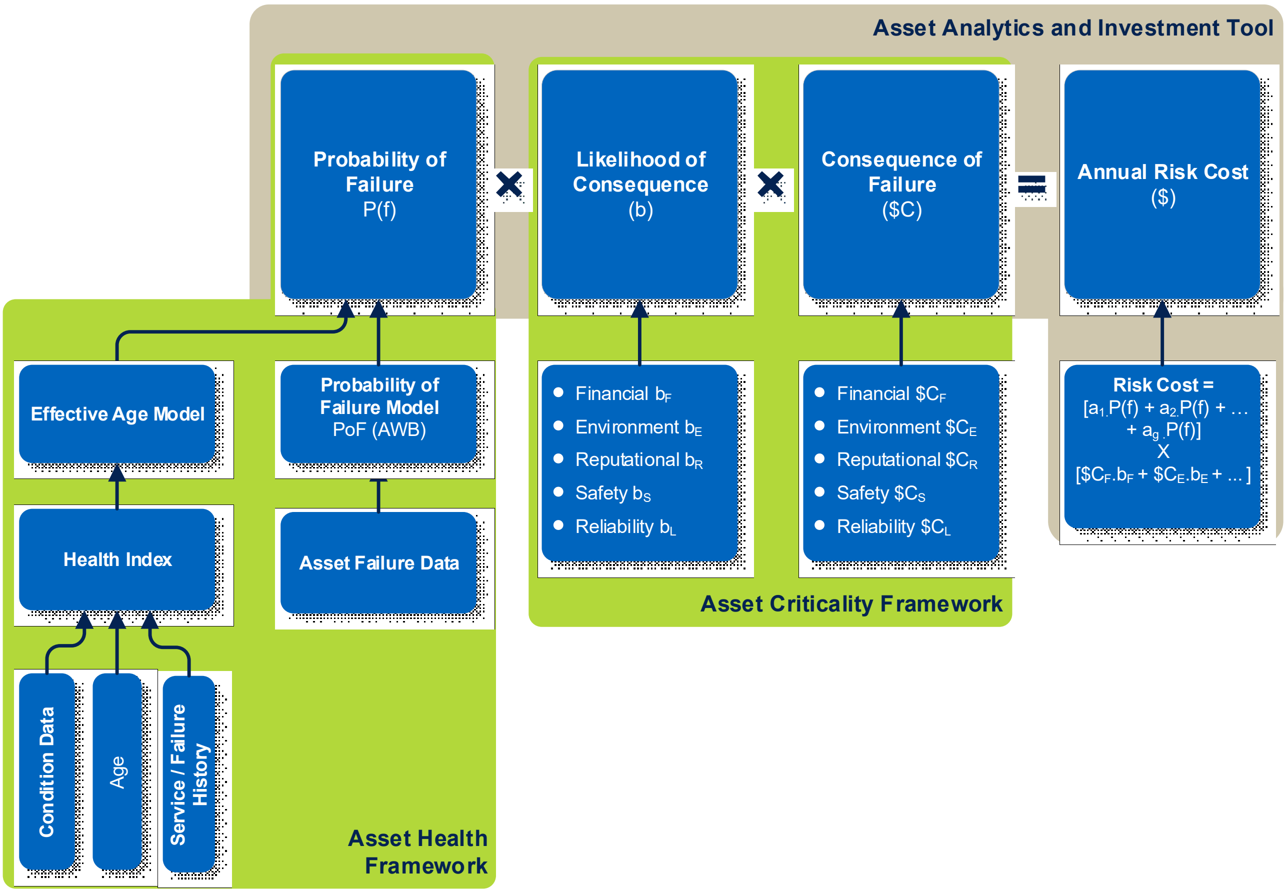
Appendix B Risk assessment framework

Summary of methodology

This appendix summarises our network risk assessment methodology that underpins the identified need for this RIT-T. Our risk assessment methodology is aligned with the AER's Asset Replacement Planning guideline.[29]

A fundamental part of the risk assessment methodology is calculating the annual 'risk costs' or the monetised impacts of reliability, safety, bushfire, environmental and financial risks. The monetary value of risk (per year) for an individual asset failure resulting in an undesired outcome, is the likelihood (probability) of failure (in that year with respect to its age), as determined through modelling the failure behaviour of an asset (Asset Health), multiplied by the consequence (cost of the impact) of the undesired outcome occurring, as determined through the consequence analysis (Asset Criticality). Figure B-1 illustrates the base risk equation that we apply.

Figure B-1 Risk cost calculation



29 Industry practice application note - Asset replacement planning, AER January 2019

Economic justification for replacement expenditure to address an identified need is provided where the risk reduction benefit (i.e., the value of avoided risks and costs) is greater that the costs of the project or program. The major quantified risks we apply for replacement expenditure justifications include asset failures that materialise as:

- Bushfire risk
- Safety risk
- Environmental risk
- Reliability risk, and
- Financial risk.

The risk categories relevant to this RIT-T are explained in Section 2.3.

Further details are available in our Network Asset Risk Assessment Methodology.

Asset health and probability of failure

The Probability of Failure (PoF) is the likelihood that an asset will fail during a given period resulting in a particular adverse event. The first step in calculating the probability of failure of an asset is determining the Asset Health and associated effective age.[30] This is based on the following considerations:

- An asset consists of different components, each with a particular function, criticality, underlying reliability, life expectancy and remaining life. The overall health of an asset is a compound function of all of these attributes.
- Key asset condition measures and failure data provides vital information on the current health of an asset. The 'current effective age' is derived from asset information and condition data.
- The future health of an asset (health forecasting) is a function of its current health and any factors causing accelerated (or decelerated) degradation or 'age shifting' of one or more of its components. Such moderating factors can represent the cumulative effects arising from continual or discrete exposure to unusual internal stresses, external stresses, overloads and faults. 'Future effective age' is derived by moderating 'current effective age' based on factors such as external environment/influence, expected stress events and operating/loading condition.

The outputs of the PoF calculation are one or more probability of failure time series which provide a mapping between the effective age, discussed above, and the yearly probability of failure value for a given asset class. This analysis is performed by generating statistical failure curves, normally using Weibull analysis, to determine a PoF time series set for each asset that gives a probability of failure for each further year of asset life. This establishes how likely it is that the asset will fail over time.

The Weibull parameters which represent the PoF curve for assets considered in this RIT-T are summarised in the table below.

Further details are available in our Network Asset Health Methodology.

[30] Apparent age of an asset based on its condition.

Table C-1 Weibull parameters for assets

Asset	Weibull parameters	
	η	β
Circuit breakers	47.76	4.3
Oil Reactors	38.84	2.95
Disconnector	67	4.8

Asset criticality

Asset criticality is the relative risk of the consequences of an undesired outcome. Asset criticality considers the severity of the consequences of the asset failure occurring and the likelihood the consequence will eventuate. Our approach to determining these factors for each relevant risk category is set out in our Network Asset Criticality Framework. The analysis leverages data from past events, relevant research / publications and technical insights, to determine an economic value of the impact.

Appendix C Assets at End of Life

The table below details the assets in this project that have reached or exceeded their end of life and will be captured under the preferred solution (Option 3). Highlighted assets are isolators which require an X2 outage to repair or replace and circuit breakers which will cause an X2 forced or emergency outage in event of a failure.

Bay	PIC	Type	EGI/Model	Comment
SWSBRG3C2	EC00014806	CBR-	ASEHPL245-0	Included in RP3 - N2345
SWSBRG3C3	EC00014810	CBR-	ASEHPL245-0	Included in RP3 - N2345
SWSBRG3D1	EC00014808	CBR-	ASEHPL245-0	Included in RP3 - N2345
SWSBRG3D3	EC00014812	CBR-	ASEHPL245-0	
SWSBRG3G1	EC00014809	CBR-	ASEHPL245-0	0X1 CBR – **Redundant (PEC)**
SWSBRG3BA	EC00020079	ISOL	TDA245MC100	Bus B Section 1-2 ISOL
SWSBRG3BA	EC00020070	ISOL	TDA245MC100	0X1 Bus ISOL
SWSBRG3BA	EC00020077	ISOL	TDA245MC100	Bus Section A-B ISOL - **Redundant (PEC)**
SWSBRG3BA	EC00020065	ISOL	C68/85/2	0X1 Bypass - **Redundant (PEC)**
SWSBRG3BB	EC00020080	ISOL	TDA245MC100	Bus B Section 1-2 ISOL
SWSBRG3BB	EC00020074	ISOL	TDA245MC100	X2 Bus ISOL
SWSBRG3BB	EC00020073	ISOL	TDA245MC100	X3 Bus ISOL
SWSBRG3BB	EC00020078	ISOL	TDA245MC100	Bus Section A-B ISOL - **Redundant (PEC)**
SWSBRG3BB	EC00020067	ISOL	C68/85/2	X2 Bypass
SWSBRG3BB	EC00020066	ISOL	C68/85/2	X3 Bypass - **Redundant (Operations)**
SWSBRG3C1	EC00020076	ISOL	TDA245MC100	X2 Reactor ISOL
SWSBRG3C1	EC00020075	ISOL	TDA245MC100	X2 Line ISOL
SWSBRG3D2	EC00020071	ISOL	TDA245MC100	X3 Line ISOL
SWSBRG3D2	EC00020072	ISOL	TDA245MC100	X3 Reactor ISOL
SWSBRG3G2	EC00020069	ISOL	TDA245MC100	0X1 Line ISOL - **Redundant (PEC)**
SWSBRG3C1	EC00020061	ESW-	'TEC245MC50	Replace with associated ISOL
SWSBRG3D2	EC00020060	ESW-	'TEC245MC50	Replace with associated ISOL
SWSBRG3G2	EC00020062	ESW-	'TEC245-100	0X1 Line ESW - **Redundant (PEC)**

Appendix D Option 3 concept scoping drawing