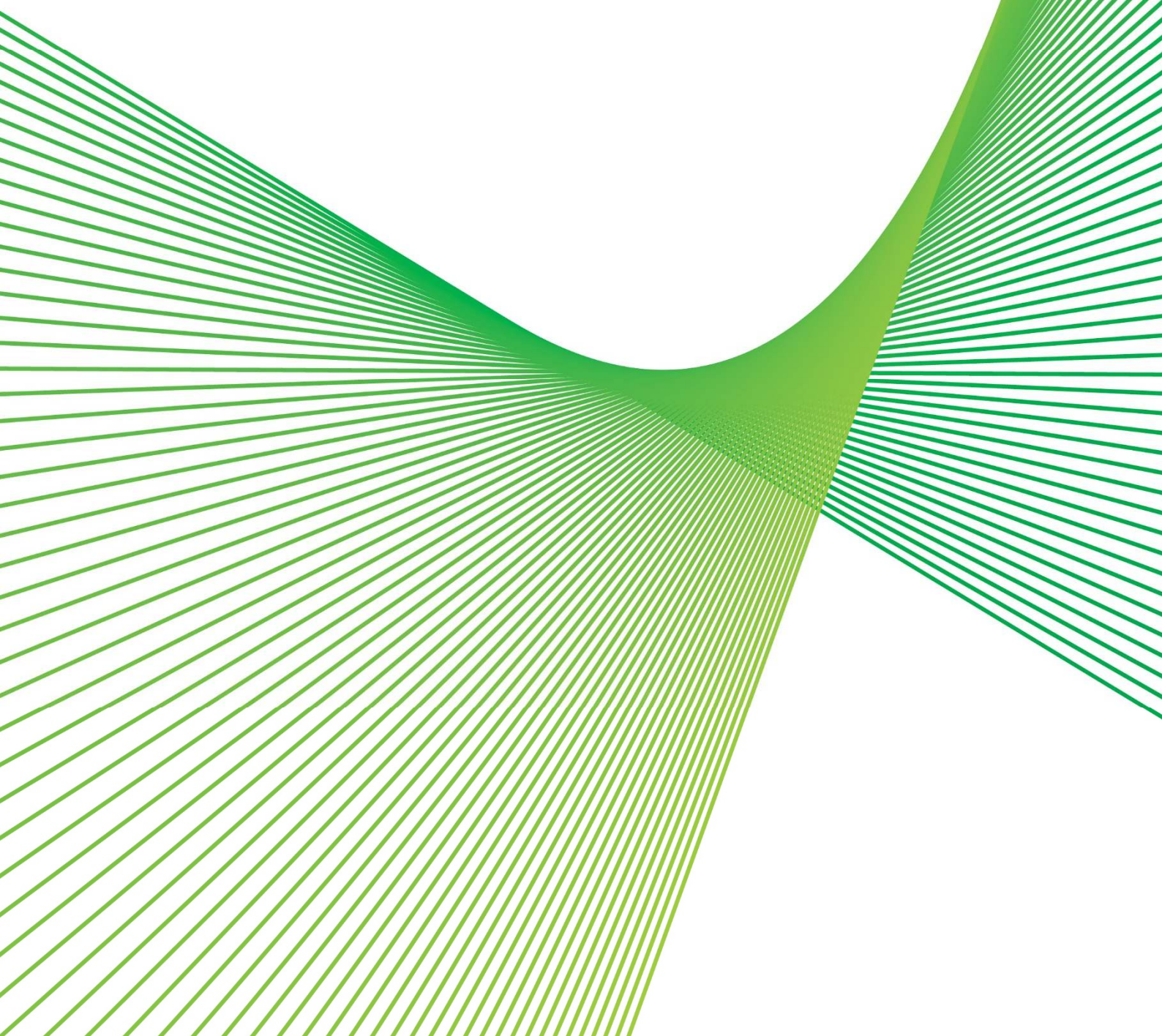


Maintaining safe and reliable operation of Buronga substation

RIT-T Project Assessment Conclusions Report

Issue date: 6 December 2024



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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining the safe and reliable operation of Buronga Substation. Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process.

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.

Identified need: ensure the safe and reliable operation of Buronga substation

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 at Buronga substation.

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 disconnecter, line disconnecter and bypass disconnecter prevent outage access for the CB replacement. Due to the disconnecter 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.

Transgrid notes the recent outage of the X2 line following an extreme weather event that began on 16 October 2024. Transgrid confirms that this event has not impacted the identified need, or the credible options considered. Line X2 travels 250km from Buronga to Broken Hill and the seven towers that were damaged were located close to Broken Hill.

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).

No submissions received in response to the Project Specification Consultation Report

We published a Project Specification Consultation Report (PSCR) on 15 August 2024 and invited written submissions on the material presented within the document. No submissions were received in response to the PSCR.

No material developments since publication of the PSCR

No additional credible options were identified during the consultation period following publication of the PSCR. In addition, no material changes have occurred since the PSCR that have made an impact on the preferred option.

Credible options considered

We identified three credible network options that meet the identified need from a technical, commercial, and project delivery perspective¹. These options are summarised in Table E-1.

Table E-1 Summary of credible options, \$2024/25

Option	Description	Capital costs (\$m +/- 25%, \$2024/25)
Option 1	In-situ like-for-like replacements through Asset Renewal Strategies ²	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%)

No submissions received in relation to non-network options

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 risks associated with failure of the identified substation assets that have reached or are approaching the end of their technical life. In addition, we did not receive any submissions from proponents of these solutions in response to the PSCR.

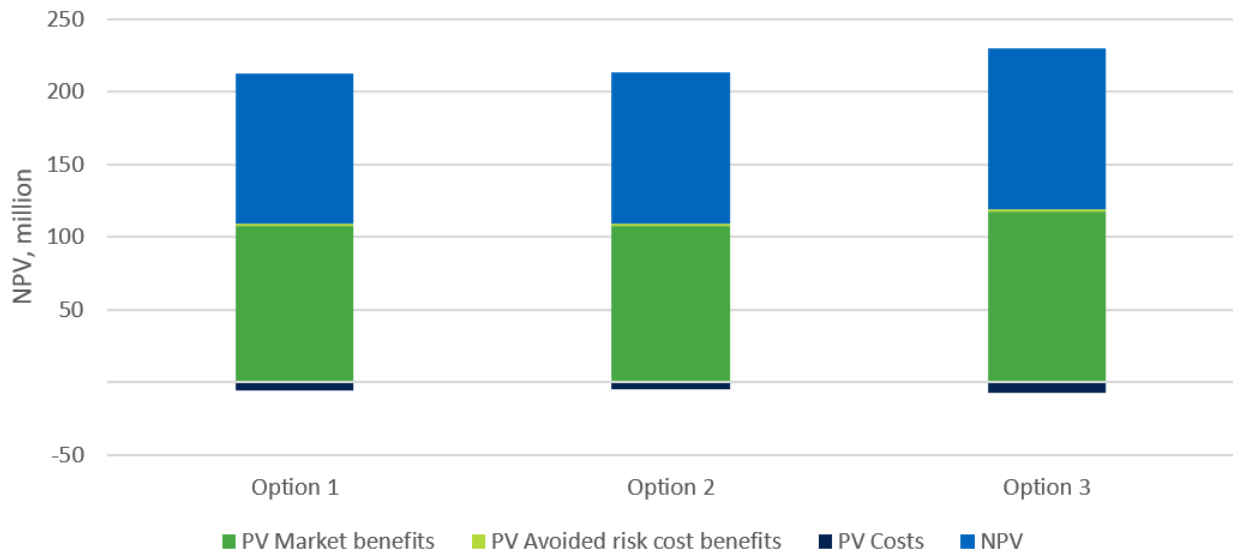
Option 3 delivers the highest net economic benefit and will meet NER requirements

We have assessed that Option 3 is the best performing option under all three reasonable scenarios considered in this PACR. 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. On a weighted basis, where each scenario is weighted equally, Option 3 is expected to deliver net benefits of approximately \$110.99 million.

¹ As per clause 5.15.2(a) of the NER.

² Renewal and maintenance strategies for transmission line assets are defined in [Transgrid's Renewal and Maintenance Strategy 2021/22](#).

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



Conclusion

This PACR finds that Option 3 is the preferred option to address the identified need. Option 3 involves 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). 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).

Next steps

This PACR represents the final step of the consultation process in relation to the application of the Regulatory Investment Test for Transmission (RIT-T) process undertaken by Transgrid. It follows a PSCR released in August 2024. No submissions were received in response to the PSCR.

The second step of the RIT-T process, production of a Project Assessment Draft Report (PADR), was not required as Transgrid considers its investment in relation to the preferred option to be exempt from that part of the RIT-T process under NER clause 5.16.4(z1). Production of a PADR is not required due to:

- the estimated capital cost of the preferred option being less than \$54 million;
- the PSCR stating:
 - 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 options 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;

- no PSCR submissions identifying additional credible options that could deliver a material market benefit; and
- the PACR addressing any issues raised in relation to the proposed preferred option during the PSCR consultation.

Parties wishing to raise a dispute notice with the AER may do so prior to 17 January 2025³ (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 100 days, after which the formal RIT-T process will conclude.

Further details on the RIT-T can be obtained from Transgrid's Regulation team via regulatory.consultation@transgrid.com.au. In the subject field, please reference 'Buronga substation renewal PACR'.

³ Additional days have been added to cover public holidays

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1. Introduction

This Project Assessment Conclusions Report (PACR) represents the final step in the application of the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining the safe and reliable operation of Buronga substation.

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 RIT-T is to examine and consult on options to address the deterioration of the high voltage and secondary systems asset condition and the risk from technology obsolescence of the secondary systems at Buronga substation.

1.1. Purpose of this report

The purpose of this PACR⁴ is to:

- describe the identified need;
- describe and assess credible options to meet the identified need;
- describe the assessment approach used; and
- provide details of the proposed preferred option to meet the identified need.

Overall, this report provides transparency into the planning considerations for investment options to ensure continuing reliable supply to our customers. A key purpose of this PACR is to provide interested stakeholders the opportunity to review the analysis and assumptions and have certainty and confidence that the preferred option has been robustly identified as optimal.

1.2. No submissions received in response to the Project Specification Consultation Report and there have been no material developments

We published a Project Specification Consultation Report (PSCR) on 15 August 2024 and invited written submissions on the material presented within the document. No submissions were received in response to the PSCR.

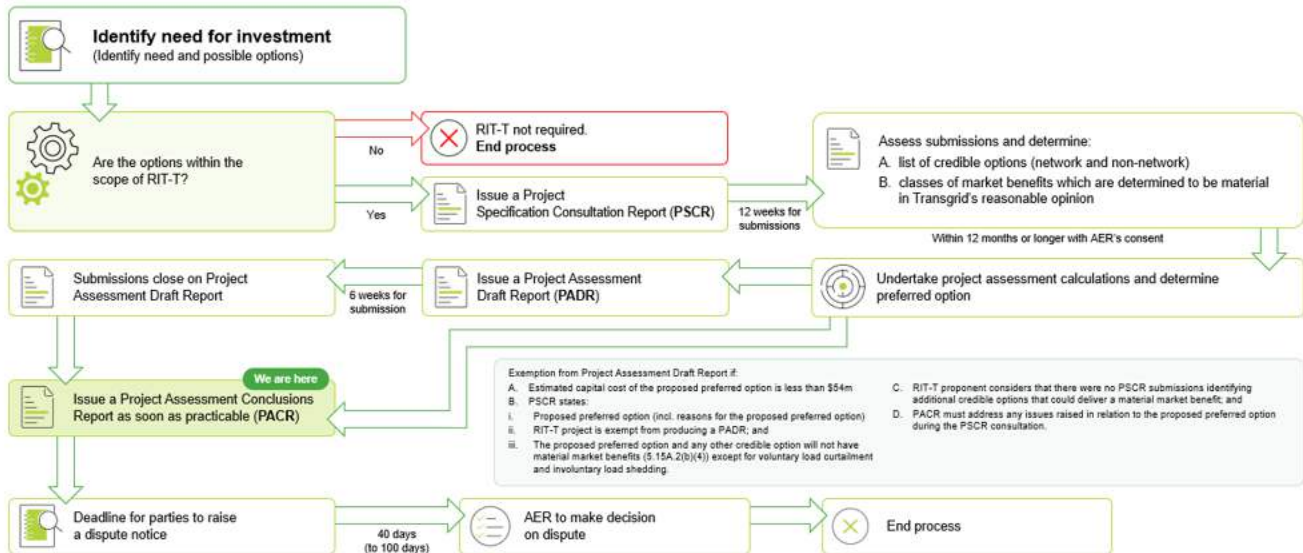
In addition, no additional credible options were identified during the consultation period following publication of the PSCR. No other material changes have occurred since the PSCR that have made an impact on the preferred option.

⁴ See Appendix A for the National Electricity Rules requirements.

1.3. Next steps

This PACR represents the final step of the consultation process in relation to the application of the RIT-T process undertaken by Transgrid.

Figure 1-1 This PACR is the final stage of the RIT-T process⁵



Parties wishing to raise a dispute notice with the AER may do so prior to 17 January 2025⁶ (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 100 days, after which the formal RIT-T process will conclude.

Further details on the RIT-T can be obtained from Transgrid's Regulation team via regulatory.consultation@transgrid.com.au. In the subject field, please reference 'Buronga substation renewal PACR'.

⁵ Australian Energy Market Commission. "[Replacement expenditure planning arrangements, Rule determination](#)". Sydney: AEMC, 18 July 2017.

⁶ Additional days have been added to cover public holidays

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 loads⁷ 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. 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.

Transgrid notes the recent outage of the X2 line following an extreme weather event that began on 16 October 2024. Transgrid confirms that these events have not impacted the identified need, or the credible options considered.

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).

⁷ The maximum POE 50 load for Broken Hill substation 22 kV is forecast to be approximately 42 MW in 2028 and is currently a mix of residential and commercial

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).

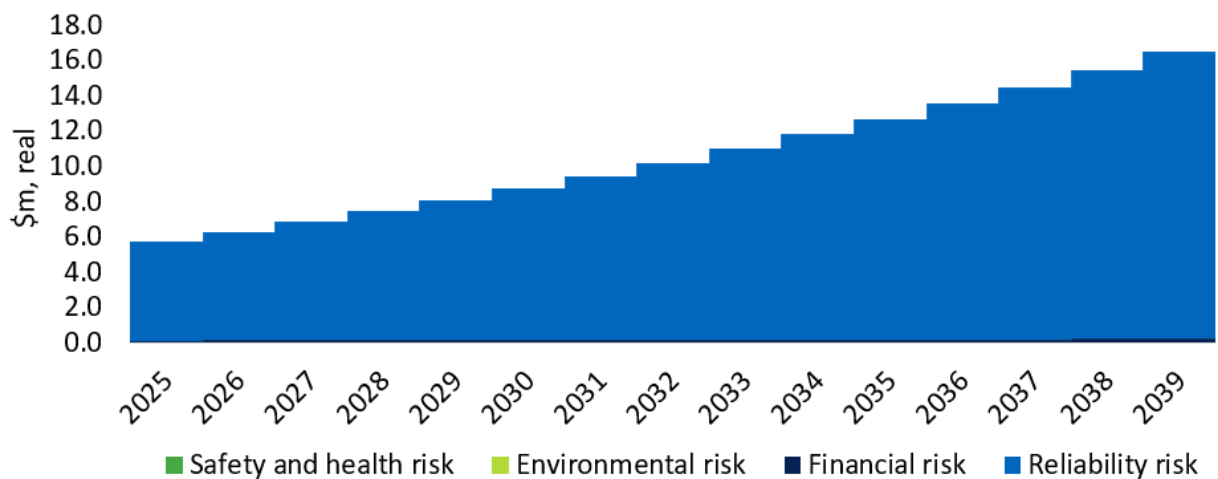
2.3. Assumptions underpinning the identified need

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 summarises the increasing risk costs over the assessment period under the base case.

Figure 2-2 Estimated risk costs under the central scenario (\$m, real 2024/25)



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. Asset health and the probability of failure

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 PACR. 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 is 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. Potential credible options

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 technically and commercially feasible options to address the identified need. These options are summarised in Table 3-1. We do not consider non-network options to be technically or commercially feasible to assist with meeting the identified need for this RIT-T.

Table 3-1: 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

All costs and benefits presented in this PACR are in 2024/25 dollars, unless otherwise stated.

3.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken in this PACR 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.⁸

"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 2024/25).

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).

⁸ AER, Regulatory Investment Test for Transmission Application Guidelines, November 2024, p. 21.

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.

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 Strategies⁹. 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.

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).¹⁰ 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 3-2 Option 1 Capital and Operating Cost (\$2024/25)

Year	Capital Cost	Operating Cost
2024/25	\$500,000	\$0.00
2025/26	\$6,357,461	\$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

⁹ Renewal and maintenance strategies for transmission line assets are defined in Transgrid’s Renewal and Maintenance Strategy 2021/22.

¹⁰ Average operating costs over the period 2024/25 to 2051/52.

2041/42	-	\$33,862.74
2042/43	-	\$34,309.65
2043/44	-	\$34,748.92
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.

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).¹¹ The table below provides a breakdown of the estimated capital and operating cost.

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

Year	Capital Cost	Operating Cost
2024/25	\$500,000	\$0.00
2025/26	\$5,417,688	\$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

¹¹ Average operating costs over the period 2028/29 to 2049/50.

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
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.

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).¹² 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 3-4 Option 3 Capital and Operating Cost (\$2024/25)

Year	Capital Cost	Operating Cost
2024/25	\$500,000	\$0.00
2025/26	\$7,939,201	\$61,607.20

¹² Average operating costs over the period 2024/25 to 2051/52.

2026/27	-	\$62,061.17
2027/28	-	\$62,705.00
2028/29	-	\$63,299.70
2029/30	-	\$63,855.78
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	\$8,439,201	\$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 3-6.

Table 3-5 Options considered but not progressed

Option	Reason(s) for not progressing
Refurbishment and overhaul	<p>Circuit Breakers:</p> <p>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:</p> <p>Outdated and suboptimal component design may be retained in the overhaul.</p> <p>Parts and technician support is expected to be limited or unavailable.</p> <p>Continuous current and fault level ratings may not be suitable.</p> <p>Local overhaul is expected to result in higher defect and failure rates to factory manufacturing processes.</p> <p>With consideration the potential for life extension is expected to be no more than 10 years.</p> <p>Disconnectors:</p> <p>The refurbishment option for the ASEA model disconnectors has also been investigated and eliminated for the following reasons:</p> <p>Feedback from field staff indicates that the design of the disconnectors is inherently poor and unreliable.</p> <p>Corrective maintenance activities have been ineffective in providing a lasting improvement to disconnector operation.</p> <p>Manufacturer parts support is no longer available.</p> <p>The option has not been progressed as it is considered not economically feasible.</p>
Increased maintenance or inspections	<p>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.</p>
Elimination of all associated risk	<p>This can only be achieved by retiring the assets, which is not technically feasible due to the requirement to maintain the existing network reliability.</p>
Non-network solutions	<p>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 risks associated with failure of the identified substation assets that have reached or are approaching the end of their technical life.</p>

3.6. No material inter-network impact is expected

We have considered whether the credible option listed above is expected to have material inter-regional impact.¹³ 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

¹³ As per clause 5.16.4(b)(6)(ii) of the NER.

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."

By reference to AEMO's screening test for an inter-network impact,¹⁴ 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.

¹⁴ 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. 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.¹⁵

4.1. 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 PACR. In the base case, involuntary load shedding would be expected to occur following a failure asset 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.

4.2. Wholesale electricity market benefits are not material

The AER has recognised that if the credible options considered 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.¹⁶

The credible options considered in this RIT-T will not address 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

4.3. No other classes of market benefits are material

In addition to the classes of market benefits listed above, NER clause 5.15A.2(4) requires that we consider the following classes of market benefits, listed in Table 4-1, 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 4-1.

¹⁵ 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 – NER clause 5.15A.2(5). See Appendix A for requirements applicable to this document.

¹⁶ Australian Energy Regulator. “*Application guidelines Regulatory Investment Test for Transmission – November 2024.*” Melbourne: Australian Energy Regulator.

Table 4-1 Reasons non-wholesale electricity market benefits are considered immaterial

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	<p>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.¹⁷</p> <p>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.¹⁸</p> <p>We do not consider there to be any option value with the options considered in this PSCR. Additionally, a significant modelling assessment would be required to estimate the option value benefits which would be disproportionate to the potential additional benefits for this RIT-T. Therefore, we have not estimated additional option value benefit.</p>
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.

¹⁷ AER, *Regulatory Investment Test for Transmission Application Guidelines*, November 2024, p.52-54.

¹⁸ AER, *Regulatory Investment Test for Transmission Application Guidelines*, November 2024, p.52-54.

5. 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.

5.1. Assessment against 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 proactive capital investment is made to remediate the deterioration of existing CBs or disconnectors at Buronga substation.

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.¹⁹

5.2. Assessment period and discount rate

The RIT-T analysis considers a 20-year assessment period from 2024/25 to 2043/44. A 20-year 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 have been calculated based on 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 PACR, consistent with AEMO's Inputs Assumptions and Scenarios Consultation Report²⁰ 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.²¹ We have also adopted an upper bound discount rate of 10.50 per cent (ie, AEMO's 2023 Inputs Assumptions and Scenarios Report).²²

¹⁹ Transgrid notes that 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, *Regulatory Investment Test for Transmission Application Guidelines*, November 2024, p.21).

²⁰ AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.

²¹ This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (Transgrid) as of the date of this analysis, see: AER, TasNetworks – 2024-29 – Final decision – PTRM, April 2024, WACC sheet.

²² AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.

5.3. 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 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 Advancement of Cost Engineering (AACE) classification system.

As work is in an in-service substation, no allowance for access has been made. It has been assumed that all civil works will be within normal soil.

All cost estimates are prepared in real, 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.

5.4. Value of customer reliability

We have applied a NSW-wide VCR value based on the estimates developed and consulted on by the AER²³. The options considered involve the replacement of capacitor banks 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.

5.5. Three different scenarios have been modelled

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 will be assessed under three scenarios as part of the PACR assessment, which differ in terms of the key drivers of the estimated net market benefits (ie, the estimated risk costs avoided).

²³ AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 124.

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 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) will be 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).^{24, 25, 26}

Table 5-1 Summary of scenarios

Variable / Scenario	Central scenario	Low risk costs scenario	High risk costs scenario
Scenario weighting	33%	33%	33%
Discount rate	7%	7%	7%
VCR (\$2024/25) ²⁷	51,196/MWh	51,196/MWh	51,196/MWh
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

5.6. 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 PACR are:

- lower and higher value of customer reliability;
- lower and higher assumed capital costs; and
- alternate commercial discount rate assumptions.

²⁴ AER, *Application Guidelines Regulatory Investment Test for Transmission*, November 2024.

²⁵ We consider the approach to scenarios and sensitivities to be consistent with the AER guidance provided in November 2022 in the context of the disputes of the North West Slopes and Bathurst, Orange and Parkes RIT-Ts. See: AER, *Decision: North West Slopes and Bathurst, Orange and Parkes Determination on dispute - Application of the regulatory investment test for transmission*, November 2022, pp. 18-20 & 31-32, as well as with the AER’s RIT-T Guidelines.

²⁶ AEMO ‘2023 Inputs, Assumptions and Scenarios Report’, July 2023, p 123-124

²⁷ This VCR is equal to the \$49,216 within AEMO’s July 2023 2023 Inputs, Assumptions and Scenarios Report inflated to September 2024.

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 6.4.

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.

6. Assessment of credible options

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

All costs and benefits presented in this PACR are in 2024/25 dollars.

Estimated gross benefits

Figure 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 the assessment are:

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

Table 6-1 Estimated gross benefits from credible options relative to the base case (\$m, PV)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
<i>Scenario weighting</i>	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).

6.1. Estimated costs

Table 6-2 below summarises the 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 6-2 Costs of credible options relative to the base case (\$m, PV)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
<i>Scenario weighting</i>	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.

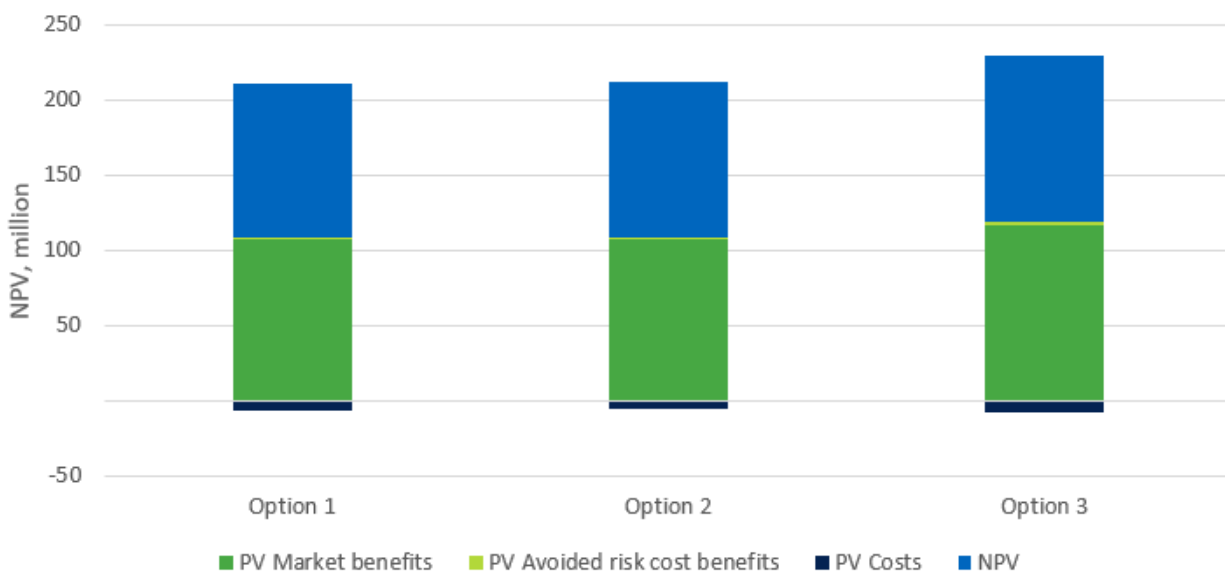
6.2. Estimated net economic benefits

The net economic benefits are 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. 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 6-3 Net economic benefits for Option 1 relative to the base case (\$m, PV)

Option	Central	Low risk cost scenario	High risk cost scenario	Weighted
<i>Scenario weighting</i>	33%	33%	33%	
Option 1	102.85	75.59	130.12	102.85
Option 2	103.69	76.42	130.96	103.69
Option 3	110.99	81.26	140.72	110.99

Figure 6-1 Net economic benefits (\$m, PV)



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

6.3. Sensitivity testing

We have undertaken sensitivity testing to examine how the net economic benefit of the credible options changes with respect to changes in key modelling assumptions. 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 PACR are:

- Optimal timing of the project
- Alternate 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.

6.3.1. 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:

- a 25% increase / decrease in capital costs
- a lower discount rate of 3.63% and a higher discount rate of 10.5%
- a 30% increase / decrease in the VCR

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 6-2 Distribution of optimal timing under a range of different key assumptions



6.3.2. 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).

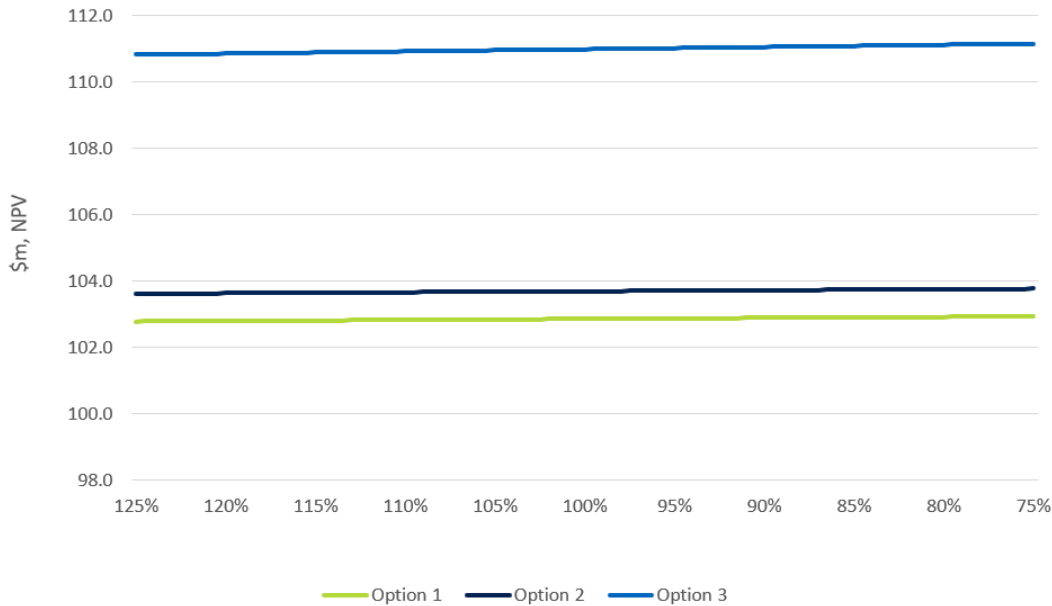
6.3.3. Value of customer reliability

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 6-4 Sensitivity of net economic benefits under a lower and higher VCR (\$2024/25m)

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

Figure 6-1 Sensitivity of net economic benefits under a lower and higher VCR (\$2024/25 m)



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

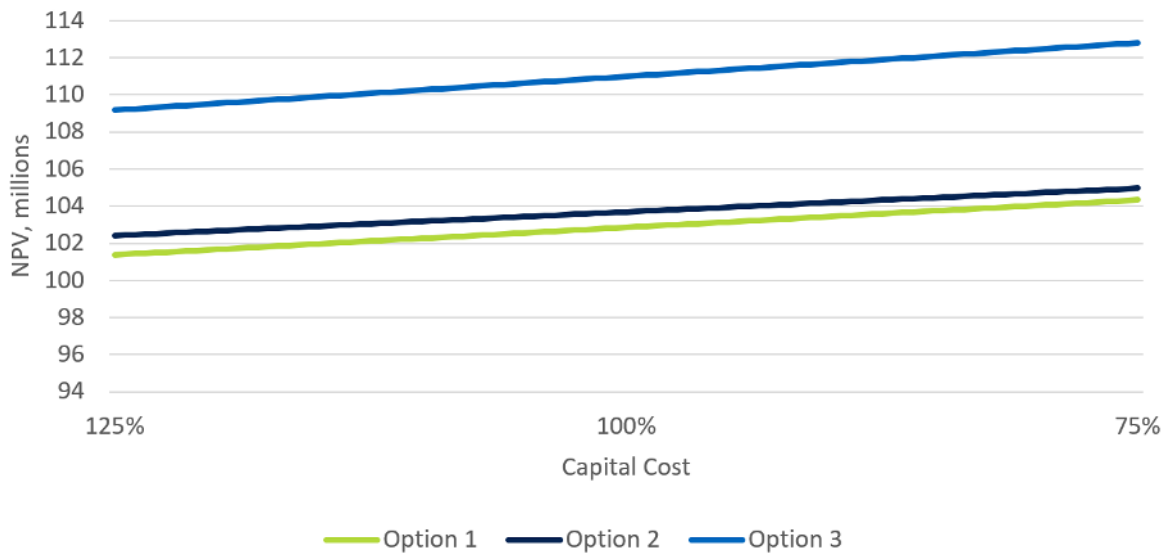
6.3.4. Network capital costs

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 6-5: Sensitivity of net economic benefits under lower and higher capital costs (\$2024/25 m)

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

Figure 6-2: Sensitivity of net economic benefits 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.

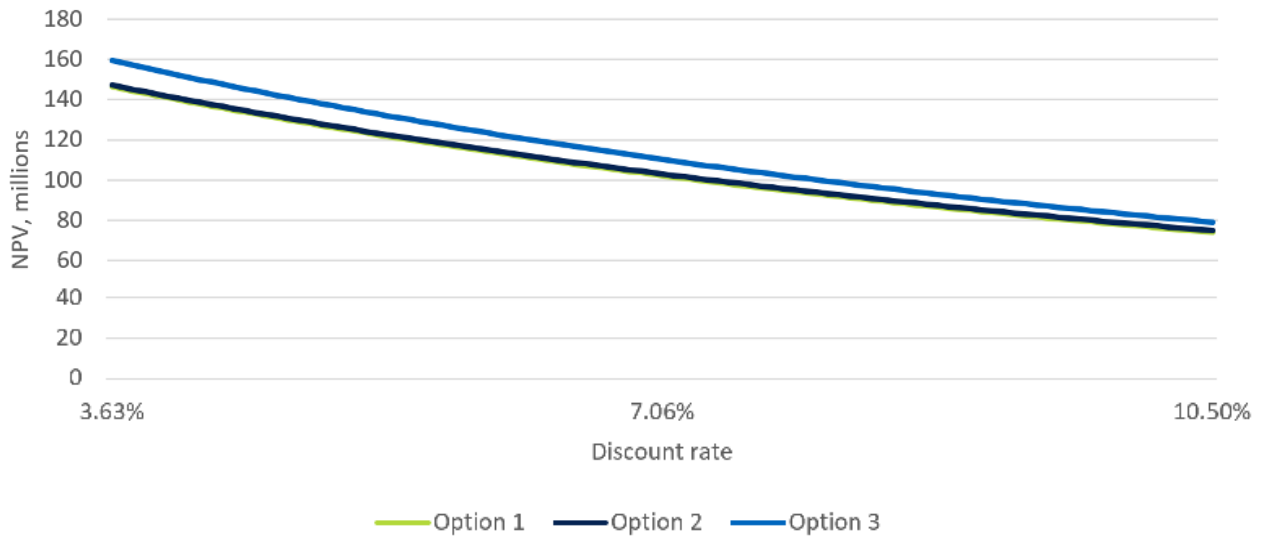
6.3.5. Discount rate

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 6-6: Sensitivity of net economic benefits under a lower and higher discount rates (\$2024/25 m)

Option/scenario	Low discount rate	High discount rate	Ranking
<i>Sensitivity</i>	3.63%	10.50%	
Option 1	73.96	146.44	3
Option 2	74.84	147.18	2
Option 3	79.02	159.41	1

Figure 6-3 Sensitivity of net economic benefits 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.

7. Final conclusion on the preferred option

The analysis in this PACR finds that Option 3 is the preferred option to address the identified need. 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). 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).

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.

Option 3 is the preferred option in accordance with NER clause 5.15A.2(b)(12) because it is the credible option that maximises the net present value of the net economic benefit to all those who produce, consume and transport electricity in the market. The analysis undertaken and the identification of Option 3 as the preferred option satisfies the RIT-T.

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PACR with the requirements of the National Electricity Rules version 220.

Rules clause	Summary of requirements	Relevant section(s) in the PACR
5.16.4(v)	The project assessment conclusions report must set out:	–
	(1) the matters detailed in the project assessment draft report as required under paragraph (k); and	See below.
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought under paragraph (q).	NA
5.16.4(k)	The project assessment draft report must include:	–
	(1) a description of each credible option assessed;	3
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	NA
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	3 & 6
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	4 & 5
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	4
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	NA
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	6
	(8) the identification of the proposed preferred option;	7
(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide:	3 & 7	
(i) details of the technical characteristics;		
(ii) the estimated construction timetable and commissioning date;		
(iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and		
(iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.		

	<p>(10) if each of the following apply to the RIT-T project:</p> <ul style="list-style-type: none"> (i) if the estimated capital cost of the proposed preferred option is greater than \$103 million (as varied in accordance with a cost threshold determination); and (ii) AEMO is not the sole RIT-T proponent, The RIT-T reopening triggers applying to the RIT-T project. 	<p>NA</p>
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In addition, the table below outlines a separate compliance checklist demonstrating compliance with the binding guidance in the latest AER RIT-T guidelines.

Guidelines section	Summary of the requirements	Section in the PACR
3.5A.1	<p>Where the estimated capital costs of the preferred option exceeds \$103 million (as varied in accordance with a cost threshold determination), a RIT-T proponent must, in a RIT-T application:</p> <ul style="list-style-type: none"> i. outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T ii. for all credible options (including the preferred option), either <ul style="list-style-type: none"> • apply the cost estimate classification system published by the AACE, or • if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate 	NA
3.5A.2	<p>For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T:</p> <ul style="list-style-type: none"> i. all key inputs and assumptions adopted in deriving the cost estimate ii. a breakdown of the main components of the cost estimate iii. the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates) iv. the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied v. the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance 	6.2
3.5.3	<p>The RIT-T proponent is required to provide the basis for any social licence costs in their RIT-T reports and may choose to refer to best practice from a reputable, independent and verifiable source.</p>	NA ²⁸
3.8.2	<p>Where the estimated capital cost of the preferred option exceeds \$103 million (as varied in accordance with an applicable cost threshold determination), a RIT-T proponent must undertake sensitivity analysis on all credible options, by varying one or more inputs and/or assumptions.</p>	NA
3.9.4	<p>If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain:</p> <ul style="list-style-type: none"> • the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and • how the level or quantum of the contingency allowance was determined. 	NA
4.1	<p>RIT-T proponents are required to describe in each RIT-T report</p> <ul style="list-style-type: none"> • how they have engaged with local landowners, local council, local community members, local environmental groups or traditional owners and sought to address any relevant concerns identified through this engagement • how they plan to engage with these stakeholder groups, or • why this project does not require community engagement 	NA ²⁸

²⁸ These are new requirements stipulated in revised RIT-T Application Guidelines released by the AER, which came into effect on 21 November 2024. For compliance purposes, the AER only have regard to the guidance that was in effect when Transgrid initiated the RIT-T in question. In this context, initiated means from the publication of a project specification consultation report (PSCR). As the PSCR was published prior to 21 November 2024, these new requirements are not applicable to this RIT-T.

Appendix B Risk Assessment Methodology

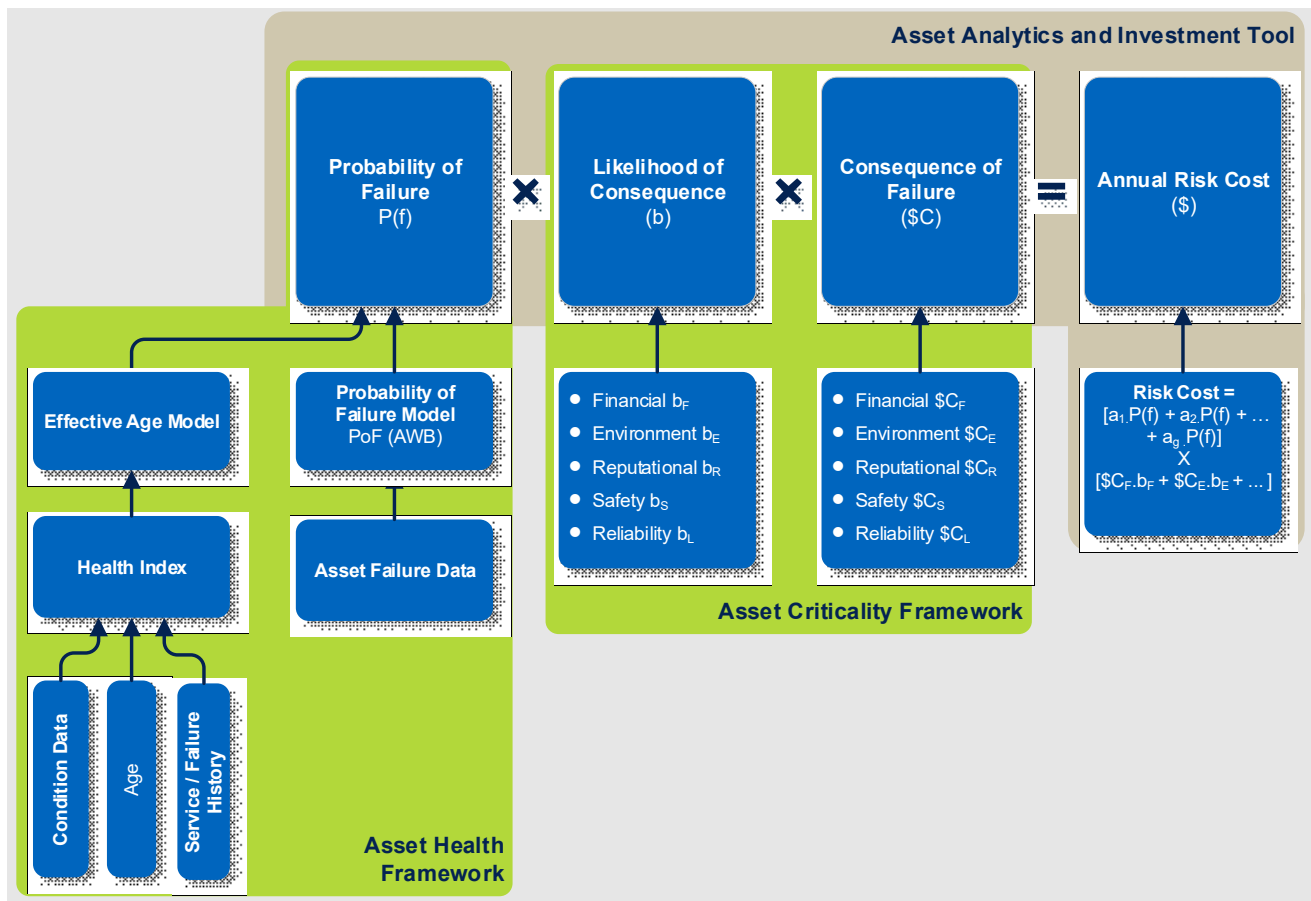
This appendix summarises our network risk assessment methodology that underpins the identified need for this RIT-T. Our risk assessment methodology is aligned with the AER’s Asset Replacement Planning guideline²⁹ and its principles.

A fundamental part of the risk assessment methodology is calculating the annual ‘risk costs’ or the monetised impacts of the 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 below summarises the framework for calculating the ‘risk costs’, which has been applied on our asset portfolio considered to need replacement or refurbishment.

Figure C-1 Risk cost calculation



Economic justification of repx to address an identified need is supported by risk monetised benefit streams, to allow the costs of the project or program to be assessed against the value of the avoided risks

²⁹ [Industry practice application note - Asset replacement planning, AER July 2024](#)

and costs. The major quantified risks we apply for repex 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](#).

Appendix C Asset Health and Probability of Failure

The first step in calculating the Probability of Failure (PoF) of an asset is determining the asset health and associated effective age,³⁰ which considers that:

- 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, where 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, external stresses, overloads and faults; and
- '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 PoF is the likelihood that an asset will fail during a given period resulting in a particular adverse event, e.g., equipment failure, pole failure, broken overhead conductor.

The outputs of the PoF calculation are one or more probability of failure time series which provide a mapping between the effective age 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 probability of failure curve for key transmission line components are summarised in Table below.

Further details are available in our [Network Asset Health Methodology](#).

Table D-1 Weibull parameters for asset components

Asset	Weibull parameters	
	η	β
Transformer	54.21	3.61
Oil Reactor	38.84	2.95
Circuit Breaker	47.76	4.3
Oil filled Current Transformer	50	3.08
Magnetic Voltage Transformer	50	3.8
Capacitive Voltage Transformer	50	3.8
Disconnecter	67	4.8
Surge Arrester	55	3.2
Auxillary Transformer	70	4.5

³⁰ Apparent age of an asset based on its condition.

Asset	Weibull parameters	
	η	β
Capacitor bank	50	4.5
Multifunction Intelligent Electronic Device: - Protection - Controller - Telecommunication	14.3	1.78
Protection Relay - Solid State	32.7	1.24
Protection Relay - Electromechanical	92.9	1.57
Protection Relay - Intertrip	26.2	1.54
Remote Terminal Unit	22.5	1.77
PC	12.7	2.09
Meter - Microprocessor	15.5	1.74
DC Battery	16.5	1.49
DC Charger	19.8	1.24

Appendix D Option 3 concept scoping drawing

