Transgrid

People. Power. Possibilities.

Maintaining safe and reliable operation of Beryl substation

RIT-T Project Specification Consultation Report

Region: Central West NSW

Date of issue: 18 May 2023

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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 Beryl Substation. Publication of this Project Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

Beryl substation was commissioned in 1976 and forms part of our network that serves the central west NSW area and is supplied via two 132kV feeders (Line 94B and 94M), and feeds six customer 66kV lines operated by Essential Energy. The substation is expected to continue to play a central role in the safe and reliable operation of the power system throughout and after the transition to a low-carbon electricity future. The central west NSW area is expected to experience strong growth over the next 10 years, with maximum demand forecast to grow by approximately 17% by 2031/32.[1]

The condition of certain 132 kV and 66 kV high voltage and secondary system assets at Beryl substation has deteriorated over time leading to an increasing risk of failure which could result in reliability, safety, environment and financial consequences. The secondary systems assets are also impacted by obsolescence of the equipment, increasing the time to reactively rectify faults and increasing the risk that primary assets at the substation may not be able to reliably operate.

The purpose of this PSCR 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 Beryl substation.

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

The identified need for this project is to maintain the safe and reliable operation of Beryl substation and the broader transmission network in NSW by addressing the risk of failure of certain high voltage and secondary systems at the substation.

Condition assessments performed through our routine maintenance program has shown degradation in the condition of these high voltage and secondary systems assets which will increase their risk of failure. Without intervention, other than ongoing business-as-usual maintenance, the assets are expected to deteriorate further and more rapidly. This will increase the risk of supply interruptions to our customers as well as safety, environmental and financial consequences.

The secondary system assets are also subject to obsolescence of the equipment. This means that the technology is no longer being manufactured or supported and reactive replacement of failed secondary systems component is not sustainable and impacts our ability to meet the requirements of the National Electricity Rules (NER).

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 to be the case under the base case), including obligations set out in Schedule 5.1 of the NER to provide redundant secondary systems and ensure that the transmission system is adequately protected.

[1] Transgrid, NSW Transmission Annual Planning Report 2022, p.128.

One credible network option has been identified

We have identified one credible network option that meets the identified need from a technical, commercial, and project delivery perspective.[2] This option is summarised in the below. Table 1-2 below presents a list of the specific assets with deteriorating condition to be replaced under Option 1.

Table 1-1: Summary of the credible options

Option	Description	Capital costs ($M, 2021-22)	Operating costs ($M/yr, 2021-22)
Option 1	Targeted replacement of high voltage and secondary system assets	7.06	0.02

Table 1-2: List of assets to be replaced under Option 1

Item	Asset
Protection relays	Line 94B 132kV – No2 Protection 66kV Capacitor No.2 - No1 Protection 66kV Capacitor No.2 - No2 Protection 66kV Capacitor No.3 - No1 Protection 66kV Capacitor No.3 - No2 Protection 66kV Capacitor No.4 - No1 Protection 66kV Capacitor No.4 - No2 Protection Line 86J 66kV – No1 Protection Line 86J 66kV – No1 Protection Line 80R 66kV – No1 Protection Line 80R 66kV – No1 Protection Line 381 66kV – No1 Protection Line 381 66kV – No1 Protection Line 851 66kV – No1 Protection Line 851 66kV – No1 Protection Line 80U 66kV – No1 Protection Line 80U 66kV – No1 Protection Line 852 66kV – No1 Protection Line 852 66kV – No1 Protection
Control systems	110V DC Supply – No1. Battery 110V DC Supply – No1. Charger 110V DC Supply – No2. Battery 110V DC Supply – No2. Charger
Metering systems	Transformer No.2 - Revenue metering Transformer No.2 - Check metering Transformer No.3 - Revenue metering Transformer No.3 - Check metering
Capacitor banks	66kV 10MVAr No.2 Capacitor Bank
Disconnectors	132kV busbar section 2 132kV busbar section 3
Current transformers	66kV No.3 Transformer

[2] As per clause 5.15.2(a) of the NER.

Non-network options are not expected to be able to assist with 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 will not mitigate the safety and environmental risk and are not able to meet NER obligations to provide redundant secondary systems and ensure that the transmission system is adequately protected.

Option 1 delivers the highest net economic benefit and will meet NER requirements

We have assessed that Option 1 is net beneficial under all three reasonable scenarios considered in this PSCR. On a weighted basis, where each scenario is weighted equally, Option 1 is expected to deliver net benefits of approximately $76.39m. Option 1 will also enable us to meet a range of obligations under the NER and jurisdictional instruments (which is not expected to be the case under the base case), including obligations set out in Schedule 5.1 of the NER to provide redundant secondary systems and ensure that the transmission system is adequately protected.

Draft Conclusion

This PSCR finds that Option 1 is the preferred option to address the identified need. Option 1 involves targeted replacement of high voltage and secondary system assets at Beryl substation that have deteriorating condition and have reached (or will soon reach) the end of their technical lives and for which only limited manufacturer support and spares are available.

The capital cost of this option is approximately $7.06 million (in $2021-22). The work will be undertaken over a five-year period with all works expected to be completed by 2027/28. Routine operating and maintenance costs are estimated at approximately $0.02 million per annum (in $2021-22).

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 preferred option is less than $46 million;[3]
- we have identified in this PSCR our preferred option and the reasons for that option, and noted that we will be exempt from publishing the PADR for our preferred option; and
- we consider that the preferred option and any other credible options do not have a material market benefit (other than benefits associated with changes in voluntary load curtailment and involuntary load shedding).

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)

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

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 15 August 2023[5] and should be emailed to our Regulation team via regulatory.consultation@Transgrid.com.au.[6] In the subject field, please reference 'Beryl substation renewal 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 September 2023.

4 In accordance with NER clause 5.16.4(z2).
5 Consultation period is for 12 w eeks, 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 maintaining the safe and reliable operation of Beryl substation. Publication of this Project Specification Consultation Report (PSCR) is the first step in the RIT-T process.

Beryl substation will continue to play a central role in the safe and reliable operation of the power system throughout and after the transition to a low-carbon electricity future. The central west NSW area is expected to experience strong growth over the next 10 years, with maximum demand forecast to grow by approximately 17% by 2031/32.[7]

The condition of certain 132 kV and 66 kV high voltage and secondary system assets at Beryl substation has deteriorated over time leading to an increasing risk of failure which could result in reliability, safety, environment and financial consequences. The secondary systems assets are also impacted by obsolescence of the equipment, increasing the time to reactively rectify faults and increasing the risk that primary assets at the substation may not be able to reliably operate.

The purpose of this PSCR 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 Beryl substation.

1.1 Purpose of this report

The purpose of this PSCR[8] is to:

- set out the reasons why Transgrid proposes that action be taken (the 'identified need')
- present the options that Transgrid is currently considering to address the identified need
- outline the technical characteristics that non-network options would need to provide
- 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 preferred option is less than $46 million;[9]
- we have identified in this PSCR our preferred option and the reasons for that option, and noted that we will be exempt from publishing the PADR for our preferred option; and

7 Transgrid, NSW Transmission Annual Planning Report 2022, p.128.
8 See Appendix A for the National Electricity Rules requirements.
9 Varied from $43m to $46m based on the AER Final Determination: Cost threshold review, November 2021.

- we consider that the preferred option and any other credible options do not have a material market benefit (other than benefits associated with changes in voluntary load curtailment and involuntary load shedding).

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.

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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 September 2023.

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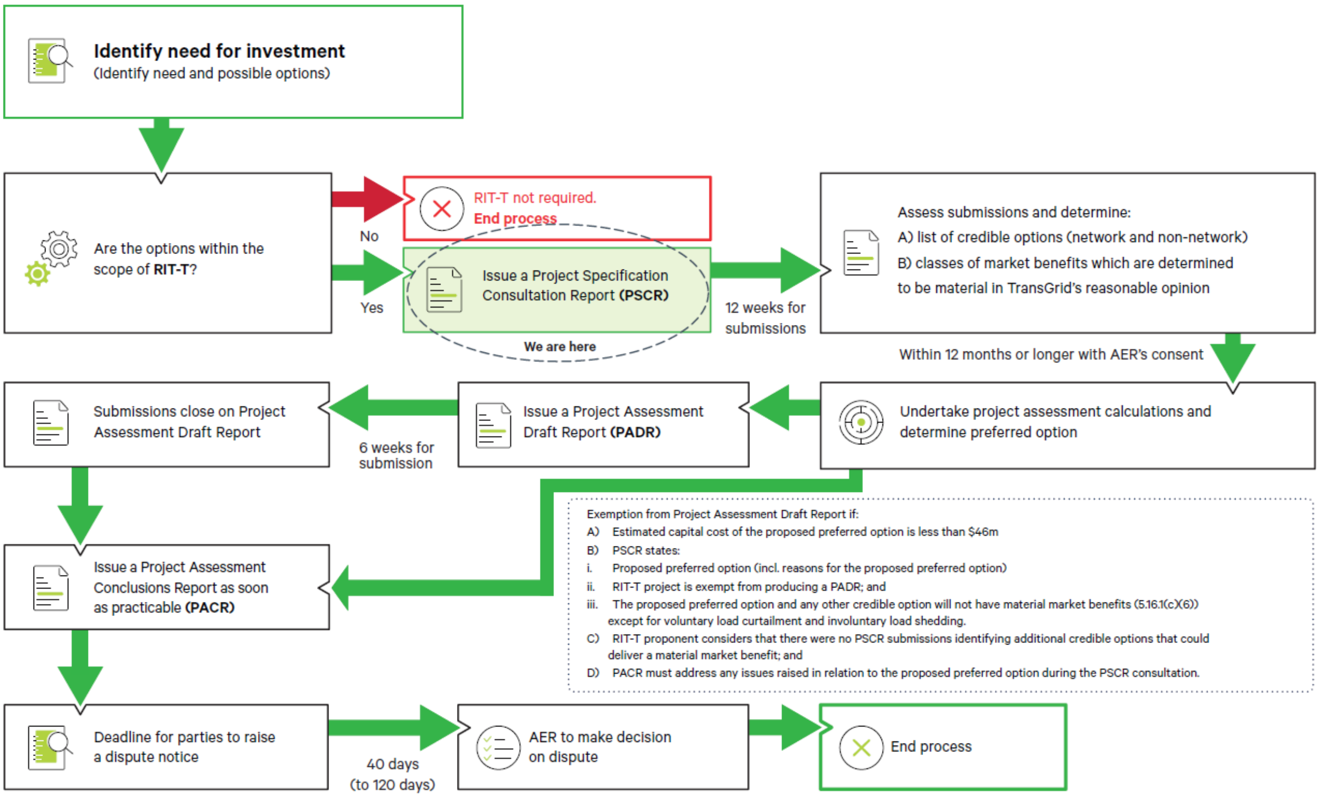
Figure 1-1 This PSCR is the first stage of the RIT-T process



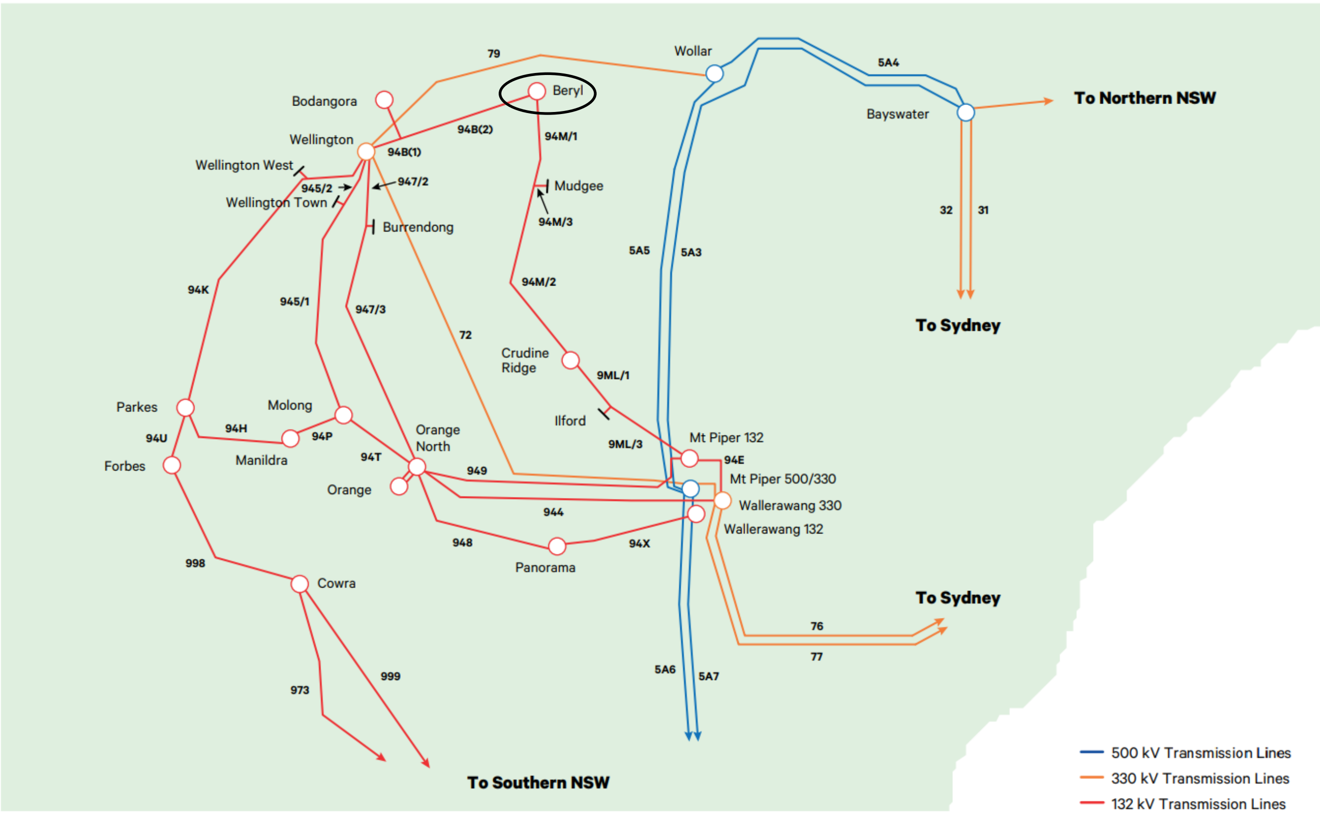
2. The identified need

2.1 Background to the identified need

Beryl substation was commissioned in 1976 and forms part of our network that serves the central west NSW area. It is supplied via two 132kV feeders (Line 94B and 94M) and feeds six customer 66kV lines operated by Essential Energy. These 66kV feeders run between Beryl substation and Essential Energy substations in the surrounding area, including the Mudgee, Ulan and Dunedoo regions. The Beryl substation is comprised of two 132/66kV transformers, one 66kV frequency injection feeder, and three 66kV capacitor banks.

A map showing the location of Beryl substation on our network is shown in Figure 2-1.

Figure 2-1 Location of Beryl substation

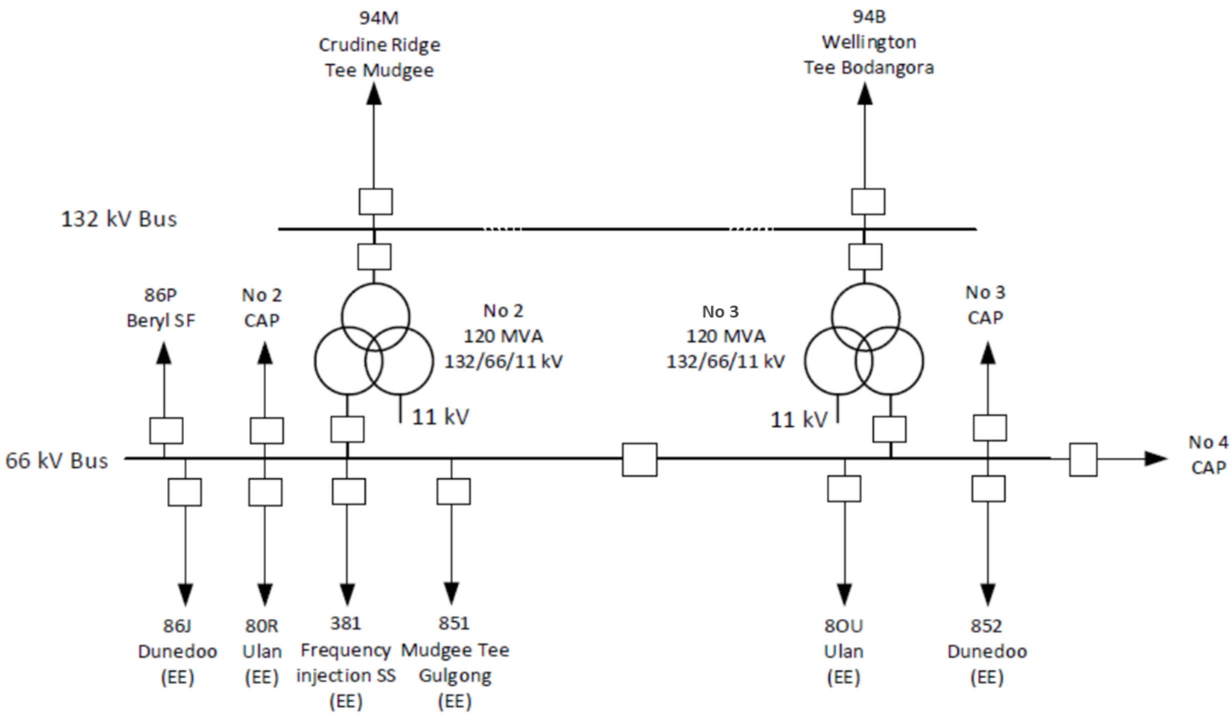


Beryl substation will continue to play a central role in the safe and reliable operation of the power system throughout and after the transition to a low-carbon electricity future. The central NSW area is expected to experience strong growth over the next 10 years. Maximum demand is forecast to be 90MW in 2022/23, and to increase to approximately 106MW by 2031/32 (an increase of around 17%).[13]

The existing electrical layout of Beryl 132kV substation is shown in Figure 2-2.

[13] Transgrid, *NSW Transmission Annual Planning Report 2022*, p.128.

Figure 2-2 Beryl 132kV substation electrical layout



2.2 Description of the identified need

The identified need for this project is to maintain the safe and reliable operation of Beryl substation and the broader transmission network in NSW by addressing the risk of failure of certain high voltage and secondary systems at the substation.

Condition assessments performed through our routine maintenance program has shown degradation in the condition of these high voltage and secondary systems assets which will increase their risk of failure. Without intervention, other than ongoing business-as-usual maintenance, the assets are expected to deteriorate further and more rapidly. This will increase the risk of supply interruptions to our customers as well as safety, environmental and financial consequences.

Secondary systems are used to control, monitor, protect and secure communication to facilitate safe and reliable network operation. They are necessary to ensure the secure operation of the transmission network and prevent damage to primary assets when adverse events occur.

A failure of the secondary systems would require replacement of the failed component and/or taking the affected primary assets, such as lines and transformers, out of service. While the replacement of failed secondary systems component is a possible interim measure, the approach is not sustainable as spare components will deplete due to the technology no longer being manufactured or supported. Once all spares are used, asset replacement will cease to be a viable option to meet performance standards applicable to Beryl substation secondary systems. Increasing failure rates, along with the increased time to rectify faults due to the obsolescence of the equipment, significantly affects the availability and reliability of the secondary systems at Beryl substation and their ability to continue to meet the requirements of the NER.

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 to be the case under the base case).

In particular, s5.1.2.1(d) requires TNSPs to ensure that all protection systems for lines at a voltage above 66 kV are well-maintained so as to be available at all times other than for short periods (less than eight hours), while the maintenance of protection systems is being carried out. In the event of an unplanned outage, AEMO's Power System Security Guidelines require that the primary network assets must be taken out of service within 24 hours.[14] Under s5.1.9(c), TNSPs must provide sufficient primary and back-up protection systems, including breaker fail protection systems and any communications facilities on which the protection systems depend, to ensure that a fault of any type anywhere on our transmission system is automatically disconnected. In addition, clause 4.11.1 of the NER, remote monitoring and control systems are required to be maintained in accordance with the standards and protocols determined and advised by AEMO.

2.3 Assumptions underpinning the identified need

We adopt a risk cost framework to quantify and evaluate the risks and consequences of increased failure

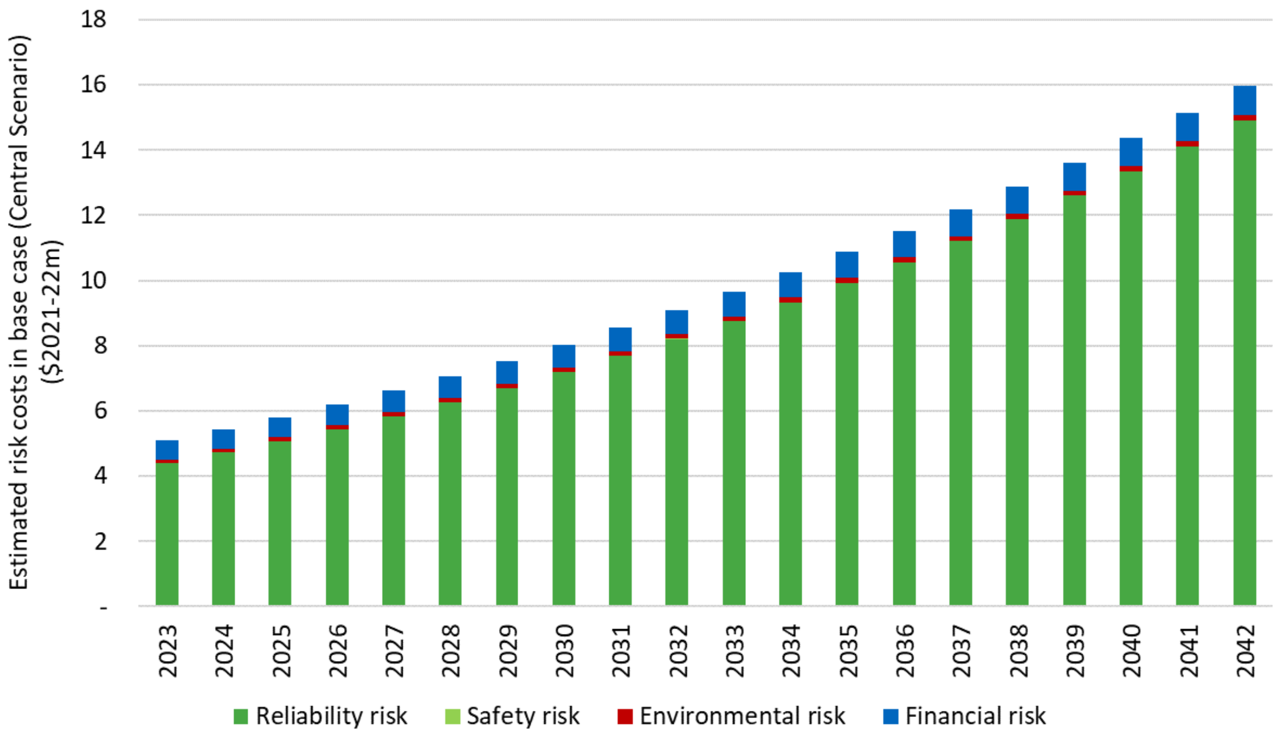
[14] AEMO, *Power System Security Guidelines*, 6 February 2023, p.33.

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 2-3 summarises the increasing risk costs over the assessment period under the base case.

Figure 2-3 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 $5.1 million/year and it is expected to increase going forward if action is not taken and the line is left to deteriorate further (reaching approximately $8.0 million/year by 2030 and $16.0 million/year by the end of the 20-year assessment period).

2.3.1 Asset health and the probability of failure

2.3.1.1 Protection relays

Protection relays are assets the monitor the network and trip circuit breakers when an abnormality in operating conditions is detected. They protect other components of the electricity system by ensuring faults are cleared within the times specified in the NER.[15]

[15] S5.1a.8 of the NER outlines the requirements regarding fault clearance times, including the specific maximum permitted fault clearance times

We have identified the following protection relays at Beryl substation are experiencing increasing failure rates, manufacturer obsolescence and a lack of support and are targeted for replacement.

Table 2-1: Protection relays considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
Line 94B 132kV – No2 Protection	11	Exceeded technical life and relay type experiencing increased failure rates Technology obsolescence resulting in a lack of spares and no manufacturer support
66kV Capacitor No.2 - No1 Protection	54	
66kV Capacitor No.2 - No2 Protection	54	
66kV Capacitor No.3 - No1 Protection	13	
66kV Capacitor No.3 - No2 Protection	12	
66kV Capacitor No.4 - No1 Protection	13	
66kV Capacitor No.4 - No2 Protection	12	
Line 86J 66kV – No1 Protection	13	
Line 86J 66kV – No1 Protection	12	
Line 80R 66kV – No1 Protection	37	
Line 80R 66kV – No1 Protection	37	
Line 381 66kV – No1 Protection	12	
Line 381 66kV – No1 Protection	15	
Line 851 66kV – No1 Protection	16	
Line 851 66kV – No1 Protection	13	
Line 80U 66kV – No1 Protection	37	
Line 80U 66kV – No1 Protection	37	
Line 852 66kV – No1 Protection	16	
Line 852 66kV – No1 Protection	37	

The protection relays are at or beyond the end of their technical life. If left unreplaced, it is likely that a number of these assets will fail at an increasing rate going forward. This may result in involuntary load shedding on parts of the network and increased costs to replace these assets in a reactive fashion. Like-for-like replacements in the event of failures are not feasible due to the absence of technical support from the manufacturers. This will mean that replacing the currently installed protection relays after a failure will take considerably longer and result in significant corrective maintenance costs as new relays will be required rather than components. Replacement of the protection relays is required to ensure compliance with the NER, including requirements around maintaining adequate protection systems[16] and maximum clearance times.[17]

2.3.1.2 Control systems

Control assets allow for the remote monitoring, control and automation of primary assets. These assets allow us to operate and monitor the status of unmanned substations and switching stations throughout the state. These assets also collect significant amounts of status and condition information to facilitate some level of remote diagnostics during failures and faults.

We have identified the following control system assets at Beryl substation experiencing increasing failure rates which are targeted for replacement.

Table 2-2: Control systems considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
110V DC Supply – No1. Battery	16	Exceeded technical life and component type experiencing increased failure rates Technology obsolescence resulting in a
110V DC Supply – No1. Charger	23	
110V DC Supply – No2. Battery	13	
110V DC Supply – No2. Charger	15	

These control systems have reached the end of their technical life, increasing the risk that they will not operate properly when required. A failure of control systems will significantly undermine our ability to operate the substation remotely, and to detect failures in other substation assets when they occur. Replacement of these control systems is required to ensure compliance with the NER, including requirements to ensure that remote monitoring and control systems are maintained in accordance with the standards and protocols determined and advised by AEMO.[18]

2.3.1.3 Metering systems

Metering systems located at customer connection points in our substations record the amount of power being transmitted at that point. Their purpose is to provide metering data for NEM settlement.

We have identified the following metering systems at Beryl substation experiencing increasing trends in failure rates and manufacturer obsolescence which are targeted for replacement.

[16] NER, s5.1.2.1(d) and s5.1.9(c).
[17] NER, s5.1a.8.
[18] NER, clause 4.11.1.

Table 2-3: Metering systems considered under this RIT-T

Asset	Effective age (years as at 2027/28)	Key issues
Transformer No.2 - Revenue metering	15	Exceeded technical life and component type experiencing increased failure rates Technology obsolescence resulting in a lack of spares and no manufacturer support
Transformer No.2 - Check metering	14	
Transformer No.3 - Revenue metering	15	
Transformer No.3 - Check metering	14	

The identified metering assets have reached the end of their technical life, increasingly the likelihood of asset failure. If a malfunction occurs, clause 7.8.10 of the NER requires us to repair the metering system within 2 days. However, technological obsolescence means that access to spares and manufacturer support is limited. This will increase the time required to undertake the repair, and so the likelihood that the asset may be out of service for an extended period of time in breach of clause 7.8.10 of the NER.

2.3.1.4 Capacitor banks

Capacitor banks are required to ensure that system voltage levels are maintained within ±10% of nominal voltage which is a requirement under the NER Clause S5.1.a.4.

We have identified the following capacitor bank at Beryl substation experiencing condition deterioration with limited spare equipment available in the event of a failure.

Table 2-4: Capacitor banks considered under this RIT-T

Asset	Effective age (years as at 2027/28)	Key issues
66kV No. 2 Capacitor Bank	45	Condition deterioration Limited spare capacitor cans and no spare reactors

In assessing the ongoing viability of this capacitor bank, we have considered several factors. This includes existing holdings of spares and the ability to source more spares; the general condition of the equipment; and its age. The identified capacity bank has been in service longer than its expected economic life, which is 30 years. We do not currently hold any spare reactors, and only possess a limited number of spare cans which are expected to deplete quickly. Given its age, the ability to source additional spares in a reasonable time period is challenging due to reduced manufacturer support.

If left unreplaced, the likelihood that the identified capacity bank will fail is expected to increase significantly as the capacity bank continues to age. If the capacitor bank is not available at times of high load, load shedding will be required to take place for customers in central west NSW to ensure that system voltage levels remain within ±10% as required by the NER.[19] Given the limited availability of spares, the duration of such outages will also be expected to increase over time. On the basis of this assessment, we consider

[19] NER, clause S5.1.a.4.

that replacing the identified capacitor bank would be expected to result in economic benefits for consumers by reducing the risk of load shedding.

2.3.1.5 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 circuit breakers.

We have identified the following disconnectors at Beryl substation experiencing condition deterioration with limited spare equipment available in the event of a failure.

Table 2-5: Disconnectors considered under this RIT-T

Asset	Effective age (years as at 2027/28)	Key issues
Disconnector 132kV busbar section 2	52	Condition deterioration Technology obsolescence resulting in a lack of spares and no manufacturer support
Disconnector 132kV busbar section 3	52	

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.

2.3.1.6 Current transformers

Current transformers (CTs) are high voltage equipment whose purpose on the network is to transform main system current levels to a range that is useable by secondary systems equipment. CTs are typically installed in a set of three in a switch bay and are essential for the control, protection and revenue metering of the high voltage network.

We have identified the following current transformer at Beryl substation with condition deterioration for replacement.

Table 2-6: Current transformers considered under this RIT-T

Asset	Effective age (years as at 2027/28)	Key issues
66kV No.3 Transformer	36	Condition deterioration

The identified CTs at Beryl substation are oil filled CTs. These assets will reach the end of their economic life before 2027/28. As oil filled CTs age, the following conditions materialise which increase the risk of asset failure:

- Degradation of the high voltage oil and paper insulation system due to electrical stress
- Oil leaks due to degradation of seals and outer housing
- Corrosion due to weathering

If left unreplaced, continued degradation in the condition of the asset will significantly increase the risk of asset failure and the risk of unplanned network outages. There will be an increased cost to replace the assets upon failure in a reactive fashion. A failure can also pose serious safety and environmental hazards. Oil filled CTs have the highest risk of explosive failure which can result in the risk of injuring people, cause collateral damage and outages of nearby services due to the porcelain insulator being ejected from the failed asset, and other environmental issues such as fires. Replacing the identified CTs at Beryl substation will reduce the risk of involuntary load shedding for customers in central west NSW, and reduce the risk of safety and environmental hazards associated with any catastrophic failures occurring.

2.3.2 Reliability risk

We have considered the risk of unserved energy for customers following a failure of one or more of the high voltage and secondary systems assets identified in this PSCR. The likelihood of a consequence takes into account the likelihood of contingent planned/unplanned outages, the anticipated load restoration time (based on the expected time to undertake any repair work), and the load at risk (based on forecast demand). The monetary value is based on an assessment of the value of customer reliability, which measures the economic impact to affected customers of a disruption to their electricity supply.

Reliability risk makes up 90.4 per cent of the total estimated risk cost in present value terms.

2.3.3 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 takes into account the frequency of workers on-site, the duration of maintenance and capital work on-site, and the probability and area of effect of an explosive asset failure. The monetary value takes into account 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.

2.3.4 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 takes into account 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 bushfires. The monetary value takes into account 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 1.5 per cent of the total estimated risk cost in present value terms.

2.3.5 Financial risk

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

Financial risk makes up 8.2 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 is only one technically and commercially feasible option to address the identified need.[20] This involves targeted replacement of the high voltage and secondary systems assets at Beryl substation that have reached, or will reach by 2027/28, the end of their technical life based on an assessment of their age, condition, and technological obsolescence. This option is summarised in the table below. 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 credible options

Option	Description	Estimated capex ($M, 2021-22)	Expected commission date (Financial year)
1	**Targeted replacement of high voltage and secondary systems assets at Beryl substation**	**7.06**	
	A) Protection relays	2.36	2028
	B) Control	0.12	2028
	C) Metering	0.25	2028
	D) Capacitor bank	3.03	2025
	E) Disconnectors	1.13	2028
	F) Current Transformers	0.16	2028

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.:[21]

> “*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, no proactive capital investment is made to remediate the deterioration of the high voltage and secondary systems assets at Beryl substation, or to address the technological obsolescence, spares unavailability, and discontinued manufacturer support for these assets. The assets will continue to be operated and maintained under the current regime.

[20] As per clause 5.15.2(a) of the NER.
[21] AER, *Regulatory Investment Test for Transmission Application Guidelines,* August 2020, p. 21.

The table below provides a breakdown of the expected operating expenditure under the base case.

Table 3-2 Breakdown of operating expenditure under the base case (($M, 2021-22))

Item	Operating expenditure ($M, 2021-22)
Protection relays	0.010
Control systems	0.000
Metering systems	0.004
Capacitor banks	0.001
Disconnectors	0.001
Current transformers	0.001
Total	**0.017**

Under the base case, increases to the regular maintenance regime will not be able to mitigate the risk of asset failure due to continued deterioration in asset condition. This will lead to an increase in the probability of failure at Beryl substation. Rectification of asset failures will take longer due to the limited availability of spares and discontinued manufacturer support. This will lead to an increase in the duration of an outage when it occurs at Beryl substation.

These factors will increase the risk of prolonged and frequent involuntary load shedding for end-customers. We have estimated that the cost of involuntary load shedding due to asset failure at Beryl substation will increase from approximately $889,000 in 2022/23 to approximately $8.42 million in 2032/33 (in $2021-22). The above factors will also expose us and our end-customers to greater environmental, safety and financial risks associated with catastrophic asset failure, such as increased risk of explosive failure resulting in injury to nearby people and collateral damage to nearby assets. We have estimated that environmental, safety and financial risks costs under the base case will be approximately $685,000 in 2022/23 and increase to $899,000 in 2032/33 (in $2021-22).

3.2 Option 1 – Targeted asset replacement at Beryl substation

Option 1 involves targeted replacement of high voltage and secondary system assets at Beryl substation that have reached, or will reach by 2027/28, the end of their technical life based on an assessment of their age, condition, and technological obsolescence. The option is based on a like-for-like replacement approach whereby the asset is replaced by its modern equivalent. The assets that will be replaced under this option are set out in the table below.

Table 3-3 Assets to be replaced under Option 1

Item	Asset
Protection relays	Line 94B 132kV – No2 Protection 66kV Capacitor No.2 - No1 Protection 66kV Capacitor No.2 - No2 Protection 66kV Capacitor No.3 - No1 Protection 66kV Capacitor No.3 - No2 Protection 66kV Capacitor No.4 - No1 Protection 66kV Capacitor No.4 - No2 Protection

	Line 86J 66kV – No1 Protection Line 86J 66kV – No1 Protection Line 80R 66kV – No1 Protection Line 80R 66kV – No1 Protection Line 381 66kV – No1 Protection Line 381 66kV – No1 Protection Line 851 66kV – No1 Protection Line 851 66kV – No1 Protection Line 80U 66kV – No1 Protection Line 80U 66kV – No1 Protection Line 852 66kV – No1 Protection Line 852 66kV – No1 Protection
Control systems	110V DC Supply – No1. Battery 110V DC Supply – No1. Charger 110V DC Supply – No2. Battery 110V DC Supply – No2. Charger
Metering systems	Transformer No.2 - Revenue metering Transformer No.2 - Check metering Transformer No.3 - Revenue metering Transformer No.3 - Check metering
Capacitor banks	66kV 10MVAr No.2 Capacitor Bank
Disconnectors	132kV busbar section 2 132kV busbar section 3
Current transformers	66kV No.3 Transformer

Overall, the work will be undertaken over a five-year period with all works expected to be completed by the end of 2027/28. The capital cost of this option is approximately $7.06 million (in $2021-22). Table 3-4 below provides a breakdown of the estimated capital cost.

Table 3-4 Capital cost of Option 1 ($M, 2021-22)

Capital cost	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Protection relays	0.472	0.472	0.472	0.472	0.472	2.360
Control systems	0.024	0.024	0.024	0.024	0.024	0.120
Metering systems	0.050	0.050	0.050	0.050	0.050	0.250
Capacitor banks	0.560	2.470	-	-	-	3.030
Disconnectors	-	-	-	-	1.134	1.134
Current transformers	-	-	-	-	0.16	0.160
Total	**1.106**	**3.016**	**0.546**	**0.546**	**1.841**	**7.055**

The routine operating and maintenance costs are estimated at approximately $0.02 million per annum (in $2021-22). We expect that the new protection relays, control systems, and metering systems will have an asset life of 15 years, the capacitor banks will have an asset life of 35 years, and the disconnectors and current transformers will have an asset life of 40 years.

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 in order to complete the works with minimal impact on the network.

Implementation of Option 1 is expected to reduce the probability of failure for high voltage and secondary systems at Beryl substation. This will reduce the frequency and duration of involuntary load shedding associated with the failure of these assets. Option 1 will also reduce the risk of asset failure, which will in turn reduce associated environmental, safety and financial risk costs.

3.3 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 3-5.

Table 3-5: Options considered but not progressed

Option	Reason(s) for not progressing
Complete in-situ replacement of protection relays, control systems, and metering systems and targeted replacement of the high voltage equipment	This option cannot be delivered in sufficient time to meet the identified need due to resource constraints imposed by our overall portfolio of work. This option would also be higher cost than the credible option assessed to meet the identified need.

3.4 No material inter-network impact is expected

We have considered whether the credible options listed above are expected to have material inter-regional impact.[22] A 'material inter-network impact' is defined in the NER as:[23]

> "*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.*"

By reference to AEMO's screening test for an inter-network impact,[24] 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.

22 As per clause 5.16.4(b)(6)(ii) of the NER.
23 Definition of 'material inter-network impact,' in the Glossary to the NER.
24 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 commercially and technically feasible to assist with meeting the identified need for this RIT-T. The objective of this identified need is to largely meet service level requirements in the NER for high voltage and secondary systems, as well as to avoid the increasing risks of asset failure.

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 the primary and secondary systems assets).

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 NER and whether they are considered material for this RIT-T.[25]

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 PSCR. In the base case, involuntary load shedding would be expected to occur following a failure of the high voltage or secondary systems assets at Beryl substation which would require taking affected primary assets, such as lines and transformers, out of service.

The probability of asset failure is expected or increase over time as the condition of the relevant assets continue to deteriorate. This is expected to increase the frequency of outages. Rectification of asset failures will take longer due to the limited availability of spares and discontinued manufacturer support. This is expected to increase the duration of outages.

We have estimated expected unserved energy under the base case and Option 1. These forecasts are based on probabilistic planning studies of failure rates and repair times. Option 1 significantly reduces the amount of expected unserved energy that would occur. The avoided unserved energy for a credible option is calculated as the difference between the expected unserved energy under the base case and the expected unserved energy under Option 1.

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 PSCR 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 the RIT-T proponent;
- changes in ancillary services costs;
- competition benefits; and
- Renewable Energy Target (RET) penalties.

[25] 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 (See: NER, clause 5.15A.2(b)(4)-(6). See Appendix A for requirements applicable to this document.

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5.3 No other classes of market benefits are material

In addition to the classes of market benefits identified above, the NER also requires us to consider the following classes of market benefits, listed in Table 5-1, arising from each credible option.[26] 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.[27] 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.[28] 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.
Changes in network losses	We do not expect any material difference in transmission losses between options.

[26] NER, clause 5.15A.2(b)(4)-(6).
[27] AER, *Regulatory Investment Test for Transmission Application Guidelines,* August 2020, p.53-54.
[28] AER, *Regulatory Investment Test for Transmission Application Guidelines,* August 2020, p.53-54.

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 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 the high voltage and secondary systems assets at Beryl substation, or to address the technological obsolescence, spares unavailability, and discontinued manufacturer support for these assets. We incur regular and reactive maintenance costs, and environmental, safety and financial related risks costs, that are caused by the failure of assets at Beryl substation. In addition, there would be a small avoided cost of routine operating and maintenance costs in option compared to the base case.

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.[29]

6.2 Assessment period and discount rate

The RIT-T analysis considers a 20-year assessment period from 2022/23 to 2041/42. A 20-year period takes into account the size, complexity and expected asset life of the secondary systems and provides a reasonable indication of the costs and benefits over a long outlook period.

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 and expected operating and maintenance cost for the remaining asset life. As a conservative assumption, we have effectively assumed that there are no additional cost and benefits after the analysis and period.

A real, pre-tax discount rate of 5.50 per cent has been adopted as the central assumption for the NPV analysis presented in this PSCR, consistent with the assumptions adopted in AEMO's 2022 Integrated System Plan (ISP).[30] 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 2.30 per cent.[31] We have also adopted an upper bound discount rate of 7.50 per cent (i.e., the upper bound proposed for the 2022 ISP).[30]

[29] 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,* August 2020, p.21).

[30] AEMO, *2022 Integrated System Plan, June 2022*, p 91.

[31] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powerlink-determination-2022%E2%80%9327/final-decision

6.3 Approach to estimating option costs

We have estimated the capital and operating 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 (ie, there is an equal likelihood of over- or under-spending the estimate total).[32]

We estimate that the actual cost is within +/- 25 per cent of the central capital cost. An accuracy of +/-25 per cent 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 real, 2021-22 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.[33] Since we are only assessing one credible option, the value of the VCR is not considered material to this RIT-T, i.e., it does not have any impact on the identification of the preferred option.

6.5 Three different scenarios have been modelled

The RIT-T must include any of the ISP scenarios from the most recent IASR that are relevant unless:[34]

- the RIT–T proponent demonstrates why it is necessary to vary, omit or add a reasonable scenario to what was in the most recent IASR, and
- the new or varied reasonable scenarios are consistent with the requirements for reasonable scenarios set out in the RIT–T instrument.

The AER's RIT-T Guidelines clarifies that the number and choice of reasonable scenarios must be appropriate to the credible options under consideration, and that the choice of reasonable scenarios must reflect any variables or parameters that are likely to affect the ranking or sign of the net benefit of any credible option.[35]

For the purposes of this RIT-T, we consider that the ISP scenarios are not relevant. The key input parameter that is likely to affect the ranking or sign of the net market benefits of the credible options is the

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[32] For further detail on our cost estimating approach refer to section 6 of our Repex Overview Paper submitted with our 2023-28 Revenue Proposal.

[33] AER, *Values of Customer Reliability, Final Report on VCR Values*, December 2019. Escalated to December 2022 values. Based on CPI inflation published by the AER in its annual VCR updates.

[34] AER, *Regulatory investment test for transmission*, August 2020, clause 20(b).

[35] AER, *Regulatory investment test for transmission: Application guidelines*, August 2020, p.41.

probability of failure and consequence of failure of the assets at Beryl substation. The probability and consequence is assessed by reference to the condition of the asset under consideration and the reliability, safety, environmental and financial consequences. These are independent from the assumptions underpinning the ISP scenarios. It follows that adopting the ISP scenarios would not be consistent with adopting scenarios that reflect parameters that could reasonably change the ranking or sign of the net market benefits of the credible options.

In line with the RIT-T Guideline, we have constructed reasonable alternative scenarios. To do this, we developed a **Central Scenario** which reflects our best estimate of each of the modelling parameters, including the asset risk (probability of failure and consequence of failure), expected unserved energy, and capital and operating costs. We developed the Central Scenario around a static model of demand scenarios, described further in our 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 sign or ranking of the credible options.

As indicated above, we consider that the key input parameter that is likely to affect the ranking or sign of the net market benefits of the credible options is the asset failure risk of the identified high voltage and secondary systems assets. We do not consider that variations in other parameters of the Central Scenario are likely to affect the outcome of the RIT-T assessment. In view of this, we have developed additional reasonable scenarios that reflect variations in the asset risk while holding other parameters the same as the Central Scenario.

Specifically, we have developed the following additional scenarios:

- A **High Risk Costs Scenario**, where the asset failure risk is 25% higher than in the Central Scenario. This higher risk would be expected to increase the frequency and duration of outages, and safety, environmental and financial risk costs, in the base case (as compared with the Central Scenario). We have modelled this scenario by increasing our estimate of gross benefits associated with avoided unserved energy and risk costs in this scenario by 25%.
- A **Low Risk Costs Scenario**, where the asset failure risk is 25% lower than in the Central Scenario. This lower failure risk would be expected to reduce the frequency and duration of outages, and safety, environmental and financial risk costs, in the base case (as compared with the Central Scenario). We have modelled this scenario by reducing our estimate of gross benefits associated with avoided unserved energy and risk costs in this scenario by 25%.

The NPV results in this PSCR are reported for each scenario, as well as on a weighted basis. As we have no evidence or rationale for assigning a higher probability for one reasonable scenario over another, we have weighted each reasonable scenario equally.[36]

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

[36] As per: AER, *Regulatory investment test for transmission: Application guidelines*, August 2020, p.50.

Table 6-1 Summary of scenarios

Variable / Scenario	Central scenario	Low risk costs scenario	High risk costs scenario
Scenario weighting	33%	33%	33%
Discount rate	5.50%	5.50%	5.50%
VCR ($2021-22)	$46.86/kWh	$46.86/kWh	$46.86/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

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 value of customer reliability;
- lower and higher assumed capital costs; 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.

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

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 ($2021/22 m)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*33%*	*33%*	*33%*	
Option 1	81.11	60.83	101.38	81.10

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 costs relative to the base case ($2021/22 m)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*33%*	*33%*	*33%*	
Option 1	5.76	5.76	5.76	5.76

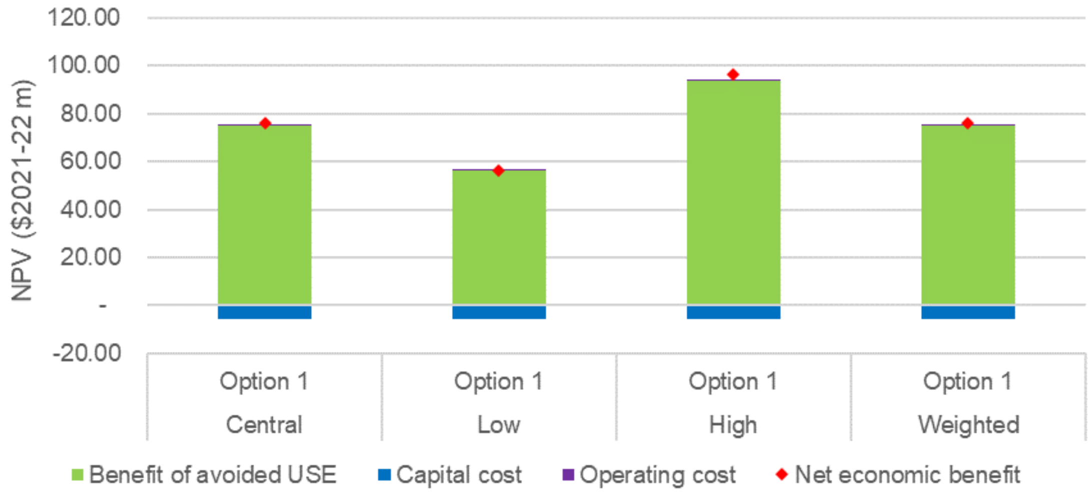
7.3 Estimated net economic benefits

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. Since we have only identified one credible option, Option 1 has the greatest net market benefits and is therefore our preferred option.

Table 7-3: NPV of net economic benefits relative to the base case ($2021/22 m)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*33%*	*33%*	*33%*	
Option 1	76.39	56.12	96.67	76.39

Figure 7-1 NPV of net economic benefits ($2021/22 m)



7.4 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 factors tested as part of the sensitivity analysis for this PSCR 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.

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.

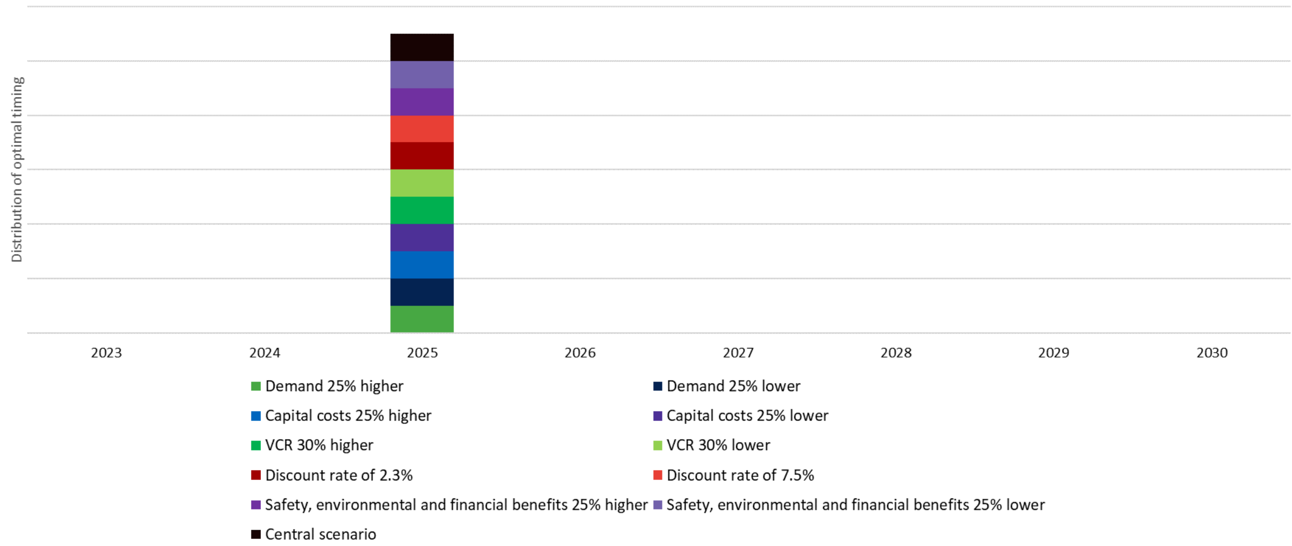
The sensitivities we considered are:

- a 25% increase / decrease in capital costs
- a 25% increase / decrease in demand
- a lower discount rate of 2.3% and a higher discount rate of 7.5%
- a 30% increase / decrease in the VCR
- a 25% increase / decrease in safety, environmental and financial risk costs

The results of this analysis are presented in the figure below. In all cases, the optimal timing for the preferred option is 2024/25. That is, the annual benefits from the first stage of the Beryl sub-station renewal (capacitor bank replacement) is higher than the annualised investment costs, even before benefits ramp up from 2028/29 when the entire sub-station renewal is complete.

Please note that the figure below shows the optimal year to commission the entire replacement program (as a whole). Given the scale of the investment and limitations on resources, the Beryl sub-station renewal will be undertaken over a five year period ranging from 2023/24 to 2027/28.

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



7.4.2 Scenario weights

As we have identified only one credible option, and since we have assessed this option to be net beneficial under all three reasonable scenarios, there are 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).

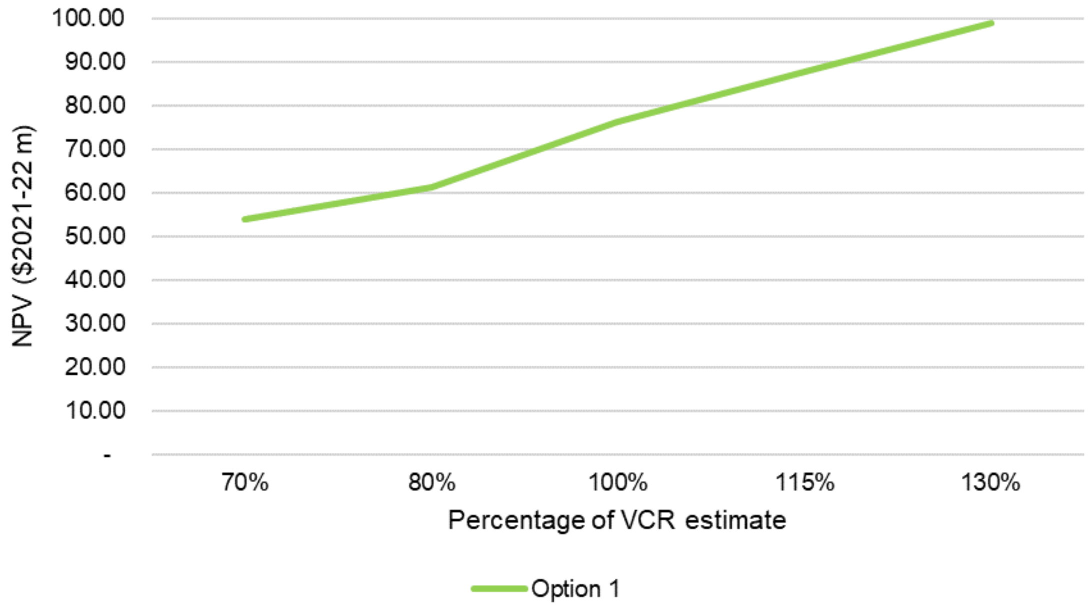
7.4.3 Value of customer reliability

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 7-4: Sensitivity of net economic benefits under a lower and higher VCR ($2021/22 m)

Option/scenario	Low VCR	High VCR	Ranking
Sensitivity	*Central estimate - 30%*	*Central estimate + 30%*	
Option 1	53.89	98.89	1

Figure 7-3 Sensitivity of net economic benefits under a lower and higher VCR ($2021/22 m)



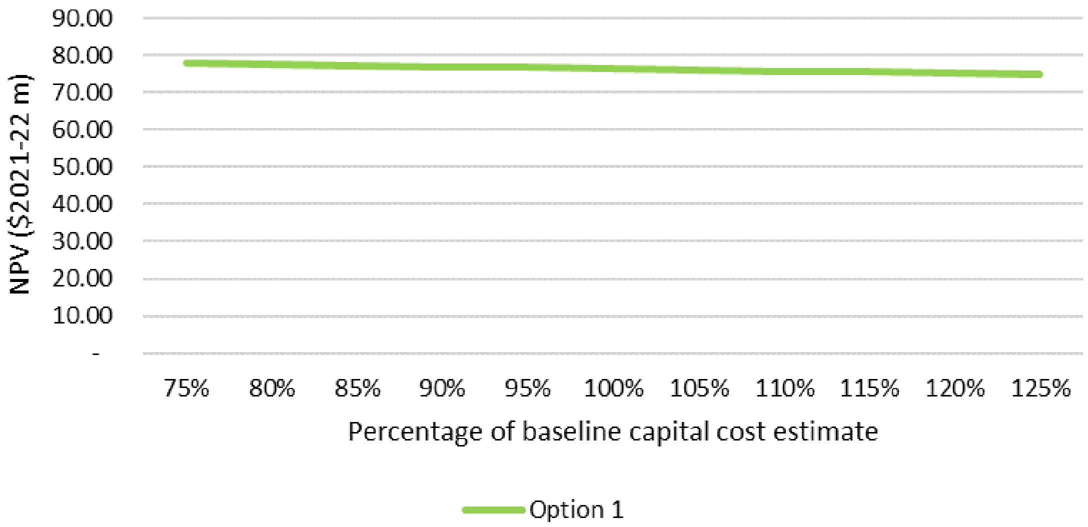
7.4.4 Network capital costs

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 7-5: Sensitivity of net economic benefits under lower and higher capital costs ($2021/22 m)

Option/scenario	Low capex	High capex	Ranking
Sensitivity	*Central estimate - 25%*	*Central estimate + 25%*	
Option 1	77.83	74.95	1

Figure 7-4: Sensitivity of net economic benefits under lower and higher capital costs ($2021/22 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 the level of increase in the capital costs of Option 1 to change the RIT-T outcome (i.e. the base case to be the preferred option). The result of this analysis was that the capital cost would need to increase by more than 1000% for the RIT-T outcome to change. Such a change in capital costs is outside the expected range of costs and, as such, this result of Option 1 being the preferred options is robust to reasonable capital cost sensitivities.

7.4.5 Discount rate

We estimated the net economic benefit of each option by adopting a low discount rate of 2.3% which is consistent with the AER's latest final determination for a TNSP (the 'Low discount rate' scenario),[37] and a high discount rate of 7.5% which aligns with the high discount rate scenario in the 2022 IASR (the 'High discount rate' scenario).[38] The results of this analysis are presented in the table and figure below.

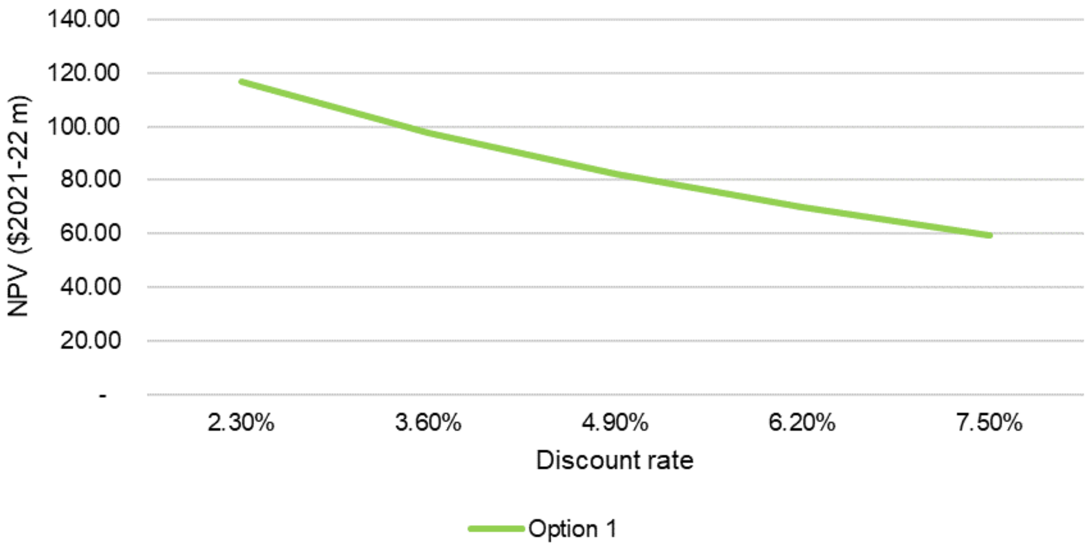
Table 7-6: Sensitivity of net economic benefits under a lower and higher discount rates ($2021/22 m)

Option/scenario	Low discount rate	High discount rate	Ranking
Sensitivity	*2.3%*	*7.5%*	
Option 1	116.64	59.47	1

37 The lower bound discount rate is based on the WACC (pre-tax, real) in the most recent final decision for a TNSP revenue determination which was Powerlink in April 2022.

38 AEMO July 2021 2021 Inputs, Assumptions and Scenarios Report

Figure 7-5 Sensitivity of net economic benefits under a lower and higher discount rates ($2021/22 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 solving for the discount rate that would result Option 1 not being the preferred option (i.e. the base case becoming 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 Option 1 is the preferred option to address the identified need. Option 1 involves targeted replacement of high voltage and secondary system assets at Beryl substation that have reached, or will reach by 2027/28, the end of their technical life based on an assessment of their age, condition, and technological obsolescence.

The capital cost of this option is approximately $7.06 million (in $2021-22). The work will be undertaken over a five-year period with all works expected to be completed by 2027/28. Routine operating and maintenance costs are estimated at approximately $0.02 million per annum (in $2021/22).

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 preferred option is less than $46 million;[39]
- we have identified in this PSCR our preferred option and the reasons for that option, and noted that we will be exempt from publishing the PADR for our preferred option; and
- we consider that the preferred option and any other credible options do not have a material market benefit (other than benefits associated with changes in voluntary load curtailment and involuntary load shedding).

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.[40]

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

[40] 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 199.

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[41] (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

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

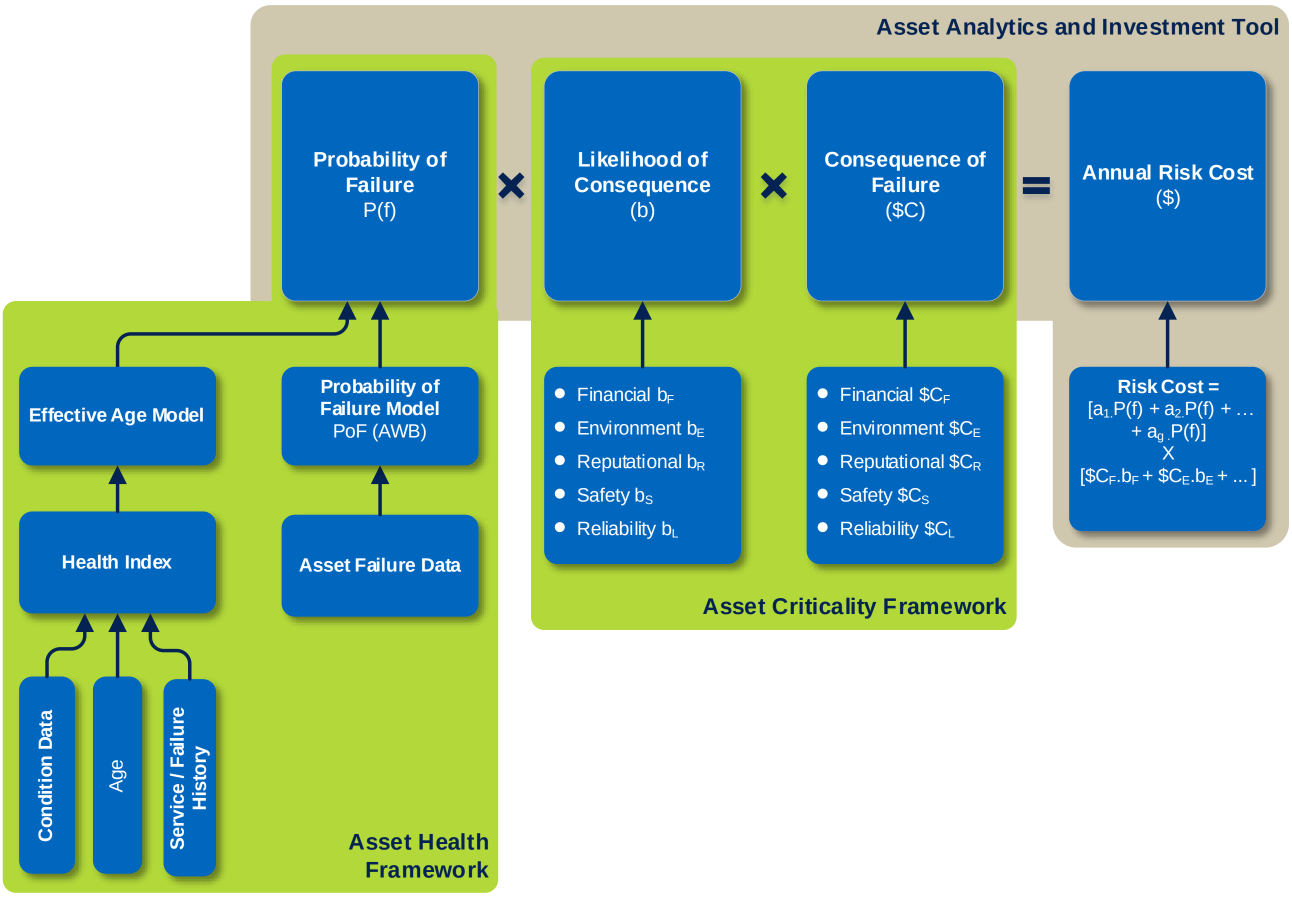
Appendix B Risk assessment framework

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[42] 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 B-1 illustrates the base risk equation that we apply.

Figure B-1 Risk cost calculation



Economic justification of Repex 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 and costs. The major quantified risks we apply for Repex justifications include asset failures that materialise as:

[42] Industry practice application note - Asset replacement planning, AER January 2019

- 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 of an asset is determining the Asset Health and associated effective age,[43] which considers:

- 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, 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 Probability of Failure (PoF) is the likelihood that an asset will fail during a given period resulting in a particular adverse event.

The outputs of the Probability of Failure (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 probability of failure curve for key assets are summarised in the table below.

Asset	Weibull parameters	
	η	β
Oil filled Current Transformer	50	3.08
Disconnector	67	4.8
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

43 Apparent age of an asset based on its condition.

Asset	Weibull parameters	
	η	β
PC	12.7	2.09
Meter - Microprocessor	15.5	1.74
DC Battery	16.5	1.49
DC Charger	19.8	1.24