Transgrid

People. Power. Possibilities.

Maintaining compliance with performance standards applicable to Regentville substation secondary systems

RIT-T Project Specification Consultation Report

Region: Greater Sydney

Date of issue: 6 May 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 Regentville substation. Publication of this Project Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

The Regentville substation is a customer connection point supplying Endeavour Energy's 132 kV network in an area which contains the Nepean Hospital and Richmond Royal Australian Air Force (RAAF) Air Base. The site will remain a connection point to Endeavour Energy into the foreseeable future as outlined in the load forecasts of the 2023 Transmission Annual Planning Report.

Secondary systems assets at Regentville substation are facing technological obsolescence, increasing the time to rectify defects 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 risk of secondary systems failure as a result of technological obsolescence at Regentville substation.

Identified need: meet the service level required under National Electricity Rules for protection schemes

Secondary systems are used to control, monitor, protect and provide communication to facilitate safe and reliable network operation.[1] They are necessary to ensure the secure operation of the transmission network and prevent damage to primary assets when adverse events occur.

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

Redundant protection schemes are required to ensure the transmission system is adequately protected as outlined in the Network Performance Requirement under Schedule 5.1 of the National Electricity Rules (NER), therefore the condition issues affecting the identified protection relays on the NSW transmission network must be addressed. The Network Performance Requirements, set out in Schedule 5.1 of the NER, place an obligation on Transmission Network Service Providers (TNSPs) to provide redundant protection schemes to ensure the transmission system is adequately protected. Clause 5.1.9(c) of the NER requires a TNSP to provide sufficient primary and back-up protection systems (including breaker fail protection systems), to ensure that a fault of any type anywhere on its transmission system is automatically disconnected.

Additionally, TNSPs are required to disconnect the unprotected primary systems where secondary systems fault lasts for more than eight hours (for planned maintenance) or 24 hours (for unplanned outages). TNSPs must also 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

[1] As per Schedule 5.1 of the NER.

of protection systems is being carried out.[2] 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[3].

Furthermore, as per 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.

A failure of the secondary systems would involve replacement of the failed component or removing the affected primary assets, such as lines and transformers, out of service. Though replacement of failed secondary systems component is a possible interim measure, the approach is not sustainable as the stock of spare components will deplete due to the technology no longer being manufactured or supported. Once all spares are used, replacement will cease to be a viable option to meet performance standards stipulated in clause 4.6.1 of the NER.

If the failure to provide functional secondary systems due to technology obsolescence is not addressed by a technically and commercially feasible credible option in sufficient time (by 2027/28), the likelihood of not recovering from secondary systems faults and not maintaining compliance with NER performance requirements will increase. It is noted that the optimal timing for this project through analysis is FY2029/30, Transgrid requires commencement of works earlier to allow the project to be completed in a timely manner and to balance conflicting bodies of work and the long timelines of such complex projects typically extending over 3 or more years.

The proposed investment will enable us to continue to meet the standards for secondary systems availability set out in the NER, and to avoid the impacts of taking primary assets out of service. Consequently, it is considered a reliability corrective action under the RIT-T.

A reliability corrective action differs from a 'market benefits'-driven RIT-T in that the preferred option is permitted to have negative net economic benefits on account of it being required to meet an externally imposed obligation on the network business.

Two credible network options have been identified

We have identified two credible network option that meet the identified need from a technical, commercial, and project delivery perspective.[4] These options are summarised in Table 1-1 below.

Table 1-1: Summary of the credible options

Option	Description	Capital costs ($M, 2023/24)	Operating costs ($/yr, 2023/24)
Option 1	Replacement of individual assets	$11.28m	$7,892
Option 2	Complete in-situ replacement	$9.52m	$159

Assets with deteriorating condition to be replaced include protection relays, control systems and metering systems. See Appendix B Assets identified for replacement for a full list of assets to be replaced under Option 1.

2 As per S5.1.2.1(d) of the NER.
3 AEMO. "Power System Security Guidelines, 9 March 2023." Melbourne: AEMO, 2023.23. Accessed 6 September 2023.
4 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 are not able to meet NER obligations to provide redundant secondary systems, metering or control and ensure that the transmission system is adequately protected.

The options have been assessed against three reasonable scenarios

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

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios assume the most likely scenario from AEMO's Inputs, Assumptions and Scenarios Report (IASR) (ie, the 'Step Change' scenario). The scenarios differ by the assumed level of risk costs, 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.

Table E-2 Summary of scenarios

Variable / Scenario	Central	Low risk cost scenario	High risk cost scenario risk
Scenario weighting	1/3	1/3	1/3
Discount rate	7%	7%	7%
VCR ($2023/24)[5]	$50,099/MWh	$50,099/MWh	$50,099/MWh
Network capital costs	Base estimate	Base estimate	Base estimate
Operating and maintenance costs	Base estimate	Base estimate	Base estimate
Environmental, safety and financial risk benefit	Base estimate	Base estimate – 25%	Base estimate + 25%
Avoided unserved energy	Base estimate	Base estimate – 25%	Base estimate + 25%

The sensitivity analysis presented in this PSCR demonstrates how the NPV results are affected by changes to other variables, including the discount rate and capital costs.

Option 2 delivers the highest net economic benefit and will meet NER requirements

We have assessed that Option 2 is net beneficial under all three reasonable scenarios considered in this PSCR. On a weighted basis, where each scenario is weighted equally, Option 2 is expected to deliver net benefits of approximately -$2.53 million. This is greater than Option 1, which is expected to deliver net benefits of approximately -$2.63 million. Option 2 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.

[5] This VCR is sourced from AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 124. However, this VCR has been escalated to December 2023 using Australian CPI.

Draft Conclusion

This PSCR finds that Option 2 is the preferred option to address the identified need. Option 2 involves replacement of all secondary systems assets at the site. This option will adopt an automation philosophy consistent with current design standards and practices. This option also includes replacement of Direct Current (DC) supplies to account for an increase in secondary systems power requirements and remediation of the 415V Alternating Current (AC) distribution in the building and the switchyard.

The condition of various categories of automation assets such as protection relays, control systems, AC distribution, DC supply systems, and market meters creates a need for modernisation. This will deliver benefits such as reduced preventative maintenance requirements, improved operational efficiencies, better utilisation of our high-speed communications network, improved visibility of assets using modern technologies and reduced reliance on routine maintenance and testing. There are also additional operational benefits available due to improved remote monitoring, control and interrogation, efficiency gains in responding to faults, and phasing out of obsolete and legacy systems and protocols.

The capital cost of this option is approximately $9.525 million (in $2023/24). The work will be undertaken in stages over the 15-year assessment period with all works expected to be completed by 2034/35. Routine operating and maintenance costs are estimated to be approximately $159 per annum (in $2023/24).

Exemption from preparing a Project Assessment Draft Report

Subject to additional credible options being identified during the consultation period, publication of a Project Assessment Draft Report (PADR) is not required for this RIT-T as we consider its investment in relation to the preferred option to be exempt from that part of the process under NER clause 5.16.4(z1). Production of a PADR is not required due to:

- the estimated capital cost of the proposed preferred option being less than $46 million[6];
- the PSCR states:
  - the proposed preferred option, together with the reasons for the proposed preferred option;
  - the RIT-T is exempt from producing a PADR; and
  - the proposed preferred option and any other credible option will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding except for voluntary load curtailment and involuntary load shedding;
- the RIT-T proponent considers that there were no PSCR submissions identifying additional credible options that could deliver a material market benefit; and
- the PACR must address any issues raised in relation to the proposed preferred option during the PSCR consultation.

We consider the investment in relation to Option 1 and Option 2 meets these criteria and therefore that we are exempt from producing a PADR under NER clause 5.16.4(z1).

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

In accordance with NER clause 5.16.4(z1)(4), the exemption from producing a PADR will no longer apply if we consider that an additional credible option that could deliver a material market benefit is identified during the consultation period.

Accordingly, if we consider that any additional credible options are identified, we will produce a PADR which includes an NPV assessment of the net market benefit of each additional credible option.

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, and presents our conclusion on the preferred option for this RIT-T.

Submissions and next steps

We welcome written submissions on materials contained in this PSCR.

Submissions are due on 2 August 2024[7] and should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[8] In the subject field, please reference 'Regentville Secondary Systems 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 October 2024.

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

[8] 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 Regentville substation. Publication of this Project Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

Secondary systems assets at Regentville substation are impacted by technological obsolescence of the equipment, increasing the time to rectify defects 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 risk of secondary systems failure as a result of technological obsolescence at Regentville substation. As investment is intended to maintain compliance with NER requirements, we consider this a reliability corrective action RIT-T.

1.1 Purpose of this report

The purpose of this PSCR[9] 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 additional credible options being identified during the consultation period, publication of a Project Assessment Draft Report (PADR) is not required for this RIT-T as we consider its investment in relation to the preferred option to be exempt from that part of the process under NER clause 5.16.4(z1). Production of a PADR is not required due to:

- the estimated capital cost of the proposed preferred option being less than $46 million[10];
- the PSCR states:
  - the proposed preferred option, together with the reasons for the proposed preferred option;
  - the RIT-T is exempt from producing a PADR; and
  - the proposed preferred option and any other credible option will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding except for voluntary load curtailment and involuntary load shedding;
- the RIT-T proponent considers that there were no PSCR submissions identifying additional credible options that could deliver a material market benefit; and

[9] See Appendix A Compliance checklist for the National Electricity Rules requirements.
[10] Varied from $43m to $46m based on the AER Final Determination: Cost threshold review November 2021.

- the PACR must address any issues raised in relation to the proposed preferred option during the PSCR consultation.

If an additional credible option that could deliver a material market benefit is identified during the consultation period, then we will produce a Project Assessment Draft Report (PADR) that updates the NPV assessment presented in this PSCR.

If no additional credible options with material market benefits are identified during the consultation period, then the next step in this RIT-T process 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.

1.3 Submissions and next steps

We welcome written submissions on materials contained in this PSCR.

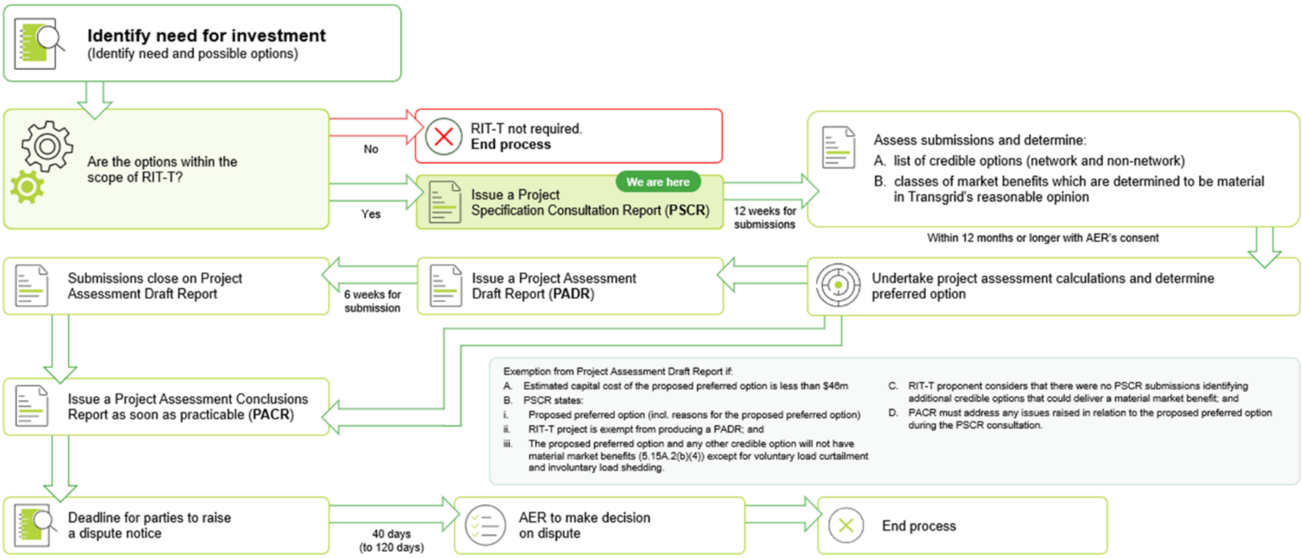
Submissions are due on 2 August 2024[11]and should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[12] In the subject field, please reference 'Regentville Secondary Systems PSCR.' At the conclusion of the consultation process, all submissions received will be published 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 October 2024.

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

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

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



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2. The identified need

This section outlines the identified need for this RIT-T, as well as the assumptions and data underpinning it. It first sets out background information related to the identified secondary systems.

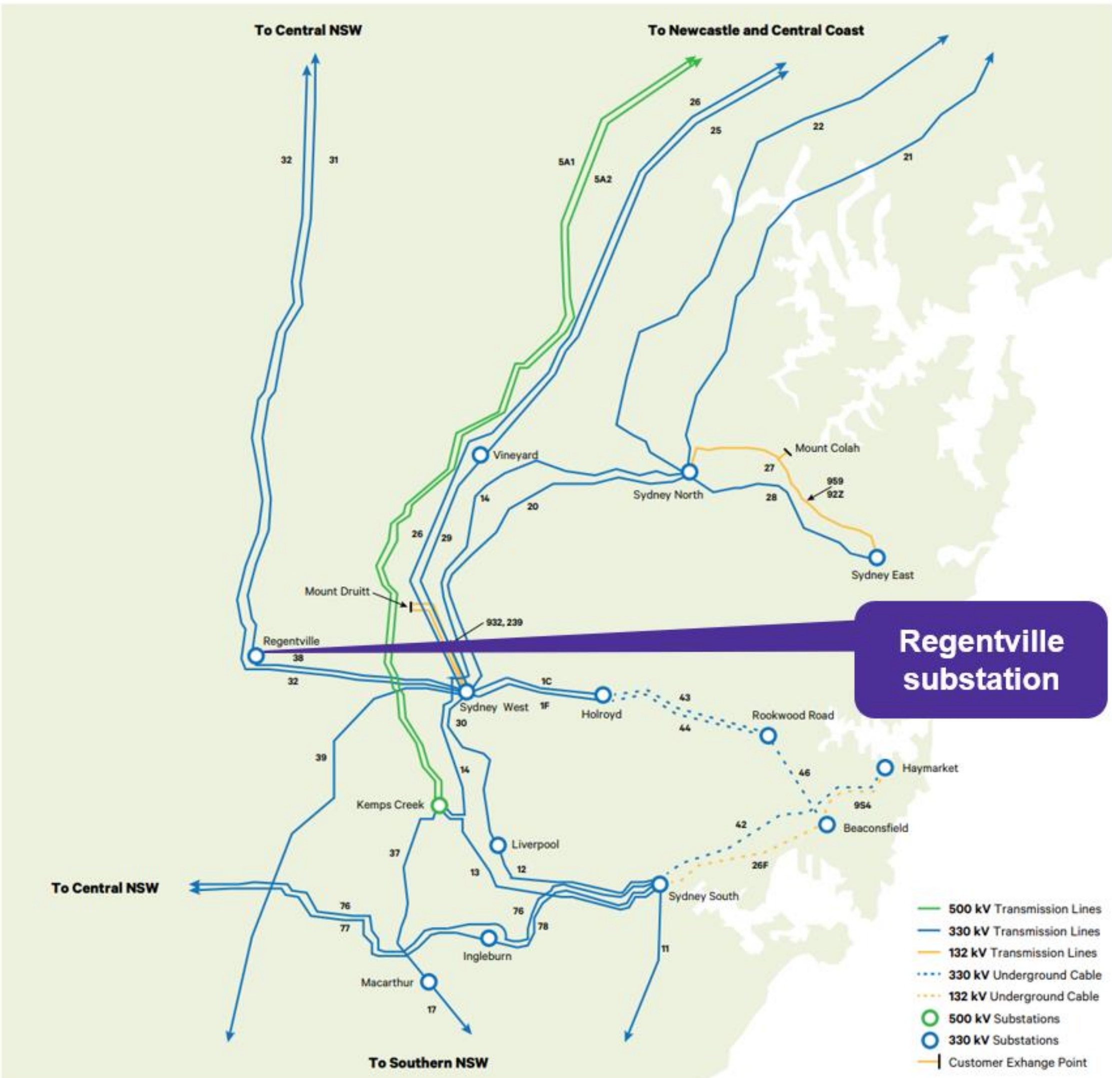
2.1 Background to the identified need

Regentville substation comprises 2x 330kV feeders, 2x 330/132/11kV transformers, 5x 132kV feeders and 2x 132kV capacitor banks. The site was established in 1997, and the secondary systems assets have install-years ranging between 1997 and 2014.

Regentville substation is a customer connection point supplying Endeavour Energy's 132kV network in an area which contains the Nepean Hospital and Richmond RAAF Air Base. The site will remain a connection point to Endeavour Energy into the foreseeable future as outlined in the load forecasts of the 2023 Annual Planning Report.

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

Figure 2-1 Location of Regentville substation



2.2 Description of the identified need

Secondary systems are used to control, monitor, protect and provide communication to facilitate safe and reliable network operation.[13] They are necessary to ensure the secure operation of the transmission network and prevent damage to primary assets when adverse events occur.

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

Redundant protection schemes are required to ensure the transmission system is adequately protected as outlined in the Network Performance Requirement under Schedule 5.1 of the National Electricity Rules (NER), therefore the condition issues affecting the identified protection relays on the ACT and NSW transmission network must be addressed. The Network Performance Requirements, set out in Schedule 5.1 of the NER, place an obligation on Transmission Network Service Providers (TNSPs) to provide redundant protection schemes to ensure the transmission system is adequately protected. Clause 5.1.9(c) of the NER requires a TNSP to provide sufficient primary and back-up protection systems (including breaker fail protection systems), to ensure that a fault of any type anywhere on its transmission system is automatically disconnected.

Additionally, TNSPs are required to disconnect the unprotected primary systems where secondary systems fault lasts for more than eight hours (for planned maintenance) or 24 hours (for unplanned outages). TNSPs must also 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.[14]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[15].

Furthermore, as per 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.

A failure of the secondary systems would involve replacement of the failed component or taking the affected primary assets, such as lines and transformers, out of service. Though replacement of failed secondary systems component is a possible interim measure, the approach is not sustainable as the stock of spare components will deplete due to the technology no longer being manufactured or supported. Once all spares are used, interim replacement will cease to be a viable option to meet performance standards stipulated in clause 4.6.1 of the NER.

If the failure to provide functional secondary systems due to technology obsolescence is not addressed by a technically and commercially feasible credible option in sufficient time (by 2027/28), the likelihood of not recovering from secondary systems faults and not maintaining compliance with NER performance requirements will increase.

[13] As per Schedule 5.1 of the NER.
[14] As per clause 5.1.2.1(d) of the NER.
[15] AEMO. "Power System Security Guidelines, 9 March 2023." Melbourne: AEMO, 2023.23. Accessed 6 September 2023. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715%20Power-System-Security-Guidelines.pdf

The proposed investment will enable us to continue to meet the standards for secondary systems availability set out in the NER, and to avoid the impacts of taking primary assets out of service. Consequently, it is considered a reliability corrective action under the RIT-T.

A reliability corrective action differs from a 'market benefits'-driven RIT-T in that the preferred option is permitted to have negative net economic benefits on account of it being required to meet an externally imposed obligation on the network business.

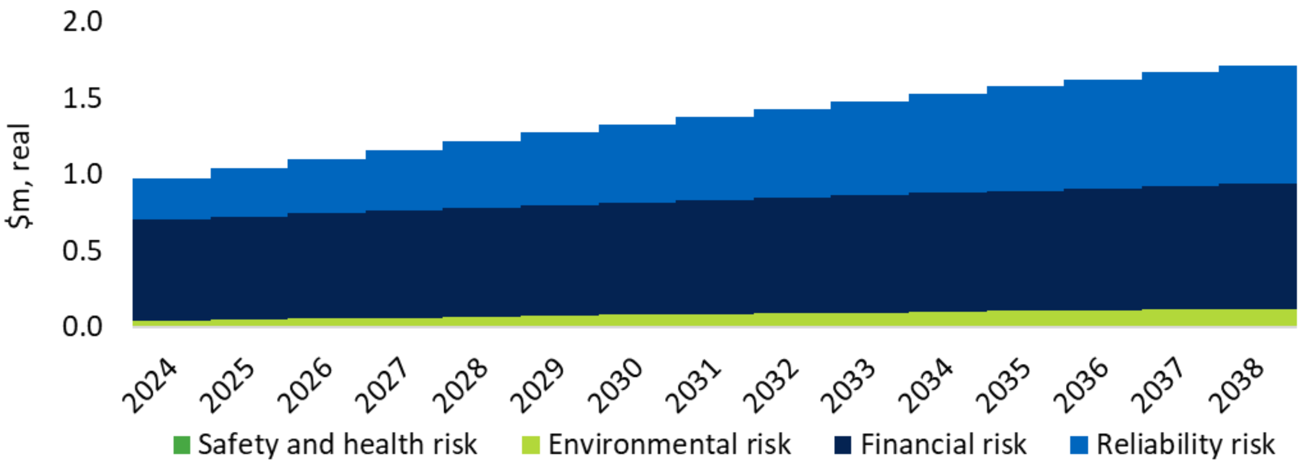
2.3 Assumptions underpinning the identified need

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

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

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

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



This section describes the assumptions underpinning our assessment of the risk costs, i.e., the value of the risk avoided by undertaking each of the credible options. For the central scenario, the aggregate risk cost under the base case is currently estimated at around $0.98 million/year and it is expected to increase going forward if action is not taken and the secondary systems assets are left to deteriorate further (reaching approximately $1.71 million/year by the end of the 15-year assessment period).

2.3.1 Asset health and the probability of failure

2.3.1.1 Protection relays

Protection relays are assets that monitor the network and trip circuit breakers when an abnormality in the network is detected. They protect other components of the electricity system by ensuring faults are cleared within the times specified in the NER.[16]

We have identified the 26 protection relays at Regentville substation are experiencing increasing failure rates, manufacturer obsolescence and a lack of support and are targeted for replacement. A list of these relays can be found in Appendix B Assets identified for replacement. The effective age of these relays in 2023 ranges from 7 years to 32 years, with an average effective age of 17 years. In contrast, the typically useful life of a relay is around 15 years. Key issues presented by these relays are:

- exceedance of their technical life and/or relay type experiencing increased failure rates; and
- technology obsolescence resulting in a lack of spares and no manufacturer support.
- Younger relays have faced ongoing issues with no resolution from the manufacturer.

73% of the protection relays included in this RIT-T are at or beyond the end of their technical life, with some of the remaining targeted assets facing ongoing performance issues. 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 just relay components. Replacement of the protection relays is required to ensure compliance with the NER, including requirements around maintaining adequate protection systems[17] and maximum clearance times.[18]

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 all control system assets at Regentville substation experiencing increasing failure rates which are targeted for replacement. A list of these control systems can be found in Appendix B Assets identified for replacement. The effective age in 2023 of these control systems is 17 years. In contrast, the typically useful life of control systems are around 15 years. Key issues presented by control systems are:

- exceedance of their technical life and model types experiencing increased failure rates; and
- technology obsolescence resulting in depleted spares and no manufacturer support.
- Control system is limited in capacity due to age of technology.

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

[17] NER, s5.1.2.1(d) and s5.1.9(c).

[18] NER, s5.1a.8.

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.[19]

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 4 metering systems at Regentville substation experiencing increasing failure rates which are targeted for replacement. A list of these metering systems can be found in Appendix B Assets identified for replacement. The effective age in 2023 of each of these metering systems is 37 and 40 years. In contrast, the typically useful life of a meter is around 25 years. Key issues presented by metering systems are:

- technology obsolescence resulting in depleting spares and no manufacturer support.

The identified metering assets will approach 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 will be 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.

2.3.2 Financial risk

This refers to the financial consequence of an asset failure. The likelihood of a consequence considers duplicated protection, control system or metering failing. In addition, the financial consequence of primary plant considers the likelihood of a fault occurring during the failure of both protection schemes and the likelihood of the watchdog failing to successfully detect the failed unit where available. The monetary value considers the cost of replacement or repair of the failed asset and the protected asset, including any temporary measures across protection, control, and metering systems. Due to the obsolescence of many of the assets targeted in this Need, their failure will result in a complete redesign and renewal under defect conditions as direct replacement is no longer feasible. Particularly the control system.

Financial risk makes up 56.13 per cent of the total estimated risk cost in present value terms.

2.3.3 Reliability risk

The risk of unserved energy for customers following a failure of secondary systems identified has been assessed in the NPV analysis. The likelihood of a consequence considers the likelihood of duplicated secondary systems failing, the likelihood of a fault occurring during the failure of both secondary systems, for microprocessor-based devices, the likelihood of the watchdog failing to successfully detect the failed unit, the anticipated load restoration time (based on the expected time to undertake repair), and the load at

[19] NER, clause 4.11.1.

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.

For protection assets unit protection is an industry standard whereby protection schemes are limited in their range of cover to only those protected assets. This approach maximises system security by mitigating the risk of false trips due to adjacent equipment conditions.

Adjacent protection schemes cannot detect faults outside their protection zone when unit protection is implemented. Reliable protection operation is achieved through the duplication of protection schemes.

As outlined in our Network Asset Criticality Framework, we have undertaken quantification of the reliability consequence of an uncleared fault on the ACT and NSW 500 kV and 330 kV network. The impact of an uncleared or slow-to-clear fault is one of the main risks presented by Transgrid's protection systems to the primary transmission 500 kV and 330 kV network. The consequence of this risk can vary dramatically depending on a complex array of variables; the extreme result being a 'Black Start' – that is, the de-energisation of the entire ACT and NSW transmission network.

We have analysed the performance of protection schemes at voltage levels of 220kV and below. The analysis determined that an uncleared fault would result in the associated busbar effectively becoming a fuse to assist in a consistent analysis, the reliability consequence for these assets is calculated as the loss of load of the site associated with the failed protection element.

Control systems risks have factored the loss of monitoring and control of primary assets which will result in extended outages in the event of a credible contingency occurring. This risk forms a part of the reliability risk calculated and is evaluated based on the unserved energy consequence of individual primary plant and likelihood of a fault occurring during the outage of the control system.

We have considered the risk of unserved energy for customers following a failure of one or more of the secondary systems assets identified in this PSCR.

Reliability risk makes up 38.01 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 considers the duplicated protection also failing, the likelihood of a fault occurring during the failure of both protection schemes, for microprocessor-based devices, the likelihood of the watchdog failing to successfully detect the failed unit 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 5.78 per cent of the total estimated risk cost in present value terms.

2.3.5 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 likelihood of duplicated protection also failing, the likelihood of a fault occurring during the failure of both protection schemes, for microprocessor-based devices, the likelihood of the watchdog failing to successfully detect the failed unit. For protected assets within the boundary of a site, we consider 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. For protected assets outside the boundary of a site (typically transmission lines), we consider the probability of the public within the vicinity of those assets, The monetary value considers the cost associated with fatality or injury compensation, loss of productivity, litigation fees, fines and any other related costs.

Safety risk makes up 0.08 per cent of the total estimated risk cost in present value terms.

3. Options that meet the identified need

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

We consider that there are two technically and commercially feasible options to address the identified need.[20] These options are summarised in the table below.

Table 3-1 Summary of credible options

Option	Description	Estimated capex ($M, 2023/24)	Expected commission date (Financial year)
1	Replacement of individual assets	$0.79m (per year)	2024-2028
		$7.15m	2029
		$0.16m	2035
	Total capex for Option 1	**$11.28m**	
2	Complete in-situ replacement	$1.83m	2024
		$6.09m	2025
		$1.60m	2026
	Total capex for Option 2	**$9.52m**	

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 secondary systems assets at Regentville 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.

The routine operating and maintenance costs under the base case are estimated at approximately $7,892 in FY24, temporarily increasing to $45,586 in FY28 before decreasing back to $7,892 in FY32 for the rest of the 15-year assessment period (in $2023/24). The substantial increase in opex during FY28 to FY31 is due to building refurbishment works, where were necessary to address the rectification costs identified in the dilapidation reports.

20 As per clause 5.15.2(a) of the NER.

21 AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, p. 22.

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

Table 3-2 Breakdown of capital and operating expenditure under the base case ($2023/24)

Years	Capital cost	Operating cost
2024	-	$7,892
2025	-	$7,892
2026	-	$7,892
2027	-	$7,892
2028	-	$7,892
2029	-	$7,892
2030	-	$45,586
2031	-	$45,586
2032	-	$45,586
2033	-	$45,586
2034	-	$7,892
2035	-	$7,892
2036	-	$7,892
2037	-	$7,892
2038	-	$7,892
Total	-	$269,160

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 Regentville 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 Regentville 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 Regentville substation will increase from approximately $0.27 million in 2023/24 to approximately $0.78 million at the end of the 15-year assessment period (in $2023/24). 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 $0.70 million in 2023/24 and increase to $0.94 million at the end of the 15-year assessment period (in $2023/24).

3.2 Option 1 – Replacement of individual assets

Option 1 involves individual replacements of identified assets from 2023/24 to 2034/35. The option is based on a like-for-like approach whereby the asset is replaced by its modern equivalent. Additional system modifications or additional functionalities would not be deployed under this option. This option will lock

Transgrid to a system architecture that cannot be expanded to match modern technology capabilities into the future.

The assets that will be replaced under this option are set out in Table B-5 in Appendix B Assets identified for replacement.

The capital cost of this option is approximately $11.28 million (in $2023/24). The work will be undertaken in stages over the 15-year assessment period. This capital cost is comprised of $5.4m in labour costs, $3.6m in material costs, and $2.3m in expenses.

The routine operating and maintenance costs are estimated at approximately $7,892 in FY24, temporarily increasing to $45,586 in FY28 before decreasing back to $7,892 in FY32 for the rest of the 15-year assessment period (in $2023/24). As mentioned above, the increase in opex during FY28 to FY31 is due to building refurbishment works, which were necessary to address the rectification costs identified in the dilapidation reports, which is also relevant in this option. We expect that the new protection relays, control systems, and metering systems will have an asset life of 15 years. The table below provides a breakdown of the expected operating expenditure under Option 1.

Table 3-3 below provides a breakdown of the estimated capital and operating cost.

Table 3-3 Capital and operating cost of Option 1

Years	Capital cost ($2023/24)	Operating cost ($2023/24)
2024	$794,306	$7,892
2025	$794,306	$7,892
2026	$794,306	$7,892
2027	$794,306	$7,892
2028	$794,306	$7,892
2029	$7,149,360	$7,892
2030	-	$45,586
2031	-	$45,586
2032	-	$45,586
2033	-	$45,586
2034	-	$7,892
2035	$160,848	$7,892
2036	-	$7,892
2037	-	$7,892
2038	-	$7,892
Total	**$11,281,738**	$269,160

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 impact on the network.

3.3 Option 2 – Complete in-situ replacement

This option involves replacement of all secondary systems assets at the site. This option will adopt an automation philosophy consistent with current design standards and practices. This option also includes replacement of Direct Current (DC) supplies to account for an increase in secondary systems power requirements and remediation of the 415V Alternating Current (AC) distribution in the building and the switchyard.

The condition of various categories of automation assets such as protection relays, control systems, AC distribution, DC supply systems, and market meters creates a need for modernisation. This will deliver benefits such as reduced preventative maintenance requirements, improved operational efficiencies, better utilisation of our high-speed communications network, improved visibility of assets using modern technologies and reduced reliance on routine maintenance and testing. There are also additional operational benefits available due to improved remote monitoring, control and interrogation, efficiency gains in responding to faults, and phasing out of obsolete and legacy systems and protocols.

The work will be undertaken in stages over a three-year period with all works expected to be completed by 2025/26.

The capital cost of this option is approximately $9.52 million (in $2023/24). This cost is comprised of $4.6m of labour costs, $3.1m in material costs, and $1.9m in expenses.

The routine operating and maintenance costs are estimated at approximately $7,753 in FY24, decreasing to $157 in FY27 continuing until the end of the 15-year assessment period (in $2023/24). The table below provides a breakdown of the expected operating expenditure under Option 2.

Table 3-4 below provides a breakdown of the estimated capital and operating cost.

Table 3-4 Capital and operating cost of Option 2

Years	Capital cost ($2023/24)	Operating cost ($2023/24)
2024	$1,827,633	$7,892
2025	$6,089,672	$7,892
2026	$1,603,794	$7,892
2027	-	$7,892
2028	-	$7,892
2029	-	$159
2030	-	$159
2031	-	$159
2032	-	$159
2033	-	$159
2034	-	$159
2035	-	$159
2036	-	$159
2037	-	$159

2038	-	$159
Total	**$9,521,099**	$41,055

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 impact on the network.

3.4 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 SSB Replacement	Whilst this option is technically feasible, it requires the installation of new cabling and buildings. Based on the 2020 building dilapidation report and no noted rise in cable defects, the condition of these assets on site does not support their replacement.
Upgrade to IEC61850	Whilst this option is technically feasible, it requires the installation of new cabling and buildings. Based on the 2020 building dilapidation report and no noted rise in cable defects, the condition of these assets on site does not support their replacement.
Asset Retirement	This can only be achieved by retiring the associated primary assets, which is not technically or economically feasible. This site will remain an essential connection point into the foreseeable future.
Non-network solutions	Is not technically feasible for non-network solutions to provide the functionality of secondary systems assets for protection, control, communications and metering.

3.5 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."*

[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.

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.

[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. Secondary systems are fundamentally about enabling the safe and reliable control and operation of Transgrid's network assets, and there are currently no known non-network alternatives that can effectively augment or substitute for the investments that Transgrid is proposing.

Irrespective of technical characteristics such as the size of load reduction or additional supply, location and operating profile, we do not consider that non-network options can meet regulatory obligations under Schedule 5.1 of the NER to provide redundant secondary systems and ensure that the transmission system is adequately protected. This consideration also extends to the ability to meet regulatory obligations under clauses 4.6.1 and 4.11.1 related to remote monitoring and control systems, and clause 7.8.10 related to metering.

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]

On 21 September 2023, the National Energy Laws were amended to reflect the incorporation of emissions reductions within the National Energy Objectives.[27] Following this the AEMC made harmonising changes to the National Electricity Rules, prompted by a rule change request from energy ministers, to ensure that network investment and planning frameworks are consistent with the new emissions reduction objective. The AEMC's Final Determination, published on 1 February 2024, included introducing a 'changes in Australia's greenhouse gas emissions' as a new class of market benefit to be considered within the RIT-T process.[28]

Transgrid supports greater consideration of emissions impact within network planning and investment frameworks. These changes enable network planning and investment frameworks to support achievement of the Commonwealth Government's net zero targets. Transgrid has set our own science-based targets to cut emissions and decarbonise our business. These include:

- Reducing Scope 1 and 2 emissions by 60 per cent by 2030, compared with a base year of 2021 and net zero by 2040.
- Reducing Scope 3 emissions from Purchased Goods and Services, and Capital Goods by 48 per cent for every million dollars that we spend on these two categories by 2030, compared with a base year of 2021, and net zero by 2050.[29]

We have applied the updated NEO to this RIT-T assessment and do not consider there to be any material changes to greenhouse gas emissions under the proposed options, as the proposed options are unlikely to significantly alter the generation mix across the NEM. Nonetheless, Transgrid is working to understand how to assess the quantum and value of expected changes in greenhouse gas emissions. Outcomes from this emissions modelling will be considered and presented within the PACR. Where possible and practical, we will refine this approach and any results following updated guidance being provided by the AER on RIT-T-related emissions reduction assessments.

5.1 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);

[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(5). See Appendix A Compliance checklist for requirements applicable to this document.

- changes in costs for parties other than the RIT-T proponent;
- changes in ancillary services costs;
- changes in Australia's greenhouse gas emissions; and
- competition benefits.

5.2 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
Changes in involuntary load shedding	A failure of any single secondary system asset would result in a low probability of unserved energy. Individual replacements are assessed using the Network Asset Criticality Framework and replaced where investment is prudent.
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,* October 2023, p.57-58.
[28] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, p.57-58.

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 condition of the secondary systems assets at Regentville substation, or to address the technological obsolescence, spares unavailability, and discontinued manufacturer support. We incur regular and reactive maintenance costs, and environmental, safety and financial related risks costs, that are caused by the failure of assets at Regentville substation.

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 15-year assessment period from 2023/24 to 2037/38 has been adopted for this RIT-T. This period takes into account the size, complexity and expected asset life of the options.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values have been calculated based on the undepreciated value of capital costs at the end of the analysis period. 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 7 per cent has been adopted as the central assumption for the NPV analysis presented in this PSCR, consistent with AEMO’s Inputs, Assumptions and Scenarios Consultation Report[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 3 per cent.[31] We have also adopted an upper bound discount rate of 10.5 per cent (ie, from AEMO’s 2023 Inputs, Assumptions and Scenarios Report).[32]

[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,* October 2023, p.22).

[30] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.

[31] 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: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/transgrid-determination-2023%E2%80%9328/final-decision

[32] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.

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 capital 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 capital 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).[33]

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, 2023-24 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. Access to the substation is deemed adequate, hence, no temporary access track was allowed for in this estimate.

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.[34] As a result, we consider that a state-wide VCR is likely to reflect the weighted mix of customers that will be affected by these options.

6.5 The options have been assessed against three reasonable scenarios

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

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

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

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios implicitly assume the most likely scenario from the 2023 IASR (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

[33] For further detail on our cost estimating approach refer to section 6 of our Repex Overview Paper submitted with our 2023-28 Revenue Proposal.
[34] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 124.

ranking of the credible options. Risk cost assumptions do not form part of AEMO's ISP assumptions, and have been based on Transgrid's analysis, as discussed in section 2.

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

How the NPV results are affected by changes to other variables (including the discount rate and capital costs) has been investigated in the sensitivity analysis. We consider this is consistent with the latest AER guidance for RIT-Ts of this type (ie, where wholesale market benefits are not expected to be material).[35,36,37]

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

Table 6-1 Summary of scenarios

Variable / Scenario	Central scenario	Low risk costs scenario	High risk costs scenario
Scenario weighting	1/3	1/3	1/3
Discount rate	7%	7%	7%
VCR ($2023/24)[38]	$50,099/MWh	$50,099/MWh	$50,099/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

6.6 Sensitivity analysis

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

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

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

[35] AER, *Application Guidelines Regulatory Investment Test for Transmission*, August 2020, pp. 40-41.

[36] 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.

[37] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123-124

[38] This VCR is sourced from AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 124. However, this VCR has been escalated to December 2023 using Australian CPI.

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 0.

In addition, we have also sought to identify the ‘boundary value’ for key variables beyond which the outcome of the analysis would change (the preferred option would no longer be preferred). In terms of boundary testing we find the following:

- assumed network capital costs (for both options) would need to increase by 7 per cent;
- the estimated risk costs (in aggregate) would need to decrease by 7 per cent; and
- the discount rate would need to increase to 7.49 per cent.

While these identified boundary values are not unlikely to be realised, given the various qualitative benefits associated with Option 2 (which are not considered within the NPV analysis), we remain confident in our preference for Option 2.

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 a 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 ($2023/24 m)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*1/3*	*1/3*	*1/3*	
Option 1	$4.50	$3.37	$5.62	$4.50
Option 2	$5.77	$4.33	$7.21	$5.77

The results show that under all two scenarios, the estimated gross benefits are positive for Options 1 and 2 (in NPV terms).

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 ($2023/24 m)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*1/3*	*1/3*	*1/3*	
Option 1	$7.12	$7.12	$7.12	$7.12
Option 2	$8.30	$8.30	$8.30	$8.30

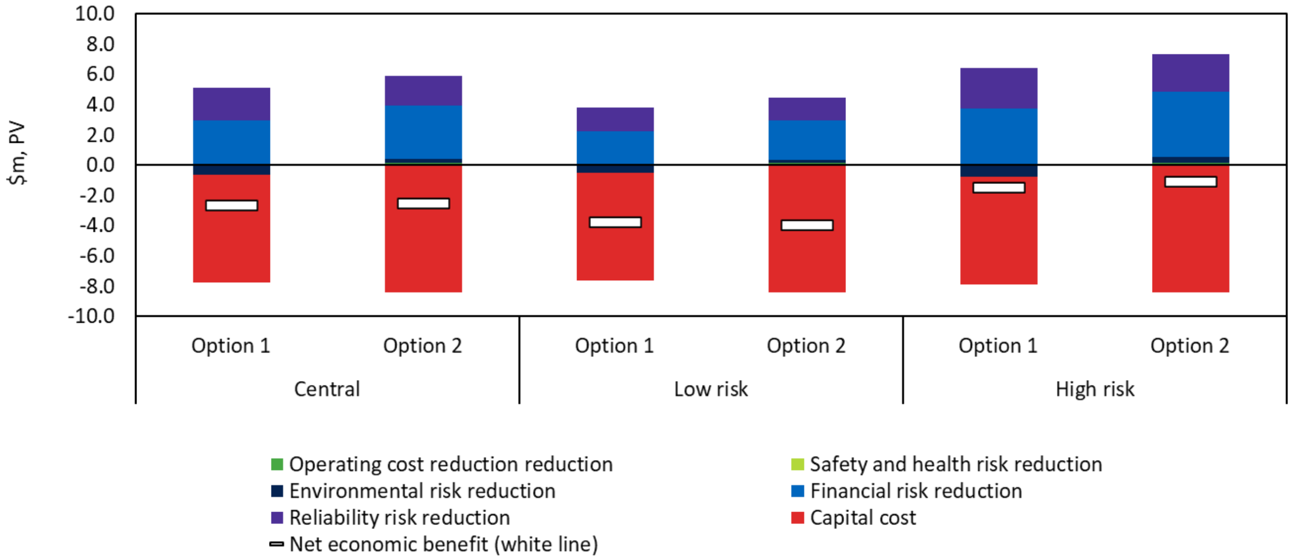
7.3 Estimated net economic benefits

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. Option 2 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 ($2023/24 m)

Option	Central scenario	Low risk costs scenario	High risk costs scenario	Weighted scenario
Scenario weighting	*1/3*	*1/3*	*1/3*	
Option 1	-$2.63	-$3.75	-$1.50	-$2.63
Option 2	-$2.53	-$3.98	-$1.09	-$2.53

Figure 7-1 NPV of net economic benefits ($2023/24 m)



7.4 Sensitivity testing

We have undertaken sensitivity testing to understand the robustness of the RIT-T assessment to underlying assumptions about key variables. In particular, we have undertaken two sets of sensitivity tests:

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

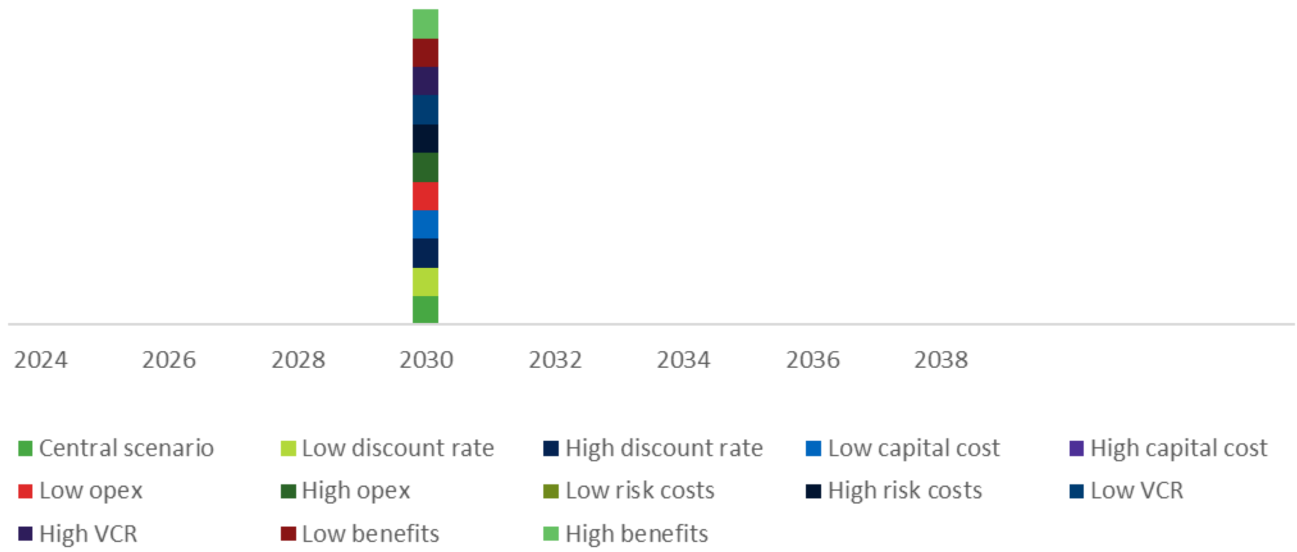
Having assumed to have committed to the project by this date, we have also looked at the consequences of 'getting it wrong' under step 2 of the sensitivity testing. That is, if expected safety and environmental risks are not as high as expected, for example, the impact on the net economic benefit associated with the project continuing to go ahead on that date.

The application of the two steps to test the sensitivity of the key findings is outlined below.

7.4.1 Step 1 – Sensitivity testing of the optimal timing

- This section outlines the sensitivity of the identification of the commissioning year of Option 2 to changes in the underlying assumptions. For all sensitivities undertaken, the optimal commissioning year identified was 2030. This is demonstrated below visually in Figure 7-2.

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



7.4.2 Step 2 – Sensitivity of the overall net benefit

We have conducted sensitivity analysis on the present value of the net economic benefit. Specifically, we have investigated the same sensitivities under this step as in the first step:

- a 25 per cent increase/decrease in the assumed network capital costs;
- a 25 per cent increase/decrease in the assumed safety, environmental and financial risks; and
- lower discount rate of 3 per cent as well as a higher rate of 10.5 per cent;

All these sensitivities investigate the consequences of 'getting it wrong' having committed to a certain investment decision.

Option 2 and 1 deliver negative net economic benefits under all scenarios considered. While Option 2 is generally preferred to Option 1, Option 1 was found to be superior if:

- risk costs decreased by more than 7 percent;
- capital costs increased by more than 7 percent;
- the discount rate was higher than 7.49 per cent.

The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting lower and higher risk values, which includes safety & health risk, environmental risk and financial risk. We estimated the net economic benefit of each option by adopting risk costs that is 25% higher (the 'High Risk scenario) and 25% lower (the 'Low Risk' scenario) than the estimate of risk adopted in our central scenario. The results of this analysis are presented in the table and figure below. As can be seen, no reasonable risk costs were identified that resulted in either option breaking even.

Table 7-4: NPV of net economic benefits relative to the base case under a lower and higher risk costs ($2023/24 m)

Option/scenario	Lower Risk Cost	Higher Risk Cost	Ranking (<93%)	Breakeven (%)
Sensitivity	75% of Central estimate	125% of Central estimate		
Option 1	-$3.19	-$2.02	1	N/A
Option 2	-$3.44	-$1.57	2	N/A

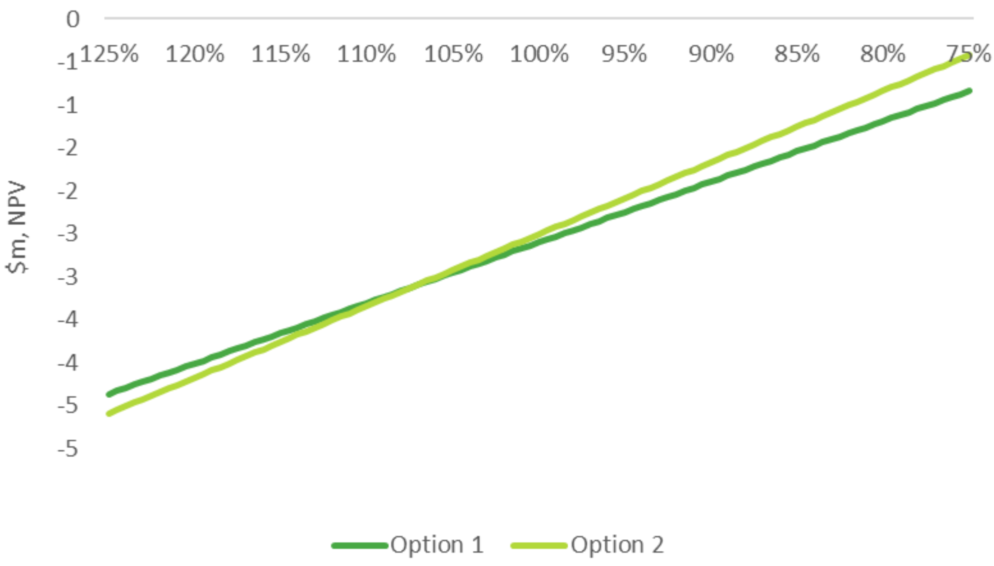
Figure 7-3 Sensitivity of net economic benefits under a lower and higher risk costs ($2023/24 m)

The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting lower and higher 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. As can be seen, no reasonable capital costs were identified that resulted in either option breaking even.

Table 7-5: Sensitivity of net economic benefits under lower and higher capital costs ($2023/24 m)

Option/scenario	Lower capex	Higher capex	Ranking (>107%)	Breakeven (%)
Sensitivity	75% of Central estimate	125% of Central estimate		
Option 1	-$0.84	-$4.37	1	N/A
Option 2	-$0.42	-$4.60	2	N/A

Figure 7-4: Sensitivity of net economic benefits under lower and higher capital costs ($2023/24 m)



The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting alternative discount rates. Specifically, we considered a low discount rate of 3% which is consistent with the AER's latest final determination for a TNSP (the 'Low discount rate' scenario),[39] and a high discount rate of 10.5% which aligns with the high discount rate scenario in the 2023 IASR (the 'High discount rate' scenario).[40] The results of this analysis are presented in the table and figure below. As can be seen, no reasonable discount rates were identified that resulted in either option breaking even.

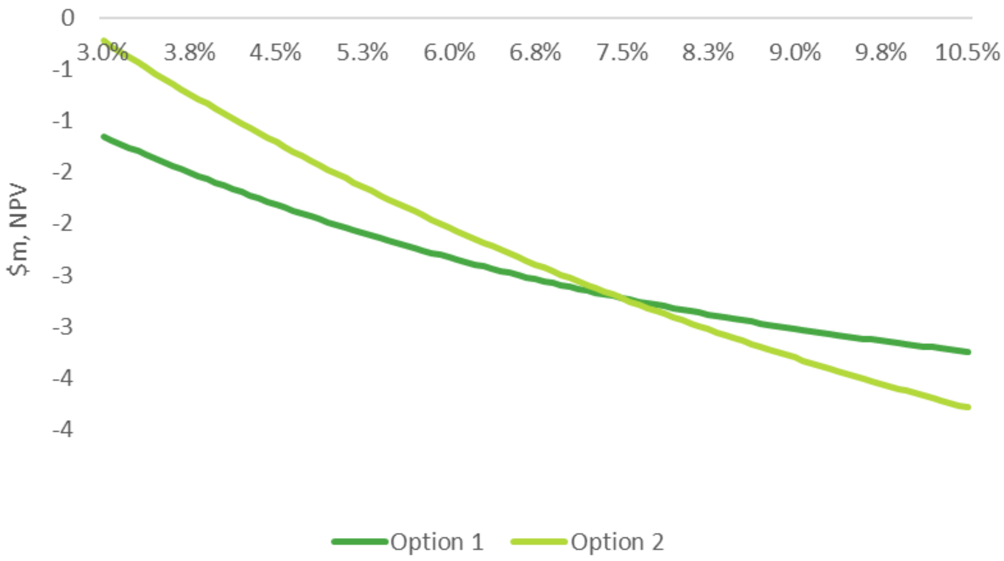
Table 7-6: Sensitivity of net economic benefits under a lower and higher discount rates ($2023/24 m)

Option/scenario	Lower discount rate	Higher discount rate	Ranking (>7.49%)	Breakeven (%)
Sensitivity	*3%*	*10.5%*		
Option 1	-$1.15	-$3.24	1	N/A
Option 2	-$0.23	-$3.79	2	N/A

39 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: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/transgrid-determination-2023%E2%80%9328/final-decision

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

Figure 7-5 Sensitivity of net economic benefits under a lower and higher discount rates ($2023/24 m)



8. Draft conclusion and exemption from preparing a PADR

This PSCR finds that Option 2 is the preferred option to address the identified need. This is because Option 2 is expected to deliver net benefits of approximately -$2.53 million, whereas Option 1 is expected to deliver net benefits of approximately -$2.63 million Option 2 involves replacement of all secondary systems assets at the site. This option will adopt an automation philosophy consistent with current design standards and practices. This option also includes replacement of Direct Current (DC) supplies to account for an increase in secondary systems power requirements and remediation of the 415V Alternating Current (AC) distribution in the building and the switchyard.

The condition of various categories of automation assets such as protection relays, control systems, AC distribution, DC supply systems, and market meters creates a need for modernisation. This will deliver benefits such as reduced preventative maintenance requirements, improved operational efficiencies, better utilisation of our high-speed communications network, improved visibility of assets using modern technologies and reduced reliance on routine maintenance and testing. There are also additional operational benefits available due to improved remote monitoring, control and interrogation, efficiency gains in responding to faults, and phasing out of obsolete and legacy systems and protocols.

The capital cost of this option is approximately $9.52 million (in $2023/24). The work will be undertaken in stages over 15-year assessment period with all works expected to be completed by 2025/26. Routine operating and maintenance costs are estimated to be approximately $159 per annum (in $2023-24).

Subject to additional credible options being identified during the consultation period, publication of a Project Assessment Draft Report (PADR) is not required for this RIT-T as we consider its investment in relation to the preferred option to be exempt from that part of the process under NER clause 5.16.4(z1). Production of a PADR is not required due to:

- the estimated capital cost of the proposed preferred option being less than $46 million[41];
- the PSCR states:
    - the proposed preferred option, together with the reasons for the proposed preferred option;
    - the RIT-T is exempt from producing a PADR; and
    - the proposed preferred option and any other credible option will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding except for voluntary load curtailment and involuntary load shedding;
- the RIT-T proponent considers that there were no PSCR submissions identifying additional credible options that could deliver a material market benefit; and
- the PACR must address any issues raised in relation to the proposed preferred option during the PSCR consultation.

We consider the investment in relation to all credible options identified meets these criteria and therefore that we are exempt from producing a PADR under NER clause 5.16.4(z1).

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

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

proposed preferred option raised during the consultation period, and presents our conclusion on the preferred option for this RIT-T.

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 209.

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 an option would be required to deliver, such as: (i) the size of load reduction or additional supply; (ii) location; and (iii) operating profile;	4[42]
	(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 Integrated System 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, system strength services, 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 5.15A.2(b)(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

[42] There are currently no known credible non-network options

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[43] (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 5.15A.2(b)(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 5.15A.2(b)(4)except those classes specified in clauses 5.15A.2(b)(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

[43] Varied to $46m based on the AER Final Determination: Cost threshold review November 2021.4. Accessed 19 November 2021 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021

Appendix B Assets identified for replacement

Table B-1 presents a list of the specific assets with deteriorating condition to be replaced under Option 2.

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

Item	Asset
Protection relays	132kV A Section Bus – No1 Protection 132kV A Section Bus – No2 Protection 132kV B Section Bus – No1 Protection 132kV B Section Bus– No2 Protection Line 38 330kV – No1 Protection Line 38 330kV – No2 Protection Line 31 330kV – No1 Protection Line 31 330kV – No2 Protection Line 222 132kV – No1 Protection Line 222 132kV – No2 Protection Line 231 132kV – No1 Protection Line 231 132kV – No2 Protection Line 232 132kV – No1 Protection Line 232 132kV – No2 Protection Line 937 132kV – No1 Protection Line 937 132kV – No2 Protection Transformer 1 330kV – No1 Protection Transformer 1 330kV – No2 Protection Transformer 2 330kV – No1 Protection Transformer 2 330kV – No2 Protection Capacitor 1 132kV – No1 Protection Capacitor 1 132kV – No2 Protection Capacitor 2 132kV – No1 Protection Capacitor 2 132kV – No2 Protection
Control systems	Sitewide Bay Controller Site SCADA Gateway 110V DC Supply A 110V DC Supply B
Metering systems	Transformer 1 330kV – Revenue Metering Transformer 1 330kV – Check Metering Transformer 2 330kV – Revenue Metering Transformer 2 330kV – Check Metering

Table B-2 presents a list of protection relays considered under this RIT-T. We have identified the following protection relays at Regentville substation experiencing increasing trends in failure rates and manufacturer obsolescence which are targeted for replacement.

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

Asset	Effective age (as at 2027/28)	Key issues
132kV A Section Bus – No1 Protection	24	Exceeded technical life and/or relay type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support.
132kV A Section Bus – No2 Protection	24	
132kV B Section Bus – No1 Protection	24	
132kV B Section Bus– No2 Protection	24	
Line 38 330kV – No1 Protection	13	
Line 38 330kV – No2 Protection	18	
Line 31 330kV – No1 Protection	13	
Line 31 330kV – No2 Protection	18	
Line 222 132kV – No1 Protection	15	
Line 222 132kV – No2 Protection	12	
Line 231 132kV – No1 Protection	15	
Line 231 132kV – No2 Protection	12	
Line 232 132kV – No1 Protection	13	
Line 232 132kV – No2 Protection	21	
Line 937 132kV – No1 Protection	13	
Line 937 132kV – No2 Protection	21	
Transformer 1 330kV – No1 Protection	37	
Transformer 1 330kV – No2 Protection	37	
Transformer 2 330kV – No1 Protection	37	
Transformer 2 330kV – No2 Protection	37	
Capacitor 1 132kV – No1 Protection	15	
Capacitor 1 132kV – No2 Protection	21	
Capacitor 2 132kV – No1 Protection	15	
Capacitor 2 132kV – No2 Protection	21	

Table B-3 presents a list of control systems considered under this RIT-T. We have identified the following control systems at Regentville substation experiencing increasing trends in failure rates and manufacturer obsolescence which are targeted for replacement.

Table B-3: Control systems considered under this RIT-T

Asset	Effective age (as at 2027/28)	Key issues
110 V DC Supply – No1. Battery	17	Exceeded technical life and component type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support.
110 V DC Supply – No1. Charger	23	
110 V DC Supply – No2. Battery	17	
110 V DC Supply – No2. Charger	23	
SCADA Gateway	22	
Centralised Controller	22	
Alarms Controller	22	

Table B-4 presents a list of metering systems considered under this RIT-T. We have identified the following metering systems at Regentville substation experiencing increasing trends in failure rates and manufacturer obsolescence which are targeted for replacement.

Table B-4: Metering systems considered under this RIT-T

Asset	Effective age (years as at 2027/28)	Key issues
Transformer 1 330kV – Revenue Metering	45	Exceeded technical life and component type experiencing increased failure rates. Technology obsolescence resulting in a lack of spares and no manufacturer support
Transformer 1 330kV – Check Metering	42	
Transformer 2 330kV – Revenue Metering	45	
Transformer 2 330kV – Check Metering	42	

Table B-5 presents a list of assets to be replaced under Option 1.

Table B-5 Assets to be replaced under Option 1

Item	Asset
Protection relays	132kV A Section Bus – No1 Protection 132kV A Section Bus – No2 Protection 132kV B Section Bus – No1 Protection 132kV B Section Bus– No2 Protection Line 38 330kV – No1 Protection Line 38 330kV – No2 Protection Line 31 330kV – No1 Protection

	Line 31 330kV – No2 Protection Line 222 132kV – No1 Protection Line 222 132kV – No2 Protection Line 231 132kV – No1 Protection Line 231 132kV – No2 Protection Line 232 132kV – No1 Protection Line 232 132kV – No2 Protection Line 937 132kV – No1 Protection Line 937 132kV – No2 Protection Transformer 1 330kV – No1 Protection Transformer 1 330kV – No2 Protection Transformer 2 330kV – No1 Protection Transformer 2 330kV – No2 Protection Capacitor 1 132kV – No1 Protection Capacitor 1 132kV – No2 Protection Capacitor 2 132kV – No1 Protection Capacitor 2 132kV – No2 Protection
Control systems	Site SCADA Gateway 110V DC Supply A 110V DC Supply B
Metering systems	Transformer 1 330kV – Revenue Metering Transformer 1 330kV – Check Metering

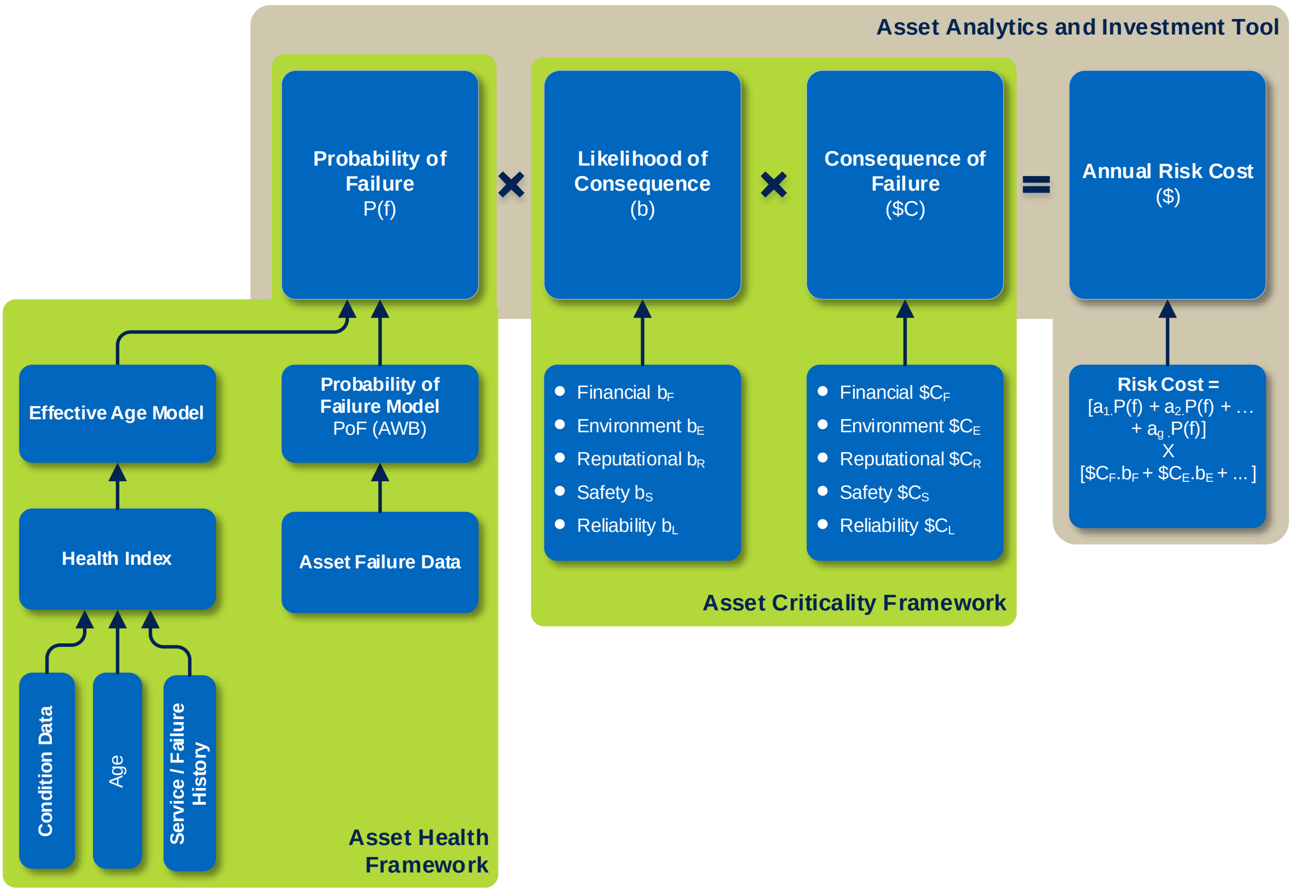
Appendix C Risk assessment framework

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[44] 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 C-1 illustrates the base risk equation that we apply.

Figure C-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:

44 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 D 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,[45] 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.
- Future effective age is linearly applied from assessed effective age.

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.

Table D-1 Weibull parameters for assets

Asset	Weibull parameters	
	η	β
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

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