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# Maintaining compliance with performance standards applicable to Lower Tumut substation secondary systems

RIT-T Project Assessment Conclusions Report

Issue date: 17 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 Lower Tumut Substation. Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process.

Built as part of the Snowy Mountains Scheme, Lower Tumut substation was commissioned in 1972 and forms part of our network that serves Southern New South Wales and the Australian Capital Territory. Lower Tumut substation is connected to Yass, Canberra, Wagga, Murray and Upper Tumut substations, via Transgrid's 330 kV network.

Secondary systems assets at Lower Tumut 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.

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

Secondary systems are used to control, monitor, protect and provide secure 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 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.[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].

1 As per Schedule 5.1 of the NER.
2 As per S5.1.2.1(d) of the NER.
3 AEMO. "Power System Security Guidelines, 20 March 2024." Melbourne: AEMO, 2024. Accessed 15 April 2024.

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.

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.

## No submissions received in response to the Project Specification Consultation Report

We published a Project Specification Consultation Report (PSCR) on 1 February 2024 and invited written submissions on the material presented within the document. No submissions were received in response to the PSCR.

## No material developments since publication of the PSCR

No additional credible options were identified during the consultation period following publication of the PSCR.

Since publication of the PSCR the cost estimates from Labour, Materials and Expenses across all options have been adjusted to reflect the latest project plan to implement the preferred option. This adjustment did not impact upon the overall capital cost figures.

Option 2 remains the preferred option at this stage of the RIT-T process.

## Credible options considered

We consider there are two credible options that would meet the identified need from a technical, commercial, and project delivery perspective.[4] These are summarised in Table E-1.

Table E-1: Summary of the credible options

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

| Option | Description | Capital costs ($M, 2023-24) | Operating costs ($/yr, 2023-24) |
|---|---|---|---|
| Option 1 | Strategic asset replacement | 15.27 | 21,078 |
| Option 2 | Complete replacement with Secondary Systems Buildings (SSBs) | 27.18 | 10,770 |

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

## No submissions received in relation to non-network options

In the PSCR we noted that 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 protection schemes (secondary systems) and ensure that the transmission system is adequately protected. No submissions were received in response to the PSCR in relation to non-network options.

## Conclusion: complete replacement with Secondary Systems Buildings (SSBs) optimal

This PACR finds that implementation of Option 2 is the preferred option to address the identified need. Option 2 involves the complete upgrade and renewal of the secondary systems by using modular Secondary Systems Buildings (SSBs) and installing new cable throughout the site. This option assumes that the new secondary systems will be designed to be accommodated within a similar panel arrangement as the existing installation. Redundant panels and tunnel boards in the ASB relay room will need to be progressively decommissioned and removed as the new secondary systems are cut-over and commissioned.

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 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 $27.18 million (in $2023-24). The work will be undertaken in stages over a five-year period with all works expected to be completed by 2027/28. Routine operating and maintenance costs are estimated to be approximately $10,770 per annum (in $2023-24).

## Next steps

This PACR represents the final step of the consultation process in relation to the application of the Regulatory Investment Test for Transmission (RIT-T) process undertaken by Transgrid.

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

- the estimated capital cost of the preferred option being less than $46 million;

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

Parties wishing to raise a dispute notice with the AER may do so prior to 16 June 2024 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 120 days, after which the formal RIT-T process will conclude. Further details on the RIT-T can be obtained from Transgrid's Regulation team via regulatory.consultation@transgrid.com.au.[5] In the subject field, please reference 'Lower Tumut Secondary Systems PACR'.

# Contents





Official

# 1. Introduction

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

Secondary systems assets at Lower Tumut substation are impacted by technological obsolescence of the equipment, increasing the time to reactively rectify faults and increasing the risk that primary assets at the substation may not be able to reliably operate.

The purpose of this RIT-T is to examine and consult on options to address the risk of secondary systems failure as a result of technological obsolescence at Lower Tumut 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 PACR[6] is to:

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

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

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

We published a Project Specification Consultation Report (PSCR) on 1 February 2024 and invited written submissions on the material presented within the document. No submissions were received in response to the PSCR.

In addition, no additional credible options were identified during the consultation period following publication of the PSCR.

Since publication of the PSCR the Labour, Material and Expense cost estimates across all options have been adjusted to reflect the latest project plan to implement the preferred option.

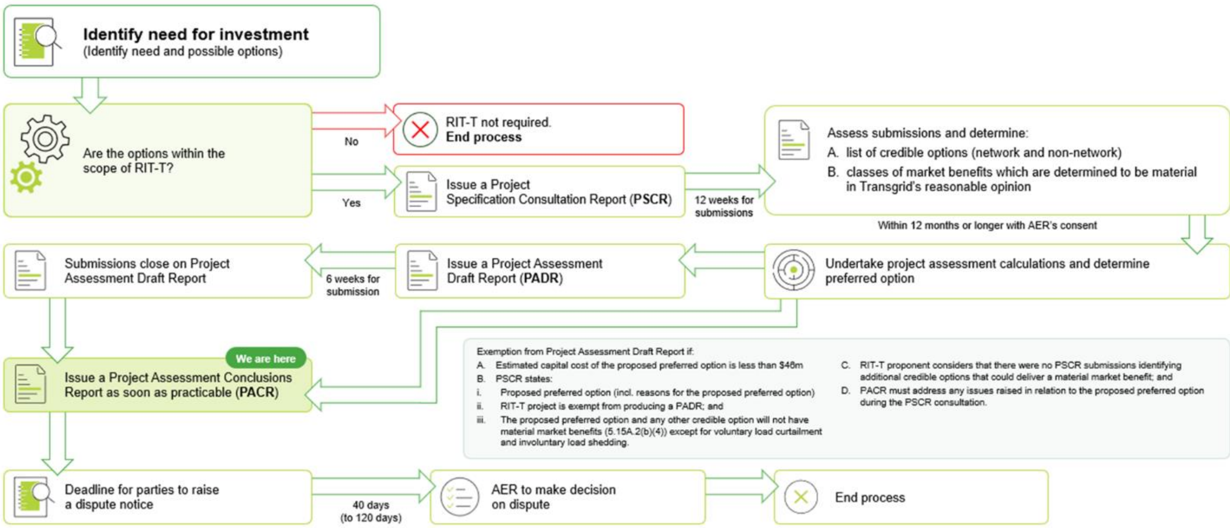
No other material changes have occurred since the PSCR that have made an impact on the preferred option.

[6] See Appendix A for the National Electricity Rules requirements.

## 1.3. Next steps

This PACR represents the final step of the consultation process in relation to the application of the RIT-T process undertaken by Transgrid. It follows the PSCR released in February 2024. No submissions were received in response to the PSCR.

Figure 1-1 This PACR is the final stage of the RIT-T process[7]




Parties wishing to raise a dispute notice with the AER may do so prior to 16 June 2024 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 120 days, after which the formal RIT-T process will conclude.

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

[7] Australian Energy Market Commission. "*Replacement expenditure planning arrangements, Rule determination*". Sydney: AEMC, 18 July 2017.

# 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.

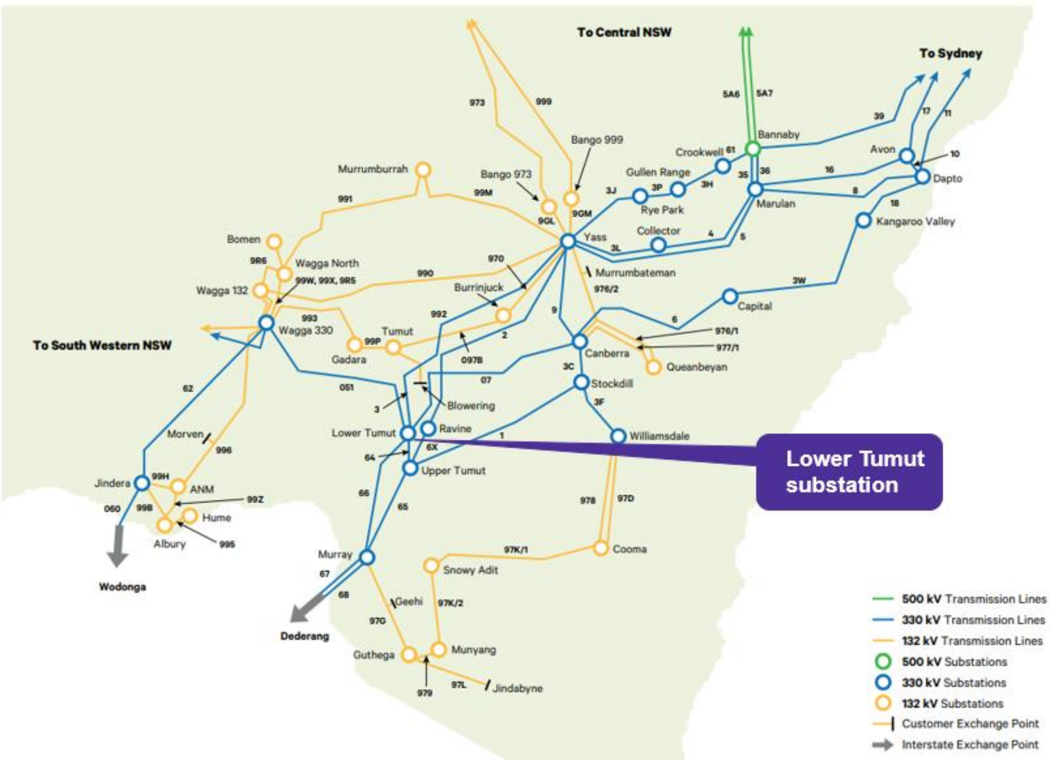
## 2.1. Background to the identified need

Built as part of the Snowy Mountains Scheme, Lower Tumut substation was commissioned in 1972 and forms part of our network that serves Southern New South Wales and the Australian Capital Territory. Lower Tumut substation is connected to Yass, Canberra, Wagga, Murray and Upper Tumut substations, via Transgrid's 330 kV network. The substation is comprised of 8 x 330 kV feeders (including 3 generation lines), 6 x 11kV feeders, and 3 x 415V feeders (for auxiliary supply). The secondary systems assets were installed at various stages between 1972 and 2019.

Lower Tumut substation connects Snowy Hydro's Tumut 3 power station with a generating capacity of 1,500MW. The substation was previously the Control Centre for the entire Snowy Hydro Scheme and as such, several legacy systems have remained since it was transferred to Transgrid's ownership. These include integrated and shared control systems, outdated pilot wire protection systems and a building that is significantly larger than required for Transgrid's purposes and in need of significant upgrades to bring it to modern standards. the site utilises 250V DC for powering all secondary systems and is only one of two sites within Transgrid's network to do so.

A map showing the location of Lower Tumut substation on our network is shown in **Error! Reference source not found.**.

Figure 2-1: Location of Lower Tumut substation



## 2.2. Description of the identified need

Secondary systems are used to control, monitor, protect and provide secure communication to facilitate safe and reliable network operation.[8] 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 at Sydney East substation 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.[9]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[10].

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.

[8] As per Schedule 5.1 of the NER.
[9] As per clause 5.1.2.1(d) of the NER.
[10] AEMO. "Power System Security Guidelines, 20 March 2024." Melbourne: AEMO, 2024. Accessed 15 April 2024.

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.

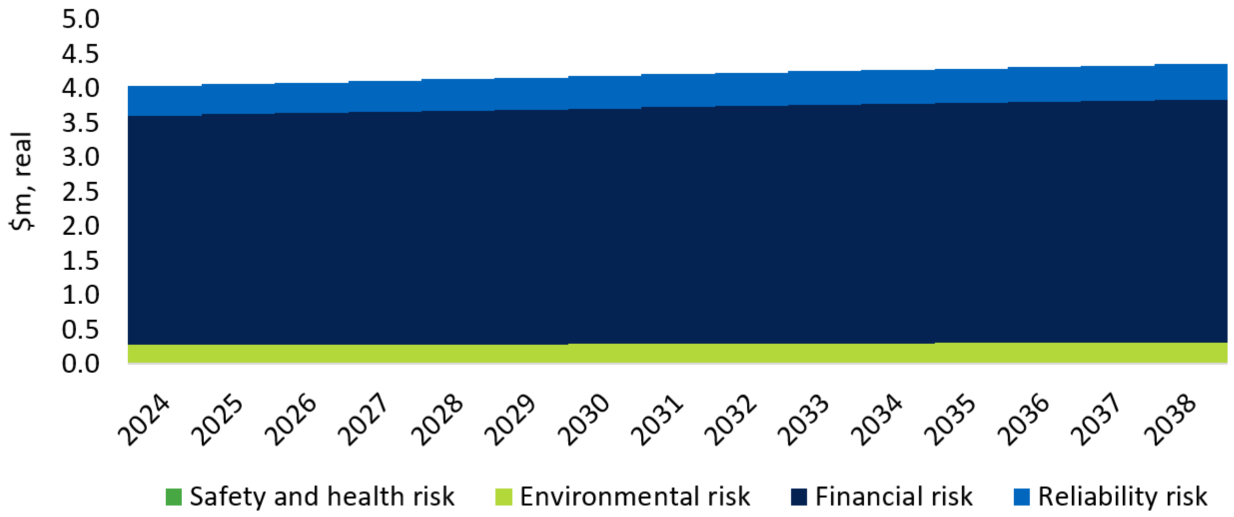
A reliability corrective action differs from a 'market benefits'-driven RIT-T in that the preferred option is permitted to have negative net economic benefits on account of it being required to meet an externally imposed obligation on the network business.

## 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 C 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 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 $4.03 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 $4.45 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.[11]

We have identified the 23 protection relays at Lower Tumut switching station are experiencing increasing failure rates, manufacturer obsolescence and a lack of support are targeted for replacement. A list of these relays can be found in Appendix B. The effective age of these relays in 2024 ranges from 9 years to 64 years, with an average effective age of 36 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.

70% 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[12] and maximum clearance times.[13]

#### 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 Lower Tumut substation experiencing increasing failure rates which are targeted for replacement. A list of these control systems can be found in Appendix B. The effective age in 2024 of these control systems ranges from 19 years to 24 years, with an average effective age of 19 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 a lack of spares and limited to no manufacturer support.

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

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

[13] 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.[14]

#### 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 11 metering systems at Lower Tumut substation experiencing increasing failure rates which are targeted for replacement. A list of these metering systems can be found in Appendix B. The effective age in 2024 of each of these metering systems is 10 and 12 years. In contrast, the typically useful life of a meter is around 15 years. Key issues presented by metering systems are:

- technology obsolescence resulting in a lack of spares and no manufacturer support.

The identified metering assets will be approaching the end of their technical life by the 2023-28 regulatory period, 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 81.8 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 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.

[14] NER, clause 4.11.1.

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 500kV and 330kV 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 500kV and 330kV 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 PACR.

Reliability risk makes up 11.21 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 6.98 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 less than 1 per cent of the total estimated risk cost in present value terms.

## 3. Potential credible options

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 credible network options from a technical, commercial, and project delivery perspective that can be implemented in sufficient time to meet the identified need.[15] Four other options were considered but not progressed for reasons outlined in Table 3-7.

We do not consider non-network options to be technically feasible to provide the functionality of the equipment required for addressing the identified need in this RIT-T. No submissions were received in response to the PSCR in relation to non-network options.

The credible options considered are summarised in Table 3-1.

Table 3-1: Summary of the credible options

| Option | Description | Estimated capex ($M, 2023-24) | Expected commission date (Financial year) |
| --- | --- | --- | --- |
| 1 | Strategic Asset Replacement | 3.05 (per year) | 2024-2028 |
| | **Total capex for Option 1** | **15.27** | |
| 2 | Complete replacement with Secondary Systems Buildings (SSBs) | 0.51 | 2024 |
| | | 2.04 | 2025 |
| | | 5.70 | 2026 |
| | | 10.99 | 2027 |
| | | 7.94 | 2028 |
| | **Total capex for Option 2** | **27.18** | |

### 3.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken in this PACR compares the costs and benefits of each credible option to a 'do nothing' base case. The base case is the (hypothetical) projected case if no action is taken, i.e.:[16]

> "*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 Lower Tumut substation, or to address the technological obsolescence,

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

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

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 $10,770 in FY24, temporarily increasing to $304,634 in FY28 before decreasing back to $21,078 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.

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

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

| Years | Operating cost |
|---|---|
| 2024 | 10,770 |
| 2025 | 10,770 |
| 2026 | 10,770 |
| 2027 | 10,770 |
| 2028 | 304,634 |
| 2029 | 304,634 |
| 2030 | 304,634 |
| 2031 | 304,634 |
| 2032 | 21,078 |
| 2033 | 21,078 |
| 2034 | 21,078 |
| 2035 | 21,078 |
| 2036 | 21,078 |
| 2037 | 21,078 |
| 2038 | 21,078 |
| **Total** | **1,409,162** |

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 Lower Tumut 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 Lower Tumut 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 Lower Tumut substation will increase from approximately $0.43 million in 2023-24 to approximately $0.52 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 $3.60 million in 2023-24 and increase to $3.83 million at the end of the 15-year assessment period (in $2023-24).

## 3.2. Option 1 – Strategic asset replacement

Option 1 involves individual replacements of identified assets up to 2027/28. 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 than cannot be expanded to match modern technology capabilities into the future.

This option would deliver the least benefits to consumers and the network by only affecting the probability of failure of targeted assets. This option will not provide any additional benefits such as improved capabilities for remote interrogation and predictive activities.

This option is planned for deployment across the 2023-24-2027/28 regulatory period with remaining assets at the site to incur investment in future years. Targeted assets will be in service for approximately 15 years. The assets that will be replaced under this option are set out in Table B-5 in Appendix B.

The capital cost of this option is approximately $15.27 million (in $2023-24), which is comprised of:

- $4.4 million in labour costs;
- $3.0 million in materials costs; and
- $7.8 million in expenses.

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

Table 3-3 Capital cost of Option 1 ($M, 2023-24)

| Years | Capital cost |
|---|---|
| 2024 | 3.05 |
| 2025 | 3.05 |
| 2026 | 3.05 |
| 2027 | 3.05 |
| 2028 | 3.05 |
| **Total** | **15.27** |

The routine operating and maintenance costs are estimated at approximately $10,770 in FY24, temporarily increasing to $304,634 in FY28 before decreasing back to $21,078 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 3-4 Breakdown of operating expenditure under Option 1 ($2023-24)

| Years | Operating cost |
|---|---|
| 2024 | 10,770 |
| 2025 | 10,770 |
| 2026 | 10,770 |
| 2027 | 10,770 |
| 2028 | 304,634 |
| 2029 | 304,634 |
| 2030 | 304,634 |
| 2031 | 304,634 |
| 2032 | 21,078 |
| 2033 | 21,078 |
| 2034 | 21,078 |
| 2035 | 21,078 |
| 2036 | 21,078 |
| 2037 | 21,078 |
| 2038 | 21,078 |
| **Total** | **1,409,162** |

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 replacement with Secondary Systems Buildings (SSBs)

Option 2 involves the complete upgrade and renewal of the secondary systems by using modular Secondary Systems Buildings (SSBs) and installing new cable throughout the site. This option assumes that the new secondary systems will be designed to be accommodated within a similar panel arrangement as the existing installation. Redundant panels and tunnel boards in the ASB relay room will need to be progressively decommissioned and removed as the new secondary systems are cut-over and commissioned.

This option will also modernise the automation philosophy to current design standards and practices. A complete SSB replacement will also 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. However, there is a significant cost associated with the installation of new modular buildings and cabling.

The work will be undertaken in stages over a five-year period with all works expected to be completed by 2027/28.

The capital cost of this option is approximately $27.18 million (in $2023-24). This cost is comprised of $8.1m of labour costs, $3.3m in material costs, and $15.8m in expenses.

Table 3-3-5 below provides a breakdown of the estimated capital cost.

Table 3-5 Capital cost of Option 2 ($M, 2023-24)

| Years | Capital cost |
|---|---|
| 2024 | 0.51 |
| 2025 | 2.04 |
| 2026 | 5.70 |
| 2027 | 10.99 |
| 2028 | 7.94 |
| **Total** | **27.18** |

The routine operating and maintenance costs are estimated at approximately $10,770 in FY24, decreasing to $10,237 in FY28 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 3-6 Breakdown of operating expenditure under Option 2 ($2023-24)

| Years | Operating cost |
|---|---|
| 2024 | 10,770 |
| 2025 | 10,770 |
| 2026 | 10,770 |
| 2027 | 10,770 |
| 2028 | 10,237 |
| 2029 | 10,237 |
| 2030 | 10,237 |
| 2031 | 10,237 |
| 2032 | 10,237 |
| 2033 | 10,237 |
| 2034 | 10,237 |
| 2035 | 10,237 |
| 2036 | 10,237 |
| 2037 | 10,237 |
| 2038 | 10,237 |
| **Total** | **155,687** |

Implementation of Option 2 is expected to reduce the probability of failure for secondary systems at Lower Tumut switching station. This will reduce the frequency and duration of involuntary load shedding associated with the failure of these assets. Option 2 will also reduce the risk of asset failure, which will in turn reduce associated environmental, safety and financial risk costs.

## 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 3-7.

Table 3-7: Options considered but not progressed

| Option | Reason(s) for not progressing |
|---|---|
| In-Situ Replacement | This cannot be delivered due to the nature of the building and the inability to manage panels or cabling due to space restrictions. |
| IEC61850 Replacement | Transgrid is revising its IEC61850 standard due to operational challenges and product limitations with the current system. As a result, this option has been screened out, as standard development will likely take an additional 18-24 months. This means the solution would not be implemented in sufficient time to meet the identified need by 2027/28 and is therefore not considered credible. |
| 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 is expected to have material inter-regional impact[17]. A 'material inter-network impact' is defined in the NER as:

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

By reference to AEMO's screening test for an inter-network impact,[18] 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.

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

[18] 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 15 April 2024. https://aemo.com.au/-/media/files/electricity/nem/network_connections/transmission-and-distribution/170-0035-pdf.pdf

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.

# 4. Materiality of market benefits

This section outlines the categories of market benefits prescribed in the National Electricity Rules (NER) and whether they are considered material for this RIT-T.[19]

## 4.1. 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 RIT-T will not affect network constraints between competing generating centres and are therefore not expected to result in any change in dispatch outcomes and wholesale market prices. We therefore consider that the following classes of market benefits[20] are not material for this RIT-T assessment:

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no impact on pool price);
- changes in costs for parties other than Transgrid;
- changes in ancillary services costs;
- changes in network losses; and
- competition benefits.

## 4.2. No other classes of market benefits are material

In addition to the classes of market benefits listed above, NER clause 5.15A.2(b)(4) requires us to consider the following classes of market benefits, listed in Table 4-14-1, arising from each credible option. We consider that none of the classes of market benefits listed are material for this RIT-T assessment for the reasons in Table 4-1.

Table 4-1: 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 |

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

[20] As per NER clause 15A.2(b)(4)

| | |
|---|---|
| | change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[21]<br><br>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.[22]<br><br>We do not consider there to be any option value with the options considered in this PACR. 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. |
| Changes in Australian greenhouse gas emissions | Neither option is expected to induce a material change in Australia's greenhouse gas emissions. |

[21] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, p.57-58.
[22] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, p.57-58.

# 5. Overview of the assessment approach

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

## 5.1. Assessment against the base case

The costs and benefits of each option in this document are compared against a 'do nothing' base case. Under this base case, no proactive capital investment is made to remediate the condition of the secondary systems assets at Lower Tumut 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 Lower Tumut 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.[23]

## 5.2. 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 PACR, consistent with AEMO's Inputs, Assumptions and Scenarios Consultation Report[24]. The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 3.63 per cent.[25] We have also adopted an upper bound discount rate of 10.5 per cent (ie, from AEMO's 2023 Inputs, Assumptions and Scenarios Report).[26]

[23] 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).

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

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

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

## 5.3. Approach to estimating option costs

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

The cost estimates are developed using our 'MTWO' cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a 'P50' portfolio value for a total program of works (i.e., there is an equal likelihood of over- or under-spending the estimate total).[27]

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

All cost estimates are prepared in 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.

## 5.4. Value of customer reliability

We have applied a NSW-wide VCR value based on the estimates developed and consulted on by the AER.[28] The options considered involve the replacement of capacitor banks across our network. As a result, we consider that a state-wide VCR is likely to reflect the weighted mix of customers that will be affected by these options.

## 5.5. 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 PACR 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

[27] For further detail on our cost estimating approach refer to section 7 of our Augmentation Expenditure Overview Paper submitted with our 2023-28 Revenue Proposal.

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

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

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

How the NPV results are affected by changes to other variables (including the discount rate and capital costs) has been investigated in the sensitivity analysis. We consider this is consistent with the latest AER guidance for RIT-Ts of this type (ie, where wholesale market benefits are not expected to be material).[29,30,31]

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

Table 5-1 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 | $49,216/MWh | $49,216/MWh | $49,216/MWh |
| Network capital costs | Base estimate | Base estimate | Base estimate |
| Avoided unserved energy | Base estimate | Base estimate - 25% | Base estimate +25% |
| Safety, environmental and financial risk benefit | Base estimate | Base estimate - 25% | Base estimate +25% |
| Avoided routine operating and maintenance costs | Base estimate | Base estimate | Base estimate |

## 5.6. Sensitivity analysis

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

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

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

[29] AER, *Application Guidelines Regulatory Investment Test for Transmission*, October 2023, pp. 43-44.

[30] 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.

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

The above list of sensitivities focuses on the key variables that could impact the identified preferred option. The results of the sensitivity tests are set out in section 6.4.

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

# 6. Assessment of credible options

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

All costs and benefits presented in this PACR are in 2023-24 dollars.

## 6.1. 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 6-1: 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 | 9.36 | 7.02 | 11.70 | 9.36 |
| Option 2 | 27.39 | 20.54 | 34.24 | 27.39 |

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

## 6.2. 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 6-2: NPV of capital 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 | 12.21 | 12.21 | 12.21 | 12.21 |
| Option 2 | 18.85 | 18.85 | 18.85 | 18.85 |

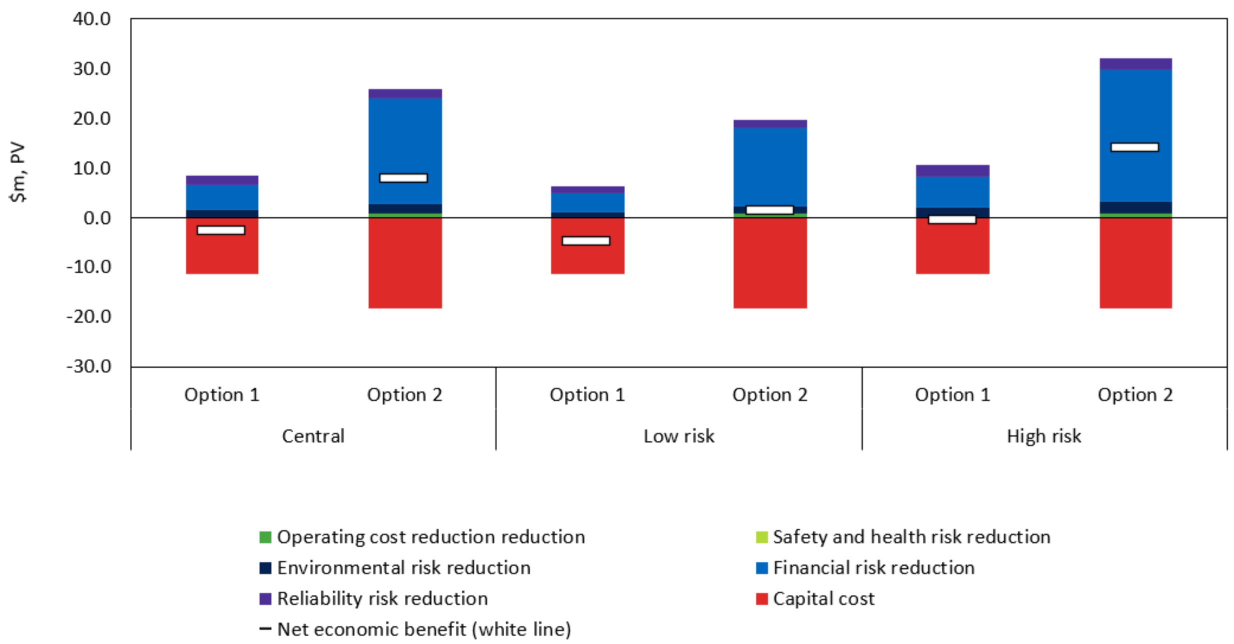
## 6.3. Estimated net economic benefits

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 6-3: 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 | -2.85 | -5.19 | -0.51 | -2.85 |
| Option 2 | 8.54 | 1.69 | 15.39 | 8.54 |

Figure 6-1 NPV of net economic benefits ($2023-24 m)




## 6.4. Sensitivity testing

We undertook sensitivity testing to understand the robustness of the RIT-T assessment to underlying assumptions about key variables. In particular, we undertook 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.

### 6.4.1. 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. In particular, the optimal timing of Option 2 is found to be largely invariant to most of the sensitivities undertaken on the central scenario, apart from:

- a 25 per cent decrease in capital costs; and
- a 25 per cent decrease in risk costs

Figure 6-2 below outlines the impact on the optimal commissioning year, under a range of alternative assumptions. It illustrates that for Option 2, the optimal commissioning date is found to be in 2027/28 for all of the sensitivities investigated apart from low capital costs and high-risk costs scenarios, whilst noting there was no optimal year solution for high capital costs or low risk costs scenarios.

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


### 6.4.2. 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 risk cost values
- lower discount rate of 3.63 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.

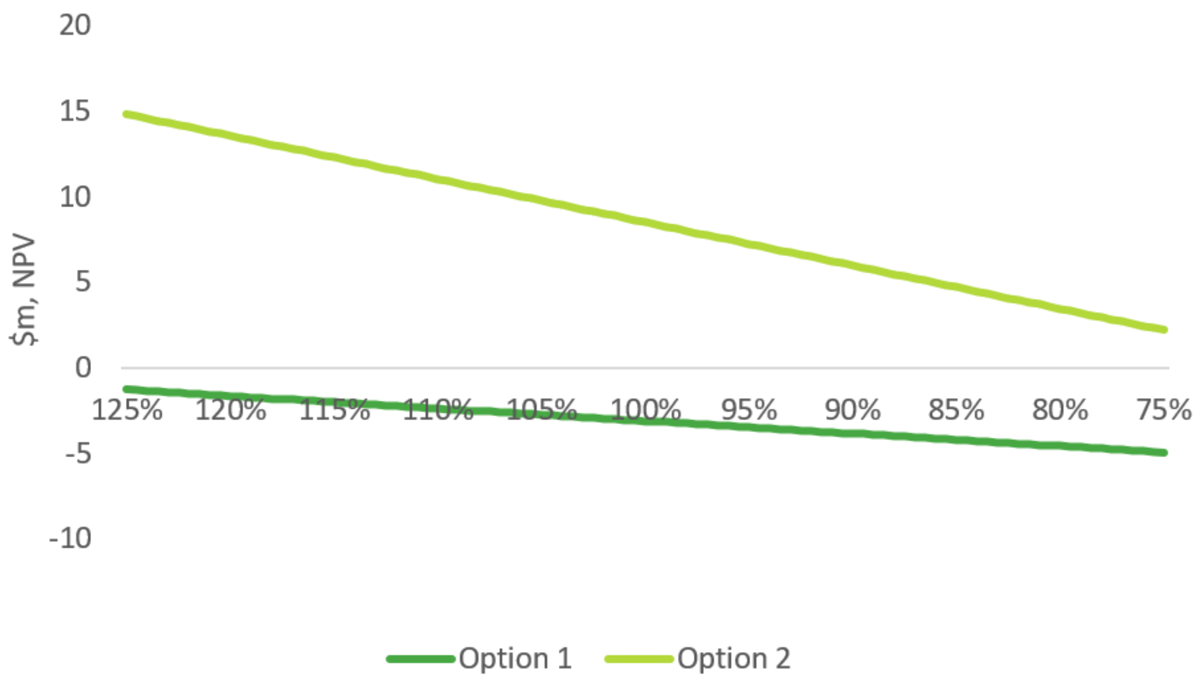
Option 2 delivers positive benefits under most scenarios and is the preferred option, however, it is worth noting that through this analysis Option 1 may be preferred over Option 2 under high discount rate, high capital cost and low risk scenarios. As such, both threshold analysis and boundary testing had been conducted to provide more information on when these scenarios would occur.

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 cost values, which includes safety & health risk, environmental risk and financial risk. We estimated the net economic benefit of each option by adopting a risk cost 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.

Table 6-4: NPV of net economic benefits relative to the base case under a lower and higher risk costs ($2023-24 m)

| Option/scenario | Lower risk | Higher risk | Ranking (>85%) | Breakeven (%) |
|---|---|---|---|---|
| *Sensitivity* | *Central estimate - 25%* | *Central estimate + 25%* | | |
| Option 1 | -4.90 | -1.24 | 2 | N/A |
| Option 2 | 2.23 | 14.86 | 1 | 75 |

Figure 6-3 Sensitivity of net economic benefits under a lower and higher risk costs ($2023-24 m)

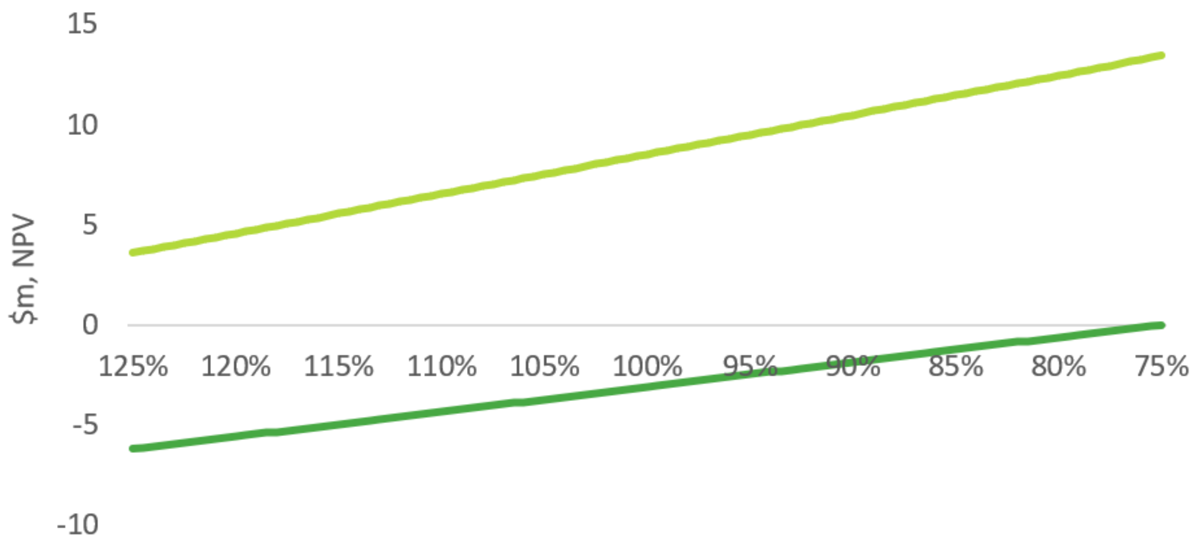



The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting lower and higher capital costs. We estimated the net economic benefit of each option by adopting capital costs for each option that are 25% higher (the 'High capex' scenario) 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.

Table 6-5: Sensitivity of net economic benefits under lower and higher capital costs ($2023-24 m)

| Option/scenario | Lower capex | Higher capex | Ranking (<117%) | Breakeven (%) |
|---|---|---|---|---|
| *Sensitivity* | *Central estimate - 25%* | *Central estimate + 25%* | | |
| Option 1 | 0.04 | -6.18 | 2 | 75 |
| Option 2 | 13.47 | 3.62 | 1 | 125 |

Figure 6--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 3.63% which is consistent with the AER's latest final determination for a TNSP (the 'Low discount rate' scenario),[32] 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).[33] The results of this analysis are presented in the table and figure below.

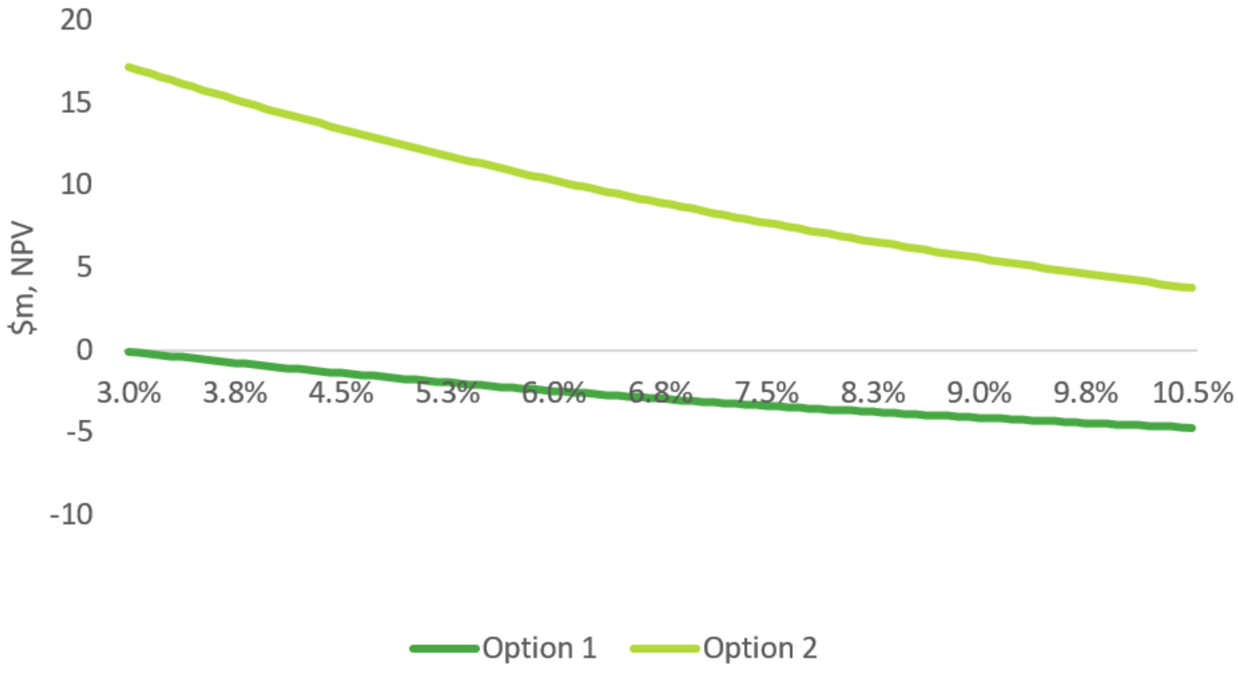
Table 6-6: Sensitivity of net economic benefits under a lower and higher discount rates ($2023-24 m)

| Option/scenario | Low discount rate | High discount rate | Ranking (<9.52%) | Breakeven (%) |
|---|---|---|---|---|
| *Sensitivity* | *3.63%* | *10.5%* | | |
| Option 1 | -0.05 | -4.68 | 3 | N/A |
| Option 2 | 17.18 | 3.79 | 1 | 10.50 |

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

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

Figure 6--5 Sensitivity of net economic benefits under a lower and higher discount rates ($2023-24 m)



# 7. Final conclusion on the preferred option

This PACR finds that Option 2 is the preferred option to address the identified need. Option 2 involves the complete upgrade and renewal of the secondary systems by using new modular Secondary Systems Buildings (SSBs) and installing new cable throughout the site.

This option will adopt an automation philosophy consistent with current design standards and practices. A complete SSB replacement will also 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.

The capital cost of this option is approximately $27.18 million (in $2023-24). The work will be undertaken over a four-year period with all works expected to be completed by 2027/28. Routine operating and maintenance costs are estimated at approximately $10,770 per annum (in $2023-24).

In assessing Option 1 and Option 2 access to the substation is deemed adequate, hence, no temporary access track was allowed for in this estimate.

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

Transgrid considers this conclusion to be robust to changes in capital cost inputs, estimated risk costs and underlying discount rates, noting that there would need to be unrealistic changes to these key assumptions to change the ranking of the options (as shown via the boundary testing at the end of section 6). Transgrid will however continue to monitor these key assumptions and will notify the AER if such changes do occur (or appear likely), which would constitute a material change in circumstance.

# Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PACR with the requirements of the National Electricity Rules version 209.

| Rules clause | Summary of requirements | Relevant section(s) in the PACR |
|---|---|---|
| 5.16.4(v) | The project assessment conclusions report must set out: | – |
| | (1) the matters detailed in the project assessment draft report as required under paragraph (k); and | See below. |
| | (2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought under paragraph (q). | NA |
| 5.16.4(k) | The project assessment draft report must include: | – |
| | (1) a description of each credible option assessed; | 3 |
| | (2) a summary of, and commentary on, the submissions to the project specification consultation report; | NA |
| | (3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option; | 3 & 6 |
| | (4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost; | 4 & 5 |
| | (5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material; | 4 |
| | (6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions); | NA |
| | (7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results; | 6 |
| | (8) the identification of the proposed preferred option; | 7 |
| | (9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide:<br>(i) details of the technical characteristics;<br>(ii) the estimated construction timetable and commissioning date;<br>(iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and<br>(iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission. | 3 & 7 |
| | (10) if each of the following apply to the RIT-T project:<br>(i) if the estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination); and<br>(ii) AEMO is not the sole RIT-T proponent,<br>The RIT-T reopening triggers applying to the RIT-T project. | N/A |

# Appendix B Assets identified for replacement under Option 1

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

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

| Item | Asset |
|---|---|
| Protection relays | 330kV East Bus – No1 Protection<br>330kV East Bus – No2 Protection<br>330kV West Bus – No1 Protection<br>330kV West Bus– No2 Protection<br>Line 051 330kV – No1 Protection<br>Line 051 330kV – No2 Protection<br>Line 07 330kV – No1 Protection<br>Line 07 330kV – No2 Protection<br>Line 3 330kV – No1 Protection<br>Line 3 330kV – No2 Protection<br>Line 64 330kV – No1 Protection<br>Line 64 330kV – No2 Protection<br>Line 66 330kV – No1 Protection<br>Line 66 330kV – No2 Protection<br>Line L1 T3 330kV – No1 Protection<br>Line L1 T3 330kV – No2 Protection<br>Line L3 T3 330kV – No1 Protection<br>Line L3 T3 330kV – No2 Protection<br>Line L5 T3 330kV – No1 Protection<br>Line L5 T3 330kV – No2 Protection<br>Line No1 Talbingo Town 11kV – No1 Protection<br>Line No2 TU3 PS 11kV – No1 Protection<br>Line No3 TU3 Pipeline 11kV – No1 Protection<br>Line No4 TU3 PS 11kV – No1 Protection |
| Control systems | Sitewide Bay Controller<br>Site SCADA Gateway<br>110V DC Supply A<br>110V DC Supply B |
| Metering systems | Line L1 T3 – Revenue Metering<br>Line L1 T3 – Check Metering<br>Line L3 T3 – Revenue Metering<br>Line L3 T3 – Check Metering<br>Line L5 T3 – Revenue Metering<br>Line L5 T3 – Check Metering<br>Line No1 Talbingo Town – Revenue Metering<br>Line No2 TU3 PS 11kV – Revenue Metering<br>Line No3 TU3 Pipeline 11kV – Revenue Metering |

| Item | Asset |
|---|---|
| | Line No4 TU3 PS 11kV – Revenue Metering |

Table B-2 presents a list of protection relays considered under this RIT-T. We have identified the following protection relays at Lower Tumut 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 |
|---|---|---|
| 330kV East Bus – No1 Protection | 65 | Exceeded technical life and/or relay type experiencing increased failure rates.<br><br>Technology obsolescence resulting in a lack of spares and no manufacturer support. |
| 330kV East Bus – No2 Protection | 67 | |
| 330kV West Bus – No1 Protection | 65 | |
| 330kV West Bus– No2 Protection | 67 | |
| Line 051 330kV – No1 Protection | 38 | |
| Line 051 330kV – No2 Protection | 14 | |
| Line 07 330kV – No1 Protection | 38 | |
| Line 07 330kV – No2 Protection | 14 | |
| Line 3 330kV – No1 Protection | 38 | |
| Line 3 330kV – No2 Protection | 15 | |
| Line 64 330kV – No1 Protection | 38 | |
| Line 64 330kV – No2 Protection | 14 | |
| Line 66 330kV – No1 Protection | 38 | |
| Line 66 330kV – No2 Protection | 14 | |
| Line L1 T3 330kV – No1 Protection | 21 | |
| Line L1 T3 330kV – No2 Protection | 40 | |
| Line L3 T3 330kV – No1 Protection | 12 | |
| Line L3 T3 330kV – No2 Protection | 12 | |
| Line L5 T3 330kV – No1 Protection | 12 | |
| Line L5 T3 330kV – No2 Protection | 12 | |
| Line No1 Talbingo Town 11kV – No1 Protection | 65 | |
| Line No2 TU3 PS 11kV – No1 Protection | 53 | |
| Line No3 TU3 Pipeline 11kV – No1 Protection | 53 | |
| Line No4 TU3 PS 11kV – No1 Protection | 67 | |

| Asset | Effective age (as at 2027/28) | Key issues |
|---|---|---|
| 110V DC Supply – No1. Battery | 16 | Exceeded technical life and component type experiencing increased failure rates.<br><br>Technology obsolescence resulting in a lack of spares and no manufacturer support. |
| 110V DC Supply – No1. Charger | 23 | |
| 110V DC Supply – No2. Battery | 13 | |
| 110V DC Supply – No2. Charger | 15 | |

Table B-3 presents a list of control systems considered under this RIT-T. We have identified the following control systems at Lower Tumut 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 | 16 | Exceeded technical life and component type experiencing increased failure rates.<br><br>Technology obsolescence resulting in a lack of spares and no manufacturer support. |
| 110 V DC Supply – No1. Charger | 16 | |
| 110 V DC Supply – No2. Battery | 16 | |
| 110 V DC Supply – No2. Charger | 16 | |
| SCADA Gateway | 16 | |
| Local HMI | 27 | |
| Centralised Controller | 16 | |
| Alarms Controller | 16 | |

Table B-4 presents a list of metering systems considered under this RIT-T. We have identified the following metering systems at Lower Tumut 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 |
|---|---|---|
| Line L1 T3 – Revenue Metering | 14 | Exceeded technical life and component type experiencing increased failure rates.<br><br>Technology obsolescence resulting in a lack of spares and no manufacturer support |
| Line L1 T3 – Check Metering | 13 | |
| Line L3 T3 – Revenue Metering | 14 | |

| | | |
|---|---|---|
| Line L3 T3 – Check Metering | 13 | |
| Line L5 T3 – Revenue Metering | 16 | |
| Line L5 T3 – Check Metering | 15 | |
| Line No1 Talbingo Town – Revenue Metering | 14 | |
| Line No2 TU3 PS 11kV – Revenue Metering | 14 | |
| Line No3 TU3 Pipeline 11kV – Revenue Metering | 16 | |
| Line No4 TU3 PS 11kV – Revenue Metering | 16 | |

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 | Line 051 330kV – No1 Protection<br>Line 051 330kV – No2 Protection<br>Line 07 330kV – No1 Protection<br>Line 07 330kV – No2 Protection<br>Line 3 330kV – No1 Protection<br>Line 3 330kV – No2 Protection<br>Line 64 330kV – No1 Protection<br>Line 64 330kV – No2 Protection<br>Line 66 330kV – No1 Protection<br>Line 66 330kV – No2 Protection<br>Line L1 T3 330kV – No1 Protection<br>Line L1 T3 330kV – No2 Protection<br>Line L1 T3 330kV – No1 Protection<br>Line L1 T3 330kV – No2 Protection<br>Line L1 T3 330kV – No1 Protection<br>Line L1 T3 330kV – No2 Protection<br>Line No1 Talbingo Town 11kV – No1 Protection<br>Line No2 TU3 PS 11kV – No1 Protection<br>Line No3 TU3 Pipeline 11kV – No1 Protection<br>Line No4 TU3 PS 11kV – No1 Protection |
| Control systems | Site SCADA Gateway |
| Metering systems | Line L1 T3 – Check Metering<br>Line L3 T3 – Check Metering<br>Line L5 T3 – Check Metering<br>Line No1 Talbingo Town – Revenue Metering<br>Line No2 TU3 PS 11kV – Revenue Metering<br>Line No3 TU3 Pipeline 11kV – Revenue Metering<br>Line No4 TU3 PS 11kV – Revenue Metering |

# Appendix C Risk Assessment Methodology

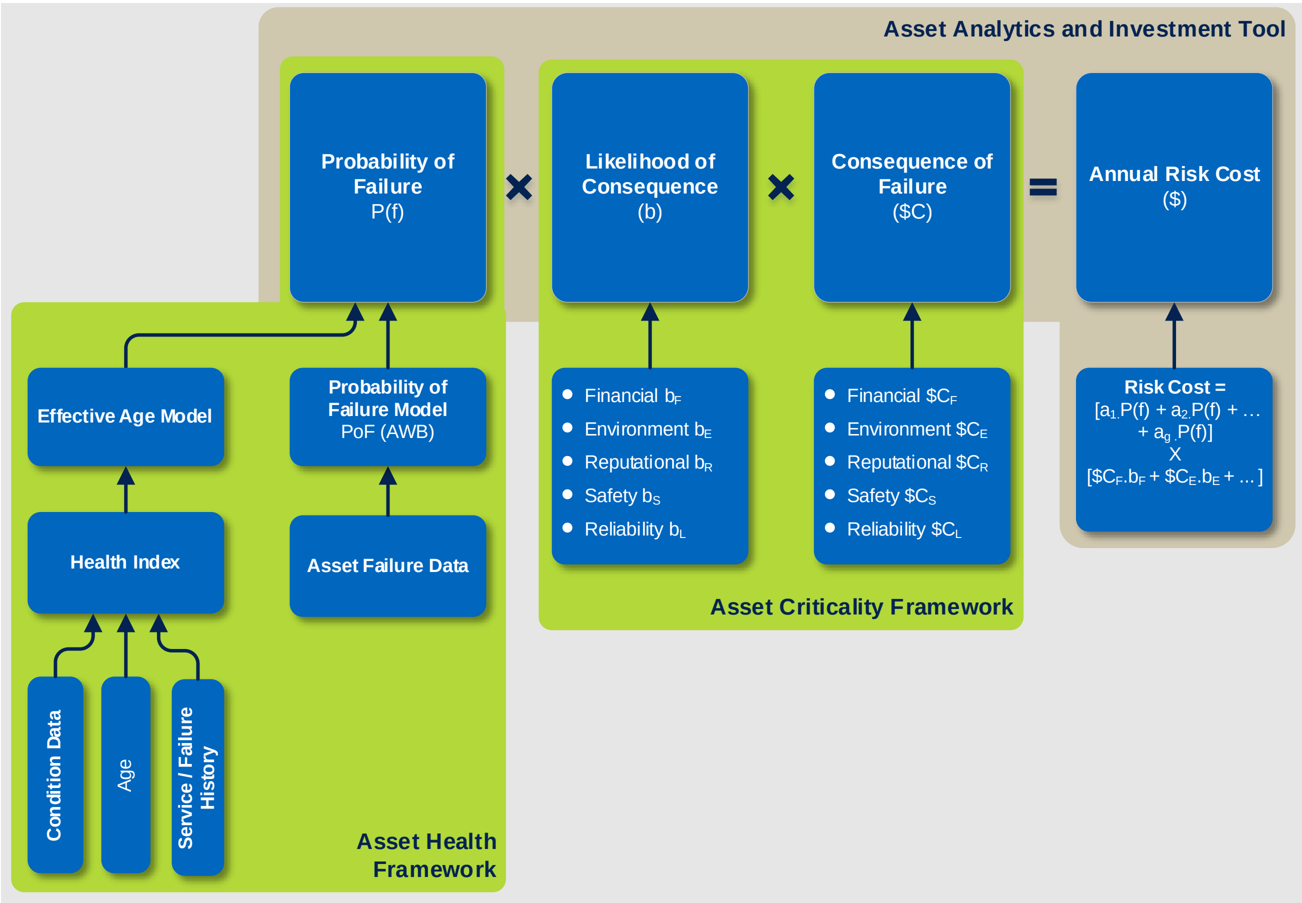
This appendix summarises our network risk assessment methodology that underpins the identified need for this RIT-T. Our risk assessment methodology is aligned with the AER's Asset Replacement Planning guideline[34] and its principles.

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 below summarises the framework for calculating the 'risk costs', which has been applied on our asset portfolio considered to need replacement or refurbishment.

Figure C-1 Risk cost calculation




Economic justification of 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

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

and costs.  The major quantified risks we apply for repex justifications include asset failures that materialise as:

- bushfire risk;
- safety risk;
- environmental risk;
- reliability risk; and
- financial risk.

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

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

# Appendix D Asset Health and Probability of Failure

The first step in calculating the Probability of Failure (PoF) of an asset is determining the asset health and associated effective age,[35] which considers that:

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

The PoF is the likelihood that an asset will fail during a given period resulting in a particular adverse event, e.g., equipment failure, pole failure, broken overhead conductor.

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

The Weibull parameters which represent the probability of failure curve for key transmission line components are summarised in Table D-1 below.

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

Table D-1 Weibull parameters for assets

| Asset | Weibull parameters | |
|---|---|---|
| | η | β |
| Multifunction Intelligent Electronic Device:<br>- Protection<br>- Controller<br>- 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 |

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

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