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Maintaining compliance with performance standards applicable to protection relays

RIT-T Project Assessment Conclusions Report

Issue date: 24 June 2024

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining compliance with performance standards applicable to protection relays. This RIT-T includes 419 protection relays at various locations on the ACT and NSW transmission network, based on their assessed condition. Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process.

Protection relays are used throughout the transmission network to isolate network faults and reduce their impact on system security, system reliability and network infrastructure. In this RIT-T we are examining options to address the risk of failure of individual protection relays that isolate faults on transmission lines, transformers, reactors, capacitors, and busbars (interzone). Additionally, this RIT-T includes options for addressing risks to under frequency load shedding (UFLS) schemes. These UFLS schemes at various substations on the network are designed to arrest a fall in frequency by progressively disconnecting load in a coordinated and automatic manner. These schemes are implemented to satisfy requirements set out in the National Electricity Rules (NER)[1].

The identified protection relays will reach the end of their technical life by 2027/28, with manufacturer support, access to spares and defects rates being the largest drivers for remediation. The risk of failing to protect primary assets increases as technology becomes superseded by the manufacturer, manufacturer support ceases, and spare parts become scarce.

If the deteriorating condition of these identified assets is not addressed by 2027/28, the risk of asset failure will increase. Table E-1 outlines the condition issues associated with the protection relays, the impact of each condition issue if not remediated, as well the consequences of each issue if no action is taken.

Table E-1 Condition issues on protection relays on the ACT and NSW network, their potential impact, and consequences

Issue	Potential impact	Consequence
Technology obsolescence	Manufacturer support is limited or withdrawn, repair and replacement facilities are expected to be unavailable.	Assets continue to deteriorate and risk of failure increases.
Decreased function	Assets have increasing numbers of faults as they progress along their failure curves, deteriorating components or are prone to mechanical wear.	Likelihood of a hazardous event occurring increases.

Given the high population of protection relays that have been identified for replacement, we consider it prudent and cost effective to manage this risk through a single asset replacement program.

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

Protection relays play a central role in supplying electricity across the ACT and NSW transmission network. Used to control, monitor, protect and secure communication to facilitate safe and reliable network

[1] As per Schedule 5.1 of the NER.

operation, protection relays are necessary to operate the transmission network and prevent damage to primary assets when adverse events occur. [2]

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 assets where the secondary system 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 voltages above 66 kV are always well-maintained and available other than for short periods (less than eight hours), while the maintenance of protection systems is being carried out.[3] 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[4].

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 a 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 replacements will cease to be a viable option to meet performance standards stipulated in clause 4.6.1 of the NER.

If the need 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 Assessment Draft Report

We published a Project Assessment Draft Report (PADR) on 22 April 2024 and invited written submissions on the material presented within the document. No submissions were received in response to the PADR.

[2] As per Schedule 5.1 of the NER.
[3] As per S5.1.2.1(d) of the NER.
[4] AEMO. "Power System Security Guidelines, 3 June 2024." Melbourne: AEMO, 2023.23. Accessed 4 June 2024. SO_OP_3715 - Power System Security Guidelines (aemo.com.au)

No material developments since publication of the PADR

Following the publication of the PADR the renewal program's scope was adjusted to include additional assets. These assets have been incorporated within the updated program because of emerging issues identified after the PADR was published. There is a minor cost decrease to the preferred option (Option 1) and related changes in the base case and option risks.

In addition, there is an increase in annual operating costs for the base case and the preferred option. The method for calculating the operating expenditure in the PADR aligned with the method we typically use to assess protection relays at individual sites. However, as we are conducting a RIT-T to assess a program of works which are part of our Asset Renewal Strategy (ARS), we have re-calculated the opex to reflect the scope and scale of the project, and with consideration of the varying asset condition across the network. Overall, this update has not materially impacted the assessment.

Option 1 remains the preferred option for meeting the service level required under the National Electricity Rules for protection schemes at this stage of the RIT-T process.

Credible options considered

In the PADR we identified one credible network option that we consider would meet the identified need from a technical, commercial, and project delivery perspective.[5] The only option that meets these criteria is summarised in Table E-2.

Table E-2 Summary of the credible option

Option	Description	Estimated capex ($2023-24 m)	Expected commission date
Option 1	Renewal of individual assets		2024-2028
Transmission line protection relays		$35.17	
Transformer protection relays		$8.30	
Reactor protection relays		$1.89	
Capacitor protection relays		$2.88	
Busbar (and interzone) protection relays		$0.98	
Protection relays associated with UFLS schemes		$0.96	
		Total: $50.18	

Four other options were considered (secondary systems renewal, refurbishment of individual assets, asset retirement, and non-network solutions) but not progressed. The reasons for not progressing these options are outlined in Table 3-5.

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

No submissions received in relation to non-network options

In the PSCR and PADR, 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 and ensure that the transmission system is adequately protected. No submissions were received in response to the PSCR, nor the PADR, in relation to non-network options.

Conclusion: Renewal of individual assets is optimal

This PACR finds that Option 1 is the preferred option to address the identified need. Option 1 involves individual replacements of 419 identified assets (listed in Appendix C) across 48 sites within the regulatory period. 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 would deliver risk mitigation and reduced corrective maintenance benefits to consumers and the networks by only targeting the probability of failure of identified assets. This option will not deliver any additional operational benefits such as improved capabilities for remote interrogation and predictive activities. This option will phase asset renewals across the regulatory control periods. Deployments are prioritised based on investment benefit with consideration also given to efficient delivery strategies. Targeted assets will be in service for approximately 15 years, with some assets remaining in-service until investment in future years.

We have assessed that Option 1 is net beneficial under all three reasonable scenarios considered in this PACR. On a weighted basis, where each scenario is weighted equally, Option 1 is expected to deliver net benefits of approximately $19.19 million. Option 1 will also enable us to meet a range of obligations under the NER and jurisdictional instruments (which is not expected to be the case under the base case), including obligations set out in Schedule 5.1 of the NER to provide redundant secondary systems and ensure that the transmission system is adequately protected.

The work will be undertaken over a five-year period with all works expected to be completed by the end of 2027/28. The capital cost of this option is approximately $50.18 million (in $2023-24). In addition, routine operating and maintenance costs are estimated at approximately $61,650 per annum (in $2023-24). We expect that the protection relays will have an asset life of 15 years.

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.

Parties wishing to raise a dispute notice with the AER may do so prior to 26 July 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.[6] In the subject field, please reference 'Protection Relays PACR.'

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

Contents

1. Introduction

1.1. Purpose of this report

The purpose of this PACR[7] 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 PADR and no material developments

We published a PADR on 22 April 2024 and invited written submissions on the material presented within the document. No submissions were received in response to the PADR. In addition, no additional credible options were identified during the consultation period following publication of the PADR.

Following the publication of the PADR the renewal program's scope was adjusted to include additional assets. These assets have been incorporated within the updated program because of emerging issues identified after the PADR was published. There is a minor cost decrease to the preferred option (Option 1) and related changes in the base case and option risks.

In addition, there is an increase in annual operating costs for the base case and the preferred option. The method for calculating the operating expenditure in the PADR aligned with the method we typically use to assess protection relays at individual sites. However, as we are conducting a RIT-T to assess a program of works which are part of our Asset Renewal Strategy (ARS), we have re-calculated the opex to reflect the scope and scale of the project, and with consideration of the varying asset condition across the network. Overall, this update has not materially impacted the assessment.

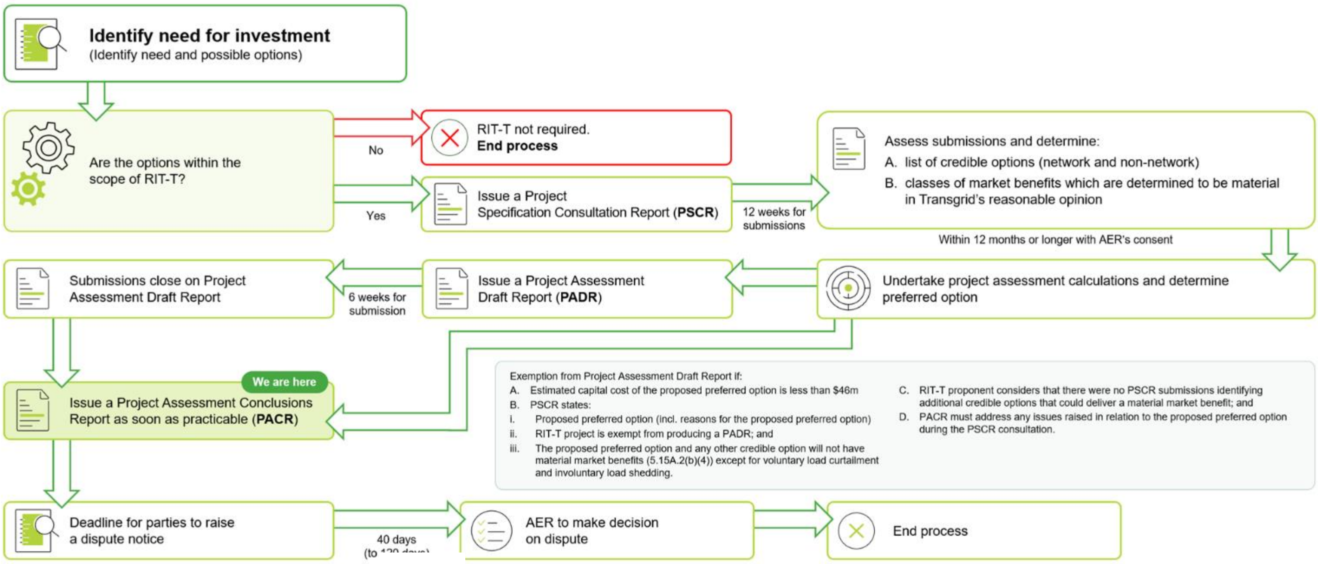
Option 1 remains the preferred option for meeting the service level required under the National Electricity Rules for protection schemes at this stage of the RIT-T process.

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 PADR released in April 2024. No submissions were received in response to the PADR.

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

Figure 1-1 This PACR is the final stage of the RIT-T process[8]



Parties wishing to raise a dispute notice with the AER may do so prior to 26 July 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 'Protection Relays PACR.'

[8] 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

Protection relays are used throughout the transmission network to isolate network faults and reduce their impact on system security, system reliability and network infrastructure. In this RIT-T we are examining options to address the risk of failure of individual protection relays that isolate faults on transmission lines, transformers, reactors, capacitors, and busbars (interzone). Additionally, this RIT-T includes options for addressing risks to four under frequency load shedding (UFLS) schemes. These UFLS schemes at various substations on the network are designed to arrest a fall in frequency by progressively disconnecting load in a coordinated and automatic manner. These schemes are implemented to satisfy requirements set out in the National Electricity Rules (NER)9.

The assets included in this RIT-T will reach the end of their serviceability by FY2027/28. Serviceability is evaluated against multiple factors including manufacturer support for repairs and replacements, historical defect rates of individual models, availability of spares and statistical probability of failure. We have identified 419 protection assets on our network that will reach the end of their serviceability by 2027/28. These assets comprise of various technologies such as electromechanical, discrete component and microprocessor-based relays. A list of the targeted devices is provided in Appendix C.

The end-of-life assets have been identified through the application of our Network Asset Health Framework based on their asset health index and effective age. The evaluated health index inputs for protection assets considers multiple factors including manufacturer support for repairs and replacements, historical defect rates of individual models, availability of spares and statistical probability of failure.

A protection relay failing to operate during a network fault would result in a catastrophic failure of the primary asset, placing a burden on the connected busbar. This would then cause a cascading failure on the connected bus, nearby transformers and transmission lines. The failure of the surrounding assets would be the only feasible way to trigger another active protection scheme. This would then be a matter of either the generators tripping or further surrounding assets failing.

2.2. Description of the identified need

Protection relays control, monitor, protect and secure communication to facilitate safe and reliable network operation and to prevent damage to primary assets when adverse events occur[10].

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

[9] As per Schedule 5.1 of the NER.
[10] As per Schedule 5.1 of the NER.

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 assets where the secondary system 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 voltages above 66 kV are well-maintained and available at all times other than for short periods (less than eight hours), while the maintenance of protection systems is being carried out.[11]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[12].

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 a 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 protection schemes 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.

Given the high population of protection relays that have been identified for replacement, we consider it prudent and cost effective to manage this risk through a single asset replacement program.

2.3. Assumptions underpinning the identified need

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

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

Figure 2-3 summarises the increasing risk costs over the under the base case and our central scenario of asset failure risk.

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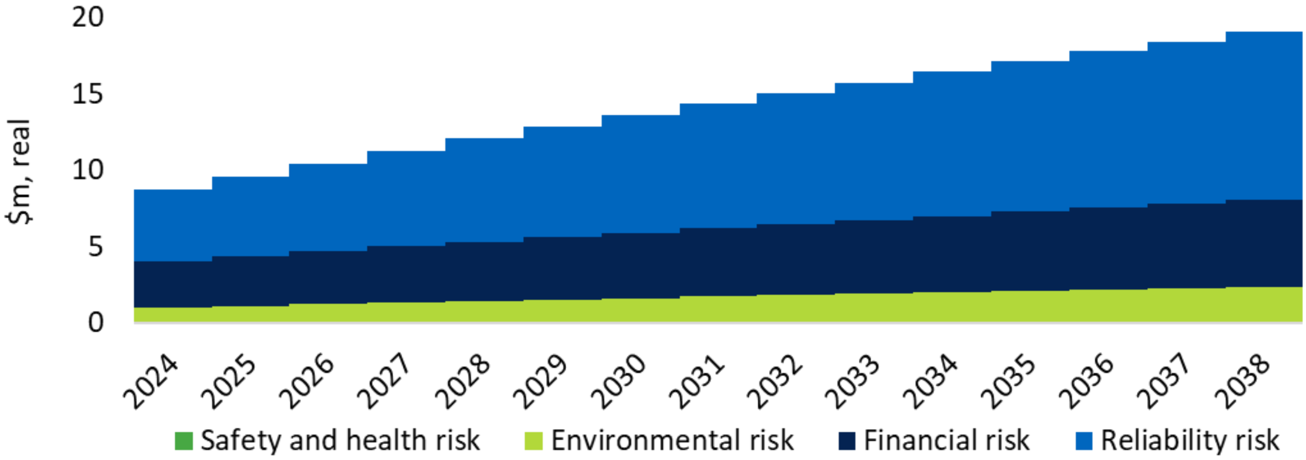
11 As per S5.1.2.1(d) of the NER.

12 AEMO. "Power System Security Guidelines, 6 November 2023." Melbourne: AEMO, 2023.23. Accessed 15 March 2024. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715%20Power-System-Security-Guidelines.pdf

Figure 2-3 Estimated risk costs under the base case (central scenario)



This section describes the assumptions underpinning our assessment of the risk costs, i.e., the value of the risk avoided by undertaking each of the credible options. The aggregate risk cost under the base case is currently estimated at around $8.72 million in 2023/24, and it is expected to increase going forward if action is not taken (reaching approximately $19.05 million in 2037/38 by the end of the 15-year assessment period).

2.3.1.1. Asset health and the probability of failure

The health index score for a protection relay is dependent on the asset serviceability factors outlined below.

Spares and Support: Due to the proprietary nature of protection assets, an evaluation of manufacturer support and/or spares availability is critical for ensuring the continuing operability of these assets. This figure represents the ability to repair or replace an in-service failed asset.

Historical defect rates: A key factor into asset health is the historical rate of defects experienced across individual models. A 3-year average is utilised to minimise bias to peaks and troughs. This figure represents the potential underlying issues with a particular model.

Asset type: The type of technology on which the asset is based affects the overall health index of the asset. Older technologies such as electromechanical and discrete component assets suffer from degradation over time, being effectively mechanical devices. These also lack self-monitoring capabilities and as such can fail between maintenance testing cycles. Modern microprocessor-based devices do not suffer from degradation in a similar manner and have the ability to self-monitor and alarm on failure (watchdog).

Natural age: A protection asset’s natural age is calculated from its first install date. This age contributes to the overall health index.

2.3.2. Reliability risk

The likelihood of a consequence considers the likelihood of duplicated protection 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 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.

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.

Reliability risk makes up approximately 56.42 per cent of the total estimated risk cost in present value terms.

2.3.1. Financial risk

This refers to the financial consequence of an asset failure. The likelihood of a consequence considers 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 monetary value considers the cost of replacement or repair of the failed asset and the protected asset, including any temporary measures.

Financial risk makes up approximately 31.63 per cent of the total estimated risk cost in present value terms.

2.3.2. 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 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 approximately 11.83 per cent of the total estimated risk cost in present value terms.

2.3.3. Safety risk

This refers to the safety consequence to staff, contractors and/or members of the public of an asset failure. The likelihood of a consequence 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

We consider credible options in this RIT-T assessment as those that would meet the identified need from a technical, commercial, and project delivery perspective[13].

We have identified one network option that we consider will meet the identified need for this RIT-T, as summarised in Table 3-1 below.

Table 3-1 Summary of the credible options

Option	Description	Estimated capex ($2023-24 m)	Expected commission date
Option 1	Renewal of individual assets		2024-2028
Transmission line protection relays		$35.17	
Transformer protection relays		$8.30	
Reactor protection relays		$1.89	
Capacitor protection relays		$2.88	
Busbar (and interzone) protection relays		$0.98	
Protection relays associated with UFLS schemes		$0.96	
		Total: $50.18	

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.[14]

> *“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 investment is undertaken to replace existing protection relays that are reaching end of life. These assets will continue to be maintained under the current regime and will operate until they fail. The annual routine operating, and maintenance is expected to cost $66,199 each year from 2023/24 to 2038/39. This is an increase from the annual operating cost of $14,410 presented within the PADR, and this change stems from the change in assets and improved opex calculation for assets in the renewal program.

[13] As per clause 5.15.2(a) of the NER.
[14] AER, Regulatory Investment Test for Transmission Application Guidelines, October 2023, p.21.

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

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

Year	Operating expenditure ($2023-24)
2024	$66,199
2025	$66,199
2026	$66,199
2027	$66,199
2028	$66,199
2029	$66,199
2030	$66,199
2031	$66,199
2032	$66,199
2033	$66,199
2034	$66,199
2035	$66,199
2036	$66,199
2037	$66,199
2038	$66,199
Total	$992,991

The condition of the protection relays that have been identified for replacement under this program will lead to an increase in unplanned outages as the assets continue to deteriorate and age and increase the probability of not clearing a fault in the transmission network. Their failure will directly impact primary assets, such as lines, transformers and reactive plant, as they will be out of service for longer periods. This is expected to result in unserved energy of approximately 94 MWh in 2023/24 and 228 MWh in 2038/39.[15] It will also lead to higher safety, environmental, and financial risk costs, that are caused by the failure of protection assets to operate when required.

The aggregate risk cost under the base case is currently estimated at around $8.72 million in 2023/24, and it is expected to increase going forward if action is not taken (reaching approximately $19.67 million by the end of the 15-year assessment period).

3.2. Option 1 – Renewal of individual assets

Option 1 involves individual replacements of 419 identified assets (listed in Appendix C) across 48 sites within the regulatory period. 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.

[15] Yearly figures for unserved energy

This option would deliver risk mitigation and reduced corrective maintenance benefits to consumers and the networks by only targeting the probability of failure of identified assets. This option will not deliver any additional operational benefits such as improved capabilities for remote interrogation and predictive activities.

This option will phase asset renewals across the regulatory control periods. Deployments are prioritised based on investment benefit with consideration also given to efficient delivery strategies. Targeted assets will be in service for approximately 15 years, with some assets remaining in-service until investment in future years.

The work will be undertaken over a five-year period with all works expected to be completed by 2027/28. The capital cost of this option is approximately $50.18 million (in $2023-24), which is comprised of:

- $32.03 million in labour costs;
- $1.87 million in materials costs; and
- $16.16 million in expenses.

The table below provides a breakdown of the estimated capital cost.

Table 3-3 Option 1 Capital Cost ($2023-24 m)

Year	Capital expenditure ($m, 2023-24)
2024	$10.04
2025	$10.04
2026	$10.04
2027	$10.04
2028	$10.04
2029	-
2030	-
2031	-
2032	-
2033	-
2034	-
2035	-
2036	-
2037	-
2038	-
Total	$50.18

In addition, routine operating and maintenance costs are estimated at approximately $61,650 per annum (in $2023-24). We expect that the protection relays will have an asset life of 15 years.

Table 3-4 Breakdown of operating expenditure under Option 1 ($2023-24 m)

Year	Operating expenditure ($2023-24)
2024	$66,199
2025	$65,290

2026	$64,380
2027	$63,470
2028	$62,560
2029	$61,650
2030	$61,650
2031	$61,650
2032	$61,650
2033	$61,650
2034	$61,650
2035	$61,650
2036	$61,650
2037	$61,650
2038	$61,650
Total	$938,403

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

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

We have estimated that total risk costs under Option 1 will be approximately $1.97m in 2028/29, after all identified protection relays have been replaced (in $2023-24).

3.3. Options considered but not progressed

We considered several additional options to meet the identified need in this RIT-T. Table 3-5 summarises the reasons the following options were not progressed further.

Table 3-5 Options considered but not progressed

Description	Reason(s) for not progressing
Secondary systems renewal	This option would have required the complete renewal of all secondary systems assets at each site with targeted assets. The condition of remaining assets at identified sites did not warrant additional expenditure. Therefore, this option is not commercially feasible and does not represent optimal expenditure for electricity consumers.
Refurbishment of individual assets	This option is not technically feasible due to the specialised skillsets required and the inability to resolve the lack of support from manufacturers.
Asset retirement	This can only be achieved through retirement of the associated primary assets, which is not technically or commercially feasible.

Non-network solutions	It is not technically feasible for non-network solutions to provide the functionality of secondary systems assets for protection.

3.4. No material inter-network impact is expected

We have considered whether the credible options listed above is expected to have material inter-regional impact.[16] 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."

AEMO's suggested screening test to indicate that a transmission augmentation has no material inter-network impact is that it satisfies the following:[17]

- a decrease in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3% of the maximum transfer capability and 50 MW;
- an increase in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3% of the maximum transfer capability and 50 MW;
- an increase in fault level by less than 10 MVA at any substation in another TNSP's network; and
- the investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

We note that each credible option satisfies these conditions as it does not modify any aspect of electrical or transmission assets. By reference to AEMO's screening criteria, there is no material inter-network impacts associated with any of the credible options considered.

[16] As per clause 5.16.4(b)(6)(ii) of the NER.
[17] 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 14 May 2020. [Criterial for Assessing Material Inter-Network of Transmission Augmentations : Final Determination (aemo.com.au)]

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.[18]

4.1. Wholesale electricity market benefits are not material

The AER has recognised that if the credible options considered will not have an impact on the wholesale electricity market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[19]

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

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no impact on pool price);
- changes in costs for parties other than the RIT-T proponent;
- changes in ancillary services costs;
- 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)(6) requires that we consider the following classes of market benefits, listed in Table 4-1, arising from each credible option. We consider that none of the classes of market benefits listed are material for this RIT-T assessment.

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

Market benefits	Reason
Changes in involuntary load shedding	A failure of any single secondary system element results in an extremely low chance of unserved energy.
Differences in the timing of 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 other network 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

[18] 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)(6). See Appendix A for requirements applicable to this document.

[19] Australian Energy Regulator. "*Application guidelines Regulatory Investment Test for Transmission – October 2023*." Melbourne: Australian Energy Regulator. https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

Market benefits	Reason
	change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[20] We also note the AER's view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T. We note that no credible option is sufficiently flexible to respond to change or uncertainty for this RIT-T. Specifically, each option is focused on proactively replacing deteriorating assets ahead of when they fail.
Changes in Australian greenhouse gas emissions	Neither option is expected to induce a material change in Australia's greenhouse gas emissions.

[20] Australian Energy Regulator. "*Application guidelines Regulatory Investment Test for Transmission – October 2023.*" Melbourne: Australian Energy Regulator. https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

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

Under the base case, no investment is undertaken to replace existing protection relays that are reaching end of life. These assets will continue to be maintained under the current regime and will operate until they fail.

The condition of the protection relays that have been identified for replacement under this program will lead to an increase in unplanned outages as the assets continue to deteriorate and age and increase the probability of not clearing a fault in the transmission network. Their failure will directly impact primary assets, such as lines, transformers and reactive plant, as they will be out of service for longer periods. This is expected to result in unserved energy of approximately 94 MWh in 2023/24 and 228 MWh in 2038/39.[21] It will also lead to higher safety, environmental, and financial risk costs, that are caused by the failure of protection assets to operate when required.

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.[22]

5.2. Assessment period and discount rate

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

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

A real, pre-tax discount rate of 7 per cent has been adopted as the central assumption for the NPV analysis presented in this PACR, consistent with AEMO's Inputs Assumptions and Scenarios Consultation Report[23] and the assumptions adopted in AEMO's 2022 Integrated System Plan (ISP).[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

[21] Yearly figures for unserved energy

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

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

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

bound discount rate of 3.63 per cent.[25] We have also adopted an upper bound discount rate of 10.5 per cent (ie, AEMO's 2023 Inputs Assumptions and Scenarios Report).[26]

5.3. Approach to estimating option costs

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

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

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 an 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.

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[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: [Final decision | Australian Energy Regulator (AER)]

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

[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.

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

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios implicitly assume the most likely scenario from the 2022 ISP (ie, the 'Step Change' scenario). The scenarios differ by the assumed level of risk costs and unserved energy, given that these are key parameters that may affect the ranking of the credible options. Risk cost assumptions do not form part of AEMO's ISP assumptions, and have been based on Transgrid's analysis, as discussed in section 2.

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

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

Table 5-1 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)[32]	$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%

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

29 AER, *Application Guidelines Regulatory Investment Test for Transmission*, October 2023, pp. 42.
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
32 This VCR is equal to the $49,216 within AEMO's July 2023 2023 Inputs, Assumptions and Scenarios Report inflated to December 2023.

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 include:

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

The above list of sensitivities focuses on the key variables that could impact the identified preferred option.

In addition, we will seek 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

Table 6-1 below summarises the present value of the gross benefits of Option 1 under the three scenarios. The benefits included in the assessment are:

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

Table 6-1 PV of estimated gross benefits from credible options relative to the base case ($m, 2023-24)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	33%	33%	33%	
Option 1	$60.60	$45.45	$75.75	$60.60

6.2. Estimated costs

Table 6-2 below summarises the costs of Option 1, relative to the base case, in present value terms. 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 PV of costs of credible options relative to the base case ($m, 2023/24)

Option/scenario	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	33%	33%	33%	
Option 1	$41.41	$41.41	$41.41	$41.41

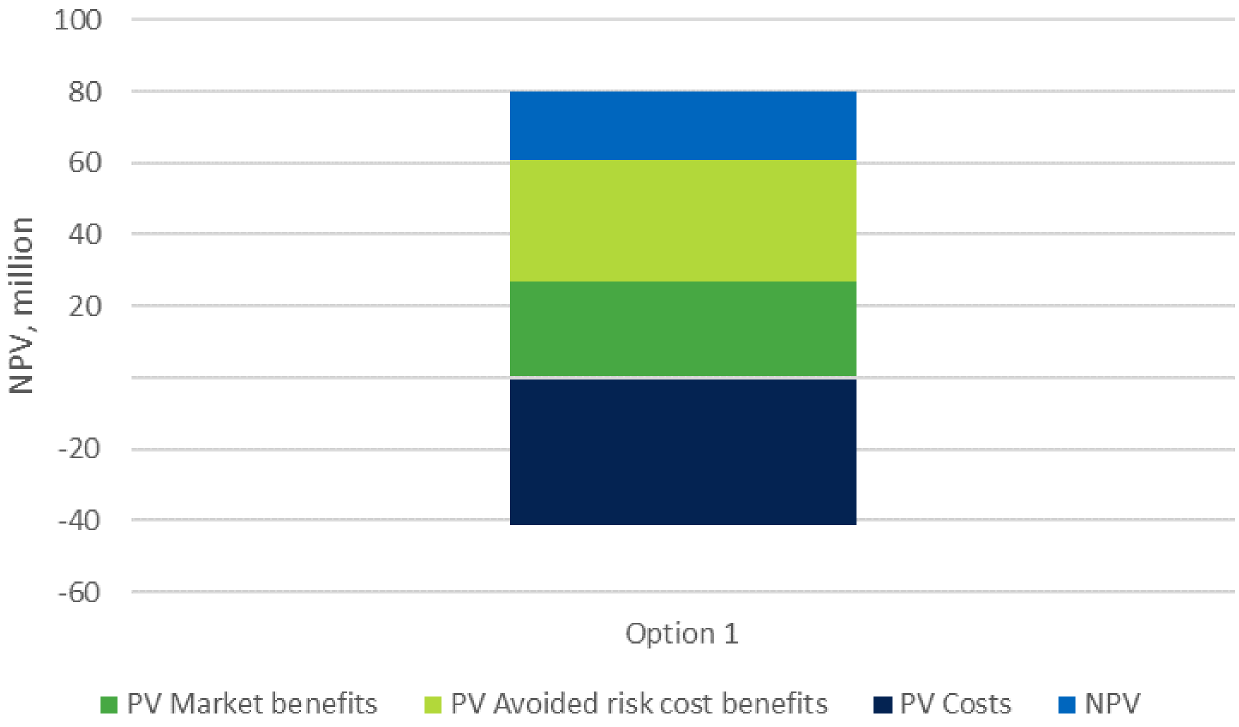
6.3. Estimated net economic benefits

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

Table 6-3 PV of net economic benefits for Option 1 relative to the base case ($m, 2023/24)

Option	Central	Low risk cost scenario	High risk cost scenario	Weighted
Scenario weighting	33%	33%	33%	
Option 1	$19.19	$4.04	$34.34	$19.19

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



6.4. Sensitivity testing

We have undertaken sensitivity testing to examine how the net economic benefit of the credible options changes with respect to changes in key modelling assumptions. The factors tested as part of the sensitivity analysis for this PACR are:

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

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

6.4.1. Sensitivity testing of the optimal timing

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

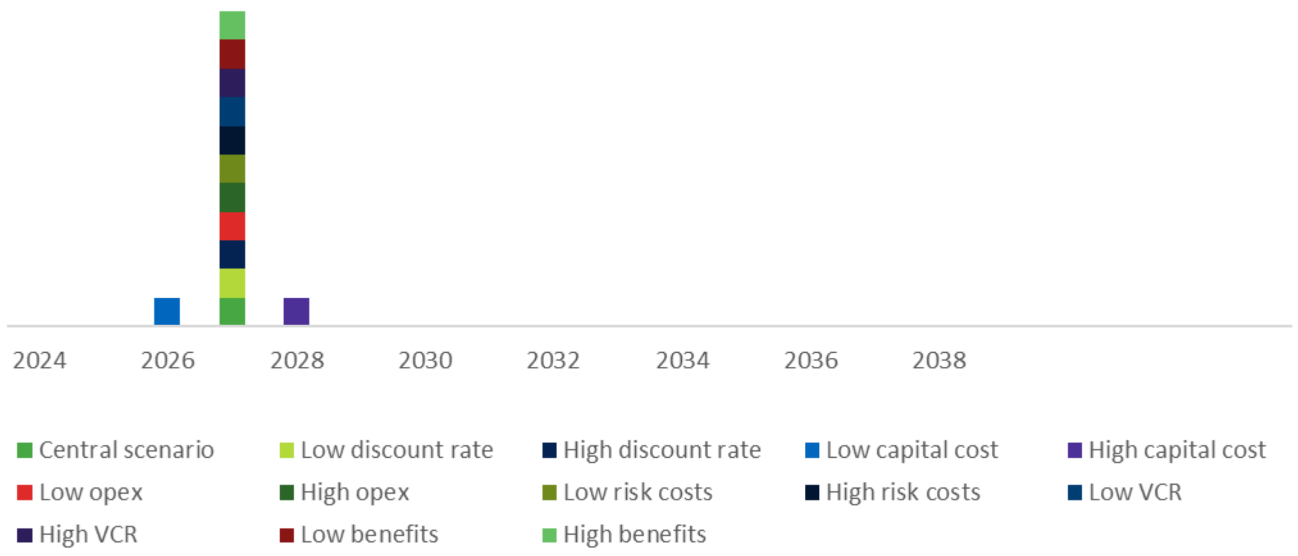
The sensitivities we considered are:

- a 25% increase / decrease in capital costs
- a 25% increase / decrease in demand
- a lower discount rate of 3.63% and a higher discount rate of 10.5%
- a 30% increase / decrease in the VCR
- a 25% increase / decrease in safety, environmental and financial risk costs

The results of this analysis are presented in the figure below. For the majority of cases the optimal timing for the preferred option is 2026/2027. However a 25% decrease in capital costs sees this timing being moved to 2025/26. At the same time, a 25% increase in capital costs sees this optimal timing being pushed back to 2027/28.

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

Figure 6-1 Distribution of optimal timing under a range of different key assumptions



6.4.2. Scenario weights

As we have identified only one credible option, and since we have assessed this option to be net beneficial under all three reasonable scenarios, there are no alternative scenario weights that will change the RIT-T outcome (i.e., lead to the identification of a different preferred option, or no preferred option).

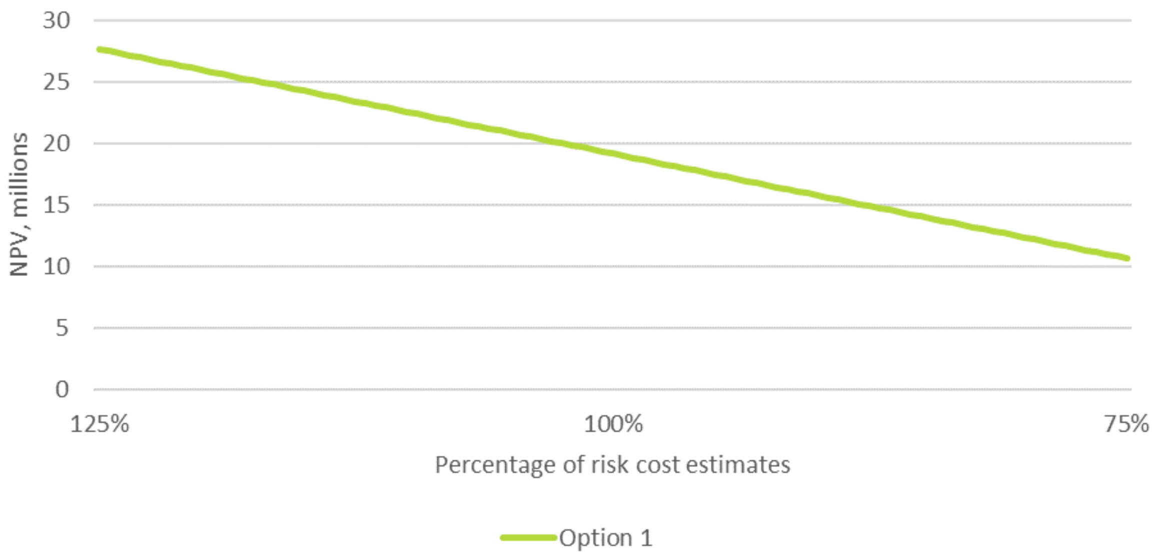
6.4.3. Value of risk costs

We estimated the net economic benefit of each option by adopting a risk cost that is 25% higher (the ‘Higher risk cost’ scenario) and 25% lower (the ‘Lower risk cost’ scenario) than the estimate of VCR adopted in our central scenario. The results of this analysis are presented in the table and figure below.

Table 6-4 Sensitivity of net economic benefits under a lower and higher VCR ($2023/24m)

Option/scenario	Lower risk cost	Higher risk cost
Sensitivity	Central estimate - 25%	Central estimate + 25%
Option 1	$10.69	$27.69

Figure 6-2 Sensitivity of net economic benefits under a lower and higher risk costs ($2023/24 m)



We have also undertaken a threshold analysis to identify whether a change in risk costs would change the RIT-T outcome (i.e. the base case to be the preferred option). The result of this analysis was that risk costs for both the base case and Option 1 would need to decrease by more than 56% for the RIT-T outcome to change. Such a change in risk costs is outside the expected range of costs and, as such, this result of Option 1 being the preferred options is robust to reasonable risk cost sensitivities.

6.4.4. Network capital costs

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

Table 6-4: Sensitivity of net economic benefits under lower and higher capital costs ($2023/24 m)

Option/scenario	Lower capex	High capex
Sensitivity	Capital costs - 25%	Capital costs + 25%
Option 1	$29.55	$8.83

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

We have also undertaken a threshold analysis to identify whether a change in capital cost estimates would change the RIT-T outcome. Specifically, we analyse the extent to which capital costs would need to change to alter the RIT-T outcome (i.e. the base case to be the preferred option). The result of this analysis was that the capital cost would need to increase by more 46% than for the RIT-T outcome to change. Such a change in capital costs is outside the expected range. As a result, the preference of Option 1 is considered robust to reasonable capital cost sensitivities.

6.4.5. Discount rate

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, with AEMO's Inputs Assumptions and Scenarios Consultation Report[33] and the assumptions adopted in AEMO's 2022 Integrated System Plan (ISP).[34] 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

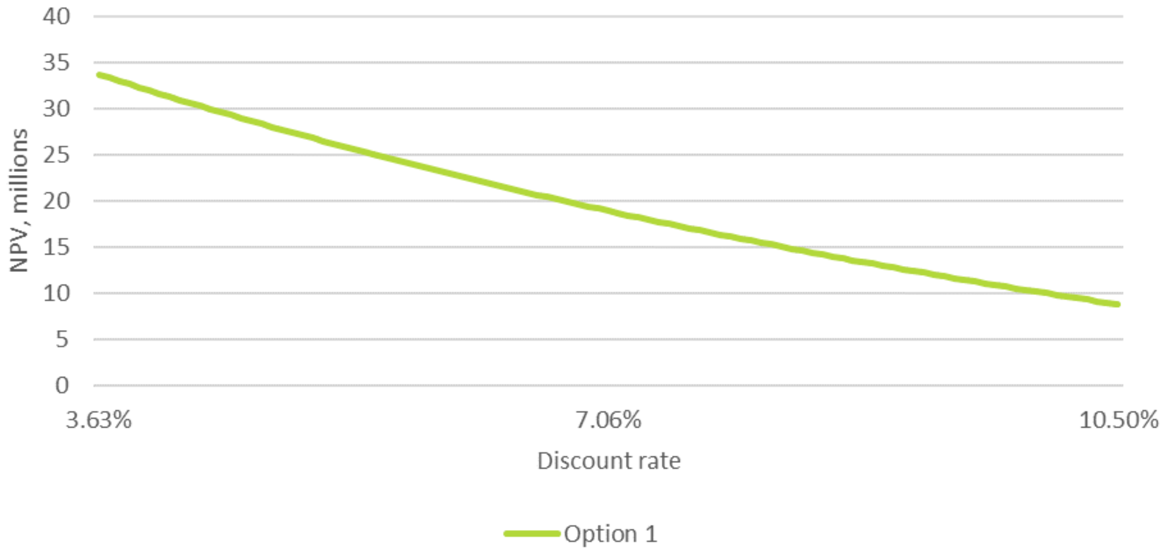
[33] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023, p 123.
[34] AEMO, *2022 Integrated System Plan, June 2022*, p 91.

discount rate of 3.63 per cent.[35] We have also adopted an upper bound discount rate of 10.5 per cent (ie, AEMO's 2023 Inputs Assumptions and Scenarios Report).[36] The results of this analysis are presented in the table and figure below.

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

Option/scenario	Lower discount rate	Higher discount rate
Sensitivity	3.63 percent	10.5 percent
Option 1	$33.72	$8.83

Figure 6-4 Sensitivity of net economic benefits under a lower and higher discount rates ($2023/24 m)



We have also undertaken a threshold analysis to identify whether a change in the discount rate would change the RIT-T outcome. Our approach involved solving for the discount rate that would result Option 1 not being the preferred option (i.e. the base case becoming the preferred option). This discount rate is approximately 15.02% per cent. As this exceeds the upper bound discount rate of 10.5 percent, we therefore consider the preference of Option 1 to be robust to reasonable discount rate sensitivities.

35 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: Final decision | Australian Energy Regulator (AER)

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

7. Final conclusion on the preferred option

This PACR finds that Option 1 addresses the condition issues associated with protection relays through the replacement of all problematic protection relays.

The capital cost of this option is approximately $50.18 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 $61,650 per annum (in $2023-24).

Option 1 yields a weighted average NPV of $19.19 million across the scenarios used in this RIT-T. None of the scenarios provided an NPV for Option 1 that was below zero.

Option 1 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 1 as the preferred option satisfies the RIT-T.

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PACR with the requirements of the National Electricity Rules version 211.

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) See below.	See below
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought	N/A
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which 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;	N/A
	(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 & 4
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	5 & Appendix B
	(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);	4
	(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;	6
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	3 & 7
	(10) if each of the following apply to the RIT-T project: (i) if estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination); and (ii) AEMO is not the sole RIT-T proponent, the reopening triggers applying to the RIT-T project.	N/A
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[37] (as varied in accordance with a cost threshold determination);	1

[37] Varied to $46m based on the AER Final Determination: Cost threshold Review published November 2021 (see: https://www.aer.gov.au/industry/registers/resources/reviews/cost-thresholds-review-regulatory-investment-tests-2021) .

	2. the relevant Network Service Provider has identified in its project specification consultation report: (i) its proposed preferred option; (ii) its reasons for the proposed preferred option; and (iii) that its RIT-T project has the benefit of this exemption; 3. the RIT-T proponent considers, in accordance with clause 5.16.1(c)(6), that the proposed preferred option and any other credible option in respect of the identified need will not have a material market benefit for the classes of market benefit specified in clause 5.16.1(c)(4) except those classes specified in clauses 5.16.1(c)(4)(ii) and (iii), and has stated this in its project specification consultation report; and 4. the RIT-T proponent forms the view that no submissions were received on the project specification consultation report which identified additional credible options that could deliver a material market benefit.	

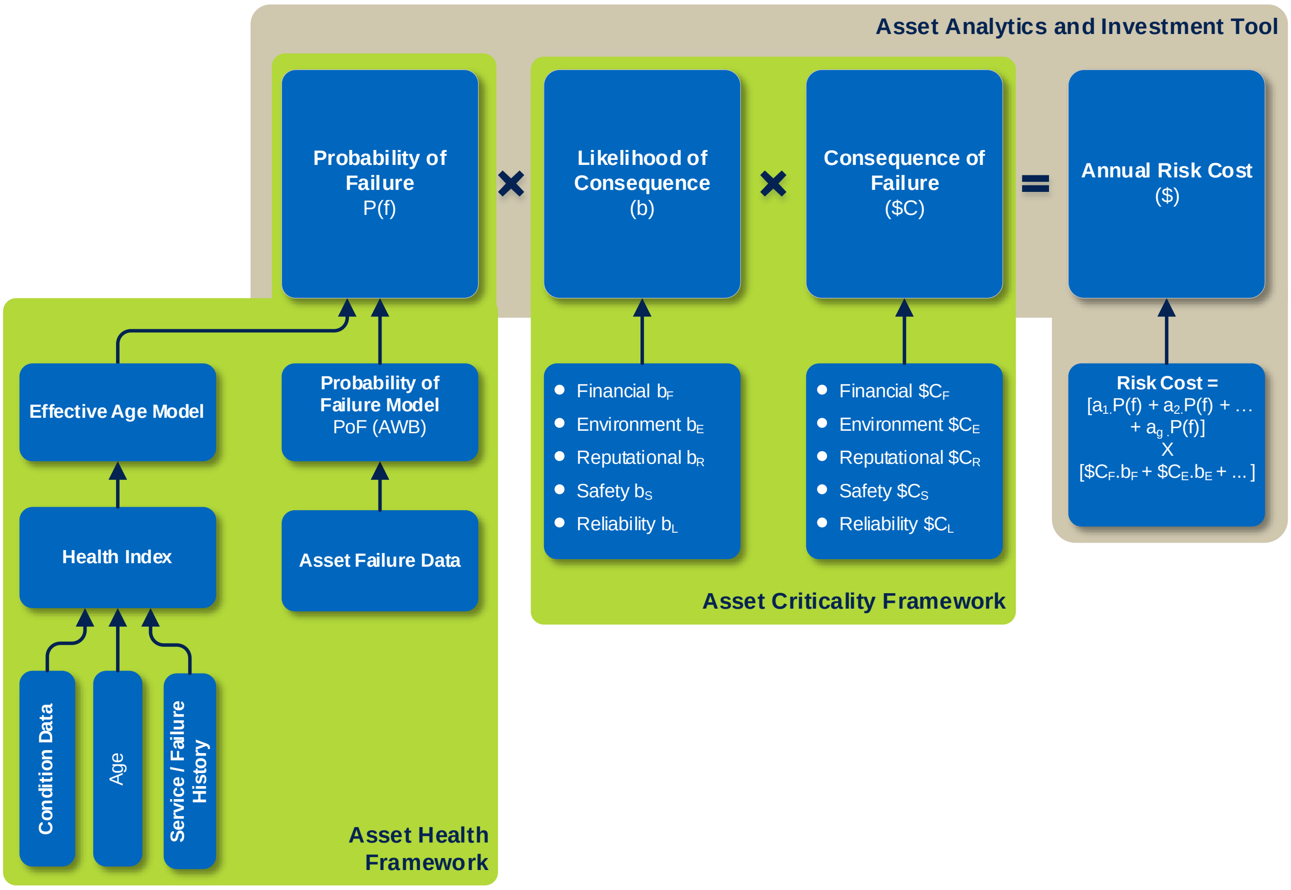
Appendix B Risk Assessment Methodology

Summary of methodology

This appendix summarises our network risk assessment methodology that underpins the identified need for this RIT-T. Our risk assessment methodology is aligned with the AER's Asset Replacement Planning guideline.[38]

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). The figure below illustrates the basic risk equation that we apply.

Figure B-1 Risk cost calculation



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

[38] 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.

Asset health and probability of failure

The first step in calculating the PoF of an asset is determining the asset health and associated effective age,[39] which considers that:

- an asset consists of different technologies, each with a particular capability, 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, 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 transmission line components are summarised in the table below.

Further details are available in our Network Asset Health Methodology.

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

Table B-1 Weibull parameters for asset components

Asset component	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

Appendix C Protection relays identified for replacement

The table below details the protection relays identified by this need under the preferred option (Option 1).

Table C-2 Protection relays identified for this RIT-T

Substation name	Number of protection relays
Australian News Print 132 kV	3
Bayswater 500 kV	8
Bannaby 500/330 kV	4
Boambee South 132 kV	2
Buronga 220 kV	5
Canberra 330 kV	8
Dapto 330 kV	2
Forbes 132 kV	16
Finley 132 kV	17
Gunnedah 132 kV	11
Inverell 132 kV	17
Jindera 330 kV	2
Kemps Creek 500 kV	20
Koolkhan 132 kV	11
Kempsey 132 kV	26
Lismore 330 kV	17
Macarthur 330 kV	9
Munmorah 330 kV	1
Manildra 132 kV	2
Munyang 132 kV	1
Mt Piper 132 kV	14
Moree 132 kV	3
Mt Piper 500 kV	11
Murray 330 kV	1
Macksville 132 kV	2
Nambucca 132 kV	16
Newcastle 330 kV	48
Parkes 132 kV	3
Pt Macquarie 132 kV	9
Queanbeyan 132 kV	11
Raleigh 132 kV	2

Sydney South 330 kV	15
Sydney West 330 kV	2
Tumut 1 Power Station	4
Tumut 2 Power Station	4
Tamworth 330 kV	1
Taree 132 kV	2
Tenterfield 132 kV	10
Tomago 330kV	34
Upper Tumut 330 kV	3
Vineyard 330 kV	5
Wellington 330 kV	21
Wollar 500 kV	1
Waratah West 330 kV	6