# Managing safe and reliable operation of Chapel Street Substation

## RIT-T Project Specification Consultation Report

9 August 2024

**Public**

Powering a Bright Future

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TasNetworks acknowledges the palawa (Tasmanian Aboriginal community) as the original owners and custodians of lutruwita (Tasmania). TasNetworks, acknowledges the palawa have maintained their spiritual and cultural connection to the land and water. We pay respect to Elders past and present and all Aboriginal and Torres Strait Islander peoples.

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# Glossary

| | |
|---|---|
| AACE | Association for the Advancement of Cost Engineering |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| CNAIM | Common Network Asset Indices Methodology |
| EHV | Extra High Voltage |
| HV | High Voltage |
| IASR | Input Assumptions and Scenarios Report |
| ISP | Integrated System Plan |
| kV | Kilovolt |
| MVA | Megavolt Ampere |
| MW | Megawatt |
| NER | National Electricity Rules |
| NPV | Net Present Value |
| PACR | Project Assessment Conclusions Report |
| PADR | Project Assessment Draft Report |
| PoF | Probability of Failure |
| PPE | Personal Protective Equipment |
| PSCR | Project Specification Consultation Report |
| R24 | Regulatory control period 2024-2029 |
| R29 | Regulatory control period 2029-2034 |
| RIT-T | Regulatory Investment Test for Transmission |
| TNSP | Transmission Network Service Provider |
| VCR | Value of Customer Reliability |
| WACC | Weighted Average Cost of Capital |

# Disclaimer

This document has been prepared and published solely for the purpose of meeting TasNetworks' Regulatory Investment Test for Transmission obligations as required under the National Electricity Rules. TasNetworks has used its best endeavours to ensure the accuracy of the information in this document is fit for purpose, and makes no other representation or warranty about the accuracy or completeness of the document or its suitability for any other purpose.

# Executive summary

This Project Specification Consultation Report (PSCR) represents the first step in the application of the Regulatory Investment Test for Transmission (RIT-T) to options for addressing safety and reliability risks caused by age-related condition issues of the switchgear at Chapel Street Substation.

Chapel Street Substation is located in Hobart. Reflecting its location, Chapel Street is a critical substation in the network because it supplies electricity to approximately 12,772 customers across southern Tasmania and northern Hobart. In addition, Chapel Street Substation serves the Hydro Tasmania owned 450 MW Gordon-Pedder hydroelectric power generation system.

Chapel Street Substation currently operates with 11 kV metal-clad switchgear with fixed type circuit breakers that were installed in 1983. Switchgear is critical to the reliable supply of electricity because it is used to collect and distribute electricity from feeder lines for transportation throughout the transmission and distribution networks.

TasNetworks has identified that the switchgear at Chapel Street Substation is approaching its end of life based on regular asset inspections and condition assessment. The switchgear is not designed for internal arc containment and in the event of an arc fault, the release of electrical energy can cause metal projectiles to be discharged from the switchgear along with heat and other byproducts. This can lead to harm to workers, surrounding equipment and cascading asset failures. As a result, TasNetworks' extra high voltage (EHV) operators must wear special arc flash rated (Cat 4) personal protective equipment (PPE) suits to operate the switchgear. Whilst effective, it is the lowest form of risk and hazard control and the need to wear Cat 4 PPE is cumbersome and time consuming, increasing the time required to conduct maintenance tasks.

In addition, the existing switchgear has long been obsolete, leading to a growing scarcity of spare parts. The spare parts that TasNetworks maintained have been used in the existing switchgear and there are no more spare parts available. While TasNetworks maintains operational spares within the existing switchgear, using these spares for reactive replacement requires additional time, leading to longer outages.

## Identified need: managing risks at Chapel Street Substation

TasNetworks has identified an opportunity to increase market benefits by addressing reliability, financial and safety risks associated with aging switchgear at Chapel Street Substation.

If action is not taken, the condition of the switchgear at Chapel Street substation will expose us and our customers to increasing levels of risk going forward, as deterioration of asset condition increases the likelihood of failure.

Under the 'do nothing' base case switchgear faults could occur. Such incidents pose significant reliability risks due to unserved energy and could have serious safety consequences for our field crew who may be working on or near the asset. These incidents also have financial risks associated with the cost of reactive maintenance that may be required under emergency conditions.

Addressing the condition issues of the switchgear will enable us to manage reliability, financial, and safety risks at Chapel Street Substation. TasNetworks expects that addressing these issues will result in significant market benefits and, as such, we consider the identified need for this investment to be market benefits under the RIT-T.

## Two credible options have been considered

We consider that there are two feasible options from a technical, commercial and project delivery perspective that can be implemented in sufficient time to meet the identified need. Specifically:

- Option 1 involves the replacement of the high voltage (**HV**) switchgear in the 2024-29 regulatory control period; and
- Option 2 involves the replacement of the HV switchgear in the 2029-34 regulatory control period.

The capital expenditure of both options is approximately $6.19 million.

No option will affect annual routine operating costs since they do not affect the frequency of inspections or maintenance activities.

## Non-network options are not expected to be able to assist with this RIT-T

We do not consider non-network options to be commercially or technically feasible to assist with meeting the identified need for this RIT-T, as non-network options will not mitigate the reliability, safety and financial risks posed as a result of asset deterioration.

For non-network options to assist, they would need to provide greater net economic benefits than the network options. That is, non-network options would need to reduce these risks at a lower cost than network options. We consider that non-network options are unable to sufficiently reduce risk costs and provide greater net economic benefits than the network options because:

- non-network options are unable to address the risk of switchgear failure, so will not substantially reduce safety and financial risk related costs; and
- non-network options are unlikely to completely eliminate reliability risk costs due to the need to be connected to all 18 feeders.

## The options have been assessed against three reasonable scenarios

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

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios assume the expected most likely scenario for the 2024 ISP (i.e. the 'Step Change' scenario). The scenarios differ by the assumed level of risk costs, given that these are key parameters that may affect the ranking of the credible options. Risk cost assumptions do not form part of AEMO's ISP assumptions and have therefore been based on TasNetworks' analysis.

Table 1 Summary of scenarios

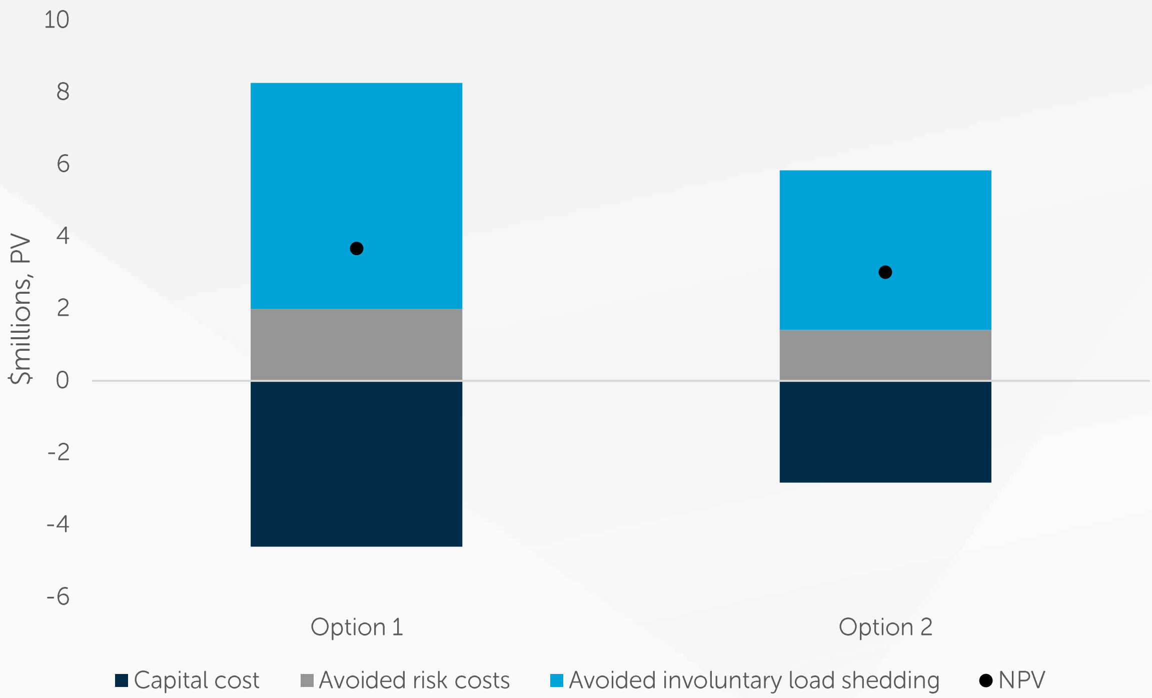
| Variable / Scenario | Central | Low risk cost scenario | High risk cost scenario |
|---|---|---|---|
| Scenario weighting | 1/3 | 1/3 | 1/3 |
| Discount rate | 7.00% | 7.00% | 7.00% |
| Network capital costs | Base estimate | Base estimate | Base estimate |
| Operating and maintenance costs | Base estimate | Base estimate | Base estimate |
| Environmental, safety and financial risk benefit | Base estimate | Base estimate – 25% | Base estimate +25% |

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

## Option 1 delivers the greatest estimated net benefits

Both credible options are found to have positive benefits for all scenarios investigated. All scenarios find that Option 1 will deliver the greatest net economic benefits. On a weighted basis, the net economic benefits of Option 1 are approximately $3.7 million. Figure 1 below shows a breakdown of the weighted net economic benefits for each option.

Figure 1 Weighted net economic benefits ($m, PV)




## Draft conclusion

This PSCR has found that Option 1 is the preferred option at this draft stage of the RIT-T. Option 1 involves the replacement of the HV switchgear in the 2024-29 regulatory control period (and in particular by financial year 2025/26).

The estimated capital expenditure associated with Option 1 is $6.19 million (in 2023/24 dollars).

The works are estimated to take place across financial years 2024/25 and 2025/26, with practical completion and commissioning by the beginning of financial year 2026/27.

## Exemption from preparing a PADR

NER 5.16.4(z1) provides for a TNSP to be exempt from producing a Project Assessment Draft Report (PADR) for a particular RIT-T application.

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

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

Accordingly, if we consider that any such additional credible options are identified, we will produce a PADR. Should we consider that no additional credible options were identified, we intend to produce a PACR that addresses all submissions received and presents our conclusion on the preferred option for this RIT-T.

# Introduction

This Project Specification Consultation Report (**PSCR**) represents the first step in the application of the Regulatory Investment Test for Transmission (**RIT-T)** to options for addressing safety and reliability risks caused by age-related condition issues of the switchgear at Chapel Street Substation.

Chapel Street Substation currently operates with 11 kV metal-clad switchgear with fixed type circuit breakers that were installed in 1983. Switchgear is critical to the reliable supply of electricity to consumers because it is used to distribute electricity to feeder lines for transportation through the distribution network. TasNetworks has identified through our regular asset inspections and condition assessment that the switchgear at Chapel Street Substation is approaching end of life, which will affect the reliability of its performance now and into the future. These condition issues are consistent with the age of the asset and its usage since commissioning.

More broadly, the switchgear is not designed for internal arc containment as required by Australian Standard 62271 200 2019. As a result, TasNetworks extra high voltage (**EHV**) operators must wear special arc flash rated (Cat 4) personal protective equipment (**PPE**) suits to operate the switchgear. Whilst effective, it is the lowest form of risk and hazard control and the need to wear Cat 4 PPE is cumbersome and time consuming, increasing the time required to conduct maintenance tasks.

In addition, the existing switchgear has long been obsolete leading to a growing scarcity of spare parts. The spare parts that TasNetworks maintained have been used in the existing switchgear and there are no more spare parts available. While TasNetworks maintains operational spares within the existing switchgear, using these spares for reactive replacement requires additional time, leading to longer outages.

TasNetworks is therefore examining options for addressing the age-related condition issues of the switchgear so that Chapel Street Substation continues to operate in a safe and reliable manner. We expect that addressing these issues will significantly reduce reliability and safety risks and, by consequence, result in significant market benefits. Consequently, we consider the identified need for this investment to be market benefits under the RIT-T.

## Purpose of this report

The purpose of this PSCR[1] is to:

- set out the reasons why we propose that action be undertaken (the 'identified need');
- present the options that we currently consider address the identified need;
- outline the technical characteristics that non-network options would need to provide (although we note that non-network options are unlikely to be able to contribute to meeting the identified need for this RIT-T);
- present the economic assessment of all credible options, as well as the assumptions feeding into the analysis, and identify a preferred option at this draft stage of the RIT-T; and

[1] See *Appendix 1 Compliance checklist* for the National Electricity Rules requirements. Note that that National Electricity Rules Version 214 was referenced during the preparation of this document.

- allow interested parties to make submissions and provide inputs to the RIT-T assessment.

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

# Exemption from preparing a PADR

The National Electricity Rules (**NER**) 5.16.4(z1) provides for a Transmission Network Service Provider (**TNSP**) to be exempt from producing a Project Assessment Draft Report (**PADR**) for a particular RIT-T application, in the following circumstances:

- if the estimated capital cost of the preferred option is less than $46 million;[2]
- if the TNSP identifies in its PSCR its proposed preferred option, together with its reasons for the preferred option and notes that the proposed investment has the benefit of NER 5.16.4(z1) exemption; and
- if the TNSP considers that the proposed preferred option and any other credible options in respect of the identified need will not have a material market benefit for the classes of market benefit specified in NER 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding.

We consider the investment in relation to all of the options considered and the analysis presented in this PSCR meets these criteria and therefore that we are exempt from producing a PADR under NER clause 5.16.4(z1).

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

Accordingly, if we consider that any such additional credible options are identified, we will produce a PADR which includes a Net Present Value (**NPV**) assessment of the net market benefit of each additional credible option.

# Submissions and next steps

We welcome written submissions on materials contained in this PSCR. Submissions are due on 04 November 2024.

Submissions should be emailed to our Regulation team via **regulation@tasnetworks.com.au**.[3] In the subject field, please reference ‘Chapel Street Substation PSCR’.

[2] NER 5.16.4(z1) refers to the preferred option being less than $35 million, or as varied in accordance with a cost threshold determination. The cost threshold was varied to $46m based on the AER Final Determination: Cost threshold review November 2021. Accessed 19 November 2021 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021

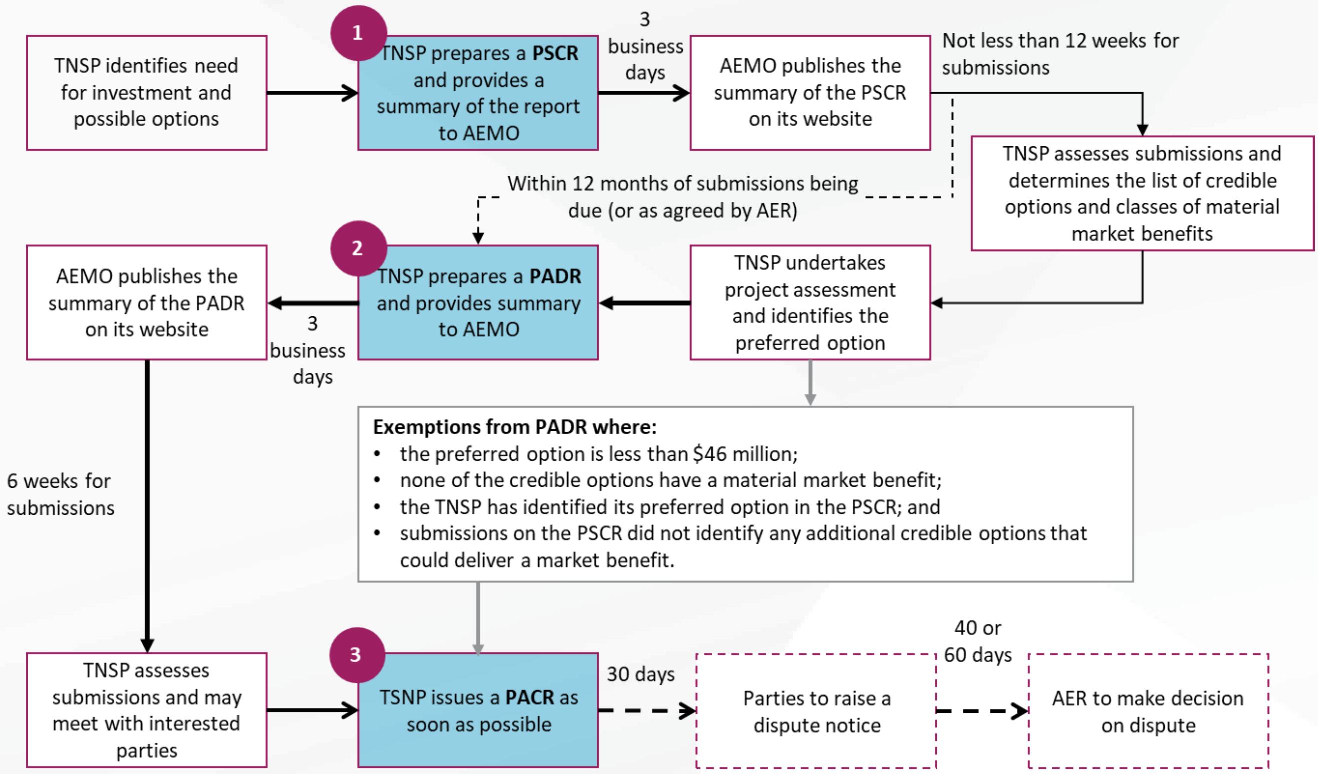
[3] We are bound by the *Privacy Act 1988 (Cth)*. In making submissions in response to this consultation process, we will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do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

At the conclusion of the consultation process, all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

Should we consider that no additional credible options were identified during the consultation period that could provide material market benefits, we intend to produce a Project Assessment Conclusions Report (**PACR**) that addresses all submissions received including any issues in relation to the proposed preferred option raised during the consultation period, and presents our conclusion on the preferred option for this RIT-T.[4] Subject to additional credible options being identified, we anticipate publication of a PACR in December 2024]. The PACR will update the net present value analysis with the latest information where relevant.

Figure 2 summarises the RIT-T process.

Figure 2: Overview of the RIT-T process




[4] In accordance with NER 5.16.4(z2).

# 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 Chapel Street Substation and the relevant switchgear.

## Background to the identified need

Figure 3 provides an overview of TasNetworks' transmission network and illustrates that the Chapel Street Substation is located in Hobart. Figure 4 provides an overview of the wider Hobart transmission network. Reflecting its location, Chapel Street is a critical substation in the network because it supplies electricity to approximately 12,772 customers across southern Tasmania and northern Hobart. In addition, Chapel Street substation serves the Hydro Tasmania owned 450 MW Gordon-Pedder hydroelectric power generation system.

Figure 3 Tasmania's electricity transmission network, showing the location of Chapel Street substation

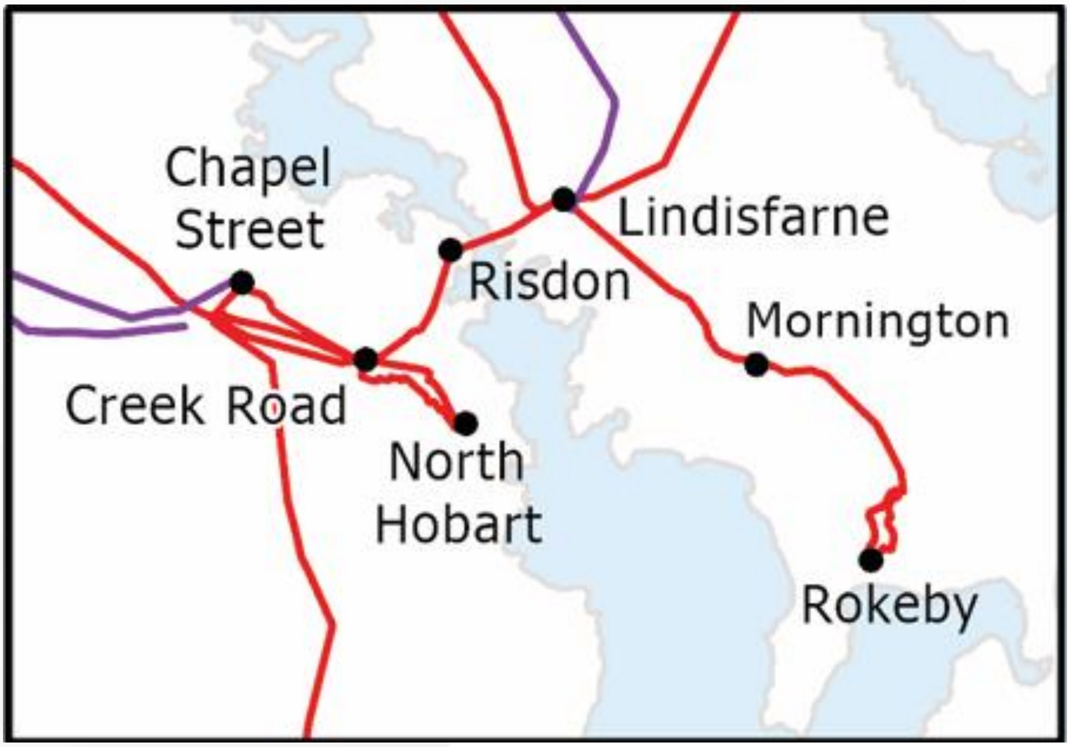




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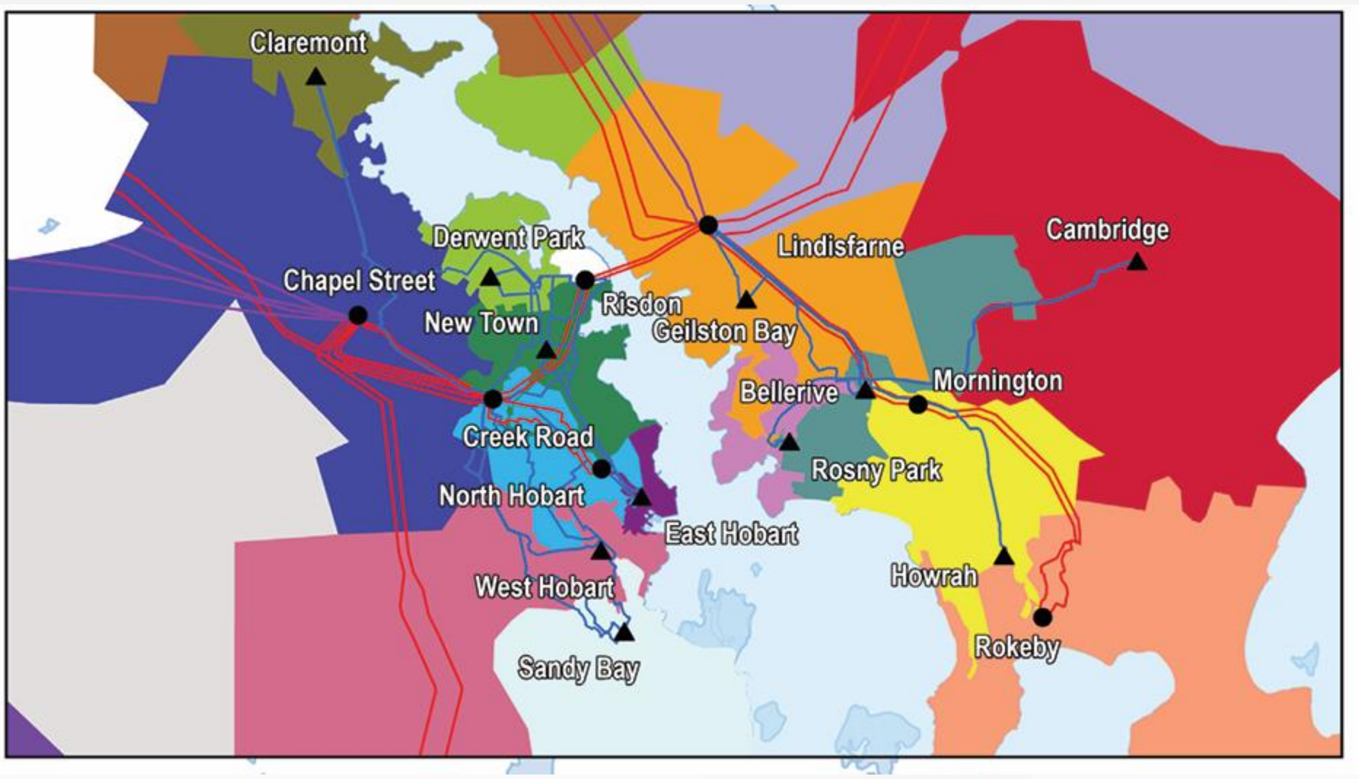
Figure 4 Wider Hobart electricity transmission network




Chapel Street Substation currently operates with 11 kV metal-clad switchgear with fixed type circuit breakers that were installed in 1983. Switchgear is critical to the reliable supply of electricity because it is used to collect and distribute electricity from feeder lines for transportation throughout the transmission and distribution networks.

TasNetworks has identified through our regular asset inspections that the switchgear at Chapel Street Substation is approaching end of life based on a condition assessment using the Common Network Asset Indices Methodology (**CNAIM**). This condition, which will continue to deteriorate over time, will affect the reliability of its performance now and into the future. These condition issues are consistent with the age of the asset and its usage since commissioning.

More broadly, the switchgear is not designed for internal arc containment as required by Australian Standard 62271 200 2019. An arc fault is an unintended high power electrical discharge that occurs when current flows through an unintended path. In the event of an arc fault, the release of electrical energy can cause metal projectiles to be discharged from the switchgear along with heat and other byproducts. This can lead to harm to workers, surrounding equipment and cascading asset failures. As a result, TasNetworks' EHV operators must wear special arc flash rated (Cat 4) PPE suits to operate the switchgear. Whilst effective, it is the lowest form of risk and hazard control and the need to wear Cat 4 PPE is cumbersome and time consuming, increasing the time required to conduct maintenance tasks.

In addition, the existing circuit breakers within the switchgear are fixed type, compared to the modern withdrawable type. Withdrawable type circuit breakers are advantageous as they provide physical and visual isolation from the other in-service equipment, improving safety when work is undertaken. Replacing the fixed type circuit breakers with the modern withdrawable type will decrease the time and cost required for routine and reactive maintenance.

The number of unplanned maintenance activities has increased with age. Further, the existing switchgear has long been obsolete leading to a growing scarcity of spare parts. As a result, the spare parts which TasNetworks maintained have been used in the existing switchgear and there are no more spare parts available. While TasNetworks maintains operational spares within the existing switchgear, using these spares for reactive replacement when faults occur requires additional time and expense. Further, these operational spares will eventually be exhausted.

# Description of the identified need

If action is not taken, the condition of the switchgear at Chapel Street Substation will expose us and our customers to increasing levels of risk going forward, as deterioration in asset condition increases the likelihood of failure.

Under the 'do nothing' base case switchgear faults could occur. Such incidents pose significant reliability risks due to unserved energy, resulting in involuntary load shedding (loss of customer supply). Switchgear faults could also have serious safety consequences for our field crew who may be working on or near the asset. These incidents also have financial risks associated with the costs of reactive maintenance that may be required under emergency conditions. The level of reactive corrective maintenance needed to keep the switchgear operating within required standards may also increase, particularly when asset failures ultimately occur.

Addressing the condition issues of the switchgear will enable us to manage reliability, financial, and safety risks at Chapel Street Substation. TasNetworks expects that addressing these issues will result in significant market benefits and, as such, we consider the identified need for this investment to be market benefits under the RIT-T.

# Assumptions underpinning the identified need

TasNetworks has applied an asset 'risk cost' evaluation framework to quantify the risks caused by the deteriorating condition of the switchgear and the risk cost reductions resulting from addressing the condition issues. Risks are assessed against TasNetworks' risk framework using the Australian Energy Regulator's (**AER**) risk-cost assessment methodology outlined in their Industry practice Application Note: Asset Replacement Planning 2019.[5]

The risk costs have been calculated by reference to the following formula:

$$TQR = \sum_{n=0}^{n} (PoF \times No) \times (LoC \times CoC)$$

where:

- TQR is the total quantified risk/risk cost per year of the event happening;
- PoF is the annual asset probability of failure, which is obtained from our asset performance records, as well as being benchmarked against national and international standards where applicable;
- No is the number of assets;
- CoC is the cost of consequence of the failure event, which is evaluated by an external consultant to align with contemporary methodologies of risk based asset management; and
- LoC is the likelihood of consequence of failure event, which is determined using both actual (as observed by both TasNetworks and its peers) and estimated data.

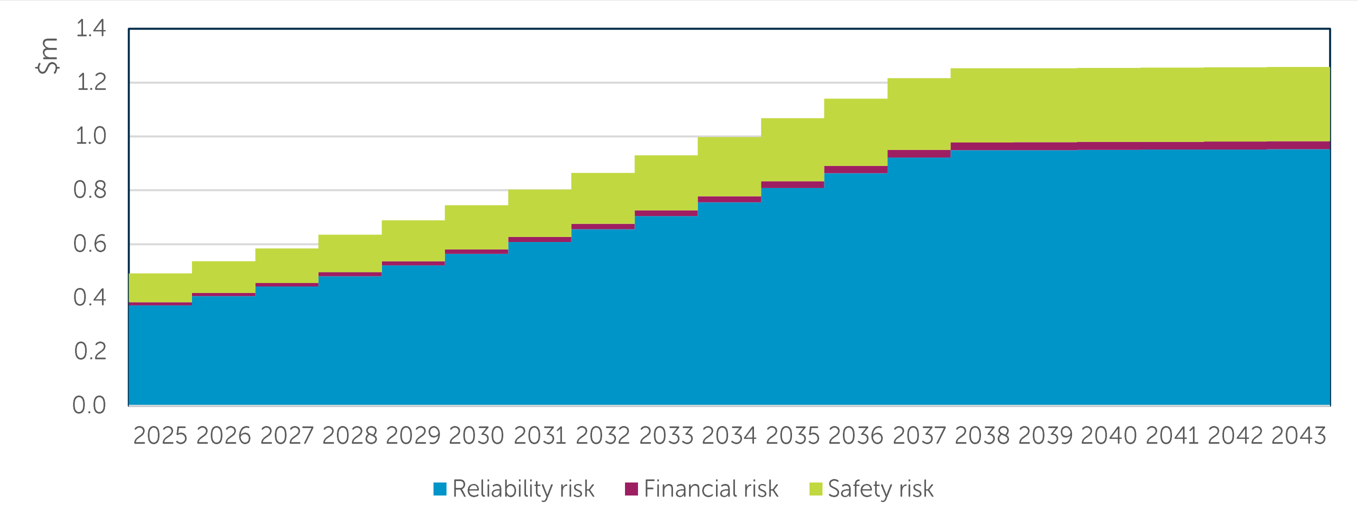
[5] See: https://www.aer.gov.au/system/files/D19-2978%20-%20AER%20-Industry%20practice%20application%20note%20Asset%20replacement%20planning%20-%2025%20January%202019.pdf .

The key risks considered as part of the this RIT-T are:

- network performance risk, i.e. involuntary load shedding;
- direct financial costs risk, e.g. reactive maintenance upon failure of the asset; and
- safety risks, e.g. from an arc containment fault.

The remainder of 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. Figure 5 summarises the increasing risk costs over the assessment period under the base case.

Figure 5: Estimated risk costs




The aggregate risk cost under the base case is currently estimated (in 2023/24 dollars) at approximately $0.5 million in 2024/25, increasing to approximately $1.3 million by 2038.

## Asset health and the probability of failure

Our asset health modelling aligns with Chapter 3.2 and 5.2 of the AER's Asset replacement planning guideline.[6] Condition information for each asset is assessed to generate an asset health index and assets approaching their end of life, as identified through the asset health index, are candidates for a replacement or refurbishment intervention. Specifically, asset health is rated on a scale of 0.5 to 10 using CNAIM.[7] The asset health ratings determine a health based PoF in line with industry standard.

The asset health issues identified in relation to the switchgear at Chapel Street Substation are summarised in Table 2.

Table 2 Asset health issues at Chapel Street substation and their consequences

| Issue | Consequences if not remediated |
|---|---|
| Increasing risk of switchgear failure | Involuntary load shedding |
| No internal arc containment | Safety incident resulting in potential injury or death<br>Electrical fires, cascading asset failure and damage to |

[6] AER, *Industry practice application note – Asset replacement planning*, January 2019 – available at https://www.aer.gov.au/system/files/D19-2978%20-%20AER%20-Industry%20practice%20application%20note%20Asset%20replacement%20planning%20-%2025%20January%202019.pdf

[7] For more information on CNAIM see, The Office of Gas and Electricity Markets (UK), DNO common network asset indices methodology, 1 April 2021, available at https://www.ofgem.gov.uk/sites/default/files/docs/2021/04/dno_common_network_asset_indices_methodology_v2.1_final_01-04-2021.pdf.

| Issue | Consequences if not remediated |
|---|---|
| | surrounding equipment<br>Increased maintenance costs from heightened PPE requirement |
| Lack of spare parts | Increased reactive replacement costs<br>Eventual inability to repair faults |
| Fixed type circuit breakers | Additional time and cost to carry out work |

## Reliability risk

This risk refers to the consequence arising from a reduction in reliability of electricity supply for customers that result in involuntary load shedding and is valued using the AER's 2023 estimated Value of Customer Reliability (VCR) for Tasmania, weighted by load connected to the Chapel Street Substation.[8] Table 3 summarises our calculation of the load-weighted VCR used in our analysis.

Table 3: Calculation of load-weighted VCR

| Load type | VCR ($/kWh) | Weighting (%) |
|---|---|---|
| Residential | 19.89 | 50 |
| Business customer – industrial | 74.79 | 25 |
| Business customer – commercial | 52.20 | 25 |
| **Weighted VCR** | **41.69** | - |

As discussed above, if there was to be a switchgear fault at Chapel Street Substation, involuntary load shedding may occur because electricity may not be able to be distributed to feeder lines. While the network in Hobart is meshed, allowing for load switching between substations, switching is not instant. For the purposes of this RIT-T we have calculated the level of load at risk by taking the average load from the previous year supplied by one of the 18 active feeders from the Chapel Street Substation that supplies electricity to the northern part of Hobart. This load is then multiplied by a conservative estimate of the expected outage duration of two hours. We have adopted this conservative estimate of the outage duration by reference to previous restorations of the equipment and the fact that an outage could occur at any time during the year requiring a manual site visit by a technician wearing Category 4 PPE.

The load at risk is calculated from the possible load not being served by the 18 11 kV feeders. There will be no impact to other 110 kV and 220 kV network lines connected to the Chapel Street Substation with the failure of Chapel Street Substation 11 kV switchgear. As such, we do not need to consider the load from Southern Tasmania or generation from the Gordon-Pedder system.

We have adopted the average for the purposes of this analysis because all 18 feeders have a similar load range. TasNetworks considers this to be a proportionate approach in the context of the identified need and we note that our methodology results in a conservative estimate of load at risk because it does not account for future load growth in the area and an outage may in practice last longer than two hours.

Reliability risk is the largest of all risks quantified under the base case for this RIT-T, making up approximately 76 per cent of the total estimated risk cost in present value terms.

[8] AER, *2023 Values of Customer Reliability Annual Adjustment*, 31 December 2023.

## Safety risk

This risk refers to the safety consequence to our workforce, contractors and/or members of the public of an asset failure whose failure modes can create harm. The main safety risk associated with the switchgear at Chapel Street Substation is that workers in the area may be impacted by an arc fault if they are in the immediate vicinity. The estimated value accounts for the cost associated with a fatality or injury including compensation, loss of productivity, litigation fees, fines and any other related costs.

Under the total quantified risk framework detailed above, the likelihood of a safety consequence takes into account the frequency of workers on-site, the duration of maintenance and capital work on-site, and the probability and area of effect of an explosive asset failure. Further, the cost of a safety consequence accounts for the cost associated with a fatality or injury including compensation, loss of productivity, litigation fees, fines and any other related costs.

Safety risk is the second largest of all risks quantified under the base case for this RIT-T, making up approximately 22 per cent of the total estimated risk cost in present value terms.

## Financial risk

This risk refers to the direct financial consequence arising from the failure of an asset, including the cost of replacement which may need to be under emergency conditions. Our estimation of financial risk for this RIT-T does not include the expected escalating cost of reactive maintenance associated with the aging switchgear. It follows that our financial risk cost estimate is conservative and understates the true financial risk cost.

Financial risk is the smallest of all risks quantified under the base case for this RIT-T, making up approximately two per cent of the total estimated risk cost in present value terms.

# Credible options

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

We consider that there are two credible options from a technical, commercial, and project delivery perspective that can be implemented in sufficient time to meet the identified need. Other options were considered but not progressed for various reasons, as outlined in Table 8.

Both credible options involve replacing the existing 11 kV metal-clad switchgear with modern 11 kV metal-clad switchgear. The new switchgear would have internal arc fault containment for the front, lateral and rear compartments. In addition, the switchgear would have internal venting pathways to direct arc-fault energy away from the switchgear, significantly reducing hazards to operational staff and limiting damage to adjacent equipment. Further, the new switchgear would replace the existing fixed type circuit breakers with modern type withdrawable circuit breakers. The new switchgear would be the standard type adopted by TasNetworks.

For the purposes of this RIT-T we have not considered changes in routine operating costs. While routine maintenance is expected to be less frequent for the new switchgear, this is not material to the selection of the preferred option as the option which has the new switchgear installed earlier (i.e. Option 1) is already found to be net beneficial. It follows that the market benefits reported for each option are conservative.

All costs and benefits presented in this PSCR are in real 2023/2024 dollars, unless otherwise stated.

## Base case

The costs and benefits of each option in this PSCR are compared against those of a base case. Under this base case, no proactive capital investment is made to remediate the deterioration of the switchgear at the Chapel Street Substation. The switchgear at the Chapel Street Substation is left in service until it experiences a mechanical failure of one of its components due to age-related deterioration and requires replacement.

While the base case is not a situation we plan to encounter, and this RIT-T has been initiated specifically to avoid it, the RIT-T assessment is required to use this base case as a common point of reference when estimating the net benefits of each credible option. For clarity, the base case is not considered a credible option.

## Option 1 – Replace HV switchgear in R24

Option 1 involves the replacement of the high voltage (**HV**) switch gear in the 2024-2029 regulatory control period (**R24**). Specifically, the switchgear will be replaced in 2025/26 with commissioning by the beginning of 2026/27.

The estimated capital cost of this option is approximately $6.19 million. Table 4 provides a breakdown of these capital costs by category of expenditure.

Table 4: Breakdown of Option 1's expected capital cost, $m real

| Component | Procurement | Installation | Design | TasNetworks | Total |
|---|---|---|---|---|---|
| Switchgear | 2.77 | 2.45 | 0.62 | 0.35 | 6.19 |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The expenditure for Option 1 is expected to occur between 2024/25 and 2025/26, reflecting the procurement of long lead time equipment and the ultimate commissioning works. Table 5 shows the expected expenditure profile of Option 1 across the construction period.

Table 5: Annual breakdown of Option 1's expected capital cost, $m real

| Year | Option 1 |
|---|---|
| 2024/25 | 2.55 |
| 2025/26 | 3.64 |
| **Total** | **6.19** |

# Option 2 – Replace HV switchgear in R29

Option 2 involves the replacement of the high voltage (**HV**) switchgear in the 2029-2034 regulatory control period (**R29**). Specifically, the switchgear will be replaced in 2030/31, with commissioning by the beginning of 2031/32, a five year delay compared to Option 1.

The estimated capital cost of this option is approximately $6.19 million. Table 6 provides a breakdown of these capital costs by category of expenditure.

Table 6: Breakdown of Option 2's expected capital cost, $m real

| Component | Procurement | Installation | Design | TasNetworks | Total |
|---|---|---|---|---|---|
| Switchgear | 2.77 | 2.45 | 0.62 | 0.35 | 6.19 |

The expenditure for Option 2 is expected to occur between 2029/30 and 2030/31, reflecting the procurement of long lead time equipment and the ultimate commissioning works. Table 7 shows the expected expenditure profile of Option 2 across the construction period.

Table 7: Annual breakdown of Option 2's expected capital cost, $m real

| Year | Option 2 |
|---|---|
| 2029/30 | 2.55 |
| 2030/31 | 3.64 |
| **Total** | **6.19** |

# Options considered but not progressed

TasNetworks has considered several additional options to meet the identified need in this RIT-T. Table 8 summarises the reasons the following options were not progressed further.

Table 8 Options considered but not progressed

| Description | Reason(s) for not progressing |
|---|---|
| Increased inspections | The condition issues have already been identified and cannot be rectified through increased inspections. This option is therefore not technically feasible. |
| Elimination of all associated risk | This can only be achieved through retirement and decommissioning of the associated assets. This option is therefore not technically feasible. |
| Non-network solutions | We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need, as non-network options will not mitigate the safety, reliability and financial risks posed as a result of asset deterioration. This is outlined in more detail below. |
| Retrofit the switchboard with arc flash protection | While retrofitting the switchboard with arc flash protection would resolve the safety issues, it would not resolve the failure risk associated with the aging asset. Further, this option would not resolve the spare parts issue. Full replacement would still be required when all operational spares are utilised. |

# No material inter-network impact is expected

We have considered whether the credible options listed above is expected to have material inter-regional impact.[9] A “material inter-network impact” is defined by the NER in the following terms:[10]

> “A material impact on another Transmission Network Service Provider’s network, which 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.”

In determining whether a proposed transmission augmentation can be expected to have a material inter-network impact, the Australian Energy Market Operator (**AEMO**) screening test can be applied which describes the following considerations:[11]

- an increase in fault level of more than 10 MVA at any substation in another TNSPs network;
- a change in power transfer capability between transmission networks or in another TNSPs network of more than the minimum of 3% of maximum transfer capability and 50 MW;
- there is a significant change to voltage or any power quality metrics at the network boundary; 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.

[9] As per NER 5.16.4(b)(6)(ii).

[10] Refer NER 10.

[11] 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. https://www.aemo.com.au/-/media/Files/PDF/170-0035-pdf

# Non-Network options

We do not consider non-network options to be commercially and technically feasible to assist with meeting the identified need for this RIT-T, since non-network options will not mitigate the safety, reliability and financial risks posed as a result of asset deterioration.

For non-network options to assist, they would need to provide greater net economic benefits than the network options. That is, non-network options would need to reduce the environmental, safety, financial and reliability risk related costs (which in practice are not expected to be affected by non-network solutions).

## Required technical characteristics of non-network options

The identified safety, reliability and financial risk related costs are, for the most part, not load dependant. While the extent of reliability risk may reduce if load is reduced through a non-network option, it is likely that the risk costs will not be sufficiently reduced to make the non-network option viable. Further, while non-network options such as a battery unit may reduce the reliability risk related costs, it is unlikely to substantially reduce the safety, and financial risk related costs.

In the case of switchgear failure at Chapel Street Substation, any non-network option would need to be capable of providing at least 2 MW of power into the network for 1-2 hours for each feeder. The requirement of power could be in any part of the network supplied from the 18 11 kV feeders from Chapel Street Substation. As such, any non-network option would need to be capable of supplying power to all 18 feeder lines.

In summary, we consider that non-network options are unable to sufficiently reduce risk costs and provide greater net economic benefits than the network options.

This is based on:

- non-network options being unable to address the risk of switchgear failure, so will not substantially reduce safety, and financial risk related costs; and
- non-network options being unlikely to completely eliminate reliability risk costs due to the need to supply all 18 feeders.

# Materiality of market benefits

The NER requires that RIT-T proponents consider a number of different classes of market benefits that could be delivered by a credible option.[12] Furthermore, the NER requires that a RIT-T proponent consider all classes of market benefits as material unless it can provide reasons why:[13]

- a particular class of market benefit is likely not to materially affect the outcome of the assessment of the credible options under the RIT-T; or
- the estimated cost of undertaking the analysis to quantify the market benefit is likely to be disproportionate to the scale, size and potential benefits of each credible option being considered.

We note that there has been a law change to introduce an emissions reduction objective into the national energy objectives[14] and that the NER have been updated to add a new category of market benefit to the RIT-T reflecting changes in Australia's greenhouse gas emissions.[15] While we acknowledge this important change to the RIT-T, we note that the two credible options for this RIT-T are not expected to affect the dispatch of generation in the wholesale market nor materially impact Australia's greenhouse gas emissions in any other way, including through changes in SF6 emissions. This new category of market benefit is therefore not expected to be material for this RIT-T and so has not been estimated.

## Market benefits considered material

### Changes in involuntary load shedding

If there was to be a switchgear fault at Chapel Street Substation, involuntary load shedding may occur because electricity may not be able to be distributed to feeder lines. While the network in Hobart is meshed, allowing for load switching between substations, switching is not instant. Further, due to the current design of the switchgear, if there is a fault on one feeder line, cascading asset failure may occur, impacting the entire switchgear.

Replacing the switchgear at Chapel Street Substation reduces the risk of failure and reduces the likelihood of involuntary load shedding. Reductions in expected involuntary load shedding are included as a market benefit for this RIT-T. Our approach to calculating this category of market benefit is outlined in our description of the identified need above, i.e. using the probability of failure, a load-weighted VCR and average demand on a representative feeder line at the Chapel Street Substation over the past three to four years.

[12] Refer NER 5.15A.2(b)(4)

[13] NER clause 5.15A.2(b)(6).

[14] On 12 August 2022, Energy Ministers agreed to fast track the introduction of an emissions reduction objective into the national energy objectives, consisting of the National Electricity Objective (NEO), National Gas Objective and National Energy Retail Objective. On 21 September 2023, the *Statutes Amendment (National Energy Laws) (Emissions Reductions Objectives) Act 2023* (the Act) received Royal Assent.

[15] NER clause 5.15A.2(b)(4)(viii).

# Market benefits not considered material

## Wholesale market benefits

The AER has recognised that if the credible options considered will not have an impact on the wholesale electricity market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[16]

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

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no impact on pool price);
- changes in costs for parties other than the RIT-T proponent;
- changes in ancillary services costs;
- changes in Australia's greenhouse gas emissions;
- changes in network losses; and
- competition benefits.

# No other classes of market benefits are considered material

In addition to the classes of market benefits discussed above, NER clause 5.15A.2(b)(4) requires that we consider the following classes of market benefits arising from each credible option. We consider that none of the classes of market benefits listed will be material for this RIT-T assessment for the reasons in Table 9.

Table 9: Reasons why other non-wholesale electricity market benefits are considered immaterial

| Market benefits | Reason |
|---|---|
| Difference in the timing of unrelated expenditure | The investment is specific to one switchgear and will not affect investment in other parts of the network. |
| Option value | We note the AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[17] |

[16] Australian Energy Regulator, *Regulatory investment test for transmission Application guidelines*, 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

[17] Australian Energy Regulator, Regulatory investment test for transmission, Application guidelines, October 2023, Melbourne: Australian Energy Regulator. https://www.aer.gov.au/system/files/2023-10/AER%20-%20RITT%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

# 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.

## Description of the base case

The costs and benefits of each option are compared against the base case. Under this base case, no proactive investment is undertaken, we incur regular and reactive maintenance costs, and the switchgear will continue to operate with an increasing level of risk.

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.[18]

## Assessment period and discount rate

A 20-year assessment period from 2024/25 to 2043/44 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 functional 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 serviceable 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 7.0 per cent has been adopted as the central assumption for the NPV analysis presented in this PSCR, consistent with AEMO's latest Input Assumptions and Scenarios Report (**IASR**).[19] 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.[20] We have also adopted an upper bound discount rate of 10.5 per cent (i.e. the upper bound in the latest IASR).[19]

[18] We note 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. Australian Energy Regulator, *Regulatory investment test for transmission Application guidelines*, 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

[19] AEMO, *2023 Inputs, Assumptions and Scenarios Report*, Final report, July 2023, p 123.

[20] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (TasNetworks) as of the date of this analysis. See: https://www.aer.gov.au/industry/registers/determinations/tasnetworks-determination-2024-29

# 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.

Specifically, we apply a bottom-up approach whereby the cost of each component within an option is individually estimated, and the cost of each of these components is then aggregated to provide a total central capital cost estimate for the option. This tool draws upon the latest quotes that we have received from our suppliers for the relevant equipment and the associated unit costs. TasNetworks has escalated these costs to reflect the later timing of the options in this RIT-T, in line with our experience of increasing costs in the past.

TasNetworks considers the cost estimate for the Chapel Street Substation options to have a cost accuracy of 12.5 per cent, which reflects a level three estimate. TasNetworks utilises three levels of project estimating. As the level of project definition improves the level of uncertainty may reduce and the cost accuracy may improve. As such, selection of the estimate level is primarily driven by the stage of the project. The three levels of estimate and their respective normal application are:

- level one, which is used for the project concept stage, to perform feasibility and options analysis – considering scope and time risks;
- level two, which is used for the project development stage and to evaluate the preferred option – considering scope, time and contingent risk; and
- level three, which is used for the project implementation stage and to support business case approval – considering all management elements.

TasNetworks' estimating process was developed with consideration of the Association for Advancement of Cost Engineering International (AACE) guidelines and Guide to the Project Management Body of Knowledge (PMBOK).

No specific contingency allowance has been included in the cost estimates for the options evaluated in this RIT-T.

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 from the point at which they have been estimated.

# The options have been assessed against three reasonable scenarios

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

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

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

Given that wholesale market benefits are not relevant for this RIT-T, the three scenarios assume the most likely scenario from the 2024 Integrated System Plan (**ISP**) (i.e. the 'Step Change' scenario). The scenarios differ by the assumed level of risk costs, given that these are key parameters that may affect the ranking of the credible options. Risk cost assumptions do not form part of AEMO's ISP assumptions, and have been based on TasNetworks' analysis, as discussed in the description of the identified need above.

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 (i.e. where wholesale market benefits are not expected to be material).[21,22]

Table 10 Summary of scenarios

| Variable / Scenario | Central | Low risk cost scenario | High risk cost scenario |
|---|---|---|---|
| Scenario weighting | 1/3 | 1/3 | 1/3 |
| Discount rate | 7.00% | 7.00% | 7.00% |
| 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% |

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

# Sensitivity analysis

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

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

- lower and higher assumed capital costs;
- lower and higher weighted VCR;
- lower and higher estimated safety, reliability and financial risk benefits; and
- alternate commercial discount rate assumptions.

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

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.

[21] AER, *Regulatory investment test for transmission Application guidelines*, October 2023, pp. 44-46.

[22] 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.

# 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 the credible option to the base case. Benefits of the credible option are represented by reduction in costs or risks compared to the base case.

## Estimated gross benefits

Table 11 below summarises the present value of the gross benefit estimates for each credible option relative to the base case under the three scenarios. The benefits included in this assessment consist of avoided risk, i.e. a reduction in reliability, financial, and safety risks.

Table 11 Estimated gross benefits from credible options relative to the base case ($m, PV)

| Option/scenario | Central | Low risk cost scenario | High risk cost scenario | Weighted |
|---|---|---|---|---|
| *Scenario weighting* | *1/3* | *1/3* | *1/3* | |
| Option 1 | 8.3 | 7.8 | 8.8 | 8.3 |
| Option 2 | 5.8 | 5.5 | 6.2 | 5.8 |

### Estimated gross costs

Table 12 below summarises the costs of the options, relative to the base case, in present value terms.

The costs consist of the direct capital costs for each option, relative to the base case. The capital costs are the same for each option across all scenarios.

Table 12 Costs of credible options relative to the base case ($m, PV)

| Option/scenario | Central |
|---|---|
| Option 1 | -4.6 |
| Option 2 | -2.8 |

### Estimated net market benefits

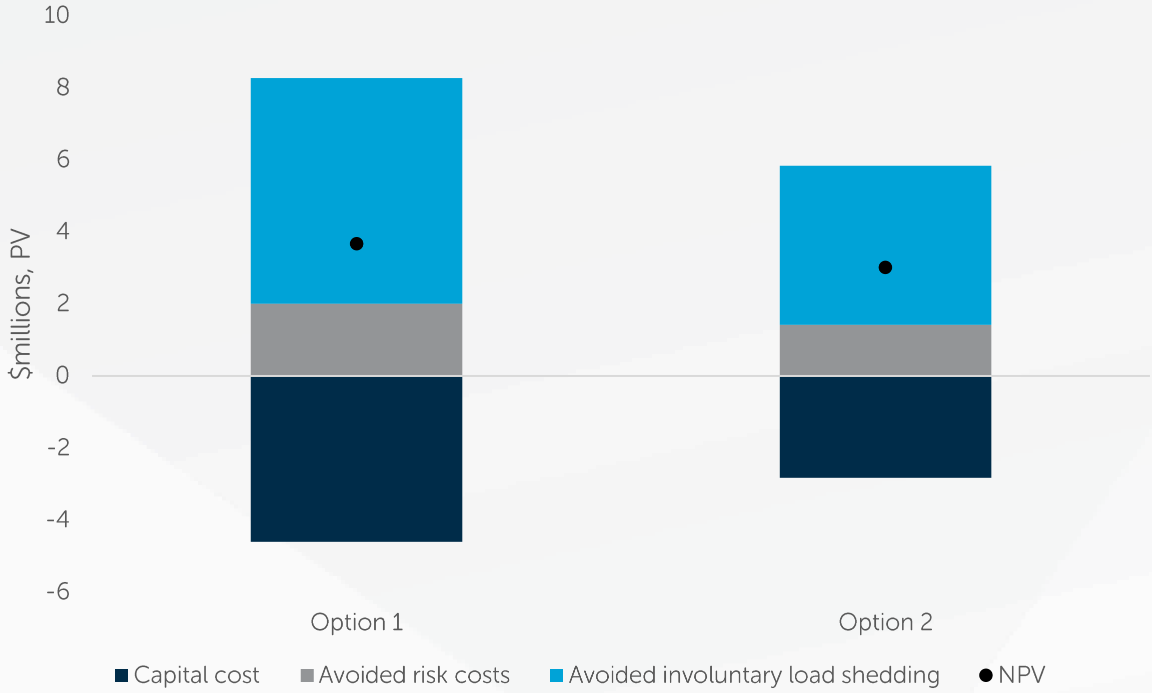
The net economic benefits are the differences between the estimated gross benefits less the estimated costs. Table 13 below summarises the present value of the net economic benefits for each credible option across the three scenarios and the weighted net economic benefits.

Table 13: Net economic benefits for credible options relative to the base case ($m, PV)

| Option/scenario | Central | Low risk cost scenario | High risk cost scenario | Weighted |
|---|---|---|---|---|
| *Scenario weighting* | *1/3* | *1/3* | *1/3* | |
| Option 1 | 3.7 | 3.2 | 4.2 | 3.7 |
| Option 2 | 3.0 | 2.7 | 3.4 | 3.0 |

Both credible options are found to have positive benefits for all scenarios investigated. All scenarios find that Option 1 will deliver the greatest net economic benefits. On a weighted basis, the net economic benefits of Option 1 are approximately $3.7 million. Figure 6 below shows a breakdown of the weighted net economic benefits for each option.

Figure 6 Weighted net economic benefits ($m, PV)




## Sensitivity testing

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

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

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

**Step 1 – sensitivity testing of the optimal timing**

This section outlines the sensitivity of the identification of the commissioning year to changes in the underlying assumptions. Each timing sensitivity has been undertaken on the central scenario.

The optimal timing of Option 1 is found to be invariant to the assumptions of:

- a 12.5 per cent increase/decrease in the assumed network capital costs, which is alignment with TasNetworks cost estimate accuracy for this RIT-T;
- higher weighted average VCR;
- lower (or higher) assumed safety and financial risks; and
- lower discount rate of 3.63 per cent as well as a higher rate of 10.50 per cent.

A lower weighted average VCR delays the optimal timing of Option 1 to 2027/28.

Specifically, Figure 7 below outlines the impact on the optimal commissioning year for each line, under a range of alternate assumptions. It demonstrates that the optimal timing for Option 1 is 2026/27.

Figure 7: Optimal timing for Option 1


### Step 2 – sensitivity of the overall net benefit

We have conducted sensitivity analysis on the present value of the net economic benefit, based on undertaking the project in 2024/25 and completion in 2025/26 with commissioning prior to the beginning of 2026/27. Specifically, we have investigated the following same sensitivities under this step as in the first step:

- a 12.5 per cent increase/decrease in the assumed network capital costs;
- lower (or higher) weighted average VCR;
- lower (or higher) assumed safety and financial risks; and
- lower discount rate of 3.63 per cent as well as a higher rate of 10.50 per cent.

All these sensitivities investigate the consequences of 'getting it wrong' having committed to a certain investment decision. Figures below illustrate the estimated net economic benefits for each option if separate key assumptions in the central scenario are varied individually.

Figure 8 shows that Option 1 delivers higher expected benefits than Option 2 for all sensitivities of capital costs within TasNetworks 12.5 per cent cost accuracy for this RIT-T (i.e. 87.5 per cent to 112.5 per cent of estimated capital costs).

Figure 8: Capital costs sensitivity testing

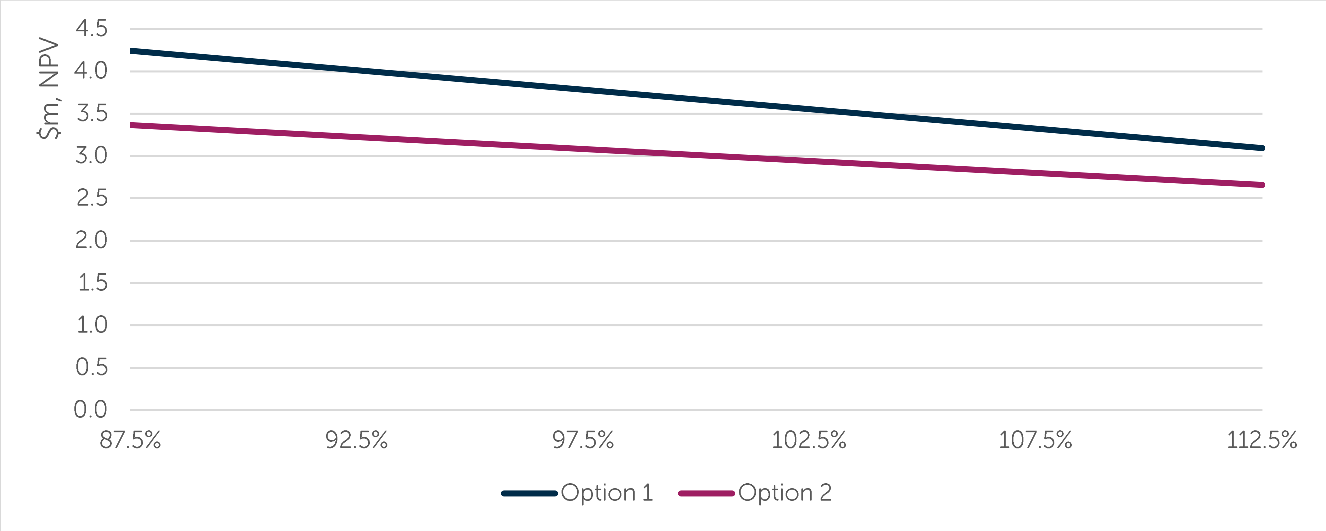



Figure 9 shows that Option 1 delivers higher expected benefits than Option 2 for all sensitivities of the VCR (ie plus and minus 30 per cent, or $29.19/kWh to $54.20/kWh).

Figure 9: VCR sensitivity testing

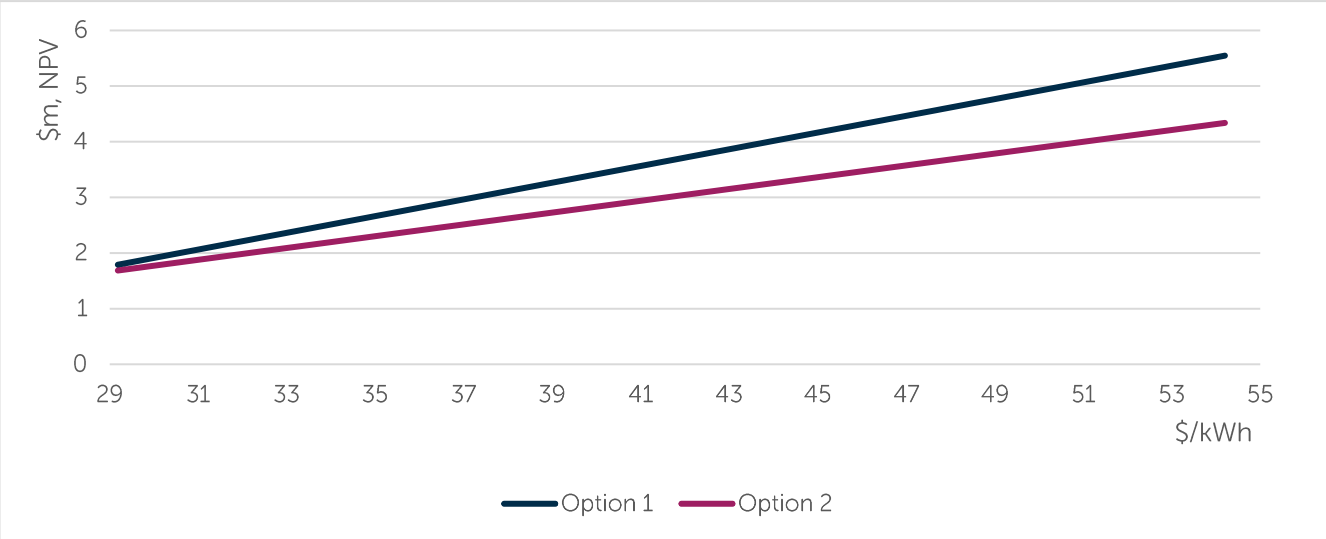



Figure 10 shows that Option 1 delivers higher expected benefits than Option 2 for all sensitivities of the safety and financial risk costs (i.e. plus and minus 30 per cent).

Figure 10: Risk costs sensitivity testing

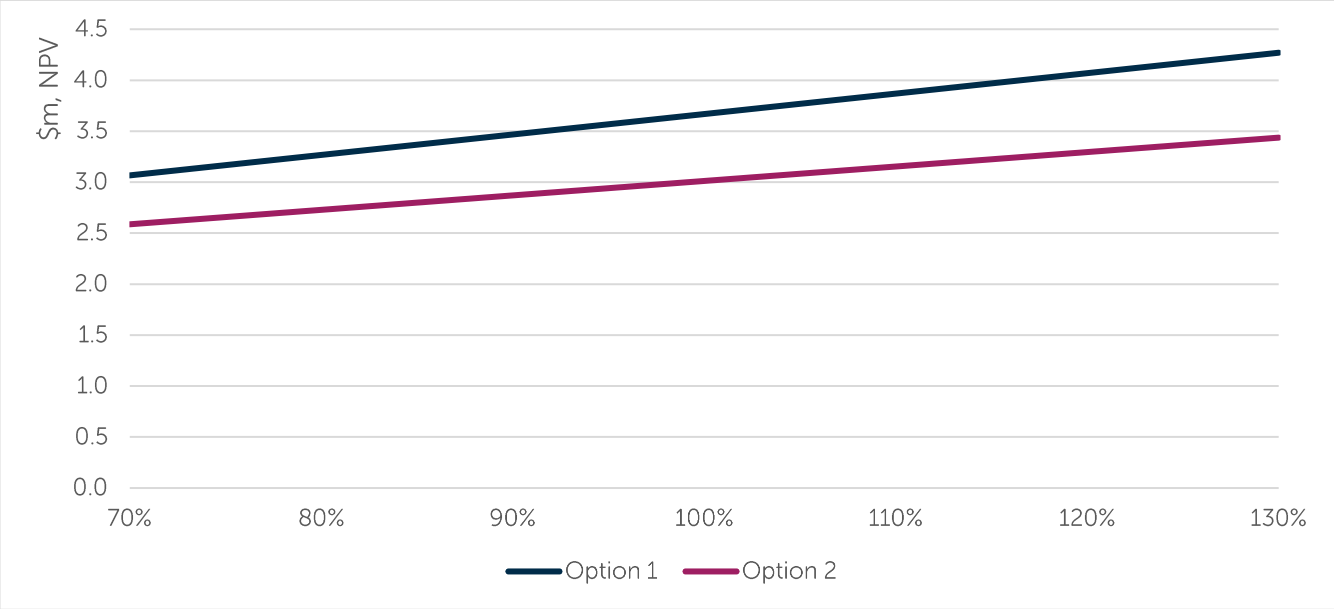
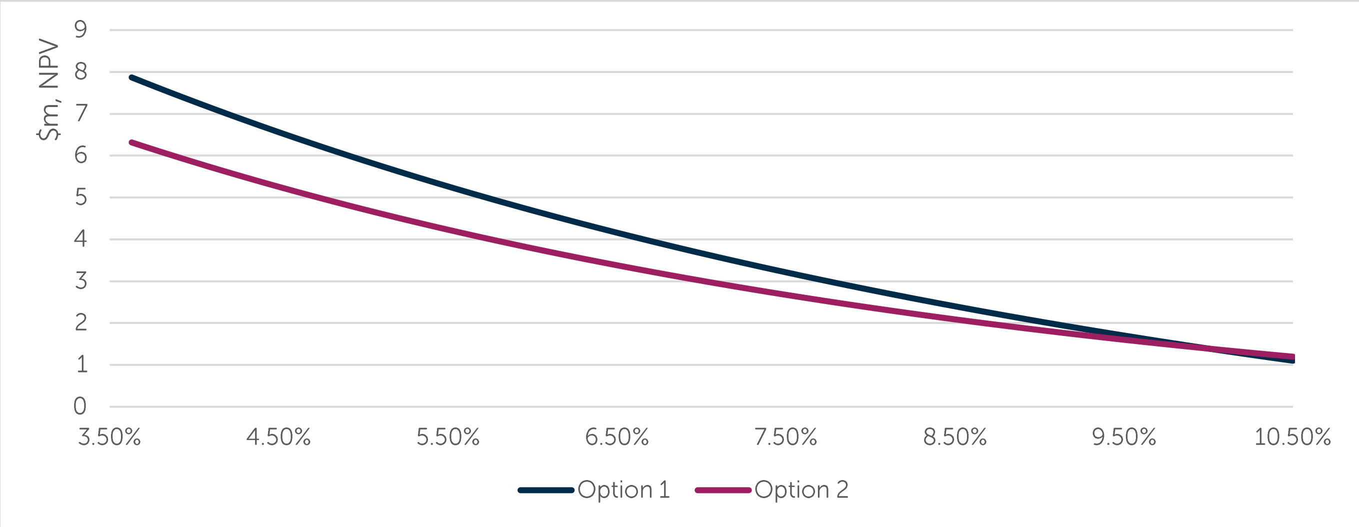



Figure 11 shows that Option 1 delivers higher expected benefits than Option 2 for all sensitivities of the commercial discount rate below 10 per cent. Option 2 delivers higher expected benefits than Option 1 for all sensitivities of the commercial discount rate above 10 per cent.

Figure 11: Commercial discount rate sensitivity testing




Option 1 is expected to deliver positive benefits in all sensitivities and is expected to deliver higher benefits than Option 2 in all sensitivities other than that of a commercial discount rate of above 10 per cent.

In terms of boundary testing, we find that the following will need to occur for Option 1 to have lower net benefits than Option 2:

- assumed network capital costs would need to increase by approximately 37 per cent, which is substantially outside of TasNetworks' cost accuracy estimate for the network options considered in this RIT-T of 12.5 per cent;
- the VCR would need to decrease by approximately 35 per cent to $26.83/kWh. For this to occur, and assuming that *Business customer – industrial* and *Business customer – commercial* maintain equal VCR weightings, *Residential* customers would have to make up approximately 84 per cent of the load, which is significantly above TasNetworks' estimate of 50 per cent;

- the estimated risk costs (in aggregate) would need to decrease by 116 per cent (i.e. go below zero); or
- a discount rate of over 10 per cent.

We therefore consider the finding that Option 1 being the preferred option is robust to the key underlying assumptions.

# Draft conclusion and exemption from preparing a PADR

This PSCR has found that Option 1 is the preferred option at this draft stage of the RIT-T. Option 1 involves the replacement of the switchgear in financial year 2025/26.

The estimated capital expenditure associated with Option 1 is $6.19 million (in 2023/24 dollars).

The works are estimated to take place in financial years 2024/25 and 2025/26, with commissioning by the beginning of 2026/27.

NER 5.16.4(z1) provides for a TNSP to be exempt from producing a Project Assessment Draft Report (PADR) for a particular RIT-T application, in the following circumstances:

- if the estimated capital cost of the preferred option is less than $46 million;[23]
- if the TNSP identifies in its PSCR its proposed preferred option, together with its reasons for the preferred option and notes that the proposed investment has the benefit of NER 5.16.4(z1) exemption; and
- if the TNSP considers that the proposed preferred option and any other credible options in respect of the identified need will not have a material market benefit for the classes of market benefit specified in NER 5.15A.2(b)(4), with the exception of market benefits arising from changes in voluntary and involuntary load shedding.

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

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

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

Should we consider that no additional credible options were identified during the consultation period that could have material market benefits, we intend to produce a PACR in December 2024 that addresses all submissions received, including any issues in relation to the proposed preferred option raised during the consultation period, and presents our conclusion on the preferred option for this RIT-T.

[23] NER 5.16.4(z1) refers to the preferred option being less than $35 million, or as varied in accordance with a cost threshold determination. The cost threshold was varied to $46m based on the AER Final Determination: Cost threshold review November 2021. Accessed 19 November 2021 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021

# Appendices

## Appendix 1 Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PSCR with the requirements of the National Electricity Rules version 214.

| Rules clause | Summary of requirements | Relevant section |
|---|---|---|
| 5.16.4 (b) | A RIT-T proponent must prepare a report (the project specification consultation report), which must include: | |
| | (1) a description of the identified need; | The identified need |
| | (2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary); | The identified need |
| | (3) the technical characteristics of the identified need that a non-network option would be required to deliver, such as:<br>(i) the size of load reduction of additional supply;<br>(ii) location; and<br>(iii) operating profile; | Non-Network options |
| | (4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan | NA |
| | (5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alterative transmission options, interconnectors, generation, demand side management, market network services or other network options; | Credible options |
| | (6) for each credible option identified in accordance with subparagraph (5), information about:<br>(i) the technical characteristics of the credible option;<br>(ii) whether the credible option is reasonably likely to have a material inter-network impact;<br>(iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefit are not likely to be material;<br>(iv) the estimated construction timetable and commissioning date; and<br>(v) to the extent practicable, the total indicative capital and operating and maintenance costs. | Credible options *and* Materiality of market benefits |
| 5.16.4(z1) | A RIT-T proponent is exempt from paragraphs (j) to (s) if: | Draft conclusion |


TasNetworks Powering a Bright Future

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| (1) the estimated capital cost of the proposed preferred option is less than $35 million[24] (as varied in accordance with a cost threshold determination);<br>(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;<br>(3) the RIT-T proponent considers, in accordance with clause 5.15A.2(b)(6), that the proposed preferred option and any other credible option in respect of the identified need will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4) except those classes specified in clauses 5.15A.2(b)(4)(ii) and (iii), and has stated this in its project specification consultation report; and<br>(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. | and exemption from preparing a PADR |

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

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