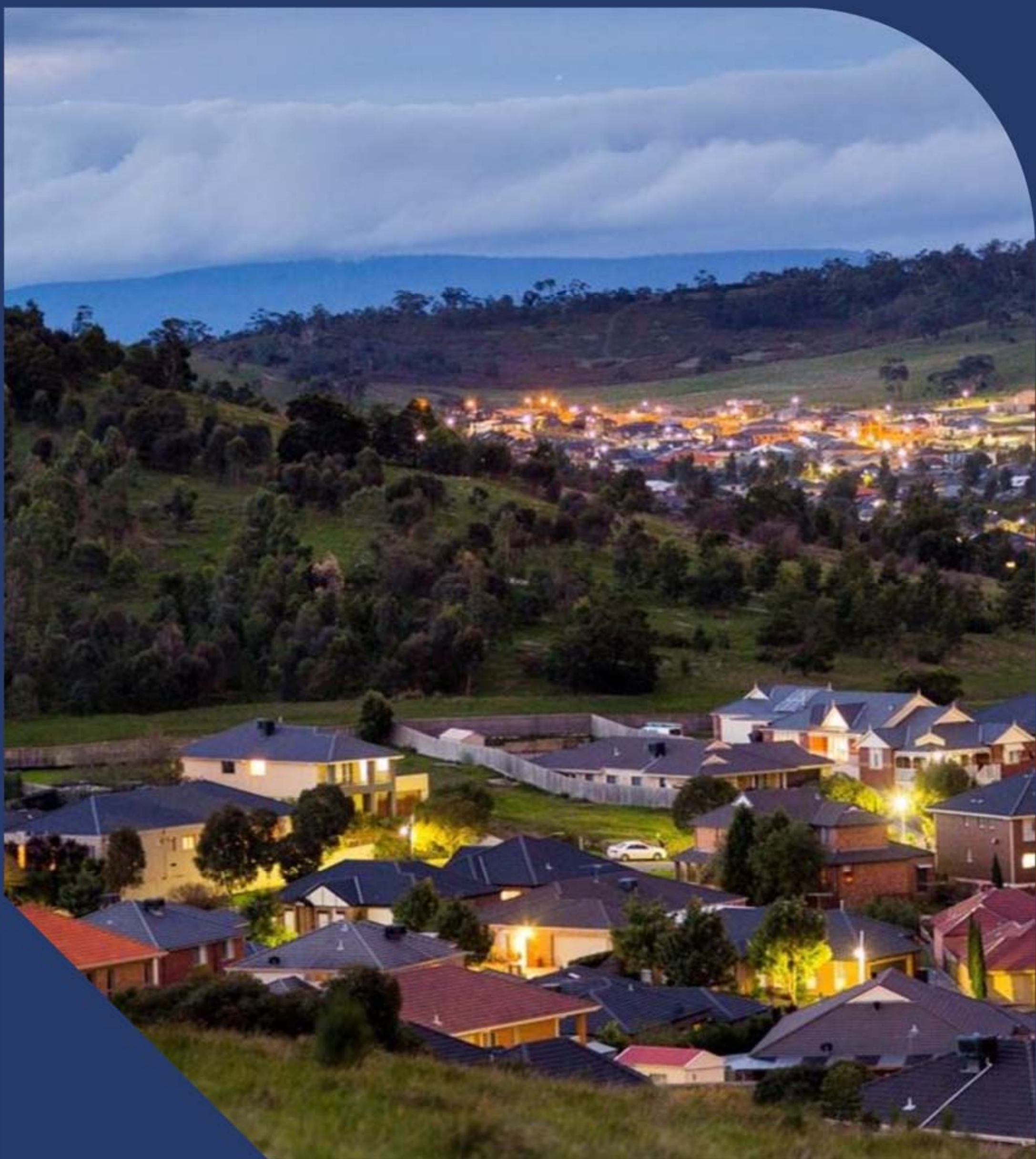
Service constraints at Traralgon (TGN) Zone Substation

Regulatory Investment Test for Distribution

Draft Project Assessment Report

Tuesday, 16 August 2022



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1. Executive summary

AusNet Services is a regulated Victorian Distribution Network Service Provider (DNSP) that supplies electrical distribution services to more than 745,000 customers. Our electricity distribution network covers eastern rural Victoria and the fringe of the northern and eastern Melbourne metropolitan area.

As expected by our customers and required by the various regulatory instruments that we operate under, AusNet Services aims to maintain service levels at the lowest possible cost to our customers. To achieve this, we develop forward looking plans that aim to maximise the present value of economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

Our planning approach includes the application of a probabilistic planning methodology, under which conditions often exist where some of the load cannot be supplied under rare but possible conditions, such as during extreme demand conditions or with a network element out of service. Where relevant, we also prepare, publish, and consult on a regulatory investment test for distribution (RIT-D), which further helps ensure all credible options are identified and considered, and the best option is selected.

This Draft Project Assessment Report (DPAR) is the second stage of the RIT-D consultation process to address the existing and emerging service level constraints in the Traralgon (TGN) Zone Substation supply area. It follows the publication of our non-network options report, which invited non-network proponents to engage on alternatives to our preferred network solution. We did not receive any submissions in response to that report.

This DPAR has been prepared by AusNet Services in accordance with the requirements of clause 5.17 of the National Electricity Rules (NER). This DPAR complies with the requirements of Clause 5.17.4(j) of the NER, as detailed in section 7 of this document, and the AER's RIT - D application guidelines.

1.1. Identified Need

TGN commenced operation as a 66/22kV transformation station in 1969. Two 10/13.5 MVA transformers were manufactured in 1949 and 1979, and one 20/33 MVA transformer was manufactured in 2012.

The 22kV switchyard consists of one indoor switchboard with four feeders installed in 2013, and three outdoor 22kV busses with four feeder CBs installed in 1969. The 66kV switchyard has had some modifications since the site was established, and now consists of two 66kV lines to MWTS and one line to Maffra Zone Substation.

Two of the 66kV circuit breakers were installed in 1977, while the other two were installed in 2013 when the new 20/33 MVA transformer was installed. The station 66kV bus is partially switched with the two 10/13.5MVA transformers connected in a single switching zone group.

The physical and electrical condition of some assets has deteriorated and they now present an increased failure risk. The key service constraints at TGN are:

- Security of supply risk presented by the switching of the No.2 and No.3 transformers in a single group, and lack of 66kV ring bus;
- Security of supply risks presented by increasing likelihood of asset failure due to the deteriorating condition of the assets;
- Health and safety risks presented by a possible explosive failure of bushings on a number of the assets;
- Plant collateral damage risks presented by a possible explosive failure of a number of the assets;
- Environmental risks associated with insulating oil spill or fire;
- Reactive asset replacement risks presented by the increasing likelihood of asset failure due to the deteriorating condition of the assets;
- Health and safety risks presented by exposed live terminals at the rear of the secondary panels in the control room; and
- Health and safety risks presented by asbestos containing cement sheets or electrical switch boards in the control building, store room and toilet.

1.2. Options considered and preferred option

The potentially credible options that AusNet Services believes may be capable of meeting the identified need include:

(1) Do Nothing (counterfactual);

(2) Retire one transformer;

(3) Retire one transformer and shore up supply capacity via network support;

(4) Network support to defer retirement and replacement;

(5) Replace 22kV switchgear with new switchboard;

(6) Replace two 66kV circuit breakers and 22kV switchgear;

(7) Integrated replacement; and

(8) Integrated replacement, with different staging

Our analysis concludes that only Options 5, 6, 7 and 8 are credible options, and the preferred option is Option 8.

1.3. Consultation

In accordance with Clause 5.17.4(k) of the NER, we request submissions on the matters set out in this DPAR. Notification of this request for submissions will also be provided to Registered Participants, AEMO, non-network providers, interested parties and persons on our demand side engagement register as required by the NER.

Submissions should be sent to ritdconsultations@ausnetservices.com.au by 4 October 2022 and telephone enquiries can be directed to Murtaza Latif on (03) 9695 6000.

Submissions will be published on AusNet Services' website. If you do not wish to have your submission published, please clearly stipulate this at the time of lodging your submission.

2. Background

2.1. Existing network

TGN is located approximately 170km east of Melbourne (VicRoads map reference 343 M-7) and is the main source of supply for Traralgon, Glengarry, Calilgnee, Gormandale, Rosedale and surrounding areas. TGN is located at an elevation of 60m above sea level. TGN has a summer average maximum temperature of 26°C and a winter average minimum temperature of 4.1°C. Extreme temperatures reach 46.3°C in summer and -4.8°C in winter. The mean rain fall varies from 37.2mm to 60.1mm per month within a year.

TGN supplies approximately 17,500 customers. The load at TGN includes town and rural based residential, with some town based commercial, industrial and farming.

The location of TGN within the AusNet Services distribution network is shown in the figure below.

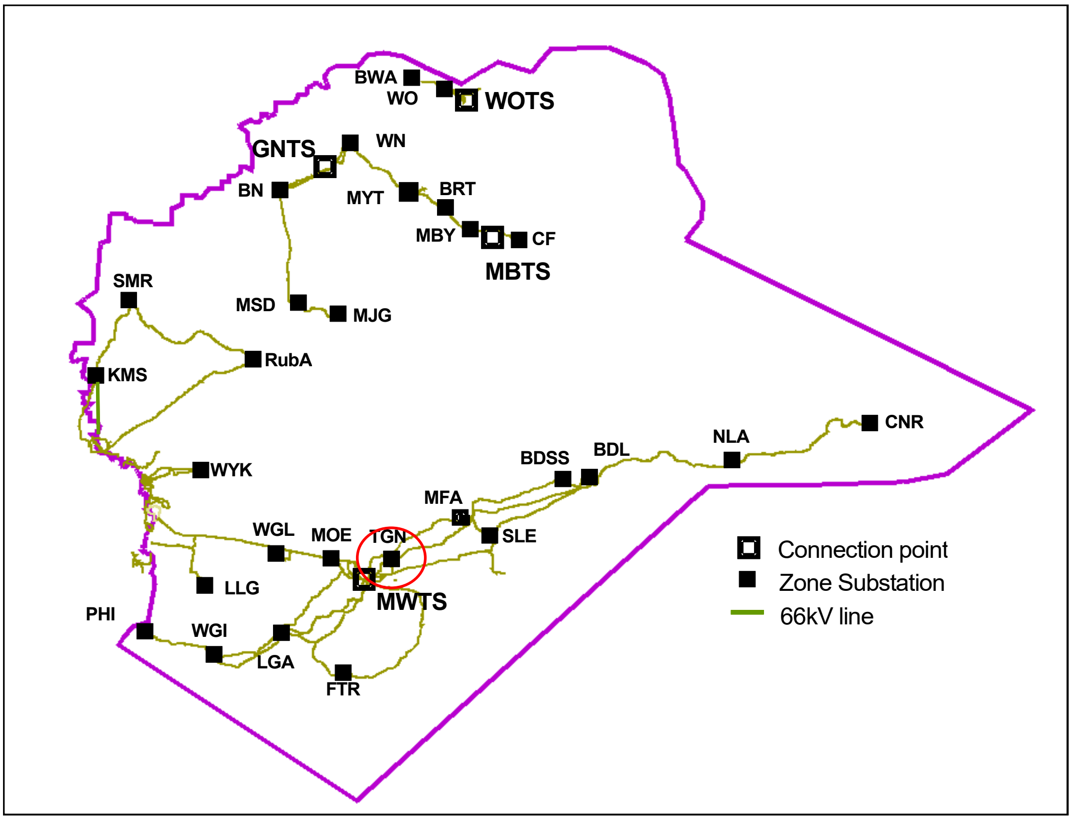

Figure 1: TGN location within AusNet Services network

TGN is supplied via three 66kV circuits, two of which come from Morwell Terminal Station (MWTS) and the third from Maffra Zone Substation. The configuration of primary electrical circuits within TGN is as shown in the following single line diagram below.

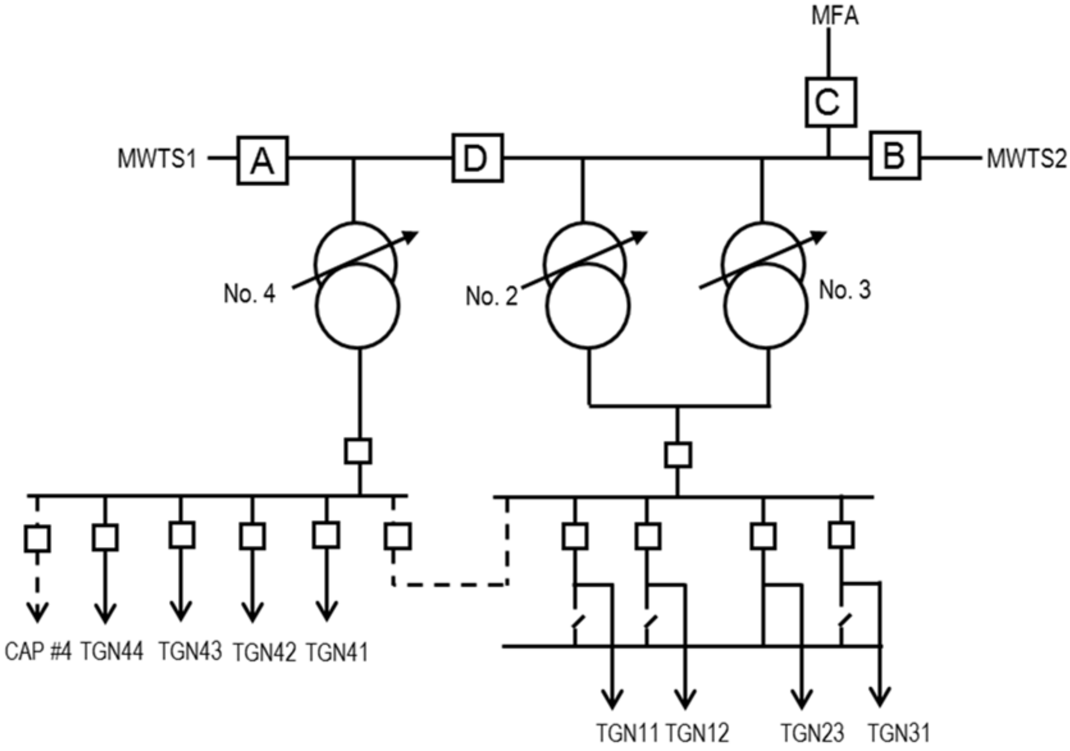

Figure 2: Single Line Diagram of TGN

2.2. Customer Composition

TGN has eight 22kV feeders supplying AusNet Services' customers. One of the feeders has a 10MW power station connected to it that has previously been used for network support, however the contract has now expired.

Table 1 provides detail of the 22kV supply feeders.

Table 1: TGN feeder information

Feeder	Feeder Length (km)	Feeder description	Number of Customers	Type of Customers
TGN11	54	Summer peaking, short rural feeder	3,671	95% residential 2% commercial 1% industrial 2% farming.
TGN12	5	Summer peaking, urban feeder	466	50% residential 47% commercial 3% industrial.
TGN23	176	Summer peaking, short rural feeder	2,433	86% residential 4% commercial 1% industrial 9% farming
TGN31	346	Summer peaking, long rural feeder	1,981	62% residential 8% commercial 1% industrial 29% farming
TGN41	337	Summer peaking, long rural feeder	1,805	57% residential 16% commercial 3% industrial 24% farming
TGN42	6	Summer peaking, urban feeder	629	35% residential 64% commercial 1% industrial
TGN43	24	Summer peaking, short rural feeder	3,884	97% residential 3% commercial

Feeder	Feeder Length (km)	Feeder description	Number of Customers	Type of Customers
TGN44	32	Summer peaking, short rural feeder	2,611	96% residential 3% commercial 1% industrial and farming combined

The 22kV feeders interconnect with 22kV feeders from Morwell and Maffra zone substations. Approximately 9.7MVA of load is able to be transferred away from TGN to these stations via 22kV feeders, predominantly to Morwell.

2.3. Zone Substation Equipment

2.3.1. Primary Equipment

TGN includes an air insulated 66kV switchyard with four circuit breakers. It does not have a 66kV ring bus and is therefore more susceptible to bus faults impacting the station load. There are three air insulated outdoor 22kV busbars and a transfer bus supplying four 22kV feeders and one 9 MVAr capacitor bank.

The 66kV circuits are switched by two minimum oil 66kV circuit breakers ‘A’ and ‘B’ installed in 1977 and two dead tank 66kV circuit breakers, ‘C’ and ‘D’, installed in 2013.

There are four 22kV outdoor feeder circuit breakers manufactured between 1967 and 1969, one 22kV outdoor circuit breaker manufactured in 1983, two outdoor 22kV transformer circuit breakers installed in 2013 and the remaining indoor 22kV circuit breakers are part of an integrated 22kV switchboard installed in 2013.

Transformation comprises two 10/13.5 MVA 66/22kV transformers (No.2 and No.3), which are switched as a single group, and one 20/33 MVA 66/22kV transformer (No.1).

The No.2 and No.3 transformers were manufactured in 1949 and 1979 respectively. No.1 transformer was manufactured and installed in 2013.

2.3.2. Secondary Equipment

The 66kV line circuit breakers have circuit breaker failure and auto reclose schemes using Group relays. The 22kV feeder circuit breakers have overcurrent, earth fault and sensitive earth fault using modern numerical relays. The 22kV capacitor bank protection has neutral balance and capacitor control device functions using modern numerical relays.

The transformers have differential protection, voltage regulating and restrictive earth fault protection using old electronic relays. The bus protection has overcurrent and distance protection using old electronic relays.

3. Identified need

TGN commenced operation as a 66/22kV transformation station in 1969. There are two 10/13.5 MVA transformers that were manufactured in 1949 and 1979. There is one 20/33 MVA transformer that was manufactured in 2012.

The 22kV switchyard consists of one indoor switchboard with four feeders installed in 2013, and three outdoor 22kV busses with four feeder CBs installed in 1969. The 66kV switchyard has had some modifications since the site was established, and now consists of two lines to MWTS and one line to Maffra Zone Substation. Two of the 66kV circuit breakers were installed in 1977 while the other two were installed in 2013 when the new 20/33 MVA transformer was installed.

The physical and electrical condition of these assets has deteriorated and they are now presenting an increasing failure risk. The station 66kV bus is partially switched, hence faults on the 66kV transformer bus or either one of the transformers could result in load shedding at TGN, or elsewhere in the East Gippsland network due to a reduction in 66kV supplies. Failure of the 66kV bus tie CB will result in loss of supply to all (approximately 17,500) customers supplied from TGN.

The key service constraints at TGN are:

- Security of supply risk presented by the switching of the No.2 and No.3 transformers in a single group, and lack of 66kV ring bus;
- Security of supply risks presented by increasing likelihood of asset failure due to the deteriorating condition of the assets;
- Health and safety risks presented by a possible explosive failure of bushings on a number of the assets;
- Plant collateral damage risks presented by a possible explosive failure of a number of the assets;
- Environmental risks associated with insulating oil spill or fire;
- Reactive asset replacement risks presented by the increasing likelihood of asset failure due to the deteriorating condition of the assets;
- Health and safety risks presented by exposed live terminals at the rear of the secondary panels in the control room; and
- Health and safety risks presented by asbestos containing cement sheets or electrical switch boards in the control building, store room and toilet.

4. Assumptions underpinning the identified need

The purpose of this chapter is to summarise the key input assumptions that underpin the identified need described in the previous chapter.

4.1. Regulatory obligations

In addressing the identified need, we must satisfy our regulatory obligations, which we summarise below.

Clause 6.5.7 of the National Electricity Rules requires AusNet Services to only propose capital expenditure required in order to achieve each of the following:

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services, and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

Section 98(a) of the Electricity Safety Act requires AusNet Services to design, construct, operate, maintain and decommission its supply network to minimise as far as practicable:

(a) the hazards and risks to the safety of any person arising from the supply network; and

(b) the hazards and risks of damage to the property of any person arising from the supply network; and

(c) the bushfire danger arising from the supply network.

The Electricity Safety act defines 'practicable' to mean having regard to –

(a) severity of the hazard or risk in question; and

(b) state of knowledge about the hazard or risk and any ways of removing or mitigating the hazard or risk; and

(c) availability and suitability of ways to remove or mitigate the hazard or risk; and

(d) cost of removing or mitigating the hazard or risk.

Clause 3.1 of the Electricity Distribution Code requires AusNet Services to:

> *develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets and plans for the establishment and augmentation of transmission connections:*

(i) to comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in this Code;

(ii) to minimise the risks associated with the failure or reduced performance of assets; and

(iii) in a way which minimises costs to customers taking into account distribution losses.

Under clause 5.2 of the Electricity Distribution Code, AusNet Services:

must use best endeavours to meet targets required by the Price Determination and targets published under clause 5.1 and otherwise meet reasonable customer expectations of reliability of supply.

4.2. Asset condition

AMS 10-13 Condition Monitoring describes AusNet Services' strategy and approach to monitoring the condition of assets. Asset condition is measured with reference to an asset health index on a scale of C1 to C5. The table below provides a description of the asset condition scores.

Table 2: Asset Condition Score and Remaining Service Potential

Condition Score	Condition	Condition Description
C1	Very Good	Initial service condition
C2	Good	Deterioration has minimal impact on asset performance. Minimal short term asset failure risk.
C3	Average	Functionally sound showing some wear with minor failures, but asset still functions safely at adequate level of service.
C4	Poor	Advanced deterioration – plant and components function but require a high level of maintenance to remain operational.
C5	Very Poor	Extreme deterioration approaching end of life with failure imminent.

The condition of the key assets at TGN is discussed in the Asset Health Reports for the key asset classes such as power transformers, instrument transformers and switchgear with information on asset condition rankings, recommended risk mitigation options and replacement timeframes. A summary of the condition is provided in the table below.

Table 1: Asset Condition Summary

Asset Type	Number of Assets				
	C1	C2	C3	C4	C5
66kV Circuit Breakers	2			2	
66kV Current Transformers	6				
66kV Voltage Transformers	3				6
66/22kV Power Transformers	1		1	1	
22kV Circuit Breakers	11		1	1	3
22kV Current Transformers	21				5
22kV Voltage Transformers	1	3		1	

These condition scores are then used to calculate the asset failure rates using the Weibull parameters determined for each asset class.

4.3. Zone Substation Supply Capacity

TGN is a summer peaking station and the peak electrical demand reached 45MVA in the summer of 2017/18. The recorded peak demand during the winter of 2018 was 31MVA.

The demand at TGN is forecast to grow at approximately 1% per annum. Figure 3 shows the forecast maximum demand and supply capacities (cyclic ratings) for TGN.

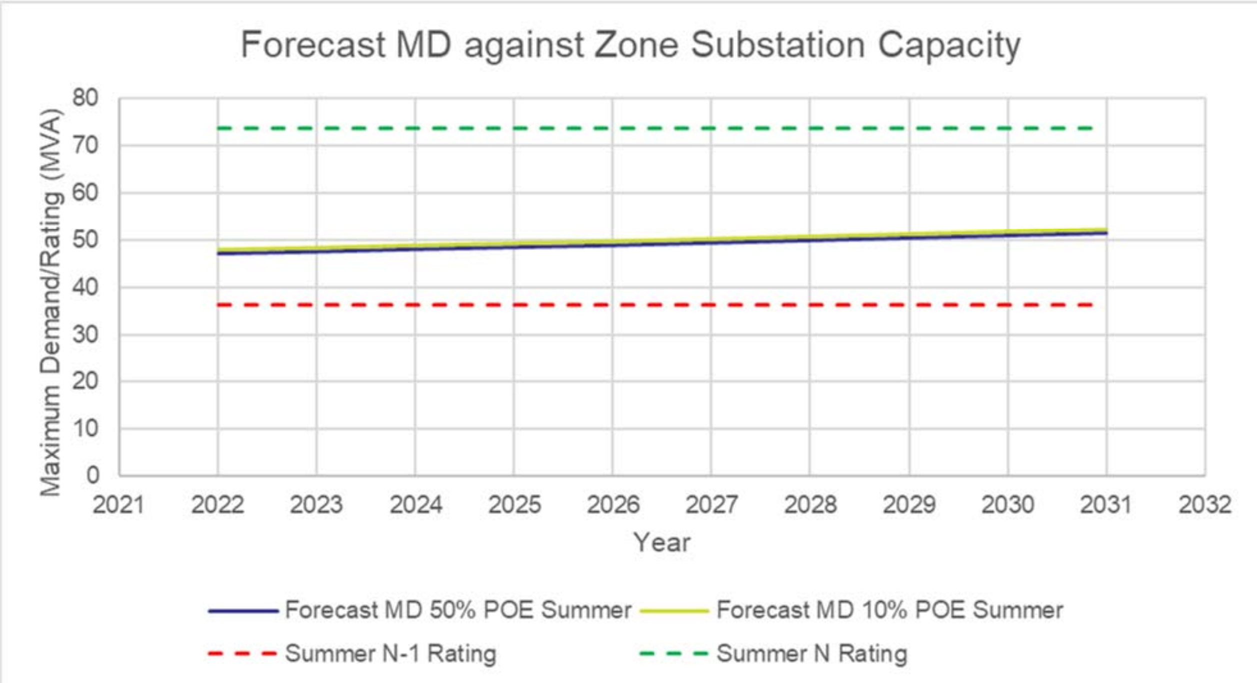

Figure 3: TGN Forecast Maximum Demand against Zone Substation Capacity

4.4. Load Duration Curves

The zone substation load duration curves that feed into the risk-cost assessment model are derived from historical actual demands between:

- 1 October 2019 and 31 March 2020 for the summer 50% probability of exceedance (POE) curves;
- 1 April 2020 and 30 September 2020 for the winter 50% POE curves;
- 1 October 2019 and 31 March 2020 for the summer 10% POE curves; and
- 1 April 2020 and 30 September 2020 for the winter 10% POE curves.

The historical hourly demands are separated by season and unitised based on the recorded maximum demand within that season (summer and winter) and time period, which allows the load duration curve to be scaled according to the seasonal forecast maximum demand for each year of the assessment period.

The 50% POE unitised load duration for TGN Zone Substation is presented in

Figure 4, and the 10% POE unitised load duration for TGN Zone Substation is presented in Figure 5.

Figure 4: TGN 50% Load Duration Curves

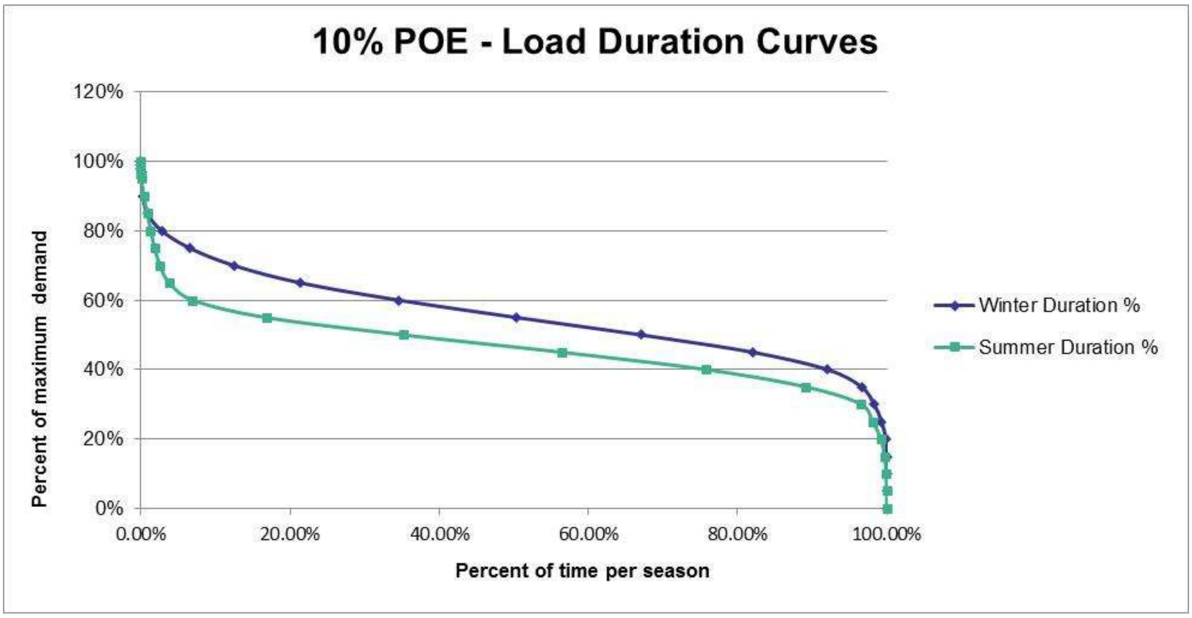

Figure 5: TGN 10% POE Load Duration Curves

4.5. Feeder Circuit Supply Capacity

There is currently no requirement for additional feeders at TGN due to the modest load growth expected in the area.

4.6. Load Transfer Capability

The Distribution Annual Planning Report (DAPR) provides the load transfer capability (in MW) of the feeder interconnections between TGN and its neighbouring zone substations. The load transfer capability for TGN is set out in the table below.

Table 3: TGN Load Transfer Capability

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Transfer Capability (MW)	9.7	9.6	9.5	9.4	9.3	9.3	9.2	9.1	9.0	8.9

4.7. Station Configuration Supply Risk

The configuration of TGN mean that failure of some 66kV and 22kV equipment will result in supply outages to customers, as backup circuit breakers operate to isolate the failed equipment. The resultant supply outage would be for an estimated duration of two hours, which is the time typically required by operators to travel to site and manually re-configure circuits to isolate the failed equipment and sequentially restore supply to customers.

Table 4 lists the estimated bus outage consequence factors for each major type of equipment based on the substation layout.

Table 4: TGN Bus Outage Consequence Factors

Equipment	Estimated Bus Outage Consequence
Transformer	0%
22kV circuit breaker	54%
66kV circuit breaker	25%
22kV current transformer	54%
66kV current transformer	25%
22kV voltage transformer	56%
66kV voltage transformer	0%

5. Potential Credible Options

This section outlines the potential options that have been considered to address the identified need, and summarises the key works and costs associated with implementing these options. In subsequent analysis some of these options have been found not to be credible but are nevertheless included here for completeness.

(1) Do Nothing (counterfactual)

(2) Retire one transformer

(3) Retire one transformer and shore up supply capacity via network support

(4) Network support to defer retirement and replacement

(5) Replace 22kV switchgear with new switchboard

(6) Replace two 66kV circuit breakers and 22kV switchgear

(7) Integrated replacement

(8) Integrated replacement, with different staging

5.1. Option 1: Do Nothing

The Do Nothing (counterfactual) option assumes that AusNet Services would not undertake any investment, outside of the normal operational and maintenance processes. Under this option, increasing supply risk would be managed by increased levels of involuntary load reduction. Increased non-supply risks, such as those associated with safety, collateral damage, reactive replacement and environmental impacts, would be accepted as unmanaged rising risk costs.

The Do Nothing (counterfactual) option establishes the base level of risk, and provides a basis for comparing other credible options. Whilst the direct capital costs of this option are zero, the continued exposure to residual risks means that this option has significant risk costs associated with it.

5.2. Options 2-4 are not credible

The purpose of the non-network options report was to test with non-network proponents whether this option is feasible and to better understand the likely costs of procuring network support. No submissions were received from non-network proponents and, therefore, options 2, 3 and 4 are no longer regarded as credible and not considered further in this DPAR.

5.3. Option 5: Replace 22kV switchgear with new switchboard

Under this option only the 22kV outdoor switchgear will be replaced with a new 22kV indoor switchboard. The estimated capital cost of this option is $11.51 million (Real $2022).

5.4. Option 6: Replace two 66kV circuit breakers and 22kV switchgear

Under this option the 22kV outdoor switchgear will be replaced with a new 22kV indoor switchboard and two 66kV circuit breakers will be replaced,

The estimated capital cost of this option is $12.82 million (Real $2022).

5.5. Option 7: Integrated replacement

Under this option the deteriorated No.2 and No.3 transformers will be replaced with new 20/33 MVA units.

The outdoor 22kV switchgear will be replaced with a new indoor 22kV switchboard. The 66kV bus will be fully switched to further improve reliability.

The estimated capital cost of this option is $16.70 million (Real $2022).

5.6. Option 8: Integrated replacement, with different staging

This option is similar to option 7 with split scope arrangement. In stage 1, the deteriorated No.2 and No.3 transformers will be replaced with new 20/33 MVA units and the 66kV bus will be fully switched to further improve reliability. In stage-2, the outdoor 22kV switchgear will be replaced with a new indoor 22kV switchboard, which would be scheduled for implementation around 5-10 years after stage 1.

The capital cost of this option is $16.70 million (Real $2022).

6. Economic assessment of the credible options

6.1. Market benefit

The regulatory investment test for distribution requires the RIT-D proponent to consider whether each credible option provides the classes of market benefits described in clause 5.17.1(c)(4) of the NER. To address this requirement, the table below discusses our approach to each of the market benefits listed in clause 5.17.1(c)(4) in assessing the credible options to address the identified need at TGN.

Table 5: Analysis of Market Benefits

Class of Market Benefit	Analysis
(i) changes in voluntary load curtailment;	The options are not expected to lead to changes in voluntary load curtailment.
(ii) changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers;	The options are expected to have an impact on involuntary load shedding, although the identified need relates to asset condition. The cost benefit analysis will therefore consider the impact of each option on load shedding. AusNet Services applies probabilistic planning techniques to assess the expected cost of unserved energy for each option.
(iii) changes in costs for parties, other than the RIT-D proponent, due to differences in: *(A) the timing of new plant;* *(B) capital costs; and* *(C) the operating and maintenance costs;*	There is no impact on other parties.
(iv) differences in the timing of expenditure;	This project will not result in changes in the timing of other expenditure.
(v) changes in load transfer capacity and the capacity of Embedded Generators to take up load;	This project will not impact on the capacity of Embedded Generators to take up load.
(vi) any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the National Electricity Market;	This project will not impact the option value in respect to likely future investment needs of the NEM.
(vii) changes in electrical energy losses; and	This project will not result in changes to electrical energy losses.
(viii) any other class of market benefit determined to be relevant by the AER.	We do not consider any other class of market benefit as relevant to the selection of the preferred option.

6.2. Methodology

The purpose of this section is to provide a high-level explanation of our methodology for identifying the preferred option. As a general principle, it is important that the methodology takes account of the identified need and the factors that are likely to influence the choice of the preferred option. As such, the methodology is not a 'one size fits all' approach, but one that is tailored for the particular circumstances under consideration.

The identified need for this project can be described in terms of two types of risk:

- supply risk, where an asset failure may lead to a loss of supply to customers; and
- non-supply risk, which captures the potential consequences of an asset failure, which may include safety and environmental costs, in addition to damage to adjacent assets or property.

In relation to supply risk, we adopt a probabilistic planning methodology which considers the likelihood and severity of critical network conditions and outages. The expected annual cost to customers associated with supply risk is calculated by multiplying the expected unserved energy (the expected energy not supplied based on the probability of the supply constraint occurring in a year) by the value of customer reliability (VCR).

In relation to non-supply risks, our approach monetises this risk by multiplying the following parameter estimates:

- the probability of asset failure;
- the cost of consequence of the asset failure;
- the likelihood of the consequence given the failure has occurred; and
- the number of assets to which the analysis relates.

The purpose of the cost benefit analysis that underpins the RIT-D assessment is to determine whether there is a cost effective option to mitigate the supply and non-supply risks (the aggregate 'risk-cost'). In order to be cost effective, the reduction in the aggregate risk-cost that an option is expected to provide must exceed the cost of implementing that option. The preferred option provides greatest expected net benefit, expressed in present value terms.

- In the absence of remedial action,

Figure 6 shows how the aggregate risk-cost will typically increase as the risk of asset failure and energy at risk increase over time. The optimal timing of the preferred option occurs when the annualised capital cost of that option (or the operating cost for a non-network option) is equal to the aggregate risk-cost.

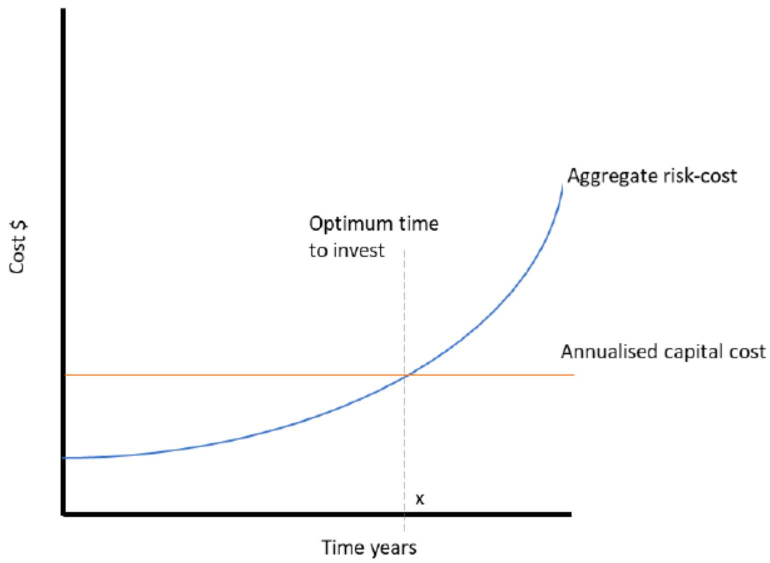

Figure 6: Increasing risk-cost over time and optimal project timing[1]

In effect, the preferred option delivers the lowest total cost to customers, which is the sum of the cost of implementing that option and any residual risk-cost. The identification of the preferred option is complicated by the

[1] This figure is reproduced from the AER's Industry practice application note, Asset replacement planning, January 2019, figure 8. This figure assumes that the option eliminates the aggregate risk-cost in full, which may not be the case.

fact that the future is uncertain and that various input parameters are 'best estimates' rather than known values. As a consequence, the RIT-D analysis must be conducted in the face of uncertainty.

To address uncertainty in our assessment of the credible options, we use sensitivity analysis and scenario analysis in our cost benefit assessment. As recommended by the AER's application guidelines, we use sensitivity analysis to assist in determining an appropriate set of reasonable scenarios.[2] The relationship between sensitivity analysis and scenarios is best explained by the AER's practice note:[3]

> *Scenarios should be constructed to express a reasonable set of internally consistent possible future states of the world. Each scenario enables consideration of the prudent and efficient investment option (or set of options) that deliver the service levels required in that scenario at the most efficient long run service cost consistent with the National Electricity Objective (NEO).*
>
> *Sensitivity analysis enables understanding of which input values (variables) are the most determinant in selecting the preferred option (or set of options). By understanding the sensitivity of the options model to the input values a greater focus can be placed on refining and evidencing the key input values. Generally the more sensitive the model output is to a key input value, the more value there is in refining and evidencing the associated assumptions and choice of value.*
>
> *Scenario and sensitivity analyses should be used to demonstrate that the proposed solution is robust for a reasonable range of futures and for a reasonable range of positive and negative variations in key input assumptions. NSPs should explain the rationale for the selection of the key input assumptions and the variations applied to the analysis.*

In applying sensitivities and scenarios to our cost benefit assessment, we have regard to the particular circumstances to ensure that the approach is appropriate. Where our analysis shows that an option is clearly preferred, we will not undertake further testing. This approach is consistent with clause 5.17.1(c)(2) of the Rules, which states that the RIT–D must not require a level of analysis that is disproportionate to the scale and likely impact of each credible option considered.

In preparing the RIT-D, we have also had regard to AEMO's 2021 Inputs, Assumptions and Scenarios Report and its 2022 Integrated System Plan (ISP). We note that the scenarios adopted by AEMO are focused particularly on the matters that are relevant to major transmission investments, rather than distribution investments of the type considered in this report. Accordingly, we have adopted an approach that is appropriate to the particular circumstances described in this report relating to the identified need and the credible options.

6.3. Key variables and assumptions

Table 6 below lists the key variables and assumptions applied in the economic assessment, which are essential inputs to our methodology described above. The table also sets out the upper and lower bounds of the range of forecasts adopted for each of these variables. As explained above, the lower bound and upper bound estimates are used to undertake sensitivity testing and scenario analysis. The detailed results of this modelling is provided in section 6.4.

Table 6: Key variables and assumptions ($M)

Variable / assumption	Lower bound	Central estimate	Upper bound
Demand forecasts	5% reduction in central estimate of annual growth rate	Average annual growth rate of 0.9%	5% increase in central estimate of annual growth rate
Cost of involuntary supply interruption	25% reduction in central estimate	Value of Customer Reliability (VCR) of $37,189 per MWh[4]	25% increase in central estimate
Safety cost	Central Estimate	Value of statistical life of $4.5 million[5]	Central estimate
Safety cost Disproportionate Factor	Central estimate	Factor of 3	Central estimate
Option cost	15% reduction in central estimate	In-house cost estimates using detailed and high-level project scopes	15% increase in central estimate

2 AER, Application guidelines, Regulatory investment test for distribution, December 2018, page 42.
3 AER, Asset replacement planning, January 2019, page 36.
4 Calculated using the latest VCR estimates for each sector, refer to model 'Inputs – Global' tab.
5 Best Practice Regulation Guidance Note Value of statistical life, December 2014, escalated, refer to model 'Inputs – Global' tab.

Variable / assumption	Lower bound	Central estimate	Upper bound
Real discount rate per annum[6]	2.0%	5.5%	7.5%
Probability of asset failure	25% reduction in central estimate	Historical asset performance data, plus forecasts based on condition monitoring and CBRM modelling	25% increase in central estimate

Source: TGN_V6.0_Economic_Model-Master_Template_22-06-22

6.4. Cost benefit analysis

The economic analysis presented below allows comparison of the economic cost and benefits of each option to rank the options and to determine the optimal timing of the preferred option. It quantifies the capital costs and the cost of the residual risk for each option, to determine a total cost for each option. The net economic benefit for each credible option is the total cost associated with that option minus the costs of the 'Business as Usual' option.

As each of the credible options involves the replacement of existing assets, we have assumed that the operating cost for each option is unchanged from the 'Business as Usual' option. For the purpose of this RIT-D, we consider this approach to be a reasonable working assumption. The capital cost for each option has been described in section 5 of this DPAR.

We present our analysis as follows:

- Section 6.4.1 presents the NPV analysis using central estimates; and
- Section 6.4.2 presents the sensitivity testing and scenarios analysis.

6.4.1. Present value analysis using central estimates

Table 7 presents the annualised net economic benefit of each credible option for each year and highlights the option with the highest net economic benefit, assuming the central estimates for the key variables presented in the previous section. For each option, we have selected the optimal timing or indicated for some options that the solution will not deliver a net benefit over the study period.

It should be noted that a residual risk-cost and benefit also applies for each option, which captures the costs and benefits beyond 2031. We have not shown the residual costs and benefits for each option in the table below, but it is considered in our PV analysis which is reported later in this section.

Table 7: Annualised net economic benefit ($M)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Option 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Option 2	This option is no longer considered credible, as explained in section 5.2.									
Option 3	This option is no longer considered credible, as explained in section 5.2.									
Option 4	This option is no longer considered credible, as explained in section 5.2.									
Option 5	0.000	0.000	0.000	0.053	0.109	0.168	0.228	0.291	0.354	0.418
Option 6	0.000	0.046	0.111	0.179	0.249	0.322	0.397	0.475	0.553	0.633
Option 7	0.000	0.000	0.034	0.122	0.216	0.319	0.431	0.553	0.683	0.824
Option 8	0.000	0.095	0.178	0.266	0.360	0.463	0.574	0.696	0.825	0.966

Source: TGN_V6.0_Economic_Model-Master_Template_22-06-22

6 The discount rates are consistent with AEMO's 2021 Inputs, Assumptions and Scenarios Report.

As explained in the table above, Options 2, 3 and 4 are no longer considered to be credible options and are not considered further in this RIT-D assessment. Of the remaining options, Option 8 provides greater net benefits in each year to 2031.

While the above table is useful in understanding how the options compare with one another in the early years following their implementation, the analysis required by the RIT-D must consider the relative performance of the credible options over the life of the asset. Accordingly, the following table shows that the present values for each option over its life, using our central estimates, based on the optimal timing for each option.

Table 8: Net economic benefit ($M)

	PV of risk reduction Benefit	PV of Option costs	PV of net economic benefit
Option 1	0.0	0.0	0.0
Option 2		Not a credible option	
Option 3		Not a credible option	
Option 4		Not a credible option	
Option 5	$14.70	$9.82	$4.88
Option 6	$20.18	$12.37	$7.81
Option 7	$24.78	$15.16	$9.63
Option 8	$25.66	$13.81	$11.85

Source: TGN_V6.0_Economic_Model-Master_Template_22-06-22

The present value analysis shown in

Table 8 shows that Option 8 is preferred to the remaining credible options and the 'Business as Usual' option because it delivers the highest expected net benefit over the expected life of the investment, based on our central estimates.

6.4.2. Sensitivity testing and scenario analysis

As explained in section 6.2, we undertake sensitivity testing to examine how the net benefit for each option would be affected if certain parameters were varied. In this instance, we considered variations in the risk of asset failure; demand; the cost of each option; and the discount rate. The results of this analysis is presented below.

Table 9: Net benefit - sensitivity testing ($M)

	High asset failure	Low asset failure	High demand	Low demand	High option cost	Low option cost	High discount rate	Low discount rate
Option 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Option 2				Not a credible option				
Option 3				Not a credible option				
Option 4				Not a credible option				
Option 5	13.10	-1.53	5.40	4.37	3.41	6.36	1.34	10.86
Option 6	19.10	-0.99	8.41	7.21	5.95	9.66	2.86	15.81
Option 7	25.33	-1.68	12.09	7.78	7.35	11.90	3.50	19.75
Option 8	28.06	0.16	14.36	9.97	9.78	13.92	6.08	21.50

Source: TGN_V6.0_Economic_Model-Master_Template_22-06-22

The sensitivity analysis shows that Option 8 delivers the highest net benefit for each sensitivity. This finding provides a high level of confidence that Option 8 should be preferred. Nevertheless, we have conducted scenario analysis to test this proposition.

Table 10: Definition of reasonable scenarios

Scenario	Probability of failure	Option Cost	Forecast Demand	VCR	Discount rate
Central Case	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate
Low demand	Central estimate	Central estimate	Lower bound	Central estimate	Central estimate
Weak economic growth	Central estimate	Lower bound	Lower bound	Central estimate	Lower bound
High demand	Central estimate	Upper bound	Upper bound	Central estimate	Upper bound

Table 11 below provides a brief description of each scenario.

Table 11: Guide to scenarios

Scenario	Description
Central Case	This scenario adopts the central estimate for each variable in the economic assessment. It represents the most likely outcome.
Low demand	This scenario represents low demand driven by an increase in distributed energy resources. We have retained the other parameters at their central estimates, noting that the scenario is not driven by weak economic growth.
Weak economic growth	This scenario reflects weak economic growth, possibly as a result of the continuing impact of COVID-19. It has lower costs of delivering the option, lower demand and a lower discount rate
High demand	This scenario represents an economic rebound and continuing supply side issues. It is characterised by higher costs of delivering the option, higher demand and an upper bound discount rate.

Table 12: Net benefit for each scenario ($M)

	Central case	Low demand	Weak economic growth	High demand
Option 1	0.0	0.0	0.0	0.0
Option 2	Not a credible option			
Option 3	Not a credible option			
Option 4	Not a credible option			
Option 5	4.88	4.37	11.65	0.30
Option 6	7.81	7.21	16.84	1.46
Option 7	9.63	7.78	19.39	3.06
Option 8	11.85	9.97	20.97	5.94

Source: TGN_V6.0_Economic_Model-Master_Template_22-06-22

On the basis of this scenario analysis, Option 8 is preferred to the other options, as it delivers a higher net economic benefit across all four scenarios.

6.5. Preferred option

The results of our cost benefit analysis is that Option 8 is the preferred option, which involves the following works:

In stage 1, the deteriorated No.2 and No.3 transformers will be replaced with new 20/33 MVA units and the 66kV bus will be fully switched to further improve reliability. In stage-2, the outdoor 22kV switchgear will be replaced with a new indoor 22kV switchboard, which would be scheduled for implementation around 5-10 years after stage 1, which is currently planned for completion in 2023/24.

The total capital cost of this option is $16.70 million (real $2022).

This option is expected to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

6.6. Capital and operating costs of the preferred option

The direct capital expenditure for stage 1 is $8.85 million (real $2022) and $7.44 million (real $2022) for stage 2, excluding management reserve and capitalised overheads, as shown in the table below.

Table 13: Summary of capital expenditure requirements – Stage 1, $2022

	PROJECT EXPENDITURE FORECASTS	2021/22	2022/23	2023/24	2024/25	2025/26	TOTAL
1	DESIGN	$0	$700,000	$0	$0	$0	$700,000
2	INTERNAL LABOUR	$0	$208,475	$208,475	$0	$0	$416,950
3	MATERIALS	$0	$2,565,736	$0	$0	$0	$2,565,736
4	PLANT & EQUIPMENT	$0	$100,265	$200,530	$0	$0	$300,794
5	CONTRACTS	$0	$1,124,185	$2,248,370	$0	$0	$3,372,555
7	OTHER - RISK ALLOWANCE	$0	$196,191	$196,191	$0	$0	$392,381
8	**PROJECT DIRECT EXPENDITURE P(50)**	**$0**	**$4,894,852**	**$2,853,566**	**$0**	**$0**	**$7,748,417**
9	OVERHEADS	$0	$484,590	$282,503	$0	$0	$767,093.33
10	FINANCE CHARGES (IDC)	$0	$117,288	$219,832	$0	$0	$337,119.95
11	PROJECT DIRECT EXPENDITURE (SAP)	$0	$5,496,730	$3,355,901	$0	$0	$8,852,631
12	MANAGEMENT RESERVE [P(90)-P(50)]						$210,495
13	**TOTAL EXPENDITURE FOR APPROVAL (Including P(90) Risk)**	**$0**	**$5,496,730**	**$3,355,901**	**$0**	**$0**	**$9,063,125.30**

Source: AusNet Services.

In relation to the timetable for completing the Stage 1 works, we expect to publish FPAR in October 2022, allowing the construction to commence for stage-1 from November 2022 onwards with commissioning readiness scheduled for December 2024. Stage-1 of the project is expected to reach completion by March 2025.

Stage-2 construction works are scheduled to commence by April 2029 and stage-2 is expected to reach completion by March 2030.

Table 14: Summary of capital expenditure requirements – Stage 2, $2022

	PROJECT EXPENDITURE FORECASTS	2025/26	2026/27	2027/28	2028/29	2029/30	TOTAL
1	DESIGN	$0	$0	$0	$470,000	$0	$470,000
2	INTERNAL LABOUR	$0	$0	$0	$171,312	$269,204	$440,516
3	MATERIALS	$0	$0	$0	$2,272,482	$0	$2,272,482
4	PLANT & EQUIPMENT	$0	$0	$0	$28,885	$144,425	$173,310
5	CONTRACTS	$0	$0	$0	$466,733	$2,333,663	$2,800,396
7	OTHER - RISK ALLOWANCE	$0	$0	$0	$135,479	$212,896	$348,376
8	**PROJECT DIRECT EXPENDITURE P(50)**	**$0**	**$0**	**$0**	**$3,544,890**	**$2,960,188**	**$6,505,079**
9	OVERHEADS	$0	$0	$0	$350,944	$293,059	$644,002.79
10	FINANCE CHARGES (IDC)	$0	$0	$0	$70,627	$218,132	$288,758.82
11	PROJECT DIRECT EXPENDITURE (SAP)	$0	$0	$0	$3,966,462	$3,471,379	$7,437,840
12	MANAGEMENT RESERVE [P(90)-P(50)]						$202,446
13	**TOTAL EXPENDITURE FOR APPROVAL (Including P(90) Risk)**	**$0**	**$0**	**$0**	**$3,966,462**	**$3,471,379**	**$7,640,286.71**

Source: AusNet Services.

The operating expenditure associated with this option will relate to the on-going inspection and maintenance of the assets. Our assessment is that a reasonable estimate of the annual operating expenditure is approximately 1.2% of the direct capital cost of the asset, which equates to approximately $200k per annum.

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7. Satisfaction of the RIT-D

In accordance with clause 5.17.4(j)(11)(iv) of the NER, we certify that the proposed option satisfies the regulatory investment test for distribution. The table below shows how each of these requirements have been met by the relevant section of this report.

Table 15: Compliance with regulatory requirements

Requirement			Section
5.17.4(j) The draft project assessment report must include the following:			
(1)		a description of the identified need for the investment;	Section 3.
(2)		the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary);	Section 4.
(3)		if applicable, a summary of, and commentary on, the submissions on the non-network options report;	No submissions were received.
(4)		a description of each credible option assessed;	Section 5.
(5)		where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option;	Section 6.4.
(6)		a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	Sections 5 and 6.4.
(7)		a detailed description of the methodologies used in quantifying each class of cost and market benefit;	Section 6.2.
(8)		where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option;	Section 6.1.
(9)		the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Section 6.4.
(10)		the identification of the proposed preferred option;	Section 1.1 and 6.5.
(11)		for the proposed preferred option, the RIT-D proponent must provide:	
	(i)	details of the technical characteristics;	Appendix.
	(ii)	the estimated construction timetable and commissioning date (where relevant);	Section 6.6.
	(iii)	the indicative capital and operating cost (where relevant);	Section 6.6.
	(iv)	a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and	Section 7, including this table.
	(v)	if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent;	Not applicable.
(12)		contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	Section 1.3.

Requirement		Section
5.17.4(k)	The RIT-D proponent must publish a request for submissions on the matters set out in the draft project assessment report, including the proposed preferred option, from: (1) Registered Participants, AEMO, non-network providers and interested parties; and (2) if the RIT-D proponent is a Distribution Network Service Provider, persons on its demand side engagement register.	Section 1.3.
5.17.4(l)	If the proposed preferred option has the potential to, or is likely to, have an adverse impact on the quality of service experienced by consumers of electricity, including: (1) anticipated changes in voluntary load curtailment by consumers of electricity; or (2) anticipated changes in involuntary load shedding and customer interruptions caused by network outages, then the RIT-D proponent must consult directly with those affected customers in accordance with a process reasonably determined by the RIT-D proponent.	Not applicable.
5.17.4(m)	The consultation period on the draft project assessment report must not be less than six weeks from the publication of the report.	Section 1.3.

Appendix – Technical Characteristics

Scope of works

The scope is to design, procure, install, and commission all necessary primary, civil/structural, transmission lines and secondary equipment for Traralgon Zone Substation. Almost all major switchyard equipment are to be retired due to their poor condition upon completion the stage two of this scope. Below equipment is planned to be removed in two separate stages. These are:

Stage One:

- Two (2) 66/22kV 10/13.5 MVA Transformers (No.2 and No.3)
- One Cap Bank (No.4), 3×3 Mvar
- 66kV VT: Two (2) Sets
- 66kV ES and SA: Four (4) Sets each
- 66kV Under slung isolators only: Eight (8) Sets
- 66kV CBs and associated CTs: Two (2) Sets
- 66kV RDB: Two (2) Sets

Stage Two:

- One off 22kV cable head structure
- 22kV Switchyard connected to No.3 and No.2 Transformer includes Three insulated outdoor 22kV busbars, One Transfer bus, Eighteen (18) 22kV DS, Five (5) 22kV CBs, Four (4) 22kV CVT

One new 20/33 MVA transformer will replace two (2) retired transformers. The TGN ZSS 66kV arrangement is not a ring bus and is therefore more susceptible to bus faults impacting the station load. A new 66kV ring bus arrangement has been proposed upon completion of stage two (2) therefore new equipment will be installed at TGN ZSS as below respectively in two separate stages:

Stage One:

- One (1) 66/22kV 20/33 MVA Transformer (No.5)
- One Cap Bank, 3×3 Mvar
- 66kV transformer support structure: One (1) Set
- All required primary connections and associated earthing grid connections
- All required secondary control, protection, communications, and SCADA equipment, and associated secondary connections to complete the works
- Removal and disposal of redundant equipment and structures
- Reinstatement of switchyard areas to complete the works
- Noise and firewall engineering studies to be undertaken
- 66kV interplant connection
- 66kV CVT: Two (2) Sets
- 66kV ES and SA: Three (3) Sets each
- 66kV Under slung isolators: Ten (10) Sets
- 66kV DTCBs: Three (3) Sets
- 66kV RDB: Three (3) Sets
- 66kV Strung Bus support structures: Eight (8)
- Two new 66kV pole for MFA and MWTS line re-location

- All required primary connections and associated earthing grid connections
- 66kV interplant connection
- Removal and disposal of redundant equipment and structures
- One 22kV cable head pole

Stage Two:

- One (1) 22kV Urban modular switch room
- All required secondary control, protection, communications, and SCADA equipment, and associated secondary connections to complete the works
- Reinstatement of switchyard areas to complete the works
- Install 22kV Cable as follows:
  - from New Transformer (No.5) to New Switch room (No.2)
  - from No.1 Switchroom to No.2 Switch room (bus-tie)
- Benching and surfacing of new 22kV urban switch room
- Removal and disposal of redundant equipment and structures

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