


Regulatory Investment Test for Distribution (RIT-D)

Rockhampton Glenmore Network Limitation

Final Project Assessment Report

12 May 2022

Part of Energy Queensland

EXECUTIVE SUMMARY

About Ergon Energy

Ergon Energy Corporation Limited (Ergon Energy) is part of Energy Queensland and manages an electricity distribution network which supplies electricity to more than 765,000 customers. Our vast operating area covers over one million square kilometres (around 97% of the state of Queensland) from the expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

Our electricity network consists of approximately 160,000 kilometres of powerlines and one million power poles, along with associated infrastructure such as major substations and power transformers.

We also own and operate 33 stand-alone power stations that provide supply to isolated communities across Queensland which are not connected to the main electricity grid.

Identified Need

Rockhampton Glenmore 66/11kV substation (ROGL) is located on the northern banks of the Fitzroy River, about 2km north of Rockhampton CBD. The substation is part of the Rockhampton 66kV sub-transmission network and takes supply from the adjacent T023 Rockhampton 132/66kV transmission substation. The 66kV bus at ROGL is the main of three (3) transmission connection points (TCPs) for the 66kV network that supplies 60,627 customers via 14 substations with a total peak load of around 200MVA, forecast to grow to around 220MVA in the next 10 years. The 66kV bus at ROGL forms a key central node in the meshed network, supplying around half of the load under system-normal network configuration. The 66/11kV transformers at ROGL supply 6,066 customers of which 84% are residential and 16% are commercial, with a peak load of approximately 20MVA.

ROGL was established circa 1966 to standards applicable at the time. There is a number of asset limitations affecting the ongoing reliable and safe operation of ROGL 66kV bus. A Substation Condition Assessment Report (SCAR) has identified primary and secondary assets at ROGL which have been deemed to reach their retirement age prior to 2028, these include:

- 66kV Voltage Transformers (VTs) (1 set),
- Protection Relays (PRs) (34),
- SACS RTUs (2).

The following assets have been identified as problematic:

- 66kV ASEA HLC Circuit Breakers (CBs) (6),
- 66kV Surge Arrestor (SA) Sets (4).

The following primary assets at ROGL have also been identified as inadequately rated for the existing 66kV fault current or are unmonitored capacitive voltage transformers (CVTs):

- 66kV Isolators (IS) (2),
- 66kV Current Transformers (CTs) (27 – 9 sets),
- 66kV Capacitive Voltage Transformers (unmonitored CVTs) (4).

There are also space limitations in around the 66kV bus which present clearance risks when performing construction and maintenance.

The majority of the identified plant is on the single 66kV bus and its protection schemes at ROGL. For an outage to this bus, the remaining network can supply up to 148MVA leaving approximately 50MVA at risk, forecast to grow to 70MVA in the next 10 years. Under the same outage, the entire 11kV load at ROGL of up to 20MVA is interrupted.

Approach

The National Electricity Rules (NER) require that, subject to certain exclusion criteria, network business investments for meeting service standards for a distribution business are subject to a Regulatory Investment Test for Distribution (RIT-D). Ergon Energy has determined that network investment is essential in this case for it to continue to provide electricity to the consumers in the Rockhampton supply area in a reliable, safe, and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

Ergon Energy published a Notice of no non-network options for the above-described identified need on 28 September 2021.

One potentially feasible option has been investigated:

- **Option A:** Replace Aged and Poor Condition Assets at ROGL.

This Final Project Assessment Report (FPAR), where Ergon Energy provides both technical and economic information about possible solutions, has been prepared in accordance with the requirements of clause 5.17.4(o) of the NER.

Ergon Energy's preferred solution to address the identified need is Option A – Replace Aged and Poor Condition Assets at ROGL.

CONTENTS

1 INTRODUCTION

This Final Project Assessment Report has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(o) of the NER.

This report represents the final stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need for the Rockhampton Glenmore bulk network area.

In preparing this RIT-D, Ergon Energy is required to consider reasonable future scenarios. With respect to major customer loads and generation, Ergon Energy has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Ergon Energy is aware of are in different stages of progress and are subject to change (including outcomes where none or all proceed). These and other customer activity can occur over the consultation period and may change the timing and/or scope of any proposed solutions.

1.1 Structure of the Report

This report:

- Identifies the need which Ergon Energy is seeking to address, together with the assumptions used in identifying and quantifying that need.
- Quantifies costs and classes of material market benefits for each of the credible options.
- Describes the credible options that are considered in this RIT-D assessment.
- Describes the methods used in quantifying each class of market benefit.
- Provides details of classes of market benefits that are not considered material to this RIT-D assessment and provides explanations as to why these classes of market benefits are not considered material.
- Provides the results of Net Present Value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.

1.2 Dispute Resolution Process

In accordance with the provisions set out in clause 5.17.5(a) of the NER, Registered Participants or Interested Parties may, within 30 days after the publication of this report, dispute the conclusions made by Ergon Energy in this report with the Australian Energy Regulator. Accordingly, Registered Participants and Interested Parties who wish to dispute the conclusions outlined in this report based on a manifest error in the calculations or application of the RIT-D must do so within 30 days of the publication date of this report. Any parties raising a dispute are also required to notify Ergon Energy. Dispute notifications should be sent to demandmanagement@ergon.com.au

If no formal dispute is raised, Ergon Energy will proceed with the preferred option.

1.3 Contact Details

For further information and inquiries please contact:

E: demandmanagement@ergon.com.au
P: 13 74 66

2 BACKGROUND

2.1 Geographic Region

ROGL is located on the Northern banks of the Fitzroy River, approximately 2km North of Rockhampton CBD. The geographical location of ROGL in relation to Ergon Energy's sub-transmission network and other substations in the area is shown in Figure 1.

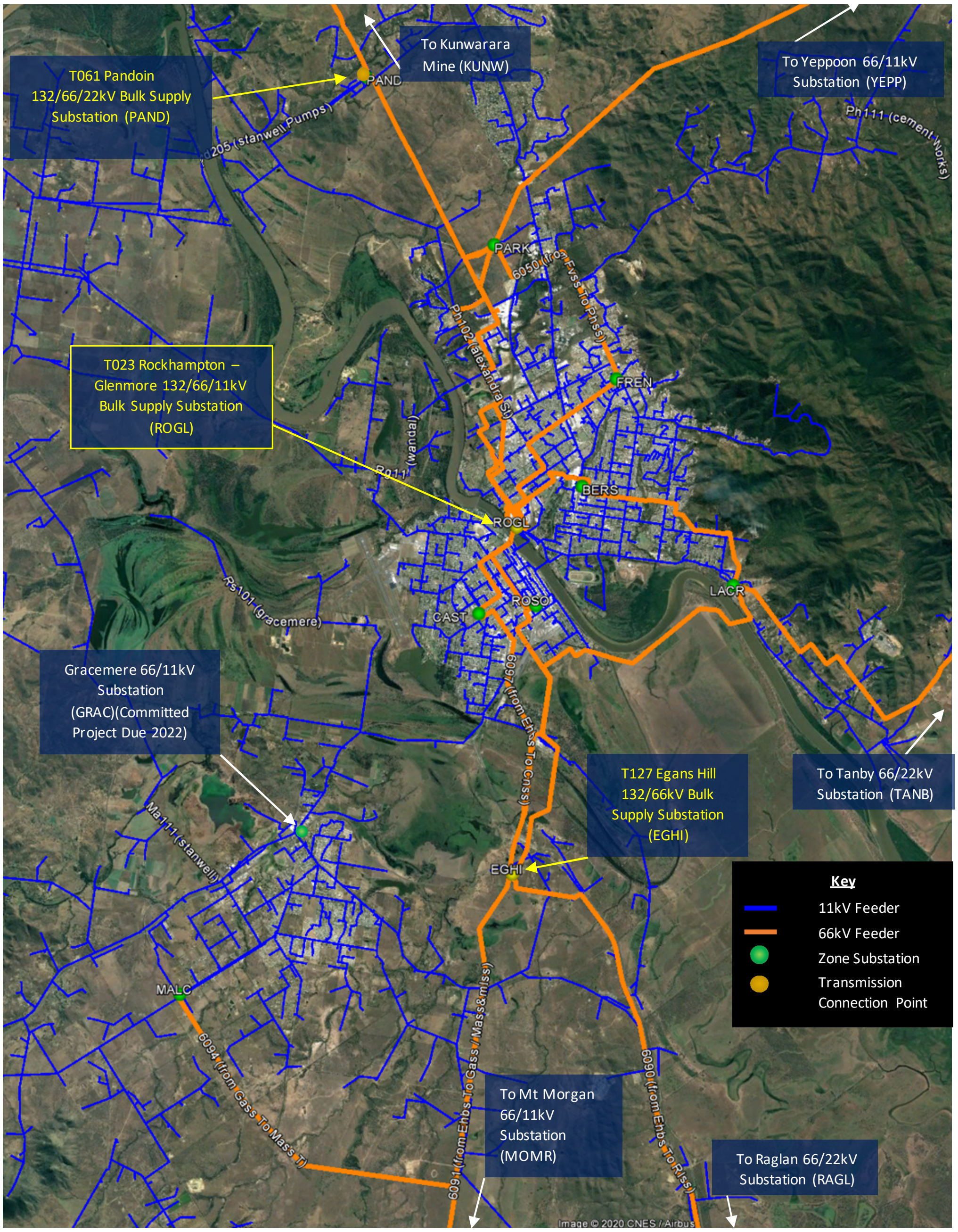

Figure 1: Existing network arrangement (geographic view)

2.2 Existing Supply System

ROGL is the main of three (3) transmission connection points (TCPs) for the Rockhampton area. The interconnecting 66kV network supplies a total of 60,627 customers via 14 substations with total peak load of approximately 200MVA. The TCP at ROGL is supplied from two (2) Powerlink owned 100MVA transformers at the adjacent T023 Rockhampton 132/66kV substation, and normally supplies around 100MVA of the peak load. Ergon Energy's 66kV network is meshed, with two other single transformer TCPs supplying it: one to the north with a single 100MVA transformer - T061 Pandoin (PAND), and one to the south with a single 80MVA transformer – T127 Egans Hill (EGHI).

A schematic view of the existing sub-transmission network arrangement is shown in Figure 2 below.

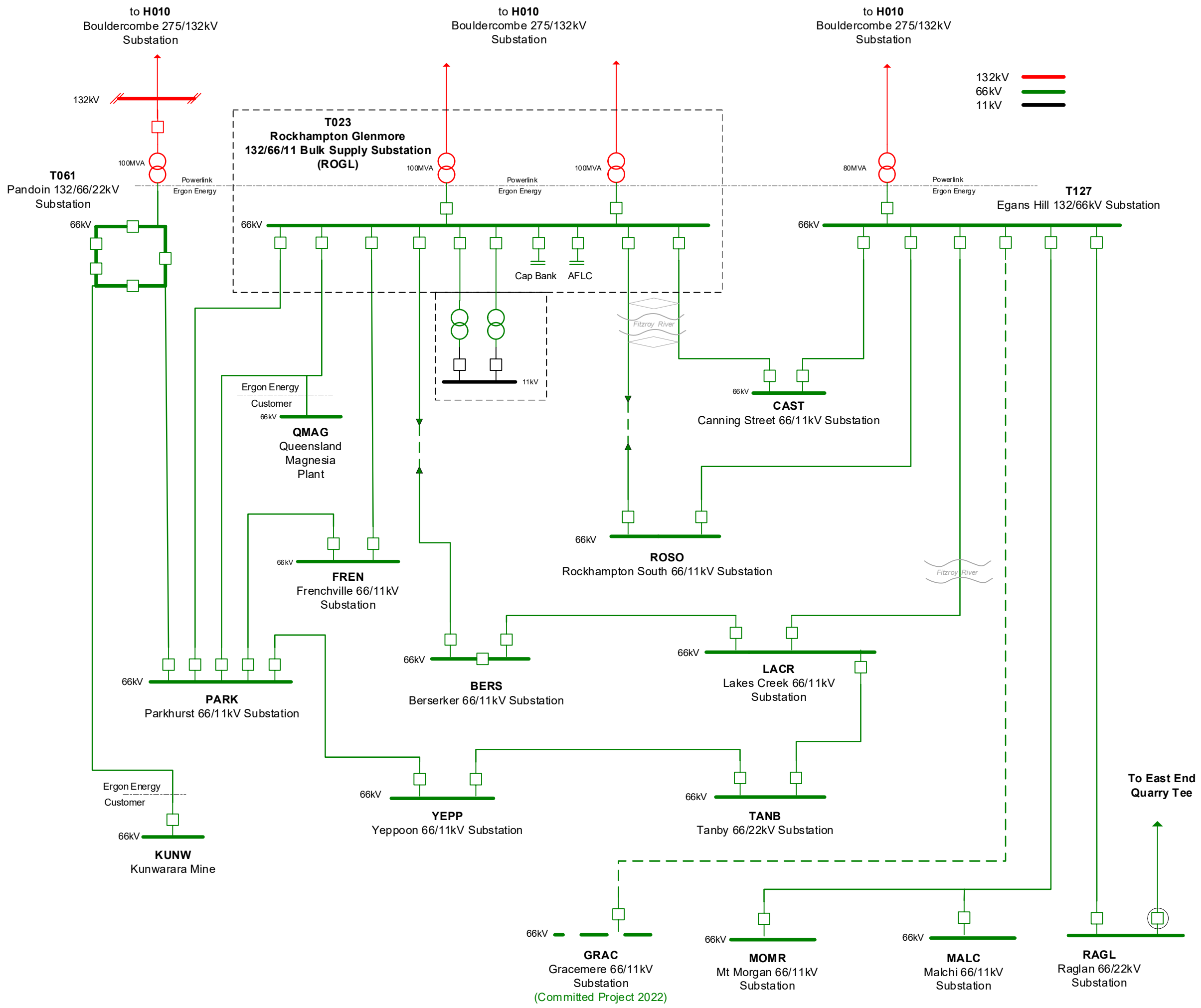

Figure 2: Existing area network arrangement (schematic view)

The 66kV bus at ROGL is a central node in the 66kV network and normally supplies around half of the network load. ROGL has two incoming 66kV bays from the two 100MVA 132/66kV Powerlink owned transformers, two (2) 20/25MVA 66/11kV transformers and six (6) 66kV feeders. It also has a 66kV 24MVAr capacitor bank and the 66kV AFLC injection unit that services load control signal to the entire Rockhampton area. The 66/11kV transformers at ROGL supply 6,066 customers of which 84% are residential and 16% are commercial, with a peak load of around 20MVA.

A schematic view of the existing substation is shown in Figure 3, with an aerial view of the substation in Figure 4.

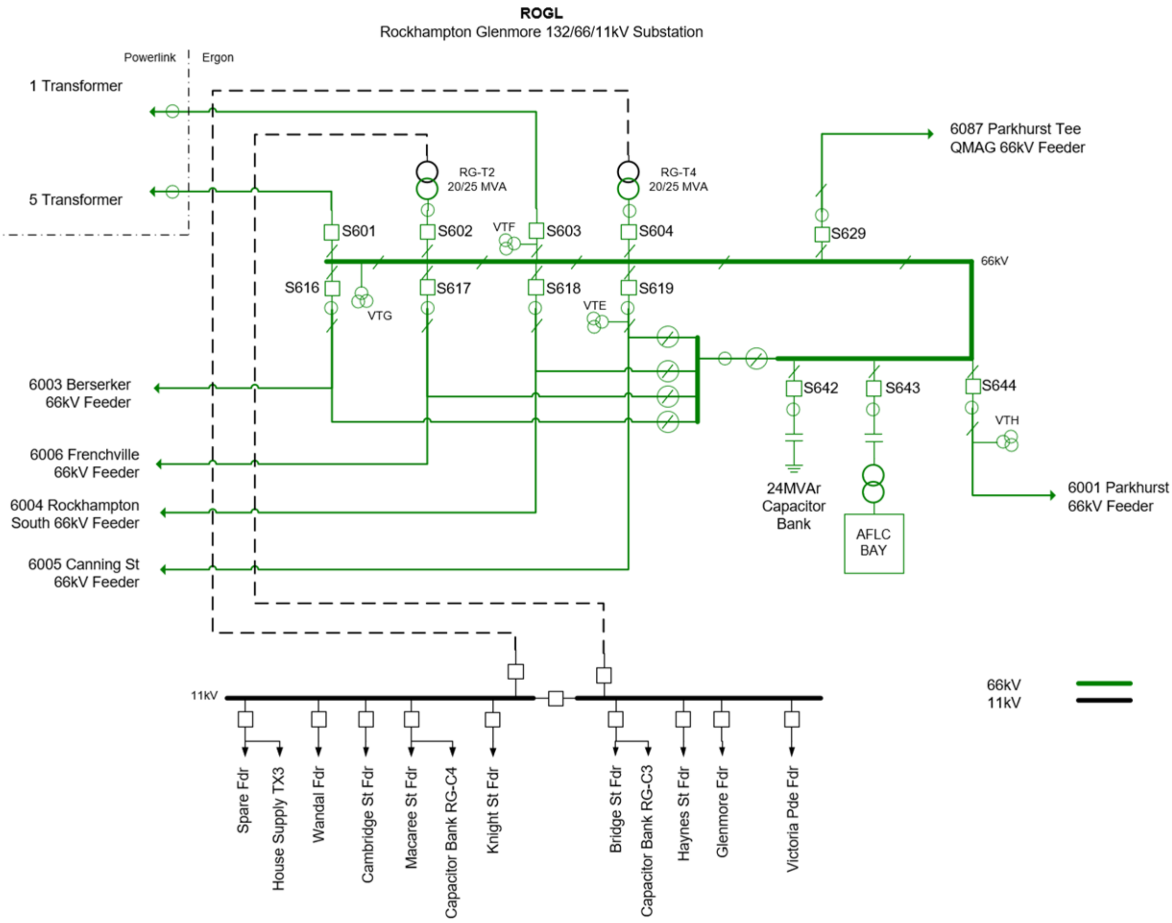

Figure 3: Existing ROGL (schematic view)

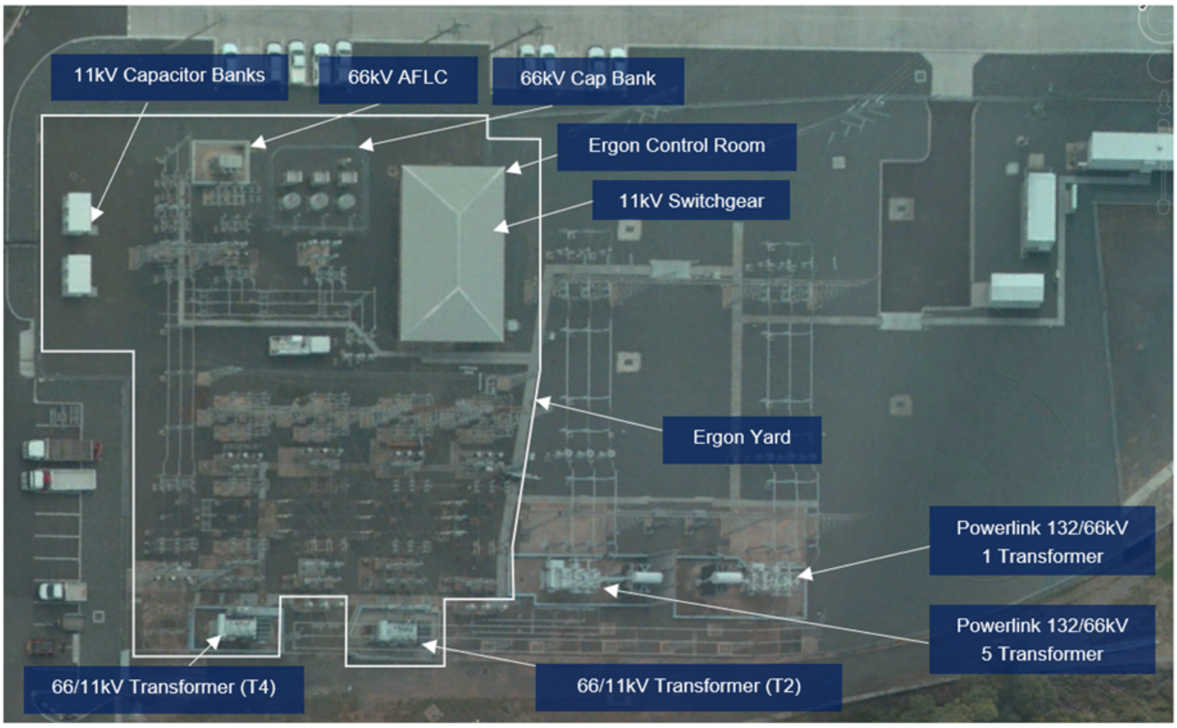

Figure 4: ROGL (Aerial View)

2.3 Load Profiles / Forecasts

ROGL is the main of three (3) transmission connection points (TCPs) for the Rockhampton area. The 66kV bus at ROGL supplies around half of the system load for the meshed Rockhampton 66kV network in system normal configuration. The load profiles and forecasts presented here are for the entire mesh load, compared to the system capacity for an outage to the 66kV bus at ROGL.

2.3.1 Full Annual Load Profile

The full annual load profile for the Rockhampton area 66kV meshed network over the 2020/21 financial year is shown in Figure 5. It can be noted that the peak load occurs during summer and exceeds N-1 capacity for a ROGL 66kV bus outage by around 50MVA. Note that this is forecast to grow to 70MVA in the next 10 years.

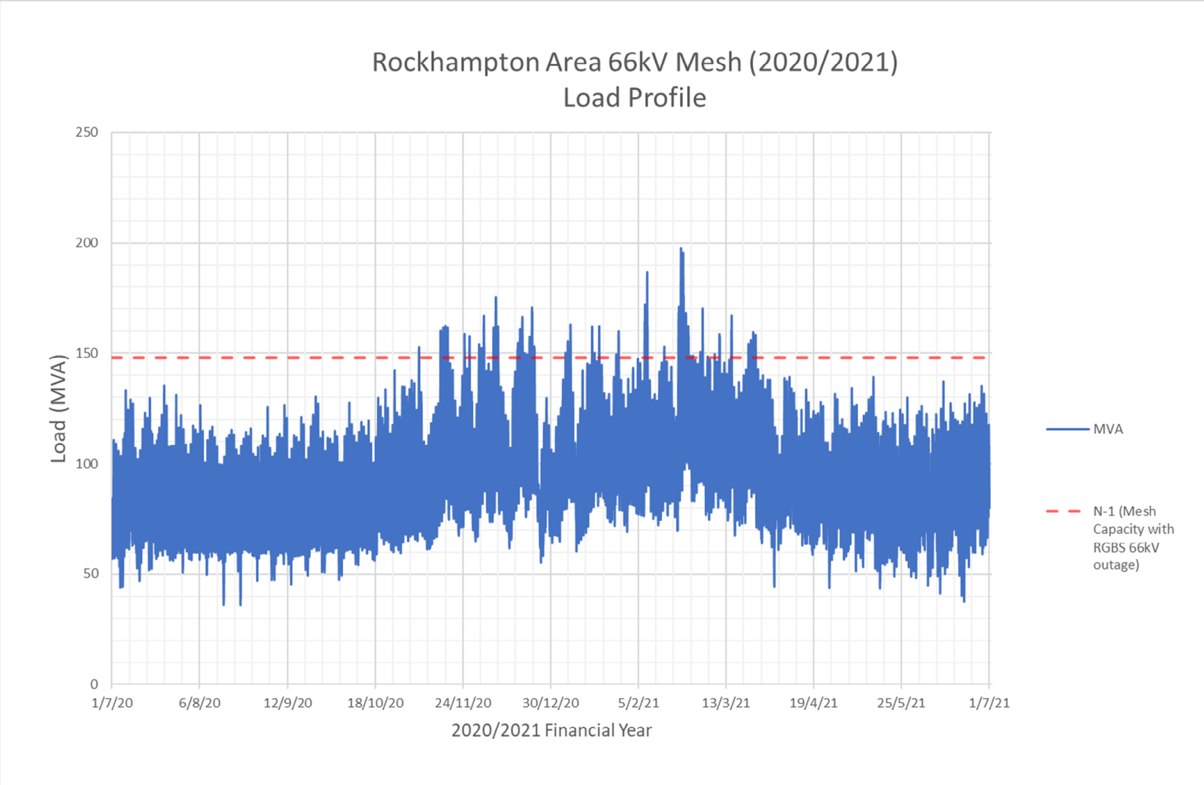

Figure 5: Rockhampton network actual annual load profile

2.3.2 Load Duration Curve

The load duration curve for the Rockhampton area 66kV meshed network over the 2020/2021 financial year is shown in Figure 6. The load exceeds N-1 capacity for a ROGL 66kV bus outage for 2% of the year, by up to 50MVA. Note that this is forecast to grow to 70MVA in the next 10 years.

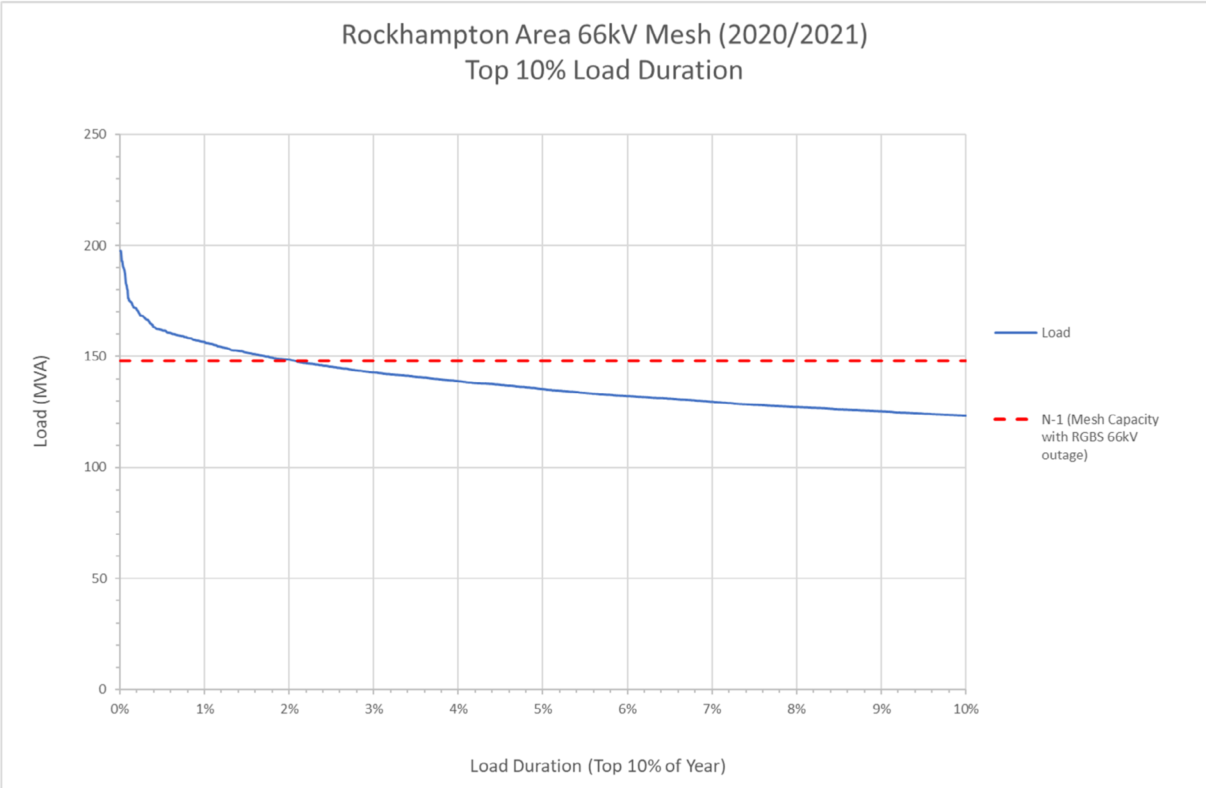

Figure 6: Rockhampton network load duration curve

2.3.3 Average and Peak Weekday Load Profile (Summer)

The daily load profile for the average and peak weekday during summer is illustrated below in Figure 7. The summer peak loads for the Rockhampton area 66kV meshed network are historically experienced in the late afternoon and evening.

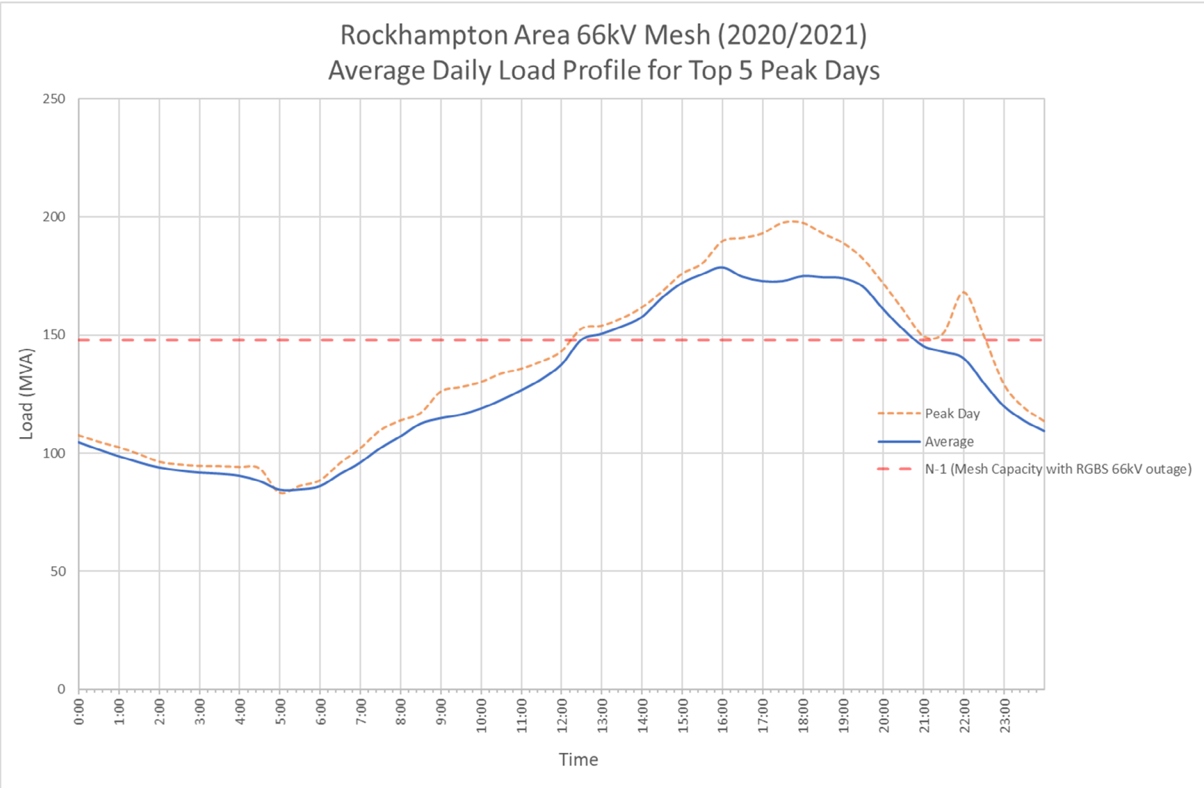

Figure 7: Network average and peak weekday load profile (Summer)

2.3.4 Base Case Load Forecast

The 10 PoE and 50 PoE load forecasts for the base case load growth scenario are illustrated in Figure 8. The historical peak load for the past five years has also been included in the graph.

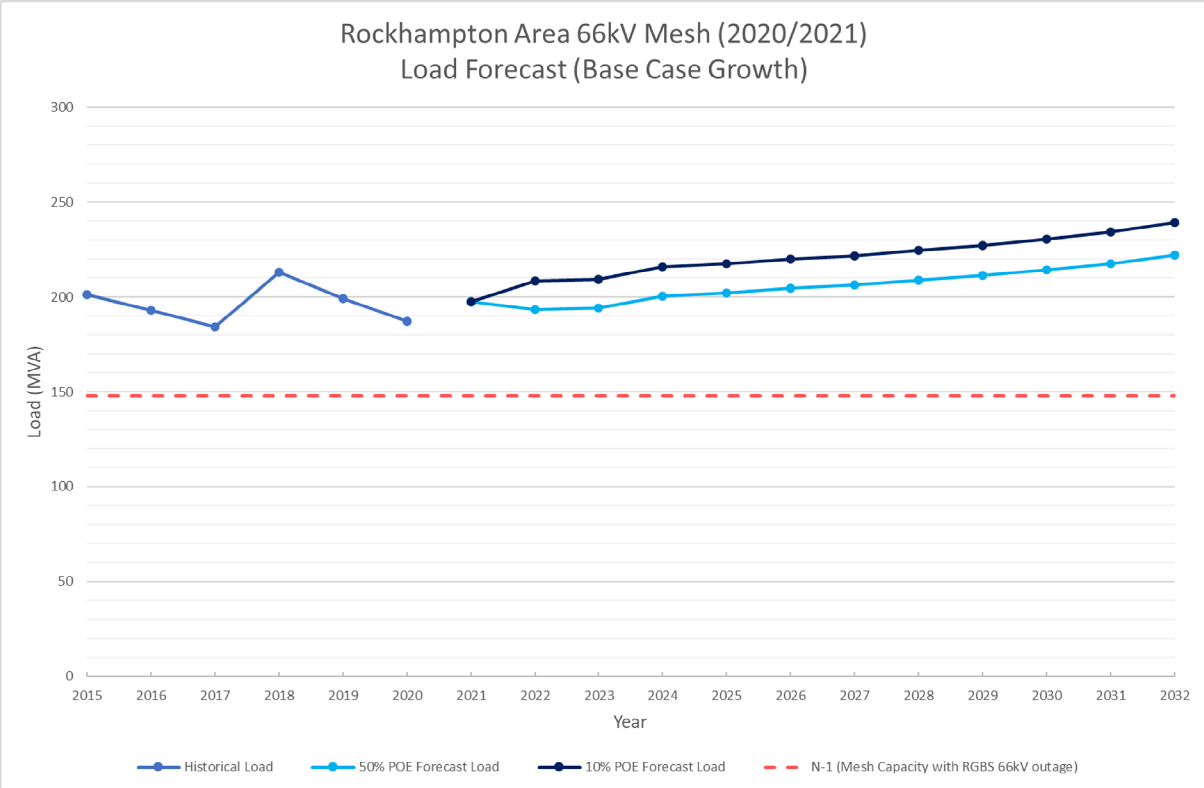

Figure 8: Network base case load forecast

2.3.5 High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the high load growth scenario are illustrated in Figure 9. With the high growth scenario, the peak load is forecast to increase over the next 10 years.

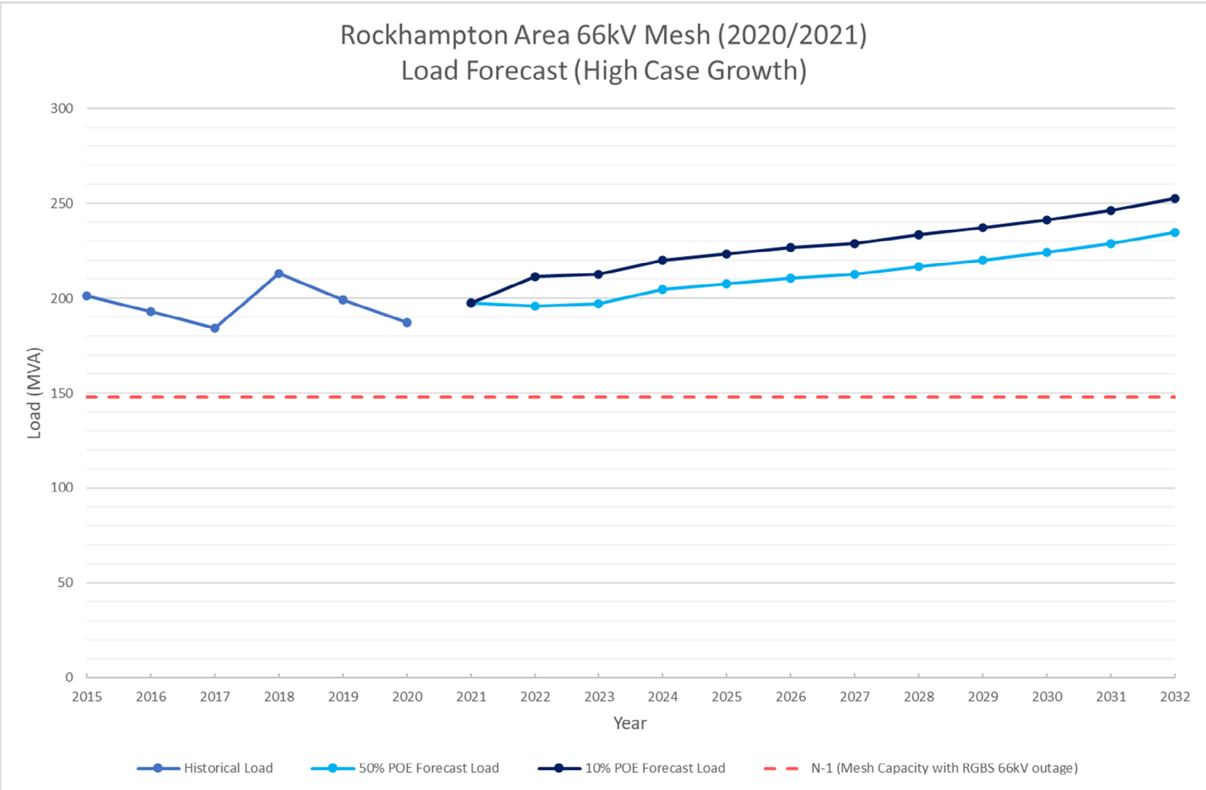

Figure 9: Network high growth load forecast

2.3.6 Low Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the low load growth scenario are illustrated in Figure 10. With the low growth scenario, the peak load is forecast to remain relatively steady over the next 10 years.

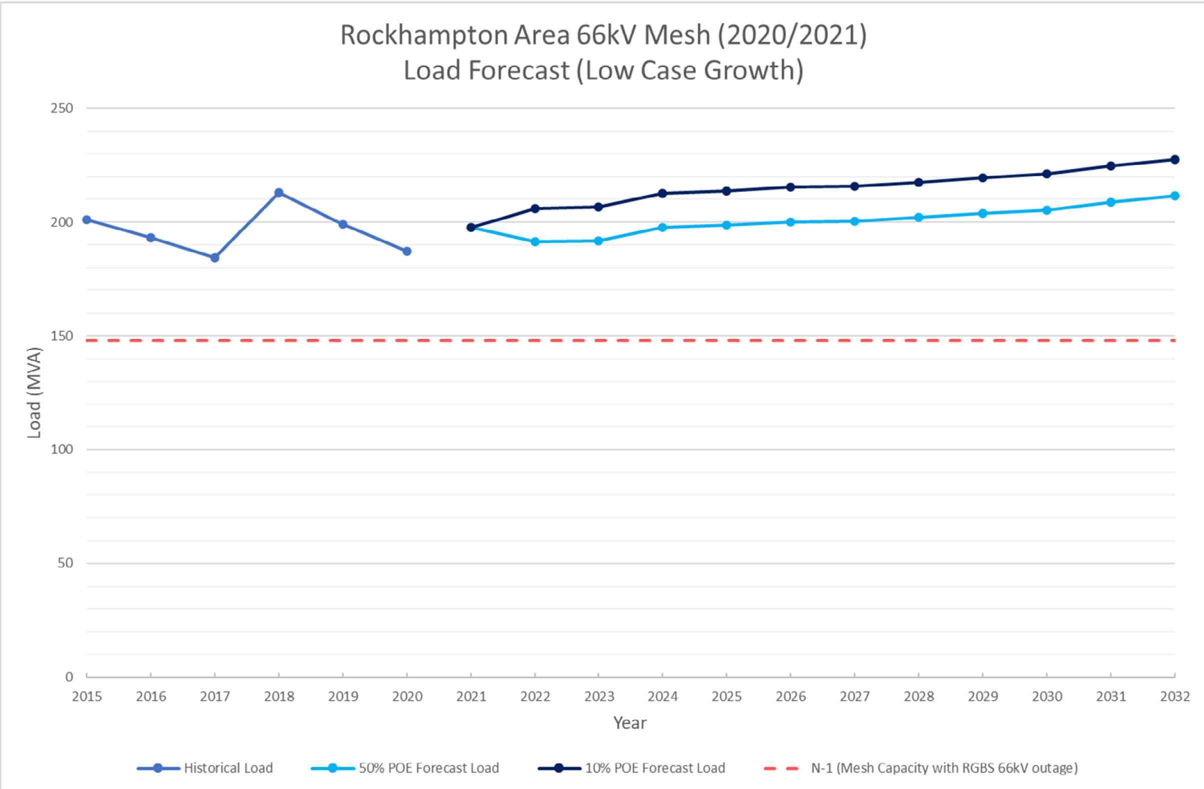

Figure 10: Network low growth load forecast

3 IDENTIFIED NEED

3.1 Description of the Identified Need

A recent condition assessment at ROGL has highlighted that a number of critical assets are at end of life and are in poor condition. The condition of these assets presents a considerable safety, environmental and reliability risk.

The Substation Condition Assessment Report (SCAR) has identified primary and secondary assets at ROGL which have been deemed to reach their retirement age prior to 2028, these include:

- 66kV Voltage Transformers (VTs) (1 set),
- Protection Relays (PRs) (34),
- SACS RTUs (2).

The following assets have been identified as problematic:

- 66kV ASEA HLC Circuit Breakers (CBs) (6),
- 66kV Surge Arrestor (SA) Sets (4).

The following primary assets at ROGL have also been identified as inadequately rated for the existing 66kV fault current or are unmonitored capacitive voltage transformers (CVTs):

- 66kV Isolators (IS) (2),
- 66kV Current Transformers (CTs) (27 – 9 sets),
- 66kV Capacitive Voltage Transformers (unmonitored CVTs) (4).

There are also space limitations in around the 66kV bus which present clearance risks when performing construction and maintenance.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard. It also poses a safety risk to the general public, through the increased likelihood of protection relay mal operation. Without remediation, Ergon Energy views that the safety risk to the public and its staff to not be reduced So Far As Is Reasonably Practicable.

Additionally, the poor condition of these assets significantly increases the likelihood of outages, resulting in a reduction in the level of reliability experienced by the customers supplied directly from ROGL substation and the broader Rockhampton area subtransmission network.

The majority of the identified plant is on the single 66kV bus and its protection schemes at ROGL. For an outage to this 132/66kV injection point, the remaining subtransmission network can supply up to 148MVA of 200MVA load leaving approximately 52MVA at risk, forecast to grow to 70MVA in the next 10 years. Under the same outage, the entire 11kV load at ROGL of up to 20MVA is interrupted until transfers can be operated via the 11kV network.

Furthermore, the Audio Frequency Load Control (AFLC) injection unit for the entire Rockhampton Region is connected to the 66kV bus at ROGL, so demand reduction via AFLC load control is lost for a 66kV bus contingency at ROGL.

3.2 Quantification of the Identified Need

3.2.1 Aged and Poor Condition Assets

A recent condition assessment has highlighted that a number of critical assets are at end of life and are in poor condition. The condition of these assets presents a considerable safety, environmental and reliability risk.

Condition data indicates that multiple 66kV CBs, CTs and VTs and most of the protection relays are either known problematic type or reaching end of life.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard. It also poses a safety risk to the general public, through the increased likelihood of protection relay mal-operation and failure of the circuit breakers. Additionally, the poor condition of these assets significantly increases the likelihood of outages, resulting in a reduction in the level of reliability experienced by the customers supplied from ROGL.

Where Ergon Energy identifies an imminent asset safety risk, immediate temporary measures are put in place to ensure safety of staff and public until permanent remediation can be performed.

3.2.2 Risk Quantification Benefit Summary

The majority of the identified plant is on the single 66kV bus and its protection schemes at ROGL. For an outage to this bus, 200MVA of a total of 380MVA of bulk supply transformer capacity is lost, and a central node in the Rockhampton meshed 66kV network is taken out of service.

For a single bus outage at ROGL the remaining meshed network can only supply up to 148MVA before interconnecting lines are overloaded. This leaves approximately 50MVA load at risk, forecast to grow to 70MVA in the next 10 years. Under the same outage, the entire 11kV load supplied from ROGL is interrupted until 11kV transfers are enacted.

Risk quantification analysis has been completed for Option A which includes the Value of Customer Reliability (VCR), safety risks, and cost of emergency replacement (ERC). Figure 11 shows the benefits of Option A in comparison to the counter-factual, which in this case is continuing the use of the existing circuit breakers. (Note that initial negative benefits are due to infant failure rates assumed in standard failure rate curves).

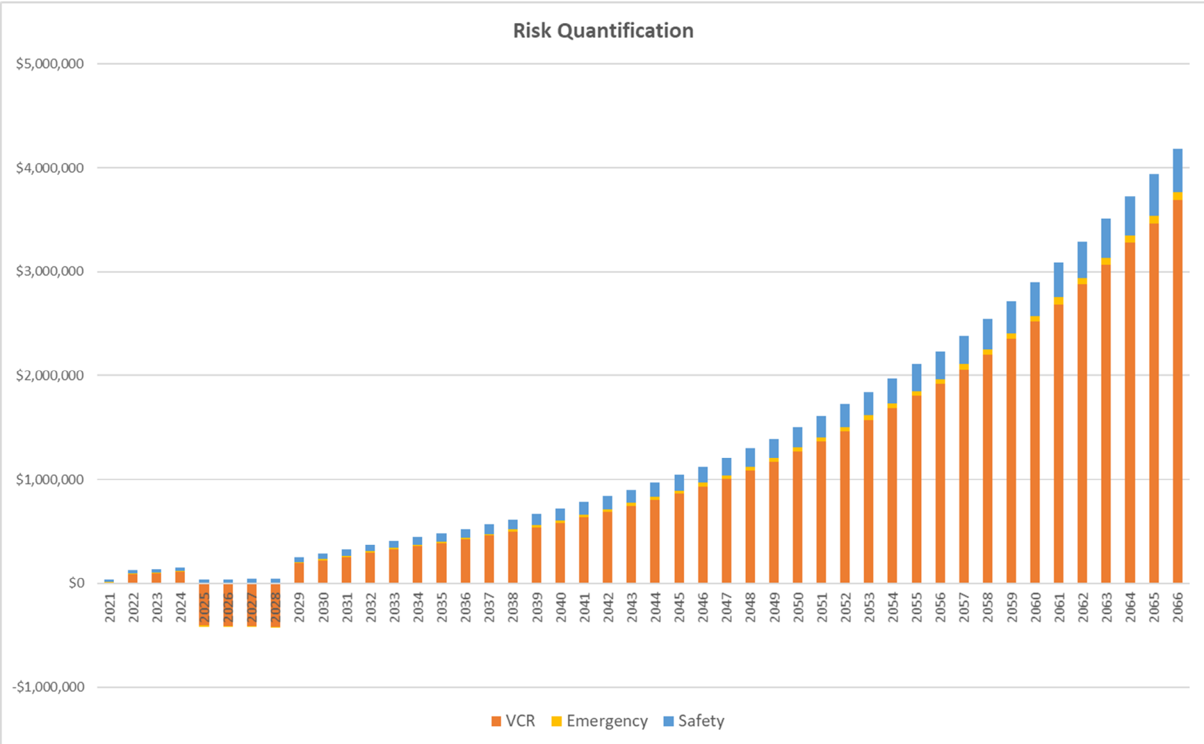

Figure 11 Estimated annualised benefits of Option A

The VCR component of the plot above shows the estimated increase in the cost of unserved energy over the assessment period associated with deteriorating asset condition at ROGL if no credible option is commissioned.

Note that the cost of unserved energy over the assessment period has been based on an uninflated VCR rate of $38.2/kWh for 66kV general network load, and $34.0/kWh for ROGL 11kV loads.

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3.3 Assumptions in Relation to Identified Need

Below is a summary of key assumptions that have been made when the identified need has been analysed and quantified.

It is recognised that the below assumptions may prove to have various levels of correctness, and they merely represent a 'best endeavours' approach to predict the future identified need.

3.3.1 Forecast Maximum Demand

It has been assumed that forecast peak demand at ROGL will be consistent with the base case forecast outlined in Section 2.3.

Factors that have been taken into account when the load forecast has been developed include the following:

- load history;
- known future developments (new major customers, network augmentation, etc.);
- temperature corrected start values (historical peak demands); and
- forecast growth rates for organic growth.

3.3.2 Load Profile

Characteristic peak day load profiles shown in Section 2.3 are unlikely to change significantly from year to year and the shape of the load profile is assumed to remain virtually the same with increasing maximum demand.

4 SUMMARY OF SUBMISSIONS RECEIVED

There was no consultation period required under the RIT-D process. A Notice of no non-network options was published 28 September 2021 as Ergon Energy did not identify any credible non-network solutions. A Draft Project Assessment Report (DPAR) and a consultation period was not required under the RIT-D process as the identified network option estimated cost was less than the applicable threshold.

5 CREDIBLE OPTIONS ASSESSED

5.1 Assessment of Network Solutions

Ergon Energy has identified one (1) credible network option that will address the identified need.

5.1.1 Option A: Replace Aged and Poor Condition Assets as ROGL

This option involves primary plant, secondary systems, remote end protection, and substation security works.

Substation works at ROGL are summarised as follows:

- Recover the 66kV strung transfer bus, structures, foundations, and isolators to provide the physical area required to reduce the clearance risks presented by replacement of the aged assets at this site in line with safety in design principles.
- Replacement of end-of-life assets in T1 and T5 incoming bays, Berserker, Frenchville, QMAG TEE, Parkhurst, Canning Street, T2 and T4 bays in situ.
- Build 1 new bay opposite the QMAG TEE feeder, relocate Canning Street feeder to this new bay and Rockhampton South to the previously Canning Street feeder bay.
- Connect the 66kV buses via a new 66kV cable.
- Replace protection relays on the 66kV bus zone, local and remote ends of the 66kV Rockhampton South feeder, remote end only of the Canning feeder, local end only of the QMAG Tee, Berserker, Parkhurst and Frenchville feeders, 66kV capacitor bank, 66kV load control, transformers 2 and 4 and 11kV bus protection to the latest protection standards in situ.
- Duplicate AC and DC systems replace aged SACS SCADA system, and upgrade site security to the requirements outlined in STNW3039.

Figure 12 provides geographic arrangement for Option A.

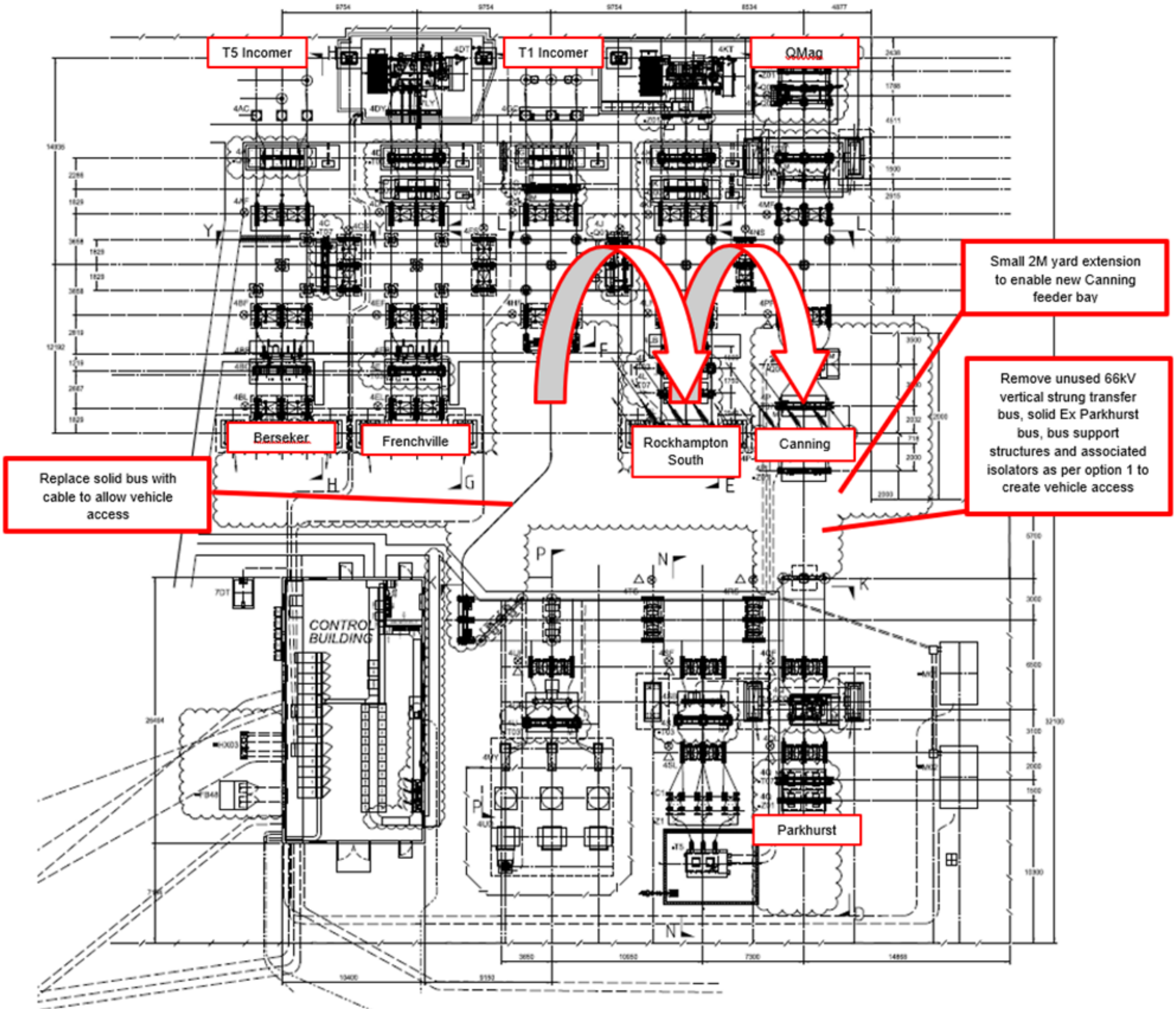


Figure 12: Proposed network arrangement – Option A (geographic arrangement)

Figure 13 shows a schematic highlighting the primary plant identified for replacement.

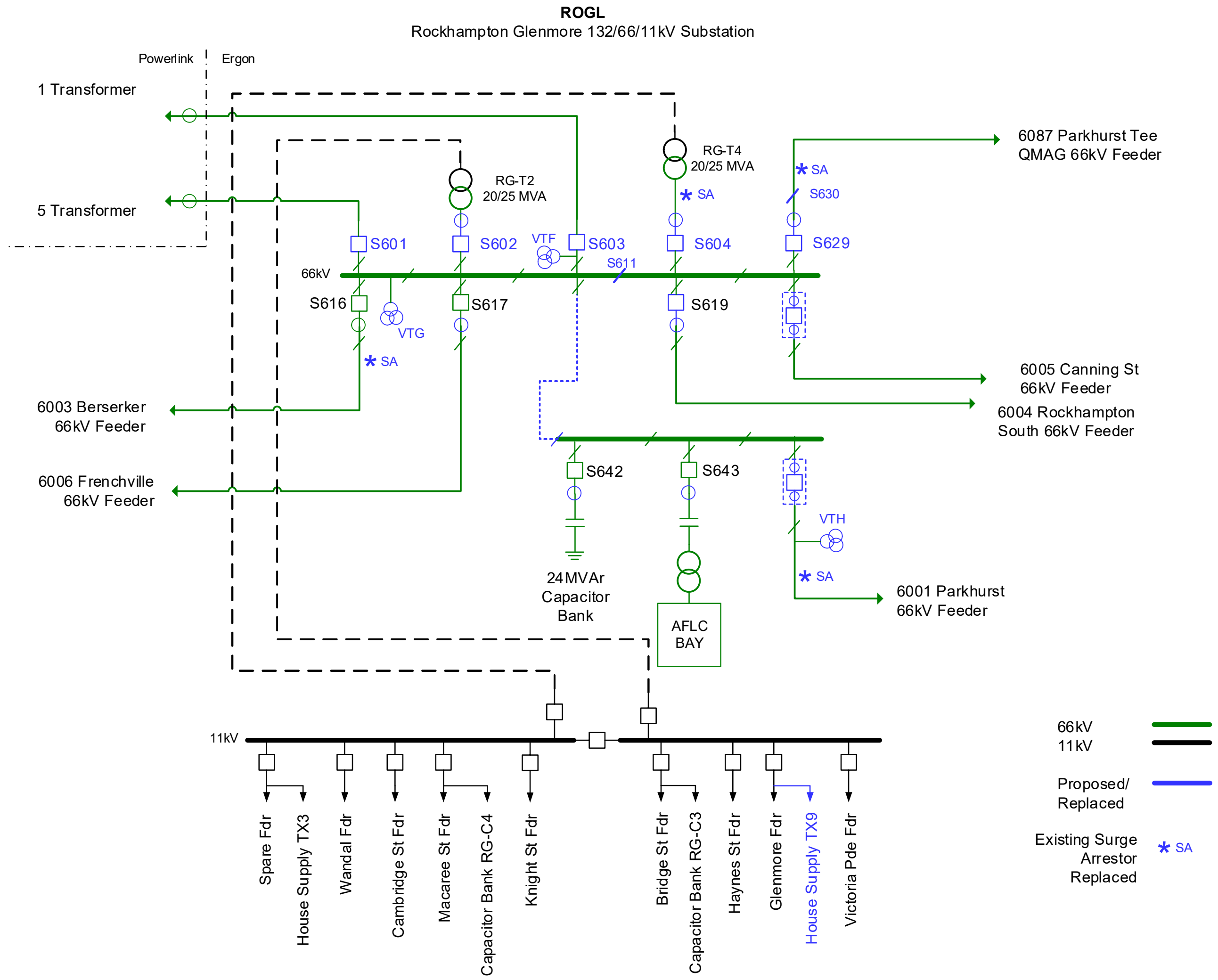


Figure 13: Option A proposed network arrangement

5.2 Assessment of Non-Network Solutions

A Notice of no non-network options was published as Ergon Energy did not identify any credible non-network solutions.

Ergon Energy has not identified any viable non-network solutions internally that will provide a complete or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Rockhampton area to address the identified need.

Ergon Energy has assessed the potential non-network alternative options required to defer the network option and determine if there is a viable option to replace or reduce the need for the network options proposed.

Credible options must be technically and commercially viable and must be able to be implemented in sufficient time to satisfy the identified risk to the public and/or the network due to the identified constraints.

Once the aged, identified 66kV assets at ROGL reach their retirement age and can no longer be safely operated, 50-70MVA of existing load would need to be supplied via non-network alternative solutions while satisfying the Service Safety Net Targets as specified in the Distribution Authority issued to Ergon Energy.

It is considered that no available demand management products or strategies can provide sufficient demand support at ROGL to address the identified need. It is evident that an economically feasible non-network option would not be available to defer or eliminate the requirement to replace the aged 66kV outdoor buses/switchgear at ROGL with and continue to provide a safe, sufficient, and reliable supply to customers in the Rockhampton Area.

Demand Management (Demand Reduction)

A non-network investigation Ergon Energy normally undertakes is to assess the potential of Demand and Energy Management (DEM). However, for this project to be deferred, the 66kV load would need to be reduced approximately 70MVA, therefore demand reduction through demand management is not economically comparable to the network option.

Network Load Control

The Audio Frequency Load Control (AFLC) injection unit for the entire Rockhampton Region is connected to the 66kV bus at ROGL, so the control mechanism for load control is lost for the contingency under consideration, i.e. an outage to the 66kV bus.

Demand Response

Four methods utilising demand response technology for deferring network investment are: Call Off Load (COL), Customer Embedded Generation (CEG), Large Scale Customer Generation (LSG) and customer solar power systems.

Customer Call Off Load (COL)

COL is an effective technique for deferring network investment where the need is for a short time period. However, in this instance, the need is required on a long-term permanent basis. There are a small number of large customers in the catchment area but the $/kVA funding available for demand reduction is low therefore customer call off load has been assessed as not a viable proposition as it will not address the identified need, nor benefit the community.

Customer Embedded Generation (CEG)

CEG is an effective technique for deferring network investment where the need is for a short time period. The primary driver for investment in this instance is asset safety and performance. A short-term deferral of network investment by using CEG is not a technically or financially feasible option (due to the number of contracts required to be negotiated and managed).

This option has been assessed as technically not viable as it would not address the identified network requirement to provide a continual reliable supply to this part of the network on an ongoing basis.

Large-Scale Customer Generation (LSG)

LSG sites such as renewable energy generation, solar or wind farms of multiple MW's capacity constitute an opportunity to support substation investment by reducing demand on, and potentially providing reactive power support for substation assets.

This option could potentially address the identified need, however, has been assessed as technically not viable as there is no known existing or proposed LSG demand response available that could connect at 11kV in the Mona Park catchment area and provide a continual reliable supply to this part of the network on an ongoing basis.

Customer Solar Power Systems

The daily peak demand occurs between 4:00pm and 8:00pm. As such customer solar generation does not coincide with the peak load period.

Business customers with large solar arrays are deemed to present a significant opportunity for targeted load control or load curtailment if coupled with a Battery Energy Storage System (BESS). Contracting such customers is attractive as they represent a larger load across fewer customers and therefore are cheaper and easier to engage and contract.

PV systems with BESS present a future portfolio opportunity for potential demand response but currently this supply area has a very limited solar/BESS, orders of magnitude less than the required 50-70MVA.

5.2.1 Non-Network Solution Summary

Ergon Energy has not identified any viable non-network solutions internally that will provide a complete or a hybrid (combined network and non-network) solution to provide the magnitude of network support required to address the identified need.

5.2.2 Preferred Network Option

Ergon Energy's preferred internal network option is Option A: Replace Aged and Poor Condition Assets at ROGL.

Upon completion of these works, the asset safety and reliability risks at ROGL Substation will be addressed. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete, non-compliant and high maintenance assets, while ensuring more efficient use of design and construction resources.

The estimated capital cost of this option inclusive of interest, risk, contingencies, and overheads is $10.154 million. The estimated project delivery timeframe has design commencing in December 2021 and construction completed by February 2026.

It should be noted that the estimated capital cost has increased from $8.736 million since the Notice of no non-network option was published.

6 MARKET BENEFIT ASSESSMENT METHODOLOGY

The purpose of the RIT-D is to identify the option that maximises the present value of net market benefits to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

In order to measure the increase in net market benefit, Ergon Energy has analysed the classes of market benefits required to be considered by the RIT-D.

6.1 Classes of Market Benefits Considered and Quantified

Value of Customer Reliability, or involuntary load shedding and avoidance of future emergency replacement of assets have been considered and quantified in this analysis.

6.1.1 Changes in Involuntary Load Shedding

Involuntary load shedding is where a customer's load is interrupted from the network without their agreement or prior warning. As discussed in Section 3.2 a number of scenarios exist where an in-service failure of a circuit breaker results in a network outage.

6.2 Classes of Market Benefits not Expected to be Material

The following classes of market benefits are not considered to be material for this RIT-D, and have not been included in this RIT-D assessment:

- Changes in voluntary load curtailment
- Changes in costs to other parties
- Changes in timing of expenditure
- Changes in load transfer capability
- Changes in network losses
- Option value

6.2.1 Changes in Voluntary Load Curtailment

Because none of the credible options include any voluntary load curtailment, and because there are no customers on voluntary load curtailment agreements in the Rockhampton area at present, any market benefits associated with changes in voluntary load curtailment have not been considered.

6.2.2 Changes in Costs to Other Parties

Ergon Energy does not anticipate that any of the credible options included in this RIT-D assessment will affect costs incurred by other parties.

6.2.3 Changes in Timing of Expenditure

None of the credible options included in this RIT-D assessment are expected to affect the timing of other distribution investments for unrelated identified needs.

6.2.4 Changes in Load Transfer Capability

None of the credible options included in this RIT-D assessment are expected to have an impact on the load transfer capability between the zone substations in the area.

6.2.5 Changes in Network Losses

Ergon Energy does not anticipate that any of the credible options included in the RIT-D assessment will lead to any significant change in network losses.

6.2.6 Option Value

The AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change[1].

Ergon Energy does not consider that the identified need for the options included in this RIT-D would be affected by uncertain factors about which there may be more clarity in future.

[1] AER "Regulatory Investment Test for Distribution Application Guidelines", Section A6. Available at: http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-investment-test-for-distribution-rit-d-and-application-guidelines

7 DETAILED ECONOMIC ASSESSMENT

7.1 Methodology

The RIT-D requires Ergon Energy to identify the credible option that maximises the present value of net economic benefit to all who produce, consume, and transport electricity in the NEM.

Accordingly, a base case Net Present Value (NPV) comparison of the alternative development options has been undertaken.

7.2 Key Variables and Assumptions

The economic assessment contains anticipated costs of providing, operating, and maintaining the options as well as expected costs of compliance and administration associated with each option.

The present value comparison summary includes all costs directly associated with constructing and providing the option. This includes the cost of land and easements currently owned or to be acquired for network augmentation.

Interest on borrowings is not included as a cost in the comparison of options as it represents a cost of project financing, and as such is accounted for in present value calculations through the discounting of the project cash flows at the regulated weighted average cost of capital. The interest on borrowings is included in the Total Project Cost for which approval is being sought as it represents a legitimate cost of network augmentation.

7.3 Net Present Value (NPV) Results

An overview of the initial capital cost and NPV results are provided in Table 1.

Option	Option Name	Rank	Initial Capital Cost	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)	PV of Benefits ($ real)
A	Replace Aged and Poor Condition Assets at ROGL	1	$10,153,911	$ 11,587,000	-$9,169,000	-$4,182,000	$ 24,938,000

Table 1: Base case NPV ranking table

7.4 Selection of Preferred Option

Ergon Energy’s preferred option is Option A, to replace the assets in poor condition at Rockhampton Glenmore Substation.

Upon completion of these works, the asset safety and reliability risks at Rockhampton Glenmore Substation will be addressed. The preferred option will provide a reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources.

The estimated capital cost of this option inclusive of interest, risk, contingencies, and overheads is $10.154 million. The estimated project delivery timeframe has design commencing in December 2021 and construction completed by February 2026.

It should be noted that the estimated capital cost has increased from $8.736 million since the Notice of no non-network option was published.

8 CONCLUSION

The Final Project Assessment Report (FPAR) represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to take steps to progress the proposed preferred option to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements, as necessary.

8.1 Preferred Option

Ergon Energy's preferred option is Option A, to replace the assets in poor condition at Rockhampton Glenmore Substation.

Upon completion of these works, the asset safety and reliability risks at Rockhampton Glenmore Substation will be addressed. The preferred option will provide a reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources.

The estimated capital cost of this option inclusive of interest, risk, contingencies, and overheads is $10.154 million. The estimated project delivery timeframe has design commencing in December 2021 and construction completed by February 2026.

It should be noted that the estimated capital cost has increased from $8.736 million since the Notice of no non-network option was published.

8.2 Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

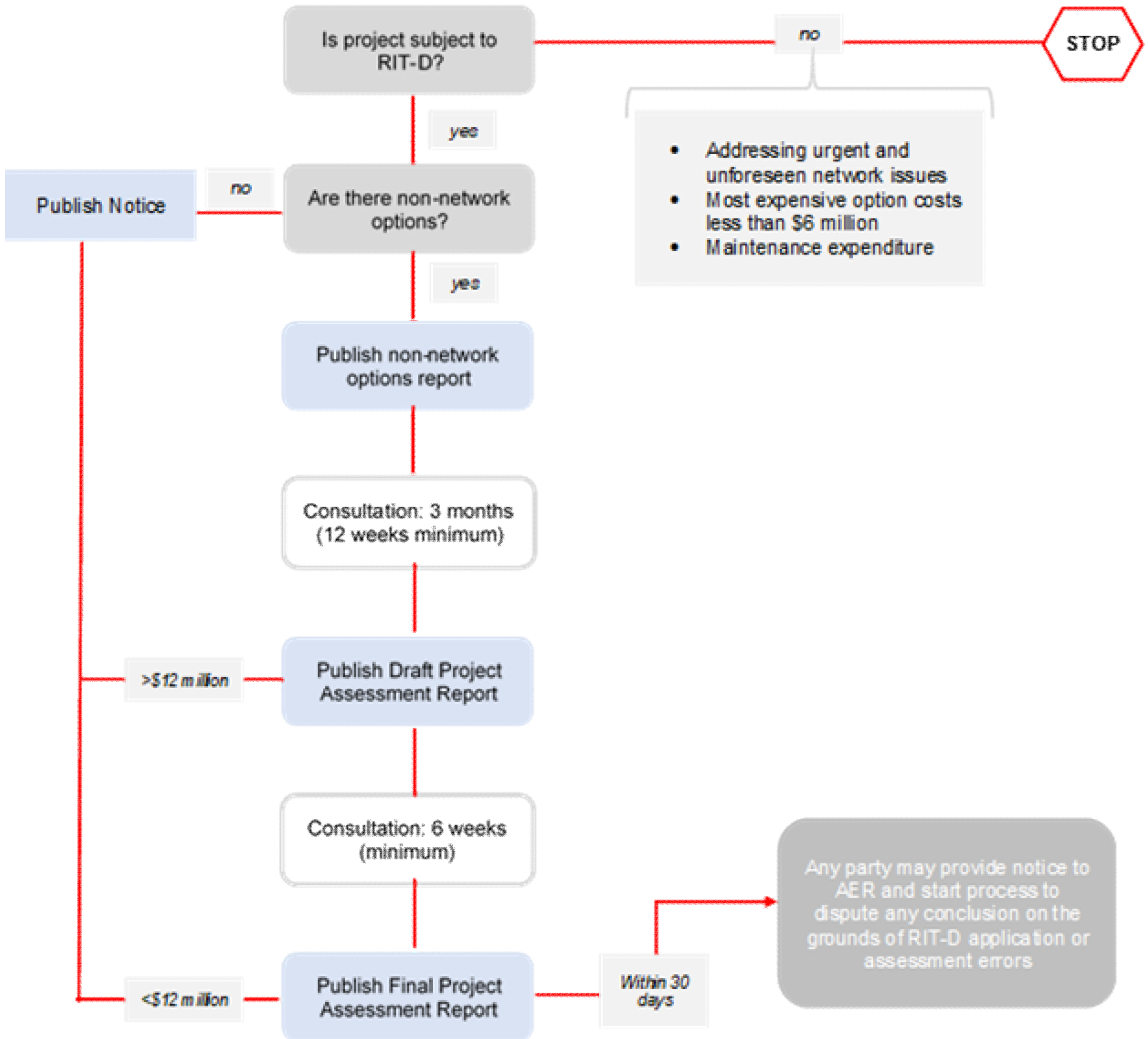
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

9 COMPLIANCE STATEMENT

This Final Project Assessment Report complies with the requirements of NER section 5.17.4(r)(2) and (j) as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the DPAR;	N/A
(4) a description of each credible option assessed	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 of each credible option	6
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	5
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	6
(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	6.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	7
(10) the identification of the proposed preferred option	8.3
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (ii) the indicative capital and operating costs (where relevant); (iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	8
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.3

APPENDIX A – THE RIT-D PROCESS



Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.