Regulatory Investment Test for Distribution (RIT-D)

Rockhampton South Network Limitation

Final Project Assessment Report

24 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 South 66/11kV Substation (ROSO) is located in the southern part of the central business district (CBD) of Rockhampton. ROSO supplies a large portion of Rockhampton CBD and the surrounding areas to the south of Rockhampton, including a total of 2,201 customers, of which 60% are residential and 40% are commercial, agricultural and industrial.

ROSO was established in 1968, and in accordance with applicable design and construction standards during that time. It has an outdoor 66kV switchyard with steel structures, two 15/20MVA 66/11kV power transformers, an indoor 11kV switchboard supplying seven outgoing 11kV feeders, and a protection and control room.

A substation condition assessment of ROSO was completed in 2019 and has identified that significant primary plant and majority of secondary plant and equipment are recommended for retirement based on Condition Based Risk Management (CBRM) analysis.

The assessment identified that two 66kV circuit breakers, the indoor 11kV switchboard, and all secondary systems including protection relays, SCADA systems and voltage regulation control relays are at the end of their serviceable life.

There are also identified issues with a number of primary and secondary system assets which poses a safety risk to staff working within the switchyard, a reliability risk to the customers supplied from ROSO, and an environmental risk associated with inadequate transformer bunding. These assets include:

- three of the 66kV current transformers that are not compatible with new protection schemes and have reached end of life;
- the 11kV switchboard fault rating which is lower than the ultimate maximum fault level (currently managed with a normally-open 11kV bus tie breaker);

- the 415Va.c. station services supply which is not duplicated and is supplied via an aged and obsolete isolation transformer;
- the DC backup battery supply to the protection system which is not duplicated;
- the substation security fence and transformer oil containment which does not meet current day standards; and
- structural issues with the roof on one of the transformer enclosures.

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 ROSO 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 26 February 2021.

Ergon Energy published a Draft Project Assessment Report (DPAR) for the above-described network constraint on 22 October 2021. No submissions were received by the closing date 3 December 2021.

Two potentially feasible options are detailed:

- **Option 1:** Replace identified 66kV equipment in situ, replace switchboard and secondary systems and progressively replace the aged 66kV plant and the transformers when they reach retirement age.
- **Option 2:** Replace entire substation with a greenfield substation.

Ergon Energy's preferred solution to address the identified need is Option 1.

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.

CONTENTS

1. INTRODUCTION

This FPAR has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(i) of the NER.

This report represents the second 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 South 66/11kV Substation (ROSO) 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.
- Describes the credible options that are considered in this RIT-D assessment.
- Quantifies costs and classes of material market benefits for each of the credible options.
- 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

ROSO is located on the southern part of Rockhampton CBD on the southern side of the Fitzroy river. ROSO supplies the southern half of the CBD precinct, as well as Depot Hill, and Port Curtis areas with a total of 2,201 customers, of which 1,310 are residential and 880 are commercial and industrial. Commercial and Industrial customers include a commercial mall district, newly developed riverside precinct, courthouse and police headquarters, government premises, council chambers, a range of commercial premises typical of a regional centre, and larger customers including milk processing facility, significant railway and mining equipment maintenance facilities. Most of the residential customers supplied from ROSO are in Depot Hill and Port Curtis areas. ROSO also provides transfer capability and security of supply to customers normally supplied from neighbouring Rockhampton substations Rockhampton-Glenmore (ROGL) and Canning Street (CAST), and Gracemere area substation Malchi (MALC). A geographic view of the network area is provided in Figure 1.

Rockhampton South Network Limitation
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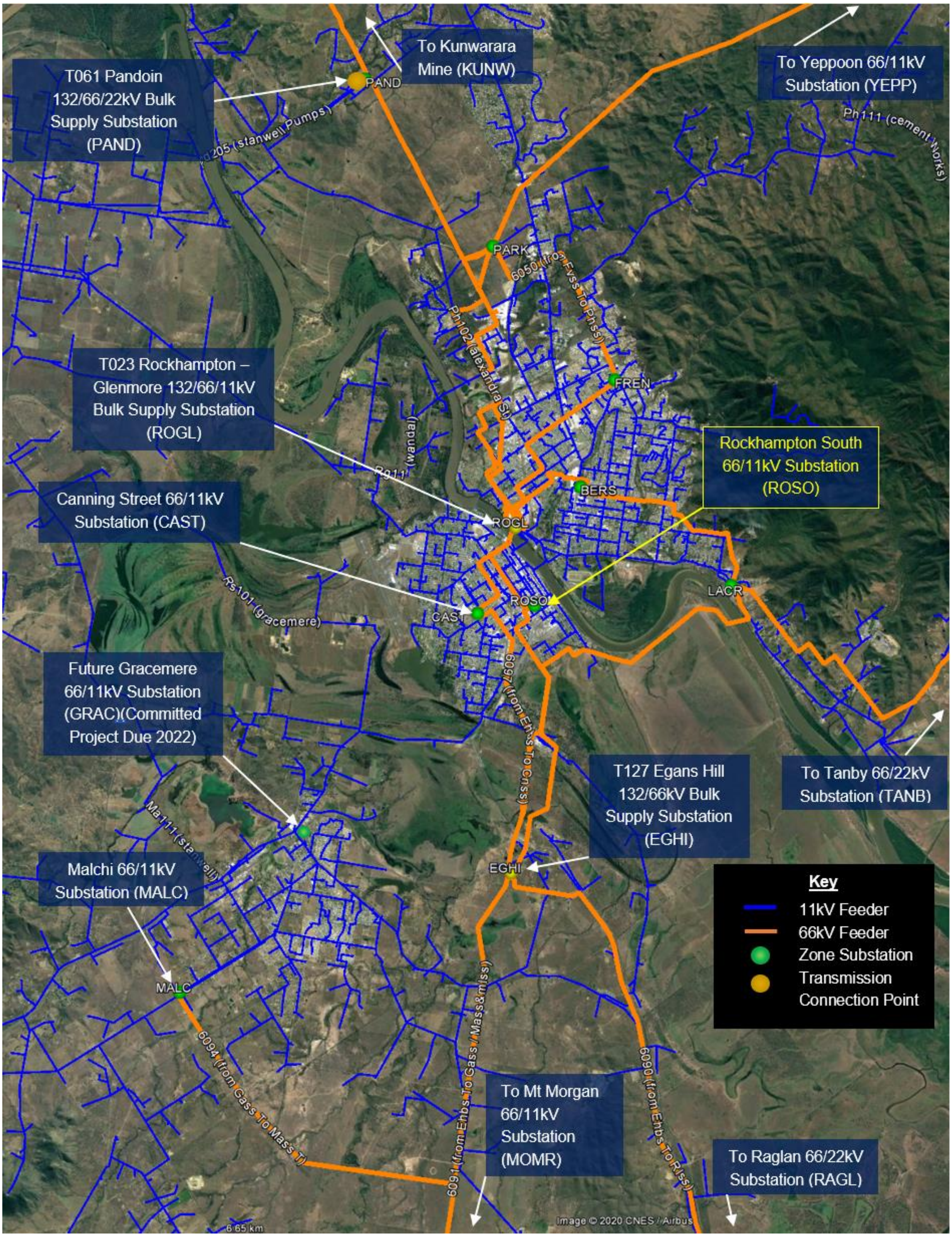


Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

ROSO 66kV bus is part of the Rockhampton 66kV sub-transmission meshed network which takes supply from three 132/66kV Transmission Connection Points: T023 Rockhampton-Glenmore (ROGL) in the centre of Rockhampton, T127 Egans Hill (EGHI) to the south, and T061 Pandoin to the north. ROSO is presently supplied via two 66kV feeders which together form the strongest of three links between ROGL and EGHI bulk supply points.

The substation is equipped with two 66/11kV 15/20MVA transformers (one limited to 15.5MVA), an outdoor 66kV bus in “H” arrangement with four (4) circuit breakers and no bus tie breaker, and an indoor 11kV switchboard with two (2) bus sections, seven (7) outgoing feeders, two (2) capacitor bank breakers, two (2) transformer breakers and a normally open bus tie breaker.

ROSO supplies seven 11kV distribution feeders which contain a total of twelve 11kV feeder ties to 11kV feeders supplied from Rockhampton Glenmore 66/11kV substation (ROGL), Canning Street 66/11kV substation (CAST), and currently Malchi, soon to be Gracemere 66/11kV substation (MALC/GRAC).

A schematic view of the existing sub-transmission network arrangement is shown in Figure 2 and the geographic view of ROSO is illustrated in Figure 3.

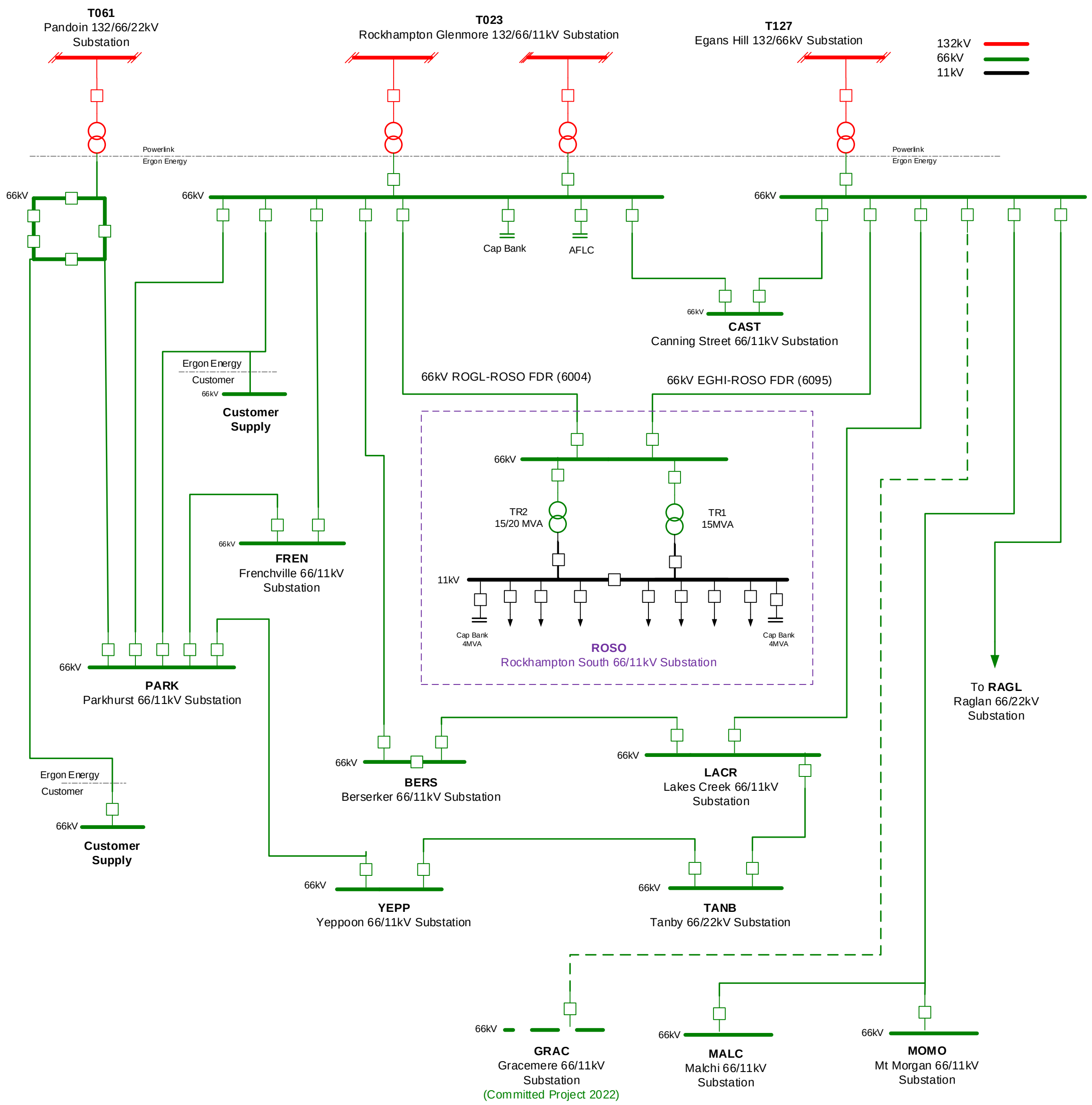


Figure 2: Existing network arrangement (schematic view)

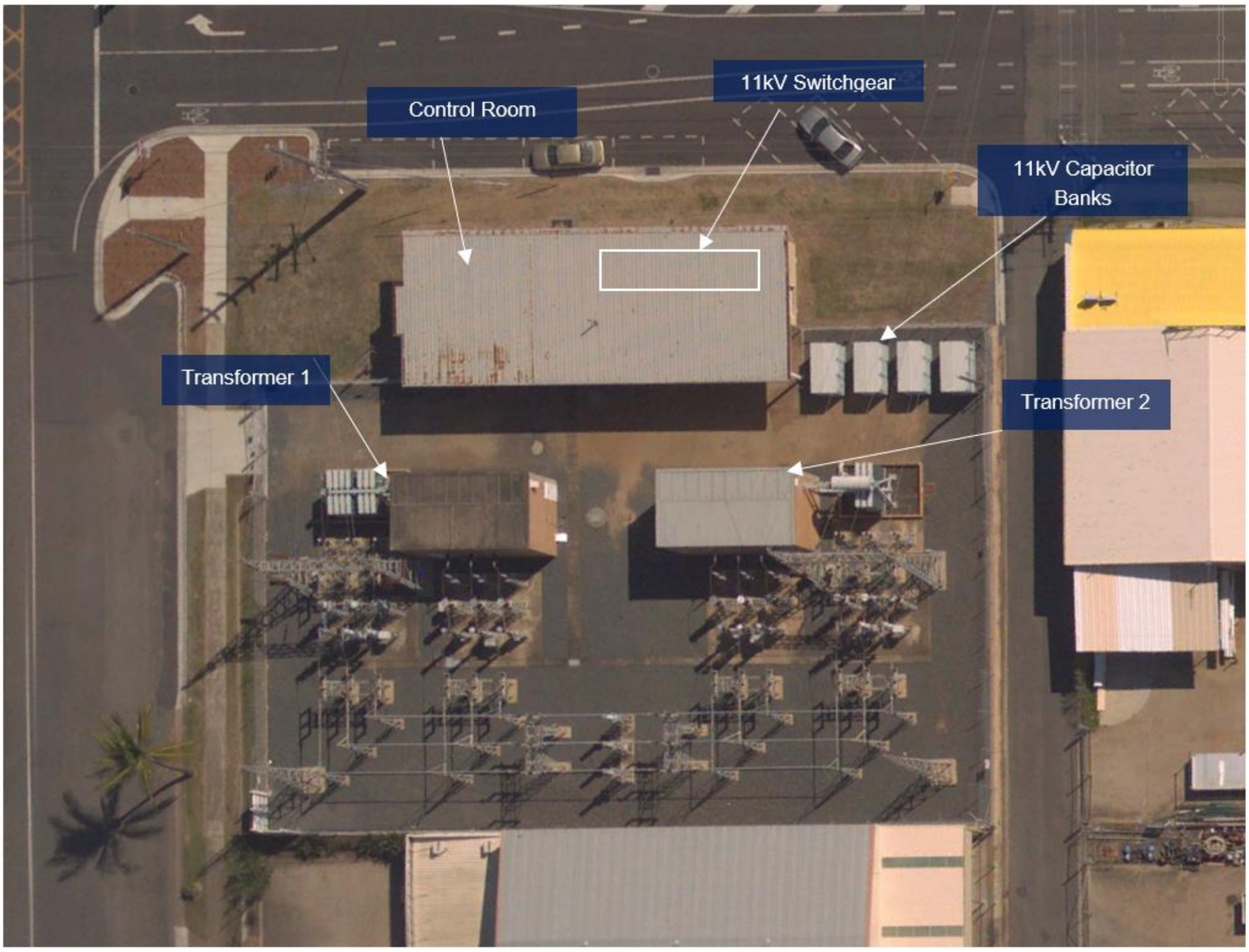


Figure 3: ROSO Substation (geographic view)

2.3. Load profiles & forecasts

The load at ROSO comprises a mix of residential, commercial and industrial customers. The load is summer peaking, and the annual peak loads are predominantly driven by commercial and residential loads.

2.3.1. Full annual load profile

The full annual load profile for ROSO over the 2019/20 financial year is shown in Figure 4.

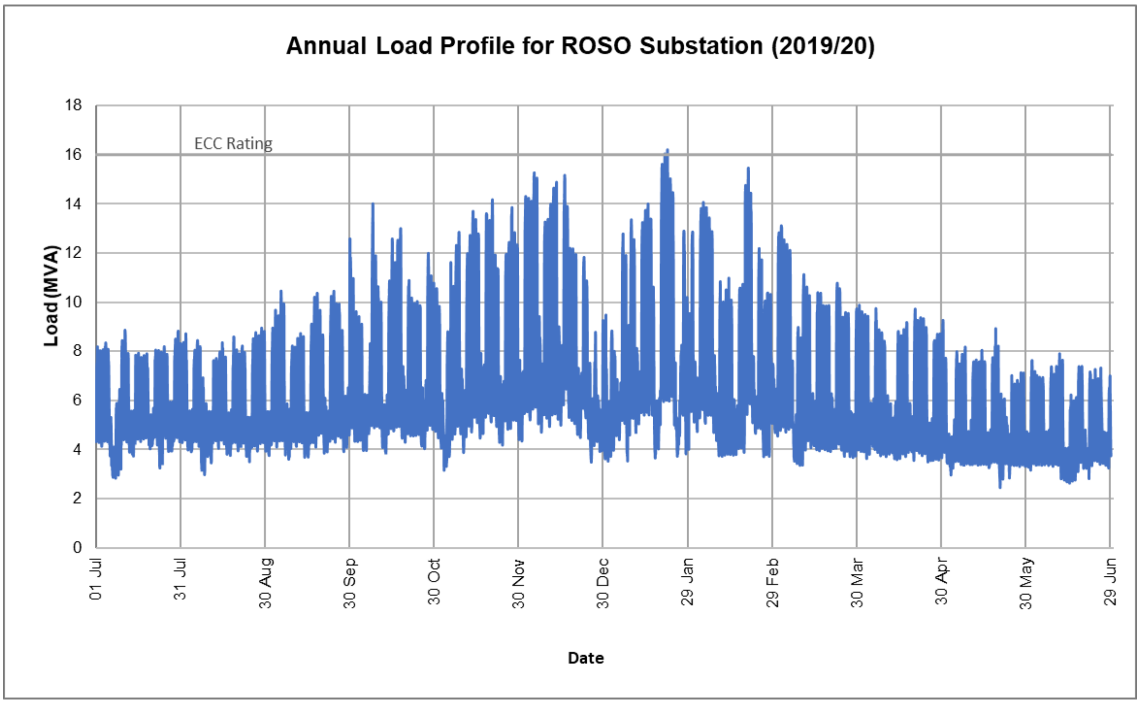


Figure 4: Substation actual annual load profile

2.3.2. Load duration curve

The load duration curve for ROSO over the 2019/20 financial year is shown in Figure 5.

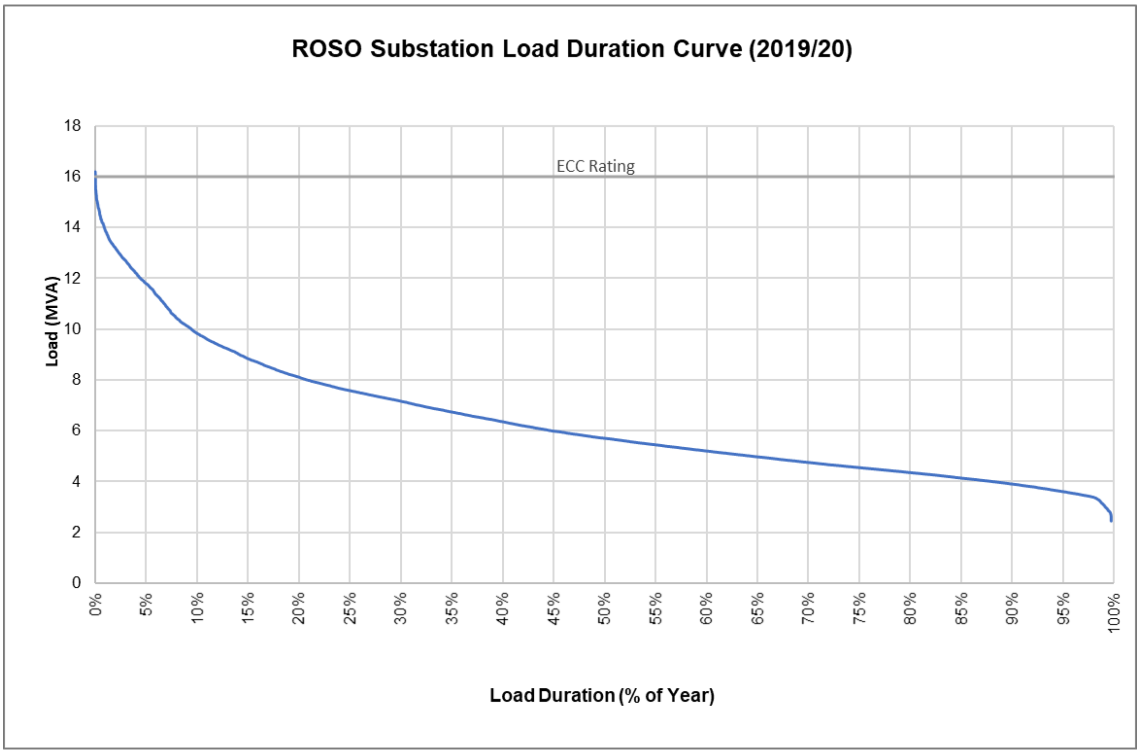


Figure 5: Substation load duration curve

2.3.3. Average peak weekday load profile (summer)

The daily load profile for an average peak weekday during summer is illustrated below in Figure 6. It can be noted that the summer peak loads at ROSO are historically experienced midday through to late afternoon and evening.

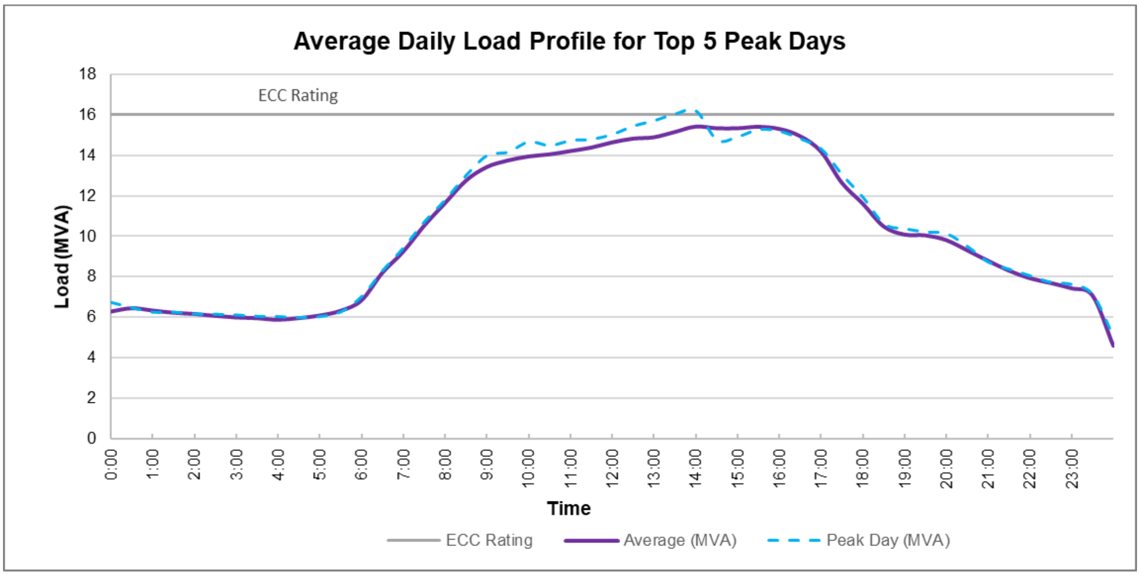


Figure 6: Substation average peak weekday load profile (summer)

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 7. The historical peak load for the past six years has also been included in the graph.

The reduction in peak load in 2017 was due to load being shifted off ROSO to Rockhampton-Glenmore (ROGL) to alleviate 11kV exit cable constraints at ROSO Substation. This 2-3MVA of load will be shifted back to ROSO when its exit cables are replaced.

Excluding the above factor, with the base case growth scenario, the peak load is forecast to remain relatively steady over the next 10 years.

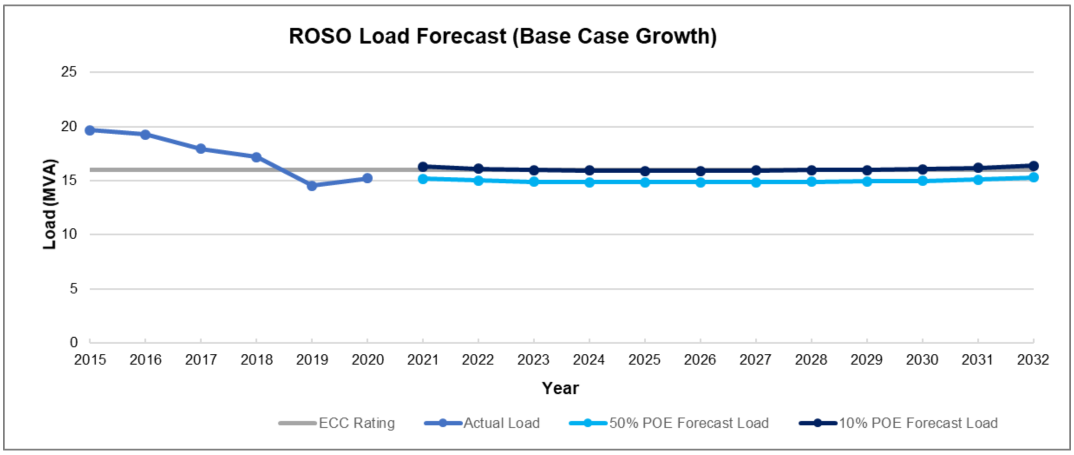


Figure 7: Substation base case load forecast

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 8. With the high growth scenario, the peak load is forecast to increase slightly over the next 10 years.

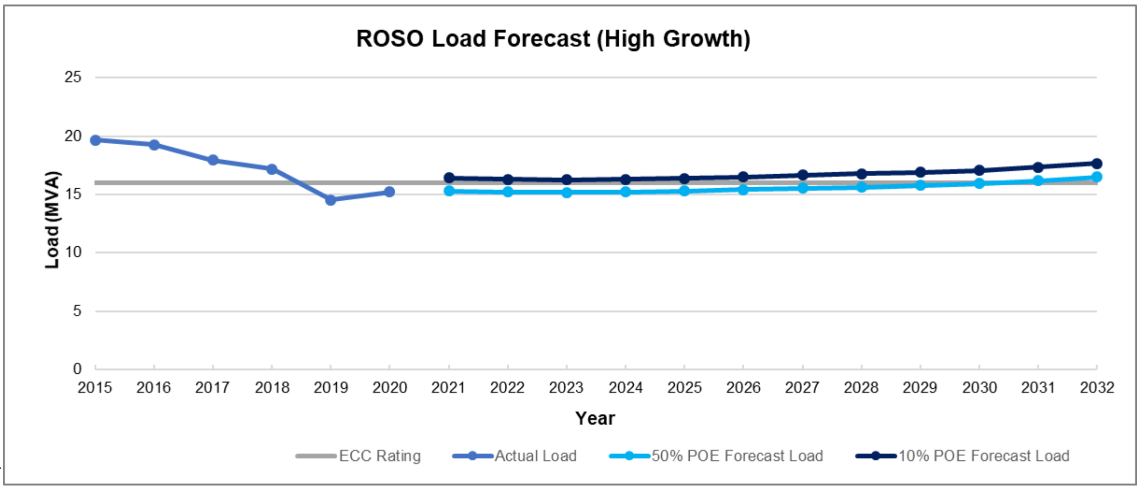


Figure 8: Substation high growth load forecast

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 9. With the low growth scenario, the peak load is forecast to reduce marginally over the next 10 years.

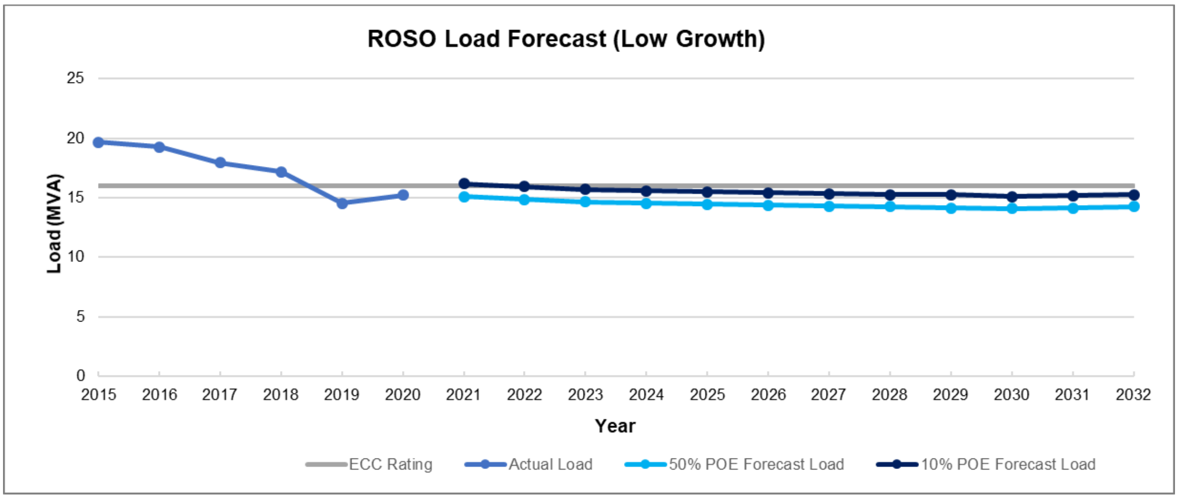


Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Poor Condition Assets

ROSO was established in 1968 according to applicable design and construction standards during that time. It has an outdoor 66kV switchyard with steel structures, two 15/20MVA 66/11kV power transformers, an indoor 11kV switchboard supplying seven outgoing 11kV feeders, and a protection and control room.

A substation condition assessment of ROSO was completed in 2019 and has identified that significant primary plant and majority of secondary plant and equipment are recommended for retirement based on Condition Based Risk Management (CBRM) analysis.

The assessment identified that two 66kV circuit breakers, the indoor 11kV switchboard, and all secondary systems including protection relays, SCADA systems and voltage regulation control relays are at the end of their serviceable life.

There are also identified issues with a number of primary and secondary system assets which poses a safety risk to staff working within the switchyard, a reliability risk to the customers supplied from ROSO, and an environmental risk associated with inadequate transformer bunding. These assets include:

- three of the 66kV current transformers which are not compatible with new protection schemes and have reached end of life;
- the 11kV switchboard fault rating which is lower than the ultimate maximum fault level (currently managed with a normally-open 11kV bus tie breaker);
- the 415Va.c. station services supply which is not duplicated and is supplied via an obsolete isolation transformer;
- the DC backup battery supply to the protection system which is not duplicated;
- the substation security fence and transformer oil containment which do not meet current day standards; and
- structural issues with the roof on one of the transformer enclosures.

3.2. Quantification of the Identified Need

3.2.1. Poor Condition Assets

A risk assessment has been undertaken on the condition of the deteriorated assets at ROSO and Ergon Energy has deemed that without undertaking remediation the safety risks associated with the asset condition would not be reduced to be So Far As Is Reasonably Practicable (SFAIRP). Secondly, there is also customer impacts and environmental risks associated with the asset condition and inadequately bunded transformers that will also not be As Low As Reasonably Practicable (ALARP). As such, retention of these assets in their current condition is not considered an acceptable option.

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 ROSO will be consistent with the base case forecast outlined in Section 2.3.

Factors that have been considered 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 IN RESPONSE TO DRAFT PROJECT ASSESSMENT REPORT

On 22 October 2021 Ergon Energy published the DPAR providing details on the identified need at ROSO. This report provided both technical and economic information about possible solutions and sought information from interested parties about possible alternate solutions to address the need for investment.

In response to the DPAR, Ergon Energy received no submissions by 3 December 2021, which was the closing date for submissions to the DPAR.

5. CREDIBLE OPTIONS ASSESSED

5.1. Non-Network Options Identified

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

5.2. Network Options Identified

Ergon Energy has identified two credible network options that will address the identified need.

Option 1: In-situ Replacement

This option involves replacing one of the existing transformers and upgrading bunding, replacing two 66kV circuit breakers and three 66kV current transformers, replacing the 11kV switchboard, replacing secondary systems, AC and DC supply, and upgrading the substation physical security in order to address the identified need.

A schematic diagram of the proposed network arrangement for Option 1 is shown in Figure 10.

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $12.93 million. Annual operating and maintenance costs are anticipated to be approximately $70,000.

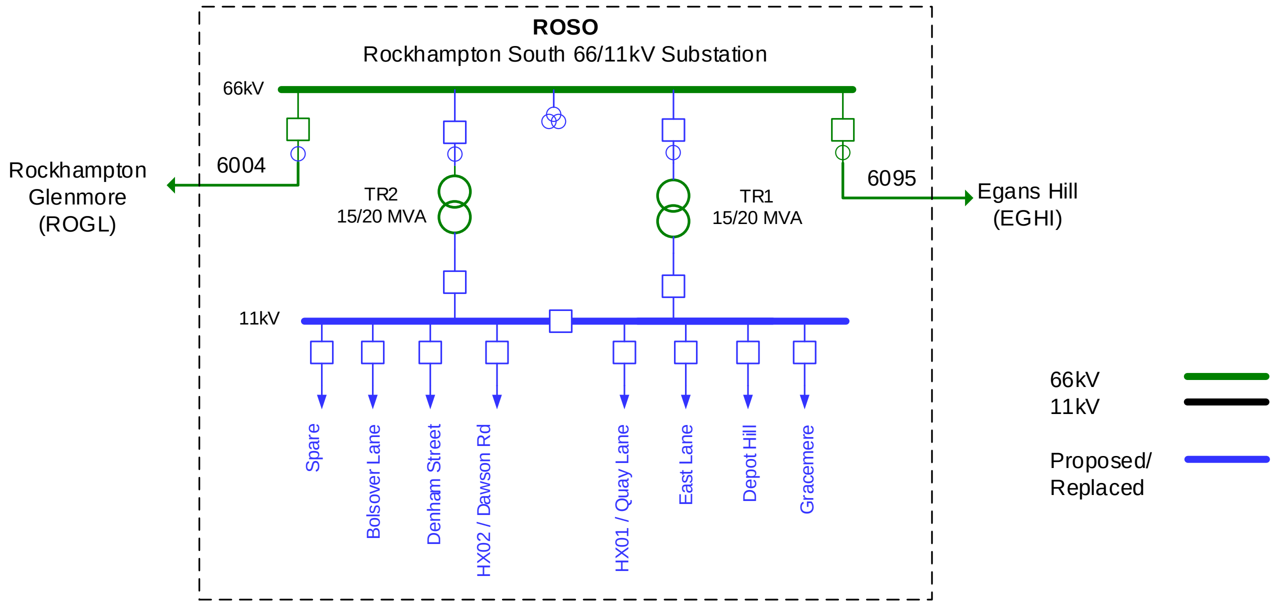


Figure 10: Option 1 proposed network arrangement (schematic view)

Option 2: Full Substation Replacement

This option involves rebuilding the substation with a new substation to current design standards on a new allotment, with the advantage of greenfield works in a single construction stage and with simplified project dependencies. The disadvantages are the need for site acquisition and early retirement of the balance of plant.

A schematic diagram with the proposed network arrangement for Option 2 is shown in Figure 11.

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $25 million. Annual operating and maintenance costs are anticipated to be approximately $50,000.

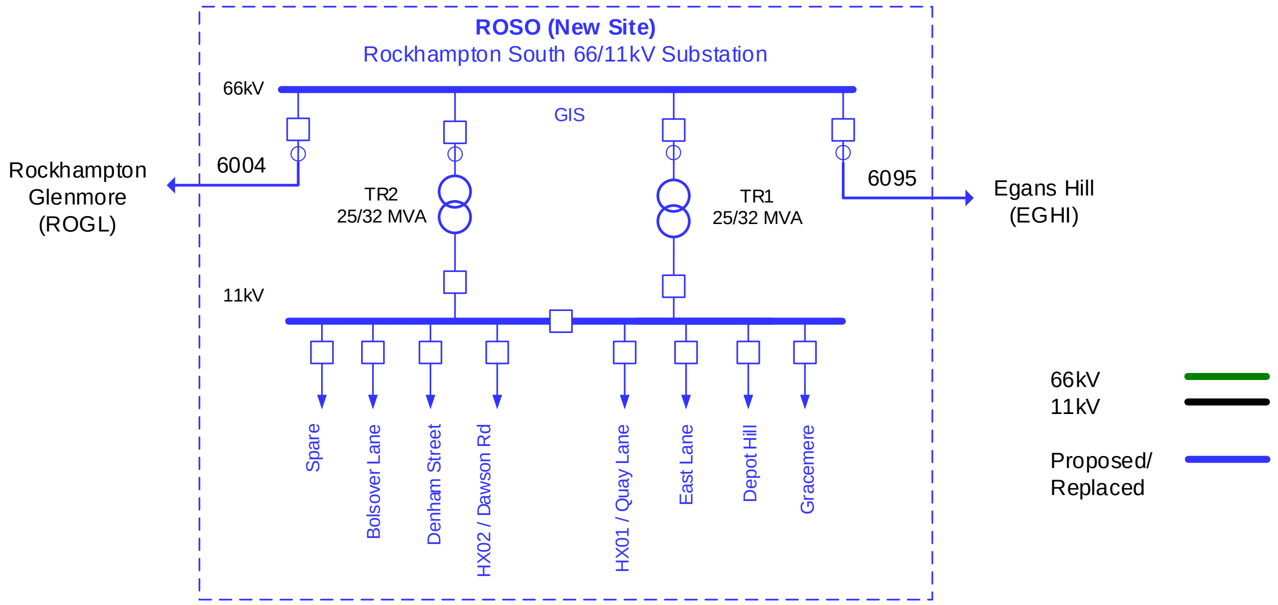


Figure 11: Option 2 proposed network arrangement (schematic view)

5.3. Assessment of Non-Network Solutions

Ergon Energy's Demand & Energy Management (DEM) team has assessed the potential non-network alternative (NNA) options required to defer the network option and determine if there is a viable demand management (DM) 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.

5.3.1. Demand Management (Demand Reduction)

Ergon Energy has completed a review of the ROSO customer base and considered a number of demand management technologies. Asset safety and performance risks are the key project drivers (i.e. the need) at ROSO Substation. It has been determined that the available demand management options will not be viable propositions.

5.3.2. Network Load Control

The residential and commercial customers appear to drive the daily peak demand which generally occurs between 12:00pm and 6:00pm. There are 826 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 496kVA[1] is available.

ROSO supply area LC signals are controlled from T023 Rockhampton Glenmore Bulk Supply Substation (ROGL). The Tariff 33 and 31 hot water LC channels are dynamic (that is, it responds to exceedance settings not on a timetable) and the current control strategy only calls LC due to ROSO loading when the load on Denham St 11kV feeder exceeds 3.71MW or load on Depot Hill 11kV feeder exceeds 3.54MW. Tariff 33 air-conditioning channels are under manual control of the operational control centre and are used as required.

5.3.3. 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.

[1] Hot water diversified demand saving estimated at 0.6kVA per system

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 ROSO catchment area and provide a continual reliable supply to this part of the network on an ongoing basis.

Customer Solar Power Systems

A total of 271 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 3,693kVA.

The daily peak demand is driven by a mixture of residential and commercial customer demand and the peak generally occurs between 12:00pm and 6:00pm. Customer solar generation does tend to coincide with the peak load period. Forecast uptake of residential and commercial PV systems has been included in the forecast substation loads for base, high and low growth scenarios.

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.

However, only a small percentage of customers in this supply area have solar PV systems and possibly none have a BESS. PV systems with BESS present a future portfolio opportunity for potential demand response but currently this supply area has a very limited solar/BESS. Solar customers without a BESS will not meet the technical needs of the demand reduction as their solar contribution may not be available when the network un-met need is required.

5.3.4. 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 in the ROSO area to address the identified need.

5.4. Preferred Network Option

Ergon Energy's preferred network option is Option 1, to replace two 66kV circuit breakers and three 66kV current transformers, replace the 11kV switchboard, secondary systems, AC and DC supply, and upgrade oil bunding and separation, and upgrade physical security at the existing ROSO Substation.

Upon completion of these works, the asset safety, environmental and reliability risks at ROSO 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 $12.93 million. Annual operating and maintenance costs are anticipated to be approximately $70,000. The estimated project delivery timeframe has design commencing in late-2022 and construction completed by December 2025.

5.5. 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.

5.6. Potential Deferred Augmentation Charge

Ergon Energy has estimated the capital cost of the network options to within ± 30% of estimation accuracy. Using these costs as a guide, a deferral of the preferred network option by a year represents a deferral saving of approximately $418,964 per annum, assuming the same reliability outcomes are maintained as with the preferred network option. While this should not be considered as the precise deferral cost available to a non-network proponent, it serves as a guide for interested parties to determine the viability of their proposal. Ergon Energy will work with non-network proponents based on the specifics of what the proponents offer and any necessary further works that Ergon Energy may have to undertake to ensure the reliability, security and safety of the network are maintained.

6. MARKET BENEFIT ASSESSMENT METHODOLOGY

The identified need is to reduce the safety risk associated with the condition of the identified primary and secondary system assets at ROSO to SFAIRP. As such, the assessment methodology is a lowest cost process among the credible options that have been assessed to address the identified need, rather than a cost/benefit analysis based on market benefits.

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 NPV comparison of the alternative development options has been undertaken. A sensitivity analysis was then conducted on this base case to establish the option that remained the lowest cost option in the scenarios considered.

Further to the scenarios considered, a Monte-Carlo analysis simulation was undertaken on the base case project timings to assess the projects sensitivity to a change in the parameters of the NPV model.

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 WACC. The interest on borrowings is included in the Total Project Cost as it represents a legitimate cost of network augmentation.

Table 1 outlines the major sensitivities analysed within the Monte-Carlo analysis which was undertaken to assess the sensitivity to a change in parameters of the NPV model.

Parameter	Mode Value	Lower Bound	Upper Bound
Project Costs	Standard estimates	-30%	+30%
Opex Costs	Calculated Opex	-5%	+5%

Table 1: Economic parameters and sensitivity analysis factors

7.3. Net Present Value (NPV) Results

An overview of the base case NPV results are provided in Table 2.

Option	Option Name	Rank	Initial Capital Cost (Total Project Cost)	Net Economic Benefit($k)	PV of Capex ($k)	PV of Opex ($k)
1	Substation Staged Replacements	1	$12,930,734	-17,353	-15,937	-1,415
2	Substation Greenfield Replacement	2	$25,000,000	-23,151	-21,967	-1,183

Table 2: Base case NPV ranking table

Further to the scenarios considered, a Monte-Carlo analysis simulation was undertaken on the base case project timings to assess the projects sensitivity to a change in the parameters of the NPV model. The Monte-Carlo analysis undertook 1000 simulations of all the variables. Table 3 shows the percentage of times each option was the most economical across the simulations and also the average NPV cost of all the simulations.

Option Number	Option Name	Rank 1	Rank 2	Average NPV ($k)
A	Substation Staged Replacements (Option 1)	92.5%	7.5%	-18,025
B	Substation Greenfield Replacement (Option 2)	7.5%	92.5%	-23,021

Table 3: Monte Carlo Analysis for Base Case Forecast

Option 1 is the lowest cost option in the weighted average NPV results across the two identified options. Option 1 is also the lowest cost option in the weighted average NPV results in 92.5% of cases in the Monte-Carlo simulations.

Based on the detailed economic assessment, Option 1 is considered to provide the optimum solution to address the identified need and is therefore the recommended development option.

8. CONCLUSION

The 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 network option is Option 1, to replace two 66kV circuit breakers and three 66kV current transformers, replace the 11kV switchboard, secondary systems, AC and DC supply, and upgrade oil bunding and separation, and upgrade physical security at the existing ROSO Substation.

Upon completion of these works, the asset safety, environmental and reliability risks at ROSO 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 $12.93 million. Annual operating and maintenance costs are anticipated to be approximately $70,000. The estimated project delivery timeframe has design commencing in late-2022 and construction completed by December 2025.

8.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

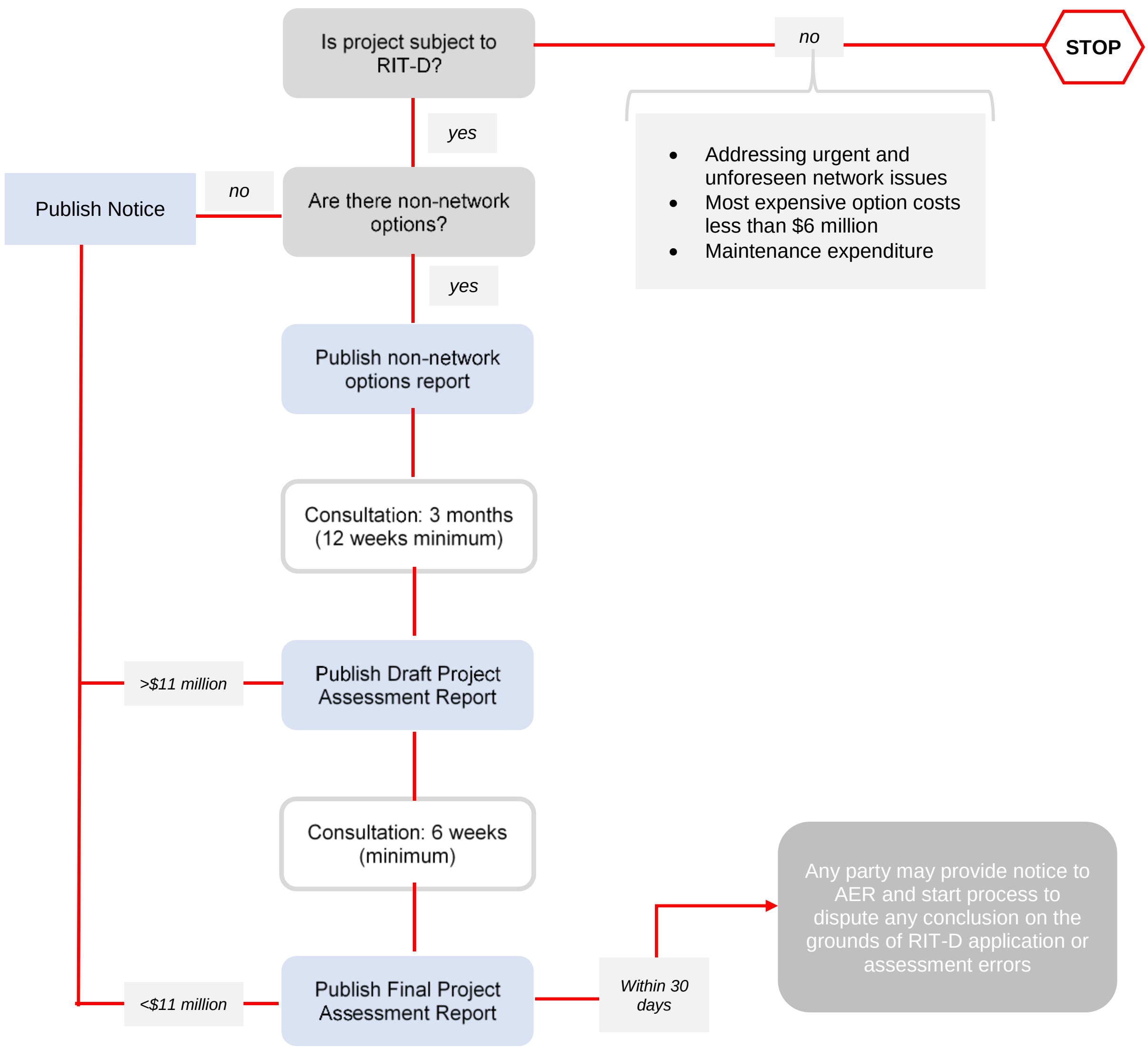
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

9. COMPLIANCE STATEMENT

This FPAR complies with the requirements of NER section 5.17.4(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;	4
(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	7
(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
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	7.3
(10) the identification of the proposed preferred option	8.1
(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); (iii) 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[1]



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

[1] RIT-D process as applicable when the DPAR was published.