Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Biloela Network Area

Draft Project Assessment Report

10 January 2022

ERGON ENERGY NETWORK

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

Biloela 132/66/11kV (BILO) combined bulk supply and zone substation is located on the western edge of Biloela Township. BILO supplies the township of Biloela, Callide and Boundary Hill Mine, as well as the surrounding communities via Wowan and Monto substations. Powerlink own and operate the 132/66kV transformer, while Ergon own and operate downstream of the 66kV bus. The substation supplies 4,080 residential, industrial, commercial and rural customers; with a peak load of 18.25MVA.

Biloela zone substation has two power transformers: WILSON 66/11kV (25/32MVA); and TYREE 66/11kV (15/20MVA). The substation was established circa 1965 and has had a number of individual replacement projects to address high risk poor condition assets over the past 10 years. The 11kV switchboard and several 66kV secondary plant items are still original and at end of life.

In order to maintain continuity of supply to its' customers, the end-of life 66kV and 11kV assets at BILO will need replacing.

There are access issues due to limitations of the 11kV Bus 1, where it is only possible to access during light load periods and weekends, in conjunction with the use of LV generation.

The ongoing operation of these assets beyond 2027 presents a significant risk to safety and customer reliability.

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 Biloela supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

Addressing Reliability Requirements in the Biloela Network Area Draft Project Assessment Report

Ergon Energy published a Notice of No Non-Network Options for the above described network constraint on 20th December 2021.

This Draft Project Assessment Report (DPAR), 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(i) of the NER as the next stage in this RIT-D.

One feasible option has been investigated and Ergon Energy's preferred solution to address the identified need is Option 1 – Biloela Asset Replacement.

The DPAR seeks information from interested parties about possible alternate solutions to address the need for investment.

Submissions in writing are due on the **25th February 2022** by 4pm and must be lodged to demandmanagement@ergon.com.au

For further information and inquiries please contact:

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CONTENTS

1. INTRODUCTION

This DPAR 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 Biloela 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:

- Provides background information on the network capability limitations of the distribution network supplying the Biloela area.
- 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.
- Is an invitation to registered participants and interested parties to make submissions.

1.2. Contact Details

Submissions in writing are due by 4pm on **25th February 2022** and should be lodged to demandmanagement@ergon.com.au.

For further information and inquiries please contact:

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2. BACKGROUND

2.1. Geographic Region

Biloela 66/11kV zone substation (BILO) is located on the western edge of the township of Biloela. The substation and associated 66kV feeders is shown in Figure 1 and the 11kV feeders are shown in **Figure 2**.

Figure 1: Biloela 66/11kV Zone substation and 66kV Feeders, Existing Network Arrangement (Geographic View)

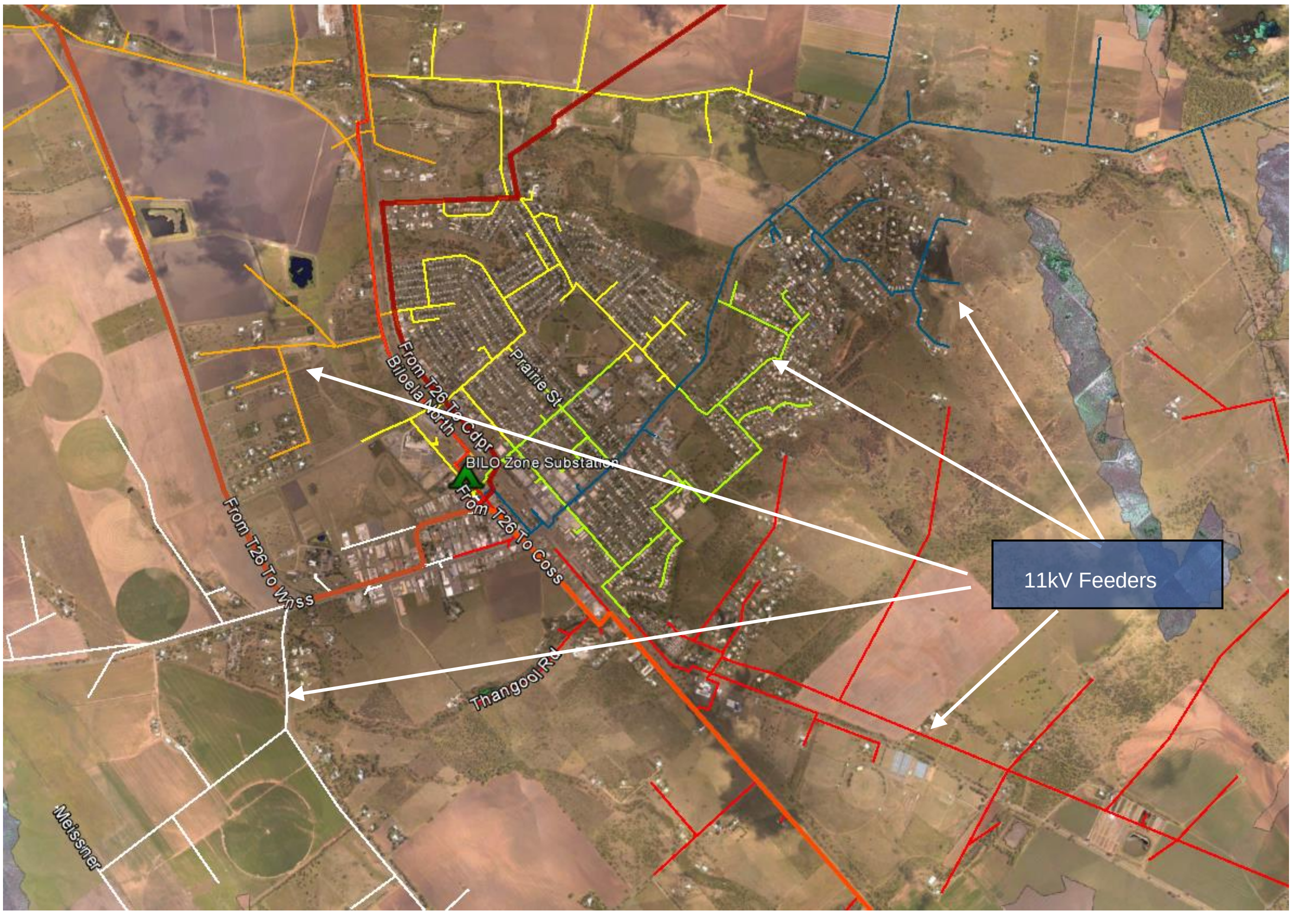


Figure 2: Biloela 66/11kV locality map and associated 11kV feeders

2.2. Existing Supply System

BILO is supplied from Powerlink owned feeders 7109 and 7110, with the 132kV bus and 132/66kV transformers also owned and operated by Powerlink. Ergon Energy owns and operates downstream of the 66kV bus. The 66kV bus has four feeders which supply two mines and two 66/11kV nearby substations, Monto and Wowan. The 66kV feeders 6009 and 6010 have a normal open tie which allows either feeder to be supplied via the alternate feeder for CB maintenance or failure. The combined peak loading on the 66kV and 11kV bus is 34.17MVA. BILO has two power transformers: WILSON 66/11kV (25/32MVA); and TYREE 66/11kV (15/20MVA), with a total of three transformer breakers, this allows T5 to supply both bus 1 and bus 2. The 11kV switchboard has six active feeders which supplies a total of 4,080 residential, industrial, commercial and rural customers, with a peak of 18.25MVA. The 11kV bus section breaker is normally operated closed. BILO also has a 66kV AFLC injection unit which services load control signal to the Biloela area.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 3 and Figure 4 below.

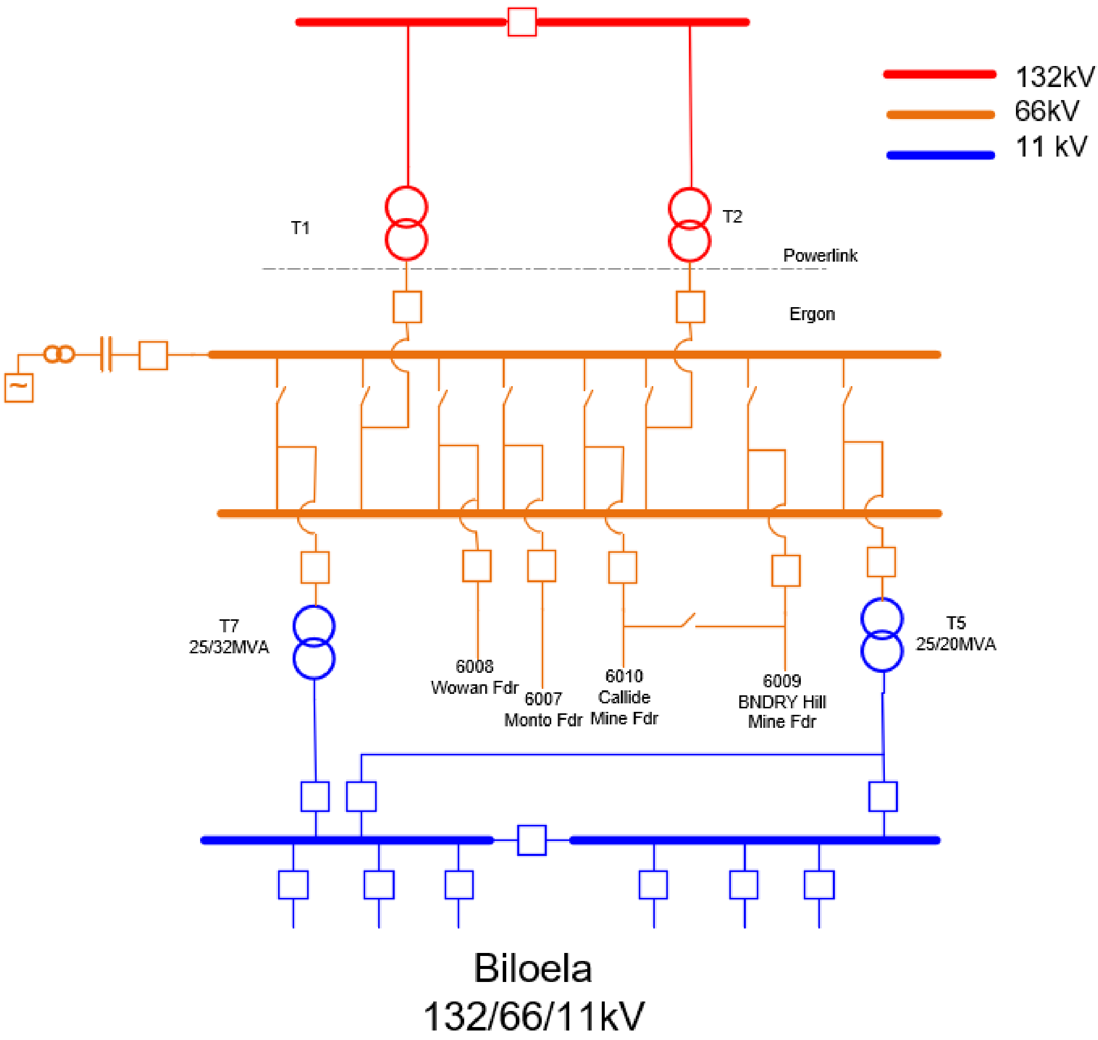


Figure 3: Existing area network arrangement (schematic view)

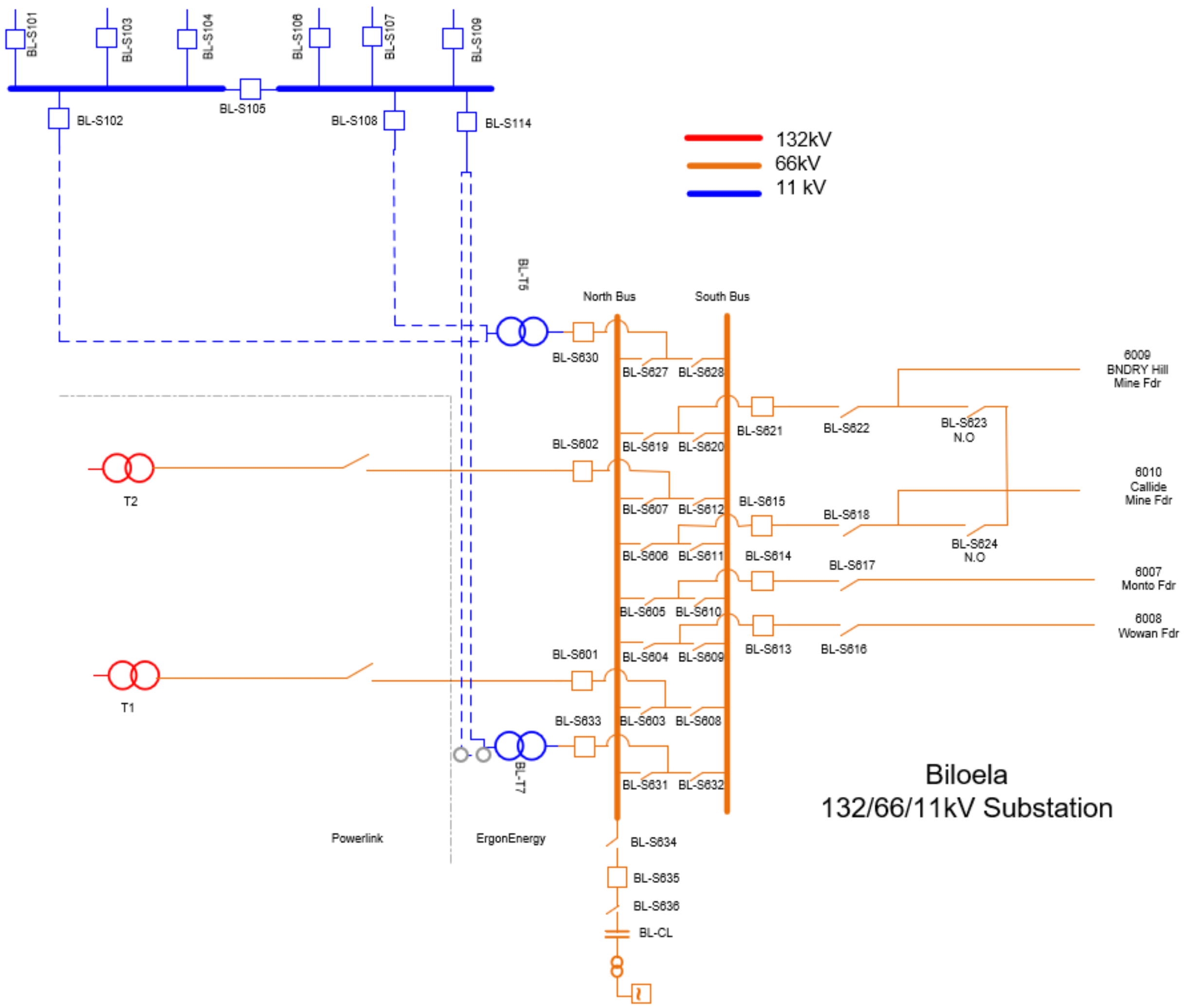


Figure 4: Existing network arrangement (schematic view)

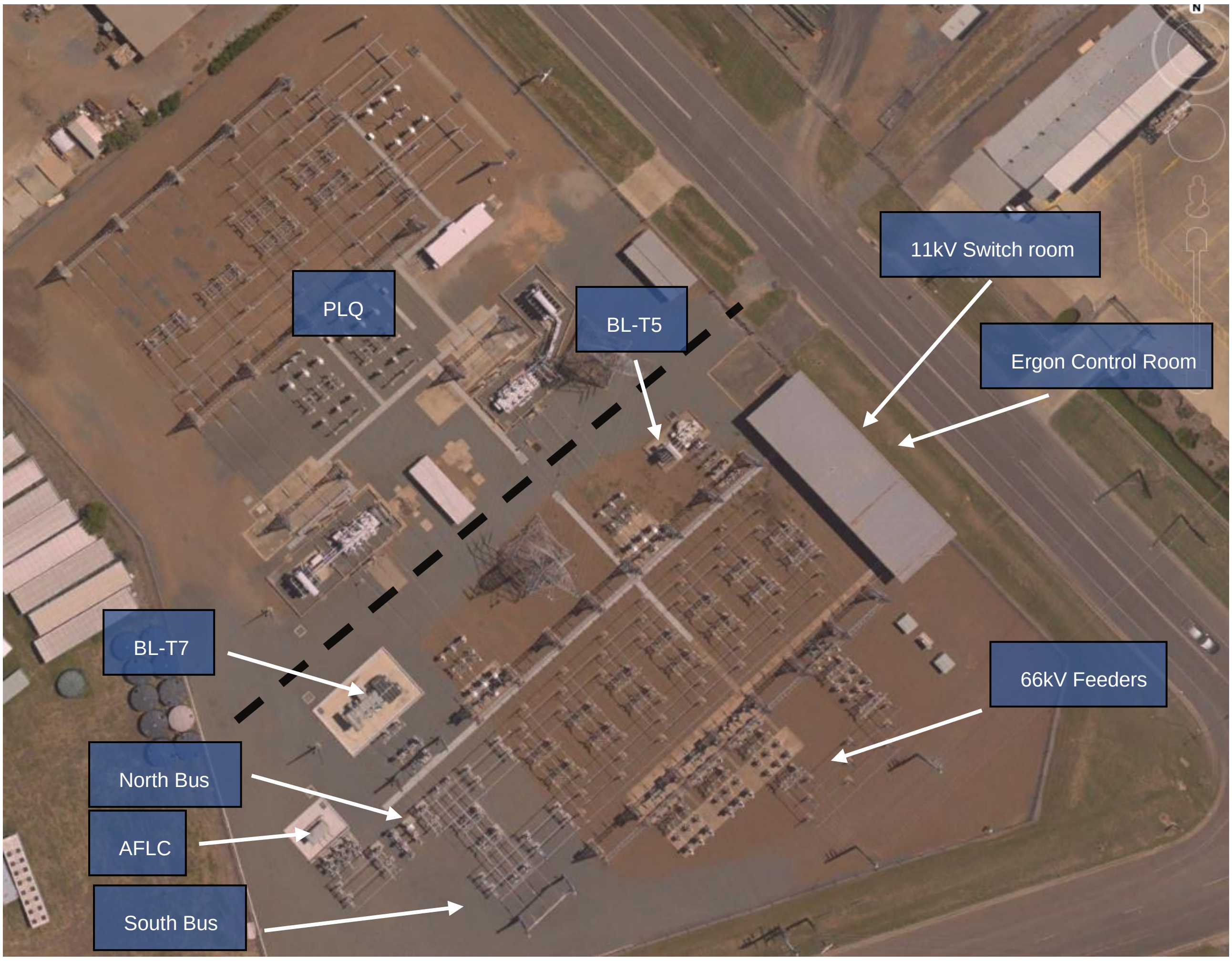


Figure 5: Biloela Substation (geographic view)

2.3. Load Profiles / Forecasts

The primary limitation at BILO is the poor conditioned 11kV equipment. The load profiles and forecasts presented here will focus on the 11kV load. However, the combined 66kV load has also been provided.

2.3.1. Full Annual Load Profile

The full annual load profile for Biloela 66/11kV zone substation for 2020/21 financial year is shown in Figure 7 and the combined 66kV feeder load is shown in Figure 6. The peak on the 11kV occurs through the summer period, however it does not exceed the N-1 capacity of 27.25MVA.

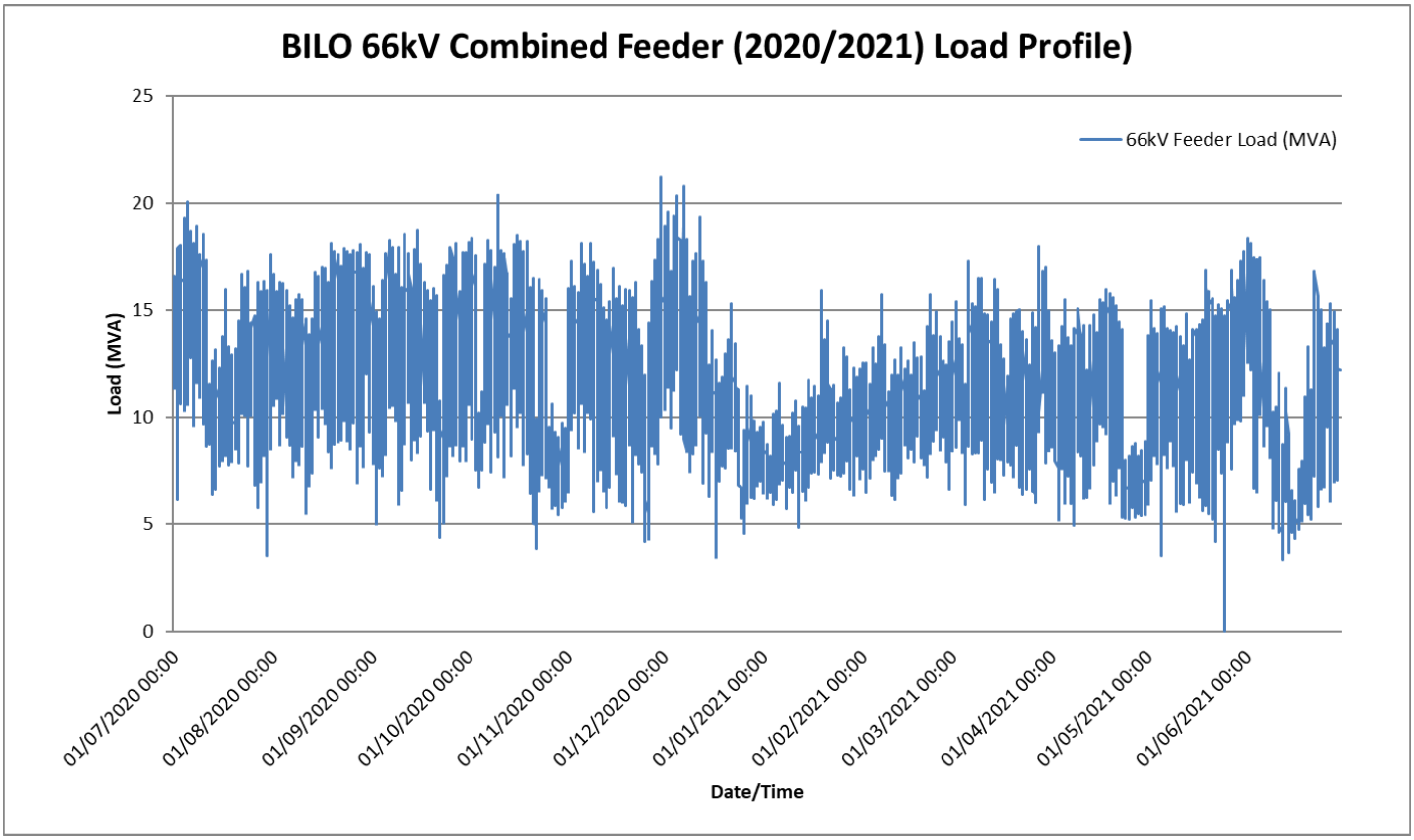


Figure 6: Biloela 66kV combined Feeder annual load profile

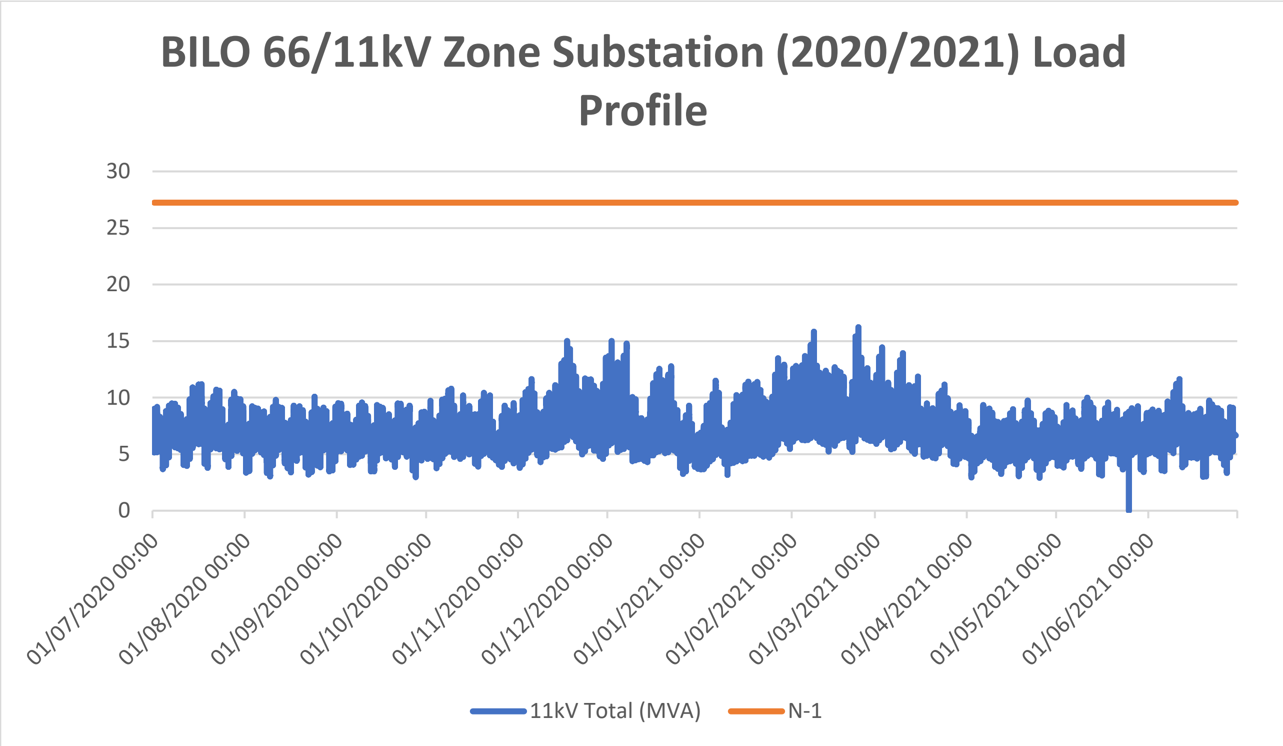


Figure 7: BILO 11kV loading

2.3.2. Load Duration Curve

The load duration curve for the 66kV combined feeder load for 2020/21 is shown in Figure 8 and the 11kV load duration is shown in Figure 9. The load does not exceed the N-1 capacity of 27.25MVA.

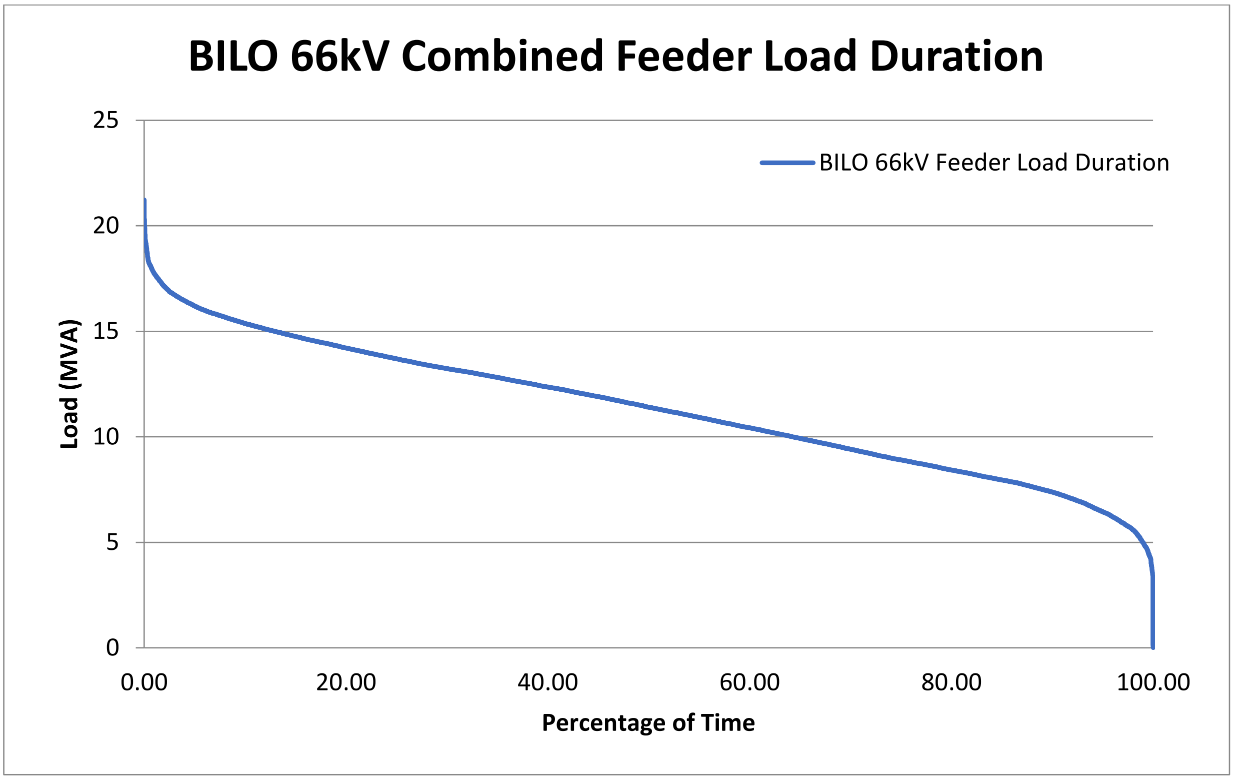


Figure 8: BILO 66kV Combined Feeder Load Duration

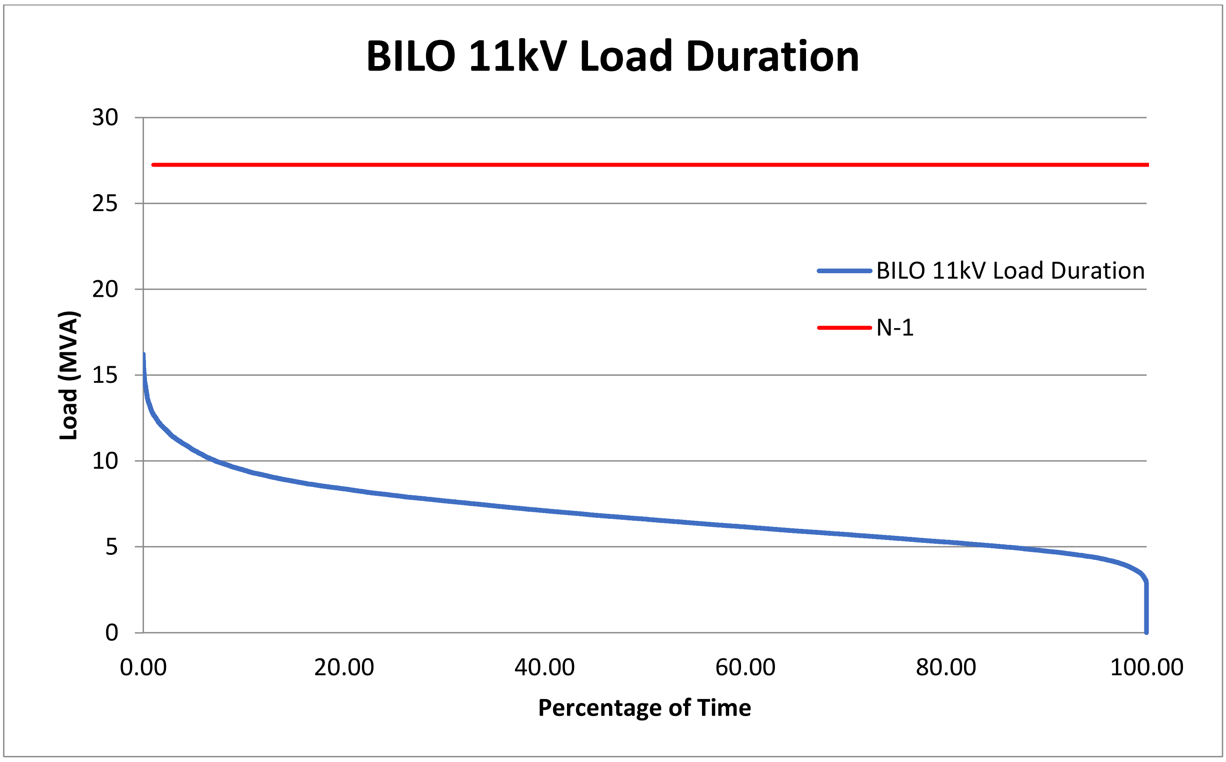


Figure 9: BILO 11kV Load Duration

2.3.3. Average Weekday Load Profile (Summer)

The daily load profile for the average and peak weekday during summer is illustrated below in Figure 10 and Figure 11. The summer peak loads for Biloela 11kV are historically experienced in the late afternoon and evening. As two of the 66kV feeders supply a mine, the load profile is more constant

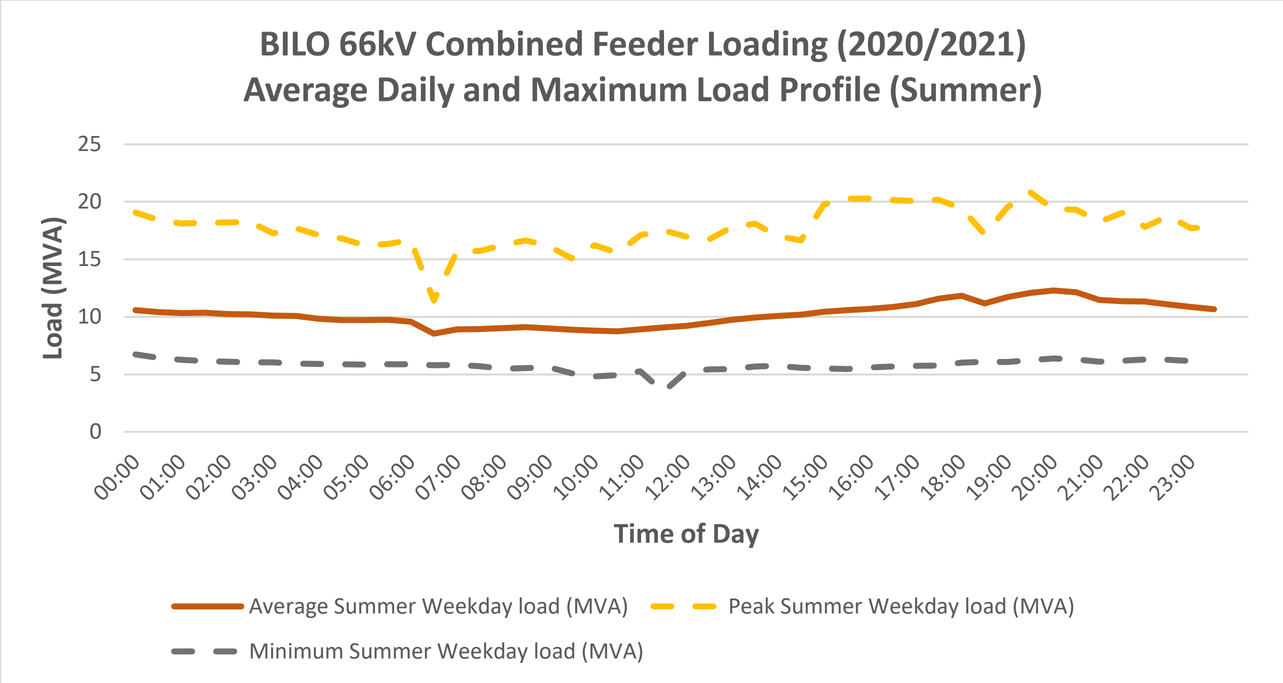


Figure 10: 66kV Average Daily and Maximum Load Profiles (Summer)

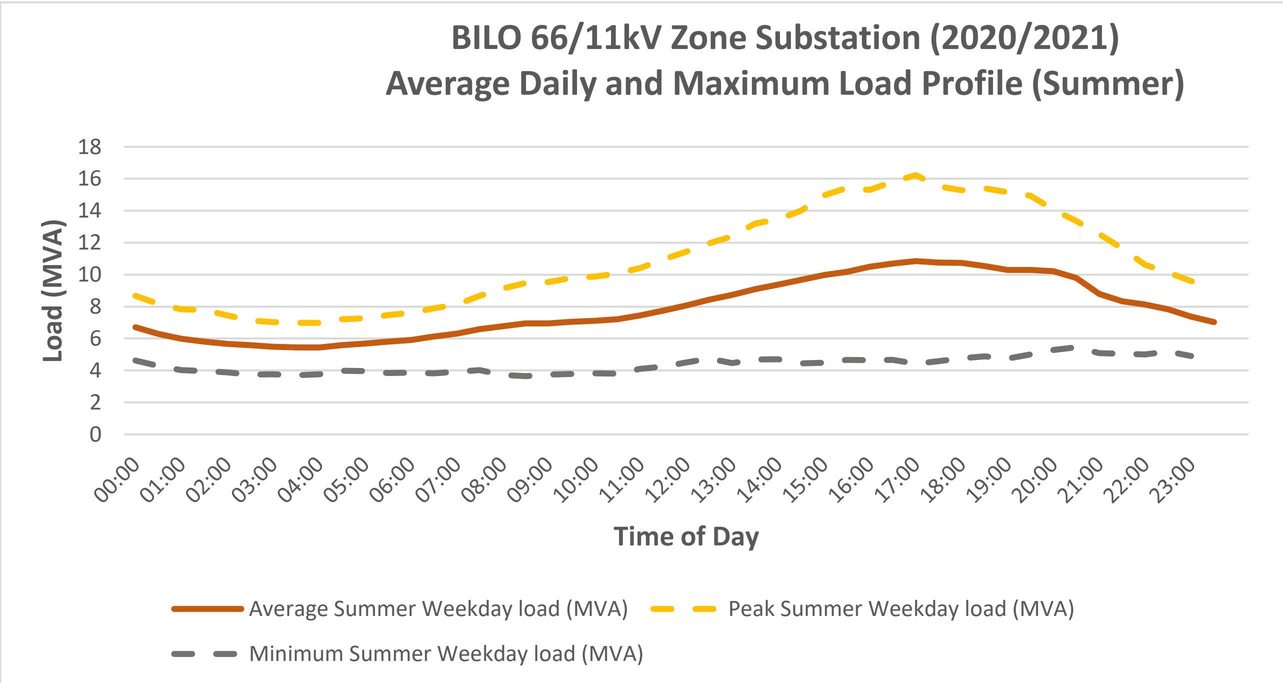


Figure 11: Average Daily and Maximum Load Profiles (Summer)

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 12. The historical peak load for the past five years has also been included in the graph. It can be seen that the forecast load growth in the base case scenario does not exceed the N-1 rating of 27.25MVA.

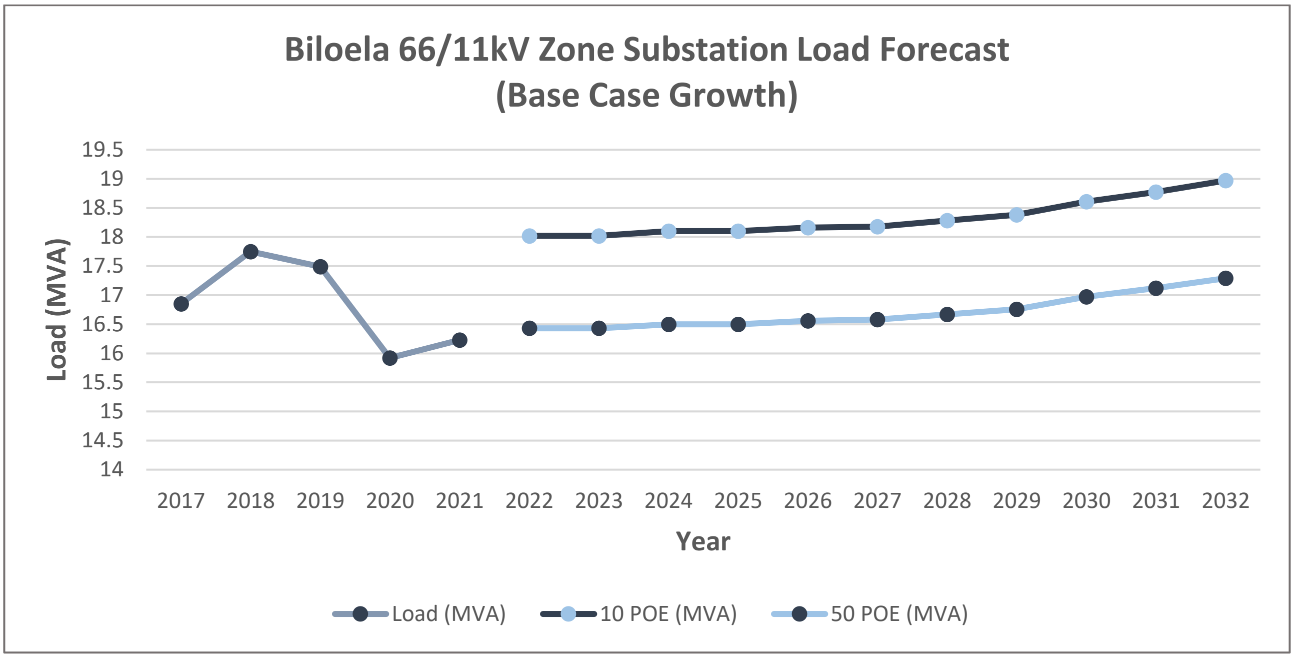


Figure 12: Network Base case load forecast

2.3.5. High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the high load growth scenario are illustrated Figure 13. With the high growth scenario, the peak load is forecast to increase over the next 10 years. It can be seen the forecast load growth in the base case scenario does not exceed the N-1 rating of 27.25MVA.

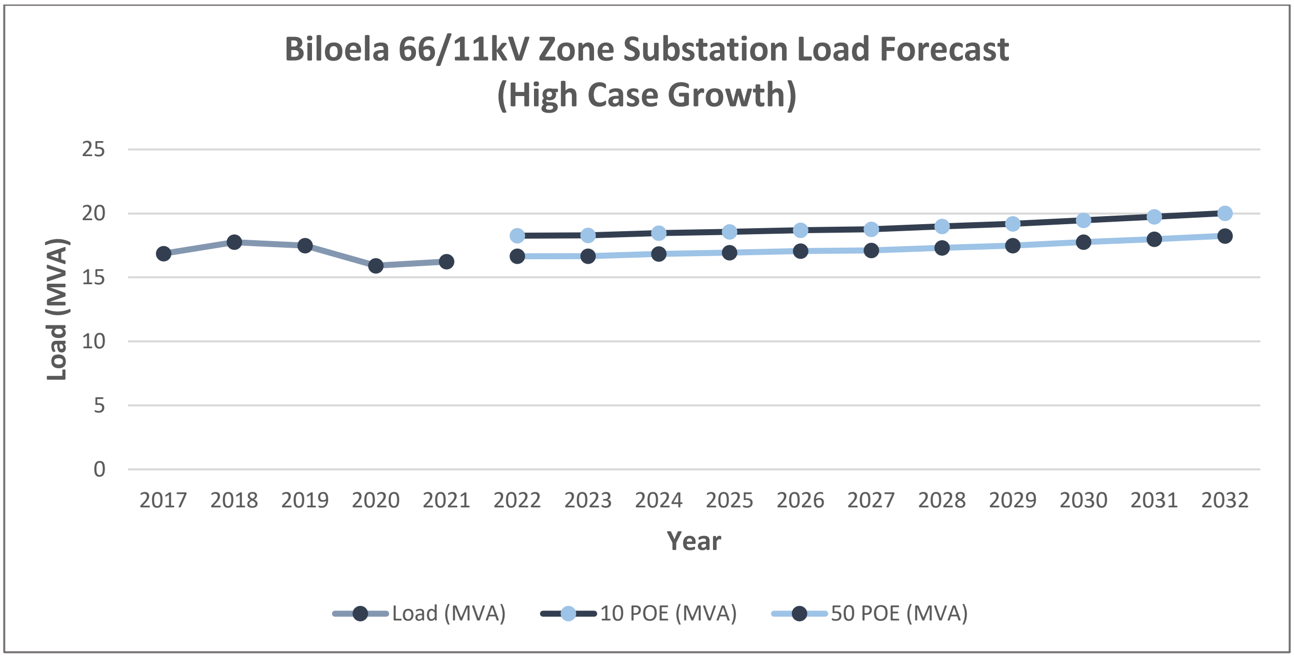


Figure 13: Network High Growth Load Forecast

2.3.6. Low Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the low load growth scenario are illustrated Figure 14. With the low growth scenario, the peak load is forecast to remain relatively steady over the next 10 years.

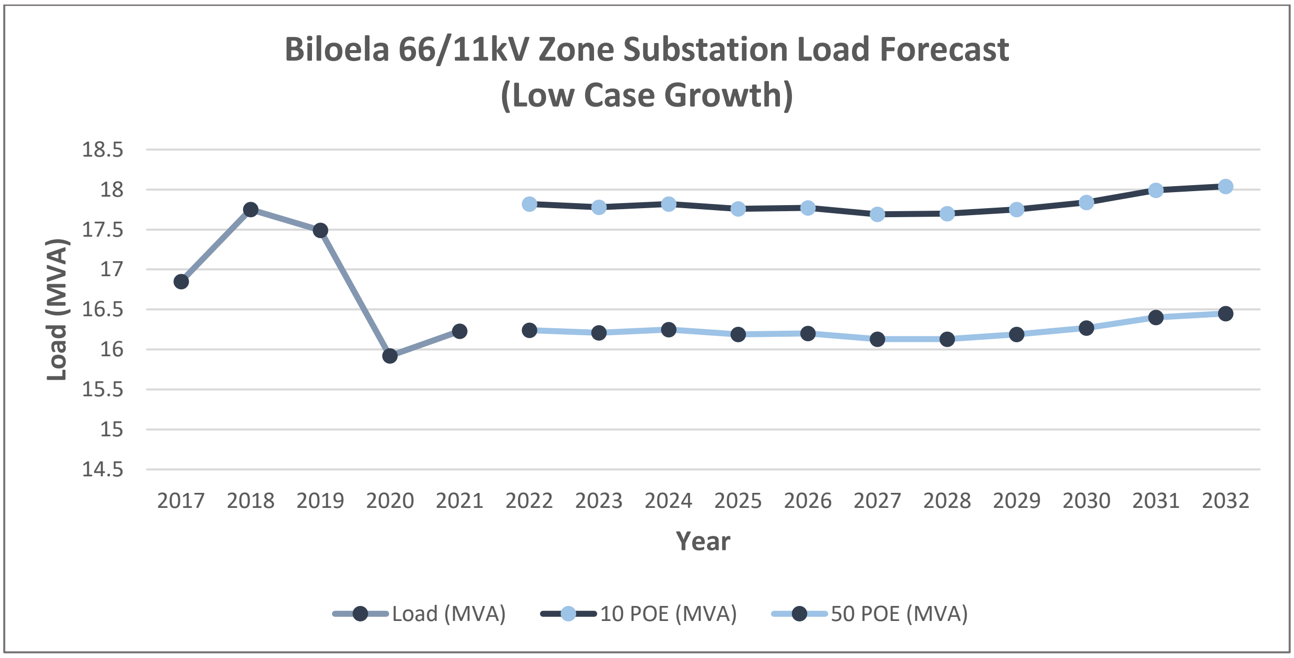


Figure 14: Network Low Growth Load Forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Poor Condition Assets

BILO substation was established circa 1965 to standards applicable at the time. A recent condition assessment and substation works have highlighted a number of critical assets are at the end of their serviceable life, are in poor condition or are targeted for removal. The condition of these assets presents considerable safety and customer reliability risk. These assets include:

- Replace 11kV switchboard and six (6) outgoing bays in new switch room
- Six (6) 11kV Feeder Circuit Breakers
- One (1) 11kV Bus Breaker
- Two (2) 11kV Transformer Circuit Breakers
- Two (2) 11kV Voltage transformer set
- Remove one (1) 11kV surge arrestor
- One (1) 66kV Circuit Breakers
- One (1) 66kV Current Transformer
- One (1) 66kV Voltage transformer set
- One (1) 66kV Surge Arrestor set
- One (1) 66kV Air Break Switch
- One (1) 66kV Marshalling Box
- Thirty (30) Protection Relays

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 from Biloela Substation.

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.

3.1.2. Reliability

Currently the aged assets present a risk to the reliability of supply at Biloela. Figure 15 shows that the value of customer reliability by replacing the assets is $800,000 after the first five years. The scenarios that have been considered included:

- 11kV feeder CB failure
- 11kV transformer CB failure
- Bus section CB failure and;
- 1 x 66kV CB failure

For the 66kV CB the load can be immediately transferred onto the adjacent feeder and therefore no load was considered to be at risk. For 11kV feeder and/or transformer CB failure it was assumed that up to half the load on the 11kV switchboard could potentially be lost; however, it was assumed that this load could be supplied by transfers within 3hrs. This provides a conservative estimate for VCR.

A bus fault would result in an outage to all 11kV customers, which affects 4,000 customers and results in a load at risk of approximately 20MVA. Given the condition of the board it has been assumed that a bus fault could cause permanent, irreversible damage to the switchboard, with no ability to transfer the load.

3.2. Quantification of the Identified Need

3.2.1. 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 the 11kV switchboard, feeder CBs, bus section CB, transformer CBs, one 66kV CB and most of the protection relays are 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 Biloela Substation.

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

3.2.2. Risk Quantification Benefit Summary

Risk quantification analysis has been completed for option A which includes the value of customer reliability and cost of emergency replacement. Figure 15 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 and maintenance and operation. The benefits of this is option is greater than $1M by 2032.

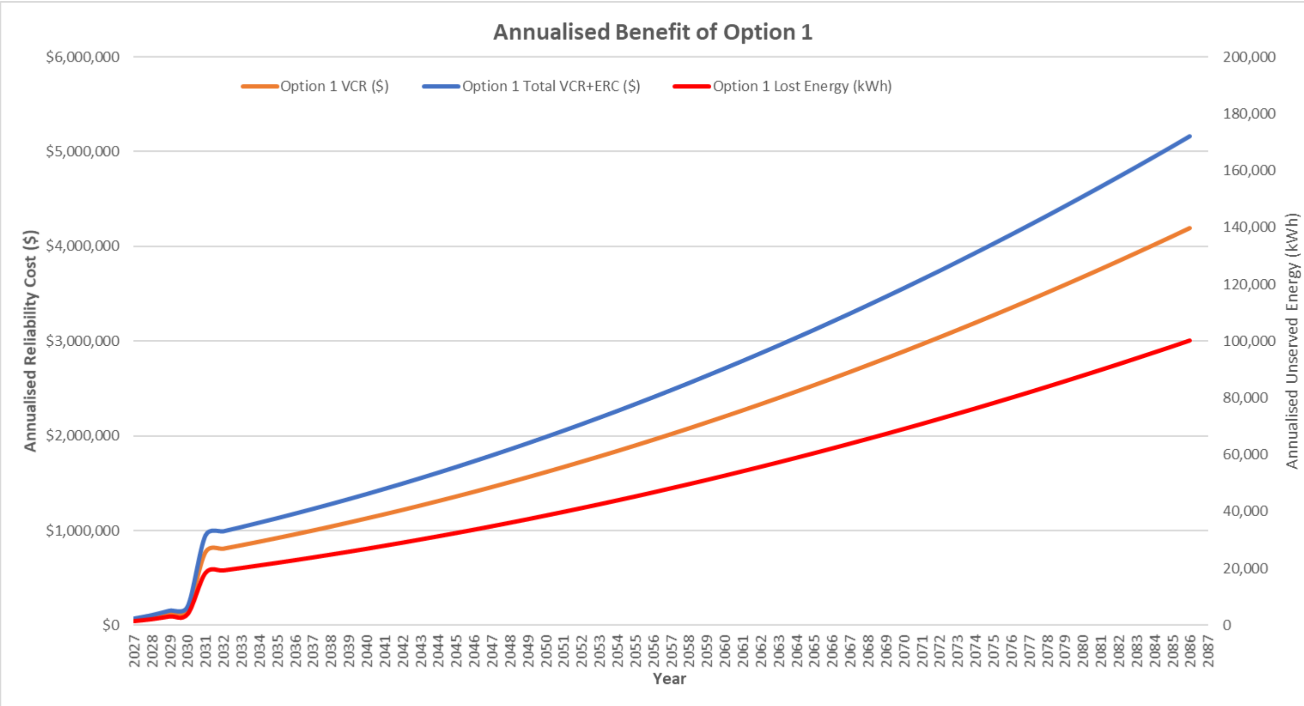


Figure 15: Annualised Benefits of Option 1 compared with Counter-factual

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 Biloela Substation will be consistent with the base case forecast outlined in Section 2.3.4.

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. Future Load Profile

Characteristic average day load profiles shown in Section 2.3.3 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.

3.3.3. System Capability – Line Ratings

The lines supplying T26 Biloela 132/66/11kV are owned and operated by Powerlink QLD.

4. TECHNICAL CHARACTERISTICS OF NON-NETWORK OPTIONS

This section describes the technical characteristics of the identified need that a non-network option would be required to comply with. The information provided in this section should be understood within the context that Ergon Energy has published a Notice of No non-network options. Any non-network options would be required to supply the entire 11kV load continuously and remove the safety and customer risks relating to the 11kV switchboard.

4.1. Size

To meet Ergon Energy's ongoing operational needs, it is expected that any alternate solution must provide stand-alone supply to the distribution network that supports a load up to the values listed in the table below.

Year	Demand Reduction Required
2021	18.75 MVA
2022	18.75 MVA
2023	19 MVA
2024	19 MVA
2025	19 MVA
2026	19 MVA
2027	19 MVA
2028	19 MVA
2029	19 MVA
2030	20 MVA
2031	20 MVA

Table 1: Demand reduction required

4.2. Location

The location where network support and load restoration capability will be measured / referenced is the Biloela 11kV bus. Options located downstream of the 11kV bus can only be considered where it mitigates the safety and customer risks relating to the 11kV switchboard.

4.3. Timing

4.3.1. Implementation Timeframe

In order to ensure compliance with Ergon Energy's planning criteria and the National Electricity Rules, a non-network solution will need to be implemented by March 2027.

4.3.2. Time of Year and Duration

Non-network options will need to be capable of supplying the full 11kV load continuously, 24 hours a day, every day of the year.

4.4. Compliance with Regulations and Standards

As a distribution network service provider, Ergon Energy must comply with regulations and standards, including the Queensland Electricity Act and Regulation, Distribution Authority, National Electricity Rules and applicable Australian Standards.

These obligations must be taken in consideration when choosing a suitable solution to address the identified need at Biloela as discussed in this RIT-D report.

4.5. Longevity

Proposed non-network options will typically be required to provide solutions to the identified need for a period of at least 40 years. However, alternative solutions that can defer additional network investment for a smaller number of years may also be considered.

4.6. Potential Deferred Augmentation Charge

The annual deferred augmentation charge associated with the identified need is approximately $430k per year.

4.7. Feasible vs Non-Feasible Options

4.7.1. Potentially Feasible Options

The identified need presented in this RIT-D is driven by the capability and reliability of the existing distribution network that supplies Biloela. As such, solutions that cost-effectively provide increased contingency load restoration capability are likely to represent reasonable options.

Ergon Energy has not identified any feasible non-network options.

4.7.2. Options that are Unlikely to be Feasible

Without attempting to limit a potential proponent's ability to innovate when considering opportunities, some technologies / approaches are unlikely to represent a technically or financially feasible solution.

A non-exhaustive list of options that are unlikely to be feasible includes:

- Renewable generation

- Battery Energy Storage Systems
- Unproven, experimental, or undemonstrated technologies

4.7.3. Timing of Feasible Options

In order to ensure compliance with Ergon Energy's planning criteria and the National Electricity Rules, a non-network solution will need to be implemented before March 2027.

5. CREDIBLE OPTIONS ASSESSED

5.1. Assessment of Network Solutions

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

5.1.1. Option 1: Biloela Asset Replacement

This option involves replacement of primary plant and secondary systems works

- Summary of Primary Plant Works
  - Replace 11kV switchboard in new switch room
  - Replace six (6) 11kV feeder CBs
  - Replace one (1) 11kV bus CB
  - Replace two (2) 11kV transformer CBs
  - Replace two (2) 11kV voltage transformer sets
  - Remove on (1) 11kV surge arrestors
  - Replace one (1) 66kV CB
  - Replace one (1) 66kV CT
  - Replace one (1) 66kV VT set
  - Replace one (1) 66kV surge arrestor set
  - Replace one (1) 66kV ABS
  - Replace one (1) Marshalling box
- Summary of Secondary Systems Works
  - Replace the 11kV Bus Zone 1 and Bus Zone 2 protection relay.
  - Replace Monto 66kV distance relay and OC/EF relay with duplicate X & Y protection relay
  - Replace Monto 66kV statical metering relay
  - Replace Wowan 66kV distance relay and OC/EF relay with duplicate X & Y protection relay
  - Replace Wowan 66kV statical metering relay
  - Replace Boundary Mine 66kV distance relay and OC/EF relay with duplicate X & Y protection relay
  - Replace Boundary Mine 66kV statical metering relay
  - Replace Callide Mine 66kV distance relay and OC/EF relay with duplicate X & Y protection relay
  - Replace Callide Mine 66kV statical metering relay

- Replace two (2) electro-mechanical high impedance bus zone relays with two (2) high impedance or low impedance relays (pending detailed design)
- Replace 66kV bus zone protection relay
- Replace right and left 11kV bus protection schemes and neutral check scheme with current standard protection relays
- Replace three (3) 11kV electro-mechanical protection relays with single MICOM P142 (or equivalent) for Biloela North feeder
- Replace three (3) 11kV electro-mechanical protection relays with single MICOM P142 (or equivalent) for Callide
- Replace three (3) 11kV electro-mechanical protection relays with single MICOM P142 (or equivalent) for Meissner
- Replace three (3) 11kV electro-mechanical protection relays with single MICOM P142 (or equivalent) for Prairie St
- Replace three (3) 11kV electro-mechanical protection relays with single MICOM P142 (or equivalent) for Washpool St
- Perform a HVAC study for the control room and install HVAC systems to ensure the longevity of all equipment therein, including modern electronic protection, comms and SCADA equipment, batteries and the 11kV switchgear
- Install duplicate DC system and associated distribution

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $12.062 million. Annual operating and maintenance costs are anticipated to be 1.5% of the capital cost.

A schematic diagram of the proposed network arrangement for Option 1 is shown in Figure 16.

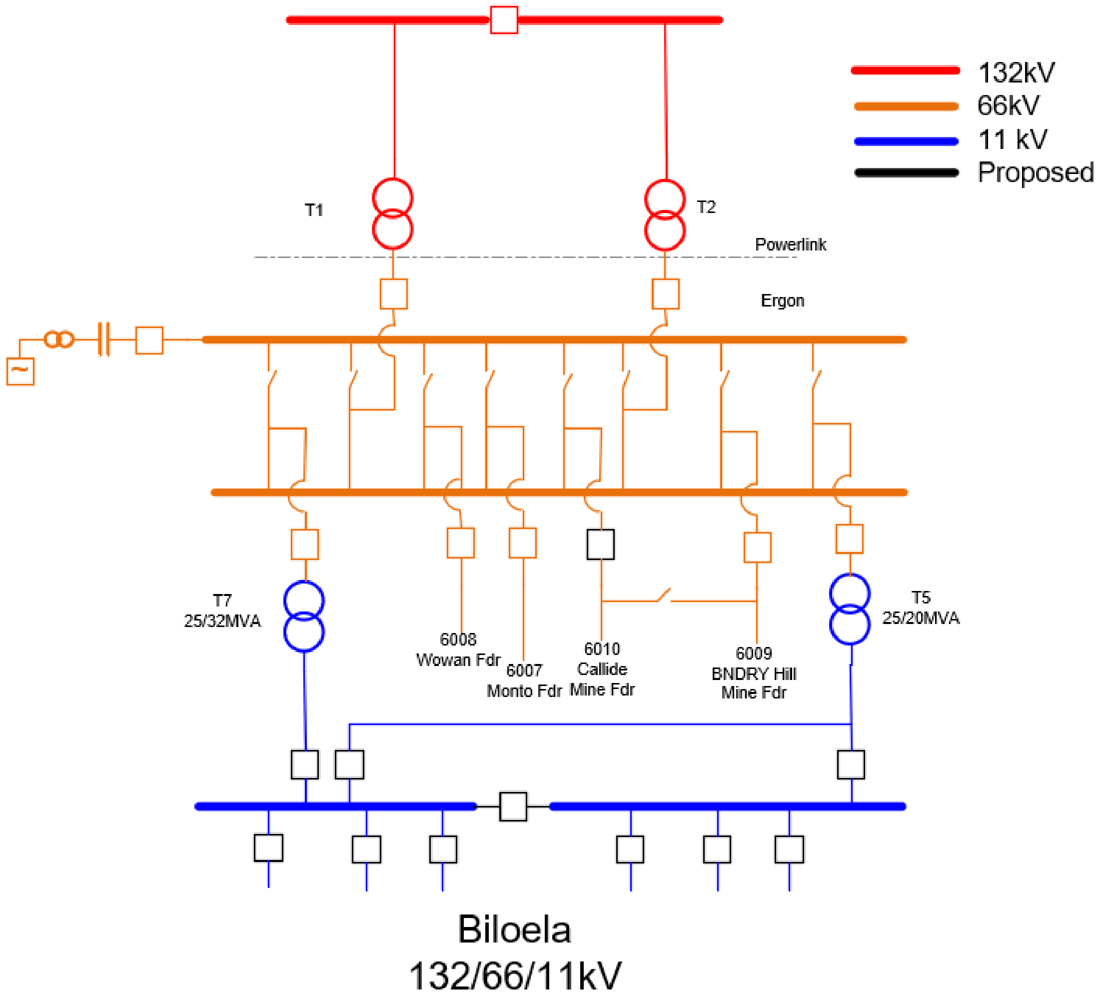


Figure 16: Option A proposed network arrangement (schematic view)

5.2. Assessment of Non-Network Solutions

A Notice of no non-network options was published as Ergon Energy as our investigations did not reveal any credible non-network solutions to address the identified need.

5.2.1. Demand Management (Demand Reduction)

A non-network investigation Ergon Energy normally undertakes is to assess the potential of demand and energy management solutions. However, for this project to be deferred, the 11kV load would need to be reduced to be zero MVA, therefore demand reduction is not applicable.

5.2.2. 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 Biloela area to address the identified need.

5.3. Preferred Network Option

Ergon Energy's preferred internal network option is Option 1: BILO Asset Replacement.

Upon completion of these works, the asset safety and reliability risks at BILO 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 $12.062 million. Annual operating and maintenance costs are anticipated to be 1.5% of the capital cost. The estimated project delivery timeframe has design commencing in September 2022 and construction completed by March 2027.

6. NOTICE OF NO NON-NETWORK OPTIONS

On 20th December 2021, Ergon Energy published the Notice of No Non-Network Options providing details on the identified need at Biloela Zone substation. This report provided the technical information of the poor condition asset limitations and identified that no non-network options were viable. However, as the value of the project is >$11M the RIT-D process requires that a DPAR be published before publishing the FPAR in accordance with NER clause 5.17.4(i).

7. 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.

7.1. 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. This can be seen in Section 3.2 to have a material impact; and has therefore been included in this RIT-D assessment. All Market benefits considered have been listed in section 7.2 for completeness.

7.1.1. 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. Options which will remove or reduce the involuntary load shedding will have a market benefit.

7.2. 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

7.2.1. 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 Biloela area at present, any market benefits associated with changes in voluntary load curtailment have not been considered.

7.2.2. 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.

7.2.3. Changes in Timing of Expenditure

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

7.2.4. 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 BILO area.

7.2.5. 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.

7.2.6. 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

8. DETAILED ECONOMIC ASSESSMENT

8.1. Methodology

The Regulatory Investment Test for Distribution 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 National Electricity Market.

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

8.2. 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 for which approval is being sought as it represents a legitimate cost of network augmentation.

8.3. Net Present Value (NPV) Results

An overview of the initial capital cost and the base case NPV results are provided in Table 2.

Option	Option Name	Rank	Initial Capital Cost	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
1	BILO Asset Replacement	1	$12,062,000	$49, 337,000	-$11,766,000	-$603,000

Table 2: Base case NPV table

8.4. Selection of Preferred Option

Ergon Energy's preferred internal network option is Option 1: BILO Asset Replacement.

This option involves replacement of primary plant and secondary systems works

- Summary of Primary Plant Works
    - Replace 11kV switchboard in new switch room
    - Replace six (6) 11kV feeder CBs
    - Replace one (1) 11kV bus CB
    - Replace two (2) 11kV transformer CBs

- Replace two (2) 11kV voltage transformer sets
- Remove on (1) 11kV surge arrestors
- Replace one (1) 66kV CB
- Replace one (1) 66kV CT
- Replace one (1) 66kV VT set
- Replace one (1) 66kV surge arrestor set
- Replace one (1) 66kV ABS
- Replace one (1) Marshalling box

- Summary of Secondary Systems Works
  - Replace the 11kV Bus Zone 1 and Bus Zone 2 protection relay.
  - Replace Monto 66kV distance relay and OC/EF relay with duplicate X & Y protection relay
  - Replace Monto 66kV statical metering relay
  - Replace Wowan 66kV distance relay and OC/EF relay with duplicate X & Y protection relay
  - Replace Wowan 66kV statical metering relay
  - Replace Boundary Mine 66kV distance relay and OC/EF relay with duplicate X & Y protection relay
  - Replace Boundary Mine 66kV statical metering relay
  - Replace Callide Mine 66kV distance relay and OC/EF relay with duplicate X & Y protection relay
  - Replace Callide Mine 66kV statical metering relay
  - Replace two (2) electro-mechanical high impedance bus zone relays with two (2) high impedance or low impedance relays (pending detailed design)
  - Replace 66kV bus zone protection relay
  - Replace right and left 11kV bus protection schemes and neutral check scheme with current standard protection relays
  - Replace three (3) 11kV electro-mechanical protection relays with single MICOM P142 (or equivalent) for Biloela North feeder
  - Replace three (3) 11kV electro-mechanical protection relays with single MICOM P142 (or equivalent) for Callide
  - Replace three (3) 11kV electro-mechanical protection relays with single MICOM P142 (or equivalent) for Meissner
  - Replace three (3) 11kV electro-mechanical protection relays with single MICOM P142 (or equivalent) for Prairie St
  - Replace three (3) 11kV electro-mechanical protection relays with single MICOM P142 (or equivalent) for Washpool St

- Perform a HVAC study for the control room and install HVAC systems to ensure the longevity of all equipment therein, including modern electronic protection, comms and SCADA equipment, batteries and the 11kV switchgear
- Install duplicate DC system and associated distribution

Upon completion of these works, the asset safety and reliability risks at BILO 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 $12.062 million. Annual operating and maintenance costs are anticipated to be 1.5% of the capital cost. The estimated project delivery timeframe has design commencing in September 2022 and construction completed by March 2027.

8.5. 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. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

9. SUBMISSION AND NEXT STEPS

9.1. Submissions from Solution Providers

Ergon Energy invites written submissions to address the identified need in this report from registered participants and interested parties.

Ergon Energy will not be legally bound in any way or otherwise obligated to any person who may receive this RIT-D report or to any person who may submit a proposal. At no time will Ergon Energy be liable for any costs incurred by a proponent in the assessment of this RIT-D report, any site visits, obtainment of further information from Ergon Energy or the preparation by a proponent of a proposal to address the identified need specified in this RIT-D report.

The RIT-D process is aimed at identifying a technically feasible non-network alternative to the internal option that has greater net economic benefits. However, the selection of the solution provider to implement the preferred option will be done after the conclusion of the Final Project Assessment Report (FPAR) and in accordance with Ergon Energy's standards for procurement.

Submissions in writing are due by 4pm on the **25 February 2022** and should be lodged to demandmanagement@ergon.com.au

9.2. Next Steps

Following Ergon Energy's consideration of submissions received in response to this report, the preferred option, and a summary of and commentary on any submissions received will be included as part of the Final Project Assessment Report (FPAR). The FPAR represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to publish the FPAR no later than 01 March 2022. Ergon Energy will use its reasonable endeavours to publish the FPAR by the above date. This may however not be achievable due to changing power system conditions or other circumstances beyond the control of Ergon Energy.

At the conclusion of the consultation process, Ergon Energy intends to take steps to progress the recommended solution(s) to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvement(s), as necessary.

Please note that at the conclusion of the Final Project Assessment Report (FPAR), for Ergon Energy to act on a submission from a non-network proponent, Ergon Energy will need to enter into a legally binding contract with that non-network proponent for delivery of the non-network solution within a timeframe satisfactory to Ergon Energy to ensure timely completion of the project. Failure to enter into a contract within a satisfactory timeframe will result in Ergon Energy reverting to the next preferred credible option identified in the FPAR.

Step 1	Publish Notice of No Non-Network Options	Date Released: **20 December 2021**
Step 2	Release of Draft Project Assessment Report (DPAR)	Date Released: **22 December 2021**
Step 3	Consultations in response to the DPAR	**Minimum of 6 weeks**
Step 4	Publish the Final Project Assessment Report (FPAR)	Anticipated to be released by: **01 March 2022**
Ergon Energy reserves the right to revise this timetable at any time. The revised timetable will be made available on the Ergon Energy RIT-D website.		

Ergon Energy will take all reasonable efforts to maintain the consultation schedule listed above. Due to various circumstances the schedule may change, however, up-to-date information will be available on the Ergon Energy website.

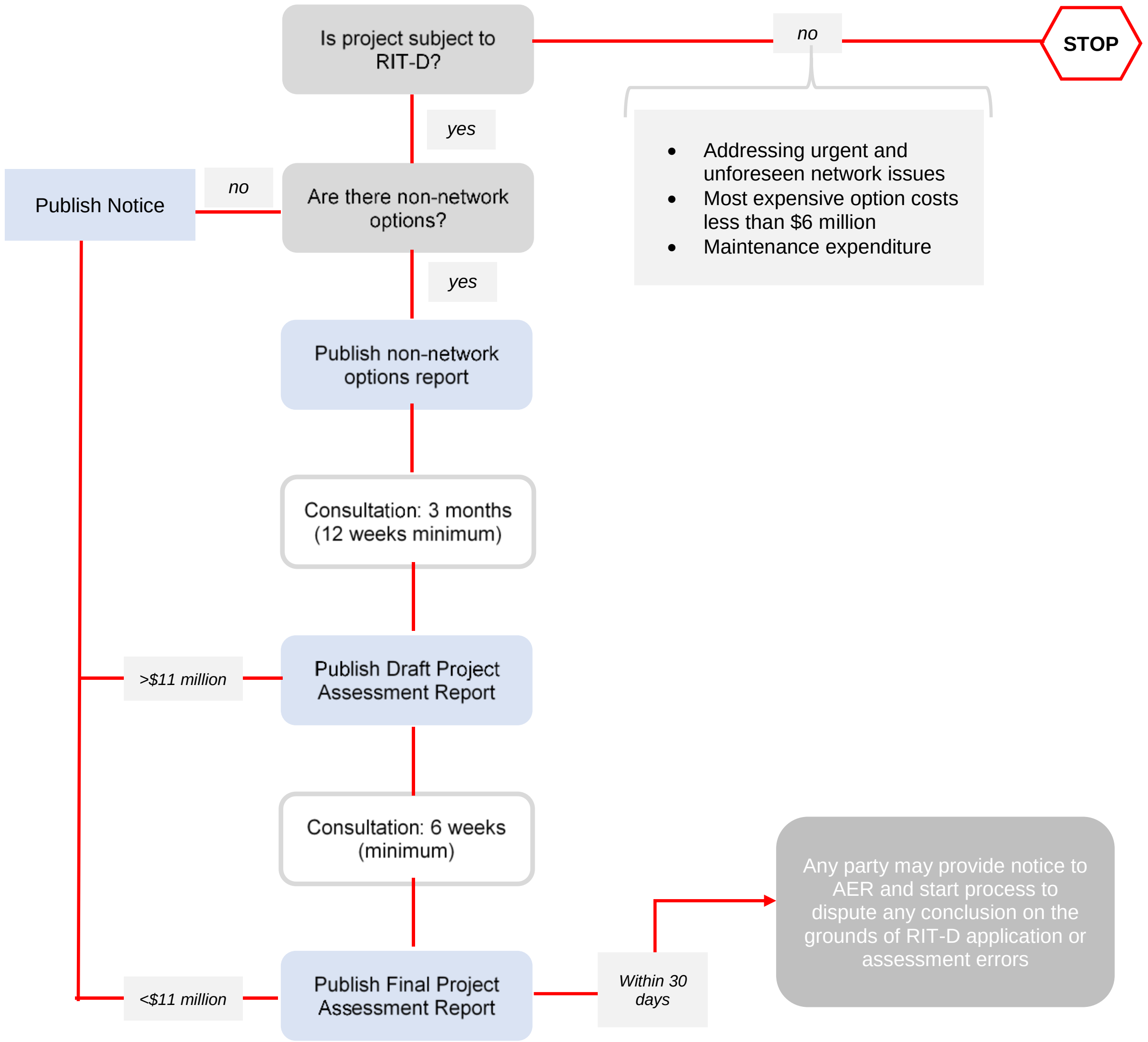
During the consultation period, Ergon Energy will review, compare and analyse all internal and external solutions. Detailed economic options analysis and comparisons of expected market benefits will be undertaken during this time. At the end of the consultation and review process Ergon Energy will publish a final report which will detail the most feasible option and proceed to implement that option.

10. COMPLIANCE STATEMENT

This Draft Project Assessment Report 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 NNOR;	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	7
(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	7.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	8
(10) the identification of the proposed preferred option	8.4
(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	8.4 & 8.5
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	9.1

APPENDIX A – THE RIT-D PROCESS



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