# Regulatory Investment Test for Distribution (RIT-D)

# Addressing increased customer demand in the Bohle Plains Area

## Draft Project Assessment Report

7 March 2025

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

The Northern Beaches and Bohle Plains areas have been the main development areas in the Townsville region over the past few years with several new subdivisions under development including Sanctum, Mt Low, Kingston Park, North Shore, Greater Ascot, Cosgrove, Liberty Rise, Kalynda Chase, Harris Crossing, Mount Margaret and The Reserve. Due to the projected growth in this area Ergon Energy strategically acquired future substation sites at Mt Low and Bohle Plains to cater for the future electrical supply requirements.

The Bohle Plains area is currently supplied from the DG-07, DG-10, BO-05 and BO-10 11kV distribution feeders from Dan Gleeson (DAGL) 66/11kV Substation and Bohle (BOHL) 66/11kV Substation. The DG-07, DG-10, BO-05 and BO-10 11kV feeders supply 4,181 predominantly residential customers and there has been significant growth in customer numbers and load due to the developments in the area.

Due to the forecasted increase in customer demand, Ergon Energy is seeking to invest in the network to undertake a reliability corrective action in order to continue to meet the service standards in its applicable regulatory instruments (Safety Net requirements imposed in its Distribution Authority[1] issued under the *Electricity Act 1994* (Qld)[2]). The forecast loading for the

[1] Ergon Energy Distribution Authority:
Section 7 - Guaranteed Service Levels
Section 8 - Distribution Network Planning
Section 9 - Minimum Service Standards
Section 10 – Safety Net

[2] QLD Electricity Act 1994 Part 5, Division 5, Section 42(a)

substations and distribution feeders supplying the Bohle Plains area is expected to exceed the available N-1 substation and feeder capacity within the next 10 years. In the event of a fault on a substation transformer or an underground substation exit cable for one of the feeders supplying the Bohle Plains area there is a risk that a portion of the forecast load would be unsupplied for more than 24 hours, thereby breaching Safety Net requirements.  The typical repair times for a substation transformer fault or an underground cable fault would exceed the 24 hour period required to restore supply to all customers.

## Local Renewable Energy Zones – Townsville

The Local Renewable Energy Zone (LREZ) pilot project being established in Townsville aims to put the community at the centre of the renewable energy transition by helping the community generate more renewable energy, store it, share it and coordinate it across the local electricity infrastructure that already exists. LREZs will maximise the value of local customer energy resources like solar, storage, EVs, hot water and other appliances by coordinating them with our network and network energy storage across entire communities to take full advantage of the scale and value of the roof tops of Queenslanders. The LREZ pilot project will see the deployment of up to 8.4MW/18.8MWh of battery storage and support up to an additional 2.8MW of solar PV, and 0.9MW of demand management across nearly 550 residential and commercial customer sites starting from January 2025. More information is available at https://www.ergon.com.au/network/manage-your-energy/smarter-energy/our-network-batteries/local-renewable-energy-zone-lrez-pilot.

The Bohle Plains area falls within the Townsville LREZ.  The LREZ is a trial project and despite having some clear targets for rooftop solar, energy storage and demand management, it is not yet clear whether those LREZ objectives will be sufficient to completely resolve the forecast identified constraints that this RIT-D Report outlines. For that reason, the steps required as part of the RIT-D will occur concurrently to the LREZ project. The project teams for both this project and LREZ project will continue to collaborate throughout the life of both projects to ensure that the most appropriate solution or mix of solutions is deployed to ensure that Ergon Energy Network can continue to meet Safety Net requirements and to provide electricity to the consumers in the Bohle Plains supply area in a reliable, safe and cost-effective manner.

## 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 meet Safety Net requirements and to provide electricity to the consumers in the Bohle Plains supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

Ergon Energy published an Options Screening Report for the identified need in the Bohle Plains area on 12 October 2024. No submissions were received by the closing date of 31 January 2025.

Three potentially feasible options have been investigated:

- **Option A:** Establish Bohle Plains Zone Substation with a single 66/11kV transformer.

- **Option B:** Establish Bohle Plains Zone Substation with two 66/11kV transformers.
- **Option C:** Upgrade Dan Gleeson, Bohle and Black River Substations and install additional 11kV feeders into the area to defer the establishment of Bohle Plains Substation.

This Draft Project Assessment Report (DPAR), where Ergon Energy provides both technical and economic information about possible solutions, has been prepared in accordance with clause 5.17.4(i) of the NER and includes the required contents pursuant to clause 5.17.4(j) of the NER.

Ergon Energy's preferred solution to address the identified need is Option A, to establish a new zone substation at Bohle Plains with 2 x 66kV feeder bays, 1 x 66kV transformer bay, 1 x 32MVA 66/11kV transformer, 11kV switchboard, establishment of 4 x 11kV feeders and reconfiguration of the BLRI, BOHL and DAGL 11kV network.

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

Submissions in writing are due on **24 April 2025** by 4pm and must be lodged to demandmanagement@ergon.com.au

For further information and inquiries please contact:

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

# CONTENTS

# 1. INTRODUCTION

This Draft Project Assessment Report has been prepared by Ergon Energy in accordance with clause 5.17.4(i) of the NER and includes the required contents pursuant to clause 5.17.4(j) 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 Bohle Plains 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 Bohle Plains 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.
- Quantifies the applicable costs for each credible option, including a breakdown of operating and capital expenditure.
- 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 **24 April 2025** and should be lodged to demandmanagement@ergon.com.au.

# Addressing increased customer demand in the Bohle Plains Area Draft Project Assessment Report

For further information and inquiries please contact:

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

# 2. BACKGROUND

## 2.1. Geographic Region

The Bohle Plains area is currently supplied from the DG-07, DG-10, BO-05 and BO-10 11kV distribution feeders from Dan Gleeson (DAGL) 66/11kV Substation and Bohle (BOHL) 66/11kV Substation. DAGL is supplied from T092 Dan Gleeson 132/66kV Bulk Supply Substation which is located on the same site. The other two main substations in the Townsville West area BOHL and Black River (BLRI) 66/11kV substation are normally supplied from two 66kV feeders, the DAGL-BOHL 66kV feeder from T092 Dan Gleeson 132/66kV Bulk Supply Substation and the GARB-BOHL 66kV feeder from T046 Garbutt Bulk Supply Substation.

The geographical location of Ergon Energy's sub-transmission network and substations in the area is shown in Figure 1.

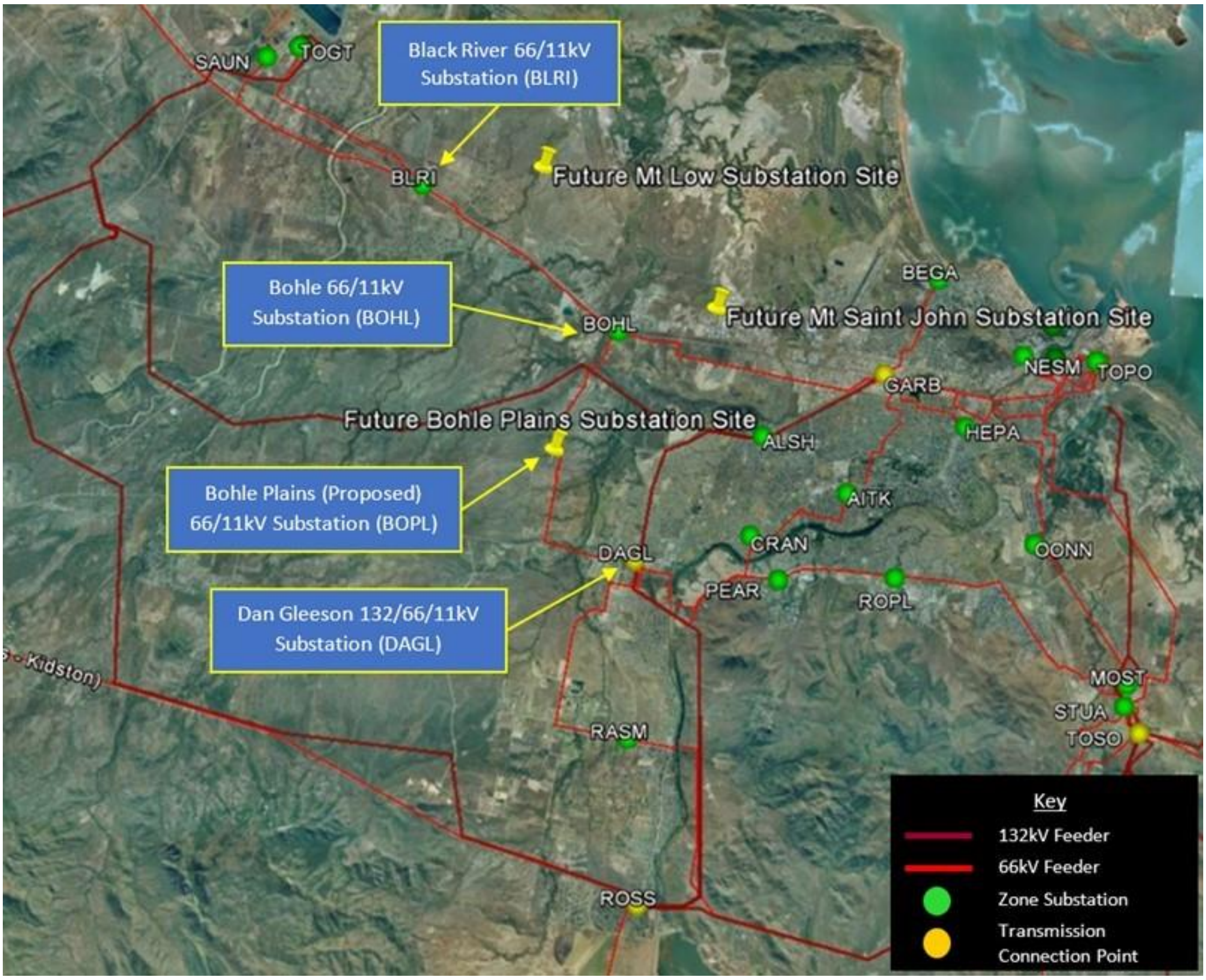



**Figure 1: Existing network arrangement (geographic view)**

## 2.2. Existing Supply System

The Bohle Plains area is currently supplied from the DG-07, DG-10, BO-05 and BO-10 11kV distribution feeders from Dan Gleeson (DAGL) 66/11kV Substation and Bohle (BOHL) 66/11kV Substation. DAGL is supplied from T092 Dan Gleeson 132/66kV Bulk Supply Substation which is located on the same site. The other two main substations in the Townsville West area BOHL and Black River (BLRI) 66/11kV substation are normally supplied from two 66kV feeders, the DAGL-BOHL 66kV feeder from T092 Dan Gleeson 132/66kV Bulk Supply Substation and the GARB-BOHL 66kV feeder from T046 Garbutt Bulk Supply Substation.

BOHL is equipped with 2 x 25MVA 66/11kV transformers and has 10 x 11kV feeders which supply approximately 5,112 predominantly residential customers. BOHL supplies 100 GWh of energy annually, with 35% of this energy consumed by residential customers.

DAGL is equipped with 2 x 25MVA 66/11kV transformers and has 10 x 11kV feeders which supply approximately 8,127 predominantly residential customers. DAGL supplies 95 GWh of energy annually, with 66% of this energy consumed by residential customers.

BLRI is equipped with 2 x 20MVA 66/11kV transformers and has 10 x 11kV feeders which supply approximately 8,349 predominantly residential customers. BLRI supplies 87 GWh of energy annually, with 78% of this energy consumed by residential customers.

The DG-07, DG-10, BO-05 and BO-10 11kV feeders supply 4,181 predominantly residential customers and there has been significant growth in customer numbers and load due to the developments in the area.

Energy Queensland has installed two 4MW/8MWh Battery Energy Storage Systems (BESS) in this part of the Ergon Energy network as part of the Local Network Battery Plan[3]. The Black River 4MW/8MWh BESS is connected to BLRI and the Bohle 4MW/8MWh BESS is connected to BOHL.

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

---

[3] https://www.ergon.com.au/network/manage-your-energy/smarter-energy/our-network-batteries

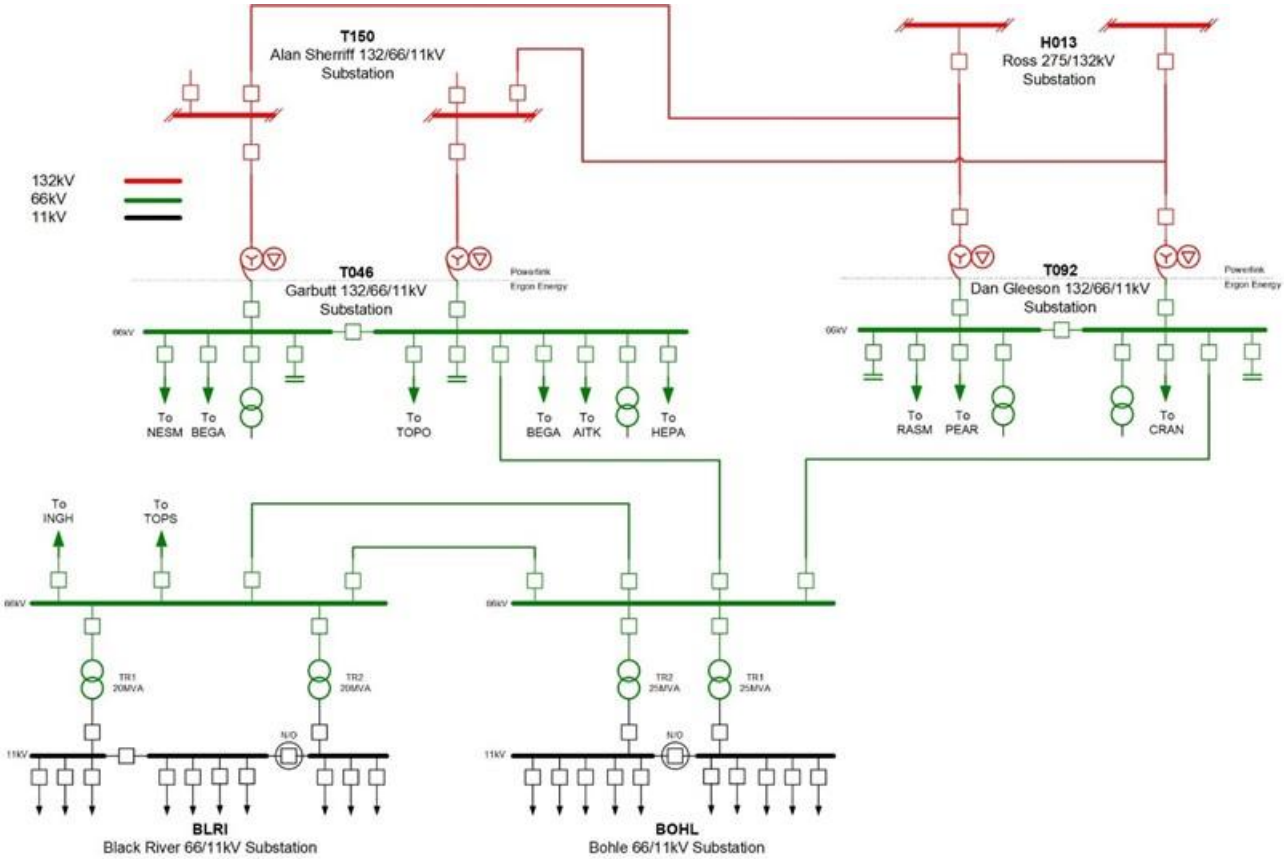



Figure 2: Existing network arrangement (schematic view)

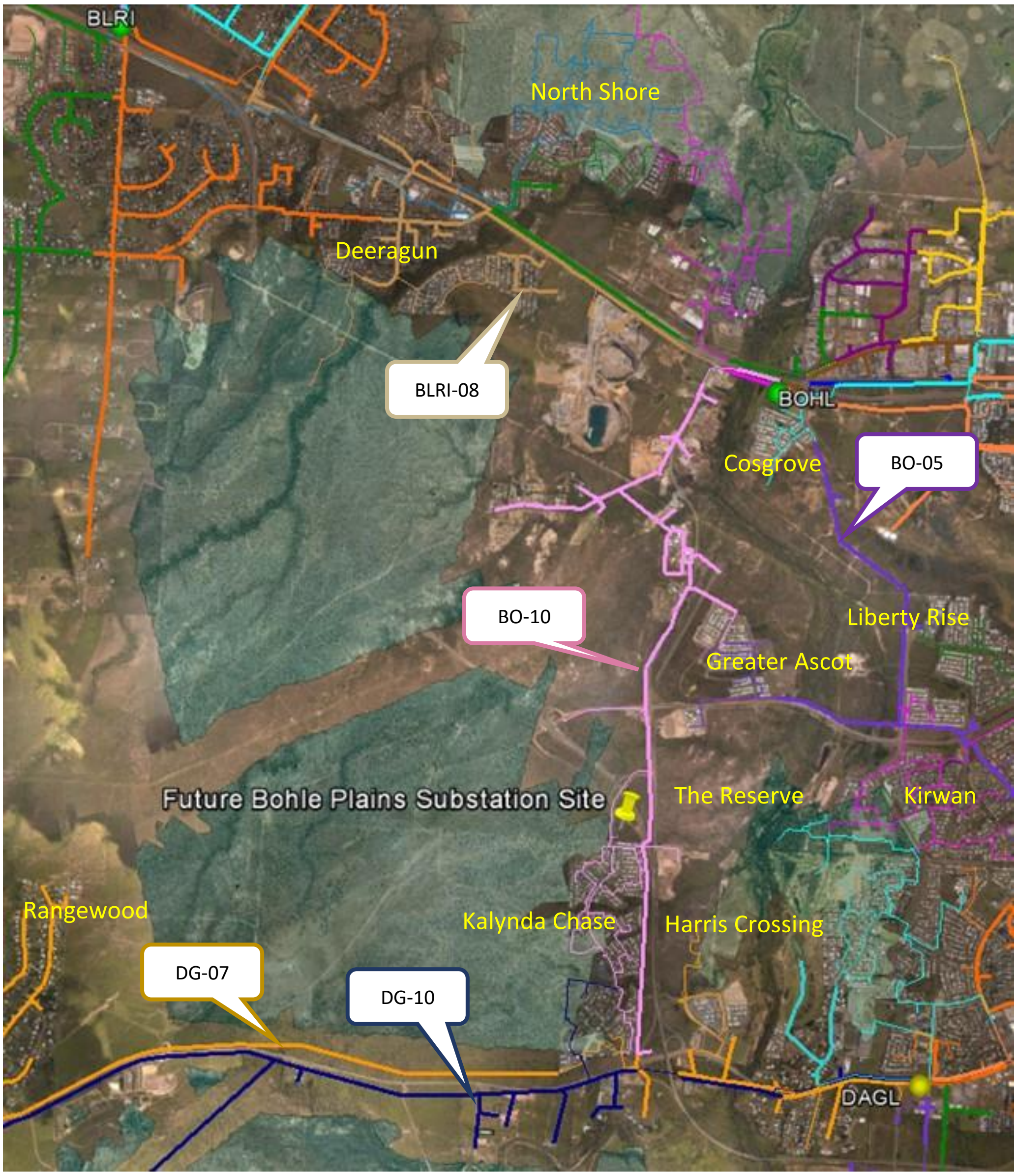



**Figure 3: 11kV distribution feeders supplying Bohle Plains area (geographic view)**

## 2.3. Load Profiles / Forecasts

The 11kV load at DAGL, BOHL and BLRI comprises a mix of residential and commercial/industrial customers. The load is Summer peaking, and the annual peak loads are predominantly driven by air conditioning loads during the Summer evening peak period. The annual minimum load generally occurs during the Winter and Spring midday period when export from rooftop solar PV systems can exceed the load in the area resulting in reverse flows from the distribution feeders into the zone substations.

### 2.3.1. Full Annual Load Profile

The full annual load profiles for DAGL, BOHL and BLRI over the 2022/23 and 2023/24 financial years is shown in Figure 4, Figure 5 and Figure 6. It can be noted that the peak load at these substations occurs during the Summer evening period and the minimum load at these substations occurs during the Winter and Spring midday periods.

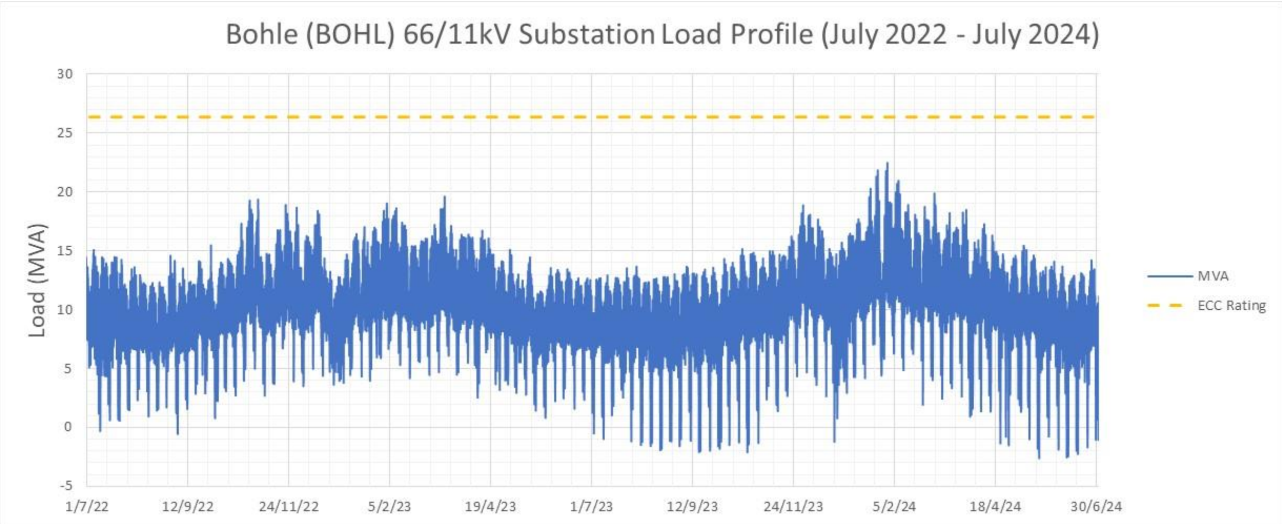



**Figure 4: BOHL Substation 11kV load profile for period July 2022-July 2024**

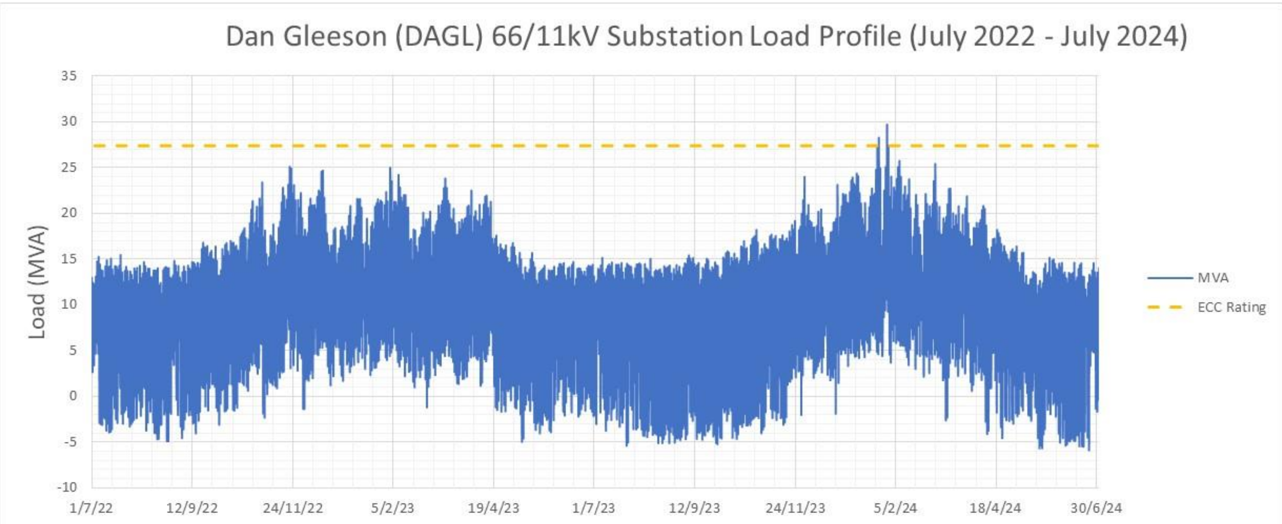



**Figure 5: DAGL Substation 11kV load profile for period July 2022-July 2024**

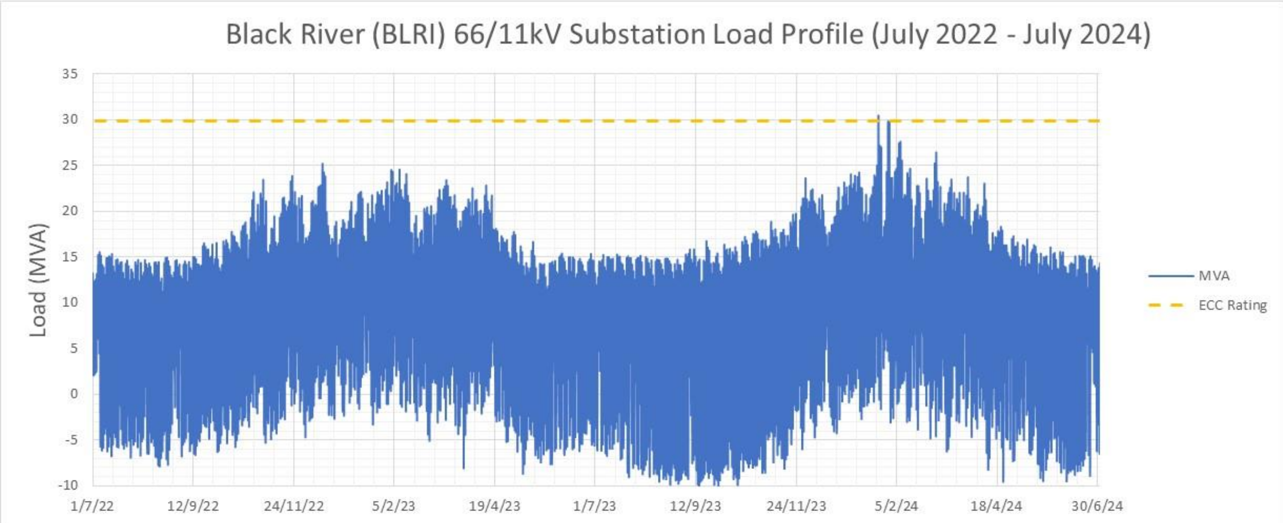



**Figure 6: BLRI Substation 11kV load profile for period July 2022-July 2024**

### 2.3.2. Load Duration Curve

The load duration curve for DAGL, BOHL and BLRI over the 2022/23 and 2023/24 financial years is shown in Figure 7, Figure 8 and Figure 9.

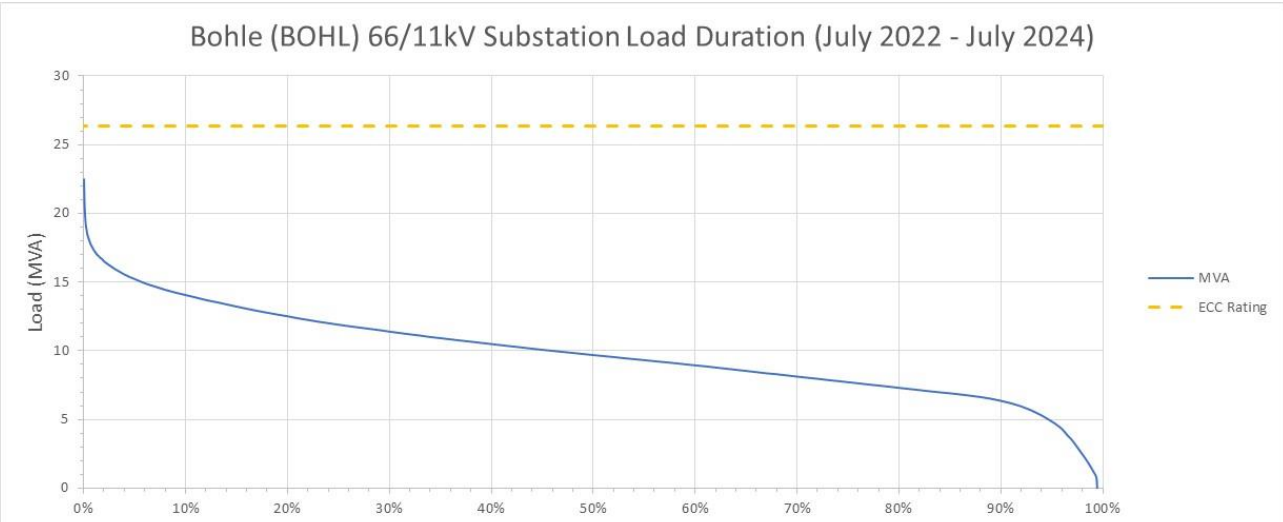



**Figure 7: BOHL Substation 11kV load duration curve for period July 2022-July 2024**

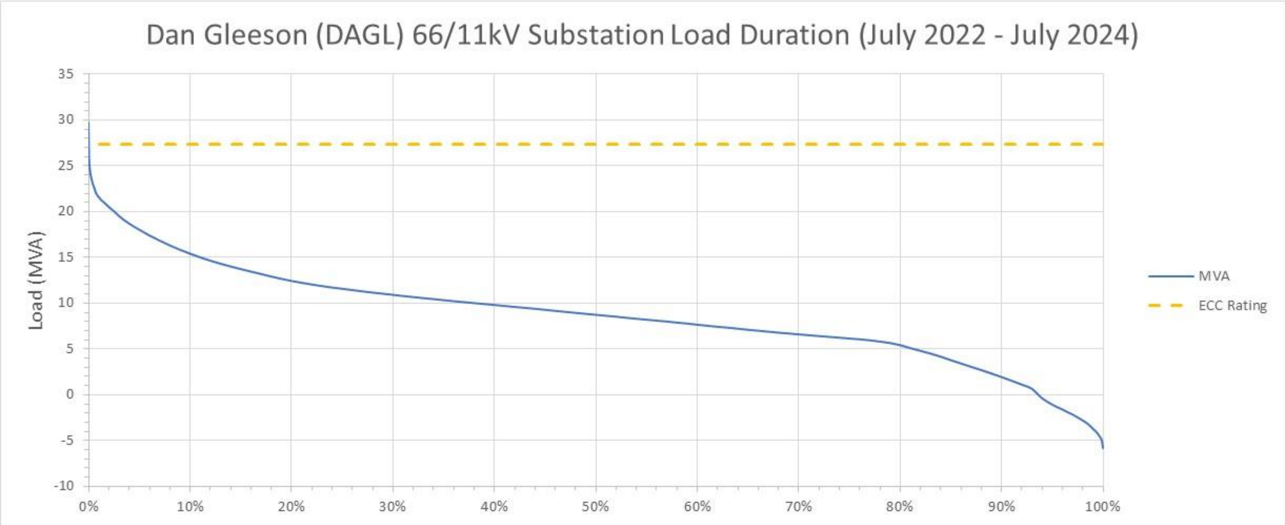



**Figure 8: DAGL Substation 11kV load duration curve for period July 2022-July 2024**

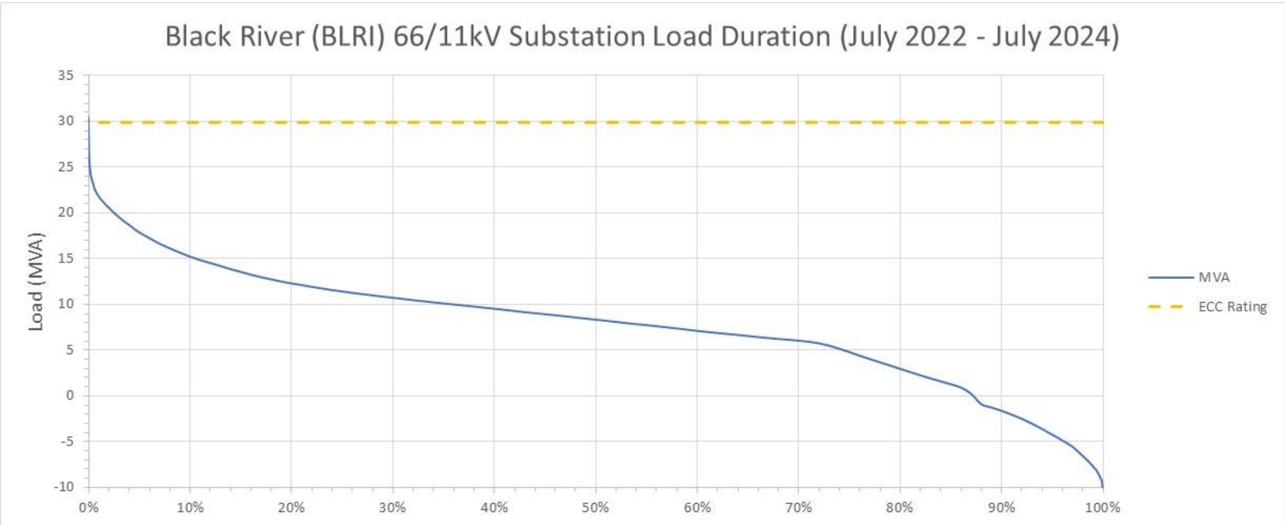



**Figure 9: BLRI Substation 11kV load duration curve for period July 2022-July 2024**

### 2.3.3. Average Peak Day Load Profile (Summer)

The daily load profile for the peak day and average of the top 5 peak days during the 2023/24 Summer period is illustrated below in Figure 10, Figure 11 and Figure 12. It can be noted that the Summer peak loads at DAGL, BOHL and BLRI are historically experienced in the late afternoon and evening.

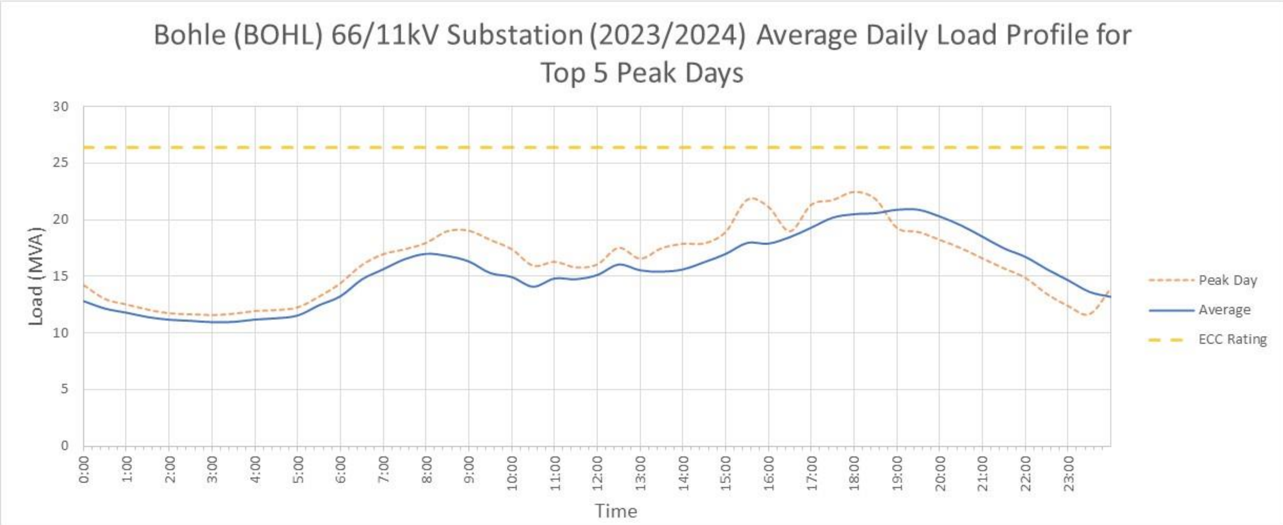



**Figure 10: BOHL Substation average peak 11kV load profile (summer)**

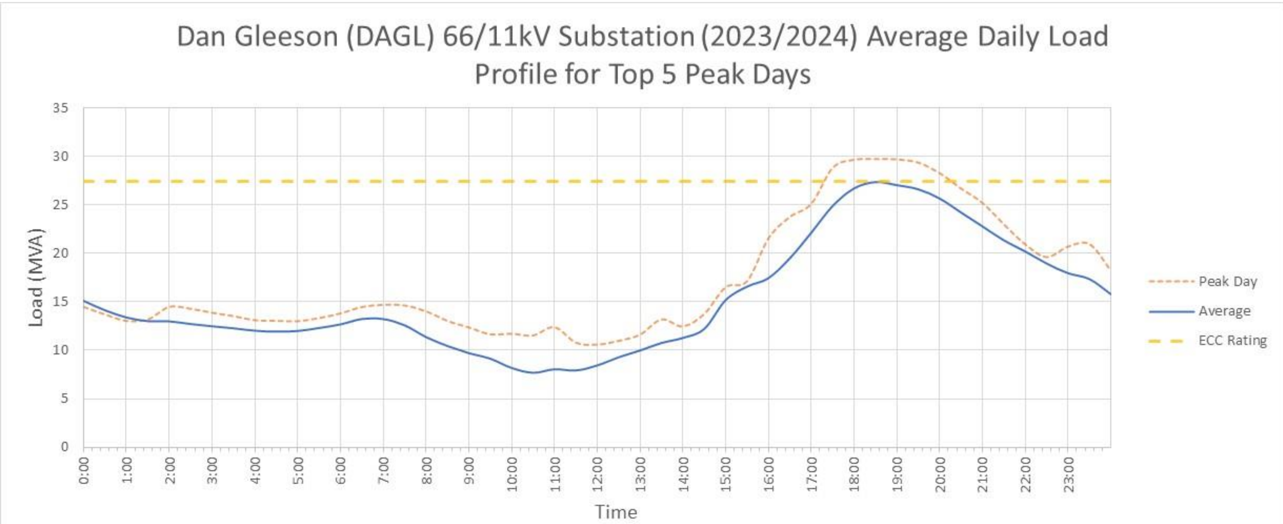



**Figure 11: DAGL Substation average peak 11kV load profile (summer)**

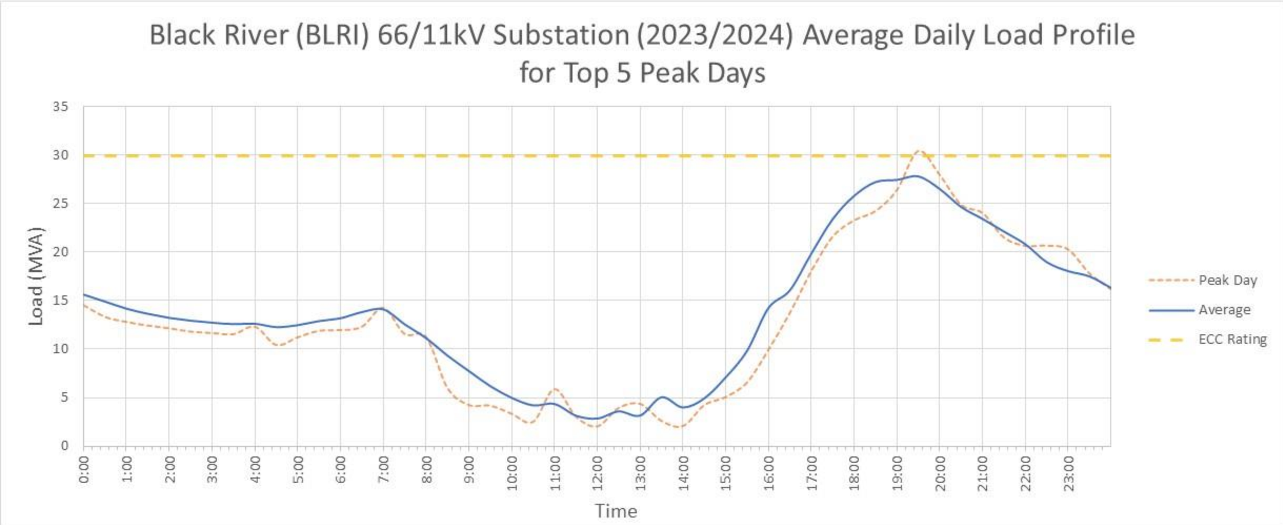



**Figure 12: BLRI Substation average peak 11kV load profile (summer)**

### 2.3.4. Average Load/Generation Profiles for 11kV feeders and Bohle BESS

The average daily load/generation profiles for the BO05, BO10, DG07 and DG10 11kV feeders and the Bohle BESS during the 2022/23 and 2023/24 Summer periods is illustrated below in Figure 13, Figure 14, Figure 15 and Figure 16. It can be noted that the Summer peak loads on the 11kV feeders are historically experienced in the late afternoon and evening. The Bohle BESS is connected to the BO10 feeder with import and export time of day limits based on the loading and capacity of the BO10 11kV feeder.

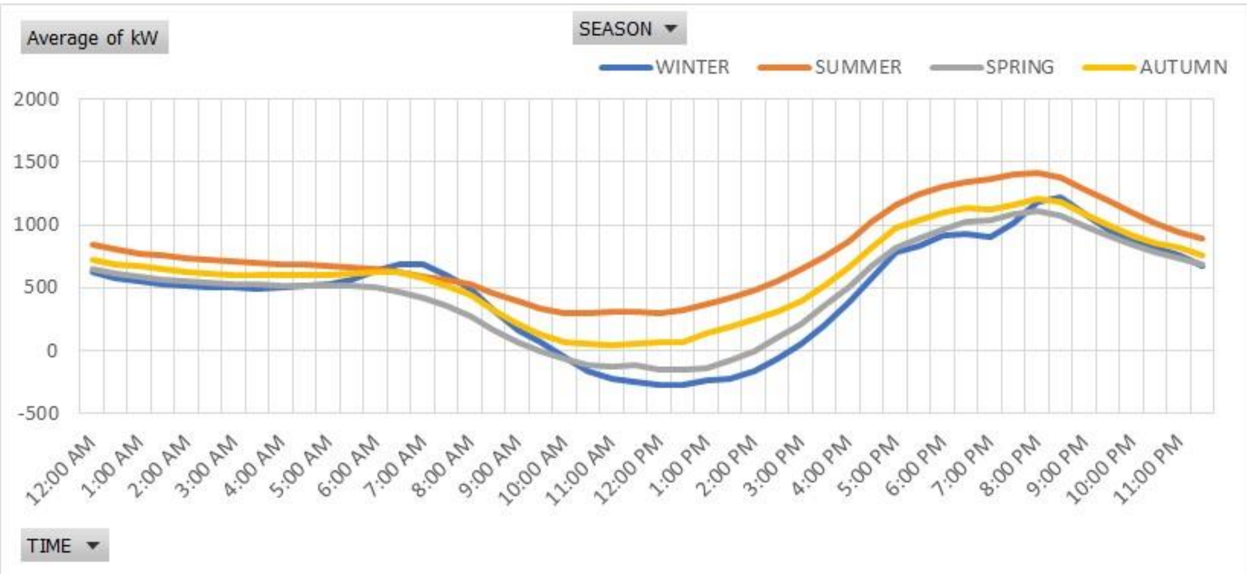



**Figure 13: BO05 11kV feeder average load profile**


**Figure 14: BO10 11kV feeder average load profile (Bohle BESS is connected to this feeder)**

The Bohle BESS influences the BO10 profile as it typically exports during the morning peak and evening peak periods.

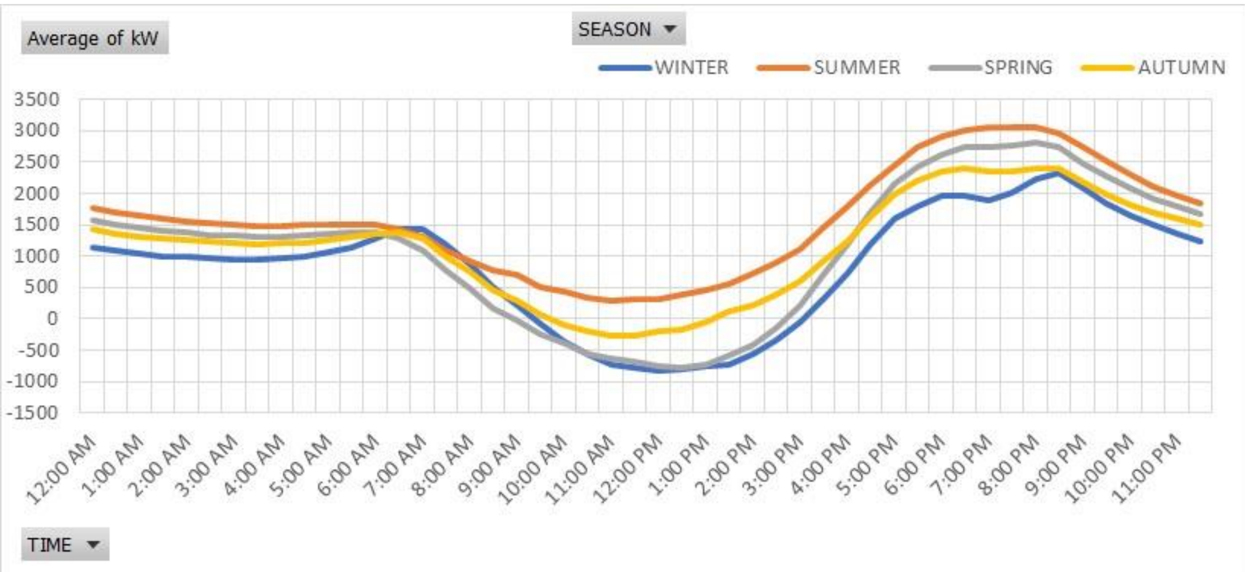



**Figure 15: DG07 11kV feeder average load profile**

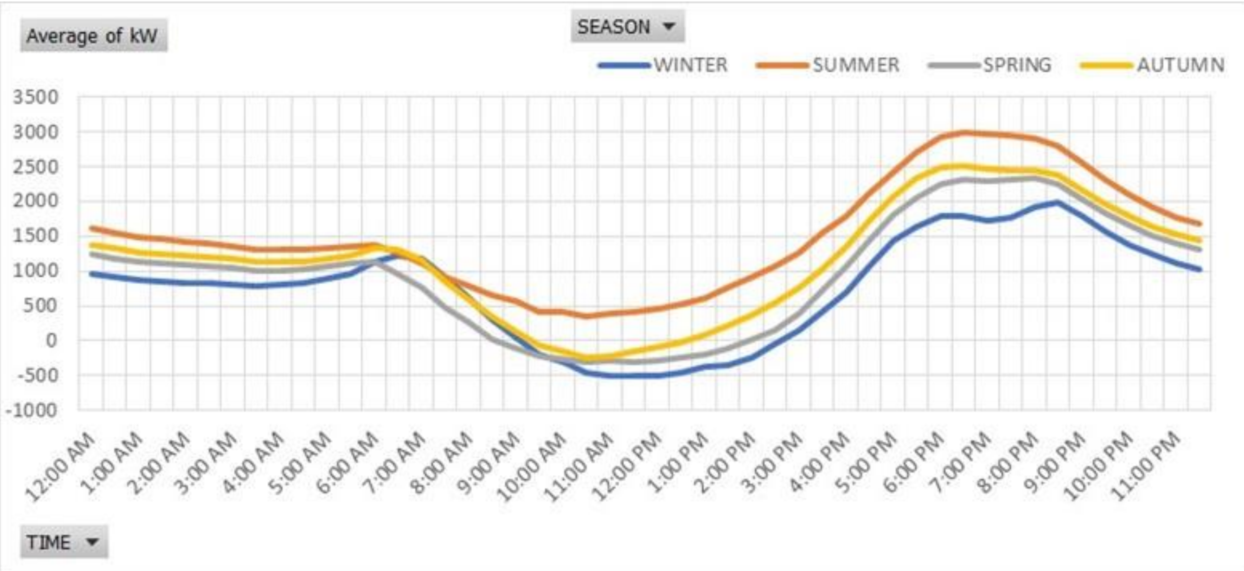



**Figure 16: DG10 11kV feeder average load profile**

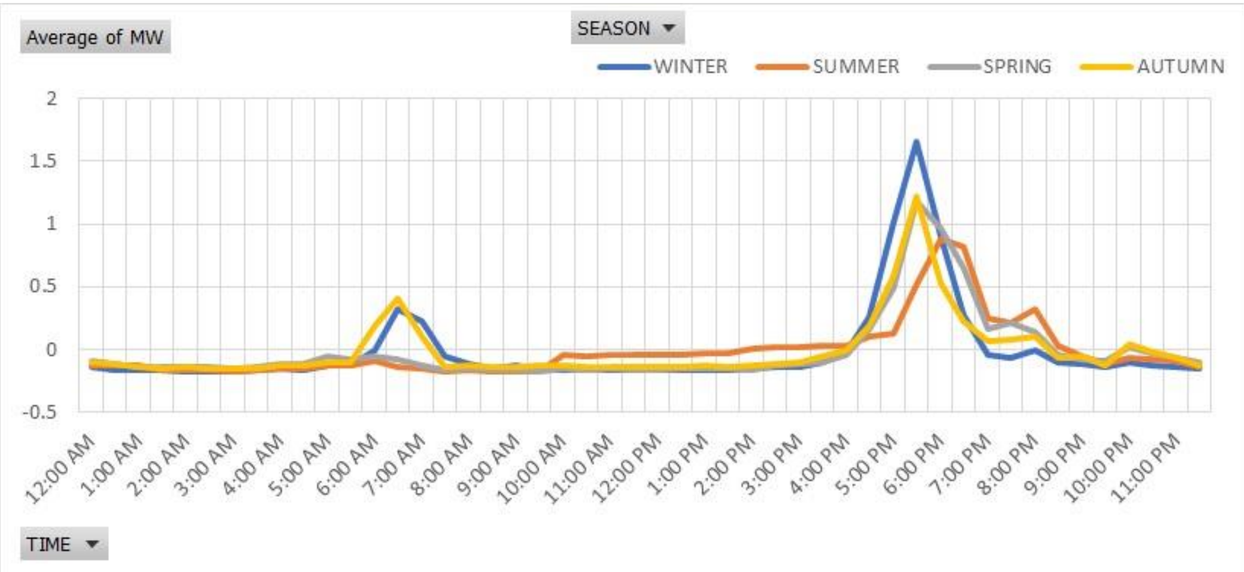



**Figure 17: Bohle BESS average 11kV load/generation profile (positive = generation)**

Note that the Bohle BESS import and export has time of day limits based on the loading and capacity of the BO10 11kV feeder.

### 2.3.5. Base Case Load Forecast

The 10 PoE (10% probability of exceedance) and 50 PoE (50% probability of exceedance) load forecasts for DAGL, BOHL and BLRI for the base case load growth scenario are illustrated in Figure 18, Figure 19 and Figure 20. The historical peak load for the past six years has also been included in the graph.

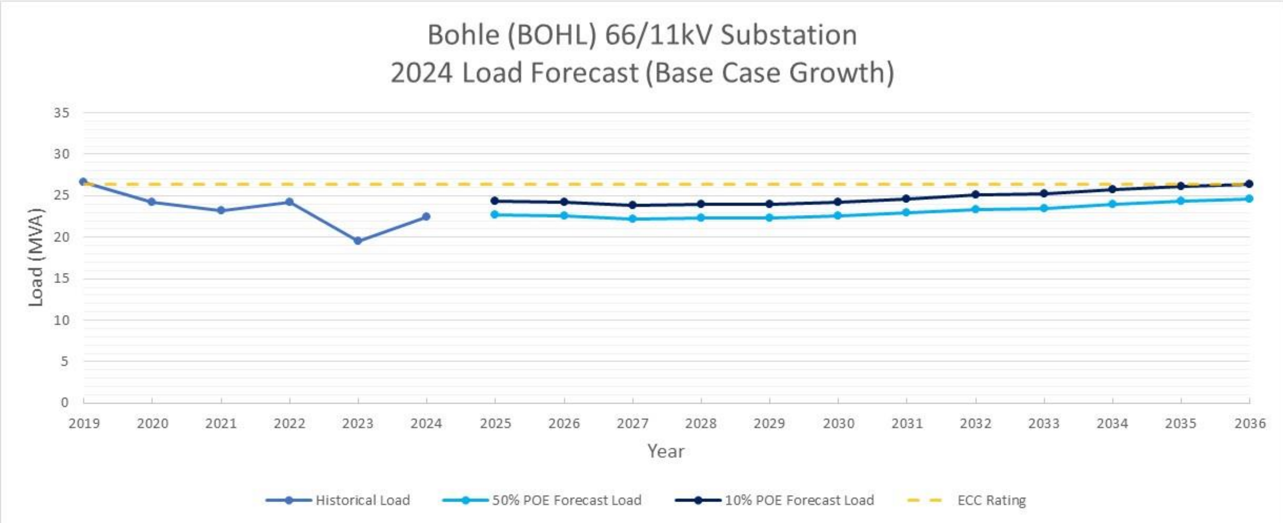



**Figure 18: BOHL Substation base case 11kV load forecast**

The historical annual peak loads at BOHL have fluctuated over the past six years due to changes in customer loads, fluctuations in ambient conditions and transfer of load to and from adjacent substations. In recent years the Bohle BESS has also influenced the peak loading on BOHL. The peak load is forecast to increase over the next 10 years under the base case scenario.

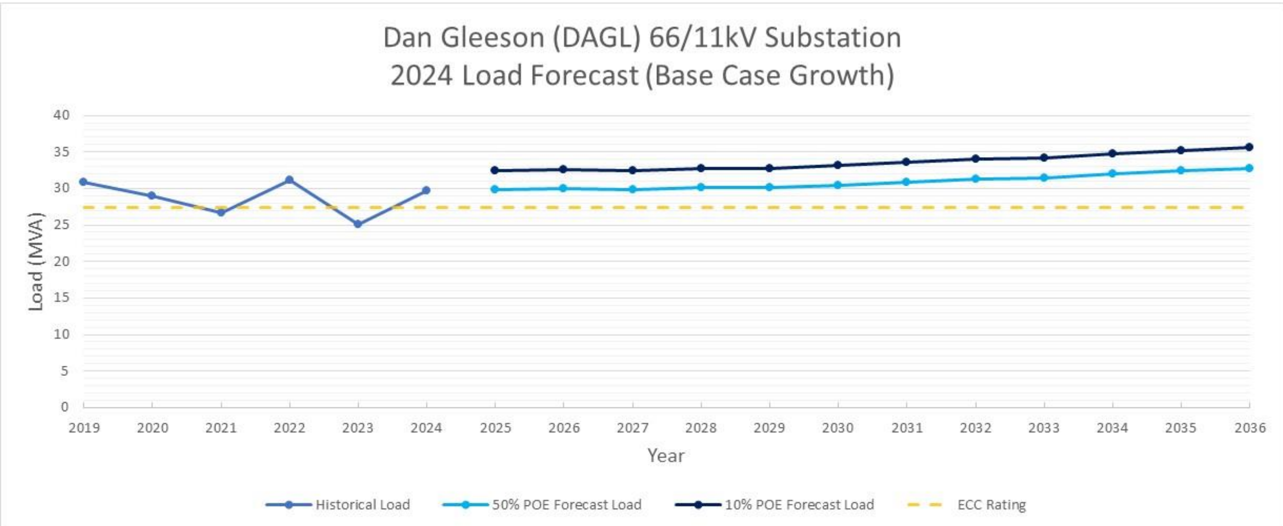



**Figure 19: DAGL Substation base case 11kV load forecast**

The historical annual peak loads at DAGL have fluctuated over the past six years due to changes in customer loads, fluctuations in ambient conditions and transfer of load to and from adjacent substations. The peak load is forecast to increase over the next 10 years under the base case scenario.

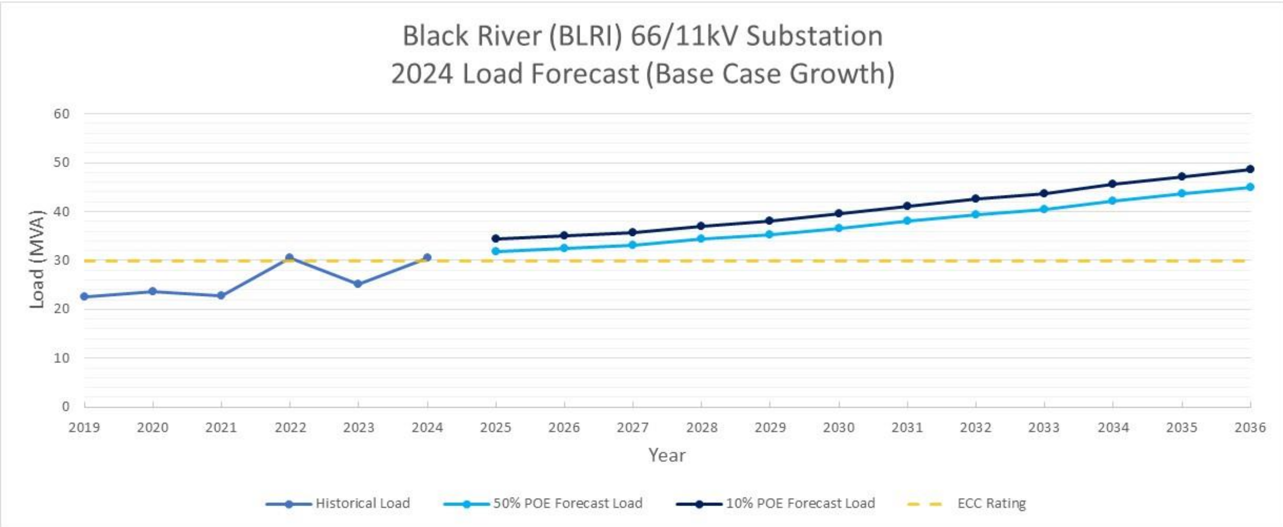



**Figure 20: BLRI Substation base case 11kV load forecast**

The historical annual peak loads at BLRI have fluctuated over the past six years due to changes in customer loads, fluctuations in ambient conditions and transfer of load to and from adjacent substations. The peak load is forecast to increase significantly over the next 10 years under the base case scenario.

### 2.3.6. High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for DAGL, BOHL and BLRI for the high load growth scenario are illustrated in Figure 21, Figure 22 and Figure 23. With the high growth scenario, the peak load at BOHL, DAGL and BLRI is forecast to increase over the next 10 years.

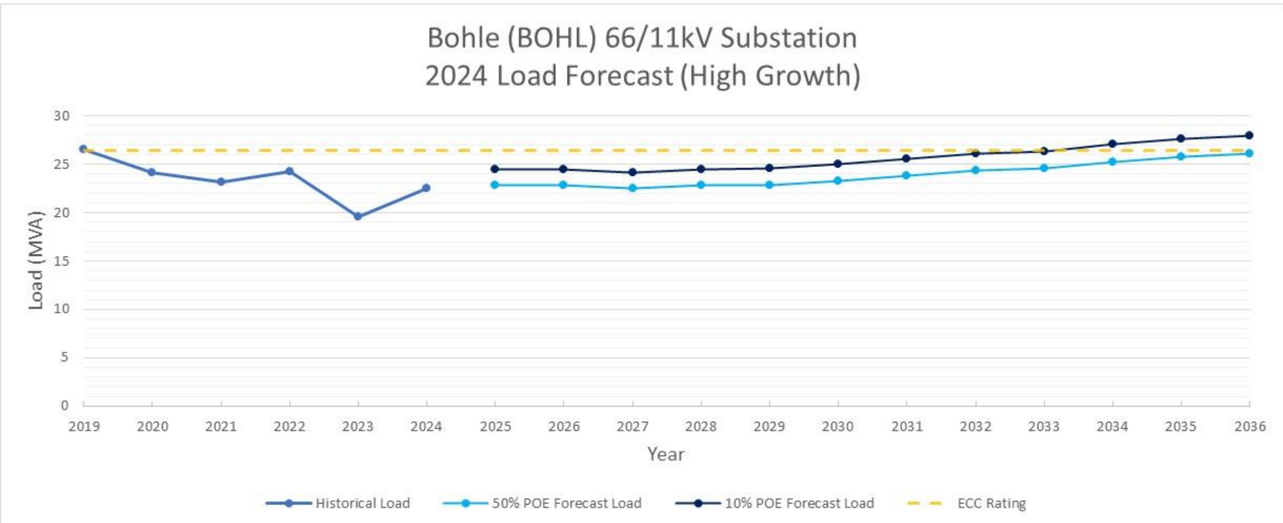



**Figure 21: BOHL Substation high growth 11kV load forecast**

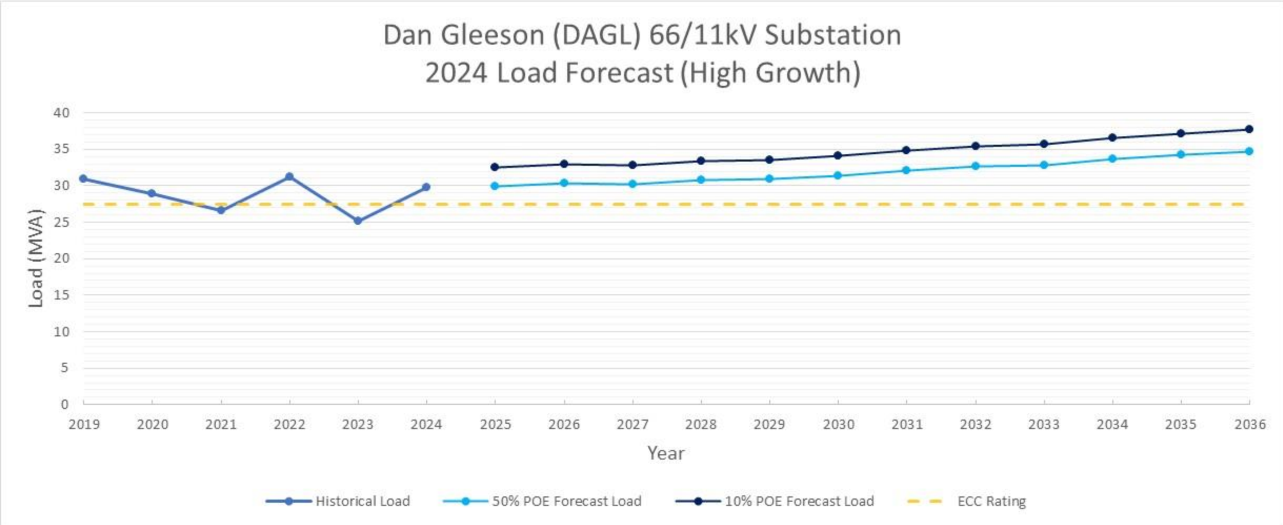



**Figure 22: DAGL Substation high growth 11kV load forecast**

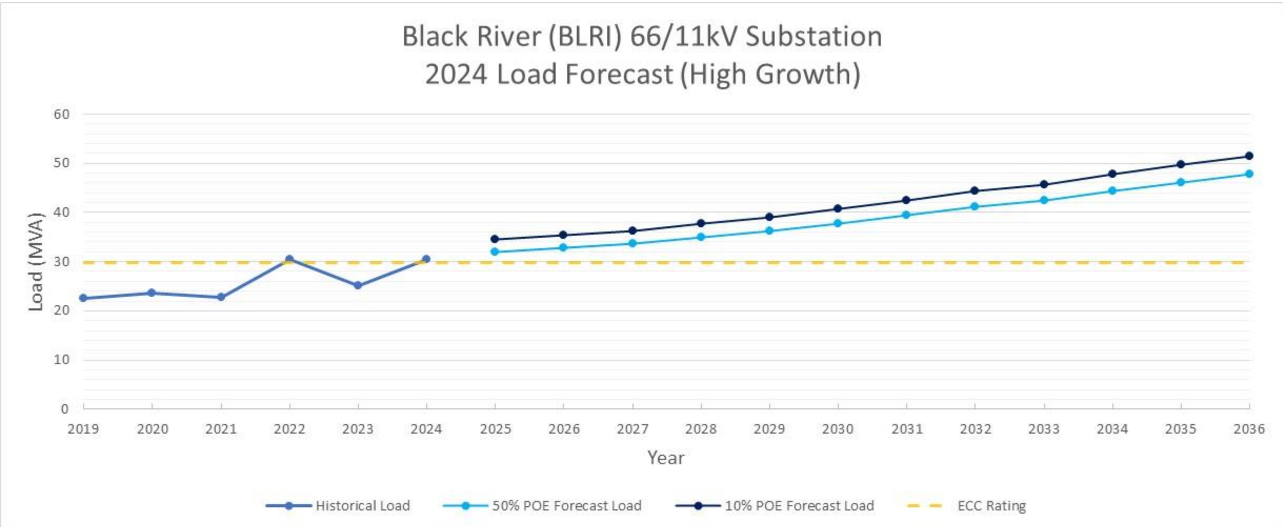



**Figure 23: BLRI Substation high growth 11kV load forecast**

### 2.3.7. Low Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for DAGL, BOHL and BLRI for the low load growth scenario are illustrated in Figure 24, Figure 25 and Figure 26. With the low growth scenario, the peak load at BOHL and DAGL is forecast to remain relatively steady over the next 10 years, however the peak load at BLRI is forecast to increase over the next 10 years.

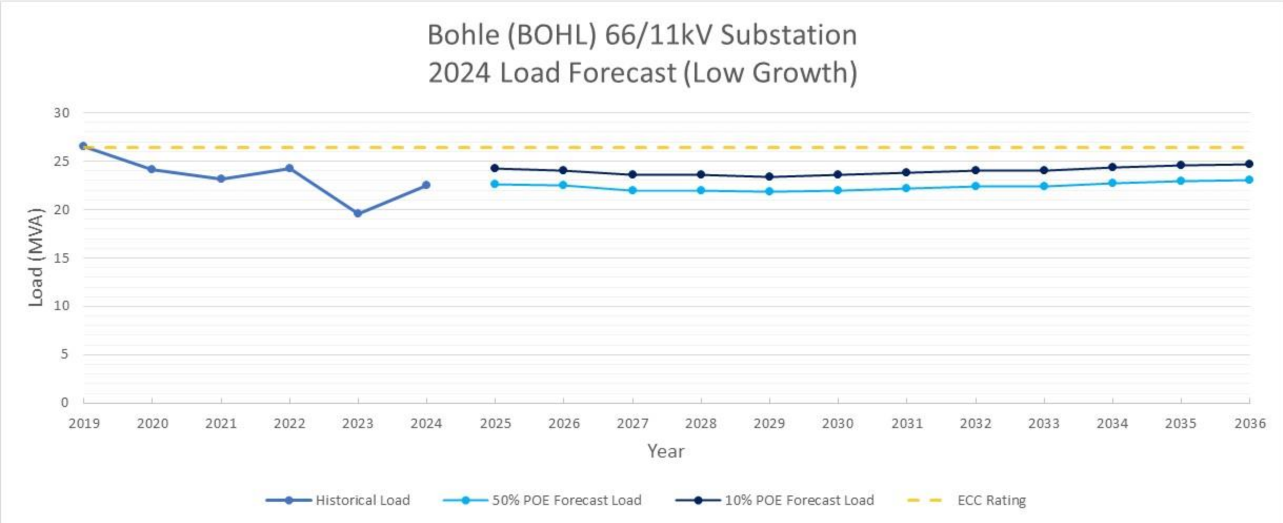



**Figure 24: BOHL Substation low growth 11kV load forecast**

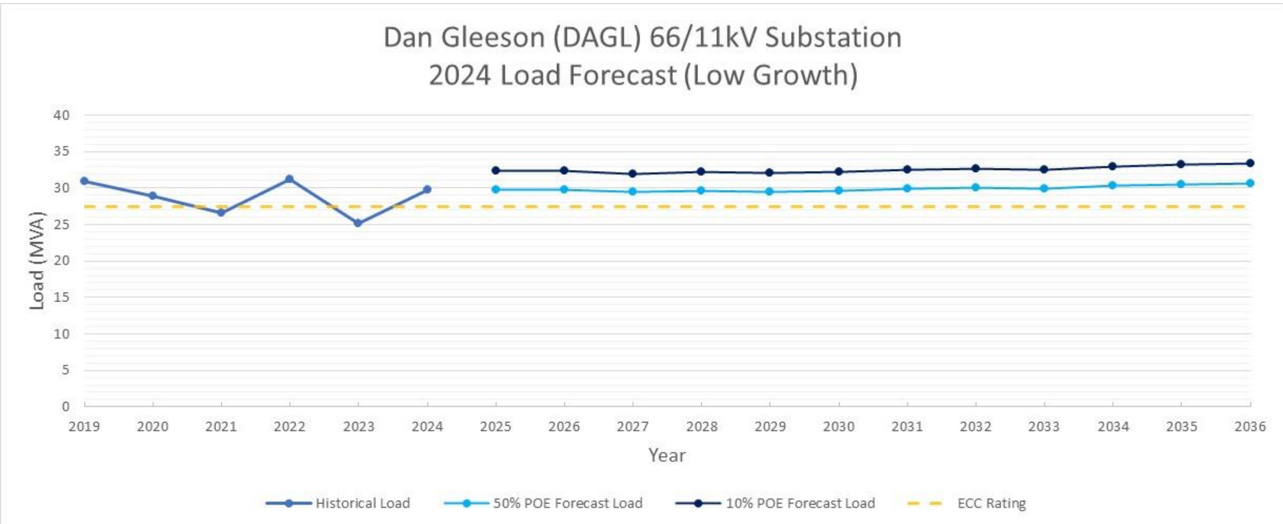



**Figure 25: DAGL Substation low growth 11kV load forecast**

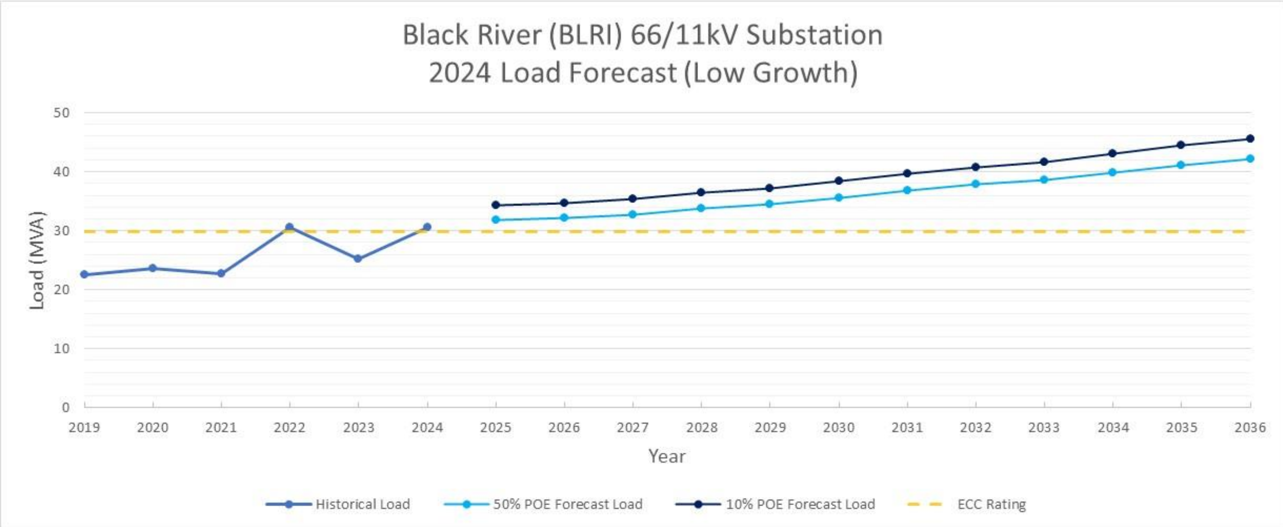



**Figure 26: BLRI Substation low growth 11kV load forecast**

# 3. IDENTIFIED NEED

## 3.1. Description of the Identified Need

### 3.1.1. Reliability Corrective Action

The Bohle Plains area is currently supplied from the DG-07, DG-10, BO-05 and BO-10 11kV distribution feeders from Dan Gleeson (DAGL) 66/11kV Substation and Bohle (BOHL) 66/11kV Substation. The Bohle Plains area is one of the main residential development areas in the Townsville region with a number of new subdivisions under development.

Due to the forecasted increase in customer demand, Ergon Energy is seeking to invest in the network to undertake a reliability corrective action in order to continue to meet the service standards in its applicable regulatory instruments (Safety Net requirements imposed in its Distribution Authority[4] issued under the *Electricity Act 1994* (Qld)[5]). The forecast loading for the substations and distribution feeders supplying the Bohle Plains area is expected to exceed the available N-1 substation and feeder capacity within the next 10 years. In the event of a fault on a substation transformer or an underground substation exit cable for one of the feeders supplying the Bohle Plains area there is a risk that a portion of the forecast load would be unsupplied for more than 24 hours, thereby breaching Safety Net requirements. The typical repair times for a substation transformer fault or an underground cable fault would exceed the 24 hour period required to restore supply to all customers.

## 3.2. Quantification of the Identified Need

The benefits of each credible option are assessed against the counterfactual, which in this case is to continue to operate the network with existing in-service assets.

### 3.2.1. Safety Net Non-Compliance

**Bohle Substation Limitations**

BOHL substation capacity is limited by the 66/11kV transformers, providing a Normal Cyclic Capacity (NCC) of 52.7 MVA and an Emergency Cyclic Capacity (ECC) of 26.4 MVA. The 50PoE load forecast and Safety Net load at risk for a contingency is shown in Table 1 and Table 2. In the event of a transformer failure at BOHL during a peak load period, up to 4 MVA of load can be transferred to adjacent substations via the 11kV feeder ties and supplemented by mobile

[4] Ergon Energy Distribution Authority:
Section 7 - Guaranteed Service Levels
Section 8 - Distribution Network Planning
Section 9 - Minimum Service Standards
Section 10 – Safety Net

[5] QLD Electricity Act 1994 Part 5, Division 5, Section 42(a)

generation if required. This assessment assumes that the Bohle 4MW / 8MWh BESS would be exporting and that load transfer capacity and mobile generation will be available in the event of a contingency during the peak load period. If the BESS, load transfer capacity and mobile generation are not available at the time of the contingency the load at risk levels specified in Table 1 and Table 2 would increase. As load continues to grow on the 11kV distribution network the transfer capacity is likely to reduce.

| Year | Forecast 50 PoE Load (MVA) | Security Standard Load At Risk (MVA) | Days/Yr Above Limit | % Time Above Limit | Hrs Over Limit |
|---|---|---|---|---|---|
| 2028 | 22.4 | 0.0 | - | - | - |
| 2029 | 22.3 | 0.0 | - | - | - |
| 2030 | 22.6 | 0.0 | - | - | - |
| 2031 | 23.0 | 0.0 | - | - | - |
| 2032 | 23.4 | 0.0 | - | - | - |
| 2033 | 23.5 | 0.0 | - | - | - |
| 2034 | 24.0 | 0.0 | - | - | - |
| 2035 | 24.4 | 0.0 | - | - | - |
| 2036 | 24.6 | 0.0 | - | - | - |
| 2037 | 24.9 | 0.0 | - | - | - |
| 2038 | 25.2 | 0.0 | - | - | - |
| 2039 | 25.5 | 0.0 | - | - | - |

**Table 1: BOHL Base Case Growth 50PoE Forecast Load at Risk**

Table 1 illustrates that there is no load at risk forecast at BOHL substation prior to 2039 under a base case growth scenario with existing load transfer capacity, BESS export and mobile generation deployment.

| Year | Forecast 50 PoE Load (MVA) | Security Standard Load At Risk (MVA) | Days/Yr Above Limit | % Time Above Limit | Hrs Over Limit |
|---|---|---|---|---|---|
| 2028 | 22.8 | 0.0 | - | - | - |
| 2029 | 22.9 | 0.0 | - | - | - |
| 2030 | 23.3 | 0.0 | - | - | - |
| 2031 | 23.8 | 0.0 | - | - | - |
| 2032 | 24.4 | 0.0 | - | - | - |
| 2033 | 24.6 | 0.0 | - | - | - |
| 2034 | 25.3 | 0.0 | - | - | - |
| 2035 | 25.7 | 0.0 | - | - | - |
| 2036 | 26.1 | 0.0 | - | - | - |
| 2037 | 26.5 | 0.0 | - | - | - |
| 2038 | 26.9 | 0.0 | - | - | - |
| 2039 | 27.4 | 0.0 | - | - | - |

**Table 2: BOHL High Growth Case 50PoE Forecast Load at Risk**

Table 2 illustrates that there is no load at risk forecast at BOHL substation prior to 2039 under a high growth scenario with existing load transfer capacity, BESS export and mobile generation deployment.

### Dan Gleeson Substation Limitations

DAGL substation capacity is limited by the 11kV transformer cables, providing a Normal Cyclic Capacity (NCC) of 42.4 MVA and an Emergency Cyclic Capacity (ECC) of 27.2 MVA. The 50PoE load forecast and Safety Net load at risk for a contingency is shown in Table 3 and Table 4. In the event of a transformer failure at DAGL during a peak load period, up to 4 MVA of load can be transferred to adjacent substations via the 11kV feeder ties and supplemented by mobile generation if required. This assessment assumes that load transfer capacity and mobile generation will be available in the event of a contingency during the peak load period. If load transfer capacity and mobile generation are not available at the time of the contingency the load at risk levels specified in Table 3 and Table 4 would increase. As load continues to grow on the 11kV distribution network the transfer capacity is likely to reduce.

| Year | Forecast 50 PoE Load (MVA) | Security Standard Load At Risk (MVA) | Days/Yr Above Limit | % Time Above Limit | Hrs Over Limit |
|---|---|---|---|---|---|
| 2028 | 30.1 | 0.0 | - | - | - |
| 2029 | 30.2 | 0.0 | - | - | - |
| 2030 | 30.5 | 0.0 | - | - | - |
| 2031 | 30.9 | 0.0 | - | - | - |
| 2032 | 31.3 | 0.1 | 1 | 0.01% | 0.5 |
| 2033 | 31.4 | 0.2 | 1 | 0.01% | 0.5 |
| 2034 | 32.0 | 0.8 | 1 | 0.01% | 1 |
| 2035 | 32.4 | 1.2 | 2 | 0.02% | 2 |
| 2036 | 32.8 | 1.6 | 2 | 0.03% | 3 |
| 2037 | 33.2 | 2.0 | 3 | 0.05% | 4 |
| 2038 | 33.6 | 2.4 | 4 | 0.07% | 6 |
| 2039 | 33.9 | 2.7 | 5 | 0.10% | 8.5 |

**Table 3: DAGL Base Case Growth 50PoE Forecast Load at Risk**

Table 3 illustrates the amount and duration of support required at DAGL under a base case growth scenario with existing load transfer capacity and mobile generation deployment, starting at 0.1MVA for 1 day in 2032 increasing to 2.7MVA for 5 days in 2039.

| Year | Forecast 50 PoE Load (MVA) | Security Standard Load At Risk (MVA) | Days/Yr Above Limit | % Time Above Limit | Hrs Over Limit |
|---|---|---|---|---|---|
| 2028 | 30.7 | 0.0 | - | - | - |
| 2029 | 30.9 | 0.0 | - | - | - |
| 2030 | 31.4 | 0.2 | 1 | 0.01% | 0.5 |
| 2031 | 32.0 | 0.8 | 1 | 0.01% | 1 |
| 2032 | 32.6 | 1.4 | 2 | 0.03% | 2.5 |
| 2033 | 32.8 | 1.6 | 2 | 0.03% | 3 |
| 2034 | 33.6 | 2.4 | 4 | 0.07% | 6.5 |
| 2035 | 34.2 | 3.0 | 6 | 0.11% | 9.5 |
| 2036 | 34.7 | 3.5 | 7 | 0.15% | 13 |

| | | | | | |
|---|---|---|---|---|---|
| 2037 | 35.3 | 4.1 | 9 | 0.19% | 16.5 |
| 2038 | 35.8 | 4.6 | 13 | 0.26% | 23 |
| 2039 | 36.4 | 5.2 | 15 | 0.35% | 30.5 |

**Table 4: DAGL High Growth Case 50PoE Forecast Load at Risk**

Table 4 illustrates the amount and duration of support required at DAGL under a high growth scenario with existing load transfer capacity and mobile generation deployment, starting at 0.2MVA for 1 day in 2030 increasing to 5.2MVA for 15 days in 2039.

### Black River Substation Limitations

BLRI substation capacity is limited by the 66/11kV transformers, providing a Normal Cyclic Capacity (NCC) of 56 MVA and an Emergency Cyclic Capacity (ECC) of 29.9 MVA. The 50PoE load forecast and Safety Net load at risk for a contingency is shown in Table 5 and Table 6. In the event of a transformer failure at BLRI during a peak load period, up to 4 MVA of load can be transferred to adjacent substations via the 11kV feeder ties and supplemented by mobile generation if required. This assessment also assumes that the Black River 4MW / 8MWh BESS would be exporting and that load transfer capacity and mobile generation will be available in the event of a contingency during the peak load period. If the BESS, load transfer capacity and mobile generation are is not available at the time of the contingency the load at risk levels specified in Table 5 and Table 6 would increase. As load continues to grow on the 11kV distribution network the transfer capacity is likely to reduce.

| Year | Forecast 50 PoE Load (MVA) | Security Standard Load At Risk (MVA) | Days/Yr Above Limit | % Time Above Limit | Hrs Over Limit |
|---|---|---|---|---|---|
| 2028 | 34.3 | 0.4 | 1 | 0.01% | 0.5 |
| 2029 | 35.3 | 1.4 | 5 | 0.06% | 5 |
| 2030 | 36.6 | 2.7 | 10 | 0.15% | 13.5 |
| 2031 | 38.0 | 4.1 | 18 | 0.36% | 31.5 |
| 2032 | 39.4 | 5.5 | 26 | 0.61% | 53.5 |
| 2033 | 40.5 | 6.6 | 33 | 0.90% | 78.5 |
| 2034 | 42.2 | 8.3 | 45 | 1.38% | 120.5 |
| 2035 | 43.6 | 9.7 | 56 | 1.83% | 160.5 |
| 2036 | 45.1 | 11.2 | 68 | 2.36% | 206.5 |
| 2037 | 46.5 | 12.6 | 85 | 2.93% | 256.5 |
| 2038 | 47.9 | 14.0 | 100 | 3.53% | 309.5 |
| 2039 | 49.3 | 15.4 | 113 | 4.18% | 366 |

**Table 5: BLRI Base Case Growth 50PoE Forecast Load at Risk**

Table 5 illustrates the amount and duration of support required at BLRI under a base case growth scenario with existing load transfer capacity, BESS export and mobile generation deployment, starting at 0.4MVA for 1 day in 2028 increasing to 15.4MVA for 113 days in 2039.

| Year | Forecast 50 PoE Load (MVA) | Security Standard Load At Risk (MVA) | Days/Yr Above Limit | % Time Above Limit | Hrs Over Limit |
|---|---|---|---|---|---|
| 2028 | 35.0 | 1.1 | 3 | 0.04% | 3.5 |
| 2029 | 36.2 | 2.3 | 7 | 0.11% | 9.5 |

| | | | | | |
|---|---|---|---|---|---|
| 2030 | 37.7 | 3.8 | 16 | 0.29% | 25.5 |
| 2031 | 39.4 | 5.5 | 26 | 0.61% | 53.5 |
| 2032 | 41.1 | 7.2 | 38 | 1.06% | 93 |
| 2033 | 42.4 | 8.5 | 47 | 1.44% | 126 |
| 2034 | 44.4 | 10.5 | 61 | 2.09% | 183 |
| 2035 | 46.1 | 12.2 | 79 | 2.77% | 242.5 |
| 2036 | 47.8 | 13.9 | 100 | 3.47% | 304 |
| 2037 | 49.4 | 15.5 | 114 | 4.22% | 370 |
| 2038 | 51.1 | 17.2 | 133 | 5.08% | 445 |
| 2039 | 52.8 | 18.9 | 150 | 6.03% | 528.5 |

**Table 6: BLRI High Growth Case 50PoE Forecast Load at Risk**

Table 6 illustrates the amount and duration of support required at BLRI under a high growth scenario with existing load transfer capacity, BESS export and mobile generation deployment, starting at 1.1MVA for 3 days in 2028 increasing to 18.9MVA for 150 days in 2039.

### 11kV Feeder Limitations

The Bohle Plains area is currently supplied from the DG-07, DG-10, BO-05 and BO-10 11kV distribution feeders from Dan Gleeson (DAGL) 66/11kV Substation and Bohle (BOHL) 66/11kV Substation. There are existing projects planned to increase the capacity of the DG07 and DG10 feeders to address supply limitations, however due to the growth in the Bohle Plains area these feeders are forecast to become constrained again within the next 10 years. The 50PoE load forecast and Safety Net load at risk for a contingency on one of these feeders is shown in Table 7 and Table 8. After the upgrade works on these feeders have been completed, in the event of a cable failure on either the DG07 or DG10 11kV feeder during a peak load period, up to 10.43 MVA of the combined DG07 & DG10 feeder load can be supplied via transfers to adjacent 11kV feeders and supplemented by 1MVA of mobile generation if required. As load continues to grow on the 11kV distribution network the transfer capacity to adjacent feeders is likely to reduce.

| Year | Forecast 50 PoE Load (MVA) | Security Standard Load At Risk (MVA) | Days/Yr Above Limit | % Time Above Limit | Hrs Over Limit |
|---|---|---|---|---|---|
| 2028 | 11.6 | 0.19 | 1 | 0.01% | 1 |
| 2029 | 11.7 | 0.31 | 1 | 0.01% | 1 |
| 2030 | 11.9 | 0.45 | 1 | 0.01% | 1 |
| 2031 | 12.0 | 0.60 | 2 | 0.02% | 1.5 |
| 2032 | 12.1 | 0.69 | 2 | 0.02% | 2 |
| 2033 | 12.2 | 0.79 | 2 | 0.02% | 2 |
| 2034 | 12.3 | 0.90 | 3 | 0.03% | 3 |
| 2035 | 12.5 | 1.02 | 3 | 0.04% | 3.5 |
| 2036 | 12.6 | 1.15 | 4 | 0.06% | 5 |
| 2037 | 12.7 | 1.29 | 5 | 0.09% | 8 |
| 2038 | 12.9 | 1.43 | 7 | 0.13% | 11 |
| 2039 | 12.9 | 1.51 | 7 | 0.14% | 12 |

**Table 7: DG07 & DG10 Feeders Base Case Growth 50PoE Forecast Load at Risk**

Table 7 illustrates the amount and duration of support required for the DG07 & DG10 feeders under a base case growth scenario with existing load transfer capacity and mobile generation deployment, starting at 0.19MVA for 1 day in 2028 increasing to 1.51MVA for 7 days in 2039.

| Year | Forecast 50 PoE Load (MVA) | Security Standard Load At Risk (MVA) | Days/Yr Above Limit | % Time Above Limit | Hrs Over Limit |
|---|---|---|---|---|---|
| 2028 | 11.7 | 0.22 | 1 | 0.01% | 1 |
| 2029 | 11.8 | 0.36 | 1 | 0.01% | 1 |
| 2030 | 11.9 | 0.51 | 2 | 0.02% | 1.5 |
| 2031 | 12.1 | 0.67 | 2 | 0.02% | 2 |
| 2032 | 12.2 | 0.76 | 2 | 0.02% | 2 |
| 2033 | 12.3 | 0.86 | 2 | 0.03% | 2.5 |
| 2034 | 12.4 | 0.97 | 3 | 0.03% | 3 |
| 2035 | 12.5 | 1.08 | 3 | 0.05% | 4 |
| 2036 | 12.6 | 1.19 | 4 | 0.06% | 5.5 |
| 2037 | 12.8 | 1.32 | 5 | 0.10% | 8.5 |
| 2038 | 12.9 | 1.44 | 7 | 0.13% | 11.5 |
| 2039 | 13.0 | 1.58 | 7 | 0.14% | 12 |

**Table 8: DG07 & DG10 Feeders High Growth Case 50PoE Forecast Load at Risk**

Table 8 illustrates the amount and duration of support required for the DG07 & DG10 feeders under a high growth scenario with existing load transfer capacity, BESS export and mobile generation deployment, starting at 0.22MVA for 1 day in 2028 increasing to 1.58MVA for 7 days in 2039.

### 3.2.2. Risk Quantification Value Streams

The risk quantification of the counterfactual at Bohle Plains has considered three primary value streams, *reliability, financial* and *export,* as shown in Figure 27 and described in further detail below.

- **Reliability:** There is potential unserved energy within the Bohle Plains area following an outage on a substation transformer or 11kV distribution feeder due to limited backup transfer capacity.
- **Financial:** Replacing single assets on failure as individual failed in-service projects has been assumed to incur a 30% increase in cost in comparison to a planned project.
- **Export:** There is potential customer export curtailment within the Bohle Plains area under system normal conditions and following an outage on a substation transformer or 11kV distribution feeder due to limited backup transfer capacity.

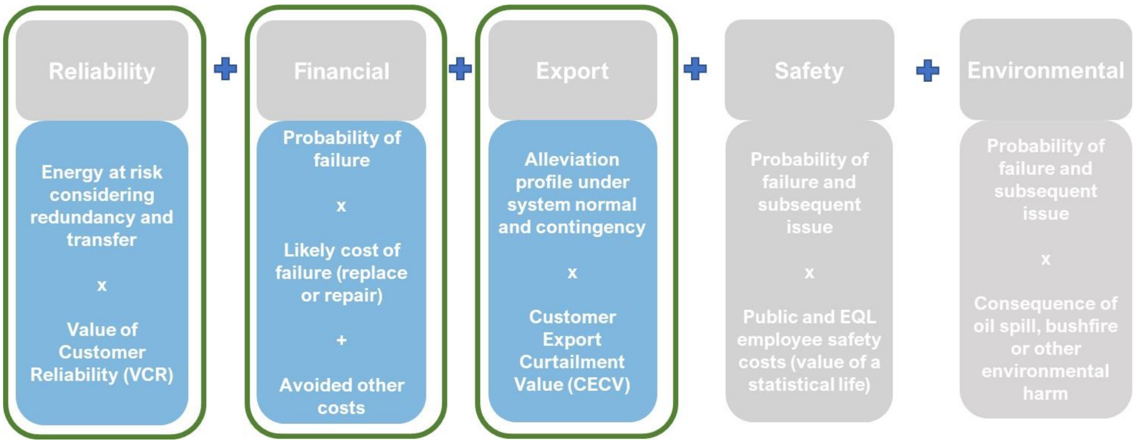



**Figure 27 – Value Streams for Investment**

### 3.2.3. Counterfactual Risk Quantification

The counterfactual risks are the expected unserved energy, emergency replacement cost and customer export curtailment, associated with equipment failure and unplanned supply outages at BOHL, DAGL, BLRI or on one of the 11kV distribution feeders supplying the Bohle Plains area.

In calculating the value streams the following assumptions are used:

- **Forced Outage Rate Transformers** – The transformer outage rates are predicted using a Weibull distribution with a Shape Parameter (β) of 3.6 and a Characteristic Life (η) of 79 for 66/11kV transformers. A flat outage rate of 0.027 has been applied for the first 4 years to capture the increased risk of failure in the first years of a transformers life.
- **Forced Outage Rate Cables** – 11kV feeder cable outage rates are predicted using an average outage rate of 0.75 outages per 100km / year.
- **Restoration Transformers** – it has been estimated that the average rectification time would be 48 hours for a 66/11kV transformer outage. This considers repair / replacement time in the event of a permanent fault on the transformer.
- **Restoration Cables** – it has been estimated that the average rectification time would be 24 hours for a 11kV cable fault. This considers time to locate, excavate and repair / replace the cable.
- **Transfers** – for this assessment it has been assumed that 4MVA of manual load transfer capacity is available to BOHL, DAGL and BLRI via 11kV feeder ties from neighbouring substations. For 11kV distribution feeder outages on BO5, BO10, DG7 and DG10, the assessment assumes 4 into 3 capacity is available on these four feeders and that 1MVA of load can also be shifted to other neighbouring feeders.
- **Generation Support** – for this assessment it has been assumed that 1MVA of generation could be deployed to supply load in the Bohle Plains area within 8hours.
- **VCR Rate** – a VCR rate of $34.68 / kWh has been used for the 11kV load supplied from BOHL, a VCR rate of $35.26 / kWh has been used for the 11kV load supplied from DAGL

and a VCR rate of $35.34 / kWh has been used for the 11kV load supplied from BLRI. The weighting applied to each customer type is shown in Table 9.

- **CECV** – determined using the values published in the customer export curtailment value (CECV) methodology on the AER website[6].
- **Emergency replacement Cost:** On failure of assets the plant will be replaced like-for-like with an additional 30% cost in comparison to the planned project.
- **Risk timeframe** – the risks have been quantified over a 60-year period, starting from 2030 to align with the investment year of Option A (see below).

Figure 28 shows the quantified risk per annum for the counter-factual increasing over the 60-year period from 2030 to 2090.

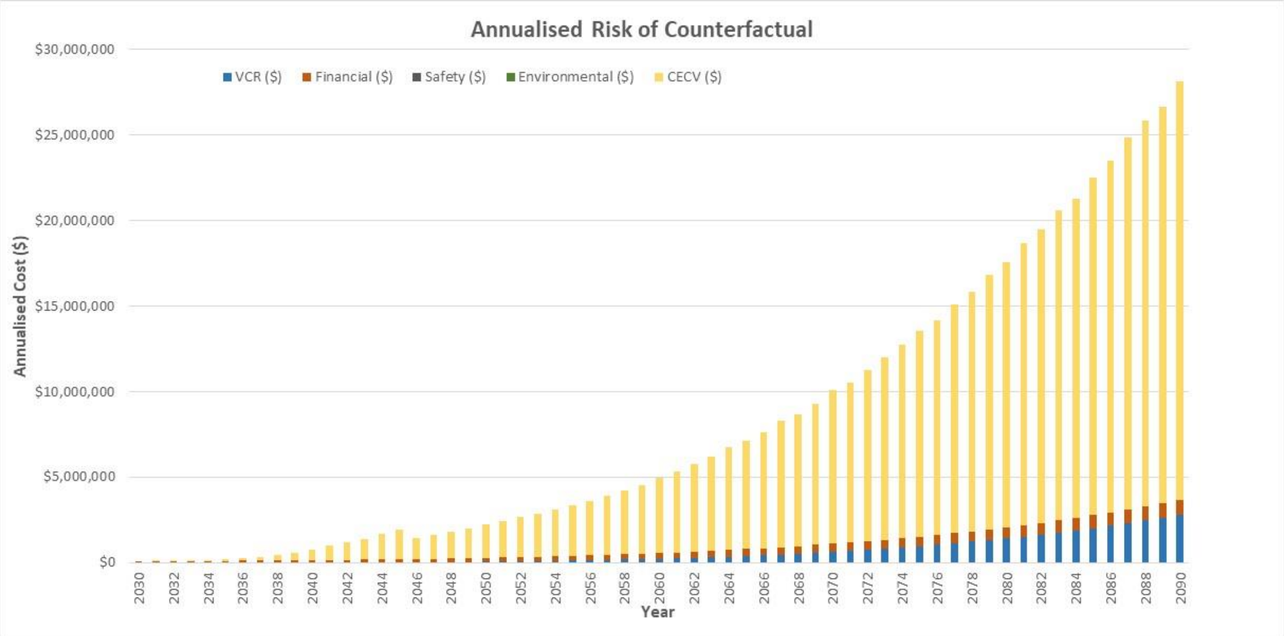



**Figure 28: Annualised Risk of Counterfactual**

Value of Customer Reliability (VCR) is an economic value applied to customers' unserved energy for any particular year. VCR values represent customers' willingness across the National Electricity Market (NEM) to pay for reliable electricity supply. The VCR is used for estimating market benefits that relate to reliability, such as changes in involuntary and voluntary load curtailment.

The VCR calculated for this analysis for the customers supplied from BOHL, DAGL and BLRI is shown in Table 9 based on the VCR values for different customer types as published by the AER.

[6] https://www.aer.gov.au/industry/registers/resources/guidelines/customer-export-curtailment-value-methodology

| Substation | Sector | Annual Consumption (kWh) | $/kWh (2024) |
|---|---|---|---|
| **BOHL** | Residential (Climate Zone 1) | 36,600,683 | $35.69 |
| | Commercial* | 42,789,529 | $34.39 |
| | Industrial* | 20,966,768 | $33.49 |
| | Agriculture* | - | $22.25 |
| | Average VCR | | **$34.68** |
| **DAGL** | Residential (Climate Zone 1) | 66,134,682 | $35.69 |
| | Commercial* | 29,703,442 | $34.39 |
| | Industrial* | 1,649,117 | $33.49 |
| | Agriculture* | 10,062 | $22.25 |
| | Average VCR | | **$35.26** |
| **BLRI** | Residential (Climate Zone 1) | 74,844,641 | $35.69 |
| | Commercial* | 14,491,174 | $34.39 |
| | Industrial* | 6,622,975 | $33.49 |
| | Agriculture* | 23,484 | $22.25 |
| | Average VCR | | **$35.34** |

**Table 9: AER VCR values for BOHL, DAGL and BLRI**

*Business using <10MVA peak demand

$$VCR = \frac{(Residential\ kWh\ \times\ VCR) + (Commercial\ kWh\ \times\ VCR) + (Industrial\ kWh\ \times\ VCR) +\ (Agriculture\ kWh\ \times\ VCR)}{Total\ Energy}$$

## 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.

On the basis of these assumptions, Ergon Energy has come to the conclusion that a reliability corrective action is necessary. Without taking a reliability corrective action, Ergon Energy considers that it would be in breach of its Safety Net requirements. In the event of a fault on a substation transformer or an underground substation exit cable for one of the feeders supplying the Bohle Plains area there is a risk that a portion of the forecast load would be unsupplied for more than 24 hours, thereby breaching Safety Net requirements.

### 3.3.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at BOHL, DAGL and BLRI will be consistent with the base case forecast outlined in Section 2.3.5.

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 2.3.3 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. Network Batteries

As part of the Local Network Battery Plan, Energy Queensland has installed two 4MW/8MWh batteries in this area to capture extra energy generated from rooftop PV systems and then export this energy back into the network during the peak demand period. Energy Queensland is planning to install more batteries across the network to maximise the benefits of rooftop solar and provide network support. The Bohle Plains area also falls within the recently announced Townsville Local Renewable Energy Zone (LREZ) which proposes the installation of local network-connected batteries.

If they provide support during the peak demand period in the required locations, the installation of additional batteries within the Bohle Plains area is anticipated to assist in reducing the peak demand and may change the timing and/or scope of any proposed solutions. However, at this stage as details on the location and size of these batteries has not been confirmed it has been assumed that these batteries would not fully address the identified need.

# 4. TECHNICAL CHARACTERISTICS OF SAPS AND NON-NETWORK OPTIONS

This section describes the technical characteristics of the identified need that a Stand-alone Power System (SAPS) and/or a non-network option would be required to comply with, including:

- Size of load reduction or additional supply
- Location
- Contribution to power system security or reliability
- Contribution to power system fault levels as determined under clause 4.6.1 of the NER
- Operating profile

## 4.1. Size

To address the identified need, it is expected that any SAPS or non-network option would provide load reduction or additional supply to the distribution network that supports a load up to the values listed in the tables below. Demand reduction or additional supply at both DAGL and BLRI must be provided in order to meet the identified need.

| Year | Demand Reduction Required | Days/Year Required | Hours/Year Required |
|---|---|---|---|
| 2028 | 0.19 MVA | 1 | 1 |
| 2029 | 0.31 MVA | 1 | 1 |
| 2030 | 0.45 MVA | 1 | 1 |
| 2031 | 0.6 MVA | 2 | 1.5 |
| 2032 | 0.69 MVA | 2 | 2 |
| 2033 | 0.79 MVA | 2 | 2 |
| 2034 | 0.9 MVA | 3 | 3 |
| 2035 | 1.2 MVA | 2 | 2 |
| 2036 | 1.6 MVA | 2 | 3 |
| 2037 | 2 MVA | 3 | 4 |
| 2038 | 2.4 MVA | 4 | 6 |
| 2039 | 2.7 MVA | 5 | 8.5 |

**Table 10: Demand reduction or additional supply required at DAGL (DG07 & DG10 feeders)**

| Year | Demand Reduction Required | Days/Year Required | Hours/Year Required |
|---|---|---|---|
| 2028 | 0.4 MVA | 1 | 0.5 |
| 2029 | 1.4 MVA | 5 | 5 |
| 2030 | 2.7 MVA | 10 | 13.5 |
| 2031 | 4.1 MVA | 18 | 31.5 |

| | | | |
|---|---|---|---|
| 2032 | 5.5 MVA | 26 | 53.5 |
| 2033 | 6.6 MVA | 33 | 78.5 |
| 2034 | 8.3 MVA | 45 | 120.5 |
| 2035 | 9.7 MVA | 56 | 160.5 |
| 2036 | 11.2 MVA | 68 | 206.5 |
| 2037 | 12.6 MVA | 85 | 256.5 |
| 2038 | 14 MVA | 100 | 309.5 |
| 2039 | 15.4 MVA | 113 | 366 |

**Table 11: Demand reduction or additional supply required BLRI**

## 4.2. Location

The location where network support and load restoration capability will be measured / referenced is on the DG07 and DG10 11kV feeders supplied from DAGL and on the BLRI 11kV network. The location of the network support measurement would be depended on the option proposed and would need to be negotiated between Ergon Energy and the provider.

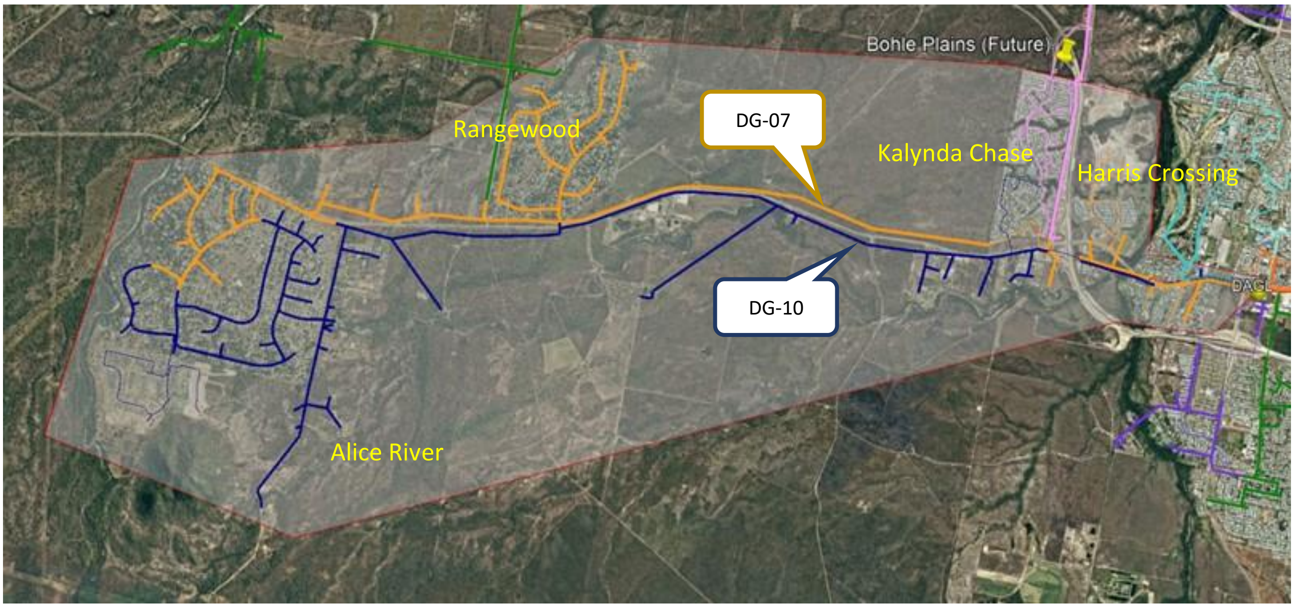



**Figure 29: Location where network support is required for DAGL (DG07 & DG10 11kV feeders)**

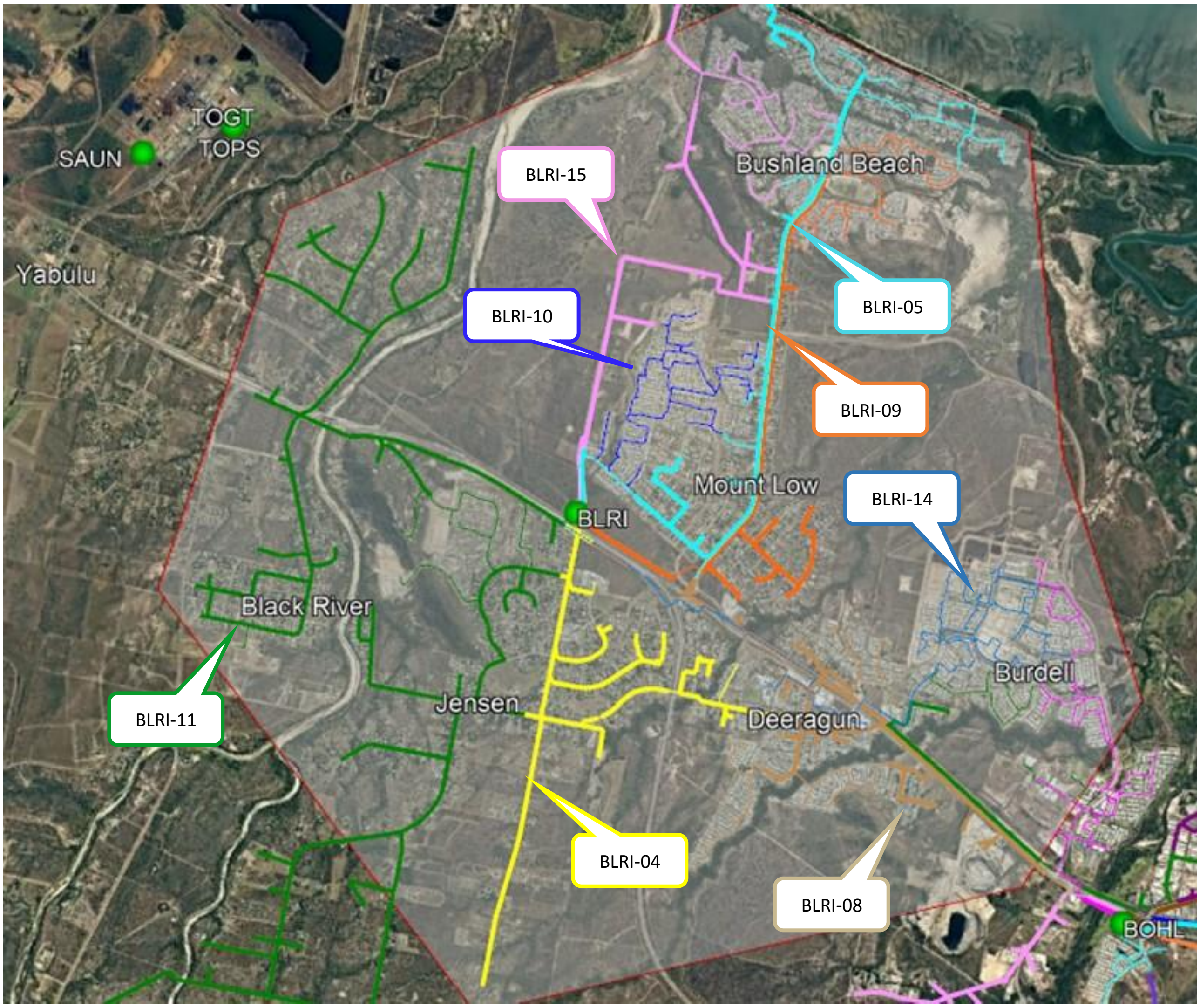



**Figure 30: Location where network support is required for BLRI**

## 4.3. Contribution to Power System Security and Reliability

In order to meet Ergon Energy's criteria under Safety Net the SAPS/non-network option would be required to provide the required level of network support in the specified location and must also ensure that the reliability of the network in the location that support is being provided remains above the minimum service standard outlined in the National Electricity Rules and the Distribution Authority.

## 4.4. Contribution to Power System Fault Levels

The existing system normal maximum fault levels at BOHL, DAGL and BLRI are provided in Table 12, it is expected that a credible SAPS/non-network solution would not increase the network fault levels above plant ratings.

| Location | 3-Ph Fault Level (kA) | 3-Ph Fault Level (MVA) | Ph-G Fault Level (kA) | Ph-G Fault Level (MVA) |
|---|---|---|---|---|
| BOHL 11kV Bus | 10.97 | 209 | 11.52 | 73 |
| BOHL 66kV Bus | 12.68 | 1450 | 10.67 | 407 |
| DAGL 11kV Bus | 10.94 | 208 | 11.34 | 72 |
| DAGL 66kV Bus | 17.22 | 1968 | 19.79 | 754 |
| BLRI 11kV Bus | 7.84 | 149 | 8.19 | 52 |
| BLRI 66kV Bus | 10.13 | 1158 | 8.82 | 336 |

**Table 12: Existing Maximum Fault Levels at BOHL, DAGL and BLRI**

## 4.5. Operating Profile

The non-network option must be capable of continuous operation between 5pm and 10pm in order to reduce the peak demand (as outlined in section 4.1) sufficiently to negate the need for network investment. The solution must be available for immediate operation, when requested, for 99.8% of the time between October and March.

## 4.6. Timing

### 4.6.1. Implementation Timeframe

In order to continue to meet the service standards in the National Electricity Rules and the *Electricity Act 1994* (Qld), a non-network solution will need to be implemented by October 2029.

### 4.6.2. Time of Year

Ergon Energy envisages that project proponents would be required to be available to provide the load reduction or additional supply between 5pm and 10pm during the October to March period for the number of days per year estimated in Table 10 for DAGL and Table 11 for BLRI.

### 4.6.3. Duration

Support would normally only be called upon following a fault on the network and the duration would vary depending on network repair times. Specific timing would be agreed with providers as part of the contract negotiations.

## 4.7. Compliance with Regulations and Standards

As a distribution network service provider, Ergon Energy must comply with regulations and standards, including Queensland legislation, such as the *Electricity Act 1994* (Qld) and the *Electricity Regulation 2006* (Qld), its Distribution Authority, the NER and applicable Australian Standards.

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

## 4.8. Longevity

Proposed non-network options will typically be required to provide solutions to the identified need for a period of at least 10 years. However, alternative solutions that can defer additional network investment for a smaller number of years may also be considered. Proposed non-network options will require a minimum of 5 years notice to Ergon Energy before ceasing to operate. This will provide sufficient time for Ergon Energy to consider alternate supply arrangements.

## 4.9. Potential Deferred Augmentation Charge

The annual deferred augmentation charge associated with the identified need is approximately $500k per year.

Ergon Energy have estimated the capital cost of the network options to within ± 40% 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 $500k 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.

## 4.10. Feasible vs Non-Feasible Options

### 4.10.1. Potentially Feasible Options

Ergon Energy has not identified any feasible SAPS or non-network options to address the identified need.

### 4.10.2. 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 to the identified need.

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

- Renewable generation not coupled with energy storage and/or dispatchable generation
- Unproven, experimental or undemonstrated technologies

### 4.10.3. Timing of Feasible Options

In order to continue to meet the service standards in the National Electricity Rules and the *Electricity Act 1994* (Qld), a non-network solution will need to be implemented by October 2029.

# 5. CREDIBLE OPTIONS ASSESSED

## 5.1. Assessment of Network Solutions

Ergon Energy has identified three credible network options that would address the identified need.

### 5.1.1. Option A: Establish Bohle Plains Zone Substation with a single 66/11kV transformer

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2029 and would address the identified need by providing additional network capacity to supply the forecast load in the Bohle Plains area. This would ensure Ergon Energy is complaint with applicable regulatory instruments, including its Safety Net requirements.

This option involves establishing a new zone substation at Bohle Plains with 2 x 66kV feeder bays, 1 x 66kV transformer bay, 1 x 32MVA 66/11kV transformer, 11kV switchboard, establishment of 4 x 11kV feeders and reconfiguration of the BLRI, BOHL and DAGL 11kV network to address the identified need.  A second transformer would be installed as part of a future project when the loading on the proposed new substation exceeds the available backup capacity.

Due to the scope of works being entirely contained within the existing substation sites, as well as the expected reliability benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline.  While Ergon Energy does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Ergon Energy Community Engagement Framework which is integrated into the project workflow.

The estimated capital cost of this option is $14.7 million, which has been factored into the NPV to be incurred in 2029. The installation of a future second transformer with an estimated capital cost of $2.8 million has been factored into NPV calculations to be incurred in 2038.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 31.

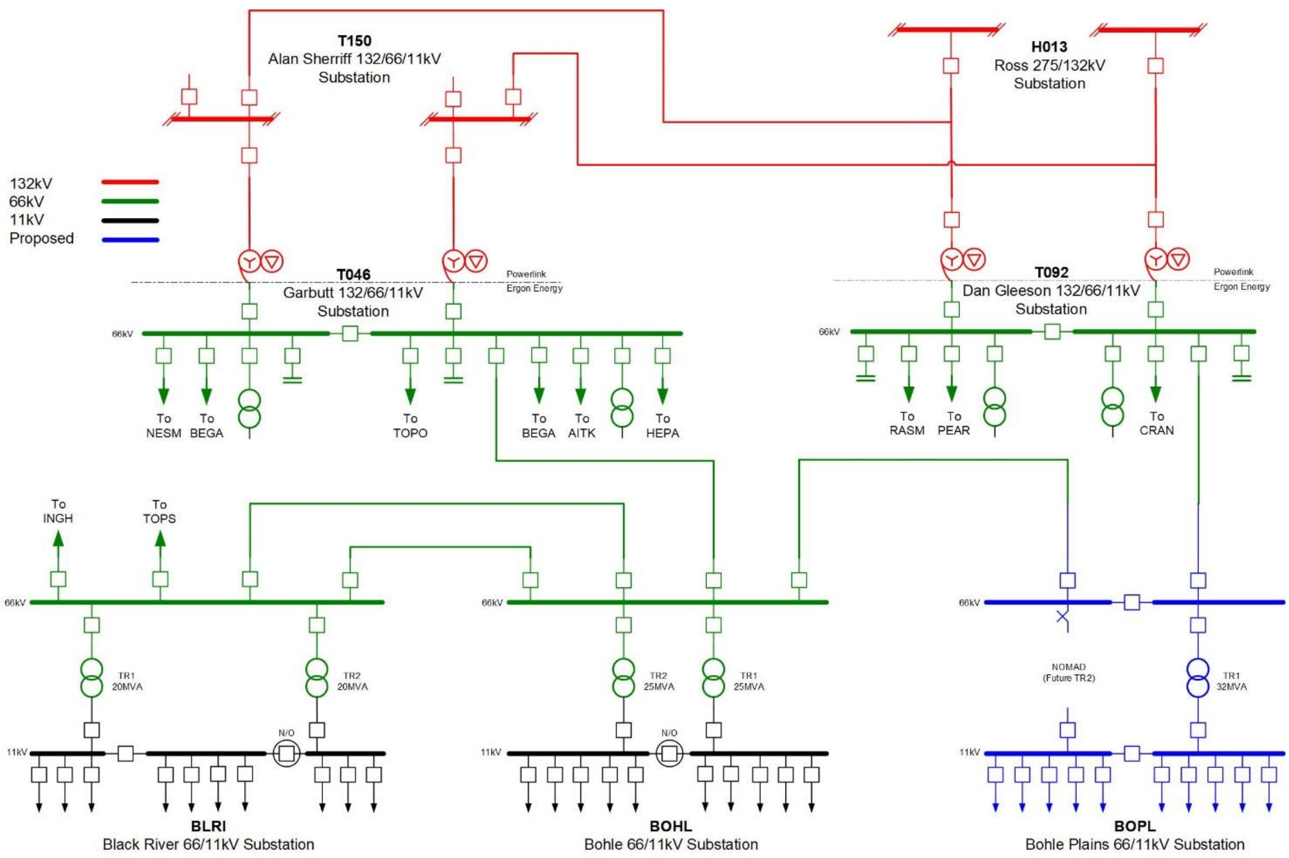



**Figure 31: Option A proposed network arrangement (schematic view)**

### 5.1.2. Option B: Establish Bohle Plains Zone Substation with two 66/11kV transformers

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2029 and would address the identified need by providing additional network capacity to supply the forecast load in the Bohle Plains area. This would ensure Ergon Energy is complaint with applicable regulatory instruments, including its Safety Net requirements.

This option involves establishing a new zone substation at Bohle Plains with 2 x 66kV feeder bays, 2 x 66kV transformer bays, 2 x 32MVA 66/11kV transformers, 11kV switchboard, establishment of 4 x 11kV feeders and reconfiguration of the BLRI, BOHL and DAGL 11kV network to address the identified need.

Due to the scope of works being entirely contained within the existing substation sites, as well as the expected reliability benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline.  While Ergon Energy does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Ergon Energy Community Engagement Framework which is integrated into the project workflow.

The estimated capital cost of this option is $17.2 million, which has been factored into the NPV to be incurred in 2029.

A schematic diagram with the proposed network arrangement for Option B is shown in Figure 32.

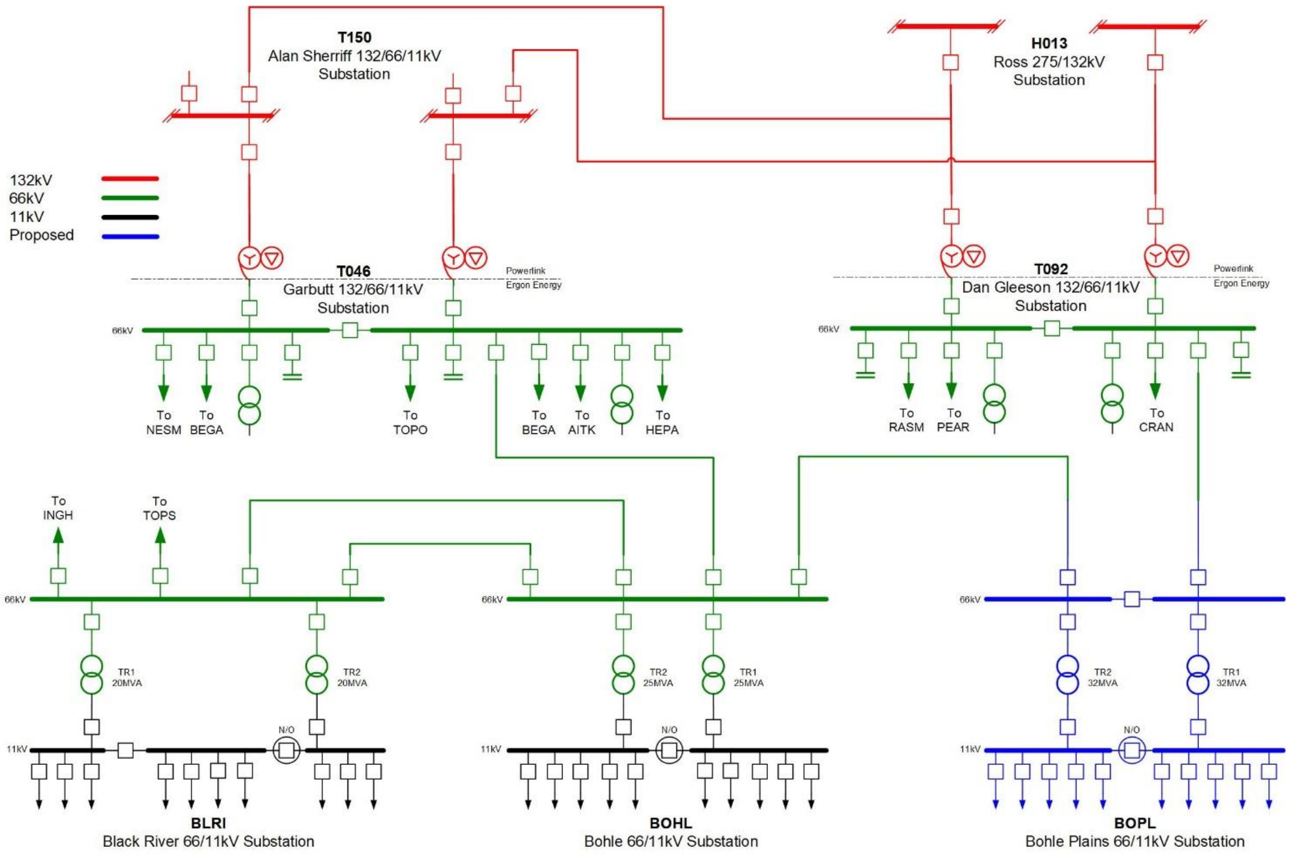



**Figure 32: Option B proposed network arrangement (schematic view)**

### 5.1.3. Option C: Upgrade Dan Gleeson, Bohle and Black River Substations and install additional 11kV feeders into the area to defer the establishment of Bohle Plains Substation

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2029 and would address the identified need by providing additional network capacity to supply the forecast load in the Bohle Plains area. This would ensure Ergon Energy is complaint with applicable regulatory instruments, including its Safety Net requirements.

This option involves upgrading BLRI with 2 x 32MVA 66/11kV transformers, upgrading BOHL with 2 x 32MVA transformers, upgrading BOHL 11kV transformer cables, upgrading DAGL 11kV transformer cables, installing new 11kV feeder bays at BOHL & DAGL, establishing a new 11kV feeder from DAGL and a new 11kV feeder from BOHL to supply the Bohle Plains area to address the identified need. This option defers the need for the proposed new Bohle Plains substation by around 10 years.

Due to the scope of works being entirely contained within the existing substation sites, as well as the expected reliability benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline.  While Ergon Energy does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Ergon Energy Community Engagement Framework which is integrated into the project workflow.

The estimated capital cost of this option is $11.8 million, which has been factored into the NPV to be incurred in 2029. The establishment of the future Bohle Plains Substation with an estimated capital cost of $17.2 million has been factored into NPV calculations to be incurred in 2038.

A schematic diagram of the proposed network arrangement for Option C is shown in Figure 33.

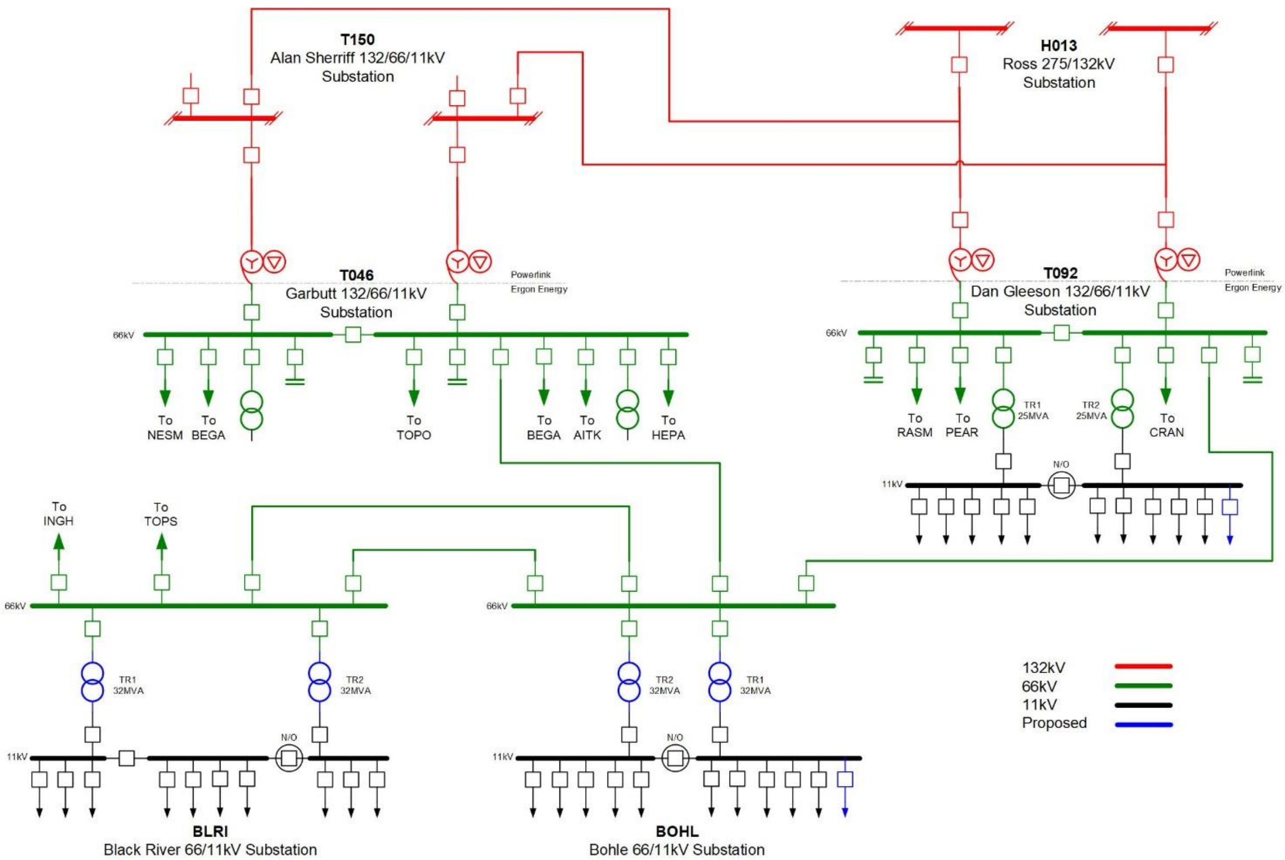



**Figure 33: Option C proposed network arrangement (schematic view)**

## 5.2. Assessment of SAPS and 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) or SAPS option to replace or reduce the need for the network options proposed.

Credible options must be technically and commercially feasible and must be able to be implemented in sufficient time to satisfy the identified need.

### 5.2.1. Consideration of SAPS Options

Ergon Energy considers there is no SAPS option that could form a potential credible option on a standalone basis, or that could form a significant part of the credible option. In particular the load requirements, per the forecast in the Bohle Plains area could not be supported by a network that is not part of the interconnected national electricity system. Therefore, a SAPS option is not technically feasible.

### 5.2.2. Demand Management (Demand Reduction)

The DEM team has completed a review of the BOHL, DAGL and BLRI customer base and considered a number of demand management technologies.

#### Network Load Control

The residential customer load appears to drive the daily peak demand which generally occurs between 5:00pm and 10:00pm.

BOHL has 3465 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 2079kVA[7] is available.

DAGL has 6343 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 3805kVA[8] is available.

BLRI has 6641 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 3984kVA[9] is available.

LC signals in the Townsville area are controlled from T046 Garbutt 132/66kV Substation (GARB) and Stuart 66/11kV Substation (STUA). 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 when the T046 Garbutt 132/66kV Substation 66kV load exceeds 91MW or the T092 Dan Gleeson 132/66kV Substation 66kV load exceeds 110MW or the Stuart Substation 66kV load exceeds 100MW. This strategy does not directly address demand peaks experienced at BLRI, BOHL or DAGL or the 11kV feeders. Tariff 33 air-conditioning channels are under manual control of the operational control centre and are used as required. Therefore, network load control alone does not sufficiently address the identified need.

### 5.2.3. 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)

[7] Hot water diversified demand saving estimated at 0.6kVA per system
[8] Hot water diversified demand saving estimated at 0.6kVA per system
[9] Hot water diversified demand saving estimated at 0.6kVA per system

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 will not address the identified network requirement.

### 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 has been assessed as technically not viable as there is no known existing LSG or proposed LSG that could address the identified network requirement.

### Customer Solar Power Systems

BOHL has a total of 2,289 customers with solar photo voltaic (PV) systems with a total connected inverter capacity of 18,977kVA.

DAGL has a total of 4,463 customers with solar photo voltaic (PV) systems with a total connected inverter capacity of 26,233kVA.

BLRI has a total of 4,813 customers with solar photo voltaic (PV) systems with a total connected inverter capacity of 29,680kVA.

The daily peak demand is driven by residential customer demand and the peak generally occurs between 5:00pm and 10:00pm. 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 a 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. 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.

#### 5.2.4. SAPS and Non-Network Solution Summary

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

### 5.3. Preferred Network Option

Ergon Energy's preferred option is Option A, to establish a new zone substation at Bohle Plains with 2 x 66kV feeder bays, 1 x 66kV transformer bay, 1 x 32MVA 66/11kV transformer, 11kV switchboard, establishment of 4 x 11kV feeders and reconfiguration of the BLRI, BOHL and DAGL 11kV network. Based on NPV calculations comparing all network options, this is the network option that provides the greatest net economic benefit.

Upon completion of these works the identified need would be addressed by establishing a new zone substation at Bohle Plains ensuring Ergon Energy continues to adhere to the applicable regulatory instruments. This option will address the identified need, is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

The estimated capital cost of this option is $14.7 million.  Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design commencing in mid-2026 and construction completed by mid-2029.

# 6. SUMMARY OF SUBMISSIONS RECEIVED IN RESPONSE TO OPTIONS SCREENING REPORT

On 22 October 2024, Ergon Energy published an Options Screening Report providing details on the identified need in the Bohle Plains area. This report provided both technical and economic information about possible solutions and sought information from interested parties about possible alternate solutions to address the identified need.

In response to the Options Screening Report, Ergon Energy received no submissions by 31 January 2025, which was the closing date for submissions to the Options Screening Report.

# 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 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

The following classes of market benefits are considered material, and have been included in this RIT-D assessment:

- Changes in involuntary load shedding and Customer Interruptions caused by Network Outages

### 7.1.1. Changes in Involuntary Load Shedding and Customer Interruptions caused by Network Outages

Involuntary load shedding is where a customer's load is interrupted from the network without their agreement or prior warning. Ergon Energy has forecast load over the assessment period and has quantified the expected unserved energy by comparing forecast load to network capabilities under system normal and network outage conditions. A reduction in involuntary load shedding expected from an option, relative to the base case, results in a positive contribution to the market benefits of the credible option being assessed.

Involuntary load shedding of a credible option is derived by the quantity in MWh of involuntary load shedding required assuming the credible option is completed multiplied by the Value of Customer Reliability (VCR). The VCR is measured in dollars per MWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D.

Ergon Energy has applied a VCR estimate of $34.68/kWh for the BOHL 11kV load, $35.26/kWh for the DAGL 11kV load and $35.34 for the BLRI 11kV load, which has been derived from the AER 2024 Value of Customer Reliability (VCR) values. In particular, Ergon Energy has weighted the AER estimates according to the make-up of the specific load considered.

Customer export Curtailment value (CECV) represents the detriment to all customers from the curtailment of DER export (e.g. rooftop solar PV systems). A reduction in curtailment due to implementing a credible option results in a positive contribution to the market benefits of that option. These benefits have been calculated according to the AER CECV methodology based on the capacity of DER currently installed and forecast to be installed within the Bohle Plains area.

## 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
- Differences in timing of expenditure
- Changes in load transfer capacity and the capacity of Embedded Generators to take up load
- Changes in electrical energy losses
- Changes in Australia’s greenhouse gas emissions
- Option value
- Costs Associated with Social Licence Activities

### 7.2.1. Changes in Voluntary Load Curtailment

The credible options presented in this RIT-D assessment do not include any voluntary load curtailment as there are no customers on voluntary load curtailment agreements in the Bohle Plains area. Therefore, 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. Differences in Timing of Expenditure

The credible options included in this RIT-D assessment is/are not expected to affect the timing of other distribution investments for unrelated identified needs.

### 7.2.4. Changes in Load Transfer Capacity and the capacity of Embedded Generators to take up load

The credible options included in this RIT-D assessment are not expected to have an impact on the load transfer capacity or the capacity of embedded generators to take up load between the zone substations in the Bohle Plains area.

### 7.2.5. Changes in Electrical Energy 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 electrical energy losses.

### 7.2.6. Changes in Australia's Greenhouse Gas Emissions

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

### 7.2.7. 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[10].

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.

### 7.2.8. Costs Associated with Social Licence Activities

Ergon Energy does not anticipate that any of the credible options included in the RIT-D assessment will involve costs associated with social licence activities.

[10] AER "Regulatory Investment Test for Distribution Application Guidelines", Section A8.
Available at: https://www.aer.gov.au/documents/aer-regulatory-investment-test-distribution-clean-21-november-2024

# 8. DETAILED ECONOMIC ASSESSMENT

## 8.1. 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.

## 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.

Table 13 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 |
|---|---|---|---|
| WACC | 3.5% | 2.5% | 4.5% |
| Project Costs | Standard estimates | -40% | +40% |
| Project Costs | Preferred option estimates | -40% | +40% |
| Opex Costs | Calculated Opex | -10% | +10% |

**Table 13: Economic parameters and sensitivity analysis factors**

## 8.3. Scenarios Adopted for Sensitivity Testing

A sensitivity analysis was conducted on the base case to establish the option that remained the lowest cost option in the scenarios considered. In this instance, the scenarios that have been considered are:

- **Medium demand** – under this scenario the existing load remains around the same as it currently is. This is consistent with the base case load forecast.

## 8.4. Net Present Value (NPV) Results

An overview of the initial capital cost and the base case NPV results are provided in Table 14.

| Option | Option Name | Rank | Net NPV | Capex NPV | Opex NPV | Benefits NPV |
|---|---|---|---|---|---|---|
| A | Establish Bohle Plains Zone Substation with a single 66/11kV transformer | 1 | $4,650,000 | -$17,137,000 | -$6,608,000 | $28,394,000 |
| B | Establish Bohle Plains Zone Substation with two 66/11kV transformers | 2 | $4,032,000 | -$17,546,000 | -$6,700,000 | $28,278,000 |
| C | Upgrade Dan Gleeson, Bohle and Black River Substations and install additional 11kV feeders into the area to defer the establishment of Bohle Plains Substation | 3 | $1,413,000 | -$19,887,000 | -$7,527,000 | $28,827,000 |

**Table 14: Base case NPV ranking table**

A sensitivity analysis was conducted on this base case to establish the option that remained the lowest cost option in the scenarios considered. Table 15 provides the results of the WACC sensitivity analysis.

| Option Number | Option Name | Rank | Net NPV (2.5% WACC) | Net NPV (4.5% WACC) |
|---|---|---|---|---|
| A | Establish Bohle Plains Zone Substation with a single 66/11kV transformer | 1 | $15,379,000 | -$1,784,000 |
| B | Establish Bohle Plains Zone Substation with two 66/11kV transformers | 2 | $14,871,000 | -$2,496,000 |
| C | Upgrade Dan Gleeson, Bohle and Black River Substations and install additional 11kV feeders into the area to defer the establishment of Bohle Plains Substation | 3 | $11,447,000 | -$4,392,000 |

**Table 15: Scenario Analysis – WACC sensitivity**

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 16 shows the average NPV cost of all the simulations.

| Option Number | Option Name | Average NPV | Maximum NPV | Minimum NPV |
|---|---|---|---|---|
| A | Establish Bohle Plains Zone Substation with a single 66/11kV transformer | $4,697,000 | $9,659,000 | -$149,000 |
| B | Establish Bohle Plains Zone Substation with two 66/11kV transformers | $4,064,000 | $9,832,000 | -$1,035,000 |
| C | Upgrade Dan Gleeson, Bohle and Black River Substations and install additional 11kV feeders into the area to defer the establishment of Bohle Plains Substation | $1,479,000 | $6,839,000 | -$2,838,000 |

**Table 16: Monte Carlo Analysis for Base Case Forecast**

Option A also has the lowest average cost and is the most economical in 58.9% of cases in the Monte-Carlo simulations.

Based on the detailed economic assessment, Option A is considered to provide the optimum solution to address the forecast limitations and is therefore the preferred option.

## 8.5. Selection of Preferred Option

Ergon Energy’s preferred option is Option A, to establish a new zone substation at Bohle Plains with 2 x 66kV feeder bays, 1 x 66kV transformer bay, 1 x 32MVA 66/11kV transformer, 11kV switchboard, establishment of 4 x 11kV feeders and reconfiguration of the BLRI, BOHL and DAGL 11kV network.

Upon completion of these works the identified need would be addressed by establishing a new zone substation at Bohle Plains ensuring Ergon Energy continues to adhere to the applicable regulatory instruments. This option will address the identified need, is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

The estimated capital cost of this option is $14.7 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design commencing in mid-2026 and construction completed by mid-2029.

## 8.6. Satisfaction of RIT-D

The preferred option satisfies the RIT-D and maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

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 network 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 **24 April 2025** 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 9 May 2025. 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 address the identified need.

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 as part of the preferred option published in the FPAR.

| | | |
|---|---|---|
| Step 1 | Publish Options Screening Report (this report) inviting SAPS and non-network options from interested participants | Date Released:<br>**22 October 2024** |
| Step 2 | Consultation period | **Minimum of 3 months (12 weeks)** |
| Step 3 | Deadline for Submission of proposals for SAP and non-network alternatives | **31 January 2025** |
| Step 4 | Release of Draft Project Assessment Report (DPAR) | Date Released:<br>**7 March 2025** |
| Step 5 | Consultations in response to the DPAR | **Minimum of 6 weeks** |
| Step 6 | Publish the Final Project Assessment Report (FPAR) | Anticipated to be released by:<br>**9 May 2025** |
| 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.

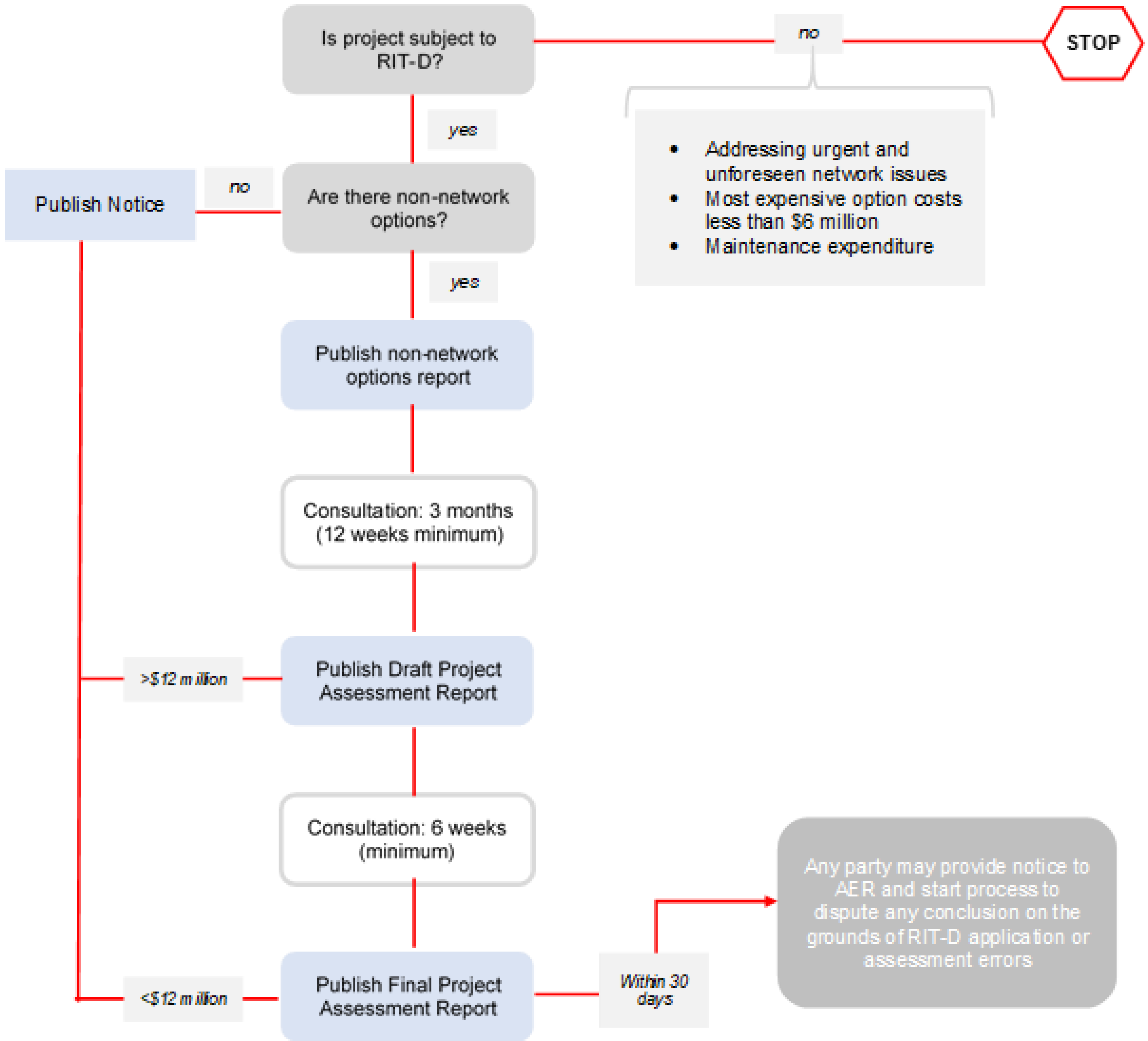
During the consultation period, Ergon Energy will review, compare and analyse all internal and external solutions. Detailed economic options analysis and comparisons of expected market benefits will be undertaken during this time. At the end of the consultation and review process Ergon Energy will publish 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 Options Screening Report; | 6 |
| (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 & 8 |
| (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 | 8.5 |
| (11) for the proposed preferred option, the RIT-D proponent must provide:<br>(i) details of the technical characteristics;<br>(ii) the estimated construction timetable and commissioning date (where relevant);<br>(ii) the indicative capital and operating costs (where relevant);<br>(iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and<br>(v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent | 8.5 & 8.6 |
| (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.