Establish Thabeban Zone Substation

Memo

18 January 2024

Part of Energy Queensland

DOCUMENT VERSION

Version Number	Change Detail	Date	Updated by
1.0	Review	08/12/2023	J Hockey
2.0	Endorsed	08/12/2023	J Patel
3.0	Approved	13/12/2023	S Weeratunga

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1 SUMMARY

Title	Establish Thabeban Zone Substation
DNSP	Ergon Energy
Expenditure category	☐ Replacement ☒ Augmentation ☐ Connections ☐ Non-Network
Identified need and option requirements	☒ Legislation ☒ Regulatory compliance ☐ Reliability ☐ CECV ☐ Safety ☐ Environment ☐ Financial ☒ Other Ergon Energy received a connection application to supply a major customer load of up to 10MW in the Bundaberg region near Thabeban, with a connection timeframe of October 2026. The customer infrastructure will provide services to the Bundaberg region which will see further development and growth in the suburb of Thabeban. Forecast load growth indicates a safety net non-compliance on the 66kV Bundaberg ring which emerges as early as 2027. Planning consideration for connecting the large load included not only the immediate customer requirements but also the future requirements to meet safety net and supply forecast load and DER growth in the area. Financial consideration of the split between Alternate Service Controls (ACS) and Standard Control Services (SCS) as defined in Chapter 10 of the National Electricity Rules (NER) were also considered for credible options. The minimal technical requirements for an option to be considered credible included, • Supply of major customer up to 10MW and • Provide an N-1 supply. Additional requirements: • Overcome 66kV Safety Net Limitation After lengthy consultations with the customer and EQL planning teams only one option was considered credible to meet the immediate customer requirements and future network needs. This option is for the development of 2 x 20/25MVA 66/11kV Thabeban substation (THAB) to be established at Thabeban, and a new 66kV feeder from South Bundaberg 66/11kV substation (SOBU) to THAB be established. The completion date for the works is October 2026, which is driven by the customer timeframes for connection. The option has a significant SCS and ACS component associated with it. Given the SCS costs, NPV analysis of other non-credible options was undertaken to demonstrate that not only does the preferred option meet the customer requirements, safety net limitations and future forecast for the area, but also provides the most efficient economic investment. Further information for this investment can be found in the published RIT-D (attached in this document) and found at

	RIT-D Final Project Assessment Report, **Note:** Works classified as ACS requires that the customer fund the cost directly. SCS works are those that are central to the supply of electricity and provided by Ergon Energy, including design, construction and operation of the shared network. Cost for these services is recovered through network charges for all relevant customers.
Summary of preferred option	The preferred option (Option 1 of this report) is to develop a 2 x 20/25MVA 66/11kV Thabeban substation (THAB) at Thabeban, build a new 66kV feeder from South Bundaberg 66/11kV substation (SOBU) to THAB. **Note: A new 66kV feeder from BUND (T20) will be established, which will reinforce the 66kV ring however this will be ACS costs.**
Expenditure	(see table below)

Year	Previous period	2025-26	2026-27	2027-28	2028-29	2029-30	2025-30
$m, direct 2022-23	-	11.769	5.494	0.135	0.102	-	$17.5

1. IDENTIFIED NEED

The primary driver for this project is the connection of a major customer in the Bundaberg Region by October 2026. Due to commercial in confidence all details of the enquiry cannot be disclosed, however the information pertinent to this investment is the connection of a load up to 10MW and requirement for an N-1 supply.

Ergon Energy also has forecast a requirement to reinforce the 66kV Bundaberg ring to ensure obligations under its Distribution Authority Safety Net criteria, are met following a credible contingency of a portion of the 66kV feeder ring. It was anticipated that approximately an 4km 66kV feeder between Bundaberg (T20) and South Bundaberg (SOBU) would be required and for the reinforcement work to be completed as early as 2027.

2. CREDIBLE OPTIONS ASSESSED

2.1. Option 1: Development of Thabeban 66/11kV Substation

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

This option involves the development of a new greenfield 2 x 20/25MVA 66/11kV substation, which will be known as Thabeban (THAB). In order to provide diverse N-1 supply at the 66kV level, THAB will be supplied via an approximately 4km 66kV feeder from Bundaberg Bulk Supply Substation (T20) (ACS works) and an approximately 4km feeder from South Bundaberg substation (SOBU) (SCS works).

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

Note: The overall project includes both ACS and SCS costs components, however this investment only focuses on the SCS component.

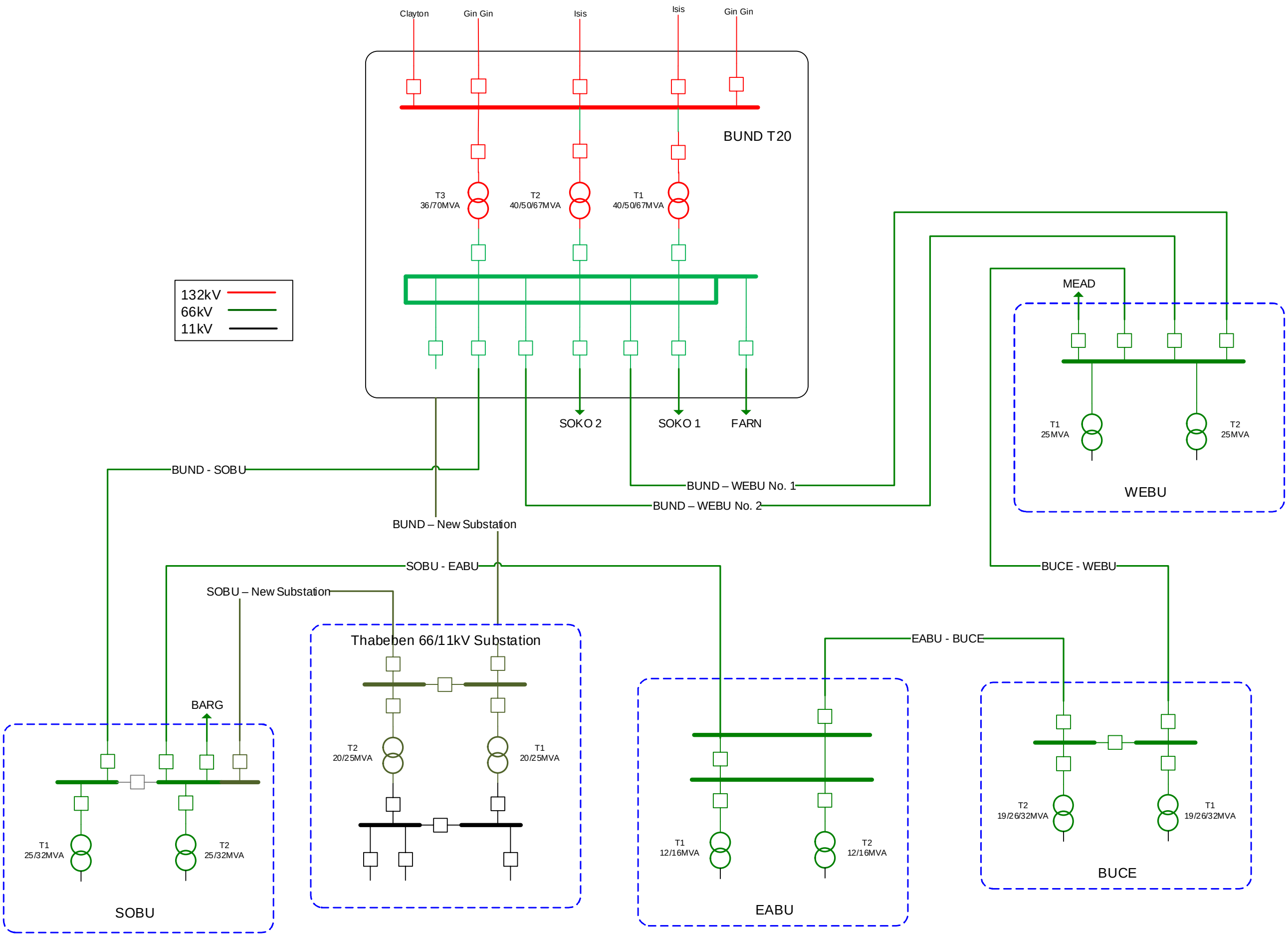

Figure 1: Option 1 proposed network arrangement (schematic view)

3. ECONOMIC ANALYSIS

Although there was only one credible option identified which meets all the identified needs, including N-1 supply to a major customer; given that the SCS component cost of the project will also address the future 66kV limitation and provide future 11kV capacity, alternate options for meeting those specific limitations have been shown in the NPV.

This is to provide transparency and to demonstrate that the SCS investment provides the most prudent investment in the network, meeting both the present and future needs. However, it should be noted that options 2 and 3 cannot address all of the identified needs, only future network limitations.

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

1.1 NPV Analysis

Table 1: Base Case NPV Ranking Table

Option	Option Name	Rank	Net NPV ($ real)	PV of Capex ($ real)	PV of Opex ($ real)	Net Economic Benefit ($ real)
1	Build Thabeban 2 x 20/25MVA Substation	1	$37,006,000	$-17,500,000	$-7,932,000	$62,438,000
2	SOBU TR Upgrade + 66kV Upgrade + THAB 2050	3	$29,518,000	$-22,668,000	$-10,253,000	$62,438,000
3	SOBU 66kV in 2027 + SOBU Upgrade in 2040 + THAB 2050	2	$34,367,000	$-19,069,000	$-8,508,000	$61,945,000

1.2 Sensitivity Analysis

A sensitivity analysis was conducted based on the information in Table 2 to establish the option that provided the lowest cost option in various scenarios. Table 3 and

Table 4 provides the results of the sensitivity analysis and under all scenarios Option 1 remains the preferred option.

Table 2: Economic Parameters and Sensitivity Analysis Factors

Parameter	Mode Value	Lower Bound	Upper Bound
WACC	2.72%	2.0%	5%
Project Costs	Project Estimates	-20%	+20%
Opex Costs	Calculated Opex	-10%	+10%

Table 3: Scenario Analysis – Comparison of Options

Option Number	Option Name	Weighted Rank	Average NPV	Maximum NPV	Minimum NPV
1	Build Thabeban 2 x 20/25MVA Substation	1	\$35,679,000	\$37,193,000	\$33,855,000
2	SOBU TR Upgrade + 66kV Upgrade + THAB 2050	3	\$28,219,000	\$31,249,000	\$24,383,000
3	SOBU 66kV in 2027 + SOBU Upgrade in 2040 + THAB 2050	2	\$32,927,000	\$35,472,000	\$29,577,000

Table 4: WACC Sensitivity Analysis for Base Case Forecast

Option Number	Option Name	2.00% WACC	5.00% WACC
1	Build Thabeban 2 x 20/25MVA Substation	$48,879,000	$14,886,000
2	SOBU TR Upgrade + 66kV Upgrade + THAB 2050	$40,865,000	$8,489,000
3	SOBU 66kV in 2027 + SOBU Upgrade in 2040 + THAB 2050	$45,388,000	$14,604,000

Based on the detailed economic assessment, Option 1 is considered to provide the optimum solution to address not only the immediate identified need but also the forecast network limitations and is therefore the recommended development option.

1.2.1 Cost summary 2025-30

The preferred option, Option 1 has an estimated direct cost of $17.5m.

2 RECOMMENDATION

It is recommended to build a new 2 x 20/25MVA substation at Thabeban, with N-1 66kV supply, to initially supply the major load and to support forecast load growth in the area. The timing for the investment is driven by the customer requirements with a project completion of October 2026.

Table 5 – Options Analysis Scorecard

Criteria	Option1– Asset replacement.
Net Present Value	$37.006m
Investment cost (TCO)	$17.5m
Investment Risk	Medium
Benefits	$62.438m
Delivery Time	October 2026

Regulatory Investment Test for Distribution (RIT-D)

Connection of a Major Customer in the Bundaberg Region

Final Project Assessment Report

30 October 2023

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

Ergon Energy has received a connection application for a major customer to connect to the network in the Bundaberg region with a requirement for a large supply. The connection arrangement, which has been agreed to through consultation with the customer, is for a dedicated connection which is composed of both Alternate Control Services (ACS) and Standard Control Services (SCS) as defined in Chapter 10 of the National Electricity Rules (NER).

Works classified as ACS requires that the customer fund the cost directly. SCS works are those that are central to the supply of electricity and provided by Ergon Energy, including design, construction and operation of the shared network. Cost for these services is recovered through network charges for all relevant customers.

The RIT-D only considers the SCS component, as this is network expenditure under the identified need; however, any solution must be capable of supplying the major customer up to 10MW and provide an N-1 supply. The proposed connection arrangement requires that a new 2 x 20/25MVA 66/11kV Thabeban substation (THAB) is established at Thabeban, a new 66kV feeder from Bundaberg (T20) 132/66kV substation (BUND) to THAB and new 66kV feeder from South Bundaberg 66/11kV substation (SOBU) to THAB. The completion date for the works is October 2026, which is driven by the customer timeframes for connection.

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

Bundaberg supply area in a reliable, safe and cost-effective manner and for the connection of a major customer. Accordingly, this investment is subject to a RIT-D.

Ergon Energy published a Draft Project Assessment Report for the above described network constraint on 11 September 2023. No submissions were received by the closing date of 25 October 2023.

One potentially feasible option has been investigated:

- **Option A:** Develop Thabeban 66/11kV Substation

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

Ergon Energy's preferred solution to address the identified need is Option A – Develop Thabeban 66/11kV Substation.

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1. INTRODUCTION

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

This report represents the final stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need for the Bundaberg 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. Response to the DPAR

Ergon Energy published a Draft Project Assessment Report for the identified need in the Bundaberg network area on the 11 September 2023. No submissions were received by the closing date of the 25 October 2023.

1.2. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the Bundaberg 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 the single credible option and accompanying explanatory statements regarding the results along with NPV for options that will address only the network limitations.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.

1.3. Dispute Resolution Process

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

If no formal dispute is raised, Ergon Energy will proceed with the preferred option to develop a greenfield 66/11kV Substation at Thabeban.

1.4. Contact Details

For further information and inquiries please contact:

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

2. BACKGROUND

2.1. Geographic Region

The Bundaberg region is supplied via five 66/11kV zone substations, West Bundaberg (WEBU), Bundaberg Central (BUCE), East Bundaberg (EABU), South Bundaberg (SOBU) and Bargara (BARG). The 66kV network is supplied from Bundaberg (T20) 132/66kV Bulk Supply Substation, where the 66kV network forms a ring, connecting WEBU, BUCE, EABU and SOBU, with Bargara supplied radially from South Bundaberg. A major customer has requested electrical connection within the Thabeban suburb of the Bundaberg region. During the consultation with the customer a planning report was developed to identify the credible options for connection, with the preferred option being an N-1 11kV connection from a new 66/11kV substation located near Thabeban.

The geographical location of Ergon Energy's sub-transmission network and substations in the area is shown in Figure 1 and Figure 2.

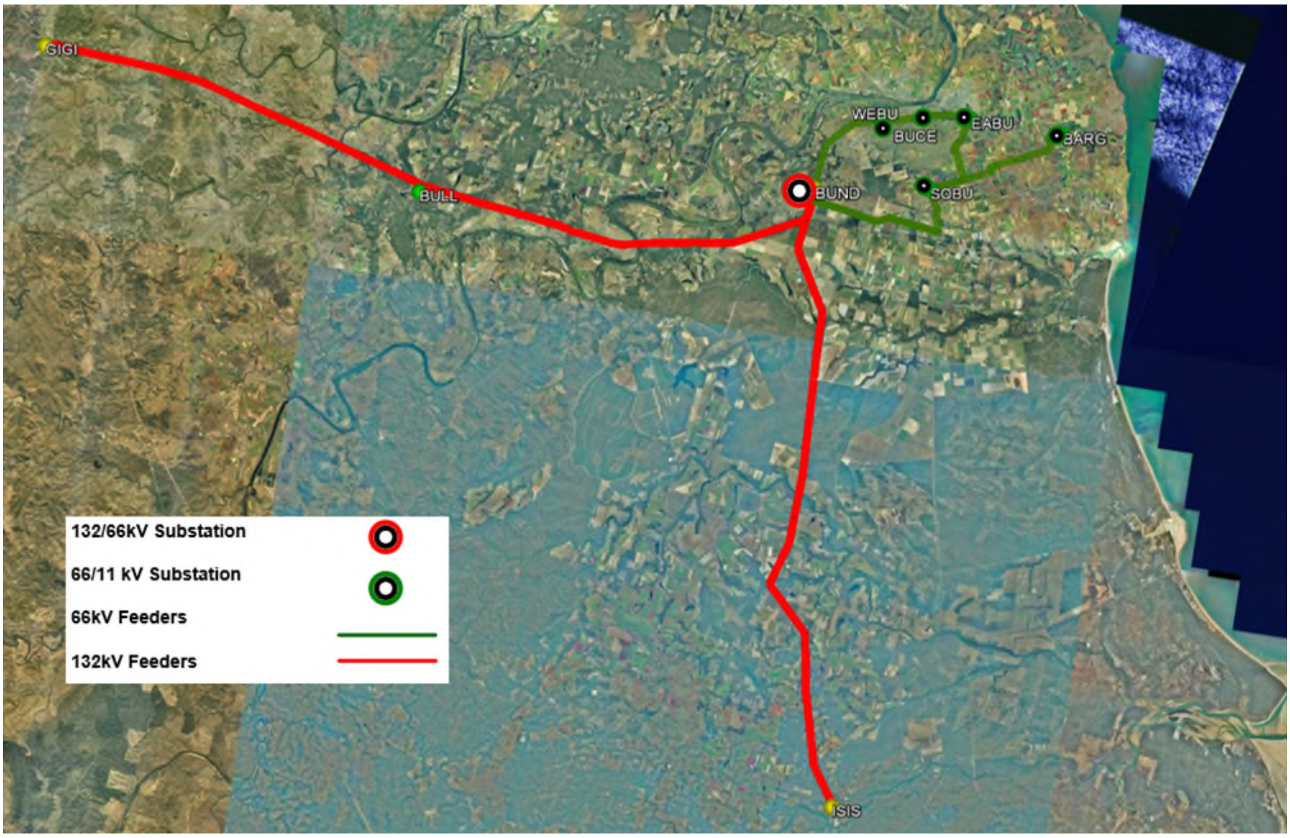


Figure 1: Existing network arrangement (geographic view)

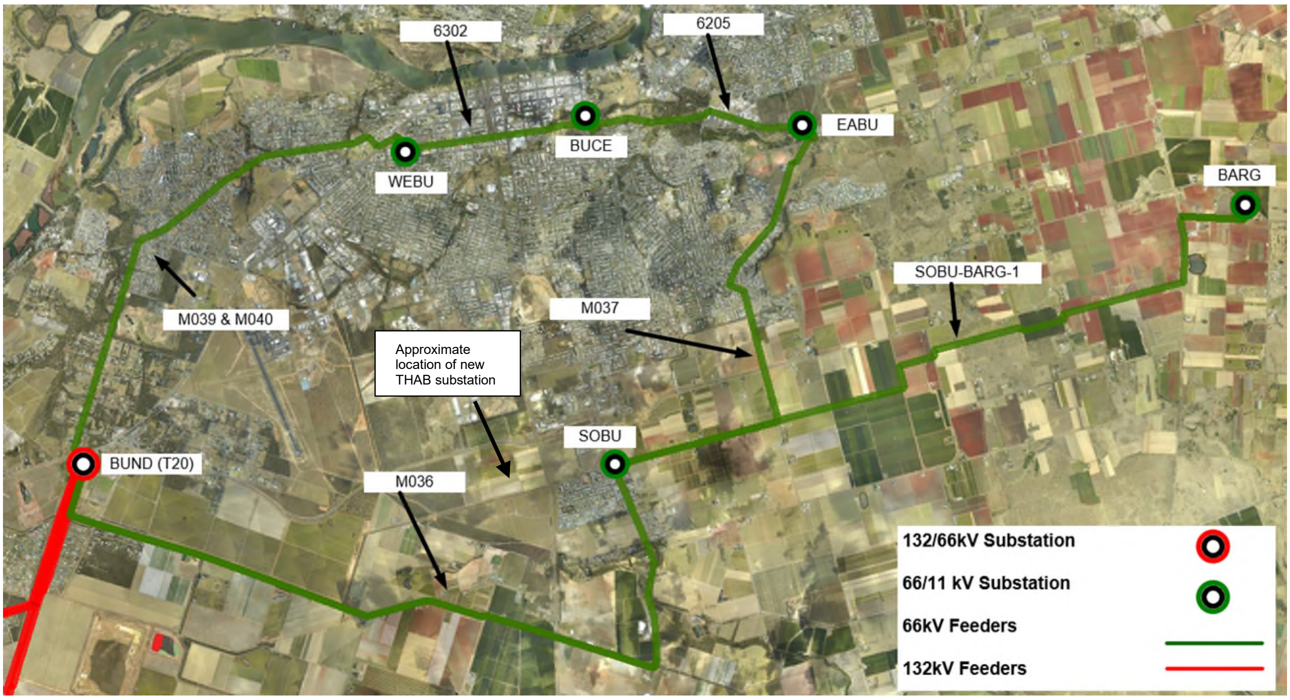


Figure 2: Existing Geographic view of the network arrangement (Zoomed)

2.2. Existing Supply System

The existing 66kV network is supplied from Bundaberg (T20) 132/66kV Bulk Supply substation, which is located approximately 2.5km West of the Bundaberg Airport. The 66kV network supplies the Bundaberg ring, connecting WEBU, BUCE, EABU and SOBU; BARG is also supplied radially from SOBU at 66kV. Each of these zone substations subsequently supplies local customers at 11kV.

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

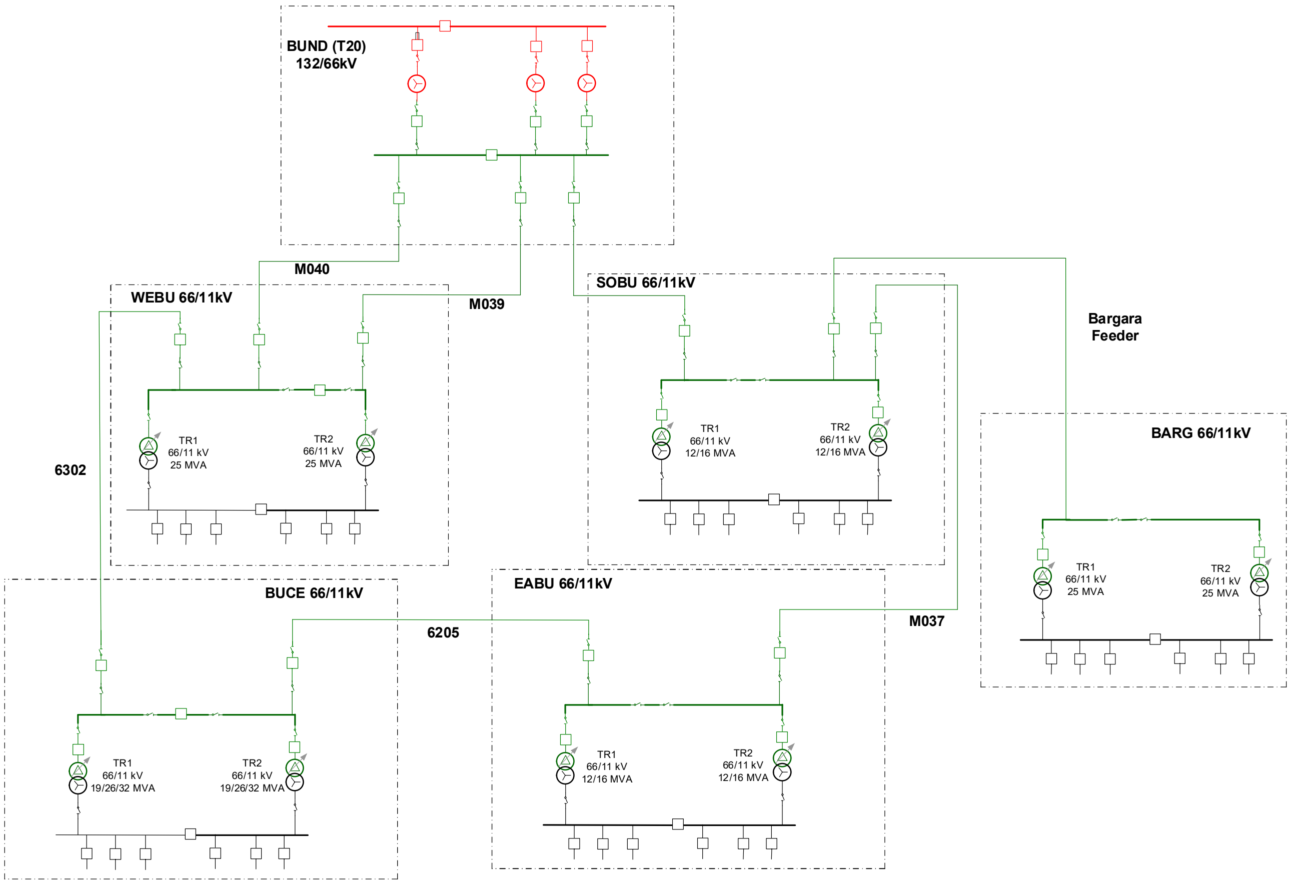


Figure 3: Existing network arrangement (schematic view)

2.3. Load Profiles / Forecasts

The load profiles pertinent to this project include WEBU, BUCE, EABU and SOBU. Each of these are provided in the following sections. The loads of the four zone substations are predominantly summer peaking.

2.3.1. Full Annual Load Profile

The full annual load profile for West Bundaberg, Bundaberg Central, East Bundaberg and South Bundaberg Substation over the 2022/23 financial year are shown in Figure 4, Figure 5, Figure 6, and Figure 7.

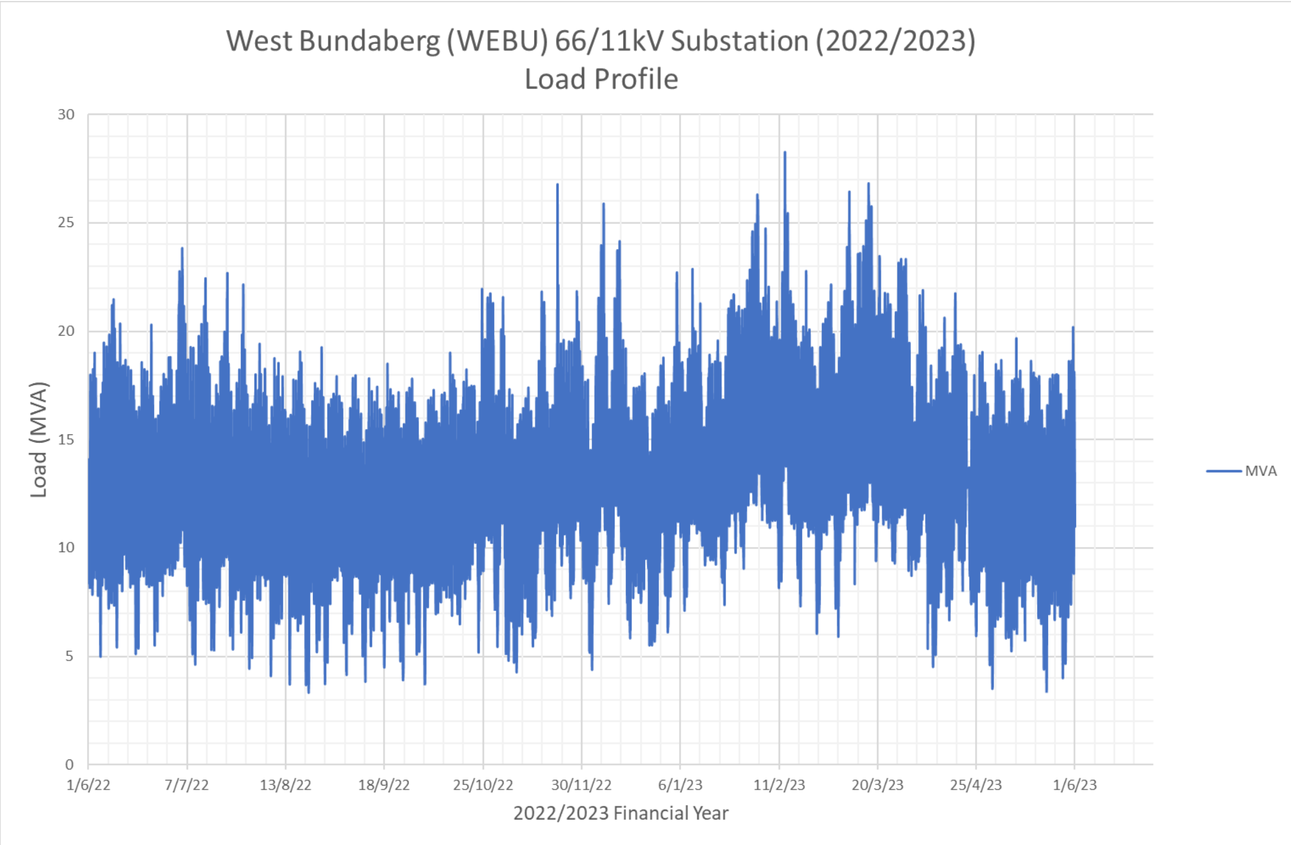


Figure 4: West Bundaberg Substation actual annual load profile

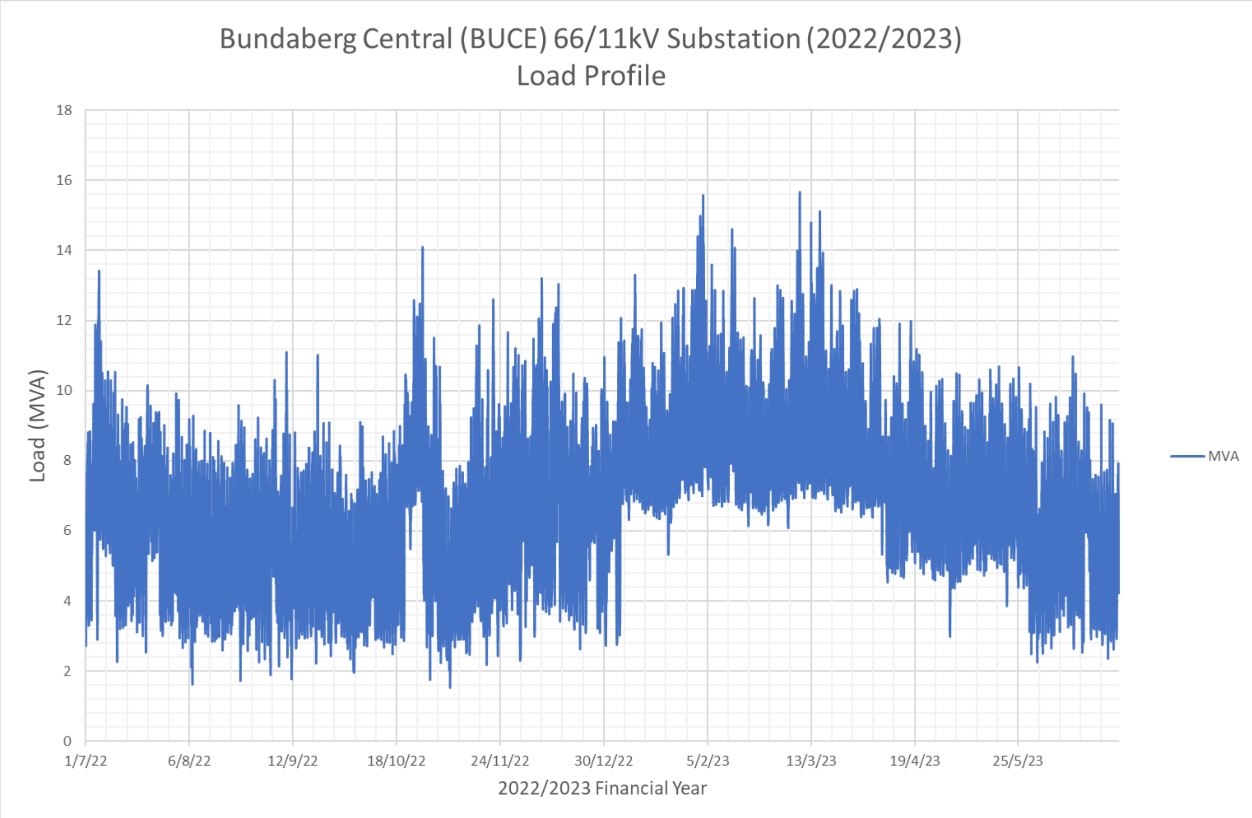


Figure 5: Bundaberg Central Substation actual annual load profile

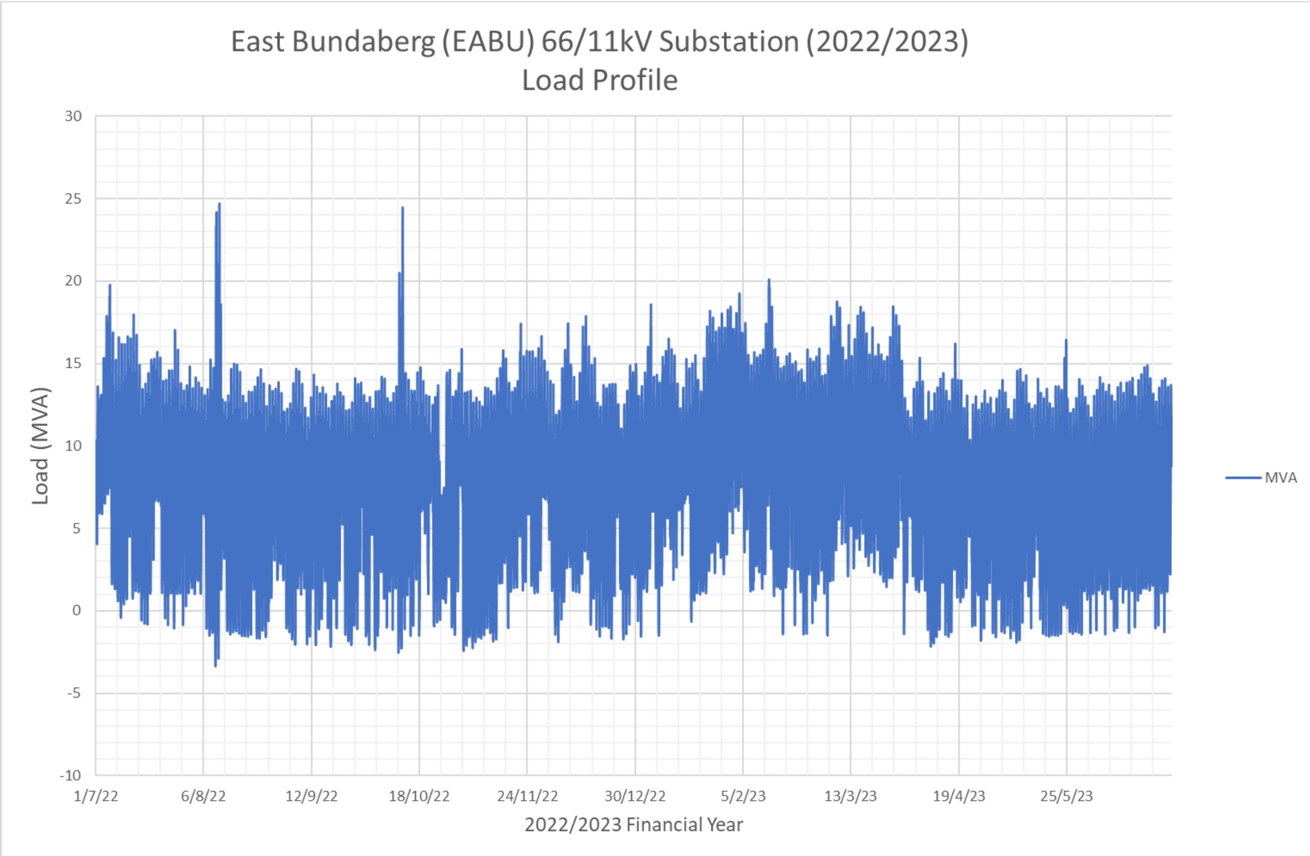


Figure 6: East Bundaberg Substation actual annual load profile

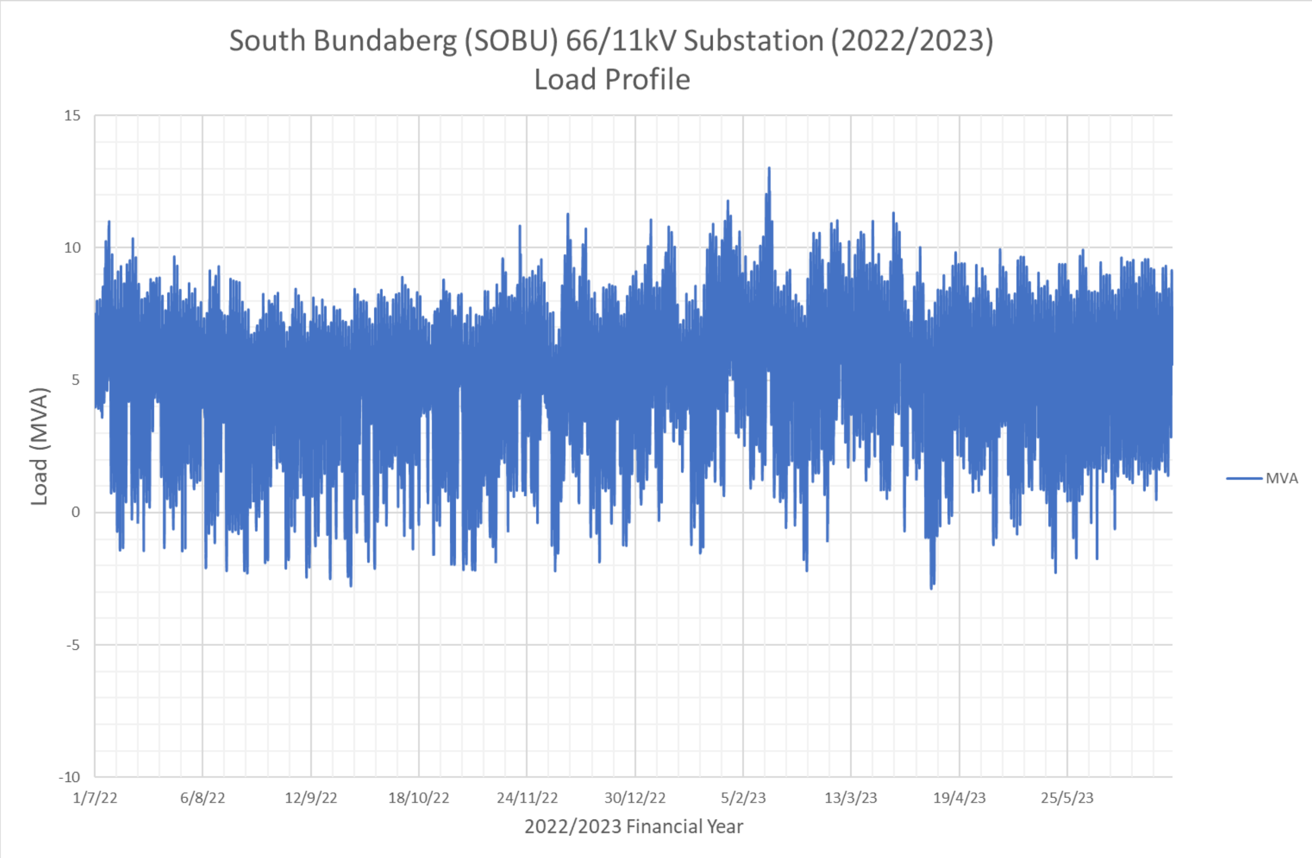


Figure 7: South Bundaberg Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for West Bundaberg, Bundaberg Central, East Bundaberg and South Bundaberg Substation over the 2022/23 financial year is shown in Figure 8, Figure 9, Figure 10, and Figure 11.

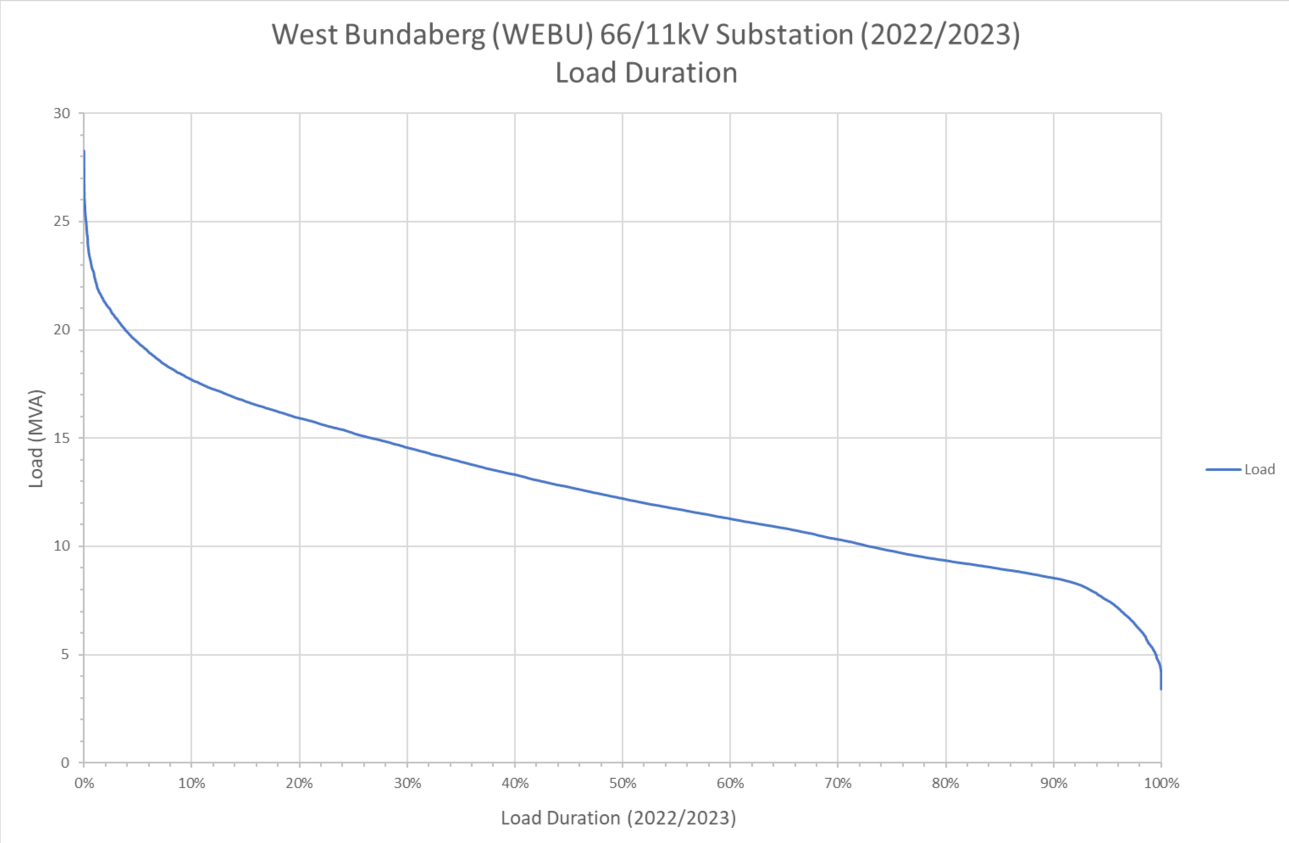


Figure 8: West Bundaberg Substation load duration curve

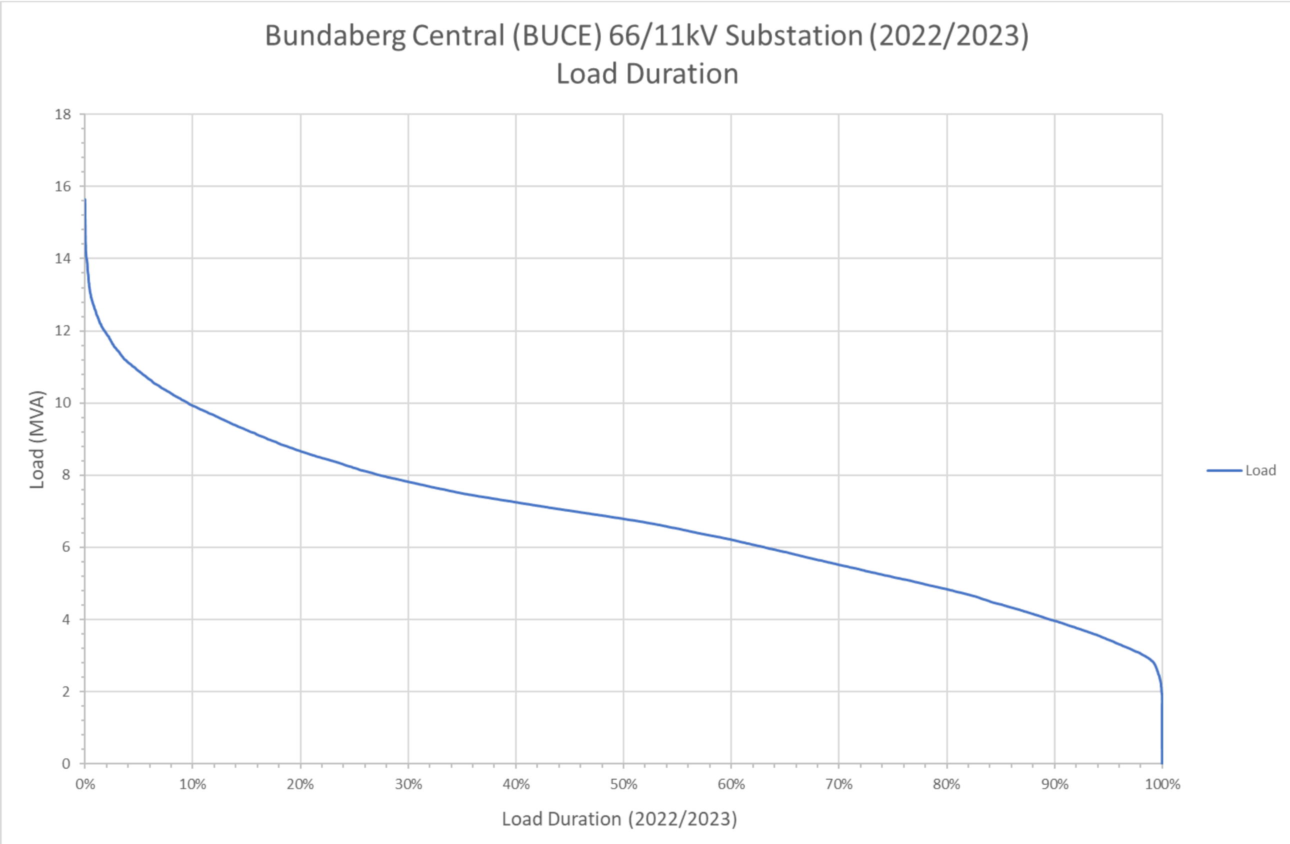


Figure 9: Bundaberg Central Substation load duration curve

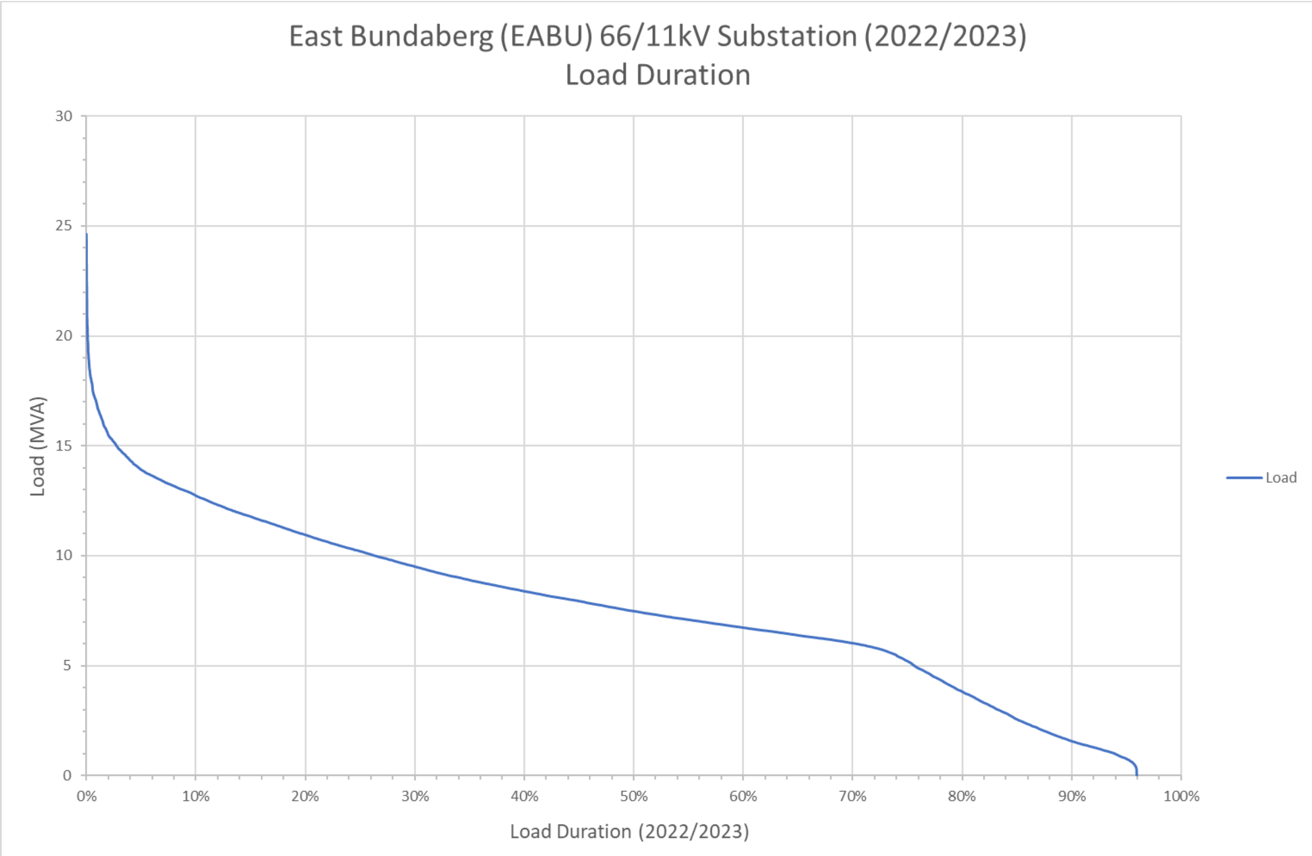


Figure 10: East Bundaberg Substation load duration curve

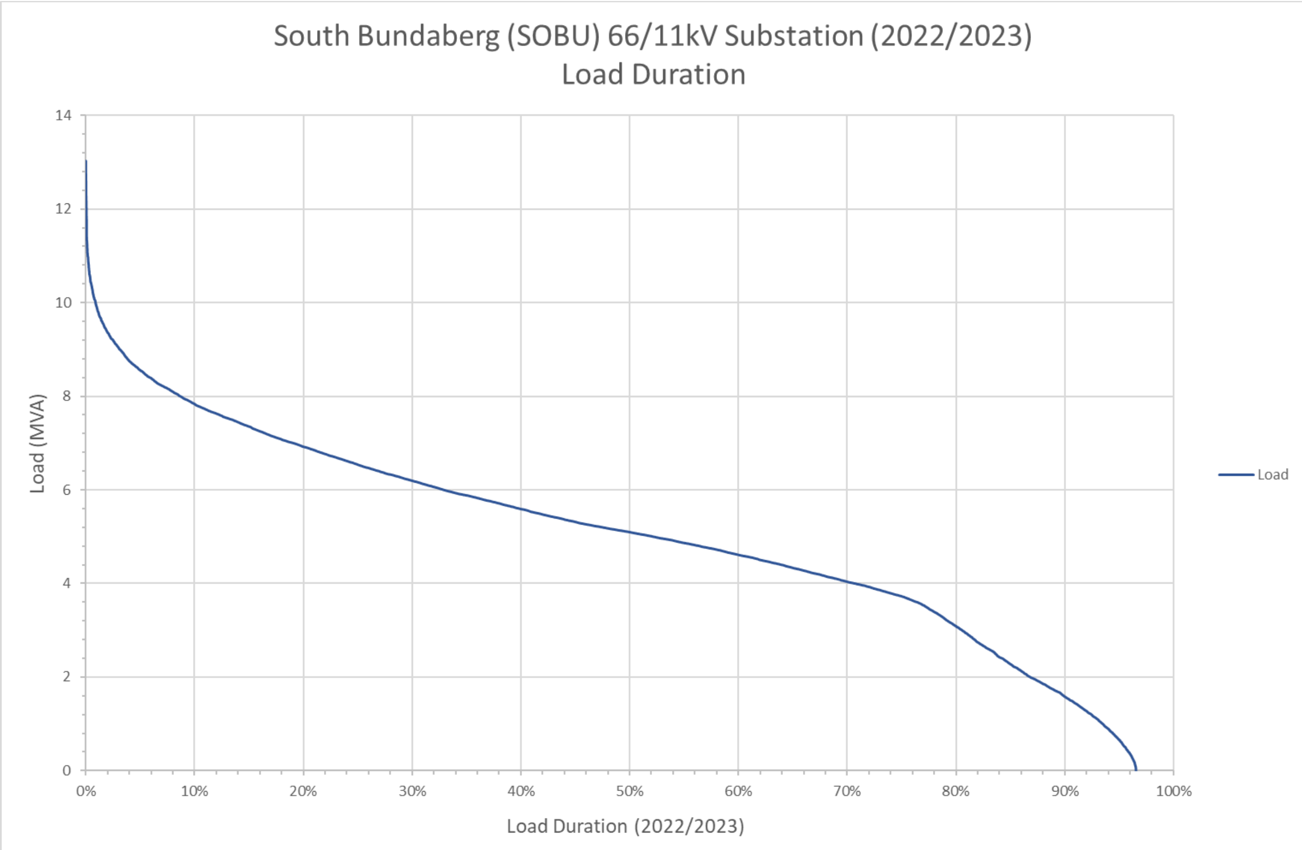


Figure 11: South Bundaberg Substation load duration curve

2.3.3. Average Peak Weekday Load Profile (Summer)

The daily load profile for an average peak weekday during summer is illustrated below in Figure 12, Figure 13, Figure 14, and Figure 15. It can be noted that there is a daytime minimum demand with an evening peak for most of the zone substations in the Bundaberg region.

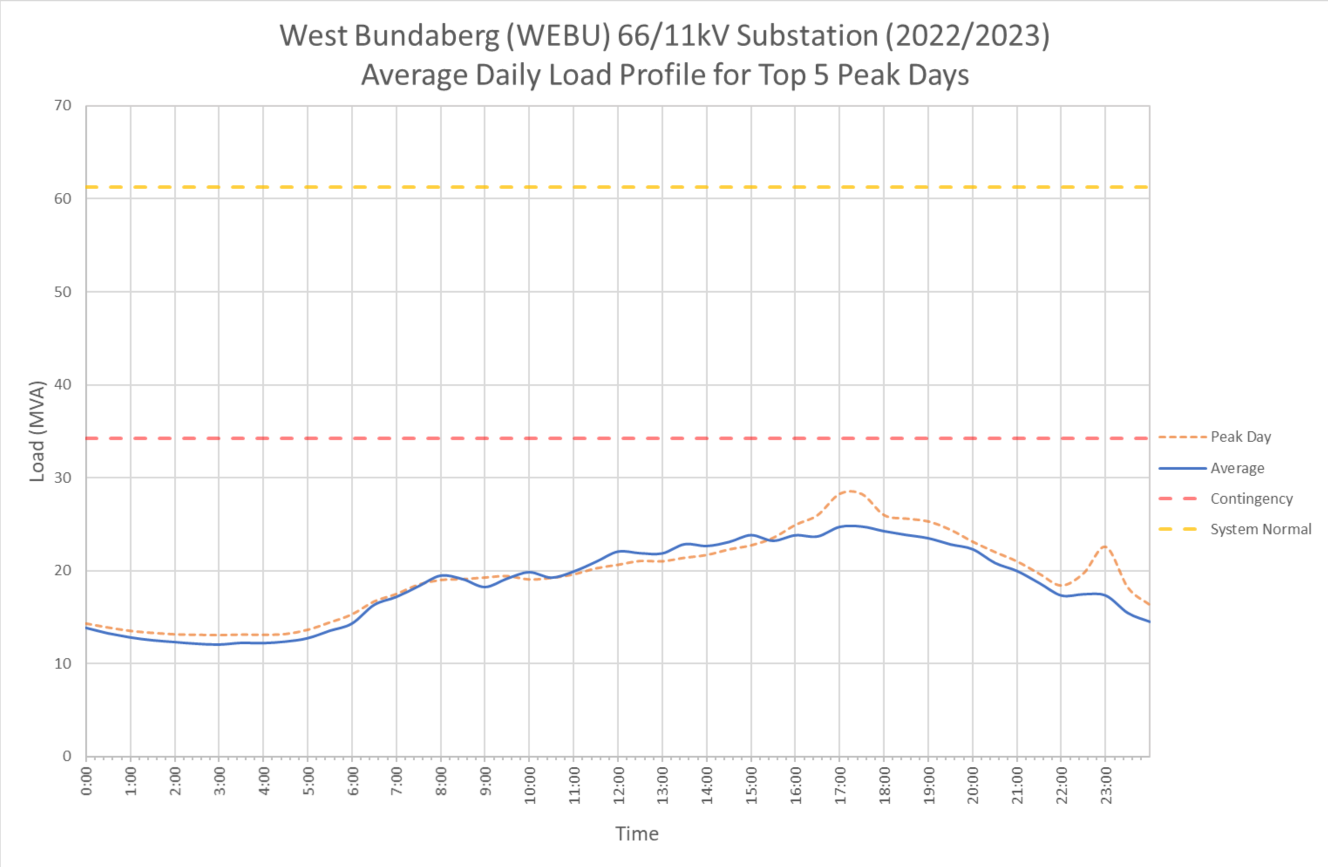


Figure 12: West Bundaberg Substation average peak weekday load profile (summer)

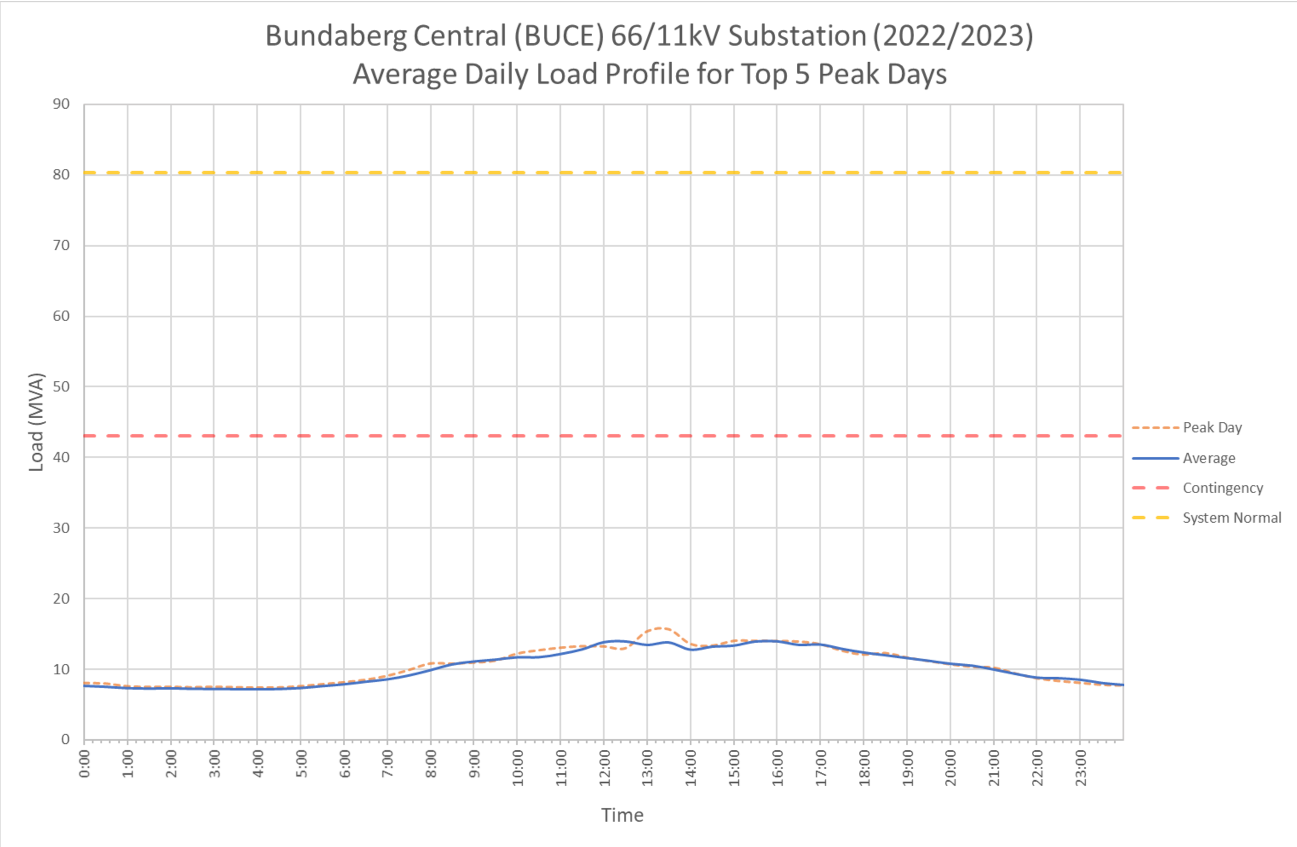


Figure 13: Bundaberg Central Substation average peak weekday load profile (summer)

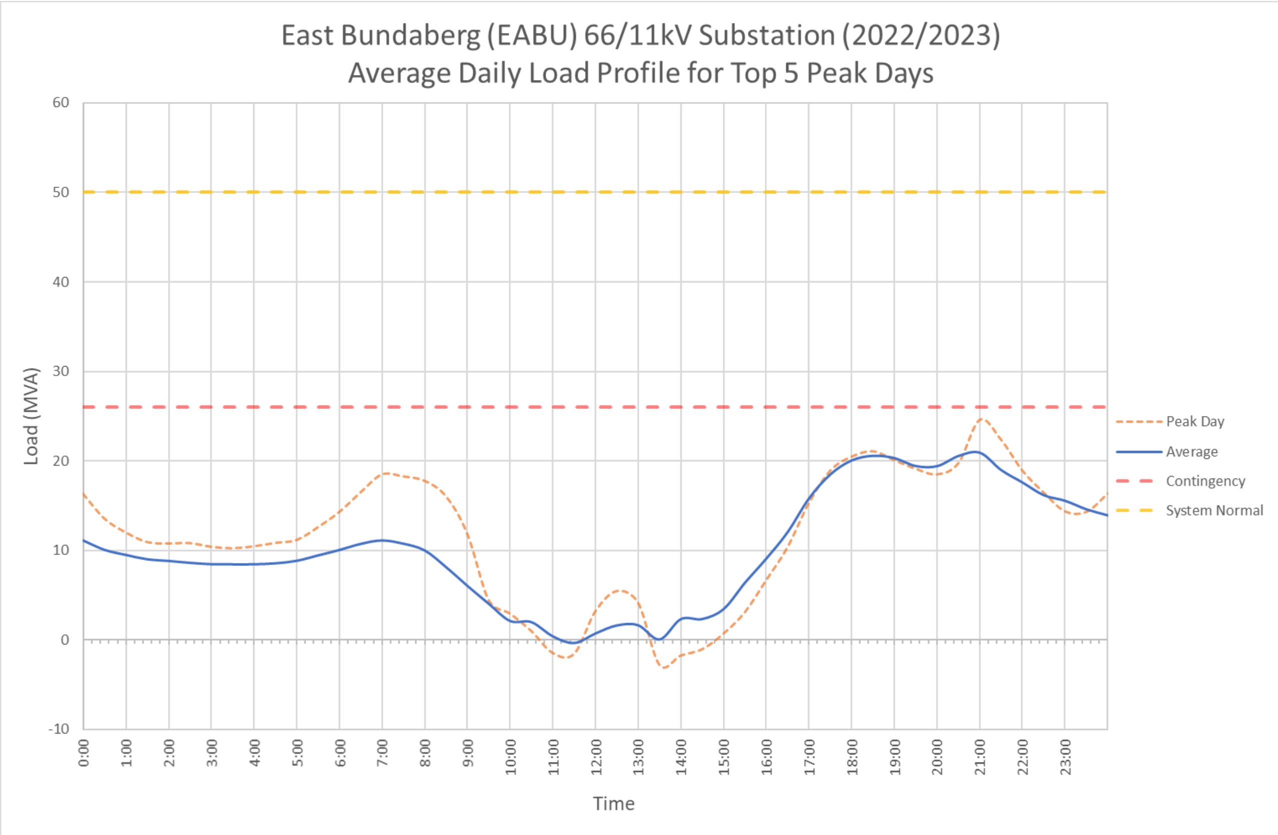


Figure 14: East Bundaberg Substation average peak weekday load profile (summer)

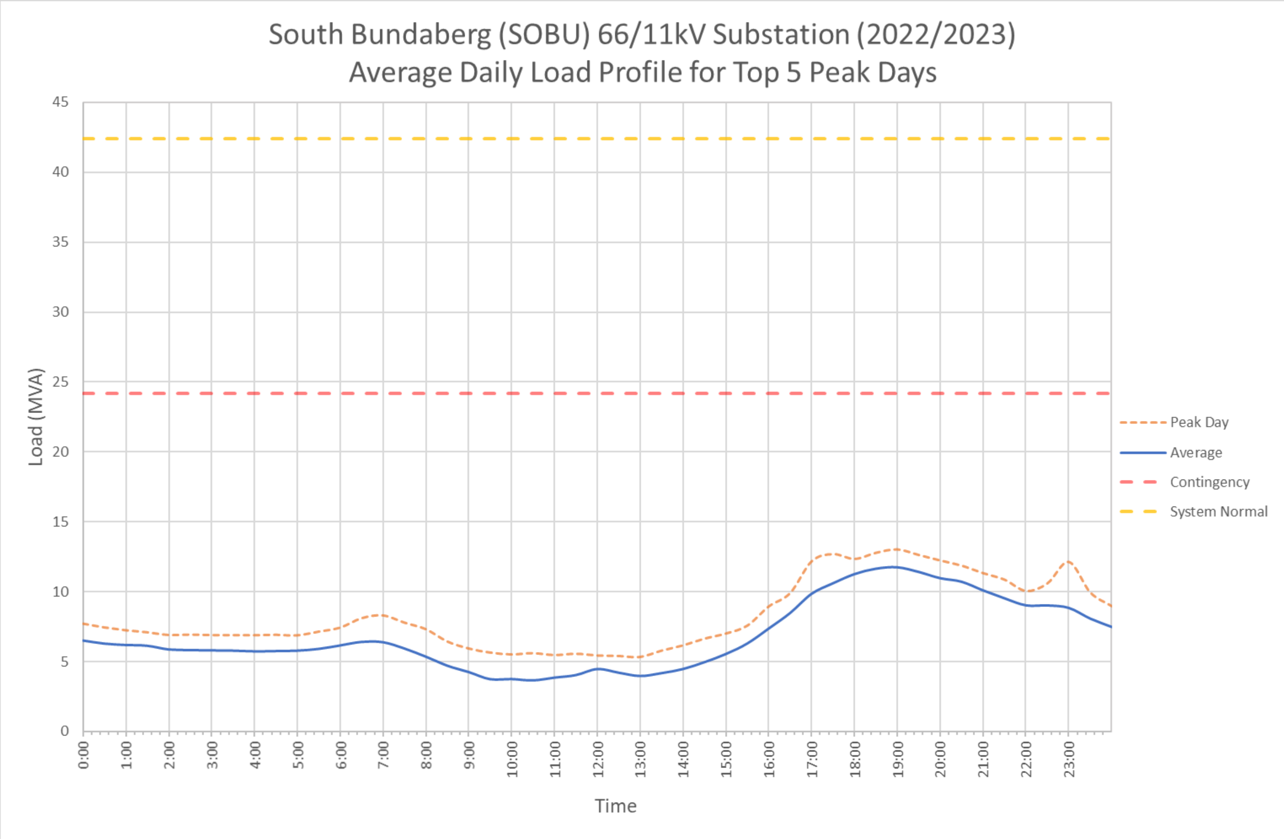


Figure 15: South Bundaberg Substation average peak weekday load profile (summer)

2.3.4. Base Case Load Forecast

The 10 PoE and 50 PoE load forecasts for the base case load growth scenario are illustrated in Figure 16, Figure 17, Figure 18 and Figure 19. The historical peak load for the past six years has also been included in the graph. Each graph also contains an indicative forecast loading if the major customer was to be supplied from each zone substation respectively. This indicative loading has only been included for the base load forecast to demonstrate the constraints at the existing zone substation 11kV supply. As can be seen, with the major customer connected upgrade works would be required at all substations except Bundaberg Central.

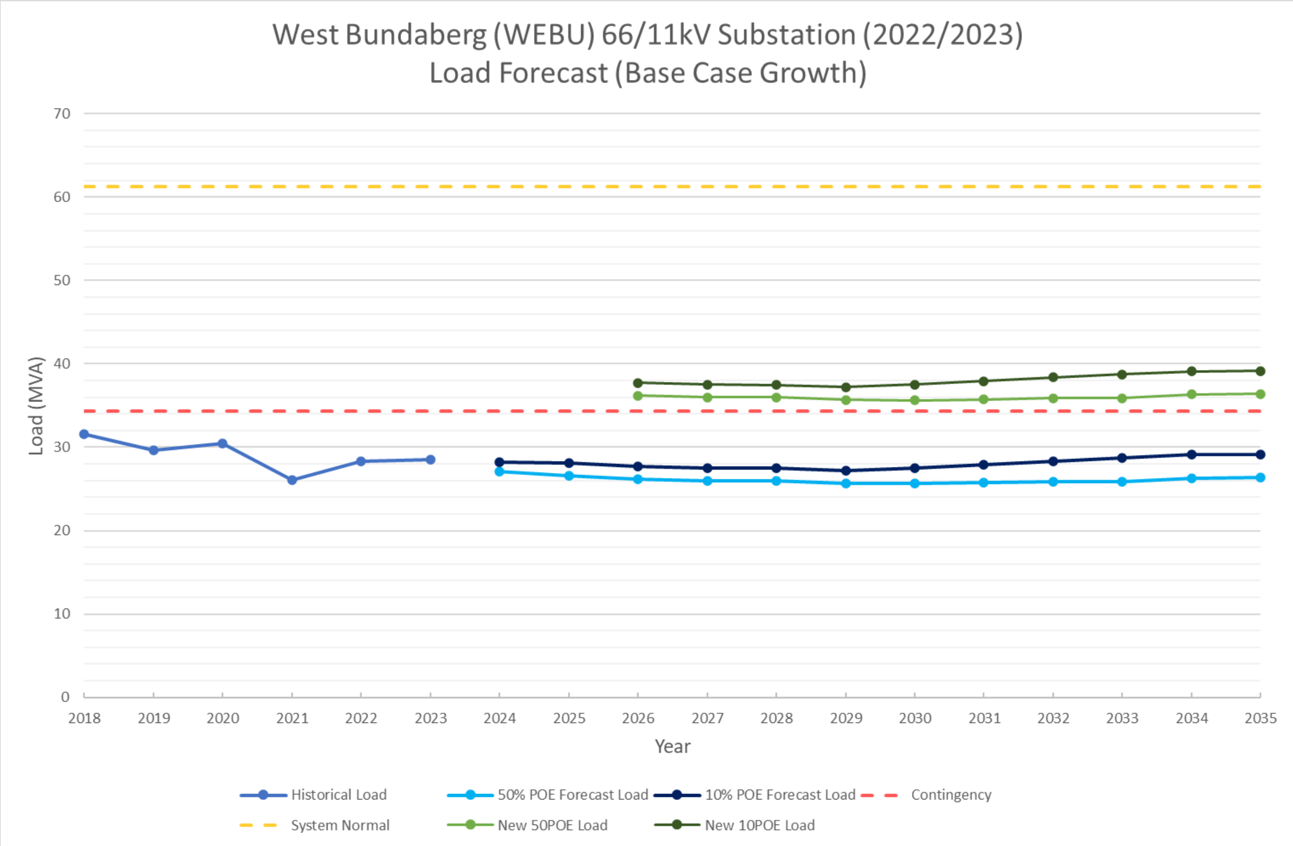


Figure 16: West Bundaberg Substation base case load forecast

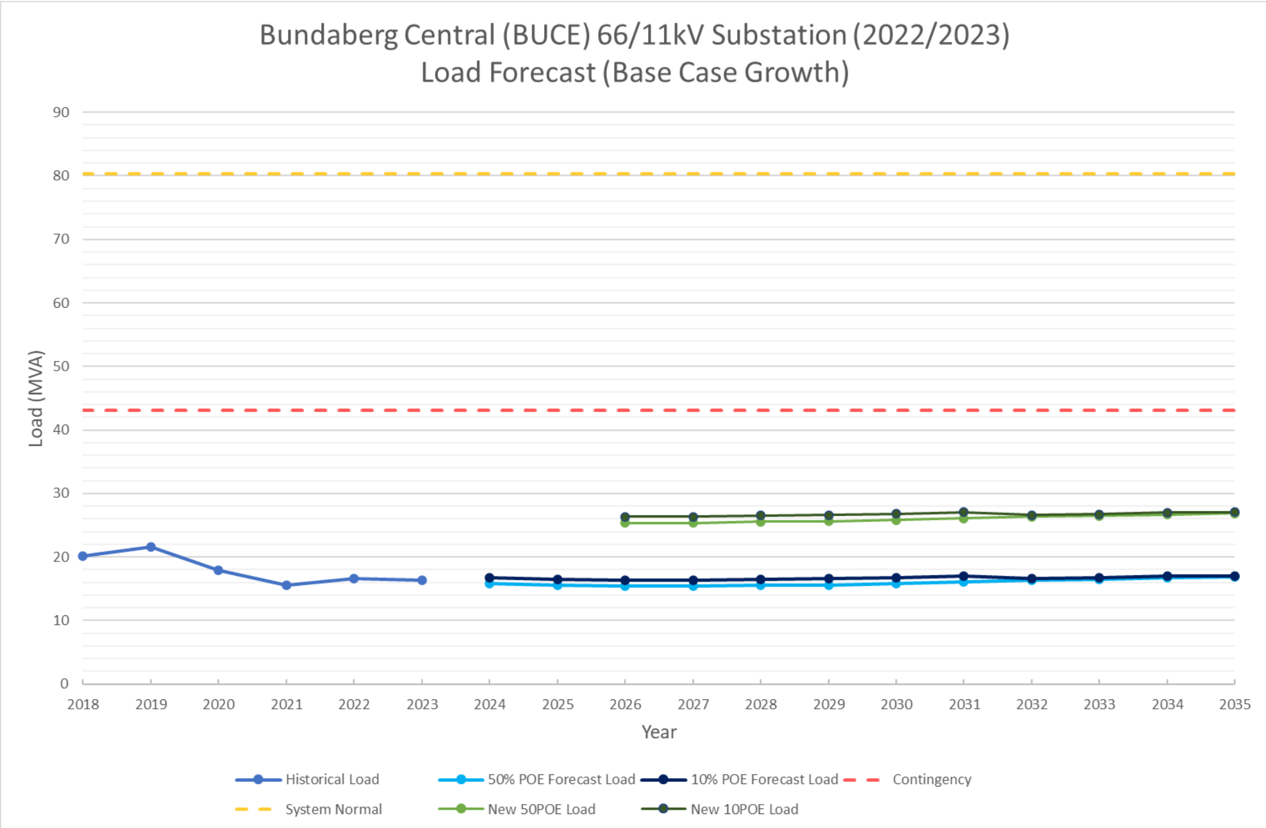


Figure 17: Bundaberg Central Substation base case load forecast

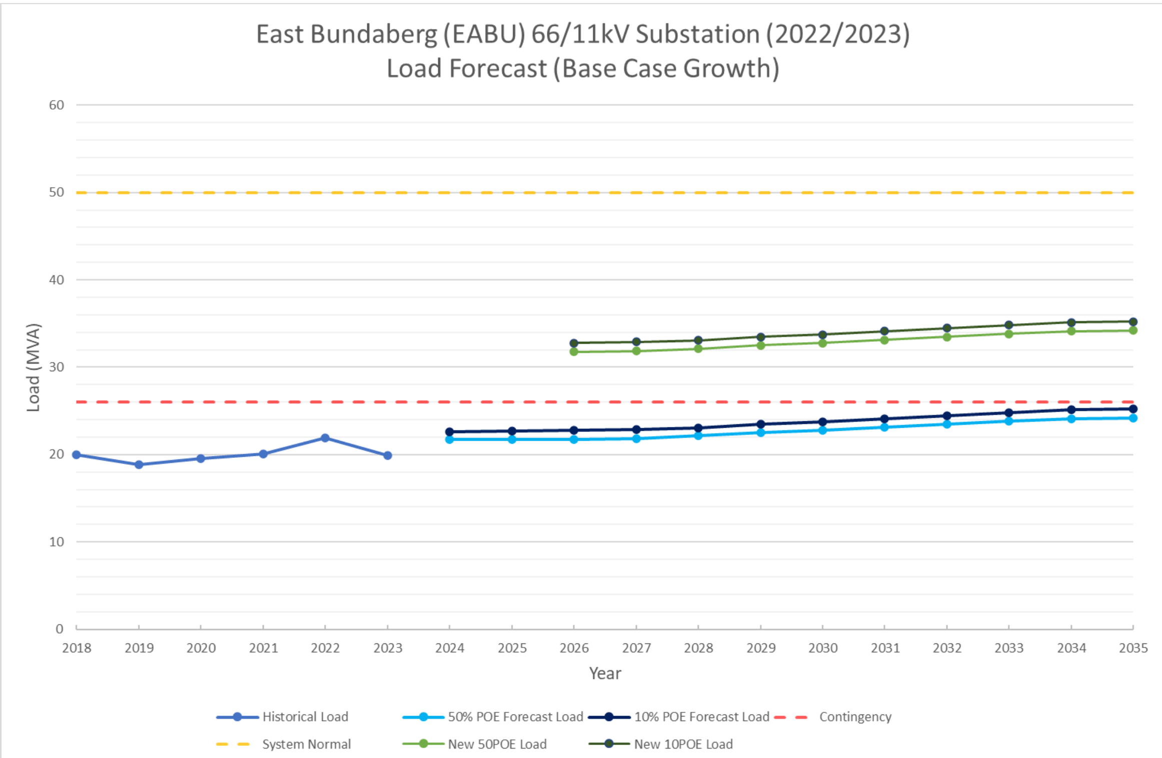


Figure 18: East Bundaberg Substation base case load forecast

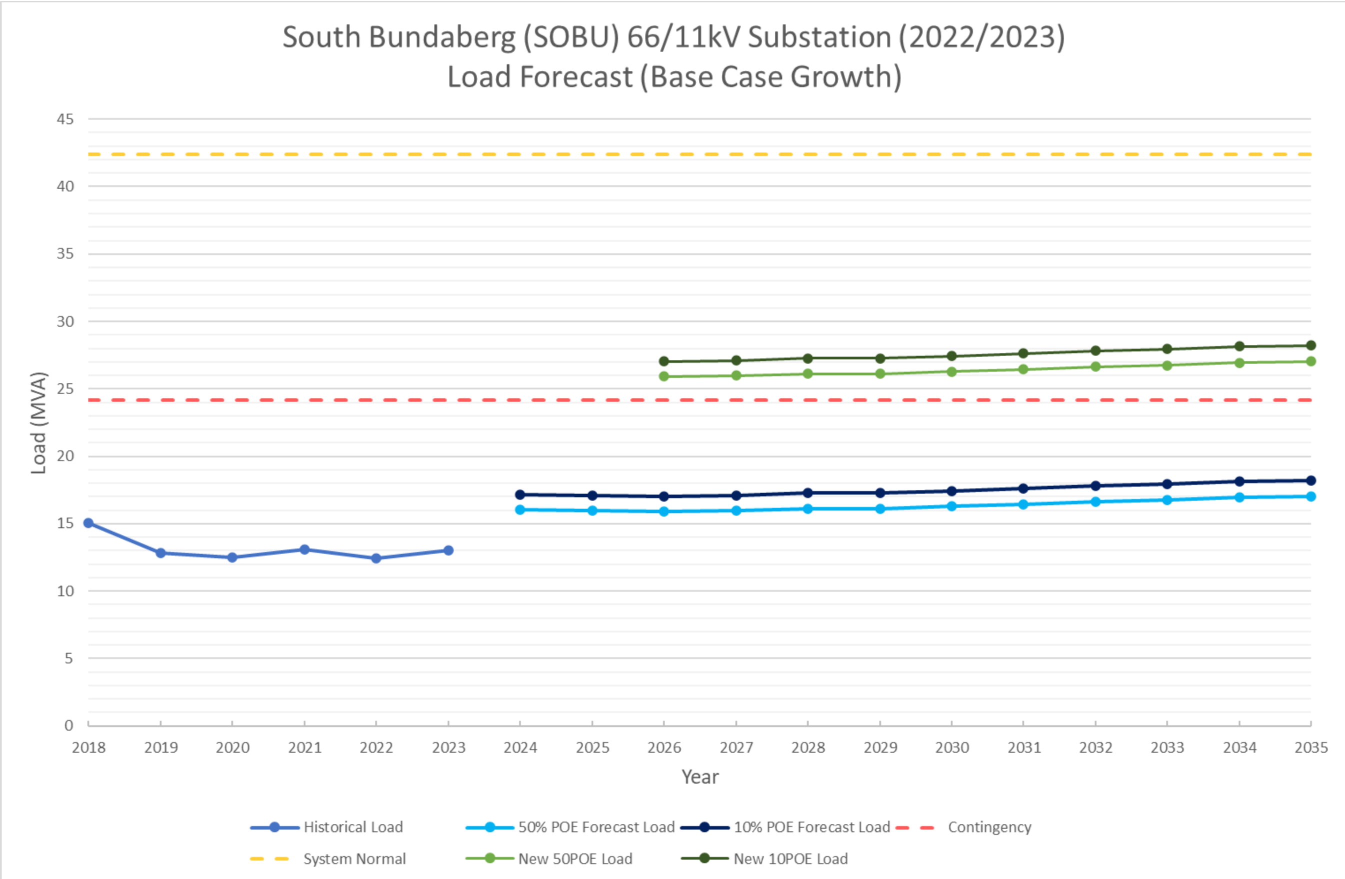


Figure 19: South Bundaberg Substation base case load forecast

2.3.1. High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the high load growth scenario are illustrated in Figure 20, Figure 21, Figure 22, and Figure 23. With the high growth scenario, the peak load is forecast to increase over the next 10 years.

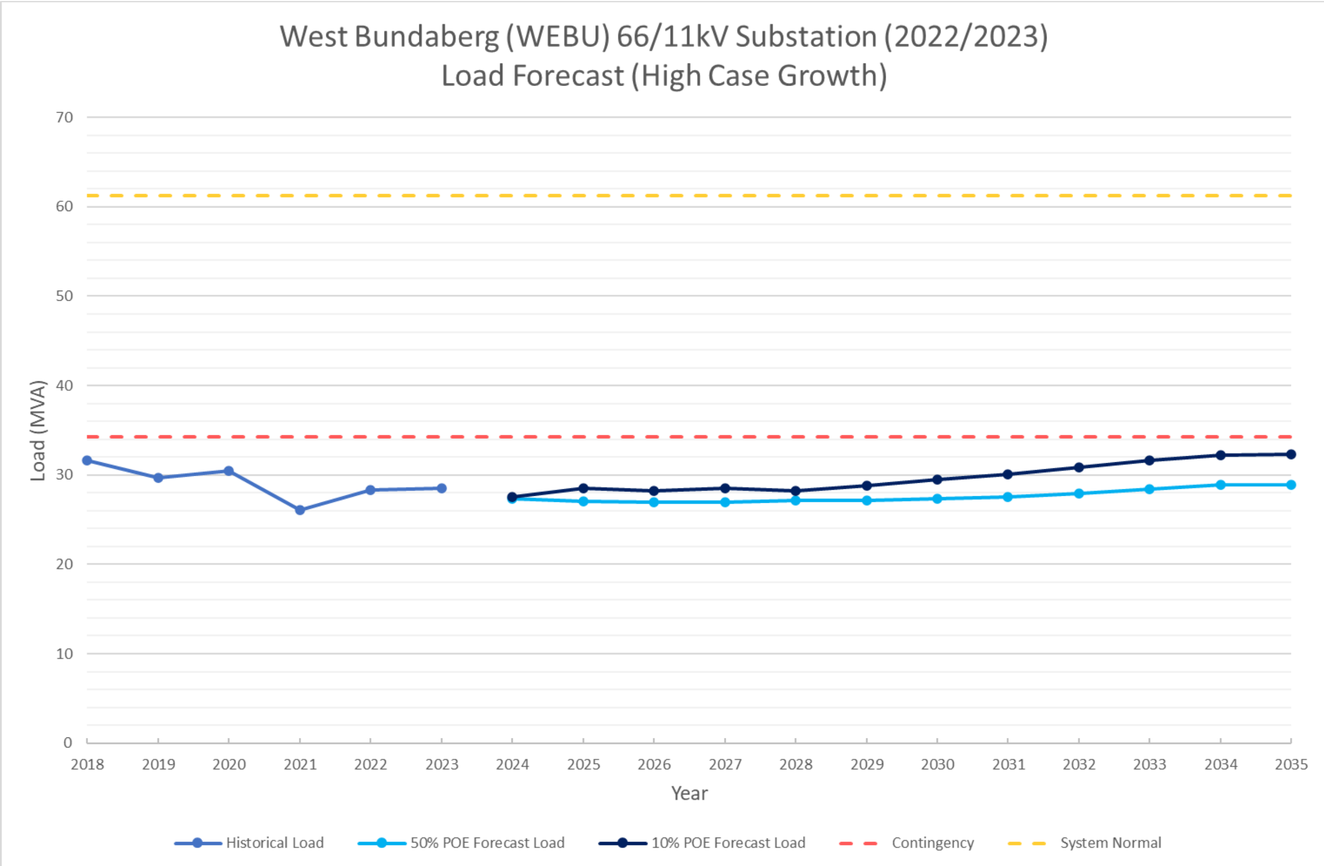


Figure 20: West Bundaberg Substation high growth load forecast

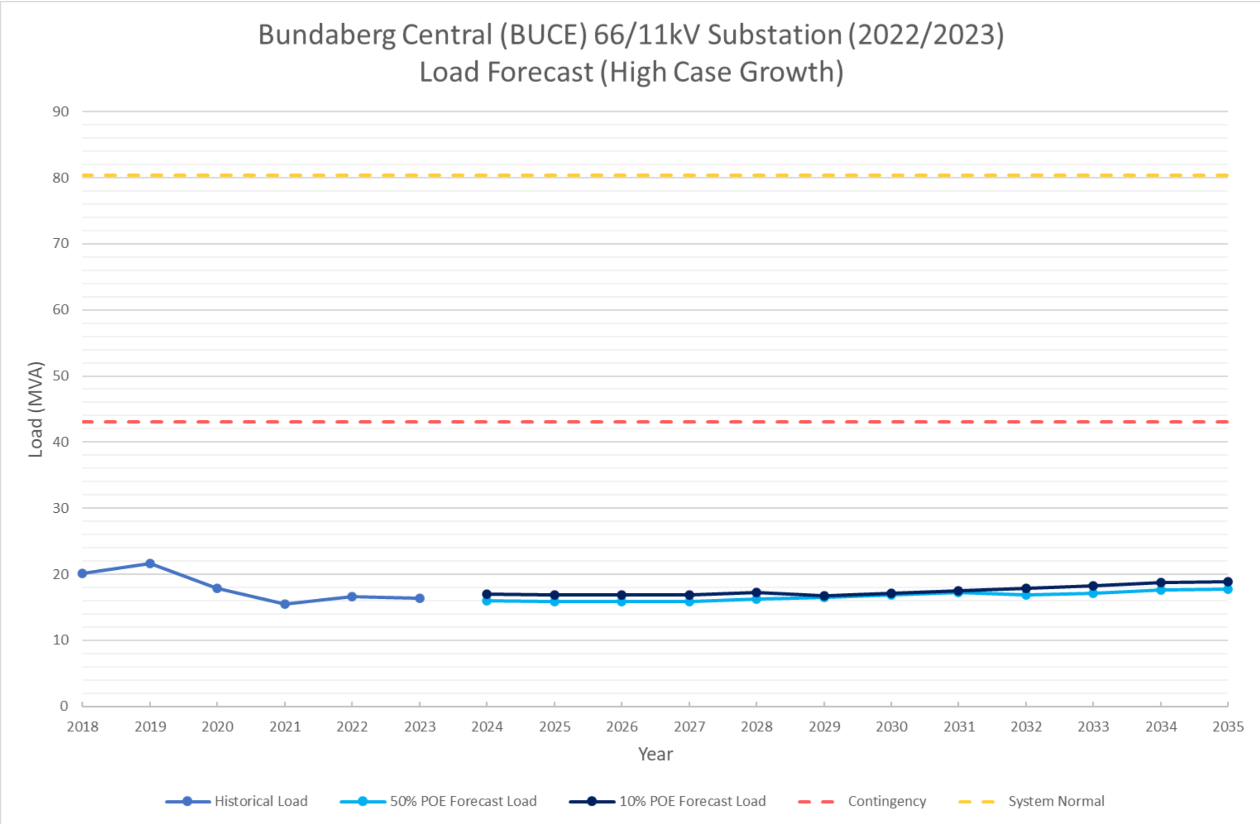


Figure 21: Bundaberg Central Substation high growth load forecast

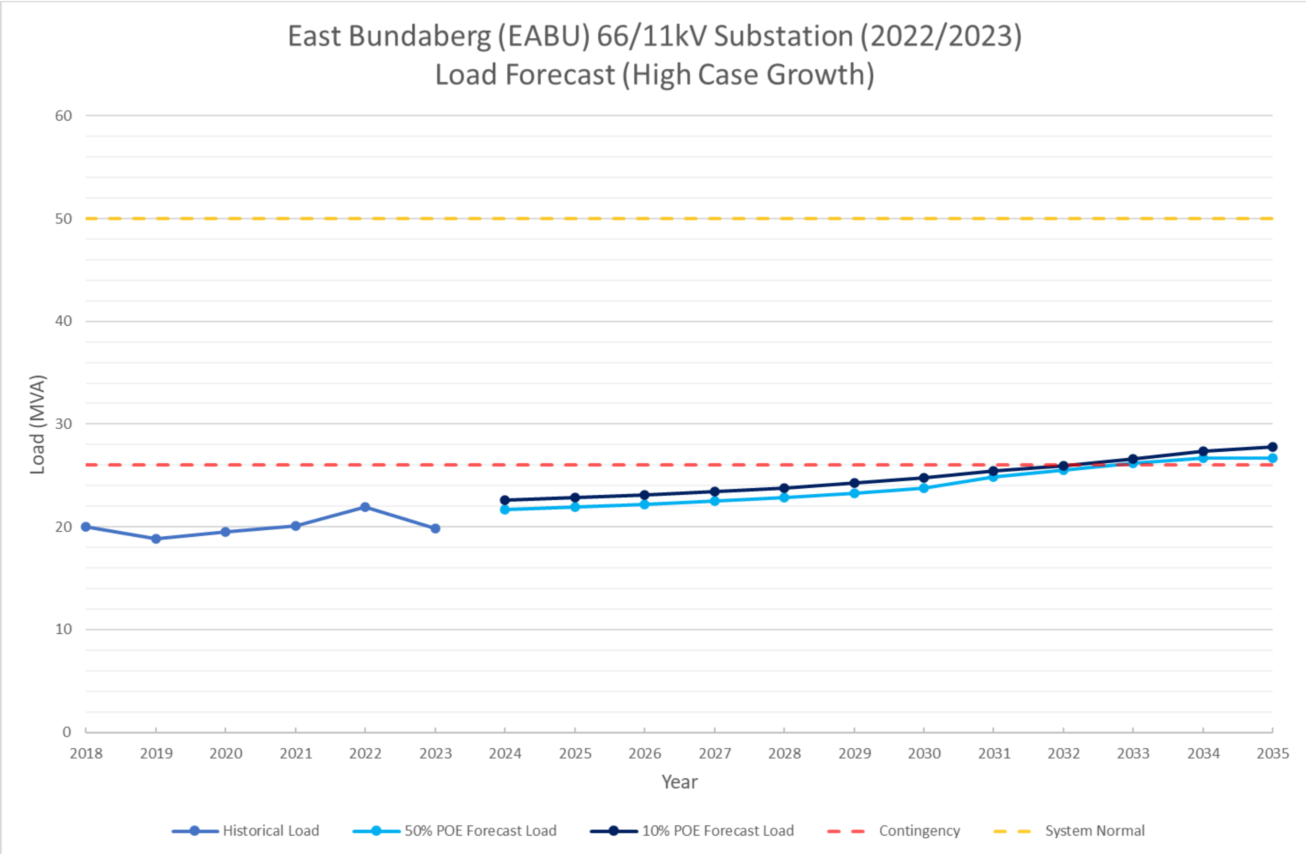


Figure 22: East Bundaberg Substation high growth load forecast

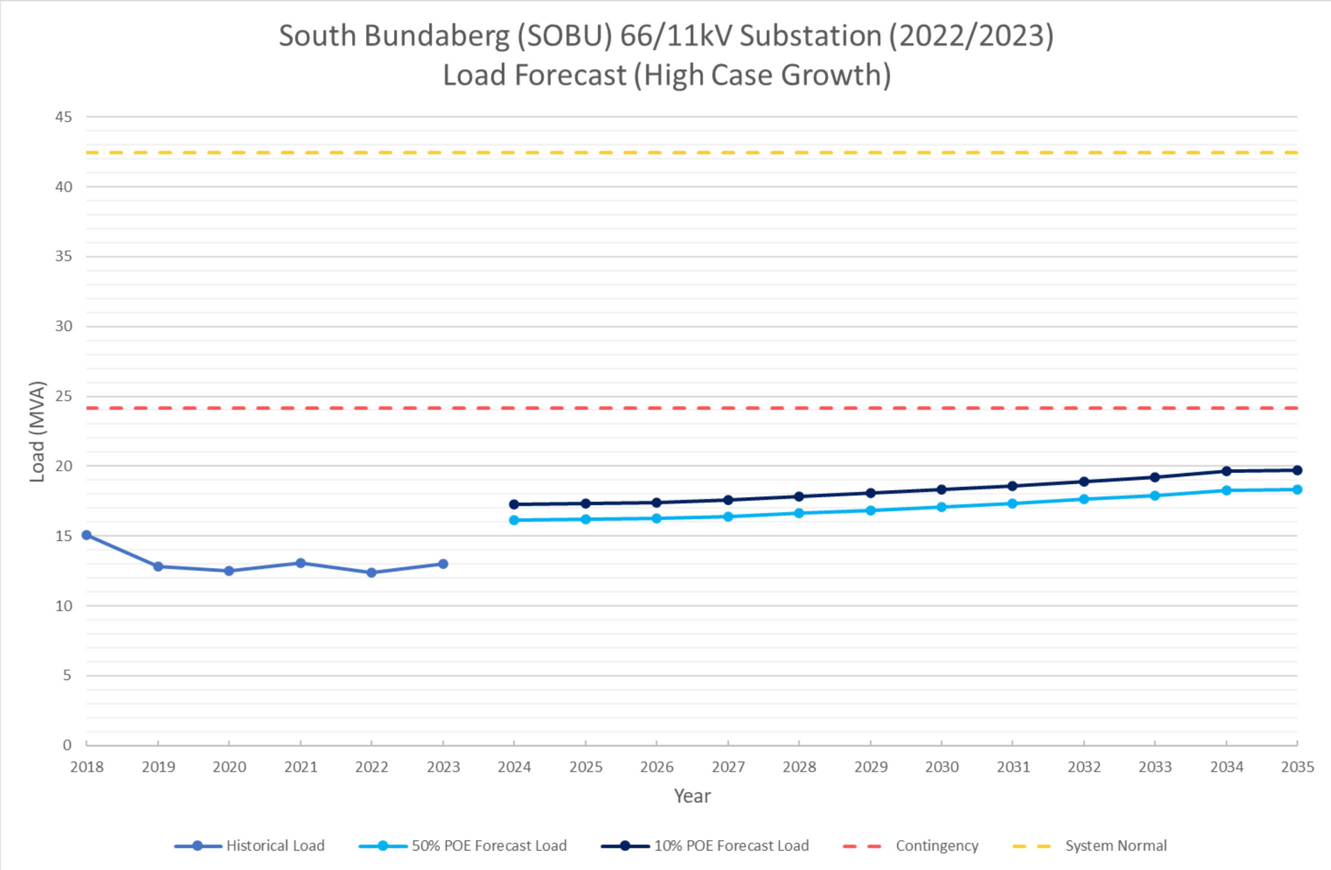


Figure 23: South Bundaberg Substation high growth load forecast

2.3.2. Low Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the low load growth scenario are illustrated in Figure 24, Figure 25, Figure 26, and Figure 27. With the low growth scenario, the peak load is forecast to remain relatively steady over the next 10 years.

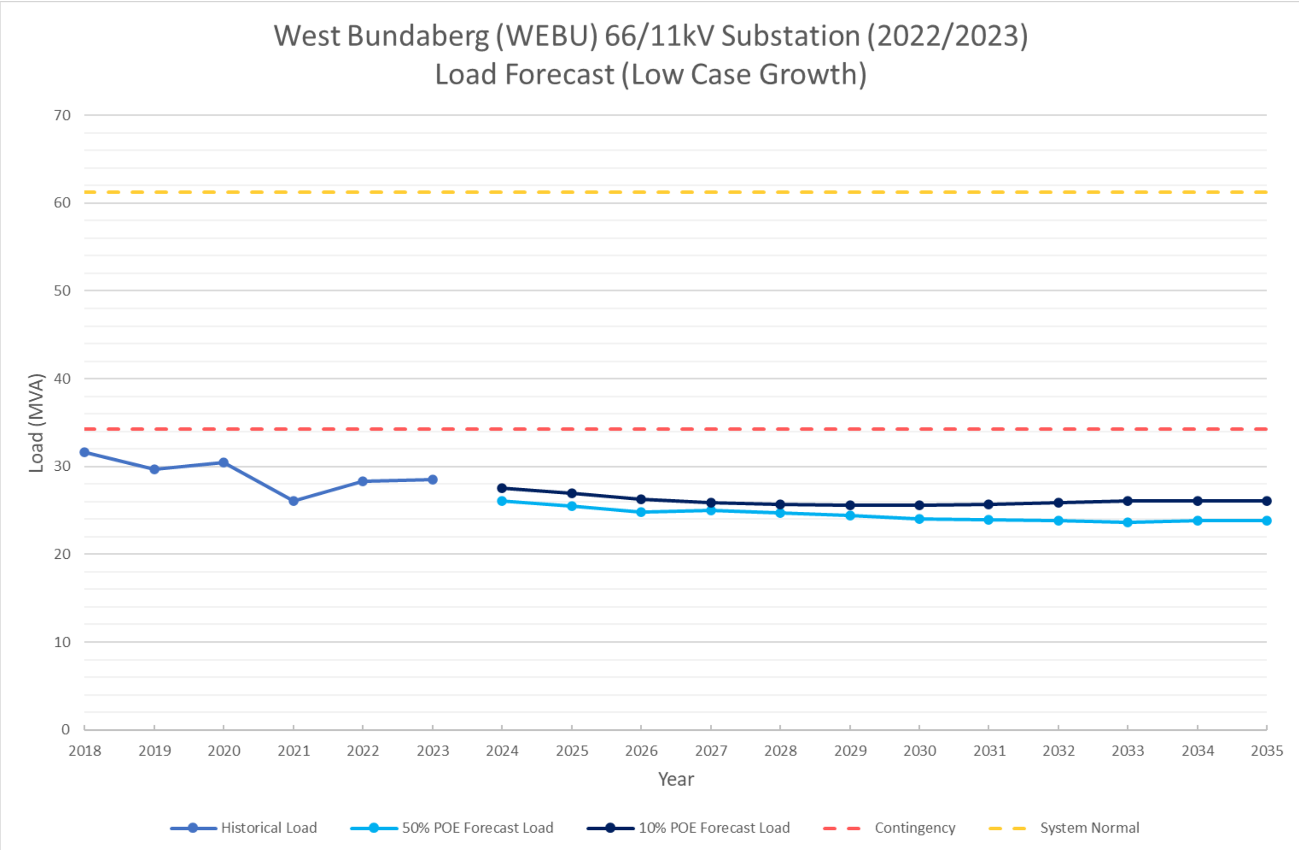


Figure 24: West Bundaberg Substation low growth load forecast

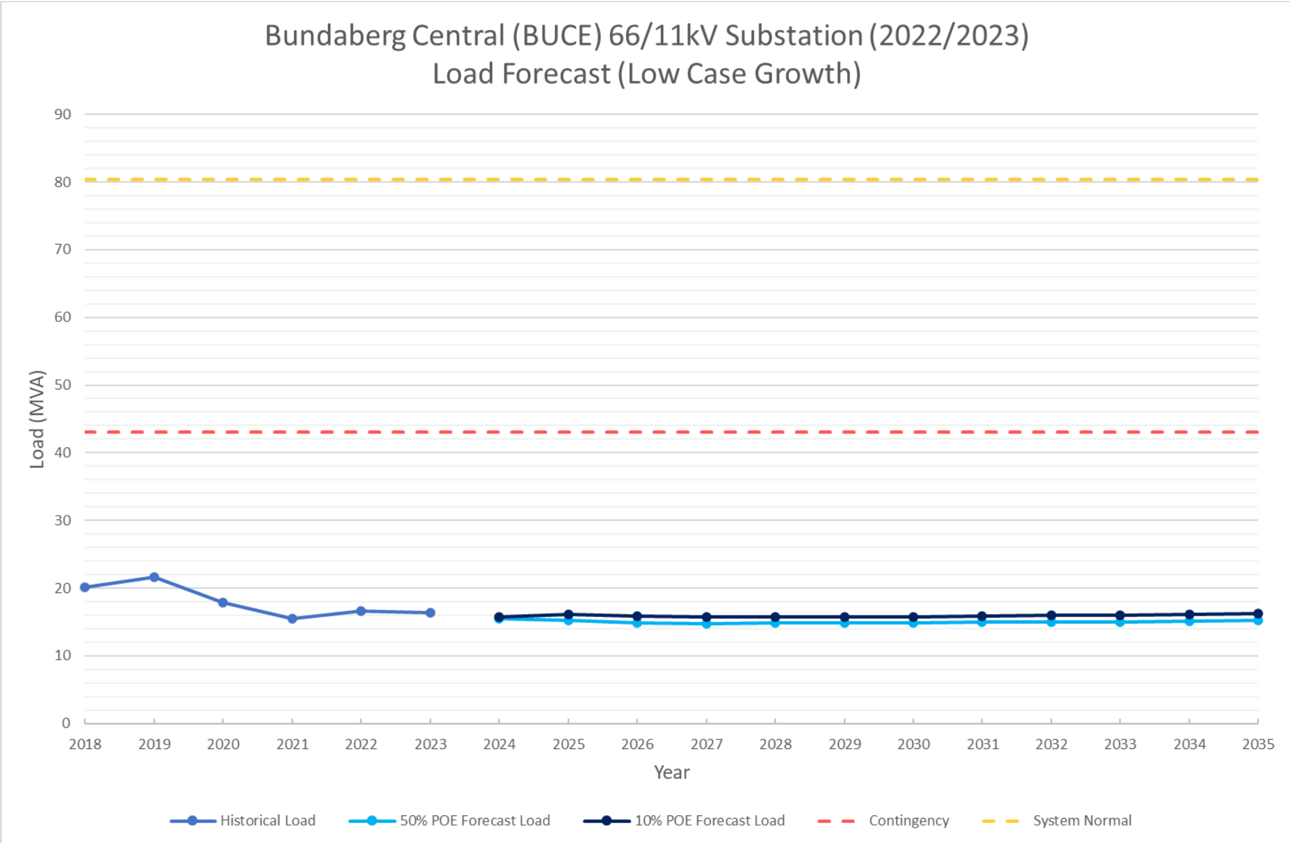


Figure 25: Bundaberg Central Substation low growth load forecast

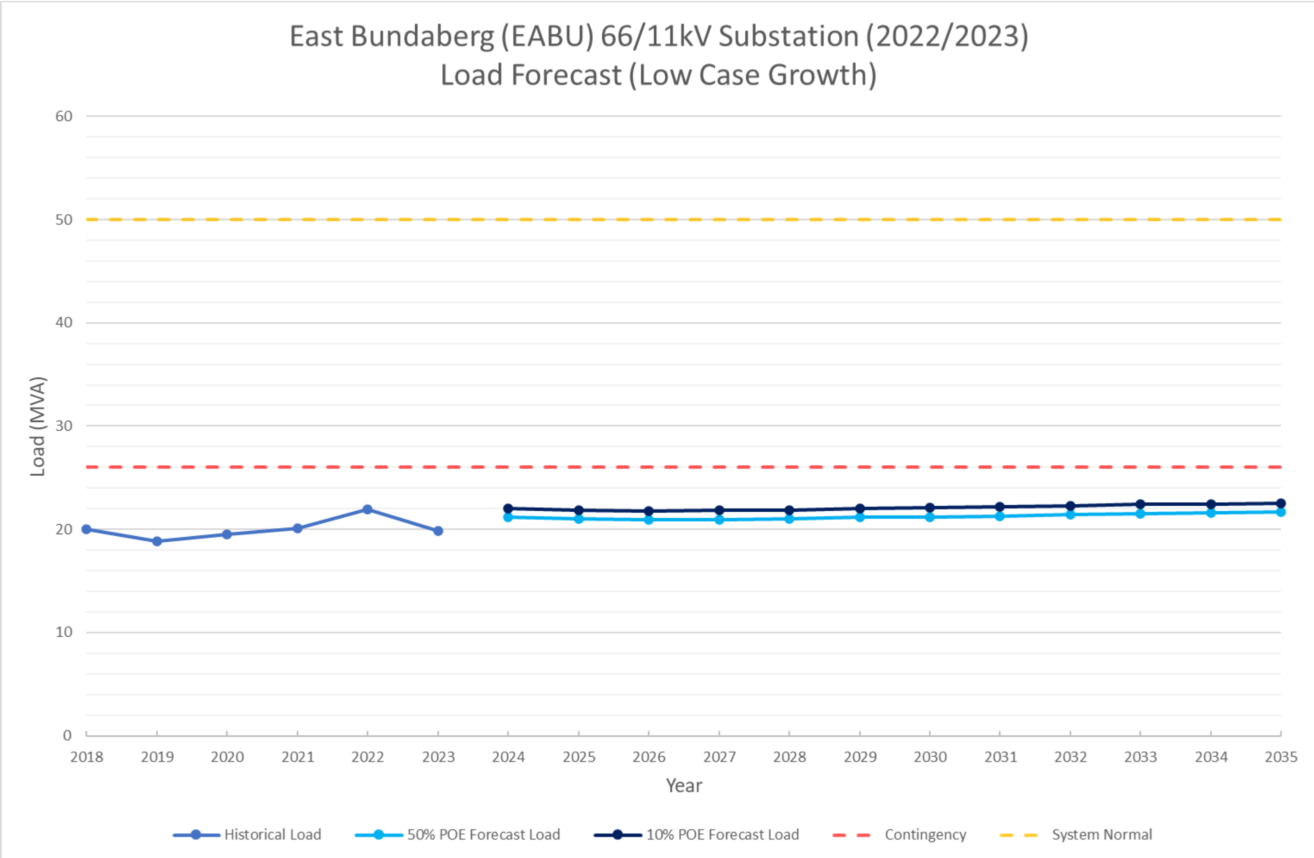


Figure 26: East Bundaberg Substation low growth load forecast

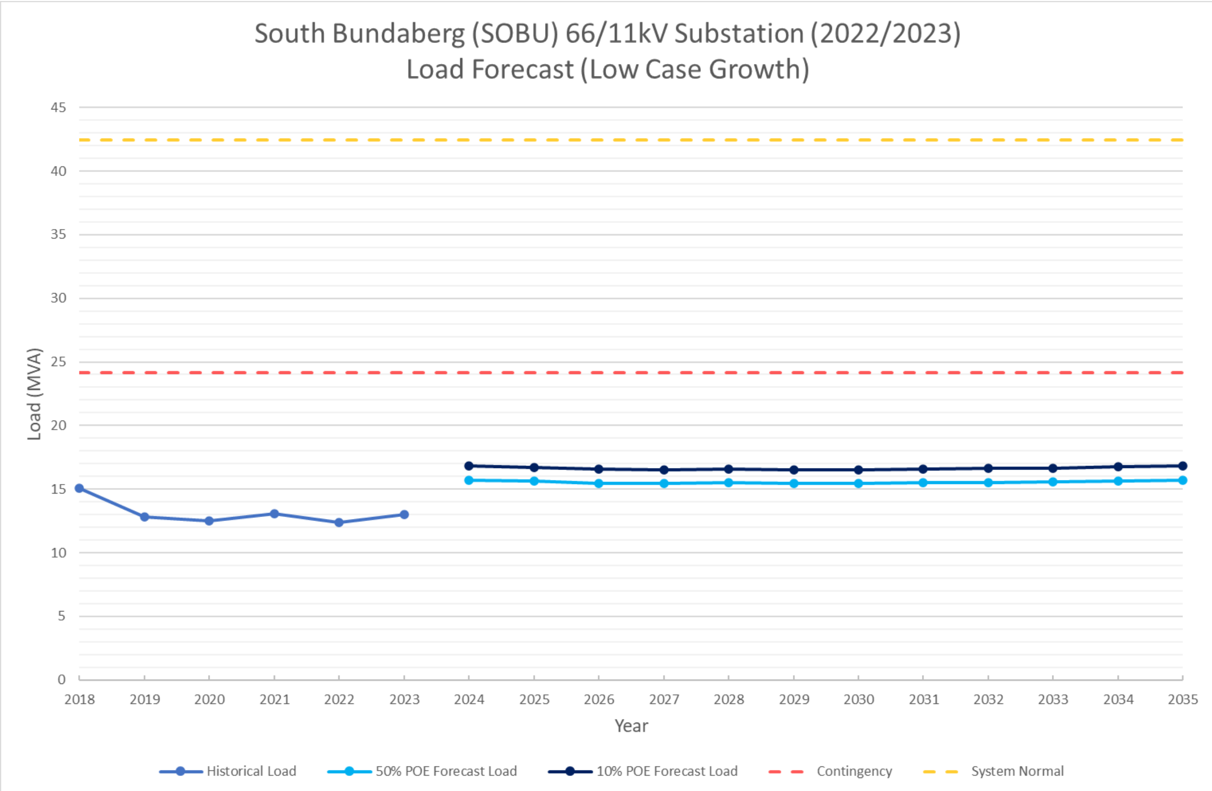


Figure 27: South Bundaberg Substation low growth load forecast

2.4. 66kV Sub-transmission Network

The 66kV network in the Bundaberg region emanates from Bundaberg (T20) Bulk Supply Substation and forms a ring between WEBU, BUCE, EABU and SOBU. M039 and M040 supply WEBU, which subsequently supplies Meadowvale (MEAD) and Gooburrum (GOOM) via M041, along with partial supply to BUCE via 6302 under system normal. This is an anticipated combined forecast load in 2034 of 67MVA. M036 supplies SOBU, which subsequently supplies EABU and partial supply to BUCE under system normal, along with BARG. The anticipated combined forecast load in 2034 is 65MVA.

It can be seen when comparing against values in Table 1 that the anticipated load in 2034 on M036 will exceed the rating of the feeder, without the major customer connected to the 11kV distribution network. With connection of the major customer at 11kV at any of the substation, SOBU, EABU or BUCE M036 would be overloaded and require augmentation as SCS costs. As shown in Section 1.3 only BUCE would have sufficient capacity to connect the customer without Zone substation augmentation.

It should be noted that the load flows through the Bundaberg Ring is complex and depends on network configuration. The above loading is indicative of the expected flows on the sub-transmission network under system normal, without the load of the major customer included.

Feeder Name	M040	M039	6302	6205	M037	M036
Voltage (kV)	66	66	66	66	66	66
Conductor Type	Taurus 19/4.75 AAC 1350	Taurus 19/4.75 AAC 1350	Wasp 7/.173" (7/4.39) AAC 1350 (British)	Wasp 7/.173" (7/4.39) AAC 1350 (British)	Wasp 7/.173" (7/4.39) AAC 1350 (British)	Iodine 7/4.75 AAAC 1120
Design Temp	75	75	75	75	50	75
Length (m)						
***Ergon Energy* Climate Zone**	Eastern & Coastal - Special	Eastern & Coastal - Special	Eastern & Coastal - Special	Eastern & Coastal - Special	Eastern & Coastal - Special	Eastern & Coastal - Special
Summer Day A (MVA)	809 (92.5)	809 (92.5)	397 (45.4)	397 (45.4)	225 (25.7)	440 (50.3)
Summer Evening A (MVA)	906 (103.6)	906 (103.6)	436 (49.8)	436 (49.8)	311 (35.6)	480 (54.9)
Summer Night Morning A (MVA)	748 (85.5)	748 (85.5)	356 (40.7)	356 (40.7)	258 (29.5)	390 (44.6)
Winter Day A (MVA)	849 (97.1)	849 (97.1)	419 (47.9)	419 (47.9)	285 (32.6)	456 (52.1)
Winter Evening A (MVA)	799 (91.3)	799 (91.3)	381 (43.6)	381 (43.6)	295 (33.7)	417 (47.7)
Winter Night Morning A (MVA)	804 (91.9)	804 (91.9)	383 (43.8)	383 (43.8)	297 (34)	419 (47.9)

Table 1: 66kV Sub-transmission Network Ratings

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Connection of Major Customer

The primary driver for this project is the connection of a major customer in the Bundaberg Region by 2026. Due to commercial in confidence all details of the enquiry cannot be disclosed, however the information pertinent to this RIT-D is the connection of a load up to 10MW and requirement for an N-1 supply. The overall project includes both ACS and SCS costs components, however this RIT-D only focuses on the SCS component.

3.1.2. Zone Substation Limitations

As shown in section 2.3 the zone substations in the area have limited capacity and the connection of up to 10MW would exceed the substations N-1 capacity and induce a safety Net limitation, with the exception being BUCE.

3.1.3. Sub-transmission Limitations

As discussed in section 2.4 the sub transmission network between BUND (T20) and SOBU will have a limitation in 2034 based on the current load forecast without the connection of the major customer. This limitation had been on Ergon Energy horizon and tentative project placeholder for Bundaberg 66kV reinforcement had been proposed with completion dates between 2028-2030. This future project would implement a second 66kV feeder from BUND (T20) to SOBU to address the limitation.

3.2. 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.

3.2.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at WEBU, BUCE, EABU and SOBU Substations will be consistent with the base case forecast outlined in Section2.5.

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)

- temperature corrected start values (historical peak demands); and
- forecast growth rates for organic growth.

3.2.2. 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 and decreasing minimum demand.

4. CREDIBLE OPTIONS ASSESSED

4.1. Assessment of Network Solutions

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

4.1.1. Option A: Development of Thabeban 66/11kV Substation

This option involves the development of a new greenfield 2 x 20/25MVA 66/11kV substation, which will be known as Thabeban (THAB). In order to provide diverse N-1 supply at the 66kV level THAB will be supplied via an approximately 4km 66kV feeder from BUND (T20) and an approximately 4km feeder from SOBU.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 28.

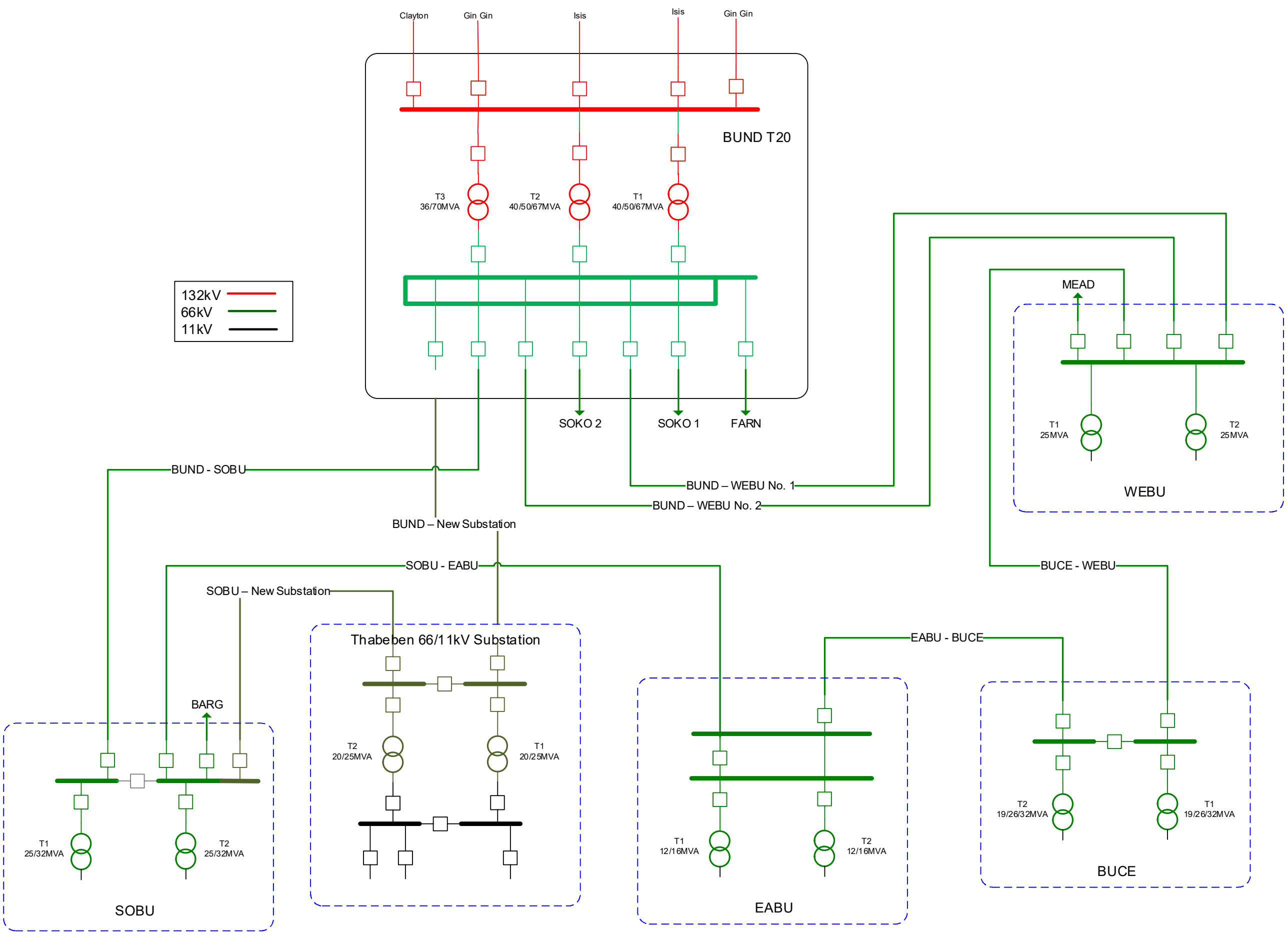


Figure 28: Option A proposed network arrangement (schematic view)

4.2. Assessment of Non-Network Solutions

Ergon Energy in assessing the major customer requirements for connection have not identified any full or partial non-network solutions.

Any credible options must be technically and commercially viable and must be able to be implemented in sufficient time (2026) to satisfy the identified need for the network to connect the major customer.

4.2.1. Demand Management (Demand Reduction)

Given the ultimate load requirement of up to 10MW and the need for high reliability and N-1 supply no demand management reduction methodologies have been identified that would provide a partial or total solution to the identified need.

4.2.2. Network Load Control

Across the four zone substations, WEBU, SOBU, EABU and BUCE the daily peak demand generally occurs between 5:00pm and 9:00pm.

There are 3,919 customers on tariff T31 and 14,193 customers on tariff T33 hot water load control (LC).

The Bundaberg Zone Substations LC signals are controlled from T020 Bundaberg Bulk Supply Substation (BUND). The Tariff 33 and 31 hot water LC channels are dynamic (that is, it responds to exceedance settings not on a timetable). Tariff 33 air-conditioning channels are under manual control of the operational control centre and are used as required. Network load control does not address the identified need, especially once an additional 10MW load is added to the system.

4.2.3. 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)

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. 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 vs short time frame).

This option has also 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. The requirements for the major customer are such that LSG will not provide a technically feasible solution.

Customer Solar Power Systems

The capacity of solar photo voltaic (PV) systems connected at each zone substation is 20,055kVA at WEBU, 20,330kVA at EABU, 6,796kVA at BUCE and 12,301kVA at SOBU.

The daytime peak between 9:00am and 3:00pm is reducing year on year in the Bundaberg region due to the integration of residential inverter energy systems. As such customer solar generation does not coincide with the peak load period. Residential Solar PV coupled with BESS may have the potential in the future to reduce peak demand, however when coupled with EV growth and charging profiles the peak may not be reduced substantially. However, it should be noted that reduction of the afternoon peak through BESS integration will not meet the requirements of identified need.

4.2.4. Non-Network Solution Summary

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

4.3. Preferred Network Option

Ergon Energy's preferred internal network option is Option A, to develop a new greenfield 2 x 20/25MVA 66/11kV substation, Thabeban.

Upon completion of these works, identified needs listed in section 3 for the Bundaberg region will be addressed. The major customer can be connected with all of their requirements met, the 66kV network limitation is addressed and increase 11kV capacity in the region for future growth and connections. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure and providing future capacity for growth in the region.

The estimated direct SCS capital cost of this option has been estimated $15.41 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 late 2023 and construction completed by October 2026.

5. SUMMARY OF SUBMISSIONS RECEIVED IN RESPONSE TO DRAFT PROJECT ASSESSMENT REPORT

On 11 September 2023, Ergon Energy published the Draft Project Assessment Report providing details on the identified need on the identified needs for the Bundaberg region. This report provided both technical and economic information about possible solutions and sought information from interested parties about possible alternate solutions to address the need for investment.

In response to the Draft Project Assessment Report, Ergon Energy received no submissions by 25 October 2023, which was the closing date for submissions to the Draft Project Assessment Report.

6. MARKET BENEFIT ASSESSMENT METHODOLOGY

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

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

6.1. Classes of Market Benefits Considered and Quantified

The class of market benefit that were considered to be material for this RIT-D assessment was:

- Changes in Load Transfer Capacity and the capacity of Embedded generators to take up load
- Changes in involuntary load shedding and Customer Interruptions caused by Network Outages

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

By establishing a new zone substation in the Bundaberg region with a duplicated 66kV connection between BUND (T020) and SOBU there will be an increase in the load transfer capability in the Bundaberg ring. As 11kV feeders are established from THAB 66/11kV substation it will provide additional transfer capacity to the zone substations in the area. These have been added as benefits in the NPV and calculated as a VCR benefit based on the ability to transfer load in a contingency.

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

The credible options presented in this RIT-D assessment do not include any involuntary load shedding. Using a reasonable forecast of the value of electricity distribution services to customers, Ergon Energy has undertaken an analysis and consider the changes to be material.

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 $41.83/kWh, which has been derived from the AER 2022 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 Bundaberg supply area

6.2. Classes of Market Benefits not Expected to be Material

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

- Changes in voluntary load curtailment
- Changes in costs to other parties
- Differences in timing of expenditure
- Changes in network losses
- Option value
- Other Class of Market Benefit

6.2.1. 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 [insert location here] area. Therefore, market benefits associated with changes in voluntary load curtailment have not been considered.

6.2.2. Changes in Costs to Other Parties

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

6.2.3. Differences in Timing of Expenditure

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

6.2.4. 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.

6.2.5. Other Class of Market Benefit

Ergon Energy has not identified any other relevant class of market benefit for this RIT-D.

7. DETAILED ECONOMIC ASSESSMENT

7.1. 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. A sensitivity analysis was then conducted on this base case to establish the option that remained the lowest cost option in the scenarios considered.

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

7.2. 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.

Table 3 outlines the major parameters analysed within the sensitivity analysis which was undertaken to assess the impact of changing parameters of the NPV model.

Parameter	Mode Value	Lower Bound	Upper Bound
WACC	2.72%	2.5%	5%
Project Costs	Standard estimates	-40%	+40%
Project Costs	Preferred option estimates	-20%	+20%
Opex Costs	Calculated Opex	-10%	+10%

Table 2: Economic parameters and sensitivity analysis factors

7.3. 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 provided in SIFT.

7.4. Net Present Value (NPV) Results

Although there was only one credible option identified which meets all the identified needs, including N-1 supply to a major customer; given that the SCS component cost of the project will also address the future 66kV limitation and provide future 11kV capacity, alternate options for meeting these limitations have been shown in the NPV.

This is to provide transparency and to demonstrate that the SCS investment provides the most prudent investment in the network, meeting the present and future needs. However, it should be noted that options B and C do not address all of the identified needs, only future network limitations.

An overview of the initial capital cost and the base case NPV results are provided in Table 4.

Option	Option Name	Rank	PV of Capex ($ real)	PV of Opex ($ real)	Net Economic Benefit ($ real)
A	Build Thabeban 2 x 20/25MVA Substation	1	$15,406,000	$6,983,000	$62,438,000
B	SOBU TR Upgrade + 66kV Upgrade + THAB 2050	3	$22,668,000	$10,253,000	$62,438,000
C	SOBU 66kV in 2026 + SOBU Upgrade in 2040 + THAB 2050	2	$19,069,000	$8,508,000	$61,945,000

Table 3: 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 5 provides the results of the sensitivity analysis.

Option Number	Option Name	Weighted Rank	Average NPV	Maximum NPV	Minimum NPV
A	Build Thabeban 2 x 20/25MVA Substation	1	$38,664,000	$40,128,000	$37,088,000
B	SOBU TR Upgrade + 66kV Upgrade + THAB 2050	3	$27,996,000	$31,265,000	$24,641,000
C	SOBU 66kV in 2026 + SOBU Upgrade in 2040 + THAB 2050	2	$32,739,000	$35,350,000	$29,780,000

Table 4: Scenario Analysis - Comparison of Options

Table 6 shows the NPV for the upper and lower WACC and demonstrates that under all scenarios option A is the preferred option.

Option Number	Option Name	2.00% WACC	5.00% WACC
A	Build Thabeban 2 x 20/25MVA Substation	$52,087,000	$17,605,000
B	SOBU TR Upgrade + 66kV Upgrade + THAB 2050	$40,865,000	$8,489,000
C	SOBU 66kV in 2026 + SOBU Upgrade in 2040 + THAB 2050	$45,388,000	$14,604,000

Table 5: WACC sensitivity Analysis for Base Case Forecast

Based on the detailed economic assessment, Option A is considered to provide the optimum solution to address not only the immediate identified need but also the forecast network limitations and is therefore the recommended development option.

8. CONCLUSION

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

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

8.1. Preferred Option

Ergon Energy's preferred option is Option A, to develop Thabeban 66/11kV substation with 2 x 20/25MVA transformers.

Upon completion of these works, identified needs listed in section 3 for the Bundaberg region will be addressed. The major customer can be connected with all of their requirements met, the 66kV network limitation is addressed and increase 11kV capacity in the region for future growth and connections. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure and providing future capacity for growth in the region.

The estimated direct SCS capital cost of this option has been estimated $15.41 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 late 2023 and construction completed by October 2026.

8.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

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

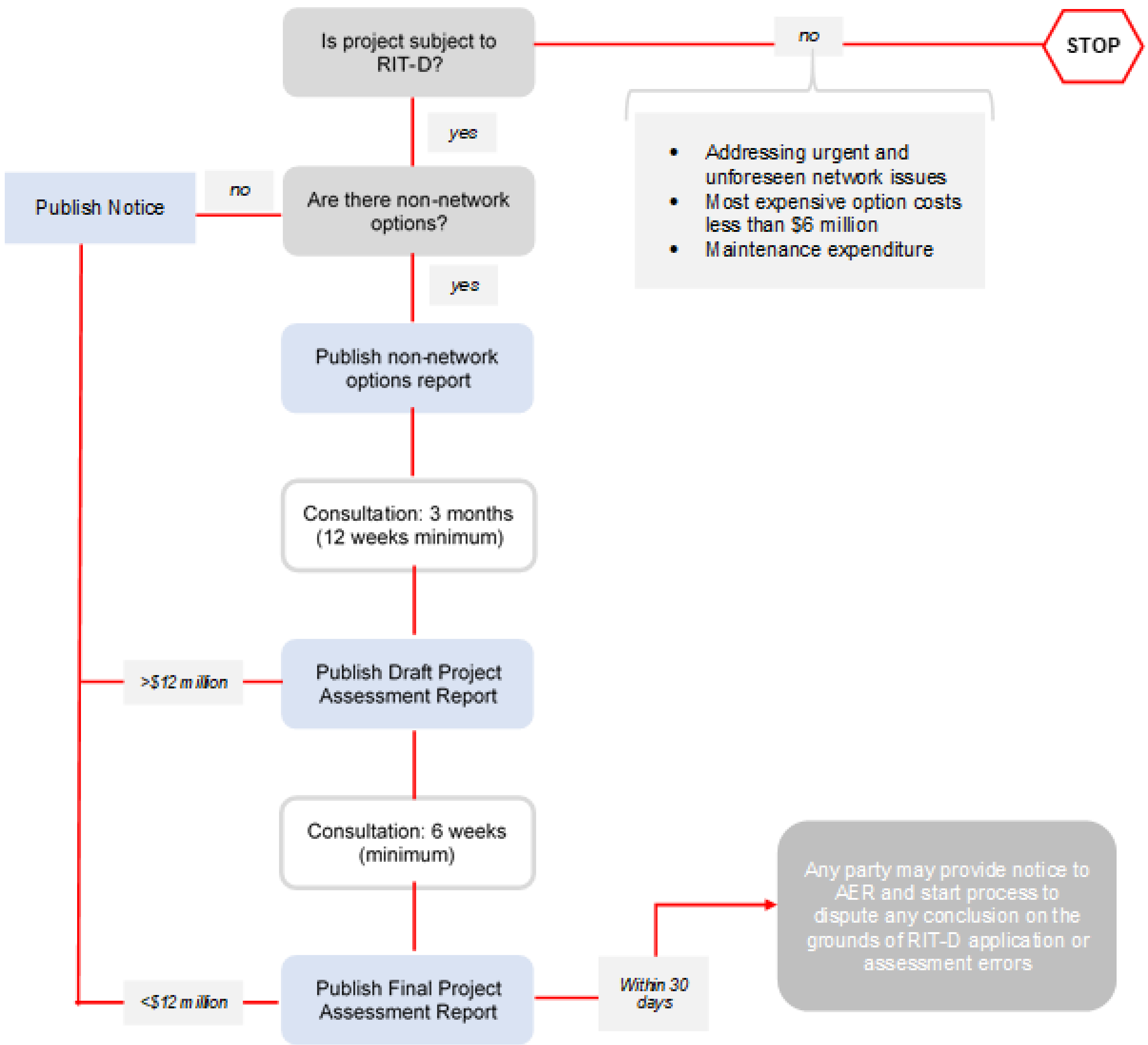
9. COMPLIANCE STATEMENT

This Final Project Assessment Report complies with the requirements of NER section 5.17.4(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;	3.2
(3) if applicable, a summary of, and commentary on, the submissions received on the DPAR;	5

(4) a description of each credible option assessed	4 & 5
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	6
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	6 & 7
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	6
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	6.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	7.4
(10) the identification of the proposed preferred option	8.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (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	8.1 & 8.2
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.4

APPENDIX A – THE RIT-D PROCESS



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