Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Sarina Network Area

Final Project Assessment Report

18 December 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

Sarina 66/11kV substation (SARI) supplies over 4,000 customers and 67GWh of energy annually. SARI substation is a critical asset for supply of energy for domestic and commercial business located into the Sarina area. Without the substation over 85% of the load in the area will be unsupplied given there is only 2MVA of load transfers available to adjacent substations. With load forecast to increase on the surrounding substations it is anticipated that this load transfer capability will also decrease year on year.

Assets vital to the operation of the substation are nearing end of life, increasing the risk of asset failure. Continued operation of the assets at SARI results in increased exposure to safety and reliability consequences due to the likelihood of asset failure

Assets which are nearing end of life, and with an increasing risk of asset failure include:

- 11kV indoor switchboard and 7 x CBs (estimated retirement year 2026)
- 4 x 33kV outdoor CBs that are aged and prone to explosive failure (estimated retirement year 2025)
- 4 x 33kV porcelain type surge arrestor sets
- outdoor 33kV galvanised steel tube bus and structures that are significantly corroded.
- 34 x protection relays (estimated retirement year 2014-20)

The purpose of this project is to remove the elevated safety and reliability risks at SARI by replacing assets identified as having an increased likelihood of failure.

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

Ergon Energy published a Notice of Screening for Options for the above-described network constraint on 15 December 2023. A Draft Project Assessment Report was not required per clause 5.17.4 (n).

One potentially feasible option has been investigated:

- **Option A:** SARI Asset Replacement

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 – SARI Asset Replacement.

CONTENTS

1. INTRODUCTION

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

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

1.2. Dispute Resolution Process

In accordance with the provisions set out in clauses within 5.17.5 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 replace aged and deteriorating assets in Sarina 33/11kV substation.

1.3. Contact Details

For further information and inquiries please contact:

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

2. BACKGROUND

2.1. Geographic Region

Sarina 66/11kV substation (SARI) is located on the QLD east coast 30km South of Mackay. SARI currently supplies 4,327 customers and delivers 67GWh of energy annually, with these numbers expected to increase within the next 10 years. SARI supplies predominantly domestic customers (40%); however, it also supplies commercial (29%), industrial (22%) and agricultural (9%) load, including a sugar mill at Sarina. Carmilla 33kV Feeder, which emanates from SARI 33kV bus supplies 1,127 customers including a prawn farm near Ilbilbie.

A geographic view of the supply area is shown in Figure 1.

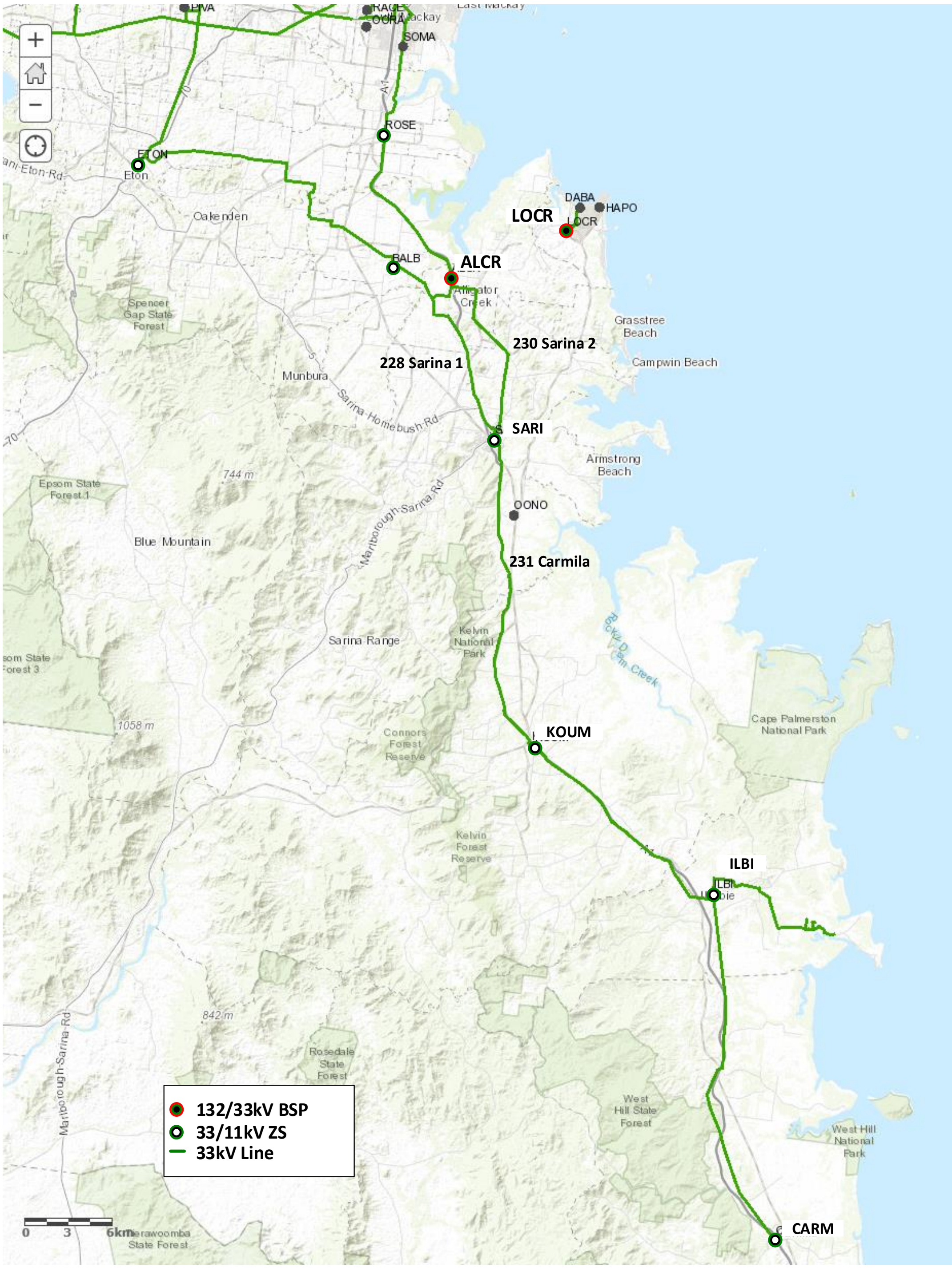


Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

Sarina 33/11kV zone substation (SARI) is normally supplied via two 33kV feeders from Alligator Creek 132/33kV bulk supply substation (ALCR) run in parallel. There is an outgoing 33kV feeder to

Carmilla 33/11kV zone substation (CARM) with intermediate connections to Ilbilbie 33/11kV zone substation (ILBI), Koumala 33/11kV zone substation (KOUM), as well as a 33kV distribution network to major customers.

The SARI distribution network consists of six 11kV feeders which supply the Sarina area. The 11kV feeders have tie points to feeders from neighbouring substations at Balbara (BALB), Rosella (ROSE) and Louis Creek (LOCR) with limited 11kV transfer capability of 2MVA, expected to decrease somewhat over time with distributed load growth.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 2 and the geographic view of Sarina Substation is illustrated in Figure 3**Error! Reference source not found.**.

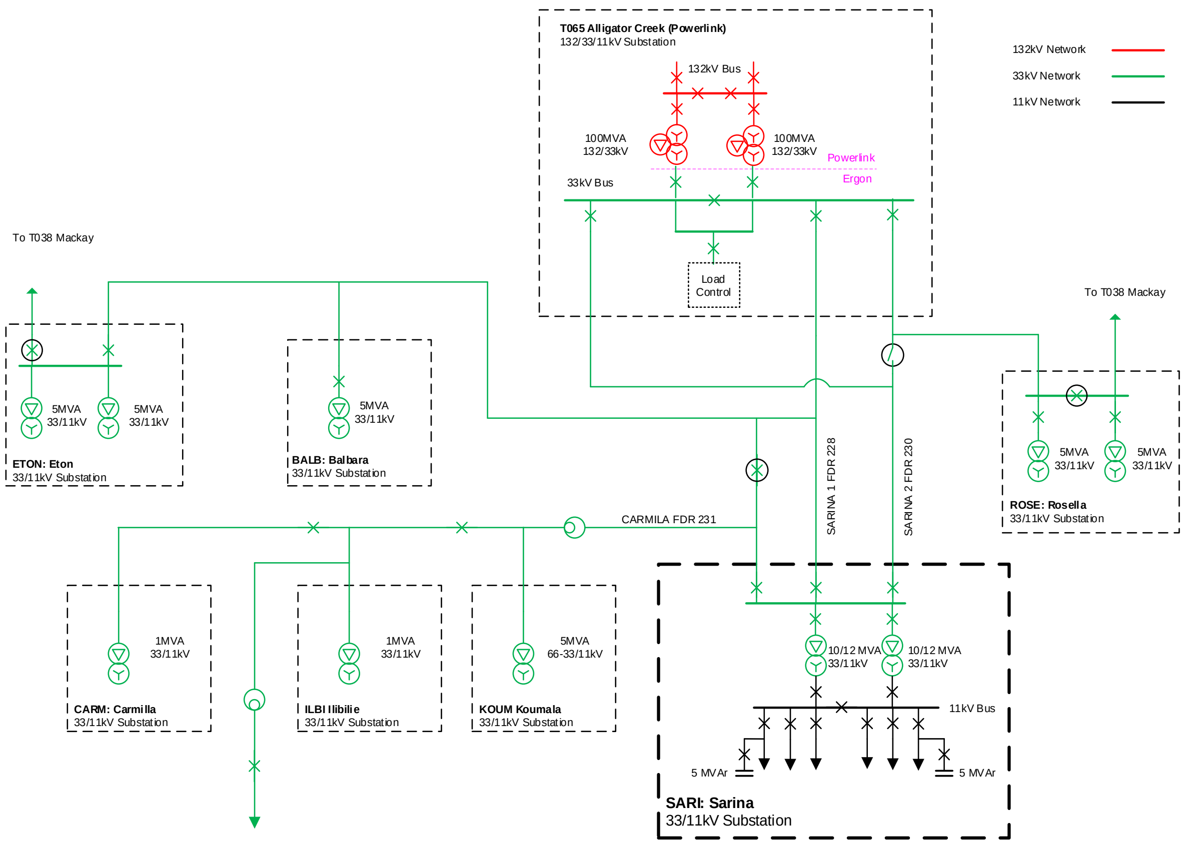


Figure 2: Existing network arrangement (schematic view)

Figure 3: Sarina Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at Sarina Substation comprises a mix of residential and commercial/industrial customers. The annual load peak for the substation occurs during Summer, with reverse power flow in late winter and through spring.

2.3.1. Full Annual Load Profile

The full annual load profile for Sarina Substation over the 2022/23 financial year is shown in Figure 4. It can be noted that the peak load occurs during summer.

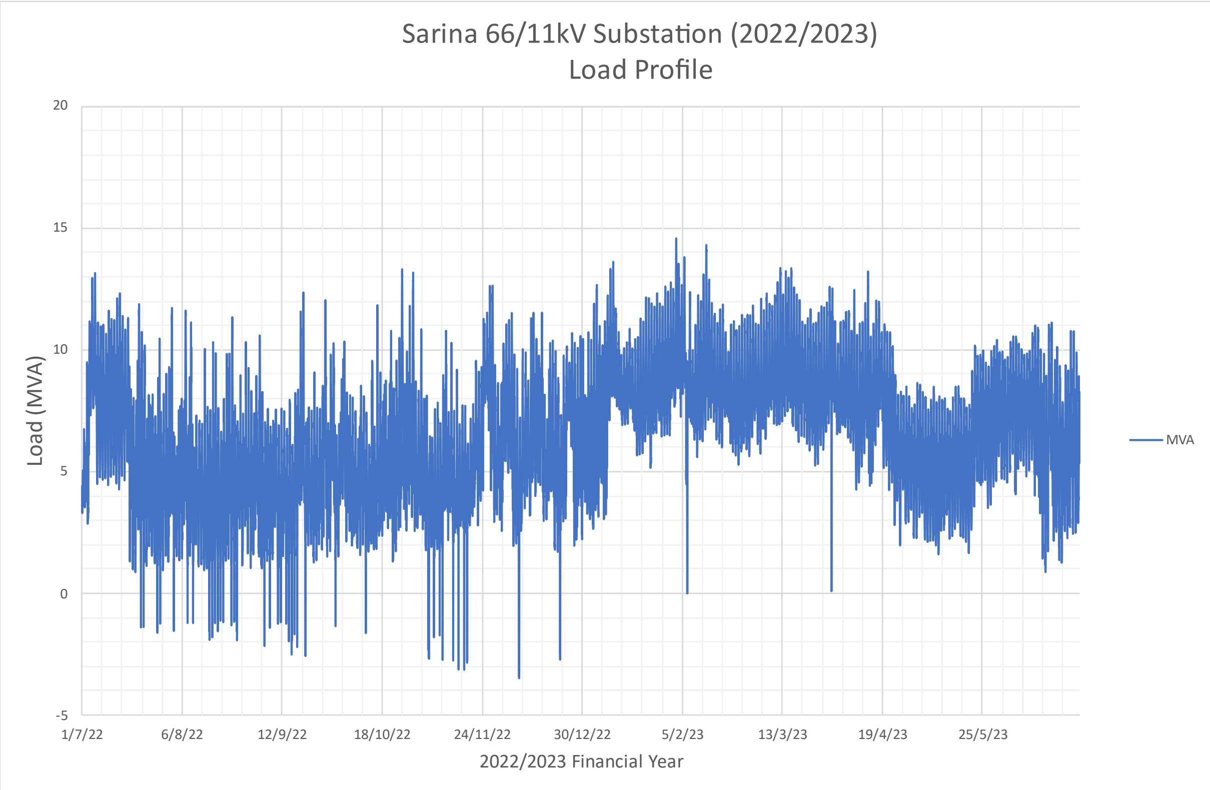


Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for Sarina Substation over the 2022/23 financial year is shown in Figure 5.

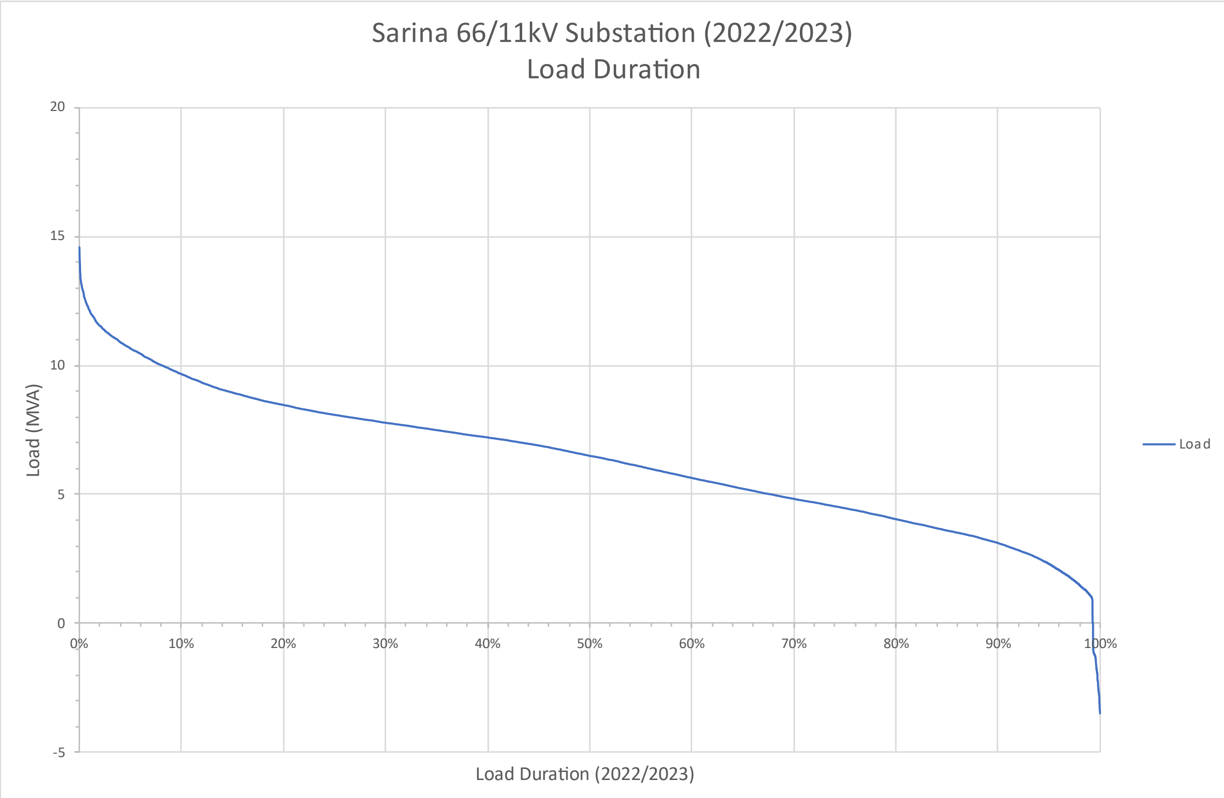


Figure 5: Substation load duration curve

2.3.3. Average Peak Weekday Load Profile (Summer)

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

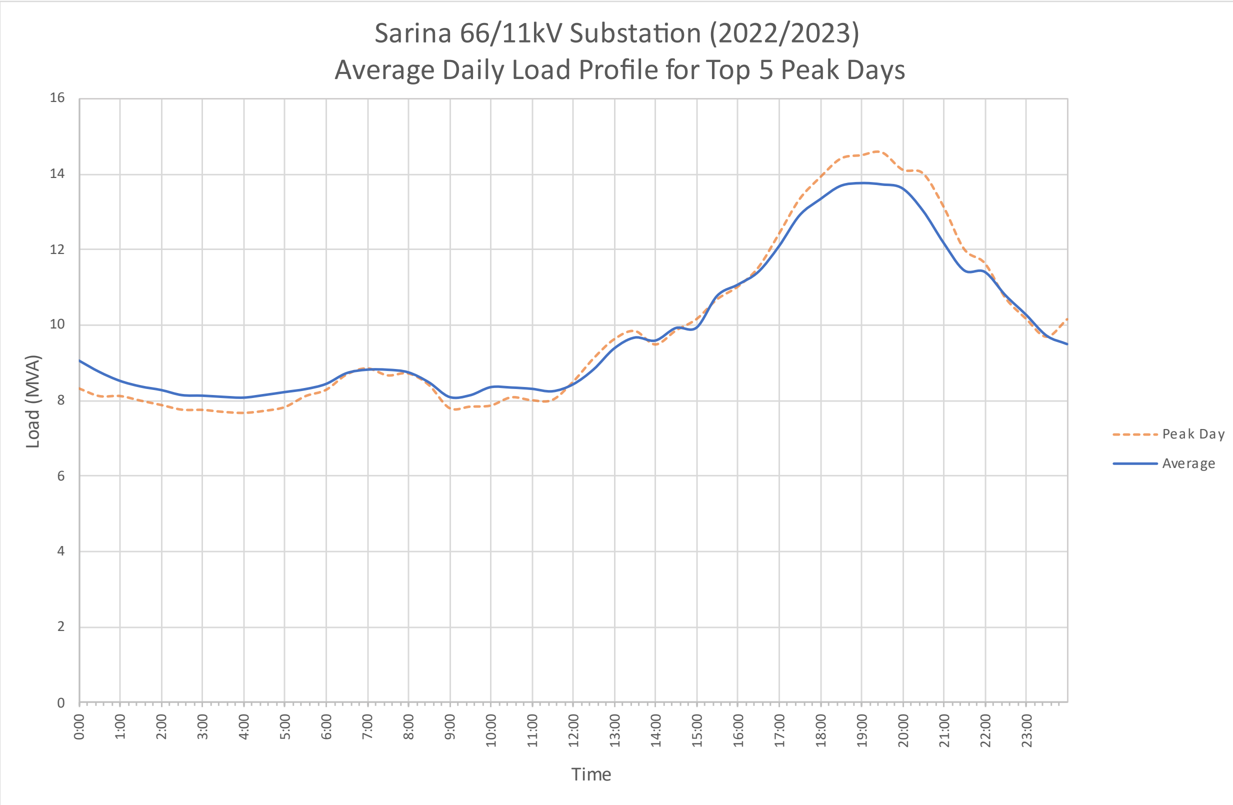


Figure 6: Substation average peak weekday load profile (summer)

2.3.4. Base Case Load Forecast

The 10 PoE and 50 PoE load forecasts for the base case load growth scenario are illustrated in Figure 7. The historical peak load for the past six years has also been included in the graph.

The peak load dropped in 2020, most likely due to COVID-19 pandemic, however the peak load has returned to pre-2020 values in the past 3 years and expected to have steady growth over the next decade.

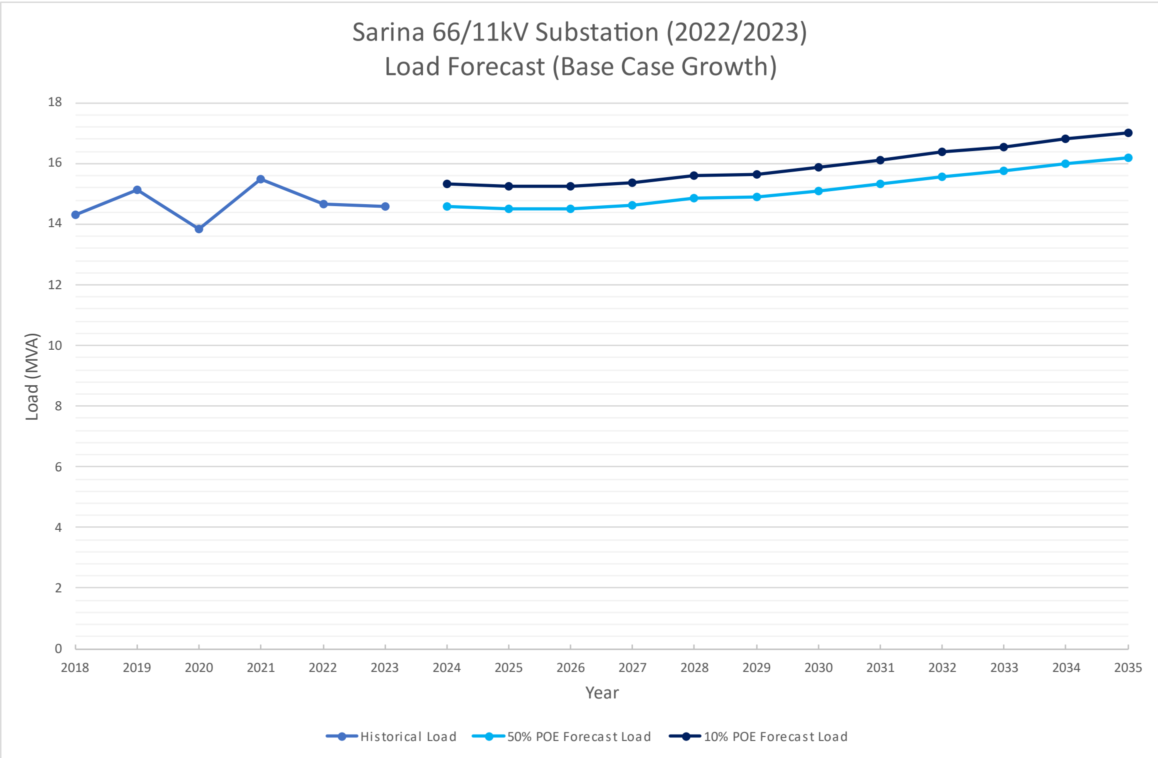


Figure 7: Substation base case load forecast

2.3.5. High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the high load growth scenario are illustrated in Figure 8. With the high growth scenario, the peak load is forecast to increase over the next 10 years.

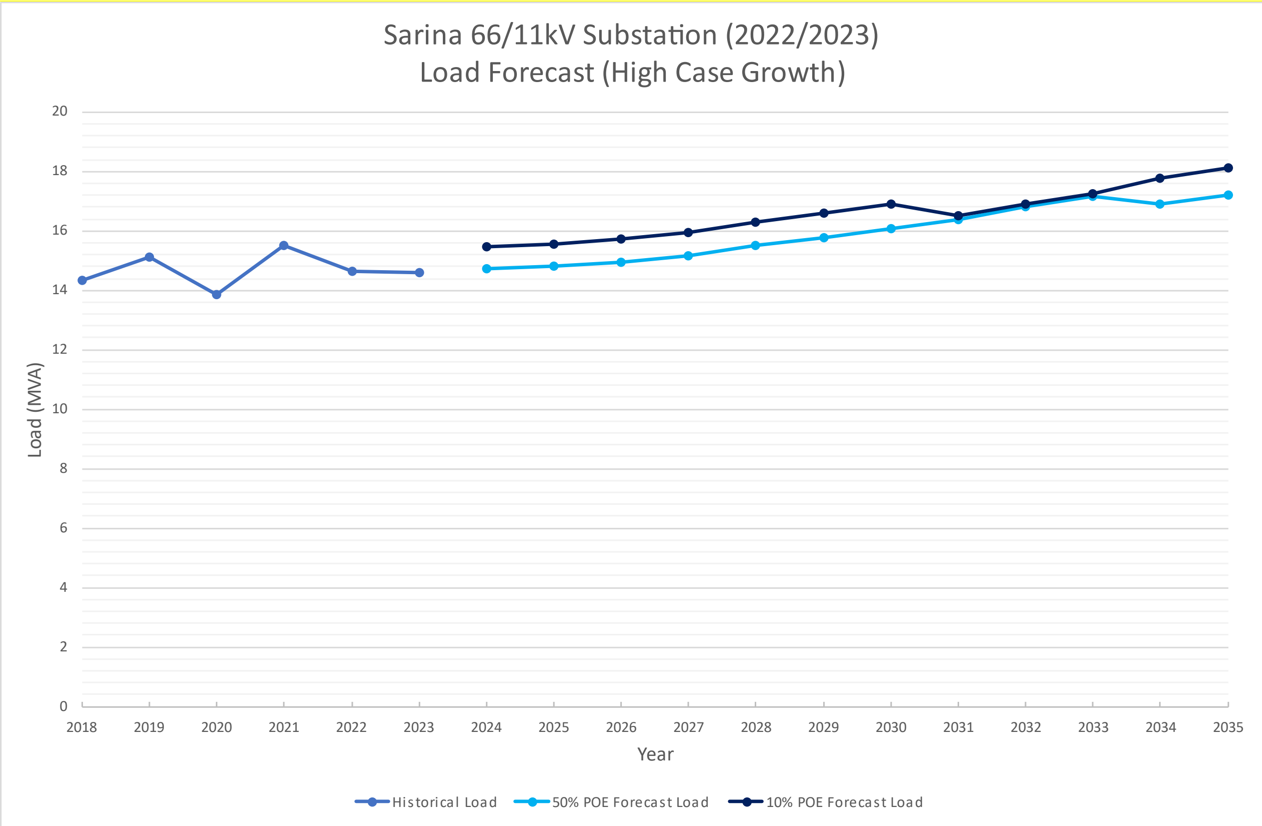


Figure 8: Substation high growth load forecast

2.3.6. Low Growth Load Forecast

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

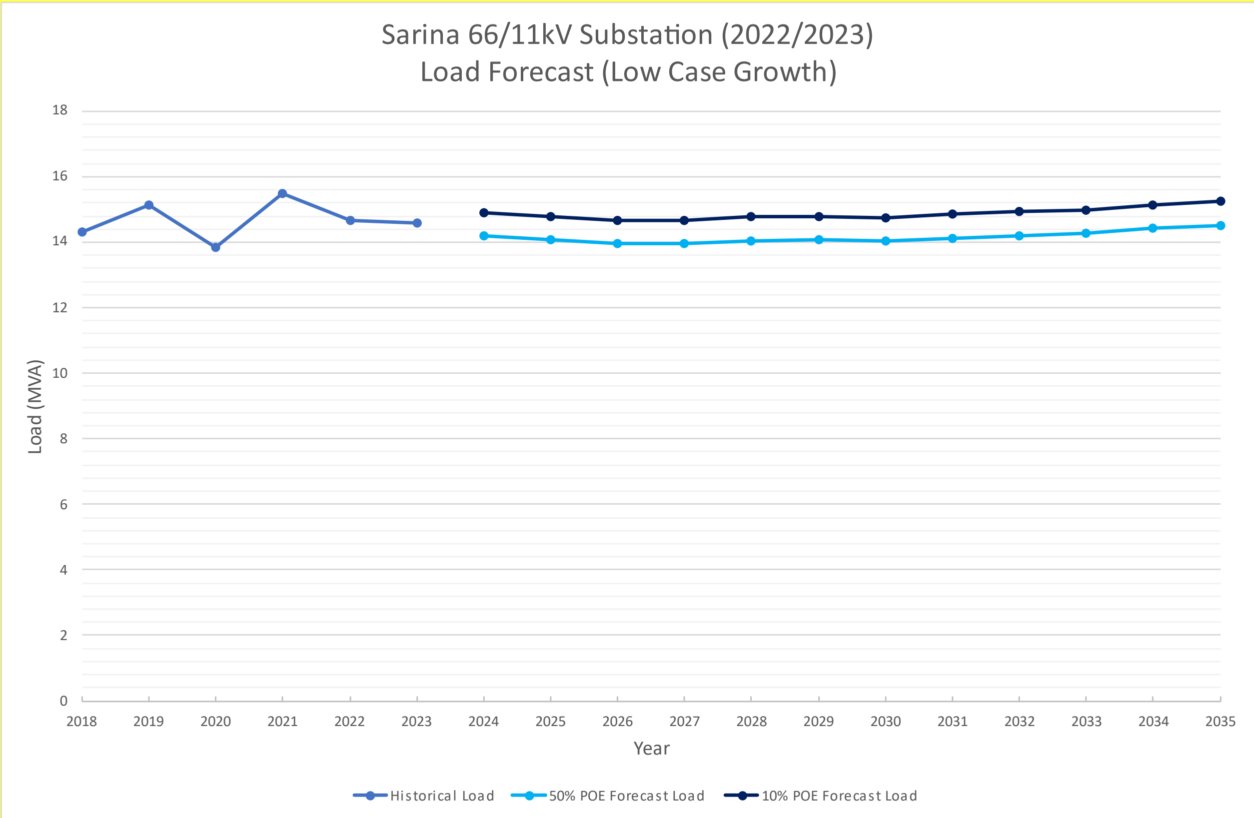


Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

SARI substation is a critical asset for supply of energy for domestic and commercial business located into the Sarina area. Without the substation over 85% of the load in the area will be unsupplied given there is only 2MVA of load transfers available to adjacent substations. With load forecast to increase on the surrounding substations it is anticipated that this load transfer capability will also decrease year on year.

SARI has a number of assets which are nearing end of life, increasing the risk of asset failure. These are further described in Section 2.1.1 The ongoing operation of these assets results in increased exposure to safety and reliability consequences, due to the increased likelihood of asset failure. The purpose of this project is to remove the elevated safety and reliability risks at SARI by replacing assets identified as having an increased likelihood of failure.

3.1.1. Aged and Poor Condition Assets

A Substation Condition Assessment Report was completed for SARI in 2021 which identified a significant number of assets recommended for replacement between 2020 and 2026. These assets, as well as others identified to be replaced in the Asset Limitation Model are summarised below:

- 11kV indoor switchboard and 7 x CBs (estimated retirement year 2026)
- 4 x 33kV outdoor CBs that are aged and prone to explosive failure (estimated retirement year 2025)
- 4 x 33kV porcelain type surge arrestor sets
- outdoor 33kV galvanised steel tube bus and structures that are significantly corroded.
- 34 x protection relays (estimated retirement year 2014-20)

The condition of these assets presents a safety, environmental and reliability risk.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard. It also poses a safety risk the general public, through the increased likelihood of protection relay mal-operation and catastrophic failure of the power transformers. Additionally, the poor condition of these assets significantly increases the likelihood of outages, resulting in a reduction in the level of reliability experienced by the customers supplied from Sarina Substation. This is especially the case with the condition of the 33kV bus structure and likelihood of failure. Failure of the structure would cause an outage to the entire substation, with rectification times likely to well exceed Safety Net thresholds.

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

3.1.2. Reliability

SAIDI or System Average Interruption Duration Index, means the sum of the durations of all the sustained interruptions (in minutes), divided by the customer base. Momentary interruptions (of three minutes or less) are excluded from the calculation of unplanned SAIDI.

SAIFI or System Average Interruption Frequency Index, means the total number of sustained interruptions, divided by the customer base. Momentary interruptions (of three minutes or less) are excluded from the calculation of unplanned SAIFI.

The three-year average network performance for the 11kV distribution feeders supplied from Sarina is shown in Table 1.

While the aged substation equipment is not the only reason for the poor performance in the area, it is a contributing factor.

Feeder	Category	Customer number	Feeder 3 year average SAIDI	Category SAIDI target	Feeder 3 year average SAIFI	Category SAIFI target
Sarina Beach	Short Rural	1,416	**589.97**	424	**5.466**	3.95
Central	Short Rural	658	**397.52**	424	**3.558**	3.95
Southern	Short Rural	915	**886.41**	424	**5.685**	3.95
Northern	Short Rural	595	**925.40**	424	**6.706**	3.95
Western	Long Rural	881	**949.02**	964	**6.513**	7.40

Table 1: Feeder reliability category and performance (existing network)

Feeder reliability classifications are defined below:

- green feeders have a three-year average ≤ target
- yellow feeders have a three-year average > target < 150% target
- amber feeders have a three-year average > 150% target < 200% target
- red feeders have a three-year average > 200% target.

3.2. Quantification of the Identified Need

The monetised risk of the counterfactual is outlined below. The counter factual considers the risks associated with the identified need by proceeding with continued operation of the existing assets with current maintenance regimes and replacing assets on failure. For risk quantification Ergon Energy considers five value streams. The ones pertinent to this project include Safety, Reliability and Financial and is shown in Figure 10.

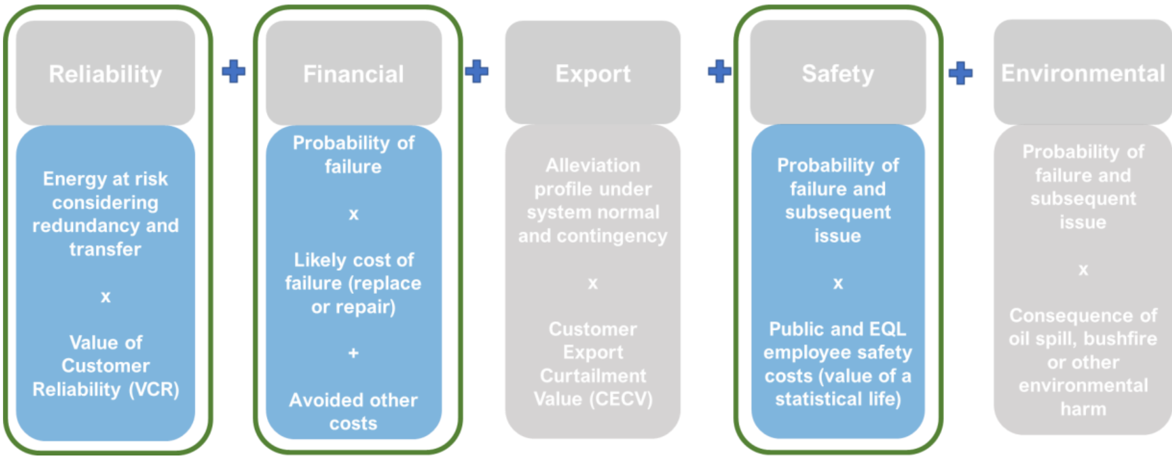


Figure 10 – Value Streams for Investment

3.2.1. Aged and Poor Condition Assets

The aged and poor condition assets at SARI present an increased risk of failure resulting in, unplanned replacement of assets at an increased cost and safety hazards for both work crews and public.

3.2.2. Reliability

Reliability is quantified by considering the probably of failure of assets, the energy at risk based on the existing load profile and the value of customer reliability for the area as shown in Table 2.

Table 2 - VCR weighting applied to each customer type

	Postcode	Annual Consumption (kWH)	VCR
Domestic	4737	26,724,242	$28.44
Commercial		19,224,708	$49.54
Industrial		14,662,132	$70.97
Agricultural		5,961,067	$42.14
Large Cust. Services (>10MVA)			$11.73
Large Cust. Industrial (>10MVA)			$131.28
Large Cust. Metals (>10MVA)			$22.10
Large Cust. Mines (>10MVA)			$39.12
Average VCR			$45.13

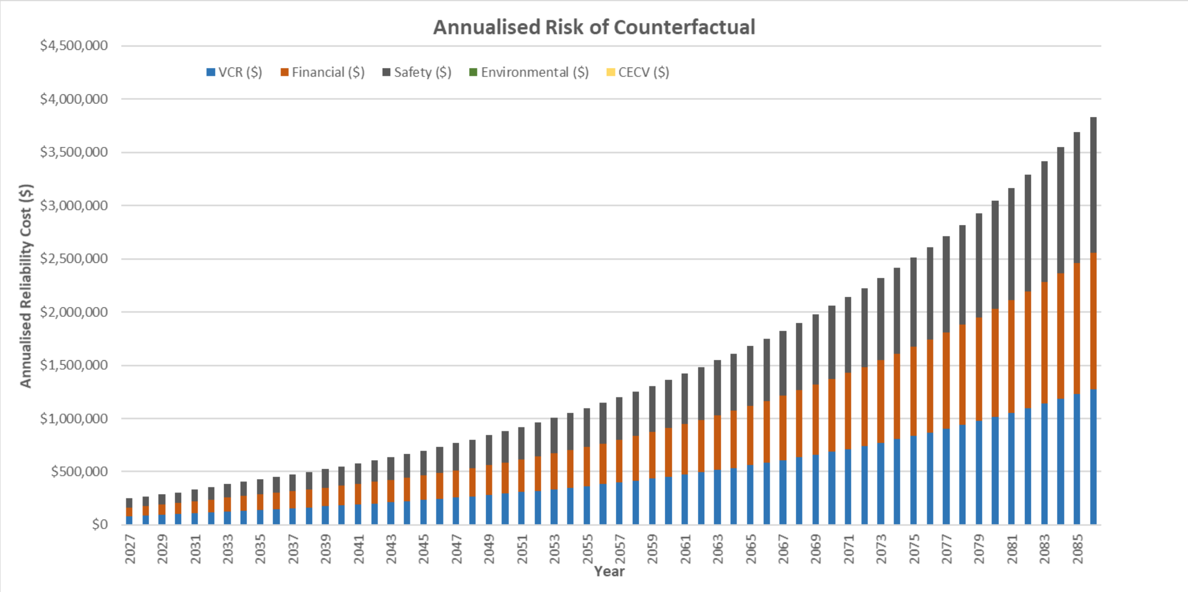


Figure 11 – Counterfactual Risk

3.3. Assumptions in Relation to Identified Need

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

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

3.3.1. Counter factual Risk Quantification

The counterfactual risks are the expected unserved energy, emergency replacement cost, and safety risks, during an equipment failure and associated unplanned supply outage at SARI. Figure 11 shows the quantified risk per annum increasing over the 60-year period from 2027 to 2087.

In calculating the value streams the following assumptions are used:

- **Forced Outage Rate** – The CB outage rate is predicted using a Weibull distribution with a Shape Parameter (β) of 4 and a Characteristic Life (η) of 75 for 11kV CBs, and a Characteristic Life (η) of 80 for 33kV CBs. 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 circuit breakers life.
- **Restoration** – it has been estimated that the average rectification time would be 48 hours for CB failures.
- **Transfers** – during a contingency at SARI,
  - The Carmilla 33kV feeder can currently be transferred from SARI bus via a bypass pole mounted 33kV recloser.

- Approximately 2 MVA of 11kV load can be transferred to adjacent substations in peak summer periods, which is expected to decrease over time with distribution load growth.

- **VCR Rate** – a VCR rate of $45.13 / kWh has been used, with the mix of customers weighted towards domestic, commercial and industrial customers. The weighting applied to each customer type is shown in Table 2.
- **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.
- **Safety** – Considers forced outage rate of the asset with a conversion factor of 0.1% that a fatality to employee and/or injury to employee will occur.
- **Risk timeframe** – risks were calculated over a 60-year period, starting from 2027 to align with the investment year of Option 1 (see below)

3.3.2. Forecast Maximum Demand

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

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

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

3.3.3. Load Profile

Characteristic peak day load profiles shown in Section 2.3.3 are unlikely to in the immediate future and the shape of the load profile is assumed to remain with an evening peak with increasing maximum 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: SARI Asset Replacement

This option involves removing the asset limitations through completion of the following work:

- Establishing a new switchgear and control building on the vacant land adjacent to the substation.

- Replacing the existing 11kV switchboard and protection and control systems into the new building.
- Replacing the existing 33kV outdoor switchgear and galvanised steel bus with 33kV indoor switchboard* in the new building.
- Replacing the existing 11kV and 33kV overhead and underground exit cables to the new switchgear building.
- Replacing the existing 11kV transformer and capacitor bank cables to the new switchgear building.
- Installing new 33kV transformer cables to the new switchgear building.
- Upgrading existing transformer bunds and oil containment systems to meet current environmental standards.
- Upgrading existing substation security fencing and systems to meet current security standards.

*For practicality, an additional 33kV bus tie CB is included for compliance with safety net in future years when 11kV load at SARI grows beyond 20MVA. It is not possible to add this breaker later.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 12.

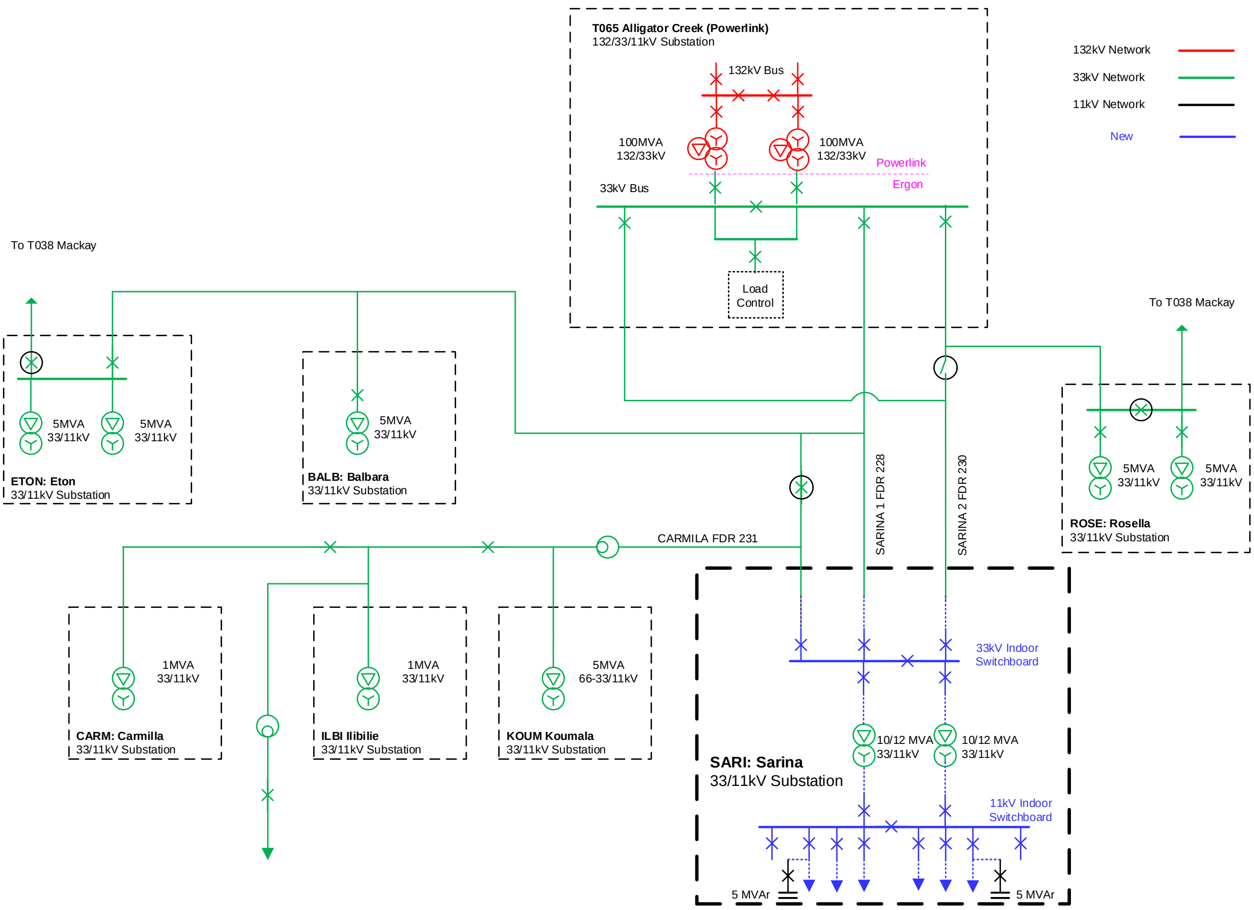


Figure 12: Option A proposed network arrangement (schematic view)

4.2. Assessment of SAPS and Non-Network Solutions

Ergon Energy has considered Standalone Power Systems (SAPS) and demand management solutions to determine their feasibility to meet the identified need. Each of these are considered below.

4.2.1. 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 Sarina region could not be supported by a network that is not part of the interconnected national electricity system. Based on the required energy supply and SAP installation cost to date the minimal cost for a SAP solution would be greater than $1.5b.

4.2.2. Demand Management (Demand Reduction)

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

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

The DEM team has completed a review of the Sarina customer base and considered a number of demand management technologies. Asset safety and performance risks are the key project drivers (i.e. the need) at Sarina. It has been determined that most demand management options will not be viable propositions and have been explored in the following sections.

Network Load Control

The residential customers appear to drive the daily peak demand which generally occurs between 5:00pm and 9:00pm.

There are 977 and 1, 681 customers on tariff T31 and T33 hot water load control (LC) respectively. An estimated demand reduction value of 1.5MVA[1] is available.

Sarina Substation LC signals are controlled from T065 Alligator Creek Bulk Supply Substation (ALCR). The Tariff 33 and 31 hot water LC channels are dynamic (that is, it responds to

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

exceedance settings not on a timetable) and the current control strategy only calls LC when the load at Alligator Creek Bulk Supply Substation exceeds 50MW. This strategy does not directly address demand peaks experienced at Sarina. Tariff 33 air-conditioning channels are under manual control of the operational control centre and are used as required. Therefore, network load control would not sufficiently address the identified need.

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. 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 could potentially address the identified need, however, has been assessed as technically not viable as there is no known existing or proposed LSG demand response available.

Customer Solar Power Systems

A total of 4,057 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 7,528kVA.

The daily peak demand is driven by residential customer demand and the peak generally occurs between 5:00pm and 9:00pm. 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.

However, only a small percentage of large business customers in this supply area with only 653kVA installed solar PV systems and two BESS units. PV systems with BESS present a future portfolio opportunity for potential demand response but currently this supply area has a very limited solar/BESS. Solar customers without a BESS will not meet the technical needs of the demand reduction as their solar contribution may not be available when the network un-met need is required.

4.2.4. SAPS and Non-Network Solution Summary

Ergon Energy has not identified any viable SAPS or 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 Sarina area to address the identified need.

4.3. Preferred Network Option

Ergon Energy's preferred internal network option is Option A, to replace end of life assets at SARI.

Upon completion of these works, the asset safety and reliability risks at Sarina Substation will be addressed. The preferred option will provide the greatest reliability benefit for customers.

The estimated direct capital cost of this option is $8.553 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-2024 and construction completed by November 2027.

5. 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.

5.1. Classes of Market Benefits Considered and Quantified

For this project no market benefits are considered to be material and included in the RIT-D.

5.2. 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 involuntary load shedding and Customer Interruptions caused by Network Outages
- 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 network losses
- Option value
- Other Class of Market Benefit

5.2.1. 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 do not consider the changes to be material.

5.2.2. Customer Export Curtailment Value (CECV)

Customer Export Curtailment Value 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.

5.2.3. 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 Sarina area. Therefore, market benefits associated with changes in voluntary load curtailment have not been considered.

5.2.4. 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.

5.2.5. Differences in Timing of Expenditure

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

5.2.6. 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 Sarina area.

5.2.7. Changes in Network Losses

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

5.2.8. 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[2].

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.

5.2.9. Other Class of Market Benefit

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

6. DETAILED ECONOMIC ASSESSMENT

6.1. 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.

[2] 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

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.

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.

6.2. 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 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 3: Economic parameters and sensitivity analysis factors

6.3. 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:

1. Change in WACC
2. Change to Failure Rate of Assets
3. Change to Benefits (e.g. Change in VCR rate)

6.4. Net Present Value (NPV) Results

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

Option	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
Option A – SARI Asset replacement	1	$4.185m	-$10.529m	$0.3m	$14.713m

Table 4: 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	Discount rate		Failure rate		Benefits	
	2.5%	4.5%	75%	125%	75%	125%
Option A – SARI Asset replacement	$10.026m	$0.310m	$3.917m	$9.681m	$2.467m	$11.131m

Table 5: Scenario Analysis - Comparison of Options

7. 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.

7.1. Preferred Option

Ergon Energy's preferred internal network option is Option A, to replace end of life assets at SARI.

Upon completion of these works, the asset safety and reliability risks at Sarina Substation will be addressed. The preferred option will provide the greatest reliability benefit for customers.

The estimated direct capital cost of this option is $8.553 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-2024 and construction completed by November 2027.

7.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

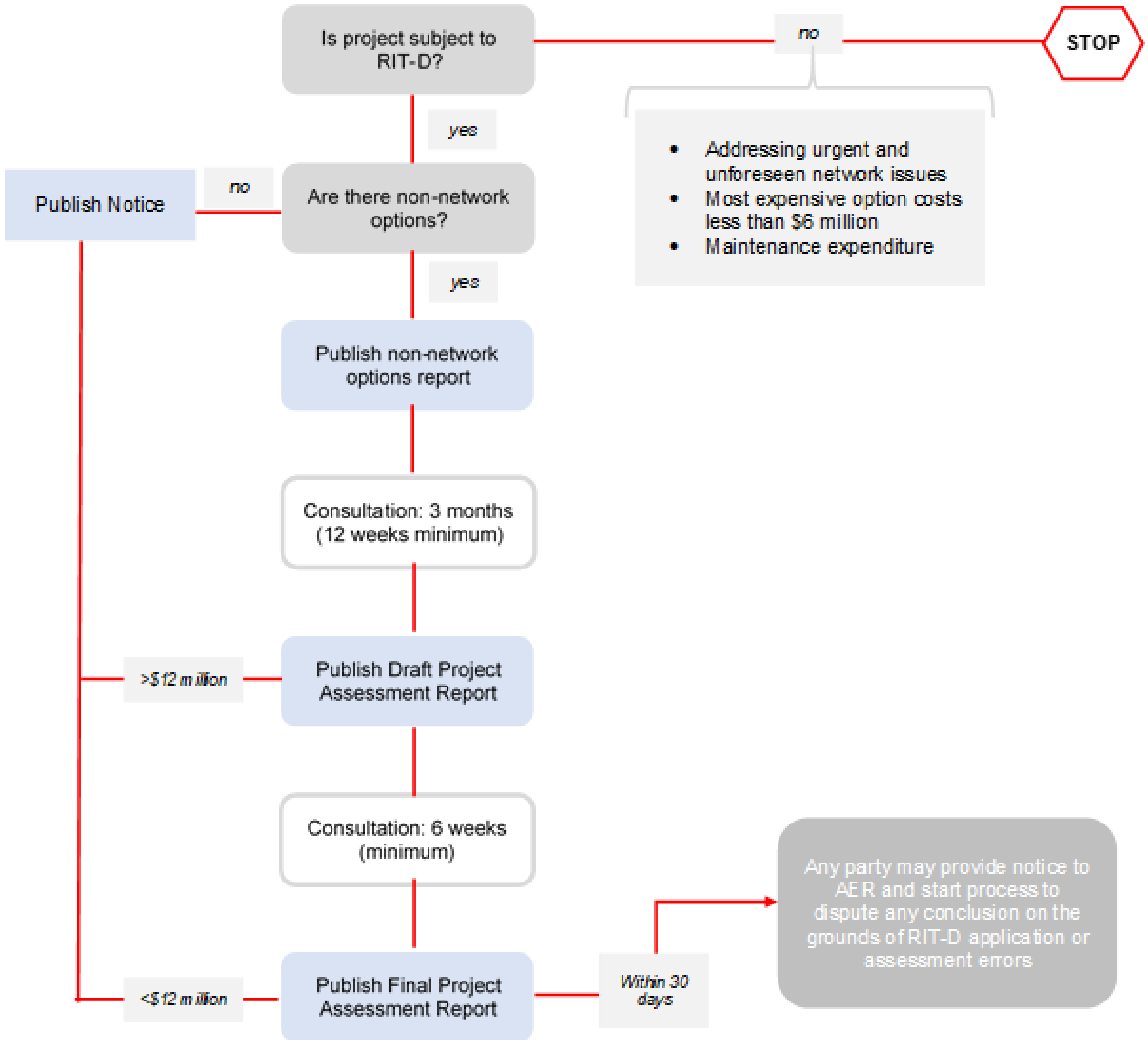
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

8. COMPLIANCE STATEMENT

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

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the DPAR;	N/A
(4) a description of each credible option assessed	4
(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	5
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	4 & 5
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	5
(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	5.1 & 5.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	6.4
(10) the identification of the proposed preferred option	7.1
(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	7.1 & 7.2
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.3

APPENDIX A – THE RIT-D PROCESS



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