Regulatory Investment Test for Distribution (RIT-D)

Reliability Corrective Action

The Acacia Ridge Network Area

Draft Project Assessment Report

14 July 2025

energex

Part of Energy Queensland

EXECUTIVE SUMMARY

Purpose

The purpose of the regulatory investment test for distribution is to identify the credible option that maximises the present value of the net economic benefit. Energex Limited (Energex) has prepared this Draft Project Assessment Report (DPAR), where Energex provides both technical and economic information about possible solutions, in accordance with the requirements of clauses 5.17.4(i) through (m) of the National Electricity Rules (NER), after having published a notice of no non-network or SAPS options for this Regulatory Investment Test for Distribution (RIT-D) project to address the identified need.

This draft sets out the reasons for the proposed preferred option, including any methodologies and assumptions used in preparing the assessment. Energex invites registered participants and interested parties to make submissions on possible alternate solutions to address the need for investment.

About Energex

Energex is a subsidiary of Energy Queensland Limited and manages the electricity distribution network in the growing region of South East Queensland which includes the major urban areas of Brisbane, Gold Coast, Sunshine Coast, Logan, Ipswich, Redlands and Moreton Bay. Our electricity distribution area runs from the NSW border north to Gympie and west to the base of the Great Dividing Range.

Our electricity network consists of approximately 54,200 kilometres of powerlines and 680,000 power poles, along with associated infrastructure such as major substations and power transformers.

Today, we provide distribution services to more than 1.4 million domestic and business connections, delivering electricity to a population base of around 3.4 million people.

Identified Need

Acacia Ridge 33/11kV Substation (SSARG) is located approximately 15km south of the Brisbane CBD. The substation is part of the Energex's 33kV sub-transmission network, is presently supplied via two incoming 33kV feeders from T161 Algester 110/33kV Bulk Supply Substation (SST161).

Acacia Ridge Substation supplies four suburbs of Brisbane - Acacia Ridge, Coopers Plains, Sunnybank, and Sunnybank Hills. Acacia Ridge Substation provides electricity supply to approximately 3,195 residential and 301 commercial and industrial customers.

Based on the condition assessment of Acacia Ridge, some primary and secondary plant and equipment are recommended for retirement.

The assessment identified that the two 33/11kV power transformers, the 11kV switchboard including eight 11kV oil circuit breakers and fourteen of the protection relays are at the end of their serviceable life.

Additionally, a civil assessment of the structures on site also identified that the transformer bunding is inadequate and does not satisfy the current requirements outlined in AS1940 and AS2067.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard, and reliability risk to the customers supplied from Acacia Ridge Substation. Therefore, the identified need for this RIT-D project is for reliability corrective action, without such investment, Energex may, in the event of failure of the above identified critical assets, be in breach of regulatory obligations including:

- *Electrical Safety Act 2002* (Qld) – Under Sections 29 and 30, Energex has a duty of care to ensure that its works are electrically safe and are operated in a way that is electrically safe. This duty also extends to ensuring the electrical safety of all persons and property likely to be affected by the electrical work.
- Energex's Distribution Authority issued under the *Electricity Act 1994* – Under its Distribution Authority, the distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services. A failure of the deteriorated 11kV switchboard could result in approximately 3,500 customers without power, which would be noncompliant with reliability thresholds stated in the Distribution Authority (specifically, the restoration time is expected to exceed the Service Safety Net Targets).

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 RIT-D. Energex has determined that network investment is essential in this case for it to continue to provide electricity to the consumers in the Acacia Ridge supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

Energex published a Notice of No Non-Network or SAPS Options for the above described network constraint on 24 June 2025.

Two potentially feasible options have been investigated:

- **Option 1:** Replace two 33/11kV transformers, 11kV switchboard and secondary systems
- **Option 2:** Replace one 33/11kV transformer, 11kV circuit breakers and upgrade 11kV feeders

Energex's proposed preferred solution to address the identified need is Option 1 – Replace two 33/11kV transformers, 11kV switchboard and secondary systems.

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

Submissions in writing are due on the **29 August 2025** by 4pm and must be lodged to demandmanagement@energex.com.au

For further information and inquiries please contact:

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

CONTENTS

1. INTRODUCTION

This DPAR represents the second stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need for the Acacia Ridge network area.

In preparing this RIT-D, Energex is required to consider reasonable future scenarios. With respect to major customer loads and generation, Energex has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Energex is aware of are in different stages of progress and are subject to change (including outcomes where none or all proceed). These and other customer activity can occur over the consultation period and may change the timing and/or scope of any proposed solutions.

1.1. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the Acacia Ridge area.
- Identifies the need which Energex is seeking to address, together with the assumptions used in identifying and quantifying that need.
- Describes the credible options that are considered in this RIT-D assessment.
- Quantifies costs and classes of material market benefits for each of the credible options.
- Quantifies the applicable costs for each credible option, including a breakdown of operating and capital expenditure.
- Describes the methods used in quantifying each class of market benefit.
- Provides details of classes of market benefits that are not considered material to this RIT-D assessment and provides explanations as to why these classes of market benefits are not considered material.
- Provides the results of Net Present Value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.
- Is an invitation to registered participants and interested parties to make submissions.

1.2. Contact Details

Submissions in writing are due by 4pm on **29 August 2025** and should be lodged to demandmanagement@energex.com.au.

For further information and inquiries please contact:

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2. BACKGROUND

2.1. Geographic Region

Acacia Ridge 33/11kV Substation (SSARG) is located approximately 15km south of the Brisbane CBD. It supplies four suburbs of Brisbane - Acacia Ridge, Coopers Plains, Sunnybank, and Sunnybank Hills. Acacia Ridge Zone Substation provides electricity supply to approximately 3,496 customers, of which 91% are residential and 9% are commercial and industrial.

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

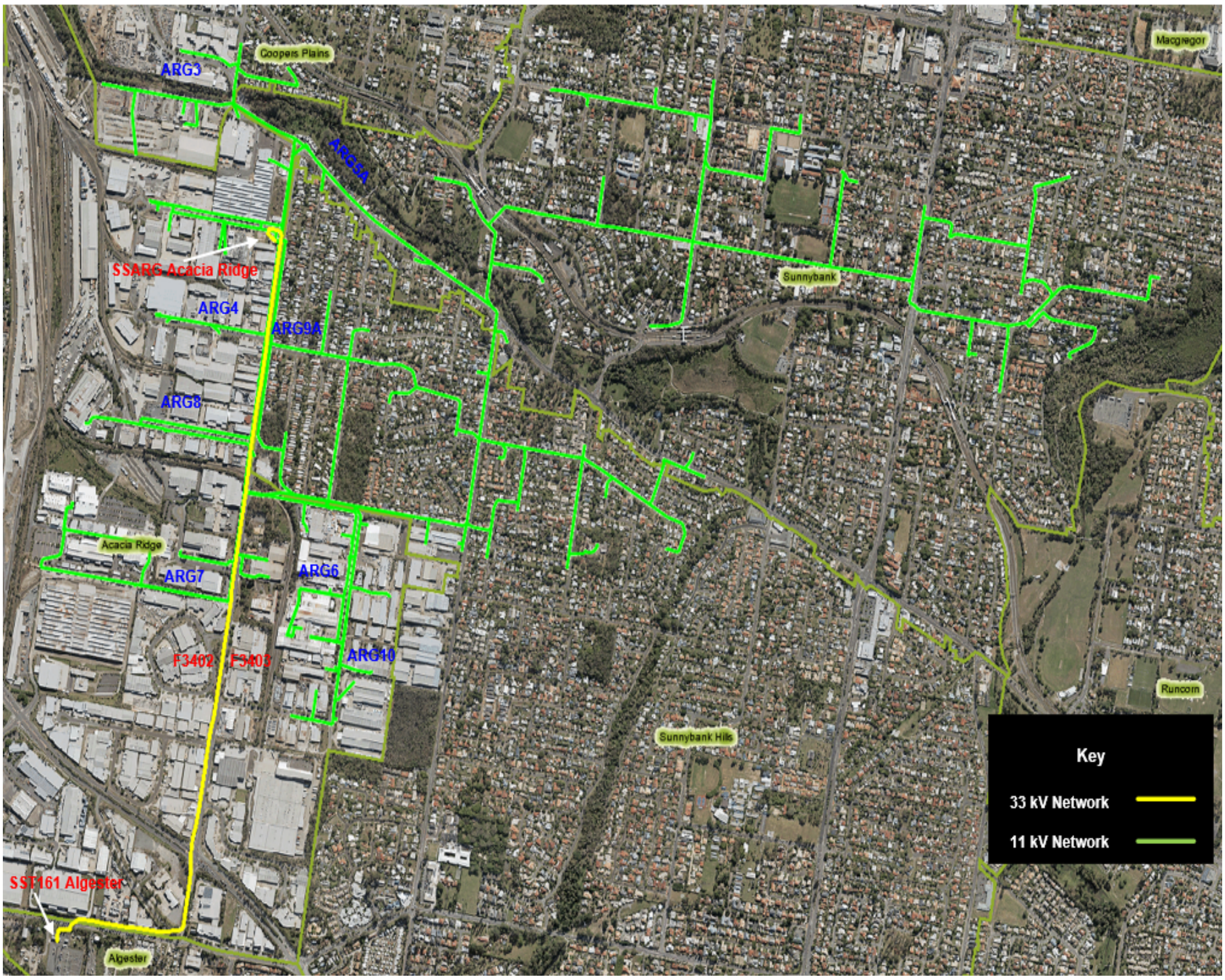

Figure 1: Existing network arrangement of Acacia Ridge zone substation supply area (geographic view)

2.2. Existing Supply System

Acacia Ridge 33/11kV Substation is part of the Energex's 33kV sub-transmission network and is presently supplied radially via two incoming 33kV feeders from SST161 Algester 110/33kV Bulk Supply Substation (SST161).

Acacia Ridge Substation was established in 1975 in line with the applicable design and construction standards of that time. It has indoor 33kV and 11kV switchyards, two 20MVA 33/11kV power transformers, two capacitor banks and control buildings. Acacia Ridge substation supplies eight 11kV distribution feeders.

Based on the substation condition assessment of Acacia Ridge, some primary and secondary plant and equipment are recommended for retirement due to deteriorated conditions.

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

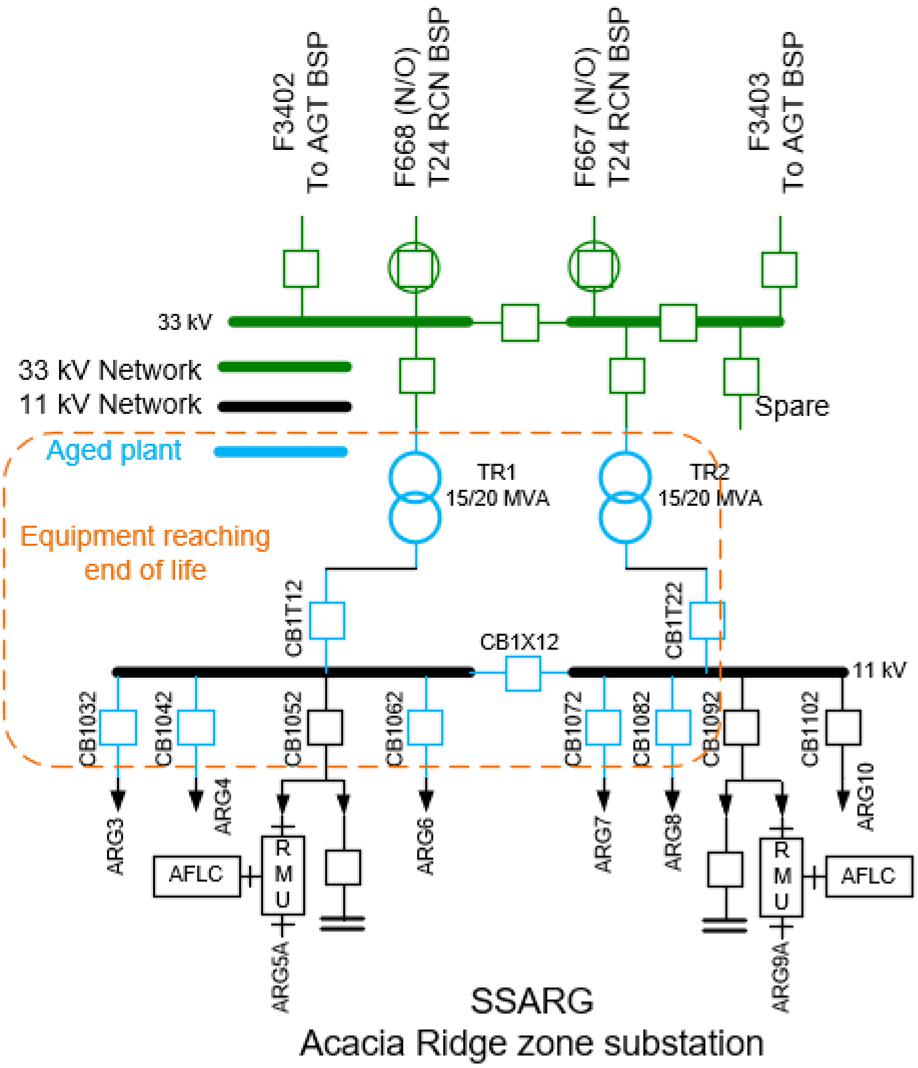

Figure 2: Existing network arrangement (schematic view)

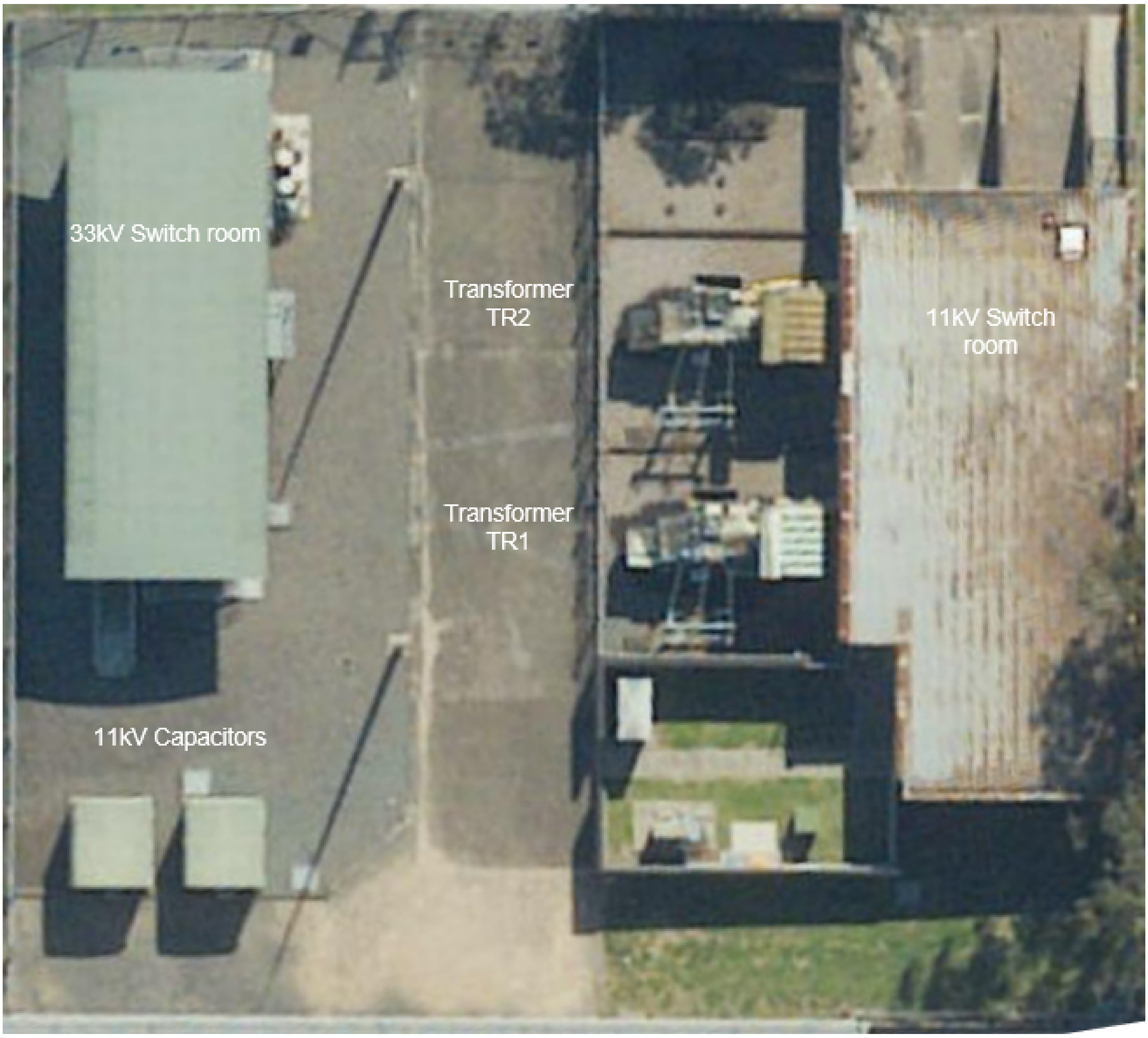

Figure 3: Acacia Ridge Substation (geographic view)

2.3. Load Profiles / Forecasts

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

2.3.1. Full Annual Load Profile

The full annual load profile for Acacia Ridge Substation over the 2023/24 financial year is shown in Figure 4. It can be noted that the peak load occurs during summer.

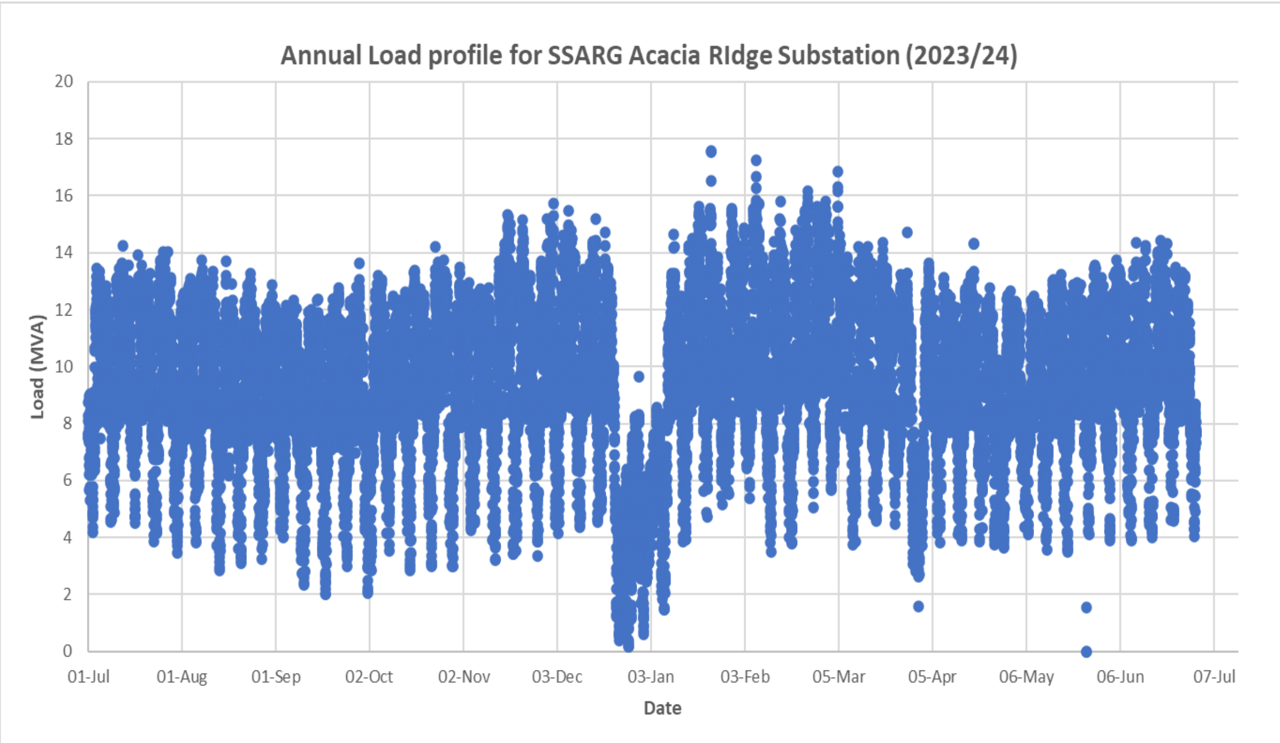

Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for Acacia Ridge Substation over the 2023/24 financial year is shown in Figure 5.

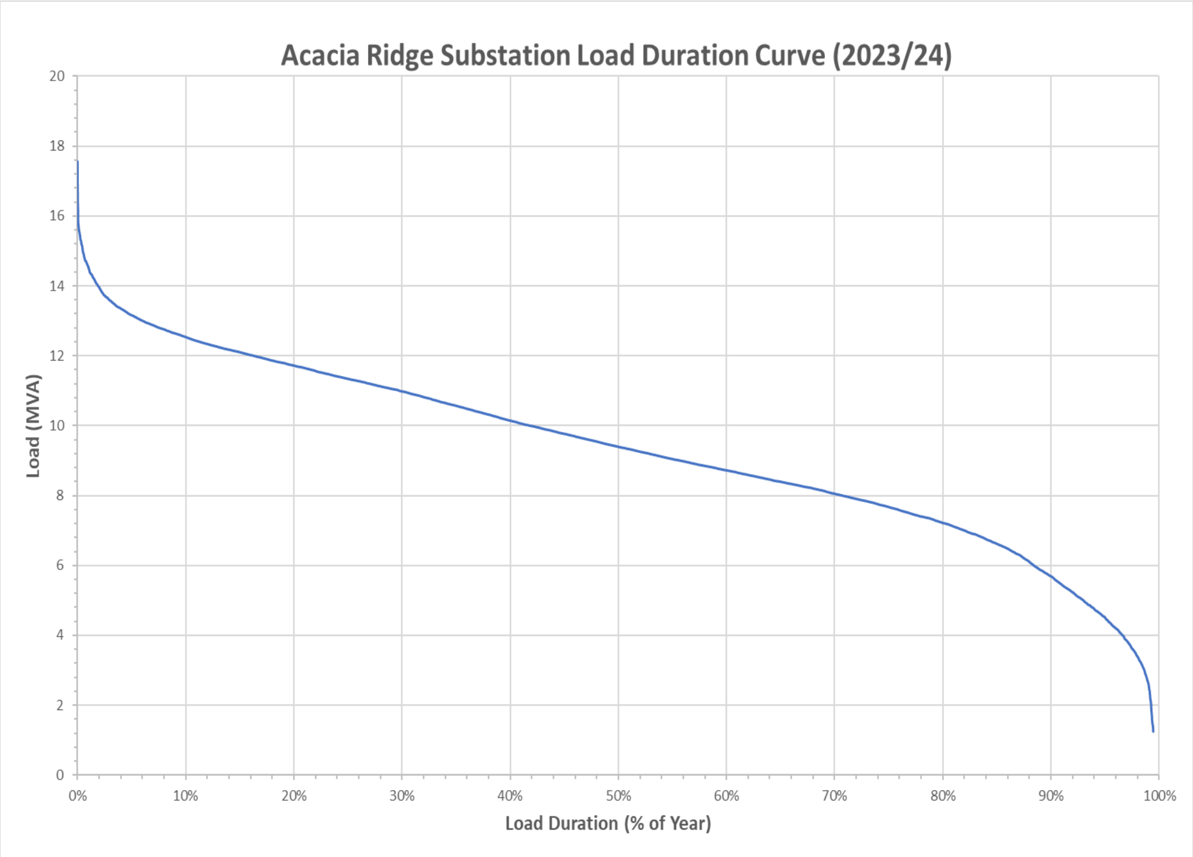

Figure 5: Substation load duration curve

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 Acacia Ridge Substation are historically experienced in the late afternoon and evening.

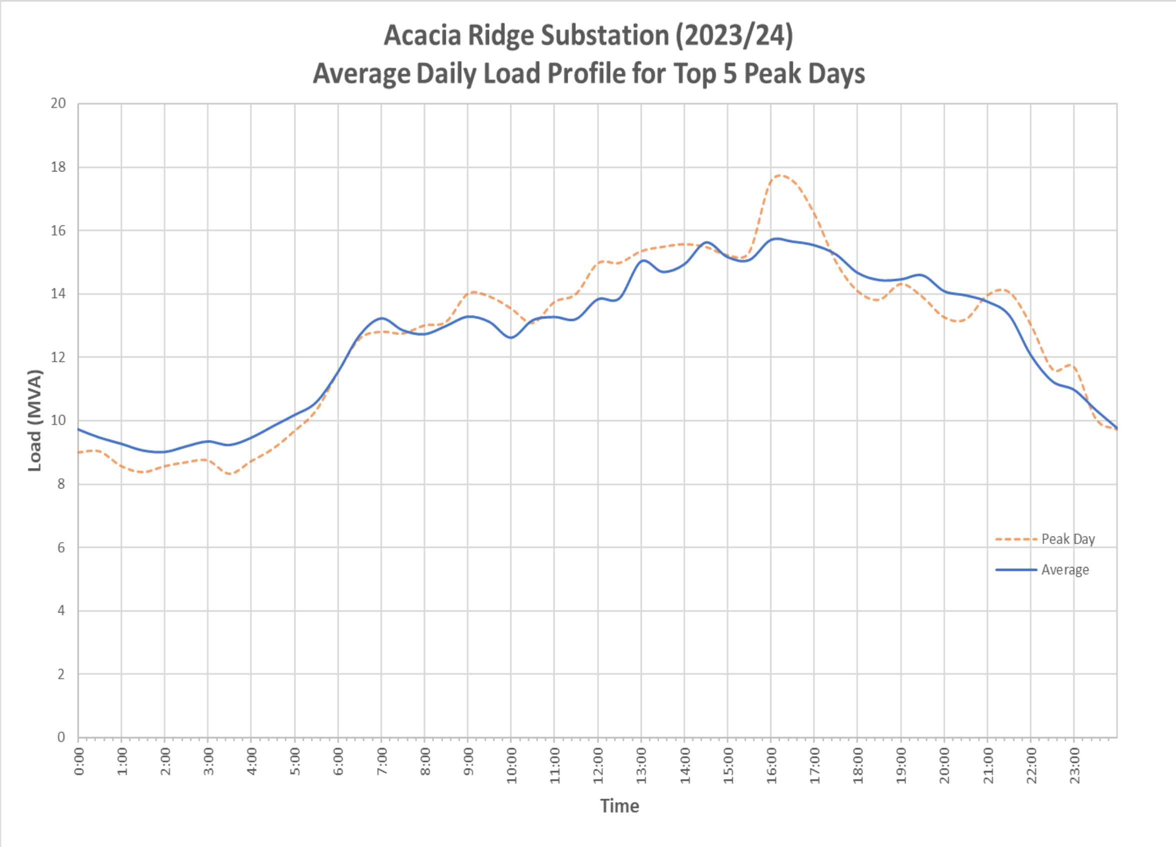

Figure 6: Substation average peak weekday load profile (summer)

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.

It can be noted that the historical annual peak loads have fluctuated over the past five years, primarily due to seasonal variation in commercial/industrial load. It can also be noted that the peak load is forecast to decrease slightly over the next 10 years under the base case scenario.

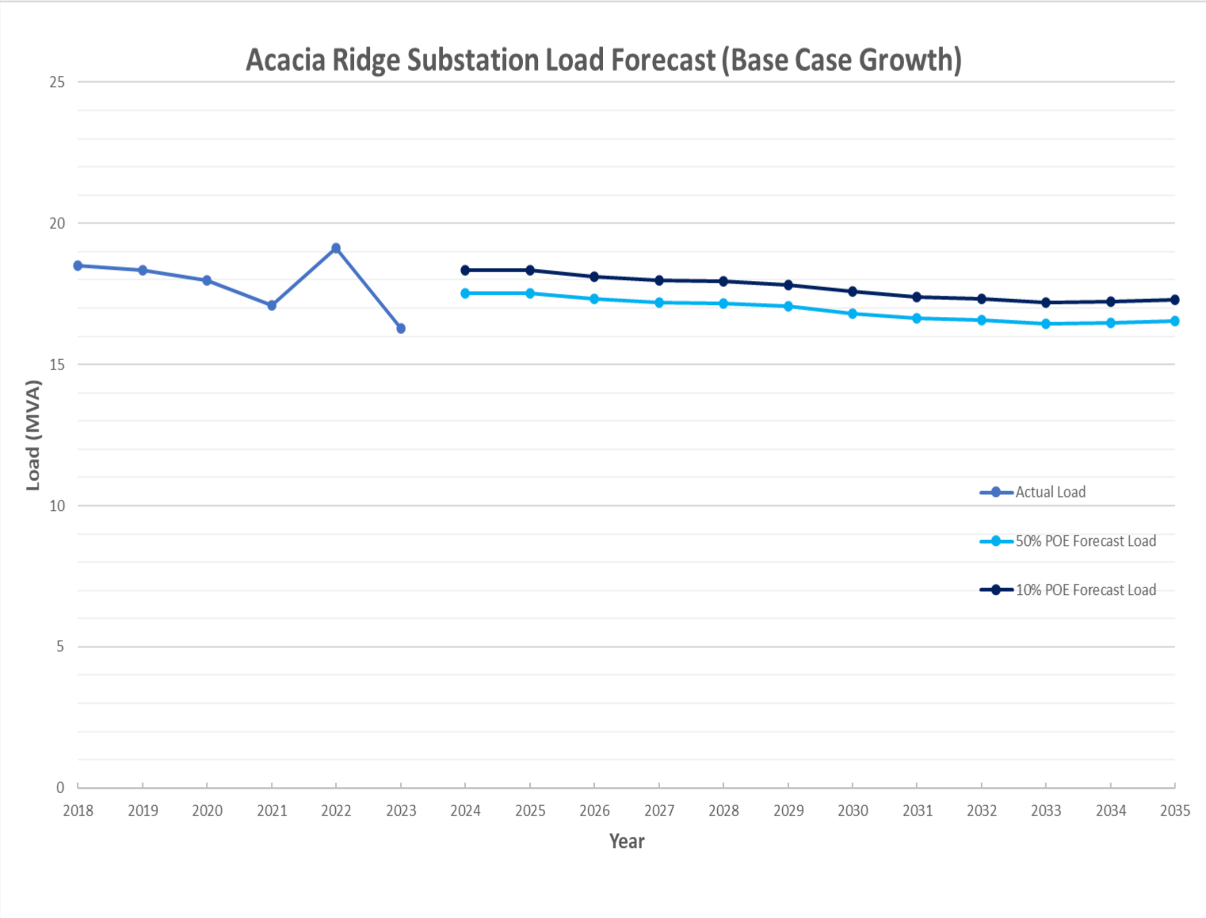

Figure 7: Substation base case load forecast

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.

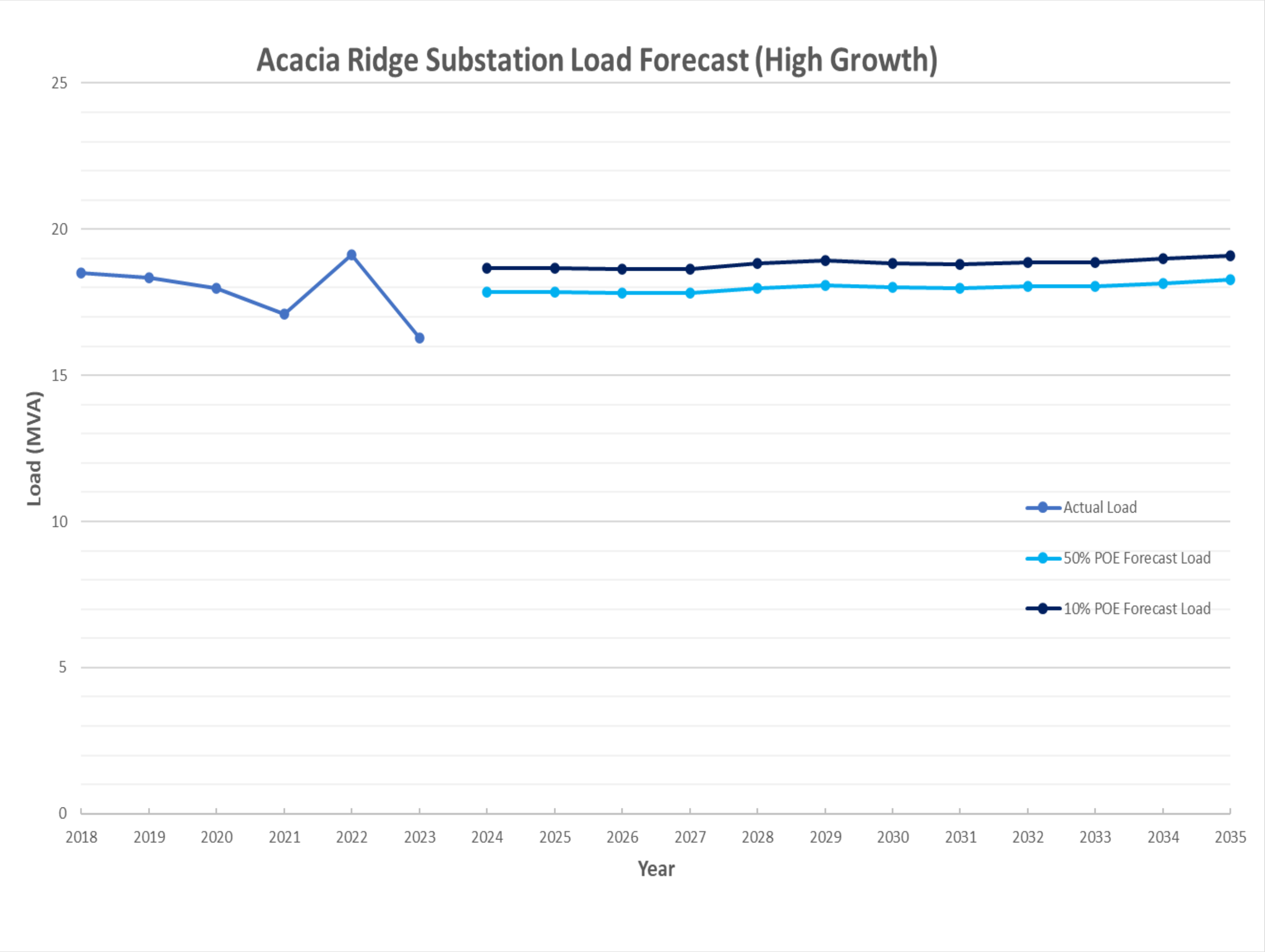

Figure 8: Substation high growth load forecast

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 decrease over the next 10 years.

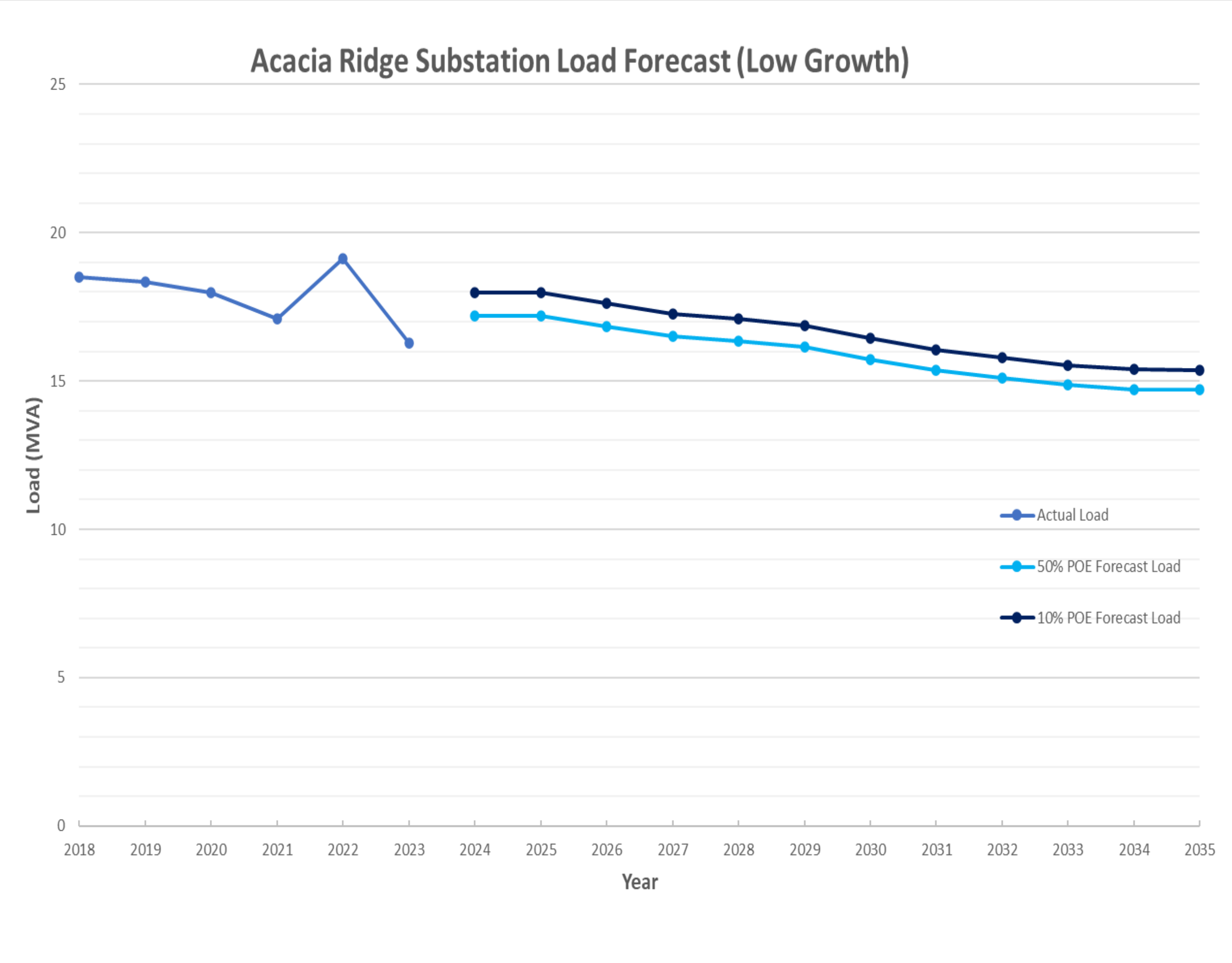

Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Reliability Corrective Action

A recent condition assessment has highlighted that several critical assets at SSARG are at the end of life and are in poor condition. The condition of these assets presents a considerable safety, environmental and reliability risk. These assets include:

- 11kV switchboard
- Two 33/11kV transformers, TR1 and TR2
- Various protection relays

Condition data indicates that the two 33/11kV power transformers, eight 11kV indoor circuit breakers and most of the protection relays at Acacia Ridge Substation are reaching end of life. Additionally, the transformer bunding is inadequate and does not satisfy the current requirements outlined in AS1940 and AS2067.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard. It also poses a safety risk to the public, through the increased likelihood of protection relays mal-operation and catastrophic failure of the power transformers. There is also a considerable risk of environmental harm due to loss of oil from the power transformers, which would require clean up and rectification.

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 Acacia Ridge Substation.

Where Energex 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.

Energex has identified a need to invest in the network for reliability corrective action to continue to meet safety standards and reliability service standards as required under applicable regulatory instruments:

- *Electrical Safety Act 2002* (Qld) – Under Sections 29 and 30, Energex has a duty of care to ensure that its works are electrically safe and are operated in a way that is electrically safe. This duty also extends to ensuring the electrical safety of all persons and property likely to be affected by the electrical work.
- Energex's Distribution Authority issued under the *Electricity Act 1994* – Under its Distribution Authority, the distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services. A failure of the deteriorated 11kV switchboard could result in approximately 3,500 customers without power, which would be noncompliant with reliability thresholds stated in the Distribution Authority (specifically, the restoration time is expected to exceed the Service Safety Net Targets).

Without such investment, Energex may, in the event of failure of the above identified critical assets, be in breach of these regulatory obligations.

3.2. Quantification of the Identified Need

3.2.1. Aged and Poor Condition Assets

A recent condition assessment indicates that:

- 33/11kV transformers TR1 and TR2 are showing advance level of insulation degradation.
- 11kV switchgear are deemed to reach their retirement age and require replacement.
- Various Protection relays are deemed to reach their retirement age and require replacement.

3.2.2. Safety

Due to the condition of the assets, there is an increased safety risks to staff working within the switchyard. Catastrophic failure of a transformer or circuit breaker can result in serious injury or fatality to staff working in close proximity to the equipment.

Where Energex 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.

3.2.3. Reliability

Currently, the aged assets present a risk to the reliability of supply at SSARG. Due to the existing condition and configuration of the substation, the following reliability risk scenarios are identified:

- 11kV feeder circuit breaker failure on bus BB11 – a failure of any of the feeder circuit breaker would result in a loss of bus BB11 load; however, it was assumed that 6.5MVA of load could be supplied by manual transfer within 3 hours.
- 11kV feeder circuit breaker failure on bus BB12 – a failure of any of the feeder circuit breaker would result in a loss of bus BB12 load; however, it was assumed that 6.5MVA of load could be supplied by manual transfer within 3 hours.
- 11kV bus section breaker failure – a failure of the bus section circuit breaker would result in a loss of all 11kV load; however, it was assumed that 6.5MVA of load could be supplied by manual transfer within 3 hours.
- 33/11kV TR1 failure – It was assumed that TR2 is in service to supply the substation load after a failure of TR1, and 6.5MVA of load could be supplied by manual transfer within 3 hours as well.
- 33/11kV TR2 failure – It was assumed that TR1 is in service to supply the substation load after a failure of TR2, and 6.5MVA of load could be supplied by manual transfer within 3 hours as well.

3.2.4. Risk Quantification Benefit Summary

Risk quantification analysis has been completed for the existing network, which includes the value of customer reliability and cost of emergency replacement. Figure 10 shows the risk of continuing the use of the existing ageing assets.

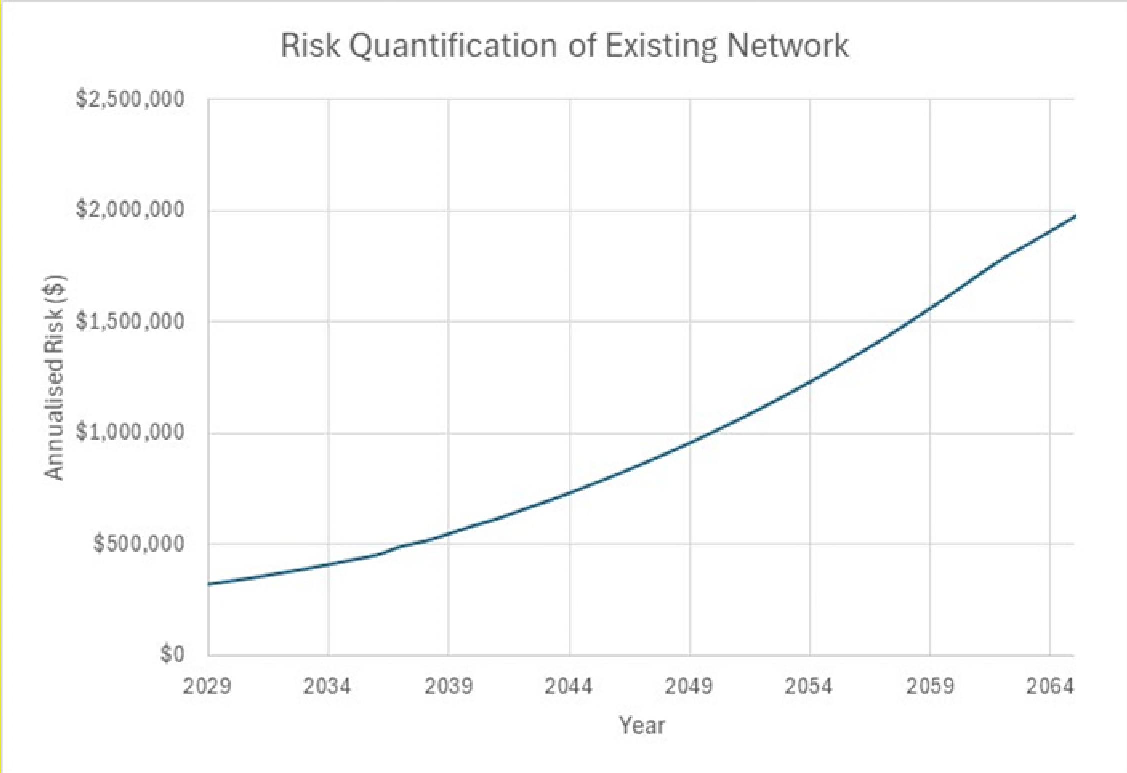

Figure 10: Annualised Risk

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. Forecast Maximum Demand

It has been assumed that forecast peak demand at Acacia Ridge Substation will be consistent with the base case forecast outlined in Section 2.3.4.

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

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

- forecast growth rates for organic growth.

3.3.2. 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.

4. TECHNICAL CHARACTERISTICS OF SAPS AND NON-NETWORK OPTIONS

This section describes the technical characteristics of the identified need that a Stand-alone Power System (SAPS) or a non-network option would be required to comply with in order to replace the proposed solution.

4.1. Size

To meet Energex's ongoing operational needs, it is expected that any alternate solution must provide supply with an acceptable level of redundancy to the distribution network that supports a load up to the values listed in the table below.

Estimated Peak Demand	Estimated Maximum Daily Energy
17 - 18 MVA	300 - 320 MWh

Table 1: Estimated peak capacity required

4.2. Location

The location where network support capability is measured / referenced is on the 11kV bus at Acacia Ridge Substation; however alternative options may be located downstream on the 11kV network, so long as they can be operationally utilised within the Acacia Ridge zone substation supply area.

4.3. Timing

4.3.1. Implementation Timeframe

In order to ensure compliance with Energex's planning criteria and the National Electricity Rules, a non-network solution will need to be implemented by June 2029.

4.3.2. Time of Year

The network support will be required continuously at all times.

4.3.3. Duration

The network support will be required continuously at all times.

4.4. Compliance with Regulations and Standards

As a distribution network service provider (DNSP), Energex must comply with regulations and standards, including, but not limited to, the Electricity Act 1994, the Electricity Regulation 2006, Energex's Distribution Authority, the National Electricity Rules and applicable Australian Standards.

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

4.5. Longevity

Proposed non-network options will typically be required to provide solutions to the identified need for a period of at least 10 years. However, alternative solutions that can defer additional network investment for a smaller number of years may also be considered.

4.6. Potential Deferred Augmentation Charge

The annual deferred augmentation charge associated with the identified need is approximately $438k per year.

4.7. Feasible vs Non-Feasible Options

4.7.1. Potentially Feasible Options

The identified need presented in this RIT-D is driven by the capability and reliability of the existing sub-transmission network that supplies Acacia Ridge. As such, solutions that can cost-effectively provide the required capability are likely to represent reasonable options.

A non-exhaustive list of potentially feasible options includes:

- New embedded dispatchable network generation
- Existing customer generation
- Embedded energy storage systems

4.7.2. Options that are Unlikely to be Feasible

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

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

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

4.7.3. Timing of Feasible Options

In order to ensure compliance with Energex's planning criteria and the National Electricity Rules, a non-network solution will need to be implemented by June 2029.

5. CREDIBLE OPTIONS

5.1. Assessment of Solutions

Energex 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 Acacia Ridge area to address the identified need.

Energex has identified two credible network options that would address the identified need.

5.1.1. Option 1: Replace two 33/11kV transformers, 11kV switchboard and secondary systems

This option is commercially and technically feasible, can be implemented in the timeframe identified, June 2029, and would address the identified need by replacing deteriorated assets at SSARG ensuring Energex continues to adhere to the applicable regulatory instruments.

This option involves recovering the two existing transformers and installing two new 25MVA 33/11kV transformers with compliant bunding, replacing the 11kV switchboard, replacing secondary systems and upgrading the substation physical security to address the identified need.

Due to the scope of works being entirely contained within the existing SSARG site, as well as the expected reliability and safety benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline.

Energex has prepared an engineering-based cost estimate for this option. The estimated capital cost of this option is $14.24 million, with an estimated completion of June 2029.

The estimated capital cost comprises the following components:

- De-commission and recover existing 11kV switchboard and replace with new 11kV switchboard.
- Recover and scrap the existing relays on CB34022, CB34032, CB3T12, CB3T22, CB1T12, CB1T22, CB1032, CB1052, CB1062, CB1082, CP11, CP12, NR1, CB3X12, and CB3X22. Install new equivalent relays in their place.
- Decommission and recover existing 33/11kV TR1 and TR2 and replace with new transformers with compliant bunding.

A schematic diagram of the proposed network arrangement for Option 1 is shown in Figure 11.

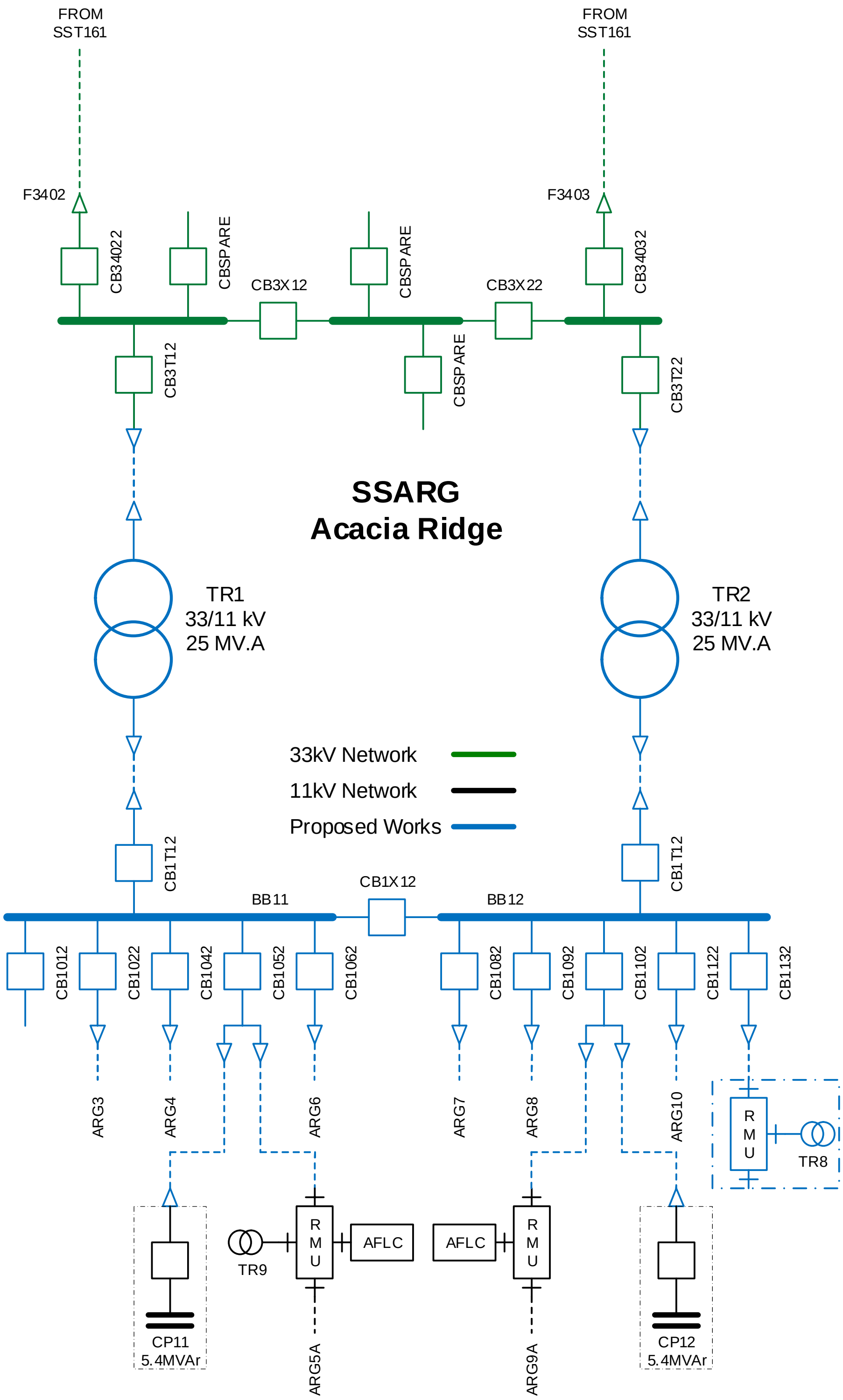

Figure 11: Option 1 proposed network arrangement (schematic view)

5.1.2. Option 2: Replace one 33/11kV Transformer, 11kV circuit breakers and upgrade 11kV feeders

This option is commercially and technically feasible, can be implemented in the timeframe identified, June 2029, and would address the identified need by replacing deteriorated assets at SSARG ensuring Energex continues to adhere to the applicable regulatory instruments.

This option involves replacing the 11kV switchboard, various protection relays, and upgrading two existing 11kV feeders to allow for more load transfers and replacing only one transformer.

The scope of works is not entirely contained within the existing SSARG site, however, due to the presence of existing distribution feeders and assets in the area, there are not expected to be social licence issues that would require additional costs to manage or increase the delivery timeline.

Energex has prepared an engineering-based cost estimate for this option. The estimated capital cost of this option is $13.89 million, with an estimated completion of June 2029.

The estimated capital cost comprises the following components:

- De-commission and recover existing 11kV switchboard and replace with new current contract equivalents 11kV switchboard.
- Recover and scrap the existing relays on CB34022, CB34032, CB3T12, CB3T22, CB1T12, CB1T22, CB1032, CB1052, CB1062, CB1082, CP11, CP12, NR1, CB3X12, and CB3X22. Install current contract equivalents in their place.
- Decommission and recover existing 33/11kV TR1 and replace with a new transformer with compliant bunding.
- Upgrade two 11kV feeders SBK21 and SBK24.
- Decommission and recover existing 33/11kV TR2.

A schematic diagram with the proposed network arrangement for Option 2 is shown in Figure 12.

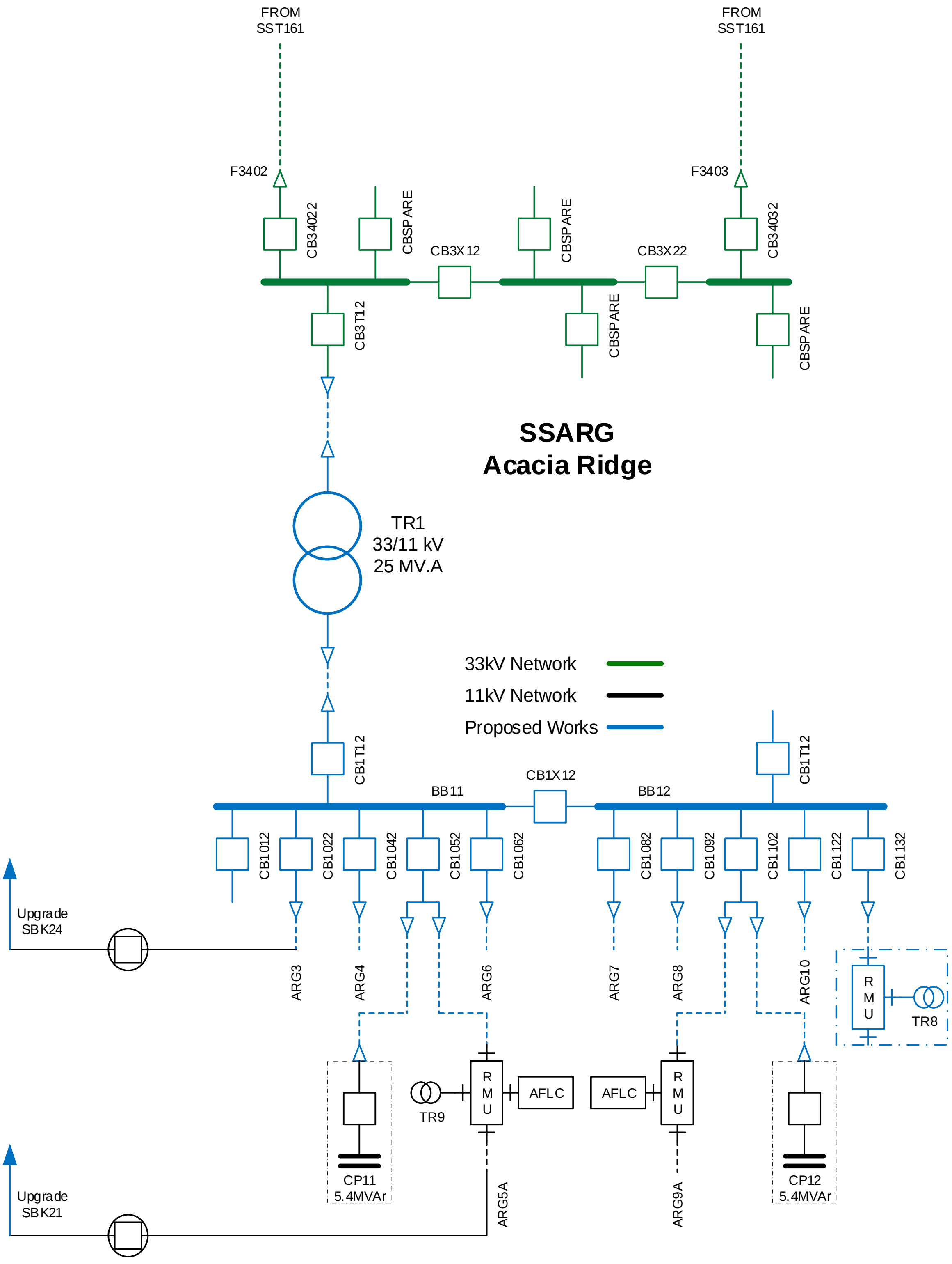

Figure 12: Option 2 proposed network arrangement (schematic view)

5.2. Assessment of SAPS and Non-Network Solutions

Energex has considered Standalone Power Systems (SAPS) and demand management solutions. Each of these are considered below.

5.2.1. Consideration of SAPS Options

Stand-alone Power Systems are off-grid systems that operate independently from the main network. It typically includes solar panels for electricity generation, a battery energy storage system (BESS) to store excess energy, and a backup generator (often a diesel generator).

Energex 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 reliability and load requirements, per the forecast of Acacia Ridge zone substation would require a system that cannot be physically installed in an urbanised area due to size, noise and emissions considerations. Furthermore, the capital and ongoing operating cost of such system is uneconomical. Therefore, a SAPS option is not technically and economically viable.

5.2.2. Consideration of Generation and Storage Options

Energex considers there is no generation and/or storage 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 reliability and load requirements, per the forecast of Acacia Ridge zone substation would require a system that cannot be physically installed in an urbanised area due to size, noise and emissions considerations. Furthermore, the capital and ongoing operating cost of such system is uneconomical. Therefore, a generation and/or storage option is not technically and economically viable.

5.2.3. Demand Management (Demand Reduction)

Energex'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 Acacia Ridge 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 Acacia Ridge. It has been determined that most demand management options will not be viable propositions and have been explored in the following sections.

5.2.4. Network Load Control

The residential customers and commercial/industrial load appear to drive the daily peak demand which generally occurs between 2:00pm and 5:00pm.

There are 1988 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 1193kVA[1] is available.

The need at Acacia Ridge is to address asset safety and reliability risks, any demand reduction needs to be permanently available. Therefore, this option has been assessed as technically not viable as it will not address the identified network requirement.

5.2.5. 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 1400 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 9941kVA.

The daily peak demand is driven by residential and commercial customer demand and the peak generally occurs between 2:00pm and 5:00pm. As such customer solar generation does not

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

coincide with the peak load period. The impact of the customer solar power systems is already included in the load profile and forecast.

Business customers with large solar arrays are deemed to present a significant opportunity for targeted load control or load curtailment if coupled with a Battery Energy Storage System (BESS). Contracting such customers is attractive as they represent a larger load across fewer customers and therefore are cheaper and easier to engage and contract.

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

5.2.6. SAPS and Non-Network Solution Summary

Energex 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 Acacia Ridge area to address the identified need.

5.3. Preferred Option

Energex's preferred option is Option 1, to replace two 33/11kV transformers, 11kV switchboard and secondary systems.

Upon completion of these works, the identified need would be addressed by replacing deteriorated assets at SSARG ensuring asset safety and reliability risks are addressed. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources.

The estimated capital direct cost of this option is $14.24 million. Annual operating and maintenance costs are estimated to be $71,209 as a result of this option.

The estimated project delivery timeframe has design commencing in November 2025 and construction completed by June 2029.

6. SOCIAL LICENCE AND COMMUNITY ENGAGEMENT

6.1. Social Licence

Energex has not identified any social licence considerations that have affected the identification and selection of credible options to address the identified need.

6.2. Community Engagement

As the scope of works for the preferred option will not extend into new areas of the community and will be entirely contained within the existing site owned by Energex, it is not expected to cause any disruption to the community at large. As a result, we have not identified any community stakeholders who might reasonably be expected to be affected by the development of this project. While Energex does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Energex Community Engagement Framework which is integrated into the project workflow.

7. MARKET BENEFIT ASSESSMENT METHODOLOGY

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

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

7.1. Classes of Market Benefits Considered and Quantified

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

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

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

Involuntary load shedding is where a customer's load is interrupted from the network without their agreement or prior warning. Energex 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 kWh 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 kWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D.

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 result 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 Acacia Ridge supply area.

7.2. Classes of Market Benefits not Expected to be Material

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

- Changes in voluntary load curtailment
- Changes in costs to other parties
- Differences in timing of expenditure

- Changes in load transfer capacity and the capacity of Embedded Generators to take up load
- Changes in electrical energy losses
- Option value
- Changes in greenhouse gas emissions
- Costs associated with social licence activities

7.2.1. Changes in Voluntary Load Curtailment

The credible options presented in this RIT-D assessment do not include any voluntary load curtailment as there are no customers on voluntary load curtailment agreements in the Acacia Ridge area. Therefore, market benefits associated with changes in voluntary load curtailment have not been considered.

7.2.2. Changes in Costs to Other Parties

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

7.2.3. Differences in Timing of Expenditure

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

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

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

7.2.5. Changes in Electrical Energy Losses

Energex does not anticipate that any of the credible options included in the RIT-D assessment will lead to any significant change in electrical energy losses.

7.2.6. 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].

[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

Energex does not consider that the identified need for the options included in this RIT-D would be affected by uncertain factors about which there may be more clarity in future.

7.2.7. Changes in Greenhouse Gas Emissions

Energex does not anticipate that the credible options included in the RIT-D assessment, which involve replacing network assets which maintain the same network configuration, would lead to any material changes in greenhouse gas emissions.

7.2.8. Costs Associated with Social Licence Activities

Energex does not anticipate that the credible option included in the RIT-D assessment will involve costs associated with social licence activities.

8. DETAILED ECONOMIC ASSESSMENT

8.1. Methodology

The Regulatory Investment Test for Distribution requires Energex 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 have 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.

8.2. Key Variables and Assumptions

The economic assessment contains anticipated costs of providing, operating and maintaining the options as well as expected costs of compliance and administration associated with each option.

The present value comparison summary includes all costs directly associated with constructing and providing the option. This includes the cost of land and easements currently owned or to be acquired for network augmentation.

Interest on borrowings is not included as a cost in the comparison of options as it represents a cost of project financing, and as such is accounted for in present value calculations through the discounting of the project cash flows at the regulated Weighted Average Cost of Capital (WACC).

8.3. Cost Estimation Methodology

Energex uses a combination of comparative and standard cost estimating methodologies, underpinned by a bottom-up approach as the basis for the estimation process.

Comparative cost estimation is based on experiences of the past and makes use of the information contained in previous proven project designs that closely match the attribute of a new project.

Standard cost estimation forms the basis of typical larger, lower volume high complexity type network projects incorporating the experience and knowledge of agreed engineered standard ways of construction of network components.

Underpinning both the comparative and standard cost estimation methodologies is a bottom-up approach that consolidates associated labour, materials, equipment, contract costs with the defined scope of works.

8.4. Quantification of Benefit for Option 1

Risk quantification analysis has been completed for option 1 which includes the value of customer reliability and cost of emergency replacement. Figure 13 shows the benefits of Option 1 in comparison to the counter-factual, which in this case is continuing the use of the existing circuit breakers and maintenance and operation. The benefit of this option is greater than $391,975 by 2033.

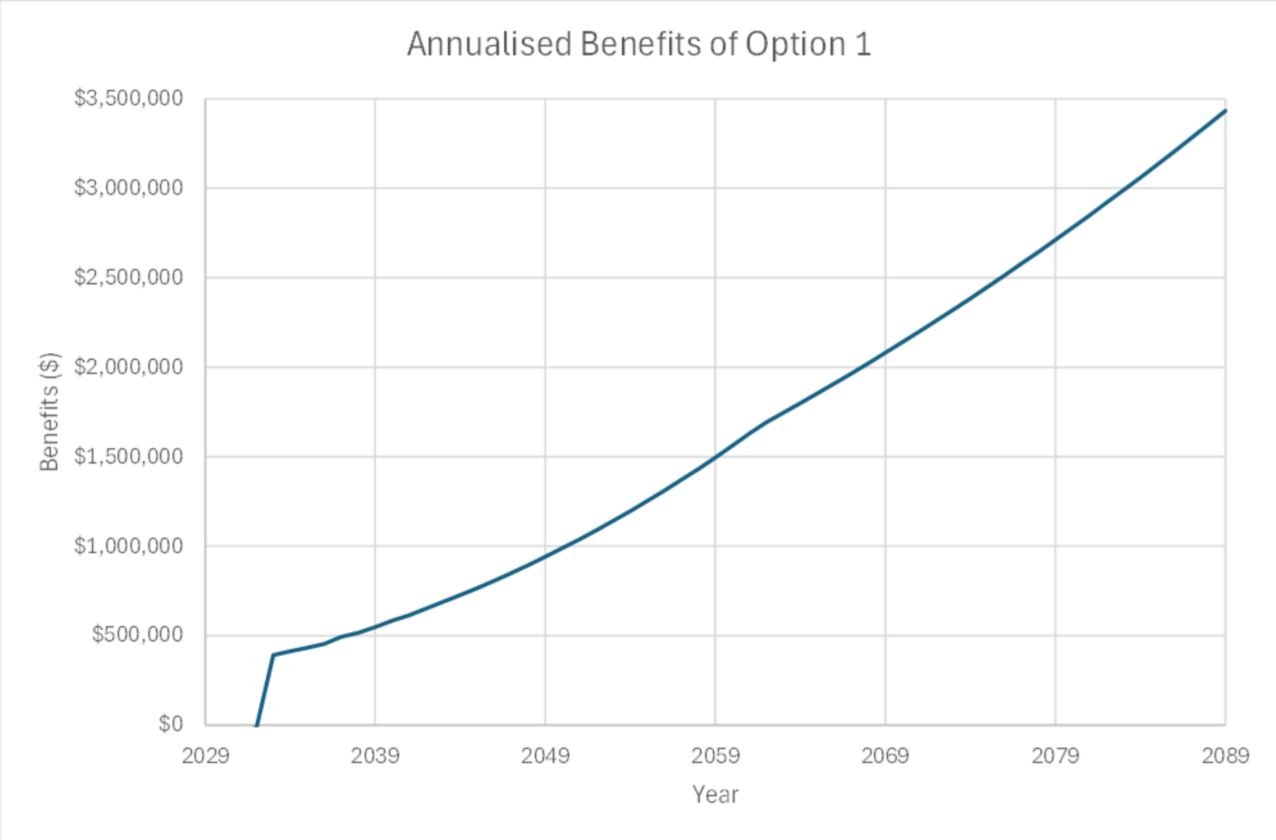

Figure 13: Annualised Benefits of Option 1 compared with Counter Factual

8.5. Net Present Value (NPV) Results

An overview of the initial capital cost and the base case NPV results are provided in Table 5.

Option	Option Name	Rank	Initial Capital Cost	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
1	Replace two 33/11kV transformers, 11kV switchboard and secondary systems	1	$14,241,872	$6,726,000	-$12,212,000	-$1,512,000
2	Replace one 33/11kV Transformer, 11kV switchboard, secondary systems and upgrade 11kV feeders	2	$13,894,771	$4,350,000	-$13,598,000	-$1,558,000

Table 2: Base case NPV ranking table

8.6. Selection of Preferred Option

Energex's preferred option is Option 1, to replace two 33/11kV transformers, 11kV switchboard and secondary systems at Acacia Ridge Substation.

Upon completion of these works, the asset safety and reliability risks at Acacia Ridge Substation will be addressed. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources. This option will address the identified need, is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

The estimated capital direct cost of this option is $14.24 million. Annual operating and maintenance costs are anticipated to be $71,209 as a result of this option. The estimated project delivery timeframe has design commencing in November 2025 and construction completed by June 2029.

8.7. Satisfaction of RIT-D

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

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

9. SUBMISSION AND NEXT STEPS

9.1. Submissions from Solution Providers

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

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

Submissions in writing are due by 4pm on the **29 August 2025** and should be lodged to demandmanagement@energex.com.au

9.2. Next Steps

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

Energex intends to publish the FPAR no later than 30 September 2025. Energex will use its reasonable endeavours to publish the FPAR by the above date. This may however not be achievable due to changing power system conditions or other circumstances beyond the control of Energex.

If at the conclusion of the RIT-D process a non-network option is identified as the preferred option, for Energex to act on a submission from a non-network proponent, Energex will need to enter into a legally binding contract with that non-network proponent for delivery of the non-network solution within a timeframe satisfactory to Energex to ensure timely completion of the project. Failure to enter into a contract within a satisfactory timeframe may result in Energex reverting to the next preferred credible option identified as part of the preferred option published in the FPAR.

Step 1	Publish Notice of No Non-network or SAPS options advising no non-network options	Date Released: **24 June 2025**
Step 2	Release of Draft Project Assessment Report (DPAR)	Date Released: **18 July 2025**
Step 3	Consultations in response to the DPAR	**Minimum of 6 weeks**
Step 4	Publish the Final Project Assessment Report (FPAR)	Anticipated to be released by: **30 September 2025**
Energex reserves the right to revise this timetable at any time. The revised timetable will be made available on the Energex RIT-D website.		

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

10. COMPLIANCE STATEMENT

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

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the Options Screening Report;	Not Applicable
(4) a description of each credible option assessed	5
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	7
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	5 & 8
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	7
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	7.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	8
(10) the identification of the proposed preferred option	8.6
(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	5.1.1, 8.6 & 8.7
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	9.1

APPENDIX A – THE RIT-D PROCESS