Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Toowoomba Network Area

Final Project Assessment Report

29 February 2024

Ergon Energy Network
Part of Energy Queensland

EXECUTIVE SUMMARY

1.1. 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.

1.2. Identified Need

Mount Sibley 33/11kV (MOSI) zone substation is located approximately 25km south of Toowoomba. The substation takes supply from South Toowoomba 110/33kV Bulk Supply Substation (SOTO).

Mt Sibley substation supplies the townships of Nobby, Greenmount and the surrounding area. Outside of Nobby and Greenmount, the supply area is primarily rural, with the customers including numerous farms. Mt Sibley Substation provides electricity supply to approximately 1,209 customers, of which 80% are residential and 20% are commercial, agricultural and industrial. Mount Sibley Substation is presently supplied via an incoming 33kV feeder from South Toowoomba Substation, and there is an outgoing 33kV feeder from Mount Sibley Substation which provides supply to Clifton 33/11kV Substation.

A preliminary evaluation of Mount Sibley Substation completed in 2022, identified primary and secondary plant and equipment recommended for retirement as assessed by Condition Based Risk Management (CBRM) analysis.

This assessment identified that two 33/11kV power transformers, one 11kV voltage transformer, eleven 33kV and 11kV isolators and three ACR controllers are at the end of their serviceable life. Additionally, a civil assessment of the structures on site also identified that the substation security fence is not compliant with AS2067 and AS1725; the transformer bunding is inadequate and does not satisfy the 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 a reliability risk to the customers supplied from Mount Sibley Substation.

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

Two potentially feasible options have been investigated:

- **Option A:** Replace both 5MVA and 3MVA 33/11kV transformers with a 5/8MVA 33/11kV transformer; replace both 33kV and 11kV buses with 33kV and 11kV RMUs respectively and install a Mobile Substation Connection
- **Option B:** Replace 5 MVA, 33/11kV transformer and 3MVA 33/11kV transformer with a 5/8MVA 33/11kV transformer and install a 33kV bus, replace 11kV bus with 11kV Rural RMU and Install Mobile Substation Connection

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 – Replace both 5MVA and 3MVA 33/11kV transformers with a 5/8MVA 33/11kV transformer; replace both 33kV and 11kV buses with 33kV and 11kV RMUs respectively and install a Mobile Substation Connection.

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 Toowoomba network area.

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

1.1. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the Toowoomba 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 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 replace both 5 MVA and 3 MVA 33/11kV transformers with a 5/8 MVA 33/11 kV transformer; replace both 33kV and 11kV buses with 33kV and 11kV RMUs respectively and install a Mobile Substation Connection.

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

Mt Sibley 33/11kV substation supplies the townships of Nobby, Greenmount and the surrounding area. Outside of the townships of Nobby and Greenmount, the supply area is primarily rural, with the customers including numerous farms. Mt Sibley Substation provides electricity supply to approximately 1,209 customers, of which 80% are residential and 20% are commercial, agricultural and industrial.

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

Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

Mount Sibley 33/11kV (MOSI) zone substation is located approximately 25km south of Toowoomba. The substation takes supply from South Toowoomba 110/33kV Bulk Supply Substation (SOTO). Mount Sibley Substation is currently supplied via an incoming 33kV feeder from South Toowoomba Substation, and there is an outgoing 33kV feeder from Mount Sibley Substation which provide supply to Clifton 33/11kV Substation.

Mount Sibley Substation was established in 1968 according to applicable design and construction standards during that time. It has an outdoor 33kV and 11kV switchyard with steel structures, one 5MVA 33/11kV and one 3MVA power transformers, and a small protection and control building. Over time, the substation was expanded with additional 11kV bays and some of the primary plants have been replaced in situ.

The 33kV bus does not contain a bus tie circuit breaker; however, there are two sets of manually operated 33kV bus isolators. The two transformer bays do not contain HV or LV circuit breakers; however, there are VTs on the 11kV side of each transformer. This arrangement impacts adversely on customer reliability.

The 33kV and 11kV bus are manually switched. The 33kV and 11kV bus contains four 33kV isolators and nine 11kV bus isolators. The 11kV bus is operated normally open, one 33/11kV transformer supplies two 11kV feeders and other transformer supplies one 11kV feeder.

Mount Sibley substation supplies three 11kV distribution feeders which contain five existing 11kV feeder ties to 11kV feeders supplied from South Toowoomba 33/11kV substation (SOTO), Kearneys Spring 33/11kV substation (KESP), Broxburn 33/11kV substation (BROX) and Clifton 33/11kV substation (CLIF). Each outgoing 11kV feeder is protected by an automatic circuit recloser (ACR).

Station services are supplied from a 25kVA 11/0.415kV local transformer, supplied off the 11kV bus.

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

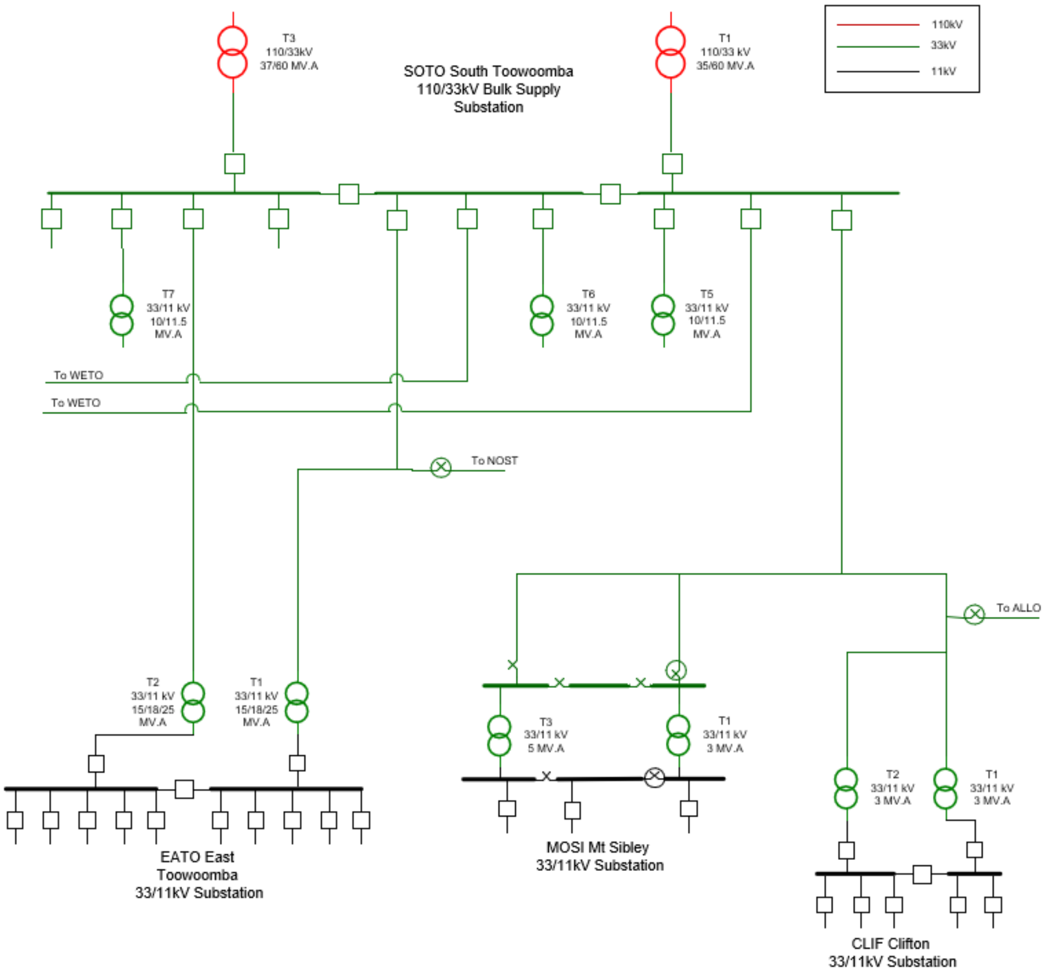


Figure 2: Existing network arrangement (schematic view)

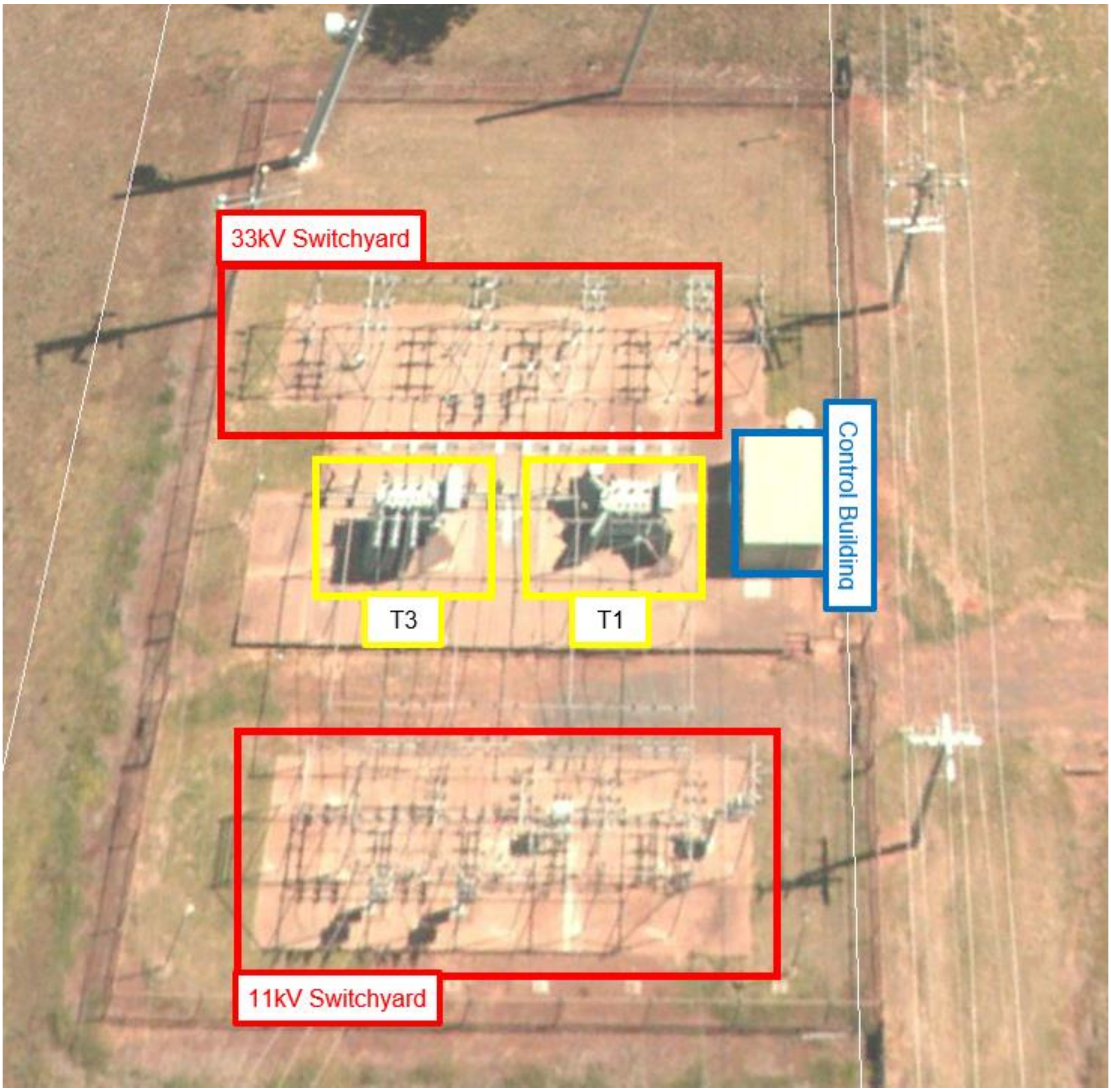


Figure 3: Mount Sibley Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at Mount Sibley Substation comprises a mix of residential and commercial/industrial customers. For the 2022/23 FY, the load has change from previous summer peaking to a winter peak signifying a move away from being predominantly driven by pumping and irrigation.

2.3.1. Full Annual Load Profile

The full annual load profile for Mount Sibley Substation over the 2022/23 financial year is shown in Figure 4. It can be noted that the peak load occurs during winter, however load is still substantial during summer.

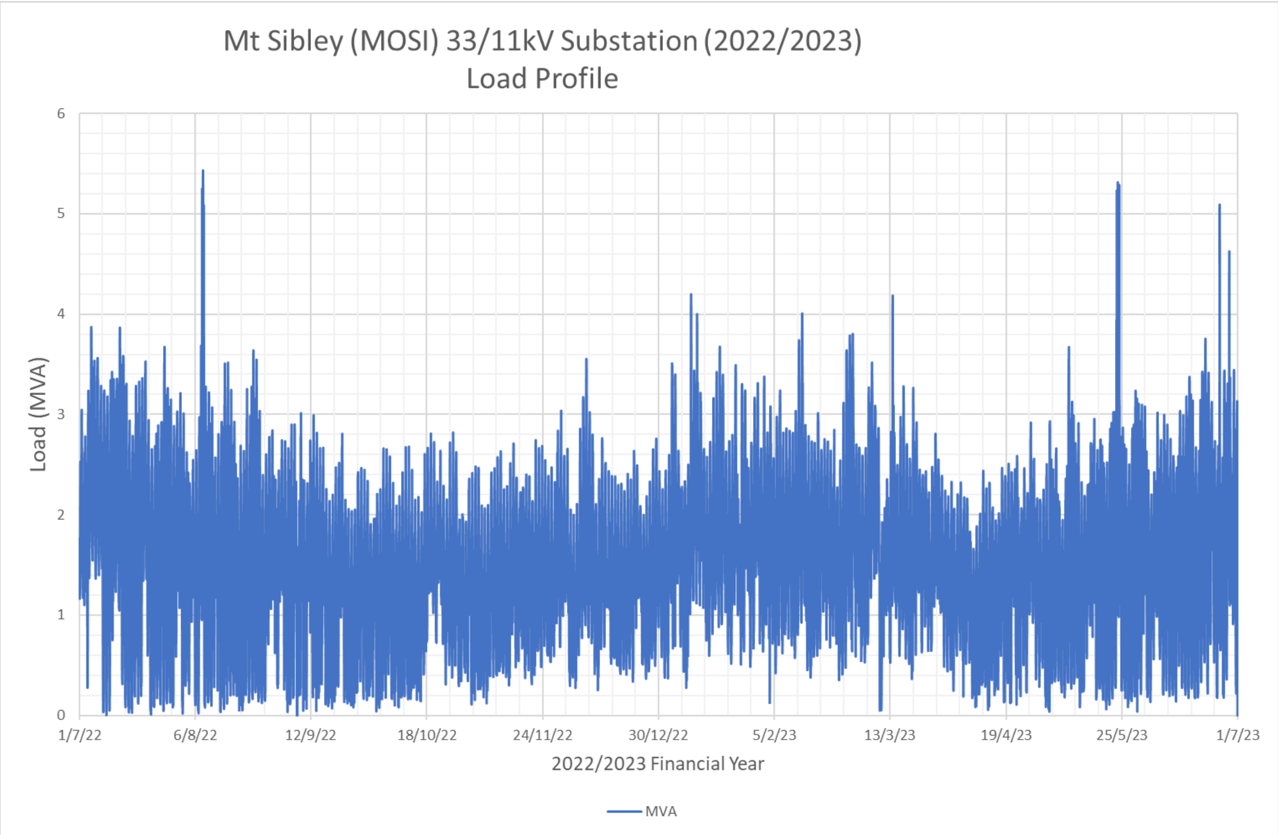


Figure 4: Substation Actual Annual Load Profile

2.3.2. Load Duration Curve

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

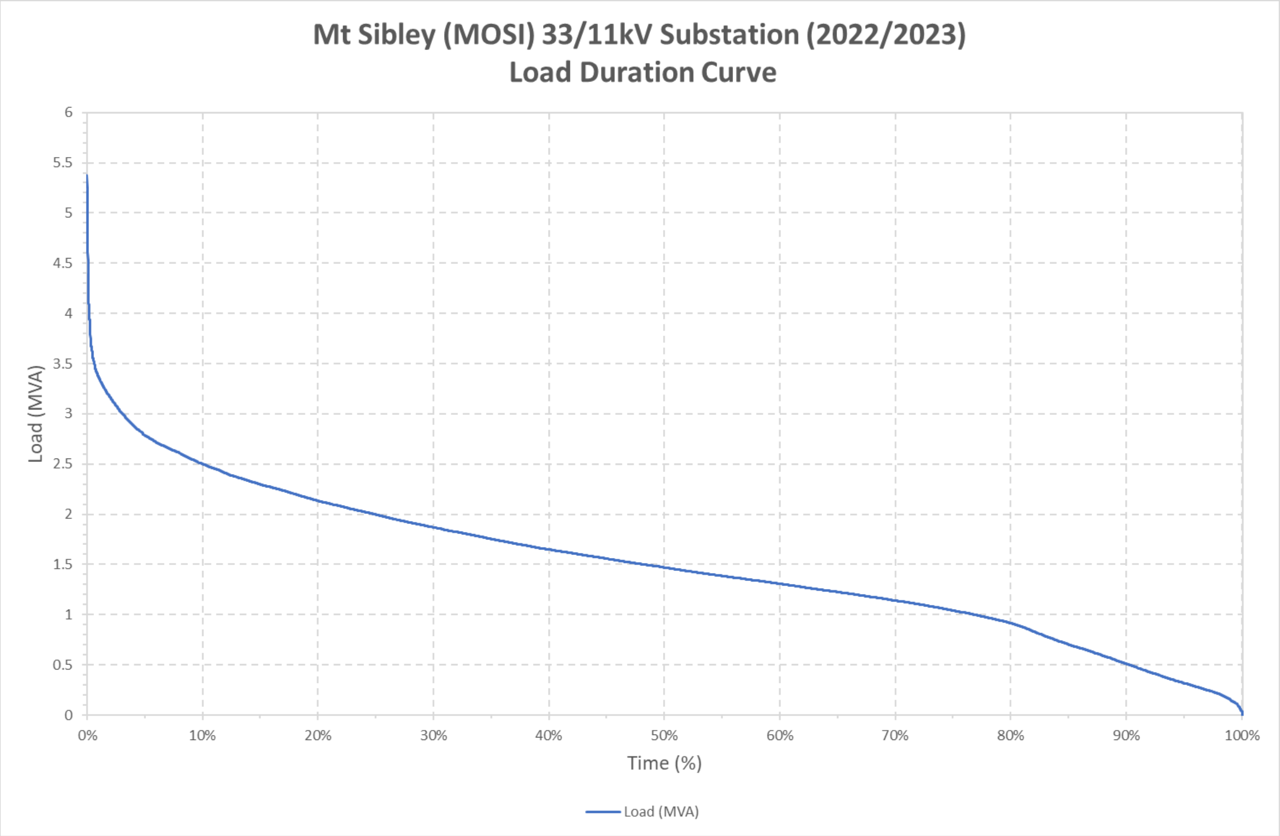


Figure 5: Substation Load Duration Curve

2.3.3. Average Peak Weekday Load Profile

The daily load profile for an average peak weekday is illustrated below in Figure 6. It is noted that historically, Mount Sibley Substation would experience summer peak loads in the late afternoon and evening. However, this behaviour has recently changed in 2022/23. Based on averages, supply is relatively even-handedly distributed during the early morning and afternoon hours with demand dropping off during normally peak mid-day hours. Peak demand has also changed to early morning hours due to agricultural activities such as irrigation.

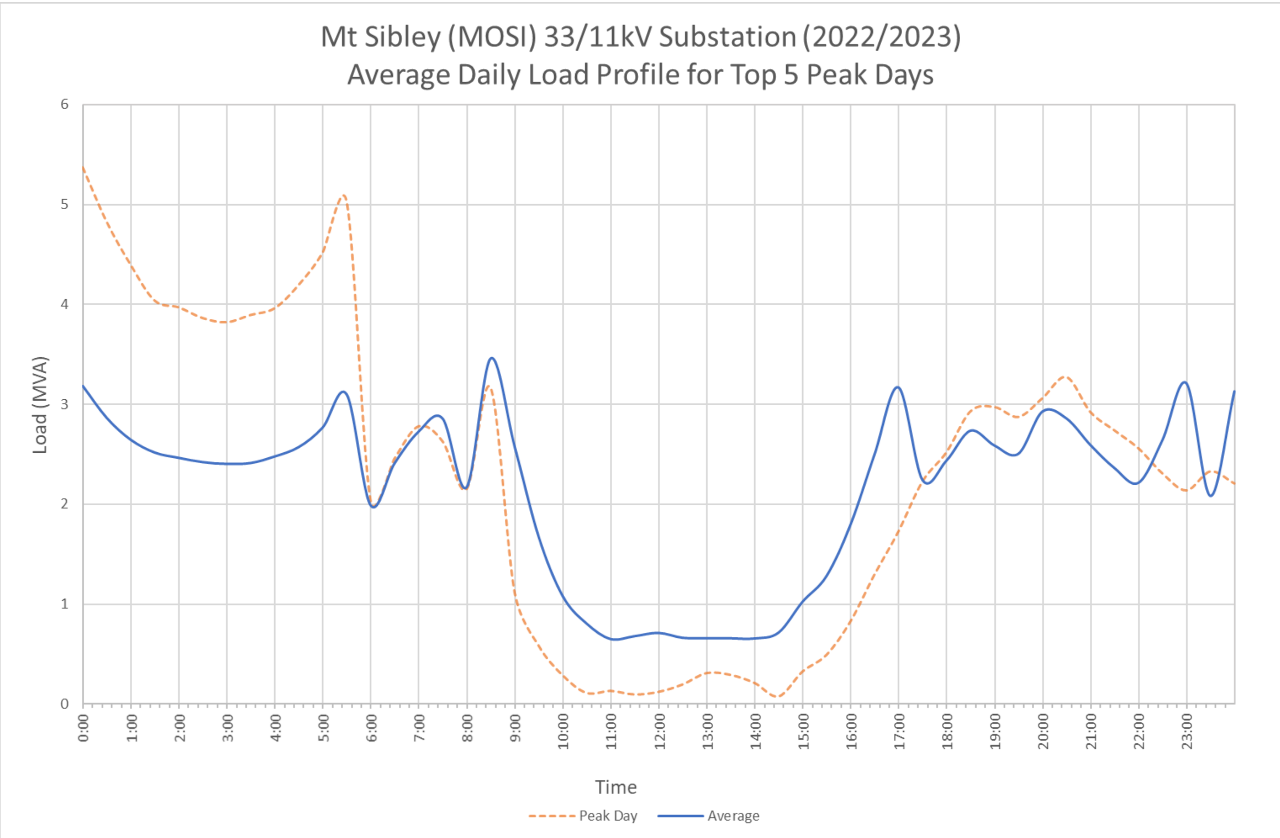


Figure 6: Substation Average Peak Weekday Load Profile

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.

Peak loads of between 4 to 5.5MVA were experienced in previous years prior to the recent peak of 5.4MVA. It is also noted that the peak load is forecast to stabilise over the next decade under the base case scenario as shown in Figure 7.

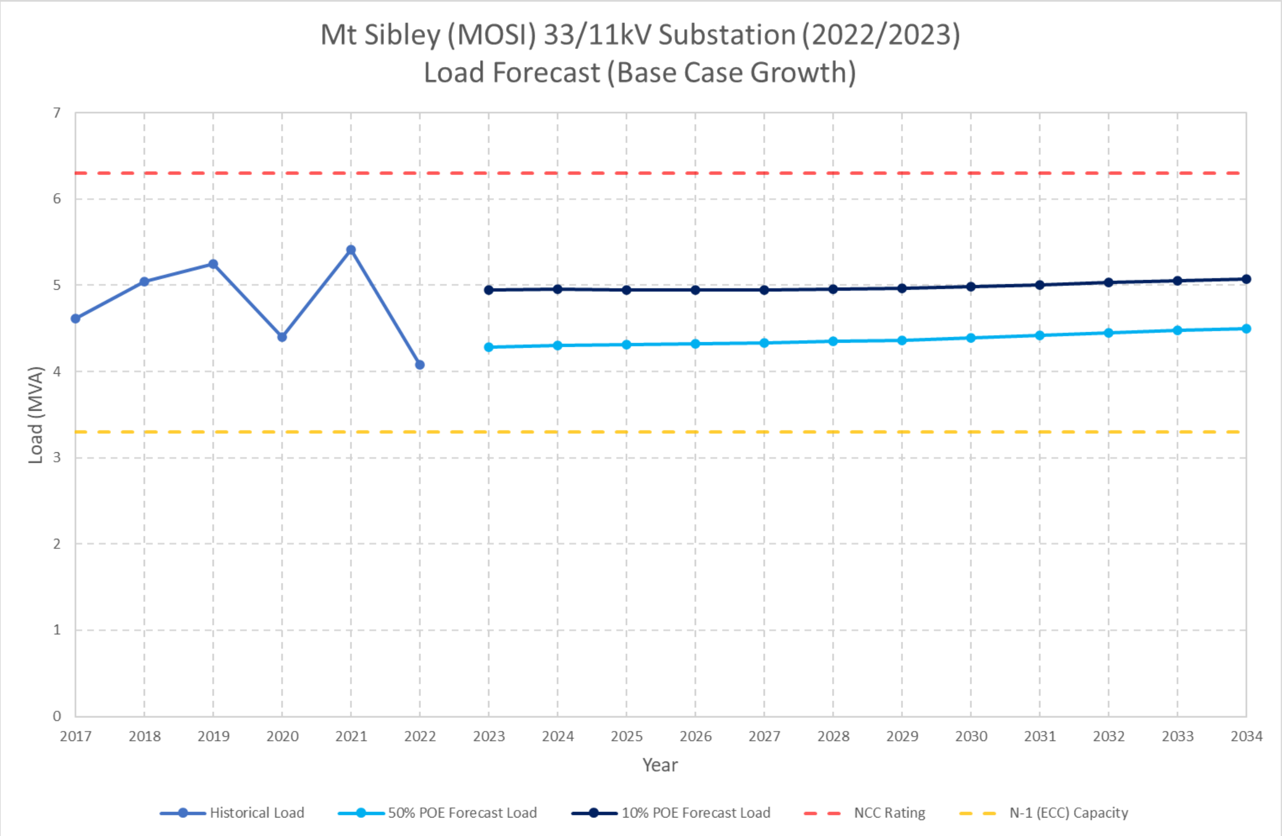


Figure 7: Substation Base Case Load Forecast

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 stabilise over the next decade.

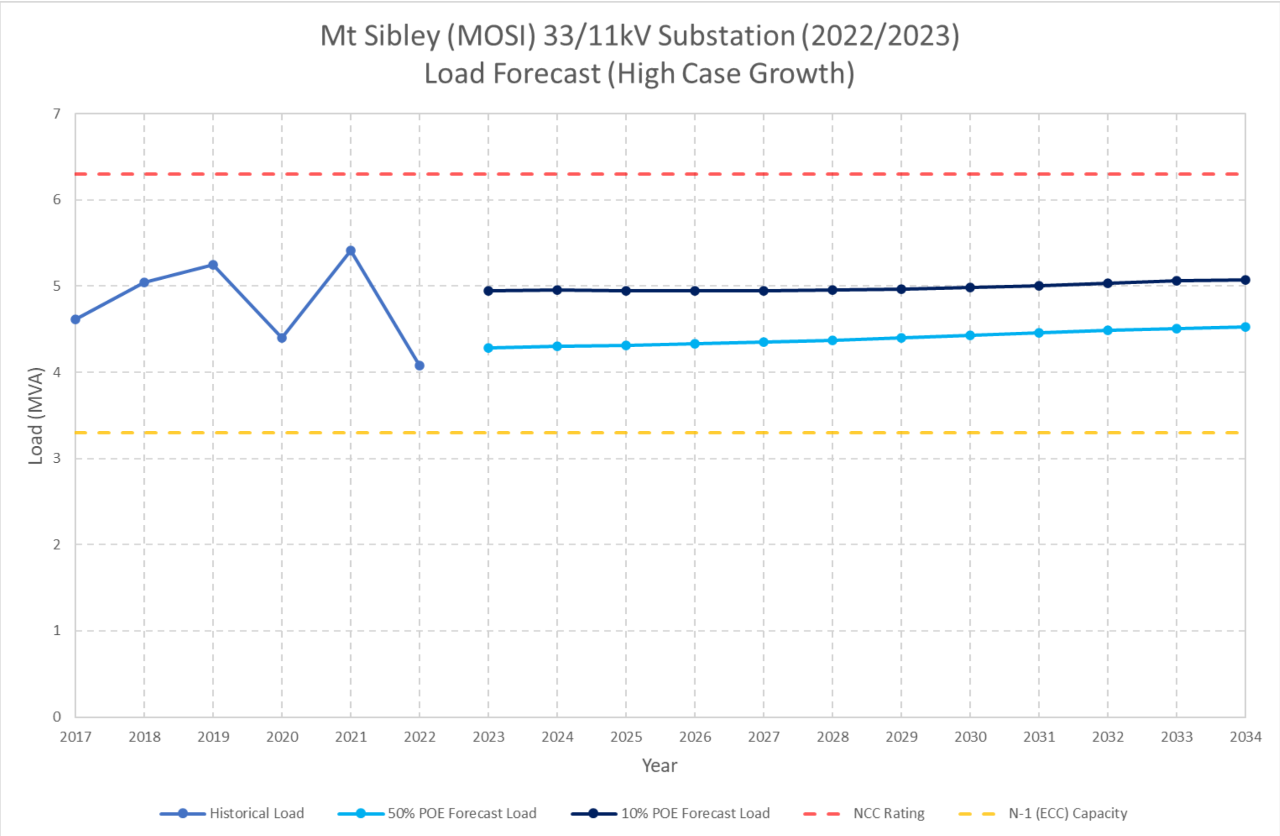


Figure 8: Substation High Growth Load Forecast

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 high growth scenario, the peak load is forecast to stabilise over the next decade.

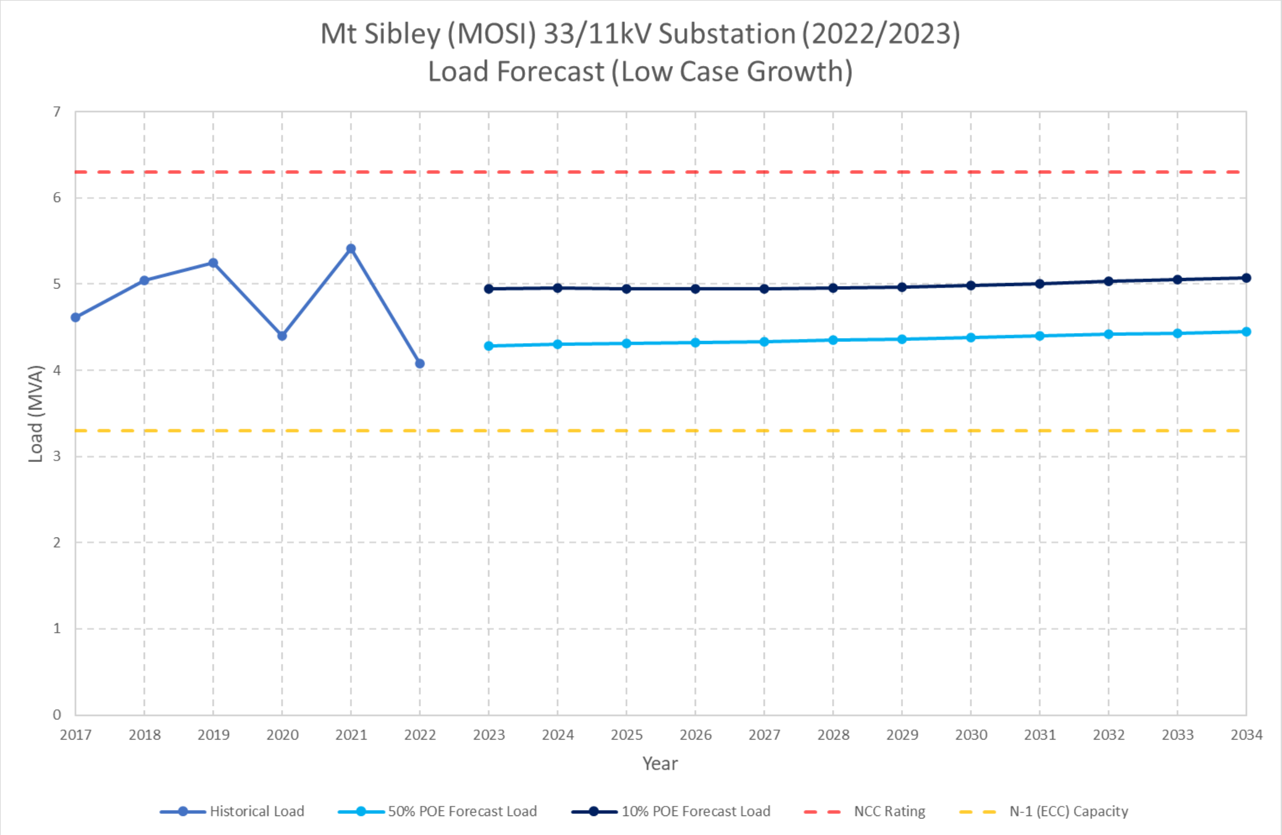


Figure 9: Substation Low Growth Load Forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Aged and Poor Condition Assets

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

Condition data indicates that the two 33/11kV power transformers, three voltage transformers and circuit breakers; as well as reclosers at Mt Sibley Substation are reaching end of life.

3.1.2. Reliability

In the 2022/23 financial year there have been several outages that have affected the operation and reliability of Mount Sibley Substation impacting ~1,132,489 customer minutes. Majority and key instances include faulty transformer tap indicator and transient circuit breaker faults.

Under the existing sub-transmission network configuration any fault within Mt Sibley Substation will result in an outage to all the customers supplied. This affects almost 1,209 customers and results in a combined peak load at risk of approximately 5MVA.

This substation's network arrangement has also contributed to a higher-than-average SAIDI and SAIFI for its short rural distribution feeders than is generally expected.

3.1.3. Safety Net Non-Compliance

Under a credible contingency event (such as for an outage of the 33/11kV 5MVA transformer (T1) at Mt Sibley Substation) benchmarked against 50% POE load, Ergon Energy will not be able to meet Safety Net restoration times as the accompanying 33/11kV 3MVA transformer (T3) does not have sufficient capacity to supply the total load of the substation.

3.2. Quantification of the Identified Need

3.2.1. Aged and Poor Condition Assets

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

Condition data indicates that the two 33/11kV power transformers, the 11kV ACR controllers and most of the 33kV and 11kV isolators at Mount Sibley Substation are reaching end of life. Additionally, a civil assessment of the structures on site also identified that the substation security fence is not compliant with AS2067 and AS1725, and the transformer bunding is inadequate and does not satisfy the 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 general public, though the increased likelihood of protection 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 Mount Sibley Substation.

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.

3.2.2. 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 Mt Sibley Substation is shown in Table 1.

Feeder	Category	Customer number	Feeder 3-year average SAIDI	Category SAIDI target	Feeder 3-year average SAIFI	Category SAIFI target
Greenmount	Short Rural	592	1,174.95	424.00	6.027	1.980
Hirstglen	Short Rural	94	1,633.29	424.00	7.186	3.950
Nobby	Long Rural	523	1,199.11	964.00	6.935	7.400

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.

3.2.3. Safety Net Non-Compliance

Mt Sibley Substation is categorised as a *Rural Area* under Ergon Energy's Distribution Authority No. D01/99.

Under a credible contingency event for the loss of the 33/11kV 5MVA transformer (T1) at Mt Sibley Substation, Ergon Energy will not be able to meet Safety Net standards as the accompanying 33/11kV 3MVA transformer (T3) does not have sufficient capacity to supply the total load of the substation.

Under this scenario it is not possible to transfer load to adjacent substations and full repair or replacement of a failed 33/11kV transformer could take up to 6 months.

Relying on mobile generation for support at short notice is a high risk due to the complex logistics involved in the deployment of mobile generation assets to Mt Sibley Substation.

Based on Ergon Energy's Safety Net contingency management plan for Mt Sibley Substation, the assessed time to deploy 5.5MVA of LV generation[1] from Toowoomba depot (including stand-up, loading, transport and phase in) is 21 hours. This is not within the 8-hour period required under the Safety Net criteria and is reflected in the figure below.

Full restoration is required within 48 hours, however the assessed time to deploy sufficient HV and LV temporary generation resources to facilitate full restoration is 60 hours[2].

3.2.4. Risk Quantification

Risk quantification analysis has been completed for Option A which includes the VCR and cost of emergency replacement (ERC). Figure 10 shows the benefits of Option A in comparison to the counter-factual, which in this case is continuing the use of the existing transformers, circuit breakers, maintenance and operation. The benefits of this option are greater than $1M by 2082.

[1] Hire generation is dependent upon what is available in Toowoomba at the time of the outage
[2] Assuming that HV generation units are not tied up in long rural deployments or planned work

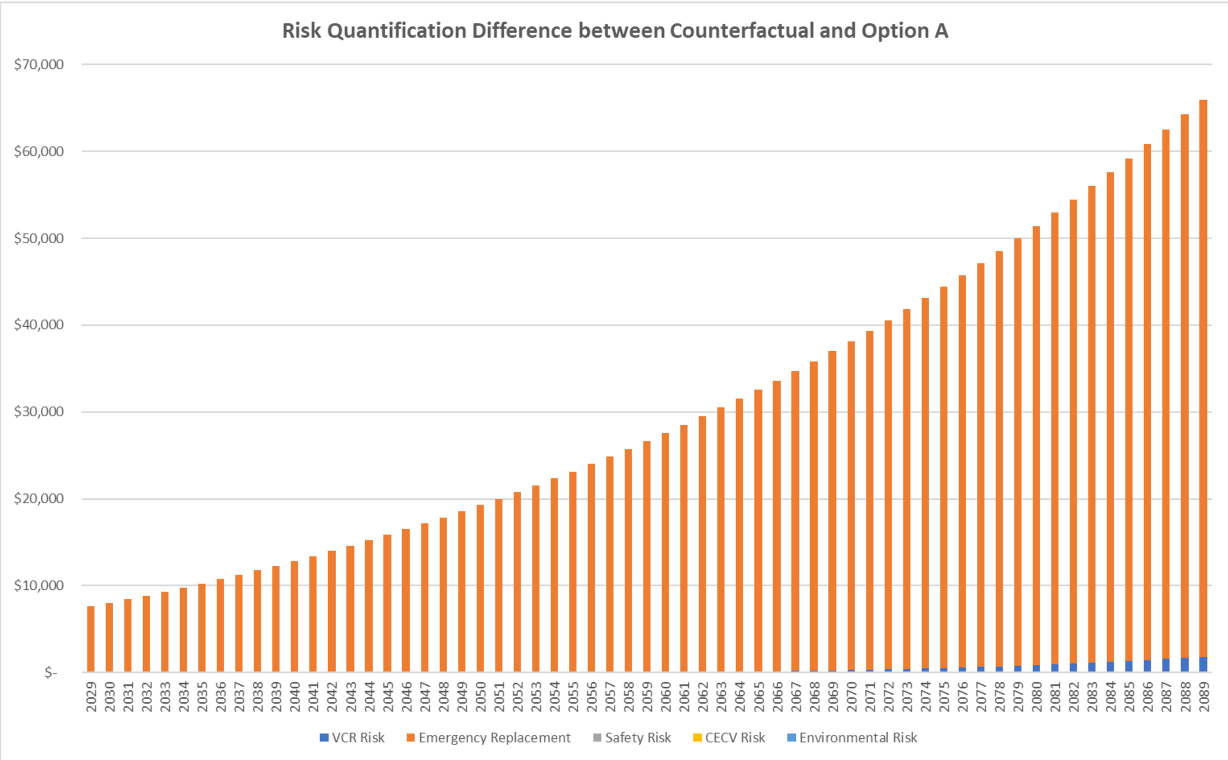


Figure 10: Annualised Benefits of Option A compared with Counter-factual

3.3. Assumptions in Relation to Identified Need

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

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

3.3.1. Forecast Maximum Demand

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

Factors that have been considered 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

The characteristic peak day load profiles shown in Section 2.3.4 for 2022/23 FY differ from previous historical trends. The seasonal demands for Mt Sibley substation have change most recently due to agricultural demands (i.e. irrigation). This most recent change in customer behaviour has seen historical peaks change from summer evenings to winter mornings.

The current 50 & 10PoE forecasts reflect a stable demand outlook, which differ from previous predictions with defined growth.

3.3.3. System Capability – Line Ratings

The thermal ratings of the limiting sub-transmission lines that supply the Mount Sibley area have been calculated based on the main parameters listed in the table below.

Parameter	Summer Day (9am – 5pm)	Summer Evening (5pm – 10pm)
Ambient Temperature	33°C	27°C
Wind Velocity	1.8 m/s	1.8 m/s
Wind Angle to Conductor Axis	45°	45°
Direct Solar Radiation	910 W/m^2	200 W/m^2
Diffuse Solar Radiation	210 W/m^2	20 W/m^2

Table 2: Line rating parameters

4. CREDIBLE OPTIONS ASSESSED

4.1. Assessment of Network Solutions

Ergon Energy has identified a number of credible network options that will address the identified need.

4.1.1. Option A: Replace both 5 MVA and 3 MVA 33/11kV transformers with a 5/8 MVA 33/11 kV transformer; replace both 33kV and 11kV buses with 33kV and 11kV RMUs respectively and install a Mobile Substation Connection

This option proposes to replace existing 33/11kV transformers with a single 5/8 MVA 33/11kV unit and associated installation works including new transformer bunding; installation of 33 and 11kV RMUs; protection system as well as mobile generation connection.

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

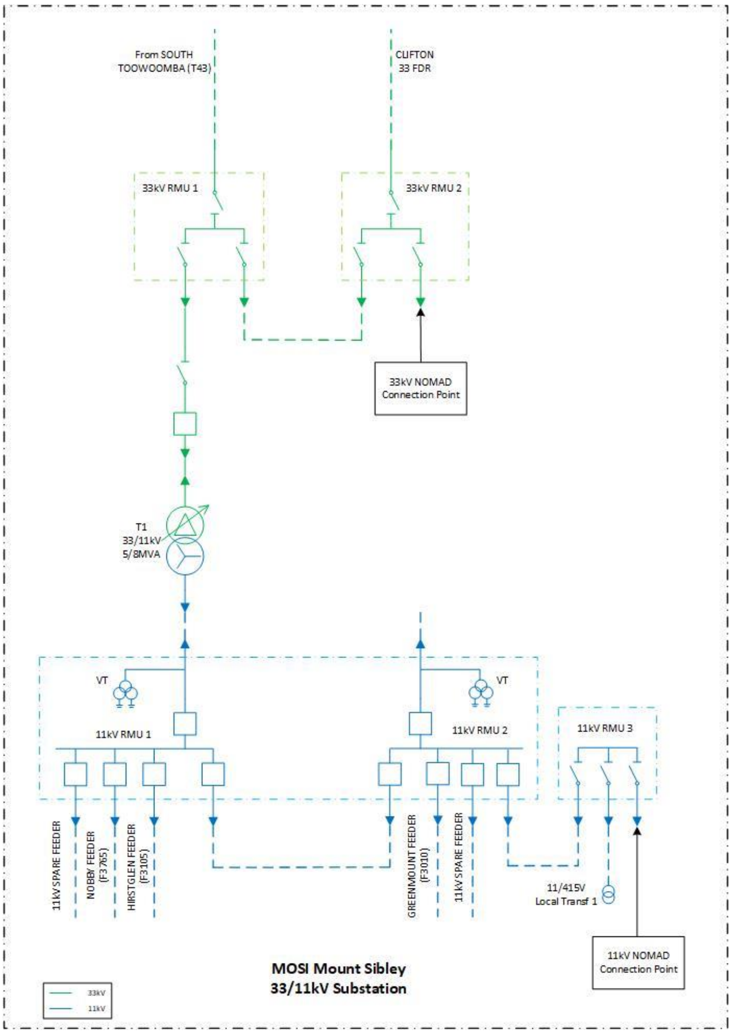


Figure 11: Option A proposed network arrangement (schematic view)

4.1.2. Option B: Replace 5 MVA, 33/11 transformer and 3 MVA 33/11kV transformer with a 5/8 MVA 33/11 kV transformer and install a 33kV bus, replace 11kV bus with 11kV Rural RMU and Install Mobile Substation Connection

This option involves recovering the two existing transformers and installing a new 5/8MVA 33/11kV transformer with compliant bunding and dedicated recloser; in addition, installing 33kV reclosers on the line; replacing the 11kV bus with RMUs; install secondary systems and mobile generation connection.

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

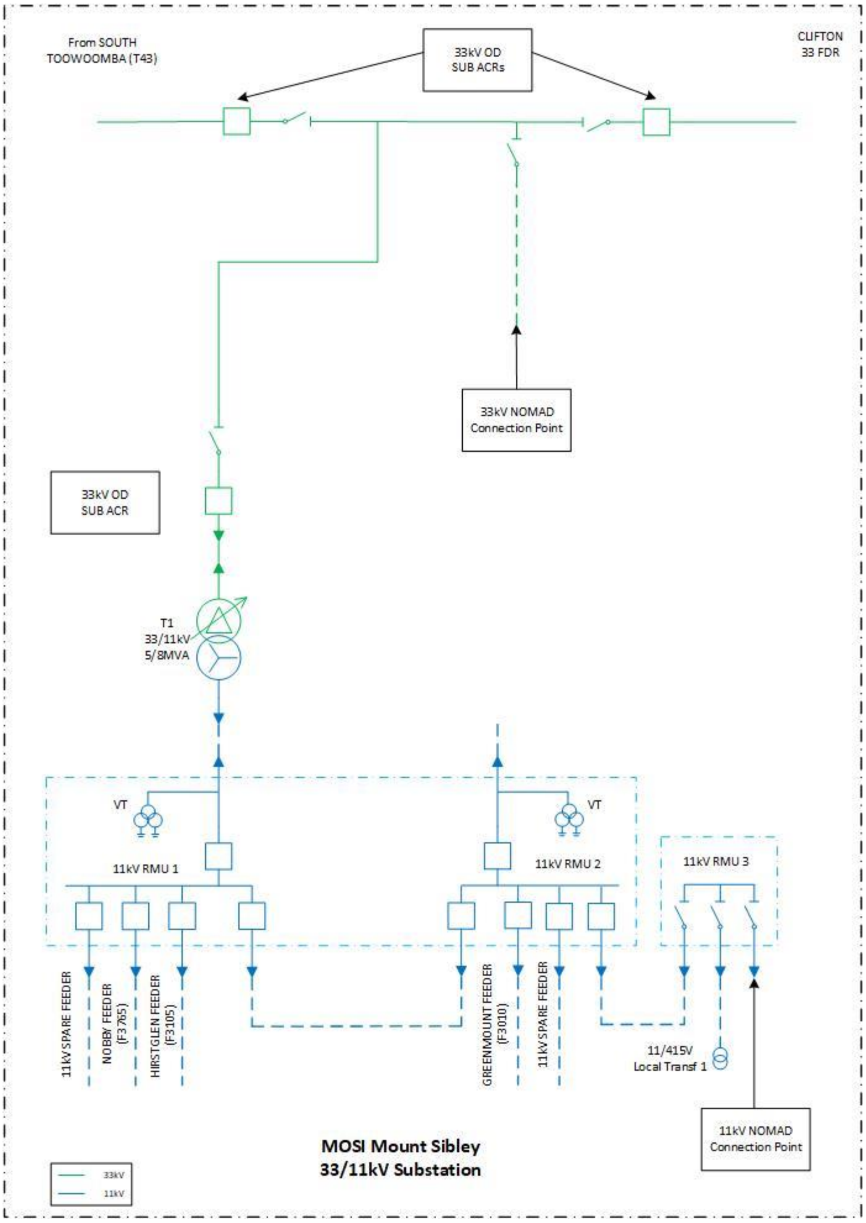


Figure 12: Option B proposed network arrangement (schematic view)

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 Toowoomba region could not be supported by a network that is not part of the interconnected national electricity system.

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 Mount Sibley 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 Mount Sibley. It has been determined that most demand management options will not be viable propositions and have been explored in the following sections.

4.2.3. Network Load Control

The residential customers and irrigation load appear to drive the daily peak demand which generally occurs between 10:00pm and 6:00am.

There are approximately 1,209 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 342kVA[3] is available.

Mount Sibley Substation LC signals are controlled from South Toowoomba Bulk Supply Substation (SOTO). The Tariff 33 and 31 hot water LC channels are dynamic (that is, it responds to exceedance settings not on a timetable) and the current control strategy only calls LC when the load at South Toowoomba Bulk Supply Substation exceeds 60MW. This strategy does not directly address demand peaks experienced at Mount Sibley. Tariff 33 air-conditioning channels are under

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

manual control of the operational control centre and are used as required. Therefore, network load control would not sufficiently address the identified need.

4.2.4. 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 491 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 3,342kVA.

The daily peak demand was previously driven by residential customer demand with the peak generally occurred between 6:00pm and 8:00pm. However, the recent 2022/23 financial year has seen a change in customer behaviour with significant early morning peak between midnight and dawn, most likely driven by agricultural irrigation. 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 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.

4.2.5. 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 Toowoomba area to address the identified need.

4.3. Preferred Network Option

Ergon Energy's preferred internal network option is Option A, replace both 5MVA and 3MVA 33/11kV transformers with a 5/8 MVA 33/11 kV transformer; replace 11kV bus with 11kV Rural RMU and install a mobile substation connection at Mt Sibley Substation.

Upon completion of these works, the asset safety and reliability risks at Mt Sibley 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.

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $12 million ($9 million in direct costs). Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design commencing mid to late-2023 and construction completed by March 2028.

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

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
- Changes in load transfer capacity and the capacity of embedded generators to take up load

5.1.1. 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.

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 $37.32/kWh, which has been derived from the AER 2020 Value of Customer Reliability (VCR) values and weighted the AER estimates according to the make-up of the specific load considered.

In addition, Ergon Energy has investigated how a reduced VCR forecast going forward changes the expected net market benefits under the options. Specifically, Ergon Energy has undertaken a reduced VCR customer economic sensitivity cost analysis to review the impact upon the credible options. The results of this sensitivity analysis are illustrated in Section 7.

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 Toowoomba supply area.

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 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 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.

5.2.2. 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.

5.2.3. Differences in Timing of Expenditure

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

5.2.4. 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 [insert location here] area.

5.2.5. Changes in Network Losses

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

5.2.6. 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[4].

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.

5.2.7. Other Class of Market Benefit

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

[4] 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

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.

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	2.62%	2.5%	4.0%
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. **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. This scenario has been assigned a likelihood of 80% in the weighted average NPV.
2. **High demand** – under this scenario the only change from the Medium Growth scenario is that the high growth load forecast provided from SIFT has been used. This scenario has been assigned a likelihood of 20% in the weighted average NPV.

Low demand was not considered because the staging of projects and VCR benefit would be very similar to that of the Medium demand scenario.

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	Option Name	Rank	Initial Capital Cost	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
A	Install 5/8 MVA 33/11 kV transformer with 33kV and 11kV RMUs with Mobile Substation Connection	1	$8,858,601	$1,634,086	-$9,013,224	-$1,280,774
B	Install a 5/8 MVA 33/11 kV transformer with 33kV bus and 11kV Rural RMU with Mobile Substation Connection	2	$9,226,003	$1,677,245	-$9,380,626	-$1,332,981

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 Number	Option Name	Weighted Rank	Weighted Net Economic Benefit	Weighted Capex PV	Weighted Opex PV	Initial Capex ($)
A	Install 5/8 MVA 33/11 kV transformer with 33kV and 11kV RMUs as well as Mobile Substation Connection	1	$1,634,086	-$9,013,224	-$1,280,774	$8,858,601
B	Install a 5/8 MVA 33/11 kV transformer with 33kV bus and 11kV Rural RMU as well as Mobile Substation Connection	2	$1,677,245	-$9,380,626	-$1,332,981	$9,226,003

Table 5: Scenario Analysis - Comparison of Options

Further to the scenarios considered, a Monte-Carlo analysis simulation was undertaken on the base case project timings to assess the projects sensitivity to a change in the parameters of the NPV model. The Monte-Carlo analysis undertook 1000 simulations of all the variables. Table 6 shows the percentage of times each option was the most economical across the simulations and also the average NPV cost of all the simulations.

Option Number	Option Name	Rank 1	Rank 2	Average NPV
A	Install 5/8 MVA 33/11 kV transformer with 33kV and 11kV RMUs as well as Mobile Substation Connection	77.1%	22.9%	-$8,657,234
B	Install a 5/8 MVA 33/11 kV transformer with 33kV bus and 11kV Rural RMU as well as Mobile Substation Connection	22.9%	77.1%	-$9,027,802

Table 6: Monte Carlo Analysis for Base Case Forecast

Option A is the lowest cost option in the weighted average results across the two scenarios. Option A also has the lowest average cost and is the most economical in 75.7% of cases in the Monte-Carlo simulations.

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

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 option is Option A, replace both 5MVA and 3MVA 33/11kV transformers with a 5/8MVA 33/11kV transformer; replace both 33kV and 11kV buses with 33kV and 11kV RMUs respectively and install a Mobile Substation Connection.

Upon completion of these works, the asset safety and reliability risks at Mount Sibley 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.

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $11 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 to late 2024 and construction completed by March 2031.

7.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

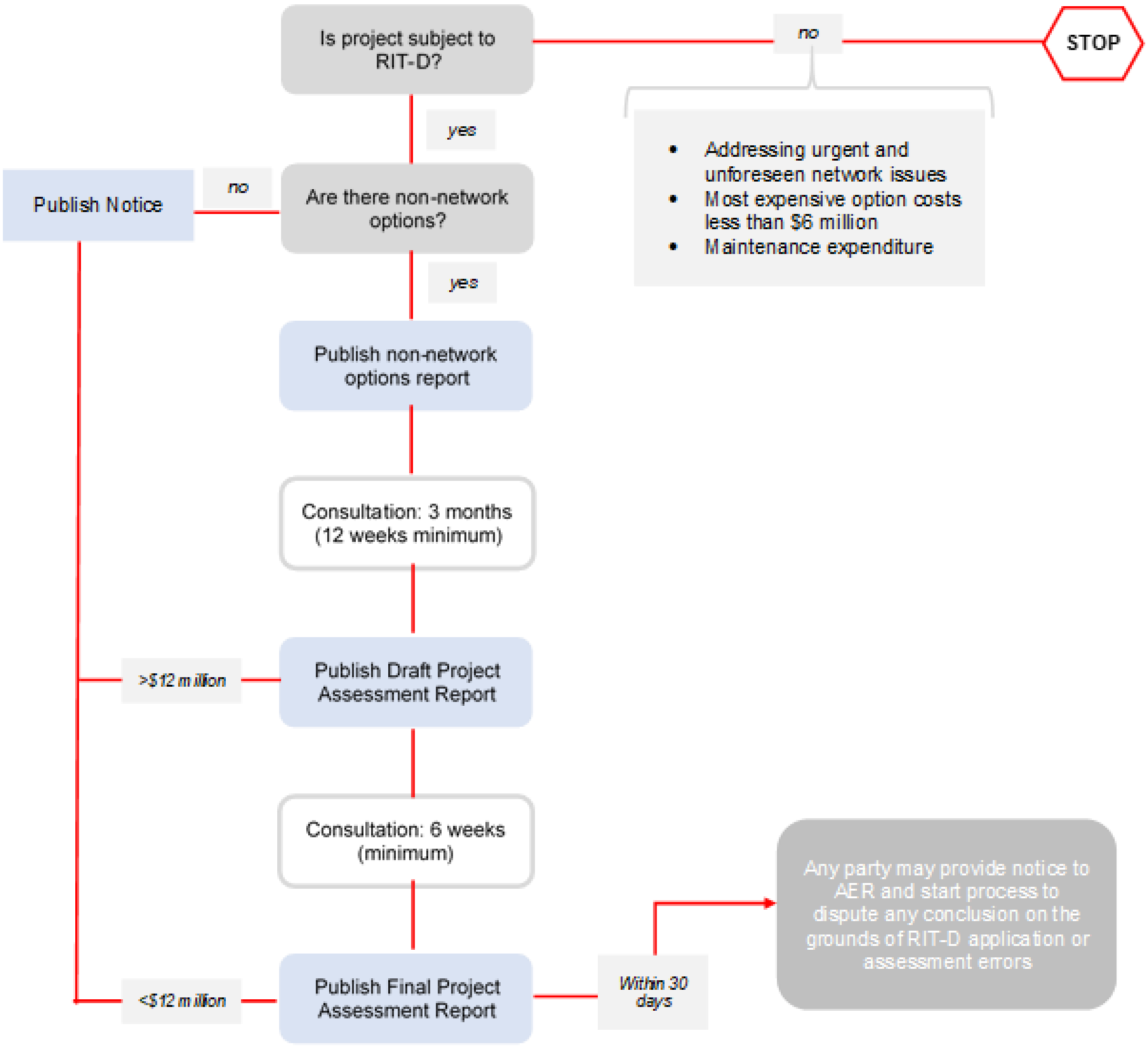
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

8. COMPLIANCE STATEMENT

This Final Project Assessment Report complies with the requirements of NER section 5.17.4(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 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	4 & 5
(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.