Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Pampas Network Area

Final Project Assessment Report

2 November 2023

Part of Energy Queensland

EXECUTIVE SUMMARY

About Ergon Energy

Ergon Energy Corporation Limited (Ergon Energy) is part of Energy Queensland and manages an electricity distribution network which supplies electricity to more than 765,000 customers. Our vast operating area covers over one million square kilometres (around 97% of the state of Queensland) from the expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

Our electricity network consists of approximately 160,000 kilometres of powerlines and one million power poles, along with associated infrastructure such as major substations and power transformers.

We also own and operate 33 stand-alone power stations that provide supply to isolated communities across Queensland which are not connected to the main electricity grid.

Identified Need

Pampas substation (PAMP) consists of two 33/11kV 5MVA transformers as well as 33kV and 11kV outdoor bus. The support structures for part of the outdoor 33kV bus and complete 11kV bus is pipework which is now more than 50 years old. The existing substation 11kV bus configuration prevents further expansion, and the 33/11kV transformers have been deemed to reach their retirement age in 2027, after almost 60 years in operation.

Millmerran 33/11kV Substation is located downstream of Pampas Substation via 33kV feeder F3530 and was previously connected via a 33kV voltage regulator R1 located at Pampas substation. Due to an internal regulator fault April 2022, Regulator R1 at Pampas is to be replaced with a pole mounted regulator in a return to service project. The regulator had originally been flagged as an identified need for replacement, however, has been removed from this scope given works will be completed before construction on this project begins. Millmerran 33/11kV Substation supplies approximately 1300 customers of which 76% are residential and 24% are commercial, agricultural, and industrial.

The 33/11kV transformers TR1 and TR3 at Pampas Substation were manufactured by AEI Engineering in 1965. Both transformers are fitted with AEI tap changers, which are considered to have good reliability. However there has been numerous oil leaks reported on the transformers which have been repaired over time. A Condition Based Risk Management (CBRM) analysis has been undertaken with the following assets deemed to reach retirement age:

- 33/11kV 5MVA transformer T1 by 2027;
- 33/11kV 5MVA transformer T2 by 2027;
- 11kV isolators are all beyond estimated retirement age.

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 Pampas 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 existing two end of life 5 MVA, 33/11kV Transformers with 5/8 MVA 33/11kV units and Replace 11kV bus with 11kV RMUs.
- **Option B:** Install a new 5/8 MVA, 33/11kV transformer, install a new 33kV Regulator and existing Transformers Run to Failure.

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 existing two end of life 5 MVA, 33/11kV Transformers with 5/8 MVA 33/11kV units and Replace 11kV bus with 11kV RMUs.

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 Pampas 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 Pampas 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 the two existing end of life 5 MVA, 33/11kV Transformers with 5/8 MVA 33/11kV units and replace 11kV bus with 11kV RMUs.

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

Pampas 33/11kV Substation (PAMP) is located approximately 60km southwest of Toowoomba. The substation is part of the Toowoomba and Southwest region 33kV sub-transmission network and takes supply from Yarranlea 110/33kV Bulk Supply Substation (YARA) via a 33kV feeder F3867.

Pampas substation supplies Pampas and the surrounding Condamine Plains, Yandilla, and Brookstead localities via four 11kV feeders. Pampas Substation provides electricity supply to approximately 630 primarily rural premise, of which 56% are residential and 44% 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.

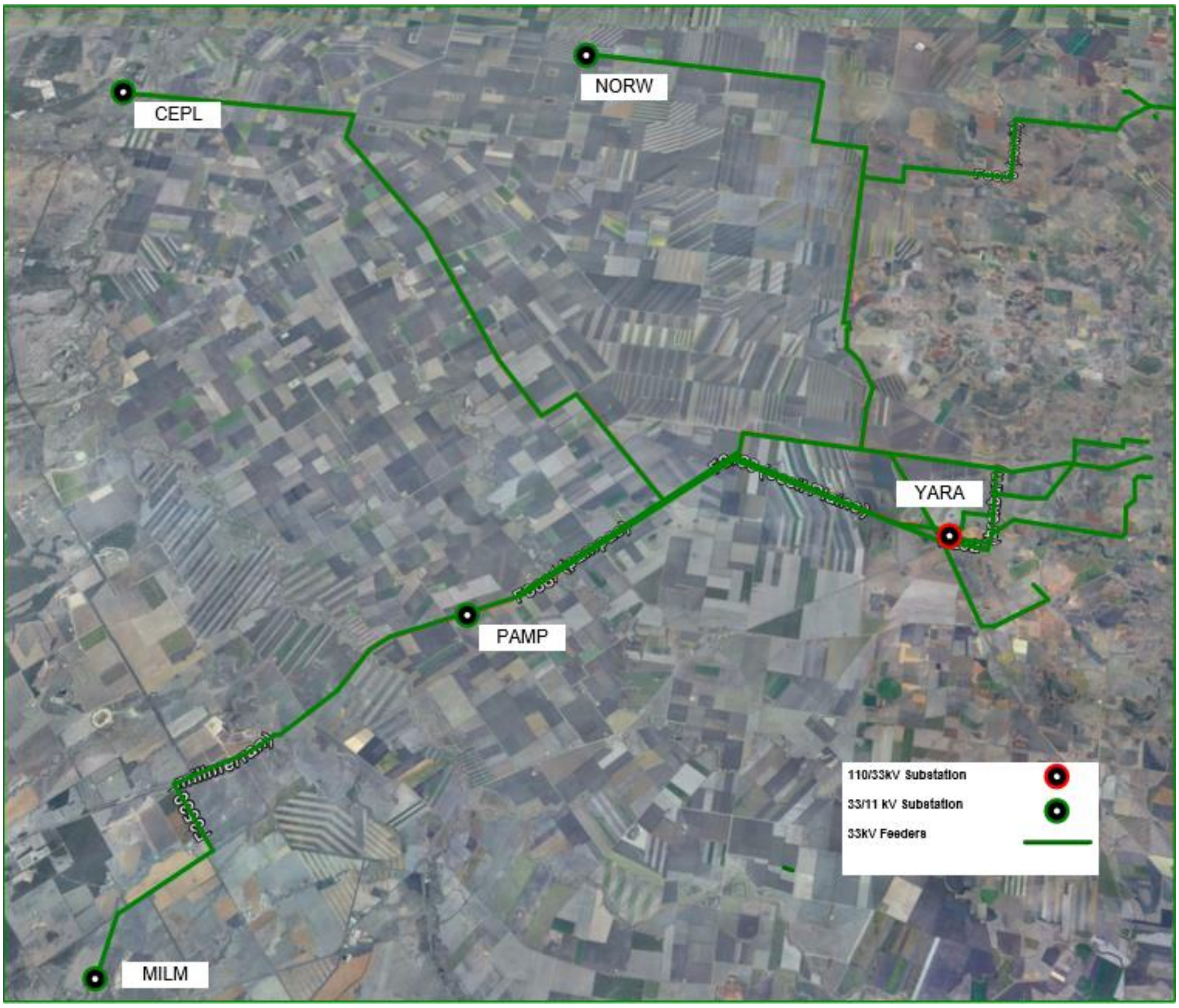


Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

Pampas 33/11kV Substation (PAMP) is located approximately 60km southwest of Toowoomba. The substation is part of the Toowoomba and Southwest region 33kV sub-transmission network and takes supply from Yarranlea 110/33kV Bulk Supply Substation (YARA) via 33kV feeder F3867. Pampas substation supplies Pampas and the surrounding Condamine Plains, Yandilla, and Brookstead localities via four 11kV distribution feeders (Anchorfield F2075, St. Ronans F4230, Yandilla F4715, Lemon Tree F3385) each protected by an automatic circuit recloser (ACR).

Pampas substation consists of an outdoor 33kV and 11kV switchyard with steel structures, two 5MVA ONAN 33/11kV power transformers, a NOMAD connection bay, and a small protection and control building. The local station services transformer is a 25kVA 11/0.415kV transformer manufactured 2012, supplied from the 11kV bus and supported by a structure below the 11kV pipe support bus structure.

There are five existing 11kV feeder ties between the four Pampas substation 11kV feeders. Three 11kV ties between F4715 and F3385, one between F4715 and F4230, and one between F4230 and F2075.

The four Pampas substation 11kV feeders also contain seven existing 11kV distribution feeder ties to Millmerran Town feeder, Brookstead feeder, Clifton West Feeder, Evanslea feeder, Haslemere feeder, and two ties to Mywybilla feeder. There is also one 12.7kV SWER tie at the end of the Yandilla 11kV feeder to Thanes Ck SWER. Pampas substations Yandilla feeder also includes a Pegasus Connection point near Kirby Rd, Leyburn.

Millmerran 33/11kV Substation is located downstream of Pampas Substation via 33kV feeder F3530 with ties into Pampas Substation and was previously connected via a 33kV voltage regulator R1 located at Pampas substation. Due to an internal regulator fault April 2022 Regulator R1 at Pampas is to be replaced with a pole mounted regulator in return to service project with a pole mounted inline regulator proposed external to Pampas substation. Millmerran 33/11kV Substation supplies approximately 1300 customers of which 76% are residential and 24% are commercial, agricultural, and industrial.

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

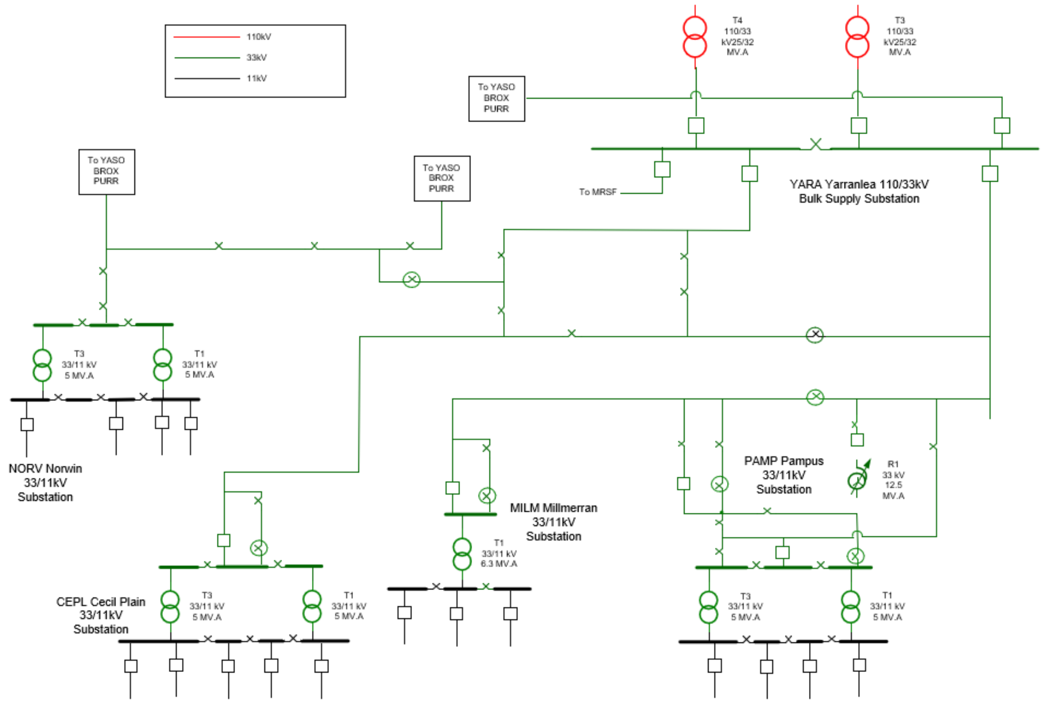


Figure 2: Existing network arrangement (schematic view)

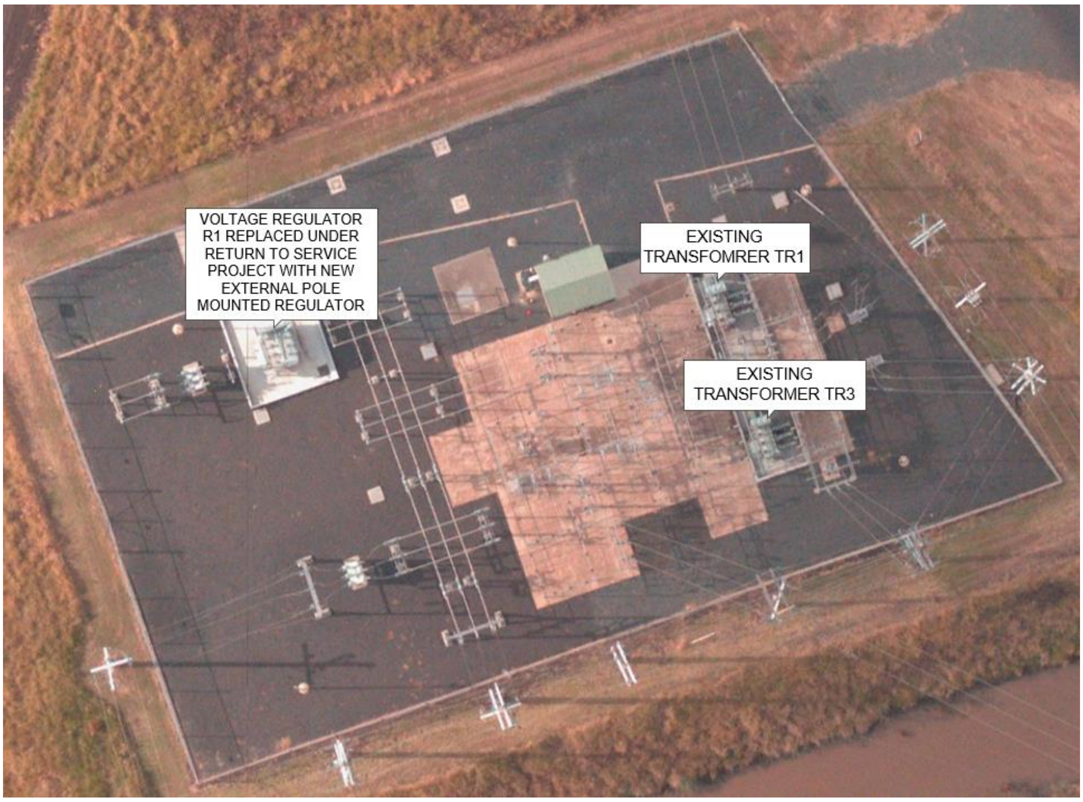


Figure 3: Pampas Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at Pampas Substation comprises a mix of residential and agricultural/commercial customers. The load is summer peaking, and the annual peak loads are predominantly driven by pumping and irrigation.

2.3.1. Full Annual Load Profile

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

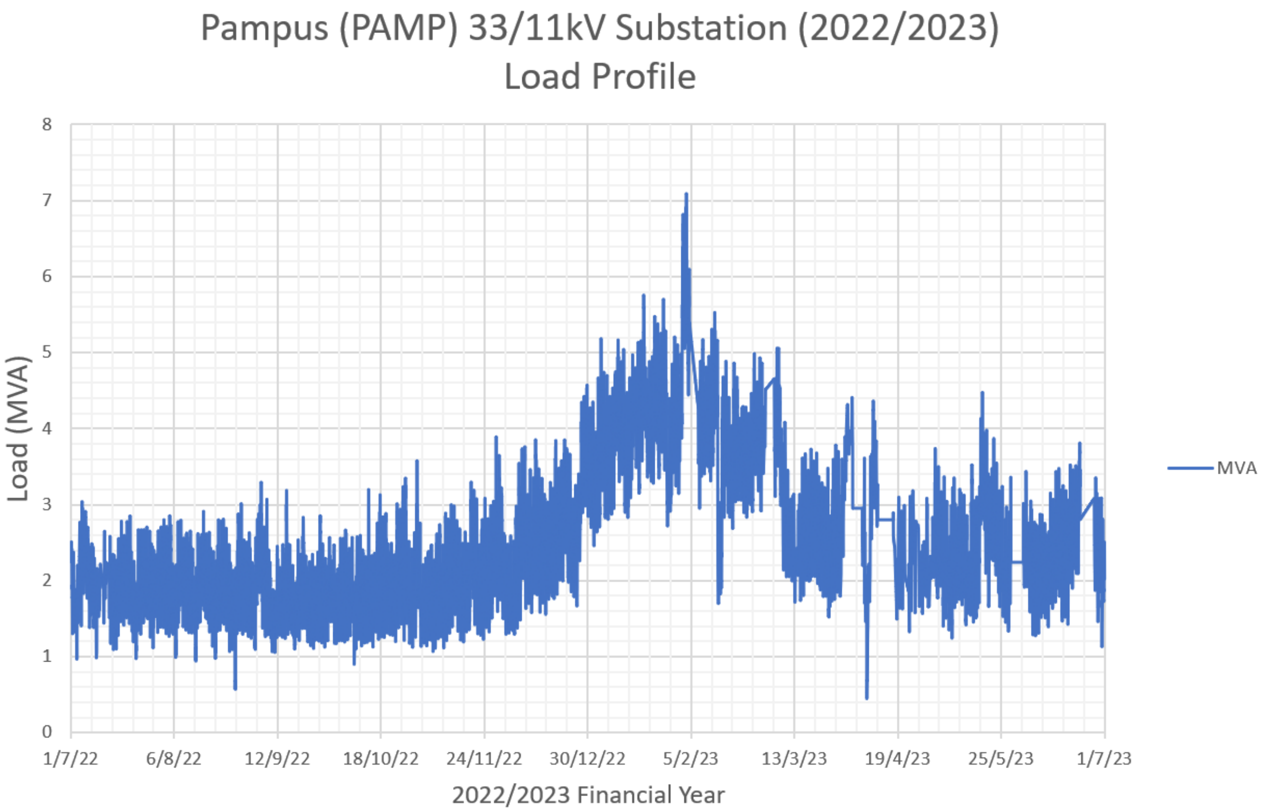


Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

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

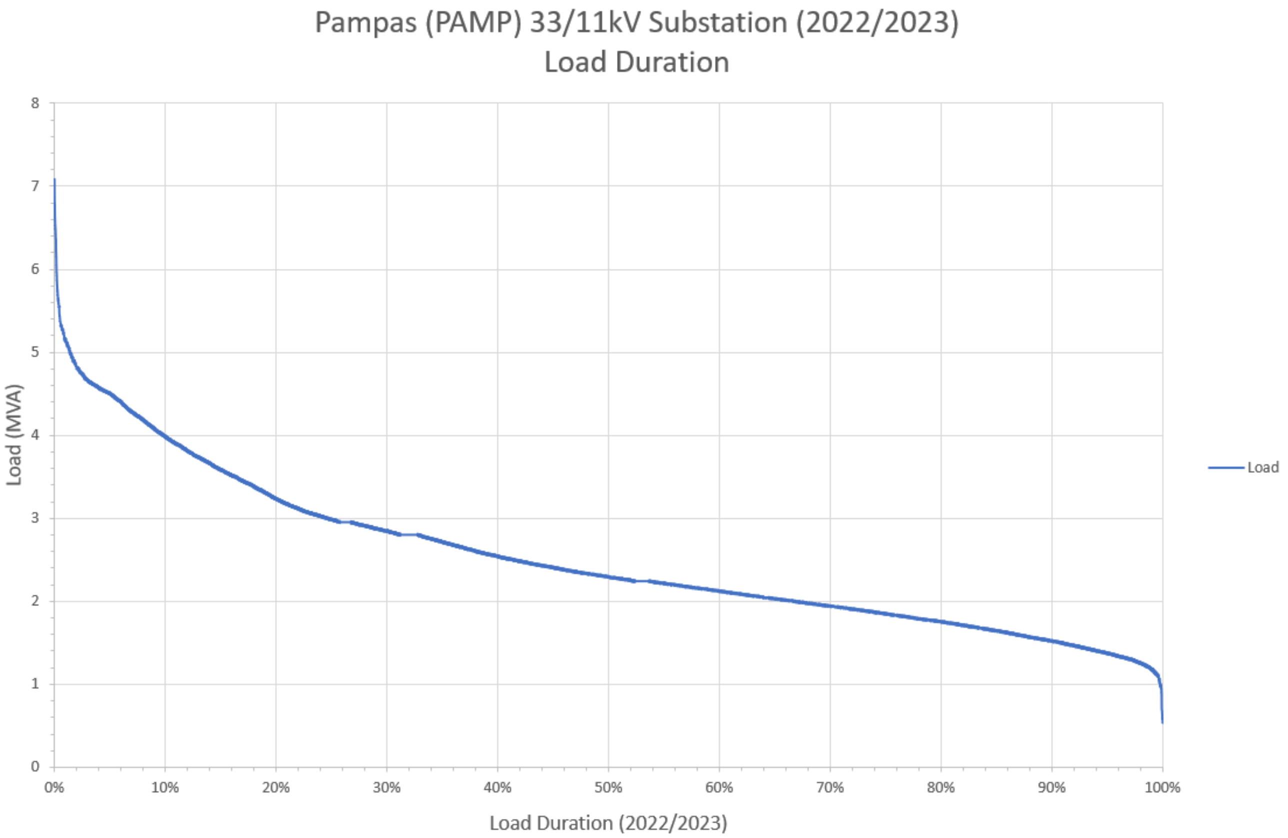


Figure 5: Substation load duration curve

2.3.3. Average Peak Weekday Load Profile (Summer)

The daily load profile for an average peak weekday during summer is illustrated below in Figure 6. It can be noted that the summer peak loads during the 2022/23 period at Pampas Substation are mornings.

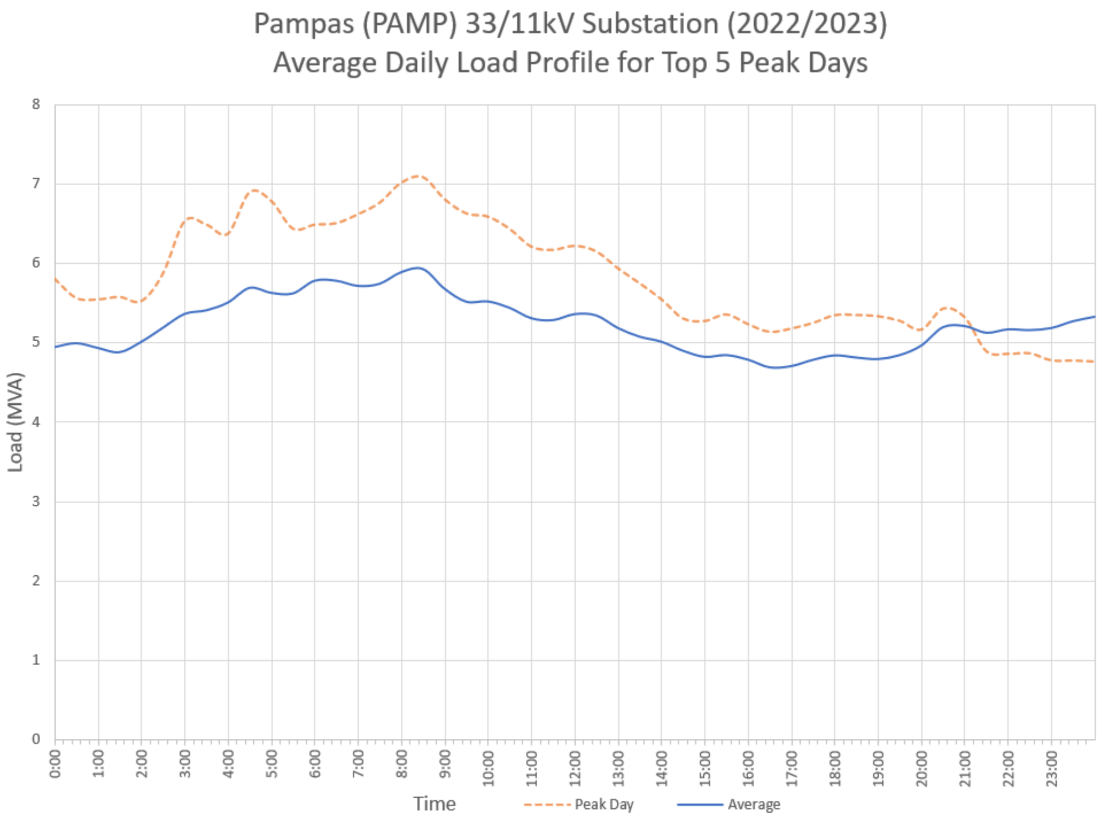


Figure 6: Substation average peak weekday load profile (summer)

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, possibly due to seasonal variation in pumping and irrigation load due to the quantity and timing of rainfall in the area. It can also be noted that the peak load is forecast to increase slightly over the next 10 years under the base case scenario.

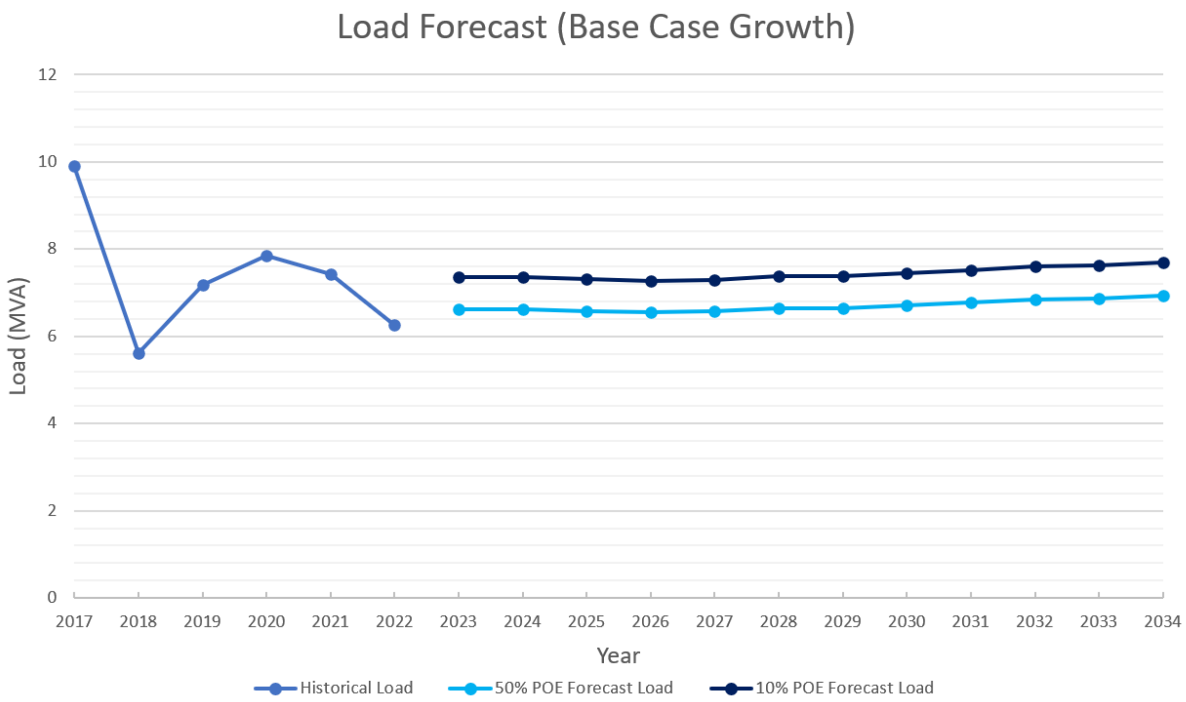


Figure 7: Substation base case load forecast

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.

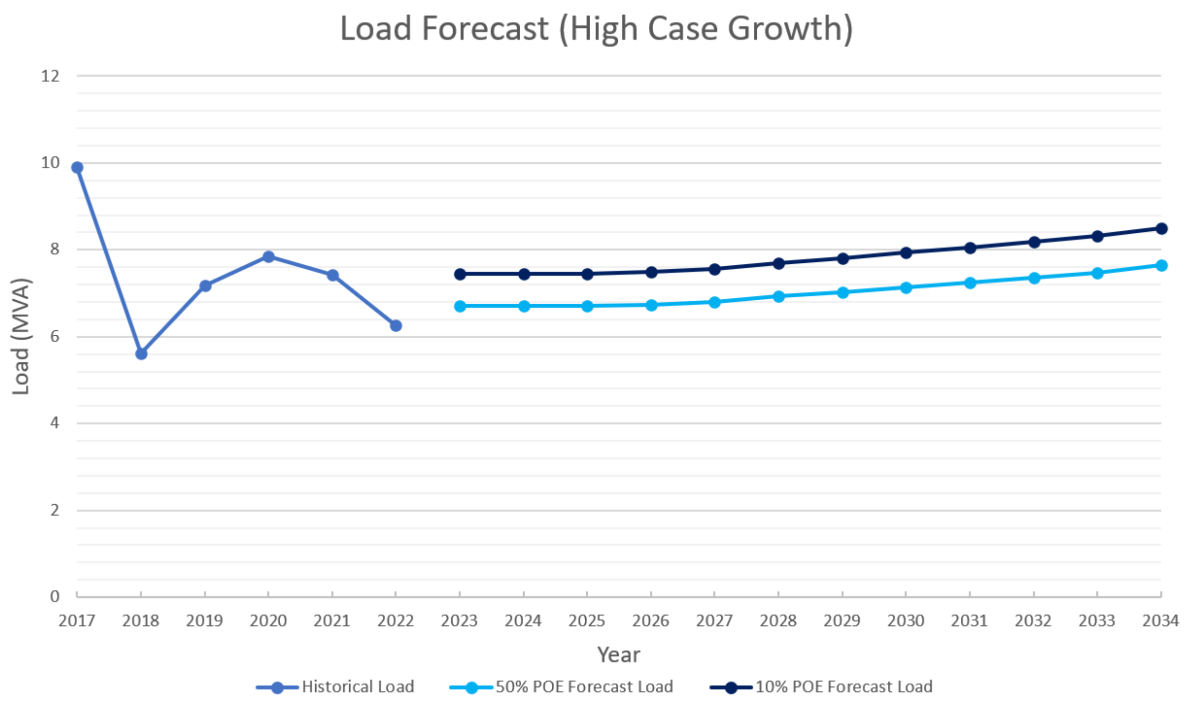


Figure 8: Substation high growth load forecast

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 remain relatively steady over the next 10 years.

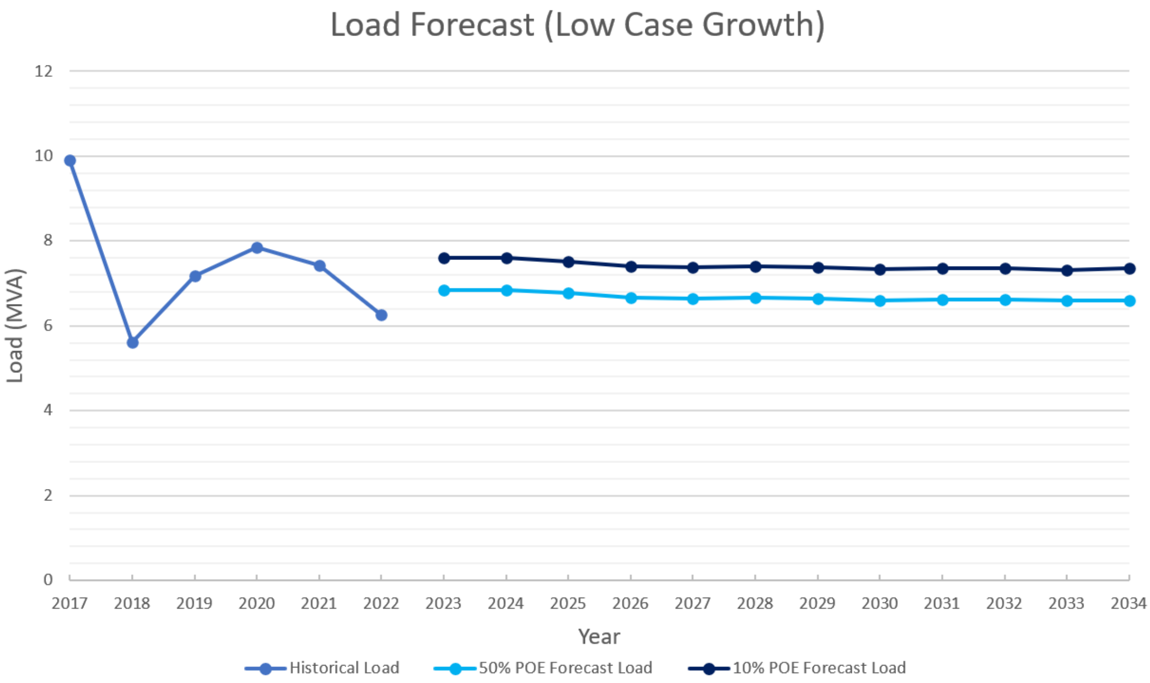


Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

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.

Based on Condition Based Risk Management (CBRM) analysis of the current condition and age on the expected life of the two existing 33/11kV power transformers they are deemed to reach retirement age by 2027, and the 11kV isolators are beyond noted retirement age. There have been numerous oil leaks reported on the transformers and repair has been completed over time. Additionally, the existing pipe work bus structure for part of the outdoor 33kV bus and the complete 11kV bus are more than 50years old, with the 11kV bus configuration preventing further expansion.

3.1.2. Reliability

Under the existing sub-transmission network configuration any fault within Pampas Substation will result in an outage to all the customers supplied from Pampas and Millmerran Substations. This affects almost 1,900 customers and results in a combined peak load at risk of approximately 10MVA.

This network arrangement has also contributed to higher than average SAIDI and SAIFI for the distribution feeders than is generally expected for a short rural network.

3.1.3. Safety Net Non-Compliance

The two existing 5MVA 33/11kV transformer arrangement, and the proposed preferred option of two new 5/8MVA 33/11kV transformers at Pampas Substation does not currently have any Safety Net breaches.

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.

Based on Condition Based Risk Management (CBRM) analysis of the current condition and age on the expected life of the two existing 33/11kV power transformers they are deemed to reach retirement age by 2027, and the 11kV isolators are beyond noted retirement age. There have been numerous oil leaks reported on the transformers and repair has been completed over time. Additionally, the existing pipe work bus structure for part of the outdoor 33kV bus and the complete 11kV bus are more than 50years old, with the 11kV bus configuration preventing further expansion.

The deterioration of these primary assets pose safety risks to staff working within the switchyard. It also poses a safety risk to the public, though the increased likelihood of 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.

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

Under the existing sub-transmission network configuration any fault within Pampas Substation will result in an outage to all the customers supplied from Pampas and Millmerran Substations. This affects almost 1,900 customers and results in a combined peak load at risk of approximately 10MVA.

This network arrangement has also contributed to higher than average SAIDI and SAIFI for the distribution feeders than is generally expected for a short rural network.

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 feeders supplied from Pampas and Millmerran Substations are shown in **Error! Reference source not found.**.

Feeder	Category	Customer number	Feeder 3 year average SAIDI	Category SAIDI target	Feeder 3 year average SAIFI	Category SAIFI target
Lemontree	Short Rural	55	1102	424	4.66	3.95
Yandilla	Long Rural	385	902	964	4.16	7.40
St Ronans	Short Rural	52	1565	424	5.50	3.95
Anchorfield	Short Rural	142	1466	424	7.38	3.95
Bringalily	Long Rural	373	1549	964	6.99	7.40
Rocky Creek	Short Rural	91	777	424	4.49	3.95
Millmerran Town	Short Rural	798	796	424	4.85	3.95

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

The two existing 5MVA 33/11kV transformer arrangement, and the proposed preferred option of two new 5/8MVA 33/11kV transformers at Pampas Substation does not currently have any Safety Net breaches under a credible contingency event for the loss of one of the 5/8MVA 33/11kV transformers. Below is the Ergon Energy Safety Net table – Interpretation Outage Times by Unsupplied Load.

Sub-transmission network type		
Regional Centre	Unsupplied Load	Allowed Outage Duration
	> 20 MVA	≤ 60 minutes
	> 15MVA ≤ 20MVA	≤ 6 hours
	> 5MVA ≤ 15MVA	≤ 12 hours
	≤ 5MVA	≤ 24 hours
	0MVA	> 24 hours (full restoration)
Rural Area	Unsupplied Load	Allowed Outage Duration
	> 20 MVA	≤ 60 minutes
	> 15MVA ≤ 20MVA	≤ 8 hours
	> 5MVA ≤ 15MVA	≤ 18 hours
	≤ 5MVA	≤ 48 hours
	0MVA	> 48 hours (full restoration)

Figure 10: Ergon Energy Safety Net Table

3.2.4. Risk Quantification Benefit Summary

Risk quantification analysis has been completed for option A which includes the financial cost of emergency replacement (ERC), safety, and value of customer reliability (VCR). Figure shows the benefits of Option A in comparison to the counter-factual, which in this case is continuing the use of the existing Transformers. The first four years of negative value reflect the risk of failure of new transformers first placed into service.

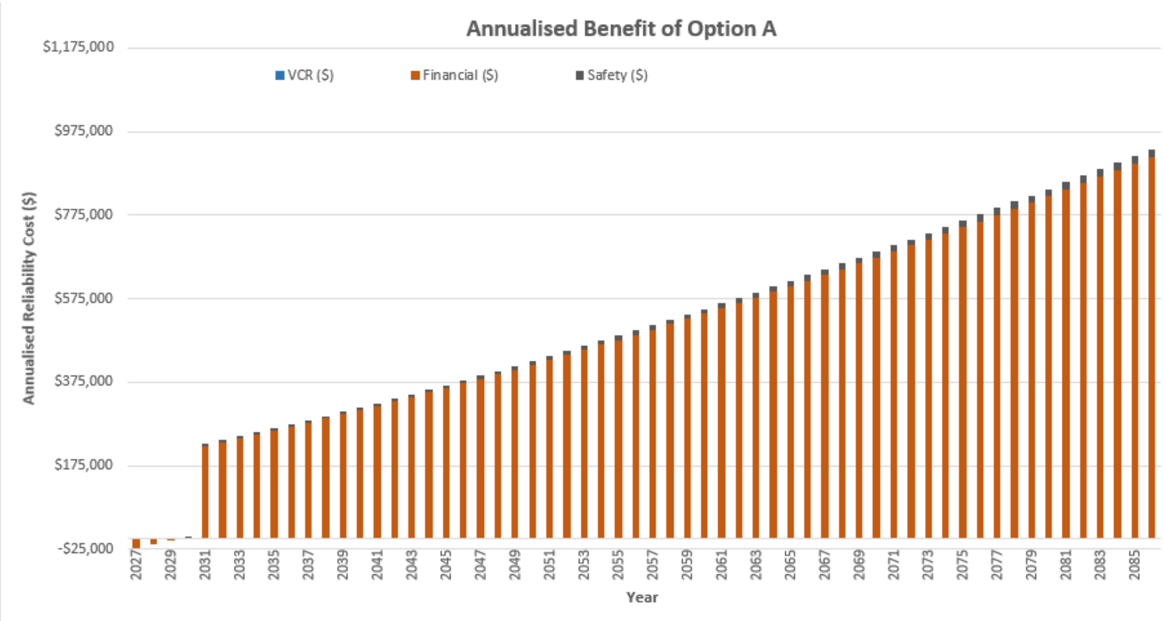


Figure 11: Annualised Benefits of Option A compared with Counter-factual

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 Pampas 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, with minor variances dependant on weather and times of irrigation. The previous year peak was during the evening, whereas the 2022/23 peak was during the morning. The shape of the load profile is assumed to remain virtually the same with peaks in mornings and evenings and with slowly increasing maximum demand year on year.

3.3.3. System Capability – Line Ratings

The thermal ratings of the sub-transmission lines that supply the Pampas 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

Below are the ratings for the limiting sections of Cecil Plains and Pampas 33kV feeders.

Feeder Name	F2460 Cecil Plains Feeder
Voltage (kV)	33
Conductor Type	Dog 6/.186"+7/.062" (6/4.72+7/1.58) ACSR/GZ 1350
Design Temp (Degree C)	50
***Ergon Energy* Climate Zone**	Central Tablelands - South
Summer Day A (MVA)	142 (8.1)
Summer Evening A (MVA)	211 (12.1)
Summer Night Morning A (MVA)	208 (11.9)
Winter Day A (MVA)	239 (13.7)
Winter Evening A (MVA)	266 (15.2)
Winter Night Morning A (MVA)	263 (15)

Table 3: Cecil Plains feeder F2460 line rating limits

Feeder Name	F3867 Pampas Feeder
Voltage (kV)	33
Conductor Type	Dog 6/.186"+7/.062" (6/4.72+7/1.58) ACSR/GZ 1350
Design Temp (Degree C)	50
***Ergon Energy* Climate Zone**	Central Tablelands - South
Summer Day A (MVA)	142 (8.1)
Summer Evening A (MVA)	211 (12.1)
Summer Night Morning A (MVA)	208 (11.9)
Winter Day A (MVA)	239 (13.7)
Winter Evening A (MVA)	266 (15.2)
Winter Night Morning A (MVA)	263 (15)

Table 4: Pampas feeder F3867 line rating limits

4. CREDIBLE OPTIONS ASSESSED

4.1. Assessment of Network Solutions

Ergon Energy has identified two (2) credible network options that will address the identified need.

4.1.1. Option A: Replace 5 MVA, 33/11kV Transformers with 5/8 MVA 33/11 kV units and Replace 11kV bus with 11kV RMUs

To address the limitation at Pampas zone substation it is proposed to replace existing 33/11kV transformers with 5/8 MVA 33/11kV units. This option also includes replacement of all pipe work bus support structures. Works include:

- Extend electric perimeter fence and earth grid to suit new installations or utilise existing substation yard if suites.
- Construct foundations for new 33/11kV transformers, 33kV circuit breakers, 33kV disconnectors, 11kV RMUs and station service transformer
- Install control building to house protection and control panels.
- Modify/Construct oil contamination tank if required and connect transformer bunding.
- Investigate the existing earth grid and improve as required.
- Recover and scrap 33/11kV transformer T1 and T2.
- Install 5/8 MVA, 33/11kV new transformers to replace T1 and T2.
- Install 33kV circuit breakers for new transformers T1 and T2.
- Install new 33kV bay for Cecil Plain 33kV feeder.
- Install 33kV disconnectors on 33kV bus as required.
- Recover and scrap 11kV bus, bus supports and reclosers.
- Install 2 X 12kV outdoor VVVVV type RMU's or equivalent to replace 11kV feeder reclosers and 11kV bus.
- Install protection panels for new transformers, 33kV and 11kV feeders.

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

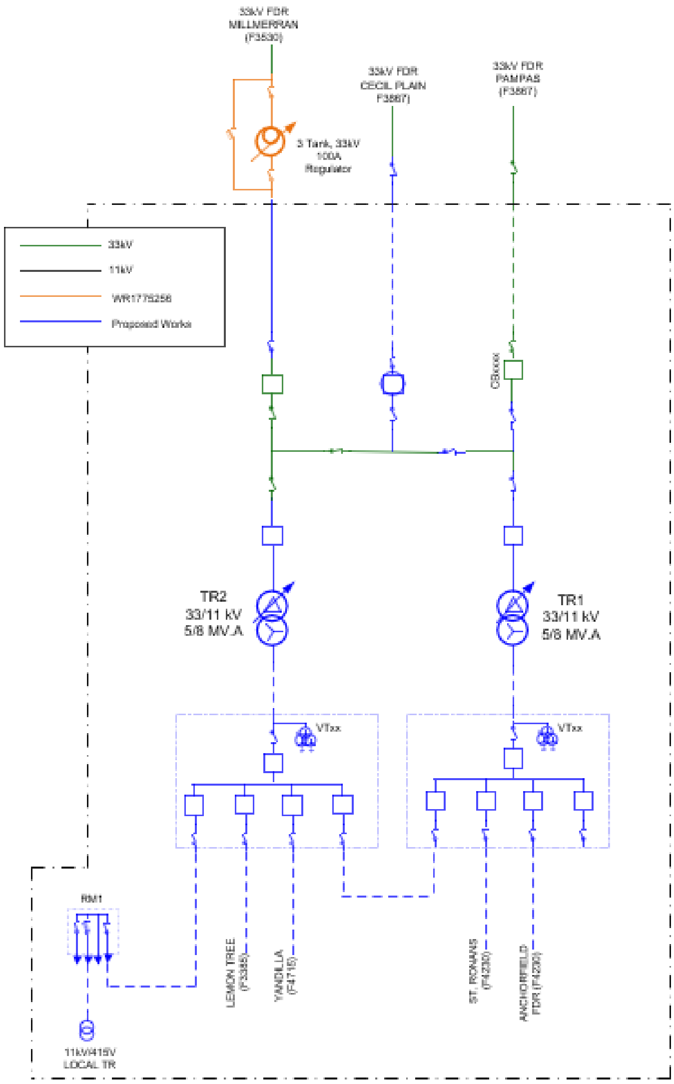


Figure 11: Option A proposed network arrangement (schematic view)

4.1.2. Option B: Install a new 5/8 MVA, 33/11kV transformer, install a new 33kV Regulator and Existing Transformers Run to Failure

This option proposes to install a new 5/8 MVA, 33/11kV transformer, install a new 33kV regulator and leave existing transformers to run to fail. Scope includes:

- Extend electric perimeter fence and earth grid to suit new installations.
- Install control building to house protection and control panels.
- Modify/Construct oil contamination tank if required and connect transformer bunding.
- Investigate the existing earth grid and improve as required.
- Construct foundations for new 33/11kV transformer, 33kV and 11kV transformer circuit breakers and 33kV regulator.
- Install 15 MVA, 33/33kV voltage regulator.

- Install a new 5/8 MVA, 33/11kV new transformer.
- Install 33kV and 11kV circuit breakers and a 33kV isolator for new transformer.
- Install 33kV and 11kV cables for new transformer.
- Install 33kV disconnector on 33kV bus for 33kV incoming feeder.
- Install protection panels for new transformers and 33kV feeders.
- Recover and scrap 11kV VTs 1VT and 3 VT. Replace 1VT and 3VT with standard units.
- Recover and scrap 33kV disconnector AB17376 and IS92902359 and replace AB17376 with a standard 33kV disconnectors.
- Recover and scrap 11kV disconnectors AB10445, AB3593, AB3594, AB3595, AB3596, AB7170, AB7171 and AB7172 with standard 11kV disconnectors.

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

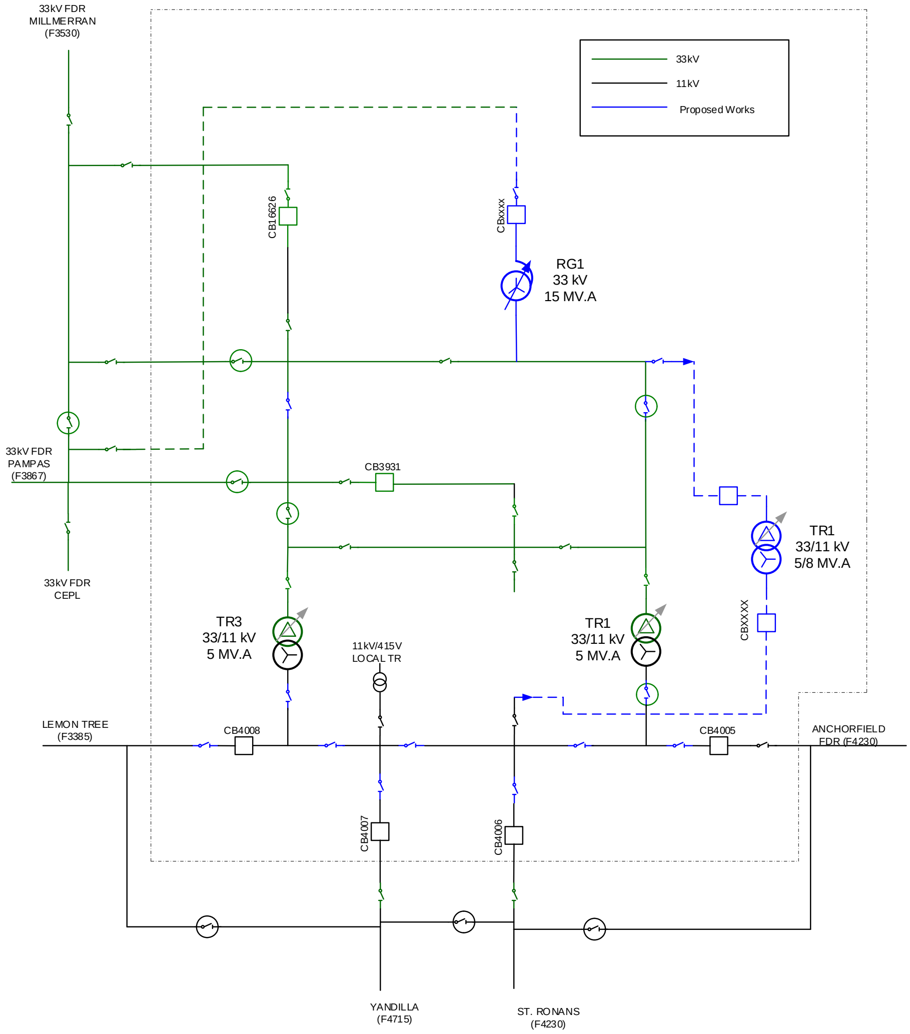


Figure 13: Option B proposed network arrangement (schematic view)

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

Network Load Control

The residential customers and irrigation load appear to drive the daily peak demand which generally occurs in the morning around 7am to 9am or the afternoon around 5pm to 7pm.

There are 263 customers on load control (LC) tariffs. An estimated demand reduction value of 157.8kVA[1] is available.

Pampas Substation LC signals are controlled from T010 Yarranlea 110/33kV Bulk Supply Substation (YARA). 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 Yarranlea Substation exceeds 23.5MW. This strategy does not directly address demand peaks experienced at Pampas. Therefore, network load control would not sufficiently address the identified need.

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

4.2.3. Demand Response

Four methods utilising demand response technology for deferring network investment are: Call Off Load (COL), Customer Embedded Generation (CEG), Large Scale Customer Generation (LSG) and customer solar power systems.

Customer Call Off Load (COL)

COL is an effective technique for deferring network investment where the need is for a short time period. However, in this instance, the need is required on a long-term permanent basis. There are a small number of large customers in the catchment area but the $/kVA funding available for demand reduction is low therefore customer call off load has been assessed as not a viable proposition as it will not address the identified need, nor benefit the community.

Customer Embedded Generation (CEG)

CEG is an effective technique for deferring network investment where the need is for a short time period. 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 177 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 2,193kVA at Pampas Substation.

The daily peak demand is driven by residential, industry and irrigation demand and the peak generally occurs in the morning around 7am to 9am or the afternoon around 5pm to 7pm. As such customer solar generation does not coincide with the peak load period.

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

However, only a small percentage of 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.

4.2.4. SAP 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 Pampas area to address the identified need.

4.3. Preferred Network Option

Ergon Energy's preferred internal network option is Option A, to install two new 5/8MVA 33/11kV transformers including required civil works, recover the two existing transformers, replace existing 11kV pipe work bus and reclosers with two new 12kV outdoor RMU's, and construct new 33kV bay for Cecil Plains 33kV feeder connection at Pampas Substation.

Upon completion of these works, the asset safety and reliability risks at Pampas 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 $10.385 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 2024 and construction completed 2027.

5. MARKET BENEFIT ASSESSMENT METHODOLOGY

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

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

5.1. Classes of Market Benefits Considered and Quantified

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

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

The options presented, particularly the preferred option provides improved reliability in comparison to the counter-factual with expected decrease in plant failure and therefore results in reduced involuntary load shedding.

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

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

Ergon Energy has applied a VCR estimate of $34.51/kWh, which has been derived from the AER 2022 Value of Customer Reliability (VCR) values. In particular, Ergon Energy has weighted the AER estimates according to the make-up of the specific load considered.

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 Pampas 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 Pampas 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[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

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.

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.

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.

6.3. Net Present Value (NPV) Results

An overview of the initial capital cost and the base case NPV results are provided in Table 3.

Option	Option Name	Rank	Initial Capital Cost	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
A	Replace existing two (2) 5 MVA, 33/11kV Transformers with 5/8 MVA 33/11 kV units and Replace 11kV bus with 11kV RMUs	1	$9,475,346	$18,481,760	-$7,912,644	$0

B	Install a new 5/8 MVA, 33/11kV transformer, install a new 33kV Regulator and Existing Transformers Run to Failure	2	$6,950,374	$16,292,093	-$5,804,098	-$76,354

Table 3: Base case NPV ranking table

Based on the detailed economic assessment, Option A although having a higher initial capital cost provides the most Net Economic Benefit and is therefore considered to provide the optimum solution to address the reliability requirements and forecast limitations at Pampas Substation. Option A 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, to install two new 5/8MVA 33/11kV transformers including required civil works, recover the two existing transformers, replace existing 11kV pipe work bus and reclosers with two new 12kV outdoor RMU's, and construct new 33kV bay for Cecil Plains 33kV feeder connection at Pampas Substation.

Upon completion of these works, the asset safety and reliability risks at Pampas 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 $10.385 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 2024 and construction completed 2027.

7.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

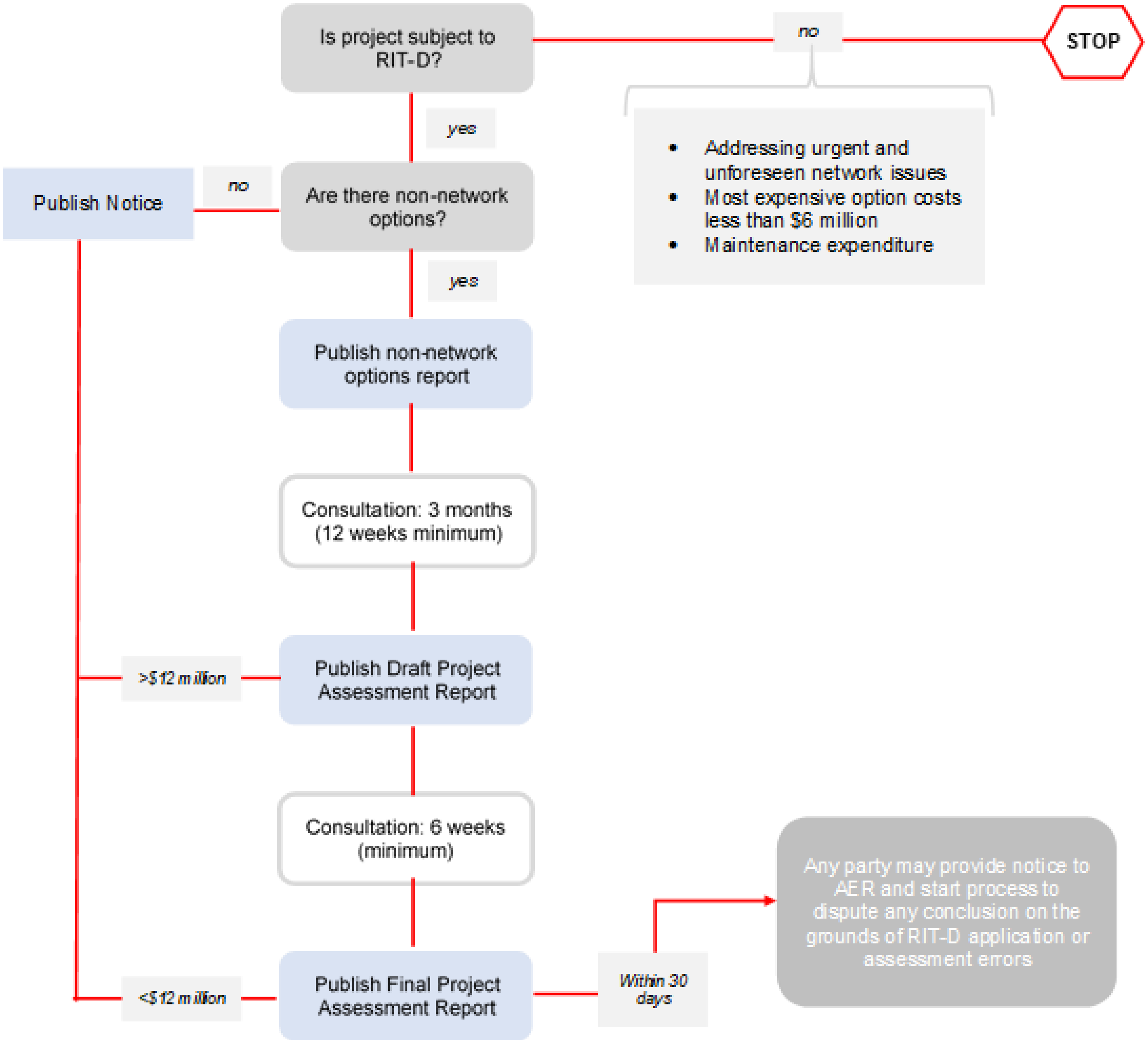
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

8. COMPLIANCE STATEMENT

This Final Project Assessment Report complies with the requirements of NER section 5.17.4(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;	N/A
(4) a description of each credible option assessed	4
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	5
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	6 & 7
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	5
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	5.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	6.3
(10) the identification of the proposed preferred option	7.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (ii) the indicative capital and operating costs (where relevant); (iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	7.1, 7.2 & 6.3
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.3

APPENDIX A – THE RIT-D PROCESS



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