Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the PLEY Network Area

Final Project Assessment Report

19 January 2022

ERGON ENERGY NETWORK

Part of Energy Queensland

EXECUTIVE SUMMARY

About Ergon Energy

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

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

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

Identified Need

Pleystowe 33/11kV Substation (PLEY) is located on the southern bank of the Pioneer River approximately 13km west of Mackay and 2.5km north-west of Walkerston. The substation is part of the Mackay 33kV sub-transmission network and takes supply from T038 Mackay 132/33kV Bulk Supply Substation (MACK).

PLEY supplies the township of Walkerston and the surrounding area. Outside of Walkerston, the supply area is primarily rural, with the customers including numerous sugar cane farms and the Pleystowe Sugar Mill (which ceased milling operation in 2008). PLEY provides electricity supply to approximately 2,400 customers, of which 85% are residential and 15% are commercial, agricultural, and industrial. PLEY is presently supplied via two incoming 33kV feeders from T038 Mackay Substation, and there are two outgoing 33kV feeders from PLEY which provide supply to Farleigh 33/11kV Substation (FARL) and the Pleystowe Mill.

A substation condition assessment of PLEY was completed in 2019 and has identified some primary and secondary plant and equipment that are recommended for retirement based on the Condition Based Risk Management (CBRM) analysis.

The assessment identified that the three 33/11kV power transformers, the three 33kV automatic circuit recloser (ACR) controllers and 17 of the protection relays are at the end of their serviceable life. Additionally, a civil assessment of the structures on site also identified that the 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, and reliability risk to the customers supplied from PLEY.

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

Ergon Energy published a Notice of No Non-Network Options for the above described network constraint on 9 October 2020. An internal assessment had determined that no non-network solutions can potentially meet the identified need or form a significant part of the solution.

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 to install two new 10MVA 33/11kV transformers, recover the three existing transformers, upgrade the secondary systems and install a new 33kV switchboard in a new control building at Pleystowe Substation.

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 PLEY network area.

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

1.1. Response to the Notice of No Non-Network Options Report

No submissions were received in response to the Notice of No Non-Network Options Report.

1.2. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the PLEY 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.

1.3. Dispute Resolution Process

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

If no formal dispute is raised, Ergon Energy will proceed with the preferred network option.

1.4. Contact Details

For further information and inquiries please contact:

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

2. BACKGROUND

2.1. Geographic Region

PLEY supplies the township of Walkerston and the surrounding area. Outside of Walkerston, the supply area is primarily rural, with the customers including numerous sugar cane farms and the Pleystowe Sugar Mill (which ceased milling operation in 2008). Pleystowe Substation provides electricity supply to approximately 2,400 customers, of which 85% are residential and 15% 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.

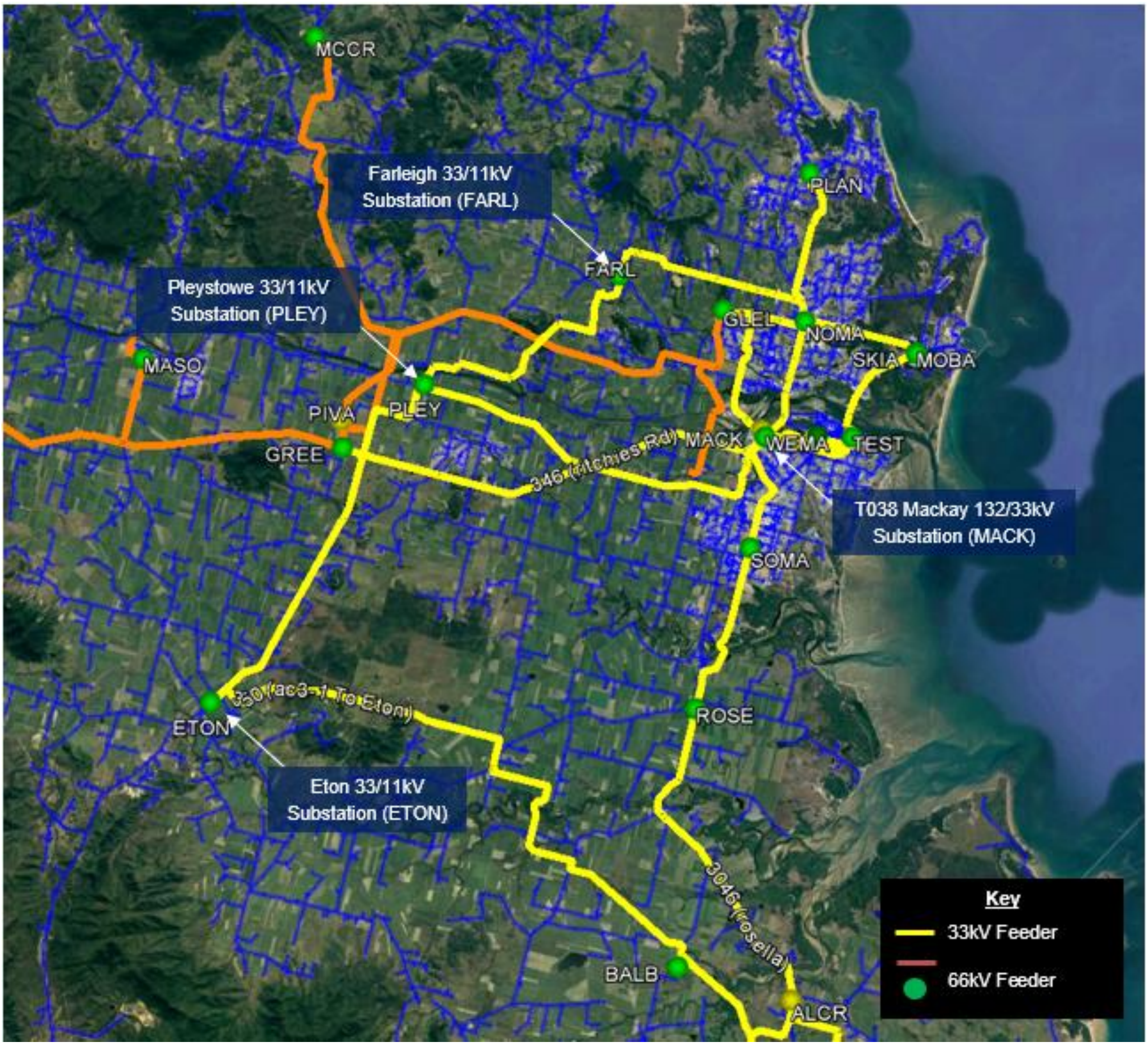

Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

PLEY is located on the southern bank of the Pioneer River approximately 13km west of Mackay and 2.5km north-west of Walkerston. The substation is part of the Mackay 33kV sub-transmission network and takes supply from T038 Mackay 132/33kV Bulk Supply Substation (MACK). PLEY is presently supplied via two incoming 33kV feeders from T038 Mackay Substation, and there are two outgoing 33kV feeders from PLEY which provide supply to FARL and the Pleystowe Mill.

PLEY was established in 1964 according to applicable design and construction standards during that time. It has an outdoor 33kV and 11kV switchyard with steel structures, three 5MVA 33/11kV power transformers, and a small protection and control building. Over time, the substation was expanded with additional 11kV bays and some of the primary plant have been replaced in situ.

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

The 11kV main bus and the 11kV transfer bus are both manually switched. Each bus contains three 11kV bus isolators. The bus isolators on the main bus are normally closed and the bus isolators on the transfer bus are normally open.

PLEY supplies four 11kV distribution feeders which contain seven existing 11kV feeder ties to 11kV feeders supplied from FARL, West Mackay 33/11kV substation (WEMA), Rosella 33/11kV substation (ROSE), Eton 33/11kV substation (ETON), Marian South 66/11kV substation (MASO) and McKinley Creek 66/11 kV substation (MCCR). Each outgoing 11kV feeder is protected by an automatic circuit recloser (ACR).

There are two station services transformers at Pleystowe substation; local transformer 1 is a 25kVA 11/0.415kV transformer supplied off the 11kV bus, and local transformer 2 is a 20kVA 33/0.415kV transformer supplied off the 33kV bus.

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

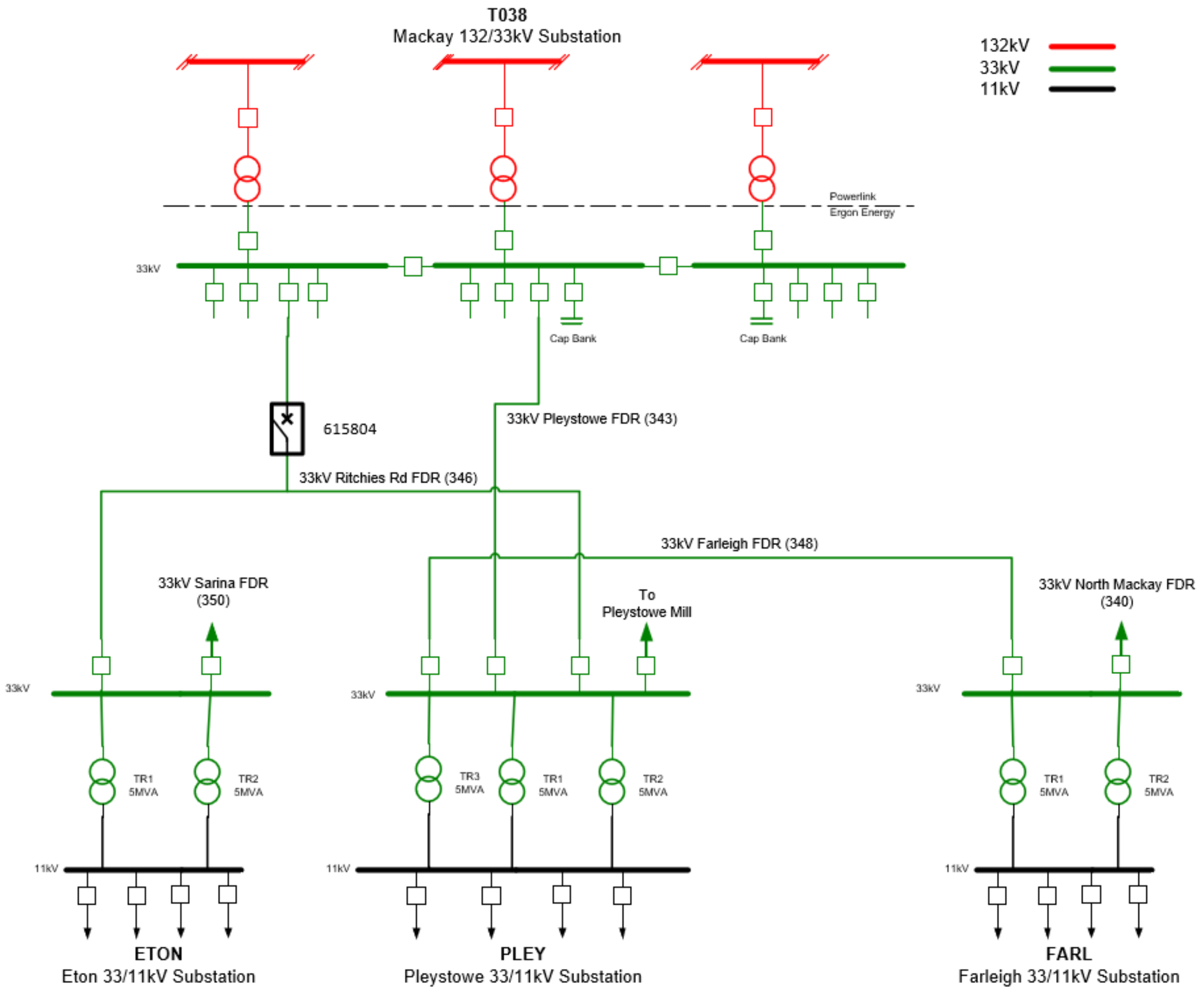

Figure 2: Existing network arrangement (schematic view)

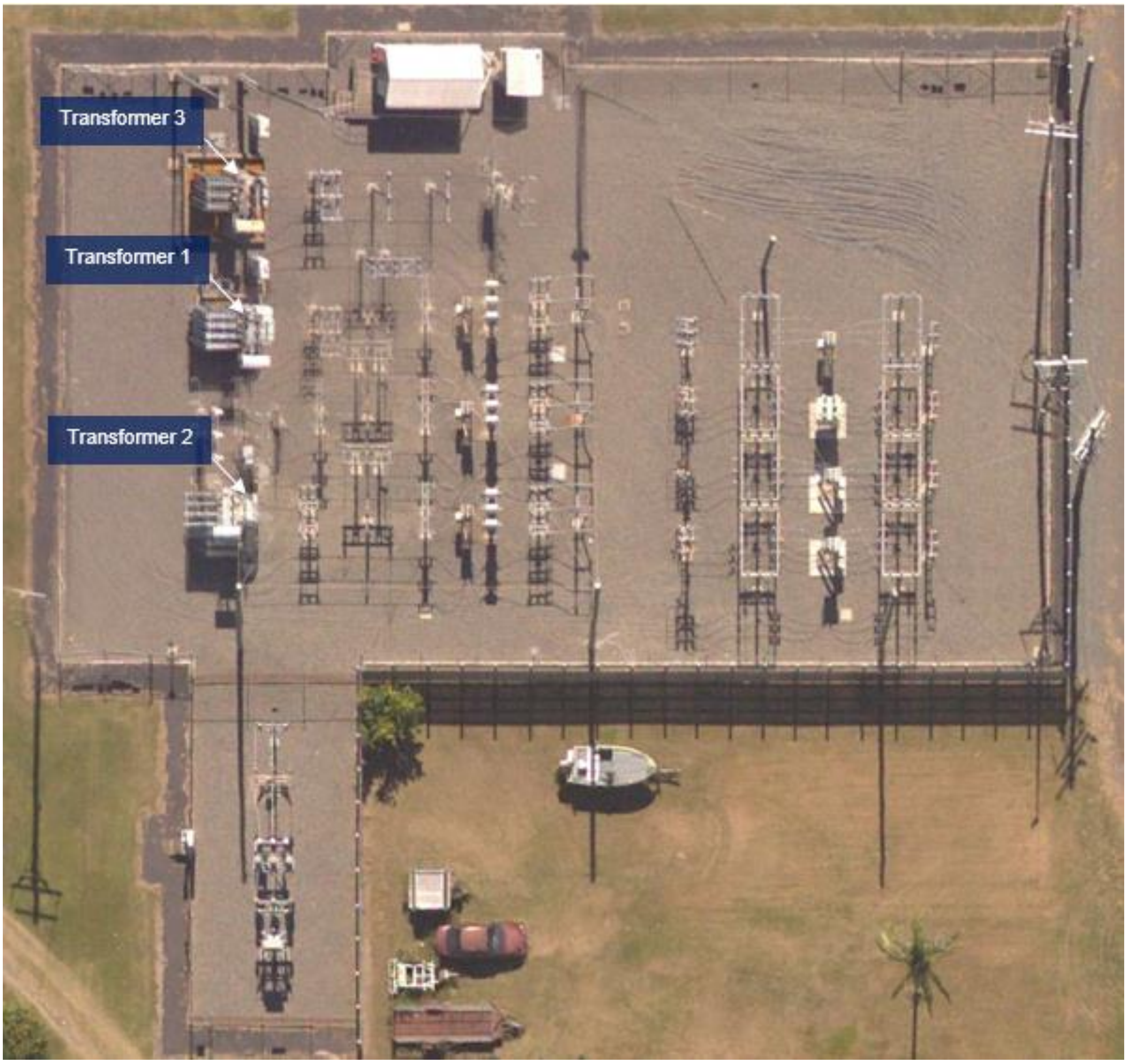

Figure 3: Pleystowe Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at Pleystowe Substation comprises a mix of residential and commercial/industrial customers. The load is summer peaking, and the annual peak loads are predominantly driven by pumping and irrigation. For consistency with the Notice, historic loads for 2019/20 have been used in this report.

2.3.1. Full Annual Load Profile

The full annual load profile for PLEY over the 2019/20 financial year is shown in Figure 4. It can be noted that the peak load occurs during summer.

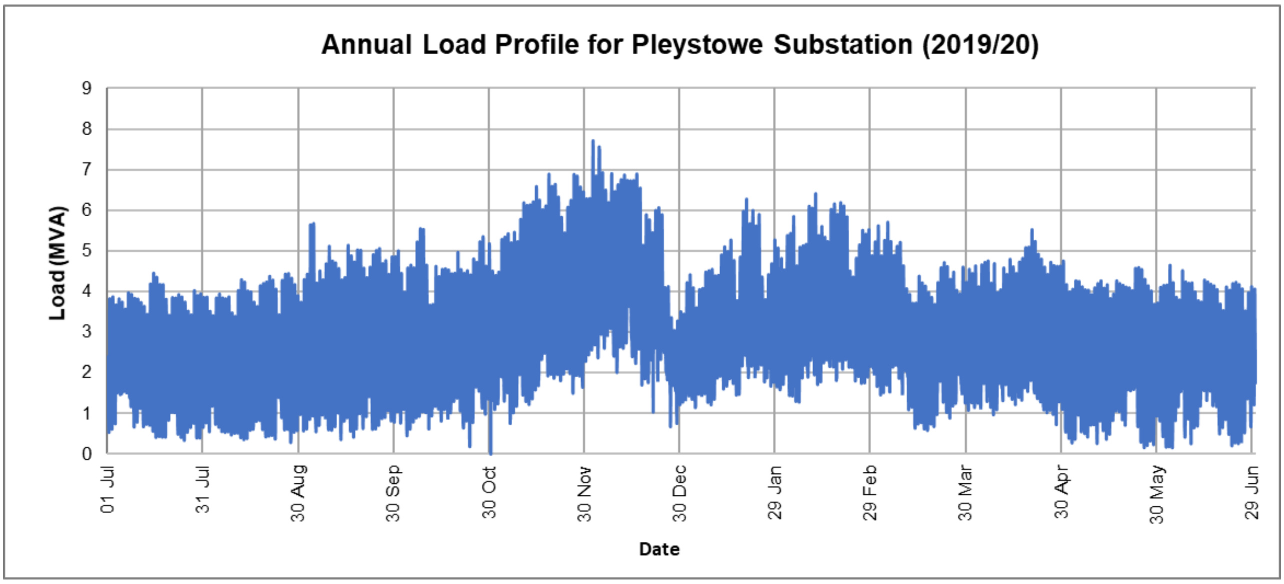

Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for PLEY over the 2019/20 financial year is shown in Figure 5.

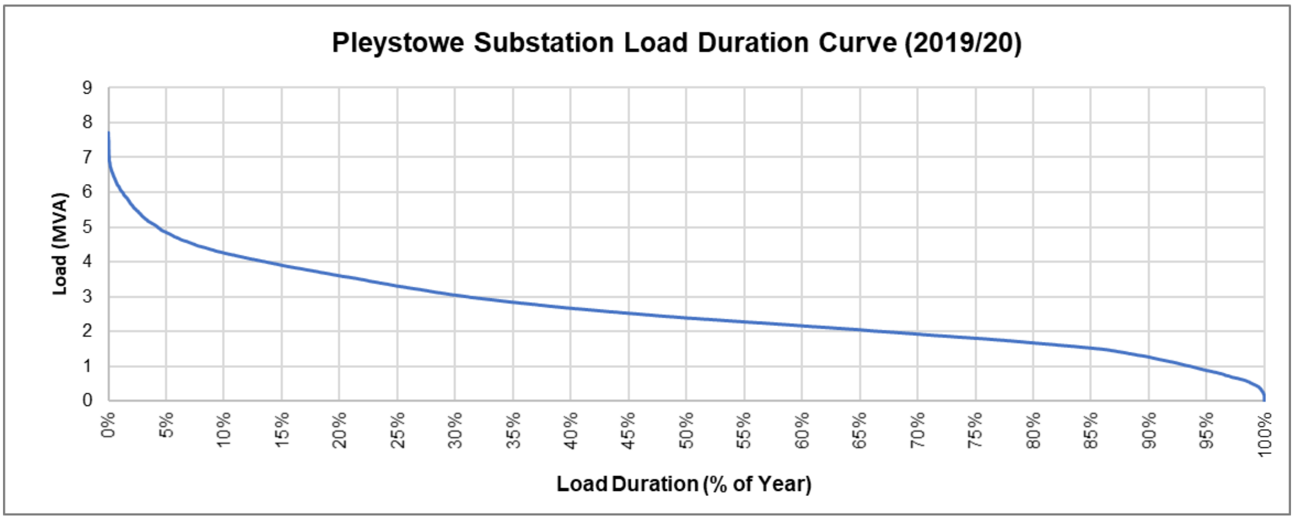

Figure 5: Substation load duration curve

2.3.3. Average Peak Weekday Load Profile (Summer)

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

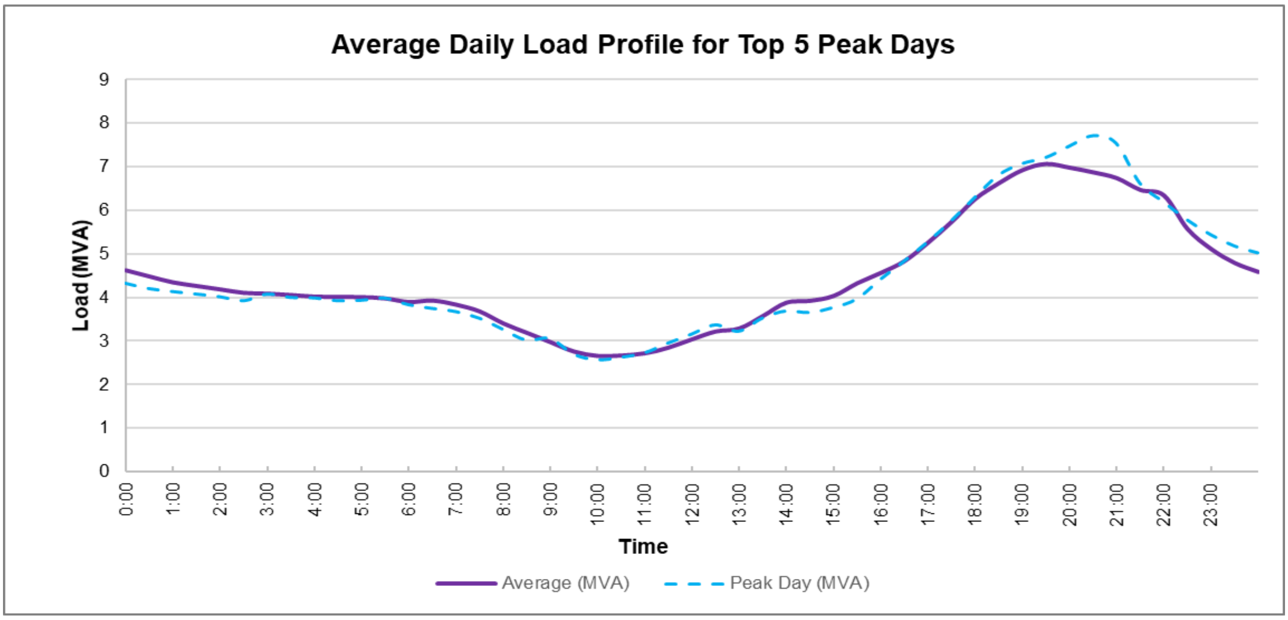

Figure 6: Substation average peak weekday load profile (summer)

2.3.4. Base Case Load Forecast

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

It can be noted that the historical annual peak loads have fluctuated over the past five years, primarily due to seasonal variation in 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.

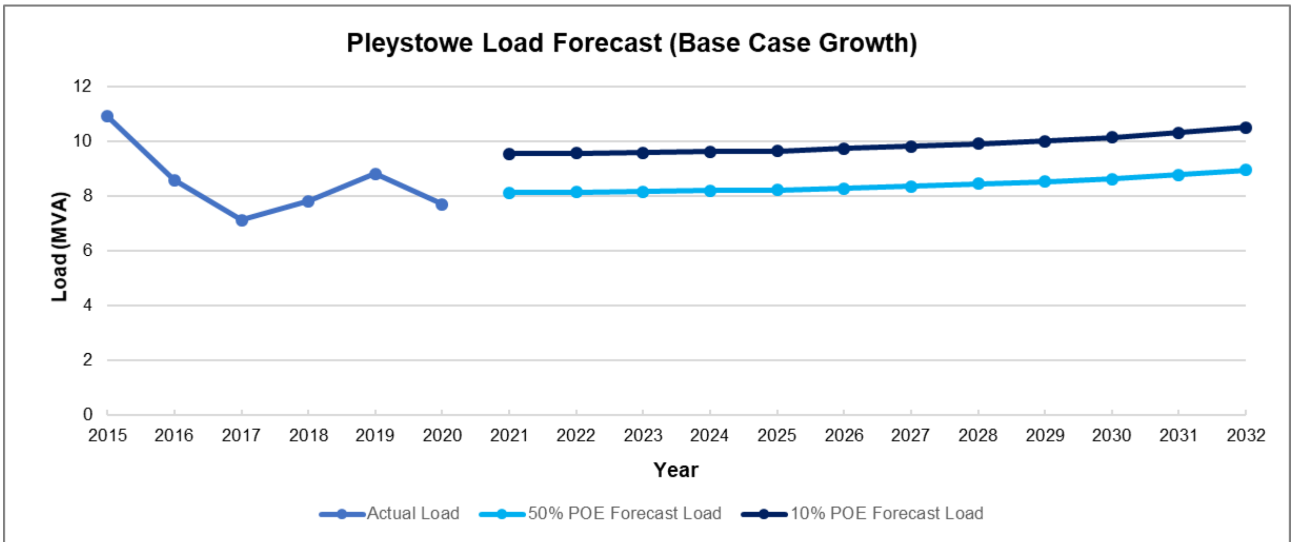

Figure 7: Substation base case load forecast

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.

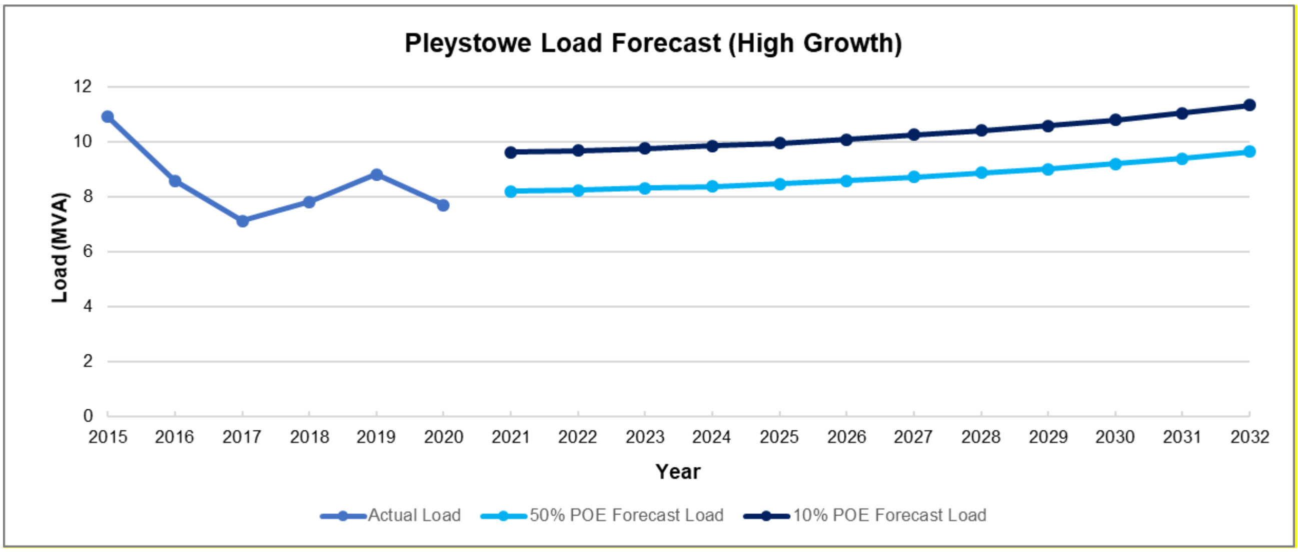

Figure 8: Substation high growth load forecast

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.

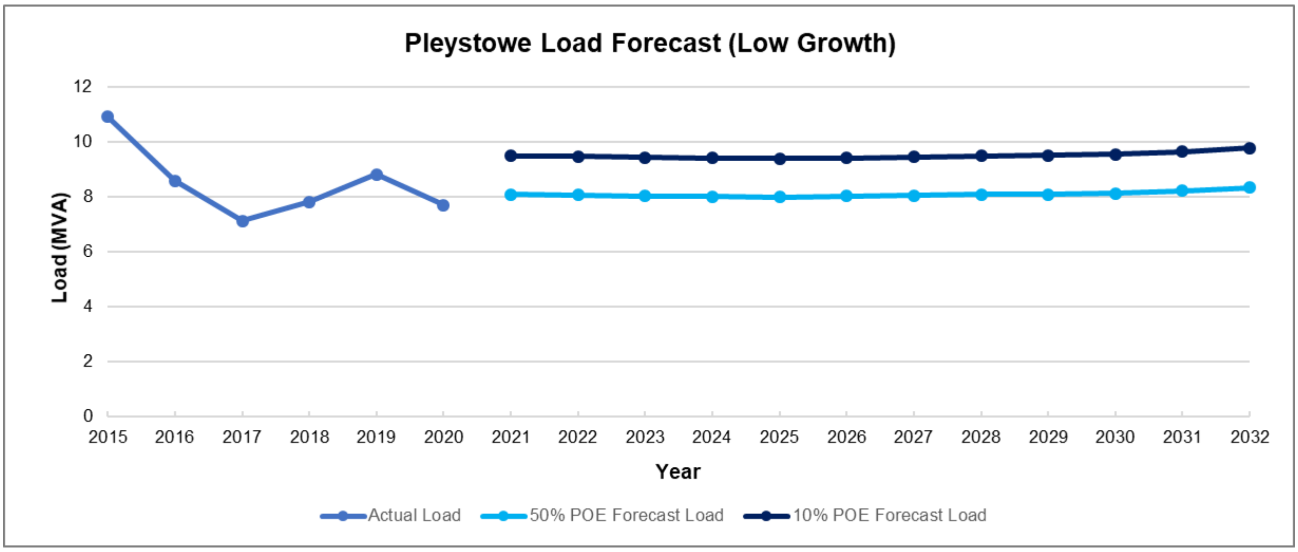

Figure 9: Substation low growth load forecast

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 a number of 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 three 33/11kV power transformers, the 33kV ACR controllers and most of the protection relays at PLEY 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.

3.1.2. Reliability

There are presently no HV or LV transformer circuit breakers and no bus tie circuit breakers on the 33kV and 11kV buses at PLEY. Under the existing sub-transmission network configuration any fault within PLEY will result in an outage to all the customers supplied from PLEY and FARL. This affects almost 4,000 customers and results in a combined peak load at risk of approximately 12MVA.

This network arrangement has also contributed to higher than average System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) for the distribution feeders than is generally expected for a short rural network.

3.2. Quantification of the Identified Need

3.2.1. Aged and Poor Condition Assets

The deterioration of the primary and secondary system assets poses safety risks to staff working within the switchyard. It also poses a safety risk to the public, through the increased likelihood of protection relay 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 Pleystowe Substation.

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

3.2.2. Reliability

SAIDI means the sum of the duration 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 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 Pleystowe and Farleigh Substations 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
Eastern	Short Rural	779	468	424	3.47	3.95
Western	Short Rural	299	516	424	3.79	3.95
Nebia	Short Rural	271	890	424	5.02	3.95
Walkerston	Short Rural	1051	228	424	2.82	3.95
Farleigh	Short Rural	699	386	424	5.01	424
Wundaru	Short Rural	752	1009	424	7.12	424

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.

3.3. 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 PLEY 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

Characteristic peak day load profiles shown in Section 2.3.3 are unlikely to change significantly from year to year and the shape of the load profile is assumed to remain virtually the same with increasing maximum demand.

3.3.3. System Capability – Transformer Capacity

Transformer ratings are normally specified by a continuous rating, supplied by the manufacturer on the nameplate. This corresponds to the load that will cause the oil and winding temperature rise to meet the specified limit, assuming a constant temperature and a constant rated load.

Cyclic ratings in excess of nameplate ratings are possible because the typical load cycle is not continuous, nor is the daily temperature cycle. Each transformer also has a typical thermal time constant of a few hours. All these factors are combined to enable cyclic loading of a transformer in excess of the nameplate rating before the temperature limits are reached.

Each transformer has two cyclic ratings for both summer and winter, based on the load profile and the ambient temperature for that transformer location.

4. CREDIBLE OPTIONS ASSESSED

4.1. Assessment of Network Solutions

Ergon Energy has identified 2 x credible network options that will address the identified need.

4.1.1. Option A: Install Two New 10MVA Transformers

This option involves recovering the three existing transformers and installing two new 10MVA 33/11kV transformers with compliant bunding, upgrading the substation physical security, and addressing secondary systems limitations in order to address the identified need.

The total estimation cost for Option A is as follow:

Works	Estimate
Two new 10MVA transformer bays & secondary system upgrades	$8.773M
OPEX – Voltage Transformer Oil Sample (every 3 years)	$0.5k
OPEX – Current Transformer Oil Sample (every 3 years)	$1.9k
OPEX – Manual Isolator Intrusive Maintenance (every 12 years)	$14.7k

Table 2: Option A estimate (total cost)

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 10.

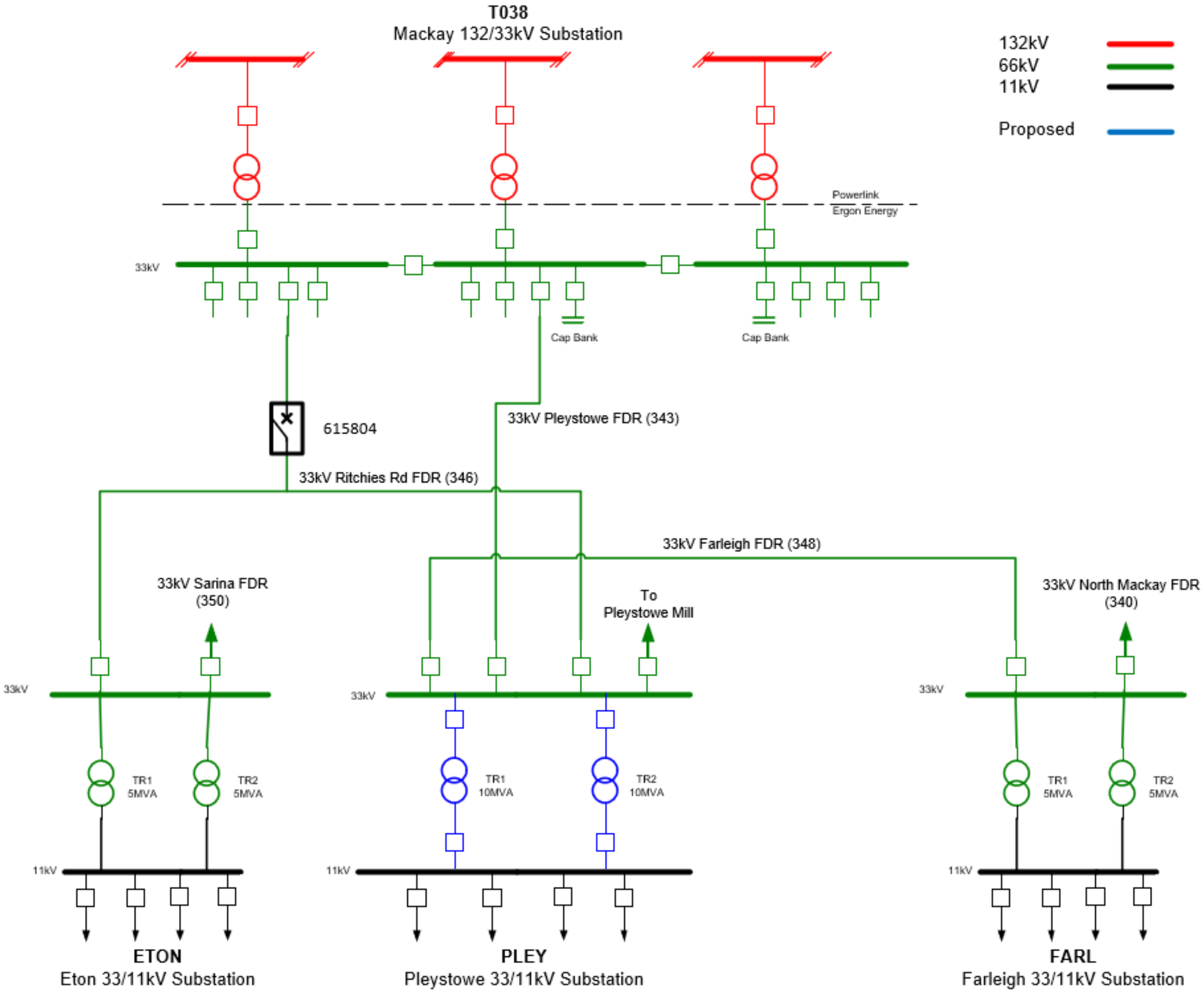

Figure 10: Option A proposed network arrangement (schematic view)

4.1.2. Option B: Install Two New 10MVA Transformers & 33kV Switchboard

This option involves recovering the three existing transformers and installing two new 10MVA 33/11kV transformers with compliant bunding, installing a fully switched 33kV bus, upgrading the substation physical security and addressing secondary systems limitations in order to address the identified need.

The total estimation cost for Option B is as follow:

Works	Estimate
Two 10MVA transformers, 33kV switchboard & secondary systems	$9.742M
OPEX – Switchboard Condition Assessment	$65k

Table 3: Option B estimate (total cost)

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

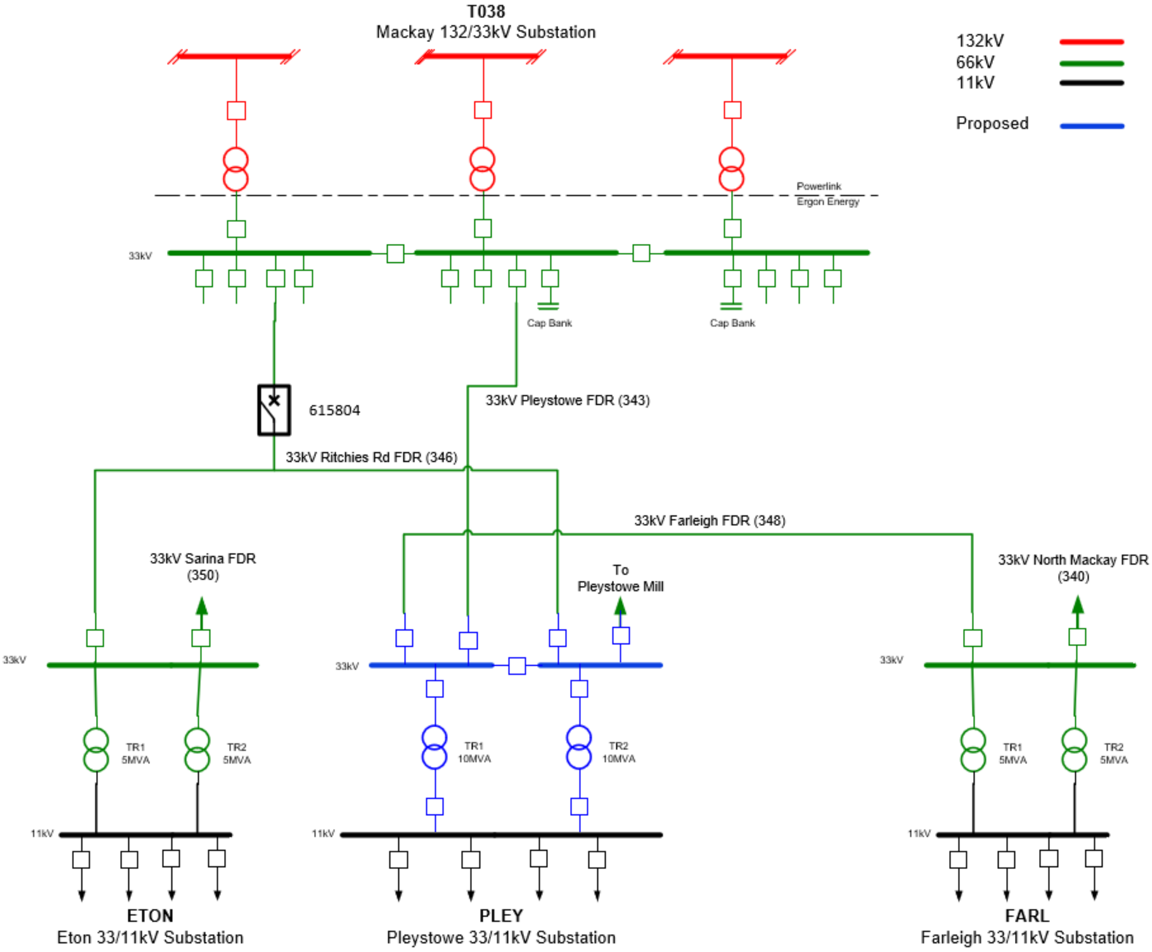

Figure 11: Option B proposed network arrangement (schematic view)

4.2. Assessment of Non-Network Solutions

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.

4.2.1. Demand Management (Demand Reduction)

The DEM team has completed a review of the Pleystowe 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 Pleystowe. 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 between 6:00pm and 10:00pm.

There are 1446 customers on Tariffs 31 and 33 hot water load control (LC). An estimated demand reduction value of 868kVA[1] is available.

Pleystowe Substation LC signals are controlled from T038 Mackay Bulk Supply Substation (MACK). 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 Mackay Bulk Supply Substation exceeds 105MW. This strategy does not directly address demand peaks experienced at Pleystowe. Tariff 33 air-conditioning channels are under manual control of the operational control centre and are used as required. Therefore, network load control would not sufficiently address the identified need.

4.2.2. 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

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

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 701 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 3,475kVA.

The daily peak demand is driven by residential customer demand and the peak generally occurs between 6:00pm and 10:00pm. As such customer solar generation does not coincide with the peak load period.

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

4.2.1. Non-Network Solution Summary

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

4.3. Preferred Network Option

Ergon Energy's preferred internal network option is Option B, to install two new 10MVA 33/11kV transformers, recover the three existing transformers, upgrade secondary systems and install a new 33kV switchboard in a new control building at Pleystowe Substation.

Upon completion of these works, the asset safety and reliability risks at Pleystowe 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 $9.74 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-2023 and construction completed by June 2027.

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

As per the RIT-D process (Appendix A), a DPAR is not required for this project.

6. MARKET BENEFIT ASSESSMENT METHODOLOGY

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

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

6.1. Classes of Market Benefits Considered and Quantified

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

- Changes in involuntary load shedding

6.1.1. Changes in 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 kWh 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 $28/kWh, which has been derived from the AER 2020 VCR values. In particular, Ergon Energy has 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. In particular, we have 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.

6.2. Classes of Market Benefits not Expected to be Material

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

- Changes in voluntary load curtailment
- Changes in costs to other parties
- Changes in timing of expenditure
- Changes in load transfer capability
- Changes in network losses
- Option value

6.2.1. Changes in Voluntary Load Curtailment

Because none of the credible options include any voluntary load curtailment, and because there are no customers on voluntary load curtailment agreements in the Pleystowe area at present, any market benefits associated with changes in voluntary load curtailment have not been considered.

6.2.2. Changes in Costs to Other Parties

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

6.2.3. Changes in Timing of Expenditure

None of the credible options included in this RIT-D assessment is expected to affect the timing of other distribution investments for unrelated identified needs.

6.2.4. Changes in Load Transfer Capability

None of the credible options included in this RIT-D assessment are expected to have an impact on the load transfer capability between the zone substations in the Pleystowe area.

6.2.5. 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.

6.2.6. 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].

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.

7. DETAILED ECONOMIC ASSESSMENT

7.1. Methodology

The RiT-D 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 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.

7.2. Key Variables and Assumptions

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

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

Interest on borrowings is not included as a cost in the comparison of options as it represents a cost of project financing, and as such is accounted for in present value calculations through the discounting of the project cash flows at the regulated WACC. The interest on borrowings is included in the Total Project Cost for which approval is being sought as it represents a legitimate cost of network augmentation.

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[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

7.3. 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 NPV ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
A	Install two 10MVA Transformers	2	$8,772,525	-$4,701,597	$10,250,872	$46,651
B	Install two 10MVA Transformers & 33kV Switchboard	1	$9,742,375	-$3,092,278	$9,742,375	$62,293

Table 4: Base case NPV ranking table

Sensitivity analysis

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. Table 5 outlines the major sensitivities analysed:

Parameter	Mode Value	Lower Bound	Upper Bound
Project Costs	Standard estimates	-40%	+40%
Project Costs	Preferred option estimates	-40%	+40%
Opex Costs	Calculated Opex	-10%	+10%
VCR	$30.19 / kWh	$25.56 / kWh	$39.94 / kWh

Table 5: Economic parameters and sensitivity analysis factors

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 two 10MVA Transformers	26.8%	73.2%	-$4,474,451
B	Install two 10MVA Transformers & 33kV Switchboard	73.2%	26.8%	-$2,797,325

Table 6: Monte Carlo Analysis for Base Case Forecast

Option analysis summary

Option B is the lowest cost option in the weighted average results across all scenarios and also has the lowest average Net Present Value and is the most economical in 73% of cases in the Monte-Carlo simulations, and is therefore the recommended development option.

Based on the above technical and economic comparisons of options, Option B is considered to provide the optimum solution to address the forecast limitations and is therefore the recommended development option.

8. CONCLUSION

The FPAR represents the final stage of the consultation process in relation to the application of the RIT-D.

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

8.1. Preferred Option

Ergon Energy's preferred option is Option B, to install two new 10MVA 33/11kV transformers, recover the three existing transformers, upgrade secondary systems and install a new 33kV switchboard in a new control building at Pleystowe Substation.

Upon completion of these works, the asset safety and reliability risks at Pleystowe 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 $9.74 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-2023 and construction completed by June 2027.

8.2. Scope of proposed works

To address the limitations at Pleystowe, it is proposed to replace assets that are reaching retirement age and install a 33kV switchboard.

The full scope of works to be covered by Option B is as followed:

Substation Works

<u>Civil and Earth Works</u>

- Extend the north-eastern corner of the Pleystowe Substation yard by approximately 200m^2 (approximately 65m of additional substation security fence required)
  - Extend the substation earth grid
  - Install lightning mast (location and number to be determined during the design phase of the project)
- Install transformer bunding compliant with AS1940 and AS2067 for two new 10MVA transformers
- Install foundations and steelwork for two new 11kV dead tank circuit breakers (transformer LV circuit breakers)

- Enhance the substation security by replacing/upgrading the fence to chain-link perimeter fence compliant with AS2067 and AS1725. The fence should meet the following requirements:
    - Fence and entry gates to the same standard with a height of 2.9m from ground level on the outside of the fence and include 0.6m vertical raisers with 4 or 5 strands of barbed wire. Contact person for SME support during the design phase is Michael Mende.
    - Fence gates with protected padlock and chain
    - Install a conduit from the fence gate to the control building for the entry card reader wiring.
- Construct foundations for new control building
- Construct a new demountable control building (for 33kV switchboard, protection panels and secondary systems) at Banyo and install on site at Pleystowe
    - Fit control room building with a commercial grade locking system
    - Install window grilles and locks on control room building
- Install new conduits for 33kV cables from the two new transformer bays to the new 33kV switchboard
- Install new conduits for the 33kV feeder exit cables
- Install new conduits for 11kV cables from the two new transformers bays to the existing 11kV switchgear
- Install conduits for control cable to the new transformers, circuit breakers and control building
- Remove existing transformer bund walls for TR1, TR2 and TR3
- Remove existing control building

<u>Primary Plant Works</u>

- Install two new 33/11kV transformer bays at Pleystowe Substation. Each bay will include the following:
    - 1 x 10MVA 33/11kV Dyn1 transformer with OLTC (17.5% boost & 10% buck tap range)
    - 1 x 11kV dead tank circuit breaker (using a 33kV rated CB)
- Install a new 33kV indoor switchboard including two bus sections with 1 x bus section CB, 2 x transformer CBs and 4 x feeder CBs
- Install new 33kV feeder exit cables from the new 33kV switchboard
- Install new 33kV transformer power cables between the new transformer bays and the new 33kV switchboard
    - Including installation of cable terminations
- Install new 11kV transformer power cables between the new transformer bays and the existing 11kV switchgear
    - Including installation of cable terminations
- Remove and dispose of the three existing 5MVA 33/11kV transformers and associated power and control cabling
- Remove and dispose of the existing outdoor 33kV switchgear (incl. bus and structures)

Secondary Systems Works

- Install 8 protection and control panels in the new control building (4 x 33kV feeders, 2 x transformers, 1 x 33kV bus & 1 x 11kV bus)
- Install main and back-up integrated differential protection relays for each transformer bay as required by STNW1002 (Standard for Substation Protection)
    - 2 x GE T60 Main Integrated Tx Diff
    - 2 x Schneider P642 Back-up Integrated Tx Diff
- Install main and back-up low impedance bus differential protection relays for the 33kV bus as per STNW1002
    - 1 x SEL 487B1 Main LoZ Bus Diff
    - 1 x Schneider P746 Back-up LoZ Bus Diff
- Install main and back-up summated bus overcurrent protection relays for the 11kV bus
    - 1 x GE F35 Main Summated Bus Overcurrent
    - 1 x Schneider P643 Back-up Summated Bus Overcurrent
- Install a distribution feeder management relay for the 33kV Pleystowe Mill feeder bay
    - 1 x Schneider P142
- Install main and back-up distance protection relays for the EB01, EB04 and EB07 33kV feeder bays as required by STNW1002
    - 3 x GE D60 Main Line Dist.
    - 3 x Schneider P543 Back-up Line Dist.
- Install new HMI
- Install new DC supply systems
- Remove the existing KVGC voltage regulation relays and use the SCD5200 RTU to perform AVR control for the new transformers
- Install new transformer protection and control cabling as required
- Remove the existing protection relays from the old control building
- Utilise the existing relays as spares where appropriate (including the CAPM4 ACR controllers)

Substation Security Works

- Based on the Network Physical Security Design Guidelines the level of importance that Pleystowe Substation has to the business is classified as ‘limited’. Besides the fence upgrade works detailed in the civil works section, the guideline recommends the following additional electronic security measures be implemented:
    - Install electronic access control with the entry card reader to be mounted near the entry gate and connected to the security panel and new security switch
    - Install intruder alarm system for the building (Zone 2) – (i.e. reed switches on door, any hatches, roller doors)
    - The arm / disarm indicated to be mounted on the control building external wall and needs to be visible at the main entrance
    - Install a new security panel (medium size enclosure) in the control building and connect to the RTU

- Install a Dell PC5000 hardened Workstation with 4TB storage
- The security switch to be connected Ergon Cisco switch which is connected to the Security Monitoring Centre in Brisbane
- Security device cables should have mechanical protection and be within control cable conduits with clear labelling. Ideally in separate conduits to avoid being damaged
- Security panel requires 2 GPO's and have its own battery that can last 48 hours with external supply
- Install security signage

8.3. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

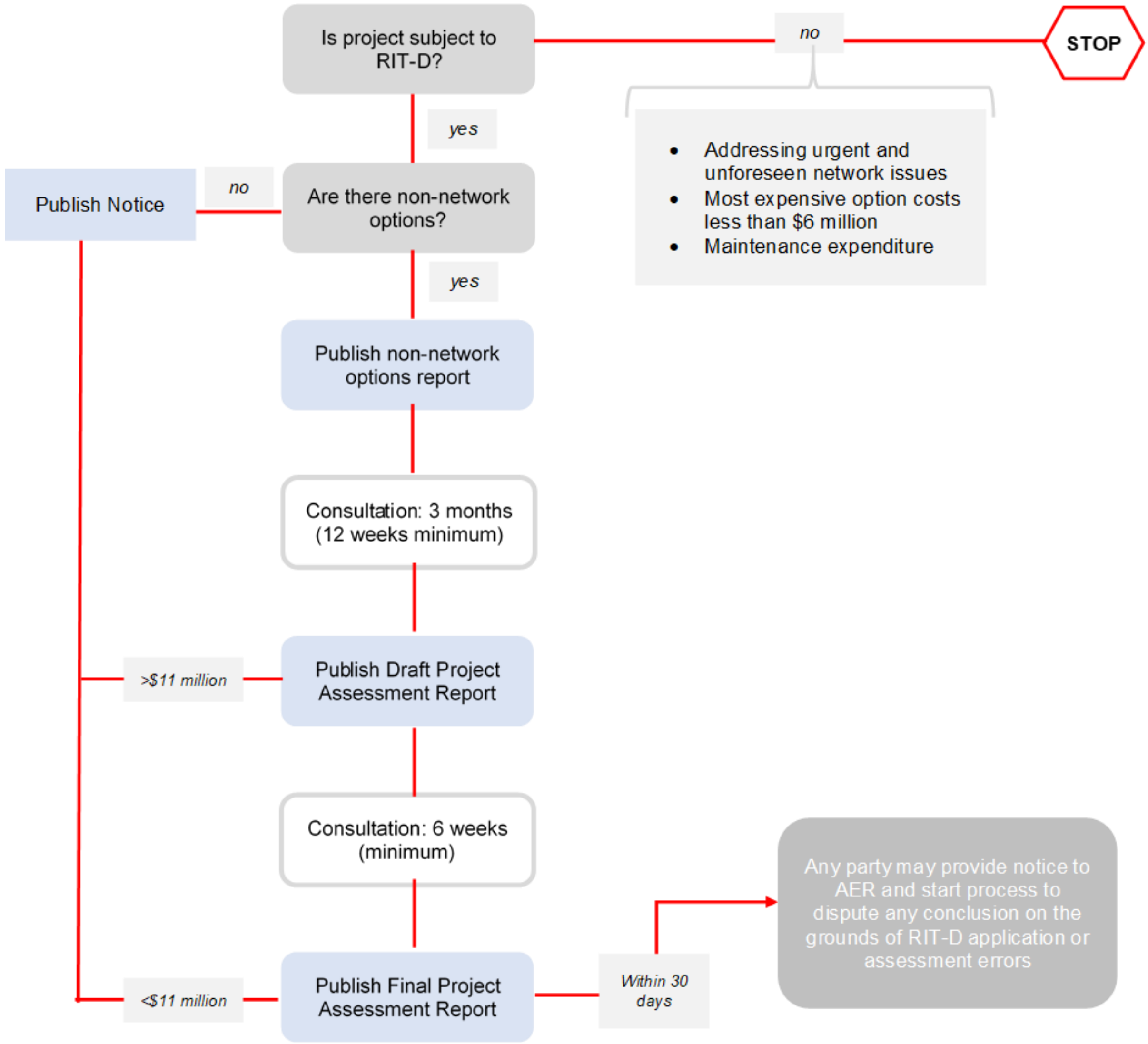
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

9. COMPLIANCE STATEMENT

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

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(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) 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
(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	7.3
(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.