Regulatory Investment Test for Distribution

Reliable Provision of Electricity to the Pialba (Hervey Bay) area

Final Project Assessment Report

This document describes the *identified need* for investment at Pialba substation and the preferred option for addressing the identified need.

Publication date: 19 July 2021

Executive Summary

ABOUT ERGON ENERGY

Ergon Energy Corporation Limited (Ergon Energy) is part of the Energy Queensland Group and manages an electricity distribution network which supplies electricity to more than 740,000 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

A condition assessment of Pialba 66/11kV substation (PIAL) in the Hervey Bay supply area has identified assets that are recommended for replacement. These assets are forecast to reach retirement based on a combination of Condition Based Risk Management (CBRM) modelling and known issues with problematic plant, which are required to be replaced or decommissioned to manage the safety and network risks associated with unplanned failure.

The assessment identified that primary and secondary plant including the 66kV circuit breakers, the 11kV switchboard, and most protection relays require replacement. An assessment of the civil structures on site also identified the control building, several plant support structures and the 66kV galvanised water pipe bus require replacement due to being defective beyond repair.

Failure of the primary and secondary plant is a risk to network security which may lead to a breach of legislated Safety Net requirements. As the substation site is located nearby to a busy intersection and several residential developments, catastrophic failure of plant or structures also presents a safety risk to the general public as well as to our own staff.

The purpose of this project is to address the risk to safety and network security posed by poor condition and problematic assets.

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 Hervey Bay supply area in a reliable, safe and cost-effective manner.

Ergon Energy published a Notice of No Non-network Options (Notice) for the above described network constraint on 03 April 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.

A Draft Project Assessment Report (DPAR) was published on 04 May 2021, where Ergon Energy provided both technical and economic information about the internal options in accordance with the requirements of clause 5.17.4(i). No submissions were received by the closing date of 18 June 2021.

This is now a Final Project Assessment Report (FPAR), where Ergon Energy presents the technical and financial analysis of the options and identifies the preferred solution 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 build a new 66/11kV substation with outdoor 66kV switchgear on the block of land owned by Ergon Energy adjacent to the existing PIAL. The preferred solution cost is estimated at $17.96M including overheads and capitalised interest.

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1 Introduction

This FPAR 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 PIAL.

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 DPAR

Ergon Energy published a DPAR for the identified need (refer to section 3) in the Pialba supply area on 04 May 2021. No submissions were received by the closing date of 18 June 2021.

1.2. Structure of the report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the Pialba 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 Ergon Energy currently considers may address the identified need, including for each:
  - Its technical definitions;
  - The estimated commissioning date; and
  - The total indicative cost (including capital and operating costs)
- Quantifies costs and classes of material market benefits for the credible option.
- In case of multiple options, this report provides the results of a comparative Net Present Value (NPV) analysis and accompanying explanatory statements regarding the results.

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 option to build a new 66/11kV substation with outdoor 66kV switchgear on the block of land owned by Ergon Energy adjacent to the existing PIAL.

1.4. Contact Details

For further information, inquiries and submissions:

E: demandmanagement@ergon.com.au

P: 13 74 66

2 Background

Pialba 66/11kV substation (PIAL) is a Zone Substation which supplies approximately 5200 customers and 16MVA of peak load. PIAL is located near the centre of Hervey Bay town and supplies the CBD area, the Hervey Bay Hospital, and the main shopping centre. There is also an extensive distribution network that supplies residential customers in the surrounding suburbs.

PIAL has three 66kV feeders connecting to Maryborough 132/66kV Bulk Supply Point (MARY), Torquay 66/11kV Zone Substation (TORQ), and Point Vernon 66/11kV Zone Substation (POVE) respectively. The feeders from MARY and TORQ form part of the Hervey Bay 66kV ring, while POVE is supplied radially.

The 11kV distribution network from PIAL is supplied through six 11kV feeders with three feeders supplying predominantly the CBD, medical precinct, and Stocklands shopping centre. The remaining feeders supply predominantly residential customers. In addition, the distribution network of POVE is also dependant on PIAL's reliability due to the radial 66kV supply.

PIAL was constructed in 1967 and a condition assessment has identified several assets that require replacement due to their condition and associated risk. The purpose of this project is to address limitations on aged and poor condition assets.

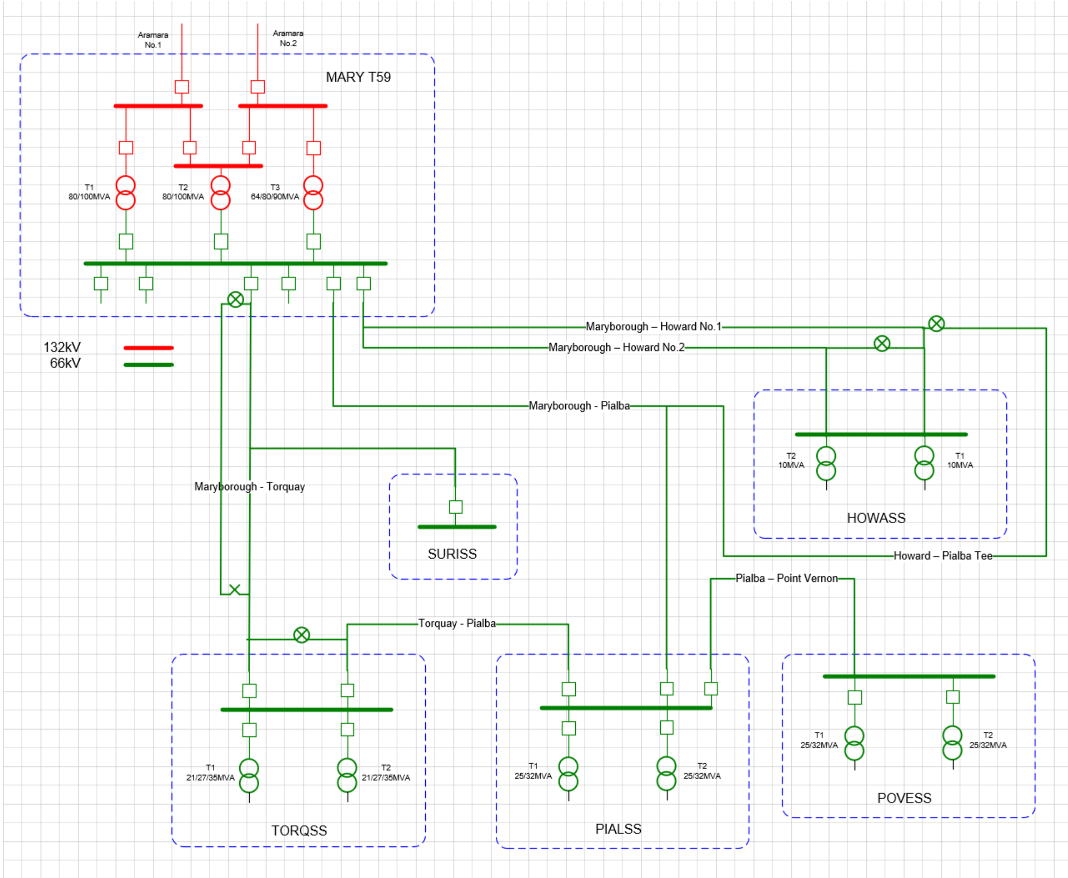


Figure 1 – Hervey Bay area Subtransmission Network

2.1. Load Profile / Forecasts

As shown in Figure 2 below load over the 2018 period has peaked a number of times around 14.5MVA, with the peak demand being 14.58MVA in December 2018. While the peak demand is above the single transformer nameplate rating, the peak is not breaching N-1 ECC and is far from approaching substation NCC and ECC.

The annual load duration curve for PIAL shown in Figure 3 illustrates that currently when either transformer is out of service the load does not exceed the N-1 ECC. The moderately flat load duration curve indicates a higher utilisation common with hospitals, aged care facilities and commercial and industrial networks.

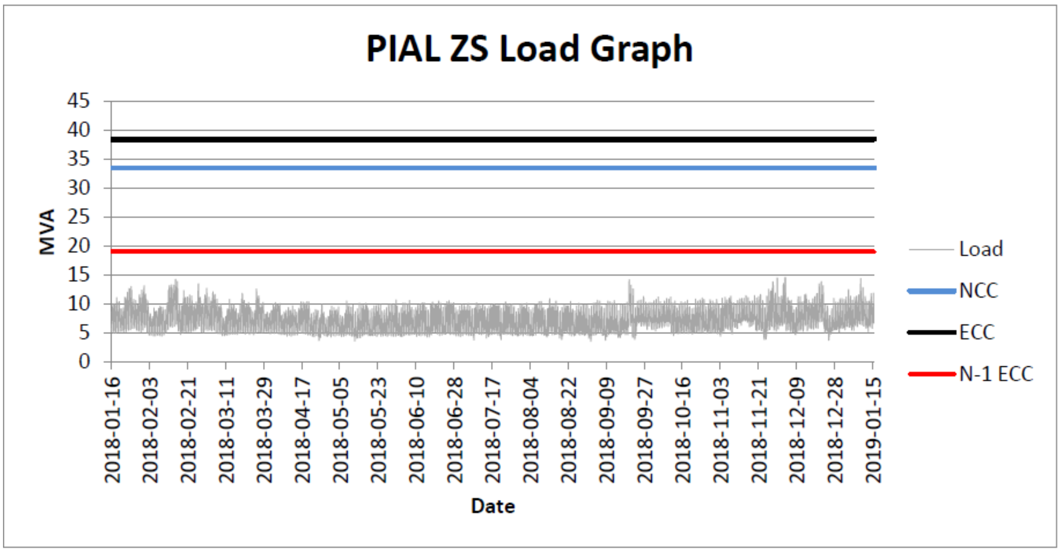


Figure 2 – Pialba substation load

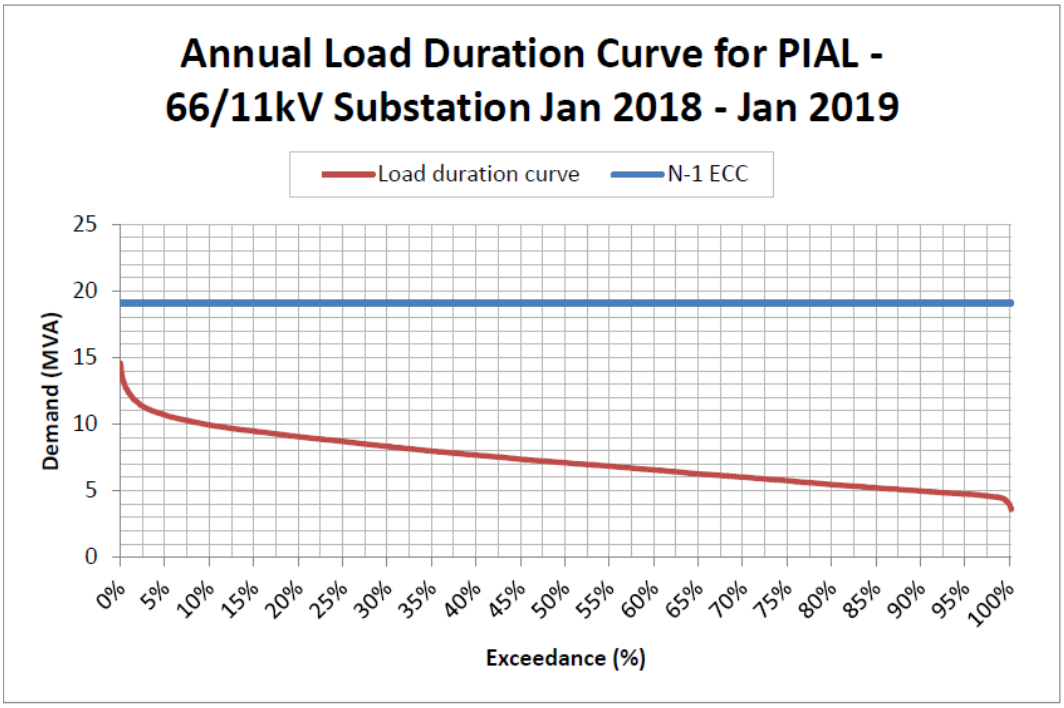


Figure 3 – Pialba substation load duration curve

Figure 4 indicates there are no augmentation drivers for the foreseeable future at Pialba substation. Based on a 10POE (10% probability of exceedance) load forecast the demand is projected to reach 16.6MVA by 2028. Pialba is located on the edge CBD and has substantial vacant and developing land around the site. Given this fact the long-term forecasts shown in Figure 4 may prove to be quite conservative.

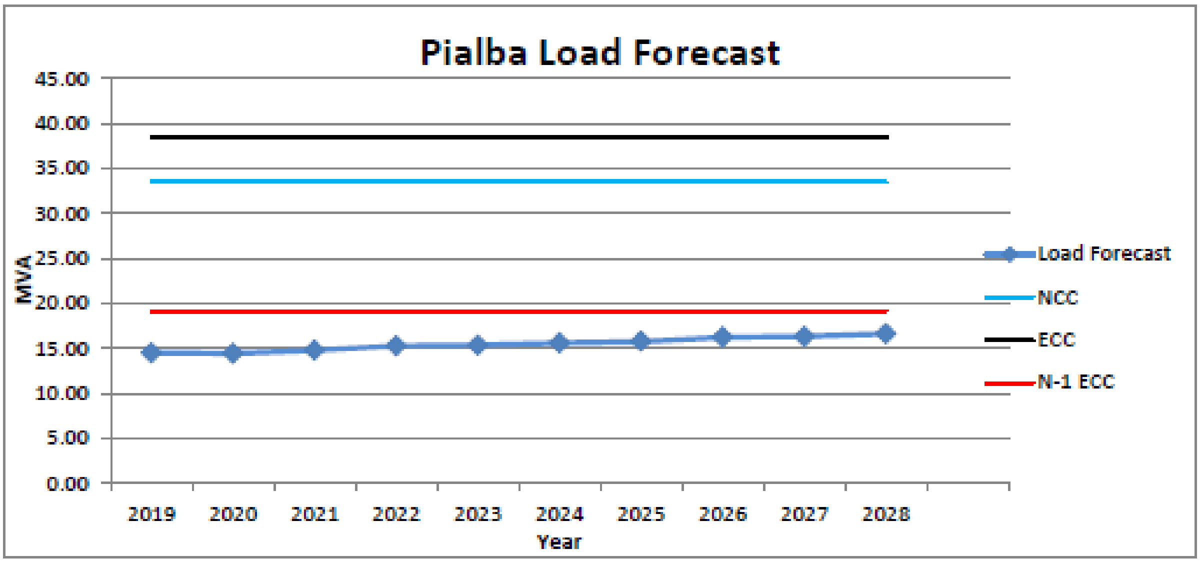


Figure 4 – Pialba load forecast

3 Identified Need

3.1. Description of the Identified Need

3.1.1. Aged and Poor Condition Assets

A condition assessment of PIAL has identified assets that are recommended for replacement. These assets are forecast to reach retirement based on a combination of Condition Based Risk Management (CBRM) modelling and known issues with problematic plant, which are required to be replaced or decommissioned to manage the safety and network risks associated with unplanned failure.

The assessment identified that primary and secondary plant including the 66kV circuit breakers, the 11kV switchboard, and most protection relays require replacement. An assessment of the civil structures on site also identified the control building, several plant support structures and the 66kV galvanised water pipe bus require replacement due to being defective beyond repair.

Failure of the primary and secondary plant is a risk to network security which may lead to a breach of legislated Safety Net requirements. As the substation site is located nearby to a busy intersection and several residential developments, catastrophic failure of plant or structures also presents a safety risk to the general public as well as to our own staff.

Primary and secondary plant assets recommended for replacement are outlined in Table 1 and Table 2.

Table 1 - Primary plant recommended for replacement

Category	Plant No	Op. Number	Voltage	Make
Switchgear	CB92543578	A1224	11kV	EMAIL > S15
Switchgear	CB94755235	A452	11kV	EMAIL > S15
Switchgear	CB92807924	A752	11kV	EMAIL > S15
Switchgear	CB92831186	B452	11kV	EMAIL > S15
Switchgear	CB92940305	B752	11kV	EMAIL > S15
Switchgear	CB92938153	C452	11kV	EMAIL > S15
Switchgear	CB92410521	D452	11kV	EMAIL > S15
Switchgear	CB92802516	E452	11kV	EMAIL > S15
Switchgear	CB91840039	A352	66kV	ASEA > HLC 72.5/2000U
Switchgear	CB91742059	B352	66kV	ASEA > HLC 72.5/2000U

Table 2 - Secondary plant recommended for replacement

Protection Relay	Function	Make
PR93210996	EA51J01 TORQUAY - PIALBA 66KV R SCHEME	SCHNEIDER P543
PRxxxxxxxxx	EA51J01 TORQUAY - PIALBA 66KV R SCHEME	EMAIL 1T10/EL/3F
PR93319021	EA52J01 HOWARD - PIALBA 66KV SCHEME	SCHWEITZER 311C
PRxxxxxxxxx	EA52J01 HOWARD - PIALBA 66KV SCHEME	EMAIL 1T10/EL/3F

PR94302174	EA53J01 66KV POINT VERNON PROT SCHEME	SCHWEITZER 311C
PR94302175	EA53J01 66KV POINT VERNON PROT SCHEME	ALSTOM P142
PR94302172	EA54J01 EA54 66KV BUS PROT SCHEME	GEC CAG32
PR94302173	EA54J01 EA54 66KV BUS PROT SCHEME	GEC CAG34
PR94302171	EA54J01 EA54 66KV BUS PROT SCHEME	GEC VTTR11
PRxxxxxxxxx	EA54J01 EA54 66KV BUS PROT SCHEME	Email 2HS10
PR93209395	TX51J01 TRANSF 1 66KV PROT SCHEME	SIEMENS 7UT61
PR93209958	TX51J01 TRANSF 1 66KV PROT SCHEME	ENGLISHELECTRIC CDG31
PRxxxxxxxxx	TX51J01 TRANSF 1 66KV PROT SCHEME	AREVA MVAJ
PR93209193	TX51J02 TRANSF 1 66KV PROT SCHEME	AREVA P142
PR93209998	TX52J01 TRANSF 2 66KV PROT SCHEME	SIEMENS 7UT61
PR93209965	TX52J01 TRANSF 2 66KV PROT SCHEME	ENGLISHELECTRIC CDG31
PRxxxxxxxxx	TX52J01 TRANSF 2 66KV PROT SCHEME	AREVA MVAJ
PR93208219	TX52J02 TRANSF 2 66KV PROT SCHEME	AREVA P142
PR93227384	FB51J03 11KV BUS 11KV PROT SCHEME	ENGLISHELECTRIC CAG32
PR93232249	FB51J03 11KV BUS 11KV PROT SCHEME	ENGLISHELECTRIC CAG12
PRxxxxxxxxx	FB51J03 11KV BUS 11KV PROT SCHEME	ENGLISHELECTRIC VAJ
PRxxxxxxxxx	FB51J03 11KV BUS 11KV PROT SCHEME	RELAYMONSYS 2HS519K23
PR93218016	FB52J01 SUSAN RIVER 11KV PROT SCHEME	SCHWEITZER 351S
PR93211382	FB53J01 BAY CENTRAL 11KV PROT SCHEME	ENGLISHELECTRIC CDG61
PR93212771 / PR93212189 / PR93210070	FB54J01 PIALBA 11KV PROT SCHEME	ENGLISHELECTRIC CDG61
PR93232732 / PR93233592 / PR93226004	FB55J01 DOOLONG SOUTH 11KV PROT SCHEME	ENGLISHELECTRIC CDG61
PR93210121 /PR93227749 / PR93225739	FB56J01 DUNDOWRAN 11KV PROT SCHEME	ENGLISHELECTRIC CDG61
PR94302170	FB57J01 URRAWEEN ROAD 11KV PROT SCHEME	SCHNEIDER P142
PR93305800	MX51J01 CAPACITOR 1 11KV PROT SCHEME	ASEA RXIL
PR94764532	MX52J01 CAPACITOR 2 11KV PROT SCHEME	ABB SPAJ 140C
PR94764533	MX52J01 CAPACITOR 2 11KV PROT SCHEME	ABB SPAJ 160C
PR93221250	MX53J01 CAPACITOR 3 11KV PROT SCHEME	ABB SPAJ 140C
PR93232324	MX53J01 CAPACITOR 3 11KV PROT SCHEME	ABB SPAJ 160C

3.1.2. Safety Net Non-compliance

To address the low probability high impact risk following an N-1 contingency, the Safety Net Security Criteria is applied to determine if supply can be restored within the allowable timeframe. The Safety Net Regional Centre timeframes are applicable to PIAL.

Currently for a 66kV bus failure at PIAL the contingency management plan states that an outage to the single 66kV bus zone will result in a loss of supply to both PIAL and Point Vernon (POVE) substations. This is because POVE is a radial feeder fed from the PIAL 66kV bus, totalling 31MVA peak demand. It is noted that a new 66kV feeder is proposed to be constructed to POVE to address these Safety Net constraints at POVE as part of project 1170529. Whilst security issues are addressed at POVE, Pialba currently has just over 5200 customers connected (Ergon Energy 2019-20 Distribution Feeder Database). If there is a 66kV bus fault at PIAL, manual switching is required to isolate the faulted bus section and to restore the unsupplied load within 1 hour, which is not considered possible.

3.2. Quantification of the Identified Need

- **Ageing plant**

The primary objective of this investment is to address the risk to the network, plant and personnel from operating such plant which is at the end of its lifecycle (lifecycle of an asset being the year of its manufacture, operational conditions and its condition assessment towards the recommended end of useful life).

- **Safety Net non-compliance**

The second objective of this investment is to address the Safety Net non-compliance. Please refer to Appendix 2 – Safety Net Compliance, for details on the applied service standards and the safety net security criteria.

3.3. Assumptions in relation to the 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.

- **Load Profile**

Characteristic peak day load profiles shown in Section 2.1 are unlikely to change significantly from year to year, i.e. the shape of the load profile will remain virtually the same with increasing maximum demand.

- **Forecast Maximum Demand**

It has been assumed that peak demand at PIAL will grow as per the base case load forecast.

Factors that have been considered when the demand 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)

- forecast growth rates for organic growth

- **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.

- **System Capability – Transfer Capacity**

In times of contingency, for example when one transformer is faulty, load may be transferred to another substation via the distribution network. The distribution network transfer capability is largely determined by the capacity of the powerlines to carry the transferred load as well as their ability to maintain system voltages.

4 Market Benefits

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). Consistent with NER clause 5.17.1(c)(4), Ergon Energy has considered the following classes of market benefits:

- Changes in voluntary load curtailment;
- Changes in involuntary load shedding and customer interruptions caused by network outages using a reasonable forecast of the value of electricity to customers;
- Changes in costs for parties other than the RIT-D proponent due to differences in the timing of new plant, capital costs, and operating and maintenance costs;
- Differences in the timing of expenditure;
- Changes in load transfer capacity and the capacity of embedded generators to take up load;
- Any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the NEM;
- Changes in electrical energy losses.

4.1. Changes in Voluntary Load Curtailment

None of the options considered in this RIT-D include any voluntary load curtailment. There are no customers on such arrangements in the Pialba area at the moment. Any market benefits associated with changes in voluntary load curtailment have been considered but not included.

4.2. Changes in Involuntary Load Shedding

A reduction in involuntary load shedding is expected from all the credible options presented in this report. The fact is that the aged substation assets present an area wide level of risk to the supply network. The benefits from changes in involuntary load shedding have not been quantified and considered in this report because they are not so significant as to impact the financial decision-making and would be similar for all options.

4.3. 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.

4.4. Differences in Timing of Expenditure

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

4.5. Changes in Load Transfer Capacity

The credible option identified in this RIT-D assessment is not expected to affect the load transfer capacity in the Pialba area.

4.6. 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.

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 the future.

4.7. Changes in Network Losses

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

5 No Non-Network Alternatives

Ergon Energy has determined there is no non-network alternative that would be technically viable to address the network risk associated with the poor condition of the existing assets, i.e. assets near end of useful life and Safety Net non-compliance.

The following non–network solutions have been assessed for either deferring or replacing the network investment required in the Pialba supply area:

- Demand Management (Demand Reduction) such as power factor correction, energy efficiency, load control.
- Demand Response through customer embedded generation, call off load and load curtailment contracts.

The above have been assessed as not technically viable as they will not address the network risk associated with poor condition of the assets.

6 Network Options Considered

Ergon Energy has considered and evaluated four network options for addressing the identified need at PIAL. These options are described below in brief.

Option 1: In-situ replacement of outdoor 66kV plant / T1 with new building

Option 2: Greenfield replacement of Torquay feeder/T1 and in-situ replacement of remaining outdoor 66kV plant with new building

Option 3: New 66/11kV substation with outdoor 66kV switchgear

Option 4: New 66/11kV substation with indoor 66kV switchgear

6.1. Option 1: In-situ Replacement of Outdoor 66kV Plant and T1

Option 1 (Stage 1) involves the following scope of works. This option consists of 5 stages over the next 40 years to replace assets in-situ as they reach end of service life.

- Expand the substation yard to the east and build a new 11kV control and protection building
- Replace 66kV Torquay and Maryborough circuit breakers (CBs) with new in-situ
- Replace 66kV busbar between the Torquay and Maryborough feeder bays
- Install new 66kV CTs to assist in the establishment of the duplicated protection scheme
- Install duplicated DC system in the new building
- Install 2 station service transformers
- Repair multiple structural defects
- Install / replace substation security fence and install new security features.

The estimated capital cost of this option is $15.6M.

6.2. Option 2: Greenfield Replacement of T1 and In-situ Replacement of Remaining Outdoor 66kV Plant

Option 2 proposes that the substation yard is expanded to the north and the east to enable greenfield replacement of T1 and the Torquay 66kV feeder bay. The remaining 66kV assets will be replaced in-situ under this option. This option consists of 3 stages over the next 40 years to replace assets reaching end of service life.

The estimated capital cost of this option is $16.04M.

6.3. Option 3: Build New 66/11kV substation with Outdoor 66kV Switchgear and Decommission Existing Substation - *Preferred*

This is the preferred network option to replace assets at PIAL that have been identified as being in poor condition by building a new 66/11kV substation with outdoor 66kV switchgear.

As per the current program of works, the start of construction is forecast in February 2023 with construction completing in May 2025.

The estimated capital cost of this option is $17.96M. As the preferred option, the scope of this option is detailed in section 6.5 below.

6.4. Option 4: Build New 66/11kV Substation with Indoor 66kV Switchgear and Decommission Existing Substation

This option is similar to Option 3 above, but with indoor 66kV and 11kV switchgear.

The estimated capital cost of this option is $27.8M.

6.5. Scope of the Preferred Internal Option – Option 3

The following works are proposed to be carried out as part of the preferred network solution at PIAL:

- Build a new substation to the north of the existing substation with 3x 66kV feeder bays, 2x 66/11kV transformers, a new building with 11kV switchgear and all protection/control panels as well as a duplicated DC system.
- Install 2x 11/0.415kV house transformers.
- Connect all 11kV feeder exit cables to the existing 11kV network.
- Extend 66kV Torquay feeder from the eastern side of the substation to connect onto the feeder bay.
- Extend 66kV Maryborough and Point Vernon feeders from the western side of the substation to connect onto the feeder bays.
- Install the substation fence and security features.
- Decommission the existing substation.
- In the remote end at Torquay substation, install new protection schemes for Pialba feeder and decommission the 11kV cap bank C403.

6.6. Financial Analysis

Net Present Values of the four network options are presented in Table 3 below. The NPV analysis demonstrates that Option 3 has the lowest Net Present Cost. Despite being lower in the capital costs of the stage 1 work, Options 1 and 2 lose out to Option 3 because of multiple additional stages of work in the future years and higher operational expenses to maintain the remaining assets associated with brownfield projects.

Table 3 – Net Present Value Analysis

SCENARIO A Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV
1	In-situ replacement of outdoor 66kV plant/T1 with new building	3	**-18,909**	-16,338	-2,571
2	Greenfield replacement of Torquay feeder/T1 and in-situ replacement of re	2	**-16,951**	-15,998	-953
3	New 66/11kV substation with outdoor 66kV switchgear	1	**-15,777**	-15,777	0
4	New 66/11kV substation with indoor 66kV switchgear	4	**-24,428**	-24,428	0

7 Conclusion

This FPAR represents the final stage of the RIT-D process to address the identified need at PIAL.

Ergon Energy intends to take steps to progress the recommended solution(s) to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements as necessary.

The preferred network option is to replace the assets in poor condition.

7.1. Satisfaction of the RIT-D

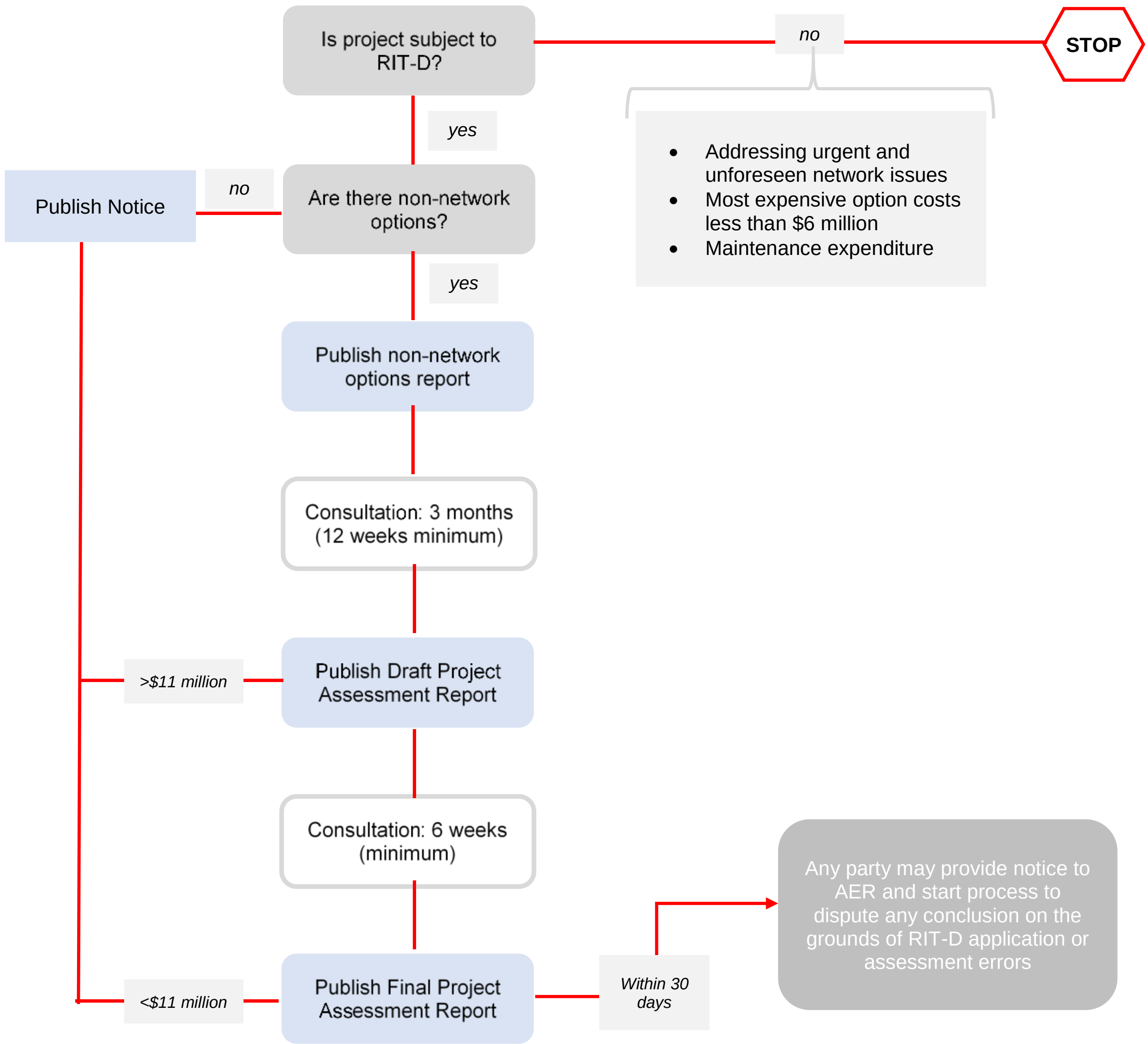
The proposed preferred option satisfies the RIT-D. This statement is made on the basis of the detailed analysis set out in this report. Compared to the other options, the proposed option is technically and economically more competitive and addresses the risks at PIAL.

8 Compliance Statement

This FPAR complies with the requirements of NER section 5.17.4(r) as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary);	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the DPAR;	1.1
(4) a description of each credible option assessed	6
(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	4
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	6
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	4
(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	4
(9) the results of an NPV analysis of each credible option and accompanying explanatory statements regarding the results	6.6
(10) the identification of the proposed preferred option	6.3
(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	6, 6.3, 6.5
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	1.2

Appendix 1 – The RIT-D Process



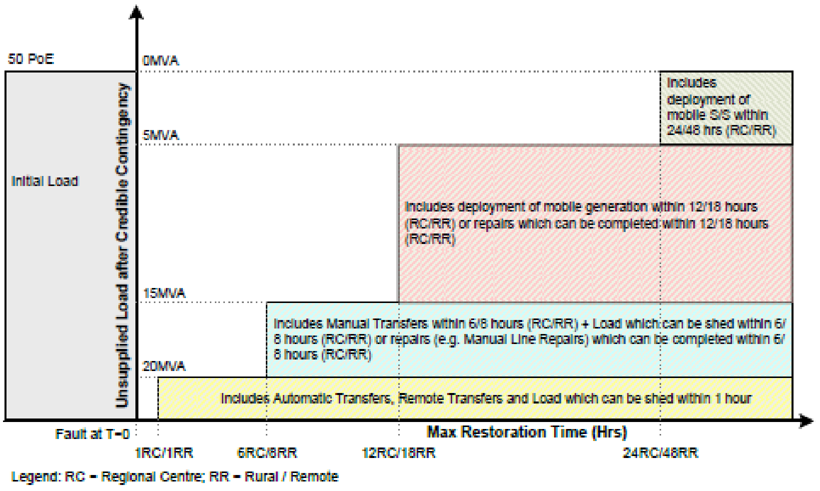
Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.

Appendix 2 – Safety Net Compliance

Applied Service Standards

The applicable service standard for this planning proposal is Safety Net[1] which is "a strategy to avoid unexpected customer hardship and/or significant community or economic disruption by mitigating the effects of credible contingencies largely on the sub-transmission network, which have a low probability of occurring and result in high consequence network outages and loss of supply to many customers. Safety Net provides a 'base-case' security level to cater for Low-Probability High Impact events". It is included in Ergon Energy's Distribution Authority and is therefore a mandatory business requirement.

The following table shows the applied service standards for Ergon Energy's sub-transmission network.



Safety net requirements

Safety Net Security Criteria

To address the low probability high impact risk for feeder outage contingencies, the Safety Net Security Criteria is applied to restore supply within the allowable timeframe. The safety net criteria are classified into Regional Centre and Rural Area, each with a different timeline as follows:

[1] *Safety Net Application, Evaluation and Economic Investment Manual*, purpose of Safety Net, p.6.

Safety Net Criteria

Safety Net – Load not supplied and maximum restoration times following a credible contingency	
Regional Centre	**Rural Areas**
Less than 20MVA (5000 customers) after 1 hour; Less than 15MVA (3600 customers) after 6 hours; Less than 5MVA (1200 customers) after 12 hours; and Fully restored within 24 hours.	Less than 20MVA (7700 customers) after 1 hour; Less than 15MVA (5800 customers) after 8 hours; Less than 5MVA (2000 customers) after 18 hours; and Fully restored within 48 hours.