Regulatory Investment Test for Distribution

Reliable Provision of Electricity to the Barcaldine, Longreach and Blackall area

Draft Project Assessment Report

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

Publication date: 21 May 2021

Consultation Period Starts: 21 May 2021

Consultation Period Closes: 09 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 Barcaldine 132/66/22kV substation (BARC) in the Barcaldine 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 a 132/66/11kV transformer, a 66/22kV transformer, a 132kV circuit breaker (CB), two 66kV CBs, nine 66kV current transformers (CT), various surge diverters (SD), and a large amount of protection relays require replacement.

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 connected to many solar farms and a generator, staff attendance is relatively frequent and catastrophic failure of plant presents a safety risk to these 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 30 June 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 is a Draft Project Assessment Report (DPAR), where Ergon Energy provides both technical and economic information about the internal options in accordance with the requirements of clause

5.17.4(i) of the NER. Ergon Energy's preferred solution to address the identified need is to replace 132/66/22kV primary and secondary plant in situ. The preferred solution cost is estimated to be $11.51M including overheads and capitalised interest.

Interested parties are invited to make submissions or any comments on the findings of this report for addressing the identified need in the Barcaldine area.

Submissions in writing are due by 09 July 2021 by 4:00 PM and should be lodged to Ergon Energy's Demand Management Inbox below.

Any inquiries about this RIT-D may also be sent to:

E: demandmanagement@ergon.com.au

P: 13 74 66

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1 Introduction

This DPAR has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(i) of the NER.

This report represents the second stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need for BARC.

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 Barcaldine 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.

1.2. Contact Details

For further information, inquiries and submissions:

E: demandmanagement@ergon.com.au

P: 13 74 66

2 Background

Barcaldine 132/66kV Bulk Supply Substation (T072) and Barcaldine 66/22kV Zone Substation (BARC) are co-located some 580kM west of Rockhampton in the central mid-west region of QLD. Fed out of Lilyvale (LILY) 275/132kV via 352km of 132kV line, T072 is a critical Energy Queensland asset that provides a reliable power supply to approximately 6323 residential and commercial customers in the Barcaldine, Blackall, and Longreach regions network spanning 144 thousand square kilometres and with a current maximum demand of 20MVA. BARC 66/22kV supplies the Barcaldine region of 1552 domestic customers and 654 commercial/industrial/agricultural customers with a current maximum demand of 7MVA including Barcaldine and Alpha townships and extensive rural SWER networks.

In addition to servicing the network load, T072 and BARC have, in recent years, become the National Electricity Market (NEM) connection point for utility scale solar farms: Dunblane (DSF) 7.2MW, Barcaldine (BSF) 20MW and Longreach (LSF) 14MW. These solar farms rely on the electrical infrastructure at T072 and BARC to provide a reliable connection capacity to the NEM. With minimum network load of only 6MW at times of peak solar generation, total dispatch is constrained by the load and the transformer capacities.

The subtransmission arrangement is shown in Figure 1. T072 is supplied radially from Lilyvale 275/132kV transmission connection point (TCP) via 92km 132kV line (7153) to Clermont (CLER) 132/66/22kV substation and 260.1km 132kV line (7154) to T072. T072 supplies 107km 66kV line (6080) to Blackall (BLAK) 66/22kV substation and 113km 66kV line (6079) to Longreach (LONG) 66/22kV substation. Co-located with T072, BARC 22kV supplies the Barcaldine region including Alpha, Jericho, Muttaburra and Aramac networks.

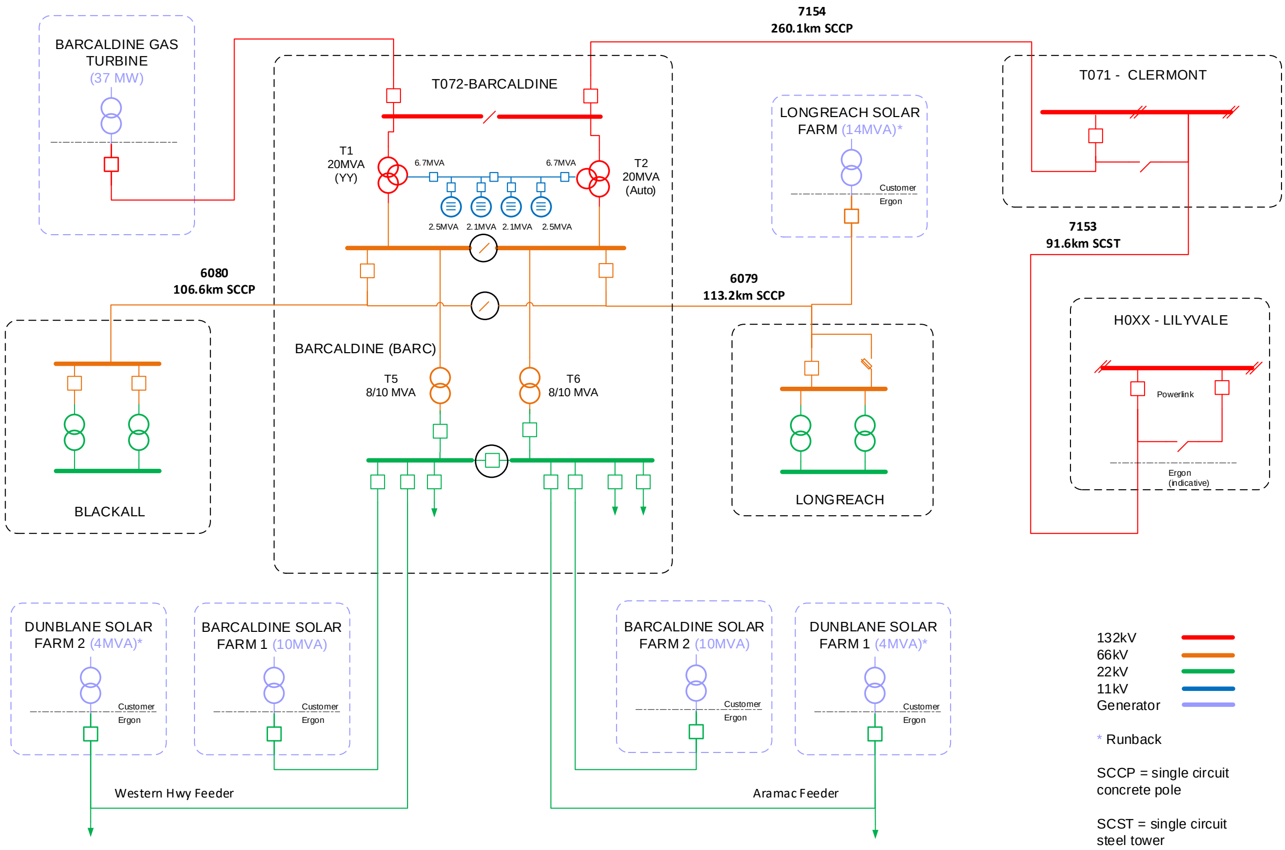


Figure 1 – Barcaldine area Network

2.1. Load Profile / Forecasts

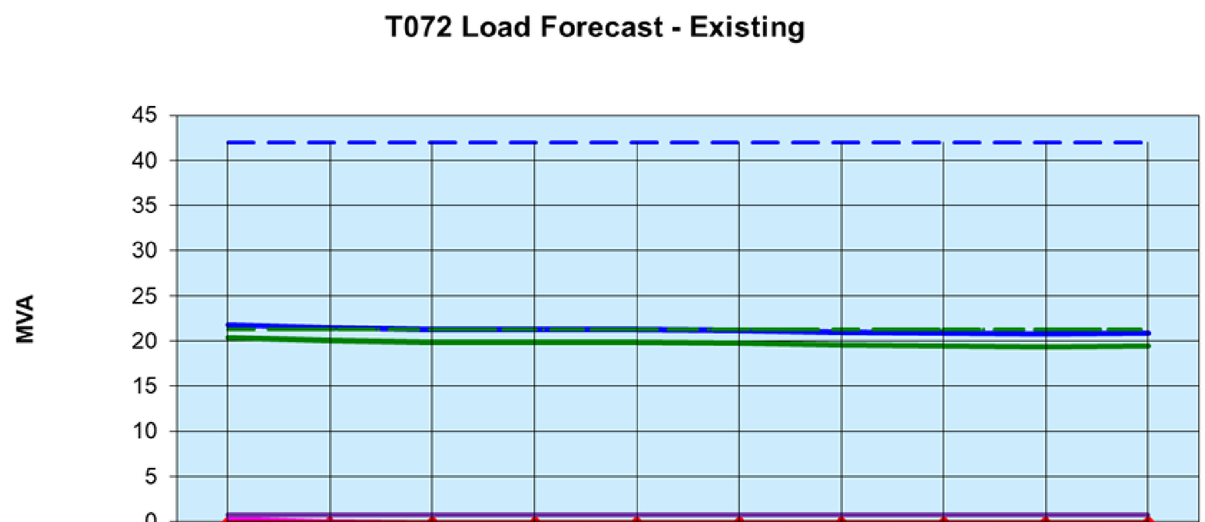
T072 and BARC are run in a split bus arrangement and as such the load is not distributed evenly between the transformers. The peak coincident loads supplied from T072 and BARC are tabulated in **Error! Reference source not found.**.

Table 1 – Substation loading summary (Peak Loads – Summer Evening – no generation)

Transformer	**Transformer Rating** (Load NCC Rating)	**Transformer Peak Load** (Summer Evening)	**Load Distribution**	
T1 (reactors OFF)	20 MVA [1]	7.1 MVA	Blackall 66kV Feeder	4.6 MVA
T5	10 MVA	2.5 MVA	Barcaldine 22kV Bus 1	2.5 MVA
Split Bus				
T2 (reactors OFF)	22 MVA [1]	15.0 MVA	Longreach 66kV Feeder	10 MVA
T6	10 MVA	5.0 MVA	Barcaldine 22kV Bus 2	5.0 MVA

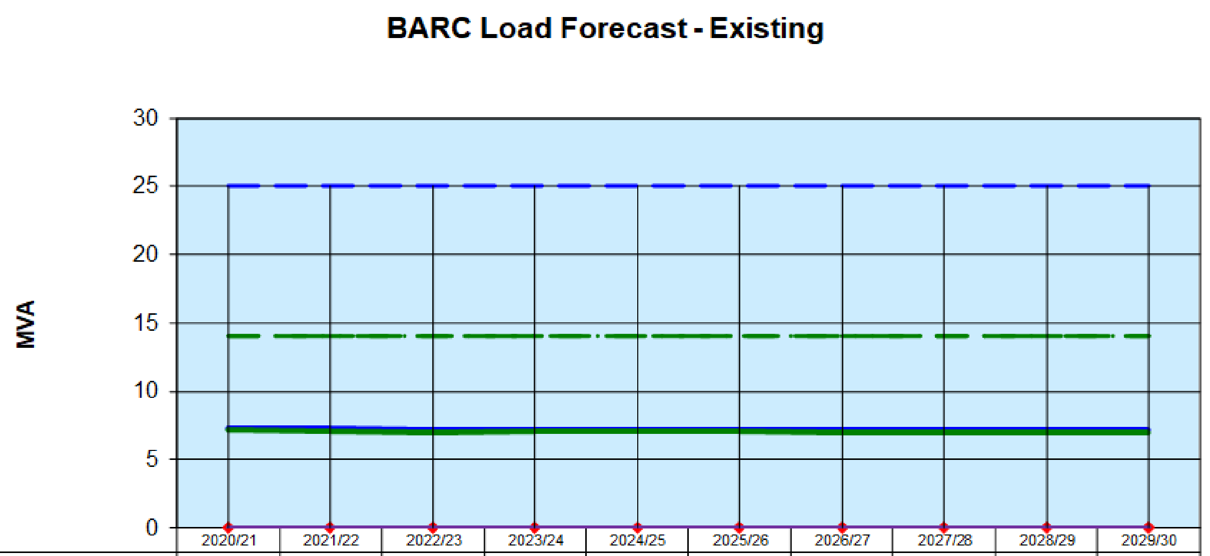
[1] 66kV rating with 11kV reactor bank not energised, as will be the case at times of peak load.

Table 1 indicates there are no augmentation drivers for the foreseeable future at Barcaldine substation. Based on a 10POE (10% probability of exceedance) load forecast the demand is projected to reach 20.8MVA by 2030.



	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
10 PoE Load	21.81	21.47	21.30	21.26	21.24	21.17	20.96	20.87	20.77	20.83
Summer NCC	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00
Load > NCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50 PoE Load	20.33	20.02	19.86	19.83	19.81	19.74	19.55	19.47	19.37	19.43
Summer ECC	21.30	21.30	21.30	21.30	21.30	21.30	21.30	21.30	21.30	21.30
Summer 2HEC	21.30	21.30	21.30	21.30	21.30	21.30	21.30	21.30	21.30	21.30
LAR	0.33	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Available Transfers	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Avail Mobile Eqpt	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70

Figure 2 – T072 load forecast



	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
10 PoE Load	7.34	7.24	7.20	7.20	7.23	7.23	7.18	7.16	7.14	7.16
Summer NCC	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
Load > NCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50 PoE Load	7.16	7.06	7.02	7.03	7.05	7.05	7.00	6.99	6.96	6.99
Summer ECC	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00
Summer 2HEC	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00
LAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Available Transfers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avail Mobile Eqpt	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 3 – BARC load forecast

BARC is equipped with 2x 8/10MVA 66/22kV transformers providing a Normal Cyclic Capacity of 25MVA. The 10 year 10 PoE and 50 PoE load forecasts, and the existing Normal Cyclic Capacity (NCC)(N capacity), Emergency Cyclic Capacity (ECC)(N-1 capacity), Residual Load at Risk (RLAR), available transfers and available mobile equipment, are shown in Figure 2 (Split bus arrangement exists - refer also to Table 1 above).

3 Identified Need

3.1. Description of the Identified Need

3.1.1. Aged and Poor Condition Assets

A condition assessment of BARC 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 a 132/66/11kV transformer, a 132kV CB, two 66kV CBs, nine 66kV CTs, various SDs, and a large number of protection relays require replacement.

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 connected to many solar farms and a generator, staff attendance is relatively frequent and catastrophic failure of plant presents a safety risk to these staff.

Primary and secondary plant assets recommended for replacement are outlined in Table 2 and Table 3.

Table 2 - Primary plant recommended for replacement

Category	Plant No	Op. Number	Voltage	Make
Switchgear	CB91640949	CB4412	132kV	MITSUBISHI
Switchgear	CB91457538	BB-S603	66kV	ASEA HLC
Switchgear	CB91942468	BB-S604	66kV	ASEA HLC
Instrument Transformer	CT94228009	11300114	66kV	Koncar
Instrument Transformer	CT94228008	11300112	66kV	Koncar
Instrument Transformer	CT94228007	11300120	66kV	Koncar
Instrument Transformer	CT94285382	997308	66kV	Koncar
Instrument Transformer	CT94286065	997294	66kV	Koncar
Instrument Transformer	CT94286064	997303	66kV	Koncar
Instrument Transformer	CT92136237	M2458	66kV	Modern Products
Instrument Transformer	CT92416269	M2461	66kV	Modern Products

Instrument Transformer	CT92552069	M2459	66kV	Modern Products
Power Transformer	T1	TR91935660	132/66/11kV	Hackbridge
Power Transformer	T5	TR91751119	66/22kV	Wilson
Cable	NA	NA	NA	NA
AC Distribution Panel	NA	NA	NA	NA
DC Distribution Panel	NA	NA	NA	NA

Table 3 - Secondary plant recommended for replacement

Protection Relay	Function	Make
PR94810034	Barcaldine GT Feeder Main CB Fail Relay	GEC KCGG130

3.1.2. Standards Non-compliance and Operational Requirements

To address non-compliance with various Australian Standards, T1 and T5 require new oil containment bund walls be built.

Due to the sizes of the new transformers, replacement of the transformer T1 132kV CB with a single-pole operated CB controlled by a Point-on-Wave (PoW) synchronism relay is required to reduce the switching transients and the transformer inrush current.

At present there is only a single Direct Current (DC) system with two battery strings and one DC charger at T072. If the DC supply fails, the ability of the protection relay to control and isolate the fault is lost. This could result in catastrophic failure of the substation equipment and loss of supply. A duplicated DC system is therefore required to ensure a reliable protection and control systems as expected in the NER.

The current configuration has a shared CB and CT for multiple transformers. Operationally this does not allow timely and minimal interruptions in case of a planned or unplanned outage. Three additional 66kV dead tank CB’s need to be installed in the transformer T5, the 66kV bus section and the 66kV Blackall feeder bays. A 66kV isolator and three 66kV voltage transformers (VT’s) are also required to be installed in the 66kV Blackall feeder bay to meet the operational requirement.

Table 4 – Primary and Secondary plant new installation

Category	Plant No	Voltage	Make
Protection Relay	Barcaldine GT Feeder Backup CB Fail Relay	NA	Schneider P142
Protection Relay	Transformer T1 132kV CB	NA	GE RPH3

	4412 PoW Relay		
Protection Relay	Transformer T1 Main CB Fail Relay	NA	ABB REF620
Protection Relay	Transformer T1 Backup CB Fail Relay	NA	Schneider P142
Circuit Breaker	66kV Bus Section CB	66kV	GE DT1
Protection Relay	66kV Bus (T1/T5 Side) Main Protection	NA	SEL 487
Protection Relay	66kV Bus (T1/T5 Side) Backup Protection	NA	Schneider P746
Circuit Breaker	Transformer T5 66V CB/CT	66kV	GE DT1
Cable	Transformer T5 22kV Cable	22kV	630mm^2 cable to achieve a total minimum rating of 28MVA
Circuit Breaker	Blackall Feeder 66kV CB/CT	66kV	GE DT1
Isolator	Blackall Feeder 66kV Isolator	66kV	PLP Isolator
Instrument Transformer	Blackall Feeder 66kV VT	66kV	Koncar

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).

- **Standards Non-compliance and Operational Requirements**

The second objective of this investment is to address non-compliance with current Standards and operational requirements to allow timely and minimal customer outages.

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.

- **Forecast Maximum Demand**

It has been assumed that peak demand at BARC and T072 will decrease 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**

Due to the radial and relatively isolated nature of the Barcaldine network, in times of contingency, for example when one transformer is faulty, no load may be transferred to another substation via the distribution network.

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 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 Barcaldine 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.

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 Barcaldine 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.

The following non–network solutions have been assessed for either deferring or replacing the network investment required in the Barcaldine 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 one network option for addressing the identified need at BARC. This option is described below in brief.

6.1. Option 1: In-situ Replacement of T1, T5 and various primary and secondary plant

Option 1 consists of replacement of assets in-situ as they reach end of service life, and involves the following scope of works:

- Replace 132/66/11kV transformer T1
- Replace 66/22kV transformer T5
- Replace 66kV T1 and T2 CBs and their associated CT's
- Replace transformer T1 132kV CB with a single pole operated CB controlled by a PoW synchronism relay.
- Install three additional 66kV dead tank CB's in the transformer T5 bay, the 66kV bus section and the 66kV Blackall feeder bays to meet operational requirements.
- Install an additional 66kV isolator and three 66kV VT's in the 66kV Blackall feeder bay to meet operational requirements.
- Replace a total of six 132kV SD's, fifteen 66kV SD's and three 22kV SD's.
- Replace the CB Fail relay in the 132kV Barcaldine Gas Turbine (GT) feeder and install an additional backup CB Fail relay.
- Install a duplicate DC system and replace two DC distribution panels.
- Install a new AC distribution panel

Table 5 – Preferred option construction timetable

Design complete	30/04/2023
Construction start	30/08/2023
Construction completion	30/02/2025

The estimated option cost is $11.51M.

6.2. Preferred Internal Option

The preferred network option is Option 1, replace assets in situ.

This proposed network option above has been scoped with the aim of meeting the identified need i.e., various equipment reaching end of life, non-compliance with current standards, and operational inflexibility. The proposed option addresses this need by replacing aged equipment in situ with equipment complying with current standards, and installing three additional circuit breakers in the 66kV bus section, and the T5 and Blackall feeder bays along with an additional VT and an additional isolator in the Blackall feeder bay to meet operational requirements by increasing operational flexibility at this site.

The estimated preferred project cost is $11.51M.

6.3. Financial Analysis

No Net Present Value analysis was carried out as only a single option has been identified. The estimate for this option is in current dollar value therefore the NPV of this option is $11.51M.

7 Submissions and Next Steps

The internal investigations undertaken on the feasibility of the non-network solutions revealed that it is unlikely to find a complete non-network solution or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Barcaldine area to address the identified need.

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

7.1. Request for Submissions

Ergon Energy invites written submissions on this report from registered participants and interested parties.

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

7.2. Next Steps

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

Ergon Energy intends to publish the FPAR no later than 30 July 2021.

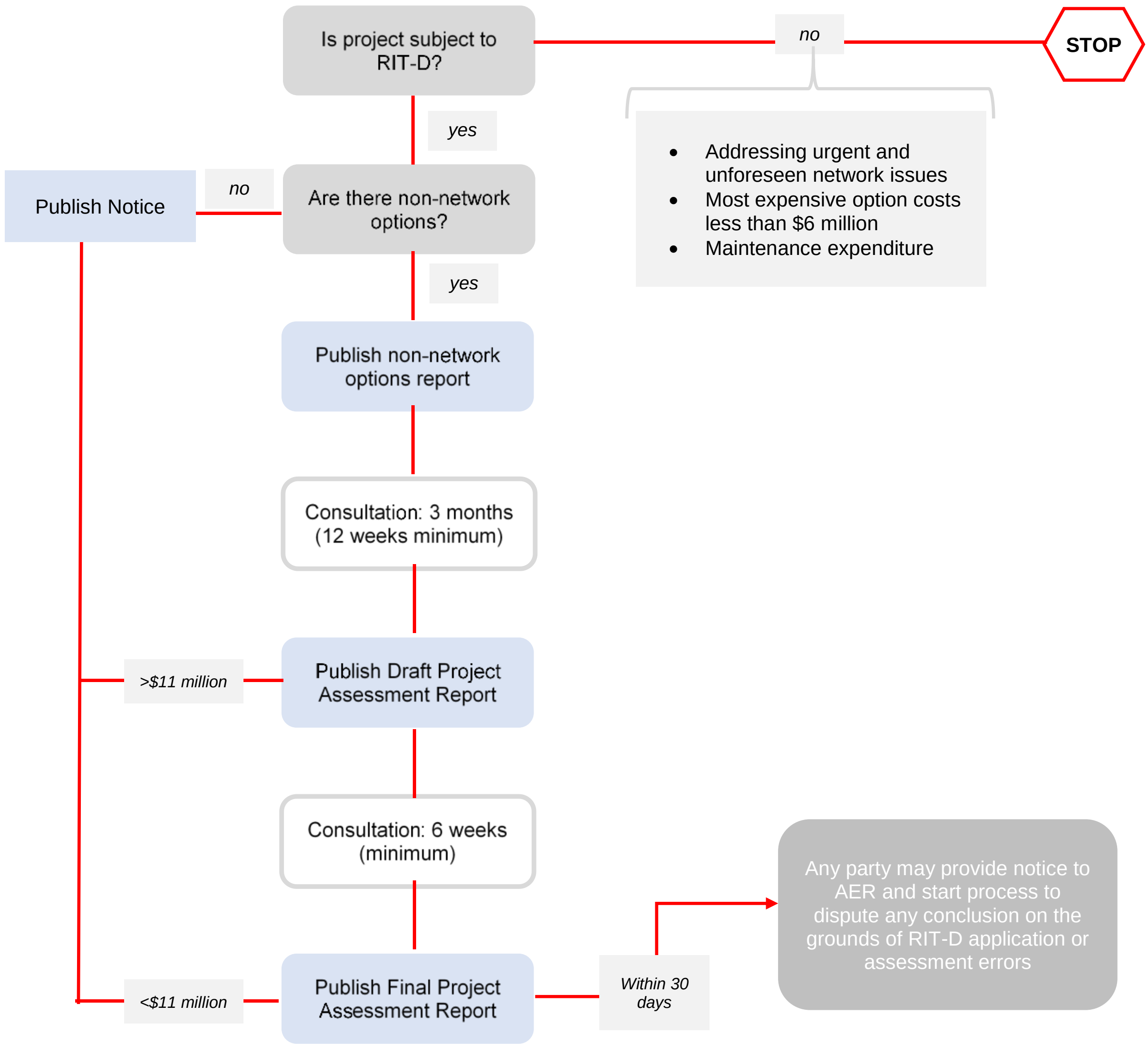
8 Compliance Statement

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

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary);	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the NNOR;	N/A
(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	6.3
(10) the identification of the proposed preferred option	6.1
(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	6, 6.1, 6.2
(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.