Addressing reliability requirements in the Bundaberg network area

Final Project Assessment Report

Publication Date: April 2018

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Executive Summary

Ergon Energy Corporation Limited (Ergon Energy) has prepared this Final Project Assessment Report (the Report) in accordance with the requirements of clause 5.17.4(p) of the National Electricity Rules (NER).

It follows a determination made by Ergon Energy that there is not a non-network option that is potential credible option, or that forms a signification part of a potential credible option to address the identified need in Bundaberg. Ergon Energy published their notice under clause 5.17.4(d) of the National Electricity Rules. This Report includes information relating to the following matters:

- A description of the identified need Ergon Energy is investing in;
- The assumptions used in identifying the need;
- A description of each credible option assessed by Ergon Energy and their:
  - associated quantified market benefits;
  - applicable cost, including breakdown of operating and capital expenditure;
- a detailed description of the methodologies used in quantifying each class of cost and market benefit;
- reasons why Ergon Energy determined that a class or classes of market benefits or costs do not apply to a credible option;
- results of a net present value analysis of each credible option and supporting explanatory statements;
- identification of Ergon Energy’s proposed preferred option, including:
  - details of the technical characteristics;
  - the estimated construction timetable and commissioning date;
  - indicative capital and operating cost;
  - a statement of accompanying detailed analysis that the proposed preferred option satisfies the RIT-D; and
  - if the preferred option is for reliability corrective action and that option has a proponent, the name of the proponent.

Ergon Energy Corporation Limited (Ergon Energy) is responsible (under its Distribution Authority) for electricity supply to the Bundaberg area in southern Queensland.

The Bundaberg region consists of approximately 45,000 customers and is located in the Wide Bay-Burnett area of the Southern Region of Ergon Energy’s Network. The region is supplied by the T20 Bundaberg Substation and its 66kV ring-feed. The West Bundaberg, Bundaberg Central, East Bundaberg and South Bundaberg substations are connected directly onto the 66kV ring-feed. The Bargara, Meadowvale and Gooburrum zone substations are supplied via radial lines connected to the 66kV ring-feed.

A fundamental requirement of Ergon Energy’s Distribution Authority D01/99 is to comply with Safety Net targets that seek to effectively mitigate the risk of low probability – high consequence network outages to avoid unexpected customer hardship and / or significant community or economic disruption. Bundaberg T020 in its current state will not meet the safety net outage restoration times should a 132kV OR 66kV bus outage occur. Bundaberg T020 bulk supply point
supplies 112MVA at peak load to the wider Bundaberg region and hence a bus outage is of significant impact.

Bundaberg T020 bulk supply point supplies between 30 – 112 MVA to the wider Bundaberg region throughout the year and the expected restoration time for a 132kV or 66kV bus outage at T020 Bundaberg is expected to be two hours therefore regardless of the time of the event, it is expected that Ergon Energy will breach the Safety Net regulatory requirement should a 132kV or 66kV bus outage occur at T020 Bundaberg if no investment is made.

To achieve the objective of complying with safety net, the only credible option considered is to establish a bus section breaker in the 66kV bus and 132kV bus at Bundaberg Substation and reconfigure the 66kV bus.
Notice of no credible non-network option.

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1. Introduction

Ergon Energy has prepared this Final Project Assessment Report in accordance with the Regulatory Investment Test for Distribution (RIT-D) provisions outlined in Chapter 5 of the NER. As the non-network credible option does not exceed $10 million, Ergon Energy has not published a Draft Project Assessment Report.

The T020 Bundaberg Contingency Management plan details that the expected restoration time for a 132kV or 66kV bus outage is two hours, while the maximum time allowable under safety net is one hour. Bundaberg T020 bulk supply point supplies between 30 – 112 MVA to the wider Bundaberg region throughout the year. Regardless of the time of the event, it is expected that Ergon Energy will breach the Safety Net regulatory requirement by up to 92 MVA should a 132kV or 66kV bus outage occur at T020 Bundaberg if no investment is made. Installation of 2 bus section circuit breakers and associated equipment will allow restoration to comply with Safety Net.

In initiating 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 the proposed solution.
2. Forecast load, capacity, and network characteristics

2.1. Restoration timeframes and safety net

The primary component of the identified need is an inability to meet safety net requirements in the event of a bus fault at T020 Bundaberg.

2.1.1. Safety net requirements

A fundamental requirement of Ergon Energy’s Distribution Authority D01/99 is to comply with Safety Net targets that seek to effectively mitigate the risk of low probability – high consequence network outages to avoid unexpected customer hardship and / or significant community or economic disruption. Bundaberg T020 in its current state will not meet the safety net outage restoration times should a 132kV OR 66kV bus outage occur.

For further information regarding the Safety Net and recent changes to reliability standards, please refer to Section 5 – Changes to Reliability Standards.

Under the revised reliability standards, Ergon Energy is no longer required to provide full N-1 security of supply on the 66kV network that supplies Bundaberg. Instead, a set of supply restoration targets, known as the ‘Service Safety Net Targets’ apply. The Safety Net targets seek to limit the severity (and thus the hardship experienced by Ergon Energy customers) following a “credible contingency” for loads up to the 50% PoE forecast.

Under the Safety Net, Bundaberg is classified as a “Regional Centre” and has the following restoration targets. The load unserved must be:

1. Less than 20 MVA after 1 hour
2. Less than 15 MVA after 6 hours
3. Less than 5 MVA after 12 hours
4. Fully restored within 24 hours
2.1.2. Safety net analysis

![Ergon Safety Net Analysis for: T020 Bundaberg - 66kV Total Load](image)

**Figure 1 – Bundaberg T020 substation safety net analysis.**

As the only supply point into the region, an outage on either the 66kV or 132kV bus will result in loss of supply to the Bundaberg region.

The T020 Bundaberg Contingency Management plan details that the expected restoration time for a 132kV or 66kV bus outage is two hours, while as detailed in section 2.1.1, the maximum time allowable under the safety net is one hour. Bundaberg T020 bulk supply point supplies between 30 – 112 MVA to the wider Bundaberg region throughout the year. Regardless of the time of the event, it is expected that Ergon Energy will breach the Safety Net regulatory requirement by up to 92MVA for an hour should a 132kV or 66kV bus outage occur at T020 Bundaberg if no investment is made.

"Expected" vs "Target" supply restoration following bus contingency at T020 Bundaberg on a peak day is shown in Figure 1. If an outage was to occur at any time, as shown in Figure 5, Ergon Energy would be unable to meet the Safety Net restoration targets. However, it should be noted that consideration needs to be given to the credibility of such an event occurring (i.e. both the permanent fault and the timing) before making decisions about the appropriate level of mitigation (including the option of none).
2.2. Network characteristics

2.2.1. Geographic region

The geographic region covered by this RIT-D is the Bundaberg region which consist of approximately 45 000 customers and is located in the Wide Bay-Burnett area of the Southern Region of Ergon Energy’s Network.

Figure 2 – Bundaberg Sub transmission Network

2.2.2. Existing supply system

The Bundaberg region is supplied by the T20 Bundaberg Substation. The West Bundaberg, Bundaberg Central, East Bundaberg and South Bundaberg substations are connected directly onto the 66kV ring-feed. The Bargara, Meadowvale and Gooburrum zone substations are supplied via radial lines connected to the 66kV ring-feed.

Bundaberg T020 bulk supply point supplies 112MVA at peak load to the wider Bundaberg region and hence a bus outage is of significant impact. The following Zone substation would be directly impacted for a 132kV or 66kV bus outage:

- Gooburrum
- Meadowvale
- West Bundaberg
- East Bundaberg
- Central Bundaberg
- South Bundaberg
- Bargara
- Woongarra
- Givelda
- South Kolan
- Bullyard
Figure 3 – The supply area of Bundaberg Substation

2.2.3. Loading - historical and forecast

Figure 4 and Figure 5 below show the historical actual demand for T020 Bundaberg with Figure 4 showing the average daily non-winter profile for the top 5 peak days at T020 Bundaberg and Figure 5 showing the load duration curve at T020 Bundaberg.

Figure 6 shows the 50% probability of exceedance level (50 POE) forecast annual maximum demand for T020 Bundaberg. Figure 9 shows little load growth forecast out to 2028 and also displays the maximum allowable unsupplied load for a 2 hour outage window (20 MVA).
Bundaberg RIT-D
Notice of no credible non-network option.

**Figure 4 – Bundaberg T020 Load Profile and Capability.**

**Figure 5 – Bundaberg T020 66kV Load Duration Curve.**
3. Proposed preferred network option

The sole credible network option is the establishment of a bus section breaker in the 66kV bus and 132kV bus at Bundaberg Substation and reconfiguring the 66kV bus.

This option includes:

**132kV Works including:**
- Installation of a new 132kV Bus Section Bay;
- Installation of a new 132kV CB and CT; and
- Installation of supporting structures for CB and CT.

**66kV Works including:**
- Building a new 66kV Feeder bay behind the AFLC bay;
- Rearrange the 66kV feeders so that West Bundaberg, Sth Kolan, & Sth Bundaberg feeders split across the two buses;
- Demolish the existing West Bundaberg No.2 feeder bay (retain CB and CTs for bus section bay);
- Relocate the two (2) bus VTS so these no longer require a bus outage to access;
- Installation of a new 66kV Bus Section Bay;
- Replacing the 66kV galvanised waterpipe with aluminium bus and removal of all aged bus isolators;
- Removing the existing 66kV overhead strung bu;
- Installation of supporting foundations, conduits and structures for a new 66kV Feeder Bay (New Isis feeder opposite the AFLC bay);
- Installation of new VT footings, conduits and structures on Bus 2 at the end of the bus;
- Installation of new 66kV CB and CT footings, conduits and structures for the 66kB Bus Tie bay;
- Removal of structures and demolishing footing of plant in the existing West Bundaberg No.2 feeder bay; and
- Installation of new VT footings, conduits and structures on Bus 1 in the spare bay adjacent to the Farnsfield feeder bay.
This option will increase sectionalising and restoration flexibility that will enable restoration to occur within the 1 hour safety net limit as prescribed in our Distribution Authority. The estimated capital cost of the preferred option is $7.3 million. Annual operating costs associated with this new capex are estimated to be around $36,500 per annum (assumed to be 0.5 per cent of the capital cost).

Figure 7 – Bundaberg 132kV proposed CB location
4. Assessment of non-network solutions

4.1. Required demand management characteristics

A viable demand management solution must be capable of reducing the unsupplied load at T020 Bundaberg to <20 MVA for the 2 hours required for restoration of supply in the event of an unplanned substation outage due to a bus outage to be considered a viable alternative solution. Current loading at T020 Bundaberg is between approximately 26 MVA and 116 MVA and is 60 MVA, 50% of the time. This equates to support in the event of a substation outage due to a credible contingency event of between 6 MVA and 96 MVA for 2 hours until restoration is completed. This reduction in unsupplied load, may be temporary or permanent, however, it must offer support in both summer and winter, and be cost effective in comparison with the preferred network alternative.

Due to the scale of the shortfall in electricity supply (Refer to Section 2.2.3 for details on the load profiles, and demand forecasts), we consider that a combination of permanent and temporary demand reductions would offer the most plausible scenario for a possible cost effective non-network alternative. A graphical representation of the unsupplied load reduction required is below in Figure 9.
As load growth is forecast to be relatively flat and there are no load transfer options in the event of a T020 Bundaberg outage, the shortfall in supply required to meet safety net requirements is significant with more detail shown in Figure 10.

<table>
<thead>
<tr>
<th>MW of support required</th>
<th>MWh of support required</th>
<th>% of year risk exists</th>
<th>Hours per year risk exists</th>
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<tr>
<td>35.5</td>
<td>71</td>
<td>50</td>
<td>4380</td>
</tr>
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<tr>
<td>55</td>
<td>110</td>
<td>10</td>
<td>876</td>
</tr>
</tbody>
</table>

To be considered a feasible option, any unsupplied load reduction must be technically feasible, and commercially feasible.

Ergon Energy estimates that the construction timeline for the preferred option is 17 months, with assumed commissioning during 2020/21. Ergon Energy intends to commence work on delivering the preferred option 1 in 2019 (in particular, we intend to commence design in mid-2018 and commence construction in April 2019). The feasible option must also be able to be implemented in sufficient time to satisfy the identified reduction need from 2020/21 for deferral of the network investment.
4.2. Demand management value

Ergon Energy’s Intelligent Grid Systems Customer Interactions (IGSCI) Team has assessed the potential demand management options required to defer the network option and to ensure that the solution is technically and commercially viable, and delivered within the required timeframe. The amount of demand management support identified to satisfy the reduction need is as per Figure 11 Ergon Energy considered a number of demand management technologies (discussed under sections 4.2.1 to 4.2.3 of this Report) to determine their commercial and technical feasibility to assist with the identified need at Bundaberg T20 Bulk Supply Point (BSP).

4.2.1. Demand Management (Demand Reduction)

Energy efficiency and other demand reduction measures such as power factor correction, lighting etc. have been assessed as not technically viable as a loss of supply at Bundaberg T20 BSP will result in a loss of power to the whole system. Therefore, reductions in demand will not help to increase restoration times for the large number of unmet load hours.

4.2.2. Demand response

Four methods utilising demand response technology for deferring network investment for the short hours of network support required for the network issue at Bundaberg T20 BSP are: call off load (COL), customers embedded generation (CEG), large scale customer generation (LSG) and customer solar power systems.

4.2.2.1. Customer Call off load (COL)

COL is an effective technique for deferring network investment where the need is for a short time period as is the case at Bundaberg T20 BSP where a 1 hour reduction of unserved load is required.

There are a small number of Large Customers in the Bundaberg area with businesses suited to call off load. Large customer demand response is valued at $250 per kVA /P.A (excluding acquisition costs). The potential maximum demand reduction 3MW would have a total cost of $750,000 P.A including fuel, customer recruitment and establishment costs.

This option has been assessed as technically not viable as it will only defer 5.5% of the identified capacity requirement.

4.2.2.2. Customer embedded generation (CEG)

CEG is an effective technique for deferring network investment where the need is for a short time period as is the case at Bundaberg T20 BSP where a 1 hour reduction of unserved load is required.

In the Bundaberg region CEG large customer demand response is valued at $50-150 per kVA. P.A.

IGSCI has recorded 14 sites that have existing diesel generation. To acquire an estimated
potential maximum demand reduction value of 6.5MW would have a total cost of $493,000 P.A including fuel, customer recruitment and establishment costs.

This option has been assessed as technically not viable as it will only defer 30% of the identified capacity requirement.

4.2.2.3. Large scale customer generation (LSG)

Millaquin Sugar Mill - 5MW Bagasse generator export demand is 2.5MW P.A
Bingera Sugar Mill - 5MW Bagasse generator export demand is 0.75 MW P.A

In the Bundaberg region LSG demand response is valued at $75/kVA P.A. The sugar mills in this area have a combined maximum generation demand capacity of 3.25MW that could be contracted at a total cost of $356,000 P.A, including customer recruitment and establishment costs. Operationally the sugar mills are only seasonally available, the crushing and subsequent availability of the generators occurring between May and December.

This option could potentially defer 20% of the requirement but has been assessed as technically not viable as the generation is not available all year and therefore may not contribute to satisfy the identified reduction need for unsupplied load at Bundaberg T20 BSP.

4.2.2.4. Customer solar power systems

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

There are 40 Large Standard Asset Customers (SAC) connected to Bundaberg T20 with approximately 900kW of export limited PV systems. These systems present a future portfolio opportunity for potential demand response but currently only a very small percentage of solar power systems have a 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.

Ergon Energy has not as yet contracted for this type of Demand Response so the maximum CEG dollar figure of $150/kVA has been used. Maximum estimated potential reduction value available would be 900kW P.A at a total cost of $135,000 P.A plus customer recruitment and establishment costs.

In terms of the unsupplied load at Bundaberg T20 as a load curtailment opportunity this option is not technically feasible, the T20 outage failure would lead to the majority of these systems to cease operating and therefore not contribute to resolving a shortfall in grid supply.
4.2.3. Conclusion

<table>
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<tr>
<th>DM measure</th>
<th>MW identified</th>
<th>% Requirement</th>
<th>$/P.A</th>
<th>Viable</th>
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<tbody>
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<td>0</td>
<td>N</td>
</tr>
<tr>
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<td>3</td>
<td>5.5</td>
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</tr>
<tr>
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<td>30</td>
<td>493,000</td>
<td>N</td>
</tr>
<tr>
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<td>20</td>
<td>356,000</td>
<td>N</td>
</tr>
<tr>
<td>DR Solar</td>
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<td>13.65</td>
<td>65.5</td>
<td>1734000</td>
<td></td>
</tr>
</tbody>
</table>

Figure 11 – Demand Management options summary

Based on the demand management options considered in Section 4, it is not considered possible that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable. Consequently, a Non-Network Options Report has not been prepared in accordance with rule 5.17.4(c) of the National Electricity Rules.

5. Changes to Reliability Standards

Ergon Energy was notified in March 2014 that the Queensland Government had made a decision to implement reforms to the electricity network reliability standards, consistent with the recommendations of the Inter-Departmental Committee on Electricity Sector Reform and the Independent Review Panel on Network Costs.

Specifically, from July 1 2014, these reforms:

1) Remove the requirement to comply with N-1 planning standards.
2) Require that Distributors take an ‘economic’ approach to building network for reliability purposes.
3) Retain the Minimum Service Standards (i.e. a set of target reliability performance indicators), while adding an additional set of “Safety Net” measures. The Safety Net measures provide an upper limit to the customer outage consequence for a single contingency, Low Probability, High Impact event on Ergon’s network.

Along with changes to the transmission system requirements, these changes are forecast to save Queensland in the order of $2 Billion over the next 15 years, applying downward pressure on electricity network charges.
5.1. Service Safety Net Targets

Under Safety Net, Bundaberg is classified as a “Regional Centre” and the following restoration time targets apply for credible contingencies. The load unsupplied must be:

1. Less than 20 MVA after 1 hour
2. Less than 15 MVA after 6 hours
3. Less than 5 MVA after 12 hours
4. Fully restored within 24 hours

Important factors to note under Safety Net:

a) The magnitudes are calculated upon the maximum demand for a 50% PoE forecast

b) The magnitudes and timelines are based on lapsed time after a credible contingency occurs. For example, no more than 20 MVA of load may be unserved 1 hour after a contingency, no more than 15 MVA is to be unserved after 6 hours, no more than 5 MVA is to be unserved after 12 hours, and supply must be fully restored after 24 hours.

c) During an actual outage, Ergon Energy will always endeavour to restore supply as early as can be safely achieved. The timelines above are “planned for” upper limits and as such, the actual customer interruption duration may be significantly less than the timeline (in many cases, no loss of supply would occur at all). For example, while 5 MVA can be “unsupplied” for 24 hours, due to the cyclic nature of network loading, in most locations supply to all customers would typically be restored during the evening/night (noting that the item of plant may not have yet been repaired/replaced). Occasionally, further loss of supply may occur during the high demand period on the following day, while the failed item of plant is still being repaired/replaced, however full supply is to be restored within 24 hours.

d) Large customers with an authorised demand above 1.5MVA, who have not paid for an N-1 supply, do not count against the Service Safety Net Targets and thus may remain unsupplied in some circumstances beyond the timelines given above.

For guidance as to what kind of events that may be considered as credible vs. non-credible contingencies, please refer to clause 4.2.3 of the National Electricity Rules.

5.2. Value of Customer Reliability

The Value of Customer Reliability (VCR) is a “measure, or index, [that] indicates what different types of customers (residential, commercial and industrial) are prepared to pay to maintain reliable electricity supplies.”

VCR forms the basis of the “economic” approach to planning for network reliability. Project costs for proposed network augmentations are compared against the improvement in network reliability they create; at the point where the benefit (i.e. the customer’s willingness to pay for that reliability) exceeds the annualised cost of the augmentation, then the project is justified under this approach.

The significant difference between this approach and the previous “N-1” prescriptive standards is that there is no level of loading on a network element that automatically triggers an augmentation; the timing and form of a network reliability improvement is highly dependent of the price of the project and the benefits generated.