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# TABLE OF CONTENTS

EXECUTIVE SUMMARY .......................................................................................................................... 1  
1.  INTRODUCTION ................................................................................................................................... 2  
2.  BACKGROUND & REASONS AUGMENTATION IS REQUIRED .............................................................. 3  
    2.1.  Background.................................................................................................................................... 3  
    2.2.  Purpose of this “Final Report” ..................................................................................................... 3  
3.  EXISTING SUPPLY SYSTEM TO The St George AREA ........................................................................ 4  
    3.1.  Geographic Region ..................................................................................................................... 4  
    3.2.  Existing Supply System .............................................................................................................. 4  
4.  EMERGING NETWORK LIMITATIONS ............................................................................................... 5  
    4.1.  Limitations of the Existing Network ............................................................................................. 5  
    4.2.  Timeframes for Taking Corrective Action ................................................................................... 5  
    4.3.  Known Future Network and Generation Development ............................................................... 5  
5.  OPTIONS CONSIDERED ....................................................................................................................... 6  
    5.1.  Consultation Summary ............................................................................................................... 6  
    5.2.  Non-Network Options Identified .................................................................................................. 6  
    5.3.  Distribution Options Identified ..................................................................................................... 6  
6.  FEASIBLE SOLUTIONS ......................................................................................................................... 7  
    6.1.  Non Feasible Solutions ................................................................................................................. 7  
    6.2.  Feasible Solutions ....................................................................................................................... 7  
7.  FINANCIAL ANALYSIS & RESULTS ................................................................................................. 8  
    7.1.  Format and Inputs to Analysis .................................................................................................... 8  
        7.1.1  Regulatory Test Requirements ........................................................................................... 8  
        7.1.2  Inputs to Analysis ................................................................................................................ 8  
    7.2.  Financial Analysis ....................................................................................................................... 8  
        7.2.1  Present Value Analysis ....................................................................................................... 9  
        7.2.2  Summary of Economic Analysis ......................................................................................... 9  
    7.3.  Discussion of Results ............................................................................................................... 10  
8.  FINAL DECISION & RECOMMENDATION ......................................................................................... 10
EXECUTIVE SUMMARY

Ergon Energy is responsible (under its Distribution Authority) for electricity supply to the St. George area in Southwest Queensland. Ergon Energy has identified emerging limitations in the electricity distribution network supplying the St. George area.

The peak load on the Roma – St. George 66kV line is above the Security of Supply Criteria threshold of 15MVA, which triggers work to enhance security of supply. The St. George area is supplied via a single 194km 66kV sub-transmission feeder from Roma Bulk Supply Point.

With regards to St. George's performance against the security criteria, during the 2010/11 financial year the load was above 15MVA for a total of 4.5 hours, spread out over 3 days.

Ergon Energy published a Request for Information relating to this emerging network constraint on 23 May 2012. 11 submissions were received by the closing date of 18 July 2012.

The evaluation process eliminated options that presented "battery only" or "solar and battery" solutions due to their inability to meet the partial contingency / risk management definition.

The other proposals were evaluated and scored with the proponents of the top three diesel/hybrid options and a renewable power station option invited to present to the evaluation panel.

Following the presentations and financial evaluations of each proposal, the recommended solution was identified as a diesel generation solution with potential for renewable integration.

Ergon Energy published a Consultation and Draft Recommendation on 5 June 2013. No submissions to the Consultation and Draft Recommendation were received by the closing date of July 2013.

In accordance with the requirements of the National Electricity Rules (NER), this is now a Final Report where Ergon Energy provides both economic and technical information about possible solutions, and our recommended solution to establish a diesel generation solution.
1. INTRODUCTION

Ergon Energy has identified emerging limitations in the electricity distribution network supplying the St George area.

When a distribution network service provider proposes to establish a new large distribution network asset to address such limitations, it is required under the National Electricity Rules (NER) clause 5.6.2(f) to consult with affected Registered Participants, AEMO and Interested Parties on possible options to address the limitations. These options may include but are not limited to demand side options, generation options, and market network service provider options.

Under clause 5.6.2(g) of the NER the consultation must include an economic cost effectiveness analysis of possible options to identify options that satisfy the Australian Energy Regulator’s (AER) Regulatory Test, while meeting the technical requirements of Schedule 5.1 of the NER.

This Final Report is based on:

• the assessment that a reliable power supply is not able to be maintained in the St George area.
• the Request for Information consultation undertaken by Ergon Energy to identify potential solutions to address the emerging distribution network limitations; and
  • an analysis of feasible options in accordance with the AER’s Regulatory Test.

This project has been considered under the reliability limb of the Regulatory Test as the service standards linked to the technical requirements of Schedule 5.1 of the NER and Ergon Energy’s licence conditions are unable to be met, as detailed in Section 4 of this report.

This project was included in the Ergon Energy Network Management Plan 2010/11 to 2014/15.

Information relating to the consultation about this project is provided on our web site:


For further information, please email: regulatory.tests@ergon.com.au
2. BACKGROUND & REASONS AUGMENTATION IS REQUIRED

2.1. Background

If technical limits of the distribution system will be exceeded and the rectification options are likely to exceed $10M, Ergon Energy is required under the NER\(^1\) to notify Registered Participants,\(^2\) AEMO and Interested Parties\(^3\) within the time required for corrective action and meet the following regulatory requirements:

- Consult with Registered Participants, AEMO and Interested Parties regarding possible solutions that may include local generation, demand side management and market network service provider options\(^4\).
- Demonstrate proper consideration of various scenarios, including reasonable forecasts of electricity demand, efficient operating costs, avoidable costs, costs of ancillary services and the ability of alternative options to satisfy emerging network limitations under these scenarios.
- Ensure the recommended solution meets reliability requirements while minimising the present value of costs when compared to alternative solutions\(^5\).

Ergon Energy is responsible for electricity supply to the St George area (under its Distribution Authority) and has identified emerging limitations in the electricity distribution network supplying Roma to St George 66kV line. Augmentation to the electricity distribution network supplying this area is required if reliable supply is to be restored.

2.2. Purpose of this “Final Report”

The purpose of this Final Report is to:

- Provide information about the existing distribution network in the St George area.
- Provide information about emerging distribution network limitations and the expected time by which action must be taken to maintain the reliability of the distribution system.
- Provide information about options identified and considered.
- Explain the process (including approach and assumptions), and the AER’s Regulatory Test used to evaluate alternative solutions, including distribution options.
- Report the solution Ergon Energy has decided on.

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\(^{1}\) Clause 5.6.2(f)  
\(^{2}\) As defined in the NER  
\(^{3}\) As defined in the NER  
\(^{4}\) NER clause 5.6.2(f)  
\(^{5}\) In accordance with the AER’s Regulatory Test Version 3, November 2007
3. EXISTING SUPPLY SYSTEM TO THE ST GEORGE AREA

3.1. Geographic Region

The geographic region covered by this Final Report is broadly described as the St George area as shown on the map below.

3.2. Existing Supply System

St. George is located in the Maranoa area of the South West Region of Ergon Energy's network. St. George area is supplied via a single 194km 66kV sub-transmission feeder from T83 Roma Bulk Supply Point. Rural areas around St. George are supplied at 33kV from 66/33kV St. George Zone Substation, whereas St. George town and Dirranbandi Township are supplied at 11kV from local 33/11kV substations.

St. George Substation consists of 2 x 20MVA 66/33kV transformers and one Static VAr Compensator (SVC) (replaced in 2012), which regulates the voltage on the 66kV bus. The SVC has a range of 8MVAR inductive to 23MVAR capacitive.

The St. George customer base is mainly domestic, but there are however, significant industrial and rural loads, mainly cotton gins and pump loads, which constitute a significant part of the peak load and energy consumption.
4. EMERGING NETWORK LIMITATIONS

4.1. Limitations of the Existing Network

The measured and forecasted peak loads on the receiving end of the Roma – St George 66kV line are shown below for a 20 year period, and have been provided by Network Forecasting. Peak loads beyond 2019/2020 have been calculated by extrapolating the 6 -10 year growth rate.

TABLE 1 – St. George – Supply Substation Load History & Forecast

<table>
<thead>
<tr>
<th>Zone Substation</th>
<th>Maximum Annual Demand Actual</th>
<th>Maximum Annual Demand Forecast</th>
<th>Compound Growth Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>08/09</td>
<td>09/10</td>
<td>10/11</td>
</tr>
<tr>
<td>SAGE St George</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(MW)</td>
<td>12.32</td>
<td>13.96</td>
<td>14.51</td>
</tr>
<tr>
<td>(MVA)</td>
<td>12.75</td>
<td>14.92</td>
<td>15.23</td>
</tr>
</tbody>
</table>

With regard to St. George’s performance against the security criteria, during the 2010/2011 financial year load was above the security of supply criteria threshold of 15MVA for a total of 4.5 hours, spread out over 3 days. The highest observed substation load occurred on 12 Dec 2005, when the load peaked at 17.5MVA. In the same financial year, the substation load exceeded 15MVA for a total of 26 hours across 4 days. Quite a few large water harvesting (flood lift) pumps are supplied by St. George substation. If a flood event was to occur it is estimated that these could add 10MW to the forecast demand.

The capacity of the Roma – St. George 66kV sub-transmission feeder is limited to well below its thermal capacity of 43.3MVA by its voltage regulation. Network modelling has indicated that voltage constraints may occur when the load reaches 20MW, which according to the above load forecast will not occur until 2025/26.

4.2. Timeframes for Taking Corrective Action

As mentioned above the load is above the levels recommended in the security of supply criteria stated in Ergon Energy/Energex Standards for Transmission and Distribution from 2010/2011, and options to enhance security of supply are to be investigated and implemented as soon as practical.

4.3. Known Future Network and Generation Development

(i.e. projects that have been approved and are firm to proceed)

Ergon Energy is not aware of any other approved network augmentations or generation developments in the St George area that could relieve the emerging network limitations described in section 4 above.
5. OPTIONS CONSIDERED

5.1. Consultation Summary

During its planning process, Ergon Energy identified that action would be required to address an anticipated distribution network limitation related to supply to the St George area.

On 23 May 2012 Ergon Energy released a Request for Information providing details on the emerging network limitations in the St George area. That paper sought information from Registered Participants, AEMO and Interested Parties regarding potential solutions to address the anticipated limitations.

Ergon Energy received 10 submissions by 18 July 2012, being the closing date for submissions to the Request for Information paper.

On 5 June 2013, Ergon Energy released a Consultation and Draft Recommendation Report. Ergon Energy received no submissions by 3 July 2013, being the closing date for submissions.

An evaluation team of 8 representatives from across the business was formed to evaluate the submissions.

5.2. Non-Network Options Identified

All 10 submissions received through the RFI process were identified as non-distribution options and can be categorised as follows:

- 5 options comprised of battery only or battery combined with solar solutions.
- 4 options comprised of diesel only or diesel combined with solar and battery solutions.
- 1 option comprised a solar thermal solution.

5.3. Distribution Options Identified

In addition to the consultation process to identify possible non-network solutions, Ergon Energy carried out studies to determine the most appropriate distribution network solution – it was considered that a ‘do nothing’ approach was unacceptable.

The distribution network option identified was to construct a duplicate 66kV sub-transmission feeder from Roma Bulk Supply Point to St George. The distribution non-network option identified was a network support power-station in conjunction with localised network demand management.
6. FEASIBLE SOLUTIONS

This section provides an overview of the feasible solution identified, with full details of the financial analysis contained in Section 7.

6.1. Non Feasible Solutions

The distribution option identified internally to construct a duplicate 66kV sub-transmission feeder from Roma Bulk Supply Point to St George was eliminated on the basis that it was not economically viable. The capital cost of the feeder alone was estimated at $36.3 million and the net present cost of the distribution option is estimated at $37.5 million, which is inclusive of operation and maintenance.

From the RFI respondents’ proposals:

- The 5 options which comprised of battery only or battery and solar solutions were eliminated on the basis of their inability to meet the partial contingency / risk management requirements.

6.2. Feasible Solutions

The 5 feasible solutions identified were 4 to design and construct generation solutions with a diesel component and 1 solar thermal power station option as follows:

<table>
<thead>
<tr>
<th>Generation Components</th>
<th>Capital Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>6 X 1MW Diesel</td>
<td>$4.2M</td>
</tr>
<tr>
<td>3 X 2.25MW Diesel</td>
<td>$5.4M</td>
</tr>
<tr>
<td>6MW Solar / 4MW Battery / 6 X 1MW Diesel</td>
<td>$27.1M</td>
</tr>
<tr>
<td>6MW Solar / 4MW Battery / 5.6MW Diesel</td>
<td>$42.3M</td>
</tr>
</tbody>
</table>
| *Note: Proponent specified a unit scaling and costing of proposed solution, which has been upscaled to satisfy Ergon Energy’s requirements. Specified unit costs of $9.05M were still higher than the lower cost alternatives.*
| 24MW Solar Thermal Power Station / 144MWh Battery / 6MW Diesel (owned and operated) | $Nil         |

The 5 feasible solutions were evaluated by the panel based on the following criteria:

- Scope & technical validity
- Financial and management capability
- Experience and corporate culture
- Network compatibility / customer & stakeholder impacts

The top 3 highest scoring proposals were short-listed – the proponents being invited to present their solutions to the evaluation panel along with the power station proponent.
7. FINANCIAL ANALYSIS & RESULTS

7.1. Format and Inputs to Analysis

7.1.1 Regulatory Test Requirements

The requirements for the comparison of options to address an identified network limitation are contained in the Regulatory Test (version 3, November 2007) prescribed by the AER.

The Regulatory Test requires that, for reliability augmentations, the recommended option be the one that “minimises the costs of meeting those requirements, compared with alternative option/s in a majority of reasonable scenarios”. To satisfy the Regulatory Test, the proposed augmentation must achieve the lowest cost in the majority of (but not necessarily all) credible scenarios.

The Regulatory Test contains guidelines for the methodology to be used to identify the lowest cost option. Information to be considered includes construction, operating and maintenance costs and the costs of complying with existing and anticipated laws and regulations. The Regulatory Test specifically excludes indirect costs and costs that cannot be measured in terms of financial transactions in the electricity market.

7.1.2 Inputs to Analysis

A solution to address the future supply requirements for the St George area as outlined in this document is required to satisfy reliability requirements linked to Schedule 5.1 of the NER and the requirements of the Queensland Electricity Act 1994.

According to the AER’s Regulatory Test, this means that the costs of all options must be compared, and the least cost solution is considered to satisfy the Regulatory Test. The results of this evaluation, carried out using a discounted cash flow model to determine the present value costs of the various options, are shown in section 7.2.2.

The cost to implement the network augmentations outlined in section 6 has been estimated by Ergon Energy. Sensitivity studies have been carried out using variations in capital cost estimates of plus or minus 20%. The operating and maintenance costs have been derived as a fixed proportion of capital cost. As a result, a variation in capital costs would be equivalent to separately varying the operating and maintenance cost.

The financial analysis considers all foreseeable cost impacts of the proposed network augmentations to market participants as defined by the regulatory process. Estimated savings in the cost of network losses have been excluded from the analysis because they were not found to differ significantly over the 20 year study period.

7.2. Financial Analysis

The economic analysis undertaken considered the present value of cost of alternative options over the 20 year period from 2013 to 2033.
7.2.1 Present Value Analysis

Financial analysis was carried out to calculate and compare the Present Value (PV) of the costs of each option under the range of assumed scenarios.

A 20 year analysis period was selected as an appropriate period for financial analysis. A discount rate of 9.99% was selected as a relevant commercial discount rate.

The Base Case (Scenario A) was developed to represent the most likely market scenario.

Market scenarios B - G were formulated to test the robustness of the analysis to variations in load forecast, capital costs and the discount rate. As required by the Regulatory Test, the lower boundary of the sensitivity testing was the regulated cost of capital.

Under the Regulatory Test, it is the ranking of options which is important, rather than the actual present value results. This is because the Regulatory Test requires the recommended option to have the lowest present value cost compared with alternative projects.

The following table is a summary of the economic analysis. It shows the present value cost of each alternative and identifies the best ranked option, for the range of scenarios considered.

The summary shows that the Diesel solutions have the lower present value under all scenarios.

7.2.2 Summary of Economic Analysis

<table>
<thead>
<tr>
<th>ST GEORGE ECONOMIC ANALYSIS NPV SUMMARIES</th>
<th>Internal</th>
<th>Option A</th>
<th>Option B</th>
<th>Option C</th>
<th>24MW Solartherm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Present Cost of Capex</td>
<td>$4.45</td>
<td>$3.77</td>
<td>$4.80</td>
<td>$24.08</td>
<td>$0.00</td>
</tr>
<tr>
<td>Present Cost of Opex</td>
<td>$0.85</td>
<td>$0.85</td>
<td>$1.03</td>
<td>$0.56</td>
<td>$25.32</td>
</tr>
<tr>
<td>Present Value of Benefits</td>
<td>-$0.62</td>
<td>-$0.57</td>
<td>-$0.68</td>
<td>-$11.40</td>
<td>$0.00</td>
</tr>
<tr>
<td>NET PRESENT COST</td>
<td>$4.67</td>
<td>$4.04</td>
<td>$5.15</td>
<td>$13.24</td>
<td>$25.32</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Sensitivity Analysis excl Overheads ($M)</th>
<th>Internal</th>
<th>Option A</th>
<th>Option B</th>
<th>Option C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario - Base Case</td>
<td>-$4.67</td>
<td>-$4.04</td>
<td>-$5.15</td>
<td>-$13.24</td>
</tr>
<tr>
<td>Scenario - Escalation Opex -High</td>
<td>-$4.84</td>
<td>-$4.21</td>
<td>-$5.36</td>
<td>-$13.35</td>
</tr>
<tr>
<td>Scenario - Escalation Opex -Low</td>
<td>-$4.50</td>
<td>-$3.87</td>
<td>-$4.95</td>
<td>-$13.13</td>
</tr>
<tr>
<td>Scenario - Discount Rate - High</td>
<td>-$4.50</td>
<td>-$3.87</td>
<td>-$4.94</td>
<td>-$14.32</td>
</tr>
<tr>
<td>Scenario - Discount Rate - Low [REG]</td>
<td>-$4.70</td>
<td>-$4.06</td>
<td>-$5.18</td>
<td>-$13.05</td>
</tr>
<tr>
<td>Scenario - Increased Capital costs</td>
<td>-$5.56</td>
<td>-$4.79</td>
<td>-$6.11</td>
<td>-$18.05</td>
</tr>
<tr>
<td>Scenario - Decreased Capital costs</td>
<td>-$3.78</td>
<td>-$3.29</td>
<td>-$4.19</td>
<td>-$8.42</td>
</tr>
<tr>
<td>Scenario - Commercial Benefits</td>
<td>-$4.80</td>
<td>-$4.16</td>
<td>-$5.29</td>
<td>-$15.52</td>
</tr>
</tbody>
</table>

| Scenario - Base Case                    | 2        | 1        | 3        | 4        |
| Scenario - Escalation Opex -High        | 2        | 1        | 3        | 4        |
| Scenario - Escalation Opex -Low         | 2        | 1        | 3        | 4        |
| Scenario - Discount Rate - High         | 2        | 1        | 3        | 4        |
| Scenario - Discount Rate - Low [REG]    | 2        | 1        | 3        | 4        |
| Scenario - Increased Capital costs      | 2        | 1        | 3        | 4        |
| Scenario - Decreased Capital costs      | 2        | 1        | 3        | 4        |
| Scenario - Commercial Benefits          | 2        | 1        | 3        | 4        |
7.3. Discussion of Results

The following conclusions have been drawn from the analysis presented in this report:

- There is no acceptable ‘do nothing’ option. The load is already above the levels recommended in Ergon Energy’s security of supply criteria.
- The power station options were ‘own and operate’ proposals which although required no capital outlay, required substantial ongoing network support payments from Ergon Energy for a minimum of 10 years – which was determined to be not economically viable in both cases.
- The economic analysis carried out indicates a diesel generation solution has the lowest net present cost. This is primarily due to the solution required being for security (back-up supply) rather than for base load purposes. Consequently, expected run times (and the resulting operational costs) are low, so proposals minimising the capital costs will be the most cost effective.
- Costings provided by the RFI proponents were high-level in nature. The external diesel generation quotes were consistent with the internal benchmark. Option A has marginally the lowest net present cost.
- Sensitivity analysis indicates that Option A has the lowest net present cost in all scenarios.
- As diesel generation options provide the lowest cost options in all scenarios, they are considered to satisfy the Regulatory Test.

8. FINAL DECISION & RECOMMENDATION

Based on the conclusions drawn from the analysis in sections 6 and 7 above, it is recommended that Ergon Energy proceeds to a closed tender to optimise a diesel generation solution for the St George area. This solution will address Ergon Energy’s security of supply requirements.

Technical details relevant to the proposed recommendation are contained in section 6.2.

Ergon Energy will commence actions to progress the solution decided on to ensure system reliability is maintained.