Regulatory Investment Test for Distribution

Final Project Assessment Report

Charleville 66kV Voltage Management

This document describes the *identified need* for investment at Charleville, including the preferred option to address the identified need.

Publication Date: **22 May 2019**

Executive Summary

Ergon Energy Corporation Limited (Ergon Energy) is responsible (under its Distribution Authority) for electricity supply to the Charleville, Quilpie and Cunnamulla area in south west Queensland.

Charleville is located in the Maranoa area of the South West Region of Ergon Energy's Network. The Charleville area is supplied via a single 276km 66kV sub-transmission Feeder from T83 Roma Bulk Supply Point (ROMA) and customers in Quilpie and Cunnamulla are supplied via separate 200km long 66kV feeders from Charleville. Distribution supply from Charleville and Cunnamulla is at 11kV for urban, and 22kV and 19.1kV single wire earth return (SWER) for more rural customers. Supply from Quilpie zone substation is exclusively 11kV with extensive 19.1kV SWER networks. Charleville substation contains 1 x 66/11kV transformer, 1 x 66/22kV transformer, and also a 22/11kV transformer to link the 22kV and 11kV busbars and hence provide backup for each of the 66kV transformers. The Charleville zone substation contains a static var compensator (SVC) which is connected to its 11kV bus. The SVC is set up to control the 66kV bus voltage and has a range of 7Mvar inductive to 10Mvar capacitive.

The Charleville SVC is approaching the end of its design life and it is recommended for replacement on the basis of its age and reliability in 2019. The SVC performs the function of maintaining stable voltages at both high and low load times. At low load times, without the SVC in service, significant voltage rise would occur on the Charleville area network. Similarly, without the SVC's capacitive support, voltage would become low during high load periods. The SVC also provides some Negative Phase Sequence (NPS) correction to address voltage balance issues associated with SWER networks. If the Charleville SVC fails, inductors and capacitors are manually switched. This switching however creates transients on the network, is difficult to manage, and also relies on some plant which is also approaching end of life. At peak load times, without the SVC in service, some loads may also need to be shed in order to maintain a suitable voltage.

Ergon Energy published a Non-Network Options Report relating to the above described network constraints on 17 January 2018. Three submissions were received by the closing date of 16 April 2018.

One of the submissions was effectively the provision of the preferred internal option given in the Non-Network Options Report and was deemed to not represent a significant non-network solution. Although this submission was removed from the analysis in this report, the submission provider would have the opportunity to submit a revised, network support solution proposal when Ergon Energy goes to the market to seek the preferred option detailed in this report.

The potentially credible feasible options have been investigated:

1. **Option A:** 10Mvar STATCOM (a 5Mvar STATCOM connected to each of the 11kV and 22kV buses at Charleville Substation) – Internal Option
2. **Option B:** Network Support Arrangement for the provision of reactive power via an external provider. In this submission this was achieved via a 10Mvar STATCOM (a 5Mvar STATCOM connected to each of the 11kV and 22kV buses) with optional 2.8MW of embedded generation - External Submission Provider
3. **Option C:** Network Support Arrangement for the provision of reactive power via an external provider. In this submission this was achieved via a 10MW solar farm, battery storage and possibly a small STATCOM connected to the 11kV and 22kV buses at Charleville Substation - External Submission Provider

Ergon Energy published a Draft Project Assessment report on 26 July 2018, where Ergon Energy provided a technical and economic analysis of the above options. Written submissions to the Draft Project Assessment Report were invited. A revised submission for

Option C was provided by the External Submission Provider by the closing date of 07 September 2018.

This is now a Final Project Assessment Report, where Ergon Energy presents the technical and economic analysis of the above options, and identifies the preferred solution. Ergon Energy's preferred solution is Option C: Network Support Arrangement for the provision of reactive power via an external provider.

To ensure an economically efficient outcome, Ergon Energy will proceed with a market based approach to seek and develop a Network Support solution for the provision of reactive power.

For further information and inquiries please refer to the "Regulatory Investment Test for Distribution (RIT-D) Partner Portal".

https://www.ergon.com.au/network/network-management/network-infrastructure/regulatory-test-consultations

Table of Contents

Tables and Figures

1. Introduction

This Final Project Assessment Report has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4 of the National Electricity Rules (NER).

This report represents the final stage of the consultation process in relation to the application of the Regulatory Investment Test for Distribution (RIT-D) on potential credible options to address the identified need in the electrical network that supplies the Charleville, Quilpie and Cunnamulla areas.

On 17 January 2018, Ergon Energy published the first stage of the RIT-D, which was the release of the Non-Network Options Report. This report sought information from Registered Participants and Interested Parties regarding alternative potential credible options, or variants to the potential credible options presented in that report. In response to the Non-Network Options Report, Ergon Energy received three submissions.

Ergon Energy published the Draft Project Assessment Report on 26 July 2018. This report presented a technical and economic analysis of credible options that would address the identified needs, and identified Ergon Energy's proposed preferred option.

Following the publication of the Draft Project Assessment Report, a period of consultation was opened and written submissions were invited. A revised submission for Option C was provided by the External Submission Provider by the closing date of 07 September 2018.

This Final Project Assessment Report:

- Provides background information on the network capability limitations of the distribution network supplying the Charleville, Quilpie and Cunnamulla areas.
- Identifies the need which Ergon Energy is seeking to address, together with the assumptions used in identifying and quantifying that need.
- Summarises and provides commentary on the submission(s) received on the Non-Network Options Report and Draft Project Assessment Report.
- Describes the credible options that are considered in this RIT-D assessment, including the cost of each credible option (operating expenditure and capital expenditure).
- Quantifies costs and classes of material market benefits for each of the credible options.
- Describes the methods used in quantifying each class of market benefit.
- Provides details of classes of market benefits that are not considered material to this RIT-D assessment, and provides explanations to why these classes of market benefits are not considered material.
- Provides the results of Net Present Value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.

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.

For further information and inquiries please refer to the "Regulatory Investment Test for Distribution (RIT-D) Partner Portal".

https://www.ergon.com.au/network/network-management/network-infrastructure/regulatory-test-consultations

2. Background

2.1 Geographic Region

The geographic region covered by this RIT-D is Charleville, Quilpie and Cunnamulla towns and surrounding rural areas in south west Queensland. Charleville is located in the Maranoa area of the South West Region of Ergon Energy's Network. The Charleville area is supplied via a single 276km 66kV sub-transmission Feeder from T83 Roma Bulk Supply Point and customers in Quilpie and Cunnamulla are supplied via separate 200km long 66kV feeders from Charleville. Distribution supply from Charleville 66/22/11kV Substation (CHAR) and Cunnamulla 66/22/11kV Substation (CUNN) is at 11kV for urban, and 22kV and 19.1kV SWER for more rural customers. Supply from Quilpie 66/11kV Substation (QUIL) is exclusively 11kV with extensive 19.1kV SWER networks. CHAR contains 1 x 66/11kV transformer, 1 x 66/22kV transformer, and also a 22/11kV transformer to link the 22kV and 11kV busbars and hence provide backup for each of the 66kV transformers. CHAR also contains a SVC which is connected to the 11kV bus. The SVC is set up to control the 66kV bus voltage and has a range of 7Mvar inductive to 10Mvar capacitive. The figures below show the subtransmission infrastructure in the area and the location of Charleville substation.

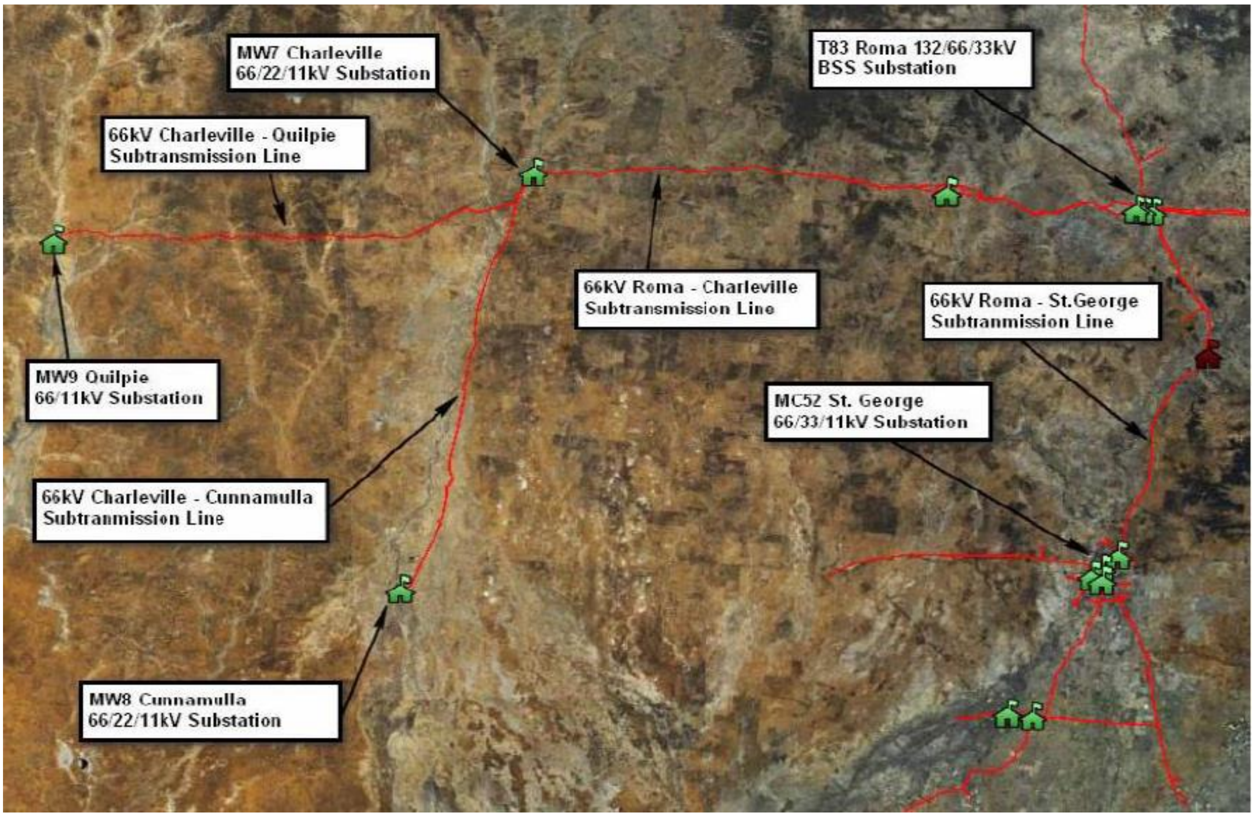

Figure 1 – Charleville Subtransmission System

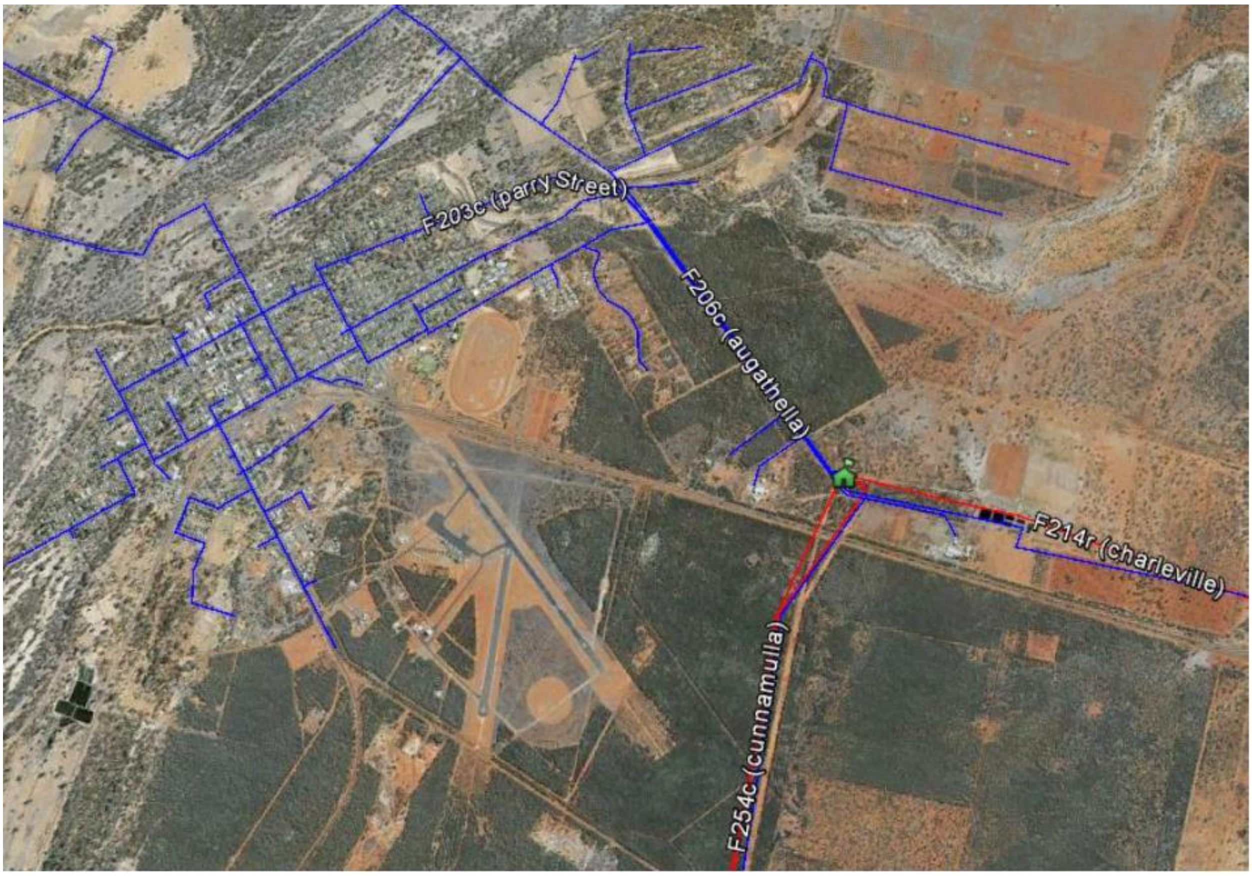

Figure 2 – Location of Charleville Substation

2.2 Charleville Supply System

As described above, the Charleville area is supplied via a single 276km 66kV sub-transmission feeder from T83 Roma Bulk Supply Point and customers in Quilpie and Cunnamulla are supplied via separate 200km long 66kV feeders from Charleville. Distribution supply from Charleville and Cunnamulla is at 11kV for urban, and 22kV and 19.1kV SWER for more rural customers. Supply from Quilpie zone substation is exclusively 11kV with extensive 19.1kV SWER networks. Charleville substation contains 1 x 66/11kV transformer, 1 x 66/22kV transformer, and also a 22/11kV transformer to link the 22kV and 11kV busbars and hence provide backup for each of the 66kV transformers. The Charleville zone substation contains a SVC which is connected to its 11kV bus. The SVC is set up to control the 66kV bus voltage and has a range of 7Mvar inductive to 10Mvar capacitive.

2.3 Existing Charleville SVC

The Charleville SVC is a critical asset approaching the end of its design life and it is recommended for replacement on the basis of its age and reliability in 2019. The SVC performs the function of maintaining stable voltages at both high and low load times. At low load times, without the SVC in service, significant voltage rise would occur on the Charleville area network. Similarly, without the SVC's capacitive support, voltage would become low during high load periods. The SVC also provides some NPS correction to address voltage balance issues associated with SWER networks. If the Charleville SVC fails, inductors and capacitors are manually switched. This switching however creates transients on the network, is difficult to manage, and also relies on some plant which is also approaching end of life. At peak load times, without the SVC in service, some loads may also need to be shed in order to maintain a suitable voltage.

SVC failure may lead to voltage compliance issues, customer complaints, loss of revenue and operational constraints in the south west Queensland distribution network. Sub-transmission and distribution voltage levels may not be controlled within statutory limits, and the network will be at risk of over-voltages and under-voltages. Some load shedding is likely to occur either due to the voltage being excessively high or too low for the customers depending on the system load at the time.

The south west Queensland distribution network is characterised by relatively low fault levels with unacceptable voltage swings if large blocks of discrete capacitors or reactors are switched in and out for reactive power compensation, hence the reason why a high reliability dynamic reactive compensator is necessary for voltage support.

2.3.1 Charleville SVC Operational Challenges

There are a number of operational challenges at Charleville substation associated with voltage control in the event that the SVC is out of service. This presents safety, voltage compliance and reliability risks. The SVC is critical to the provision of ongoing voltage/VAR support, and to meet Ergon Energy's corporate strategic objectives. Without reactive compensation, 66kV supply at Charleville and the far south western Queensland suffers from poor voltage regulation. It may be noted that although no customer minutes have been recorded against SVC outages, there remains a potential for outages due to increasing loads and either low or high voltages on the network which can lead to unwanted tripping of loads by protection or operator intervention. During SVC outages, a significant amount of time is involved in maintaining volts on the 66kV bus bar through reactor or capacitor switching and taps changing. The process is complex, slow and takes hours to manage by adjusting 66kV Roma bus volts and, on some occasions, even requesting Powerlink to lower the 132kV volts at Tarong and removing capacitor banks from service at Chinchilla. Despite these measures, the system voltage at Cunnamulla has become critically high on some occasions.

2.3.2 Charleville SVC Insufficient Reactive Power Capability

The existing SVC has a total capacitive range of 10Mvar and a total inductive range of 7Mvar. Of the 10Mvar capacitive range, only 7.6Mvar is available for steady state correction with the remaining 2.4Mvar reserved for dynamic/transient response. Similarly, for the 7Mvar inductive range, only 4.6Mvar is available for steady state correction with the remaining 2.4Mvar reserved for dynamic/transient response. The existing SVC is regularly hitting its steady state capacitive and inductive limits and any changes in the network which will increase peak load or decrease the minimum load could drive the need to increase the size of the SVC replacement.

There are significant SWER schemes emanating from these remote townships, particularly Quilpie with a very extensive SWER scheme generating significant reactive power under light load. Under light load, reactive power needs to be continuously absorbed by the SVC to prevent system over voltages which would lead to unwanted reactive power flows from Charleville back to Roma via the 66kV transmission line.

There is significant amount of Micro Embedded Generation Unit (MEGU) installations on the Charleville area network and this is expected to continue to grow (see below). Large customers in the area are also exploring opportunities to reduce their load with onsite generation. A number of larger megawatt scale solar proponents have also expressed interest in constructing solar farms at Charleville. The lowest loads are now seen during the middle of the day, during months with more mild weather conditions. In short it is expected that low load periods will continue to decline putting additional pressure on inductive compensation.

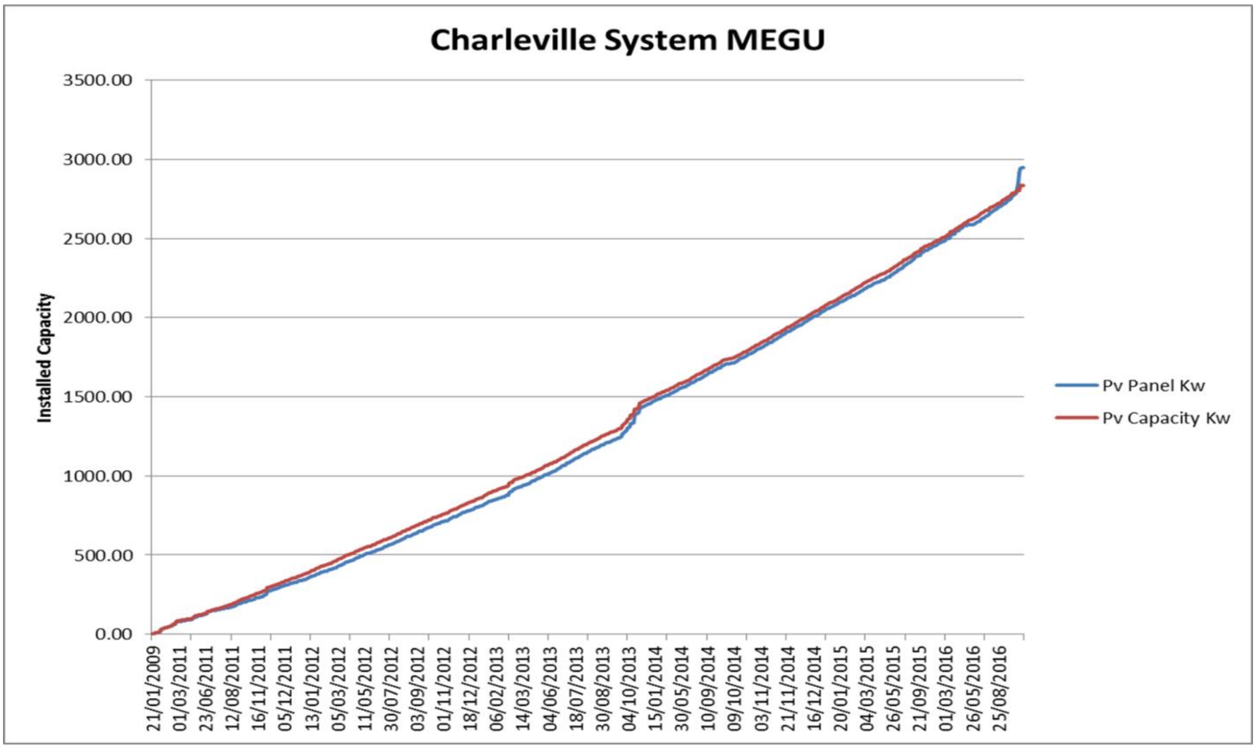

Figure 3 – PV/MEGU Connections in the Charleville Region

3. Key Assumptions in Relation to Identified Need

Below is a summary of key assumptions that have been made when the identified need has been analysed and quantified.

It is recognised that the below assumptions may prove to have various levels of correctness, and they merely represent a 'best endeavours' approach to predict the future identified need.

3.1 Forecast Load Growth

The Ergon Energy Substation Investment Forecasting Tool (SIFT) predicts generally flat load growth within the area of interest (CHAR, QUIL and CUNN zone substations) which was deemed to be the most likely scenario. To model this level of network load, an entire year (2016) of half-hourly load data was selected to represent an 'average' year. According to SIFT, 2016 represented a 50% Probability of Exceedance demand and closely matches the substation demand forecasts in the 2018 model.

It was decided that a High Demand Growth scenario was also reasonable although less likely than the flat growth scenario described above. This was modelled by scaling the 2016 load data by a positive growth rate. The growth rate and probability of occurrence of each scenario are given in Table 1 below.

Table 1 – Demand Scenarios

Scenario	Probability	Growth Rate per annum
High Demand Growth	0.2	2.00%
No Demand Growth	0.8	0.00%

3.2 Forecast Load Degradation

Unrestricted MEGU growth, such as residential photovoltaics (PV), within the substation distribution areas leads to an erosion of network demand during the day. There is an existing customer base for this region of approximately 4930 customers and within this there is approximately 2.5MW of installed effective MEGU capacity (70% efficiency of existing connected system capacity). A further 5.1MW of solar generation capacity is a possible scenario based on a 70% maximum penetration, 70% average solar diversity and existing average system sizes. This was deemed to be the High MEGU Growth scenario.

A Low MEGU Growth scenario was also modelled which was based on the official 5 year Ergon Energy MEGU (combined) low forecast extrapolated out to the study period of 20 years. This led to an additional 3.6MW of solar generation capacity.

Each MEGU growth scenario was given an equal probability of occurrence. These assumptions are summarised in Table 2 below.

Table 2 – Load Degradation Scenarios

Scenario	Probability	Additional MEGU Capacity in Year 20
High MEGU Growth	0.5	5.1MW
Low MEGU Growth	0.5	3.6MW

4. Summary of Submissions

On 17 January 2018, Ergon Energy published the Non-Network Options Report providing details on the identified need to replace the SVC at Charleville. This report sought information from Registered Participants, Australian Energy Market Operator (AEMO) and Interested Parties regarding alternative potential credible options or variants to the potential credible options presented by Ergon Energy.

In response to the Non-Network Options Report, Ergon Energy received three submissions from non-network service providers by 16 April 2018, which was the closing date for submissions to the Non-Network Options Report.

These three submissions were:

1. Network Support via a 10Mvar STATCOM (a 5Mvar STATCOM connected to each of the 11kV and 22kV buses) with optional 2.8MW of embedded generation.
2. Network Support via a 10MW solar farm (a 5MW solar farm connection to each of the 11kV and 22kV buses) and battery storage.
3. 12Mvar STATCOM (a 6Mvar STATCOM connected to each of the 11kV and 22kV buses)

Submissions 1 and 2 are Network Support Agreements composed of a STATCOM (or PV inverter functioning like a STATCOM) with a generation component and are substantially different to the Ergon Energy preferred network solution of a STATCOM alone. These options were considered to be valid, non-network alternatives to the preferred network solution.

Submission 3 is a STATCOM solution with no added significant alternate component and is essentially the same as the Ergon Energy preferred network solution. As such, it did not represent an alternative non-network solution. The provider however will be given the opportunity to participate in a market based approach for the preferred solution.

Following the conclusion of the consultation on the Non-Network Options Report, Ergon Energy published the Draft Project Assessment Report on 26 July 2018. The purpose of this report was to provide a technical and economic assessment of investigated solution options and to present Ergon Energy's preferred solution option.

Registered participants and interested parties were invited to lodge submissions in response to the Draft Project Assessment Report by 07 September 2018.

One submission was received in response to the Draft Project Assessment Report before this closing date, a revised submission for Submission 2 (referred to as Option C in this report) was provided by the External Submission Provider. This submission was essentially identical to the original however with a revised commercial proposal.

It is noted that this Final Project Assessment Report has a number of changes from the Draft Project Assessment Report. These changes are summarised in Appendix A.

5. Non-Network Solutions Considered

The two valid submissions Ergon Energy received to the Non-Network Options Report have been investigated and assessed, as detailed in the following section.

5.1 Network Support Arrangement for the provision of reactive power via an external provider (10Mvar STATCOM with optional 2.8MW of embedded generation) – External Submission Provider

This submission is based on providing Network Support (reactive power support) at Charleville Substation with the proponent owning and operating the equipment. The option assessed by Ergon Energy assumed a STATCOM component:

- 10Mvar STATCOM system (expanded to 15Mvar in year 5), modularised in separate containers of 2.5Mvar capacity each.
- Split into two separate 5Mvar STATCOMs, connected to the 11kV and 22kV buses respectively, although with the flexibility to be connected at more optimal locations within the network if required.
- The system is easily expandable by adding additional containers if required in the future. The cost analysis of this proposal includes two additional containers in year 5 to provide 15Mvar total reactive power capability.

Optional embedded generation components:

- 2MW gas generator configured for network support connected within the distribution network.
- 0.8MW cogeneration, hybrid generator connected at a large customer site and configured for network support.

Optional ancillary service:

- A controllable, 1MW / 1.5MWh thermal storage load installed at a large customer site for the purpose of network voltage / var management during light load periods.

The total cost of this option is $26.1M (without optional generation) or $31.3M (inclusive of 2.8MW of generation) in NPV[1]. This total cost includes Network Support costs as well as substation connection works costs at CHAR (refer to Table 6 for more detail).

This option is named **Option B** in this report. It is noted that a Network Support Arrangement capable of meeting the identified need, could be delivered by a variety technology solutions and is not limited to the scope outlined above or necessarily dependant on each of the components being built.

[1] Assuming a Weighted Average Cost of Capital (WACC) of 7% as per the financial figures provided in the submission.

5.2 Network Support Arrangement for the provision of reactive power via an external provider (10MW solar farm, battery storage and optional STATCOM) – External Submission Provider

This submission is based on providing Network Support (reactive power support) at Charleville Substation with the proponent owning and operating the equipment. The option assessed by Ergon Energy assumed a PV inverter (functioning like a STATCOM) component:

- 10MW solar farm composed of two separate 5MW solar farms, connected to the 11kV and 22kV buses respectively.
- Each solar farm connection will have 8.25MVA PV inverters capable of generating ±6.5Mvar of reactive power at maximum real power output of 5MW.
- PV inverters will have 'Q at night' capability to allow 60% of inverter capacity to be used for reactive power support at night.

A battery component:

- Two separate 2.5Mvar battery inverters connected to the 11kV and 22kV buses respectively.
- Batteries sized to allow load shifting of excess generation.

Optional STATCOM:

- Scope to include two separate STATCOMs, connected to the 11kV and 22kV buses respectively, if required, to meet the STATCOM performance specifications.

The cost of this option was assessed as $9.5M in NPV. This total cost includes Network Support costs as well as substation connection works costs at CHAR (refer to Table 6 for more detail).

This option is labelled as **Option C** in this report. It is noted that a Network Support Arrangement capable of meeting the identified need, could be delivered by a variety technology solutions and is not limited to the scope outlined above or necessarily dependant on each of the components being built.

6. Credible Options Included in this RIT-D

Details of the three credible options that have been investigated to address the identified need at Charleville are presented in the following sections.

6.1 Option A: 10Mvar STATCOM - Internal Option

This is the preferred internal option composed of two separate 5Mvar STATCOMs, connected to the 11kV and 22kV buses respectively, and with the capability to be easily expanded up to 7.5Mvar units in the future.

This option would:

- Provide sufficient inductive and capacitive reactive power capability to manage network voltages at Charleville, Quilpie and Cunnamulla zone substations and surrounding distribution areas.
- Be able to be easily expanded to cater for future load growth and load degradation.
- Provide NPS correction to address voltage balance issues associated with SWER networks.
- Reduce voltage transients caused by inductor or capacitor switching and flicker caused by motor starting currents.

The estimated cost of this option is approximately $11.64M in NPV. This is based on a capital cost of $10.75M and operating cost of $0.90M.

It is expected that this option is able to be built, commissioned, accepted by Ergon Energy, and fully operational by June 2020 which is the required deadline given in the Non-Network Options Report.

6.2 Option B: Network Support Arrangement for the provision of reactive power via an external provider (10Mvar STATCOM with optional 2.8MW of embedded generation) – External Submission Provider

This option includes:

- 10Mvar STATCOM with optional 2.8MW of embedded generation (as described in Section 5.1).

This option would:

- Provide sufficient inductive and capacitive reactive power capability to manage network voltages at Charleville, Quilpie and Cunnamulla zone substations and surrounding distribution areas.
- Be able to be easily expanded to cater for future load growth and load degradation.
- Provide NPS correction to address voltage balance issues associated with SWER networks.
- Reduce voltage transients caused by inductor or capacitor switching and flicker caused by motor starting currents.
- Provides on optional 2.8MW of embedded generation that could be used for peak-lopping in high load periods.

Important things to note:

- The cost analysis of this proposal includes two additional containers in year 5 to provide 15Mvar total reactive power capability.

The total cost of this option is $26.1M (without optional generation) or $31.3M (inclusive of 2.8MW of generation) in NPV[2]. This total cost includes Network Support costs as well as substation connection works costs at CHAR (refer to Table 6 for more detail).

It is expected that this option is able to be built, commissioned, accepted by Ergon Energy, and fully operational by June 2020 which is the required deadline given in the Non-Network Options Report. The estimated cost of this option assumes that each of the components outlined above would be installed. It is noted that a Network Support Arrangement capable of meeting the identified need could be delivered by a variety technology solutions and is not limited to the scope outlined above, or necessarily dependant on each of the components being built.

6.3 Option C: Network Support Arrangement for the provision of reactive power via an external provider (10MW solar farm, battery storage and optional STATCOM) – External Submission Provider

This option assessed by Ergon Energy includes:

- 10MW solar farm with battery storage and possibly a small STATCOM (as described in Section 5.2).

This option would:

- Provide sufficient inductive and capacitive reactive power capability to manage network voltages at Charleville, Quilpie and Cunnamulla zone substations and surrounding distribution areas.
- Be able to be easily expanded to cater for future load growth and load degradation.
- Provide NPS correction to address voltage balance issues associated with SWER networks.
- Reduce voltage transients caused by inductor or capacitor switching and flicker caused by motor starting currents.
- Provides potential for load shifting via a battery charging / discharging regime.
- Potentially reduce the amount of network losses by having a generation source (the solar farm / batteries) at CHAR.

The cost of this option was assessed as $9.5M in NPV. This total cost includes Network Support costs as well as substation connection works costs at CHAR (refer to Table 6 for more detail).

It is expected that this option is able to be built, commissioned, accepted by Ergon Energy, and fully operational by June 2020 which is the required deadline given in the Non-Network Options Report. The estimated cost of this option assumes that each of the components outlined above would be installed. It is noted that a Network Support Arrangement capable of meeting the identified need could be delivered by a variety technology solutions and is not limited to the scope outlined above, or necessarily dependant on each of the components being built.

[2] Assuming a Weighted Average Cost of Capital (WACC) of 7% as per the financial figures provided in the submission.

7. Market Modelling

The RIT-D requires market benefits to be calculated by comparing the 'state of the world' in the base case (the preferred Ergon Energy internal option, Option A) with the 'state of the world' with each of the credible options in place. The 'state of the world' means a reasonable and mutually consistent description of all the relevant supply and demand characteristics that may affect the calculation of the market benefits over the period of assessment. The uncertainty associated with the future state of the system is addressed by considering a number of reasonable scenarios (see Section 3.). The RIT-D assessment has been undertaken over a 20-year period.

7.1 Classes of Market Benefits Considered & Quantified

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

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

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

- Changes in network losses

7.1.1 Changes in Network Losses

Market benefits associated with the change in network losses within the Ergon Energy network have been quantified by a direct calculation of the likely MWh impact on the losses for each year of the modelling horizon. These MWh figures have been multiplied by the value of those losses, as determined by the annual volume weighted average spot price of electricity for QLD 2017/18 ($76/MWh).

It was assumed that the only option that will have a material impact in network losses is Option C - 10MW solar farm and battery storage. It was assumed that the embedded generation component of Option B would mainly be used for peak lopping and not be run for long enough during the year to have a significant effect.

The cost of energy losses for each scenario (shown in Table 3

) were calculated for Option C then probability weighted and compared to the Base Case. The total cost of energy losses for Option C is shown as a market benefit in Table 4. It can be seen that this is actually a negative benefit indicating that network losses increased with this option. This was shown in the modelling where, in the High MEGU Growth scenarios, a significant amount of real power was flowing back to ROMA on the 66kV ROMA-CHAR line for significant portions of the year.

This modelling assumed a typical generation profile for the solar farm and due to insufficient information, did not model the battery charging / discharging regime. The submission received from the external provider stated that the batteries might be used to store 'excess' solar generation to be exported at a later time. It is acknowledged that depending on the design of the particular regime, it is likely that losses could be reduced by charging the batteries during the daytime light load period and discharging during the evening peak. The exact amount of this reduction is unclear and would be dependent on such factors as maximum battery charge / discharge rate, battery capacity and regime.

Table 3 - Changes in Network Losses Scenario Probability

Load Growth Scenario	Load Growth Scenario	Probability
High Demand Growth	**High MEGU Growth**	0.1
High Demand Growth	**Low MEGU Growth**	0.1
Low Demand Growth	**High MEGU Growth**	0.4
Low Demand Growth	**Low MEGU Growth**	0.4

Table 4 – Market Benefit of Changes in Network Losses

Market Benefit	Option A: 10Mvar STATCOM – Base Case	Option B: 10Mvar STATCOM - no embedded generation	Option B: 10Mvar STATCOM - 2.8MW of embedded generation	Option C: 10MW solar farm and battery storage
Changes in Network Losses	$0	$0	$0	-$1,091,083

7.2 Classes of Market Benefits not Expected to be Material

The following classes of market benefits are not considered to be material for this RIT-D assessment:

- Changes in Involuntary Load Shedding
- Changes in voluntary load curtailment
- Changes in costs to other parties
- Changes in timing of expenditure
- Changes in load transfer capability
- Option value

7.2.1 Changes in Involuntary Load Shedding

All credible options included in this RIT-D assessment will provide similar levels of reactive power capability; adequate to meet current and future requirements at CHAR. For each option, there is negligible risk of running out of capacitive VAR support during high load conditions which might necessitate customer load shedding. Therefore there is no need to quantify these market benefits.

Some options have a level of embedded generation that might theoretically be able to be used to supply a portion of the load at risk during contingency events. Within the Draft Project Assessment Report it was assumed that it would be technically viable for this generation to island portions of the network and so these options received a market benefit due to the reduction in involuntary load shedding.

However since the publication of the Draft Project Assessment Report, further investigation into the viability of temporarily islanding parts the network has highlighted a number of (as yet unresolved) significant and potentially expensive technical and operational issues that would need to be overcome before it could be implemented. For example fault protection reach reduction, black start-up of islanded network, control infrastructure required to re-sync with the grid and the capability of the generator to supply unbalanced network loads. Therefore these market benefits are not quantified in this report.

7.2.2 Changes in Voluntary Load Curtailment

Because none of the credible options include any voluntary load curtailment, and because there are no customers on voluntary load curtailment agreements in the distribution areas of Charleville, Quilpie or Cunnamulla substations at present, any market benefits associated with changes in voluntary load curtailment have not been considered.

7.2.3 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.

7.2.4 Changes in Timing of Expenditure

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

7.2.5 Changes in Load Transfer Capability

Neither of the credible options will have a materially different impact upon the load transfer capability between CHAR, QUIL, CUNN or ROMA substations.

7.2.6 Option Value

The AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change[3].

Each option is assumed to be installed and commissioned by June 2020 which is effectively an irreversible investment. In this context each option will have the same Option Value and so it is not required to be quantified.

7.3 Quantification of Costs for each Credible Option

The capital and operational costs for each credible option considered in this RIT-D assessment are summarised in

[3] AER "Regulatory Investment Test for Distribution Application Guidelines", Section A7.
Available at: http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-investment-test-for-distribution-rit-d-and-application-guidelines

Table 5. Note that the Capital Costs include the costs to perform the work required at Charleville Substation to connect either the new STATCOM (Option A) or the Network Support Arrangement by the external provider (Option B and Option C) and include overheads.

Table 5 – Summary of Project Costs

Option	Capital Cost	Operational Cost	Network Support Cost
Option A 10Mvar STATCOM - Internal Option	$10.75M	$80K per annum or $0.89M in Net Present Cost	-
Option B – no embedded generation Network Support Arrangement for the provision of reactive power via an external provider (10Mvar STATCOM without the optional 2.8MW of embedded generation) – External Submission Provider	$5.63M	Operational costs included in the Network Support Cost	$20.50M in Net Present Cost
Option B – including 2.8MW embedded generation Network Support Arrangement for the provision of reactive power via an external provider (10Mvar STATCOM including the optional 2.8MW of embedded generation) – External Submission Provider	$5.63M	Operational costs included in the Network Support Cost	$25.70M in Net Present Cost
Option C Network Support Arrangement for the provision of reactive power via an external provider (10MW solar farm, battery storage and optional STATCOM) – External Submission Provider	$3.98M	Operational costs included in the Network Support Cost	$762,000 per annum under a 10 year contract or $5.50M in Net Present Cost

8. Financial Analysis

8.1 Net Present Value

Net Present Values of the two credible options are presented in Table 6 below. This comparison demonstrates that Option C has the greatest Net Present Value.

Table 6 – Net Present Value Analysis

Cost	Item	Option A: 10Mvar STATCOM - Internal Option	Option B: Network Support Arrangement (10Mvar STATCOM without optional 2.8MW of embedded generation)	Option B: Network Support Arrangement (10Mvar STATCOM including optional 2.8MW of embedded generation)	Option C: Network Support Arrangement (10MW solar farm, battery storage and optional STATCOM)
Project Costs	Capital Costs	$ 10,749,647	$ 5,630,092	$ 5,630,092	$ 3,982,421
	Network Support	$ -	$ 20,496,716	$ 25,696,716	$ 5,503,615
	Maintenance / Operation	$ 888,526	$ -	$ -	$ -
	Total costs (incl. overheads)	$ 11,638,173	$ 26,126,808	$ 31,326,808	$ 9,486,036
Market Benefits	Changes in electrical energy losses	$ -	$ -	$ -	-$ 1,091,083
	Total Market Benefit	$ -	$ -	$ -	-$ 1,091,083
	Benefit Less Costs	-$ 11,638,173	-$ 26,126,808	-$ 31,326,808	-$ 10,577,119
	Ranking	2	3	4	1

9. Proposed Preferred Option

The previous section has presented the results of the NPV analysis conducted for this RIT-D assessment.

The NER requires the Final Project Assessment Report to include the preferred option under the RIT-D. This should be the option which is expected to maximise the present value of the net economic benefits to all those who produce, consume and transport electricity in the NEM.

The total cost of Option C, inclusive of operating costs and a market benefit of negative $1.10M (due to increased network losses), was estimated at approximately $10.58M in present value terms. This was lower than the estimated costs of Option A ($11.64M) and Option B ($31.37M with generation and $26.13M without). For the purpose of this analysis, Ergon Energy considers that this is the maximum cost of an option involving a Network Support Agreement. This shows that a Network Support Arrangement solution maximises the present value of net economic benefits under all reasonable scenarios considered within this RIT-D. The estimated cost of Option C assumes that each of the components identified in the submission to Ergon Energy would be built. It is possible that a Network Support Agreement, capable of meeting the identified need, could be implemented in sufficient time with a different combination of assets and potentially a lower cost (and therefore a greater net benefit). In either case, a Network Support Agreement has been identified as the option resulting in the greatest net benefit. However, Ergon Energy will continue to examine whether this option can be implemented at a lower cost through its implementation process. If necessary, any material change in circumstances can be addressed through the process in clauses 5.17.4(t)-(v) of the National Electricity Rules.

The preferred option is therefore:

Option C: Network Support Arrangement by the provision of reactive power via an external provider - External Submission Provider.

It is noted that Option B is also based on the proponent owning and operating equipment to provide reactive power via a Network Support Agreement and is also a valid option. Option C is the preferred option due to its lower costs.

The technical characteristics of the Network Support solution must meet the requirements described in Section 2 and Section 3 of this report as well as the specifications provided within the Charleville Non-Network Options Report[4].

To ensure an economically efficient outcome, Ergon Energy will proceed with a market based approach to seek and develop a Network Support solution for the provision of reactive power.

[4] The Charleville Non-Network Options Report can be accessed from https://www.ergon.com.au/network/network-management/network-infrastructure/regulatory-test-consultations

10. Next Steps

This Final Project Assessment Report represents the final stage of the RIT-D process to address the identified need at Charleville.

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 analysis, conclusions, or recommendations outlined in this report must do so by **20 June 2019**. Any parties raising such a dispute are also required to notify Ergon Energy by using Ergon Energy's "Regulatory Investment Test for Distribution (RIT-D) Partner Portal". The portal is available at:

https://www.ergon.com.au/network/network-management/network-infrastructure/regulatory-test-consultations

If no formal dispute is raised, Ergon Energy will proceed with a market based approach to seek and develop a Network Support solution for the provision of reactive power to ensure economic efficiency of this investment option. Ergon Energy will at all times follow due diligent processes to ascertain the most cost effective supply of this reactive power support.

11. Appendix A - Differences between this report and the Draft Project Assessment Report

Within the Draft Project Assessment Report it was assumed that it would be technically viable for generation to island portions of the network and hence these options received a market benefit due to the reduction in involuntary load shedding. Since the publication of the Draft Project Assessment Report, further investigation into the viability of temporarily islanding parts the network has highlighted a number of (as yet unresolved) significant and potentially expensive technical and operational issues that would need to be overcome before it could be implemented. For example, fault protection reach reduction, black start-up of islanded network, control infrastructure required to re-sync with the grid and the capability of the generator to supply unbalanced network loads. Therefore these market benefits are not quantified in this report.

The Draft Project Assessment Report assumed that each option would require a similar scope of works to allow for connection to Charleville Substation. Therefore the costs of these works were omitted from the analysis for simplicity. Since publication of the Draft Project Assessment Report, estimated substation connection costs have been detailed and refined for each option. This cost has now been incorporated into the total project costs and NPV analysis for each option.

Based on the submissions received, the internal option (Option A) costs have been revised to reflect latest market pricing. The estimated cost of this internal option (Option A) is approximately $11.64M. This is based on a capital cost of $10.75M and operating cost of $0.90M.

Revised costs have been received for Option C (Network Support Arrangement by the provision of reactive power via an external provider - 10MW solar farm, battery storage and optional STATCOM) which have been updated in the analysis of this Final Project Assessment Report. This option now has a lower net present cost than all other credible options. To ensure an economically efficient outcome, Ergon Energy will proceed with a market based approach to seek and develop a Network Support solution for the provision of reactive power.