Regulatory Test – REVISED FINAL REPORT

Emerging Distribution Network Limitations in the Gracemere Area

ERGON ENERGY NETWORK

Part of Energy Queensland

30 January 2020

Purpose of Revision

In May 2016, Ergon Energy Corporation Limited (Ergon Energy) published a Final Project Assessment Report (FPAR) for the Gracemere area in Central Queensland. Since that time Ergon Energy has completed site design for the Gracemere Substation site, 66kV feeder route and distribution exit cables leading to higher estimated costs and a resulting change to the proposed option. This revision of the RIT-D is to provide an update and advise of the new proposed option.

Executive Summary

Ergon Energy Corporation Limited (Ergon Energy) is responsible (under its Distribution Authority) for electricity supply to the Capricornia region in Central Queensland. We have identified increasing risks to reliable supply in the electricity distribution network supplying the Gracemere area. The loads on Ergon Energy's Malchi 66/11kV Zone Substation and subsequent 11kV network have progressively increased such that the *Regulatory Test*[1] is satisfied via the *Market benefits limb*[2] for construction of a *New Large Network Asset* in the area.

The study area is presently supplied by the Malchi 66/11kV Zone Substation, with peak demands already exceeding its nameplate "N" capacity of the two transformer substation. As such, a contingency, resulting in the inability to utilise both transformers, will result in customer load shedding. The load is also forecast to exceed the "N" cyclic capacity of the substation during the summer of 2024/25 under normal conditions or as early as 2020/21 during very hot (10POE[3]) conditions. This will result in unserved customer energy under "system normal" conditions.

Further, a fault on the radial 66kV feeder that supplies Malchi Zone Substation will result in total loss of supply to the town and surrounds, with very limited back up options available. For contingencies involving mechanical failure, particularly of a wooden pole, this outage could last for a period of between 12 and 24 hours.

Ergon Energy published a Request for Information relating to this emerging network constraint on 19 December 2013. Six submissions were received by the closing date of 20 February 2014. Following material changes to Ergon Energy's regulatory obligations, an Addendum to this RFI was published on 9 September 2014, with only one of the previous respondents choosing to respond to the new situation. A final report was published on 4 May 2016. This revision of that final report is to provide updated estimates and detail a change of the proposed option from Option 2 to Option 1.

Ergon Energy has examined this response (consisting of embedded diesel generation), in conjunction with Ergon Energy's internally identified distribution network and non-network options. This generation option was integrated as a component into the internal options (including internally supplied generation) to produce four potentially feasible solutions:

- **Option 1:** Construct a 1x20MVA transformer substation at the Ergon Energy owned Gracemere Site
- **Option 2:** Construct a 1x10MVA compact substation at the Ergon Energy owned Gracemere Site
- **Option 3:** Construct a 1x10MVA compact substation at a new site closer to Egan's Hill BSP
- **Non-Network Options:** Deferral of all other options using generation

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[1] As per Version 53 of the National Electricity Rules (NER). The current version of the NER does not contain Regulatory Test obligations. Rather, this has been replaced with an obligation to perform a Regulatory Investment Test – Distribution from 1 January 2014. Transitional arrangements are prescribed in 11.50.5 of the NER. Assessment of this proposed investment had commenced prior to the start date of the RIT-D with the AER notified as required.

[2] As defined Regulatory Test, Version 3 and prescribed by clause 5.6.5A(b)(1) of the NER (v53).

[3] 10% Probability of Exceedance – i.e. a 1 in 10 year "hot" summer condition.

This revision of the Final Recommendation provides both economic and technical information about possible solutions, the new recommended solution is now Option 1, construct 20MVA Substation at the Gracemere Site by June 2021. The previous recommendation was Option 2 with a 10MVA compact substation.

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

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

For further information and inquiries please submit to the email address below.

Attention: Network Planning Southern
Email: regulatory.tests@ergon.com.au

Table of Contents

1. Introduction

Ergon Energy has identified increasing risks to reliable supply in the electricity distribution network supplying the Gracemere area in Central Queensland.

When a distribution network service provider proposes to establish a *New Large Distribution Network Asset*, it is required under the National Electricity Rules (NER)[4] 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.

The Final Report (this Paper) is based on:

- Assessment of the benefits to reliability, as assessed using AEMO's Value of Customer Reliability (VCR) framework and the reduction in the risk of a breach of the Safety Net provisions of Ergon Energy's Distribution Authority, of various options.
- The cost of those options.
- An assessment of whether non-network options (including embedded generation) could form all or part of an alternative option (by delivering a larger NPV benefit compared to the network option alone)
- An analysis of the identified options in accordance with the AER's Regulatory Test.

In this report, words in non-bold *italics* have special meaning within the NER or the Regulatory Test (Version 3).

2. Background

2.1 The Regulatory Test

As per the Regulatory Test version 3[5]:

> ***(1) An option satisfies the regulatory test if:***
>
> ***(a) in the event the option is necessitated principally by inability to meet the service standards linked to the technical requirements of schedule 5.1 of the NER or in applicable regulatory instruments - the option minimises the costs of meeting those requirements, compared with alternative option/s in a majority of reasonable scenarios;***

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[4]As noted, assessment is undertaken as per Version 53 of the National Electricity Rules. Unless otherwise stated, all references to clauses in the NER relate to Version 53 and not the most recent version.

[5] Page 54, Final Decision - Regulatory Test version 3 & Application Guidelines, Australian Energy Regulator, Nov 2007.

(b) in all other cases - the option maximises the expected net economic benefit to all those who produce, consume and transport electricity in the national electricity market compared to the likely alternative option/s in a majority of reasonable scenarios. Net economic benefit equals the market benefit less costs.

Where a *new large distribution network asset*[6] is proposed as a result of either of the two options above (referred to as the "*market benefits*" or "*reliability investment*" limbs, respectively), Ergon Energy is also required to:

- 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[7], within the time required for corrective action (if applicable):

In all cases, Ergon Energy needs to 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 (if applicable) under these scenarios.

2.2 Purpose of this "Final Report"

The purpose of this report is to:

- Provide information about the existing distribution network in the Gracemere area.
- Provide information about the increasing risks to reliable supply and to Ergon Energy's regulatory obligations.
- 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.
- Recommend Ergon Energy's preferred solution.

[6] As per the definition in Chapter 10 – Glossary, of the NER v53, being an investment with a total capitalised expenditure of in excess of $10M

[7] NER clause 5.6.2(f)

3. Existing Supply System for the Gracemere Area

Gracemere is a community nine kilometres to the south west of Rockhampton in Central Queensland. Gracemere has a population of approximately 8,400 people and is currently supplied by Malchi Zone Substation, which is located five kilometres from the town centre.

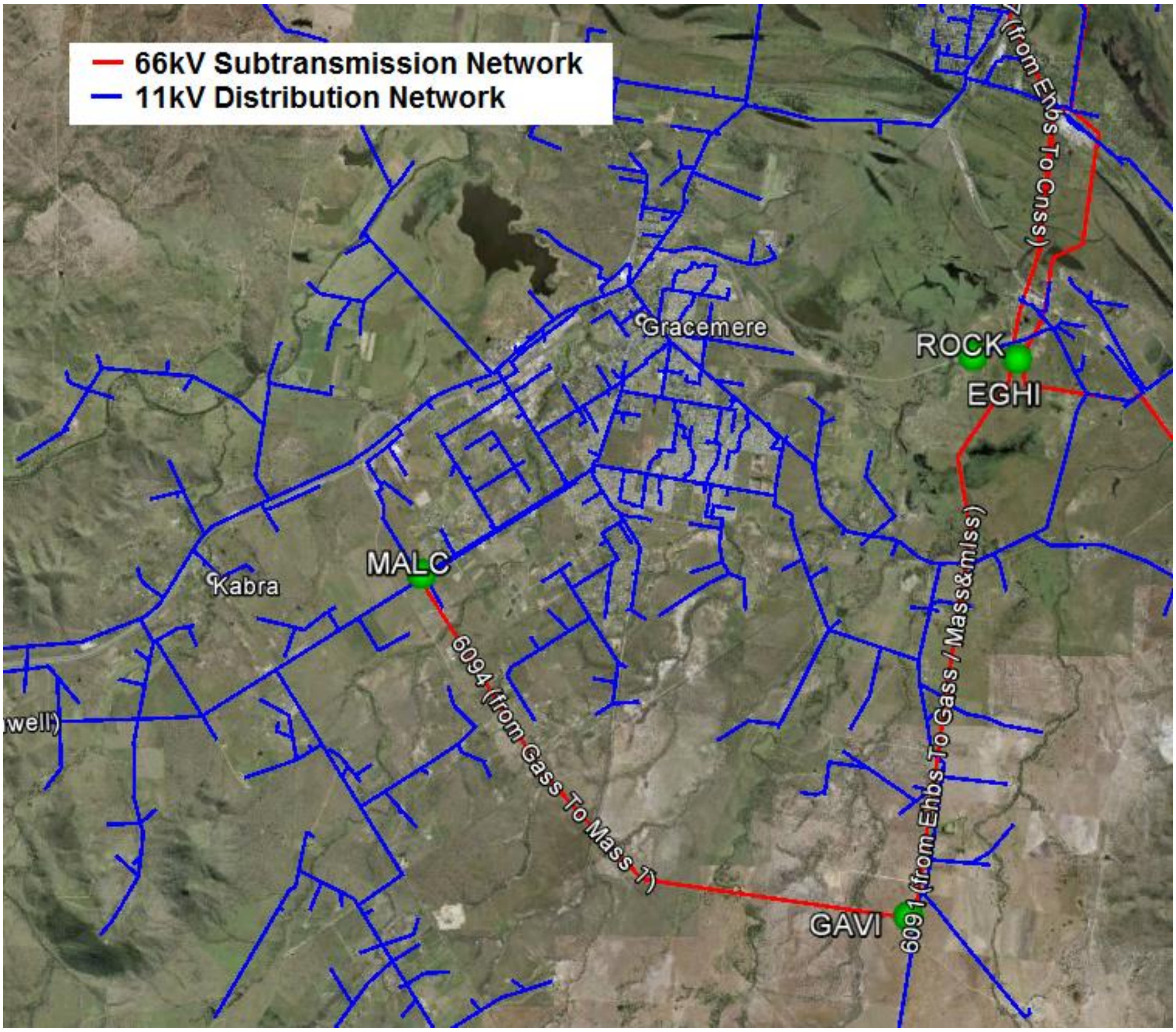

Figure 1 - Gracemere

Malchi Zone Substation comprises of two 66/11kV 10MVA transformers. The transformers and substation are considered to be in good condition.

A single incomer 66kV feeder currently supplies the substation, which runs from Gavial Switching Station. This feeder is 9km in length and has not had any outages in excess of 6 hours in the past 12 years, including during Cyclone Marcia in 2015.

Malchi Zone Substation supplies Gracemere via five 11kV distribution feeders. A feeder from Rockhampton South Zone Substation also provides some supply to the northern area of Gracemere. An 11kV distribution layout is shown in Figure 2 below.

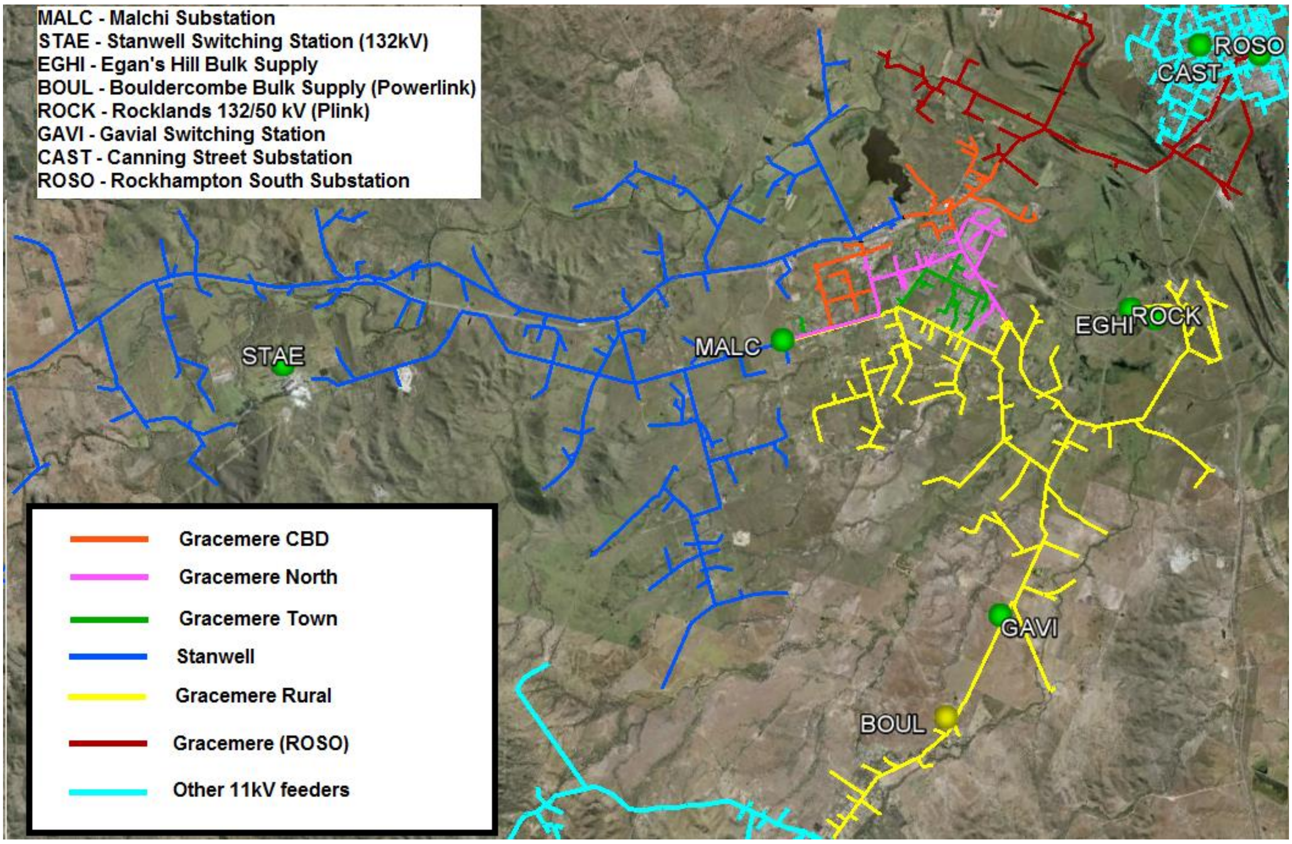

Figure 2 - Gracemere Distribution Network

The load on Malchi Zone Substation is predominately residential, as shown in Table 1**Error! Reference source not found.** below.

Sector	Customers[8]		Energy Consumption	
	Count	Percentage	MWh	Percentage
Domestic	4,984	92.5%	31,997	69.2%
Commercial	339	6.3%	6,909	14.9%
Industrial	6	0.1%	6,817	14.8%
Rural	59	1.1%	491	1.1%
TOTAL	**5,388**	**100%**	**46,215**	**100%**

Table 1 - Gracemere Customer Mix

[8] A “customer” refers to a connection point (e.g. a house) rather than an individual person

4. Network – Capabilities, Forecast and Risks

Growth on Malchi Zone Substation has been consistently high over an extended period, exceeding a decade. Even with the downturn in the mining industry and a step change in 2014 with the completion of the construction phase of the three LNG plants on Curtis Island, load growth has remained strong. In previous years, growth was in excess of 7% per annum. Current forecast has growth at 4.6% in 2019. As a result, load on the substation is approaching constraint.

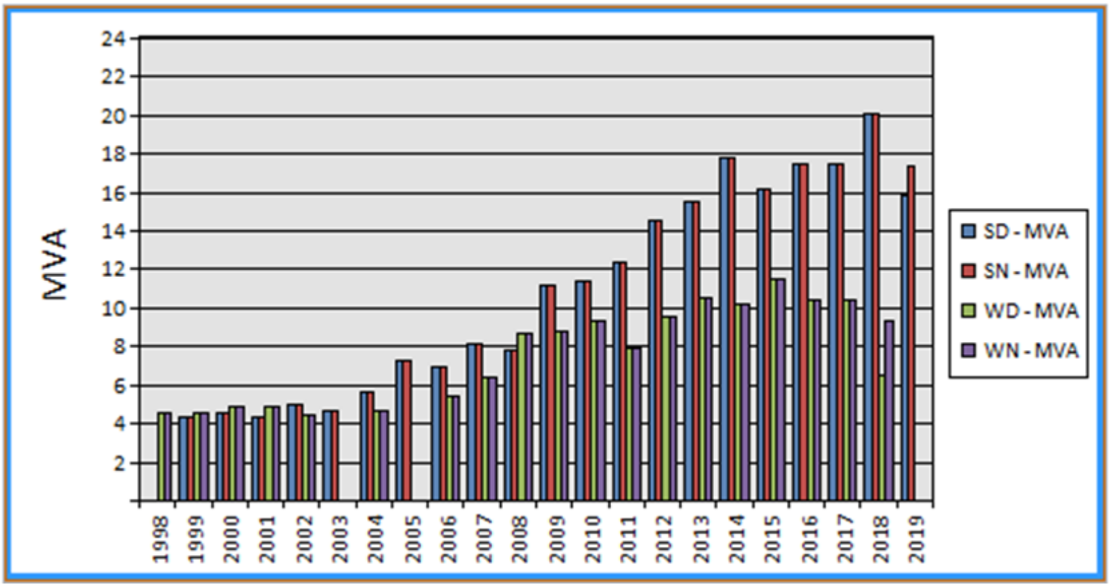

Figure 3 - Historical Peak Demands on Malchi Substation

4.1 Substation

The N-1 cyclic rating of Malchi Zone Substation is 13.3MVA. The "N" cyclic rating of the substation is 22.6MVA. Peak demand on Malchi Zone Substation was 20.1MVA over the 2017/18 summer as shown in

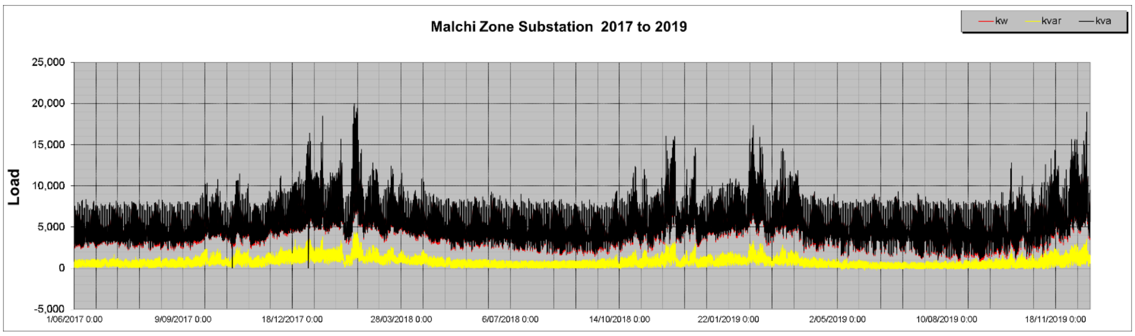

Figure 4.

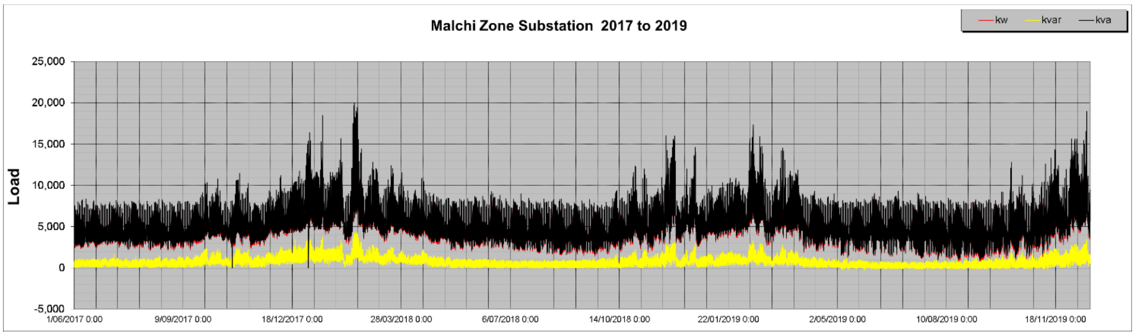

Figure 4 - Daily Maximum Demand on Malchi Zone Substation

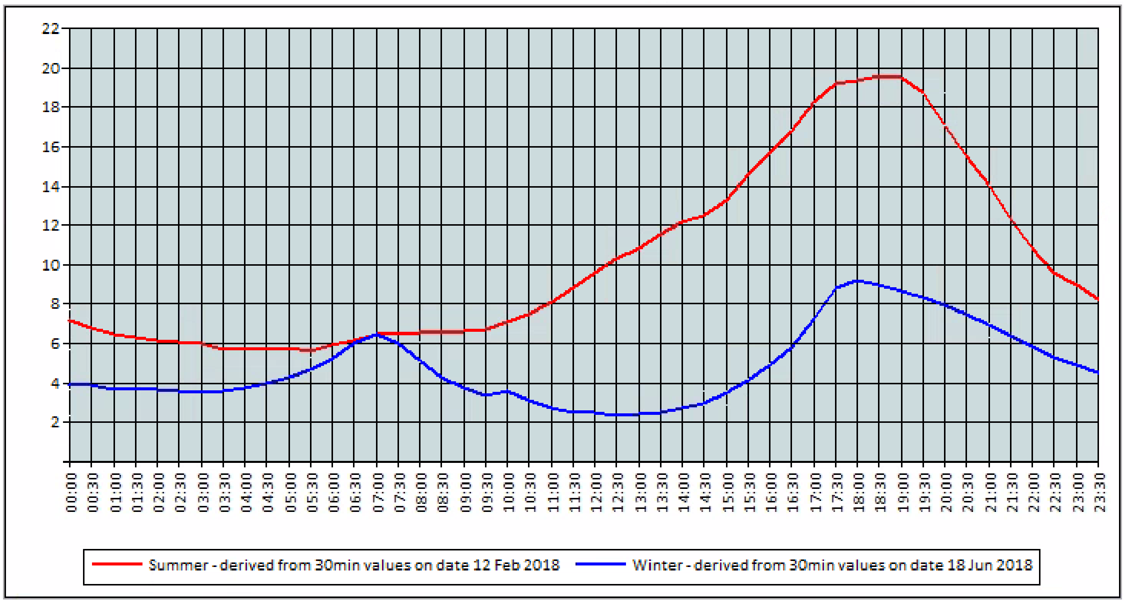

Figure 5 - Daily Load Profile for Malchi ZS for Summer and Winter Days 2018

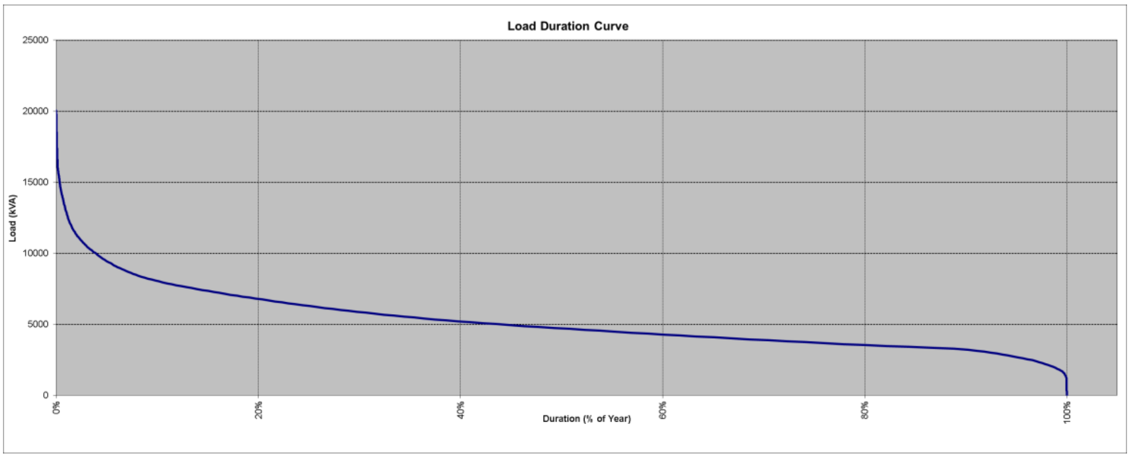

Figure 6 - Load Duration Curve for Malchi Zone Substation (2017,2018,2019)

The load profile for Malchi Zone Substation shown in Figure 5 and the load duration curve in Figure 6 associated with the demand load graph in Figure 4 indicate that Malchi Zone Substation is at risk for around 3 or 4 weeks per year, where loads are exceeding N-1 substation ratings.

At present, the load is in excess of the N-1 cyclic rating of 13.3MVA for around 70 hours per year with a forecast to continue to grow. At present, 1.0MVA can be transferred across the 11kV Gracemere Feeder out of Rockhampton South Zone Substation, and 0.5MVA can be transferred onto the Gogango Feeder (WN213) out of Wowan Zone Substation.

The transformers supplying Malchi Zone Substation are in good condition. The Ergon Energy Network Refurbishment team have determined that the probability of failure for each transformer is 0.45% for the current year and 0.66% at year 10 respectively, as shown in Table 2.

Asset Description	Replacement Year	Health Index Y0	Health Index Y10	Probability of failure Y0	Probability of failure Y10
CA MALC MA-T2 - TR92658042 1971 66/11/0.24 kV 10MVA WILSON (53352)	2040	2.8	4.1	0.45%	0.66%
CA MALC MA-T1 - TR92291585 1971 66/11/0.24 kV 10MVA WILSON (53353)	2040	2.8	4.1	0.45%	0.66%

Table 2- Condition Based Assessment of Malchi Transformers

4.2 Subtransmission Feeder

Malchi Zone Substation is supplied via a single 66kV feeder from Gavial switching station. This means, that it is a single point of failure; if the line is lost, the entire load on Malchi Zone Substation will be lost, until the line can be restored. After discussions with the Lines Manager for the area, the following scenarios in Table 3 were developed:

	Timeline (Hours)									
Scenario	**Find Fault**	**Excavator on site**	**Remote crew on site**	**Repair**	**Total[9]**	**Applicable Safety Net band**		**Line Length at Risk (km)**	**Duration of year at risk**	
"Normal" 66kV Line Outage, 6am to 12pm	3.0			5.0	**8**	12 hr	5MVA	7.0	75%	of dry days
"Normal" 66kV Line Outage, 12pm to 6am	4.0		3.0	5.0	**12**	12 hr	5MVA	7.0	25%	of dry days
Wet Weather, partially accessible poles 66kV Line Outage, 6am to 12pm	4.0	4.0		8.0	**14**	24 hr	0MVA	3.0	75%	of wet days
Wet Weather, partially accessible poles 66kV Line Outage, 12am to 6am	5.0	5.0	3.0	8.0	**19**	24 hr	0MVA	3.0	25%	of wet days

[9]Some of the restoration activities can be completed in parallel, hence the “Total” is not necessarily a summation of the duration of the listed fault finding and restoration activities.

Wet Weather, 4 worst poles 66kV Line Outage, 6am to 12pm	4.0	5.0		10.0	**17**	24 hr	0MVA	1.0	75%	of wet days
Wet Weather, 4 worst poles 66kV Line Outage, 12am to 6am	5.0	6.0	3.0	10.0	**21**	24 hr	0MVA	1.0	25%	of wet days

Table 3 - Malchi Subtransmission Feeder, Outage Scenarios

That is, restoration of supply following a permanent line fault (as opposed to a transient/temporary fault), is anticipated to take up to twelve hours under most conditions, but potentially up to 21 hours under more trying conditions. It is important to note that Ergon Energy cannot guarantee these timelines, rather they are representative of “typical, worst case” restorations. Other factors outside of Ergon Energy’s control can impact the scenarios.

4.3 Safety Net

For the purposes of Ergon Energy’s Safety Net requirements (under the Distribution Authority), Malchi Zone Substation is classified as supplying a Regional Centre. The applicable restoration targets are shown in Table 4.

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

Table 4 - Regional Centre Safety Net Restoration Targets

Where there is a risk of an exceedance that cannot be addressed with existing capabilities (such as with supply to Gracemere), investigations into appropriate capital and/or operational projects have been initiated. These range from assessment of localised availability of spares and tools of trade (e.g. appropriately sized elevated work platform vehicles), through to identification of LV and HV generation connection points (including, if needed earth mats and HV links), to significant capital projects (as with Gracemere).

It is important to note that Safety Net is a planning mechanism to capture low probability high impact events in the subtransmission and transmission network to protect the customer’s supply reliability.

4.3.1 Credible Safety Net Exceedance

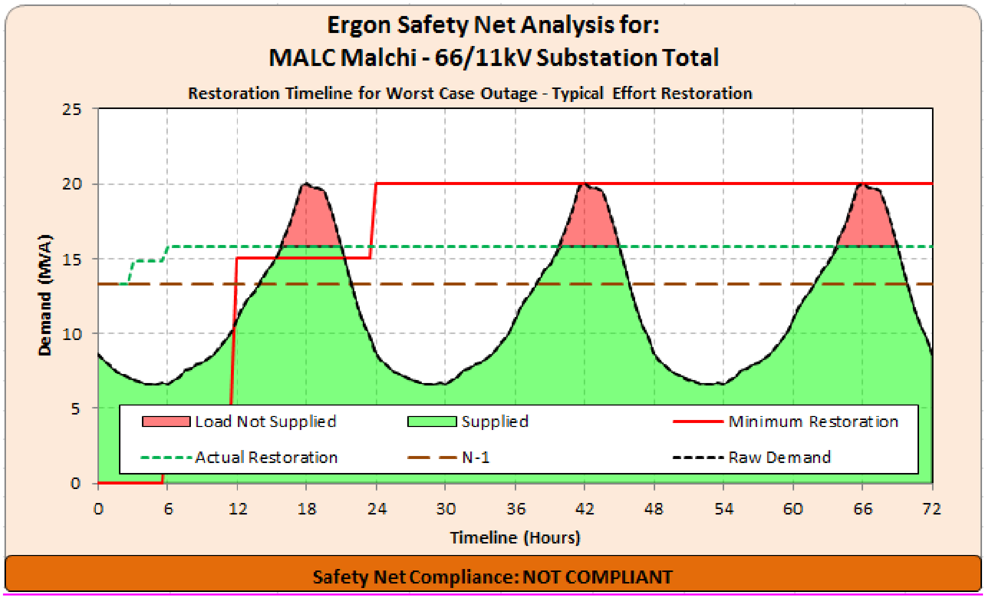

Figure 7 - Safety Net Analysis for Transformer Failure

Transformer Failure

Figure 7 highlights the Safety Net analysis of a transformer failure at Malchi Substation during a peak load week. The red in graph indicates possible unsupplied load that is outside of Safety Net guidelines. This includes 13.3MVA Transformer ECC capacity, 0.5MVA load transfer to Wowan, 1MVA load transfer to Rockhampton South Substation and 1MVA of mobile generation, leaving 4.5MVA of unserved energy.

To meet Safety Net time frames, Ergon Energy would need to install 4.5MVA of standby generation in the Gracemere area.

66kV Subtransmission Feeder

If the 66kV subtransmission feeder faulted during a peak load day of 20MVA and under an ideal situation the feeder was restored within 12 hours, Ergon would need to supply energy to 5MVA of customers within 6hrs. This includes 0.5MVA load transfer to Wowan, 1MVA load transfer to Rockhampton South Substation and 1MVA of mobile generation, leaving 2.5MVA of unserved energy.

To meet Safety Net time frames, Ergon Energy would need to install 2.5MVA of standby generation in the Gracemere area.

Safety Net Conclusion

To meet Safety Net obligations at Gracemere, 4.5MVA of standby generation is required.

4.4 11kV Distribution Network

Gracemere is supplied by five 11kV distribution feeders out of Malchi Zone Substation, and one from Rockhampton South Zone Substation. It is expected some of these will become constrained in future, however in a meshed network it is generally possible to change open points between feeders, or undertake construction of very minor ties in order to relieve these constraints.

Analysis of the feeder capacities show that these constraints are manageable while the zone substation loading is below its N rating, as shown in Table 5 below. Specifically, being that the distribution capability is well matched to the substation capability, changes in growth rates and/or growth patterns are unlikely to create a requirement for any significant intervention in the distribution network.

Further, following a contingency, at least 1.5MVA of load can be transferred to adjacent substation areas.

As such, there is unlikely to be an exceedance of a *technical limit* associated with the 11kV distribution network, until after the *technical limit* of the substation is exceeded.

Load Forecast			Growth Rates (%) 5 yrs	10 yrs	Feeder Rating UG (A)	OH (A)	OC (A)	2014/ 2015	2015/ 2016	2016/ 2017	2017/ 2018	2018/ 2019	2019/ 2020	2020/ 2021	2021/ 2022	2022/ 2023	2023/ 2024	2024/ 2025
MALC Malchi Zone Substation																		
MA150	Gracemere Town	SD	5.40	4.00	NA	338	300	167	176	185	195	206	217	226	235	244	254	264
		SN	5.40	4.00	NA	370	300	186	196	206	218	229	242	251	261	272	283	294
MA108	Gracemere Rural	SD	5.40	4.00	NA	338	300	163	172	182	191	202	213	221	230	239	249	259
		SN	5.40	4.00	NA	370	300	197	208	219	231	243	256	267	277	288	300	312
MA111	Stanwell	SD	5.40	4.00	NA	338	300	57	61	64	67	71	75	78	81	84	87	91
		SN	5.40	4.00	NA	370	300	73	77	81	86	90	95	99	103	107	112	116
MA119	Gracemere CBD	SD	5.40	4.00	320	551	300	185	195	206	217	229	241	251	261	271	282	293
		SN	5.40	4.00	320	582	300	167	176	186	196	206	218	226	235	245	255	265
MA123	Gracemere North	SD	5.40	4.00	320	338	300	226	238	251	264	279	294	305	318	330	344	357
		SN	5.40	4.00	320	370	300	240	250	264	278	293	309	321	334	347	361	375
Non Coincidental 11kV Substation Total		SD	(Amps)		640	1903	1500	799	842	888	936	986	1039	1081	1124	1169	1216	1264
		SN	(Amps)		640	2062	1500	864	907	956	1008	1062	1119	1164	1211	1259	1310	1362
Non Coincidental 11kV Substation Total			(MVA)					16.6	17.5	18.4	19.4	20.4	21.5	22.4	23.3	24.2	25.2	26.2
Diversity Factor								0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Substation 11kV Feeder Forecast Total			(MVA)					**16.1**	**16.9**	**17.8**	**18.8**	**19.8**	**20.9**	**21.7**	**22.6**	**23.5**	**24.4**	**25.4**
									Voltage (kV)		11		Setpoint		101.0%			
Dist FDR Utilisation >		75%	85%	100%														

Table 5 - Malchi Distribution Network Capability and Forecast

4.5 Value of Customer Reliability

Unplanned outages represent both a significant inconvenience and a financial cost to the economy. In 2014 the Australian Energy Market Operator (AEMO) delivered a report and application guidelines for analysing the value of customer reliability (VCR). From the Executive Summary of the Application Guideline:

> ***VCR values, estimated in dollars per kilowatt hour (kWh), represent customers' willingness across the (NEM) to pay for reliable electricity supply. This is the first time that NEM-wide VCR values for these customers have been calculated. VCRs are important in AEMO's evaluation of cost-effective ways to build or upgrade infrastructure or invest in non-network alternatives, and can be applied by industry participants in a range of planning, regulatory, market and policy contexts for customer benefit. In Victoria, VCRs are a mandatory feature of infrastructure planning assessments.***

The methodology discussed in the Report and Application Guideline was used to derive the expected annualised cost of reliability to the Gracemere community that results from the network topology supplying the area. This calculation took into account the condition of the assets in question, the restoration and mitigation options, the load profile and forecast load growth, and historical reliability performance to calculate the business as usual (BAU) VCR values out into the future.

Each option considered was also assessed in the same way to calculate the expected VCR performance of the network following implementation, with the difference to BAU representing the VCR benefit.

Based upon the energy consumption breakdown by sector given in Table 1 on page 9, and applying a loss factor of 5% (11kV distribution network), the Gracemere specific loss-adjusted, energy-weighted benchmark VCR value was calculated to be $29.73/kWh, reference year 2015. Energy-weighting is appropriate in the case of Gracemere, as the principal cause of unsupplied energy in the network is due to 11kV distribution faults. The contribution to unsupplied energy from the inability to supply energy due to exceedance of N-1 at the zone substation rises from approximately zero in the first year to less than 4% by the tenth year (representing the years of most interest to the study).

5. Option Development

5.1 Consultation Summary

During the early stages of the planning process, Ergon Energy identified that action would be required to address an anticipated distribution network exceedance of the “N-1” rating of Malchi Zone Substation; being a Queensland jurisdictional planning requirement. That is, this exceedance represented a trigger for a *reliability limb* investment, as per 5.6.5A(b)(2) of the NER.

On 19 December 2013 Ergon Energy released a Request for Information providing details on the emerging network limitations in the Gracemere area. That paper sought information from Registered Participants, AEMO and Interested Parties regarding potential solutions to address the anticipated limitations. Ergon Energy received six submissions by 20 February 2014, being the closing date for submissions to the Request for Information paper.

On 1 July 2014, the “N-x” jurisdictional planning requirement was removed and replaced by the Safety Net provisions in the Ergon Energy Distribution Authority and an economic, probabilistic, customer value based approach to investment. As such, Ergon Energy released an Addendum to the RFI on 9 September 2014, for which one submission was received by the closing date of the 11^{th} November 2014, the Final Project Assessment Report published on 4 May 2016.

5.2 Market Benefits Investment

As a result of the change in the planning criteria, the previously identified exceedance no longer existed; rather, a *technical limit* was forecast to be exceeded, but not until around 2024/25. In the meantime, aging of plant and growth of load would be expected to erode reliability, though this would also not be such that it would exceed any minimum performance requirements.

In addition to the gradual degradation of reliability, the jurisdictional Safety Net requirement would be exceeded, but as discussed in Section 4.3.1 , the total value of this risk is very low.

As per paragraph (1)(b) of the Regulatory Test, investment is allowed for where:

> ***… the option maximises the expected*** **net economic benefit** ***to all those who produce, consume and transport electricity in the national electricity market compared to the likely*** **alternative option/s** ***in a majority of*** **reasonable scenarios*****. Net economic benefit equals the*** **market benefit** ***less*** **costs*****.***

5.3 Network-Only Options Identified

Three network options have been identified. A substation site in Gracemere was purchased some time ago and is located at the corner of Platen and James Streets. Due to the high cost of subtransmission lines (particularly underground), a temporary (10 years) alternative site was also proposed on Gavial-Gracemere Road that was closer to the Bulk Supply Point at Egan's Hill.

Figure 8 - Potential Gracemere Network Solution Sites

5.3.1 Option 1: 1x20MVA 66/11kV Substation at Gracemere Site (PREFERRED OPTION)

It is proposed to construct a 20MVA transformer substation at the Gracemere site, supplying 3 new 11kV distribution feeders from a new radial 66kV feeder from Egan's Hill substation in existing easements and/or road corridors.

Estimated capital cost for this option are as follows:

1 * 20MVA Substation	$	9,817,306
EGHI - GRAC 66kV Line	$	9,558,083
Distribution Feeders	$	2,115,692
Egan's Hill 66kV Feeder Bay	$	1,930,533
	$	23,421,614

Table 6 - Capital Costs, Option 1

5.3.2 Option 2: 1x10MVA 66/11kV Compact Substation at Gracemere Site

It was proposed to construct a 10MVA compact substation at the Gracemere site, supplying 3 new 11kV distribution feeders from a new radial 66kV feeder from Egan's Hill substation in existing easements and/or road corridors.

Estimates for this option are as follows:

1 * 10MVA Compact Substation	$	5,837,958
EGHI - GRAC 66kV Line	$	9,558,083
Distribution Feeders	$	2,115,692
Egan's Hill 66kV Feeder Bay	$	1,930,533
	$	19,442,266

Table 7 - Capital Costs, Option B

In order to apply appropriate financial comparisons across a reasonable timeframe (in this case, 20 years), costs to upgrade the site to match the configuration of Option 1 (including decommissioning, estimated at $100,000) 10 years after construction of the compact substation were included in the financial analysis.

5.3.3 Option 3: 1x10MVA 66/11kV Compact Substation on Gavial-Gracemere Road

It was originally proposed to construct a temporary 10MVA compact substation along the 66kV line route path, on the Gavial-Gracemere Road, supplying 3 new 11kV distribution feeders from a new radial 66kV feeder from Egan's Hill substation in existing easements and/or road corridors.

After working with Department of Transport, Department of Transport advised that Ergon Energy could <u>NOT</u> site the temporary substation in the Main Roads road Corridor and hence this option has proved not to be feasible and is not considered further in this report.

5.4 Non-Network Options Identified

In order to satisfy the Regulatory Test, Ergon Energy sought to identify non-network options or non-network/network combinations that deliver *market benefit*s that exceed the cost of the option, while meeting all technical requirements of the applicable regulatory instruments (e.g. Schedule 5.1 of the NER).

To be considered an alternative non-network option, the proposed solution was required to:

- Meet all applied service standard requirements, and;
- Cost less than the benefits delivered, either as an entirely non-network solution, or incrementally, as a component of a non-network/network solution. This included, where applicable, any financial benefit derived by deferring or reducing the size of a capital investment.

Proponent	Technology	Configuration	Standing Cost	Operating Cost
Respondent A	Diesel Generator	1.4MVA units	$5,718 per MW per week	$242 per MWh
Internal Group	Diesel Generator	1.25MVA units	$3,654 per MW per week	$370 per MWh

Table 8 - Submissions to RFI

Due to the low likelihood of needing to operate in any given year, the Standing Cost represents the principal cost driver for any option. As the standing cost for Respondent A is significantly higher than the Internal Group, the Internal Group proposal was selected for use in further options analysis.

Additionally, as a result of the configuration of the network supplying Gracemere and the growing load, diesel generation does represent a solution by itself; rather, it can potentially be used to defer capital investment. Analysis was undertaken on this basis.

5.4.1 Non-Network Option: Deferral of Options 1 and 2

In this case, all costs and assumptions were as per previously discussed, excepting that the timing was deferred by 1 year notionally, as a result of installing generation. The timing of the later upgrades in Options 2 were not adjusted since a generator does not represent a permanent reduction in demand and as such, would not be present at year +10 as would be needed to defer that expenditure.

The presence of an embedded generator in the network was assumed to deliver a small reliability benefit, on the basis that:

- It would be connected to 1 of the 5 feeders,
- That 1MVA is roughly half the average load of an average Malchi feeder
- The average outage duration for faults in the 11kV network at Gracemere is 1.68 hours, being a mix of short and longer duration outages.
- Switching would need to be completed before the generator could assist in reducing the unsupplied energy

Thus, as an upper estimate, a 1MVA generator could reduce unsupplied energy due to 11kV network faults by 5% (being 20%x50%x50%).

The generator was assumed to be able to assist all the time with outages at the zone substation. For outages in the 66kV subtransmission network, while switching would also be required before being able to be used, it generally will take significantly longer to restore supply following permanent faults, since this would require repair, not simply switching around the faulted section. As such, for simplicity, generation was also assumed to be able to provide 100% assistance (also representing an upper estimate).

In every case, the generator is assumed to be present for the full year. Where the duration is less, the reliability benefit would be reduced by a similar ratio.

6. Feasible Solutions and Financial Analysis

6.1 Network Options

The feasible solutions for Gracemere run along a similar theme, and vary only by location. The Gracemere (GRAC) site is shown in Figure 8, as was the potential site (GAVL) on the Gracemere-Gavial Road.

All network options consist of three 11kV distribution feeders. Consideration was given to installation of fewer feeders, however in every case, the small saving in capital cost was insignificant to a much larger reduction in VCR benefit.

Option 1 has a higher VCR benefit due to the likelihood of Option 2 requirement to shed load under future contingency events when the load is above 24MVA. While both Options will meet Safety Net, Option 2 will require load to be shed for a period.

6.2 Hybrid Network/Non-Network Options

Potential generator sites are shown in Figure 9, selected since they would present good sites in terms of network connection and by not being in close proximity to residential neighbourhoods. They represent hypothetical locations for the purpose of analysing the effectiveness of an embedded generator, and do not necessarily represent a proposed location.

Figure 9 - Potential Generator Locations

As noted previously, embedded generation was used as a method of deferring capital expenditure associated with all network-only options. In each option, the deferral represents a net present cost saving, but a reduction in total VCR benefit.

Safety Net is a low probability high impact event and has removed the probability of failure, the analysis has determined that 1MVA of mobile generation will be available locally for an event and a further 4.5MVA of generation will need to be installed permanently in the network to meet safety net obligations under the Distribution Authority. Figure 7 in the Safety Net analysis section highlights the amount of unserved energy at risk during a transformer failure event.

6.3 Financial Analysis

These options were modelled, exclusive of the cost of installing the generation, with the value of benefits and risks summarised in Table 9 below:

- Base Case of managing safety net risk and peaking lopping with 4.5MVA of generation to defer 20MVA Substation
- Option 1: Single 20MVA Substation
- Option 2: 10MVA Compact substation to defer 20MVA substation

Options Included:	Yes	Yes	Yes
$ Millions	**Base Case**	**Option 1**	**Option 2**
Capex	(5.42)	(14.01)	(13.72)
Opex	(11.40)	(2.16)	(2.79)
Direct Benefits	0.00	0.00	0.00
Commercial NPV	**(16.82)**	**(16.17)**	**(16.51)**
Ranking	*3*	*1*	*2*
Indirect+Risk	4.79	9.92	9.92
Commercial + Risk	(12.03)	(6.25)	(6.59)
Ranking	*3*	*1*	*2*

* Indirect + Risk is the combined value of VCR and Safetynet Risk

Table 9 - NPV Analysis, All Viable Options

Options Included:	Yes	Yes	Yes
$ Millions	**Base Case**	**Option 1**	**Option 2**
Capex	(5.42)	(13.00)	(12.82)
Opex	(11.40)	(2.87)	(3.46)
Direct Benefits	0.00	0.00	0.00
Commercial NPV	**(16.82)**	**(15.87)**	**(16.29)**
Ranking	*3*	*1*	*2*
Indirect+Risk	4.79	9.14	9.14
Commercial + Risk	(12.03)	(6.74)	(7.15)
Ranking	*3*	*1*	*2*

* Indirect + Risk is the combined value of VCR and Safetynet Risk

Table 10 - NPV Analysis where Option 1 & 2 are deferred by Generation by 1 year

Table 9 shows the financial components for the network-only options, with Option 1 having both the lowest Commercial NPV and the highest Cost/Benefit NPV.

Table 10 provides the NPV analysis to defer the initial construction of Gracemere site by one year by utilising the 4.5MVA of generation, the same amount of generation currently required to fulfil the worst-case scenario safety net breach.

6.3.1 Feasibility of a Hybrid Option

The Base Case considers the effect of deferring the construction of a 20MVA substation capital expenditure through to 2031 using 6MVA of embedded generation and 1MVA of mobile generation. The Base Case does not consider the technical constraints and community objections to the installation of 6MVA of generation, whether temporary or full time. The 6MVA is viable to run in parallel with the system for transformer failure, whereas if the 66kV feeder failed then the generators cannot run in island mode, except for individual LV connected business; second largest customer is 500kVA limiting the number of large LV generators that can be installed. This option also does not consider the requirement, logistics and operational costs to start peak lopping from 2022 to maintain loads below NCC of the Malchi zone substation transformers.

Table 10 provides a hybrid solution where generation is utilised to defer the initial build of Options 1 and 2 by one year. As identified between Table 9 and Table 10, the cost benefits are negative, highlighting that the hybrid solution is not an economically viable option. Note the initial installation costs for generation was not considered in this analysis and if included would only increase the financial gap between the pure network and hybrid options.

Considering the network-only and the hybrid option, Option 1 has the lowest Commercial NPV, highest Cost/Benefit NPV and lowest risk of delivery.

It is important to note that the proposed investment and timing is justified on the basis of *market benefits*, specifically being the reduction in involuntary load shedding (VCR) and a reduction in the risk of non-compliance with a regulatory obligation. In this case, as seen, the reduction in benefits significantly outweighs the reduction in costs. <u>As such, the inclusion of generation (or other non-network options) does not represent a feasible *alternative option* to the network-only option</u>.

Given the advancement and reduction in battery prices since the Gracemere RFI, an investigation into battery technology options has been performed. Battery prices are readily available and were utilised for comparison purposes to defer network investment. The preferred network Option (Option 1) equates to an investment of $1,150/kW over a 50-year period. A battery option equivalent has an investment costs of approximately $2,700/kW and this is only for a 10-year period. As the difference in comparative prices is significant, the market was not tested further.

6.4 Sensitivity Analysis

Sensitivity Analysis ($M)		Base	Option 1	Option 2	Weighting
Scenario - Base Case		-$12.03	-$6.25	-$6.59	100%
		3	1	2	
Scenario - Escalation Opex -High	20%	-$12.17	-$6.68	-$6.98	100%
		3	1	2	
Scenario - Escalation Opex -Low	-20%	-$11.89	-$5.81	-$6.19	100%
		3	1	2	
Scenario - Discount Rate - High	8.00%	-$11.29	-$7.55	-$7.51	100%
		3	2	1	
Scenario - Discount Rate - Low [REG]	5.00%	-$12.62	-$4.16	-$5.01	100%
		3	1	2	
Scenario - Increased Capital costs	20%	-$2.58	-$0.12	-$0.29	100%
		3	1	2	
Scenario - Decreased Capital costs	-10%	-$10.60	-$4.10	-$4.35	100%
		3	1	2	
Scenario - Increase in VCR Value	30%	-$10.93	-$3.84	-$4.18	100%
		3	1	2	
Scenario - Decrease in VCR Value	-30%	-$13.13	-$8.65	-$8.99	100%
		3	1	2	
Scenario - Increased Demand Growth	-1 yr	-$14.10	-$7.47	-$8.19	100%
Bring Forward 1 year		3	1	2	
Scenario - Decrease Demand Growth	+1 yr	-$10.99	-$6.20	-$6.41	100%
Deferred for 1 yr		3	1	2	
Weighted Average		-$10.09	-$4.84	-$5.20	
		3	1	2	

Table 11 - Sensitivity Analysis

Additional sensitivity tests were included here compared to previous Regulatory Tests; namely for Discount Rate and VCR Benchmark. The Discount Rate test was added due to the sustained volatility in the world economy affecting selection applicable “Risk Free” rates and other components that drive the calculation of the applicable Regulatory WACC. The VCR Benchmark sensitivity test was added as a result of this Regulatory Test being driven by *market benefits*, with the principal benefit being VCR. The selection of +/-30% is as per the recommendation in Section 3.4 of AEMO’s VCR Application Guide.

The sensitivity analysis consistently shows Option 1, a 20MVA single transformer substation at Gracemere as the preferred option.

Finally, as shown in Table 11, if all sensitivity scenarios are equally weighted and combined into a single overall NPV, Option 1 NPV is more cost positive than the base case by $5.1m and is now economically preferred over option 2.

7. Final Decision

From the technical and financial analysis presented above, Ergon Energy found that neither the externally proposed and internally identified alternative options represent feasible options, either alone or in any combination with a network option. As such, Ergon Energy intends to proceed with Option 1, construction of a 1x20MVA 66/11kV substation at the Gracemere Zone Substation site by June 2021.