Regulatory Test – FINAL REPORT

Emerging Distribution Network Limitations in the Gracemere Area

4 May 2016

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 Small New Network Asset* in the area.

The study area is presently supplied by the Malchi 66/11kV Zone Substation, with demand already exceeding its "N-1" capacity. As such, a contingency resulting in the inability to utilise either transformer may result in customer load shedding. The load is also forecast to exceed the "N" capacity of the substation during the summer of 2024/25 under normal conditions or as early as 2023/24 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.

The evaluation process has taken longer than originally planned, primarily driven by the need to fully understand the complex interrelations present in the new regulatory obligations and to develop the tools and processes needed to comply with both letter and intent.

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 1x20 MVA transformer-ended substation at the Ergon Energy owned Gracemere Site by 2018/19
- **Option 2:** Construct a 1x10 MVA compact substation at the Ergon Energy owned Gracemere Site by 2018/19

---

[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.

- **Option 3:** Construct a 1x10 MVA compact substation at a new site closer to Egan’s Hill BSP by 2018/19
- **Non-Network Options:** Deferral of all other options using generation

This is now a Final Recommendation where Ergon Energy provides both economic and technical information about possible solutions. Our recommended solution is Option 2, Construct a Compact Substation at the Gracemere Site by November 2018.

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.

It should be noted that public consultation is <u>not required</u> for a proposed *New Small Network Assets*; however as it was initially thought that the capitalised cost of the proposed option would exceed $10M (thus being a *New Large Network Asset*) a Regulatory Test was commenced. Additionally, the original requirement for augmentation, as described in the Request for Information, was based upon exceedance of a *technical limit* or *applicable regulatory instrument* (thus being a Reliability limb investment[5]). While this requirement still exists, the preferred option developed meets the requirements of the *market benefits limb* at an earlier date.

As such, there is no longer a requirement that Ergon Energy undertake further consultation; however it is considered prudent to publish a Final Report, which also provides respondents to the RFI (and Addendum) with a detailed response.

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).

[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] As per clause 5.6.5A(b)(2)

2. Background

2.1 The Regulatory Test

As per the Regulatory Test version 3[6]:

> ***(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;***
>
> ***(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*[7] 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[8], 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] Page 54, Final Decision - Regulatory Test version 3 & Application Guidelines, Australian Energy Regulator, Nov 2007.

[7] 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

[8] 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. Gracemere is currently supplied by Malchi Zone Substation, which is located five kilometres from the town centre.

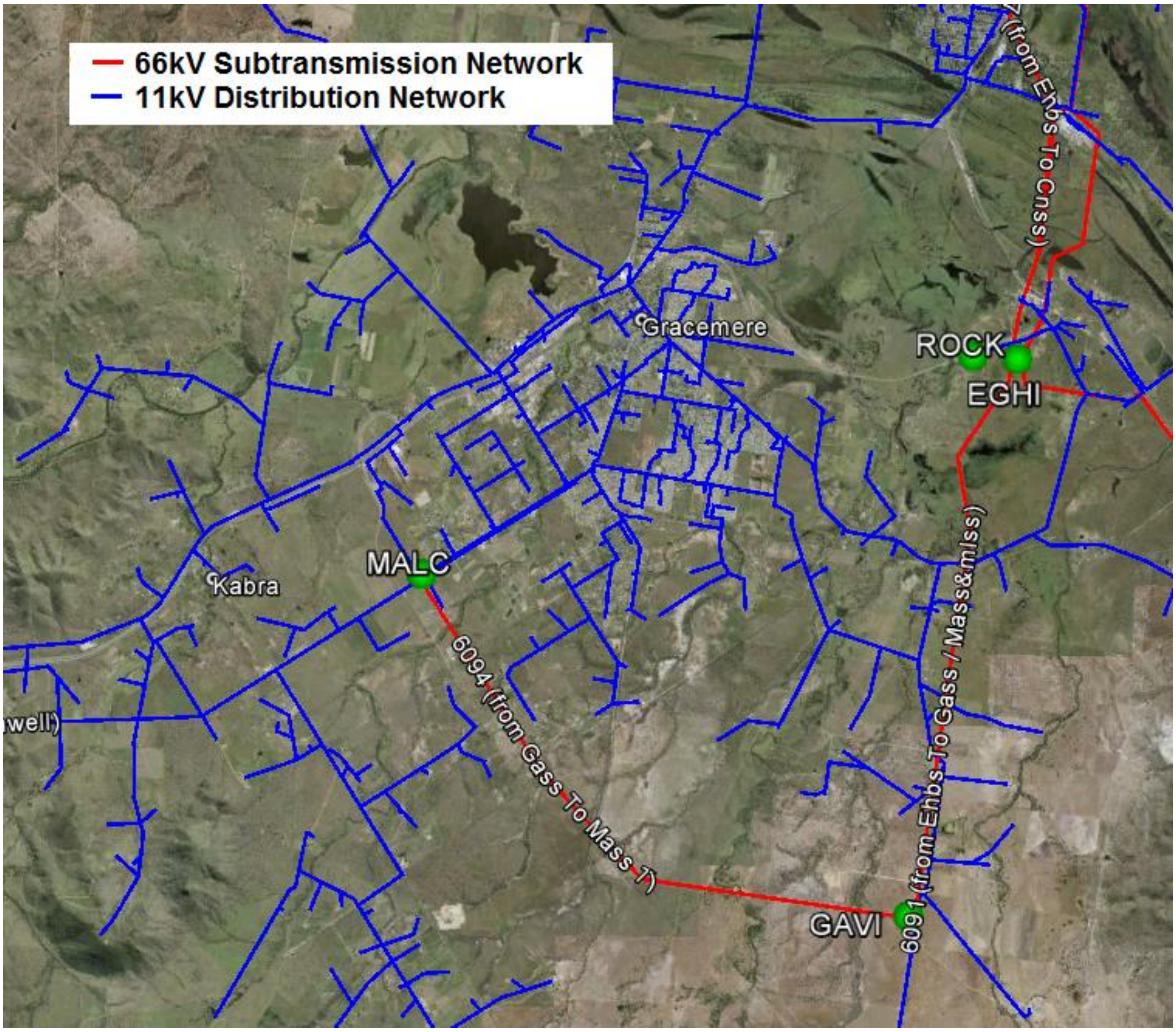

Figure 1 - Gracemere

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 10 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.

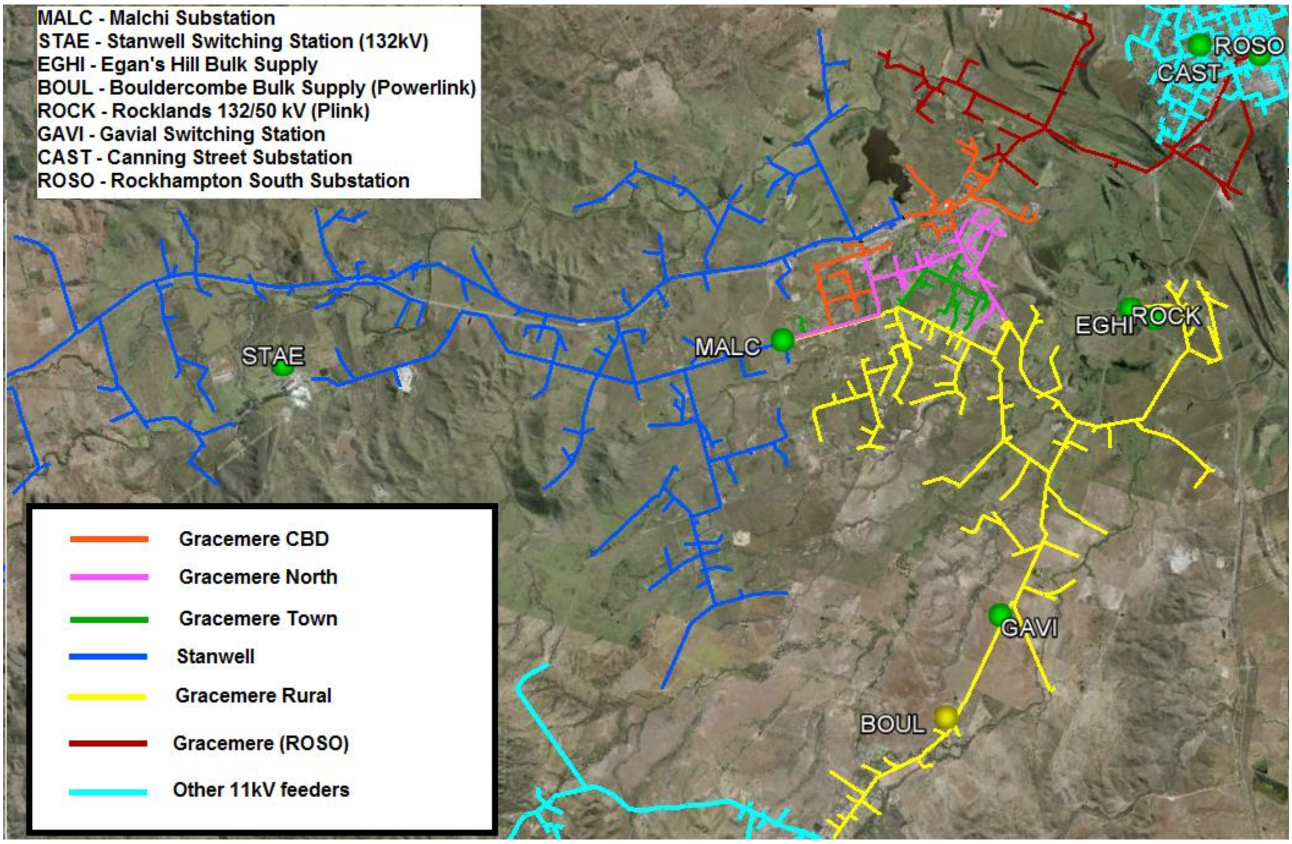

Figure 2 - Gracemere Distribution Network

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

Sector	Customers[9]		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

[9] 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, load growth has remained strong. In previous years, growth was in excess of 7% per annum. Current forecasts have growth at 7.1% in 2016, then 4.0% per annum beyond this. As a result, load on the substation is approaching constraint.

4.1 Substation

The N-1 rating of Malchi Zone Substation is 13.1 MVA. The "N" rating of the substation is 22.6MVA. Peak demand on Malchi Zone Substation was 17.4 MVA over the 2015/16 summer as shown in Figure 3.

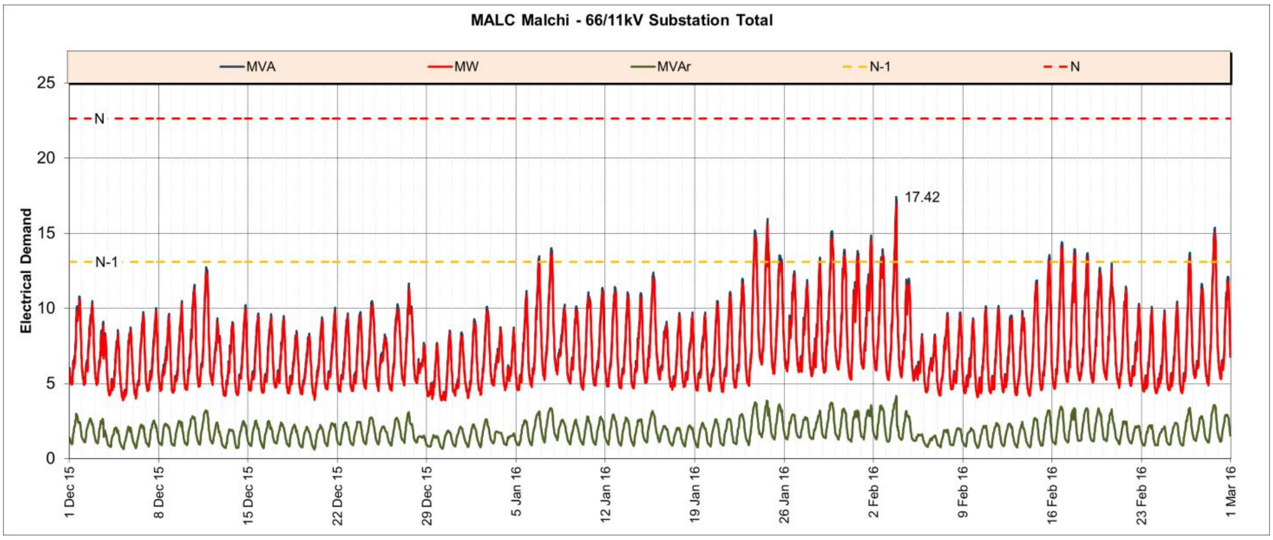

Figure 3 - Daily Maximum Demand on Malchi Zone Substation

The load on Malchi Zone Substation has a residential profile and experiences a brief peak period as illustrated in Figure 3 and Figure 4.

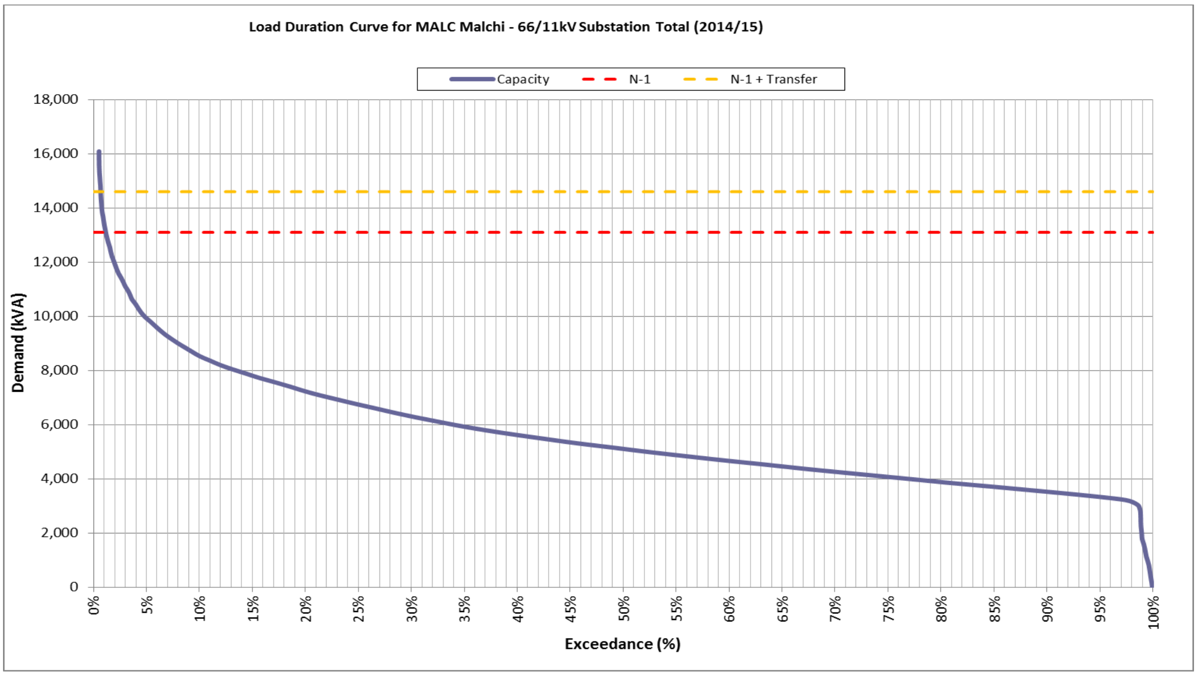

Figure 4 - Load Duration Curve for Malchi Zone Substation

At present, the load is in excess of the N-1 rating for around thirty hours per year, but is forecast to grow rapidly as shown below in Table 2 (inclusive of existing transfer options). At present, 1.0MVA can be transferred to Gracemere Feeder out of Rockhampton South Zone Substation, and 0.5MVA can be transferred onto Gogano Feeder (WN213) out of Wowan Zone Substation.

	2015/16	2016/17	2017/18	2018/19	2019/20
Exceedance	2357.7	3273.4	4238.6	5255.9	6328.1
Minimum Energy	32269.9	74038.2	147977.5	262671.1	433966.2
Hours	35.5	66.5	111.5	163.5	237.0
Days of Exceedance	12.0	19.0	29.0	39.0	51.0
Average Duration of Exceedance Event	2.7	2.9	3.7	4.1	4.3

Table 2 - Exceedance for Malchi Zone Substation

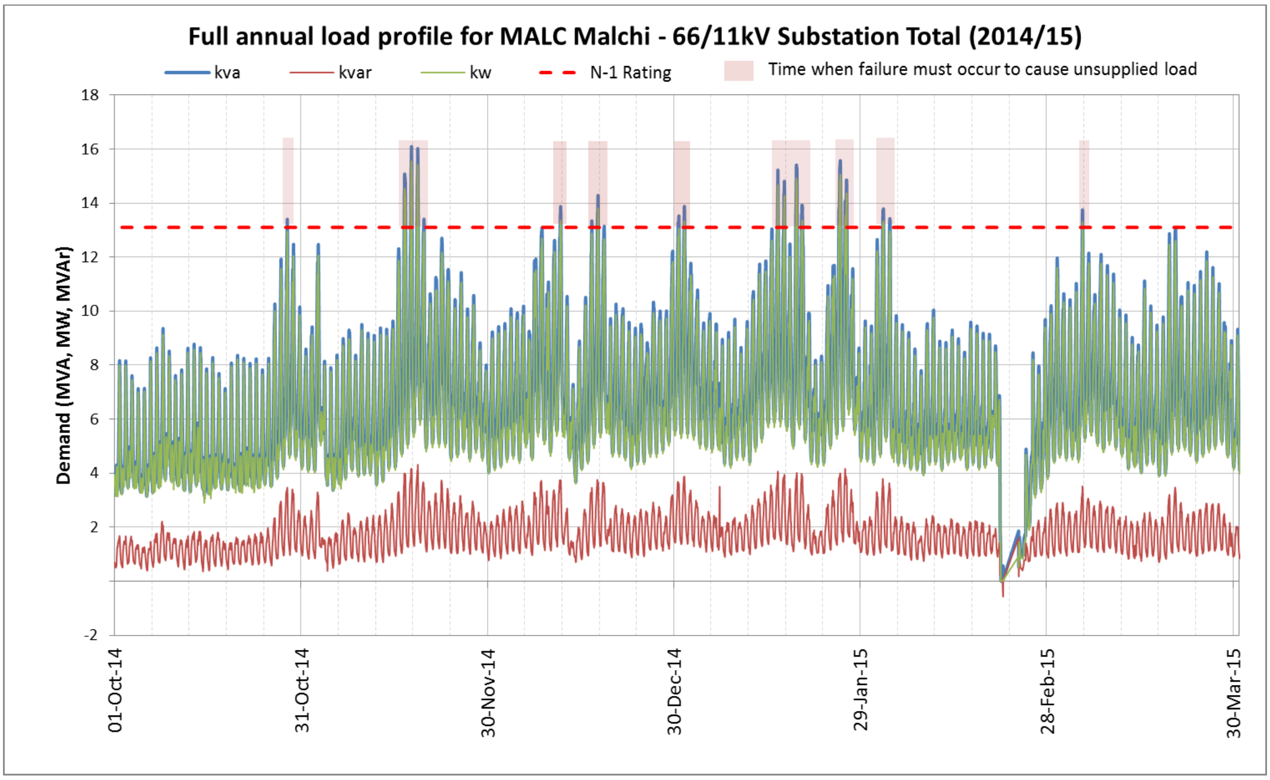

Figure 5 - Period where Energy is at Risk

The transformers supplying Malchi Zone Substation are in good condition. The Ergon Energy Network Refurbishment team has determined that the probability of failure for each transformer is 0.45% for the current year and 0.66% at year 10 as shown in Table 3.

21-Jan-2016 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 3- Condition Based Assessment of Malchi Transformers

Due to the peaky load on Malchi Zone Substation, the amount of time the substation is above its N-1 rating is minimal. From Table 2, we see that it is expected to have 35.5 hours above N-1 during 2015/16, rising to 66.5 hours the following year. Hence, there is a very small overlap between the risk of transformer failure and the percentage of the year where the load is above the N-1 limit, as shown in Figure 5.

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 were developed:

	Timeline (Hours)									
Scenario	**Find Fault**	**Excav-ator on site**	**Remote crew on site**	**Repair**	**Total** [10]	**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	5 MVA	7.0	75%	of dry days
"Normal" 66kV Line Outage, 12pm to 6am	4.0		3.0	5.0	**12**	12 hr	5 MVA	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	0 MVA	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	0 MVA	3.0	25%	of wet days
Wet Weather, 4 worst poles 66kV Line Outage, 6am to 12pm	4.0	5.0		10.0	**17**	24 hr	0 MVA	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	0 MVA	1.0	25%	of wet days

Table 4 - 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 5.

[10] 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.

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 5 - Regional Centre Safety Net Restoration Targets

Since publication of the Request for Information and the subsequent Addendum, Ergon Energy has worked extensively to develop draft Safety Net plans for all locations with load at risk. These plans document actions that can be undertaken should a credible event occur in order to restore supply in line with the Safety Net targets, with particular focus on high demand periods.

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 these Safety Net plans are primarily focused on the operational requirements, which may inform, but do not represent sufficient detail to meet the network planning requirements. This requires a detailed understanding of the actual risks posed by the identified potential exceedances, mitigation options available and the effectiveness versus cost of those options.

4.3.1 Credibility of Safety Net Exceedance

While there are periods of the year in which the load is high and if a fault were to occur during these periods, it is possible that the Safety Net targets may be exceeded (as shown in Figure 5), very detailed analysis was undertaken that considers:

- Annual load profile and forecast growth
- Fault/loss of supply scenarios, including:
  - Transformer (or transformer bay) faults
  - 66kV line faults (discussed in Section 4.2)
- Aging of plant
- Mitigation opportunities/capabilities (existing and potential)
- Environmental and working conditions, and;
- Restoration options

When all of these factors were taken into account, the risk of Ergon Energy <u>not</u> meeting the Safety Net targets fell into the range between 1% and 0.1% in any year (marginally credible), until after exceedance of the N rating of the substation (2024/25), when the risk rises above 1%.

For risks in this range, Ergon Energy's Network Risk Assessment Guidelines (NA000403R443) apply, in which consideration is given to the time taken to provide a reasonable emergency response, the size (and thus achievability) of that response and the types of load that would be interrupted (e.g. critical vs. non-critical), etc. In all cases, risk should be reduced to "*As Low As Reasonably Practicable*" (ALARP) and where residual risk remains, approval should be sought at the appropriate level of management.

As an objective test of achievement of an ALARP level of risk, assessment of the maximum foreseeable consequences (MFL) was undertaken. This figure was then multiplied by the probability of occurrence (calculated using the detailed analysis discussed above) to develop an annualised Value of Risk. The same process was used to calculate the residual value of risk following incremental implementation of further mitigation (specifically, installation of pre-contingent generation). This gave the following direct Safety Net benefit stream:

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Increase	+1MVA	$5,775	$7,291	$8,184	$10,025	$10,925	$12,752	$14,561	$16,863	$17,728	$21,252
	+2MVA	$9,370	$11,437	$13,327	$16,857	$19,699	$22,100	$24,693	$29,245	$32,116	$36,633
	+3MVA	$11,324	$14,118	$16,653	$20,771	$24,956	$29,439	$33,231	$37,745	$42,776	$48,649

Table 6 - Safety Net Incremental Additional Backup Capability - Benefits

Considering Table 6 above, for example, installation of 1 MVA of generation in 2017/18 will result in a reduction in the risk of exceeding the Safety Net targets (i.e. a benefit) of $8,184. Installation of 2 MVA, delivers a total benefit of $13,327, or if considered incrementally, a further $5,142 as a result of installation of the extra 1 MVA.

Note that these benefits are not inclusive of the cost of installing and running the generation, rather it simply provides an objective measure of the benefit of mitigation. Then, if the cost to achieve the mitigation exceeds the benefit then the risk is already ALARP.

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 7 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	Growth Rates (%) 10 yrs	Feeder Rating UG (A)	Feeder Rating OH (A)	Feeder Rating 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 7 - 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 7, 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 in with a reference year of 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 year 0 to less than 4% by year 10 (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 11th November 2014.

Since then, significant work has been required to develop an in depth understanding of how the new planning and investment requirements are used to justify investment, particularly where a *technical limit* exceedance is not present (as is the case at this time in Gracemere). Prior to this, Ergon Energy had little experience with the *market benefits* limb investment methodology.

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), an alternative site was also proposed on Gavial-Gracemere Road that was closer to the Bulk Supply Point at Egan’s Hill.

Figure 6 - Potential Gracemere Network Solution Sites

5.3.1 Option 1: 1x20MVA 66/11kV Substation at Gracemere Site

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

Estimates capital costs for this option are as follows:

1x20MVA Substation	$ 8,289,723
EGHI - GRAC 66kV line	$ 2,866,842
Distribution feeders	$ 435,627
Egan's Hill 66kV Feeder bay	$ 1,384,413

Table 8 - Capital Costs, Option A

These costs exclude further easement purchases and overheads.

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

It is 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 in existing easements and/or road corridors.

Estimates for this option are as follows:

Substation Construction	$ 2,518,352
EGHI - GRAC 66kV line	$ 2,866,842
Distribution feeders	$ 435,627
Egan's Hill 66kV Feeder bay	$ 1,384,413

Table 9 - Capital Costs, Option B

These costs exclude further easement purchases and overheads.

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 A (including decommissioning, estimated at $100,000) 10 years after construction of the compact substation were included in the financial analysis. **Note that Ergon Energy is not proposing to undertake these works past the initial new injection, they are only included for completeness of the financial analysis.**

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

It is 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 in existing easements and/or road corridors.

Estimates for this option are as follows:

Substation Construction	$ 2,518,352
66kV Line to Site	$ 1,529,922
Distribution feeders	$ 522,817
Slip lane	$ 420,000
Egan's Hill 66kV Feeder bay	$ 1,384,413

Table 10 - Capital Costs, Option C

These costs exclude further easement purchases and overheads. Due to the proposed temporary site being located on a wide Department of Main Roads road corridor, costs for the site have not been included in the financials at this time. Analysis shows this to be non-material to the selection of a preferred option.

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 A (including decommissioning and site restoration, estimated at $350,000) 10 years after construction of the compact substation were included in the financial analysis. **Note that Ergon Energy is not proposing to undertake these works, they are only included for completeness of the financial analysis.**

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	1.4 MVA units	$5,718 per MW per week	$242 per MWh
Internal Group	Diesel Generator	1.25 MVA units	$3,654 per MW per week	$370 per MWh

Table 11 - 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 to 3

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 and 3 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 1 MVA 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 6, as is 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 swamped by a much larger reduction in VCR benefit.

Additionally, all network options are functionally identical in terms of overall benefits including:

- Significant VCR benefits, and;
- The residual risk of a Safety Net breach being zero during the study period

6.2 Hybrid Network/Non-Network Options

Potential generator sites are shown in Figure 7, 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 7 - 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. Additionally, while 1 MVA of generation is not sufficient to reduce the risk of a Safety Net exceedance to zero, it does represent a benefit as given in Table 6.

6.3 Financial Analysis

These combined effects were modelled, exclusive of the cost of installing the generation and are shown in Table 12 below.

	Network-Only Options			Non-Network/Network (Hybrid) Options			1 MVA Non-Network Benefit		
$ Millions	Option 1	Option 2	Option 3	Option 1a	Option 2a	Option 3a	Option 1	Option 2	Option 3
Capex	(8.95)	(7.12)	(7.32)	(8.37)	(6.79)	(7.02)	0.58	0.33	0.30
Opex	(1.41)	(1.07)	(1.06)	(1.30)	(1.00)	(1.01)	0.11	0.06	0.06
Direct Benefits	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial NPV	**(10.36)**	**(8.19)**	**(8.38)**	**(9.67)**	**(7.79)**	**(8.03)**	**0.69**	**0.40**	**0.35**
VCR+SN Benefits	9.92	9.92	9.92	9.60	9.60	9.60	(0.33)	(0.33)	(0.33)
Cost/Benefit NPV	**(0.44)**	**1.73**	**1.54**	**(0.07)**	**1.81**	**1.57**	**0.368**	**0.072**	**0.028**

Table 12 - NPV Analysis, All Options

6.3.1 Feasibility of a Hybrid Option

The first set of columns in Table 12 shows the financial components for the network-only options, with Option 2 having both the lowest Commercial NPV and the highest Cost/Benefit NPV.

The second set shows the effect of deferring the capital expenditure using 1MVA of embedded generation, however as noted, this is exclusive of the cost of that generation. In this case, the second option is also preferred (which would be true regardless of the cost of generation, being common to all options).

Considering all network-only and hybrid options together, Option 2a appears to have the lowest Commercial NPV and highest Cost/Benefit NPV, however the cost of generation needs to be considered before a fair comparison can be made.

The third set of columns shows the comparative difference that the inclusion of generation makes. Considering Option 2 (being the preferred option in both the network-only and hybrid set of options), the deferral benefit is $0.40M, however the VCR and Safety Net benefits are significantly reduced, resulting in an Cost/Benefit NPV improvement of only $72k. That is, in order for the inclusion of 1MVA of generation to represent the best option, it has to be installed and available for operation for an entire year, **for less than $72k**.

Compared against the proposals, the internal option has an annual cost of $190k, or more than 300% of the incremental benefit delivered. With both Respondents there would also be additional costs to procure or lease, then establish an appropriate site, and to recover and restore the site at the end of the period, thus exacerbate the negative outcome.

It is worth noting that with both respondents, the specific proposals were for either 5 years or 10 years. The load on Malchi Zone Substation is currently growing at approximately 1MVA per year (though forecast to fall to approximately 650kVA annually after next year). When the same analysis above is done for a 2 year deferral, the total NPV benefit (for Option 2a, compared to Option 2) is $126k. That is, 1MVA of generation in Year 1 would rise to 1.65MVA in Year 2, and the maximum amount that could be paid for that generation across both years would be $126k. Therefore, in the second year, **1.65MVA** of generation would have to cost **less than $54k**, installed for the entire year. This "diminishing return plus increasing requirement" pattern continues to worsen with each year.

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. As such, the inclusion of generation (or other non-network options) does not represent a feasible *alternative option* to the network-only option.

6.4 Sensitivity Analysis

Sensitivity Analysis excl Overheads ($M)		Option 1	Option 2	Option 3	Weighting
Scenario - Base Case		-$0.44	$1.73	$1.54	100%
		3	1	2	
Scenario - Escalation Opex -High	+20%	-$0.72	$1.52	$1.33	100%
		3	1	2	
Scenario - Escalation Opex -Low	-20%	-$0.16	$1.95	$1.76	100%
		3	1	2	
Scenario - Discount Rate - High	=8%	-$2.04	$0.33	$0.22	100%
		3	1	2	
Scenario - Discount Rate - Low [REG]	=6.01%	$0.27	$2.36	$2.14	100%
		3	1	2	
Scenario - Increased Capital costs	+20%	-$2.58	-$0.12	-$0.29	100%
		3	1	2	
Scenario - Decreased Capital costs	-20%	$1.68	$3.51	$3.29	100%
		3	1	2	
Scenario - Increased VCR Benchmark	+30%	$2.03	$4.26	$4.01	100%
		3	1	2	
Scenario - Decreased VCR Benchmark	-30%	-$2.80	-$0.56	-$0.81	100%
		3	1	2	
Scenario - Increased Demand Growth	+1%	$6.12	$8.36	$8.10	100%
		3	1	2	
Scenario - Decreased Demand Growth	-2%	-$4.68	-$2.45	-$2.70	100%
		3	1	2	
Weighted Average		-$0.30	$1.90	$1.69	
		3	1	2	

Table 13- 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 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.

In addition to the new sensitivity tests, a more complex process was needed to test the sensitivity to demand growth. In previous Regulatory Tests, the predominant effect of changes in demand growth was simply a change in the timing of when the *technical limit* or other regulatory requirement would be exceeded and thus when the investment was needed. In this case however, changes in growth have a large effect upon the load at risk, year by year, and thus the benefits delivered by an investment.

This consistently shows Option 2, a compact substation at Gracemere, as the preferred option, with a positive NPV in 8 of the 11 scenarios. Further analysis shows that for the principal cause of the negative NPV is the inclusion of the hypothetical future investment in Options 2 and 3. It is worth noting that when Ergon Energy is approaching the point at where this future investment is recommended, a RIT-D will be undertaken at that time, but does not impact on the current recommendation.

Finally, as seen in Table 13, if all sensitivity scenarios are equally weighted and combined into a single overall NPV, Option 2 NPV positive (increased to $1.90M) and remains the preferred option.

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 2, construction of a 1x10MVA 66/11kV compact substation at the Gracemere Zone Substation site by November 2018.