Distribution Augmentation Unplanned Reliability

Business Case

19 November 2024

ERGON ENERGY NETWORK

Part of Energy Queensland

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DOCUMENT VERSION

Version Number	Change Detail	Date	Updated by
1	Approved Version	18/11/2024	General Manager Grid Planning

RELATED DOCUMENTS

Document Date	Document Name	Document Type
Dec 2019	Value of Customer Reliability - Final report on VCR values	Report
03/10/2019	Distribution Authority No. D01/99, Ergon	PDF

1 SUMMARY

Title	Ergon Energy Distribution Augmentation - Unplanned Reliability
DNSP	Ergon Energy
Expenditure category	☐ Replacement ☒ Augmentation ☐ Connections ☐ Tools and Equipment ☐ ICT ☐ Property ☐ Fleet
Identified need *(select all applicable)*	☐ Legislation ☒ Regulatory compliance ☒ Reliability ☒ CECV ☐ Safety ☐ Environment ☐ Financial Augment the Distribution Network (11kV, 22kV, 33kV, LV and SWER) as required to meet customer expectations in terms of network reliability.
Summary of preferred option	The Preferred Option is to provide funding as detailed in this business case such that customer reliability expectations as can be justified by Value of Network Resilience are met.
Expenditure	(see table below)
Benefits	Compliance with Regulatory and Legislative obligations regarding network reliability Network Reliability performance in regard to Unplanned outages will be as can be justified by VNR
Consumer engagement	This Business case is based on the AER Value of Network Resilience Final Decision which was based on extensive consultation.

Year	2025-26	2026-27	2027-28	2028-29	2029-30	2025-30
$m, direct 2022-23	$4.06	$12.58	$8.36	$11.06	$3.74	39.80

2 PURPOSE AND SCOPE

This business case is for Distribution Augmentation Unplanned Reliability driven works and is targeted at communities where significant reliability challenges. This program is required as Ergon Energy's Distribution Authority No. D01/99, specifies Ergon Energy "must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services". The AER's newly released Value of Network Resilience (VNR) framework has been used to determine the value that end users place on reliability of electricity services.

The target communities in this business case face network reliability challenges with a relatively high proportion of outages exceeding 12 hours. By following the AERs own VNR investment methodologies, Ergon Energy has been able to determine the right level of investment to deliver reliable energy services to customers in these communities.

The purpose of this business case is to justify works to improve feeder reliability based on VNR analysis to meet customers reliability expectations. It is focussed on network performance relating to unplanned outages.

3 BACKGROUND

Ergon Energy operates medium voltage distribution networks at 11kV, 22kV and 33kV as well as a range of 12.7kV and 19.1kV SWER systems. Ergon Energy operates a very different network to most Australian Distribution Network Service Providers (DNSPs) in the National Electricity Market (NEM), typified by small customer numbers, long network distances, large geographical spread of network and subsequent low network densities. The distribution network is made up of approximately 120,000km of overhead powerline and 9,000km of underground cable, with about 1,000,000 power poles and close to 100,000 distribution transformers. With approximately 8% of the total NEM customer base, Ergon Energy's network area is approximately 44% of the total area covered by the networks that form part of the NEM. Ergon Energy operates one of the lowest density networks in Australia which has a large impact on how the network is designed, managed, and operated. It is a largely overhead and radial network which includes one of the largest SWER networks in Australia and the world. Given the size, the often-difficult terrain and remoteness of the network, combined with the environmental exposure associated with a predominately overhead network, meeting customer's expectations in terms of reliability performance is a significant challenge.

Post Ergon Energy's Regulatory Proposal, in July 2024 the Australian Energy Regulator (AER) released their Draft Decision: Value of Network Resilience 2024. The AER has since released their final decisions on the 30/9/2024. This decision provides a mechanism to put a value on longer duration outages which was previously not available under the AER's Value of Customer Reliability guidelines, which only considers outage durations under 12 hours. The AERs decisions allows outage durations over 12 hours to be considered with a stronger focus on outages lasting between 12 and 72 hours. This now provides Ergon Energy an opportunity to support the network performance of more severely impacted regional communities as part of the Revised Regulatory Proposal.

As part of Ergon Energy's regulatory proposal, the AER had concerns regarding this business case (Distribution Unplanned/ Maintain Reliability) predominately based on their expectations that Ergon Energy should not be improving reliability performance. Ergon Energy acknowledges the comments and feedback provided, and based on this feedback has focused this program to target the reliability and underlying network performance of a limited subset of highly unreliable feeders that supply regional communities. As this proposal only targets 8 feeders of which the target communities only form part of the feeder, it provides no significant improvement in Ergon Energy's overall system level reliability performance. That is, this proposal meets the AER's expectation that reliability performance across the business is not materially improved on the basis that the Service Target Performance Incentive Scheme (STPIS) is the method by which Ergon Energy is incentivised to improve network performance. To explore this further, the program will not change the frequency of outages in these communities, and hence will have no impact on SAIFI STPIS measures. Outages will still occur, however their duration will be reduced as the generation will restore load to the communities following an outage. As a small number of select communities have been targeted by this program, Ergon Energy's system wide SAIDI will also not materially change. To further put this into perspective, Ergon Energy's Unplanned Energy Not Supplied last financial year (23/24) was 16.57 GWh and modelled improvement in this business case is only 0.09 GWh. This also demonstrates why the AERs new VNR methodology is important, as it provides the only meaningful measure to value longer outage durations and the issues faced in these communities. Many of the communities targeted have previously expressed reliability concerns. These concerns however were unable to be addressed, as the VNR methodology didn't exist to justify investment at the time. Figure 1 details the target communities and illustrates the long radial supply arrangements.

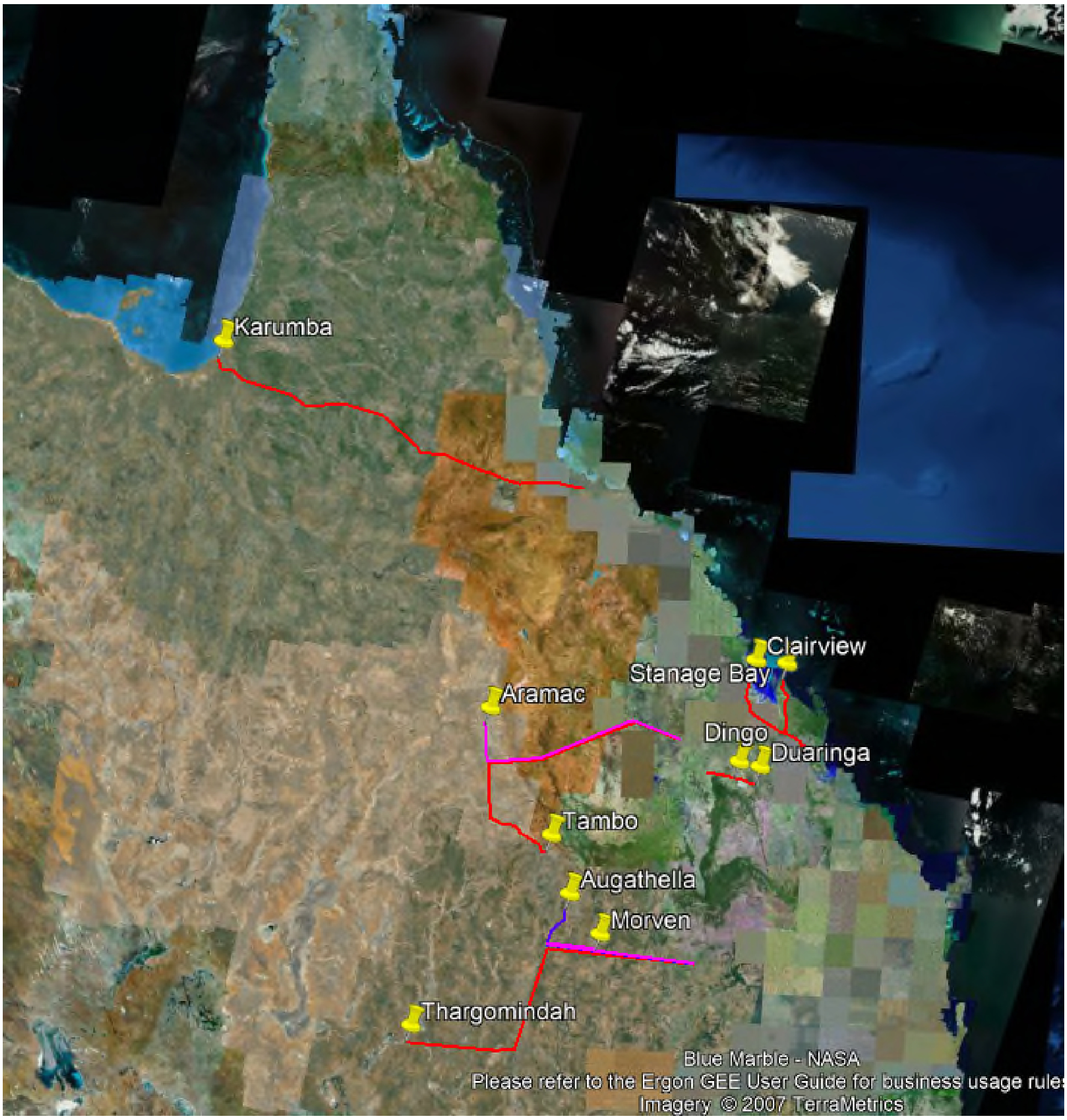

Figure 1 Radial (no ties or alternate supply arrangements) sections of lines supplying selected communities.

When benchmarked against other DNSPs Ergon Energy's reliability performance is consistently well below average and frequently has the most Energy Not Supplied in the NEM. Ergon Energy believes its customers should have the opportunity for similar outcomes that already exist for customers with other DNSPs and hence has targeted some of the communities on the network that face very poor unplanned reliability performance. Figure 2 details the energy not supplied per distributor with Ergon Energy appearing the top of the list for the last three consecutive years.

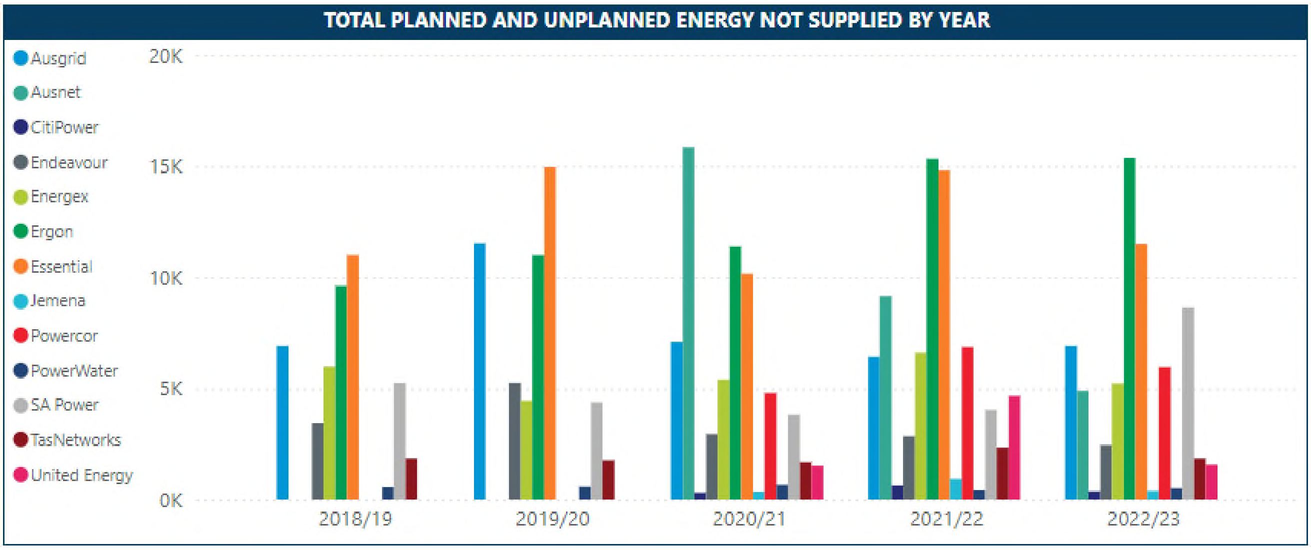

Figure 2 Unplanned Reliability DNSP comparison clearly indicating significant improvement opportunities.

Ergon Energy endeavours to maintain network performance to regional communities by ensuring the network is appropriately maintained, and by installing protection devices to minimise the probability of larger outages. As many communities are towards the end of feeders, there however are often limited or no cost-effective traditional solutions to overcome these challenges. In most cases the traditional network solutions involve building extensive additional network into these communities which is not economically justifiable on a cost-benefit basis. Ergon Energy have also found that greener alternatives incorporating renewables are cost prohibitive. Therefore, as part of this business case, Ergon Energy is proposing to install diesel generation in these communities as the most cost-effective solution to provide network support/reliability during unplanned outages.

3.1 Planned Distribution Augmentation – Unplanned Reliability

As detailed in Distribution Authority No. D01/99, Ergon Energy “must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services”. Ergon Energy’s program focuses on addressing network reliability performance by targeting a select number of communities that are severely impacted and that have a significant proportion of outages in excess of 12 hours in duration. A conservative approach has been taken as part of this analysis in terms of the assumptions applied to derive the benefits. The timing of the work has been balanced across the regulatory period to ensure a deliverable program. Table 1 details the project volumes and associated delivery timeline.

Description	25/26	26/27	27/28	28/29	29/30
Target Project Volumes	1	2	2	2	1

Table 1 Volume of projects

4 IDENTIFIED NEED

Unplanned Reliability expenditure is required based on customer expectations regarding network performance and is justified by a positive cost/benefit analysis as well as being required to meet regulatory obligations as detailed in Ergon Energy's Distribution Authority D01/99. Table 2 details the drivers that make up this planned distribution augmentation reliability business case.

Program	Sub Program	Justification	Justification Detail
Planned Augmentation	Reliability	Cost Benefit Analysis	Value of Network Resilience (VNR) Electricity Act 1994/Distribution Authority D01/99

Table 2 Distribution Augmentation Justification Matrix

All regional communities targeted in this program are subject to long duration outages as the feeder networks supplying them are very exposed to the environment due to the length of radial network. That is due to the long radial network supplying these communities they are particularly susceptible to severe weather events which will only increase further with climate change. It is noted that this program is justified based on current network performance, and the expected future impacts of climate change have not been modelled. That is, this program is fully justified based on the current state. If climate change modelling was performed, the NPV positive outcome of this program would only further increase. Communities with most of the following characteristics have been targeted as part of this program:

1) Located towards the end of very long networks and feeders which are inherently impacted more by severe weather events. As reliability performance is generally proportional to the length of feeder exposed to the environment and weather-related events, communities on these feeders have poor reliability outcomes. Whilst not modelled to justify this program, given the network exposure, these communities are also more likely to be impacted by the increase weather-related events triggered by climate change.
2) Located remotely from depots which impacts the ability to restore power quickly which results in longer duration outages.
3) Often difficult to access during and after severe weather events due to flooding and road conditions. This can make it impossible to effectively deploy temporary generation or perform network switching, which can typically take place in more urban less remote locations.
4) Are supplied by feeders/lines that often pass through difficult terrain that makes access and restoration more challenging or at times impossible. For example, lines that pass through mountainous areas without road access, flood plains, soil that becomes boggy, river crossings, etc. This can also make restoration at night either extremely slow, or sometimes impossible, resulting in restoration only being safely achievable in daylight hours. Typically, on the selected feeders much of the radial supply network does not run immediately

adjacent to road networks. It is often through paddocks etc. Appendix 1 illustrates some of the challenges faced in terms of access and terrain.

5) Are supplied by 11kV/22kV feeders with no ties to other feeders to provide backup supply.
6) Are supplied by long radial sub-transmission network with no ties to other sub-transmission feeders to provide backup supply.
7) Have a significant proportion of unplanned outages exceeding 12 hours in duration.
8) Have reliability challenges that cannot be addressed as part of Ergon Energy's worst performing feeder (WPF) program given the level of investment required and the structure and nature of that program. The WPF program focuses on low-cost solutions such as installing additional reclosers, switching points etc. which have already previously been explored. Unlike this program, the WPF program focuses on small projects that can be delivered quickly were as this program involves more capital-intensive longer duration projects. The WPF programs is also not targeted specifically at unplanned reliability performance. Realistically, the only practical options remaining to provide any significant level of improvement are to install generation or to build additional feeders into these communities, that later of which is completely cost prohibitive. This proposal is also justified through cost benefit analysis based on VNR.

The above characteristics lead to long duration outages, where the only practical solution to make a material impact on community unplanned reliability performance is with generation installed in or near the impacted communities themselves. Whilst the majority of unplanned outages across the selected feeders are associated with adverse weather, there are other causes such as animals making contact, asset failures, vehicle impacts etc. These causes however still lead and impact reliability of supply and have been considered as part of the analysis. Table 3 details the length of network supplying these communities that are exposed to the environment which inherently creates network unplanned reliability challenges.

Community	11/22kV Feeder Length (km)	Radial Subtransmission feeder length (km)	Total Feeder length exposed (km)
Thargomindah	1722	489	2211
Tambo	2390	458	2848
Morven	1423	276	1699
Augathella	1469	276	1745
Aramac	1419	352	1771
Duaringa and Dingo	614	0	614
Clairview and Stanage Bay	996	0	996
Karumba	73	674	747

Table 3 Length of network exposed to the environment without backup supply.

4.1 Problem and/or Opportunity

A number of Ergon Energy's distribution feeders and associated communities have experienced a level of unplanned reliability performance that results in significant unserved energy for those communities. This program is focussed on addressing this unplanned reliability performance. The communities targeted in the business case and the work proposed to rectify those network performance challenges has incorporated VNR into cost benefit analysis. Appendix 2 of this report summarises some of the statistics of the feeders and network arrangements supplying these communities.

4.2 Compliance

Ergon energy has an obligation to comply with Electricity Act 1994 and the associated Distribution Authority D01/99 section 8.1 which details that Ergon must have regard to the value that end users place on their reliability, and as such the approach to justification taken in this business case is to apply Cost-Benefit Analysis. This methodology is detailed in section 4.3 of this report.

4.3 Counterfactual analysis (Base case)

4.3.1 Summary

Ergon Energy broadly considers five value streams for investment. These are shown in Figure 3.

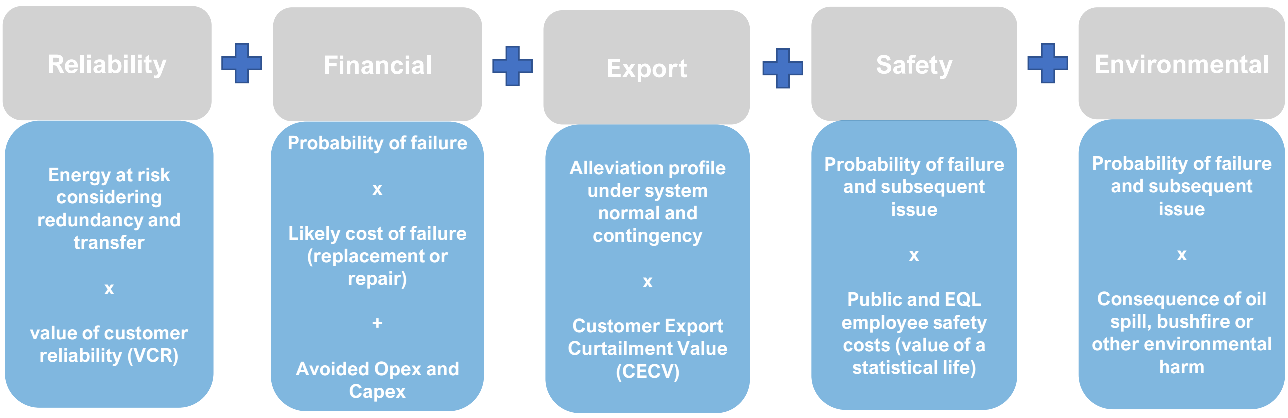

Figure 3– Value Streams for Investment

Table 4 details the value streams that are applicable to this business case is *Reliability.*

Program	Sub Program	Value Stream
Planned Augmentation	Reliability	Reliability - Value of Network Resilience (VNR)

Table 4 Program and value stream relationship

The counterfactual arrangement is to not do this program to address the unplanned reliability performance issues these communities face. The counterfactual will result in in a lost VNR benefit that would be delivered to these communities of approximately $13,000,000 per annum when compared to the recommended option.

4.3.2 Risks

Not undertaking this program will result in continued very poor unplanned reliability performance to the identified communities. Ergon Energy will also fail to meet its obligations to the community to balance the reliability performance of the network with customer expectations. This will result in a significant economic cost to the community based on measures detailed in the AER's Value of Network Resilience framework and a cumulated unaddressed risk of approximately $65 million.

By Doing nothing Ergon Energy will not meet its DA obligations of having regard to the value that end users of electricity place on the quality and reliability of electricity services.

4.4 Assumptions/ Methodology

This category of Distribution Augmentation is to specifically target communities which face significant network unplanned reliability challenges with a lot of longer duration outages due to the physical nature of the network (remote, long radial supply arrangements in challenging environments). The following methodology has been applied to justify this program:

- Identify locations/communities that are likely to face network reliability problems. The selection criteria detailed in section 3 of this business case was applied.
- Customer minutes were then apportioned to determine how many minutes were in each outage window (e.g. 0-12hrs, 12-24hrs etc)
- For each target feeder the average energy per customer minute was then calculated based on RIN data. The total kwh consumption per feeder was divided by the metered days (total number of days customers were metered on the feeder over the year) to provide this figure.
- The average annual customer minutes observed on each feeder for each VNR outage window was then multiplied by the average energy per customer minute to determine the average energy lost on the feeder over the last 5 years for each VNR outage window. Please note that overall this is a very conservative approach as the communities and reliability performance measures used were based on feeder level data, and given these communities are at the extremity of the feeders, their reliability will be below/worse than the feeder average performance.
- The number of customers in the communities was determined and divided by the number of customers on the feeder to work out an improvement percentage. Diesel generation requirements are determined based on loading to support the communities and immediate areas, not all the customers on the entire feeder and hence the need to discount the benefit.
- The VNR rates for each outage window was then individually calculated per feeder based on the customer-mix and historical consumption across Agriculture, Commercial, Industrial, and Residential categories and proportioned by the AER published VNR rates.
- By Multiplying the VNR rate by the average annual energy lost at a feeder level, the annual VNR investment potential per feeder was calculated for each outage window.
- An NPV analysis was then performed considering the VNR rates, other benefits, capital, and operational costs to assess options. Options considered as part of this analysis included:
    - Diesel Generation (localised) - Recommended Option

- A purely renewable option (Solar and Battery)
  - Hybrid Option (combination of renewables and Diesel generation)
  - Create new feeders or lengthy feeder ties. This option has been ruled out as it would involve thousands of km of new feeder and would never be an NPV positive outcome (hence not a competitive and economically equivalent option).
- Based on the above, the most NPV positive potential options were selected to formulate this program, and the proposed expenditure in this category.

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5 OPTIONS ANALYSIS

As part of this analysis, the options of a Diesel Generation, Purely Renewables and a Hybrid Option combining renewables and Diesel have been explored. Across all selected communities, the localised Diesel Generation Option provided the most positive NPV outcome. It is noted that at some sites, the Hybrid and Purely Renewable Option were still NPV positive but not to the same magnitude as the diesel generation option. All options involved the following key components in terms of initial capital costs.

- Land acquisition.
- Civils works - levelling site, installing foundations, conduits, fencing etc.
- Generator procurement (Diesel or Solar and BESS depending on the option considered)
- Connection arrangements (Switchgear and protection)
- Step up transformer to transform to 11/kV/22kV as required.
- Reclosers, coms and automation to allow the community to be islanded from the remainder of the network.

5.1 Economic Analysis

5.1.1 Cost summary 2025-30

The counterfactual is to not have an unplanned reliability program to address poor unplanned network reliability performance in these communities, resulting in zero capital investment across the regulatory period. A cost summary of the proposed expenditure compared with the counterfactual is provided in Table 5 below.

Option	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025-30
Counterfactual (Base)	$0	$0	$0	$0	$0	$0

Option	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025-30
Diesel Generation Option $in millions, direct $2022-23	$4.06	$12.58	$8.36	$11.06	$3.74	$39.8
Purely Renewable option (Solar and Battery) $in millions, direct $2022-23	$17.95	$67.01	$43.59	$35.25	$13.45	$177.31
Hybrid $in millions, direct $2022-23	$5.45	$18.03	$11.88	$13.48	$4.71	$53.55

Table 5 Cost summary 2025-30 ($ in million)

Table **6** details the NVR benefit delivered, the cost and the benefit to cost ratio.

Target Community	VNR Benefit	Cost	Benefit to Cost Ratio
Aramac	$9,716,495	$4,870,813	2.0
Augathella	$14,767,398	$5,535,945	2.7
Duaringa and Dingo	$18,222,678	$9,399,399	1.9
Thargomindah	$6,852,686	$4,558,251	1.5
Karumba	$23,557,271	$5,588,187	4.2
Morven	$6,546,612	$4,322,298	1.5
Clairview and Stanage Ba	$21,148,002	$9,131,920	2.3
Tambo	$6,651,851	$4,498,681	1.5

Table 6 Benefit to Cost Ratio

5.1.2 NPV analysis

NPV analysis has been performed based on a number of conservative assumptions. As can be seen in Table 7 the Diesel Generation Option is the most positive NPV outcome and hence the preferred option. The purely renewable option is NPV negative. The Hybrid options whilst NPV positive, still lags behind the diesel generation option. Please note that this analysis is based on approximate current prices and if there are significant changes to the benefits that can be provided by renewables or the cost of renewables during the delivery of the program, this would be reviewed and the most NPV positive outcome selected.

Option	NPV Overall Outcome $ in millions
Diesel Generation Option	$26.14
Purely Renewable option (Solar and Battery)	-$17.34
Hybrid	$21.79

Table 7 NPV comparison of Options

Target Community	Index	Option	NPV
Aramac	1	Diesel Option	$2,047,663
		Pure Renewable	-$2,401,585
		Hybrid Option	$1,602,738
AUGATHELLA	2	Diesel Option	$4,533,218
		Pure Renewable	-$3,746,878
		Hybrid Option	$3,705,208
Duaringa	3	Diesel Option	$3,478,972
		Pure Renewable	-$5,748,886
		Hybrid Option	$2,556,186
EULO	4	Diesel Option	$442,978
		Pure Renewable	-$2,525,553
		Hybrid Option	$146,125
KARUMBA	5	Diesel Option	$9,648,925
		Pure Renewable	$1,594,760
		Hybrid Option	$8,843,509
MORVEN	6	Diesel Option	$444,055
		Pure Renewable	-$1,395,183
		Hybrid Option	$260,131
Northern	7	Diesel Option	$5,189,006
		Pure Renewable	-$377,340
		Hybrid Option	$4,632,372
Tambo	8	Diesel Option	$353,088
		Pure Renewable	-$2,703,796
		Hybrid Option	$47,400

Table 8 NPV Summary of Options per Feeder

5.2 Optimal Timing

The individual projects that make up the Distribution Augmentation program have been relatively evenly spread over the regulatory period to ensure they can be resourced and delivered. Ideally these projects should be completed as soon as possible to deliver the resulting economic benefits to the communities as detailed using VNR analysis.

A prudent level of investment is assured by prioritising the timing and the need for projects that make up this program based on risks, ensuring a range of viable alternative options are considered to minimise the cost and optimise the timing of any investments made within the network. Each individual investment that forms part of this program will be approved via an individual stand-alone business case with the financial delegate approval before funding is released.

6 RECOMMENDATION

It is recommended to establish the program of work, and breakdown as detailed in this business case. Table 9 summarises the key components of this program.

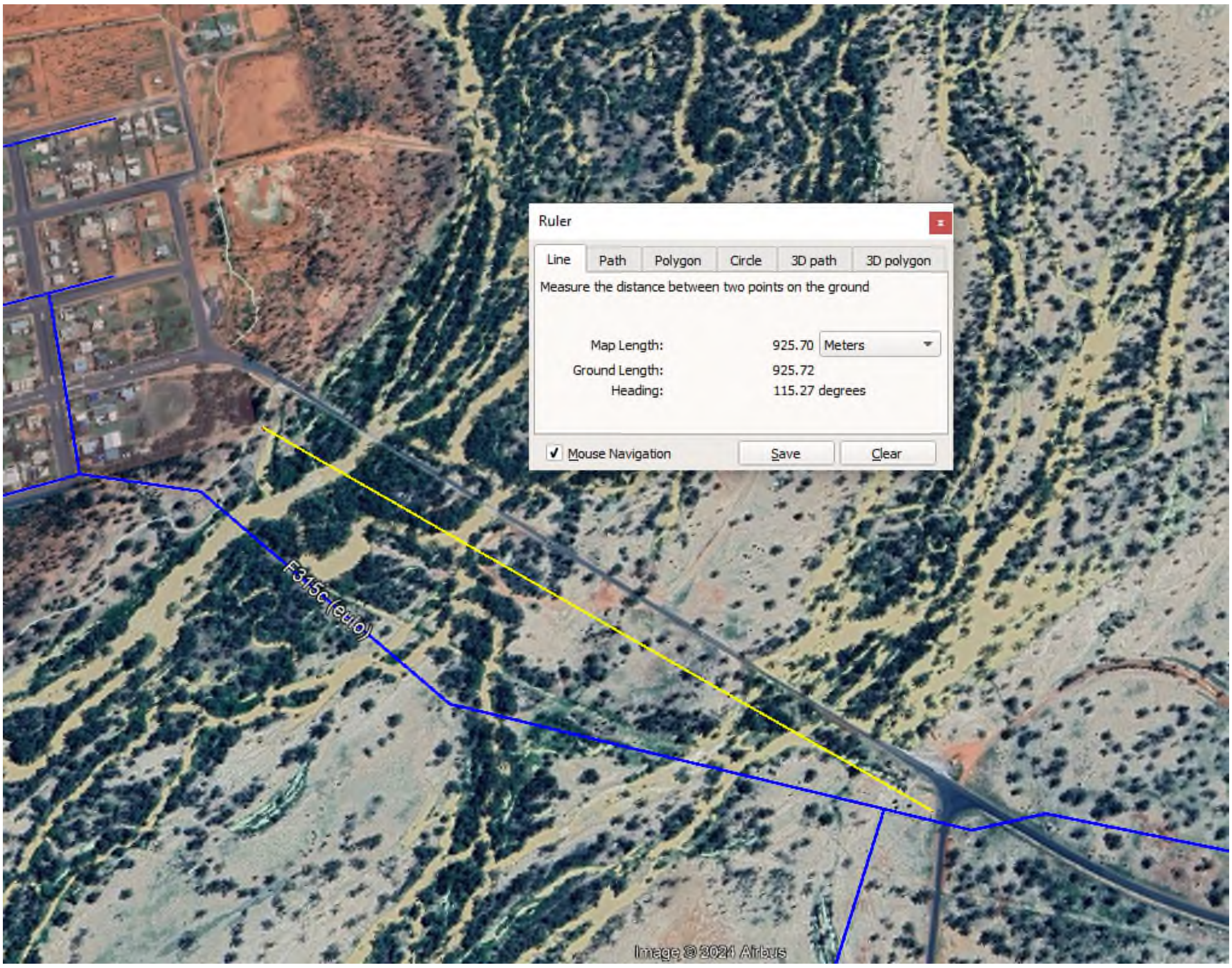
Table 9 Options Analysis Scorecard

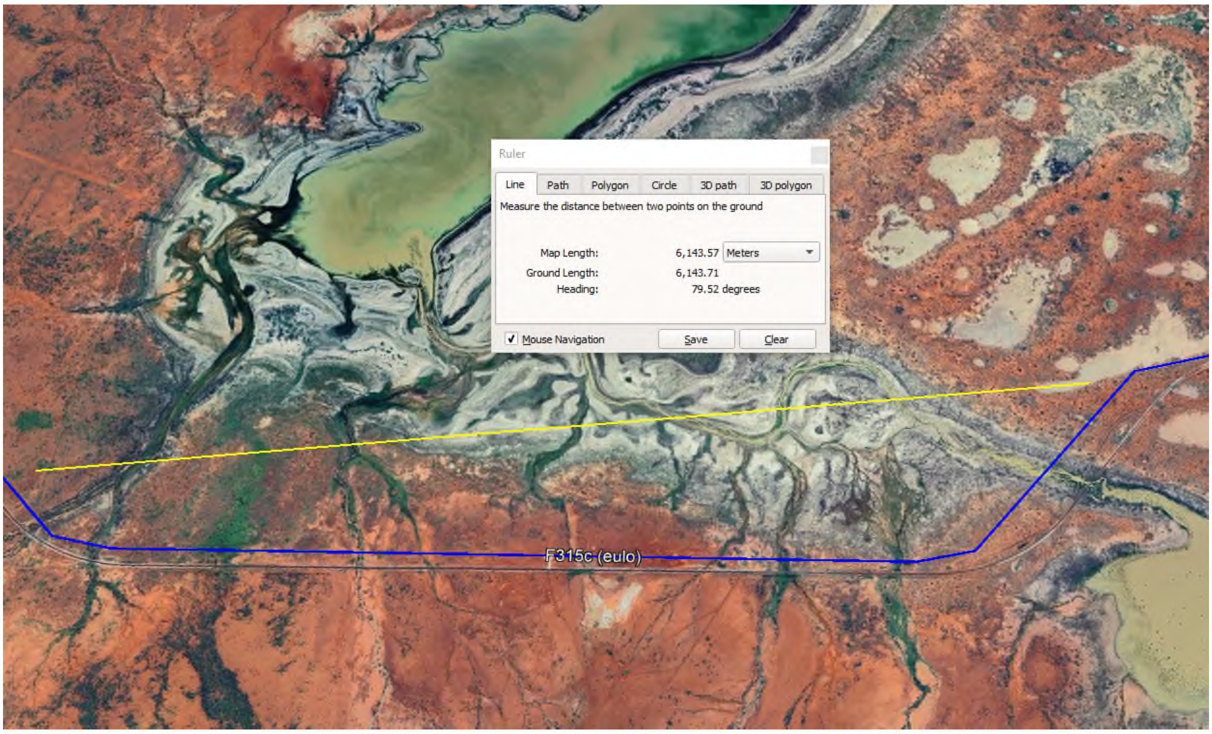
Criteria	Detail
Net Present Value	Individual Planned Augmentation Reliability projects are issued based on positive NPV outcomes
Investment cost (TCO)	$39.8m
Investment Risk	Medium
Benefits	Meet Regulatory Obligations in terms of Distribution Authority requirement. Meet customer reliability expectations
Delivery time	8 projects to be completed and phased over the regulatory period.
Detailed analysis – Benefits	Network reliability performance will also be addressed by economically justifiable (with Net Present Value positive) investments.
Detailed analysis – Risks	Conservative assumptions have been applied and a limited number of communities targeted and hence the funding requested is also conservative in comparison to the amount that could otherwise be justified.
Detailed analysis - Advantages	This option results in a distribution network where network reliability performance in some of the worst performing communities is addressed and is justified by the cost-benefit analysis (NPV positive).

APPENDICES

Appendix 1: Example of terrain which can make restoration difficult and time consuming.

Thargomindah

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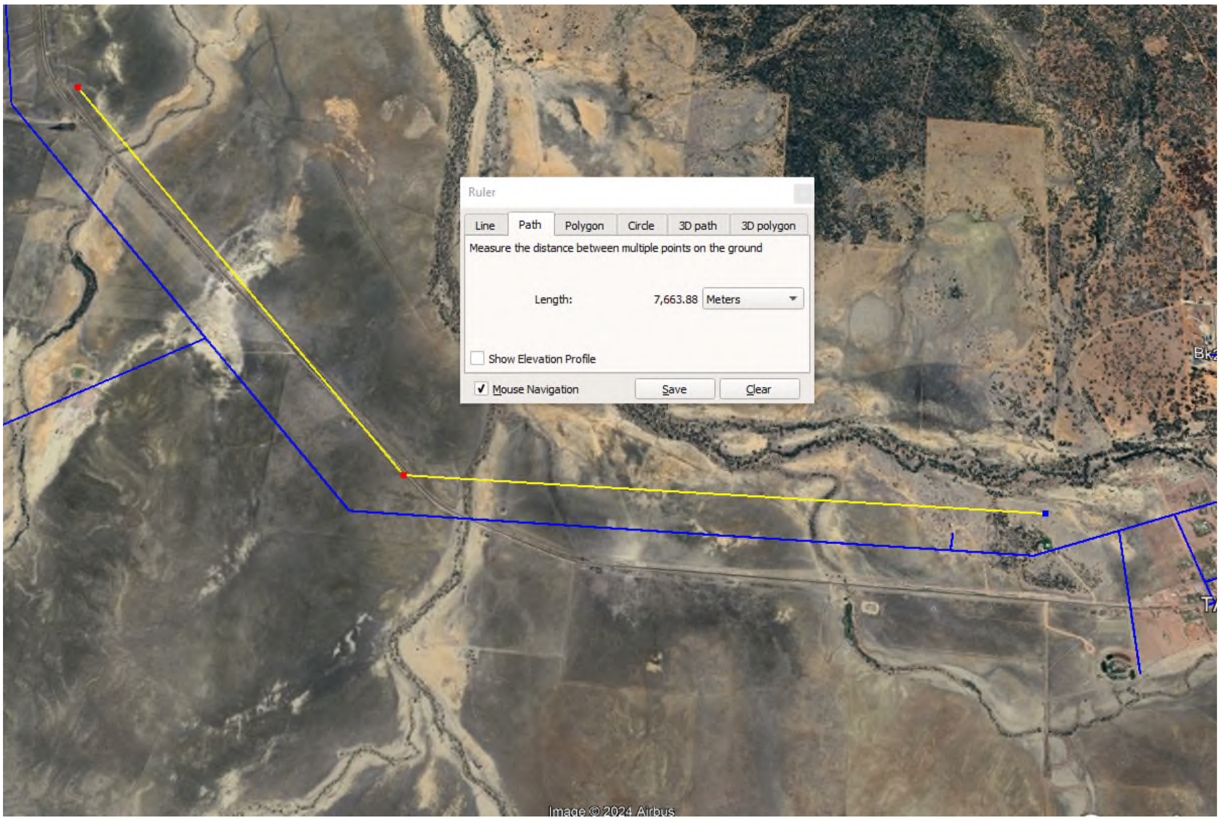
Tambo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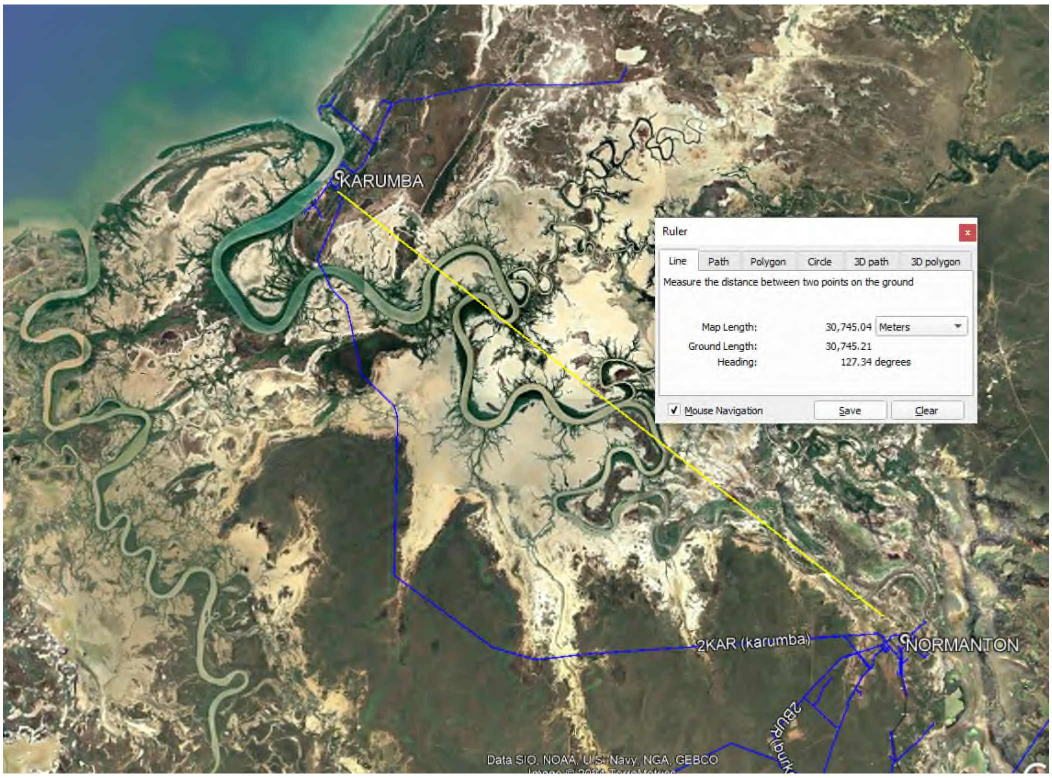
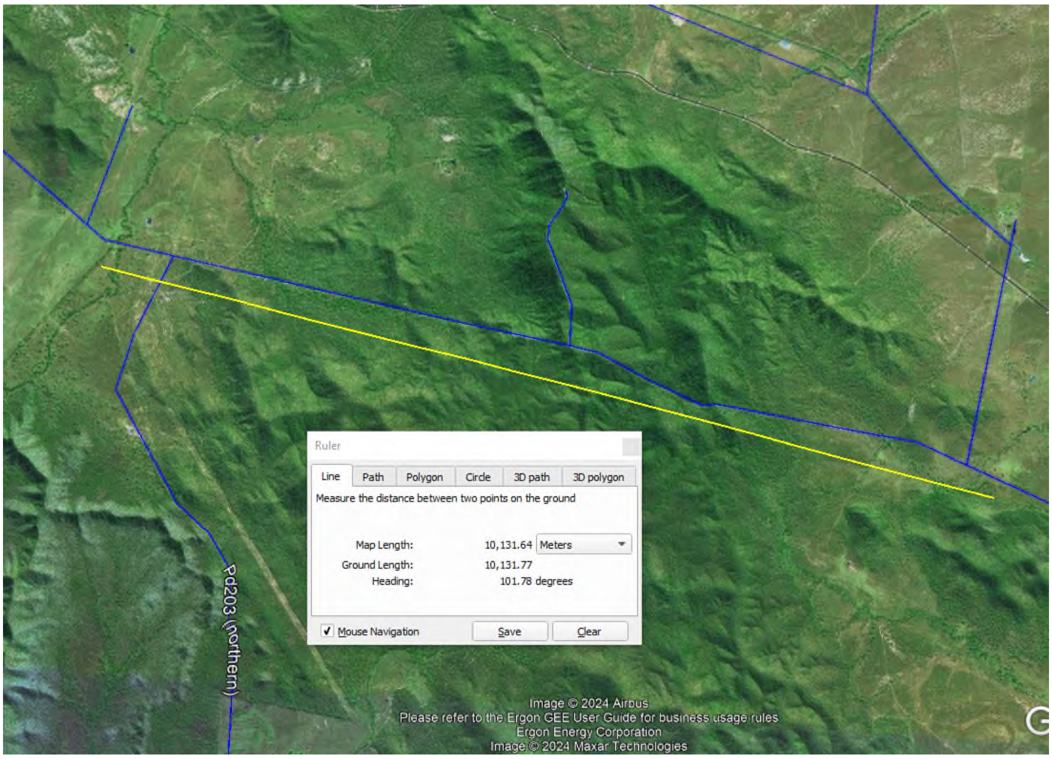
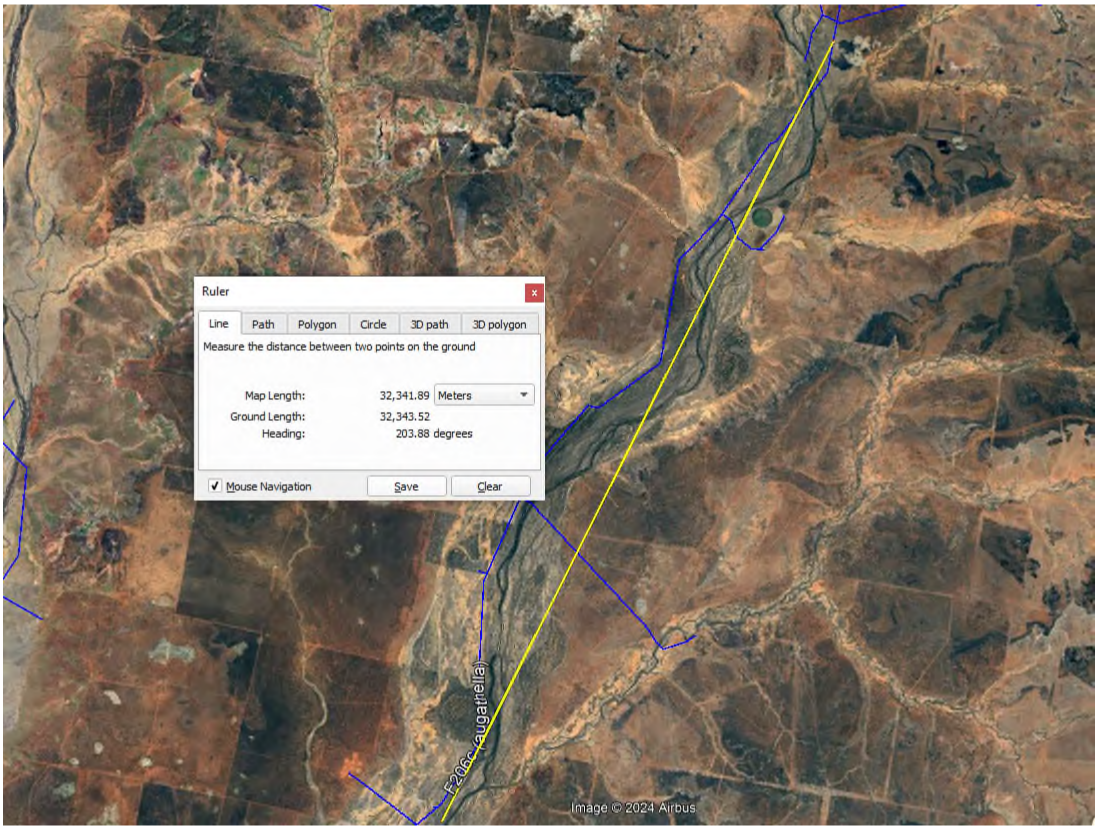
Karumba



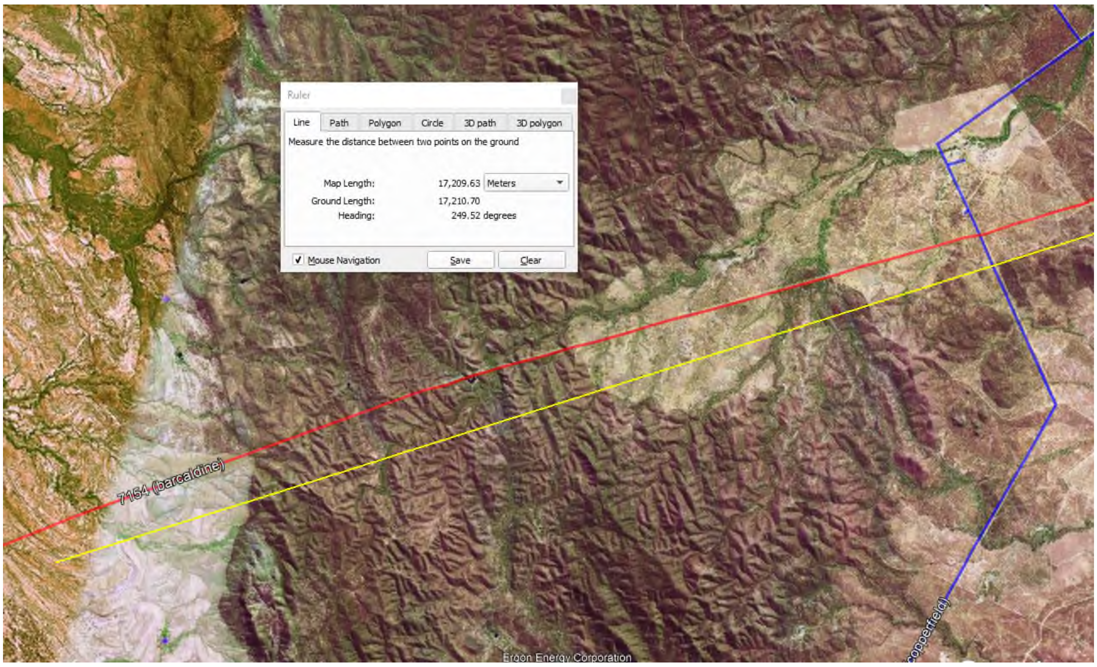
Stanage Bay and Clairview

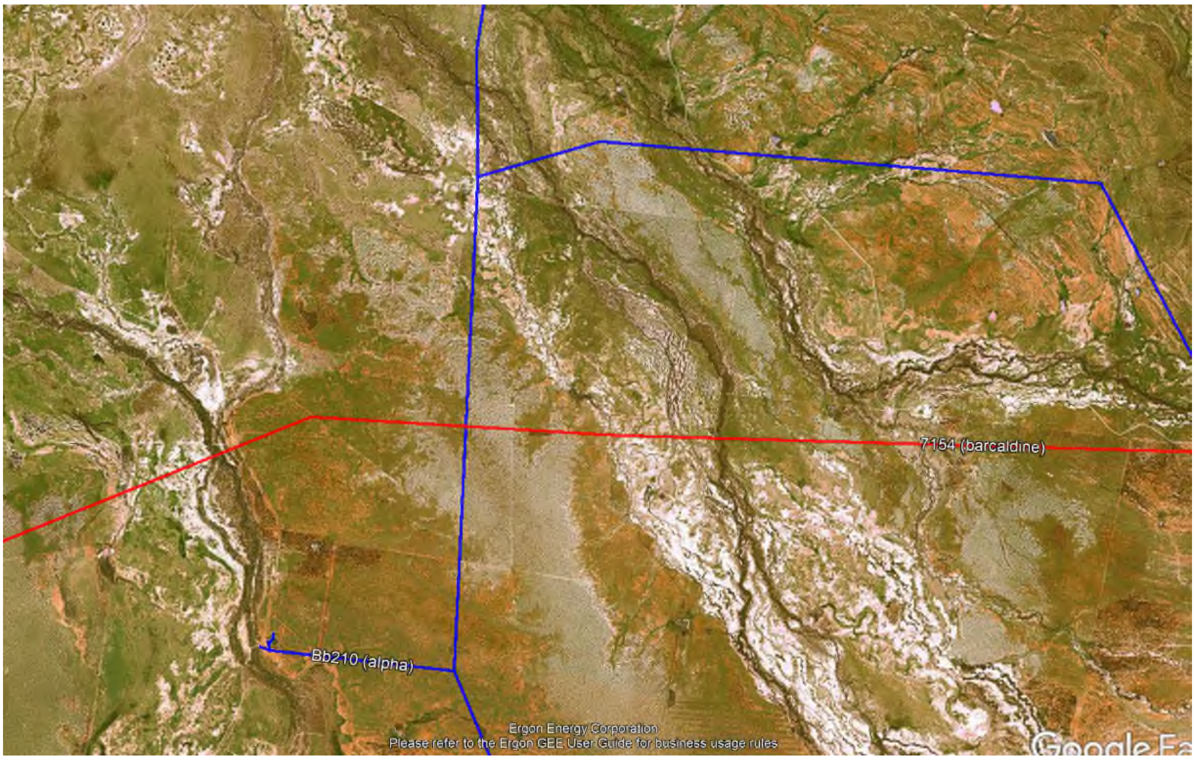


Augathella



Tambo and Aramac

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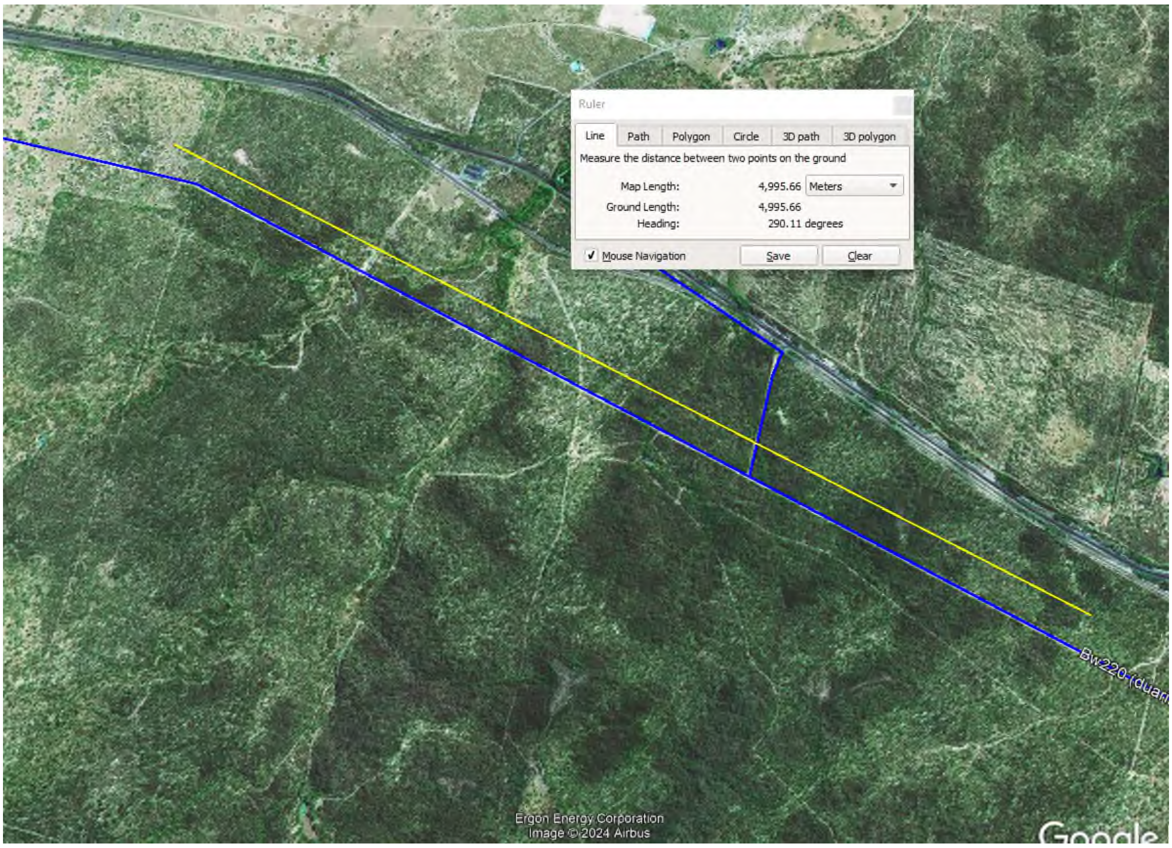
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Ergon Energy Corporation
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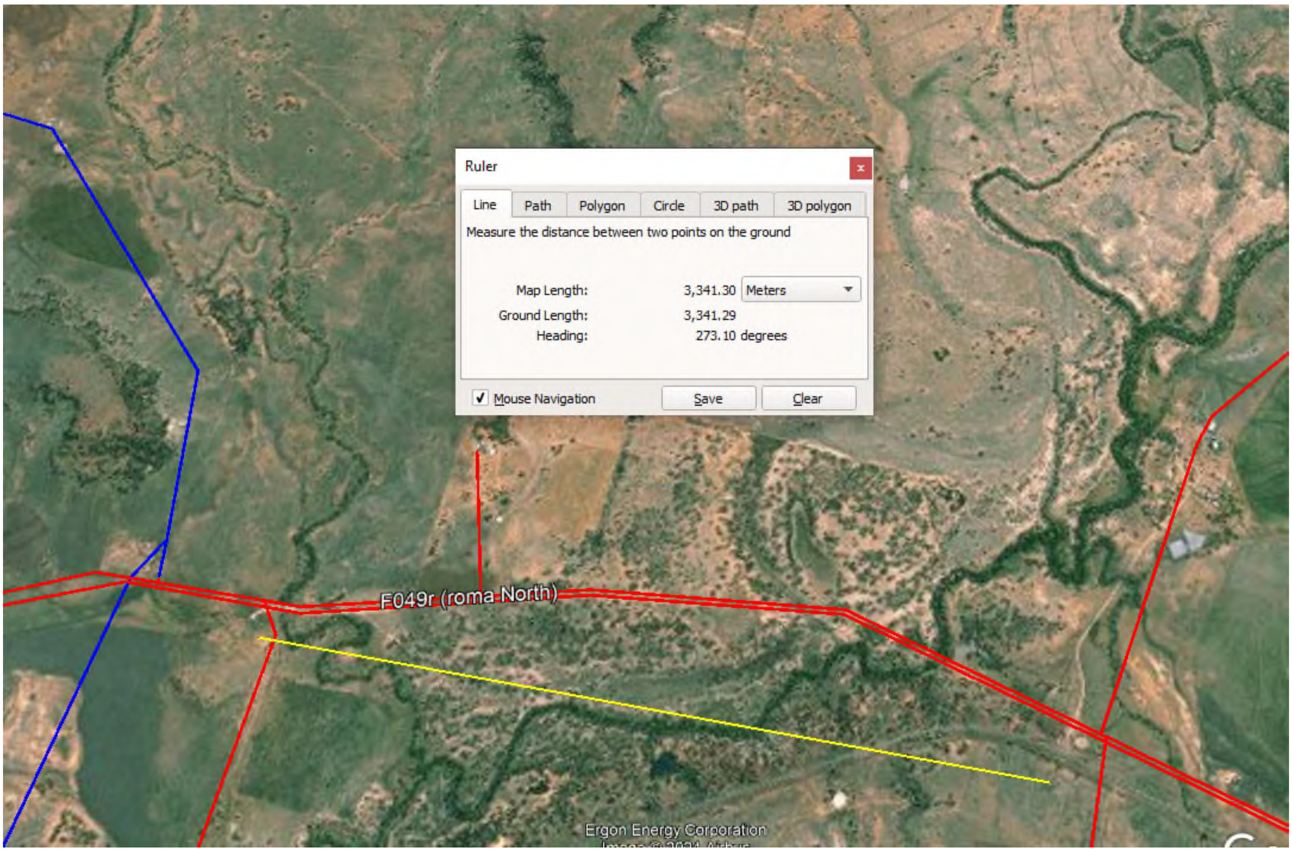
Augathella, Morvin, and Thargomindah



Appendix 2: Alignment with the National Electricity Rules

Feeder Characteristic	F315C Eulo Feeder/Thargomindah	BK206 Tambo	F233C Morven	F206C Augathella	BB208 Aramac	BW220 Duaringa	PD203 Northern Feeder	2KAR Karumba
Community	Thargomindah	Tambo	Morven	Augathella	Aramac	Duaringa and Dingo	Clairview and Stanage Bay	Karumba
Nearest Depot	Cunnamulla (196km)	Blackall (102km)	Charleville (91km)	Charleville (84km)	Barcaldine (67km)	Blackwater (85km)	Rockhampton (172km)	Normanton (70km)
11/22kV Feeder Length (km)	1722	2390	1423	1469	1419	614	996	73
Radial Subtransmission feeder length (km)	489	458	276	276	352	0	0	674
Customers	539	671	364	562	524	546	1014	393
Average Annual Energy Not Supplied (kWh)	16126	18307	13378	29993	19516	21657	46654	23359
% of customer minutes greater than 12hrs	62	52	55	49	43	51	44	59
SAIDI (last 3yr average)	3244	1769	1290	1482	2691	903	1409	2662
SAIFI (last 3yr average)	13.5	8.5	8	9.6	7.1	5.5	7.1	10.9
Inverter Capacity	1060	783	581	1742	604	940	1349	792
DER customers	134	125	103	161	101	119	240	89
DER Penetration	25%	19	28	29	19	22	24	23
No. of Voltage regulators	8	6	6	9	4	5	4	1
No of Protection Devices	22	30	12	16	26	9	31	2

Appendix 3: Alignment with the National Electricity Rules

Table 10 Recommended Option's Alignment with the National Electricity Rules

NER capital expenditure objectives	Rationale
A building block proposal must include the total forecast capital expenditure which the DNSP considers is required in order to achieve each of the following (the capital expenditure objectives):	
6.5.7 (a) (1) meet or manage the expected demand for standard control services over that period	See Section 3.1 of this Business Case
6.5.7 (a) (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;	See Section 4 of this Business Case
6.5.7 (a) (3) to the extent that there is no applicable regulatory obligation or requirement in relation to: (i) the quality, reliability or security of supply of standard control services; or (ii) the reliability or security of the distribution system through the supply of standard control services, to the relevant extent: (iii) maintain the quality, reliability and security of supply of standard control services; and (iv) maintain the reliability and security of the distribution system through the supply of standard control services	See Section 3.1 and 4 of this Business Case
6.5.7 (a) (4) maintain the safety of the distribution system through the supply of standard control services.	No Applicable as not Safety Driven
NER capital expenditure criteria	**Rationale**
The AER must be satisfied that the forecast capital expenditure reflects each of the following:	
6.5.7 (c) (1) (i) the efficient costs of achieving the capital expenditure objectives	See Section 4.4 and 5 of this Business Case
6.5.7 (c) (1) (ii) the costs that a prudent operator would require to achieve the capital expenditure objectives	See Section 4.4 and 5 of this Business Case
6.5.7 (c) (1) (iii) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives	See Section 4.4 and 5 of this Business Case

Appendix 4: Reconciliation Table

Table 11 Reconciliation

Expenditure	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Expenditure in business case $m, direct $2022-23	$4.06	$12.58	$8.36	$11.06	$3.74	$39.8
Expenditure in AER capex model $m, direct $2024-25	**$4.54**	**$14.09**	**$9.37**	**$12.41**	**$4.20**	**$44.62**

Appendix 5: Glossary

The following definitions, abbreviations and acronyms appear in this business case:

Definition, abbreviation, or acronym	Definition
AER	Australian Energy Regulator
CAPEX	Capital Expenditure
CECV	Customer Export Curtailment Value
DA	Distribution Authority
DNSP	Distribution network Service Provider
EQL	Energy Queensland Limited
HV	High Voltage (distribution feeder voltages)
LV	Low Voltage (Typically 230V single phase or 400V three phase)
NEM	National Electricity Market
NPV	Net Present Value
POE	Probability of Exceedance
SWER	Single Wire Earth Return
Unplanned Outage	As outage that occurred on the network that was not initiated by the DNSP (e.g. a branch bringing down a line)
VCR	Value of Customer Reliability
VNR	Value of Network Resilience