Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Degilbo Network Area

Final Project Assessment Report

19 December 2024

Ergon Energy Network
Part of Energy Queensland

EXECUTIVE SUMMARY

About Ergon Energy

Ergon Energy Corporation Limited (Ergon Energy) is part of Energy Queensland and manages an electricity distribution network which supplies electricity to more than 765,000 customers. Our vast operating area covers over one million square kilometres (around 97% of the state of Queensland) from the expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

Our electricity network consists of approximately 160,000 kilometres of powerlines and one million power poles, along with associated infrastructure such as major substations and power transformers.

We also own and operate 33 stand-alone power stations that provide supply to isolated communities across Queensland which are not connected to the main electricity grid.

Identified Need

Degilbo is a rural township in the North Burnett region of Queensland, known for its mining, agricultural and animal industries. Degilbo 66/11kV zone substation (DEGI) supplies approximately 1,248 customers in total, as well as major load and generator customers. It delivers 12GWh of energy annually, predominantly domestic (44%), commercial (39%) and industrial (16%) load. The continued operation of DEGI is critical to supply of customers in the North Burnett area.

Condition Based Risk Management (CBRM) analysis indicates that the two 2MVA 66/11kV transformers (T1 and T2) and the two 10.57/11kV auto-transformers (AT1 and AT2) are reaching end of life.

The Hawker Siddeley Falcon Beta 2 indoor 11kV ring main unit (RMU) is a make with a known design issue where the CB earth switch contacts can overtravel and contact the live busbar when being switched OFF and are classified as problematic plant.

The continued use of problematic plant and assets beyond end of life poses safety risks to staff working within the substation. It also poses a safety risk to the general public, through the increased likelihood of catastrophic failure of the power transformers / auto-transformers and 11kV RMU. Ergon Energy has obligations under the Electrical Safety Act 2002 (Qld)[1] to eliminate

[1] QLD Electrical Safety Act 2002:
Part 2, Subdivision 2, Section 28 - What is reasonably practicable in ensuring electrical Safety
Part 2, Division 2, Section 29 - Duty of electricity entity

electrical safety risks so far as is reasonably practicable, and where not reasonably practicable, to minimise the risks so far as is reasonably practicable.

There is a considerable risk of environmental harm due to loss of oil from the power transformers, which would require clean up and rectification. Additionally, the poor condition of these assets significantly increases the likelihood of outages, resulting in a reduction in the level of reliability experienced by the customers supplied from DEGI. Ergon Energy has obligations to comply with the reliability performance standards specified in its Distribution Authority[2] issued under the Electricity Act 1994 (Qld). Further to these requirements, the QLD Electricity Act 1994[3] stipulates that distribution entities must comply with the reliability requirements, system standards and performance requirements specified in the National Electricity Rules (NER)[4].

Ergon Energy is seeking to invest in the network to undertake a reliability corrective action in order to continue to meet the service standards in its applicable regulatory instruments (National Electricity Rules, Electricity Act 1994 (Qld), Electrical Safety Act 2002 (Qld)).

[2] Ergon Energy Distribution Authority:
Section 7 - Guaranteed Service Levels
Section 8 - Distribution Network Planning
Section 9 - Minimum Service Standards
Section 10 – Safety Net

[3] QLD Electricity Act 1994 Part 5, Division 5, Section 42(a)(i)

[4] NER:
Schedule 5.1a System Standards
Schedule 5.1 Network Performance Requirements

Approach

The National Electricity Rules (NER) require that, subject to certain exclusion criteria, network business investments for meeting service standards for a distribution business are subject to a Regulatory Investment Test for Distribution (RIT-D). Ergon Energy has determined that network investment is essential in this case for it to continue to provide electricity to the consumers in the Degilbo supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

A single potentially feasible option has been investigated:

- **Option A:** Asset replacement

This Final Project Assessment Report (FPAR), has been prepared in accordance with the requirements of clause 5.17.4 of the NER.

Ergon Energy's preferred option to address the identified need is Option A, to replace the aged T1 / AT1 and T2 / AT2 with two new 6.3MVA 66/11kV transformers, replace the problematic 11kV RMU indoor switchboard with new 12kV Ring Main Switchgear installed within a new prefabricated switchgear building, extend the substation yard and build a new 66kV switchyard at Degilbo.

CONTENTS

1. INTRODUCTION

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

This FPAR represents the final stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need for the Degilbo network area.

In preparing this RIT-D, Ergon Energy is required to consider reasonable future scenarios. With respect to major customer loads and generation, Ergon Energy has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Ergon Energy is aware of are in different stages of progress and are subject to change (including outcomes where none or all proceed). These and other customer activity can occur over the consultation period and may change the timing and/or scope of any proposed solutions.

1.1. Structure of the Report

This report:

- Provides background information on the network limitations of the distribution network supplying the Degilbo area.
- Identifies the need which Ergon Energy is seeking to address, together with the assumptions used in identifying and quantifying that need.
- Describes the credible options that are considered in this RIT-D assessment.
- Quantifies costs and classes of material market benefits for each of the credible options.
- Quantifies the applicable costs for each credible option, including a breakdown of operating and capital expenditure.
- Describes the methods used in quantifying each class of market benefit.
- Provides details of classes of market benefits that are not considered material to this RIT-D assessment and provides explanations as to why these classes of market benefits are not considered material.
- Provides the results of Net Present Value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.

1.2. Dispute Resolution Process

In accordance with the provisions set out in clause 5.17.5 of the NER, Registered Participants and other interested stakeholders may, within 30 days after the publication of this report, dispute the conclusions made by Ergon Energy in this report with the Australian Energy Regulator. Any parties raising a dispute are also required to notify Ergon Energy. Dispute notifications should be sent to demandmanagement@ergon.com.au

If no formal dispute is raised, Ergon Energy will proceed with the preferred option, to replace the aged T1 / AT1 and T2 / AT2 with two new 6.3MVA 66/11kV transformers, replace the problematic 11kV RMU indoor switchboard with new 12kV Ring Main Switchgear installed within a new prefabricated switchgear building, extend the substation yard and build a new 66kV switchyard at Degilbo.

1.3. Contact Details

For further information and inquiries please contact:

E: demandmanagement@ergon.com.au
P: 13 74 66

2. BACKGROUND

2.1. Geographic Region

Degilbo is a rural township in the North Burnett region of Queensland, known for its mining, agricultural and animal industries. Degilbo 66/11kV zone substation (DEGI) supplies approximately 1,248 customers in total, as well as major load and generator customers. It delivers 12GWh of energy annually, predominantly domestic (44%), commercial (39%) and industrial (16%) load. The continued operation of DEGI is critical to supply of customers in the North Burnett area. The geographical location of Ergon Energy's sub-transmission network and substations in the area is shown in Figure 1.

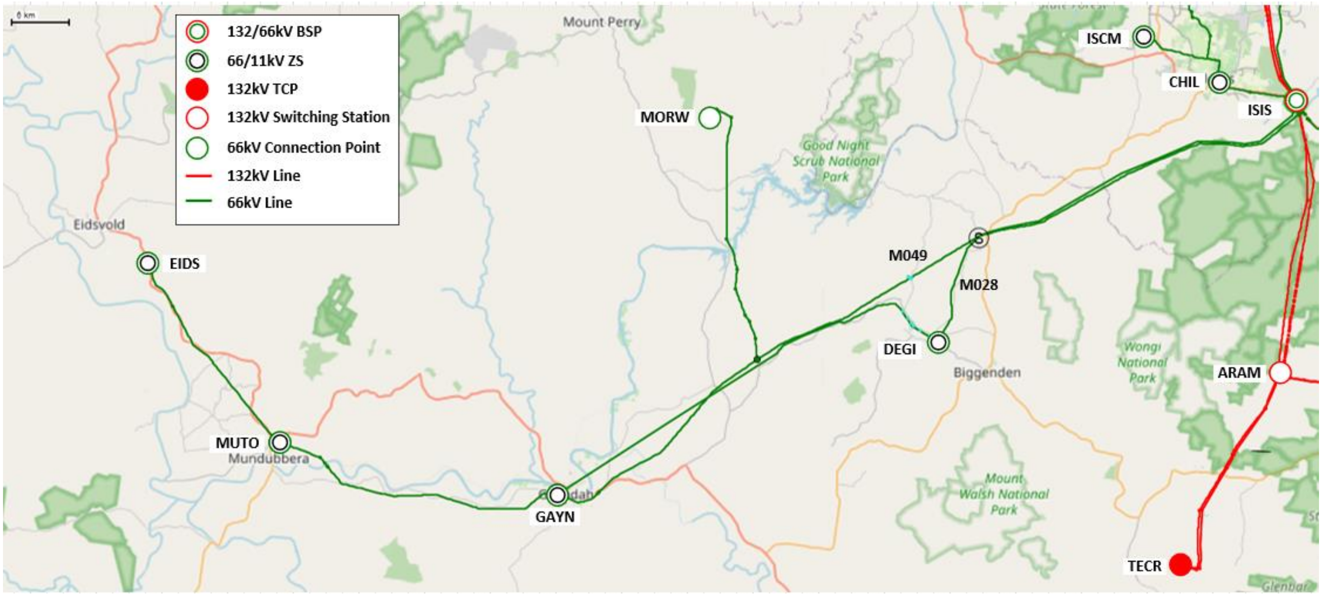


Figure 1: Geographic of the North Burnett area sub-transmission network

2.2. Existing Supply System

DEGI is supplied at 66kV from Isis 132/66kV bulk supply point (ISIS) by a tee from M028 (Isis to Gayndah) 66kV feeder. A second Isis to Gayndah 66kV feeder, M049, is run in parallel with M028. Figure 1 shows the geographic layout of the North Burnett area 66kV network.

Figure 2 gives a line diagram of DEGI and shows that there are four outgoing, 11kV distribution feeders. These feeders supply Degilbo, Biggenden, nearby rural properties, as well as major load and generator customers.

DEGI is equipped with two, non-bunded, 2MVA 66/11kV transformers (T1 and T2) and two, 2MVA 10.57/11kV auto transformers (AT1 and AT2). A 66kV strung-bus supplies each transformer via a HV fuse and connects to a fault throw switch (FTS). There is an indoor 11kV switchboard housed inside a switchgear and control building.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 2 and the general site layout of DEGI is illustrated in Figure 3.

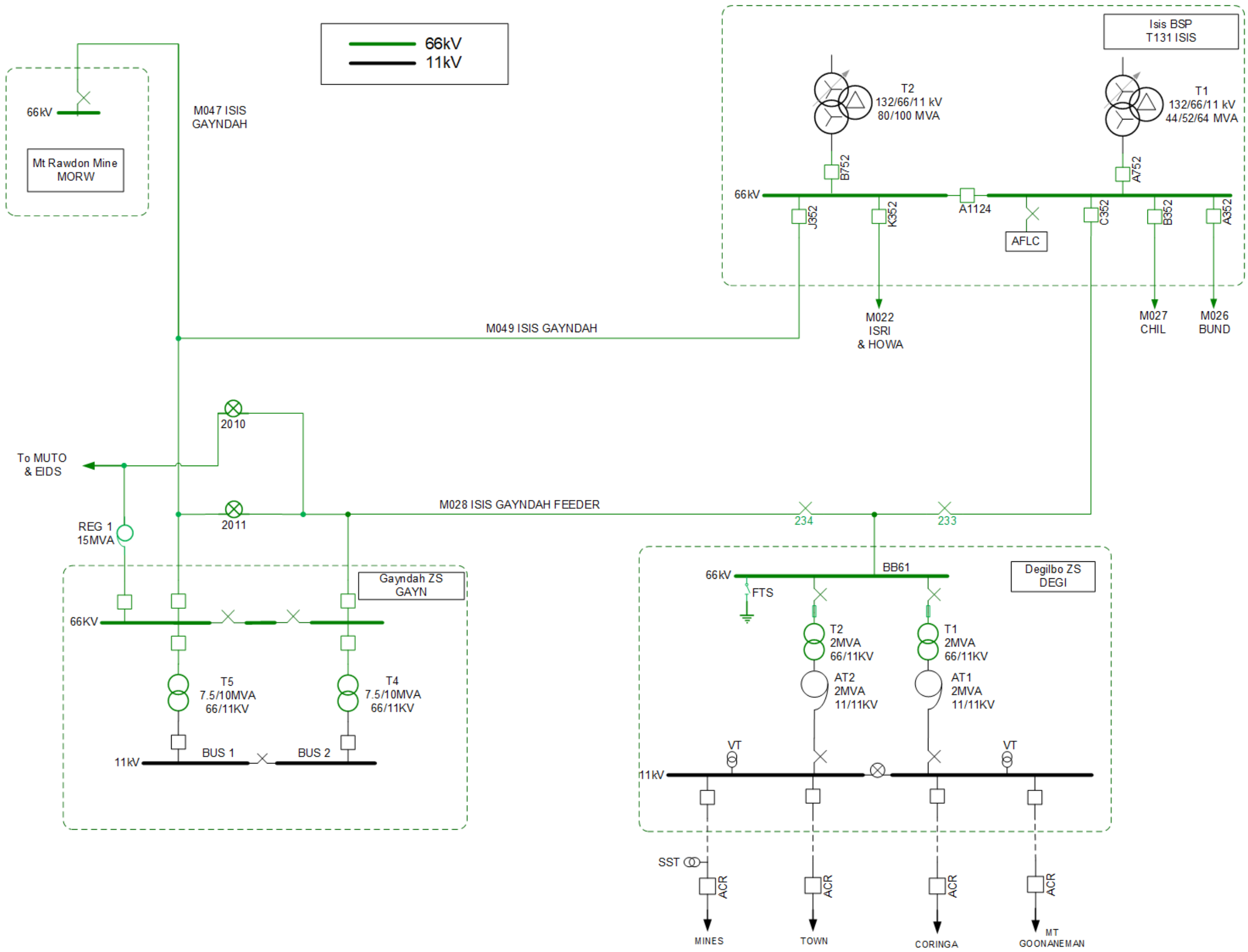


Figure 2: Existing network arrangement (schematic view)

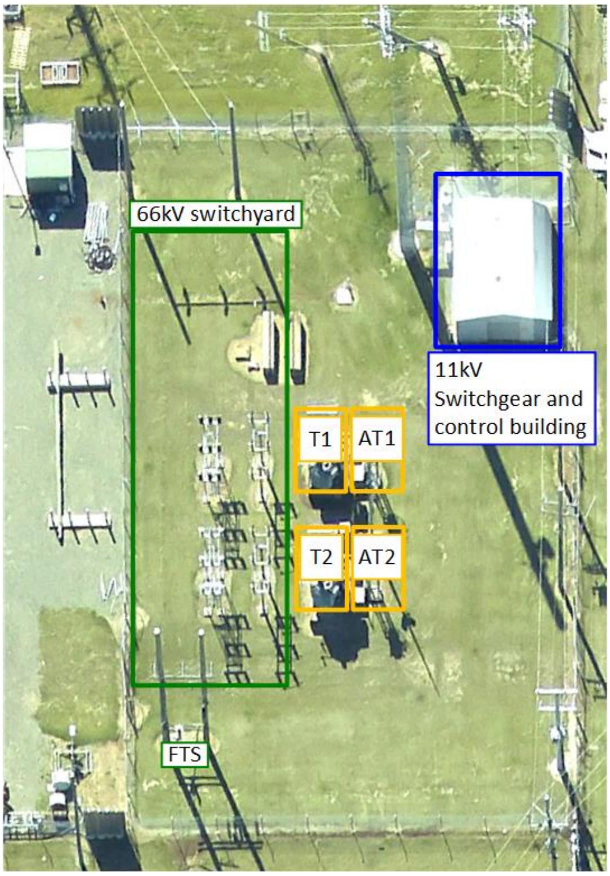


Figure 3: DEGI layout (geographic view)

2.3. Load Profiles / Forecasts

The load at DEGI comprises a mix of residential and commercial/industrial customers. The load is summer peaking.

2.3.1. Full Annual Load Profile

The full annual load profile for DEGI over the 2023/24 financial year is shown in Figure 4. It can be noted that the peak load occurs during summer.

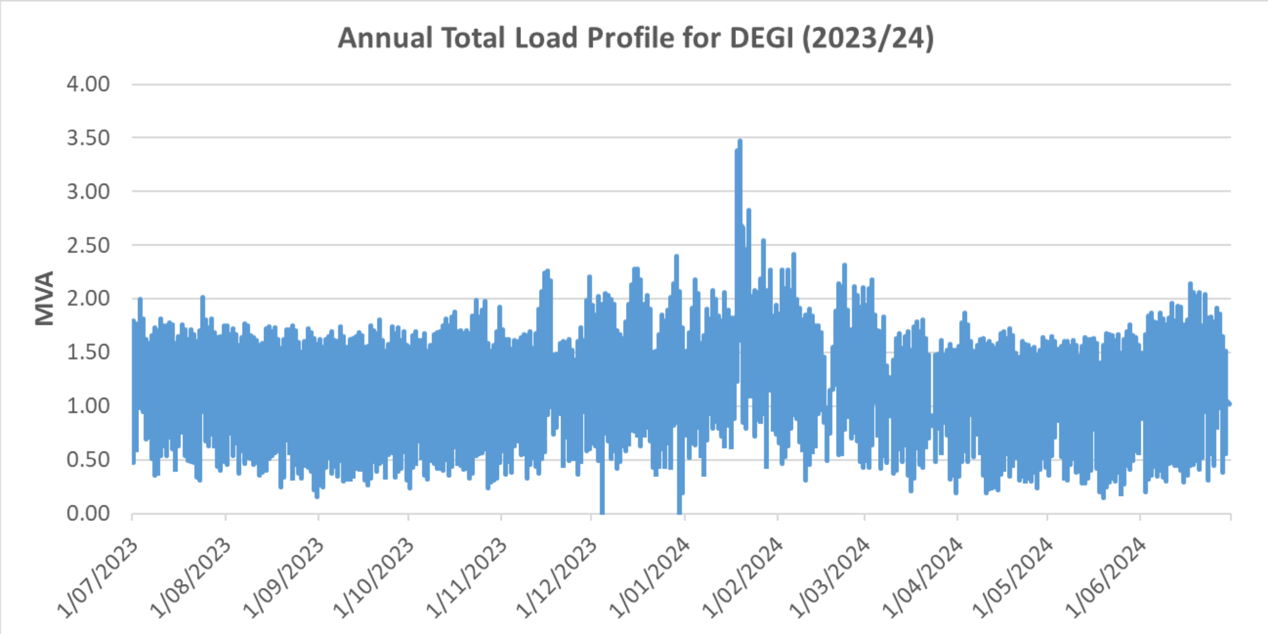


Figure 4: Substation annual load profile (2023/24)

2.3.2. Load Duration Curve

The load duration curve for DEGI over the 2023/24 financial year is shown in Figure 5.

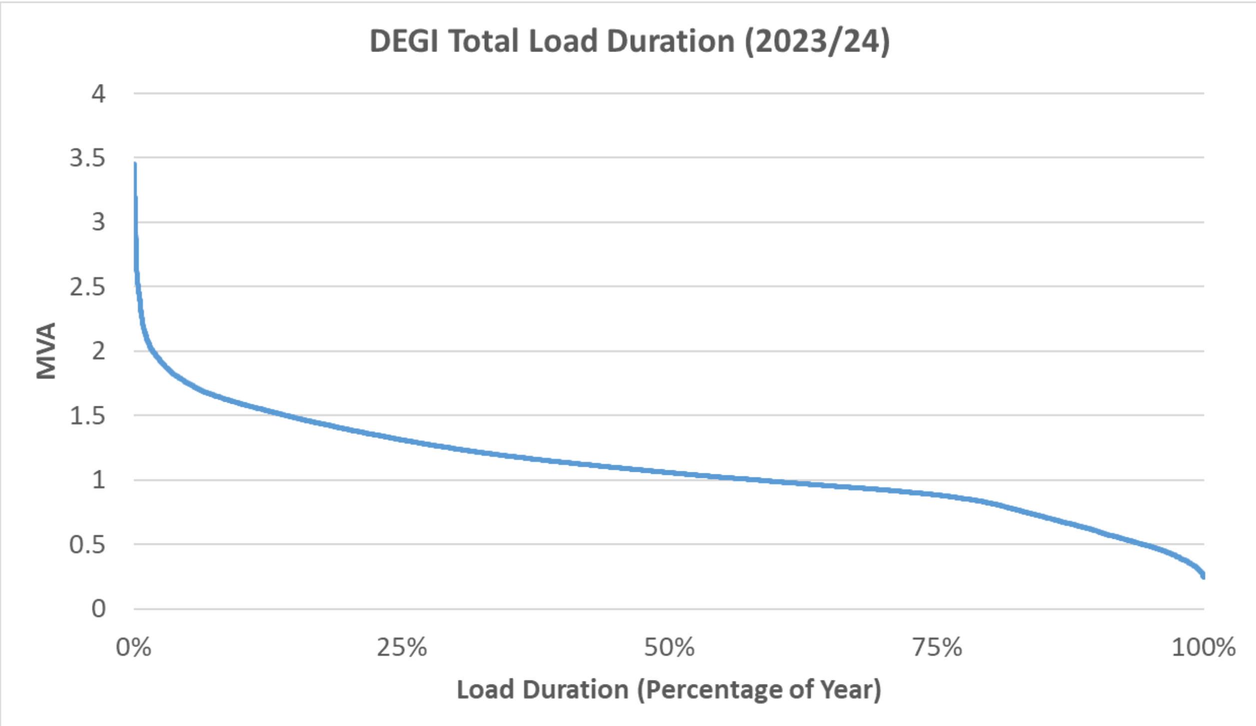


Figure 5: DEGI load duration curve

2.3.3. Average Peak Weekday Load Profile (Summer)

The summer weekday average and peak load day profiles are illustrated below in Figure 6. It can be noted that the summer peak loads at DEGI are historically experienced in the late afternoon and evening.

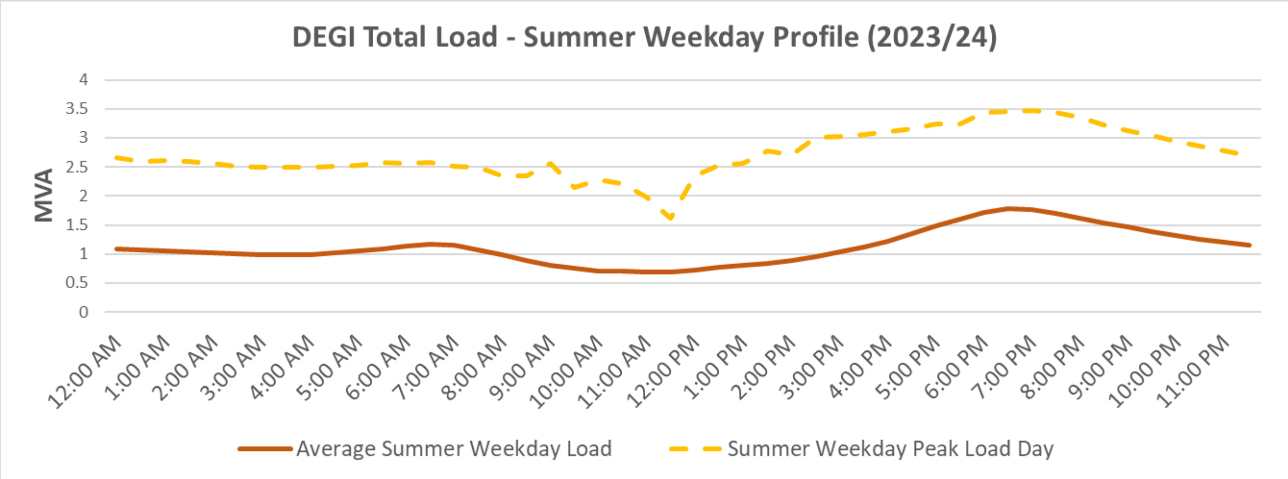


Figure 6: Substation average peak weekday load profile (summer)

2.3.4. Base Case Load Forecast

The 10 PoE and 50 PoE load forecasts for the base case load growth scenario are illustrated in Figure 7. The historical peak load for the past five years has also been included in the graph.

It can be noted that the peak load is forecast to increase by 0.7MVA from 2025 to 2026 (due to a new load connection planned) followed by a period of near zero growth from 2026 onwards under the base case scenario.

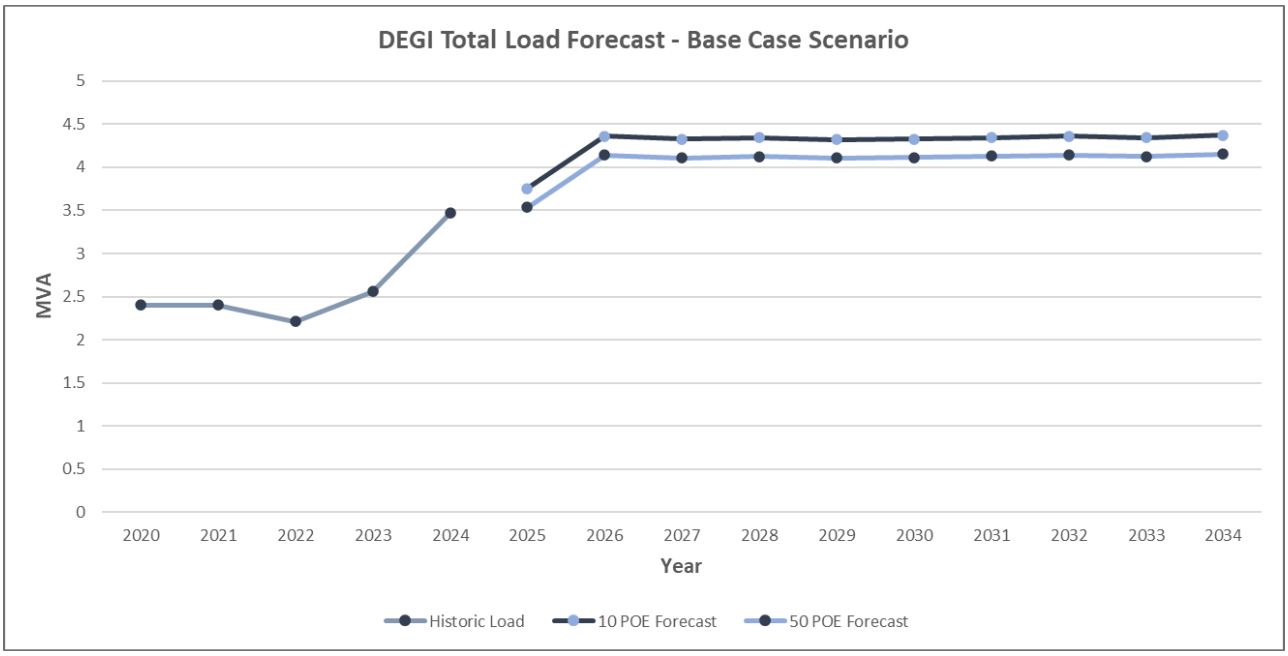


Figure 7: Substation base case load forecast

2.3.5. High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the high load growth scenario are illustrated in Figure 8. With the high growth scenario, the peak load is forecast to increase slightly over the next 10 years.

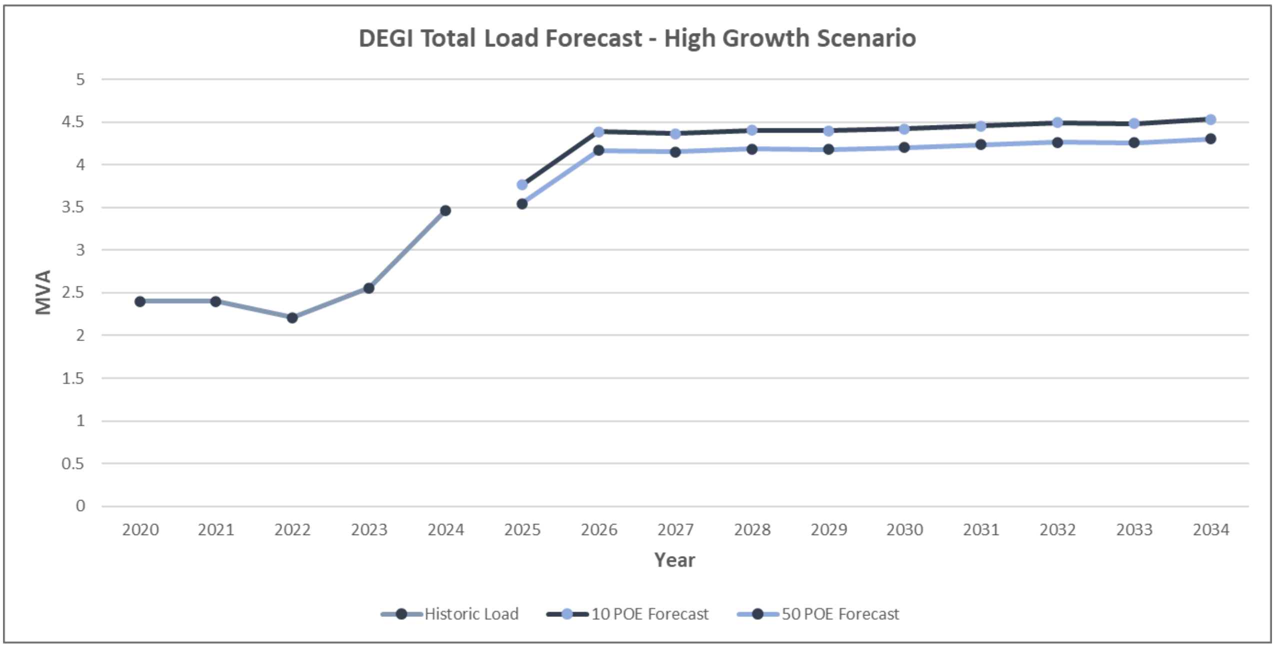


Figure 8: Substation high growth load forecast

2.3.6. Low Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the low load growth scenario are illustrated in Figure 9. With the low growth scenario, the peak load is forecast to decline slightly over the next 10 years.

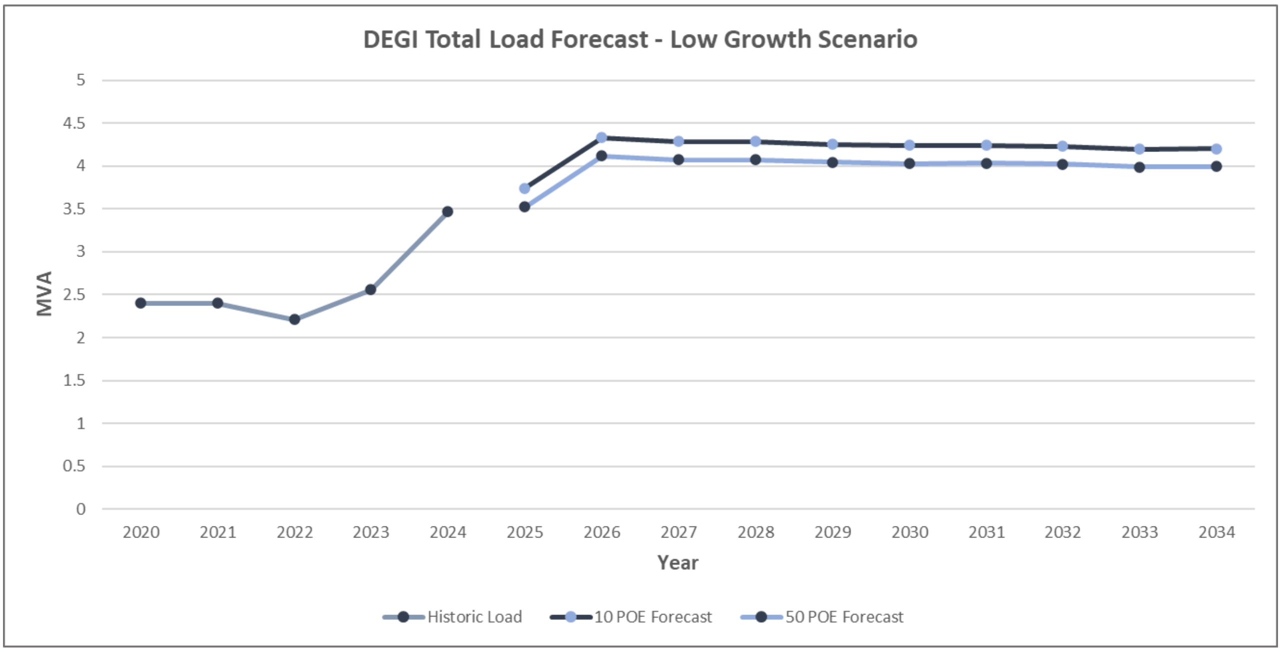


Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Reliability Corrective Action

Condition Based Risk Management (CBRM) analysis indicates that the two 2MVA 66/11kV transformers (T1 and T2) and the two 10.57/11kV auto-transformers (AT1 and AT2) are reaching end of life. The ongoing operation of these assets beyond their estimated retirement date presents a significant risk to safety, environment and customer reliability.

- 2 x 66/11kV transformers (T1, T2) (estimated retirement year 2028)
- 2 x 10.57/11kV auto-transformers (AT1, AT2) (estimated retirement year 2031)

The indoor 11kV RMU is a Hawker Siddeley Falcon Beta 2 make with 1999 YOM. This particular model is classified as being problematic due to having a known issue where the CB earth switch contacts can overtravel and contact the live busbar when being switched OFF, inadvertently energising unterminated or earthed cables connected to the CB. To minimise safety risks to field staff, special instructions must be followed when accessing or operating the RMU. These additional steps must be undertaken which adds additional complexity and expense during routine work. If these additional steps are not performed correctly then there is an increased risk of a catastrophic failure of the RMU, posing serious safety risks to any nearby field staff. Asset Maintenance and Engineering Field Support have advised that the switchboard should be replaced as part of this project.

The continued use of problematic plant and assets beyond end of life poses safety risks to staff working within the substation. It also poses a safety risk to the general public, through the increased likelihood of catastrophic failure of the power transformers / auto-transformers and 11kV RMU. Ergon Energy has obligations under the Electrical Safety Act 2002 (Qld)[5] to eliminate electrical safety risks so far as is reasonably practicable, and where not reasonably practicable, to minimise the risks so far as is reasonably practicable.

There is a considerable risk of environmental harm due to loss of oil from the power transformers, which would require clean up and rectification. Additionally, the poor condition of these assets significantly increases the likelihood of outages, resulting in a reduction in the level of reliability experienced by the customers supplied from DEGI. Ergon Energy has obligations to comply with

[5] QLD Electrical Safety Act 2002:
Part 2, Subdivision 2, Section 28 - What is reasonably practicable in ensuring electrical Safety
Part 2, Division 2, Section 29 - Duty of electricity entity

the reliability performance standards specified in its Distribution Authority[6] issued under the Electricity Act 1994 (Qld). Further to these requirements, the QLD Electricity Act 1994[7] stipulates that distribution entities must comply with the reliability requirements, system standards and performance requirements specified in the National Electricity Rules (NER)[8].

Where Ergon Energy identifies an imminent asset safety risk, immediate temporary measures are put in place to ensure safety of staff and public until permanent remediation can be performed.

3.2. Quantification of the Identified Need

The benefits of each credible option are assessed against the counterfactual, which in this case is to continue to operate the network with existing in-service assets. Existing maintenance regime would continue and equipment that fails in service would be replaced like for like through an urgent replacement project.

3.2.1. Risk Quantification Value Streams

The risk quantification of the counterfactual at DEGI has considered four primary value streams, *reliability, financial, safety* and *environmental,* as shown in Figure 12 and described in further detail below.

- **Reliability:** There is potential unserved energy within the DEGI supply area following an asset failure at DEGI. E.g., protection operating to clear a faulted 66/11kV transformer at DEGI would result in a 11kV bus section outage and > 2MW of unsupplied customer load. Customers would remain without supply until such time as field crews attended the site and performed manual HV switching.
- **Financial:** There are potential costs to perform unplanned emergency repairs or replacement of plant that fails in service. Replacing single assets on failure as individual failed in-service projects has been assumed to incur a 30% increase in cost in comparison to a planned project.
- **Safety:** Maintaining substation equipment beyond the recommended retirement year presents increasing safety risks to substation staff and the public. E.g., there is an increased chance of catastrophic failure of current transformers which could cause severe injuries to

[6] Ergon Energy Distribution Authority:
Section 7 - Guaranteed Service Levels
Section 8 - Distribution Network Planning
Section 9 - Minimum Service Standards
Section 10 – Safety Net

[7] QLD Electricity Act 1994 Part 5, Division 5, Section 42(a)(i)

[8] NER:
Schedule 5.1a System Standards
Schedule 5.1 Network Performance Requirements

workers within the substation. Mal-operation of protection relays can lead to unsafe conditions on the network which presents a risk to staff and the public.

- **Environmental:** In the event of a catastrophic failure of one of the non-bunded transformers, there is a risk of environmental harm due to an oil spill beyond the substation perimeter, which would require clean up and rectification.

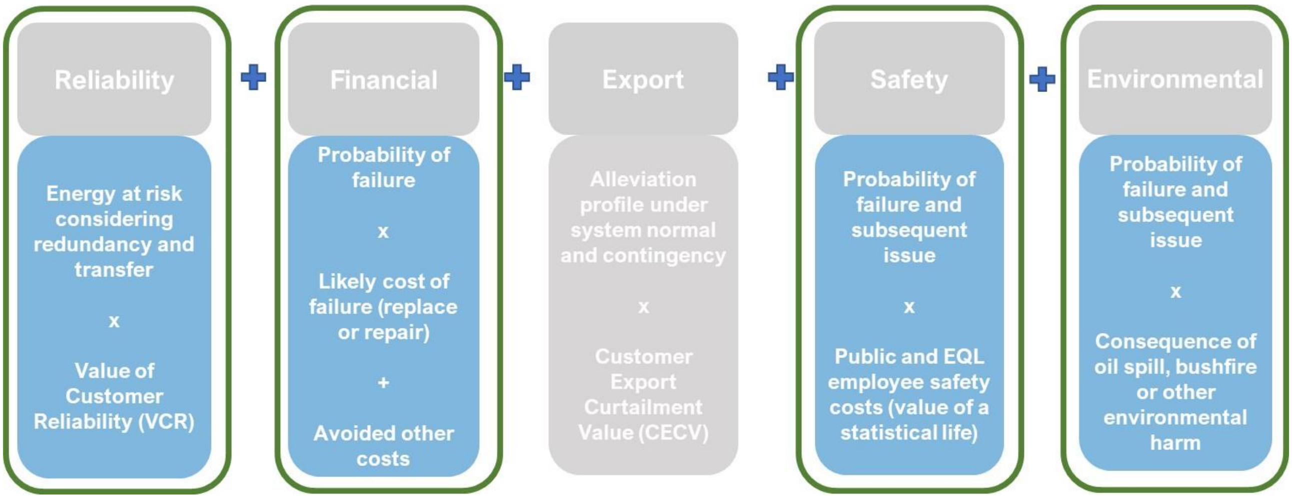


Figure 10 – Value Streams for Investment

3.2.2. Counterfactual Risk Quantification

The counterfactual risks are the expected unserved energy, emergency replacement cost, environmental risks and safety risks, during an equipment failure and associated unplanned supply outage at DEGI.

In calculating the value streams the following assumptions are used:

- **HV Bus Forced Outage Rate** – 0.03 outages / year for the outdoor 66kV bus and 0.003 outages / year the indoor 11kV bus. These are the standard outage rates used for buses of these construction types and voltage levels.
- **HV Circuit Breaker Forced Outage Rate** – The CB outage rate is predicted using a Weibull distribution with a Shape Parameter (β) of 4 and a Characteristic Life (η) of 75 for 11kV CBs, and a Characteristic Life (η) of 80 for 66kV CBs. A flat outage rate of 0.027 has been applied for the first 4 years to capture the increased risk of failure due to infant mortality of these assets.
- **Transformer Forced Outage Rate** – The zone transformer outage rate is predicted using a Weibull distribution with a Shape Parameter (β) of 3.6 and a Characteristic Life (η) of 79. A flat outage rate of 0.027 has been applied for the first 4 years to capture the increased risk of failure in the first years of transformers life.
- **Instrument Transformer Forced Outage Rate** – 0.2 outages / year for CTs and VTs greater than 60 years of age.
- **Restoration** – it has been estimated that the average rectification time would be 48 hours for all primary plant and instrument transformers. The average rectification time for protection relays is 8 hours.

- **Transfers** – during a contingency at DEGI, up to 0.3MVA of 11kV load can be transferred to adjoining zone substations within 6 hours.
- **Mobile generation** – during a contingency at DEGI, up to 1.5MVA of mobile generation can be installed within the 11kV network within 12 hours.
- **VCR Rate** – a VCR rate of $43.59 / kWh has been used, with the mix of customers weighted towards domestic and commercial customers.
- **Emergency Replacement Cost** – On failure of assets the plant will be replaced like-for-like with an additional 30% cost in comparison to the planned project.
- **Safety quantification** – Considers forced outage rate of the asset with a conversion factor of 0.1% that a fatality to an employee and/or injury to an employee will occur.
- **Risk timeframe** – risks were calculated over a 60-year period, starting from 2027 to align with the investment year of Option 1 (see below).

Figure 11 shows the quantified risk per annum for the counter-factual increasing over the 60-year period from 2027 to 2087.

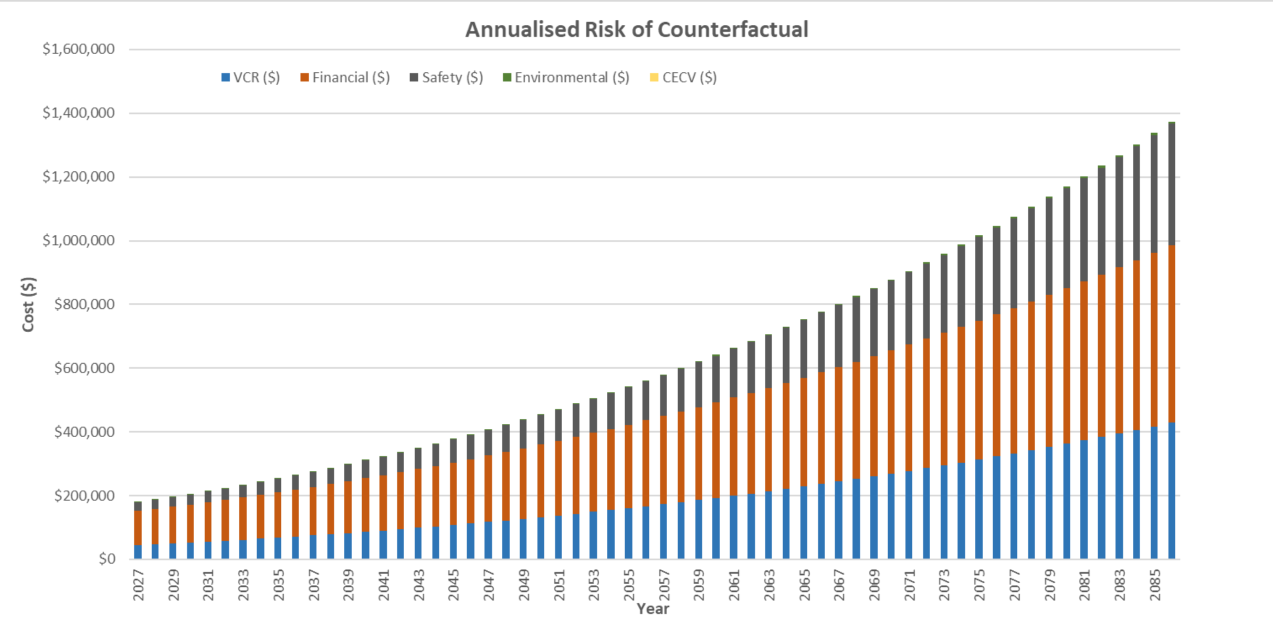


Figure 11: Annualised Risk of Counterfactual

Value of Customer Reliability (VCR) is an economic value applied to customers' unserved energy for any particular year. VCR values represent customers' willingness across the National Electricity Market (NEM) to pay for reliable electricity supply. The VCR is used for estimating market benefits that relate to reliability, such as changes in involuntary and voluntary load curtailment.

The VCR calculated for this analysis for the customers supplied from DEGI is shown in Table 1 based on the VCR values for different customer types as published by the AER.

Customers	Sector	Annual Consumption (kWh)	$/kWh (2023)
DEGI 11kV Load	Residential (Climate Zone 2)	4,619,514	$28.44
	Commercial*	4,101,187	$49.54
	Industrial*	1,675,409	$70.97
	Agriculture*	176,148	$42.14
	Average VCR		**$43.59**

Table 1: AER VCR values for DEGI

*Business using <10MVA peak demand

$$VCR = \frac{(Residential\ kWh\ \times\ VCR) + (Commercial\ kWh\ \times\ VCR) + (Industrial\ kWh\ \times\ VCR) +\ (Agriculture\ kWh\ \times\ VCR)}{Total\ Energy}$$

3.3. Assumptions in Relation to Identified Need

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

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

3.3.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at DEGI Substation will be consistent with the base case forecast outlined in Section 2.3.4.

Factors that have been taken into account when the load forecast has been developed include the following:

- load history;
- known future developments (new major customers, network augmentation, etc.);
- temperature corrected start values (historical peak demands); and
- forecast growth rates for organic growth.

3.3.2. Load Profile

Characteristic peak day load profiles shown in Section 2.3.3 are unlikely to change significantly from year to year and the shape of the load profile is assumed to remain virtually the same with increasing maximum demand.

4. CREDIBLE OPTIONS ASSESSED

4.1. Assessment of Network Solutions

Ergon Energy has identified one credible network option that would address the identified need and is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

4.1.1. Option A: Asset replacement

This option is commercially and technically feasible, can be implemented in the timeframe identified, late-2027 and would address the identified need by replacing problematic and deteriorated assets at DEGI ensuring Ergon Energy continues to adhere to the applicable regulatory instruments.

This option involves performing the following replacement works in order to address the identified need.

- Replace T1 / AT1 and T2 / AT2 with two new 6.3MVA 66/11kV transformers,
- Replace the 11kV RMU indoor switchboard with new 12kV Ring Main Switchgear installed within a new prefabricated switchgear building,
- Build a new 66kV switchyard,
- Extend the substation yard and earth-grid to accommodate the new switchgear building and new 66kV switchyard.

Due to the scope of works being entirely contained within the existing substation site at Degilbo, as well as the expected reliability and safety benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline. While Ergon Energy does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Ergon Energy Community Engagement Framework which is integrated into the project workflow.

The estimated capital cost of this option is $10.7 million, which has been factored into the NPV to be incurred in 2027.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 12.

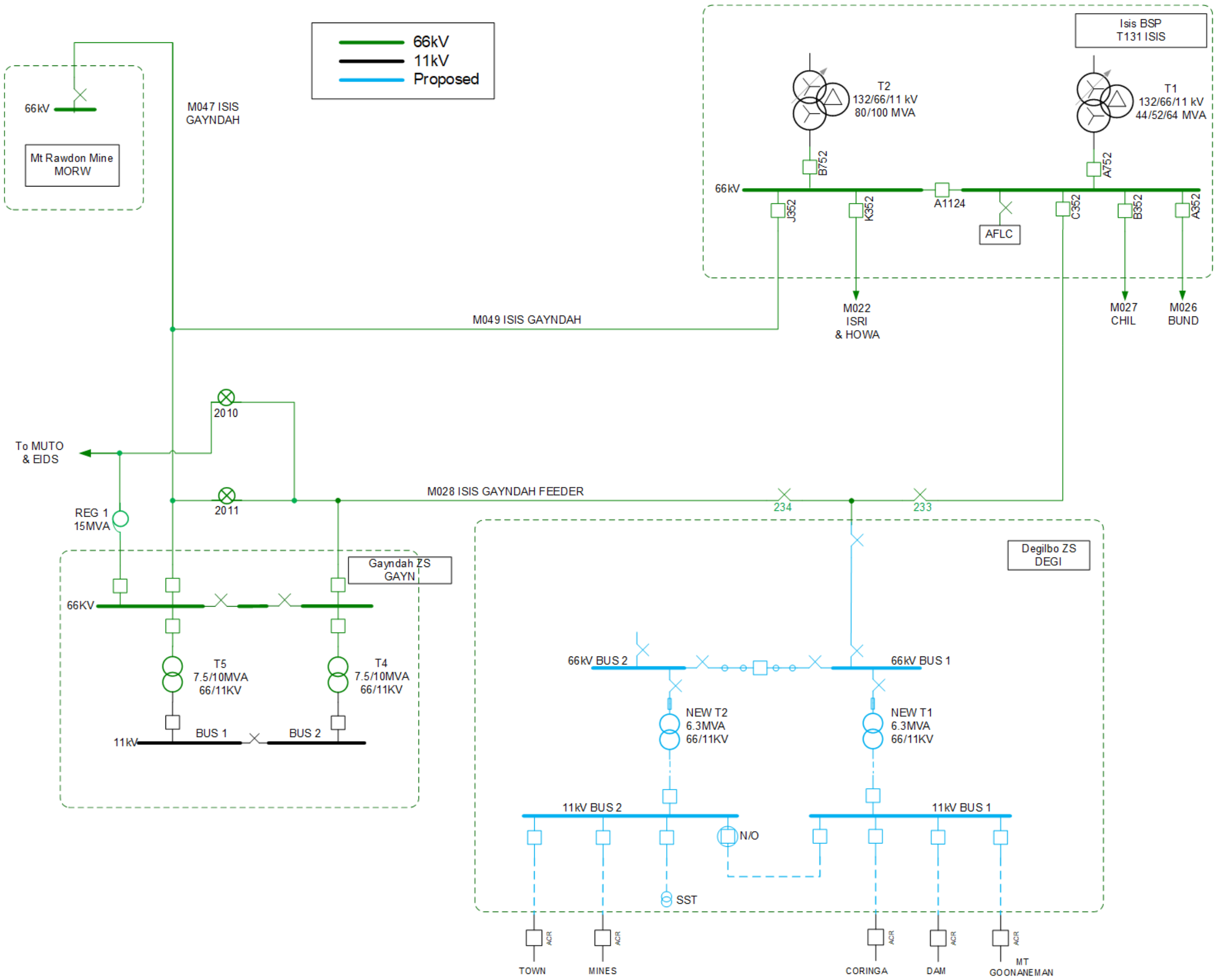


Figure 12: Option A proposed network arrangement (schematic view)

4.2. Assessment of SAPS and Non-Network Solutions

Ergon Energy has considered Standalone Power Systems (SAPS) and demand management solutions. Each of these are considered below.

4.2.1. Consideration of SAPS Options

Ergon Energy considers there is no SAPS option that could form a potential credible option on a standalone basis, or that could form a significant part of the credible option. In particular the load requirements, per the forecast in the Degilbo region could not be supported by a network that is not part of the interconnected national electricity system. Therefore, a SAPS option is not technically feasible.

4.3. Demand Management (Demand Reduction)

Ergon Energy's Demand & Energy Management (DEM) team has assessed the potential non-network alternative (NNA) options required to defer the network option and determine if there is a viable demand management (DM) option to replace or reduce the need for the network option proposed.

Credible options must be technically and commercially viable and must be able to be implemented in sufficient time to satisfy the identified risk to the public and/or the network due to the identified constraints.

The DEM team has completed a review of the Degilbo customer base and considered the suitability of a number of demand management technologies. However, as the identified need is for reliability corrective action it has been determined that demand management options would not be viable propositions for the following reasons.

4.3.1. Network Load Control

The residential customers and commercial load appear to drive the daily peak demand which generally occurs between 6:00pm and 9:00pm.

There are 667 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 400kVA[9] is available.

Degilbo Substation LC signals are controlled from ISIS bulk supply point. The Tariff 33 and 31 hot water LC channels are dynamic (that is, it responds to exceedance settings not on a timetable) and the current control strategy only calls LC when the load at ISIS exceeds 51.5MW. This strategy does not directly address demand peaks experienced at Degilbo. Tariff 33 air-conditioning channels are under manual control of the operational control centre and are used as required. Therefore, network load control would not sufficiently address the identified need.

4.4. Demand Response

Four methods utilising demand response technology for deferring network investment are: Call Off Load (COL), Customer Embedded Generation (CEG), Large Scale Customer Generation (LSG) and customer solar power systems.

4.4.1. Customer Call Off Load (COL)

COL is an effective technique for deferring network investment where the need is for a short time period. However, in this instance, the need is required on a long-term permanent basis. There are a small number of large customers in the catchment area but the $/kVA funding available for demand reduction is low therefore customer call off load has been assessed as not a viable proposition as it will not address the identified need, nor benefit the community.

[9] Hot water diversified demand saving estimated at 0.6kVA per system.

4.4.2. Customer Embedded Generation (CEG)

CEG is an effective technique for deferring network investment where the need is for a short time period. The primary driver for investment in this instance is asset safety and performance. A short-term deferral of network investment by using CEG is not a technically or financially feasible option (due to the number of contracts required to be negotiated and managed).

This option has been assessed as technically not viable as it will not address the identified network requirement.

4.4.3. Large-Scale Customer Generation (LSG)

LSG sites such as renewable energy generation, solar or wind farms of multiple MW's capacity constitute an opportunity to support substation investment by reducing demand on, and potentially providing reactive power support for substation assets.

This option could potentially address the identified need, however, has been assessed as technically not viable as there is no known existing or proposed LSG demand response available.

4.4.4. Customer Solar Power Systems

A total of 342 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 1,707kVA.

The daily peak demand is driven by residential and commercial customer demand and the peak generally occurs between 6:00pm and 9:00pm. As such customer solar generation does not coincide with the peak load period.

Business customers with large solar arrays are deemed to present a significant opportunity for targeted load control or load curtailment if coupled with a Battery Energy Storage System (BESS). Contracting such customers is attractive as they represent a larger load across a fewer customers and therefore are cheaper and easier to engage and contract.

However, only a small percentage of customers in this supply area have solar PV systems and possibly none have a BESS. PV systems with BESS present a future portfolio opportunity for potential demand response but currently this supply area has a very limited solar/BESS. Solar customers without a BESS will not meet the technical needs of the demand reduction as their solar contribution may not be available when the network un-met need is required.

4.4.5. SAPS and Non-Network Solution Summary

Ergon Energy has not identified any viable SAPS or non-network solutions that would provide a complete or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Degilbo area to address the identified need.

4.5. Preferred Option

Ergon Energy's preferred internal network option is Option A, to replace T1 / AT1 and T2 / AT2 with two new 6.3MVA 66/11kV transformers, build a new 66kV switchyard and replace the 11kV RMU indoor switchboard with new 12kV Ring Main Switchgear installed within a new prefabricated switchgear building at DEGI by 2027. The substation yard and earth-grid will be extended to accommodate the new switchgear building and new 66kV switchyard.

Upon completion of these works the identified need would be addressed by replacing deteriorated assets at DEGI ensuring Ergon Energy continues to adhere to the applicable regulatory instruments. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources. This option will address the identified need, are commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

The estimated capital cost of this option is $10.7 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design commencing in mid-2025 and construction completed by mid-2027.

5. MARKET BENEFIT ASSESSMENT METHODOLOGY

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

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

5.1. Classes of Market Benefits Considered and Quantified

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

- Changes in involuntary load shedding and Customer Interruptions caused by Network Outages

5.1.1. Changes in Involuntary Load Shedding and Customer Interruptions caused by Network Outages

Involuntary load shedding is where a customer's load is interrupted from the network without their agreement or prior warning. Ergon Energy has forecast load over the assessment period and has quantified the expected unserved energy by comparing forecast load to network capabilities under system normal and network outage conditions. A reduction in involuntary load shedding expected from an option, relative to the base case, results in a positive contribution to the market benefits of the credible option being assessed.

Involuntary load shedding of a credible option is derived by the quantity in MWh of involuntary load shedding required, assuming the credible option is completed, multiplied by the Value of Customer Reliability (VCR). The VCR is measured in dollars per MWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D.

Ergon Energy has applied a VCR estimate of $43.59/kWh for the DEGI 11kV load, which has been derived from the AER 2023 Value of Customer Reliability (VCR) values. In particular, Ergon Energy has weighted the AER estimates according to the make-up of the specific load considered.

Customer export curtailment value (CECV) represents the detriment to all customers from the curtailment of DER export (e.g. rooftop solar PV systems). A reduction in curtailment due to implementing a credible option results in a positive contribution to the market benefits of that option. These benefits have been calculated according to the AER CECV methodology based on the capacity of DER currently installed and forecast to be installed within the Degilbo supply area.

5.2. Classes of Market Benefits not Expected to be Material

The following classes of market benefits are not considered to be material for this RIT-D, and have not been included in this RIT-D assessment:

- Changes in voluntary load curtailment
- Changes in costs to other parties
- Differences in timing of expenditure
- Changes in load transfer capacity and the capacity of Embedded Generators to take up load
- Changes in electrical energy losses
- Changes in Australia's greenhouse gas emissions
- Option value
- Other Class of Market Benefit
- Costs Associated with Social Licence Activities

5.2.1. Changes in Voluntary Load Curtailment

The credible options presented in this RIT-D assessment do not include any voluntary load curtailment as there are no customers on voluntary load curtailment agreements in the Degilbo area. Therefore, market benefits associated with changes in voluntary load curtailment have not been considered.

5.2.2. Changes in Costs to Other Parties

Ergon Energy does not anticipate that any of the credible options included in this RIT-D assessment will affect costs incurred by other parties.

5.2.3. Differences in Timing of Expenditure

The credible options included in this RIT-D assessment are not expected to affect the timing of other distribution investments for unrelated identified needs.

5.2.4. Changes in Load Transfer Capacity and the capacity of Embedded Generators to take up load

The credible options included in this RIT-D assessment are not expected to have an impact on the load transfer capacity or the capacity of embedded generators to take up load between the zone substations in the Degilbo area.

5.2.5. Changes in Electrical Energy Losses

Ergon Energy does not anticipate that any of the credible options included in the RIT-D assessment will lead to any significant change in electrical energy losses.

5.2.6. Changes in Australia's Greenhouse Gas Emissions

Ergon Energy does not anticipate that any of the credible options included in the RIT-D assessment will lead to any significant change in greenhouse gas emissions.

5.2.7. Option Value

The AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change[10].

Ergon Energy does not consider that the identified need for the options included in this RIT-D would be affected by uncertain factors about which there may be more clarity in future.

5.2.8. Costs Associated with Social Licence Activities

Ergon Energy does not anticipate that any of the credible options included in the RIT-D assessment will involve costs associated with licence activities.

6. DETAILED ECONOMIC ASSESSMENT

6.1. Methodology

The RIT-D requires Ergon Energy to identify the credible option that maximises the present value of net economic benefit to all who produce, consume and transport electricity in the NEM.

Accordingly, a base case Net Present Value (NPV) calculation of the credible option has been undertaken.

6.2. Key Variables and Assumptions

The economic assessment contains anticipated costs of providing, operating and maintaining the option as well as expected costs of compliance and administration associated with the option.

The present value summary includes all costs directly associated with constructing and providing the option. This includes the cost of land and easements currently owned or to be acquired for network augmentation.

[10] AER "Regulatory Investment Test for Distribution Application Guidelines", Section A6. Available at: http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-investment-test-for-distribution-rit-d-and-application-guidelines

6.3. Net Present Value (NPV) Results

An overview of the NPV results are provided in Table 3. The only credible option assessed, Option A, shows a positive net NPV of $1,691,000 and is the recommended development option to address the identified need.

Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
A	Asset replacement by 2027	1	$1,691,000	-$10,706,000	-$1,638,000	$14,035,000

Table 2: NPV results table

7. CONCLUSION

The FPAR represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to take steps to progress the preferred option to address the identified need.

7.1. Preferred Option

Ergon Energy's preferred option is Option A, to replace T1 / AT1 and T2 / AT2 with two new 6.3MVA 66/11kV transformers, build a new 66kV switchyard and replace the 11kV RMU indoor switchboard with new 12kV Ring Main Switchgear installed within a new prefabricated switchgear building at DEGI by 2027.

Upon completion of these works the identified need would be addressed by replacing problematic and deteriorated assets at DEGI ensuring Ergon Energy continues to adhere to the applicable regulatory instruments. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources. This option will address the identified need, are commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

The estimated capital cost of this option is $10.7 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design completed by mid-2026 and construction completed by mid-2027.

7.2. Satisfaction of RIT-D

The preferred option satisfies the RIT-D and maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

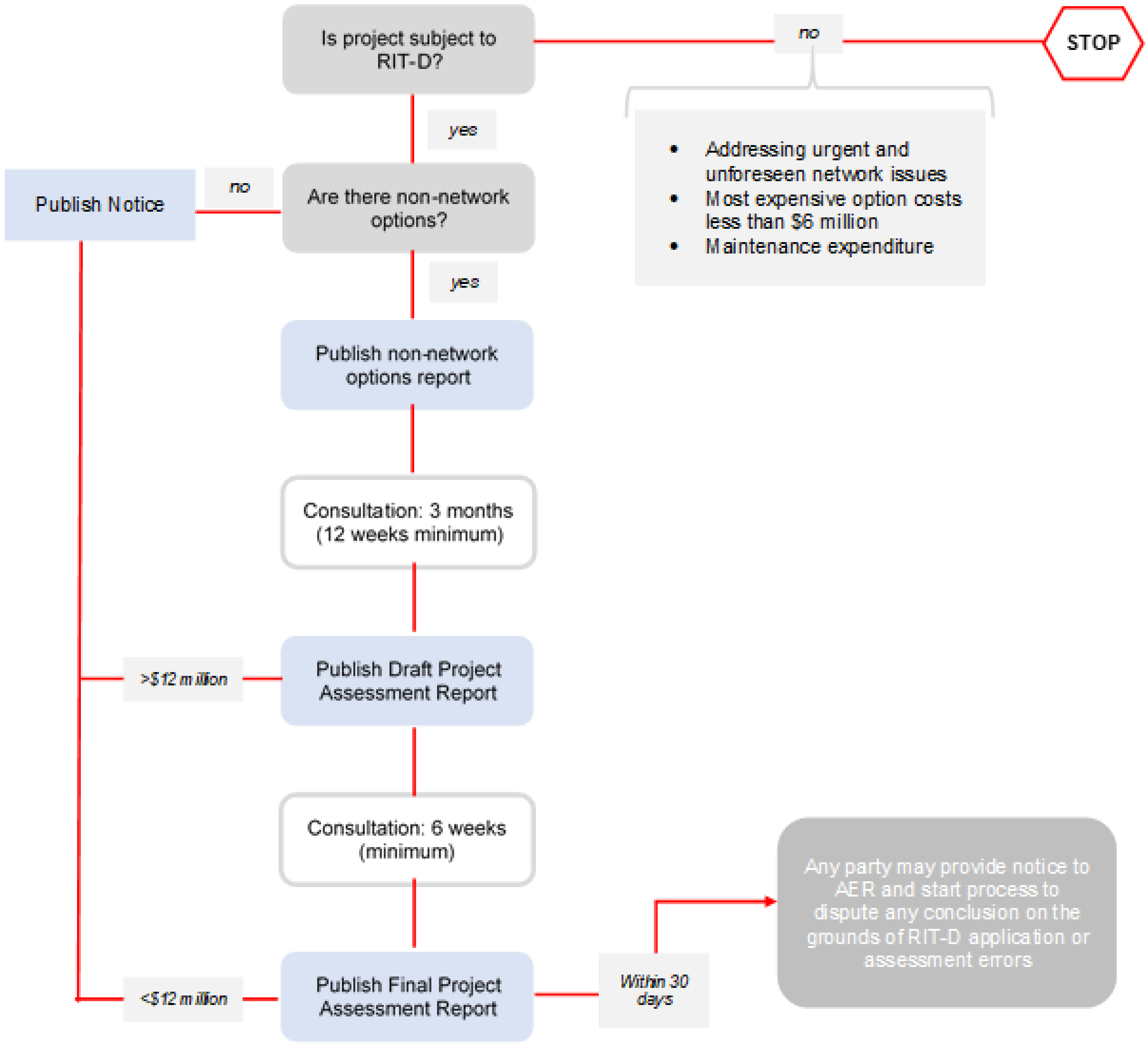
This statement is made on the basis of the detailed analysis set out in this report. The preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

8. COMPLIANCE STATEMENT

This Final Project Assessment Report complies with the requirements of NER section 5.17.4(j) as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the DPAR;	N/A
(4) a description of each credible option assessed	4 & 5
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	5.1
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	4 & 6
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	5
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	5.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	6
(10) the identification of the proposed preferred option	7.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (ii) the indicative capital and operating costs (where relevant); (iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	7.1 & 7.2
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.3

APPENDIX A – THE RIT-D PROCESS



Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.