Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Atherton Network Area

Notice of Screening for Options

28 January 2025

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

Atherton is a rural township located in the tablelands region of Far North Queensland, 80km south-west of Cairns and is known for its agriculture. Atherton 66/22kV zone substation (ATHE) was constructed in 1957 and supplies approximately 12,392 customers with over 85% of the total number of customers being residential. However, of the 140GWh of energy supplied annually, the usage is dominated by Commercial, Industrial and Agriculture (57%) with only 43% being consumed by residential customers. The energy usage helps to understand how vital the continued operation of ATHE is to the industry, agriculture and livelihood of those living in the tablelands region.

Condition Based Risk Management (CBRM) analysis indicates that the following items of plant have reached retirement:

- 1 x 66kV Circuit Breaker
- 3 x 66kV Current Transformers
- 12 x 66kV Voltage Transformers
- 14 x 66kV isolators
- 1 x local services Transformer
- 25 x Protection Relays

The ASEA >HLR 84/2001 A2U Circuit Breaker which was manufactured in 1974 has a history of high contact resistance and repairing of the spring charge chain. There is a lack of spares available for the ASEA current transformers, additionally the porcelain housings of these CTs are a known safety risk due to likelihood of explosive failure. Many of the 66kV CVTs are known to be problematic, where possible Ergon has installed CVT monitoring however it is recommended where substation projects are being completed for these problematic CVTs to be replaced sooner rather than later. Inspection of the isolators shows rust and algae evident on the surface of all the isolators. These isolators are greater than 60 years of age and are likely to have high probability of failure due to weathered and corroded contacts. This poses an issue for staff when operating these isolators as they can become stuck, however also poses a reliability risk to the network as they may not be able to be closed or have poor contact after being opened to perform maintenance within the substation.

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. Ergon Energy has obligations under the *Electrical Safety Act 2002* (Qld)[1] 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.

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 ATHE. Ergon Energy has obligations to comply with reliability performance standards specified in its Distribution Authority[2] issued under the *Electricity Act 1994* (Qld).

Ergon Energy is seeking to invest in the network to undertake a reliability corrective action to continue to meet the service standards in its applicable regulatory instruments (National Electricity Rules[3], *Electricity Act 1994* (Qld)[4], *Electrical Safety Act 2002* (Qld)).

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 Atherton supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D. An internal assessment has been conducted and it has been determined that there is no stand-alone power system (SAPS) or non-network option that is potentially credible, or that forms a significant part of a potential credible option that will meet the identified need or form a

[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

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

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

significant part of the solution. This Notice has hence been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(d) of the NER.

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1. BACKGROUND

1.1. Geographic Region

Atherton is a rural township located in the tablelands region of Far North Queensland, 80km south-west of Cairns and is known for its agriculture. Atherton 66/22kV zone substation (ATHE) was constructed in 1957 and supplies approximately 12,392 customers with over 85% of the total number of customers being residential. However, of the 140GWh of energy supplied annually, the usage is dominated by Commercial, Industrial and Agriculture (57%) with only 43% being consumed by residential customers. The energy usage helps to understand how vital the continued operation of ATHE is to the industry, agriculture and livelihood of those living in the tablelands region.

The geographical location of Ergon Energy's sub-transmission network and substations in the area is shown in Figure 1.

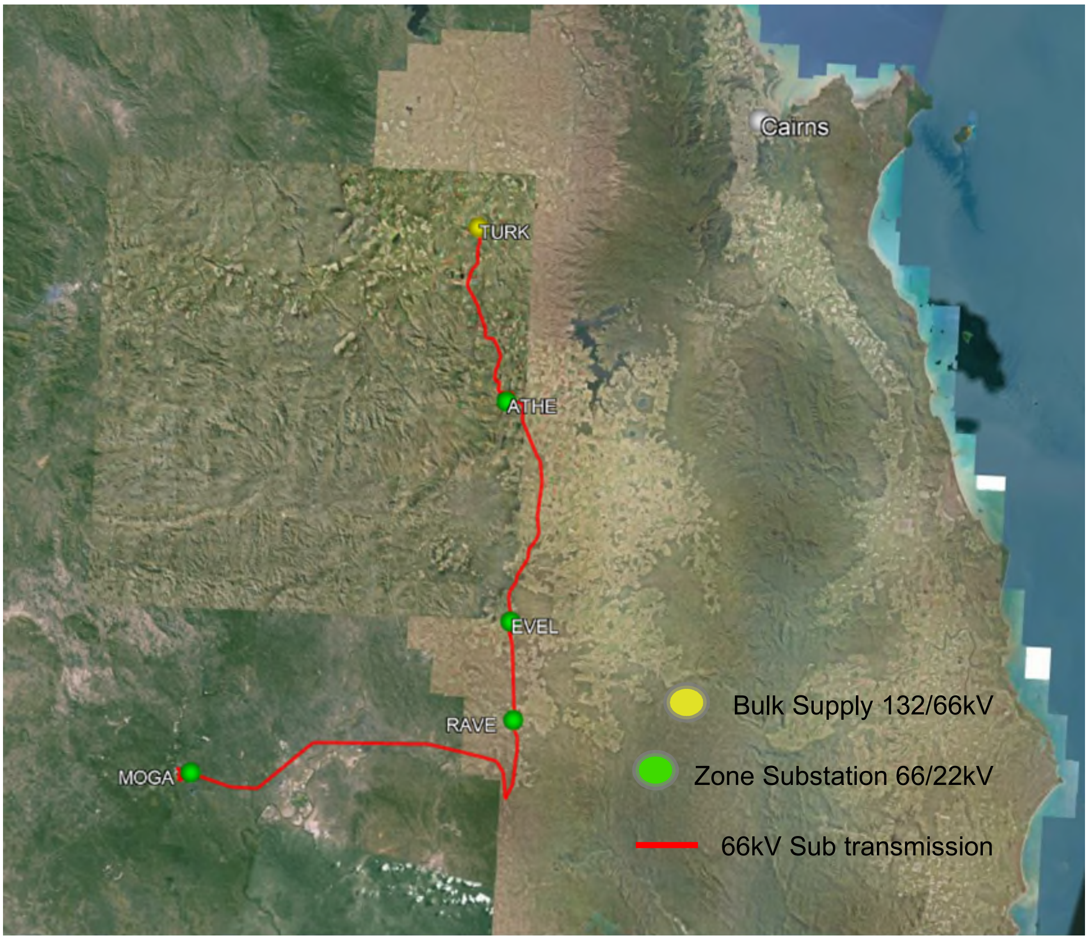

Figure 1: Geographic of the Tablelands area sub-transmission network

1.2. Existing Supply System

ATHE is supplied with two 66kV feeders (ATH No. 1 & ATHE No. 2) from T055 Tukinje 132/66kV bulk supply point (TURK). Figure 1 shows the geographic layout of the Tablelands area 66kV network.

Figure 2 gives a line diagram of ATHE and shows that there are two outgoing 66kV feeders which supply Evelyn 66/22kV substation (EVEL), Ravenshoe 66/22kV and Mt Garnett 66/22kV substation (MOGA), and nine 22kV distribution feeders which supply Atherton and the surrounding area.

ATHE is equipped with two 24/30/40MVA 66/22kV transformers (T1 and T2), with both the 66kV and 22kV switchgear being outdoor AIS. There are seven 66kV CBs including a 66kV bus section breaker and fifteen 22kV CBs including an 22kV bus section breaker.

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

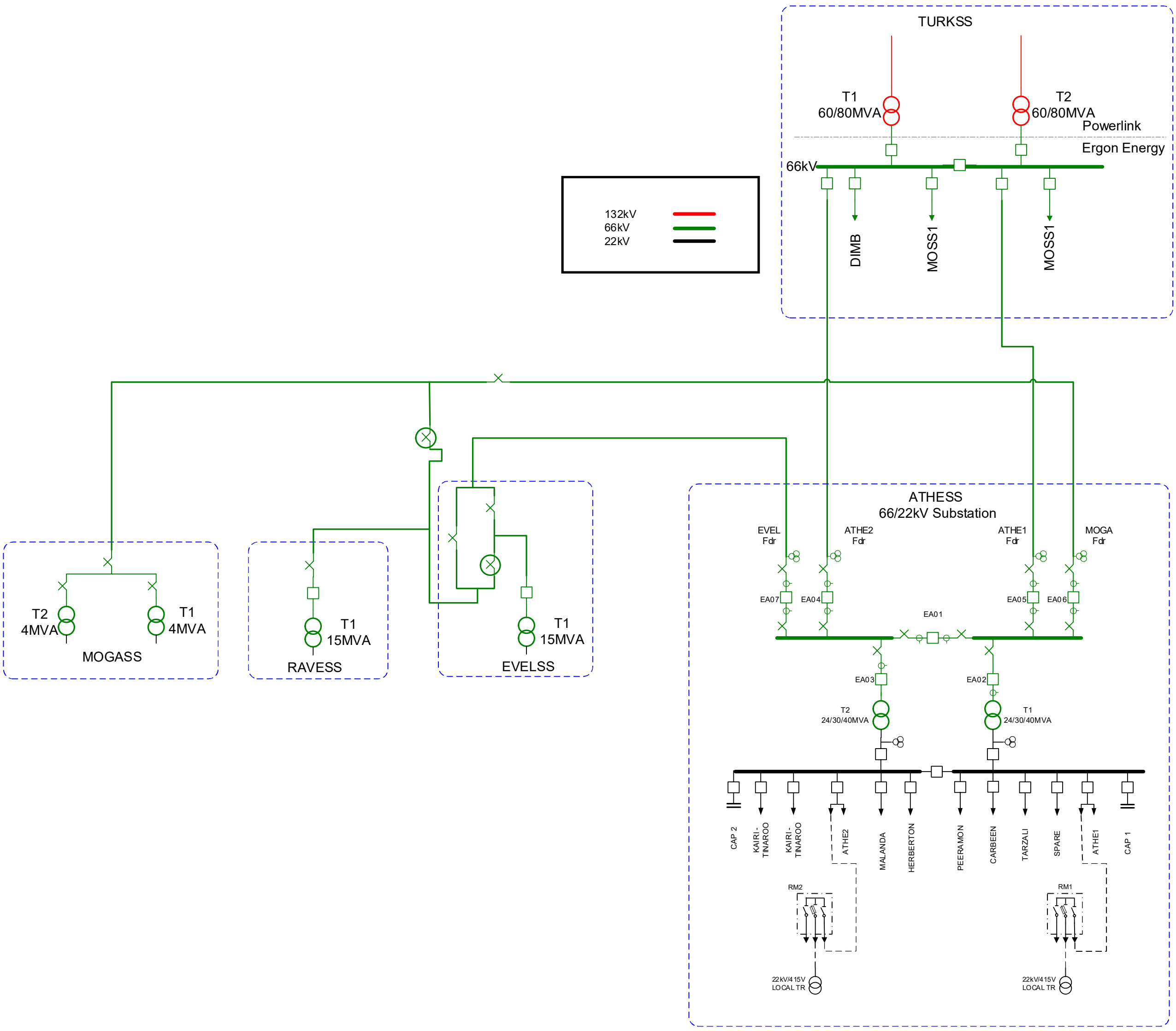

Figure 2: Existing network arrangement (schematic view)

Figure 3: ATHE layout (geographic view)

1.3. Load Profiles / Forecasts/ Constraints

The load at ATHE comprises a mix of residential and commercial/industrial/agricultural customers. The load is constant throughout the year, with comparable peaks in summer and winter alike, although the forecast peak load is slightly higher in winter than in summer.

The substation N-1 supply is limited by the transformers cables which have a maximum current carrying capacity of 35.6MVA. It can be seen in the following figures that even under a high forecast scenario the cable ratings are sufficient to beyond 2036.

The loads presented are the 22kV loads; however, Evelyn 66/22kV substation, Ravenshoe 66/22kC substation and Mount Garnett 66/22kV substation are supplied via the Atherton 66kV bus. They have peak loads expected to reach 1.6MVA, 2.6MVA and 1.9MVA respectively by 2036.

1.3.1. Full Annual Load Profile

The full annual load profile for ATHE over the 2023/24 financial year is shown in Figure 4.

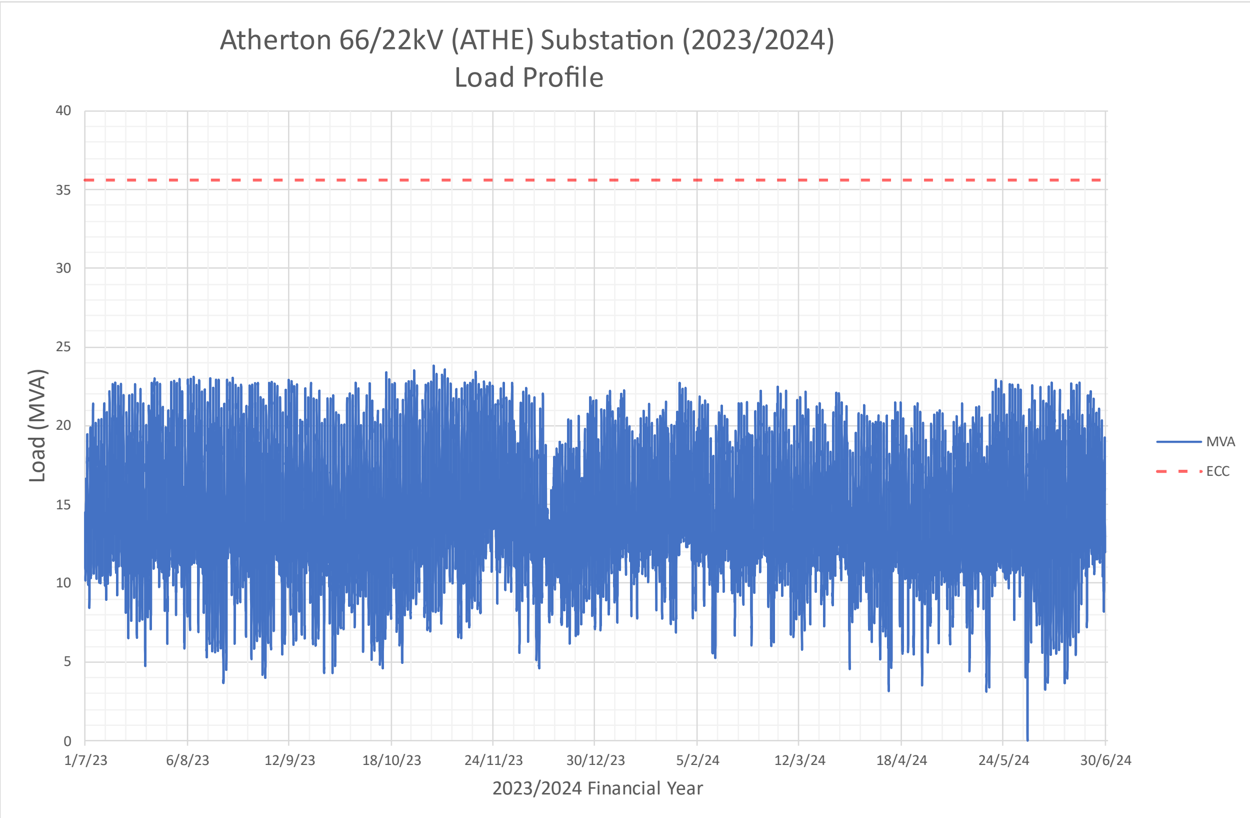

Figure 4: ATHE Substation annual load profile (2023/24)

1.3.2. Load Duration Curve

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

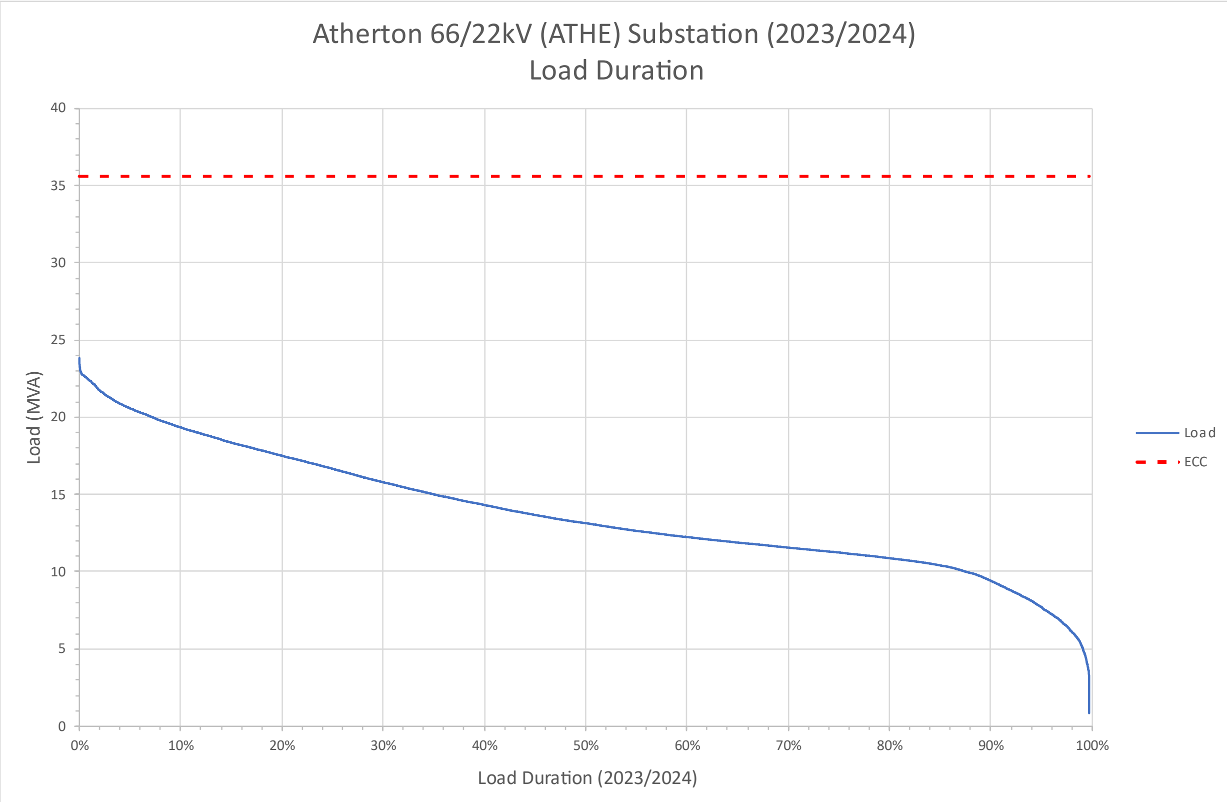

Figure 5: ATHE load duration curve

1.3.3. Average Peak Weekday Load Profile

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

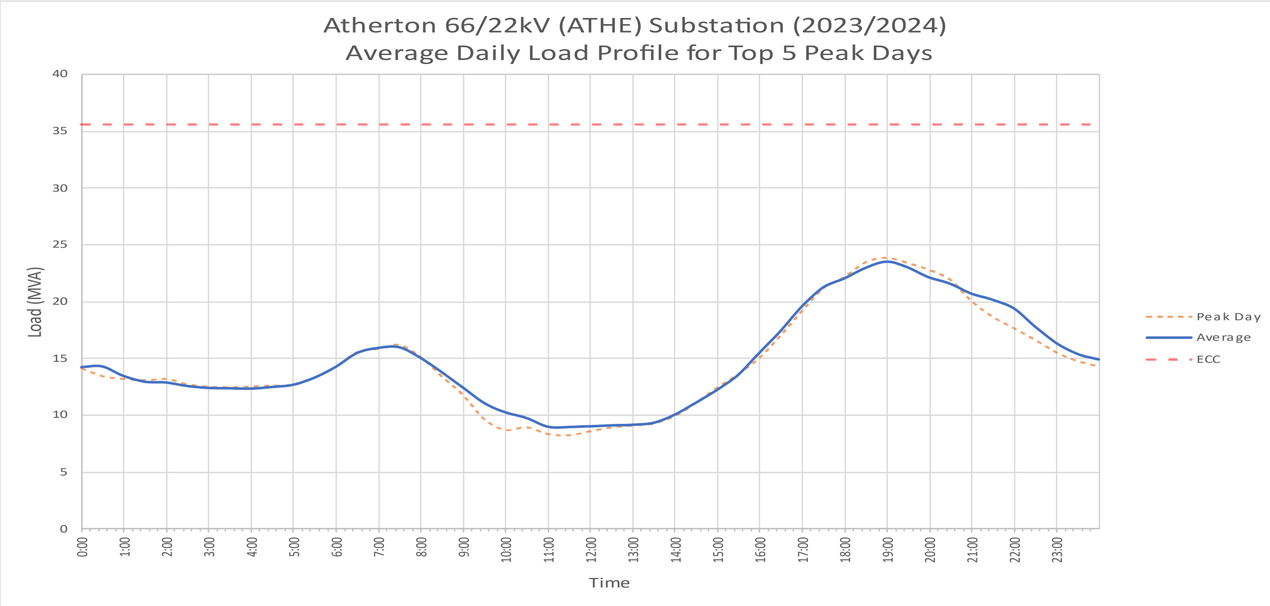

Figure 6: Substation average peak weekday load profile (summer)

1.3.4. 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 4MVA between 2025 to 2036.

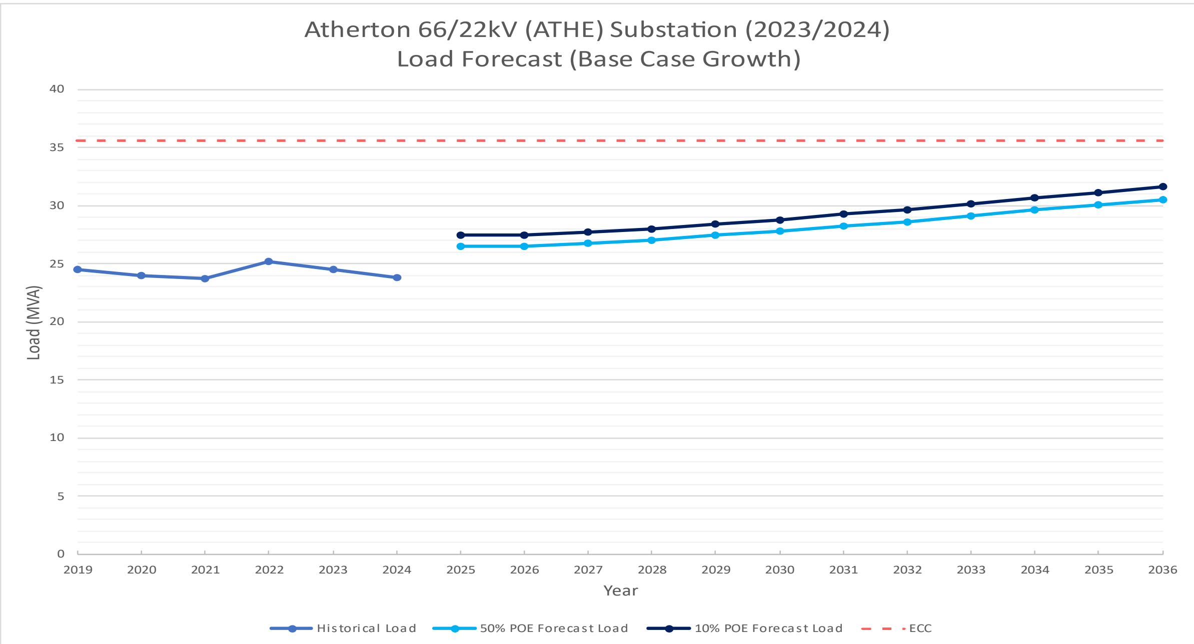

Figure 7: Substation base case load forecast

1.3.5. 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 by 19.5% over the next 10 years.

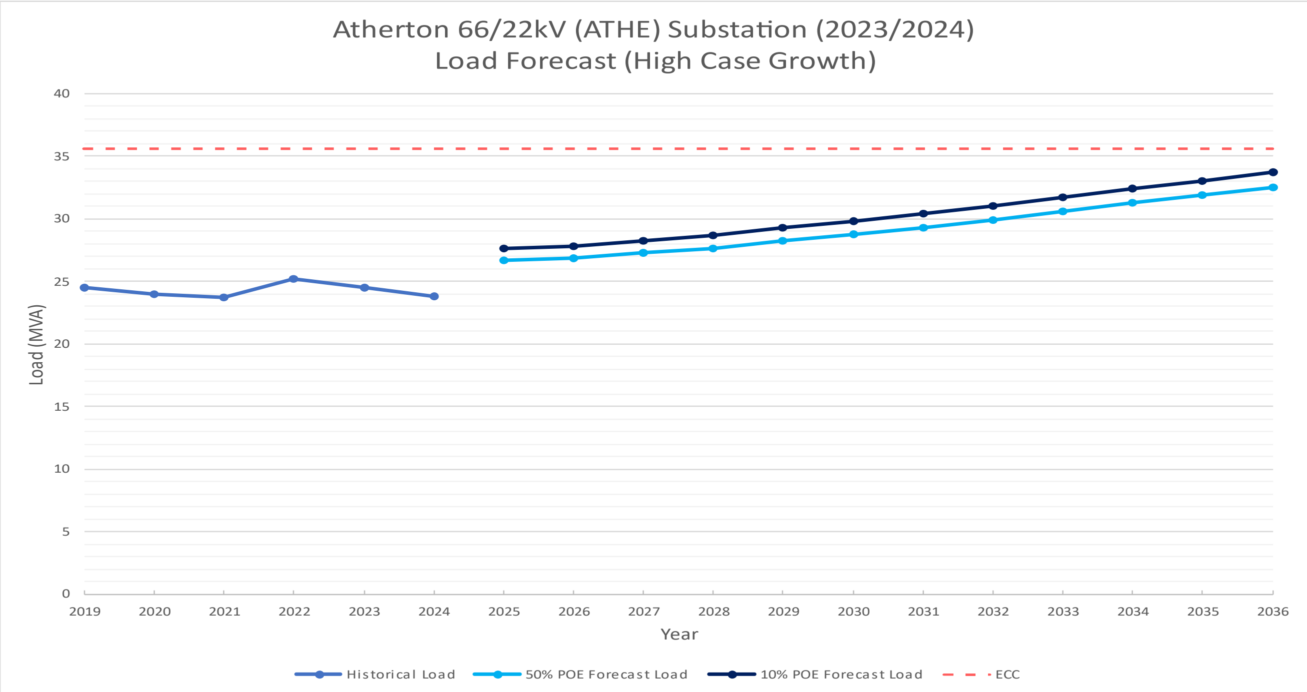

Figure 8: Substation high growth load forecast

1.3.6. 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 increase slightly over the next 10 years.

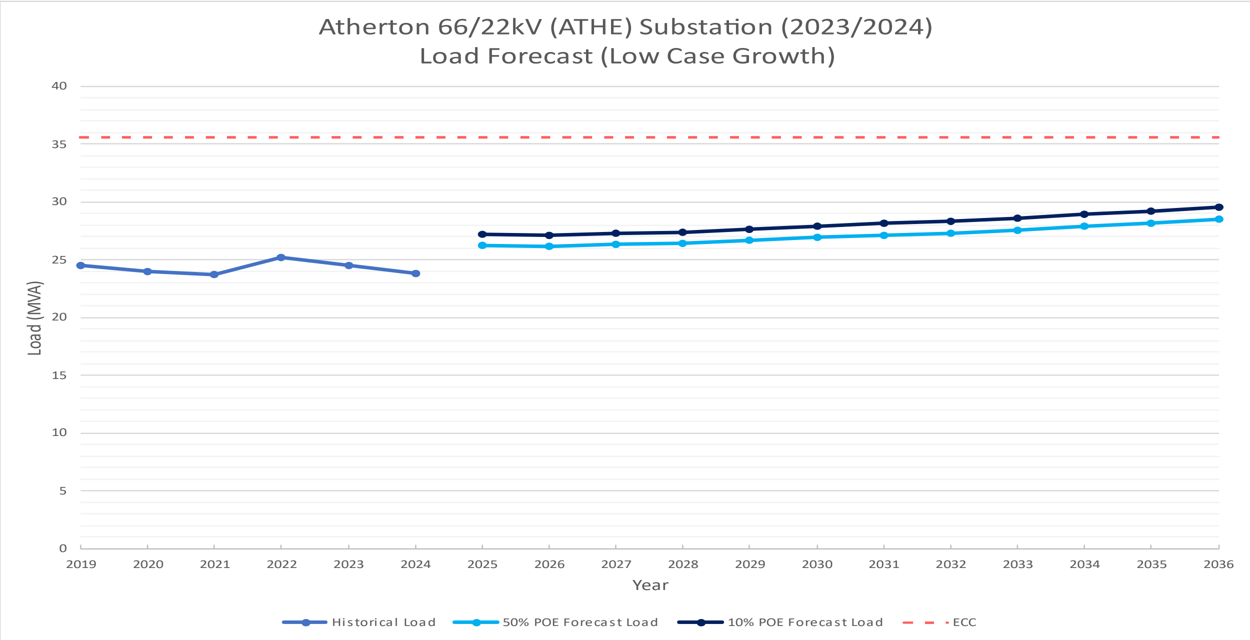

Figure 9: Substation low growth load forecast

2. IDENTIFIED NEED

2.1. Description of the Identified Need

2.1.1. Reliability Corrective Action

Condition Based Risk Management (CBRM) analysis indicates that the following items of plant have reached retirement:

- 1 x 66kV Circuit Breaker
- 3 x 66kV Current Transformers
- 12 x 66kV Voltage Transformers
- 14 x 66kV isolators
- 1 x local services Transformer
- 25 x Protection Relays

The ASEA >HLR 84/2001 A2U Circuit Breaker which was manufactured in 1974 has a history of high contact resistance and repairing of the spring charge chain. There is a lack of spares available for the ASEA current transformers, additionally the porcelain housings of these CTs are a known safety risk due to likelihood of explosive failure. Many of the 66kV CVTs are known to be problematic, where possible Ergon has installed CVT monitoring however it is recommended where substation projects are being completed for these problematic CVTs to be replaced sooner rather than later. Inspection of the isolators shows rust and algae evident on the surface of all the isolators. These isolators are greater than 60 years of age and are likely to have high probability of failure due to weathered and corroded contacts. This poses an issue for staff when operating these isolators as they can become stuck, however also poses a reliability risk to the network as they may not be able to be closed or have poor contact after being opened to perform maintenance within the substation.

The ongoing operation of these assets beyond their estimated retirement date presents a significant risk to safety, environment and customer reliability. 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 the general public, though the increased likelihood of catastrophic failure of plant, in particular the current and voltage transformers. Ergon Energy has obligations under the *Electrical Safety Act 2002* (Qld)[5] to eliminate electrical safety risks so far as is reasonably

[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

practicable, and where not reasonably practicable, to minimise the risks so far as is reasonably practicable. 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 ATHE. Ergon Energy has obligations to comply with reliability performance standards specified in its Distribution Authority[6] issued under the *Electricity Act 1994* (Qld). Further to these requirements, the *Electricity Act 1994* (Qld)[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.

[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
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3. POTENTIAL CREDIBLE OPTIONS

3.1. Non-Network Options Identified

Ergon Energy has not identified any viable non-network solutions internally that will provide a complete or a hybrid (combined network and non-network) solution to address the identified need. Further discussion of non-network options is included in Section 4.

3.2. Network Options Identified

Ergon Energy has identified one potential credible option that would address the identified need.

It should be noted that an Air insulated Switchgear (AIS) option was considered for in-situ replacement. A civil assessment has been completed on the existing structures and has deemed these to be end of life and not suitable for assets expected to be in service for the next 40- 60 years. Installation of new isolators and circuit breakers within the existing AIS infrastructure is not possible. Furthermore, due to the spacing requirements of new assets and the staging requirements to ensure continuity of supply, replacing with AIS equipment was also not a feasible option and was therefore discounted as a non-credible option. Ergon Energy has availability of 66kV GIS equipment available which can be installed within the existing substation.

3.2.1. Option A: 66kV Asset replacement with GIS

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid to late 2027 and would address the identified need by replacing end of life assets at ATHE. New assets would ensure Ergon Energy continues to adhere to the applicable regulatory requirements.

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

- Install new station services transformer
- Install new 66kV switchgear foundation
- Replace existing 66kV AIS with 66kV GIS
- Remove and replace 66kV CTs and VTs
- Install duplicate 110V DC system
- Replace Protection Relays

Due to the scope of works being entirely contained within the existing substation site at Atherton, 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.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 10.

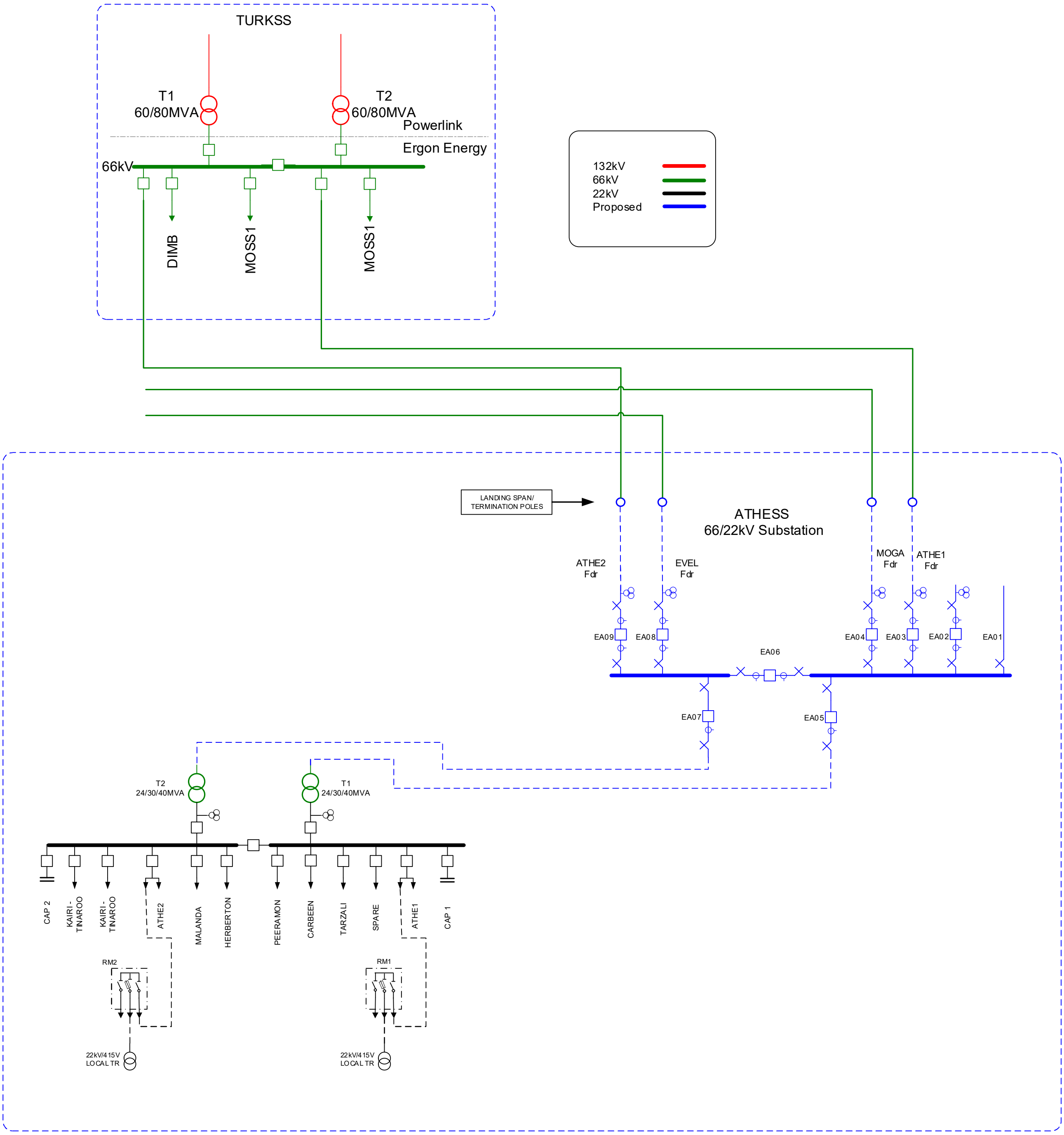


Figure 10: Option A proposed network arrangement (schematic view)

3.3. Preferred Option

Ergon Energy's preferred option is Option A, to replace the 66kV AIS with 66kV GIS, replace 66kV CTs and VTs, replace local service transformer and replace end of life protection relays by 2027.

Upon completion of these works the identified need would be addressed by replacing deteriorated assets at ATHE 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, is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

The estimated capital cost of this option is $21.3 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 early 2026 and construction completed by mid to late 2027.

4. ASSSESSMENT OF SAPS AND NON-NETWORK SOLUTIONS

Ergon Energy has considered SAPS and demand management solutions. Each of these are considered below.

4.1. 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 Atherton 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.

4.2. Demand Management (Demand Reduction)

Ergon Energy’s Demand & Energy Management (DEM) team has assessed the potential non-network alternative (NNA) options required to address the identified need.

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 Atherton 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.

4.2.1. Network Load Control

While network load control can be effective in deferring augmentation projects it does not provide sufficient reduction in load to meet the identified need. Without the replacement of the aged 66kV incoming feeder circuit breaker under a loss of the remaining 66kV feeder CB all substation load (66kV and 22kV) would be unsupplied. The load reduction required to meet safety net would be approximately 30MW.

4.3. 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.

4.3.1. 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.

4.3.2. 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.

4.3.3. 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.

4.3.4. Customer Solar Power Systems

A total of 3, 444 residential customers have solar photo voltaic (PV) systems for a connected inverter capacity of 18,838kVA and 281 business customers with a total inverter capacity of 6, 834kVA.

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.

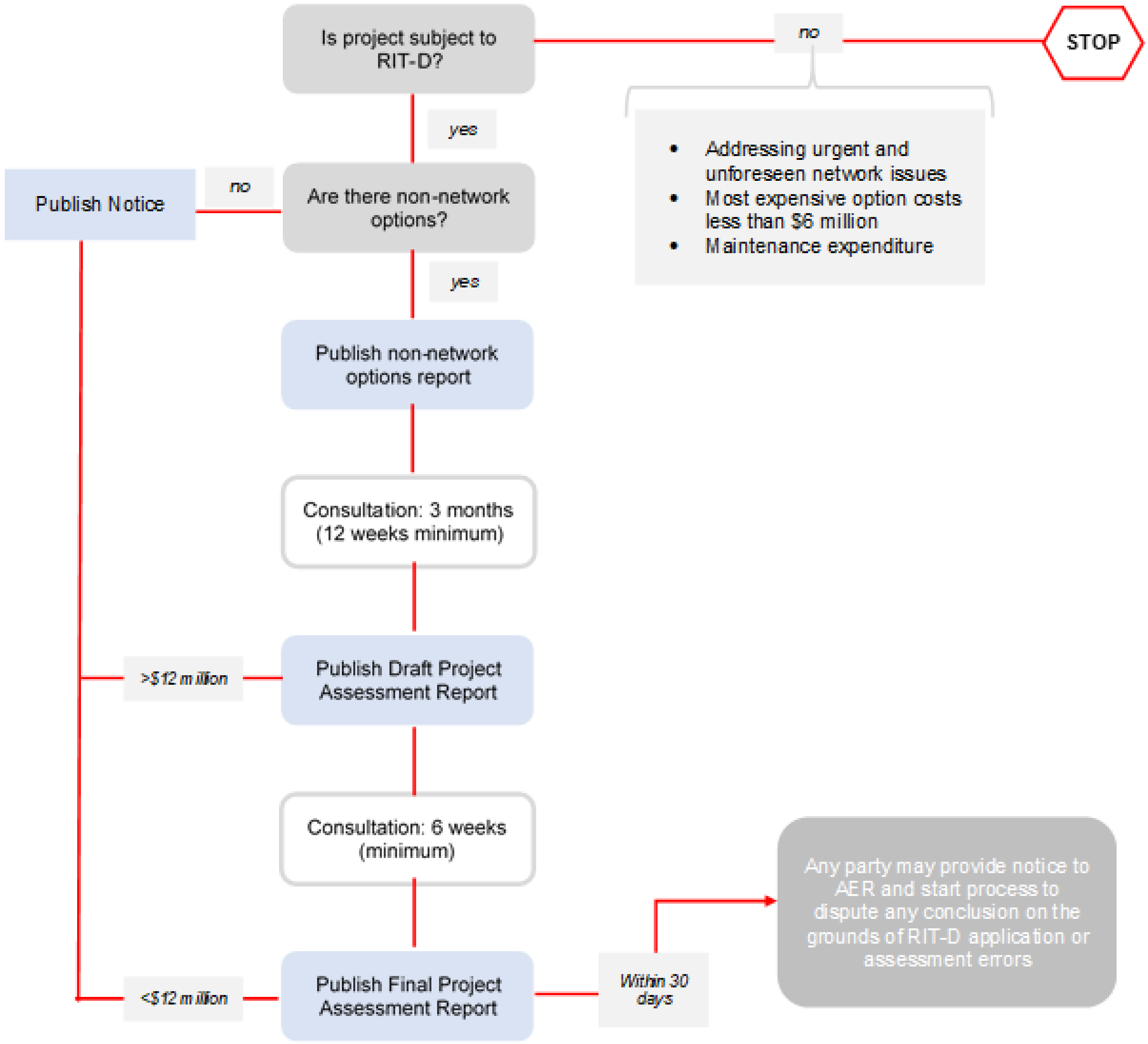
5. CONCLUSION AND NEXT STEPS

Ergon Energy has determined that there would not be a non-network option or SAPS option that is a potential credible option, or that forms a significant part or a potential credible option, to address the identified need.

The preferred credible option is Option A – 66kV Asset Replacement.

This Notice of Screening for Options is published in accordance with rule 5.17.4(d) of the National Electricity Rules. As the next step in the RIT-D process, Ergon Energy will publish a Final Project Assessment Report.

APPENDIX A – THE RIT-D PROCESS



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