Regulatory Investment Test for Distribution (RIT-D)

Mona Park Network Limitation

Notice of No Non-Network Options

30 August 2021

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

Mona Park 66/11kV Substation (MOPA) is located on the northern bank of the Burdekin River about 25km south-west of Ayr. The substation is part of the Burdekin 66kV sub-transmission network and takes supply from T193 Clare South 132/66kV Bulk Supply Substation.

Mona Park Substation consists of two 4MVA 66/11kV transformers and an indoor 11kV switchboard with four outgoing feeders supplying approximately 430 premises, of which 97 are residential and 333 are commercial, agricultural and industrial. Mona Park Substation is presently supplied via two incoming 66kV feeders, one from T193 Clare South 132/66kV Bulk Supply Substation and one from Ayr Substation.

A substation condition assessment of Mona Park Substation was completed in 2019 and has identified some primary and secondary plant and equipment that are recommended for retirement based on Condition Based Risk Management (CBRM) analysis.

The assessment identified that the two 66/11kV power transformers, five 66kV isolators, six of the segmented bus insulators and most of the protection relays are at the end of their serviceable life. Additionally, the transformers have no bunding and require firewall separation to the adjacent control building.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard, and reliability risk to the customers supplied from Mona Park Substation.

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 Mona Park 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 not a 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 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.

CONTENTS

1. BACKGROUND

1.1. Geographic Region

Mona Park substation supplies a rural area in the Burdekin region that consists predominantly of irrigated sugar cane farms. Mona Park Substation provides electricity supply to approximately 430 premises, of which 97 are residential and 333 are commercial, agricultural and industrial.

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

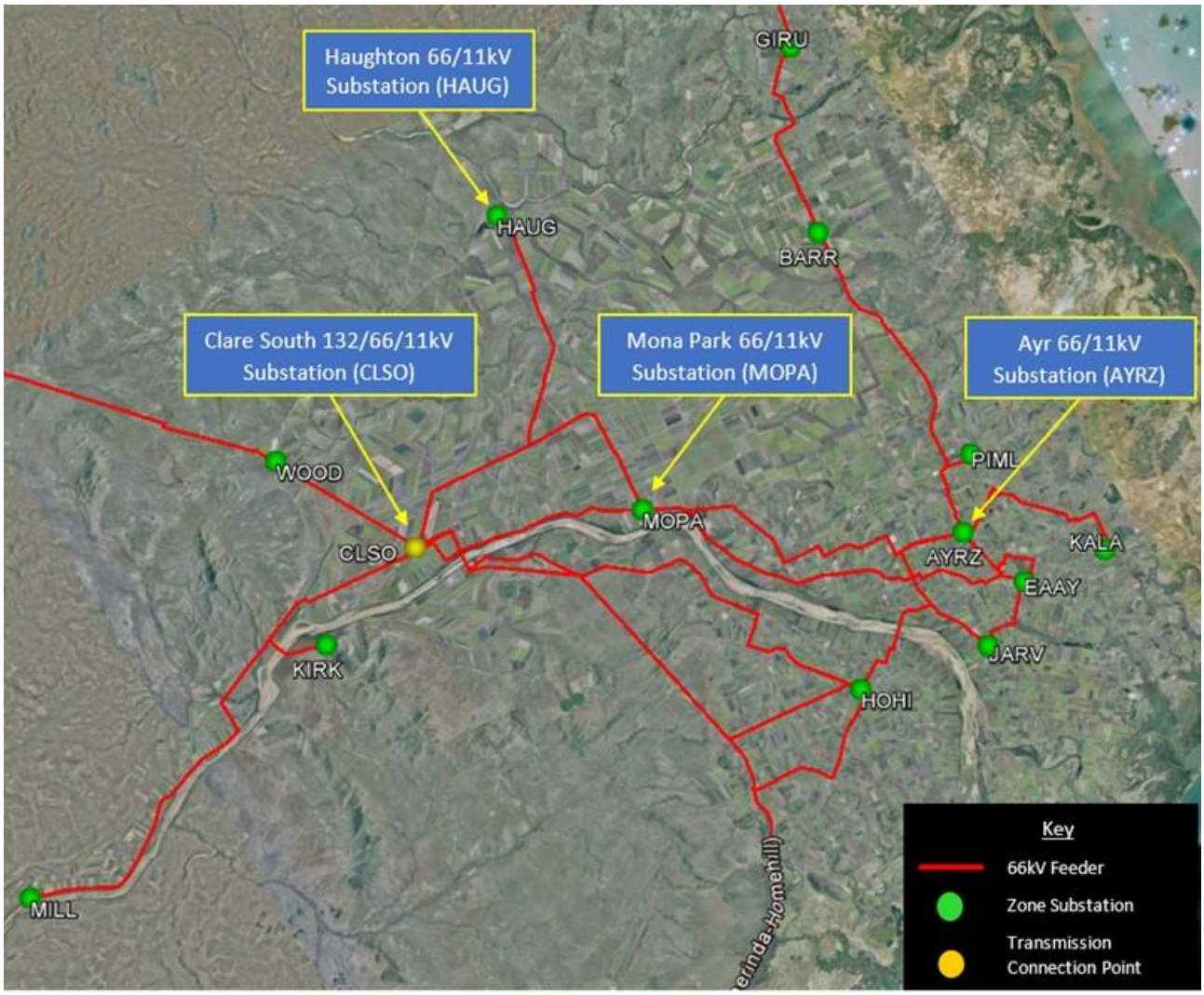


Figure 1: Existing network arrangement (geographic view)

1.2. Existing Supply System

Mona Park 66/11kV Substation (MOPA) is located on the northern bank of the Burdekin River about 25km south-west of Ayr. The substation is part of the Burdekin 66kV sub-transmission network and takes supply from T193 Clare South 132/66kV Bulk Supply Substation.

Mona Park Substation was established in the late 1960s according to applicable design and construction standards during that time. It has an outdoor 66kV switchyard, two fuse protected 4MVA 66/11kV power transformers and a control building with an indoor 11kV switchboard.

The 11kV indoor switchboard comprises seven 11kV retrofitted circuit breakers and two bus sections separated by a bus section circuit breaker which is operated normally open for safety and protection purposes (i.e. due to 66kV transformer fusing). Each bus section has two outgoing 11kV rural feeders.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 2 and the geographic view of Mona Park Substation is illustrated in Figure 3.

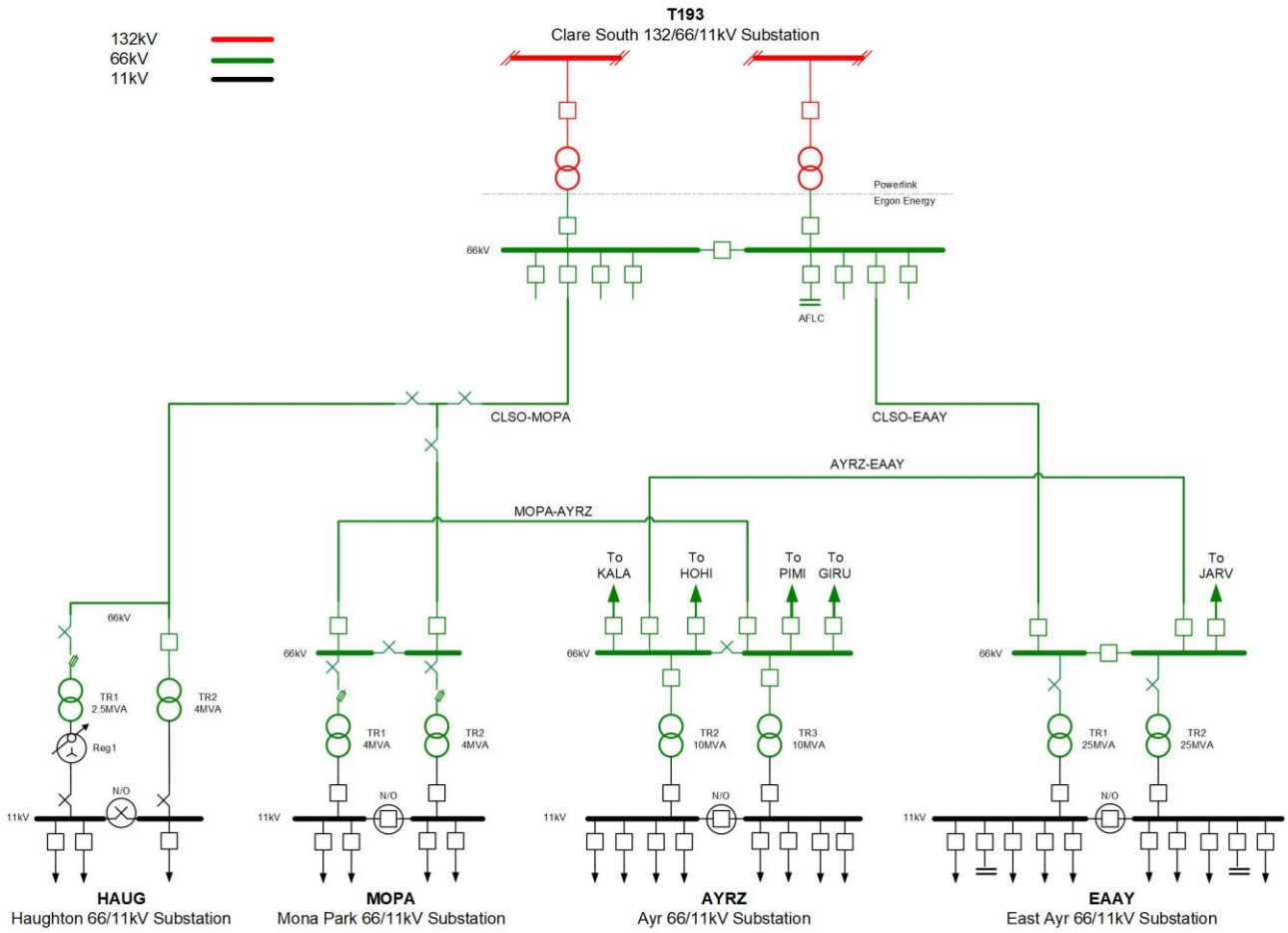


Figure 2: Existing network arrangement (schematic view)

Figure 3: Mona Park Substation (geographic view)

1.3. Load Profiles / Forecasts

The load at Mona Park Substation comprises a mix of residential and commercial/agricultural/industrial customers. The load is summer peaking, and the annual peak loads are predominantly driven by pumping and irrigation for the local sugarcane crops.

1.3.1. Full Annual Load Profile

The full annual load profile for Mona Park Substation over the 2020/21 financial year is shown in Figure 4. It can be noted that the peak load occurs during summer.

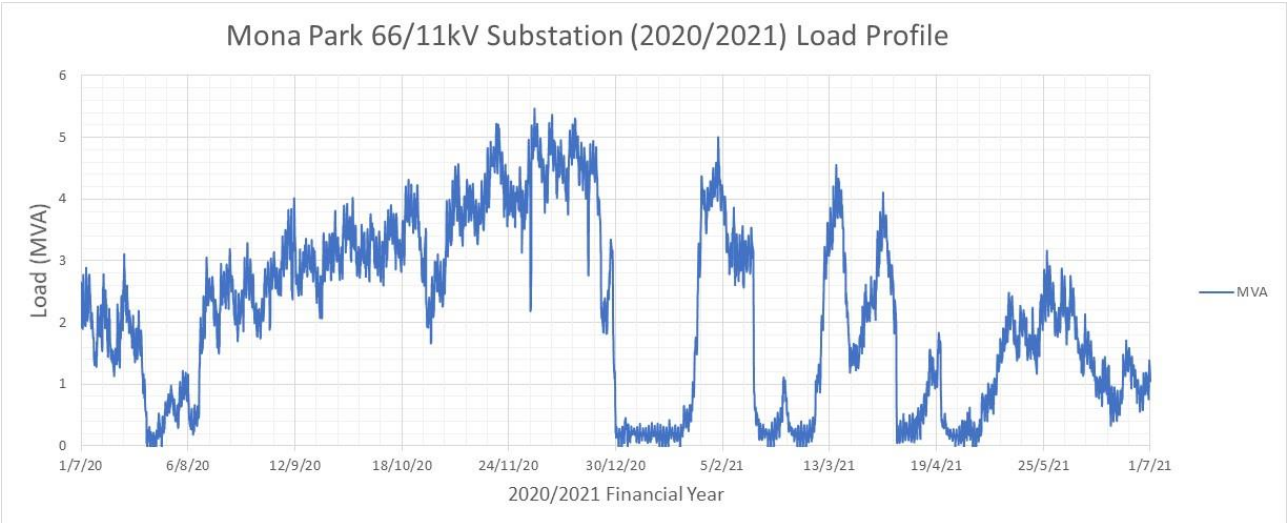


Figure 4: Substation actual annual load profile

1.3.2. Load Duration Curve

The load duration curve for Mona Park Substation over the 2020/21 financial year is shown in Figure 5.

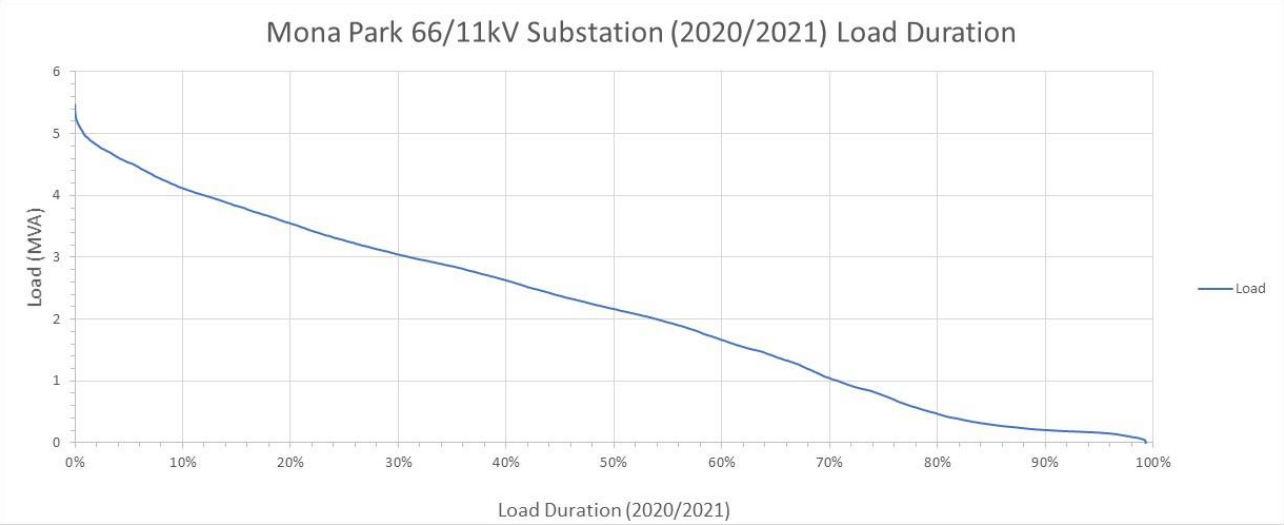


Figure 5: Substation load duration curve

1.3.3. Average Peak Weekday Load Profile (Summer)

The daily load profile for an average peak weekday during summer is illustrated below in Figure 6. It can be noted that the summer peak loads at Mona Park Substation are historically experienced in the late afternoon and evening.

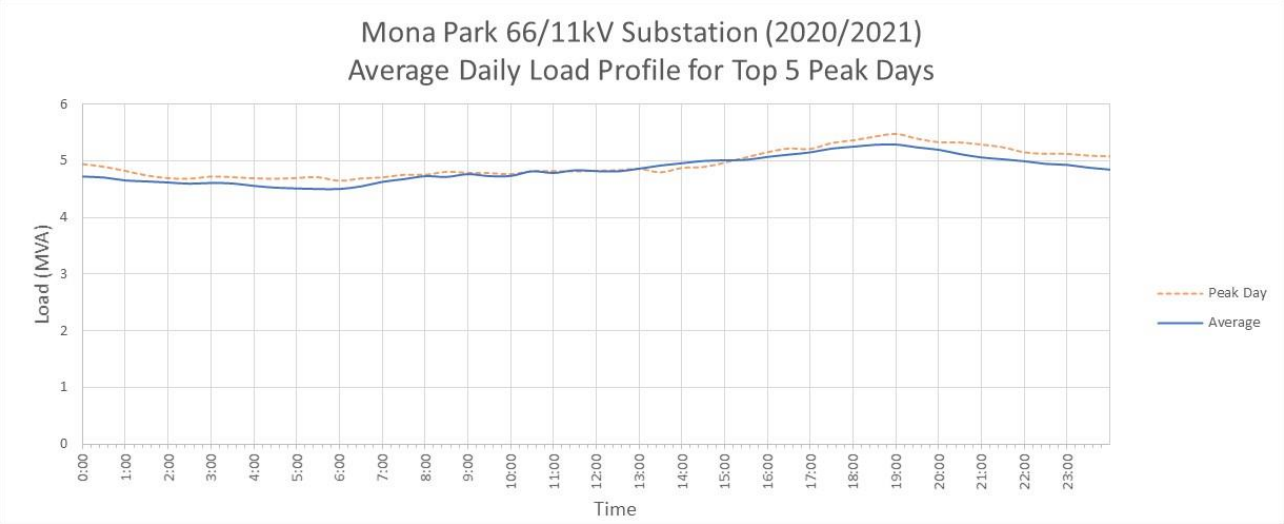


Figure 6: Substation average peak weekday load profile (summer)

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 six years has also been included in the graph.

It can be noted that the historical annual peak loads have fluctuated over the past five years, primarily due to seasonal variation in pumping and irrigation load due to the quantity and timing of rainfall in the area. It can also be noted that the peak load is forecast to increase slightly over the next 10 years under the base case scenario.

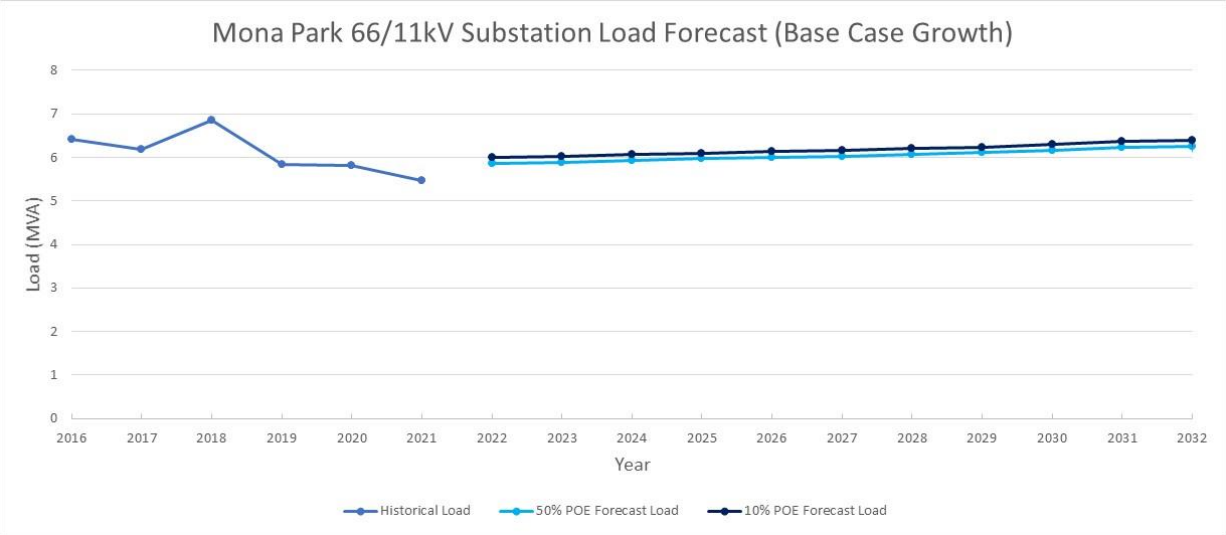


Figure 7: Substation base case load forecast

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 over the next 10 years.

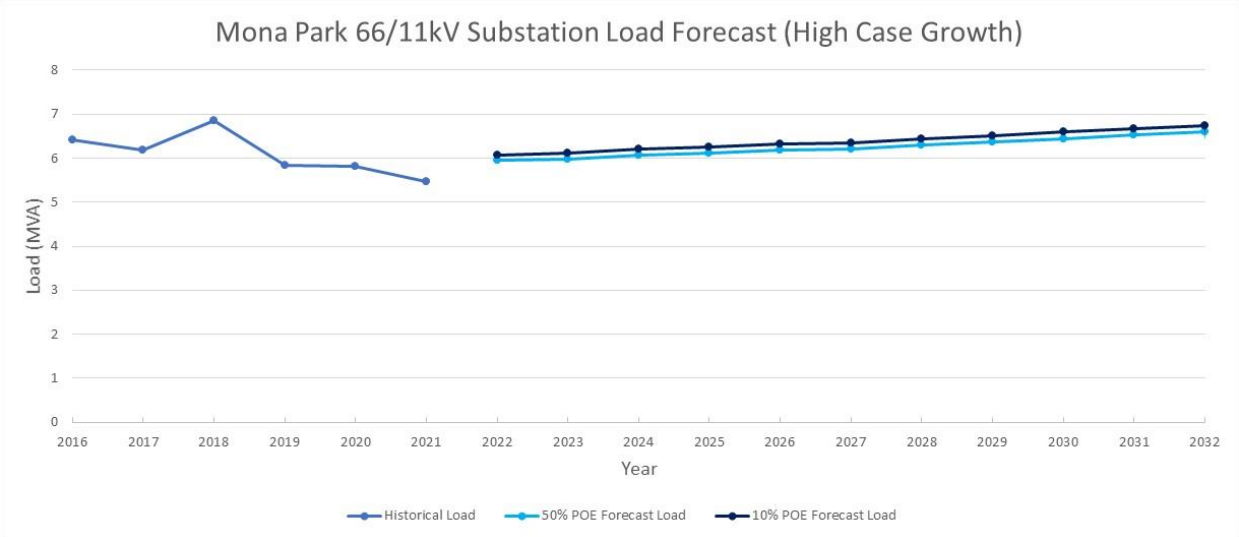


Figure 8: Substation high growth load forecast

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 remain relatively steady over the next 10 years.

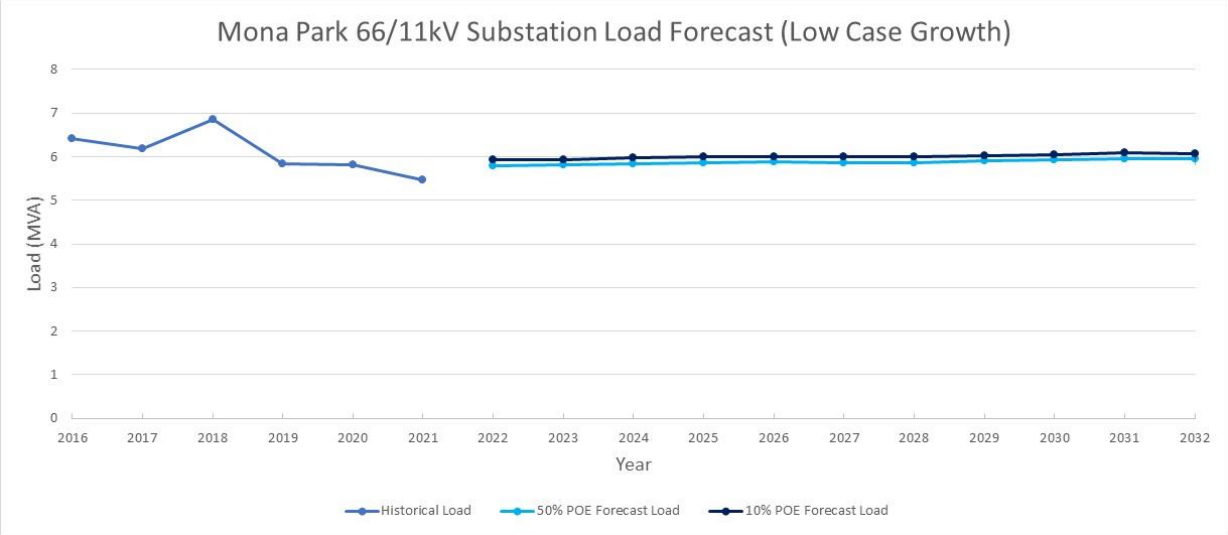


Figure 9: Substation low growth load forecast

2. IDENTIFIED NEED

2.1. Description of the Identified Need

2.1.1. Aged and Poor Condition Assets

A recent condition assessment at Mona Park Substation has highlighted that a number of critical assets are at end of life and are in poor condition. The condition of these assets presents a considerable safety, environmental and reliability risk.

Condition data indicates that the two 66/11kV power transformers, five 66kV isolators, six of the segmented bus insulators and most of the protection relays at Mona Park Substation are reaching end of life. Additionally, the transformers have no bunding and require firewall separation to the adjacent control building.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard. It also poses a safety risk the general public through the increased likelihood of protection relay mal-operation and catastrophic failure of the power transformers. There is also a considerable risk of environmental harm due to loss of oil from the power transformers, which would require clean up and rectification. Ergon considers that without rectification, this Safety risk would not be reduced 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 Mona Park Substation.

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

3. INTERNAL OPTIONS CONSIDERED

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 provide the magnitude of network support required in the Mona Park area to address the identified need.

3.2. Network Options Identified

Ergon Energy has identified two credible network options that will address the identified need.

3.2.1. Option A: Replace existing 4MVA transformers with a single 10MVA transformer with a mobile substation connection point

This option involves recovering the two existing transformers and installing a new 10MVA 66/11kV transformer with compliant bunding and new 11kV transformer cables, replacing the problematic 66kV isolators, replacing the segmented bus insulators and addressing secondary systems limitations in order to address the identified need.

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

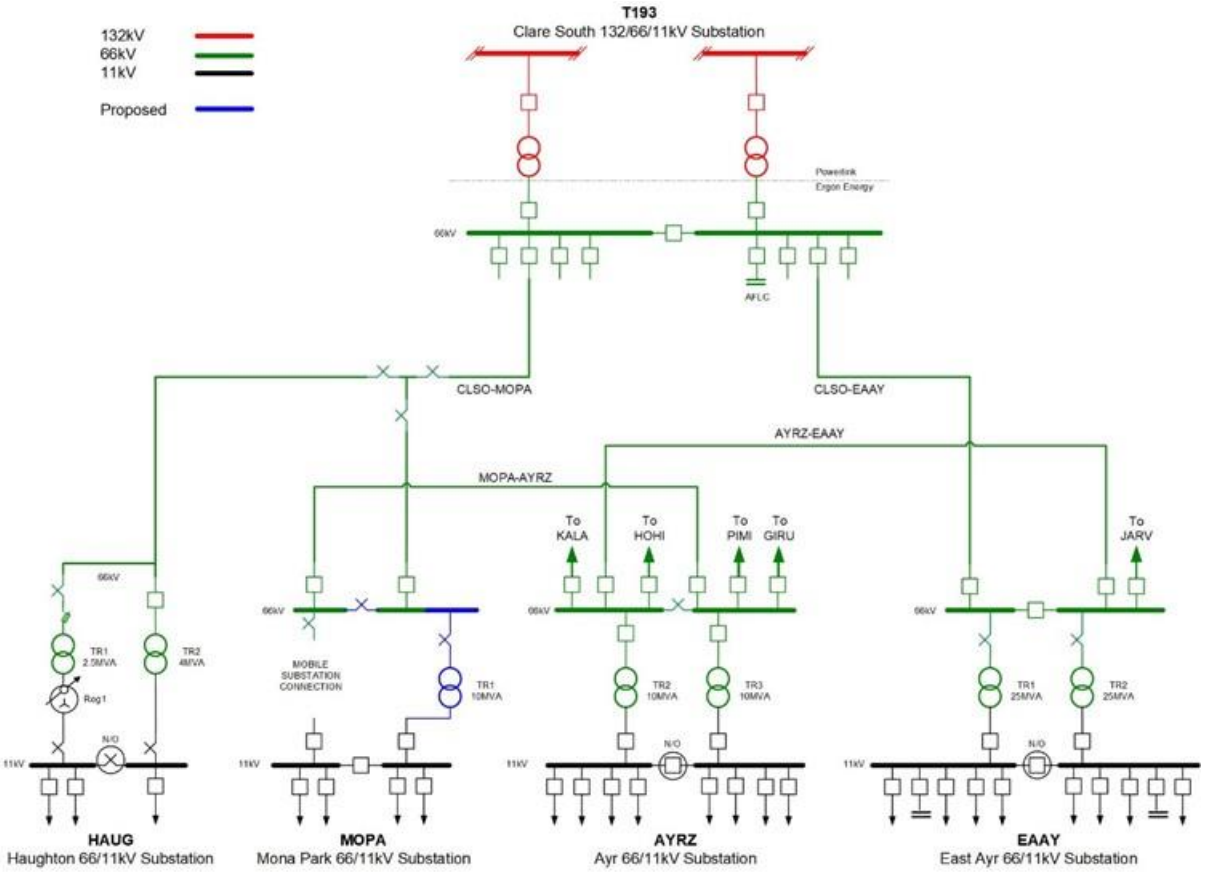


Figure 10: Option A proposed network arrangement (schematic view)

3.2.2. Option B: Replace existing 4MVA transformers with two 6.3MVA transformers

This option involves recovering the two existing transformers and installing two new 6.3MVA 66/11kV transformers with compliant bunding and new 11kV transformer cables, replacing the problematic 66kV isolators, replacing the segmented bus insulators and addressing secondary systems limitations in order to address the identified need.

A schematic diagram with the proposed network arrangement for Option B is shown in Figure 11.

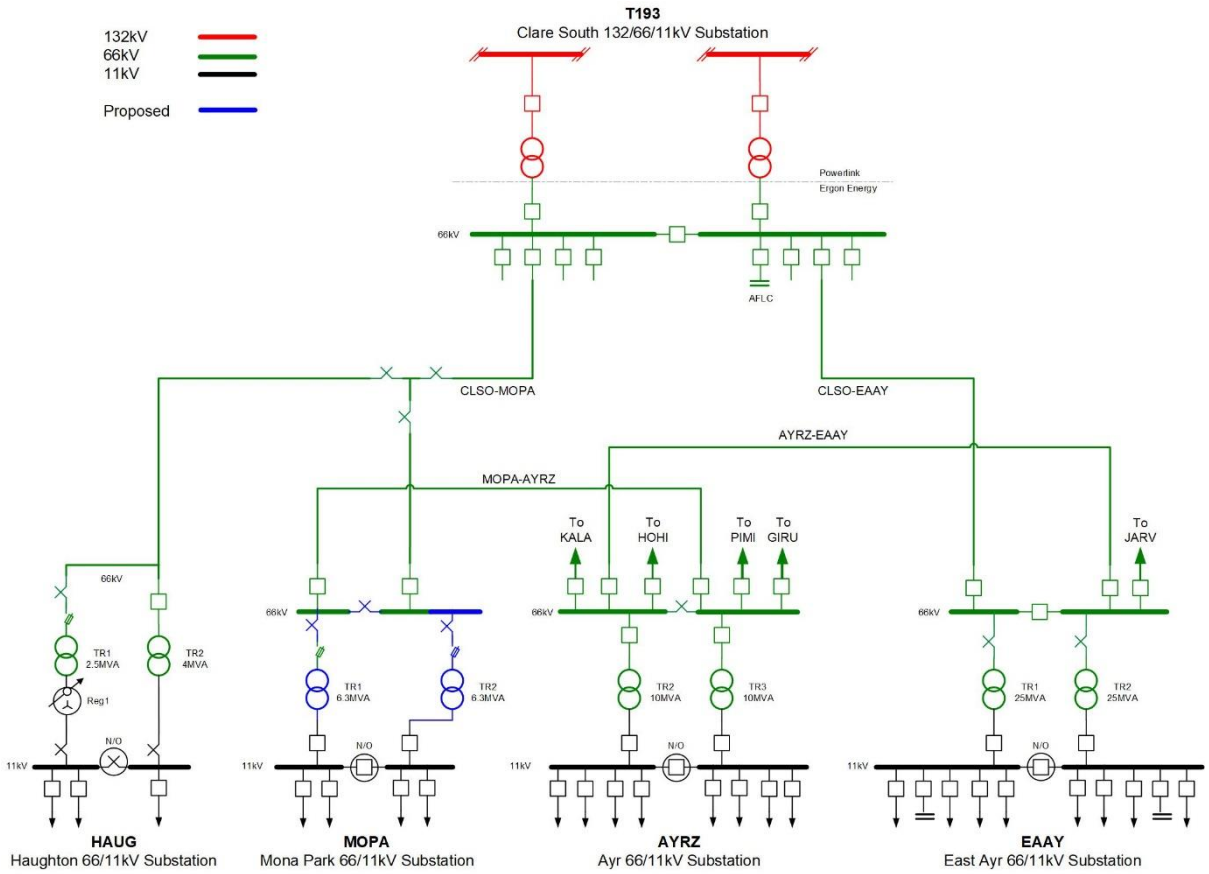


Figure 11: Option B proposed network arrangement (schematic view)

3.3. Preferred Network Option

Ergon Energy's preferred internal network option is Option A, to recover the existing transformers, install a new 10MVA 66/11kV transformer with compliant bunding and new 11kV transformer cables, replace the problematic 66kV isolators, replace the segmented bus insulators and replace protection relays at Mona Park Substation.

Upon completion of these works, the asset safety and reliability risks at Mona Park Substation will be addressed. 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.

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $5.55 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 late-2021 and construction completed by January 2025.

4. ASSSESSMENT OF NON-NETWORK SOLUTIONS

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 options 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.

4.1. Demand Management (Demand Reduction)

The DEM team has completed a review of the Mona Park customer base and considered a number of demand management technologies. Asset safety and performance risks are the key project drivers (i.e. the need) at Mona Park. It has been determined that most demand management options would not be viable propositions and have been explored in the following sections.

4.1.1. Network Load Control

The residential customers and irrigation load appear to drive the daily peak demand which generally occurs between 6:00pm and 8:00pm.

There are 84 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 50kVA[1] is available.

Mona Park Substation LC signals are controlled from T193 Clare South 132/66kV Bulk Supply Substation. 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 T193 Clare South 132/66kV Bulk Supply Substation exceeds 81MW. This strategy does not directly address demand peaks experienced at Mona Park. 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.

4.2. 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.

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

4.2.1. 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.

4.2.2. 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 would not address the identified network requirement to provide a continual reliable supply to this part of the network on an ongoing basis.

4.2.3. 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 that could connect at 11kV in the Mona Park catchment area and provide a continual reliable supply to this part of the network on an ongoing basis.

4.2.4. Customer Solar Power Systems

A total of 59 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 819kVA.

The daily peak demand is driven by agricultural customer demand and the peak generally occurs between 6:00pm and 8:00pm. 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 fewer customers and therefore are cheaper and easier to engage and contract.

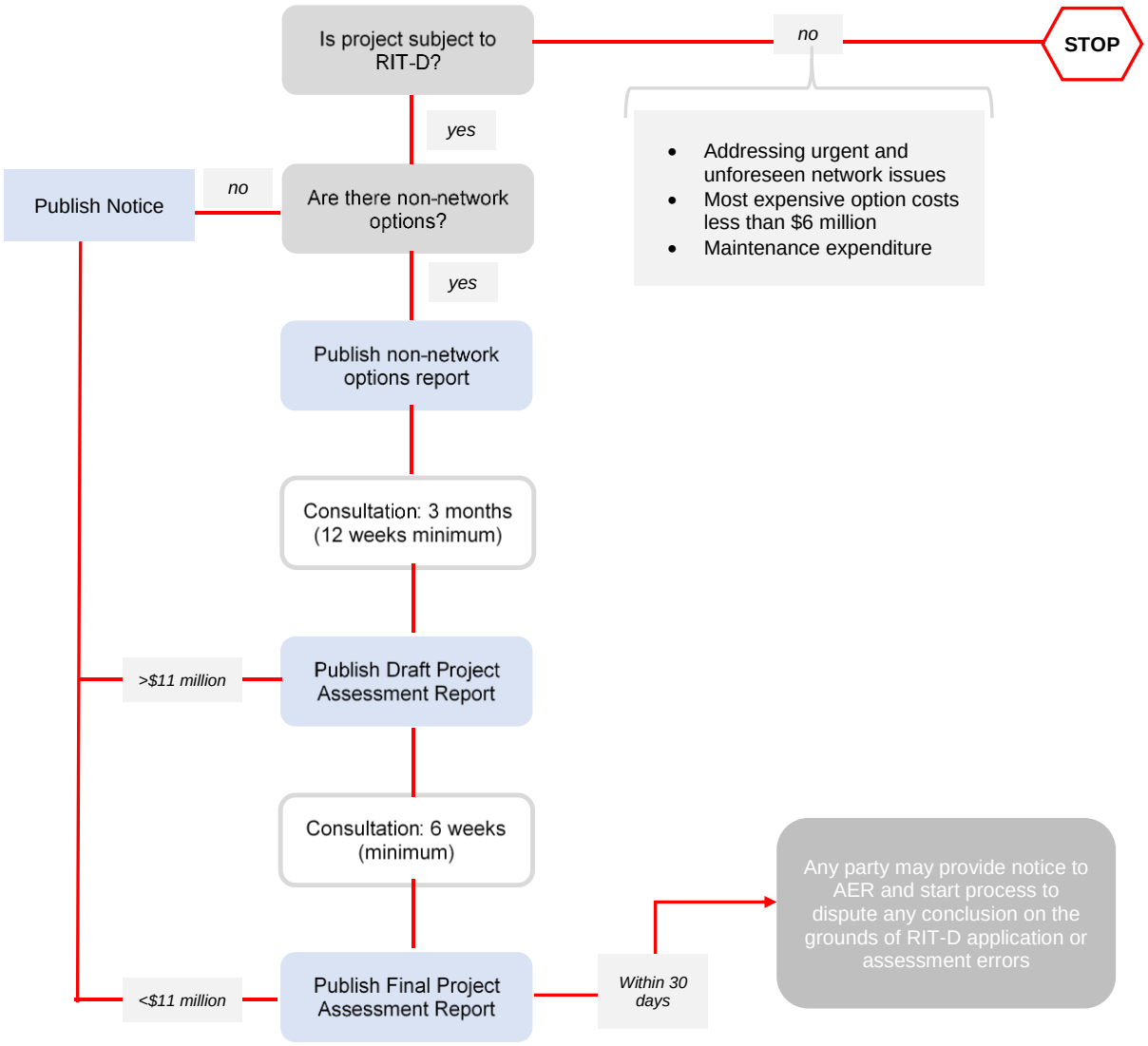
However, only a small percentage of customers in this supply area have solar PV systems and possibly none have a BESS. PV systems with BESS present a future portfolio opportunity for potential demand response but currently this supply area has a very limited solar/BESS. Solar customers without a BESS would 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

The internal investigations undertaken on the feasibility of the non-network solutions revealed that it is unlikely to find a complete non-network solution or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Mona Park area to address the identified need.

The preferred network option is Option A - to replace the assets in poor condition. This Notice of No Non-Network Options is therefore 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 now proceed to 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.