Notice of Determination Report Hastings Zone Substation 22 kV Switchgear Condition

Project No. UE-RSA-U-26-001

Document Control

Version	Amendment Overview
1	Initial Version

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1. Executive Summary

1.1 Summary

United Energy (**UE**) is a regulated Victorian electricity distribution business. UE distributes electricity to more than 720,000 customers across Melbourne's east and south-east metropolitan area, and the Mornington Peninsula. The UE network consists of more than 202,000 poles and over 13,500 kilometres of overhead lines and underground cables. Electricity is received via 92 sub-transmission lines at 47 zone substations, where it is transformed from sub-transmission voltages down to distribution voltages.

The area of the UE network that is the subject of this *Regulatory Investment Test for Distribution* (**RIT-D**) is the Hastings Zone Substation (**HGS**) supply area that spans the areas of Hastings, Merricks, Somerville and Tyabb. HGS is owned and operated by UE, providing power to approximately 17,208 customers, comprising mainly residential customers, with commercial/light industrial customers located near Western Port Bay.

The condition of the 22 kV switchgear[1] at HGS, necessary for the provision of a safe and reliable power supply to customers within the HGS supply area, is deteriorating and technically obsolete, unsupported by the original equipment manufacturers, and with no spares available.

UE has identified potential credible network options to address the asset condition risks at HGS and investigated whether viable non-network or stand-alone power system (**SAPS**) solutions exist as alternatives to, or supplements for the network options.

Based on this report, UE has concluded (on reasonable grounds), that none of the potential non-network or SAPS options investigated represent technically or commercially feasible alternatives, nor could any combination of non-network or SAPS options adequately address the identified need. Therefore, UE has determined that the publication of, and the consultation on an options screening report, is not required in this instance.

1.2 Purpose

This *Notice of Determination* has been prepared by UE in accordance with the requirements of clause 5.17.4, paragraphs (c) and (d) of the *National Electricity Rules* (NER)[2] version 248. UE is normally required to publish an options screening report and request stakeholder submissions, as detailed in NER clause 5.17.4(e). However, where there are no potential credible non-network or SAPS options (or any combination of those options with or without a network option) that could address the identified need, UE is instead required to publish a *Notice of Determination*.

1.3 The Identified Need

The AEI LG1C 22 kV outdoor bulk-oil circuit breakers at HGS are at end of life. HGS is the only zone substation on the UE network with this type of circuit breaker, with the equipment experiencing an increasing number of outstanding defects.

There are nine circuit breakers of this type installed at HGS, with defects detected in their bushings, mechanisms, current transformers, contacts (high resistance), terminations (thermal hotspot), insulation (partial discharge) and tanks/gauges (leaking oil).

These defects cannot be effectively repaired given the lack of spares and equipment obsolescence, putting at risk the ongoing safe and reliable operation of this zone substation. As an interim measure, UE has imposed operational constraints on HGS to minimise the safety risk for personnel working on site, by activating instantaneous protection settings and disabling auto-reclose functionality for risk mitigation.

The identified need at HGS is to:

i) protect power sector workers and members of the public from harm caused by equipment failure (safety)

ii) continue to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network (reliability).

Solutions to the identified need shall manage and mitigate the increasing risk of 22 kV switchgear defects, to maintain the safety and reliability of electricity supply to UE's customers and workforce within the HGS supply area.

[1] Includes all 22 kV switchyard equipment including circuit breakers, current and voltage transformers, buses, isolators, insulators and control cables.
[2] National Electricity Rules (NER), Australian Energy Market Commission (AEMC), 2026.

1.4 Next Steps

The total cost of the most expensive credible network option to address the identified need, is less than the trigger threshold of $14 million[3] for the publication of and consultation on a *Draft Project Assessment Report* (**DPAR**). On this basis, UE has prepared and published a *Final Project Assessment Report* (**FPAR**), as the next step required under NER clause 5.17.4, paragraphs (o) to (s).

For the purposes of referencing this RIT-D, this RIT-D is referred to as the "*Hastings Zone Substation 22 kV Switchgear Condition*" identified need.

[3] 2024 cost thresholds review for the Regulatory Investment Test, Australian Energy Regulator (AER), 2024.

2. Definitions

Table 1: Terms and definitions

Term	Definition
AEI	American Electrical Inc.
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFAP	As Far As Practicable
CPI	Consumer Price Index
DAPR	Distribution Annual Planning Report
DPAR	Draft Project Assessment Report
EUE	Expected Unserved Energy (MWh pa)
FPAR	Final Project Assessment Report
FSH	Frankston South Zone Substation
HGS	Hastings Zone Substation
IASR	Inputs, Assumptions and Scenarios Report
LWN	Langwarrin Zone Substation
LTI	Lost Time Injury
MWp	Megawatt peak
MTN	Mornington Zone Substation
NCC	Network Control Centre
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
O&M	Operating and Maintenance
PoE	Probability of Exceedance
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
SAPS	Stand-alone Power System
SCADA	Supervisory Control and Data Acquisition
TBTS	Tyabb Terminal Station
UE	United Energy
VCR	Value of Customer Reliability ($/MWh)
VSL	Value of Statistical Life

Term	Definition
50% PoE	The forecast maximum demand has a 50% probability of exceedance (PoE). That is, the forecast maximum demand is expected, on average, to be exceeded once in two years.
10% PoE	The forecast maximum demand has a 10% probability of exceedance (PoE). That is, the forecast maximum demand is expected, on average, to be exceeded once in ten years.
Credible option	An option that addresses the 'identified need', is commercially and technically feasible, and can be implemented in sufficient time to meet the 'identified need'.
Identified need	Any capacity, voltage, or safety limitation on the distribution system.
Limitation	Any limitations on the operation of the distribution system that will give rise to Expected Unserved Energy or safety risk consequences.
Network option	A means by which an 'identified need' can be fully or partly addressed by expenditure on distribution network assets.
Non-network or SAPS option	A means by which an 'identified need' can be fully or partially addressed other than by a network option.
Non-network service provider	A party who provides a non-network or SAPS option.
Potential credible option	An option has the potential to be a credible option based on an initial assessment of its ability to address the 'identified need'.
Preferred network option	A credible network option that maximises the present value of net economic benefit. The preferred network option can be a network option, or do nothing (i.e. status quo).
Preferred option	A credible option that maximises the present value of net economic benefit. The preferred option can be a network option, non-network or SAPS option, combination of both, or do nothing (status quo).

3. Referenced Documents

Table 2: Referenced UE documents

Title	Document No.
UE Embedded Generation Network Access Standards	UE-ST-2008.X
UE Asset Risk Quantification Guide	UE-GU-2011

4. Introduction

This *Notice of Determination* report has been prepared by UE in accordance with the requirements of clause 5.17.4, paragraphs (c) and (d) of the NER[4] version 248, for the HGS 22 kV switchgear condition identified need.

UE is not required to publish and consult on an options screening report in this instance, because it has been determined (on reasonable grounds) that there is unlikely to be a potential credible non-network or SAPS option that is able to address the identified need, nor any that forms a significant part of a potential credible option.

This report sets out the reasons for this determination, including the methods and assumptions used in making the determination.

The need for investment and the possible options for addressing the HGS 22 kV switchgear condition identified need, have been foreshadowed in UE's *2025 Distribution Annual Planning Report* (**DAPR**).[5]

This *Notice of Determination* report:

- provides background information on the network limitations at HGS and for the supply area it services
- identifies the need which UE is seeking to address, together with the assumptions used in identifying that need
- describes the credible options that UE currently considers may address the identified need, including for each:
  - technical definitions
  - the risk costs associated with the option for addressing the identified need
  - the estimated commissioning date
  - the total indicative cost (including capital and operating costs), with high-level cost breakdown.
- sets out the technical characteristics that a non-network or SAPS option would be required to deliver in order to address the identified need.

[4] National Electricity Rules (NER), Australian Energy Market Commission (AEMC), 2026.
[5] 2025 Distribution Annual Planning Report (DAPR), UE, 2025.

5. Identified Need

5.1 Network Overview

The area of the UE network that is the subject of this RIT-D is the HGS supply area that spans the areas of Hastings, Merricks, Somerville and Tyabb.

HGS is owned and operated by UE, providing power to approximately 17,208 customers, comprising mainly residential customers, with commercial/light industrial customers located near Western Port Bay.

HGS is bounded in the north by adjacent 22 kV zone substations Frankston South (**FSH**) and Langwarrin (**LWN**), and in the west by Mornington (**MTN**), providing load transfer capacity to reduce load on the zone substation in the event of an emergency (such as a major asset failure, for example). The load transfer capability away from HGS is 14.6 MVA.

HGS zone substation is served by 66 kV sub-transmission lines from the Tyabb Terminal Station (**TBTS**) and transforms electricity down to 22 kV via two 20/33 MVA transformers.

The cyclic rating of HGS with all transformers in service is 77.7 MVA (summer) 90.4 MVA (winter), and with one transformer out of service the rating reduces to 38.9 MVA (summer) 45.2 MVA (winter). This compares to a forecast 10 per cent PoE maximum demand of 66.7 MVA for summer 2029/30.

The electrical single line diagram for HGS, showing the 66 kV assets (in red), 66/22 kV transformers, and 22 kV assets (in blue, including distribution feeder exits) is illustrated in Figure 1.

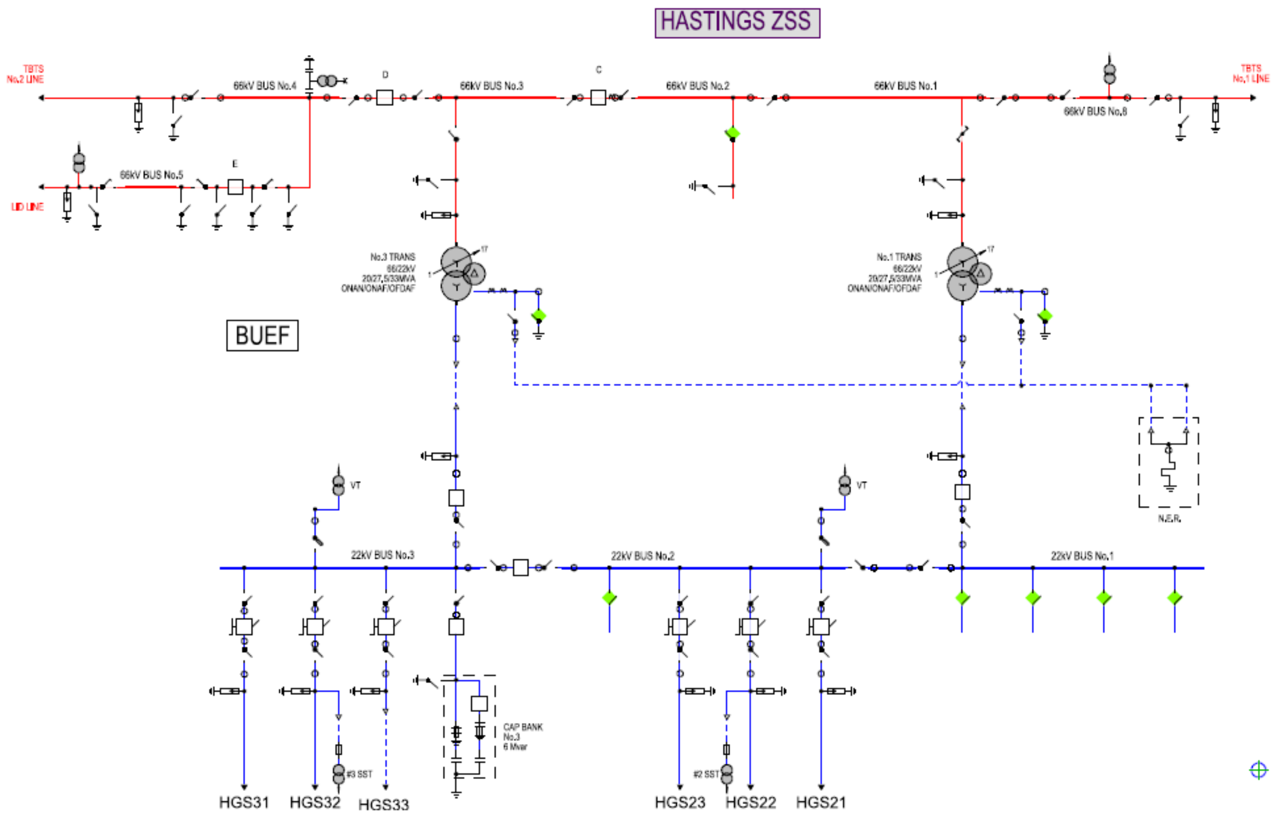

Figure 1: HGS electrical single line diagram

The aerial view of HGS showing the existing 22 kV switchyard is illustrated in Figure 2.

Figure 2: HGS aerial view

The power supply coverage of HGS relative to the supply area of adjacent zone substations FSH, LWN and MTN, and to TBTS, is illustrated in Figure 3.

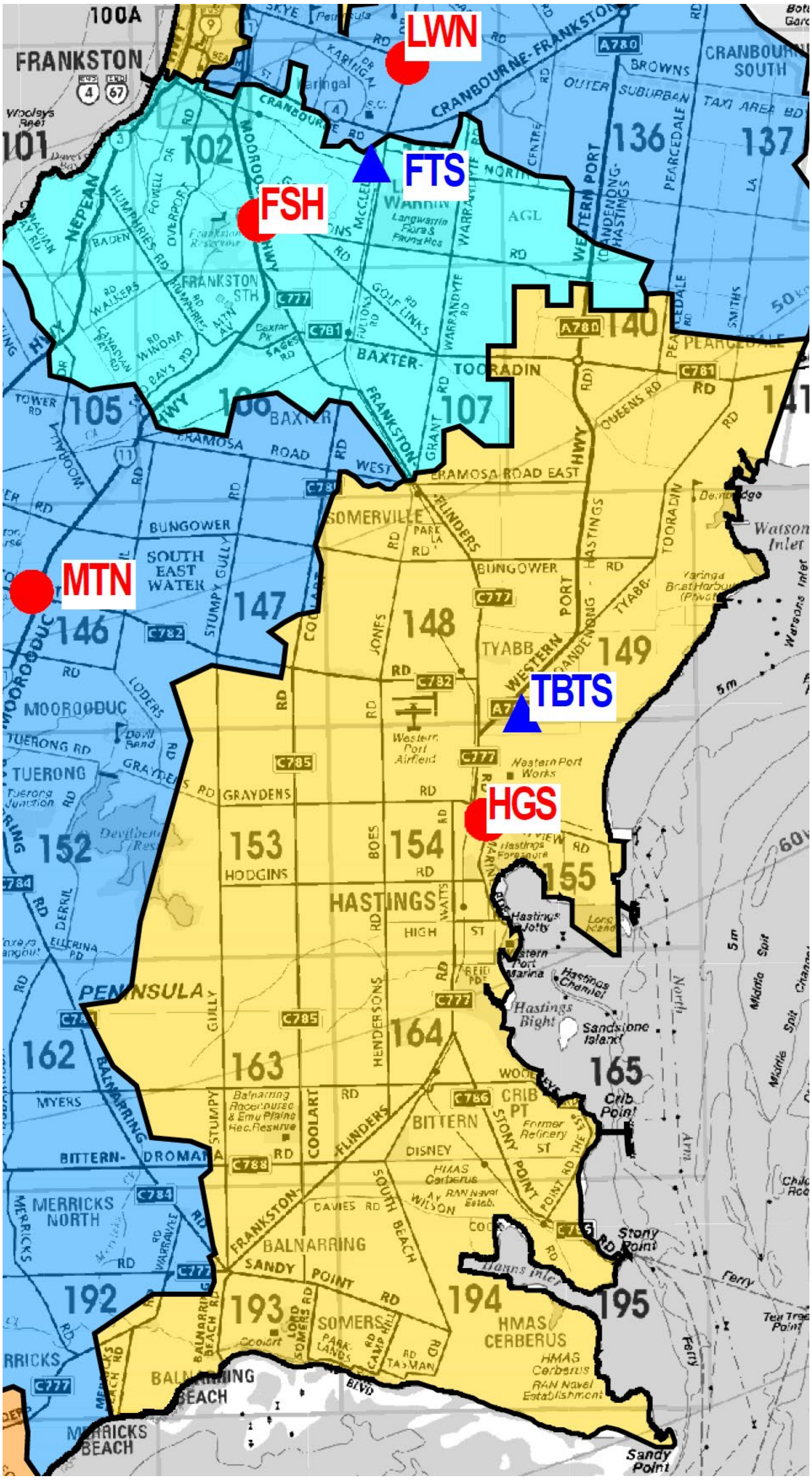

Figure 3: HGS supply area and surrounding areas

5.2 Description of the Identified Need

UE has prepared this report to assess whether the reliability and safety needs of HGS could be realised either fully, or in part through non-network or SAPS options. To assess whether a non-network or SAPS option could be beneficial, it is important firstly to define the identified need for this location.

The condition of the 22 kV switchgear[6] at HGS, necessary for the provision of a safe and reliable power supply to customers within the HGS supply area, is deteriorating and technically obsolete, unsupported by the original equipment manufacturers, and with no spares available.

The American Electrical Inc.(AEI) LG1C 22 kV outdoor bulk-oil circuit breakers at HGS are at end of life. HGS is the only zone substation on the UE network with this type of circuit breaker, with the equipment experiencing an increasing number of outstanding defects.

There are nine circuit breakers of this type installed at HGS, with defects detected in their bushings, mechanisms, current transformers, contacts (high resistance), terminations (thermal hotspot), insulation (partial discharge) and tanks/gauges (leaking oil).

These defects cannot be effectively repaired given the lack of spares and equipment obsolescence, putting at risk the ongoing safe and reliable operation of this zone substation. As an interim measure, UE has imposed operational constraints on HGS to minimise the safety risk for personnel working on site, by activating instantaneous protection settings and disabling auto-reclose functionality for risk mitigation.

The identified need at HGS is to:

i) protect power sector workers and members of the public from harm caused by equipment failure (safety)

ii) continue to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network (reliability).

Solutions to the identified need shall manage and mitigate the increasing risk of 22 kV switchgear defects, to maintain the safety and reliability of electricity supply to UE's customers and workforce within the HGS supply area.

Recent 22 kV switchgear defects experienced at HGS are listed in Table 3. Photographs of those assets are presented in Appendix A:.

Table 3: 22 kV switchgear defects

Year	22 kV circuit breaker(s)	Defective component	Identified issue
2025	HGS32, HGS22, HGS21 HGS31	Bushings Contacts	Low oil level High contact resistance
2024	HGS23	Bushings Mechanism Contacts	Low oil level, gauge cracked glass Interruption assembly broken High contact resistance
2023	HGS31, HGS32 HGS23, HGS21 HGS22	Bushings Terminations Contacts	Cracked bushings, gauge oil leak Thermal hot spot detection - poor connection Worn contacts
2022	HGS32 HGS23, HGS21	Terminations Contacts	Thermal hot spot detection - poor connection Worn contacts
2021	No.1 Transformer HGS23, HGS21, HGS31 No. 2-3 Bus Tie	Terminations Terminations Insulation	Thermal hot spot detection - poor connection Thermal hot spot detection - poor connection Failed megger reading - insulation breakdown
2020	HGS31 HGS32, HGS21 HGS21	Bushings Terminations Tank & mechanism	Partial discharge - insulation breakdown Thermal hot spot detection - poor connection Low oil level, interruption assembly broken

[6] Includes all 22 kV switchyard equipment including circuit breakers, current and voltage transformers, buses, isolators, insulators and control cables.

5.3 Quantification of the Identified Need

Table 4 summarises the forecast impact of the identified network need discussed in Section 5.2 on customers. The table shows over a 10-year forecasting period, the total risk costs comprising:

- reliability risk cost, being the value of expected unserved energy (**EUE**), which is the customer value of the energy at risk after accounting for the probability of asset failures or malfunctions at HGS, representing the deterioration in supply reliability within the HGS supply area
- safety risk cost, which is the cost of harm to UE's staff and/or the public, as a result of anticipated safety incidents caused by asset failures or malfunctions at HGS.

Table 4: HGS risk quantification ($'000, real 2026)

Year	Total risk cost
2026	1,171
2027	1,188
2028	1,195
2029	1,203
2030	1,193
2031	1,189
2032	1,196
2033	1,201
2034	1,197
2035 - 2047	1,197 pa

For the purposes of this RIT-D, economic evaluations are undertaken over a 20-year period with the risk costs held constant beyond the 10-year forecast period.

6. Key Assumptions in Relation to the Identified Need

6.1 Method for Quantifying the Identified Need

UE adopts its *Asset Risk Quantification Guide* (UE-GU-2011) in quantifying safety and reliability risks associated with asset condition failures and their consequences. This modelling is based on Weibull distribution parameters for each asset class and a probabilistic planning approach.

6.1.1 Safety

The safety risk to UE employees and the public, arising from potential failure or malfunction of network assets is quantified by UE using an annualised safety risk cost, based on the asset conditions. The safety risk cost provides a measure of the expected financial value of the safety risk event. The safety risk cost is defined as the probability weighted cost of consequences, with the likelihood of consequences being the moderating factor in quantifying the risk.

The *Electricity Safety Act*[7] requires UE to design, construct, operate, maintain, and decommission its network to minimise hazards and risks to the safety of any person as far as reasonably practicable, or until the costs become disproportionate to the benefits from managing those risks. As such, UE's approach to safety risk is based on the 'as far as practicable' (**AFAP**) principle.

In implementing this principle for assessing safety risks from asset condition failures, UE uses a value of statistical life (**VSL**) to estimate the benefits of reducing the risk of death, a value of lost time injury (**LTI**) to estimate the benefits of reducing the risk of injury, and a disproportionality factor. UE notes that this approach, including the use of a disproportionality factor, is consistent with practice notes provided by the AER[8], and is the approach taken by other network service providers.

The AFAP principle recommends safety risk reduction measures be implemented unless the cost, time or form of the risk reduction measure is grossly disproportionate to the benefit gained from the reduced risk. A "Do nothing" (or "run to failure") approach would result in the poor condition assets remaining in service, deteriorating further, and completely failing to address any safety concerns.

6.1.2 Reliability

UE's reliability planning standard for its zone substation assets is based on a probabilistic planning approach which quantifies EUE defined in terms of megawatt hours (MWh) per annum of energy not supplied, taking into account the unavailability of an asset due to a failure or malfunction and any shortfalls in capacity, and monetises this by applying a locational value of customer reliability (**VCR**) ($/MWh)[9].

6.2 Forecast Maximum Demand

A credible network, non-network or SAPS solution should consider the forecast maximum demand for the HGS supply area shown in Table 5. Forecasts of the 10 per cent PoE and 50 per cent PoE summer maximum demand and power factor at HGS are presented. These forecasts are based on an expected economic growth scenario.

Table 5: HGS maximum demand forecast

Year	Power Factor	10% PoE (MVA)	50% PoE (MVA)
2026	1.00	66.0	51.1
2027	1.00	66.7	51.4
2028	1.00	66.9	51.6
2029	1.00	67.1	51.7
2030	1.00	66.7	51.6

[7] Electricity Safety Act, Victorian State Government, Victorian Legislation and Parliamentary Documents, 1998..
[8] Industry Practice Application Note – Asset Replacement Planning, Australian Energy Regulator (AER), 2019.
[9] Values of Customer Reliability, Australian Energy Regulator (AER), 2025.

6.3 Forecast Annual Energy

A credible network, non-network or SAPS solution should consider the annual energy requirements of customers within the HGS supply area as shown in Table 6.

Table 6: HGS annual energy forecast

Time Period	Energy (GWh pa)
2026	167
2027	168
2028	168
2029	169
2030	168

6.4 Characteristic of Load Profile

A credible network, non-network or SAPS solution should be able to support the load profiles below.

UE has presented load profiles that are characterised by the most recent 50 per cent PoE year. The coincident maximum demand of the customers within the HGS supply area occurs during days of extreme ambient temperature, particularly for hot weather.

The annual demand profile at HGS expressed as a percentage of the 50 per cent PoE maximum demand listed in Table 5, is illustrated in Figure 4.

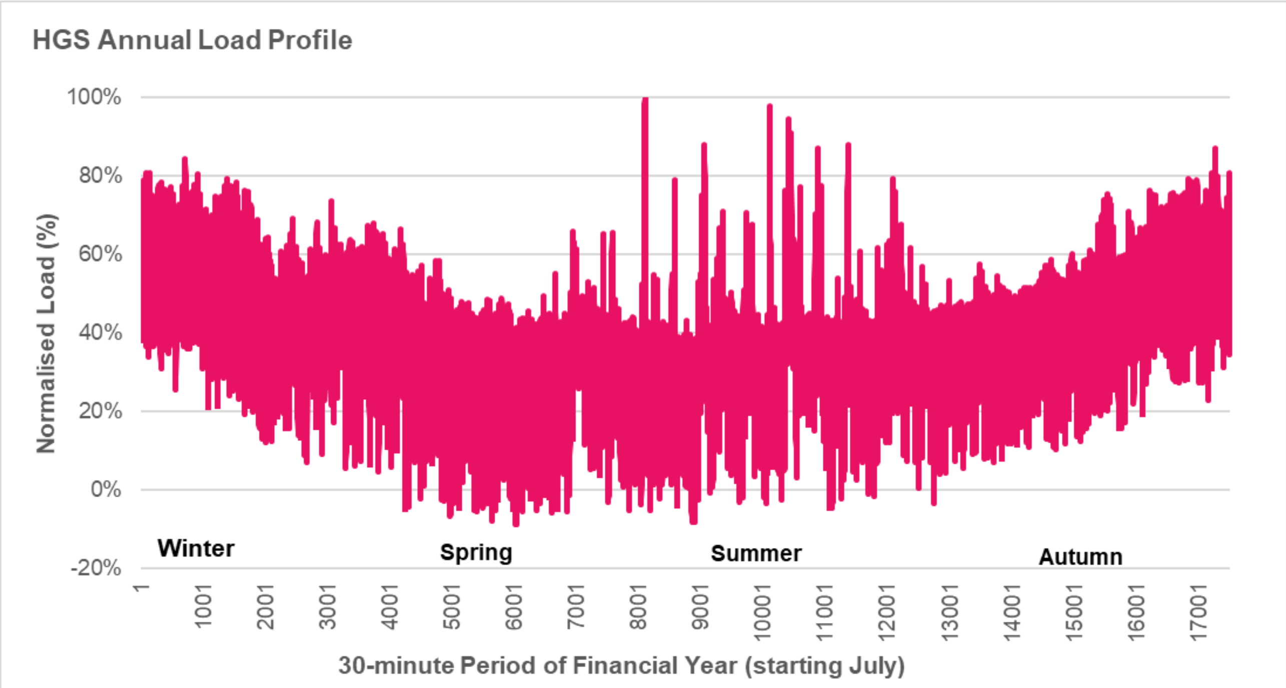

Figure 4: Annual load profile at HGS

The load profile on the day of a 50 per cent PoE summer maximum demand is illustrated in Figure 5. The prominence of air-conditioning load within the HGS supply area, results in a maximum demand occurring during the early evening as the solar PV output subsides. Embedded solar PV generation depresses the demand during daylight hours illustrated by the difference in gross (underlying) and net (observed) demand.

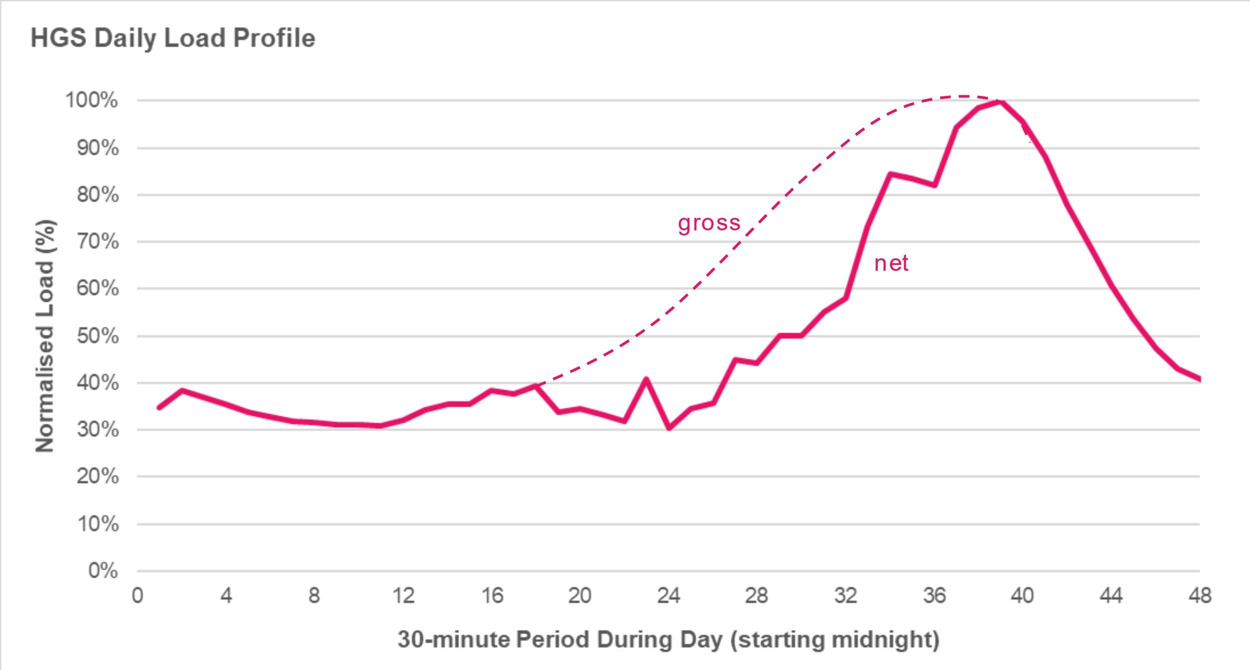

Figure 5: Load profile on day of summer maximum demand at HGS

Figure 6 shows the normalised annual load-duration curve at HGS for a 50 per cent PoE summer maximum demand year.

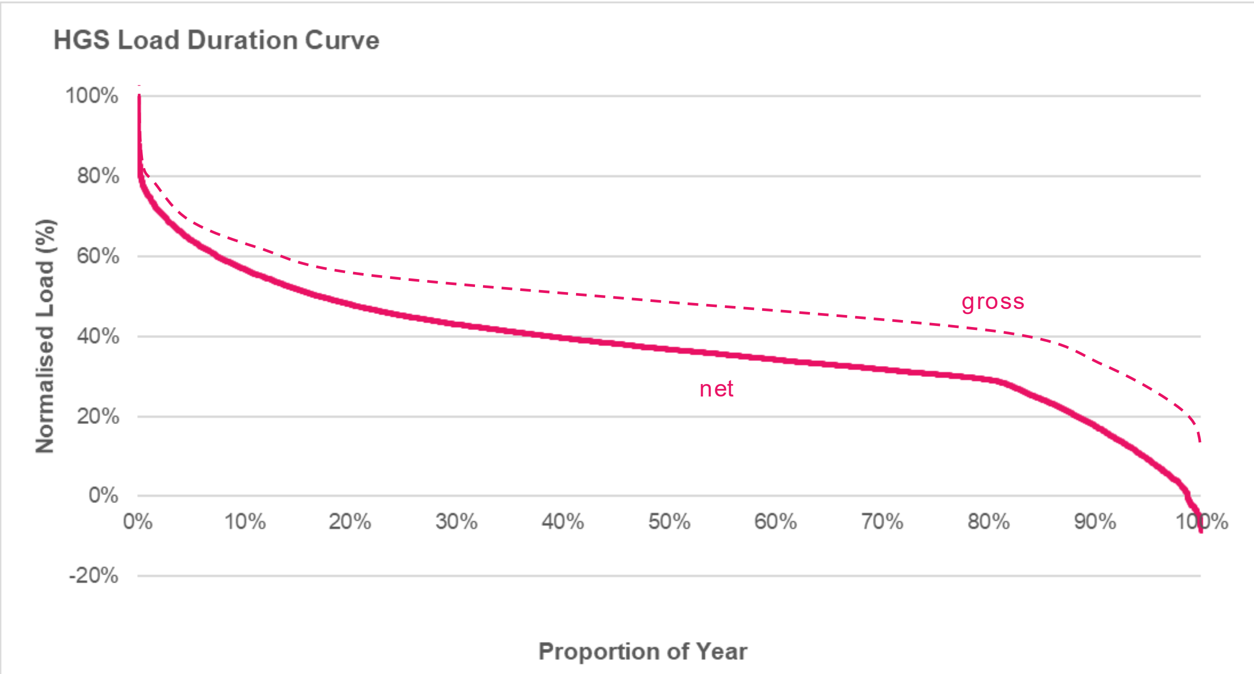

Figure 6: Annual load-duration curve at HGS

The load characteristics can vary marginally from year to year due to changes in weather, solar PV generation and storage systems growth, and underlying changes in the customers' load usage. Figure 6 shows that load more than 80 per cent of the maximum demand lasts for less than 1 per cent of the year. It also indicates that HGS has a high penetration of air conditioning which operates for a very small fraction of the year.

6.5 Load Transfer Capacity and Supply Restoration Times

A credible network, non-network or SAPS solution can assume the load transfer capability between HGS and the neighbouring networks of FSH, LWN and MTN to be 14.6 MVA for 2026.

Future load transfer capability levels between HGS and the neighbouring network can be assumed to remain relatively constant.

A credible network, non-network or SAPS solution should provide for supply to be restored within 60 minutes (on average) following the loss of a plant item causing an outage.

6.6 Asset Ratings

The existing capabilities of HGS zone substation for summer and winter are presented in Table 7 for all transformers in service (**N**), and for one transformer out of service (**N-1**).

Table 7: Summary of HGS Ratings (MVA)

Zone substation	Summer cyclic rating at 40°C		Winter cyclic rating at 10°C	
	N	N-1	N	N-1
HGS Import[10]	77.7	38.9	90.4	45.2
HGS Export[11]	-66.0	-33.0	-66.0	-33.0

6.7 Value of Customer Reliability

Location-specific VCR is used to value reliability of supply. The locational VCR for the HGS supply area was derived from the published sector VCR estimates[12], weighted in accordance with the composition of the load, by sector. This is summarised in Table 8.

Table 8: Summary of Location Specific VCR

Zone substation	VCR ($ per MWh, Real 2026)
HGS	42,259

6.8 Value of Safety Consequence

Values of safety consequence used in this RIT-D are derived from various sources including Safe Work Australia[13] for LTI, and the Department of Prime Minister and Cabinet, *Best Practice Regulation Guidance Note*[14] for VSL, adjusted for CPI. The values of safety consequence are summarised in Table 9

Table 9: Summary of safety consequence values

Safety Consequence	Value of safety consequence ($'000, real 2026)
Injury (LTI)	235
Death (VSL)	5,870
Disproportionality factor	3

[10] Power flow towards customer load.
[11] Power flow towards the transmission network.
[12] Values of Customer Reliability, Australian Energy Regulator (AER), 2025.
[13] The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community, Safe Work Australia, 2015.
[14] Best Practice Regulation Guidance Note: Value of statistical life, Department of the Prime Minister and Cabinet, Australian Government, 2026.

7. Potential Credible Options to Address the Identified Need

UE has developed a set of potential credible options to address the HSG 22 kV switchgear condition identified need.

To address the safety need, credible network, non-network or SAPS options would be required to have characteristics that would allow the safe decommissioning or rectification of the HGS 22 kV switchgear. Furthermore, to address the reliability need in anticipation of the safe decommissioning of HGS, credible options would need to be capable of supplying the annual energy requirements of customers supplied by HGS, and the forecast maximum demand at HGS over the planning horizon, accounting for the available load transfer capacity.

Table 10 provides a summary of the base case option, using the risk costs presented earlier in Table 4.

Table 10: Base case

Option	Description
Do nothing (status quo)	This base case option involves running the HGS 22 kV switchgear to failure. That is, continue with existing maintenance of this equipment, coupled with replacement upon failure. This option does not address the identified need as it does not address the network reliability and safety risks. The present value of all costs (reliability and safety risk) is $14.13 million (real, 2026).

Table 11 provides a summary of credible options that could address the identified need.

Table 11: Credible options under consideration

Option	Description
1) Replace existing outdoor 22 kV switchyard with a new indoor switch room building	This option involves retiring the existing 22 kV switchyard and establishing pre-fabricated building with 2 indoor 22 kV buses, 10 feeder, 2 transformer, and 2 bus-tie circuit breakers with 500 m of underground 22 kV cable connections. It addresses network reliability risk and safety risk to AFAP. The total capital cost of this option is $9.67 million (real, 2026) which includes 18.5% overheads. The present value of all costs (capital, O&M, residual risk) is $11.70 million (real, 2026).
2) Replace existing outdoor 22 kV switchgear in situ	This option involves replacing 5 feeder, 2 transformer and 1 bus-tie circuit breakers, and all existing 22 kV current and voltage transformers in situ. The existing 22 kV bus, connections, isolators, insulators and control cabling in the switchyard will also be replaced. It addresses network reliability risk and safety risk to AFAP. The total capital cost of this option is $10.17 million (real, 2026) which includes 18.5% overheads. The present value of all costs (capital, O&M, residual risk) is $12.17 million (real, 2026).

A credible option needs to be technically and economically feasible, and able to be implemented within a reasonable timeframe to address the identified need. Option 1 is likely to be the preferred network option at this draft stage.

Table 12 describes the options that have been considered by UE and are regarded as not being credible for the reasons set out below. These include all remaining network, non-network or SAPS options.

Table 12: Options regarded as being not credible

Option	Description
Decommission HGS and transfer all load to FSH, LWN, and MTN.	This option allows for the decommissioning of HGS by transferring all of its load to the adjacent zone substations FSH, LWN and MTN. Referring to Table 13, 52.5 MVA of new feeder capacity (at least 5 new high-voltage 22 kV feeders) would need to be established to transfer HGS's entire load base to these zone substations. LWN and MTN would each need to be augmented with an additional 20/33 MVA transformer and 22 kV switchboard. Given the cost of the works required to achieve this outcome would exceed $40 million hence is not regarded as credible.
Power factor correction	The power factor at HGS is currently unity at times of maximum demand, and there is no further opportunity to reduce demand at the network or customer level as seen by HGS. Therefore, this

Option	Description
	option is not credible, because it cannot technically address the identified need in relation to reliability or safety risks associated with deteriorating asset condition.
Demand response programmes	Demand response programmes are generally designed for peak demand management. The ability of all customers to always be self-sufficient in their electricity demand all year round to meet the identified need, is considered to be unfeasible, as it effectively requires all customers within the HGS supply area to disconnect from the network. Hence this option is not credible.
Embedded and/or customer renewable generation and energy storage	Referring to Table 13, distributed solar PV generation of up to 52 MW is likely to require approximately 84 hectares of land [15] which is feasible within the HGS supply area. Coupling this with new customer solar PV installations within the HGS supply area, particularly with the availability of commercial and residential roof-space, could be achieved at a competitive cost. The challenge however lies in the provision of storage to back-up the solar PV panels when they are not operating (including during the evenings). A viable storage option to back up the solar PV that could meet the requirements at HGS is a storage system sized to 52 MW with an energy to power ratio of around 7.0 [16]. However, the cost of the storage alone is likely to exceed that of the network option. For example, the fully installed capital cost of storage is approximately $0.6 million per MWh [17], totalling $218 million [18] (excluding land costs). This option of solar PV and storage would lead to a much higher marginal cost to the customer compared to a network solution cost, and the gap is unlikely to be covered from other market-based revenues. The planning process required for this type of investment, also means this is unlikely to be completed in time to meet the identified need. The storage resources owned by individual customers indicates that no potential existing customer-owned storage would be large enough to meet the identified need. Therefore, this option is not considered to be credible.
Embedded dispatchable generation and/or customer standby generation	Referring to Table 13, a viable dispatchable generation option that reliably meets customer requirements at HGS requires at least two generators up to 52 MW in aggregate to allow maintenance on one generator during off-peak times. The costs of this option are likely to exceed those of the preferred network option. For example, the capital cost of small gas-fired generator is approximately $1.6 million per MW [19]. For 52 MW of generation, the cost will be over $83 million [20] (excluding land, connection and operating costs). This option would lead to a much higher marginal cost to the customer compared to a network solution cost, and the gap is unlikely to be covered from other market-based revenues. The planning process required for this type of investment, also means this is unlikely to be completed in time to meet the identified need. The maximum demands of individual customers indicate that no potential existing customer-owned generation (standby or otherwise) would be large enough to meet the identified need. Therefore, this option is not considered to be credible.

[15] How To Start A Solar Farm - Energy Matters, 2026.
[16] 132,000 MWh pa / 365 days pa / 52 MW = 7.0.
[17] GenCost 2023-24 Final report, Table B.8 (Battery 4-hours, Aurecon 2023-24), CSIRO, 2024.
[18] 52 x 7.0 x 0.6 = $218 million.
[19] GenCost 2023-24 Final report, Table B.3 (Small gas open cycle, 2025), CSIRO, 2024.
[20] 52 x 1.6 = $83 million.

8. Technical Characteristics of Non-Network Options

This section describes the minimum technical characteristics that a non-network or SAPS option would be required to deliver to address the identified need.

Like the network options, credible non-network or SAPS options would be required to have characteristics that would allow the safe decommissioning of HGS and would need to be capable of supplying the annual energy requirements of all customers supplied by HGS, and the maximum demand at HGS over the planning horizon (accounting for available load transfer capacity).

A credible non-network or SAPS option, or any combination of those (including with a network option) must satisfy timing, operational and the minimum technical requirements stipulated below.

8.1 Size of Support

Table 13 outlines the estimated amount of load reduction, or additional generation needed to be supplied by a credible non-network or SAPS solution within the HGS supply area to address the identified need. These are the minimum requirements, because the values reflect the reduced requirement needed due to the availability of load transfer capability away from HGS to its surrounding zone substations.

Table 13: Minimum peak demand and annual energy offsets required from non-network or SAPS solutions

Year	Load at risk (MVA)	Hours at risk (Hours)	Minimum non-network or SAPS support required	
			Expected GWh pa	Expected MW
2026	51.4	8760	130	51.2
2027	52.1	8760	131	51.9
2028[21]	52.3	8784	131	52.1
2029	52.5	8760	132	52.3
2030	52.0	8760	131	51.9

8.2 Time of Year, Duration and Location of Support

Proposed non-network or SAPS options, at a minimum, must be capable of supplying the entirety of the HGS supply area maximum demand and annual energy, utilising the available transfer capability. This service is required no later than by 2028.

8.3 Reliability of Support

Proposed non-network or SAPS options must be capable of reliably meeting electricity demand under a range of conditions and be able to maintain reliability and quality of supply levels for customers supplied within the HGS supply area.

As such, redundancy may need to be built into a non-network or SAPS solution to maintain reliability of supply.

If the non-network option is a generator operating in parallel with UE's network, the generator must comply with the requirements set out in our *Embedded Generation Network Access Standards* (Document No. UE-ST-2008.X).

[21] Year of network option timing.

9. Conclusion and Next Steps

9.1 Conclusion

Given the size of the support needed from a non-network or SAPS solution, and it being required at all times of the year to maintain supply reliability within the HGS supply area (following the safe decommissioning of HGS), it is unlikely that a non-network or SAPS option could be technically and economically viable to address the identified need.

In conclusion, this *Notice of Determination* report demonstrates that none of the non-network or SAPS options considered are potentially feasible in this instance. The analysis demonstrates that there are no combinations of non-network or SAPS options, or in combination with network options, that are likely to adequately meet the criteria that would require the publishing of, and consultation on a RIT-D options screening report.

9.2 Next Steps

The total cost of the most expensive credible network option to address the HSG 22 kV switchgear condition identified need, is lower than the trigger threshold of $14 million [22] for the publication of and consultation on a DPAR.

Therefore, UE has prepared and published a FPAR, as required under NER clause 5.17.4, paragraphs (o) to (s), which presents a detailed economic assessment of all credible network options that address the identified need, and identifies the preferred option and its optimum timing.

The FPAR provides information required under NER clause 5.17.4, paragraph (r), and applies the latest available information on reliability and safety risk costs associated with the identified need, and the project cost estimates, in evaluating the economic viability of the preferred option against the alternative options considered.

[22] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021

Appendix A: 22 kV Switchgear Photos

The 22 kV outdoor bulk-oil AEI LG1C circuit breakers at HGS are in a poor condition and technically obsolete (with no vendor support and limited to no spares). UE has assessed there is now an unacceptable risk of asset failure, with significant consequences for safety, and for the reliability of electricity supply to UE's customers within the HGS supply area.

Figure 7: Existing outdoor 22 kV circuit breakers at HGS

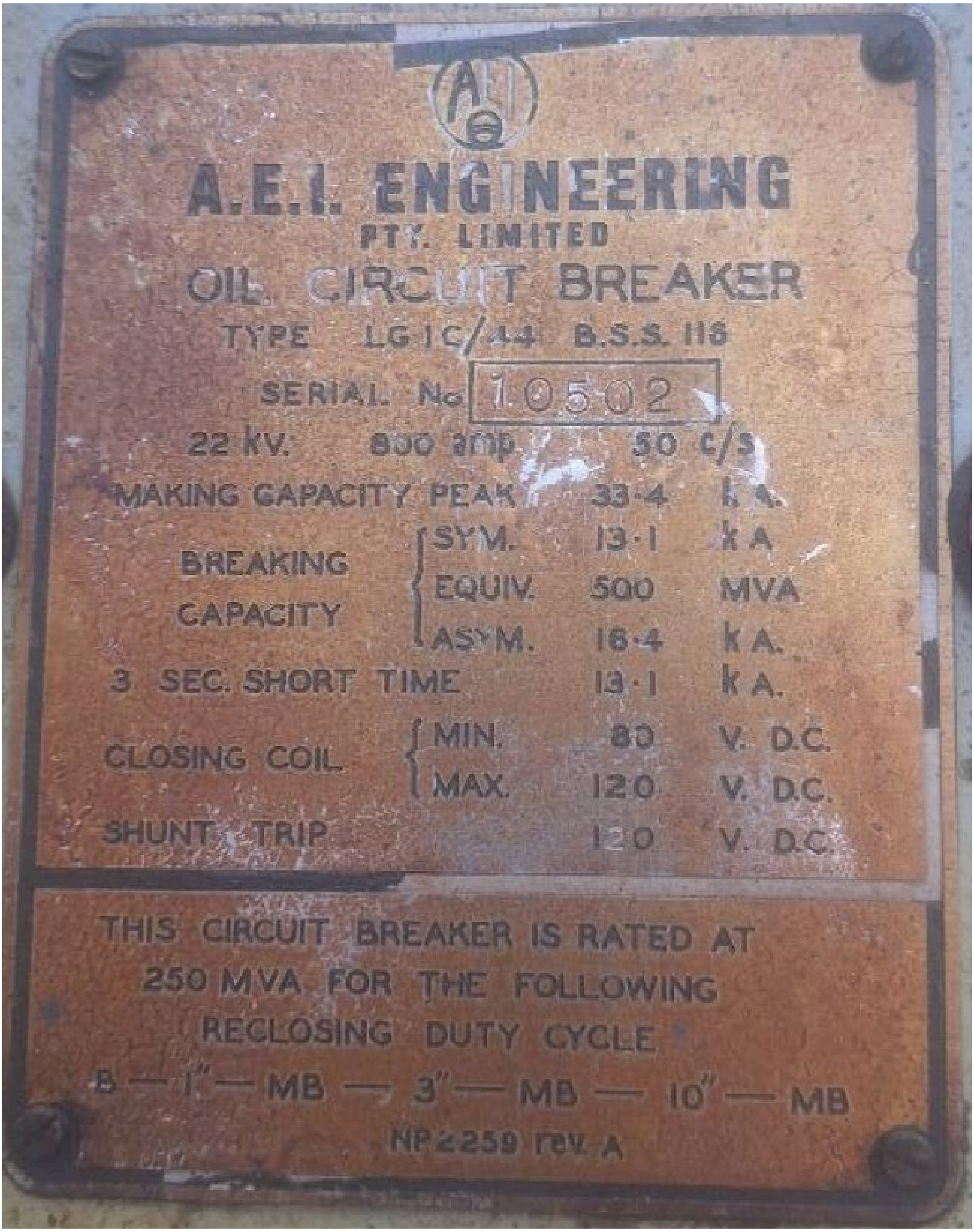

Figure 8: Nameplate of 22 kV circuit breakers at HGS