January 2026

Powerlink 2027-32 Revenue Proposal

Project Pack

CP.02729 Mudgeeraba 110kV Secondary Systems Replacement

Project Status: Unapproved

Network Requirement

The Mudgeeraba Substation (H004) is located approximately 10km north of the Queensland-NSW border and is a major injection point into the Gold Coast zone. It is also the primary hub supplying Essential Energy's Terranora Substation and power to northern NSW via the Directlink HVDC system. Mudgeeraba Substation was initially established in 1970 as a 110kV switchyard and expanded circa 1997 by the establishment of the 275kV switchyard that is supplied from Greenbank via two 275kV single circuits to a fully switchable 275kV switchyard comprising two 275/110kV transformers. The 110kV network from Molendinar to Mudgeeraba links the coastal bulk supply points at Surfers Paradise, Broadbeach and Merrimac via an underground cable network and an inland overhead 110kV network supplies Robina and Nerang substations. This network is owned and operated by Energy Queensland.

Ageing secondary systems, which are no longer supported by the manufacturer are increasingly at risk of failing to comply with Schedule 5.1.9(c) of the National Electricity Rules, AEMO's Power System Security Guidelines and the reliability standard included in Powerlink's Transmission Authority.

A condition assessment of the Mudgeeraba substation secondary systems identifies various secondary systems components requiring replacement from 2027 to 2029 [1].

Powerlink's 2025 Central scenario forecast confirms there is an enduring need to maintain electricity supply into the Gold Coast zone. Therefore, replacement of the secondary systems at the Mudgeeraba 110kV switchyard is required to allow continued operation of the substation and avoid system failures that would result in loss of load exceeding Powerlink's N-1-50MW / 600MWh Transmission Authority reliability standard and significantly impact the capability to transfer power to northern NSW via the Directlink HVDC converter stations [2].

Recommended Option

As this project is currently 'Unapproved', project need and options will be subjected to the public RIT-T consultation process to identify the preferred option closer to the time of investment.

The current lowest cost option is for replacement of secondary systems in the existing building including in-panel replacement by June 2033 [3].

Options considered but not proposed include:

- Replacement of some secondary systems and decommission some functionality – this option would require additional transformer capacity at Molendinar (including a 275kV bus) and additional 110kV network capacity between Loganlea, Molendinar and Mudgeeraba. This option is not cost effective.

Figure 1 shows the current recommended option reduces the forecast risk monetisation profile of the Mudgeeraba 110kV Substation secondary systems from around $0.42 million per annum in 2029 to less than $0.03 million per annum from 2030 [5].

Figure 1 Annual Risk Monetisation Profile ($ Real, 2025/26)

Cost and Timing

The estimated cost to replace secondary systems at Mudgeeraba substation is $26.8m ($2025/26) [4].

Target Commissioning Date: December 2029.

Documents in CP.02729 Project Pack

Public Documents

1. H004 Mudgeeraba Secondary Systems Condition Assessment Report
2. CP.02729 Mudgeeraba 110kV Secondary Systems Replacement – Planning Statement
3. CP.02729 Mudgeeraba 110kV Secondary Systems Replacement – Project Scope Report
4. CP.02729 Mudgeeraba 110kV Secondary Systems Replacement – Concept Estimate
5. CP.02729 Mudgeeraba 110kV Secondary Systems Replacement – Risk Cost Summary Report

H004 Mudgeeraba 110/275kV

Secondary Systems Condition Assessment Report

Document Details			
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Previous Document	Version 3.0	**Team**	Secondary Systems and Telecommunications Strategies

Date	Version	Nature of Change	Author	Authorisation
01/12/2010	1.0	New document	[redacted]	[redacted]
28/07/2014	2.0	General updates	[redacted]	[redacted]
05/03/2018	3.0	General updates	[redacted]	[redacted]
10/05/2019	4.0	Health Index Updated	[redacted]	[redacted]

Table of Contents

1. Introduction

This report is pertinent to H004 Mudgeeraba substation 275/110kV secondary systems and associated site infrastructure. The report is provided to assist with determining the future strategy and scope for refurbishment and replacement works of Mudgeeraba 275kV and 110kV secondary systems equipment.

The assessment has been formulated with the assistance of data extracted from SAP, SPF, Forced Outage Database (FOD), discussion with maintenance staff and a site inspection. Photographs of items are included in the text and all photographs taken during the site visit have been retained for future reference.

H004 Mudgeeraba substation is a 275kV/110kV transmission substation located at the southern Queensland transmission network and is a key switch point to Southern Queensland.

The 275/110kV yard is a major node in the wider interconnected network supplying power to Southern Queensland. The Secondary systems for the 275kV feeders Greenbank 835 & 836, 275kV capacitor banks 4, 110kV bus zone, feeders 779 & 780 & 7838, 7839, 706, 754, 755, 757 and 758 were commissioned from 2005 to 2017 while others were between early 1990s and 2000s.

H004 Mudgeeraba operating diagram

2. Site infrastructure

Mudgeeraba substation consists of one yard of 275kV and 110kV operating voltage enclosed by the one perimeter fence. The substation was built in 1972. Extensions with load growth have resulted in a mixture of secondary systems from the early 1990s through to 2017.

H004 Mudgeeraba Substation is an essential transmission yard, with:-

- 2 x 275kV bus bays;
- 3 x 275kV bus coupler bays;
- 2 x 275kV feeder bays;
- 1 x 275kV capacitor banks bay;
- 3 x 275/110kV transformer bays;
- 1 x 110/33kV transformer bay;
- 4 x 110kV bus bays;
- 2 x 110kV bus coupler bays;
- 10 x 110kV feeder bays;
- 1 x 110kV Capacitor banks bay.

2 x 275kV feeder bays are energised through Greenbank Substation. 10 x 110kV feeder bays are connected to Energex supplies such as Surfers Paradise, Nerang, Robina, Varsity Lakes and Burleigh.

Mudgeeraba substation yard bird view

The existing Mudgeeraba substation site is located at Coromandel Lane, Stephens. Emergency and routine maintenance of the secondary systems is done by Powerlink staff at Virginia, half and an hour drive away. The secondary system is housed in the Switchyard Services Building (SSB) and demountable building adjacent to the switchyard as shown above.

3. Condition Assessment

3.1 Buildings

The condition assessment of buildings is a separate document and carried out by Substation Strategies. The following details are for information only.

There are two buildings at H004 Mudgeeraba, brick building +1 and demountable building +10. The main building is one level brick construction that contains a protection/control room for secondary systems for both 275kV and 110kV network, communication rooms, standby generator room, battery room, and toilet. The building was built in 1972. There are no spaces available for future secondary system secondary system replacement or substation augmentation in the existing building +1.

Mudgeeraba control building +1

Split unit air conditioning units are used to cool the control room area and appear to be functioning. The communications room is air conditioned and appear to be functioning correctly.

Split air conditioning system

The 110kV demountable building, Building +10 was built in 2017. It houses secondary systems for 110kV bays, including 110kV bus zone, feeder 706, 754, 755, 757 and 758. There are 2 x spare panel spaces in building +10 for future secondary system replacement.

110kV Demountable building +10

3.2 Trench, marshalling cubicles and control cables

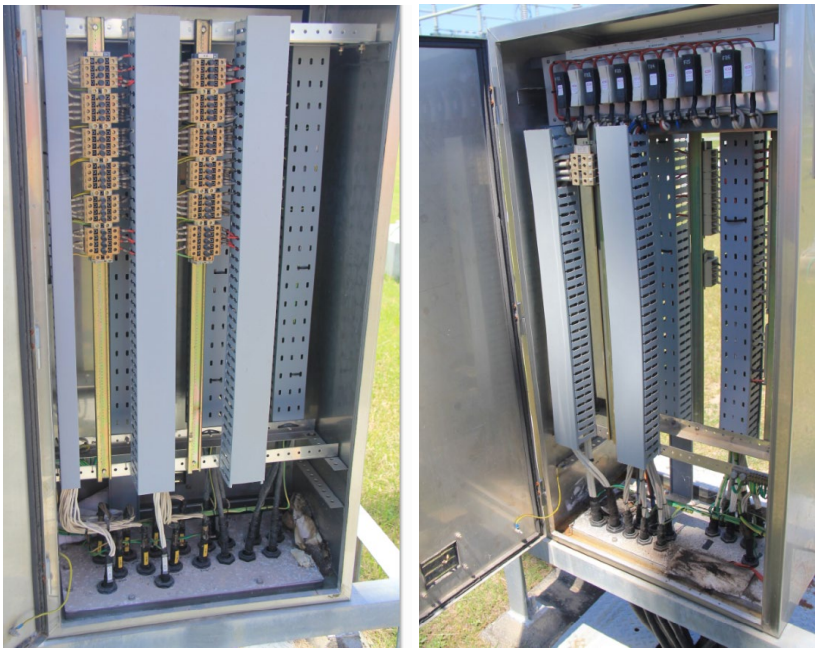
Trenches are part of primary assets. Conditions of cable trenches are not included in this report



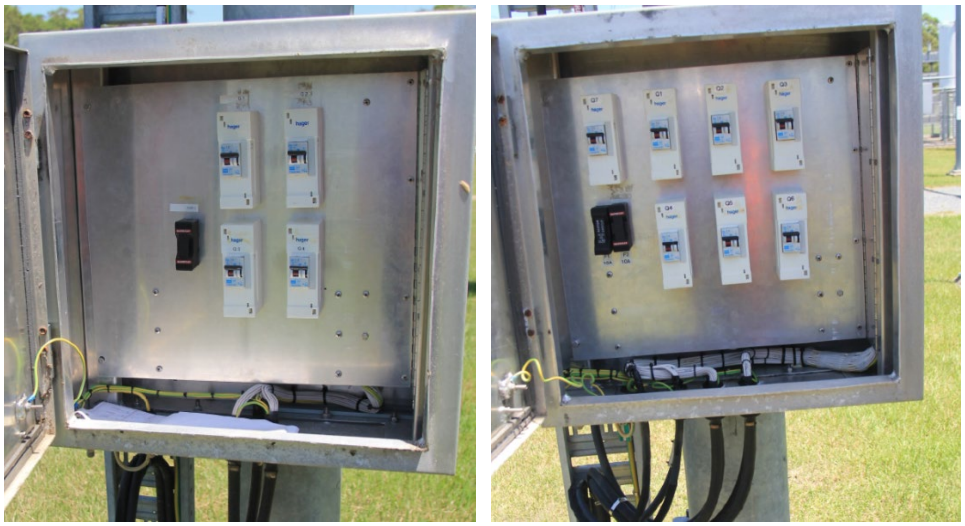
Substation trenches

3.2.1 275kV yard

Marshalling kiosk for 275kV bus protection and 1 and 2 Bus VT boxes were installed in 2001 and is in fair condition. But fuses do not provide safety and monitoring features and make the event investigation more difficult. Maintenance on these fuses is expensive. These fuses should be replaced with MCBs to improve the performance of circuitries according to current design standard.



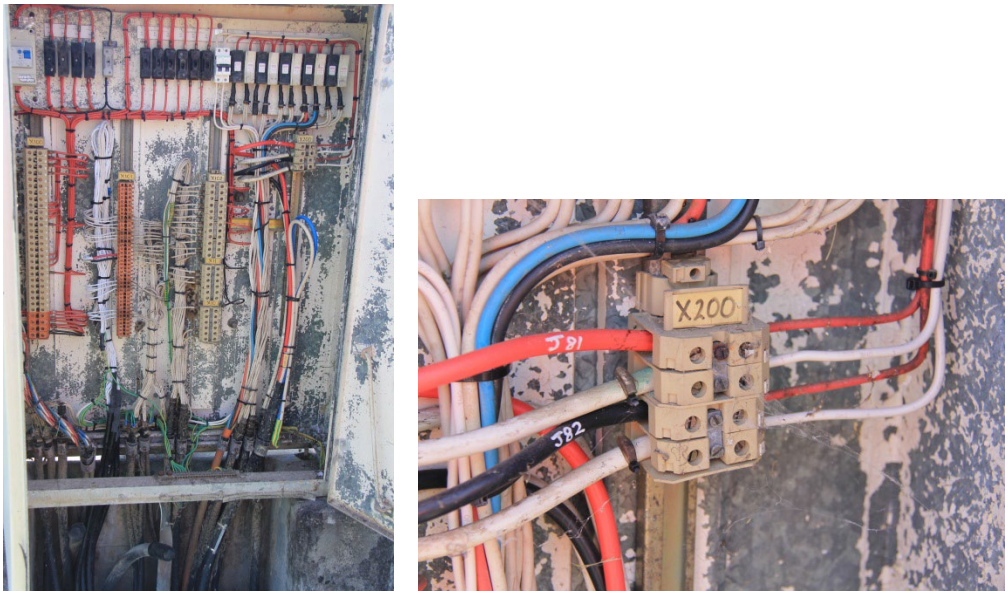
275kV bus protection marshalling kiosk



275kV 1 and 2 Bus VT box

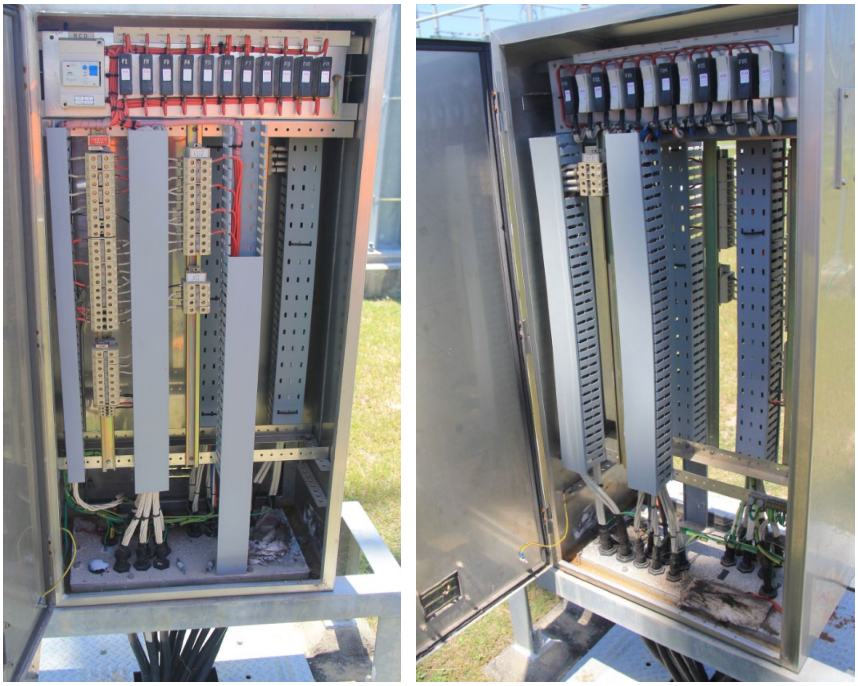
Auxiliary kiosks for 275kV diameter =C02 and =C3 were commissioned in 1991. They are very dirty. Associated terminals are cracked. These marshalling kiosks and associated control cables to the control building need to be replaced with major secondary system or primary plant replacement.

Diameter =C02 Auxiliary kiosk



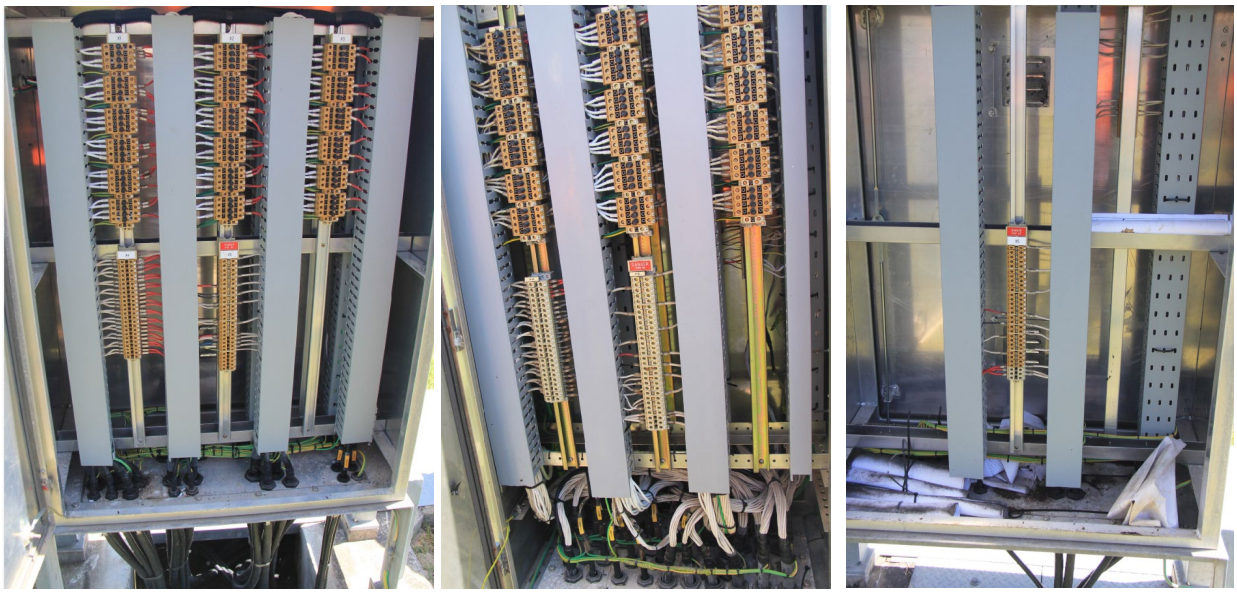
Diameter =C03 Auxiliary kiosk

The auxiliary kiosk for diameter =C01 was revised in 2001. The kiosk and associated control cables are in fair condition. But fuses need to be replaced with MCBs for reliable operation.

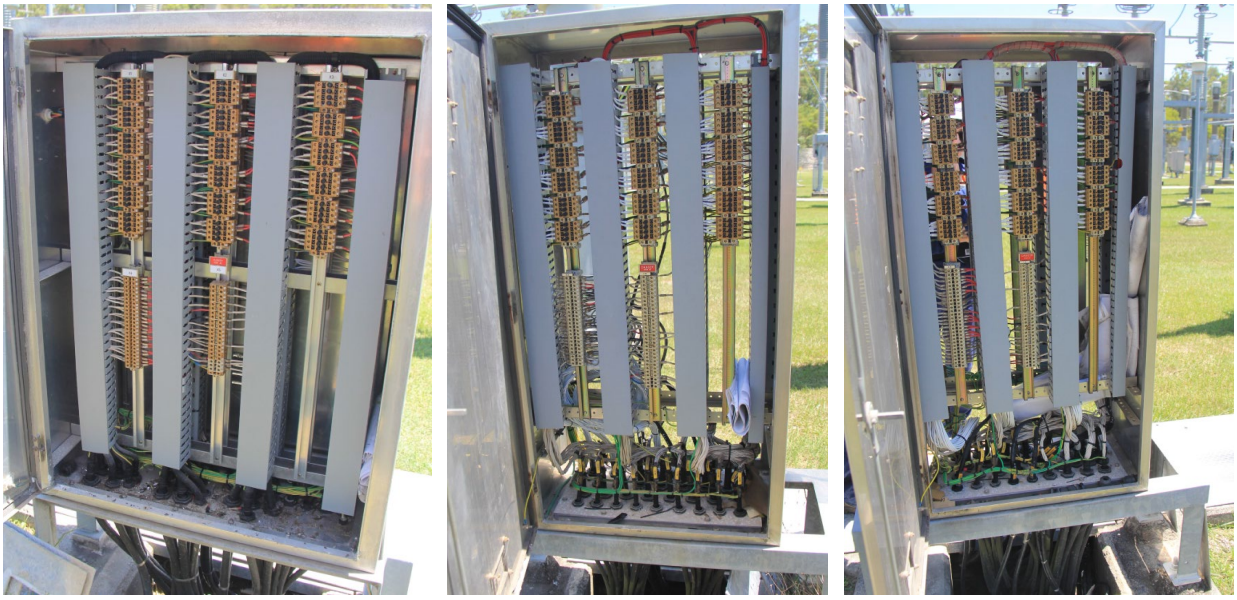


Diameter =C01 Auxiliary kiosk

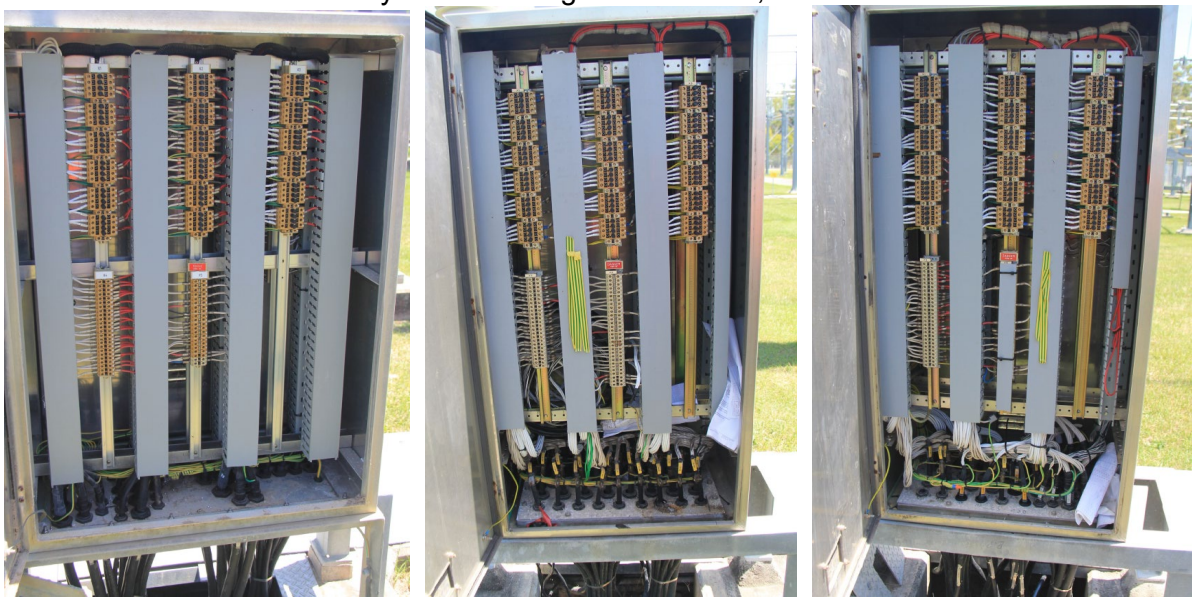
Marshalling kiosks for 275kV bay 1, 2 and 3 were installed in 2001 and are in fair condition. However 415V AC terminals need to be covered to comply with current safety design standard.



275kV Bay 1 Marshalling Kiosks – A10, A20 and A30

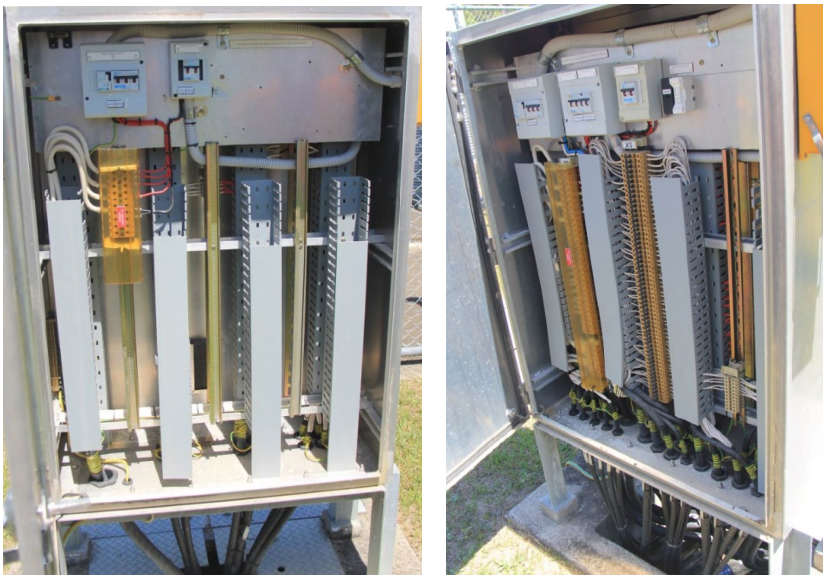


275kV Bay 2 Marshalling Kiosks – A10, A20 and A30



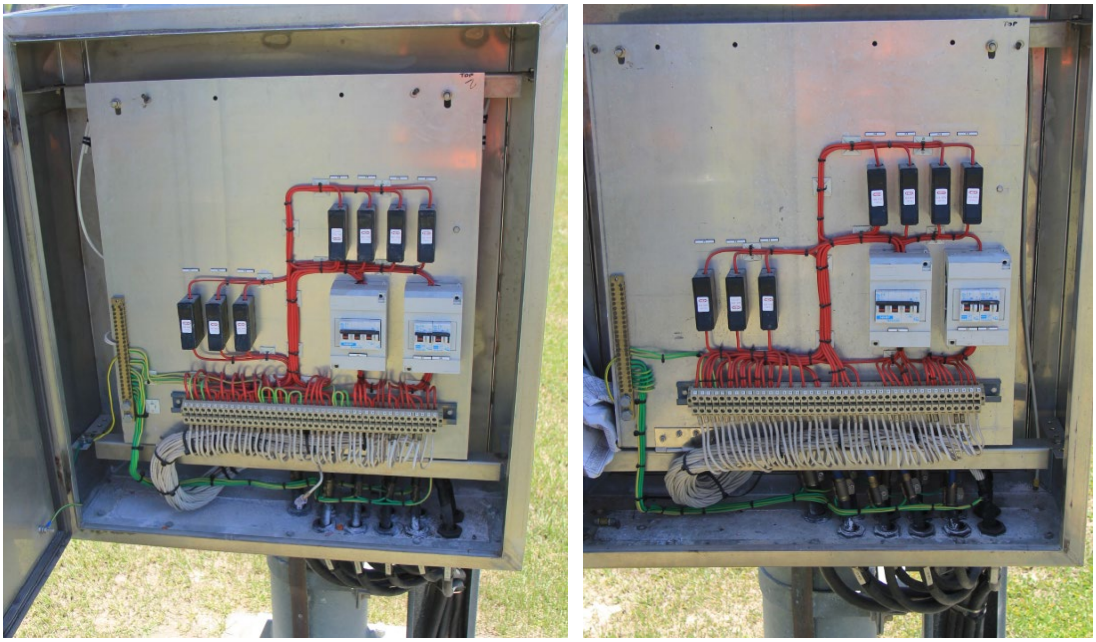
275kV Bay 3 Marshalling Kiosks – A10, A20 and A30

Marshalling kiosks for Cap 4 were installed in 2002 and are in fair condition.



Cap 4 (=C51) marshalling kiosks

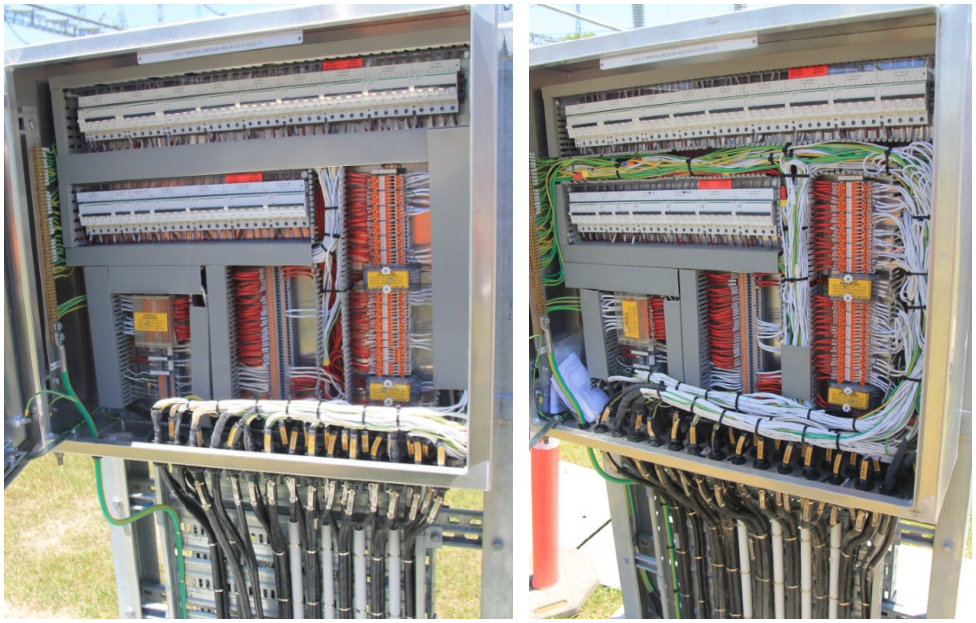
Fuses are currently used for VT boxes, AC and DC kiosks. These fuses do not provide safety and monitoring features and make the event investigation more difficult. Maintenance on these fuses is expensive. These fuses should be replaced with MCBs to improve the performance of circuitries according to current design standard.



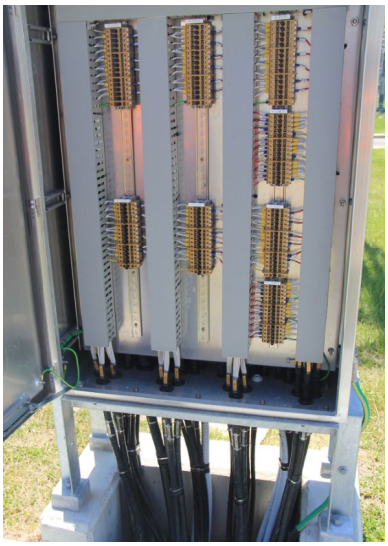
Feeder 835 and 836 VT box

3.2.2 110kV yard

110kV bus and bus coupler marshalling kiosks were installed in 2016. These kiosks and associated control cables are in good condition.

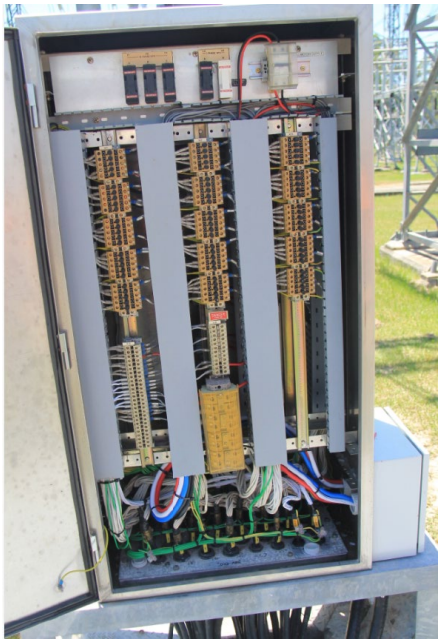


110kV 1 and 2 Bus VT marshalling kiosks



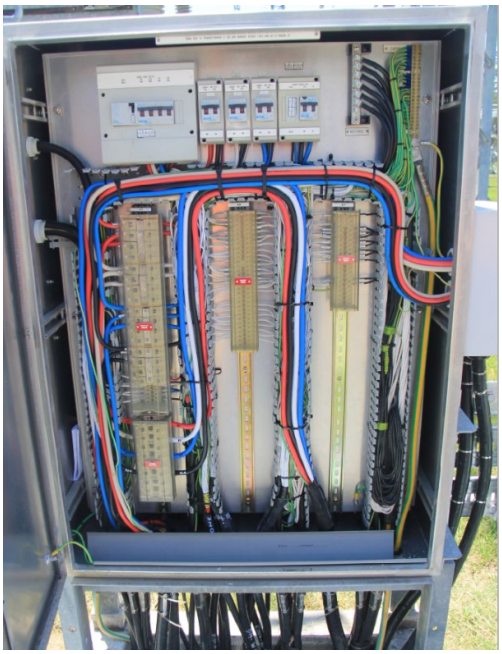
110kV bus coupler marshalling kiosk

Marshalling kiosk for 110kV T1 was installed in 1991. Marshalling kiosk and associated control cables have been in service for 27 years. They need to be replaced with major secondary system replacement to maintain reliable operation of secondary systems.



110kV Bay =D10 T1 marshalling kiosk

Marshalling kiosk and associated control cables for T3 were installed in 2005 and are in fair condition.

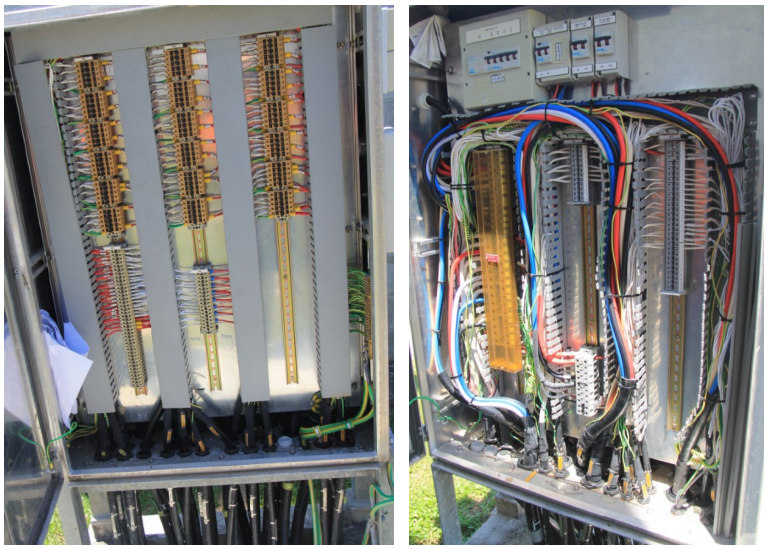


110kV Bay =D14 T3 marshalling kiosk

Marshalling kiosk and associated control cables for T5 were installed in 2016 and are in good condition.

T5 LV marshalling kiosk and 110kV VT box

Marshalling kiosk and associated control cables for T4 were installed in 2006 and are in fair condition.

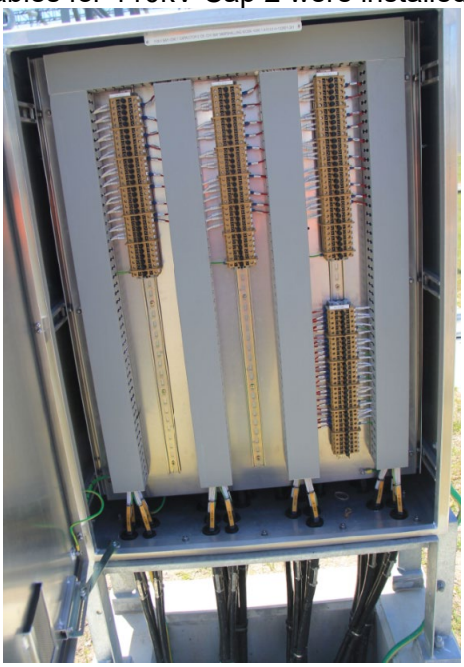


110kV Bay =D11 T4 marshalling kiosk

Marshalling kiosk and control cables for feeder 757 and 758 were installed in 2016 are in good condition. However the VT box still utilizes fuses which should be replaced to improve the performance of circuitries.

=D20 and =D721 Feeder 758 and 757 marshalling kiosks and VT box

Marshalling kiosk and control cables for 110kV Cap 2 were installed in 2016 are in good condition.

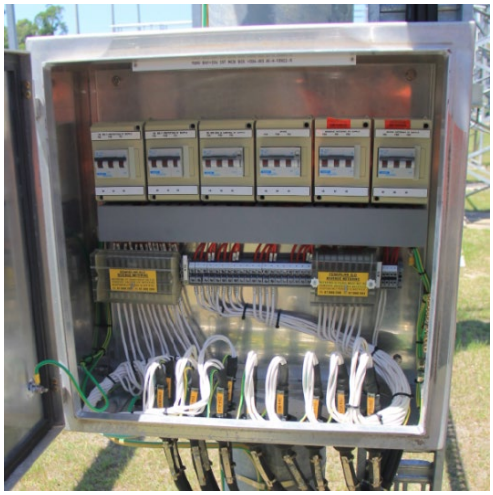


110kV Bay =D06 Cap 2 marshalling kiosk

Marshalling kiosk and control cables for Feeder 706 were installed in 2016 are in good condition.

110kV Bay =D05 Feeder 706 marshalling kiosk

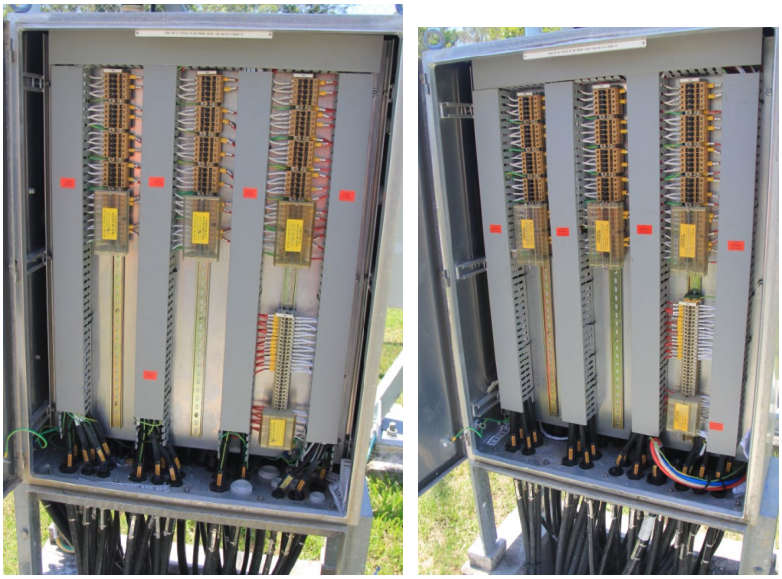
Marshalling kiosk and control cables for Feeder 794 were installed in 2006 are in fair condition.



110kV Bay =D04 Feeder 794 marshalling kiosk and VT box

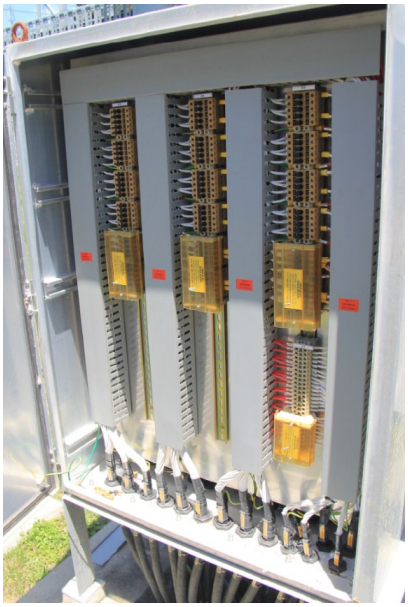
Marshalling kiosks and control cables for Feeder 779, 780, 754 and 755 were replaced in 2016 are in good condition.

110kV Bay =D07 and =D08 Feeder 779 and 780 marshalling kiosk



110kV Bay =D15 Feeder 754 and =D18 Feeder 755 marshalling kiosk

Marshalling kiosks and control cables for F838 and F839 were replaced in 2004 are in fair condition.




110kV Bay =D16 F838 marshalling kiosk and VT box


110kV Bay =D22 F839 marshalling kiosk

It is a cable termination rack arrangement at H004 Mudgeeraba. The floor and support structure are intact.

Termination racks

3.3 Control and protection bays

3.3.1 Protection and control panels

Secondary systems at Mudgeeraba are housed in a type of tunnel and SDM7/8 swing frame panel. These panels have exposed terminal in the rear of the panel which could cause safety issues. This type of construction is vulnerable to cause human error on mis-tripping of primary plant when maintenance is conducted and it is also expensive to modify because of the inter panel wiring. The current clearance does not comply with safety clearance requirements specified by ID&TS – SU0023 Clearance Requirements for Panels, Switchboard and Kiosks (Obj. ID: A2806489). These panels need to be replaced with major secondary system replacement. There are safety in design concerns on the type of SDM7/8 swing frame panel, such as isolation issues and potential termination falling loose risks. Updates on the panel are required to be conducted with major secondary system replacement according to SU0020 Updates to SDM8 Panels to Mitigate Safety in Design Concerns (Obj ID: A2753457) .

3.3.2 275kV Bus zones and couplers

Equipment details of 275kV bus zones and couplers are given below:

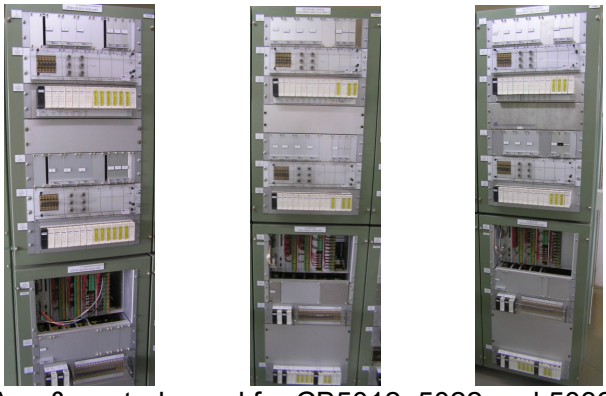
275kV Bus and coupler	Relay & control	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
1 Bus	X	[redacted]	2002	Yes	Yes	Yes	8.39
		[redacted]	2002	No	No	Yes	8.39
	Y	[redacted]	2016	Yes	Yes	Yes	1.34
2 Bus	X	[redacted]	2002	Yes	Yes	Yes	8.40
		[redacted]	1999	No	No	Yes	9.62
	Y	[redacted]	2002	Yes	Yes	Yes	8.40
Coupler 501	X	[redacted]	2002	No	Yes	Yes	8.40
	Y	[redacted]	2002	No	Yes	Yes	8.40
	RTU	[redacted]	2002	No	Yes	Limited	8.24
Coupler 502	X	[redacted]	2002	No	Yes	Yes	8.40
	Y	[redacted]	2002	No	Yes	Yes	8.40
	RTU	[redacted]	2002	No	Yes	Limited	8.24
Coupler 503	X	[redacted]	2002	No	Yes	Yes	8.40
	Y	[redacted]	2002	No	Yes	Yes	8.40
	RTU	[redacted]	2002	No	Yes	Limited	8.24

High impedance differential relays [redacted] relays are used to protect 1 and 2 bus. CB management relay [redacted] for Coupler 501, 502 and 503 becomes obsolete as the manufacturer has ceased manufacturing. The bay control RTU C50 has become obsolete and there are only limited spares available. The health index indicates that majority of these relays (except 1 Bus Y protection which was replaced in 2016) will reach the end of technical life and need to be replaced within 3-4 years.

Control Dynamics relays provide auxiliary contact with fast response. These relays have experienced reliability issues with causing mal-tripping. These relays need to be replaced with major secondary system replacement.

Bus zone protection and bus coupler panels are of the corridor construction type having separate protection and auxiliary panels. These panels have exposed terminal in the rear of the panel which could cause safety issues. This type of construction is vulnerable to cause human error on mis-tripping of primary plant when maintenance is conducted and it is also expensive to modify because of the inter panel wiring. The current clearance does not comply with safety clearance requirements specified by ID&TS – SU0023 Clearance Requirements for Panels, Switchboard and Kiosks (Obj. ID: A2806489). These panels need to be replaced with major secondary system replacement.

275kV 1 & 2 Bus protection and CB fail bus trip panel



Aux & control panel for CB5012, 5022 and 5032

3.3.3 275/110kV transformer bays

Equipment for 275/110kV transformer bays is detailed below.

Transformer	Relay & control		Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
1T	275kV	X	[redacted]	2002	No	No	Limited	8.40
			[redacted]	2011	No	Yes	Yes	4.57
		Y	[redacted]	2018	Yes	Yes	Yes	1.16
		Backup	[redacted]	2002	No	No	Yes	8.36
		X CB Fail	[redacted]	2002	No	Yes	Yes	8.40
		Y CB Fail	[redacted]	2002	No	Yes	Yes	8.40
		Local RTU	[redacted]	2002	No	Yes	Limited	8.24
	110kV	CB Fail	[redacted]	2004	No	Yes	Yes	7.19
		Local RTU	[redacted]	2004	No	Yes	Limited	7.19
3T	275kV	X	[redacted]	2002	No	No	Yes	8.15

Transformer	Relay & control		Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
			[redacted]	2011	No	Yes	Yes	4.57
		Y	[redacted]	2002	Yes	Yes	Yes	8.26
		Backup	[redacted]	2002	No	No	Yes	8.36
		X CB Fail	[redacted]	2002	No	Yes	Yes	8.40
		Y CB Fail	[redacted]	2002	No	Yes	Yes	8.40
		Local RTU	[redacted]	2002	No	Yes	Limited	8.24
	110kV	CB Fail	[redacted]	2004	No	Yes	Yes	7.21
		Local RTU	[redacted]	2004	No	Yes	Limited	7.21
5T	275kV	X	[redacted]	2017	Yes	Yes	Yes	1.16
			[redacted]	2011	No	Yes	Yes	4.57
		Y	[redacted]	2002	Yes	Yes	Yes	8.40
		X CB Fail	[redacted]	2002	No	Yes	Yes	8.40
		Y CB Fail	[redacted]	2002	No	Yes	Yes	8.40
		Local RTU	[redacted]	2002	No	Yes	Limited	8.24
	110kV	X CB Fail	[redacted]	2017	No	Yes	Yes	1.16
		Y CB Fail	[redacted]	2017	Yes	Yes	Yes	1.16
		Local RTU	[redacted]	2017	No	Yes	Limited	1.16

Electronic biased differential relays, [redacted] & [redacted] digital relay [redacted] & [redacted] and CB fail relay [redacted] are used to protect 275/110kV 1, 3 and 5 transformers. The KBCH130 relay has no technical support from the manufacturer and limited spares are available. The bay controller C50 RTU has become obsolete and there are only limited spares available. The health index indicates these relays will reach the end of technical life and need to be replaced in 3-4 years.

Thermal overload protection relays were installed to replace temporary thermal protection schemes for three 275/110kV transformers on the existing control panel in 2011.

Control Dynamics relays provide auxiliary contacts with fast response. These relays have experienced reliability issues with causing mis-tripping. These relays need to be replaced with major secondary system replacement.

Transformer protection panels (Except T5 LV protection/control swing frame panel which was installed in 2017) are of the corridor construction type having separate protection and auxiliary panels. This type of construction is vulnerable to cause human error on mis-tripping of primary plant when maintenance is conducted and it is also expensive to modify because of the inter panel wirings. The current clearance does not comply with safety clearance requirements specified by ID&TS – SU0023 Clearance Requirements for Panels, Switchboard and Kiosks (Obj. ID: A2806489). These panels need to be replaced with major secondary system replacement.

1 Transformer 275/110kV protection and control panel

3 Transformer 275/110kV protection and control panel

5 Transformer 275/110kV protection and control panel

3.3.4 275kV feeder bays

Protection and control equipment for 275kV feeder bays are detailed in the following table.

Feeder	Relay & control	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
835	X	[redacted]	2003	No	Yes	Yes	7.60
	Y	[redacted]	2006	No	Yes	Yes	6.16
		[redacted]	2002	No	Yes	Yes	7.60
	Prot Sig	[redacted]	2001	No	Yes	Yes	8.59
		[redacted]	2001	Yes	Yes	Yes	8.59
	CB Fail X	[redacted]	2002	No	Yes	Yes	8.40
	CB Fail Y	[redacted]	2002	No	Yes	Yes	8.40
	Local RTU	[redacted]	2002	No	Yes	Limited	8.36
836	X	[redacted]	2006	No	Yes	Yes	6.15
		[redacted]	2003	No	Yes	Yes	7.60
	Y	[redacted]	1997	No	Yes	Yes	10.00
	Prot Sig	[redacted]	2001	No	Yes	Yes	8.59
		[redacted]	2001	Yes	Yes	Yes	8.59
	CB Fail X	[redacted]	2002	No	Yes	Yes	8.40
	CB Fail Y	[redacted]	2002	No	Yes	Yes	8.40
	Local RTU	[redacted]	2002	No	Yes	Limited	8.36

275kV feeders 835 and 836 are protected by digital current differential relays ([redacted] and [redacted] and distance protection [redacted]. [redacted] relays have experienced mis-trips and measures such as DSP card replacement, Power Supply replacement and firmware upgrade have been taken to improve their reliability (OR.01270 and OR.01286). The health index indicates that majority of equipment will reach the end of technical life and should be replaced within 3-4 years.

Control Dynamics relays provide auxiliary contacts with fast response. These relays have experienced reliability issues with causing mis-tripping. These relays need to be replaced with major secondary system replacement.

275kV feeder bay protection panels are of the corridor construction type having separate protection and auxiliary panels. This type of construction is vulnerable to cause human error on mis-tripping of primary plant when maintenance is conducted and it is also expensive to modify because of the inter panel wiring. The current clearance does not comply with safety clearance requirements specified by ID&TS – SU0023 Clearance Requirements for Panels, Switchboard and Kiosks (Obj. ID: A2806489). These panels need to be replaced with major secondary system replacement.


Feeder 835 SIT panel


Fdr 835 X protection

Fdr 835


Y protection


Fdr 835 Aux and control


Feeder 836 SIT panel


Fdr 836 X protection


Fdr 836 Y protection


Fdr 836 Aux control panel

3.3.5 275kV 4 Capacitor Bay

Secondary systems for 275kV 4 Capacitor bank are detailed in a table below.

275kV Cap	Relay & control	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
4 CAP	X	[redacted]	2002	Yes	Yes	Yes	8.06
		[redacted]	2002	Yes	Yes	Yes	8.06
		[redacted]	2002	Yes	Yes	Yes	8.06
	Y	[redacted]	2002	No	Yes	Yes	8.06
		[redacted]	2002	Yes	Yes	Yes	8.06
	POW	[redacted]	2002	No	No	Yes	8.06

	Local RTU	[redacted]	2002	No	Yes	Limited	8.06

High Impedance [redacted] and Balance protection [redacted] are used to protect 4 capacitor banks and mounted on a swing frame panel. These relays have been providing reliable services. However, as these secondary systems were installed back to 2002, the health index shows that they will reach the end of technical asset life and need to be replaced within 3-4 years.

C50 RTUs are utilized for the function of control. These [redacted] RTUs have become obsolete. Powerlink had the last buy of [redacted] in 2014 and has relied on these spares to maintian their operation.

275kV 4 CAP protection and control panel

3.3.6 110kV Bus zones and coupler bays

Secondary systems for 110kV bus zones and coupler bays are listed in a table below.

110kV Bus	Relay & control	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
Bus zones	X	[redacted]	2017	Yes	Yes	Yes	1.16
		[redacted]	2017	Yes	Yes	Yes	1.16
		[redacted]	2017	Yes	Yes	Yes	1.16
	Y	[redacted]	2017	Yes	Yes	Yes	1.16
		[redacted]	2017	Yes	Yes	Yes	1.16
		[redacted]	2017	Yes	Yes	Yes	1.16
Coupler 401	CB fail	[redacted]	2004	No	Yes	Yes	7.39
	Local Control	[redacted]	2004	No	Yes	Limited	7.39
Coupler 411	CB fail	[redacted]	2004	No	Yes	Yes	7.39
	Local Control	[redacted]	2004	No	Yes	Limited	7.39

High impedance differential relays [redacted] are used to protect 110kV bus zones. These relays were installed in 2017 under CP.01679 Mudgeeraba 110kV primary and secondary systems replacement and are in good condition.

110kV Bus zone protection panels

[redacted] and [redacted] are used to manage the CB and control for bus couplers. There is only signle CB fail relays for both X and Y protection system. This does not comply with the National Electricity Rules. The health index shows that these protection relays will reach the end of technical asset life and need to be replaced with 5-6 years.

[redacted] RTUs are utilized for the function of control. These [redacted] RTUs have become obsolete. Powerlink had the last buy of [redacted]s in 2014 and has relied on these spares to maintian their operation.

110kV bus coupler protection panels are of the corridor construction type having separate protection and auxiliary panels. This type of construction is vulnerable to cause human error on mis-tripping of primary plant when maintenance is conducted and it is also expensive to modify because of the inter panel wiring. The current clearance does not comply with safety clearance requirements specified by ID&TS – SU0023 Clearance Requirements for Panels, Switchboard and Kiosks (Obj. ID: A2806489). These panels need to be replaced with major secondary system replacement.

110kV Bus section 3-4

110kV bus section 1-3

3.3.7 110kV feeder bays

Secondary systems for 110kV feeder bays are detailed in a table below.

Feeder	Relay & control	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
706	X	[redacted]	2017	Yes	Yes	Yes	1.16

Feeder	Relay & control	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
	Y	[redacted]	2017	Yes	Yes	Yes	1.16
	Y SAS Network	[redacted]	2017	Yes	Yes	Yes	1.60
754	X	[redacted]	2017	Yes	Yes	Yes	1.16
	Y	[redacted]	2017	Yes	Yes	Yes	1.16
	Y SAS Network	[redacted]	2017	Yes	Yes	Yes	1.60
755	X	[redacted]	2017	Yes	Yes	Yes	1.16
	Y	[redacted]	2017	Yes	Yes	Yes	1.16
	Y SAS Network	[redacted]	2017	Yes	Yes	Yes	1.60
757	X	[redacted]	2017	Yes	Yes	Yes	1.16
	Y	[redacted]	2017	Yes	Yes	Yes	1.16
		[redacted]	2017	Yes	Yes	Yes	1.16
758	X	[redacted]	2017	Yes	Yes	Yes	1.16
	Y	[redacted]	2017	Yes	Yes	Yes	1.16
		[redacted]	2017	Yes	Yes	Yes	1.16
779	X	[redacted]	2010	Yes	Yes	Yes	6.05
		[redacted]	2010	No	Yes	Yes	4.29
	Y	[redacted]	2010	Yes	Yes	Yes	5.37
	Local RTU	[redacted]	2010	No	Yes	Limited	5.91
780	X	[redacted]	2010	Yes	Yes	Yes	6.05
		[redacted]	2010	No	Yes	Yes	4.29
	Y	[redacted]	2010	Yes	Yes	Yes	5.37
	Local RTU	[redacted]	2004	No	Yes	Limited	7.38
7838	X	[redacted]	2005	No	Yes	Yes	7.46
	Y	[redacted]	2005	Yes	Yes	Yes	6.67
	Local RTU	[redacted]	2005	No	Yes	Limited	6.67
7839	X	[redacted]	2005	No	Yes	Yes	7.46
	Y	[redacted]	2005	Yes	Yes	Yes	6.67
	Local RTU	[redacted]	2005	No	Yes	Limited	6.67
794	X	[redacted]	2008	No	Yes	Yes	6.54
	Y	[redacted]	2008	Yes	Yes	Yes	5.26
	Local RTU	[redacted]	2004	No	Yes	Limited	7.25

Secondary systems for feeder 706,754, 755, 757 and 758 were replaced in 2017 under CP.01679 Mudgeeraba 110kV primary and secondary systems replacement and are in good condition.

Feeder 706, 754, 755, 757 and 758 protection and control panel

Secondary systems for Feeders 779 and 780 were replaced in 2010. They are facilitated within swing frame panels and have been providing reliable operations. There are no condition driven replacement required except the bay controller [redacted] RTUs which have become obsolete and need to be replaced within 5-6 years.

Feeder 779 and 780 protection and control panel

Secondary systems for feeder 7838 and 7839 were replaced in 2005. Health index indicates that protection control equipment will reach the end technical asset life and need to be replaced within 5-6 years.

Feeder 7838 and 7839 protection panel and interior

Protection relays for feeder 794 were replaced to coincide with Energex works at T128 Robina in 2008. The bay controller [redacted] were installed in 2004. [redacted] RTU has become obsolete. Powerlink had the last buy of [redacted]s in 2014 and has relied on limited spares to maintian their operation. The health index indicates that [redacted]RUT should be replaced within 5-6 years.

The panel was an original design with tunnel arrangement. The panel has exposed terminal in the rear of the panel which could cause safety issues. This type of construction is vulnerable to cause human error on mis-tripping of primary plant when maintenance is conducted and it is also expensive to modify because of the inter panel wiring. The current clearance does not comply with safety clearance requirements specified by ID&TS – SU0023 Clearance Requirements for Panels, Switchboard and Kiosks (Obj. ID: A2806489). These panels need to be replaced with major secondary system replacement.

Fdr 794 protection and control panel

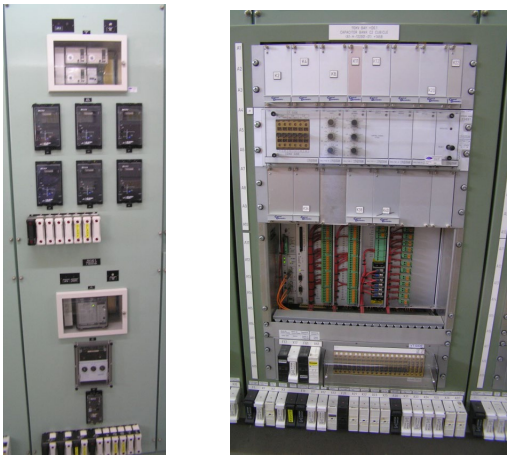
Inside of corridor panel

3.3.8 110kV Capacitor bank

Secondary systems for 110kV capacitor bank are detailed in a table below:

Capacitor	Relay & control	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
2 CAP	X	[redacted]	1995	No	No	Yes	10.00
		[redacted]	1994	Yes	Yes	Yes	10.00
	Y	[redacted]	1994	Yes	Yes	Yes	10.00
		[redacted]	1996	No	No	Yes	10.00
	CB Fail	[redacted]	2000	No	Yes	Yes	7.41
	Point On Wave	[redacted]	2011	Yes	Yes	Yes	4.17
	Local RTU	[redacted]	2004	No	Yes	Limited	7.41

Secondary systems on 110kV 2 Capacitor bank were commissioned in 1990s. Electro-mechanical relays such as electronic relay [redacted] and [redacted] have become obsolete as no technical support is available from the manufacturers. Both X and Y relays need to be replaced within 2 years while POW and the bay control RTU need to be replaced within 5-6 years. The corridor construction type of panel has separate protection and auxiliary panels. This type of construction is vulnerable to cause human error on mis-tripping of primary plant when maintenance is conducted and it is also expensive to modify because of the inter panel wiring. The current clearance does not comply with safety clearance requirements specified by ID&TS – SU0023 Clearance Requirements for Panels, Switchboard and Kiosks (Obj. ID: A2806489). These panels need to be replaced with major secondary system replacement.



2 CAP protection and control panel

3.3.9 110/33kV 4 Transformer bay

Secondary systems for 110/33kV 4 Transformer bay are detailed in a table below.

Transformer	Relay & control		Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
4T	110kV	X	[redacted]	2007	No	Yes	Yes	5.61
		Y	[redacted]	2007	Yes	Yes	Yes	5.61
		Local RTU	[redacted]	2007	No	Yes	Limited	5.91

Protection and control device on 4 Transformer are mounted on a swing frame panel were commissioned in 2006. [redacted] RTU has become obsolete. Powerlink had the last buy of [redacted]s in 2014 and has relied on limited spares to maintian their operation. The health index indicates that secondary systems for 4 Transformer will reach the end of techinical asset lfe and should be replaced in 10 years.

4T Protection and control panel

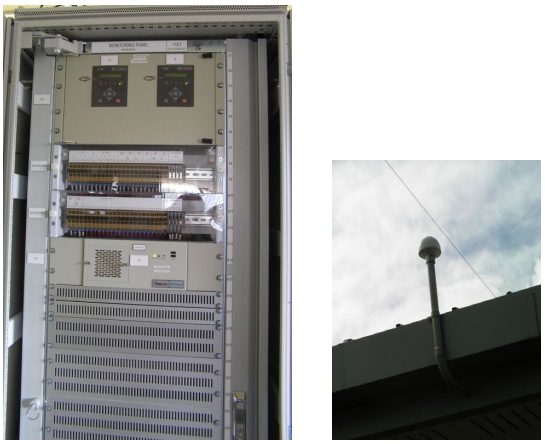
3.3.10 Power System Control and Monitoring

Power system control and monitoring equipment is detailed in a table below:

Power System Control and monitoring	Relay & control	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
Monitoring	HSM	[redacted]	2010	No	Yes	Yes	4.12
		[redacted]	2010	No	Yes	Yes	6.28
	PQM	[redacted]	2012	Yes	Yes	Yes	2.45
		[redacted]	2012	Yes	Yes	Yes	2.45
Control System (ECS)	Common RTU	[redacted]	2000	No	Yes	Limited	9.50
U/F load shedding	/	[redacted]	1992	No	No	Yes	10.00

A) High Speed Monitoring (HSM)

High Speed Monitoring (HSM) was implemented to provide synchronized information for AEMO and Powerlink to manage and investigate power system incidents. Dedicated GPS clock has been installed for HSM to provide high accurate synchronized information. These 32 channel [redacted] was commissioned in 2010 and are in fair condition. There is no condition driven replacement required within 10 years.



High Speed Monitoring with dedicated GPS

B) Power Quality Monitoring (PQM)

[redacted] devices have been installed to monitoring the power quality of 110kV network at H004 Mudgee. These devices were installed at 2012 and are in good condition.

Power Quality Monitoring Panel

C) Mudgeeraba Emergency Control System (ECS)

A plant overload and under-voltage load shedding scheme has been implemented in the Common RTU. This scheme is referred as the Emergency Control System (ECS) and has been designed to automatically prevent overloading of Powerlink plant due to the operation of the Country Energy Direct Link DC Link at T174 Terranora. The common RTU [redacted] has become obsolete and there are only limited spares available. The health index indicates that this RTU will reach the end of technical asset life and need to be replace within 2-3 years.

Common RTU

D) Under Frequency Load Shedding Scheme

Underfrequency load shedding scheme was used to trip feeder 757 and 758 when the system experiences under frequency issue. Operation has confirmed that this scheme is not required and will be decommissioned under CP.01679 in 2018.

U/F load shed panel

3.4 Metering

Secondary systems for metering at H004 Mudgeeraba are listed in a table below:

Metering	Revenue and Check Meter	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
Feeder 754	Revenue	[redacted]	2004	No	Yes	Yes	7.29
	Check	[redacted]	2004	No	Yes	Yes	7.29
Feeder 755	Revenue	[redacted]	1999	No	Yes	Yes	9.82
	Check	[redacted]	1999	No	Yes	Yes	9.82
Feeder 794	Revenue	[redacted]	2004	No	Yes	Yes	7.29
	Check	[redacted]	2004	No	Yes	Yes	7.29
Feeder 706	Revenue	[redacted]	2004	No	Yes	Yes	7.29
	Check	[redacted]	2004	No	Yes	Yes	7.29
Feeder 779	Revenue	[redacted]	2005	No	Yes	Yes	6.67
	Check	[redacted]	2009	No	Yes	Yes	4.89
Feeder 780	Revenue	[redacted]	1999	No	Yes	Yes	9.82
	Check	[redacted]	2004	No	Yes	Yes	7.29
Feeder 7838	Revenue	[redacted]	2005	No	Yes	Yes	6.67
	Check	[redacted]	2005	No	Yes	Yes	6.67
Feeder 7839	Revenue	[redacted]	2005	No	Yes	Yes	6.67
	Check	[redacted]	1999	No	Yes	Yes	9.84

Feeder 757	Revenue	[redacted]	1997	No	Yes	Yes	10.00
	Check	[redacted]	2010	No	Yes	Yes	4.12
Feeder 758	Revenue	[redacted]	1997	No	Yes	Yes	10.00
	Check	[redacted]	1999	No	Yes	Yes	10.00

EDMI energy metering devices are utilized to meter feeder 754, 755, 794, 706, 779, 780, 7838, 7839, 757 and 758. Substation extension at H004 Mudgerabah has resulted in mixture of metering devices from 1997 to 2010.

Metering devices for Feeder 754, 755, 794, 706, 779, 780, 757 and 758 are housed in a type of corridor panel construction. This type of construction is vulnerable to cause human error on mis-tripping of primary plant when maintenance is conducted and it is also expensive to modify because of the inter panel wiring. The current clearance does not comply with safety clearance requirements specified by ID&TS – SU0023 Clearance Requirements for Panels, Switchboard and Kiosks (Obj. ID: A2806489). These panels need to be replaced with associated major secondary system replacement.

Meters on feeder 754, 755, 794, 706, 779 & 780

Meters on feeder 757 & 758

Metering recorders [redacted] (TransGrid Assets) for Feeder 757 & 758 Terranora used to provide metering information for TransGrid and Country Energy and are now out of service and can be decommissioned.

[redacted] solid state recorder

Meters on Feeder 7838 and 7839 are mounted on a swing frame panel. Metering equipment was installed in 2005. The health index indicates that these devices will reach the end of technical asset life and need to be replaced within 5-7 years.

Meters on Feeder 7838 & 7839

3.5 Non-bays

Secondary systems for Non-bays at H004 Mudgeeraba are detailed in the following table:

NBay	Relay & control	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
Local control	LCF RTU	[redacted]	2000	No	Yes	Limited	9.50
	HMI	[redacted]	2009	No	No	Limited	9.77
OpsWAN	Serial Port Server	[redacted]	2017	Yes	Yes	Yes	1.82
	Interface Rack	[redacted]	2017	Yes	Yes	Yes	1.82
	Ethernet Switch	[redacted]	2017	Yes	Yes	Yes	1.82
	WYSE	[redacted]	2017	Yes	Yes	Yes	1.82

NBay	Relay & control	Model	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index
	Terminal						
	Station Server	[redacted]	2017	Yes	Yes	Yes	1.82
Central control	Common RTU	[redacted]	2000	No	Yes	Limited	9.50
SCADA	NSC1	[redacted]	2000	No	Yes	Limited	9.50
	NSC2	[redacted]	2000	No	Yes	Limited	9.50
Site Core Switch	A	[redacted]	2017	Yes	Yes	Yes	1.87
	B	[redacted]	2017	Yes	Yes	Yes	1.87
SAS Core Switch	A	[redacted]	2017	Yes	Yes	Yes	1.87
	B	[redacted]	2017	Yes	Yes	Yes	1.87
Timing clock	Timing 1	[redacted]	2017	Yes	Yes	Yes	1.21
	Timing 2	[redacted]	2017	Yes	Yes	Yes	1.21
X Station Switch	/	[redacted]	2017	Yes	Yes	Yes	1.87
YY Station Switch	Switch 1	[redacted]	2017	Yes	Yes	Yes	1.87
	Switch 2	[redacted]	2017	Yes	Yes	Yes	1.87
YZ Station Switch	/	[redacted]	2017	Yes	Yes	Yes	1.87
Gateway	Gateway 11	[redacted]	2017	Yes	Yes	Yes	1.21
	Gateway 21	[redacted]	2017	Yes	Yes	Yes	1.21
Comms RTU	/	[redacted]	2017	Yes	Yes	Yes	0.93
	/	[redacted]	2017	Yes	Yes	Yes	0.93

3.5.1 SCADA, Control and OpsWAN

Currently there is one OptoNet ring for 275kV and 110kV, and SDM9 X and Y Network for some of 110kV bays.

SDM9 X and Y network were installed in 2017 and are in good condition.

SDM9 Network Panel

Dedicated SCADA paths have been implemented for 275/110kV secondary systems. The SCADA system in Ring 1 has independent NSC1 and NSC2 RTU to implement 2 x dual SCADA paths based on Conitel protocol. The SCADA Conitel protocol is being phased out because of expensive serial infrastructures, aging skill sets and low fault tolerance. This will be migrated to DNP over IP under CP.01679 in 2018. SCADA RTUs for NOC1 and NOC2 will reach the end of technical asset life and need to be replaced within 2-3 years.

Local control LCF RTU will reach the end of technical asset life and need to be replaced within 2-3 years. [redacted] is used for local control. There are only limited spares available. The HMI functionality of [redacted] will be integrate into new [redacted] application under CP.01679 in June 2018.

LCF and SCADA RTUs

HMI

Secondary systems for 110kV bus zones, Feeder 706, 754, 755, 757 and 758 were replaced with SDM9 design standard in 2017. Dedicated SCADA system which is housed in 2 x Site Infrastructure & MPLS panels, has been implemented and is in good condition. High speed OpsWAN facilities to interface with legacy system were replaced under CP.01679 in 2017. They are in good condition.

Site Infrastructure & MPLS panel 1 and 2

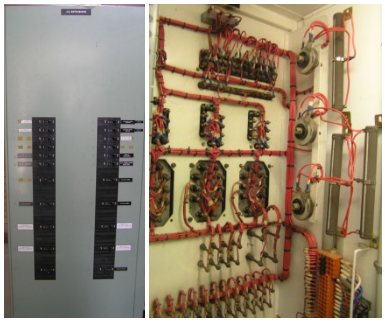
3.5.2 Auxiliary supply

The 415VAC auxiliary supplies are derived from two Energex 33kV/415V 300kVA station transformers. Standby AC supply is from an on-site 84kVA diesel generator and emergency AC supply is from a 15kVA diesel generator. Suitable monitoring and changeover arrangement are available for the site. The arrangement is considered acceptable for the situation.

AC changeover board

On site diesel generator

The AC distribution boards have 8 spare circuits available and there are 2 spare circuits on DC distribution boards. The AC distribution board in the control building is with the original design and use an exposed three phase bus for connecting to the circuit breakers. This type of circuit breaker is no longer available. Exposed terminal could cause potential safety issues. They should be replaced with major secondary system replacement.



AC Switch Board and exposed terminals

The dual 125VDC, 50VDC dual systems and associated distribution board were replaced in 2016 and are in good condition.


125VDC Batteries and charger

50VDC Batteries and charger

4. Summary Asset Health

The asset health of major equipment of H004 Mudgeeraba secondary system assets is determined by an assessment of the equipment aging profile, reliability, conditions (including the condition of panel wirings, control cables and marshalling cubicles) and obsolescence. Asset health index of equipment at H004 Mudgeeraba are summarized in the table below:-

275kV Bus and coupler	Relay & control		[redacted]	Startup Date	Still Manufactured?	Manufacture Support?	PLQ Spares	Health Index	Panel Condition	Cable to be replaced by	Marshalling Kiosk to be replaced by
1 Bus	X			2002	Yes	Yes	Yes	8.40	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2040	2040
				2002	No	No	Yes	9.62			
	Y			2016	Yes	Yes	Yes	1.34			
2 Bus	X			2002	Yes	Yes	Yes	8.40	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2040	2040
				1999	No	No	Yes	9.62			
	Y			2002	Yes	Yes	Yes	8.40			
Coupler 501	X			2002	No	Yes	Yes	8.40	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2040	2040
	Y			2002	No	Yes	Yes	8.40			
	RTU			2002	No	Yes	Limited	8.24			
Coupler 502	X			2002	No	Yes	Yes	8.40	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2021	2021
	Y			2002	No	Yes	Yes	8.40			
	RTU			2002	No	Yes	Limited	8.24			
Coupler 503	X			2002	No	Yes	Yes	8.40	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2021	2021
	Y			2002	No	Yes	Yes	8.40			
	RTU			2002	No	Yes	Limited	8.24			
1T	275kV	X		2002	No	No	Limited	8.40	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2040	2040
				2011	No	Yes	Yes	4.57			
		Y		2018	Yes	Yes	Yes	1.16			
		Backup		2002	No	No	Yes	8.36			
		X CB Fai		2002	No	Yes	Yes	8.40			
		Y CB Fai		2002	No	Yes	Yes	8.40			
		Local RTU		2002	No	Yes	Limited	8.24			
	110kV	CB Fail		2004	No	Yes	Yes	7.19	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2024	2024
		Local RTU		2004	No	Yes	Limited	7.19			
3T	275kV	X		2002	No	No	Yes	8.15	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2021	2021
				2011	No	Yes	Yes	4.57			
		Y		2002	Yes	Yes	Yes	8.26			
		Backup		2002	No	No	Yes	8.36			
		X CB Fai		2002	No	Yes	Yes	8.40			
		Y CB Fai		2002	No	Yes	Yes	8.40			
		Local RTU		2002	No	Yes	Limited	8.24			
	110kV	CB Fail		2004	No	Yes	Yes	7.21	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2045	2045
		Local RTU		2004	No	Yes	Limited	7.21			
5T	275kV	X		2017	Yes	Yes	Yes	1.16	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2021	2021
				2011	No	Yes	Yes	4.57			
		Y		2002	Yes	Yes	Yes	8.40			
		X CB Fai		2002	No	Yes	Yes	8.40			
		Y CB Fai		2002	No	Yes	Yes	8.40			
		Local RTU		2002	No	Yes	Limited	8.24			
	110kV	X CB Fai		2017	No	Yes	Yes	1.16	New swing frame	2056	2056
		Y CB Fai		2017	Yes	Yes	Yes	1.16			
		Local RTU		2017	No	Yes	Yes	1.16			
835	X			2003	No	Yes	Yes	7.60	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2040	2040
	Y			2006	No	Yes	Yes	6.16			
				2002	No	Yes	Yes	7.60			
	Prot Sig			2001	No	Yes	Yes	8.59			
				2001	Yes	Yes	Yes	8.59			
	CB Fail X			2002	No	Yes	Yes	8.40			
	CB Fail Y			2002	No	Yes	Yes	8.40			
	Local RTU			2002	No	Yes	Limited	8.36			
836	X			2006	No	Yes	Yes	6.15	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system	2040	2040
				2003	No	Yes	Yes	7.60			
	Y			1997	No	Yes	Yes	10.00			

	Prot Sig		[redacted]	2001	No	Yes	Yes	8.59	replacement	
				2001	Yes	Yes	Yes	8.59		
	CB Fail X			2002	No	Yes	Yes	8.40		
	CB Fail Y			2002	No	Yes	Yes	8.40		
	Local RTU			2002	No	Yes	Limited	8.36		
4 CAP	X			2002	Yes	Yes	Yes	8.06	Swing Frame Panel to be updated according to SU0020 with major secondary system replacement	2040	2040
				2002	Yes	Yes	Yes	8.06		
				2002	Yes	Yes	Yes	8.06		
	Y			2002	No	Yes	Yes	8.06		
				2002	Yes	Yes	Yes	8.06		
	POW			2002	No	No	Yes	8.06		
	Local RTU			2002	No	Yes	Limited	8.06		
Bus zones	X			2017	Yes	Yes	Yes	1.16	New Swing Frame Panel	2056	2056
				2017	Yes	Yes	Yes	1.16			
				2017	Yes	Yes	Yes	1.16			
	Y			2017	Yes	Yes	Yes	1.16			
				2017	Yes	Yes	Yes	1.16			
Coupler 401	CB fail			2004	No	Yes	Yes	7.39	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2056	2056
	Local Control			2004	No	Yes	Limited	7.39			
Coupler 411	CB fail			2004	No	Yes	Yes	7.39	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2056	2056
	Local Control			2004	No	Yes	Limited	7.39			
706	X			2017	Yes	Yes	Yes	1.16	New Swing Frame Panel	2056	2056
	Y			2017	Yes	Yes	Yes	1.16			
	Y SAS Network			2017	Yes	Yes	Yes	1.83			
754	X			2017	Yes	Yes	Yes	1.16	New Swing Frame Panel	2056	2056
	Y			2017	Yes	Yes	Yes	1.16			
	Y SAS Network			2017	Yes	Yes	Yes	1.83			
755	X			2017	Yes	Yes	Yes	1.16	New Swing Frame Panel	2056	2056
	Y			2017	Yes	Yes	Yes	1.16			
	Y SAS Network			2017	Yes	Yes	Yes	1.83			
757	X			2017	Yes	Yes	Yes	1.16	New Swing Frame Panel	2056	2056
	Y			2017	Yes	Yes	Yes	1.16			
				2017	Yes	Yes	Yes	1.16			
758	X			2017	Yes	Yes	Yes	1.16	New Swing Frame Panel	2056	2056
	Y			2017	Yes	Yes	Yes	1.16			
				2017	Yes	Yes	Yes	1.16			
779	X			2010	Yes	Yes	Yes	6.05	Swing Frame Panel to be updated according to SU0020 with major secondary system replacement	2056	2056
				2010	No	Yes	Yes	4.29			
	Y			2010	Yes	Yes	Yes	5.37			
	Local RTU			2010	No	Yes	Limited	5.91			
780	X			2010	Yes	Yes	Yes	6.05	Swing Frame Panel to be updated according to SU0020 with major secondary system replacement	2056	2056
				2010	No	Yes	Yes	4.29			
	Y			2010	Yes	Yes	Yes	5.37			
	Local RTU			2004	No	Yes	Limited	7.38			
7838	X			2005	No	Yes	Yes	7.46	Swing Frame Panel to be updated according to SU0020 with major secondary system replacement	2044	2044
	Y			2005	Yes	Yes	Yes	6.67			
	Local RTU			2005	No	Yes	Limited	6.67			
7839	X			2005	No	Yes	Yes	7.46	Swing Frame Panel to be updated according to SU0020 with major secondary system replacement	2044	2044
	Y			2005	Yes	Yes	Yes	6.67			
	Local RTU			2005	No	Yes	Limited	6.67			
794	X			2008	No	Yes	Yes	6.54	Tunnel panel to be replaced to	2046	2046

	Y		[redacted]	2008	Yes	Yes	Yes	5.26	engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement		
	Local RTU			2004	No	Yes	Limited	7.25			
2 CAP	X			1995	No	No	Yes	10.00	Tunnel panel to be replaced to engineer out associated risks and ensure alignment with current safety standards with major secondary system replacement	2056	2056
				1994	Yes	Yes	Yes	10.00			
	Y			1994	Yes	Yes	Yes	10.00			
				1996	No	No	Yes	10.00			
	CB Fail			2000	No	Yes	Yes	7.41			
	Point On Wave			2011	Yes	Yes	Yes	4.17			
	Local RTU			2004	No	Yes	Limited	7.41			
4T	110kV	X		2007	No	Yes	Yes	5.61	Swing Frame Panel to be updated according to SU0020 with major secondary system replacement	2046	2046
		Y		2007	Yes	Yes	Yes	5.61			
		Local RTU		2007	No	Yes	Limited	5.91			
Monitoring	HSM			2010	No	Yes	Yes	4.12	Swing Frame Panel	2050	2050
				2010	No	Yes	Yes	6.28			
	PQM			2012	Yes	Yes	Yes	2.45			
				2012	Yes	Yes	Yes	2.45			
Control System (ECS)	Common RTU			2000	No	Yes	Limited	9.50		N/A	N/A
U/F load shedding	/			1992	No	No	Yes	10.00		N/A	N/A
Local control	LCF RTU			2000	No	Yes	Limited	9.50			
	HMI			2009	No	No	Limited	9.77			
OpsWAN	Serial Port Server			2017	Yes	Yes	Yes	1.82			
	Interface Rack			2017	Yes	Yes	Yes	1.82			
	Ethernet Switch			2017	Yes	Yes	Yes	1.82			
	WYSE Terminal			2017	Yes	Yes	Yes	1.82			
	Station Server			2017	Yes	Yes	Yes	1.82			
Central control	Common RTU			2000	No	Yes	Limited	9.50			
SCADA	NSC1			2000	No	Yes	Limited	9.50			
	NSC2			2000	No	Yes	Limited	9.50			
Site Core Switch	A			2017	Yes	Yes	Yes	1.87			
	B			2017	Yes	Yes	Yes	1.87			
SAS Core Switch	A			2017	Yes	Yes	Yes	1.87			
	B			2017	Yes	Yes	Yes	1.87			
Timing clock	Timing 1			2017	Yes	Yes	Yes	1.21			
	Timing 2			2017	Yes	Yes	Yes	1.21			
X Station Switch	/			2017	Yes	Yes	Yes	1.87			
YY Station Switch	Switch 1			2017	Yes	Yes	Yes	1.87			
	Switch 2			2017	Yes	Yes	Yes	1.87			
YZ Station Switch	/			2017	Yes	Yes	Yes	1.87			
Gateway	Gateway 11			2017	Yes	Yes	Yes	1.21			
	Gateway 21			2017	Yes	Yes	Yes	1.21			
Comms RTU	/			2017	Yes	Yes	Yes	0.93			
	/			2017	Yes	Yes	Yes	0.93			

5. Conclusion

Based on the condition assessment, the main recommendations for the replacement of secondary systems equipment at H004 Mudgeeraba are:-

1. Replace both X and Y protection relay of 110kV 2 Cap by 2020

2. Conduct following secondary system replacements by 2021:-
   - Replace all fuses with MCBs for 275kV bus marshalling kiosk and VT box
   - Replace auxiliary kiosks of diameter =C02 and =C03
   - Replace all fused with MCBs for Diameter =C01 Auxiliary kiosk
   - Cover the 415V AC terminals of marshalling kiosks, -A10, A20 and A30 for =C01, =C02 and =C03
   - Replace all fuses with MCBs for Feeder 835 and 836 VT boxes
   - Replace all secondary systems for 275kV 1 & 2 Bus zone including the panel and recover MFAC34 relay
   - Replace all secondary systems for 275kV coupler 501, 502 and 503 including the protection panel
   - Replace all secondary systems for Transformer 1, 3 and 5 (except T5 LV protection/control swing frame panel) including associated protection and control panels
   - Replace marshalling kiosk of 110kV T1
   - Replace all secondary systems for Feeder 835 and 836 including the protection/control panels
   - Replace all 275kV 4 Cap protection and control equipment and update the protection and control panel according SU0020
   - Replace NSC1, NSC2 and LCF C50 RTU
   - Replace Common C50 RTU and integrate ECS system into the new system
   - Replace AC distribution board in Building +1

3. Carry out following secondary system replacements by 2024:-

   - Replace the Bay controller C50 RTU for 4T and 110kV 5T
   - Replace all secondary systems for 110kV coupler 401 and 411 including protection and control panels
   - Replace [redacted] RTU for feeder 779 and 780
   - Replace all protection relay and control device for feeder 7838 and 7839 and update the protection panel according to SU0020
   - Replace all secondary systems for feeder 794 including associated protection and control panels
   - Replace all secondary systems for 110kV Cap 2 including associated protection and control panels
   - Replace all Revenue and check meters for feeder 754, 755, 794, 706, 779, 780, 757 and 758 including the metering panel
   - Replace all Revenue and check meters for feeder 7838 and 7839 and update the metering panel according to SU0020
   - Decommission Aptech SSR403 recorders for feeder 757 and 758

4. Replace secondary systems on following bays in 10 years:-

   - 110/33kV 4 transformer
   - Replace all protection relays for feeder 779 and 780
   - Power system monitoring including HSM and PQM

5. Replace secondary systems on following bays in 20 years:-
   - Replace all protection relays for 110kV Transformer 5

6. References

(1) National Electricity Rules (NER) Version 100, AEMC, 20/10/2017
(2) AM-POL-0463 Protection Design, Powerlink, 25/02/2014
(3) AM-POL-0970 Secondary Systems Design, Powerlink, 05/05/2009
(4) OSD - SCADA Requirements for Operational Purposes - Standard, Powerlink, 13/01/2016
(5) AM-POL-0169 Secondary Systems Maintenance Policy, Powerlink, 3/11/2008
(6) AM-POL-0053 AC and DC Supplies, Powerlink, 08/05/2014
(7) SU0023 Clearance Requirements for Panels, Switchboard and Kiosks, ID&TS, 06/05/2016
(8) SU0020 Updates to SDM8 Panels to Mitigate Safety in Design Concerns (Obj. ID: A2753457), 09/2017

Planning Report	20 August 2025
Title	CP.02729 Mudgeeraba 110kV Secondary Systems Replacement
Zone	Gold Coast
Need Driver	Emerging compliance risks arising from condition and obsolescence of Mudgeeraba's 110kV ageing secondary systems.
Network Limitations and statutory requirements	Mudgeeraba Substation is required to meet Powerlink Queensland's N-1-50MW/600MWh Transmission Authority reliability standard and maintain power transfer capability to the Gold Coast and to northern NSW via the Directlink HVDC converter stations.
Pre-requisites	None

Executive Summary

Ageing and obsolete 110kV secondary systems at Mudgeeraba Substation, as defined in Reference [1], are increasingly at risk of failing to comply with Schedule 5.1.9(c) of the National Electricity Rules and AEMO's Power System Security Guidelines[1].

Powerlink's 2025 Central scenario load forecast confirms there is an enduring need to maintain electricity supply into the Gold Coast zone. The removal or reconfiguration of the Mudgeeraba's 275/110kV Substation due to secondary system failure/obsolescence would violate Powerlink's N-1-50MW/600MWh Transmission Authority reliability standard and significantly impact the power transfer capability into the Gold Coast and northern NSW.

Therefore, there is an enduring need to maintain the current function and capacity of the Mudgeeraba Substation by replacing the at-risk 110kV secondary systems.

Table of Contents

[1] AEMO, Power System Operating Procedure SO_OP_3715, Power System Security Guidelines, V105, June 2024 (the Rules require AEMO to develop and publish Power System Operating Procedures pursuant to clause 4.10.1(b) of the Rules, which Powerlink must comply with per clause 4.10.2(b)).

1. Introduction

The Mudgeeraba Substation (H004) is located approximately 10km north of the Queensland-NSW border and is a major injection point into the Gold Coast zone. It is also the primary hub supplying Essential Energy's Terranora Substation and power to northern NSW via the Directlink HVDC converter stations.

Mudgeeraba Substation was initially established in 1970 as a 110kV switchyard and expanded circa 1997 by the establishment of the 275kV switchyard that is supplied from Greenbank via two 275kV single circuits to a fully switchable 275kV switchyard comprising two 275/110kV transformers.

The 110kV network from Molendinar to Mudgeeraba links the coastal bulk supply points at Southport, Surfers Paradise and Broadbeach via an underground cable network and an inland overhead 110kV network supplies Robina and Nerang substations. This network is owned and operated by Energy Queensland.

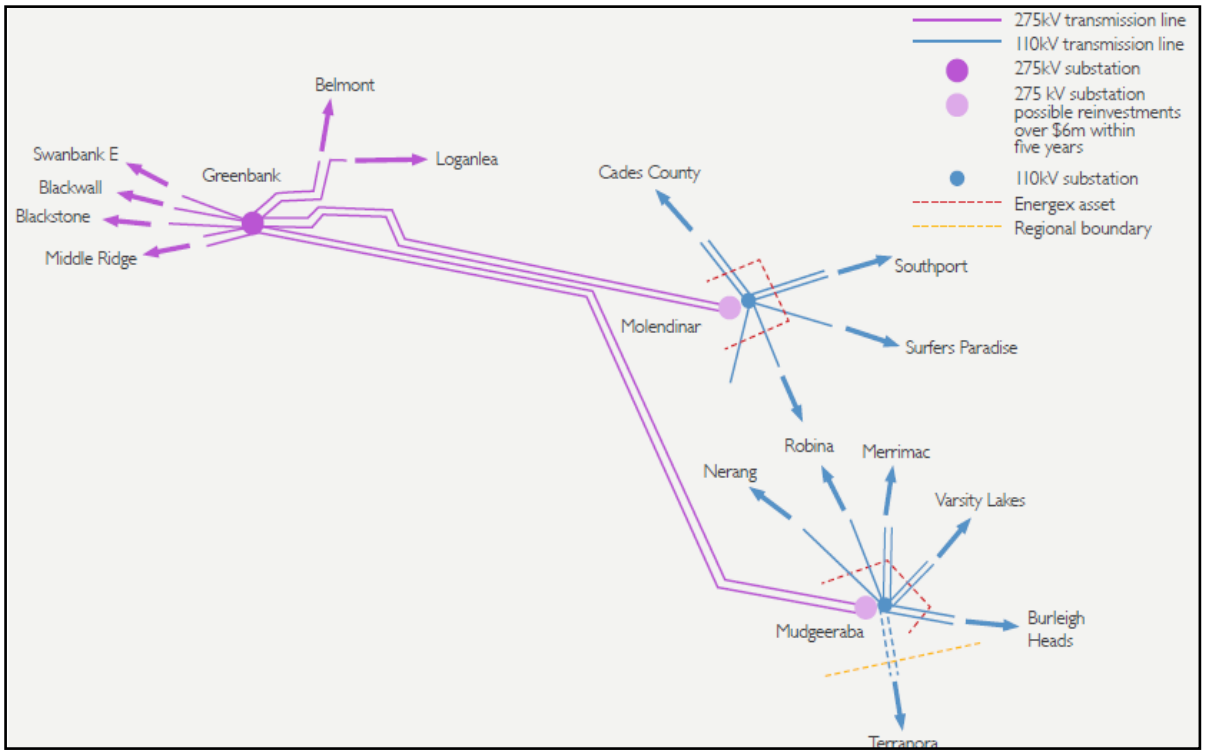


Figure 1. Mudgeeraba Substation – Gold Coast

The condition assessment [1] confirmed end of technical service life of the Mudgeeraba 110kV secondary systems equipment. There are condition and obsolescence issues, and related operational, safety and compliance risks with these assets remaining in service. Increasing failure rates, along with the increased time to rectify faults due to the obsolescence of the equipment, significantly affects the availability and reliability of these systems and their ability to continue to meet the requirements of the National Electricity Rules (the Rules).

In addition to the site-specific impacts of obsolescence at Mudgeeraba Substation, it is also important to note the compounding impact of equipment obsolescence occurring across the fleet of secondary systems assets installed in the Powerlink network. Running multiple secondary systems to failure across the network increases the likelihood of concurrent systemic faults with significant implications for network reliability and safety.

This report assesses the impact that removal of the functionality enabled by the at-risk secondary systems would have on the performance of the network and Powerlink's statutory obligations. It also establishes the indicative requirements of any potential alternative solutions to the current services provided by Mudgeeraba Substation.

2. H004 Mudgeeraba Substation configuration

The Mudgeeraba Substation was established in the early 1970s to supply the growing demand in the Southern Gold Coast zone. The 110kV switchyard of the substation consists of:

1. 2 x 275/110kV transformer bays
2. 9 x 110kV feeder/transformer bays for Energex
3. 1 x capacitor bank bay
4. 2 x 110kV feeder bays for Terranora feeders (towards Direct Link)

Figure 2 shows the existing connection configuration of the Mudgeeraba Substation, highlighting the 110kV switchyard.

Figure 2. Mudgeeraba 275/110kV Substation Line Dagram

3. Gold Coast Demand Forecast

Figure 3 shows that the maximum demand for the Gold Coast loads are forecasted to experience continuous growth in the coming years.

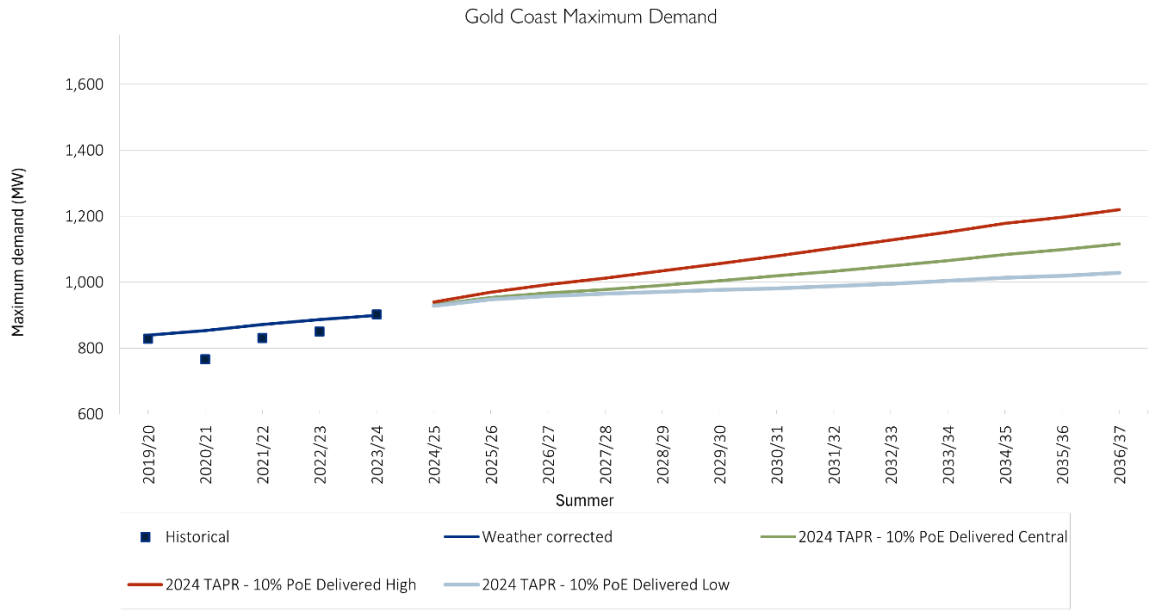


Figure 3. Gold Coast zone Maximum Demand

With consideration of rooftop PV within the Energex network supplied from Molendinar and Mudgeeraba substations, the maximum customer load is significantly higher. Figure 4 shows that rooftop PV meets up to 400MW of underlying demand.

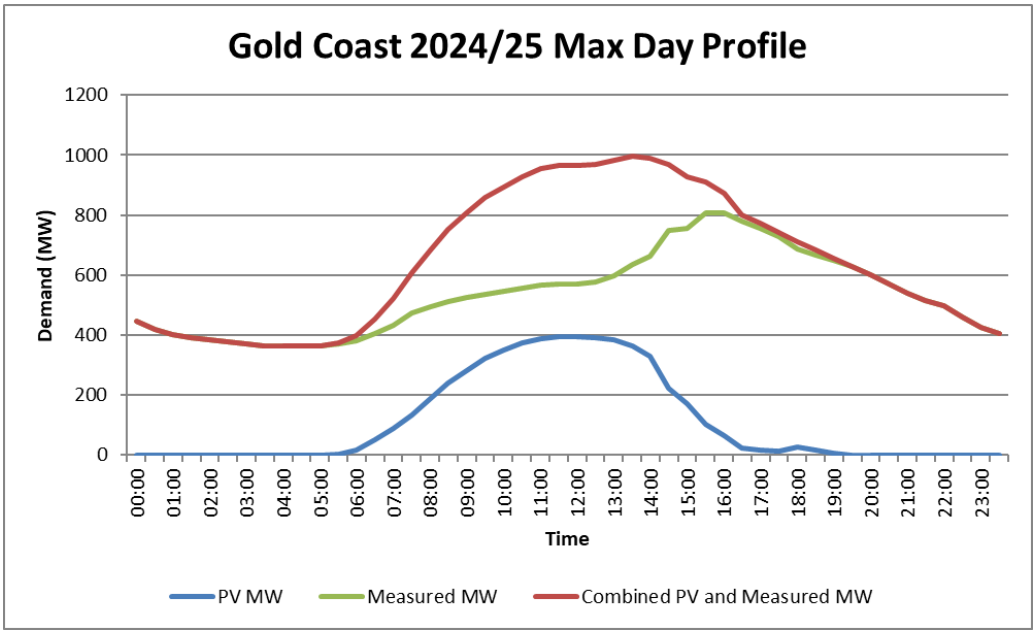


Figure 4. Gold Coast Max Day Profile 2024/25

Figure 5, shows the historical load duration curve of the Gold Coast zone with the contribution of rooftop PV excluded.

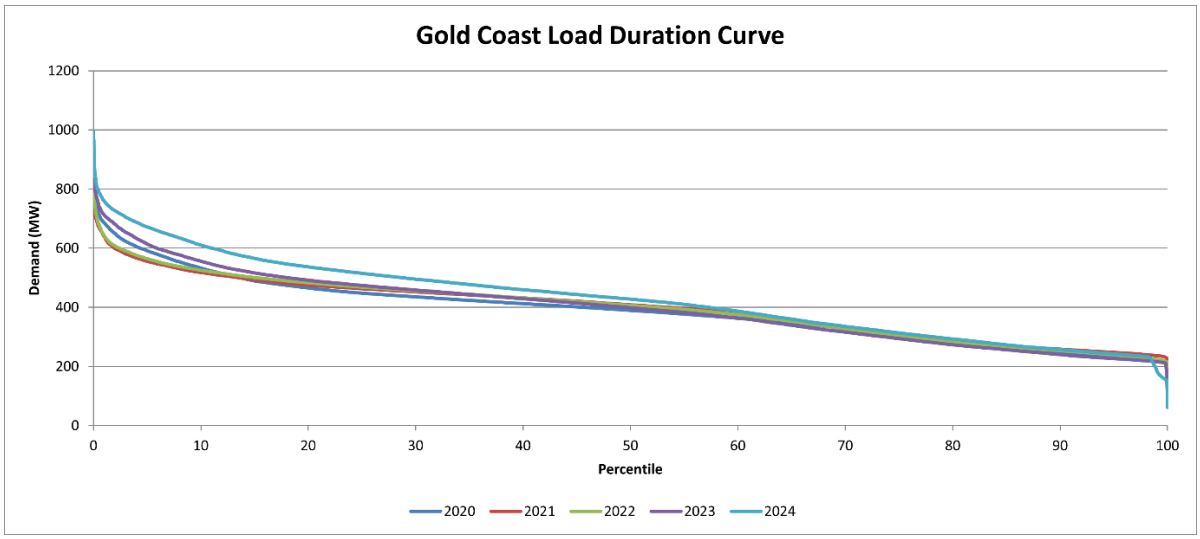


Figure 5. Gold Coast 110kV Load Duration Curve (rooftop PV out-of-service)

Figure 6, shows the comparative load duration curve for the delivered demand (i.e. with the contribution from the rooftop PV included).

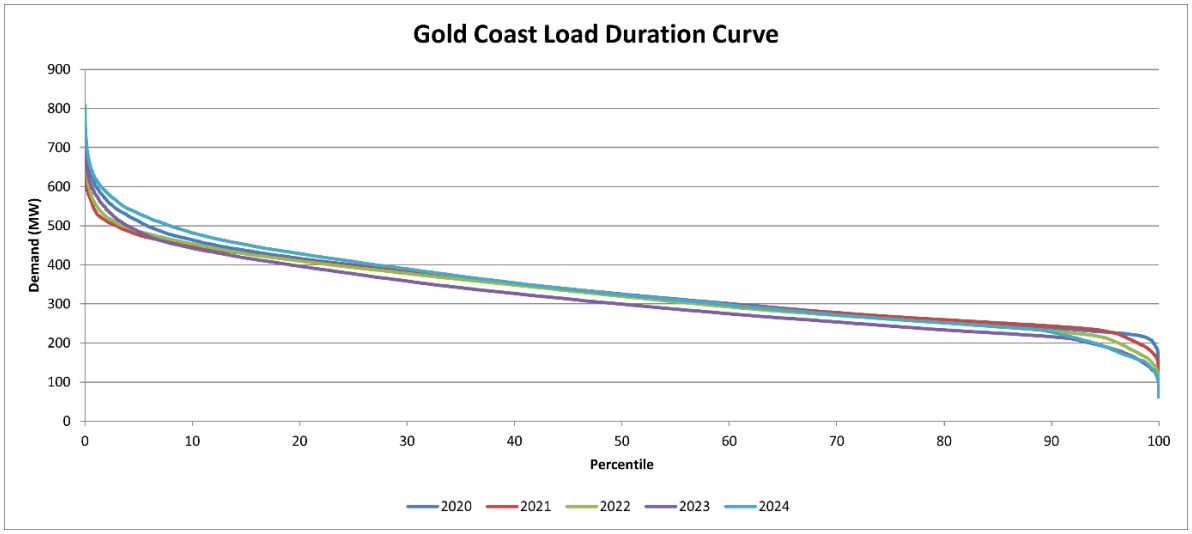


Figure 6. Gold Coast zone Load (rooftop PV in-service)

There are no new large block loads committed in the Gold Coast zone for the Central scenario forecast. However, there is an existing load that is investigating a potential 20MVA increase in its maximum demand within the forecast period. This is not yet committed but, if so it would be supplied from Varsity Lakes and Terranora.

4. Statement of Investment Need

As outlined in the Section 3, the Mudgeeraba Substation is a major bulk supply point for Energex (Energy Queensland) loads in the Gold Coast zone. Therefore, addressing the risks arising from the condition of the secondary systems by removing the functionality of the 110kV switchyard essentially disconnects Mudgeeraba Substation from the network. This would have a major impact on the performance of the Gold Coast grid section as well as impact the reliability of supply to the major load centres in the Southern Gold Coast zone.

Therefore, replacement of the secondary systems at the Mudgeeraba 110kV switchyard is required to allow continued operation of the substation and avoid system failures that would result in loss of load exceeding Powerlink's N-1-50MW / 600MWh Transmission Authority reliability standard. There would also be no capability to transfer power to northern NSW via the Directlink HVDC converter stations.

5. Network Risk

Table 1 defines the maximum and average forecast load suppled from the 110kV at Mudgeeraba (including Terranora) for summer 2028/29. The underlying load values represent the actual customer load (i.e. exclude the contribution for rooftop PV).

Table 2 summarises the results of analysis to determine the load and energy at risk for loads connected to the Mudgeeraba Substation. The estimates take into account the expected level of rooftop PV connected to the Energex network supplied from Mudgeeraba. This level of rooftop PV is discounted to capture the total level of customer load at risk of not being supplied.

It is assumed in this analysis that long term outages will occur and therefore any possible load transfers would not be sustained. In determining the forecasted load for Terranora substation, it will also be assumed that the embedded generator (Condong) may not be able to provide any support to the load as it is a non-scheduled generator. Directlink could be instructed to supply the load at Terranora, only if market conditions in NSW permits. Thus, in scenarios causing the loss of supply at Mudgeeraba, Terranora load will also be shed as well.

In the event of a Mudgeeraba 275/110kV transformer outage, the network is split such that the system is secure (refer to Appendix for network configuration). In doing so, load at Burleigh, Varsity Lakes, Merrimac, Terranora and local Mudgeeraba load will be at risk for the next contingency.

Table 1. South Gold Coast and Terranora Load Summary

Measure	2028/29
Max Underlying Load (MW)	457
Avg Underlying Load (MW)	178
Max Delivered Load (MW)	293
Avg Delivered Load (MW)	122

Table 2 below details the underlying load and energy at risk for critical outage pairs.

Table 2. South Gold Coast and Terranora underlying Load at Risk

At Risk	Contingency	Metric	2029
Mudgeeraba, Burleigh, Varsity Lakes, Merrimac, Terranora	275/110kV transformers (1T & 5T)[2]	Max (MW) > capacity limit	451
		Annual Average (MW) > capacity limit	176
		24h Potential Energy Constrained Max (MWh)	6590
		24h Potential Energy Constrained Annual Average (MWh)	4227
Terranora 33kV	110kV Feeders into Terranora (757 & 758)[3]	Max (MW) > capacity limit	117
		Annual Average (MW) > capacity limit	32
		24h Potential Energy Constrained Max (MWh)	1601
		24h Potential Energy Constrained Annual Average (MWh)	773
Mudgeeraba 33kV	Loss of 110/11kV transformer (4T)	Max (MW) > capacity limit	23
		Annual Average (MW) > capacity limit	1
		24h Potential Energy Constrained Max (MWh)	131
		24h Potential Energy Constrained Annual Average (MWh)	35
Varsity Lakes 11kV	110kV Feeders to Varsity Lakes (F839 & F838)	Max (MW) > capacity limit	66
		Annual Average (MW) > capacity limit	18
		24h Potential Energy Constrained Max (MWh)	806
		24h Potential Energy Constrained Annual Average (MWh)	428
Burleigh Heads (11kV, 33kV)	110kV Feeders to Burleigh Heads (754 & 755)	Max (MW) > capacity limit	220
		Annual Average (MW) > capacity limit	68
		24h Potential Energy Constrained Max (MWh)	3244
		24h Potential Energy Constrained Annual Average (MWh)	1625
Robina		Max (MW) > capacity limit	59
		Annual Average (MW) > capacity limit	25

[2] For the outage of 275kV injection into Mudgeeraba, the 110kV overhead and cable networks between Molendinar and Mudgeeraba would need to be split. This double outage would also result in the Directlink HVDC system tripping as it requires an AC supply at both ends to operate. Therefore, all of the Terranora load would also be lost.

[3] For the outage of 110kV double circuit between Mudgeeraba and Terranora, the Directlink HVDC system would also trip as the HVDC system requires AC supply at both ends to operate. There is little to no transfer capability to transfer load off Terranora (~1MVA).

		24h Potential Energy Constrained Max (MWh)	1164
		24h Potential Energy Constrained Annual Average (MWh)	604
Nerang		Max (MW) > capacity limit	115
		Annual Average (MW) > capacity limit	36
		24h Potential Energy Constrained Max (MWh)	1441
		24h Potential Energy Constrained Annual Average (MWh)	869

6. Market Impact

The Directlink HVDC system connects Bungalora to Mullumbimby in Northern NSW (refer to Figure 7). Bungalora connects to Terranora at 110kV. As HVDC system requires AC supply at both ends to operate. As a result, a double circuit outage between Mudgeeraba and Terranora results in the HVDC system being out of service.

The outage of the HVDC reduces the overall power transfer capability between Queensland and NSW. To the extent that there is headroom on the AC interconnector (QNI), operationally this lost capacity can the picked up across QNI. However, this will not always be the case and as such there will be times when the market will be constrained.

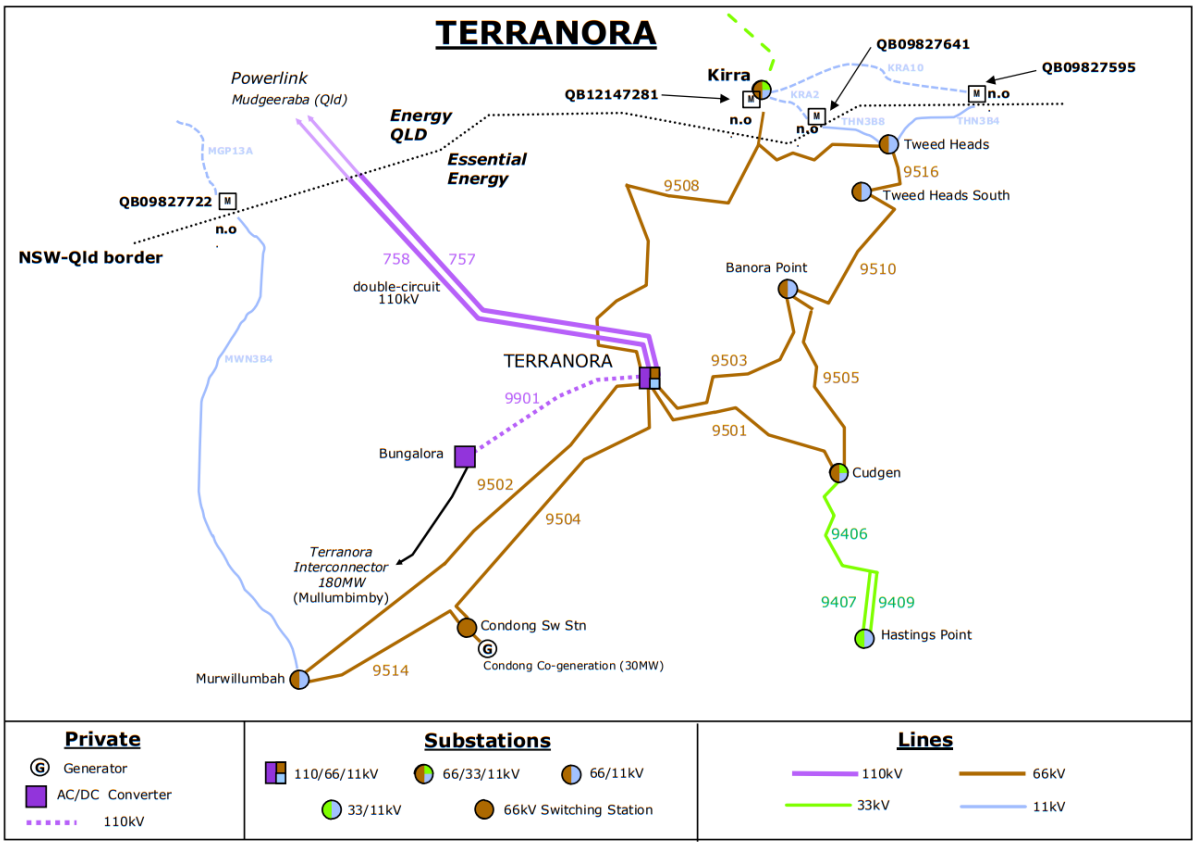


Figure 7. Northern NSW network

Table 3 defines the maximum and average difference in total system costs (including emission reduction benefits) per 24-hour period with the HVDC system removed from service. The analysis assumes that there is not impact on the generation investment pathway as a result of this outage.

The methodology used to assess these market impacts is outlined in Appendix B.

Table 3. Market impact of removing the Directlink HVDC system from service

At Risk	Contingency	Metric	$M
Loss of Directlink HVDC system	110kV Feeders into Terranora (757 & 758)[4]	Max 24h incremental system cost ($m)	1.883
		Average 24h incremental system cost ($m)	0.173

7. Non-Network Options

The Mudgeeraba Substation facilitates 275kV flow between Brisbane and the Gold Coast zone. The substation hosts two 275/110kV transformers to supply to Energex loads in the southern area of the Gold Coast (including Terranora) and northern NSW via the Directlink HVDC converter stations.

To meet the Mudgeeraba demand, the non-network solution must be capable of delivering up to 300MW and 5200MWh of energy each day.

Powerlink is not aware of any Demand Side Solutions (DSM) in the Gold Coast zone supplied from Mudgeeraba Substation. However, Powerlink will consider any proposed solution that can contribute significantly to the requirements of ensuring that Powerlink continues to meet its required reliability of supply obligations as part of the formal RIT-T consultation process prior to project approval.

8. Network Options

8.1 Proposed Option to address the identified need

To address the emerging age and obsolescence of the Mudgeeraba 110kV Substation secondary systems it is recommended that all secondary systems reaching end of life be replaced. This ensures that Powerlink's Transmission Authority reliability standard is maintained.

This option ensures that reliability of supply and asset condition criteria are met as well as maintaining the power transfer capability into the Gold Coast zone, Terranora and northern NSW via the Directlink HVDC converter stations.

[4] For the outage of 110kV double circuit between Mudgeeraba and Terranora, the Directlink HVDC system would also trip as the HVDC system requires AC supply at both ends to operate. There is little to no transfer capability to transfer load off Terranora (~1MVA).

Powerlink considers the proposed network solution will not have any material inter-network impact, and as such does not need to formally consult with other Market Participants.

8.2 Option Considered but Not Proposed

This section discusses alternative options that Powerlink has investigated but does not consider technically and/or economically feasible to address the above identified issues and thus are not considered credible options.

8.2.1 Do Nothing

“Do Nothing” would not be an acceptable option as the primary driver (secondary systems condition and obsolescence) and associated safety, reliability and compliance risks would not be addressed.

Furthermore, the “Do Nothing” option would not be consistent with good industry practice and would result in Powerlink breaching their obligations with the requirements of the System Standards of the National Electricity Rules and its Transmission Authority.

8.2.2 Decommission some functionality of Mudgeeraba 110kV Substation

Table 2 shows that the 275/110kV injection into Mudgeeraba is critical for Powerlink maintaining the N-1-50MW/600MWh Transmission Authority reliability standard. Without this injection:

- greater transformation capacity would need to be provided at Molendinar. This would drive the need to establish a 275kV bus at Molendinar and additional 110kV overhead and underground capacity between Molendinar and Mudgeeraba substations and between Loganlea and Molendinar. 275kV transmission limitations between Greenbank and Molendinar would also occur.

This is not a viable cost-effective option and has not been considered further.

In addition, not replacing the secondary systems associated with the 110kV bays for Varsity Lakes, Terranora, Burleigh Heads, Merriamc would not be cost-effective.

The bays connecting Robina and Nerang provide capacity to these Energex substations and also 110kV tie capacity between Molendinar and Mudgeeraba. Robina and Nerang could be supplied from a 110kV ring from Molendinar. However, removing this 110kV tie would result in overloading the coastal 110kV cable network, necessitating further investment.

There are one 110kV 50MVAr capacitor bank bays at Mudgeeraba (2 Cap). The capacitor bank is switched to maintain acceptable voltage profile and reactive power dispatch within the Gold Coast zone. It has been switched in up to 10% of time. This statistic would not include the full extent to which this capacitor bank would be required to be switched in post-contingent.

Figure 3 shows that the maximum demand in the Gold Coast zone is forecast to experience continuous growth in the coming years. Therefore, there is a growing need for this capacitive compensation.

Reactive power needs to be supplied locally. In addition, Mudgeeraba is not in a central location within the network where reactive power is more readily shared. Given the scarcity and value of land it is also very unlikely that large-scale battery energy storage systems will locate in the vicinity of Mudgeeraba and replace the enduring need for this capacitor bank.

9. Recommendations

Powerlink has assessed the condition of the secondary systems at Mudgeeraba 110kV Substation and concludes they will reach end of technical service life.

It is recommended that all secondary systems reaching end of life be replaced.

Retaining the Mudgeeraba 110kV Substation capacity and functionality will allow Powerlink to continue to meet its required reliability obligations (N-1-50MW/600MWh) and maintain the power transfer capability from Brisbane into the Gold Coast zone and to NSW via the Directlink HVDC converter stations.

10. References

1. H004 Mudgeeraba Secondary Systems Condition Assessment Report May 2019
2. Project Scope Report CP.02729 110kV Mudgeeraba Secondary Systems Replacement
3. 2025 Transmission Annual Planning Report (A6049612)
4. Asset Planning Criteria - Framework (ASM-FRA-A2352970)
5. Powerlink Queensland’s Transmission Authority T01/98

11. Appendix A – Network Risk methodology

Mudgeeraba 275/110kV Transformers

When the Gold Coast load exceeds approximately 550MW and one of the 275/110kV transformers at Mudgeeraba is out-of-service (T1 or T5), then the 110kV Energy Queensland network between Molendinar and Mudgeeraba must be opened to return the system to a secure state. The 110kV coastal lines between Broadbeach and Merrimac are to be opened alongside the inland 110kV overhead lines connecting to Mudgeeraba from Nerang and Robina. As a result, for the outage of the remaining 275/110kV transformer, the large load centres at Mudgeeraba, Varsity Lakes, Burleigh Heads, Merrimac and Terranora will be lost.

12. Appendix B – Market Impact Assessment

Market modelling was used to assess the operational market impact of network limitations that would result from an outage of the double circuit line between Mudgeeraba and Terranora substations due to secondary systems failure at Mudgeeraba 110kV Substation.

The market modelling approach is consistent with the regulatory investment test for transmission requirements that a market benefit "must be a benefit to those who consume, produce and/or transport electricity in the market, that is, the change in producer plus consumer surplus." Critically, a market benefit must not "include the transfer of surplus between consumers and producers".[5]

As such, the market impact is assessed by comparing the changes in costs for market participants due to the differences in the operational and maintenance costs (including fuel costs), changes in involuntary load shedding (at the value of customer reliability [VCR] [6]), and changes in greenhouse gas emissions (at the value of emissions reduction [VER] [7])

The market modelling simulations considered committed and anticipated generators were commissioned on time, coal units closed according to their announced dates (as of December 2025), and modelled generation and storage projects consistent with the Queensland Energy Roadmap 2025.[8] The profiles of demand and energy available for variable energy resources followed the 2015 weather reference year as published by AEMO, as being a year found to result in 'median' outcomes.

A schedule of generator planned outages was modelled. However, generator forced outages were not considered. Instead, a reserve requirement is maintained via a reserve constraint equation, and therefore unserved energy may be underestimated in some circumstances.

Appropriate network detail (in the form of network constraints or sub-regional transfer limits) was added to adequately represent the network capability across major grid sections.

The outage (e.g. the loss of Directlink HVDC system) was modelled as occurring in perpetuity to approximately capture the effect of this occurring at any time.

The market impact was then quantified as the differential total system cost (as above) for each hour between a base case with Directlink HVDC available against the state of the world with an outage of Directlink HVDC. Both the hourly and a moving 24-hour differential cost were determined.

The values in the report tables capture the maximum differential total system cost for any 24-hour period (averaged over the 5-year analysis period) and the average differential total system cost for a 24-hour period (over the 5-year analysis period).

[5] AER, November 2024, "Regulatory investment test for transmission", p4

[6] AER, December 2024, "Values of customer reliability: Final report on VCR values" available at

[7] AER, May 2024, "Valuing emissions reduction: AER guidance and explanatory statement"

[8] The State of Queensland (Queensland Treasury), October 2025, "Energy Roadmap"

Project Scope Report

CP.02729

Mudgeeraba 110kV Secondary Systems Replacement

Concept – Version 2

Document Control

Change Record

Issue Date	Revision	Prepared by	Reviewed by	Approved by	Background
21/12/2022	1	[redacted]	[redacted]	[redacted]	Initial PSR Concept Version 1
19/09/2025	2	[redacted]	[redacted]	[redacted]	Scope now includes CVT replacement.

Related Documents

Issue Date	Responsible Person	Objective Document Name
18/7/2018	[redacted]	PIF - H004 Mudgeeraba 110kV Secondary System Replacement - Project initiation Form A2952846
10/05/2019	[redacted]	H004 Mudgeeraba Secondary Systems Condition Assessment Report May 2019 A883976
	[redacted]	Concept Estimate for CP.02729 - H004 Mudgeeraba 110kV Secondary System Replacement Ver 1.0 A5341428

Document Purpose

The purpose of this Project Scope Report is to define the business (functional) requirements that the project is intended to deliver. These functional requirements are subject to Powerlink's design and construction standards and prevailing asset strategies, which will be detailed in documentation produced during the detailed scoping and estimating undertaken by DTS (or OSD), i.e. it is not intended for this document to provide a detailed scope of works that is directly suitable for estimating.

Project Contacts

Project Sponsor	[redacted]
Connection & Development Manager	[redacted]
Strategist – Digital Asset Strategies	[redacted]
Planner – Main/Regional Grid	TBD
Manager Projects	[redacted]
Project Manager	[redacted]
Design Manager	TBD

Project Details

1. Project Need & Objective

Mudgeeraba Substation is a 275kV/110kV substation located approximately 10km north of the Queensland-NSW border. It was initially established in 1970 as a 110kV switchyard and expanded circa 1997 by the establishment of the 275kV switchyard that is supplied from Greenbank by two 275kV single circuits to a fully switchable 275kV switchyard comprising three 275/110kV transformers. It is a major injection point into the Gold Coast area that also supplies the Essential Energy Terranora substation in northern NSW via Direct Link.

A condition assessment of the Mudgeeraba 110kV secondary systems equipment has identified condition and obsolescence issues, and related operational, safety and compliance risks with these assets remaining in service.

Project 1679, completed in 2018, addressed the replacement of selected 110kV secondary systems equipment at Mudgeeraba substation. The scope of this project will address replacement of the remaining 110kV secondary systems equipment, with delivery to be coordinated with the replacement of the current 275kV secondary systems replacement works under Project 2272.

Due to a high rate of premature failure and the difficulty of managing network risks under unplanned outages, Trench CVTs between 14 to 22 years of age will be replaced.

The objective of this project is the selected replacement of the 110kV primary plant and secondary systems at Mudgeeraba substation by December 2029.

This project will follow the two (2) stage approval process and is subject to a RIT-T.

2. Project Drawing

Figure 1 shows the location of the Mudgeeraba substation, while figure 2 shows the line diagram for the substation.

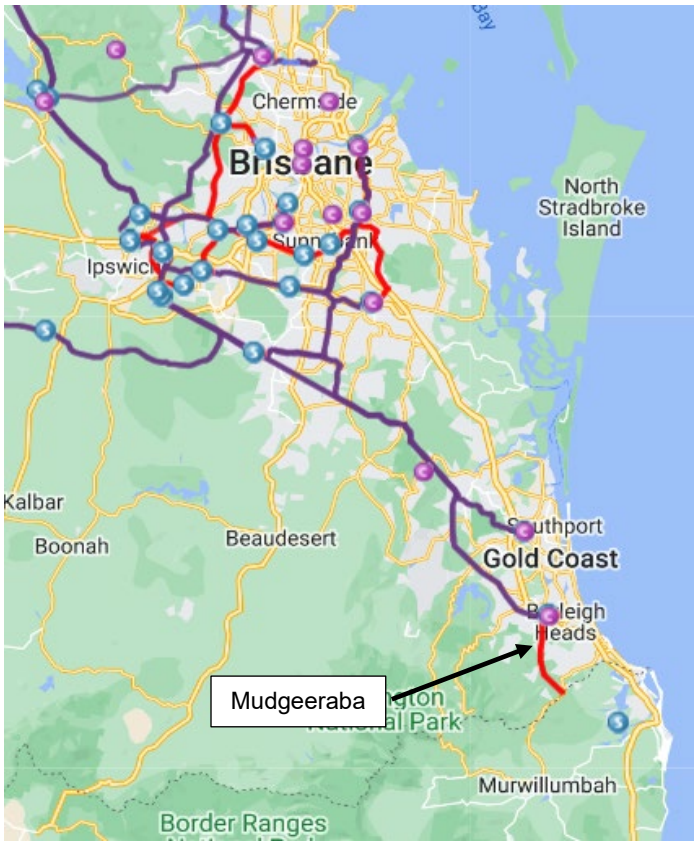


Figure 1 – Locality of H004 Mudgeeraba Substation

[redacted]

3. Deliverables

The following deliverables are to be provided for the purposes of Revenue Reset in response to this Project Scope Report. The requirement dates for these deliverables will be communicated separately.

1. A report (e.g. Concept Estimate Report) detailing the works to be delivered, high level staging, resource requirements and availability, and outage requirements and constraints;

2. A class 5 estimate (minimum);

3. Any existing assets to be removed and disposed of as part of this scope identified within the Proposal together with the forecast asset write off amounts at time of disposal; and

4. A basis of estimate document and risk table, detailing the key estimating assumptions and delivery risks.

4. Project Scope

4.1. Original Scope

The following scope presents a functional overview of the desired outcomes of the project. The proposed solution presented in the estimate must be developed with reference to the remaining sections of this Project Scope Report, in particular *Section 6 Special Considerations*.

Briefly, the project consists of the replacement of selected 110kV primary plant and secondary systems equipment at H004 Mudgeeraba Substation.

4.1.1. Transmission Line Works

Not Applicable

4.1.2. H004 Mudgeeraba Substation Works

Design, procure, construct and commission replacement of the following secondary systems equipment for the identified preferred option outlined in Section 11:

- Priority 1 Works

  Primary Plant:
  - Replacement of 18VT, 19VT, and 20VT to support the Trench CVT replacement program

  Secondary System:
  - Bus Coupler 401 and 411 control and protection panels
  - Feeders 7838 and 7839 control and protection panels.
  - Feeder 794 control and protection panel.
  - 110kV Cap 2 control and protection panel.

  - Revenue and check meters for feeders 754, 755, 794, 706, 779, 780, 757, 758, 7838 and 7839 including the metering panel
  - Implement new metering on the HV (110kV) of Transformer 4 to replace the Energex 33kV E1 and E2 connection meters. Install additional VTs, CTs or metering units as required
  - Decommission the Aptech SSR403 recorders on feeders 757 and 758
  - Replace the Bay controller C50 RTU for 110kV 5T

- Priority 2 Works
  - 4T control and protection panel.
  - Feeders 779 and 780 control and protection panels.
  - Replace IONS (OpsWAN) equipment (except OpsWAN camera) and relocate all devices (except the camera) from the OpsWAN camera housing at the top of the pole to the camera patch box at the base of the pole. Refer to ASM-FRM-A4982111 ETR 10434041.
  - Power system monitoring including High Speed Monitoring and Power Quality Monitoring

- Decommission and recover all redundant equipment, and update drawing records, SAP records, config files, etc. accordingly.

4.1.3. Remote end Substation Works

Modify protection, control, automation and communications systems as necessary. Liaise and coordinate remote end works nominally for connections to Energy Queensland substations at Burleigh, Varsity Lakes, Merrimac, Nerang, Robina, Terranora substations as required

4.1.4. Telecoms Works

As required to ensure functionality of the new protection equipment.

4.1.5. Easement/Land Acquisition & Permits Works

Not applicable

4.2. Key Scope Assumptions

Not Applicable

4.3. Variations to Scope (post project approval)

Not applicable

5. Key Asset Risks

The condition assessment has identified separate need dates for the 110kV secondary systems. Section 4.1.2 identifies replacement priorities based on the need dates. Delivery shall be programmed to prioritise replacement of the highest risk equipment.

Asset risk management shall be in accordance with the Asset Risk Management Process Guideline (A4870713).

6. Project Timing

6.1. Staged Approval Dates

The following approval for each stage are as below:

Stage 1 approval by 31/07/2028.

Stage 2 approval by 31/07/2029, subject to satisfactory completion of the RIT-T

6.2. Site Access Date

The expected site access date (SAD) when the site is available for Powerlink construction works to commence will be from date of project approval.

6.3. Commissioning Date

The latest date for the commissioning of the new assets included this scope of work and the decommissioning and removal of redundant assets, where applicable, is 30 December 2029.

7. Special Considerations

- The existing revenue metering point is installed at the LV side of T4, while the connection point is on the HV side of T4. The scope of work includes alignment of the metering point and connection point.

8. Asset Management Requirements

Equipment shall be in accordance with Powerlink equipment strategies

Unless otherwise advised Deni Mauro will be the Project Sponsor for this project. The Project Sponsor must be included in any discussions with any other areas of Network and Business Development including Asset Strategies & Planning. Project Sponsor should be kept informed of any discussions with the customer.

9. Asset Ownership

The works detailed in this project will be Powerlink Queensland assets.

10. System Operation Issues

Operational issues that should be considered as part of the scope and estimate include:

- interaction of project outage plan with other outage requirements;
- likely impact of project outages upon grid support arrangements; and

- likely impact of project outages upon the optical fibre network.

11. Options

Three options have been identified:

- Option 1 – Panel replacement in a new building
- Option 2 – Panel replacement in the existing building
- Option 3 – As per Option 2 except that in-panel replacement shall be estimated for the control and protection equipment for 4T, and feeders 779 and 780.

12. Division of Responsibilities

Not applicable

13. Related Projects

Project No.	Project Description	Planned Comm Date	Comment
Pre-requisite Projects			
CP.02272	Mudgeeraba 275kV Secondary Systems Replacement	31/12/2024	
OR.02256	Mudgeeraba T3 Decommissioning	30/06/2025	
Co-requisite Projects			
Other Related Projects			
CP.02984	Trench CVT Replacement – South Phase 1	31/12/2028	

CP.02729 H004 Mudgeeraba 110kV Secondary Systems Replacement

Concept Estimate

Table of Contents

1. Executive Summary

This concept estimate has been developed based on the CP.02729 – H004 Mudgeeraba 110kV Secondary Systems Replacement Project Scope Report (PSR).

Mudgeeraba Substation is a 275kV/110kV substation located approximately 10km north of the Queensland-NSW border. Established in 1970 as an 110kV switchyard and expanded in 1997, with the establishment of the 275kV switchyard and sharing a common platform and a perimeter fence.

The 275KV switchyard is supplied from Greenbank by two 275kV single circuits to a fully switchable 275kV switchyard comprising two 275/110kV transformers. It is a major injection point into the Gold Coast area that also supplies the Essential Energy Terranora substation in northern NSW via Direct Link.

A condition assessment of the Mudgeeraba 110kV secondary systems equipment has identified condition and obsolescence issues, and related operational, safety and compliance risks with these assets remaining in service and three credible options to replace the entire secondary systems have been identified to address the project needs with the selected replacement of the 110kV secondary systems at Mudgeeraba substation with implementation of priority 1 and priority 2 works.

Three options are requested for the replacement of the 110kV control panels for inclusion in the concept estimate:

1. Replacement of 110kV control panels in a new control building.
2. Replacement of 110kV control panels in the existing building; and,
3. Replacement of 110kV control panels in the existing building including an in-panel replacement option addressing 4T, and feeders 779 and 780 panels only.

Estimates are provided for each option to inform the feasibility of the project and to develop the basis for external consultation under the Regulatory Investment Test for Transmission (RIT-T). This project will follow the two (2) stage approval process.

2. Project and Site-Specific Information

2.1 Project Option Comparison

Option Comparison Table		Timing	Cost
Option 1	**Replacement of Control Panels in a New Control Building (Priority 1 and 2 works completed)**	**December 2029**	**$ 27,775,655**
Pros			
Management	• Complete AFC design packages for SPA contractor and MSP. • Single SPA "C" Construction contract. • Priority 1 and 2 works will be completed concurrently during the secondary systems cutover into new control building to reduce transmission network impacts. • All works will be completed in the 110kV section of the substation. • Standard PLQ management process. • Minimise risk of working with asbestos within existing control room. • Less secondary systems procurement – meters of cable to be installed by contractor.		
Resources	• Consistent PQ, MSP and SPA project resources to ensure continuity of works during the project. • Minimum OSD resource commitment due to comprehensive scope of works completed by others. • MSP has completed similar works. • SPA contractor has completed similar works.		
Network	• All secondary systems control panels same version of SDM architecture. • All secondary systems control panels located in the same control room. • Aligns all secondary systems equipment to the same maintenance schedule. • Single outages required for HV plant to complete works. • Load at risk minimised due to single outages to complete the project works. • Less network operational risk – works in new control room, 'greenfield' works. • Flexibility of securing outages in project proposal stage to align with network constraints.		
Cons			
Management	Project expenditure has limited flexibility.		
Resources	Possible delays to the project during the construction phase		
Network	Limited flexibility in execution phase due to the staged delivery and design packages		
Options Comparison Table		**Timing**	**Cost**
Option 2	**Replacement of Control Panels in the Existing Building**	**December 2029**	**$ 26,907,167**
Pros			
Management	• Complete AFC design packages for SPA contractor and MSP. • Single SPA "C" Construction contract.		

	• Priority 1 and 2 works will be completed together during the secondary systems cutover of new panels. • All works will be completed in the 110kV section of the substation. • Standard PLQ management process.
Resources	• Consistent PQ, MSP and SPA project resources to ensure continuity of works during the project. • Major OSD resource commitment due to comprehensive scope of works to be completed. • MSP has completed similar works. • SPA contractor has completed similar works
Network	• All secondary systems control panels in the same control building. • Single outages required for cutover and commissioning to complete works. • Load at risk minimised due to single outages to complete the project works. • Flexibility of securing outages to align with network constraints. • Aligns all secondary systems equipment to the same maintenance schedule. • Single outages required for HV plant to complete works.
Cons	
Management	• The HSE risks of working in the existing operational ‘live’ control room. • The identified Asbestos risks for all modification, installation and construction works within existing control room. • The design and construction work required to eliminate work within the confined space of the cable basement entry. • SPA contractor to install new panels in control room requires MSP resource to supervise all works conducted in the existing operational control room. • Design to eliminate any cable basement works.
Site	• Overall space and floor space constraints in control room to install new 110 kV control panels while existing in service panels remain. • All construction works in existing control room will require to be managed due to Asbestos and any confined space construction works required in the cable basement. • Upgrading of existing control room infrastructure to AS and PLQ standards. i.e. AC & DC supplies, Air conditioning, internal lighting, etc. • Restricted Cable Access points into existing control room for new cables. • Height constraints with control room for installation of cable tray.
Resources	• Additional MSP man hours required to load, transport, unload and installation of control panels and associated supporting infrastructure and materials i.e cable trays. • Additional MSP resource man hours to complete the works safely while managing the space restrictions within the existing control room. • Safety risks working inside operational control room and around adjacent live control panels. • Safety risks of working with the space constraints of the existing operational control building. • Confined spaces work in cable basement. • Manual handling risk of installing new panels in control room.

	• Additional FAT and SAT testing requirements during commissioning. • Building construction / modification works to be completed by third party contractor.		
Network	• All secondary systems control panels operate various versions of SDM architecture, SDM 7 and SDM 8 panels installed on site. • Extended outage durations to complete cutovers. • Risk of accidental network issues and inadvertent trips due to work to install and commission new panels in existing control room. • Restoration plans will be required for the extended outage works.		
Options Comparison Table		**Timing**	**Cost**
Option 3	**Replacement of Control Panels in the Existing Building, including an in-panel replacement option addressing 4T, and feeders 779 and 780.** **As per OPTION 2 + working in live panels**	**December 2029**	**$26,834,101**
Pros			
Management	• Complete AFC design packages for SPA contractor and MSP. • Single SPA “C” Construction contract. • Priority 1 and 2 works will be completed together during the secondary systems cutover of new panels. • All works will be completed in the 110kV section of the substation. • Standard PLQ management process.		
Resources	• Consistent PQ, MSP and SPA project resources to ensure continuity of works during the project. • Major OSD resource commitment due to comprehensive scope of works to be completed. • MSP has completed similar works. • SPA contractor has completed similar works		
Network	• All secondary systems control panels in the same control building. • Single outages required for cutover and commissioning to complete works. • Load at risk minimised due to single outages to complete the project works. • Flexibility of securing outages to align with network constraints. • Aligns all secondary systems equipment to the same maintenance schedule. • Single outages required for HV plant to complete works.		
Cons			
Management	• The HSE risks of working in the existing operational ‘live’ control panels • The HSE risks of working in the existing operational ‘live’ control room. • The identified Asbestos risks for all modification, installation and construction works within existing control room. • The design and construction work required to eliminate work within the confined space of the cable basement entry. • SPA contractor to install new panels in control room requires MSP resource to supervise all works conducted in the existing operational control room. • Design to eliminate any cable basement works.		

Site	• Overall space and floor space constraints in control room to install new 110 kV control panels while existing in service panels remain. • All construction works in existing control room will require to be managed due to Asbestos and any confined space construction works required in the cable basement. • Upgrading of existing control room infrastructure to AS and PLQ standards. i.e. AC & DC supplies, Air conditioning, internal lighting, etc. • Restricted Cable Access points into existing control room for new cables. • Height constraints with control room for installation of cable tray.
Resources	• Additional MSP man hours required to load, transport, unload and installation of control panels and associated supporting infrastructure and materials i.e cable trays. • Additional MSP resource man hours to complete the works safely while managing the space restrictions within the existing control room. • Safety risks working inside operational control room and around adjacent live control panels. • Safety risks of working with the space constraints of the existing operational control building. • Confined spaces work in cable basement. • Manual handling risk of installing new panels in control room. • Additional FAT and SAT testing requirements during commissioning. • Building construction / modification works to be completed by third party contractor.
Network	• All secondary systems control panels operate various versions of SDM architecture, SDM 7 and SDM 8 panels installed on site. • Extended outage durations to complete cutovers. • Risk of accidental network issues and inadvertent trips due to work to install and commission new panels in existing control room. • Restoration plans will be required for the extended outage works.

2.2 Project Dependencies & Interactions

This project is dependent on the completion delivery of the following projects:

Project No.	Project Description	Planned Commissioning Date	Comment
Dependencies			
N/A			

2.3 Site Specific Issues

H004 Mudgeeraba substation is located on Scottsdale Road, Varsity Lakes, Gold Coast, approximately 1.5 hours south from the Brisbane CBD

- Mudgeeraba substation is a 110/275kV operational substation with an electric fence that is accessed by swipe card pedestrian gate to disarm the electric substation fence and to gain internal access to main vehicular gate.
- The substation is located close to residential and commercial areas.
- All project works will be completed within 6m of surrounding live 110kV substation plant.
- Traffic control may be required for the safe access and egress from site for the new control room and equipment deliveries.
- Main Access Gate is flood prone during inclement weather.
- Unfavourable ground conditions in wet weather.
- Proposed utilisation of bored piers for all foundations due to known ground conditions.
- H004 Mudgeeraba has operational HV and secondary systems cables that are buried direct.
- Water course at NW (front) corner of substation, adjacent to the main gate.
- Existing OpsWAN camera is currently mounted on third party (Telstra) structure.

Environmental

- H004 Mudgeeraba works are in the following Biosecurity Zones.
  - Phylloxera Biosecurity Zone.
  - Sugar Cane Biosecurity Zone.
  - Banana Biosecurity Zone; and
  - Fire Ant Biosecurity Zone 2.
- The following Restricted or Prohibited Weeds have been previously identified within the area (refer EWP):
  - Lantana camara.
  - Spagneticola trilobata.
  - Senecio madagascariensis; and
  - Baccharis halimfolia.

Site Contamination

- Asbestos is known on site. Refer ‘Asbestos Register; and
- Unknown soil contamination levels below ground level of the 110kV substation pad.

3. Option 1 – Replacement of control panels in a new control building

3.1 Option Definition

3.1.1 Option Scope

Design, procure and install a new 110kV Control building and foundations, 110kV marshalling kiosks, associated secondary systems and site infrastructure cabling, underground conduits and cable pits and trenches.

Design, procure and install new metering 110kV CVT foundations and structures.

Design, procure, construct and commission replacement of the following secondary systems equipment.

- Bus Coupler 401 and 411 control and protection panels.
- Feeders 7838 and 7839 control and protection panels.
- Feeder 794 control and protection panel.
- 110kV Cap 2 control and protection panel.
- Revenue and check meters for feeders 754, 755, 794, 706, 779, 780, 757, 758, 7838 and 7839 including the metering panel.
- Implement new metering on the HV (110kV) of Transformer 4 to replace the Energex 33kV E1 and E2 connection meters. Install additional VTs, CTs or metering units.
- Decommission the [redacted] recorders on feeders 757 and 758.
- 4T control and protection panel.
- Feeders 779 and 780 control and protection panels.
- Replace IONS (OpsWAN) equipment (except OpsWAN camera) and relocate all devices (except the camera) from the OpsWAN camera housing at the top of the pole to the camera patch box at the base of the pole. Refer to ASM-FRM-A4982111 and ETR 10434041.

3.1.2 Major Scope Assumptions

Included in Concept Proposal

- New 110kV Control Building is proposed to be located at north end of 110kV yard, across the substation road from existing 275kV control building (+1).
- The proposed location of the new control room enables the cost-effective construction and delivery of the required extension to the site infrastructure for fire, site security and with the integration of the new 275kV control room +1.
- Additional cable trenches will be installed from the existing main cable trench to connect existing to the new control room.
- New cable trenches are proposed in each bay for the installation of new secondary systems cables due to space constraints.
- The 4T CVT Metering unit is to be installed on existing foundations and structures due to site space constraints with the current asset boundary and existing third-party equipment.
- As 4T is currently utilising a Bus VT, this assumption will reduce the risk of an extended transformer outage
- De-commissioning of Process Bus panels +1E9 and +1E10 to be added to project scope
- Metering compliant CVT's are approved for the required metering and protection purposes on:
    - FDR 706 Nerang
    - FDR's 780 & 7790 Merrimac
    - FDR's 754 & 755 Burleigh
- Includes additional civil works to construct required CVT foundations, additional marshalling kiosks foundations, cable conduits pits and cable trenches.
- All 110kV bay Marshalling kiosks and secondary system cables are being replaced.
- Resources will be available to complete the works.
- Network outages will be available to complete the cutover works as required.
- Procurement of long lead items align with project delivery requirements.

3.1.3 Scope Exclusions

- Replacement of Glass Insulators in O/H Strung bus.
- Replacement of all 'brown' insulators within 110kV substation outside agreed scope of works.
- Any works to review / redesign the current 4T bay general arrangement.
- All work to upgrade the existing control room and infrastructure to current AS standards and PQ Specifications.

3.2 Project Execution

3.2.1 Project Schedule

Option 1 – Replacement of control panels in a new 110kV control building

Task	Target Completion
Project Concept Estimate Submitted	November 2024
Request for Class 3 Estimate	October 2025
Project Proposal Submitted	May 2026
Project Stage 1 Approval	August 2026
Project Kick off meeting	August 2026
RIT-T Approval	February 2027
Full Project Stage 2 Approval	March 2027
SPA Contractor 'Notice to Proceed'	March 2027
MSP FAT Control Building	April 2027
SPA Contractor Mobilisation – Stage 1	May 2027
SPA Contractor PC date	December 2027
MSP Mobilisation	January 2028
MSP SAT H004	April 2028
MSP Secondary Systems Cutovers	April 2028 - July 2029
MSP - Removal of Redundant Equipment	August 2029 – December 2029
Project Commissioning Date	December 2029

3.2.2 Network Impacts

- Network Outages will be required to cutover and commission the new 110kV control kiosks the new control panels.
- The new kiosks will be fully wired to the new Control panels and tested prior to cut-over to minimise Network outage durations.
- Network Outage requirements

- Load at Risk – Gold Coast CBD and Northern NSW.
- Outages to be scheduled in shoulder and winter periods - Late March to October each year.
- Network Return to Service constraints.
- Detailed Restoration plans for network outages.

- It is not anticipated that Grid Support will be required.

3.2.3 Resourcing

The design works for the Primary, Secondary Systems and Telecommunications will be completed by internal Powerlink design staff. The construction works will be completed by a combination of the Maintenance Service Providers and Substation Panel contractors.

Task	Responsibility
Primary Design	Powerlink
Secondary Design	Powerlink
Construction	SPA Contractor
Commissioning	MSP

3.3 Project Estimate

		Sub Total $	Total ($)
Estimate Class	5		
Base Estimate – Un-Escalated (2025/26)			27,775,655
TOTAL			**27,775,655**

3.4 Project Financial Year Cash Flows

No escalation costs have been considered in this estimate.

DTS Cash Flow Table	Un-Escalated Cost ($)
To June 2026	138,889
To June 2027	8,779,619
To June 2028	16,459,202
To June 2029	1,444,231
To June 2030	857,215
To June 2031	96,500
TOTAL	**27,775,655**

4. Option 2 – Replacement of control panels in the existing building

4.1 Option Definition

4.1.1 Option Scope

Design, procure and install 110kV marshalling kiosks, associated secondary systems and site infrastructure cabling, underground conduits and cable pits and trenches.

Design, procure and install a new metering 110kV CVT foundations and structures.

Design, procure, construct and commission replacement of the following secondary systems equipment

- Bus Coupler 401 and 411 control and protection panels
- Feeders 7838 and 7839 control and protection panels.
- Feeder 794 control and protection panel.
- 110kV Cap 2 control and protection panel.
- Revenue and check meters for feeders 754, 755, 794, 706, 779, 780, 757, 758, 7838 and 7839 including the metering panel
- Implement new metering on the HV (110kV) of Transformer 4 to replace the Energex 33kV E1 and E2 connection meters. Install additional VTs, CTs or metering units.
- Decommission the [redacted] recorders on feeders 757 and 758
- 4T control and protection panel.
- Feeders 779 and 780 control and protection panels.
- Replace IONS (OpsWAN) equipment (except OpsWAN camera) and relocate all devices (except the camera) from the OpsWAN camera housing at the top of the pole to the camera patch box at the base of the pole. Refer to ASM-FRM-A4982111 and ETR 10434041.

4.1.2 Major Scope Assumptions

Included in Concept Proposal

- The 4T CVT Metering unit is to be installed on existing foundations and structures due to site space constraints. As 4T is currently utilising a Bus VT, this assumption will reduce the risk of an extended transformer outage
- De-commissioning of Process Bus panels +1E9 and +1E10 to be added to project scope
- Metering compliant CVT's are approved for the required metering and protection purposes on:
    - FDR 706 Nerang
    - FDR's 780 & 7790 Merrimac
    - FDR's 754 & 755 Burleigh
- Includes additional civil works to construct required CVT foundations, additional marshalling kiosks foundations, cable conduits pits and trenches
- All bay Marshalling kiosks and secondary system cables are being replaced
- Resources will be available to complete the works
- Network outages will be available to complete the cutover works as required.
- Procurement of long lead items align with project delivery requirements.

4.1.3 Scope Exclusions

- Replacement of Glass Insulators in O/H Strung bus

- Replacement of all ‘brown’ insulators within 110kV substation
- Any works to review / redesign the current 4T bay arrangement

4.2 Project Execution

4.2.1 Project Schedule

Task	Target Completion
Project Concept Estimate Submitted	November 2024
Request for Class 3 Estimate	October 2025
Project Proposal Submitted	May 2026
Project Stage 1 Approval	August 2026
Project Kick off meeting	August 2026
RIT-T Approval	February 2027
Full Project Stage 2 Approval	March 2027
SPA Contractor ‘Notice to Proceed’	March 2027
MSP FAT Control Panels	April 2027
SPA Contractor Mobilisation – Stage 1	May 2027
SPA Contractor PC date	February 2028
MSP Mobilisation	January 2028
MSP SAT H004	April 2028
MSP Secondary Systems Cutovers	April 2028 - July 2029
MSP - Removal of Redundant Equipment	August 2029 – December 2029
Project Commissioning Date	December 2029

4.2.2 Network Impacts

- Network Outages will be required to cutover the new 110kV control kiosks and associated cabling to the new control panels.
- The new kiosks will be fully wired to the new Control panels and tested prior to cut-over to minimise Network outage durations.
- Network Outage requirements
  - Load at Risk – Gold Coast CBD and Northern NSW.
  - Outages to be scheduled in shoulder and winter periods - Late March to October each year.
  - Network Return to Service constraints.
  - Detailed Restoration plans for network outages.
- It is not anticipated that Grid Support will be required.

4.2.3 Resourcing

The design works for the Primary, Secondary Systems and Telecommunications will be completed by internal Powerlink design staff. The construction works will be completed by a combination of the Maintenance Service Providers and Substation Panel contractors.

Task	Responsibility
Primary Design	Powerlink
Secondary Design	Powerlink
Construction	SPA Contractor / MSP
Commissioning	MSP

4.3 Project Estimate

		Sub Total $	Total ($)
Estimate Class	5		
Base Estimate – Un-Escalated (2025/26)			26,967,349
TOTAL			**26,967,349**

4.4 Project Financial Year Cash Flows

No escalation costs have been considered in this estimate.

DTS Cash Flow Table	Un-Escalated Cost ($)
To June 2026	138,889
To June 2027	7,958,914
To June 2028	16,511,992
To June 2029	1,403,839
To June 2030	857,215
To June 2031	96,500
TOTAL	**26,967,349**

5. Option 3 – Replacement of control panels in the existing building, including an in-panel replacement option addressing 4T, and feeders 779 and 780 panels

5.1 Option Definition

5.1.1 Option Scope

Design, procure and install 110kV marshalling kiosks, associated secondary systems and site infrastructure cabling, underground conduits and cable pits and trenches.

Design, procure and install a new metering 110kV CVT foundations and structures.

Design, procure, construct and commission replacement of the following secondary systems equipment

Priority 1 Works

- Bus Coupler 401 and 411 control and protection panels
- Feeders 7838 and 7839 control and protection panels.
- Feeder 794 control and protection panel.
- 110kV Cap 2 control and protection panel.
- Revenue and check meters for feeders 754, 755, 794, 706, 779, 780, 757, 758, 7838 and 7839 including the metering panel.
- Implement new metering on the HV (110kV) of Transformer 4 to replace the Energex 33kV E1 and E2 connection meters. Install additional VTs, CTs or metering units.
- Decommission the Aptech SSR403 recorders on feeders 757 and 758.

Priority 2 Works

- 4T control and protection panel.
- Feeders 779 and 780 control and protection panels.
- Replace IONS (OpsWAN) equipment (except OpsWAN camera) and relocate all devices (except the camera) from the OpsWAN camera housing at the top of the pole to the camera patch box at the base of the pole. Refer to ASM-FRM-A4982111 and ETR 10434041.

5.1.2 Major Scope Assumptions

- The 4T CVT Metering unit is to be installed on existing foundations and structures due to site space constraints. As 4T is currently utilising a Bus VT, this assumption will reduce the risk of an extended transformer outage.
- De-commissioning of Process Bus panels +1E9 and +1E10 to be added to project scope.
- Metering compliant CVT's are approved for the required metering and protection purposes on:
    - FDR 706 Nerang
    - FDR's 780 & 7790 Merrimac
    - FDR's 754 & 755 Burleigh
- Includes additional civil works to construct required CVT foundations, additional marshalling kiosks foundations, cable conduits pits and trenches
- All bay Marshalling kiosks and secondary system cables are being replaced.
- Resources will be available to complete the works.
- Network outages will be available to complete the cutover works as required.
- Procurement of long lead items align with project delivery requirements.

5.1.3 Scope Exclusions

- Replacement of Glass Insulators in O/H Strung bus.
- Replacement of all 'brown' insulators within 110kV substation.
- Any works to review / redesign the current 4T bay arrangement.

5.2 Project Execution

5.2.1 Project Schedule

Task	Target Completion
Project Concept Estimate Submitted	November 2024
Request for Class 3 Estimate	October 2025
Project Proposal Submitted	May 2026
Project Stage 1 Approval	August 2026
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MSP Mobilisation	January 2028
MSP SAT H004	April 2028
MSP Secondary Systems Cutovers	April 2028 - July 2029
MSP - Removal of Redundant Equipment	August 2029 – December 2029
Project Commissioning Date	December 2029

5.2.2 Network Impacts

- Network Outages will be required to cutover the new 110kV control kiosks and associated cabling to the new control panels.
- The new kiosks will be fully wired to the new Control panels and tested prior to cut-over to minimise Network outage durations.
- Network Outage requirements
  - Load at Risk – Gold Coast CBD and Northern NSW.
  - Outages to be scheduled in shoulder and winter periods - Late March to October each year.
  - Network Return to Service constraints.
  - Detailed Restoration plans for network outages.

- It is not anticipated that Grid Support will be required.

5.2.3 Resourcing

The design works for the Primary, Secondary Systems and Telecommunications will be completed by internal Powerlink design staff. The construction works will be completed by a combination of the Maintenance Service Providers and Substation Panel contractors.

Task	Responsibility
Primary Design	Powerlink
Secondary Design	Powerlink
Construction	SPA Contractor
Commissioning	MSP

5.3 Project Estimate

		Sub Total $	Total ($)
Estimate Class	5		
Base Estimate – Un-Escalated (2025/26)			26,834,101
TOTAL			**26,834,101**

5.4 Project Financial Year Cash Flows

No escalation costs have been considered in this estimate.

DTS Cash Flow Table	Un-Escalated Cost ($)
To June 2026	138,889
To June 2027	7,932,817
To June 2028	16,465,613
To June 2029	1,403,446
To June 2030	813,497
To June 2031	79,839
TOTAL	**26,834,101**

6. References

Document name and hyperlink (as entered into Objective)	Version	Date
Project Scope Report	V1	21/12/2022

Risk Cost Summary Report

CP.02729

Mudgeeraba Secondary Systems Replacement

Document Control

Change Record

Issue Date	Revision	Prepared by
23/12/2025	1.0	Asset Strategies

Related Documents

Issue Date	Responsible Person	Objective Document Name

Document Purpose

The purpose of this model is to quantify the base case risk cost profiles for the secondary systems at Mudgeeraba substation which are proposed for reinvestment under CP.02729. These risk cost profiles are then included as part of the overall cost-benefit analysis (CBA) to understand the economic benefit of the proposed infrastructure upgrades. This process provides a benchmarking and internal gate process to support Powerlink in effectively identifying prioritised infrastructure upgrades.

The CBA was designed to demonstrate and quantify the value to be gained through specific infrastructure investments. To evaluate the CBA, an NPV is derived based on the present values of costs and benefits. The flow chart in Figure 4 below designates the methodology used in designing the CBA process.

Key Assumptions

In calculating the risk cost arising from a failure of the ageing secondary systems equipment at Mudgeeraba substation, the following modelling assumptions have been made:

- Whilst the re-investment scope of secondary system upgrade projects contains a range of supporting devices (i.e network switches, firewalls and human machine interfaces), for simplicity of risk cost modelling only main protection relays, bay controllers and RTUs were considered.
- Spares for secondary system equipment have been assumed to be available prior to the point of expected spares depletion, which coincides with the expected technical asset life (20 years). After this point the cost and time to return the secondary system back to service increases significantly.
- When calculating network risk cost, it has been assumed that after 24 hours of any network element being protected by a single protection system (due to failure of the alternate system) the Australian Energy Market Operator (AEMO) will direct Powerlink to de-energise the network element.
- A site-specific value of customer reliability (VCR) of $25,060 has been applied when calculating network risks.

Base Case Risk Analysis

Risk Categories

For this project, two main categories of risk are assessed as per Powerlink's Asset Risk Management Framework:

- Financial Risk
- Network Risk (including market impact if applicable)

Table 1: Risk categories

Risk Category	Failure Type	Equipment in Scope
Financial Risk	Failure of the equipment resulting in emergency onsite replacement	All equipment
Network Risk	Failure of equipment resulting in de-energisation of network elements after 24 hours	Main protection relays only

Base Case Risk Cost

The modelled and extrapolated total base case risk costs are shown in Figures 1 and 2 below.

Risk costs associated with the equipment in scope are expected to increase from $0.44 million in 2026 to $0.9 million in 2036 and $1.3 million by 2045. Key highlights of the analysis include:

- Financial risk accounts for approximately 80% of the overall risk cost in 2030 with network risk accounting for the remaining 20%.

Figure 1: Total risk cost

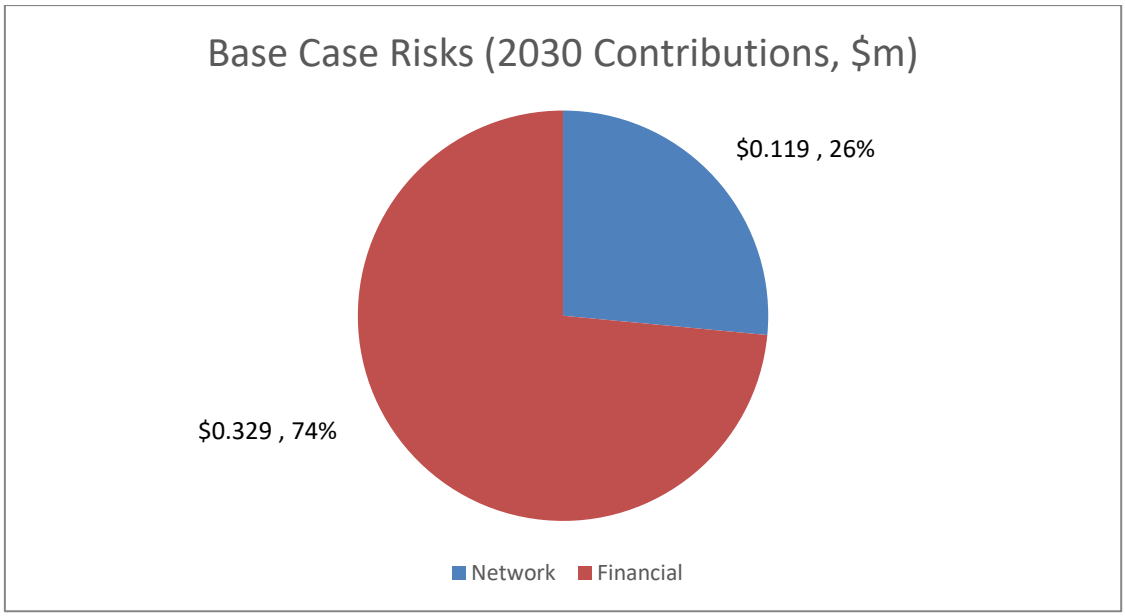

Figure 2: Base case risk cost by contributions (2030)

Option Risk Cost

For modelling purposes, the replacement of equipment at the Mudgeeraba substation reduces the probability of failure to zero in the year after investment, resulting in a lower risk cost.

The figures below set out the total project case risk cost, and associated risk cost savings incremental to the base case.

Figure 3: Project Option Risk Cost (compared to base case)

Following the investment, risk cost grows slowly over time as it is assumed sufficient spares are available resulting in lower responsive costs and shorter outage durations.

Cost Benefit Analysis

The methodology designed for the cost benefit is set out as per Figure 4 below.

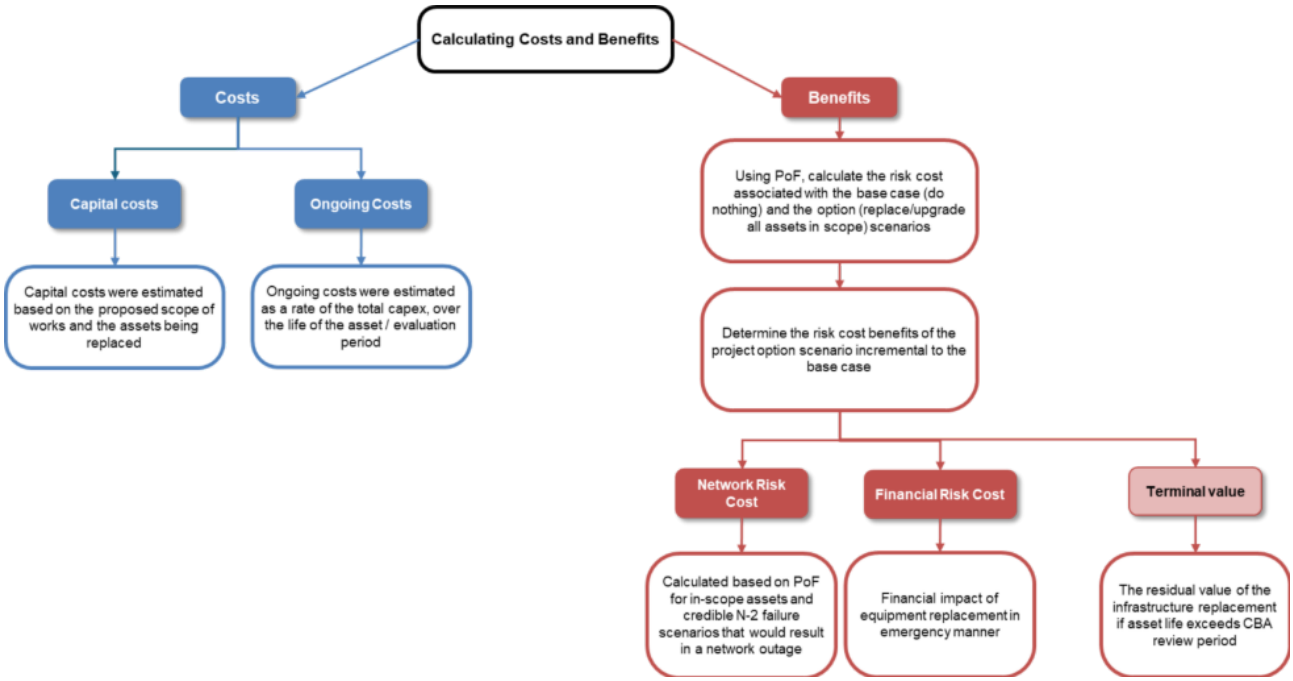

Figure 4: CBA methodology

The project is estimated to cost approximately $26.83 million resulting in a negative NPV and benefit-cost ratio (BCR) less than 1.

Table 2: Net Present Value and Benefit-Cost Ratio

		Present Value Table ($m)		
Discount rate	**%**	**3%**	**7%**	**10%**
NPV of Net Gain/Loss	$m	-$14.4	-$14.8	-$14.3
Benefit-Cost Ratio	ratio	0.41	0.3	0.24

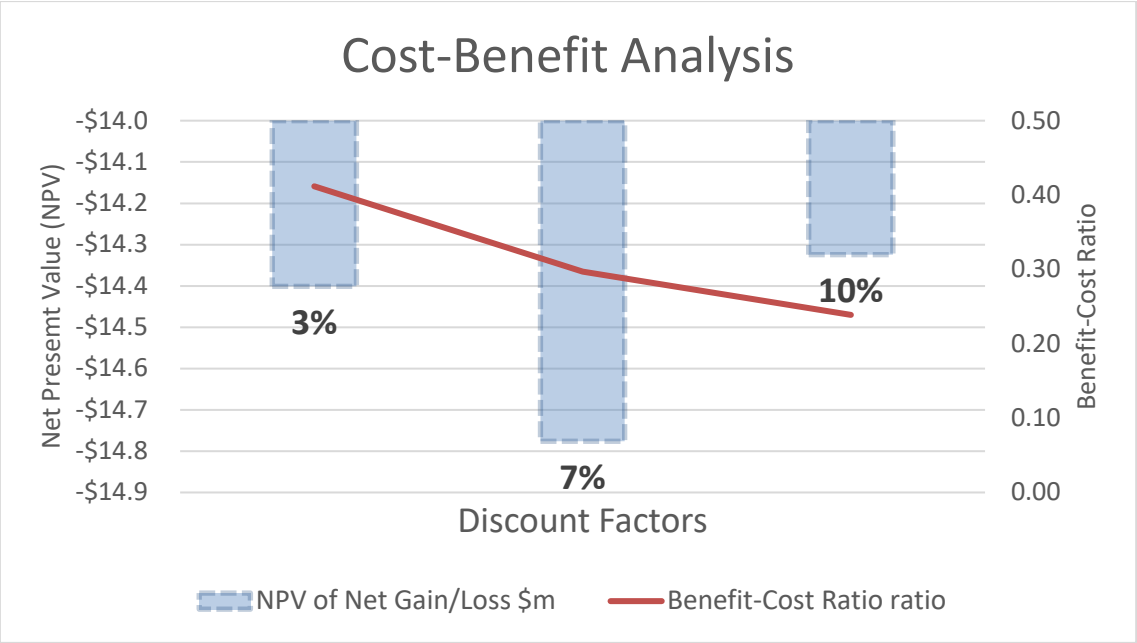

Figure 5: Cost benefit summary

Participation Factors

A sensitivity analysis was undertaken to determine the participation factors for key inputs to the risk cost models (i.e. to identify which inputs are most sensitive to overall risk cost).

The participation factor is defined as the ratio of percentage change in output (i.e. risk cost) to a percentage change in input (e.g. VCR). The participation factors for key model inputs are shown in the table below.

Due to the non-linear nature of the risk cost model (especially network risk costs, which are a function of concurrent failures), the participation factor can change depending on the magnitude of input percentage change.

The model is most sensitive to:

- **changes in bay controller emergency replacement cost** (halving the cost) results in a decrease in risk cost of $0.15 million, or approximately 24.6% of the original base risk (at 2030).
- **changes in the restoration time of a relay with no spares** (halving the restoration time) results in a decrease in risk cost of $0.1 million, or approximately 16.4% of the original base case risk (at 2030).
- **changes in relay emergency replacement cost** (halving the cost) results in a decrease in risk cost of $0.08 million, or approximately 14% of the original base risk (at 2030).

Table 3: Participation Factors

Input	Baseline value	Sensitivity value (-50%)	Change in risk cost at 2030 ($m)	Participation (%)
Network				
VCR ($/MWh)	25060	12530	-0.06	-10.00%
Restoration Time with spares – Relay (days)	2	1	0.00	0.0%
Restoration Time with no spares – Relay (days)	10	5	-0.10	-16.04%
Financial				
Emergency replacement cost with spares - Relay ($m)	0.02	0.01	-0.01	-1.28%
Emergency replacement cost without spares – Relay ($m)	0.09	0.045	-0.08	-13.96%
Emergency replacement cost with spares – Bay Controller ($m)	0.02	0.01	0.00	-0.21%
Emergency replacement cost without spares – Bay Controller ($m)	0.20	0.10	-0.15	-24.55%