Business Case
Blackwater Substation Refurbishment

ERGON ENERGY
NETWORK

Executive Summary

The Blackwater 132/66/22kV substation (BLAC) is a major node that supplies the 132kV, 66kV and 22kV networks in Western Central Queensland. The substation contains assets owned and operated by both Powerlink and Ergon Energy. Powerlink has an approved project to replace two existing transformers with a single large transformer in 2022.

One of the existing two Powerlink 132/66/11kV transformers being replaced currently supplies one of the two Ergon Energy 11/22kV regulators at the site, providing regulated supply to the 22kV network emanating from the substation. The existing Ergon Energy plant is ageing, and works are required to reduce the risks of asset failure and maintain current and future desired levels of supply from the site.

Four network options were evaluated in this business case. A 'Do nothing' option was considered and rejected, as the resulting network and business risks would not be as low as reasonably practicable (ALARP). Further, the works associated with Powerlink's approved project must be carried out in accordance with the Ergon Energy's legislated obligations under the National Electricity Rules (NER). The network options evaluated were:

Option 1 - Installation of two new 66/22kV transformers, and refurbishment of the existing 22kV switchyard in 2022.

Option 2 (Counterfactual) – Reconnection of the existing plant to the new Powerlink transformer, plus replacement of some 22kV equipment based on condition assessments in 2022. Two 66/22kV transformers would then be installed by 2033 based on condition of the two existing 11/22kV regulators

Option 3 - Replacement of 22kV equipment with a new switchboard in 2022, followed by installation of two new 66/22kV transformers in 2033

Option 4 - Installation of a single 66/22kV transformer, and refurbishment of the existing 22kV switchyard in 2022, followed by a second 66/22kV transformer in 2033.

Ergon Energy aims to minimise expenditure in order to keep pressure off customer prices, however understands that this must be balanced against critical network performance objectives. These include network risk mitigation (e.g. safety, bushfire), regulatory obligations (e.g. safety), customer reliability and security and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this case reliability is a strong driver, based on the need to replace ageing and less reliable assets, however work has been minimised to defer costs to the extent possible.

To this end the preferred option is Option 2, which allows for refurbishment of the existing 22kV switchyard in 2022. It has the lowest NPV result (i.e. least negative) result of the four options at -$6.6M. This includes direct costs of $1.9M in the 2020-25 regulatory period, and a further $6.7M in outer years (i.e. past 2025).

The direct cost of the project for each submission made to the AER is summarised in the table below. Note that all figures are expressed in 2018/19 dollars and apply only to costs incurred within the 2020-25 regulatory period for the preferred option.

Regulatory Proposal	Draft Determination Allowance	Revised Regulatory Proposal
$7.5M	$1M	$1.9M

Contents

1 Introduction

The Blackwater 132/66/22kV substation (BLAC) is a major node that supplies the 132kV, 66kV and 22kV networks in Western Central Queensland. The substation contains assets owned and operated by both Powerlink and Ergon Energy. Powerlink has an approved project to replace two of three existing transformers with a single large transformer in 2022. One of the existing two Powerlink 132/66/11kV transformers being replaced currently supplies one of two Ergon Energy 11/22kV regulators at the site, providing regulated supply to the 22kV network emanating from the substation. The existing Ergon Energy plant is aging, and some replacement works are required based on the condition of the assets.

1.1 Purpose of document

This document recommends the optimal capital investment necessary for the refurbishment and replacement of Blackwater Substation.

This is a preliminary business case document and has been developed for the purposes of seeking funding for the required investment in coordination with the Energy Queensland Revised Regulatory Proposal to the Australian Energy Regulator (AER) for the 2020-25 regulatory control period. Prior to investment, further detail will be assessed in accordance with the established Energy Queensland (EQL) investment governance processes. The costs presented are in $2018/19 direct dollars.

1.2 Scope of document

This document will outline the rationale, benefits, and drivers for asset replacement and refurbishment, as well as present options to address the limitations. These options, their associated risk assessments, delivery timeframes and project costs will be outlined and compared to provide a recommendation for the option that minimises risk and optimises cost efficiency. Please note the original Blackwater business case submitted as part of the draft proposal included 66kV circuit breaker and secondary system work. Some of this work has been coupled with another Blackwater project to gain efficiency and is currently being delivered. The scope reduction presented in the preferred option in this business provides a deferment of 2 x 66kV CBs with 4 x 66kV isolators to 2028 and deferring the need to replace the 11/22kV regulators until 2033.

1.3 Identified Need

Ergon Energy aims to minimise expenditure in order to keep pressure off customer prices, however understands that this must be balanced against critical network performance objectives. These include network risk mitigation (e.g. safety, bushfire), regulatory obligations (e.g. safety), customer reliability and security and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this case reliability is a strong driver, based on the need to replace ageing and less reliable assets at the Ergon Energy plant.

The Blackwater 132/66/22kV substation (BLAC) is equipped with one 160MVA and two 80MVA 132/66/11kV Powerlink owned transformers, and two 10MVA 11/22kV Ergon Energy owned regulators. The 66kV and 22kV switchyards at BLAC are owned by Ergon Energy. The Ergon Energy 22kV load is supplied via 11kV tertiaries off the two of the Powerlink 132/66/11kV transformers and is then stepped up to 22kV via Ergon owned 11/22kV regulators, Figure 1, Figure 2 and Figure 3, and in further detail in Appendix G.

The 22kV distribution load on Blackwater is 10.1MVA and it supplies 2,159 industrial, commercial, residential and rural customers across Blackwater, Dingo, Duaringa townships and surrounding communities. The 66kV sub-transmission bus at BLAC supplies N-1 security to Emerald Zone

Substation (ZS) and Comet ZS, and radial supply to Leichardt ZS, Bedford Weir ZS, Bingegang ZS as well as several major mining customers with a total 66kV system normal loading of 100MVA.

The existing Ergon Energy plant is aging, and reconfiguration and uprating works are required to be able to reconnect to the new Powerlink transformer and maintain current and future desired levels of supply from the site.

The 11/22kV regulators within the 22kV plant are non-standard with very minimal population in Ergon and limited system spares available for any replacement works needed. The Powerlink transformer upgrade and the upcoming asset replacements at BLAC have presented an opportunity for the removal of the redundant 11kV voltage level. An identified upgrade option is to replace the 11/22kV regulators (that are expected to reach their end of life in the next 10-15 years) with standard 66/22kV transformers, which modernises the substation, reduces system spares requirements, allows for increased capacity and optimises program efficiency.

This proposal aligns with the CAPEX objectives and criteria from the National Electricity Rules as detailed in Appendix C.

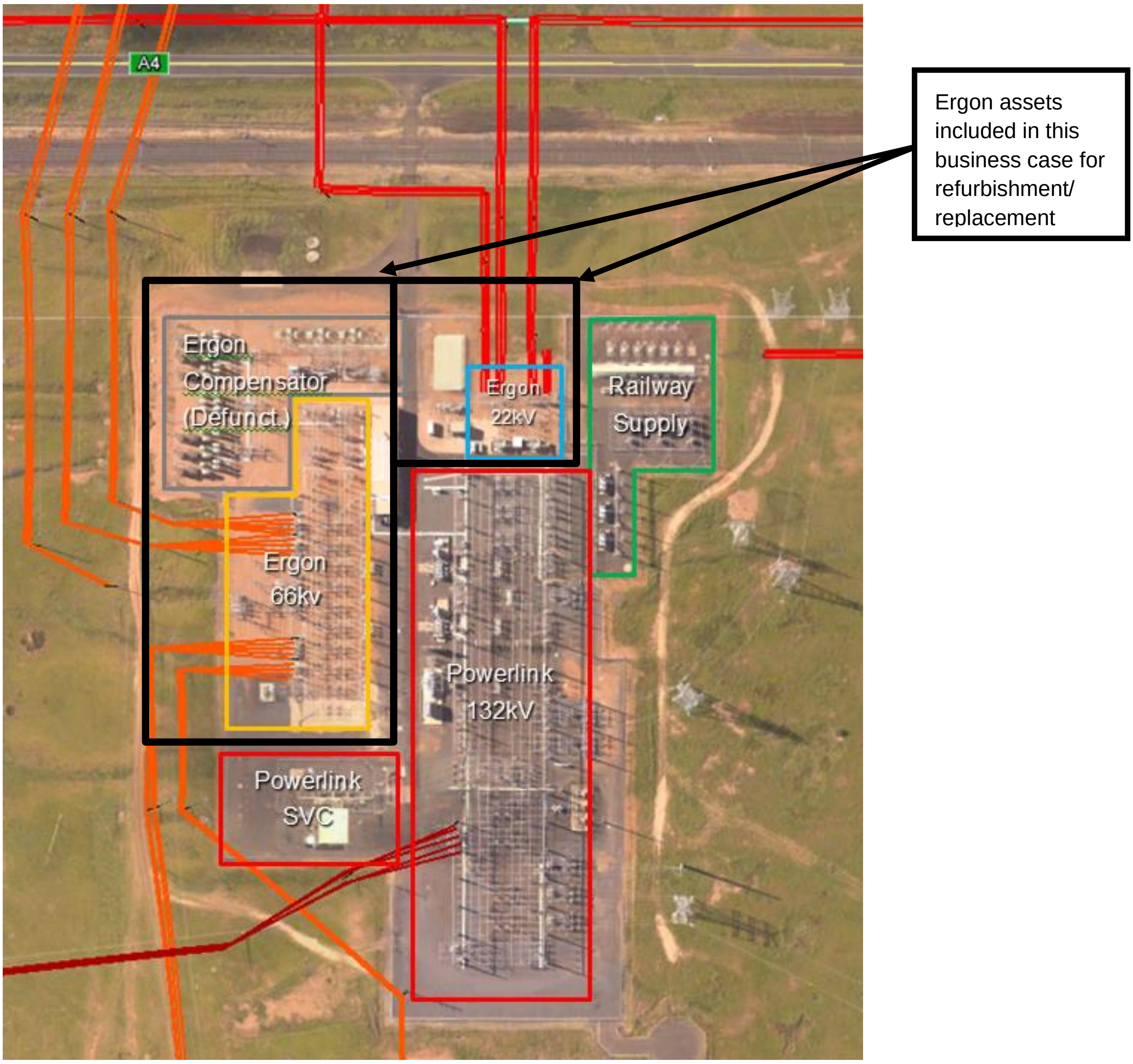


Figure 1: Blackwater Substation site arrangement

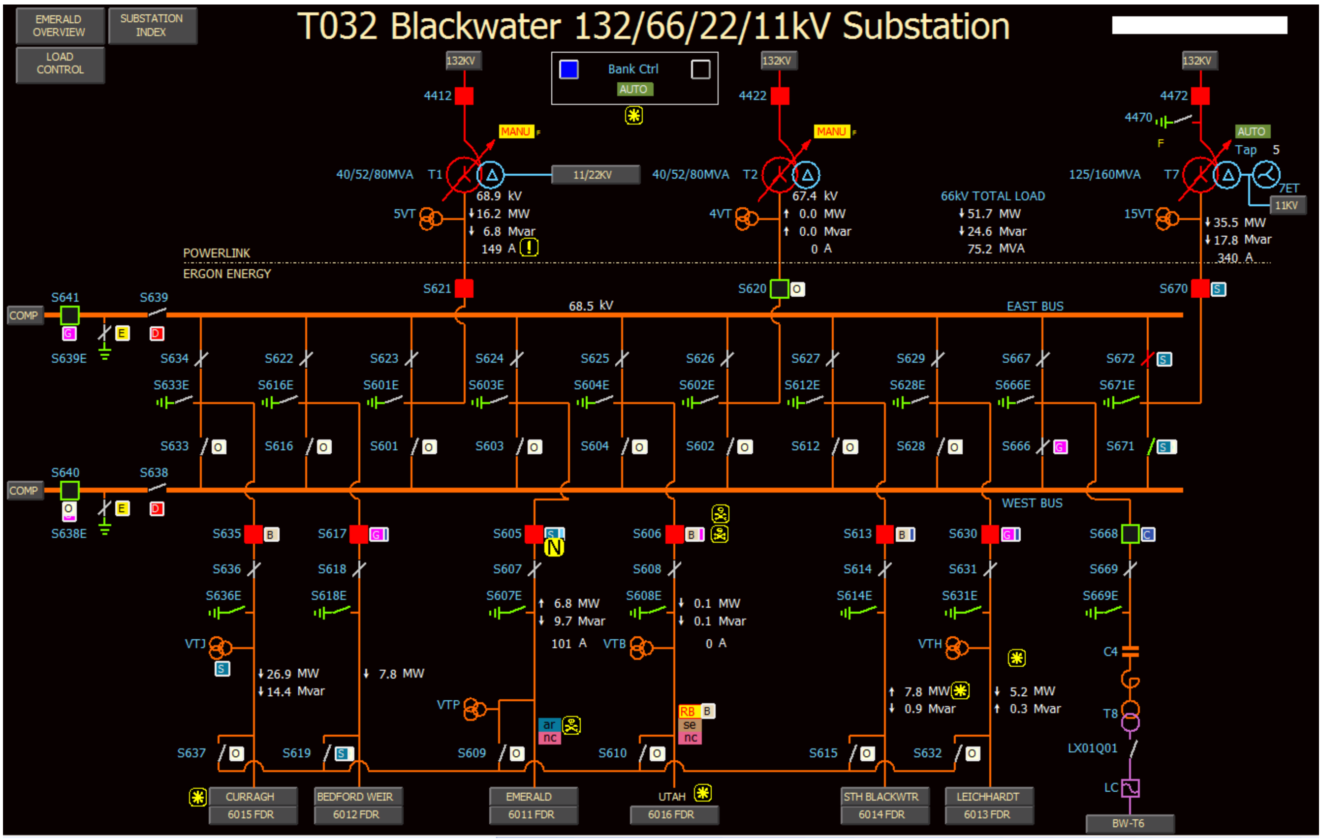


Figure 2: Blackwater Substation Overview

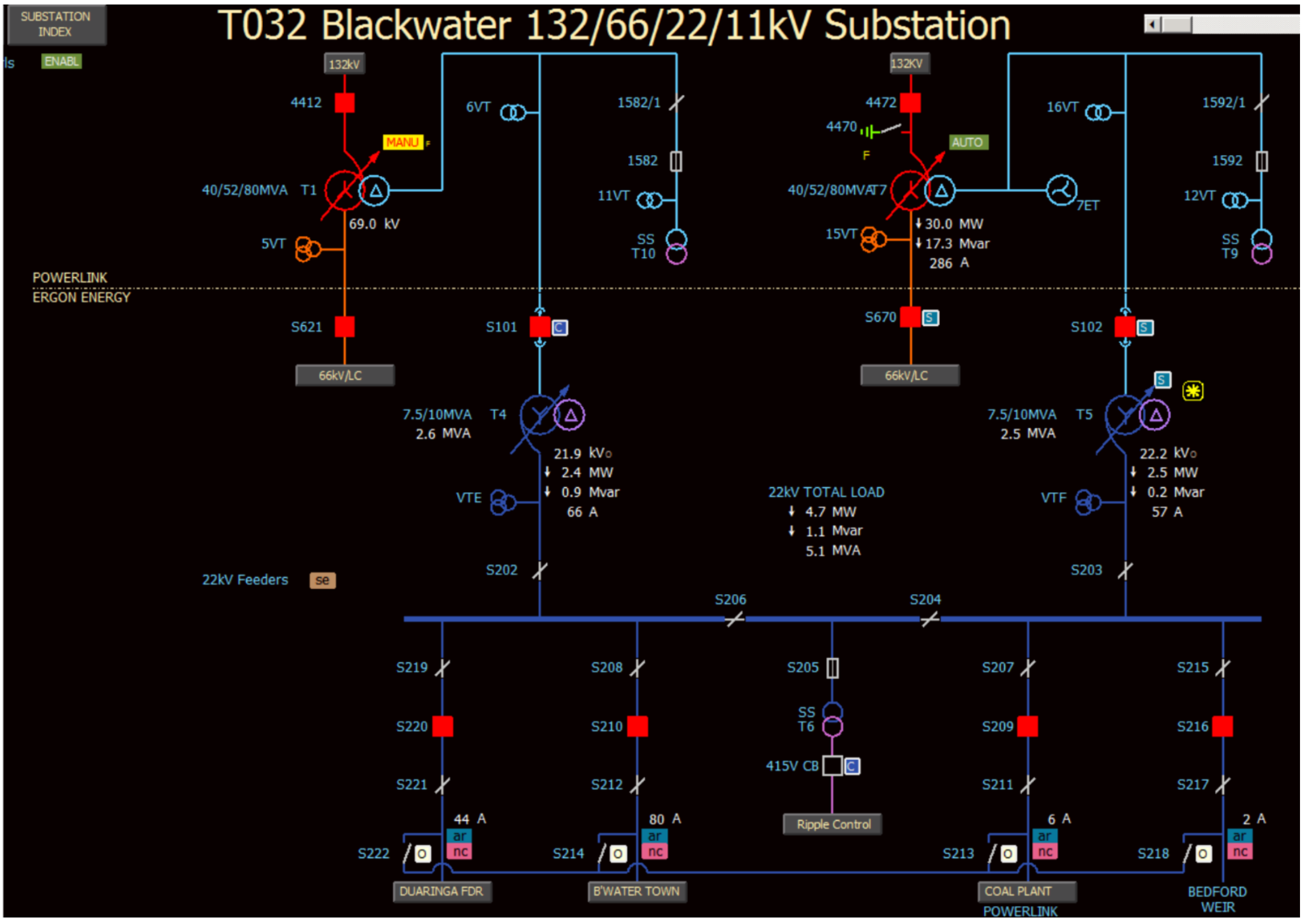


Figure 3: Blackwater Substation Single Line Diagram

1.4 Energy Queensland Strategic Alignment

Table 1 details how the Blackwater Refurbishment and Replacement contributes to Energy Queensland's corporate and asset management objectives. The linkages between these Asset Management Objectives and EQL's Corporate Objectives are shown in Appendix D.

Table 1: Asset Function and Strategic Alignment

Objectives	Relationship of Initiative to Objectives
Ensure network safety for staff contractors and the community	This business case works to reduce the risk of plant failure-in-service that could result in safety risks to staff or the public.
Meet customer and stakeholder expectations	The business case aims to reduce risk of failure, ensuring that customer supply is maintained and expectations surrounding reliability are met.
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	The initiative outlines the need for a Regulatory Investment Test for Distribution (RIT-D) to be conducted, which would allow a business case to be developed in detail that to manage risk, performance standards, and asset investments.
Develop Asset Management capability & align practices to the global standard (ISO55000)	This business case is consistent with ISO55000 objectives and drives asset management capability by promoting a continuous improvement environment.
Modernise the network and facilitate access to innovative energy technologies	This business case is directly related to modernising the network as it relates to updating to newer technologies.

1.5 Applicable service levels

Corporate performance outcomes for this asset are rolled up into Asset Safety & Performance group objectives, principally the following Key Result Areas (KRA):

- Customer Index, relating to Customer satisfaction with respect to delivery of expected services
- Optimise investments to deliver affordable & sustainable asset solutions for our customers and communities

Corporate Policies relating to establishing the desired level of service are detailed in Appendix D.

Under the Distribution Authorities, EQL is expected to operate with an 'economic' customer value-based approach to reliability, with "Safety Net measures" for extreme circumstances. Safety Net measures are intended to mitigate against the risk of low probability vs high consequence network outages. Safety Net targets are described in terms of the number of times a benchmark volume of energy is undelivered for more than a specific time period. EQL is expected to employ all reasonable measures to ensure it does not exceed minimum service standards (MSS) for reliability, assessed by feeder types as

- System Average Interruption Duration Index (SAIDI), and;
- System Average Interruption Frequency Index (SAIFI).

Both Safety Net and MSS performance information are publicly reported annually in the Distribution Annual Planning Reports (DAPR). MSS performance is monitored and reported within EQL daily.

1.6 Compliance obligations

Table 2 outlines the compliance obligations related to this proposal.

Table 2: Compliance Obligations

Legislation, Regulation, Code or Licence Condition	Obligations	Relevance to this investment
QLD Electrical Safety Act 2002 **QLD Electrical safety Regulation 2013**	We have a duty of care, ensuring so far as is reasonably practicable, the health and safety of our staff and other parties as follows: • Pursuant to the Electrical Safety Act 2002, as a person in control of a business or undertaking (PCBU), EQL has an obligation to ensure that its works are electrically safe and are operated in a way that is electrically safe.[1] This duty also extends to ensuring the electrical safety of all persons and property likely to be affected by the electrical work.[2]	This proposal maintains compliance with the Safety Act through its required refurbishment and replacement. Without these activities the risk of plant failure would be higher than acceptable which creates a safety risk to staff, contractors and the community.
Distribution Authority for Ergon Energy issued under section 195 of *Electricity Act 1994* (Queensland)	Under its Distribution Authority: • The distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services. • The distribution entity will ensure, to the extent reasonably practicable, that it achieves its safety net targets as specified. • The distribution entity must use all reasonable endeavours to ensure that it does not exceed in a financial year the Minimum Service Standards (MSS)	This proposal ensures the continued supply to the regions dependent on BLAC in alignment with good electricity industry practice.

1.7 Limitation of existing assets

In 2022, Powerlink is planning to replace two of their 132/66/11 kV 80MVA transformers (T1 and T2) with a single 160MVA unit due to their advanced age and deteriorating condition. Energy Queensland has a legislated obligation under the National Electricity Rules (NER) to accommodate these plans when the TNSP has a requirement to upgrade the transmission network. This means works on the Ergon Energy plant are essential to ensure continued supply to the Blackwater region.

Detailed condition assessments have been carried out on all substation equipment and the details are contained in the full Substation Condition Assessment Report (SCAR) in Appendix G.

22kV Supply

Refurbishment or replacement of some of the existing 22kV switchyard is necessary based on condition. This includes replacement of some circuit breakers, isolators, protection equipment, CTs and VTs as detailed in the SCAR. Further equipment replacements will be required by 2033 coinciding with the replacement of the 11/22kV regulators with 66/22kV transformers.

[1] Section 29, *Electrical Safety Act 2002*
[2] Section 30 *Electrical Safety Act 2002*

The condition of the 11/22kV regulators has been recently reassessed and as detailed in the SCAR, replacement is required for both units by 2033.

66kV Supply

Two 66kV circuit breakers and four 66kV isolators are deemed to reach end of life by 2028.

Compensator Yard

The 66kV compensator yard is out of service due to equipment failures and is no longer required to maintain quality of 66 kV supply. This aging out-of-service equipment presents unnecessary environmental risk and is due for de-commissioning and removal.

2 Counterfactual Analysis

2.1 Purpose of asset

The Blackwater 132/66/22kV substation (BLAC) is a joint Powerlink and Ergon Energy substation in Western Central Queensland. The load supported includes Emerald, Comet, Leichardt, Bedford Weir, Bingegang Zone substations, as well as major customers including Curragh Mine, Blackwater Mine, South Blackwater Mine, Cook Colliery, and Yarrabee Mine, with a total peak demand of approximately 100MVA.

The BLAC 22 kV distribution areas include the townships of Blackwater, Bluff, Dingo, and Duaringa and their surrounding rural districts totalling approximately 6000 km^2, with a total of 2,191 industrial and domestic customers.

2.2 Business-as-usual service costs

National Electricity Rules legislate that Energy Queensland has a legislated obligation to accommodate when the TNSP has a requirement to upgrade the transmission network. Therefore, there are no possible business-as-usual options, as Ergon Energy is obliged to perform some works associated with the Powerlink works to maintain operability of the substation.

2.3 Key assumptions

The counterfactual is assumed as the case where replacement of the 11/22kV regulators is deferred until their end of life in approximately 2033 with refurbishment occurring on the critical 22kV equipment in 2022. This is outlined in Option 2.

2.4 Risk assessment

This risk assessment is in accordance with the EQL Network Risk Framework and the Risk Tolerability table from the framework is shown in Appendix E.

Table 3: Counterfactual risk assessment

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Single item of primary plant fails-in-service catastrophically (includes indoor and outdoor oil-filled CTs, CBs and VTs) resulting in **multiple serious injuries** to members of staff or a member of the public.	Safety	4 *(Multiple serious injuries/ illnesses)*	3 *(Unlikely)*	**12** ***(Moderate risk)***	2019
Single item of primary plant fails-in-service catastrophically (includes indoor and outdoor oil-filled CTs, CBs and VTs) resulting in **outage >12 hours.**	Customer Impact	4 *(Interruption > 1 day)*	2 *(Very unlikely)*	**8** ***(Low risk)***	2019

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Failure of primary plant leads to an **interruption of supply to >5,000 customers**. This feeder supplies major rural town and several mines. (Strong REPEX driver).	Customer Impact	4 *(Disruption to multiple large-scale businesses)*	4 *(Likely to occur)*	**16** ***(Moderate risk)***	2019
Failure to undertake augmentation of the distribution network when the TNSP has a requirement to upgrade the transmission network resulting in a **breach in legislative requirements and an enforceable undertaking being issued by the regulator**.	Legislated Requirement	5 *(Legislated requirement issue with Acts, Regulations, Codes, Rules. Regulator involved/ Enforceable undertaking)*	2 *(Very unlikely to occur)*	**10** ***(Low risk)***	2019

2.5 Retirement or de-rating decision

Retirement of the complete substation assets would result in loss of supply to current industrial and domestic customers. This is not considered a viable option for this business case and has not been assessed. However, retirement of the 11/22kV regulators has been considered as part of this proposal.

3 Options Analysis

3.1 Options considered but rejected

Do Nothing

If no action is taken, the 22V primary plant and associated secondary systems will continue to age beyond the end of their serviceable life. Failure will occur with urgent replacements and sub-optimal design outcomes. The network and business risks that the organisation would be exposed to if the project was not undertaken are not deemed to be as low as reasonably practicable (ALARP).

Regarding the works associated with the Powerlink transformer replacement project, Ergon Energy has a legislated obligation under the National Electricity Rules (NER) to accommodate when the TNSP has a requirement to upgrade the transmission network.

Ergon Energy has a responsibility under the Electricity Act 1994 to provide a safe and reliable supply of electricity to the community. Hence, the 'do nothing' option was considered unsuitable on safety, environmental and customer service grounds.

3.2 Identified options

3.2.1 Network options

Option 1: Install 2 x 66/22kV and Refurbish 22kV Switchyard

Under this option, the 22kV switchyard is refurbished and two new, standardised transformers are installed on the site in alignment with Powerlink's approved works. The key technical components of the option are:

- Replace both 11/22kV regulators with 2 x 66/22kV 20MVA transformers and secondary systems in 2022
  - Utilise 2 x existing ex-compensator 66kV bays, replace 66kV CBs and CTs with dead tank 66kV CBs with integral CTs.
  - Install 2 x 22kV cables and 2 x dead tank 22kV CBs
- Refurbish existing 22kV switchyard equipment at or nearing end of life in 2022

Key Assumptions

- The 66/22kV transformer installation will be delivered before the Powerlink transformer replacement to secure supply while T1 and T2 are out of service.
- 15% delivery efficiency gain by delivering this work in parallel with 66kV and Sec-Sys refurbishments and Powerlink 66kV transformer bay upgrades.

Option 2: Reconnect Powerlink Tertiary with Refurbished 22kV Switchyard, Defer 66/22kV Installation (Counterfactual - Proposed)

Under this option, the 22kV switchyard is refurbished in alignment with Powerlink's approved works. In contrast to Option 1, the installation of two new, standardised transformers is deferred beyond 2025. The key technical components of this option are:

- Reconnect new Powerlink transformer tertiary to retain supply from both existing 11/22kV regulators in 2022
- Refurbish existing 22kV switchyard equipment at or nearing end of life in 2022

- Deferred Works - Replacement of 2 x 66kV CBs with 4 x 66kV isolators in 2028. Upgrade 11/22kV regulators with 2x 66/22kV 20MVA transformers and secondary systems at their end of life in 2033.

Key Assumptions

- Includes temporary transformer during project delivery to secure the network while T1 tertiary supply is unavailable during the Powerlink transformer replacement.

Option 3: New 22kV Switchboard and Deferred Installation of 2x 66/22kV Transformers

Under this option, a new switchboard is installed in alignment with Powerlink's approved works, rather than refurbishing the existing switchyard as was the case under Options 1 and 2. The installation of two new, standardised transformers is deferred beyond 2025. They key technical components of this option are:

- Install indoor 7 Circuit-Breaker (CB) switchboard in modular building in 2022
  - Install 4 x 22kV feeder exit cables
  - Demolish 22kV switchyard
- Deferred Works - Replacement of 2 x 66kV CBs with 4 x 66kV isolators in 2028. Upgrade 11/22kV regulators with 2 x 66/22kV 20MVA transformers and secondary systems in 2033

Option 4: Install 1st 66/22kV Transformer, Refurbish 22kV Switchyard and Deferred Installation of 2nd 66/22kV Transformer

Under this option, the existing switchyard is refurbished as per Options 1 and 2. In contrast to the previous options, the new, standardised transformer installations are staggered. The first will be installed at the same time as the switchyard is refurbished, in alignment with Powerlink's approved works. The second transformer is installed after 2025. They key technical components of this option are:

- Installation of 1x 66/22kV 20MVA transformer to replace one of the existing 11/22kV regulator units in 2022. Includes upgrade of secondary systems. Initial works to be ready for new Powerlink transformer to come online in 2022. 1x 11/22kV unit will remain on hot-standby as backup load.
  - Decommission 1x 11/22kV regulator
  - Utilise 2 x existing ex-compensator 66kV bays, replace 66kV CBs and CTs with dead tank 66kV CBs with integral CTs
  - Install 2 x 22kV cables and 2 x dead tank 22kV CBs
- Refurbish existing 22kV switchyard equipment at or nearing end of life in 2022
- Deferred Works - Install second 66/22kV transformer in 2033 and decommission remaining 11/22kV regulator in 2033

Key Assumptions

- The 66/22kV transformer installation will be delivered before the Powerlink transformer replacement to secure supply.
- One 11/22kV regulator will remain to operate on hot-standby for contingency events. This will also possibly extend the life of this asset from its current estimated end of life date.
- The remaining 11/22kV regulator will be decommissioned and removed.
- 15% delivery efficiency gain by delivering this work in parallel with 66kV and Sec-Sys refurbishments and Powerlink 66kV transformer bay upgrades.

3.2.2 Non-network options

Energy Queensland is committed to the implementation of Non-Network Solutions to reduce the scope or need for traditional network investments. Our approach to Demand Management is listed in Chapter 7 of our Distribution Annual Planning Report but involves early market engagement around emerging constraints as well as effective use of existing mechanisms such as the Demand Side Engagement Strategy and Regulatory Investment Test for Distribution (RIT-D). We see that the increasing penetration and improving functionality of customer energy technology, such as embedded generation, Battery Storage Systems and Energy Management Systems, have the potential to present a range of new non-network options into the future.

The primary investment driver for this project is Repex, addressing both asset safety and performance risks. A successful Non-Network Solution may be able to assist in reducing the scope required for the replacement project but will not be able to impact the project timing due to the aged equipment risk. The scope recommended network option has already recommended a reduction of asset compared to the existing configuration and it is considered that total removal of the asset would not be feasible. As the cost of options considered as part of this report are greater than $6M this investment will be subject to a RIT-D.

The customer base in the study area is a broad mixture of established residential, commercial, industrial and rural loads and presents a small opportunity to reduce demand or provide economic non-network solutions. A non-network solution for the 22kV supply arrangement would need to supply 10-15MVA of 22kV at BLAC or in the Blackwater area with an appropriate level of N-1 security. It is unlikely that a non-network alternative will defer or remove the need to replace aged assets at BLAC substation. However, non-network solutions may help to defer the installation of a future 66/22kV transformer.

Expenditure for the proposed project has been modelled as CAPEX and included in the forecast for the current regulatory control period. Funding of any successfully identified non-network alternative solutions will be treated as an efficient OPEX/CAPEX trade-off, consistent with existing regulatory arrangements.

3.3 Economic analysis of identified options

3.3.1 Cost versus benefit assessment of each option

The Net Present Value (NPV) of each option has been determined by discounting costs and benefits over the program lifetime from FY2018/19 to FY2038/39, using the EQL standard NPV analysis tool, at the Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62%. Table 4 outlines the Present Value (PV) of CAPEX and OPEX over the period, as well as the total NPV of each option. Option 2 has the lowest NPV of the assessed options.

Table 4: Net present value of options, $'000s

Option	Option Name	Rank	Net NPV	CAPEX NPV
1	Refurb 22kV yard and replace 2 x 66/22kV Tx's	3	**-8,216**	-8,216
2	Refurb 22kV yard and defer 2 x 66/22kV Tx's to 2033 (counterfactual)	1	**-6,668**	-6,668
3	New 22 kV board and defer 2 x 66/22kV Tx's to 2033	4	**-11,485**	-11,485
4	Refurb 22 kV yard and replace 1 x 66/22kV Tx, defer 2nd until 2033	2	**-7,192**	-7,192

3.4 Scenario Analysis

3.4.1 Sensitivities

The key sensitivities to this project are the capital costs and timing of project works.

Lower and upper bounds for cost inputs were tested (-20% lower bound and +20% upper bound respectively) to determine the sensitivity of capital variance to the selected NPV. Option 2 consistently presented the best NPV across the tested upper and lower bounds.

3.4.2 Value of regret analysis

In terms of selecting a decision pathway of 'least regret', Option 2 presents an economically efficient and staged approach to investment. The option also allows for a lower upfront capital investment and utilises existing assets to the maximum extent possible.

The key regret scenario in this case is the safety risk associated with failure of assets in poor condition, representing a risk to staff and the broader community. This risk is managed through timely replacement of the 22kV assets known to be in poor condition and deferral of other replacements based on the latest condition assessment.

In this way this option represents a low regret path by replacing assets in known poor condition while investing the minimum amount up-front capital and utilising existing assets to the extent possible.

3.5 Qualitative comparison of identified options

3.5.1 Advantages and disadvantages of each option

Table 5 below details the advantages and disadvantages of each option considered.

Table 5: Assessment of options

Options	Advantages	Disadvantages
Option 1 – Install 2x 66/22kV transformers; replace aged 22kV plant in-situ	• Cost effective 22kV switchyard refurbishment solution with optimal transfer arrangement and existing feeder exit • Standardisation of transformers with system spares • Decoupling of bulk supply and distribution outages • Increased capacity enabling future block loads or Distributed Energy Resources (DER) in the next 10 years • Project delivery efficiency	• Possible overcapacity for site needs and loss of capital efficiency compared to other options • 11/22kV regulators have remaining useful life • 66kV CBs, CTs have remaining useful life. • High upfront capital cost

Options	Advantages	Disadvantages
Option 2 – Reinstate tertiary supply; defer 66/22kV transformers; replace aged 22kV plant	• Cost effective 22kV switchyard refurbishment solution with optimal transfer arrangement and existing feeder exits • Defers 66/22kV transformer installation • Defers replacement of 66kV CBs, CTs • Best NPV outcome of proposed Options, and lowest upfront capital cost.	• Ongoing risk of regulator tap changer failure • No system spares for 11/22kV 10MVA regulators • On-going operational issues with existing 11kV circuit breakers
Option 3 – Replace aged 22kV plant with new switchboard	• Project delivery efficiency	• High cost compared to replacement of only equipment with condition risks • Removes 22kV transfer bus and requires reconfiguration of exit feeders to restore transfer capability
Option 4 – Install 1x 66/22kV transformer; replace aged 22kV plant in-situ; install 1x deferred 66/22kV	• Cost effective 22kV switchyard refurbishment solution with optimal transfer arrangement and existing feeder exit • Standardisation of transformers with system spares • Decoupling of bulk supply and distribution outages • Project delivery efficiency	• Does not fully utilise remaining life of existing 11/22kV regulators

3.5.2 Alignment with network development plan

The proposed works would ensure that Ergon Energy meets its Service Safety Net Targets obligations. It looks to proactively provide contingency capacity just in time for load growth, maximising utilisation of assets while also considering the long-term growth of the local network and customer base.

The preferred option aligns with the Asset Management Objectives in the Distribution Annual Planning Report. In particular it manages risks, performance standards and asset investment to deliver balanced commercial outcomes while modernising the network to facilitate access to innovative technologies.

3.5.3 Alignment with future technology strategy

This program of work does not contribute directly to Energy Queensland's transition to an Intelligent Grid, in line with the Future Grid Roadmap and Intelligent Grid Technology Plan. However, it does support Energy Queensland in maintaining affordability of the distribution network while also maintaining safety, security and reliability of the energy system, a key goal of the Roadmap, and represents prudent asset management and investment decision-making to support optimal customer outcomes and value across short, medium and long-term horizons.

3.5.4 Risk Assessment Following Implementation of Proposed Option

Table 6 outlines the risk assessment for the Ergon Energy network following implementation of the proposed option.

Table 6: Risk assessment showing risks mitigated following implementation

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Single item of primary plant fails-in-service catastrophically (includes indoor and outdoor oil-filled CTs, CBs and VTs) resulting in **multiple serious injuries** to members of staff or a member of the public.	Safety	*(Original)* 4 *(Multiple serious injuries/ illnesses)* (Mitigated) 4 *(Multiple serious injuries/ illnesses)*	 3 *(Unlikely)* 1 *(Almost no likelihood to occur)*	 **12** ***(Moderate risk)*** **4** ***(Very Low Risk)***	2019
Single item of primary plant fails-in-service catastrophically (includes indoor and outdoor oil-filled CTs, CBs and VTs) resulting in **outage >12 hours.**	Customer Impact	*(Original)* 4 *(Interruption > 1 day)* (Mitigated) 4 *(Interruption > 1 day)*	 2 *(Very unlikely to occur)* 1 *(Almost no likelihood to occur)*	 **8** ***(Low risk)*** **4** ***(Very Low Risk)***	2019
Failure of primary plant leads to an **interruption of supply to >5,000 customers**. This feeder supplies major rural town and several mines. (Strong REPEX driver).	Customer Impact	*(Original)* 4 *(Disruption to multiple large-scale businesses)* (Mitigated) 4 *(Disruption to multiple large-scale businesses)*	 4 *(Likely to occur)* 1 *(Almost no likelihood to occur)*	 **16** ***(Moderate risk)*** **4** ***(Very Low Risk)***	2019
Failure to undertake augmentation of the distribution network when the TNSP has a requirement to upgrade the transmission network resulting in a **breach in legislative requirements and an enforceable undertaking being issued by the regulator**.	Legislated Requirement	*(Original)* 5 *(Legislated requirement issue with Acts, Regulations, Codes, Rules. Regulator involved/ Enforceable undertaking)* (Mitigated) 5 *(Legislated requirement issue with Acts, Regulations, Codes, Rules. Regulator involved/ Enforceable undertaking)*	 2 *(Very unlikely to occur)* 1 *(Almost no likelihood to occur)*	 **10** ***(Low risk)*** **5** ***(Very Low Risk)***	2019

4 Recommendation

4.1 Preferred option

The recommended option is option 2 which allows for refurbishment of the existing 22kV switchyard in 2022. Subsequent stages will include replacement of 2 x 66kV CBs with 4 x 66kV isolators in 2028, and installation of 66/22kV transformers in 2033.

Option 2 has the lowest NPV cost of the assessed options as well as most adequately addressing the risks at Blackwater substation surrounding the condition risk of the assets. Option 2 also accommodates Powerlink Queensland's replacement of bulk supply transformers utilising the most cost effective and prudent solution.

4.2 Scope of preferred option

The scope of the preferred option 2 is as follows:

- Reconnect new Powerlink transformer tertiary to retain supply from both existing 11/22kV regulators in 2022
- Refurbish existing 22kV switchyard equipment at or nearing end of life in 2022
- Deferred Works - Replacement of 2 x 66kV CBs with 4 x 66kV isolators in 2028 and upgrade of 11/22kV regulators with 2x 66/22kV 20MVA transformers and secondary systems at their end of life in 2033.

The total project direct cost is $1.9M in the 2020-25 AER regulatory control period, with further costs of $6.7M in outer years ($2018/19).

Appendix A. References

Note: Documents which were included in Energy Queensland's original regulatory submission to the AER in January 2019 have their submission reference number shown in square brackets, e.g. Energy Queensland, *Corporate Strategy [1.001], (31 January 2019).*

AEMO, *Value of Customer Reliability Review, Final Report,* (September 2014).

Energy Queensland, *Asset Management Overview, Risk and Optimisation Strategy [7.025]*, (31 January 2019).

Energy Queensland, *Customer Quality of Supply Strategy [7.047],* (31 January 2019).

Energy Queensland, *Future Grid Roadmap [7.054],* (31 January 2019).

Energy Queensland, *Intelligent Grid Technology Plan [7.056],* (31 January 2019).

Energy Queensland, *Network Risk Framework*, (October 2018).

Ergon Energy, *Blackwater 132/66/11/22kV Substation (T032) Detailed Condition Assessment Report (SCAR),* (2019).

Ergon Energy, *Distribution Annual Planning Report (2018-19 to 2022-23) [7.049]*, (21 December 2018).

Appendix B. Acronyms and Abbreviations

The following abbreviations and acronyms appear in this business case.

Abbreviation or acronym	Definition
$M	Millions of dollars
$ nominal	These are nominal dollars of the day
$ real 2019-20	These are dollar terms as at 30 June 2020
2020-25 regulatory control period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALARP	As Low As Reasonably Practicable
AMP	Asset Management Plan
Augex	Augmentation Capital Expenditure
BAU	Business As Usual
BEWE	Bedford Weir Substation
BLAC	Blackwater 132/66/22kV Substation
CAPEX	Capital expenditure
CB	Circuit Breaker
CBRM	Condition Based Risk Management
Current regulatory control period or current period	Regulatory control period 1 July 2015 to 30 June 2020
CT	Current Transformer
DAPR	Distribution Annual Planning Report
DC	Direct Current
DNSP	Distribution Network Service Provider
EQL	Energy Queensland Ltd
IT	Information Technology
KRA	Key Result Areas
kV	Kilovolt
MSS	Minimum Service Standard
MVA	Megavolt Ampere
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules (or Rules)

Abbreviation or acronym	Definition
Next regulatory control period or forecast period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
NPV	Net Present Value
OPEX	Operational Expenditure
PCBU	Person in Control of a Business or Undertaking
POE	Probability of Exceedance
Previous regulatory control period or previous period	Regulatory control period 1 July 2010 to 30 June 2015
PV	Present Value
Repex	Replacement Capital Expenditure
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test – Distribution
RTS	Return to Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition
SD	Surge Diverter
TNSP	Transmission Network Service Provider
VCR	Value of Customer Reliability
VT	Voltage Transformer
WACC	Weighted average cost of capital
ZS	Zone Substation

Appendix C. Alignment with the National Electricity Rules (NER)

The table below details the alignment of this proposal with the NER capital expenditure requirements as set out in Clause 6.5.7 of the NER.

Table 7: Alignment with NER

Capital Expenditure Requirements	Rationale
6.5.7 (a) (1) The forecast capital expenditure is required in order to **meet or manage the expected demand** for standard control services.	This project is required to meet the forecast demand in the western central Queensland area.
6.5.7 (a) (2) The forecast capital expenditure is required in order to **comply with all applicable regulatory obligations or requirements** associated with the provision of standard control services	Our alignment to regulatory obligations or requirements is demonstrated in this proposal, whereby CAPEX is required in order to maintain compliance and electrical safety through alignment with the QLD Electrical Safety Act 2002 and the QLD Electrical Safety Regulation 2006, as well as provide support for upgrades required by the TNSP.
6.5.7 (a) (3) The forecast capital expenditure is required in order to: (iii) maintain the **quality, reliability and security of supply** of supply of standard control services (iv) maintain the **reliability and security of the distribution system** through the supply of standard control services	This proposal seeks to ensure we adhere to our reliability and security of distribution supply obligations. This proposal will utilise CAPEX to maintain reliability and security of supply for those customers in the above-mentioned region.
6.5.7 (a) (4) The forecast capital expenditure is required in order to maintain the **safety of the distribution system** through the supply of standard control services.	This proposal has employed a standard risk analysis to highlight the safety risks that exist for staff, contractors and the community. That risk analysis has identified safety concerns that require capital expenditure to be addressed and mitigated due to the advanced age of the assets.
6.5.7 (c) (1) (i) The forecast capital expenditure reasonably reflects the **efficient costs** of achieving the capital expenditure objectives	The Unit Cost Methodology and Estimation Approach sets out how the estimation system is used to develop project and program estimates based on specific material, labour and contract resources required to deliver a scope of work. The consistent use of the estimation system is essential in producing an efficient CAPEX forecast by enabling: • Option analysis to determine preferred solutions to network constraints • Strategic forecasting of material, labour and contract resources to ensure deliverability • Effective management of project costs throughout the program and project lifecycle, and • Effective performance monitoring to ensure the program of work is being delivered effectively. The unit costs that underpin our forecast have also been independently reviewed to ensure that they are efficient (Attachments 7.004 and 7.005 of our initial Regulatory Proposal).
6.5.7 (c) (1) (ii) The forecast capital expenditure reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objective	The prudency of this proposal is demonstrated through the options analysis conducted and the quantification of risk and benefits of each option. The prudency of our CAPEX forecast is demonstrated through the application of our common frameworks put in place to effectively manage investment, risk, optimisation and governance of the Network Program of Work. An overview of these frameworks is set out in our Asset Management Overview, Risk and Optimisation Strategy (Attachment 7.026 of our initial Regulatory Proposal).

Capital Expenditure Requirements	Rationale
6.5.7 (c) (1) (iii) The forecast capital expenditure reasonably reflects a realistic expectation of the **demand forecast and cost inputs** required to achieve the capital expenditure objective	Our peak demand forecasting methodology employs a bottom-up approach reconciled to a top-down evaluation, to develop the ten-year zone substation peak demand forecasts. Our forecasts use validated historical peak demands and expected load growth based on demographic and appliance information in small area grids. Demand reductions, delivered via load control tariffs, are included in these forecasts. This provides us with accurate forecasts on which to plan.

Appendix D. Mapping of Asset Management Objectives to Corporate Plan

This proposal has been developed in accordance with our Strategic Asset Management Plan. Our Strategic Asset Management Plan (SAMP) sets out how we apply the principles of Asset Management stated in our Asset Management Policy to achieve our Strategic Objectives.

Table 1: “Asset Function and Strategic Alignment” in Section 1.4 details how this proposal contributes to the Asset Management Objectives.

The Table below provides the linkage of the Asset Management Objectives to the Strategic Objectives as set out in our Corporate Plan (Supporting document 1.001 to our Regulatory Proposal as submitted in January 2019).

Table 8: Alignment of Corporate and Asset Management objectives

Asset Management Objectives	Mapping to Corporate Plan Strategic Objectives
Ensure network safety for staff contractors and the community	**EFFICIENCY** ***Operate safely as an efficient and effective organisation*** Continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations.
Meet customer and stakeholder expectations	**COMMUNITY AND CUSTOMERS** ***Be Community and customer focused*** Maintain and deepen our communities’ trust by delivering on our promises, keeping the lights on and delivering an exceptional customer experience every time
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	**GROWTH** ***Strengthen and grow from our core*** Leverage our portfolio business, strive for continuous improvement and work together to shape energy use and improve the utilisation of our assets.
Develop Asset Management capability & align practices to the global standard (ISO55000)	**EFFICIENCY** ***Operate safely as an efficient and effective organisation*** Continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations.
Modernise the network and facilitate access to innovative energy technologies	**INNOVATION** ***Create value through innovation*** Be bold and creative, willing to try new ways of working and deliver new energy services that fulfil the unique needs of our communities and customers.

Appendix E. Risk Tolerability Table

Network Risks - *Risk Tolerability Criteria and Action Requirements*					
Risk Score	Risk Descriptor	Risk Tolerability Criteria and Action Requirements			
30 – 36	***Intolerable*** *(stop exposure immediately)*				
24 – 29	***Very High Risk***	***ALARP** Risk in this range managed to As Low As Reasonably Practicable	**Executive Approval** (required for continued risk exposure at this level)	May require a full Quantitative Risk Assessment (QRA) Introduce new or changed risk treatments to reduce level of risk Periodic review of the risk and effectiveness of the existing risk treatments	**SFAIRP** Risks in this area to be mitigated So Far as is Reasonably Practicable
18 – 23	***High Risk***		**Divisional Manager Approval** (required for continued risk exposure at this level)	Introduce new or changed risk treatments to reduce level of risk Periodic review of the risk and effectiveness of the existing risk treatments	
11 – 17	***Moderate Risk***		**Group Manager / Process Owner Approval** (required for continued risk exposure at this level)	Introduce new or changed risk controls or risk treatments as justified to further reduce risk Periodic review of the risk and effectiveness of the existing risk treatments	
6 – 10	**Low Risk**				
1 to 5	***Very Low Risk***		No direct approval required but evidence of ongoing monitoring and management is required	*Periodic review of the risk and effectiveness of the existing risk treatments*	

Figure 4: A Risk Tolerability Scale for evaluating Semi-Quantitative risk score

Appendix F. Reconciliation Table

Reconciliation Table Conversion from $18/19 to $2020	
Business Case Value	
(M$18/19)	$1.90
Business Case Value	
(M$2020)	$1.97

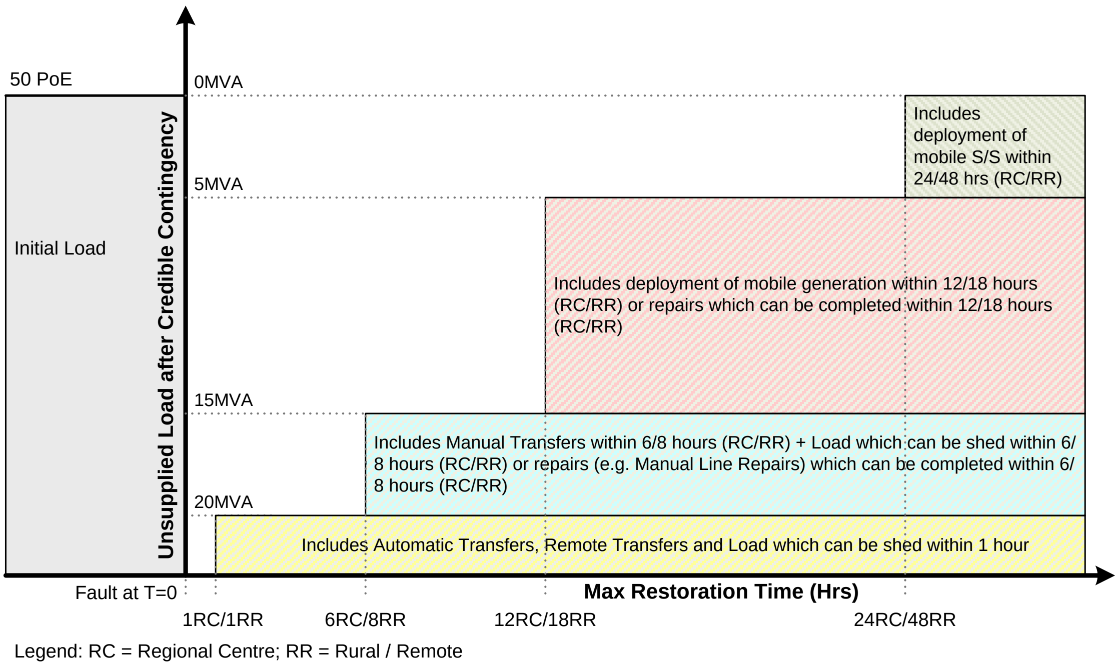
Appendix G. Additional information

Substation Condition Assessment Report Extract

Detailed analysis of the condition of all plant at the Blackwater has recently been updated and is contained in the attached report.

BLAC SCAR_v2.0.pdf

22kV Safety Net Compliance



Safety Net Assessment

Two credible contingencies have been taken into consideration for Safety Net analysis for BLAC T32 substation, which are

- Contingency 1: loss of one transformer or regulator; and
- Contingency 2: loss of the 22kV bus.

Contingency 1 (Loss of one transformer or regulator) during peak load periods will result in overloading and increased risk of failure of the remaining 11/22kV regulator. Blackwater town load can be transferred to BEWE to reduce loading on the remaining unit. This is manageable without customer outage and is therefore Safety Net Compliant.

Contingency 2 (Loss of the 22kV bus) would mean loss of the entire 22kV load until manual switching is carried out to isolate the fault and restore supply. The Safety Net assessment assumed transfer of 3MVA of Blackwater town load to BEWE within 2 hours, and fault finding and restoration of the 22kV bus within 4 hours.

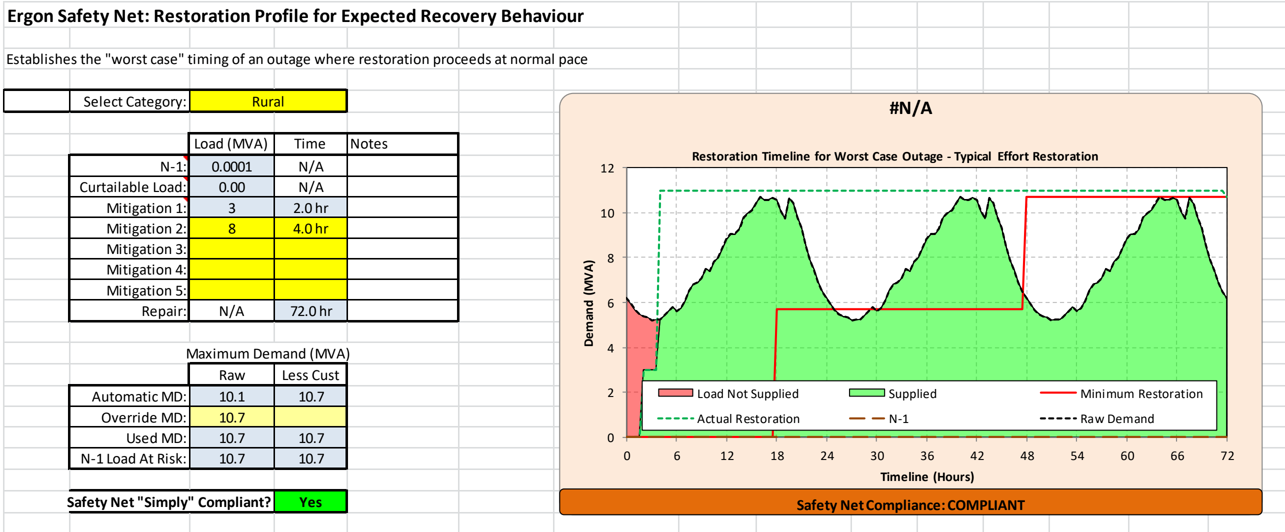


Figure 5: Safety Net Analysis for BLAC T32 22kV Supply (2017-18 loads)

Associated Projects and Project Dependencies

Table 9 - Associated Projects

Project	Project Description	Required by Date
WR1168589	Powerlink CP.02369 T032 Blackwater No. 1 & 2, Transformer Replacement	FCA June 2022
	The objective of this project is to replace both transformer 1 and transformer 2 with a single new 160MVA transformer unit by June 2022.	

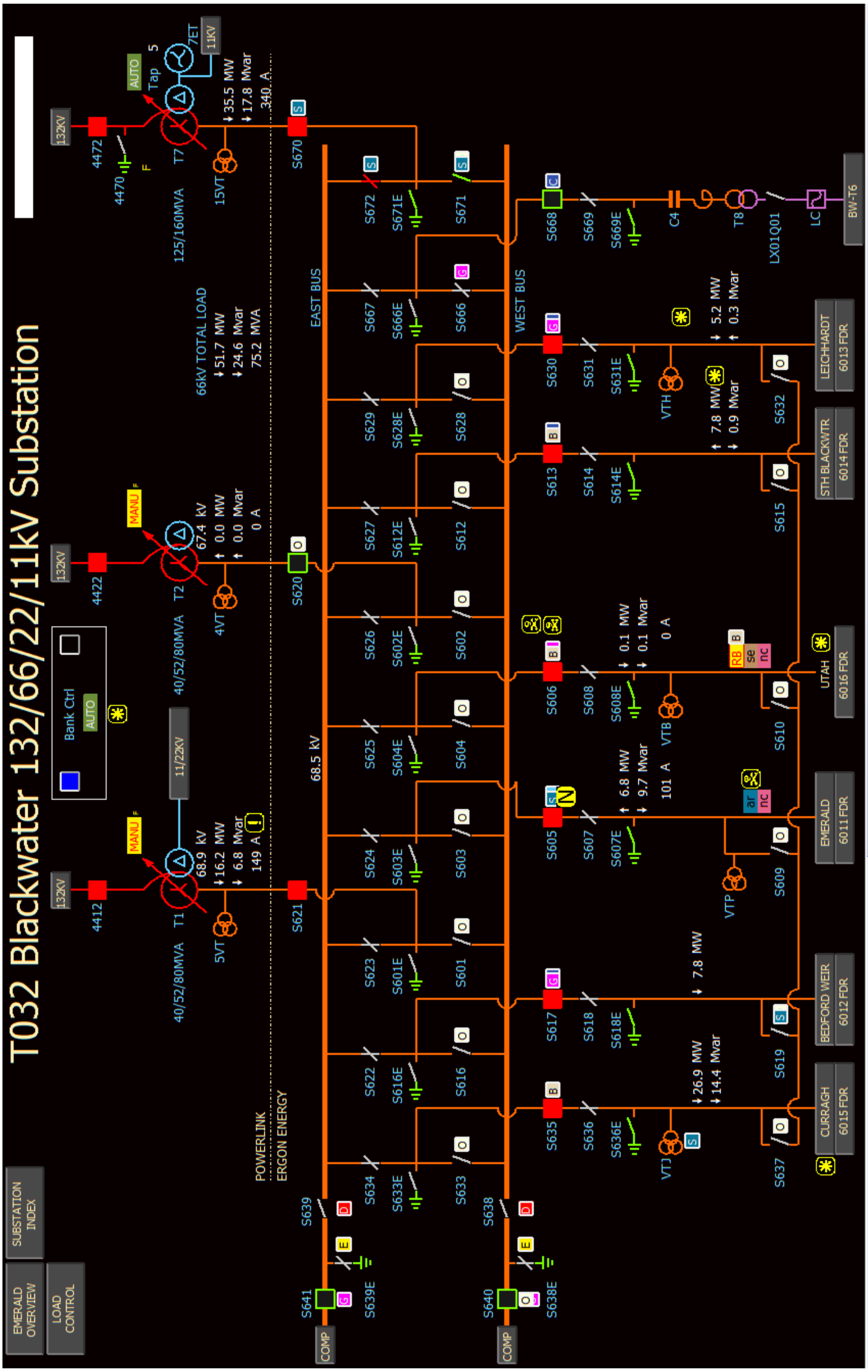


Figure 6: BLAC T32 66kV Operating Diagram

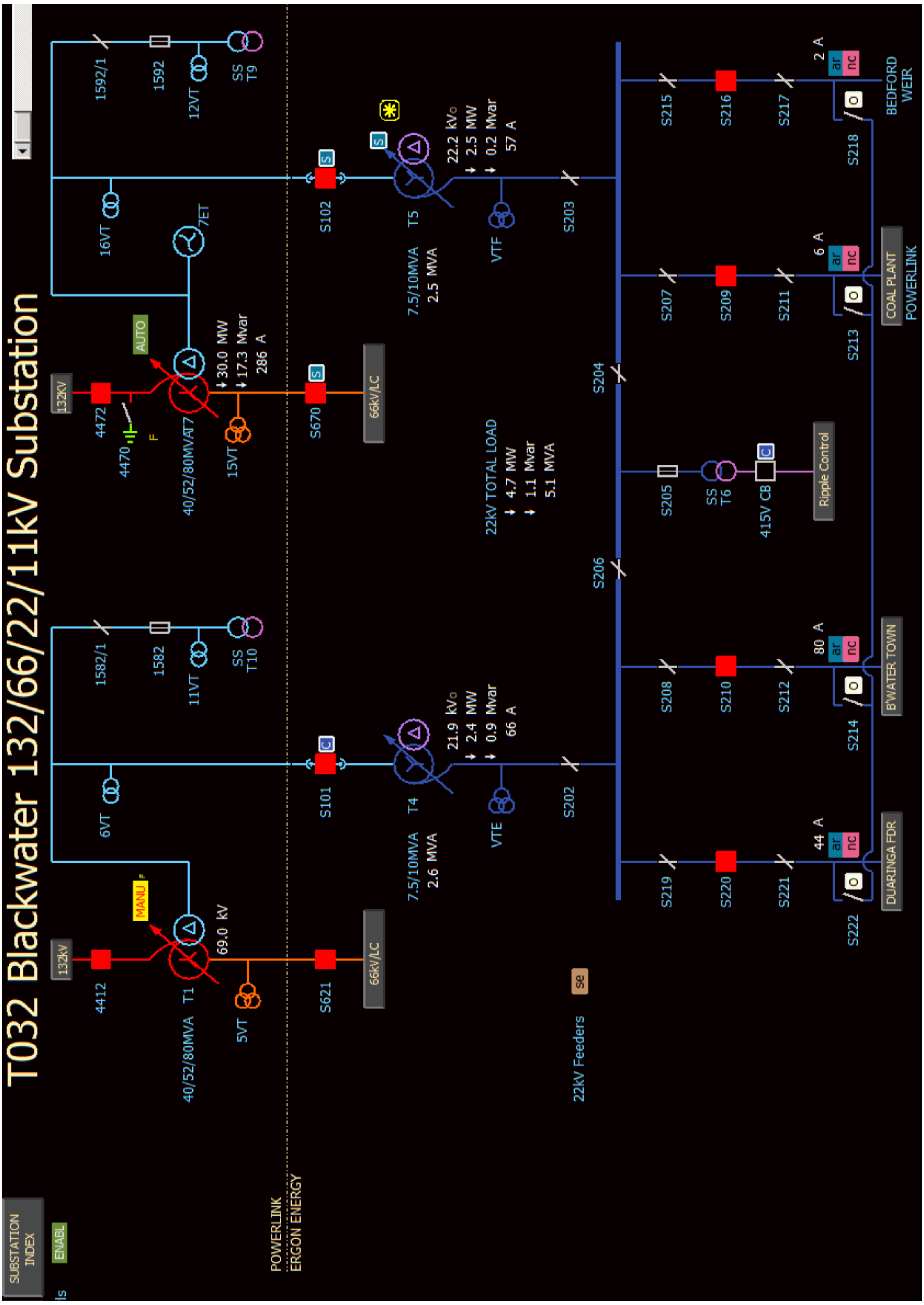


Figure 7: BLAC T32 66kV Operating Diagram