Business Case
DC Supplies Duplication

Part of the Energy Queensland Group

Executive Summary

Substation Direct Current (DC) supply systems are critical to the safe operation of control and protection assets in the Energy Queensland (EQL) network. Sufficient availability and redundancy of substation DC supplies is required in the Ergon Energy and Energex networks to ensure protection and control systems reliably operate in accordance with the National Electricity Rules (NER).

A Distribution Network Service Provider (DNSP) is obliged under the National Electricity Rules, Chapter 5 (S5.1.9), to ensure the following back-up protection is provided in the network:

- Subject to clauses S5.1.9(k) and S5.1.9(l), a Network Service Provider must provide sufficient primary protection systems and back-up protection systems (including breaker fail protection systems) to ensure that a fault of any fault type anywhere on its transmission system or distribution system is automatically disconnected in accordance with clause S5.1.9(e) or clause S5.1.9(f).

Protection relays are duplicated in most existing substation installations and all new installations to meet this requirement. The auxiliary DC systems on which protection relays depend however, often have a single point of failure; as traditionally duplicated DC supplies have only been installed at substations with voltages in excess of 100kV. Recent studies for renewable energy generation connections found it was not possible to provide remote back-up protection to downstream substations when a fault current contribution from an alternate source existed between the supplying substation and the fault location.

A counterfactual, 'do nothing' option was considered but rejected as it fails to address NER compliance obligations. Three network options for duplicating DC supplies at high risk substations have been evaluated in this business case:

Option 1 – A risk-based approach to 40 DC supply installations from 2020-2025, which assumes substations with the highest fault level are at risk of more significant levels of damage.

Option 2 – An accelerated version of Option 1, under which installations are carried out within two years (2020-22).

Option 3 – A decelerated version of Option 1, under which installations are carried out over a ten-year period (2020-2030).

Energy Queensland 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 business case both network risk and regulatory obligations are strong drivers, as failing to implement duplicate DC supplies at high-risk substations is likely to lead to delays for fault clearance that cause asset damage, and breach NER compliance obligations for protection services.

To this end, Option 1 is the preferred option. It provides the most cost-effective means, with a Net Present Value (NPV) result of -$8.4M, of addressing the need to improve DC supplies at high-risk substations, while remaining compliant with NER obligations.

The direct cost of the program 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
$9.9M	N/A	$9.9M

Contents

1. Introduction

Substation Direct Current (DC) supply systems are critical to the safe operation of control and protection assets in the Ergon Energy and Energex networks. Sufficient availability and redundancy of DC services is required in the Energy Queensland (EQL) network to ensure protection and control systems reliably operate in accordance with the National Electricity Rules (NER).

This proposal recommends the optimal capital investment necessary to ensure regulatory compliance for Ergon Energy and Energex protection systems via the strategic installation of duplicate DC supplies.

1.1 Purpose of document

This document provides options, analysis and a proposed approach to improve Ergon Energy and Energex compliance with NER back-up protection requirements; overcoming recently identified gaps in the existing remote back-up protection configuration.

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 investment governance processes. The costs presented are in $2018/19 direct dollars.

1.2 Scope of document

The scope of this document is limited to strategic expenditure for duplicate DC services (DC distribution boards, charging systems or batteries) identified for installation to meet National Electricity Rules Chapter 5 (S5.1.9).

1.3 Identified Need

Energy Queensland 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 business case both network risk and regulatory obligations are strong drivers, as failing to implement duplicate DC supplies at high-risk substations is likely to lead to delays for fault clearance that cause asset damage, and breach NER compliance obligations for protection services.

A Distribution Network Service Provider (DNSP) is obliged under the National Electricity Rules, Chapter 5 (S5.1.9), to ensure the following back-up protection is provided in the network:

- Subject to clauses S5.1.9(k) and S5.1.9(l), a Network Service Provider must provide sufficient primary protection systems and back-up protection systems (including breaker fail protection systems) to ensure that a fault of any fault type anywhere on its transmission system or distribution system is automatically disconnected in accordance with clause S5.1.9(e) or clause S5.1.9(f).

Protection relays are duplicated in most existing substation installations and all new installations to meet this requirement. The auxiliary DC systems on which protection relays depend however, often have a single point of failure; as traditionally duplicated DC supplies have only been installed at substations with voltages in excess of 100kV.

Maintaining the operational availability of substation auxiliary DC services is paramount. Failure of DC distribution boards, charging systems or batteries can lead to a complete loss of control substation protection and control systems. Hence insufficient substation DC supply availability can lead to a breach of the National Electricity Rules.

Recent studies for renewable energy generation connections, found it was not possible to provide remote back-up protection to downstream substations when a fault current contribution from an alternate source existed between the supplying substation and the fault location.

To ensure that the protection and control systems have high availability and allow the protection and control system to meet the redundancy and performance expectations of the National Electricity Rules, duplication of DC supplies is proposed for certain high-risk critical substations where remote back-up is unlikely to work.

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

1.4 Energy Queensland Strategic Alignment

Table 1 details how duplicate DC supplies contribute 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	Suitable electricity infrastructure development is critical to the safe operation of the electricity network. Without suitable redundancy, asset failures could occur resulting in unacceptable safety and network risks via loss of control of protection and control systems.
Meet customer and stakeholder expectations	The provision of suitable electricity infrastructure is critical to a safe and reliable electricity supply. This infrastructure contributes to important electricity reliability outcomes, particularly around fault recovery times, expected by the community.
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	Without suitable duplicate substation DC supplies, the risk of supply interruption is likely to increase where further alternate sources of fault current are integrated into the network (e.g. growing renewable generation assets). Hence the most suitable economic development provides strategic investment to ensure reliability obligations are met.
Develop Asset Management capability & align practices to the global standard (ISO55000)	Timely provision of suitable back-up protection and auxiliary services aligns with the practices in ISO55000.
Modernise the network and facilitate access to innovative energy technologies	The proposed strategic replacement is in line with modern standards that support integration of modern generation assets.

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 shows the relevant compliance obligations for this proposal.

Table 2: Compliance obligations related to this proposal

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 reduces safety risks which could arise from network fault and protection failure.
Distribution Authority for Ergon Energy or Energex 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 reduces risks associated with customer reliability through plant failures due to insufficient DC supply.
National Electricity Rules, Chapter 5	Schedule S5.1 of the National Electricity Rules, Chapter 5 provides a range of obligations on Network Services Providers relating to Network Performance Requirements. These include: • Section S5.1.9 Protection systems and fault clearance times • Section S5.1a.8 Fault Clearance Times • Section S5.1.2 Credible Contingency Events	This proposal reduces network risks associated with network control and fault clearance times.

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

1.7 Limitation of existing assets

Ergon Energy and Energex have traditionally only installed duplicated DC supplies at substations with voltages in excess of 100kV. Recent studies for renewable energy generation connections (at Middlemount, Dimbulah, and Cape River) found that it wasn't possible to provide remote back-up protection to downstream substations when a fault current contribution from an alternate source existed between the supplying substation and the fault location. To ensure adequate back-up protection is available, a second DC supply has been installed at these sites; removing the need for the upstream protection to provide back-up for the substation and any assets downstream of the substation with duplicated DC.

A further 40 substation sites (16 Ergon Energy, 34 Energex) have been identified across the EQL network as high-risk for remote back-up protection failure and NER non-compliance.

These sites were identified using a standardised approach to identify substations likely to have reduced or no back-up protection. Duplicate DC supplies for 2020-2025 period are proposed at major zone substations, defined by:

- sub-transmission circuits (33 or 66kV)
- more than 3 connected sub transmission feeders
- fault level greater than approximately 500MVA

Failure of the DC supply at these substations may result in NER non-compliance due to an inability to effectively disconnect the faulted network without additional network damage.

2 Counterfactual Analysis

2.1 Purpose of asset

Substation DC distribution boards, batteries and chargers (DC services) are a critical element of Ergon Energy and Energex substations. DC services ensure reliable control of substation protection equipment and control systems which allow electrical faults to be safely isolated. Maintaining the operational availability of substation DC services is paramount to:

- Effective control and protection of the EQL network
- Ensuring the safety of staff and contractors working within substations

2.2 Business-as-usual service costs

The business as usual (BAU) service costs for substation DC systems includes maintenance costs as well as replacement and restoration costs for failed in service assets. The BAU (Do Nothing) does not overcome identified gaps in Ergon Energy and Energex remote back-up protection configuration or NER requirements; hence has not been explicitly costed.

2.3 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
<u>NER Compliance</u> Failure to ensure protection systems are available. The single DC Supply at the substation has a failure and the upstream protection does not provide sufficient remote back-up protection resulting in an **improvement notice being issued by the regulator**.	Legislated	4 *(improvement notice being issued by the regulator)*	3 *(Unlikely)*	**12** ***(Moderate Risk)***	2019
<u>Asset Impact - Damage</u> Network damage due to local protection not available. Slow clearing time of the remote back-up protection allows damage to occur to plant in the event that the local protection is not available resulting in **asset damage/impact $>100,000**.	Business	2 *(asset damage/impact $>100,000)*	4 *(Likely to occur)*	**8** ***(Low Risk)***	2019
<u>Asset Impact - Control</u> Failure of the substation DC supply causes the substation to become inoperable and unmonitored by Supervisory Control and Data Acquisition (SCADA) and an **inability to remotely control the substation**.	Business	3 *(Inability to remotely control an Energex/Ergon substation)*	3 *(Unlikely to occur)*	**9** ***(Low Risk)***	2019

Further Details of the risk ratings and descriptions can be found in Energy Queensland's Network Risk Framework.

2.4 Retirement or de-rating decision

Substation DC services are vital to the reliable operation of the Ergon Energy and Energex networks. There is no suitable de-rating decision or retirement decision associated with this infrastructure due to compliance and network protection and control obligations.

3 Options Analysis

3.1 Options considered but rejected

The counterfactual BAU option has been rejected as it fails to address NER compliance obligations. In the event of a concurrent DC supply failure and power system failure, generation systems may be placed at risk of unwanted tripping as well as significant power system damage. The “Do nothing” risk has been determined to be unacceptable for substations with fault levels in excess of approximately 500MVA due to the extensive damage and consequent safety risks that could arise from a network fault and protection failure. These installations are at high risk of having no remote back-up protection and hence they are not compliant with the NER.

3.2 Identified options

3.2.1 Network options

Three options have been analysed in this report. The table below outlines the installation period proposed for each option.

Table 4 - Network options

Option	Installation Period	CAPEX ($M)
Option 1 - Strategic Implementation	5 years	$9.6M
Option 2 - Accelerated Implementation	2 years	$9.6M
Option 3 – Decelerated Implementation	10 years	$9.6M

Option 1 – Strategic Implementation (Proposed)

A risk-based approach to 40 DC supply installations from 2020-2025. This option assumes substations with the highest fault level are at risk of more significant levels of damage (including network connected downstream) in the event that a fault remains uncleared; therefore, duplicate DC supply installations occur in accordance with fault level.

Option 2 – Accelerated Implementation

Same as Option 1, but capital expenditure is accelerated to remove all identified compliance risk within a two-year period.

Option 3 – Decelerated Implementation

Same as Option 1, but capital expenditure is decelerated network risk exposure is held across a ten-year period. This option has been provided for comparison but delivers an unacceptable risk profile.

3.2.2 Non-network options

No non-network options have been assessed. The primary investment driver for this project is CAPEX, addressing both asset compliance 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 immediate risk of non-compliance.

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 considering costs and benefits over the program lifetime from FY2020/21 to FY2024/25, using EQL's standard NPV analysis tool. The Present Value (PV) of the CAPEX and NPV results of each option, discounted at the Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62%, are outlined in

Table 5: NPV comparison of options

Option	CAPEX ($M)	NPV ($M)
Option 1 - Strategic Implementation	$9.6M	$-8.4M
Option 2 - Accelerated Implementation	$9.6M	$-8.8M
Option 3 – Decelerated Implementation (non- compliant comparison only)	$9.6M	$-7.8M

All options have the same capital expenditure distributed across different time periods. Option 1 provides the highest NPV of the compliant options and removes compliance and network risk in a reasonable timeframe.

3.4 Scenario Analysis

3.4.1 Sensitivities

Sensitivity analysis was conducted around capital costs, varying the estimates by +/- 20%. Based on Monte Carlo simulation Option 1 was the preferred compliant option, returning a better NPV than Option 2 result for 85.5% of cases. These results exclude Option 3 due to non-compliance with the NER.

3.4.2 Value of regret analysis

In terms of selecting a decision pathway of 'least regret', Option 1 presents an economically efficient balanced approach to investment. The recommendation of Option 1 reflects a benefit analysis on whether the acceleration of investment (Option 2) is justified and the NPV analysis indicated that Option 1 was the optimal investment decision.

3.5 Qualitative comparison of identified options

3.5.1 Advantages and disadvantages of each option

Table 6 below details the advantages and disadvantages of each option considered.

Table 6: Assessment of options

Pros	Advantages	Disadvantages
Option 1 - Strategic Risk based Replacement	• Reduces compliance risk with assets experiencing the highest fault currents addressed first • Equally affordable option, while mitigating network and safety concerns	
Option 2 - Fast track installation	• Rapidly eliminates safety and network risk for failed remote back-up protection	• Higher up-front cost than alternative options without significant risk reduction advantage

Pros	Advantages	Disadvantages
Option 3 – Progressive installation	• Delayed installation deferring resource and capital requirements.	• Maintains network risk at an unacceptable level for a lengthy period.

The network (business) risk the organisation would be exposed to if the project was not undertaken is not deemed to be as low as reasonably practicable (ALARP). Addressing the risks as detailed above through implementation of the preferred Option 1 will reduce Ergon Energy and Energex’s risk exposure.

The risk exposure of Option 1 is greater than Option 2 where the compliance risk of substation DC services is rapidly addressed. The higher initial expenditure for Option 2 however is not considered prudent for the risk reduction provided.

3.5.2 Alignment with network development plan

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. The proposed works ensure EQL meet maintain network reliability and security by improving back-up protection availability.

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. The proposed works accommodate new assets which are designed to modern standards, increasing the reliability and safety of the asset group.

3.5.4 Risk Assessment Following Implementation of Proposed Option

Table 7: Risk assessment showing risks mitigated following Implementation

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
NER Compliance Failure to ensure protection systems are available. The single DC Supply at the substation has a failure and the upstream protection does not provide sufficient back-up protection resulting in an **improvement notice being issued by the regulator**.	Legislated	(Original) 4 *(improvement notice being issued by the regulator)* (Mitigated) 4 *(As above)*	3 *(Unlikely)* 1 *(Almost no likelihood)*	**12** ***(Moderate Risk)*** **4** ***(Very Low Risk)***	2019 2025
Asset Impact - Damage Network damage due to local protection not available. Slow clearing time of the back-up protection allows damage to occur to plant in the event that the local protection is not available resulting in **asset damage/impact $>100,000**.	Business	(Original) 2 *(asset damage/impact $>100,000)* (Mitigated) 2 *(As above)*	4 *(Likely to occur)* 2 *(Very unlikely)*	**8** ***(Low Risk)*** **4** ***(Very Low Risk)***	2019 2025
Asset Impact - Control Failure of the substation DC supply causes the substation to become inoperable and unmonitored by SCADA and an **inability to remotely control the substation**.	Business	(Original) 3 *(Inability to remotely control an Energex/Ergon substation)* (Mitigated) 3 *(As above)*	3 *(Unlikely to occur)* 1 *(Almost no likelihood)*	**9** ***(Low Risk)*** **3** ***(Very Low Risk)***	2019 2025

4 Recommendation

4.1 Preferred option

Option 1, Strategic Implementation, is the preferred options as it prudently manages risks associated with NER compliance and offers the highest NPV outcome.

4.2 Scope of preferred option

A data survey identified 40 network sites as a sub-transmission (33kV or 66kV) that have more than three infeed's and a fault level in excess of approximately 500MVA.

For each of the identified substations (Appendix G), a second DC supply system should be installed and protection and tripping supplies for each protected item up to and including the distribution feeder back-up protection be segregated.

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).

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

Energy Queensland, Corporate Strategy [1.001], (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, 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
CAPEX	Capital expenditure
Current regulatory control period or current period	Regulatory control period 1 July 2015 to 30 June 2020
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 Amperes
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules (or Rules)
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

Abbreviation or acronym	Definition
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
WACC	Weighted average cost of capital

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 8: Alignment with NER

Capital Expenditure Requirements	Rationale
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	This proposal ensures that reliability obligations outlined in *Table 2: Compliance obligations related to this proposal*, are met by providing economically efficient project to improve the availability of substation DC services. Without this project, these obligations would be at significant risk of being breached.
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 project maintains levels of network reliability, limiting losses of network control. This project is critical to providing network reliability.
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 project minimises unacceptable safety risks caused by loss of control of protection systems, delaying fault clearing time.
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 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 project lifecycle, and The works included in the project are well known and familiar to the business. 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 the costs that **a prudent operator** would require to achieve the capital expenditure objectives	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).

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 9: 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 1: 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)	$9.90
Business Case Value	
(M$2020)	$10.27

Appendix G. Supporting Information

Site List

Network	Substation	Fault Level 3 phase (MVA)	Planned Delivery
ERG	BOHLSS (BOHLE 66/11KV SUB (BOHL))	1489	30/06/2021
ERG	TOPOSS (TOWNSVILLE PORT 66/11KV SUB (TOPO))	1475	30/09/2022
ERG	BLRISS (BLACKRIVER 66/11KV SUB (BLRI))	1228	30/06/2021
ERG	RASMSS (RASMUSSEN 66/11KV SUB (RASM))	1040	30/06/2022
ERG	ALSTSS (ALFRED STREET 33/11KV SUB (ALST))	832	30/06/2022
ERG	LACRSS (LAKES CREEK 66/11KV SUB (LCSS))	822	30/06/2022
ERG	AYRZSS (AYR 66/11KV SUB (AYRZ))	727	30/06/2023
ERG	WEBUSS (WEST BUNDABERG 66/11KV SUB (WEBU))	708	30/06/2023
ERG	HOHISS (HOME HILL 66/11KV SUB (HOHI))	665	30/06/2023
ERG	EAAYSS (EAST AYR SPILLER ST 66/11KV SUB (EAAY))	640	30/06/2023
ERG	MACISS (MARYBOROUGH CITY 66/11KV SUB (MC))	618	30/06/2023
ERG	OAKESS (OAKEY 33/11KV SUB (OAKE))	611	30/06/2024
ERG	CHILSS (CHILDERS 66/11KV SUB (CHIL))	566	30/06/2024
ERG	WETOSS (WEST TOOWOOMBA 33/11KV SUB (ME005))	566	30/06/2024
ERG	SOBUSS (SOUTH BUNDABERG 66/11KV SUB (SB))	553	30/06/2025
ERG	KINGSS (KINGAROY 66/11KV SUB (KING))	528	05/02/2025

Network	Substation	Fault Level 3 phase (MVA)	Planned Date
EGX	DARRA	1354	30/06/2021
EGX	MOOROOKA	1261	30/06/2021
EGX	HEMMANT	1241	30/06/2021
EGX	SHERWOOD	1207	30/06/2021
EGX	UPPER MT GRAVATT	1188	30/06/2021
EGX	QUEENSPORT	1164	30/06/2021
EGX	TARINGA	1124	30/06/2021
EGX	ANNERLEY	1121	30/06/2022
EGX	OXLEY	1068	30/06/2022
EGX	NEWMARKET	1060	30/06/2022
EGX	ASTOR TERRACE	1045	30/06/2022
EGX	GEEBUNG	995	30/06/2022
EGX	KEDRON	979	30/06/2022
EGX	STRATHPINE	972	30/06/2022
EGX	ASHGROVE	958	30/06/2023
EGX	CALAMVALE	951	30/06/2023
EGX	BULIMBA	943	30/06/2023
EGX	CHERMSIDE	930	30/06/2023
EGX	ENOGGERA	926	30/06/2023
EGX	HENDRA	905	30/06/2023
EGX	ROCKLEA	894	30/06/2023
EGX	TOOWONG	859	30/06/2024
EGX	CLAYFIELD	856	30/06/2024
EGX	GIBSON ISLAND	852	30/06/2024
EGX	CAMP HILL	848	30/06/2024
EGX	HOLLAND PARK	825	30/06/2024
EGX	SUNNYBANK	768	30/06/2024
EGX	HAMILTON	759	30/06/2024
EGX	HAMILTON LANDS	754	30/06/2025
EGX	CAROLE PARK	748	30/06/2025
EGX	YATALA	647	30/06/2025
EGX	CABOOLTURE WEST	646	30/06/2025
EGX	ZILLMERE	586	30/06/2025
EGX	LINDUM	525	30/06/2025

NPV Analysis

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Business Case - DC Se