Business Case
Sensitive Earth Fault Protection on the Distribution Network

Part of the Energy Queensland Group

Executive Summary

Protection systems ensure the safe and reliable functioning of the power network during power system abnormalities. The primary function of the protection system is to detect and disconnect faults (for example, a power line on the ground) from the power system.

This document recommends the optimal capital investment necessary for implementation of Sensitive Earth Fault (SEF) schemes to address the safety risks posed by high impedance earth faults.

Risks associated with the program are largely due to conductors falling to the ground and remaining energised. This can result in fatalities if members of the public come into contact with the conductor, or fires if the conductor contacts on flammable material.

This document examines the needs of both Energex and Ergon Energy; however, the only work identified for compliance is in the Ergon network, and is intended to address the outstanding distribution feeders in the Ergon Energy network that were not addressed in the previous regulatory periods.

Of the approximately 227 substations and 1,126 distribution feeders in the Ergon Energy area, 11 substations and 26 feeders require SEF protection to be installed in the 2020-25 regulatory period.

A risk-based implementation program for SEF schemes was considered but rejected in this business case, due to the 10-year time frame to resolve the safety and compliance risks, which is unacceptable due to the safety risk exposure during the interim period. A counterfactual, 'do nothing' option under which no augmentation works are carried was also considered but rejected, due to unacceptable safety risks and compliance issues. Two network options were evaluated as part of this business case:

Option 1 – Install SEF capable relays or reclosers as required to provide full SEF coverage to the 26 distribution feeders lacking SEF protection.

Option 2 – Use existing relays with typical earth fault protection to detect high impedance faults by installing low ratio Current Transformers (CTs).

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 safety risks and regulatory obligations are strong drivers, due to the need to ensure SEF schemes are implemented and safety risks posed by high impedance faults are addressed.

Option 1 was selected as the proposed option, as it mitigates all identified risk drivers while also being the most cost-effective option (with a Net Present Value (NPV) of $1.09 million, compared to $0.33 million for Option 2.

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
N/A	$0	$1.8M

Note the original Regulatory Proposal bundled SEF protection schemes with those for DER and Diverse Communications, and as such there is not an applicable original direct cost for this business case from the Regulatory Proposal submissions.

Contents

1. Introduction

Protection systems ensure the safe and reliable functioning of the power network during power system abnormalities. The primary function of the protection system is to detect and disconnect faults (for example, a power line on the ground) from the power system.

Reliable operation protection schemes are vital to eliminating risks such as electrocution, damage to equipment and maintaining system stability. Failure of a protection scheme to operate correctly results in unsafe conditions until manual intervention or back up arrangements are invoked.

1.1 Purpose of document

This document recommends the optimal capital investment necessary for implementation of Sensitive Earth Fault (SEF) schemes to address the safety risks posed by high impedance earth faults.

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 (EQL) Revised Regulatory Proposal to the Australian Energy Regulator (AER) for the 2020-25 regulatory control period. Prior to investment, further detail with 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

This document describes the requirement for including SEF protection on 11kV feeders to reliably detect and de-energise high impedance earth faults that cannot be detected by typical earth fault protection. This document examines the needs of both Energex and Ergon; however, the only work identified for compliance is in the Ergon network.

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 safety risks and regulatory obligations are strong drivers, due to the need to ensure SEF schemes are implemented and safety risks posed by high impedance faults are addressed.

This program is required to ensure Energy Queensland can meet current and future business requirements and will support meeting obligations for legislated compliance, by ensuring ongoing and reliable operation of protection schemes.

In many cases, the schemes implemented in the past no longer meet the current requirements of the National Electricity Rules (NER), Electrical Safety Act 2002 (ESA), or align with current industry practice. Current performance requirements include SEF protection on 11kV feeders. SEF Protection is required to detect high impedance faults which standard earth fault protection cannot detect. This ensures that situations where energised conductors which are on the ground can be detected and de-energised. This is described in the following sections.

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

1.4 Energy Queensland Strategic Alignment

Table 1 details how SEF protection schemes 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	Ensure that high-impedance earth faults - downed conductors are de-energised rapidly, reducing the risk of downed conductors starting fires or endangering staff or the public.
Meet customer and stakeholder expectations	Reliably remove unsafe operating scenarios like energised downed conductors.
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	High-impedance earth faults that remain energised increase the electrical safety risk to staff and the public and increase the risk of fires. SEF schemes reliably detect and clear these faults, reducing risk and likelihood of equipment or consequential damage.
Develop Asset Management capability & align practices to the global standard (ISO55000)	Timely development of infrastructure, including appropriate protection schemes and using suitable asset standards aligns with the practices in ISO55000.
Modernise the network and facilitate access to innovative energy technologies	Modern industry practice and regulations stipulate the requirement for SEF protection on distribution feeders, therefore protection systems must be updated to comply.

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 • EQL has an obligation to ensure all reasonable precautions must be taken to ensure that fuses or circuit breakers in the system will operate during fault conditions[3]	SEF protection is necessary to reliably detect and de-energise high impedance earth faults on the distribution network. Energised high impedance faults pose a safety risk to staff and the community.
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)	Good electrical industry practice stipulates the need for SEF protection on distribution feeders.
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	The NER requires that all electrical faults must be de-energised. SEF protection is necessary to reliably and quickly de-energise high impedance earth faults. Without SEF, these faults may remain energised which does not comply with the NER.

[1] Section 29, *Electrical Safety Act 2002*
[2] Section 30, *Electrical Safety Act 2002*
[3] Part 9, Division 2, *QLD Electrical Safety Regulation 2013*

1.7 Limitation of existing assets

Unlike standard earth fault protection SEF can detect high impedance earth faults, providing very good detection of wires on the ground. When SEF protection is absent, wires on the ground present a very high safety risk to the public, especially during storm and cyclone conditions. Fallen conductors that remain live can also increase the risk of bushfires which can cause catastrophic damage to the community.

The current state of SEF protection in Ergon Energy's network is as follows:

- Of the approximately 227 substations and 1,126 distribution feeders in the Ergon Energy area, 23 substations with 83 distribution feeders with overhead wires have been identified as lacking SEF protection for the full feeder. Of these, 11 substations and 26 feeders require SEF protection to be installed in the 2020-25 regulatory period. The remaining sites are planned to be addressed in asset replacement programs or will be completed before the end of this regulatory period.
- Some feeders have line reclosers installed that provide SEF protection to sections of the feeder.
- 4,693 Dangerous Electrical Events (DEEs) were recorded from 2010 to 2015 that involved a piece of hardware such as a pole, cross arm or conductor failing and causing a live conductor to become accessible by the public
- 42 of these DEEs were determined to involve a High Voltage (HV) conductor coming into contact with ground and remaining live until the faulted network was manually isolated

Energex's 11kV network is SEF compliant. Targeted augmentation is not required during the regulatory period.

2 Counterfactual Analysis

Ergon Energy's protection assets are vital to ensure the safe, reliable operation of the electricity grid in Queensland. Comprehensive protection schemes are required to ensure all network faults are automatically cleared with minimal fault duration and minimal network isolation. Protection must not trip when there is no fault presented, or when another device could clear the fault with less network isolated. SEF protection is required to clear high impedance earth faults where the fault current flowing is less than that which can be detected by typical earth fault protection.

2.1 Business-as-usual service costs

The risks arising from no augmentation are as detailed below.

Ergon has historically experienced 8.4 faults per annum where a live distribution conductor is on the ground and is not deenergised without manual intervention.

The safety risk of an electric shock causing a single fatality resulting from these uncleared faults has been calculated as the Probability of Failure (PoF) multiplied by the Likelihood of Consequence (LoC) multiplied by the Cost of Consequence (CoC) as follows:

- PoF with 8.4 faults per annum is estimated at 12%.
- CoC has been estimated using the Australian Government's Value of Statistical Life (VSL)[4], with a disproportionality factor of 10 applied giving a CoC of $46M.
- LoC has been assumed to be 1 in 10-year likelihood of a conductor on the ground causing a fatality. This is based on engineering judgement with consideration to the face that electric shocks of this nature are "near miss" fatality incidents.

The monetised risk calculated using these assumptions is $0.55M per year, or approximately $2.75M over 5 years.

2.2 Key assumptions

The assumptions were applied during the analysis for this business case:

- Lack of SEF protection in the Ergon network will not be rectified within the upcoming regulatory period by other projects, for example, protection relay replacements due to age.
- The Energex network already has adequate SEF protection coverage.

2.3 Risk assessment

In addition to the quantitative risk analysis described in section 2.1, a qualitative risk assessment has been provided in accordance with the EQL Network Risk Framework and the Risk Tolerability table from the framework is shown in Appendix E.

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[4] Australian Government, Department of Prime Minister and Cabinet, *Best Practice Regulation Guidance Note, Value of Statistical Life,* (August 2019) <*https://www.pmc.gov.au/sites/default/files/publications/value-of-statistical-life-guidance-note_0_0.pdf*>

Table 3: Counterfactual risk assessment

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Failure of protection to detect a high impedance earth fault results in inadvertent contact with an energised source and **a single fatality.**	Safety	5 *(Single fatality)*	4 *(Likely)*	**20** *(High)*	2020
Failure to clear a fault results in a breach of National Electricity Rules and an **improvement notice issued by the regulator**.	Legislated	4 *(Energex/Ergon identified issue requiring regulator to be notified. Improvement notice issued)*	3 *(Unlikely)*	**12** *(Moderate)*	2020
Failure to clear an earth fault results in a bushfire causing significant equipment damage and **a single fatality**.	Safety	5 *(Single fatality)*	3 *(Unlikely)*	**15** *(Moderate)*	2020
An energised conductor fails and falls to ground starting bushfire resulting in **medium-term disruption to an eco-system**.	Environmental	4 *(medium-term disruption to an eco-system)*	3 *(Unlikely)*	**12** *(Moderate)*	2020

2.4 Retirement or de-rating decision

There is no retirement or de-rating decision available that can significantly reduce the incidence of or prevent high impedance earth faults remaining energised.

3 Options Analysis

3.1 Options considered but rejected

In addition to the counterfactual, outlined in Section 2, two other options were considered but rejected in this business case:

Risk-based augmentation program

A risk-based based program with the following scope was considered:

- Identify the highest risk sections of the remaining 26 distribution feeders. For example, this would include overhead network near schools or high traffic/high population density locations.
- Prioritise installation of SEF protection on those sections during the regulatory period
- Complete the SEF coverage on lower-risk feeders or feeder sections during the next regulatory period.

This option was rejected due to the 10-year time frame to resolve the safety and compliance risks, which is unacceptable due to the safety risk exposure during the interim period.

Convert overhead network without SEF protection to underground

Converting overhead network to underground removes the risk of a fallen conductor being accessible to the public, which resolves the safety driver for installing SEF protection on distribution feeders.

This option was considered and rejected due to the significant capital cost and the lack of capability to deliver this augmentation in a reasonable time frame.

3.2 Identified options

3.2.1 Network options

Identified options are summarised below:

Option 1 – Install SEF capable relays and/or line reclosers (Proposed)

Install SEF capable relays and/or line reclosers as required to provide full SEF coverage to the remaining 26 distribution feeders without full protection during the regulatory period.

Option 2 – Utilise existing protection relays and lower settings to be able to detect high impedance earth faults.

This would require installation of additional Current Transformers (CTs) on all 26 feeders as the typical minimum setting for standard earth fault protection in most protection relays is 10%, requiring a CT ratio of 40/1 to provide the standard distribution SEF protection pickup of 4 amps.

3.2.2 Non-network options

There are no identified non-network options available that can significantly reduce the incidence of or prevent uncleared high impedance earth faults from remaining energised and presenting a hazard to the public and Ergon staff.

3.3 Economic analysis of identified options

3.3.1 Cost versus benefit assessment of each option

The Net Present Value (NPV) of the available option has been determined by discounting costs over the program lifetime from FY2019/20 to FY2034/35 at the Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62%. The results, along with the Present Value (PV) of CAPEX discounted at the WACC rate are provided in Table 4.

Table 4: Net present value of options ($M)

Option Number	Option Name	PV CAPEX	NPV
1	Install SEF capable relays or reclosers	$1.45	$1.09
2	Use existing relays, install CTs	$2.21	$0.33

The risks for the risk-based augmentation and 'Do Nothing' options have been deemed too high for consideration.

The direct cost, based on $18/19 direct dollars, is shown in Table 5 below:

Table 5: 2020-25 Cost Summary

Option	2020/21	2021/22	2022/23	2023/24	2024/25	Total
1	$0.368M	$0.368M	$0.368M	$0.368M	$0.368M	$1.84M
2	$0.560M	$0.560M	$0.560M	$0.560M	$0.560M	$2.8M

3.4 Scenario Analysis

3.4.1 Sensitivities

Sensitivity analysis was carried out on CAPEX costs for this case, with sensitivities of +/- 20% tested on all base rates. Table 6 outlines the results of this analysis. Option 1 remains the most cost-effective option under all CAPEX costs tested.

Table 6: Unit cost sensitivity

Option Number	Option Name	NPV ($M)	+20% ($M)	-20% ($M)
1	Install SEF capable relays or reclosers	$1.09	$0.87	$1.31
2	Use existing relays, install CTs	$0.33	$0.26	$0.40

Option 2 assumes that existing CTs would not have ratios suitable for setting low enough pickups to detect high impedance earth faults using existing relays with typical earth fault protection. This is a reasonable assumption as installation of 40/1 CTs for protection on distribution networks is not standard in Ergon.

3.4.2 Value of regret analysis

The key regret identified in this business case is the fatality of a customer through a service neutral failure. The value of this risk has been quantified as part of this analysis. Option 1 which is the provision of full SEF coverage over the 2020-25 regulatory control period substantially mitigates this risk. Option 1 also has a reduced direct cost compared to Option 2 (to use existing relays, install

CTs). This reflects consideration to make an economically efficient and balanced investment decision.

3.5 Qualitative comparison of identified options

3.5.1 Advantages and disadvantages of each option

Table 7 details the advantages and disadvantages of each option considered.

Table 7: Assessment of options

Options	Advantages	Disadvantages
Option 1 – Full SEF coverage on remaining 26 feeders	• Significantly reduces risk of uncleared high impedance earth faults • Improves safety of the public across Ergon Energy's network • Reduces likelihood of damage caused to equipment or community due to bushfires • Aligns Ergon Energy's protection schemes with industry standard	• Brings cost for augmentation forward into single time-period
Option 2 – Use existing relays, install CTs	• Significantly reduces risk of uncleared high impedance earth faults • Improves safety of the public across Ergon Energy's network • Reduces likelihood of damage caused to equipment or community due to bushfires • Aligns Ergon Energy's protection schemes with industry standard	• High capital cost • Requires a slower protection clearing speed for low impedance earth faults, or risks spurious tripping • May reduce load capacity on feeders due to overloading CTs with small ratios

3.5.2 Alignment with network development plan

One of the core focusses of Ergon Energy's DAPR is to provide high levels of safety and reliability. Full coverage of SEF protection on distribution feeders is necessary to safely de-energise high impedance faults, of which a common incidence is a conductor on the ground, which poses a high safety risk to the public and Ergon staff.

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 8: Risk assessment showing risks mitigated following Implementation

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
	Safety	*(Original)*			2020

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Failure of protection to detect a high impedance earth fault results in inadvertent contact with an energised source and **a single fatality**.		*5* *(Single fatality)* (Mitigated) 5 *(As above)*	*4* *(Likely)* 1 *(Almost no likelihood)*	***20*** ***(High)*** **5** ***(Very Low)***	
Failure to clear a fault results in a breach of National Electricity Rules and an **improvement notice issued by the regulator**.	Legislated	*(Original)* *4* *(Energex/Ergon identified issue requiring regulator to be notified. Improvement notice issued.* (Mitigated) 4 *(As above)*	 *3* *(Unlikely)* 1 *(Almost no likelihood)*	 ***12*** ***(Moderate)*** **4** ***(Very Low)***	2020
Failure to clear an earth fault results in a bushfire causing significant equipment damage and **a single fatality**.	Safety	*(Original)* *5* *(Single fatality)* (Mitigated) 5 *(As above)*	 *3* *(Unlikely)* 1 *(Almost no likelihood)*	 ***15*** ***(Moderate)*** **5** ***(Very Low)***	2020
An energised conductor fails and falls to ground starting bushfire resulting in **medium-term disruption to an eco-system**.	Environmental	*(Original)* *4* *(medium-term disruption to an eco-system)* (Mitigated) 4 *(As above)*	 *3* *(Unlikely)* 2 *(Very Unlikely)*	 ***12*** *(Moderate* **8** *(Low)*	*2020*

4 Recommendation

4.1 Preferred option

The preferred option is to install SEF capable relays and/or line reclosers as required to provide full SEF coverage to the remaining 26 distribution feeders without full protection during the 2020-25 regulatory period. This option is preferred due to significantly reducing the safety risk of high impedance earth faults in the shortest timeframe and being the most economic option identified.

4.2 Scope of preferred option

Install SEF capable relays and/or line reclosers as required to provide full SEF coverage on the 26 distribution feeders without full protection. The most economic option will be chosen based on system configuration and existing equipment available at each feeder, with the estimated overall CAPEX cost to be $1.84M in $18/19 direct dollars.

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).

Energex, *Distribution Annual Planning Report (2018-19 to 2022-23) [7.050]*, (21 December 2018).

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
AMP	Asset Management Plan
Augex	Augmentation Capital Expenditure
BAU	Business as Usual
CAPEX	Capital expenditure
CoC	Cost of Consequence
CT	Current Transformer
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
DEE	Dangerous Electrical Event
DNSP	Distribution Network Service Provider
EQL	Energy Queensland Ltd
ESA	Electrical Safety Act (2002)
IT	Information Technology
KRA	Key Result Areas
kV	Kilovolt
LoC	Likelihood of Consequence
MSS	Minimum Service Standard
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

Abbreviation or acronym	Definition
NPV	Net Present Value
OPEX	Operational Expenditure
PCBU	Person in Control of a Business or Undertaking
PoF	Probability of Failure
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
SEF	Sensitivity Earth Fault
VSL	Value of Statistical Life
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 9: 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	Refer to the specific regulatory instrument – e.g. Qld Electricity Act, Qld electrical Safety Act, etc
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.	
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 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 10: 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
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*

SFAIRP Risks in this area to be mitigated So Far as is Reasonably Practicable

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)	$1.80
Business Case Value	
(M$2020)	$1.86