Distribution Annual Planning Report 2020

ERGON ENERGY NETWORK

Version Control

Version	Date	Description
1.0	22/12/2020	Final
1.1	4/09/2023	Update new website links

Further Information

Further information on Ergon Energy's network management is available on our website.[1]

Disclaimer

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It contains assumptions regarding, among other things, economic growth, load forecasts and network capacity, which may or may not prove to be correct. The forecasts included in the DAPR involve analysis which are subject to significant uncertainties and contingencies, many of which are out of the control of Ergon Energy. Ergon Energy makes no representation or warranty as to the accuracy, reliability, completeness or suitability for any particular purpose of the information in this document. All information should be independently investigated, reviewed, analysed and verified, and must not be relied upon in connection with any investment proposal or decision.

All financials presented in the DAPR are correct at the time of writing (Dec 2020) and represent the existing organisational accounting treatment, which may be subject to change. The information contained in the DAPR is subject to annual review. Ergon Energy is obligated to publish future editions by 31st December, in accordance with the National Electricity Rules.

[1] Webpage: https://www.ergon.com.au/network/our-network

Contents

Figures

Tables

Executive Summary

Ergon Energy's Distribution Annual Planning Report (DAPR) 2020-21 to 2024-25 provides the company's intentions for the next five years in an environment characterised by rapid technological change and continuously high penetrations of renewable energy resources.

The DAPR provides the community and stakeholders with an insight into the key challenges and our responses to them. Many solutions seek customer and industry participation to resolve. In addition, the online interactive network maps for market proponents indicate locations for potential investments.

To ensure we are meeting the unique and diverse needs of our communities and customers, in a period where the energy sector is undergoing rapid transformation, we coordinate engagement and performance management programs which have shaped our Regulatory Determination for 2020-25, our network tariff reform program and our investment plans.

As Ergon Energy's networks age and the risk of equipment failure towards end of life increases, focus on maintaining safety outcomes for our staff, customers and communities is paramount. We continue to focus on improving safety in our maintenance and replacement practices across all asset categories and continue to invest in trialling new technology that has the potential to deliver safer outcomes, more efficiently for our customers.

While COVID-19 has had a progressive impact on the economy, we continued to provide reliable and secure supply to our customers. As a result, Ergon Energy's network reliability performance results were favourable for four of the six measures in the Distribution Authority. In regional Queensland, Ergon Network's Minimum Service Standard (MSS) for the Urban and Long Rural System Average Interruption Duration Index (SAIDI) both exceeded their target. Planned outages associated with an increase in safety-driven works on ageing sections of the network have impacted the overall duration of supply outages across these SAIDI measures. Wherever possible, we are minimising the impact on our communities through our approach to the program's delivery.

The 2019-20 summer peak of 2,660MW, recorded at 7pm on Monday, 16 December 2019, was the highest in the history of Ergon Energy.

The uptake of solar PV in the residential, commercial and industrial sectors has created the need to forecast minimum demand on the Ergon network. Historically, Ergon Energy's minimum demand commonly takes place late afternoon. The most recent minimum demand occurred on 3 May 2020 at 1:30pm with a daytime minimum of 1,073MW.

Cyber security is an area of increasing focus of all utilities and we continue to evolve our approach as a fundamental part of maintaining network and business security. ICT programs have been initiated to improve technology to deal with evolving business needs, a distributed workforce, changing ways of working and an increasingly complex cyber security environment.

We continue to transform our networks into an intelligent grid so that our customers can leverage the many benefits of digital transformation, distributed energy resources and emerging technologies, like solar PV (Photovoltaic), battery storage and electric vehicles (EV), as well as the next generation of home and commercial energy management systems. As solar PV continues to grow at a steady level, the uptake rate of EVs is expected to rise due to a number of new models being released and the increased availability of public charging stations. In parallel, customer interest for battery storage systems is increasing, and with PVs and EVs and other distributed energy resources they will shape our energy and power demand profiles in the future.

Chapter 1

Introduction

1. Introduction

1.1 Foreword

This Distribution Annual Planning Report (DAPR) details Ergon Energy's intentions for the next five years in relation to: load forecasting, demand management, non-network initiatives, network investments, customer load and renewable connection support, reliability and supply quality in safe, prudent and efficient operation and management of our power network.

The DAPR supports our commitment to open and transparent customer, community and shareholder engagement. It presents the outcomes from our distribution network service provisions carried out in 2019-20 for the forward planning period 2020-21 to 2024-25 as a requirement under the National Electricity Rules (NER) and in in compliance with Queensland's Electricity Distribution Network Code and Distribution Authority.

The DAPR provides information for interested parties on our:

- Network and operating environment and customer engagement
- Key emerging network challenges and opportunities
- Approach to Asset Management and investment governance
- The trend in network demand and our forecasting methodology (energy and load)
- Planning framework, including planning criteria and other methodologies
- Customer load and renewable connections
- The network's current and emerging limitations and risk mitigation strategies
- An overview of demand and energy management activities
- Approach to Asset Life-Cycle Management and asset renewal
- The network's reliability performance, including details on Worst Performing Feeders
- The quality of supply being experienced and the network's power quality performance
- Metering strategy and other associated technology investments.

The investment plans outlined in this DAPR continue to reflect the strategies presented in our Regulatory Determination for 2015-16 to 2019-20 in line with the Australian Energy Regulator's (AER) Distribution Determination, and now extend to the strategies which will underpin our next Regulatory Determination for the 2020-21 to 2024-25 control period.

Ergon Energy and Energex are now operating under our parent company Energy Queensland. This new company structure was created through a merger on 30th June 2016. Collaboration has been undertaken towards the development of a common DAPR format. However, as we are maintaining separate Distribution Authorities, we will continue to present separate DAPRs.

Ergon Energy's planning maps and forecast load and capacity information are now presented via an Environmental Systems Research Institute (ESRI) Graphical Information System (GIS) portal.[2] This provides an interactive experience, with subtransmission and distribution constraints as well as tables presented in a geospatial context. Reporting Requirements

This DAPR has been prepared to comply with NER Rule 5.13 and Schedule 5.8.

[2] Webpagehttps://www.ergon.com.au/daprmap2020

The publication of this DAPR is also in compliance with Queensland's Electricity Distribution Network Code clause 2.2 and Distribution Authority (DA).

The forward planning horizon covers from 2020-21 to 2024-25. These requirements are cross-referenced in Appendix B of this report.

1.2 Network Overview

Electricity is a commodity that underpins our modern society, providing energy to domestic, commercial, industrial, agricultural and mining sectors, supporting lifestyle and prosperity of individuals as well as our state as a whole.

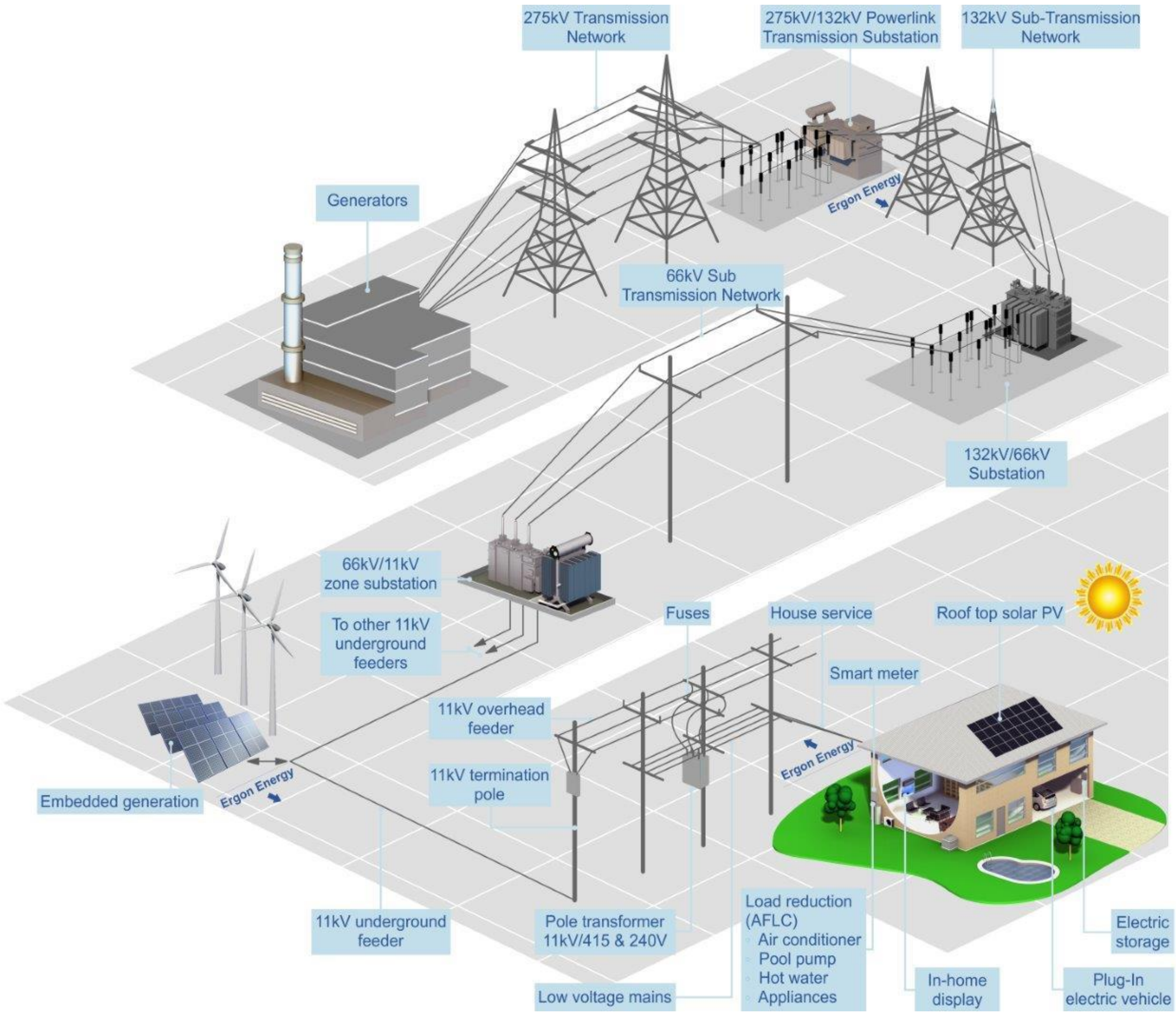
The electricity grid, including transmission and distribution networks, connects and facilitates the distribution of electrical energy between generators and users. The bulk of electricity is generated on demand at locations remote to the point of supply. The state's largest generators typically connect to the state's transmission network, which is owned and operated by Powerlink Queensland. The transmission network supplies bulk electricity to Ergon Energy's distribution network, which in turn supplies regional Queensland's industries, homes and businesses. However, in recent times an increasing number of generators, including renewable energy providers such as solar farms, are supplying directly into our distribution network.

Figure 1 illustrates how electricity is generated, transmitted and distributed to customers. The electricity carried over Powerlink's network is delivered in bulk to substations that connect to overhead or underground subtransmission feeders to supply zone substations. Zone substations are connected to overhead or underground distribution feeders. Distribution feeders deliver electricity to transformers that supply the low voltage lines at the voltage level required by the end user. Customers use the network to obtain electricity upon demand, and export electricity when excess power is generated.

The capacity of a network at each step along the supply chain is the amount of electricity it can carry at any point in time. The network must have enough capacity to handle the diversified network demand of every customer at any point in time. Peak demand occurs at different times in different parts of the network. Transmission levels must have enough capacity to meet the global peak demand for the region serviced, whereas distribution levels of the network must have enough capacity to meet peak demand in the local area.

With the increase in embedded generation (EG) systems being connected to the network, including small and large scale solar PV and other renewable energy sources, electricity is now being generated and exported into the grid from customers' premises. Depending on the size and number of these systems, power flow in parts of our networks are periodically in reverse, creating both challenges and opportunities for the network. Figure 1 depicts a typical representation of Ergon's network.

Figure 1: Typical Electricity Supply Chain[3]



[3] This figure is a simplified representation. Ergon Energy owns and operates assets at a wide variety of voltages, including:

- Subtransmission lines at 220kV, 132kV, 110kV, 66kV and some 33kV not classified as distribution feeders
- Bulk Supply and/or Zone Substations at 220/66kV, 220/11kV, 132/66kV, 132/33kV, 132/22kV, 132/11kV, 110/33kV, 110/11kV, 66/33kV, 66/22kV, 66/11kV, 66/3.3kV, 33/22kV, 33/11kV, 33/3.3kV, 33/0.415kV, 22/11kV
- MV distribution network, including SWER lines, at 33kV, 22kV, 19.1kV, 12.7kV, 11kV, 6.6kV and 3.3kV.

1.3 Peak Demand

The capacity of a network is the amount of electricity it can carry to every customer at any point in time. As electricity cannot be readily stored, the network must have sufficient capacity to deliver power to meet the needs of every customer at any point in time. The demand for electricity at the point in time when prevailing electricity use is at its highest is known as peak demand. Growth in peak demand is a critical part of what drives design and operation of the electricity system. Peak demand occurs at different times in different locations, and this has various implications at varying voltage levels of the network. Transmission levels must contain sufficient capacity to carry enough electricity to meet the global peak demand for the region serviced. Whereas, distribution levels of the network must contain sufficient capacity to carry enough electricity to meet peak demand in every street. The points in time that peak demand occurs on assets in each street, is often different to the point in time the peak occurs for the whole region. Therefore, there are varying degrees of diversity in demand between the points in time that peaks occur across each street, and the points in time that peak demands occur on the backbone network.

In a positive demand growth environment, increasing peak demand, may create the need for additional investment, dependant on detailed planning. Ergon Energy must maintain sufficient capacity and voltage stability to supply every home and business on the day of the year when electricity demand is at its maximum. In addition, growth in peak demand may occur where new property developments are being established. At the same time, over the same period, peak demand may be declining in areas where usage patterns are changing due to customer behaviour or from the impacts of alternative sources like solar PV and battery energy storage systems. This means that growth patterns of electricity demand can be flat on a global scale, but there may be pockets of insufficient network capacity in local areas experiencing increasing peak demand.

The Ergon Energy system maximum native demand for 2019-20 was recorded at 2,660MW on Monday 16th December 2020 at 7.00pm. This peak demand is greater than the previous highest recorded demand by 37MW (2,623MW in 2018-19).

1.4 Minimum Demand Forecasting

Historically, Strategic Forecasting has focused on maximum demand, energy delivered, energy purchased and customer numbers. However, the uptake of solar PV in the residential, commercial and industrial sectors has created the need to forecast minimum demand on the Energy Queensland network.

The impact of a daily minimum demand caused by the increase of rooftop solar uptake affects the distribution network at three levels all of which will affect CAPEX expenditure:

- System level – Oversupply during the middle of the day may force large solar generators to be switched off as ramp up times are quicker than coal fired power stations. To date Energy Queensland has been able to leverage voltage regulation at the transmission connection point to limit the need for downstream remediation, but increasingly this will not be possible as the transmission network runs out of transformer tap or 'buck' range
- Substation level – Cyclic issues due to reverse flow may reduce the life of zone substation transformers
- At a Feeder level – May impact the stability of individual feeders causing voltage fluctuations which, in turn, impact protection settings at a feeder level. (Given the high number of open and closed delta regulators on Ergon distribution feeder network, cogeneration settings on regulators would need to be revisited to ensure voltage levels on feeders remain at a stable level during the day).

Rooftop PV is driving an increasingly rapid change in the load on the network from the day to night. This may give rise to an expanded role for fast-ramping but more expensive generators to manage the transition and supply overnight - again limiting the economic viability of existing baseload and new renewable generators and increasing the cost of wholesale energy. Managing the transition may necessitate greater dynamic reactive plant and give rise to challenges in system operation.

Given the geographical diversity of the Ergon distribution network, minimum demand at a system level is constructed as an aggregate of minimum demand at a regional level. These regional system levels include Far North, North Queensland, Mackay, Capricornia, Wide Bay and South West.

For example, the Wide Bay region has experienced lower minimum daytime demand to night-time demand since 2014. Given that the Wide Bay region has a high residential base load, the impact of rooftop solar is impacting daytime minimum demands. Although the minimum daytime demand is not negative at a regional level, it is a real possibility if the current trend continues.

1.5 Changes from 2019 DAPR

For consultation purposes, Ergon Energy is ensuring the DAPR remains relevant and evolves with ever changing market expectations. To this end, Ergon Energy has made a number of improvements in the 2020 DAPR. These changes aim to make relevant information accessible and understood by all stakeholders, non-network providers and interested parties.

The following changes have occurred as compared to the 2019 DAPR:

- Review and merge ‘Corporate Profile’ and ‘Asset Management’ overview chapters into Chapter 2 - Corporate Profile and Asset Management
- Review and streamlined Chapter 4 – Strategic Forecasting
- Added: “Summary of Substation and Feeder Limitations” - Table 13
- There were sixteen projects approved with credible options having an estimated cost of the augmentation component greater than $6 million. RIT-D information is listed in Section 6.4 - Regulatory Investment Test Projects
- Review and update on Ergon Energy’s demand side management policy, strategy and initiatives
- Merged ‘Information and Communication Technology’, ‘Distribution Metering’ plus ‘Operational Technology and Communication Systems’ chapters into Chapter 12 – Information Technology and Communication Systems.

1.6 DAPR Enquiries

In accordance with NER 5.13.2(e), Ergon Energy welcomes feedback or enquiries on any of the information presented in this DAPR via email.[4] Alternatively, readers are encouraged to visit the Ergon Energy Network Management’s Distribution Annual Planning Report webpage[5] for further information and the opportunity to submit commentary or queries.

[4] Email address: engagement@ergon.com.au

[5] Webpagehttps://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report

Chapter 2

Corporate Profile and Asset Management

2. Corporate Profile and Asset Management

2.1 Corporate Overview

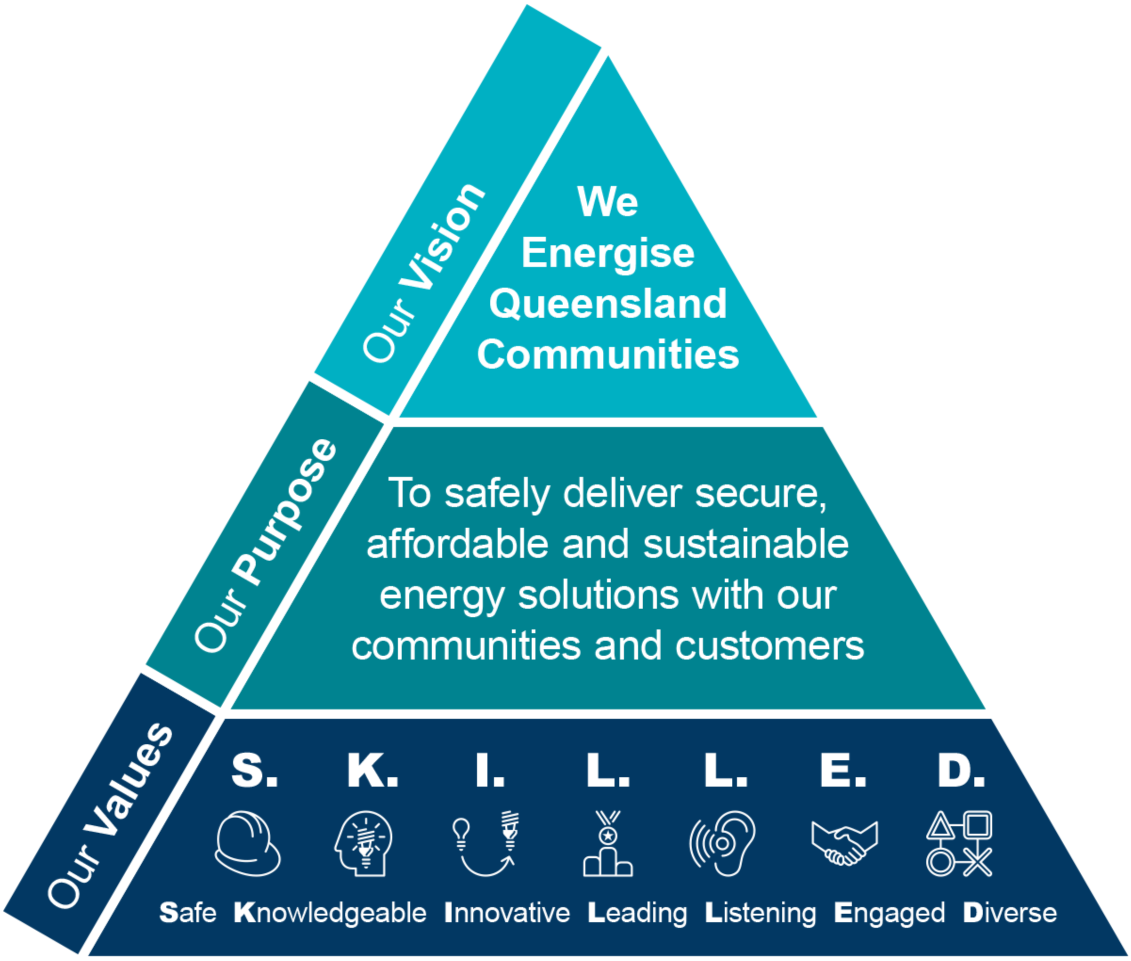
Ergon Energy (Ergon Energy Corporation Limited) is a subsidiary of Energy Queensland Limited, the Queensland government owned corporation formed through a merger in June 2016.

2.1.1 Vision, Purpose and Values

Energy Queensland's corporate vision is to energise Queensland communities.

Our purpose is to deliver secure, affordable and sustainable energy solutions with our communities and customers, and our SKILLED Values are as shown in Figure 2 below.

Figure 2: Energy Queensland Vision, Purpose and Values



2.2 Ergon Energy's Electricity Distribution Network

Ergon Energy distributes electricity to approximately 765,000 residential, commercial and industrial customer connections, supporting a population base of around 1.5 million in Northern and Southern Queensland.

At the core of the business is a high performing electricity distribution network that consists of property, plant and equipment and assets valued at approximately $11.8b.

The bulk of the electricity distributed enters Ergon's distribution network through connection points from Powerlink Queensland's high voltage transmission network, which brings the electricity from the major conventional and renewable generation plants. However, Ergon Energy also enables connection of distributed energy resources, such as solar energy systems and other embedded generators.

The Ergon Energy's network is characterised by having:

- 70% of our electricity network running through rural Queensland, making it the largest in the National Electricity Market (NEM), with the second lowest customer density per network kilometre
- A full range of diverse end users with 84% of these customers connected to the network being residential and the remaining 16% related to small to medium businesses. Our network also supplies the majority of the state's largest energy users
- 58 connection points with Powerlink's transmission network
- One of the largest Single Wire Earth Return (SWER) networks in the world reaching 64,000km in length, supplying around 26,000 customers predominantly located in western areas of regional Queensland. This unique network operates at three voltage levels: 11kV, 12.7kV and 19.1kV in a variety of configurations such as conventional, duplex, triplex and non-isolated SWER. These systems are supplied by isolated transformers ranged in size between 50kVA and 200kVA
- 33 stand-alone diesel-fired power stations with a total installed capacity of 46MW as well as small scale solar and wind energy sources. Our isolated systems operate on 33kV, 22kV, 11kV, 6.6kVA, SWER and low voltage (LV) with peaks ranging between 68kW and 4.2MW. These isolated systems supply 39 communities (approximately 7,000 customers) isolated from the main grid and are located in western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait islands and Palm Island.

A summary of our network assets and customer numbers is provided in Table 1 below.

Table 1: Network and Customer Statistics (at year end)

Network Statistics	
Network Area Serviced	1.7 million sq. km
Power Stations (isolated)	33
Switching Stations	20
Bulk Supply Substations	29
Zone Substations (ZS)	259
Distribution Transformers	102,362
Power Poles	1,027,745
Overhead Powerlines - Subtransmission	14,903km
- High Voltage Distribution	126,806km
- Low Voltage Distribution	17,000km
Underground Power Cable	9,090km
Number of Feeders - Subtransmission feeders	335
- Distribution feeders[6]	1,283
- Other Feeders	100
Network Customers	
Customers on Urban Network	239,927
Customers on Short Rural Network	440,429
Customers on Long Rural Network	84,885
Total Customers[7]	**765,241**
Isolated Network Customers	8,374

Figure 3 shows our distribution service area, including isolated community generation sites and stand-alone power supply systems.

[6] Includes island feeders

[7] Regulated network customers, as at 30th June 2020, EB RIN T3.4

Figure 3: Ergon Energy Distribution Service Area

2.3 Network Operating Environment

This section describes the external factors that underpin our planning decisions in an operating environment increasingly dominated by distributed generation. While customer demand is still the main trigger in our network augmentation decisions, bi-directional energy flow throughout the network is presenting new challenges particularly with respect to maintaining statutory voltage limits.

2.3.1 Physical Environment

The physical environment across regional Queensland creates challenges in the operation of an electricity distribution network.

Due to the size of our service area the list of environmental impacts is extensive. The variation in environmental conditions across the state influences our costs and outage/repair times relative to more dense, urban networks. It also influences infrastructure design criteria and standards, as well as our strategies to respond to incidents on the distribution system; we cannot adopt a one-size-fits-all approach.

The environmental aspects impacting the network include:

- High exposure to cyclones in the coastal northern and far north regions
- High storm and lightning activity, bushfires, flooding and storm surges
- Significant summer-winter and day-night temperature variations (impacting load profiles)
- High rainfall areas (e.g. increases vegetation growth and pole-top rot)
- Salt spray in coastal areas (resulting in reduced life of assets due to corrosion)
- Other weather impacts (e.g. the Channel Country is flooded by rains falling hundreds of kilometres away causing floods that take weeks to pass creating extended delays in accessing and repairing damaged assets)
- Significant termite populations (affecting power pole integrity)
- Unstable soil types (e.g. Darling Downs).

Performance of the network under these conditions is discussed further in Section 9.3.

2.3.2 Shareholder and Government Expectations

We are also continuing to increase the choices available to our customers, working to progress tariff reforms and developing innovative energy-related services.

This supports the Queensland Government's commitment to supply 20% of its electricity consumption with renewable energy sources by the end of 2020, making significant progress to reaching its 50% renewable energy target by 2030.Similarly, with the support of the Queensland Government, we are continuing to facilitate the adoption of emerging storage technology, both Battery Energy Storage Systems (BESS) and Electric Vehicles (EVs).

2.3.3 Community Safety

Community Powerline Safety Strategy 2018-2020

Safety is the number one value for Energy Queensland – safety for our employees, our customers and the community. The Community Powerline Safety Strategy (CPSS) outlines how our network businesses Energex and Ergon Energy Network will invest and focus activities to build powerline safety awareness, educate and encourage behaviour change in the community and high-risk industry sectors throughout 2020.

Our CPSS is a publicly available document, which aims to:

- foster positive and proactive association of powerline safety within the community
- build community awareness of potential powerline dangers
- encourage education and behaviour change
- demonstrate our commitment to community powerline safety.

Informed by incident data and learnings frominvestigating and attending incidents we continue to target industries at risk, who frequently work in close proximity to powerlines to raise awareness of the powerline safety dangers. This data identifies the industries with the greatest contact with powerlines - construction, aviation, agriculture, emergency services and transport.

Our important and long-running community safety campaign on powerline awareness has been an ongoing engagement and in 2019 EQL released the lookup and live[8] online application pinpointing our overhead powerlines and powerpole locations. The public release of the online application has been a highly successful, well-accepted extension.

The application was built by geospatially overlying powerlines onto imagery, enabling workers and the community to effectively plan work near powerlines. The user is now able to look at the worksite from a new vantage point and identify the electrical hazards, assess powerline risks, implement appropriate control measures and access links with additional safety advice.

The greatest benefit of this tool is raising workers' awareness and improve community safety around powerlines, which have resulted in significant drops in powerline incidents since 2019.

2.3.4 EQL Health, Safety and Environment Integrated Management System

The Energy Queensland Limited Health, Safety and Environment Integrated Management System (EQL HSE IMS) has been developed to provide a framework to effectively manage health, safety, environment, cultural heritage and security risks across the organisation. This framework was modelled upon the existing management system requirements for Energex and Ergon Energy to enable the transition to a centralised EQL HSE IMS. The EQL HSE IMS is currently accredited to:

- ISO 14001:2015 Environment Management System; and
- AS/NZS 4801:2001 Occupational Health and Safety Management System.

[8] Webpage: https://www.arcgis.com/apps/webappviewer/index.html?id=5a53f6f37db84158930f9909e4d30286

The EQL HSE IMS consists of 12 Standards which are aligned to accreditation requirements. Standard 8 Control of Work consists of 14 Hazard Controls (HCs) to enable business units to implement fit for purpose risk controls. HCs include requirements which are accepted practice across Energy Queensland, which may exceed legal requirements and include:

1. Transport
2. Access and Entry
3. Community Safety
4. Plant, Tools and Equipment
5. Working with Electricity
6. Asset Safety
7. Manual Tasks
8. Hazardous Materials and Waste Management
9. Fit for Work
10. Land and Water Management and Disturbance
11. Air, Energy and Greenhouse Gas
12. Occupational Health, Noise and Amenity
13. Security
14. Working at Heights

Please refer to R284. EQL HSE IMS Hazard Control Manual for further guidance on these. The EQL HSE IMS is subject to third party HSE IMS Surveillance audits and the Electrical Safety (ESO) Electrical Entity audit conducted once per year.

2.3.5 Environmental Commitments

Ergon Energy aspires to be an industry leader in environment and cultural heritage as reflected in Energy Queensland’s P058. Environmental Sustainability and Cultural Heritage (Policy) and P056. Low Carbon Future Statement.

To support this, environment and cultural heritage performance measures have been developed to support improvement. Ergon Energy is committed to working together with customers, the community and other stakeholders including traditional owners to deliver sustainable energy solutions where all interests are managed.

Ergon Energy’s electricity network traverses diverse environmental and culturally significant areas across the state including coastal, rural, urban and remote landscapes. Under the guidance of our environmental management systems we strive to protect these unique environments while providing safe and efficient energy services.

As part of a merged entity, Ergon Energy has embedded ISO14001 certified management system requirements into the EQL HSE IMS to rationalise our operations, improve environmental and cultural heritage performance while recognising environmental benefit opportunities in the process.

2.3.6 Legislative Compliance

Prior to the establishment of Energy Queensland, Ergon Energy was a Queensland GOC, with shareholding Ministers to whom the Board reported. Ergon Energy is now a subsidiary of the GOC Energy Queensland and remains subject to the same level of regulation as it did as a GOC.

Ergon Energy holds a Distribution Authority, issued by the Queensland Regulator (the Department of Natural Resources, Mines and Energy (DNRME)), to supply electricity using its distribution system throughout regional Queensland.

The two shareholding Ministers to whom Energy Queensland Limited's Board report under the Government Owned Corporations Act 1993, are the:

- Treasurer and Minister for Investment, and
- Minister for Energy, Renewables and Hydrogen and Minister for Public Works and Procurement.

Ergon Energy also operates in accordance with all relevant legislative and regulatory obligations, including:

- Government Owned Corporations Act 1993 (Qld), Government Owned Corporations Regulation 2014 (Qld) and Government Owned Corporation (Energy Consolidation) Regulation 2016 (Qld)
- Electricity Act 1994 (Qld), the Electricity Regulation 2006 (Qld) (the Queensland Electricity Regulation) and the Electricity Distribution Network Code (EDNC) under the Act
- National Electricity Law (NEL) and National Electricity Rules (NER), as in force in Queensland pursuant to the Electricity – National Scheme (Queensland) Act 1997 (Qld) and the Electricity - National Scheme (Queensland) Regulation 2014 (Qld)
- National Energy Retail Law (NERL) and National Energy Retail Rules (NERR), as in force in Queensland pursuant to the National Energy Retail Law (Queensland) Act 2014 (Qld) and the National Energy Retail Law (Queensland) Regulation 2014 (Qld)
- Electrical Safety Act 2002 (Qld) and Electrical Safety Regulation 2013 (Qld)
- The Electrical Safety Codes of Practice 2010 and 2013
- Aboriginal Cultural Heritage Act 2003 (Qld) and Torres Strait Islander Cultural Heritage Act 2003 (Qld)
- Work Health and Safety Act 2011
- Planning Act 2016 (Qld) and subsidiary and related planning and environment legislation, such as the Environmental Protection Act 1994 (Qld), Vegetation Management Act 1999 (Qld), the Nature Conservation Act 1992 (Qld), the Coastal Protection and Management Act 1995 (Qld) and subsidiary regulations, and the Environment Protection and Biodiversity Conservation Act 1999 (Cth).

Ergon Energy is subject to periodic (annual and quarterly) and incident-based reporting to verify compliance with these obligations and to ensure issues are identified and resolved at an early stage.

2.3.7 Economic Regulatory Environment

Ergon Energy is subject to economic regulation by the Australian Energy Regulator (AER) in accordance with the National Electricity Law and Rules. The AER applies an incentive-based regulatory framework that encourages Ergon Energy to provide services as efficiently as possible. The AER does so by setting the maximum regulated revenues that we are allowed to recover from our customers during each year of the regulatory control period. The revenues are based on an estimate of the costs that a prudent and efficient network business would incur to meet its regulatory obligations. Given that the revenues are locked in at the start of the period, we have a general incentive to provide our services at less than the forecast costs and keep the difference until the end of the regulatory period. In the following period, we share the benefits of efficiencies with our customers.

This general incentive framework is complemented by a suite of guidelines, models and incentive schemes, including amongst others the:

- Efficiency Benefits Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS), which encourage us to pursue efficiency improvements in opex and capex and share them with customers
- Service Target Performance Incentive Scheme (STPIS) which encourages us to set, maintain or improve service performance
- Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM), which encourage us to pursue non-network options
- Regulatory Investment Test for Distribution (RIT-D), which requires us to undertake a cost-benefit analysis and consult with stakeholders before undertaking major investments
- Ring-fencing Guideline, which requires us to separate our regulated services from contestable services.

On 5 June 2020, the AER published its Final Distribution Determination for Ergon Energy for the 2020-25 regulatory control period, commencing 1 July 2020 to 30 June 2025.

More information regarding Ergon Energy's allowed revenues and network prices can be found on the AER's website.[9]

[9] Webpage: www.aer.gov.au

2.4 Asset Management Overview

Underpinning our approach to asset management are a number of key principles, including making networks safe for employees and the community, delivering on customer promises, ensuring network performance meets required standards and maintaining a competitive cost structure.

This section provides an overview of Ergon Energy's:

- Best Practice Asset Management
- Asset Management Policy
- Strategic Asset Management Plan (SAMP)
- Investment Process.

2.4.1 Best Practice Asset Management

Ergon Energy recognises the importance of maximising value from assets as a key contributor to realising its strategic intent of achieving balanced commercial outcomes for a sustainable future. To deliver this, our asset management practice must be effective in gaining optimal value from assets.

Ergon Energy is continuing to reshape its asset management practice to align with the ISO 55000 standard. This transition is a significant undertaking and will span several years, so a phased approach has been initiated that will focus on building capability across all seven major categories covered by the standard (i.e. Organisational Context, Leadership, Planning, Support, Operation, Performance Evaluation and Improvement).

2.4.2 Asset Management Policy

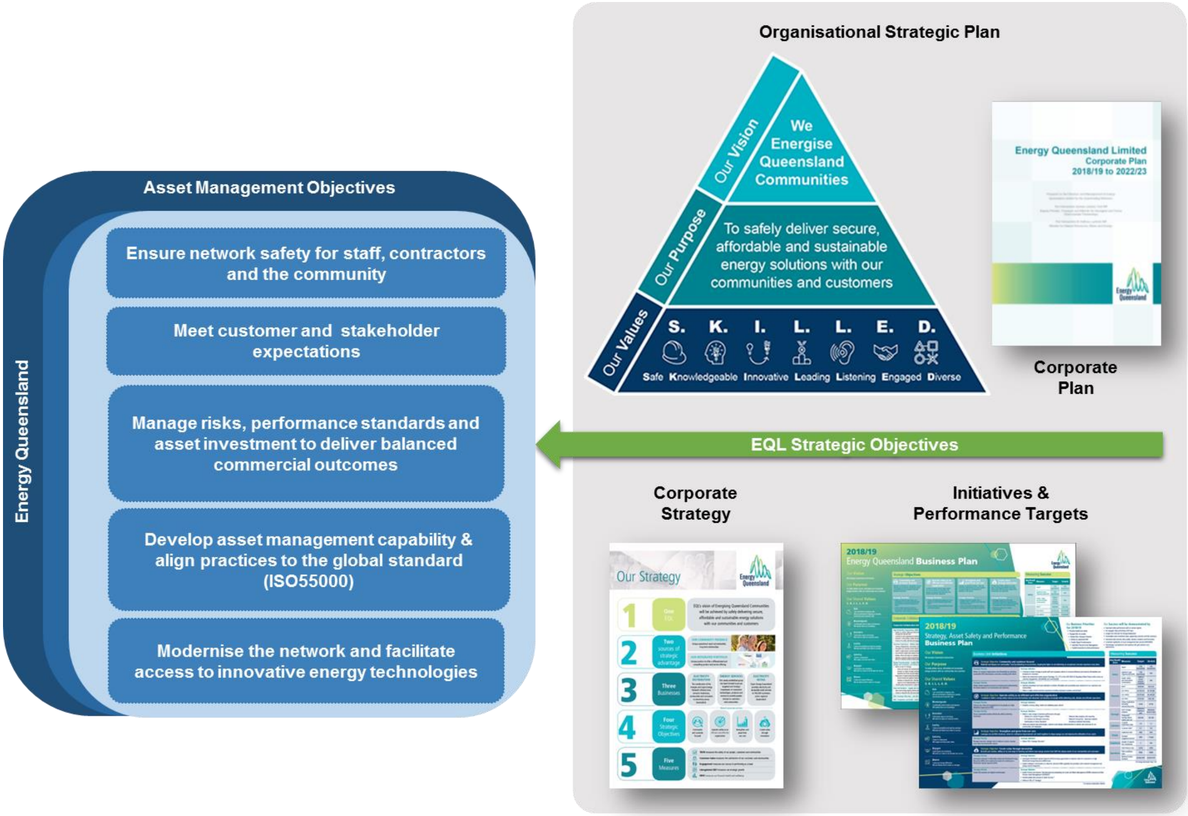
The Asset Management Policy provides the direction and broad framework for the content and implementation of Ergon Energy's asset management objectives, strategies and plans. The policy directs us to undertake requirements associated with safety, people and meeting customer needs. It describes the commitment to ensure asset management enablers and decision making capabilities meet current and future needs.

This policy together with the Strategic Asset Management Plan (SAMP), are the primary documents in the asset management documentation hierarchy and influence subordinate asset management strategies, plans, standards and processes.

2.4.3 Strategic Asset Management Plan

Ergon Energy's SAMP is the interface that articulates how organisational objectives are converted into asset management objectives as shown in Figure 4. The SAMP also sets the approach for developing asset management plans and the role of the asset management system in supporting achievement of the asset management objectives.

Figure 4: The SAMP translates Corporate Objectives to Asset Management Objectives



2.5 Investment Process

2.5.1 Corporate Governance

Ergon Energy has a four-tier governance process to oversee future planning and expenditure on the distribution network as shown in Figure 5.

Central to Ergon Energy's governance process is legislative compliance. The Government Owned Corporations (GOC) Act requires the submission of a Corporate Plan (CP) and Statement of Corporate Intent (SCI), while the NER requires preparation of the DAPR. The network investment portfolio expenditure forecast is included in the five year CP and SCI.

Figure 5: Program of Work Governance

The four tiers include:

1. **Asset Management Policy and Strategy** - Alignment of future network development and operational management with Ergon Energy's strategic direction and policy frameworks to deliver best practice asset management.
2. **Network Investment Portfolio** - Development of seven year rolling expenditure programs and a 12-month detailed program of work (PoW) established through the annual planning review process. The Governing entities oversee:
   - fulfilment of compliance commitments
   - ensure the network risk profile is managed and aligned to the corporate risk appetite
   - approval of the annual network Programs of Work and forward expenditure forecasts.
3. **PoW Performance Reporting** - Ergon Energy has specific corporate Key Result Areas (KRA) to ensure the PoW is being effectively delivered and ensures performance standards and customer commitments are being met. Program assurance checks including review of operational and financial program performance is overseen by senior management through the monthly Works Program Committee to ensure optimal outcomes with appropriate balance between governance, variation impact risks, emerging risks and efficiency of delivery. A comprehensive program of work scorecard is prepared monthly, and key metrics are included in the Program of Work Delivery Index, which is a corporate key performance indicator (KPI) that, with monthly performance reporting for key projects, informs the Executive and Board. Quarterly Program of Work updates are provided to the Board.
4. **Project and Program Approval** - Network projects and programs are overseen by senior management and subject to an investment approval process, requiring business cases to be approved by an appropriate financial delegate.

2.5.2 Network Risk Management and Program Optimisation

Management of risk is a crucial foundation for effective asset management and an integral part of ISO 55000 Asset Management suite of standards. Energy Queensland's Network Risk Management Framework ensures we apply a consistent approach to the assessment of network risks. It aligns with AS/NZS ISO 31000:2009 Risk Management - Principles & Guidelines and with Energy Queensland's Portfolio Risk Management Framework. Energy Queensland continuously reviews inherent and emerging network risks to ensure optimisation of our projects and programs.

Network risk is assessed according to the following five risk categories:

- Safety
- Environment
- Legislated Requirements
- Customer Impacts, and
- Business Impacts.

Risk assessment involves development of credible scenarios that may lead to a specific risk consequence. This is followed by estimation of the likelihood of occurrence and subsequent development of a risk rating for each scenario. Projects and programs of work are then considered for inclusion in the program of work on a priority basis to deliver appropriate network-wide risk mitigation. Energex / Ergon Network optimises its program of work to balance the inherent risk should some programs not proceed, it considers; cost and funding constraints, resourcing availability, performance targets and other project drivers including fulfilment of strategic objectives.

2.5.3 Further Information

Further information on our network management is available on the Ergon Energy website.[10]

[10] Webpage: https://www.ergon.com.au/about-us

Chapter 3

Community and Customer Engagement

3. Community and Customer Engagement

3.1 Overview

To ensure we're meeting the unique and diverse needs of our communities and customers we invest in engaging with our customers and other stakeholders on their expectations, concerns and ideas.

With our industry undergoing a period of rapid transformation, we see an open dialogue as critical to enabling diversity of thought, innovation and, ultimately, more now than ever, better, more sustainable, customer-focused solutions. Across our Group we operate a coordinated, multi-channel community and customer engagement and performance measurement program. These conversations, and the focus they provide, are fundamental to creating real long-term value for our customers, our business, and Queensland.

Most recently we have refresh our understanding and prioritisation of the economic, social and environmental and governance topics that matter most to our different stakeholders – building on our extensive engagement undertaken previously and ongoing in 2019-20 around the network businesses' investment plans and our Regulatory Determination for 2020-25, and our network tariff reform program.

Our engagement efforts continue to influence the asset management strategies and investment plans in this report and help to align our future thinking with the long-term interests of our communities and customers.

This chapter provides an overview of these engagement activities and describes how they enable us to put our communities and customers at the heart of everything we do. More information is available in our Annual Report[11] and the 2020 and Beyond Community and Customer Engagement Report[12] published with our Regulatory Determination.

[11] Website: https://www.energyq.com.au/__data/assets/pdf_file/0010/854425/2019-20-EQL-Annual-Report.pdf

[12] Website: https://s3-ap-southeast-2.amazonaws.com/ehq-production-australia/96d2da3d8a91ec1806bd62e5e724a1f4393d6a92/documents/attachments/000/096/910/original/Community_and_Customer_Engagement_Report.pdf?1548898850

3.2 Our Engagement Program

3.2.1 Customer Council and other Forums

Through Energy Queensland's Customer Council, as our flagship listening forum, we gain a customer perspective to emerging energy-related issues and potential solutions to deliver on their needs and expectations. We also have a wider group of customer and community representatives who have continued to participate in engagements around our Regulatory Determination and tariff reforms. This group met with us over the previous year, while we were revising our plans, to explore the decision remaining open for consideration and, at the same time, continue to build their capacity to understand our industry and its regulatory framework.

We also have a Major Customer Forum, Public Lighting Forum and Agricultural Forum to discuss topics relevant to specific customer groups.

3.2.2 Working with Industry Partners

We engage actively with our industry partners, both strategically and operationally.

The Energy Charter, of which we are one of 21 signatories, continues to provide a platform for collaboration with organisations from across the energy industry, building accountability across the supply chain and improving customer outcomes.

Direct engagement and service relationships with the different energy retailers who operate across the Queensland market remains critical to delivering for our customers.

Our industry engagement also includes state-wide forums to listen and share knowledge with electrical contractors, solar supplier/installers and property developers. These channels of communications are increasingly important to us as we move forward.

3.2.3 Community Leader Engagement

To better connect with our communities and ensure we are effective in our service delivery, we have 17 established operational areas across the state. Each area has a locally-based manager who build relationships with our local community stakeholders and understand the areas unique concerns.

This has been particularly important this year in managing our operational response to the COVID-19 pandemic, especially in our First Nations communities.

To support local stakeholder engagement, we also host Board stakeholder events regionally to ensure we keep in touch with our communities' expectations. While suspended with COVID-19, they provide an important means for our Directors, the Executive and a wide group of managers and decision-makers to interact with local stakeholders and customers.

3.2.4 Online Engagement

We continue to use our digital engagement platform talking energy,[13] with around 2,000 people registered for updates and engagement.

The site has proven to be an effective tool to interact with targeted stakeholders, as well as a channel to reach a wider audience as we engage on key energy topics and issues.

It has been especially useful of recent times to engage on technical matters, like changes to standards, as a single place to engage with stakeholders from across Queensland.

3.2.5 Our Customer Research Program

To improve the customer experience, as part of our Voice of the Customer program, we survey customer satisfaction following the key service interactions for each customer group, from our residential customers right through to major customer, electrical contractors, electricity retailers and key stakeholders. This is reported as the Customer Index for the Group.

This feedback mechanism is also supported by a program of additional market research activities that tracks both customer and community sentiment and enables deep exploration on specific topics.

A key annual survey is the Queensland Household Energy Survey.[14] Funded by Energex and Ergon Energy Network in conjunction with Powerlink Queensland, in late 2019 this survey captured feedback from over 4,500 Queensland households. It tracks energy use and energy efficiency behaviours, and the take up of emerging energy-related technologies. This survey also tracks customer perceptions and overall attitudes to electricity prices and power supply reliability.

Through the Queensland Chapter of the Thriving Community Partnership (TCP), we collaborated this year with other corporate, not-for-profit and government partners in a Disaster Planning and Recovery Collaborative Research Project[15] that explored the opportunities for positive change in our disaster response when the community is most vulnerable.

[13] Website: https://www.talkingenergy.com.au
[14] Website: https://www.talkingenergy.com.au/qhes
[15] Website: https://thriving.org.au/what-we-do/disaster-planning-and-recovery

This year's research builds on the in-depth research undertaken,[16] both qualitative research (deliberative forums and focus groups) and quantitative research, to inform our Regulatory Determination, and the asset strategies and future works programs outlined in this report.

We will continue to track how satisfied our customers and the wider community are with our services, and the level of trust they have in us to do the right thing.

3.3 What We Have Heard

Through our engagement activities we continue to hear the following key messages:

- Safety should never be compromised – and it is an area where we could be 'smarter'
- Electricity affordability remains a concern for many customers – both from a cost of living and a business competitiveness perspective
- Our communities and customers value how we go about keeping the lights on, especially our response to severe weather events and other natural disasters
- Our customers want greater choice and control around their energy solutions
- Interest in renewables and growing concerns around climate change is fuelling customer and community expectations around the transition to a low carbon economy
- The impact of the COVID-19 restrictions and subsequent recession has brought 'energy inclusion and vulnerability' and 'economic development and jobs' to the foreground.

3.3.1 Safety First

There is recognition across our communities and customers of the dangers of electricity, and that if the network is not appropriately managed it presents a risk to our communities and employees. We are expected to be vigilant, and to always make safety our priority.

Community education on electrical safety awareness is seen as important, especially around natural disasters.

Our customers expect that we continue to adopt technology and process improvements to look for smarter ways to deliver improved safety outcomes.

Health concerns around the COVID-19 pandemic, especially in our First Nations communities, continue to have implications for our operational response.

[16] Website: https://www.talkingenergy.com.au/haveyoursay

3.3.2 More Affordable Electricity

Pricing

Electricity affordability remains the core concern for many of our customers, both from a cost of living and a business competitiveness perspective. Earlier increases in electricity prices, despite recent tariff relief, continues to have a detrimental effect on the value our customers place on the service we deliver.

Customers generally do not consider distribution network charges separately to their retail electricity bill. They are simply looking to the industry as a whole to deliver electricity price relief, without comprising the safety, security or reliability of supply or customer service standards.

The desire for greater control, in order to manage or moderate their bill, is driving much of the disruption across the industry.

We track price and affordability perceptions, and while we were encouraged by progress this year prior to the economic impact of the COVID-19 pandemic, in the Queensland Household Energy Survey,[17] electricity bills remained the top household cost concern among regional Queensland households and third next to fuel and health costs for households in the South East.

Network Tariffs

Our customers are looking for network tariffs that offer simplicity, savings, value and choice, and that reward them for their role in energy transformation.

Many stakeholders recognise that network tariff reform is needed to respond to the changes in the market and to deliver sustainable charges for the future. However, more engagement is required to progress the reforms put forward in our Tariff Structure Statements.

Many customers would be willing to reduce their electricity use during peak times on the network, if rewarded. They recognise that there is an increasing opportunity to achieve this with emerging technologies. However, any reforms would need education awareness and support.

[17] Webpage: https://www.talkingenergy.com.au/qhes

Fairness

It is clear that we have a corporate responsibility in providing an essential service to do all we can to address electricity affordability, and to deliver to all Queenslanders whether 'coast or bush'.

There is concern around the ability of some to respond to the changes taking place in the industry. Together, we need to ensure everyone benefits equitably from solar and other emerging technologies and that vulnerable segments of the community are not left behind.

From a network tariff perspective, being 'fair and equitable' is both about minimising cross subsidies and managing the social and economic impact of any move to more cost reflective pricing. There is also a need for a trusted advisor to provide independent impartial advice, and to help customers make informed choices in their energy use and behaviours.

3.3.3 A Secure Supply – Keeping the lights on

Emergency Response

Queenslanders know that storms, cyclones, bushfires, floods and other disasters are beyond anyone's control. Feedback confirms that we respond well when these events occur and that our contribution is important to communities in getting them back up and running quickly.

We have largely had support for the way we managed our response state-wide to the COVID-19 pandemic. Safety was our priority, as we followed government advice to minimise the risk of exposure to our crews, customers and the wider community, while continuing to deliver a reliable electricity supply across Queensland. There was and remains heightened community sensitivity to residential power outages with more people working (at times even schooling) from home.

As part of Queensland's economic recovery, there are currently heightened expectations around the delivery of key capital projects going forward – the timely delivery to support economic development, maximising employee utilisation and where appropriate engaging local contractors/suppliers.

TCP's Research Project[18] interviewed residents and small business owners impacted by the 2019 North Queensland Monsoon to map their experiences leading up to, during, immediately after and in the months following the disaster. The report highlights the 'gatekeeper' role electricity plays to action before and after a disaster; how the communications across the journey influence response and recovery; and provides a range of other insights.

[18] Website: https://thriving.org.au/what-we-do/disaster-planning-and-recovery

Reliability

Our communities and customers value having a reliable and consistent electricity supply and particularly appreciate our ability to quickly and safely restore services after weather events.

Most of our customers are satisfied with the current reliability standards delivered through our networks and do not necessarily value greater investment for higher reliability. However, some customers, especially those in the more rural and remote areas of our network, consider they are poorly serviced.

76%*

are satisfied with the reliability of supply. This benchmarks above national average, despite ongoing supply challenges.

*Energy Consumers Australia Energy Consumers Sentiment Survey June 2020.

Power outages have a range of immediate customer and broader economic impacts. The quality of supply is also important to some customers.

Customer Experience

Expectations around customer experience are shifting, and generally increasing, especially around notifications around issues such as power outages.

Feedback received through our Voice of the Customer program and our Customer Index has shown steady improvement over the last three years, with a notable uplift in customer satisfaction over the last 12 months from 6.7 in 2018-19. The above target result of 7.1 out of 10 for 2019-20 (target 6.7) was supported by service improvements across the Group.

Many see outage updates and restoration times as important as preventing the initial outage. Knowing we need to provide this information in ways that work for all saw us launch improvements to our Customer Self Service Portal, which allows customers to subscribe to receive a SMS and email notification for planned and unplanned outages. Since launching the SMS notification, over 20,000 customers have signed up for the service across Queensland. We are continuing to promote this service and monitor satisfaction.

Generally our stakeholders support us in using technology to improve efficiency and reduce costs, but we note that the scale of our digital transformation program is significant and that this creates some stakeholder concerns around potential business and service disruption.

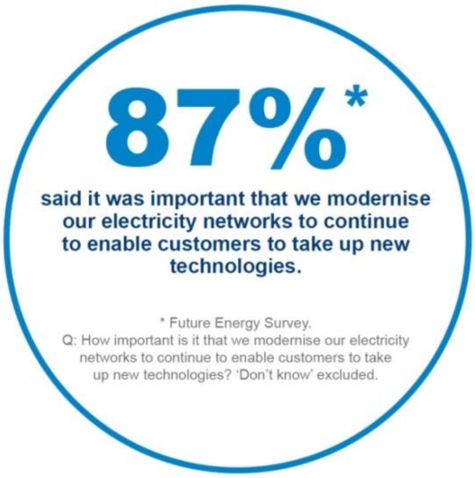
3.3.4 A Sustainable Future

Network as an Enabler

The way our customers source and use energy, and monitor their energy needs, is rapidly changing. As new technologies are embraced to manage energy use and costs, and to support action on climate change the industry is transforming. Our customers recognise that new technology is important to a modern network and support initiatives that enable their choices and reduce costs.

Our customers expect us to be able to facilitate and accommodate integration of renewables, battery storage and electric vehicles into the network, without creating risks to network security, supply quality or performance.

During 2019-20, the number of applications for the connection of large-scale (>30kW) renewable energy generating systems to our networks grew again.



Our connection teams also supported an escalating number of rooftop solar system connections to our network, with the strongest growth in the South East. There are now over 600,000 solar energy systems connected to our network across the state.

Managing solar on the network and keeping voltages within statutory limits is challenging. Despite this, and solar system performance issues receiving coverage in the media, across the Ergon Energy Network we have seen a 4.38% decrease in voltage-related complaints.

Our most recent insights from the December 2019 Queensland Household Energy Survey[19] confirm that customers intend to adopt further rooftop solar – indicating that solar penetration could increase to 48% in the next 3-5 years, with 65% possible in the future.

Queenslanders have embraced more energy efficient behaviours over the last decade, however, attempts to reduce electricity use have declined. This appears to be related to the increase in solar penetration.

The survey confirmed that decreasing battery system prices is making them more attainable for Queenslanders. The number of customers with batteries has grown dramatically over the past year, with over 7,000 now installed. However, the intention to purchase battery storage in the next three years has dropped, especially in regional Queensland, with concerns around return on investment. Despite this, we expect around 150,000 energy storage systems to be in use by 2030.

Additionally, the survey tracks customer intention to go off-grid. Outback households are more likely to be considering this for the future. The reasons are largely around cost and price, but also the desire for self-sufficiency and to protect the environment.

[19] Website: https://www.talkingenergy.com.au/33323/widgets/238713/documents/165976

While Electric Vehicles (EV) are still niche, the survey indicated a tipping point is approaching. By mid-year there were 2,300 fully electric Battery Electric Vehicles (BEVs) and almost 1,100 Plug-in Hybrid Electric Vehicles (PHEVs) on Queensland's roads. With a number of new, more affordable vehicle models scheduled for release over the coming year, the trend towards greater EV adoption is expected to continue.

There is a strong expectation that we will innovate and create a future-focused network to support our commitments and customers' lifestyles.

Our stakeholders are concerned with our ability to 'predict the future' given the level of change and potential impacts on the electricity grid combined with our long-life asset profile.

Collaboration

Our customers, communities and other stakeholders, expect us to engage with them in a transparent, meaningful manner on a regular basis.

Only two-fifths of Queenslanders in Energy Consumers Australia's Sentiment Survey June 2020[20] are confident the market will provide better value for money outcomes in the future. While there has been some improvement here, trust and relationships need to be rebuilt

There is a strong desire to engage and work with us to realise the benefits from today and tomorrow's emerging technologies, and the valuable role the network provides in the energy transformation.

53%*

are confident that the energy market will provide better supply and cost outcomes through technology advances.

*Energy Consumers Australia Energy Consumers Sentiment Survey June 2020.

Education and awareness are seen as important. Customers need to be informed to take advantage of emerging technologies and participate in the market. Vulnerable customers must not be left behind – information is important to removing barriers to participation.

There is strong interest in collaborating around non-network alternatives and support for continuing existing demand management. Our demand management program is viewed positively, with our stakeholders expecting us to collaborate with, and provide incentives to, customers and the supply chain to assist in demand management delivery and uptake.

This collaboration is being outworked by Ergon Energy and Energex's Demand Side Engagement Strategy,[21] which seeks to inform and include customer and non-network service provider participation to address any network limitations. We have a variety of means to which stakeholders become informed about network limitations and express interest and indicate ability for participation on non-network solutions.

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[20] Website: https://energyconsumersaustralia.com.au/projects/consumer-sentiment-survey

[21] Website: https://www.ergon.com.au/__data/assets/pdf_file/0003/165819/Demand-Side-Engagement-Strategy.pdf

Connections

Reasonable, clear timeframes and costs for connections are critical to Queensland's economic development. Customers are seeking a simplification of our connection process, and for continued equitable support of embedded generator connections. They have told us that network connections need to be timely, simpler and cost-reflective – there remains support for our efforts to align our service offering across Queensland. Customers also expect that we adapt to their changing preferences on connecting to our network.

3.4 Our Customer Commitments

As part of our planning process for our Regulatory Determination, we responded to the above community and customer insights with a set of commitments for 2020 and beyond. Our Customer Commitments, provided on the following page, continue to prioritise our investment plans, including the strategies and specific investments reflected in this report.

OUR **CUSTOMER COMMITMENTS**

SAFETY FIRST

Our priority is to be *Always Safe* – to show leadership in health, safety and wellbeing across our industry and the broader community.

AFFORDABLE

We continue to look for ways to make electricity more affordable across our networks, and to advocate for the reforms needed for a bright energy future all Queenslanders.

PRICING

To help take the pressure off electricity prices, we'll continue to drive down the cost of distributing the electricity across Queensland.

NETWORK TARIFFS

Our tariff and other reforms will be transparent, fair and equitable. We'll continue to show leadership in the energy transformation – with reforms that help to realise the potential value of emerging technologies.

FAIRNESS

We recognise the need to support our customers and communities, especially during times of vulnerability. We are committed to delivering responsibly on what really matters so that no-one is left behind and our communities grow stronger.

SECURE

We're here 24/7 to keep the lights on – providing the peace of mind of a safe, reliable electricity supply, and from knowing that we'll be there 'after the storm'. We're here to make life easy.

EMERGENCY RESPONSE

We'll be there after the storm, prepared and with the resources to safely respond to whatever Mother Nature delivers. And work closely with others in emergency response.

RELIABILITY

We'll maintain recent improvements in power reliability – and continue to improve the experience of those being impacted by outages outside the standard.

SERVICE PROMISE

We'll strive to find new ways to provide a great customer experience – to make it easy. And we'll meet our Guaranteed Service Levels – if we don't, we'll pay you.

SUSTAINABLE

Making it easier to connect to the network – we give you as much control as you choose for your energy solutions with information and more sustainable choices.

NETWORK AS AN ENABLER

We're looking to the future and evolving the network to best enable customer choice in their electricity supply solutions. We'll innovate to integrate solar, batteries and other technologies with the network in a way that is cost effective and sustainable.

COLLABORATION

We'll engage with you and provide you with the information you need, when and how you need it, to support sustainable energy choices.

CONNECTIONS

We'll make it easier and more timely to connect to the network, helping you from beginning to end, with an aligned state-wide service offering and further system improvements.

Chapter 4

Strategic Forecasting

4. Strategic Forecasting

Forecasting is a critical element of Ergon's network planning and is essential to the planning and development of the electricity supply network. Growth in peak demand is not uniform across the State of Queensland, therefore electrical demand forecasts are used to identify emerging local network limitations and network risks needing to be addressed by either supply side or customer-based solutions. Peak demand forecasts then guide the timing and scope of capital expenditure (to expand or enhance the network), or the timing required for demand reduction strategies to be established, or for risk management plans to be put in place.

A brief summary of the methodology and assumptions underpinning Ergon's peak demand forecasts has been provided in this Chapter.

A Strategic Forecasting Annual Report is available which details

- Further discussion on the methodology and assumptions applied in the peak demand forecasts and also including:
    - Minimum demand forecasts
    - Energy purchases and energy sales forecasts, and
    - Distributed Energy Resources forecasts (solar PV, electric vehicles and battery storage systems).
- Economic and demographic forecasts and commentary relating to population growth, GSP and the Queensland economic outlook.

4.1 Forecasting Assumptions

There are a number of factors which influence forecasts of peak demand, including the uptake of energy efficient appliances, adoption of solar PV, and customer response to electricity prices and tariffs. Assumptions used in the development of the peak demand forecasts are discussed in the following sections.

4.2 Economic Growth

Covid-19 has had a progressive impact on economic growth and our network over the course of the year. While the system level peak demand, zone substation and feeder level forecasts have been updated this year, there was not enough (post Covid-19) econometric data available at the time of the forecasts' construction to incorporate expected Covid-19 impacts

The level of economic growth is a major driver of many forecasts, and we primarily use Gross State Product (GSP). Queensland's economy experienced a high of 5.5% in 2011-12 followed by a decline in growth rates for the following three years. 2017-18 saw a resurgence in GSP to 3.7% buoyed by improvements in both private (e.g. mining) and Government investment and global commodity prices.

The Queensland economy will experience a recession in the short term, predominantly impacted by the COVID-19 event. External sources have forecast that the Queensland economy may fall marginally (in the range between -0.1% ~ -0.3%) in the 2019/20 financial year, and a further decrease between -0.4% ~ -2.7% in the 2020/21 financial year, as a result of the unprecedented COVID-19 impacts. As COVID-19 impacts fade away, a strong recovery is expected to occur over the following two years. In the longer term, there is considerable divergence in forecasts around the strength of the State economy. However, the underlying economic conditions remain solid and the business activities will be boosted by improved activities in the volume of commodity exports, tourism, education services, housing, agriculture, and small manufacturing industries, as a result of the relatively competitive lower value of the Australian dollar, low interest rates and favourable international commodity prices.

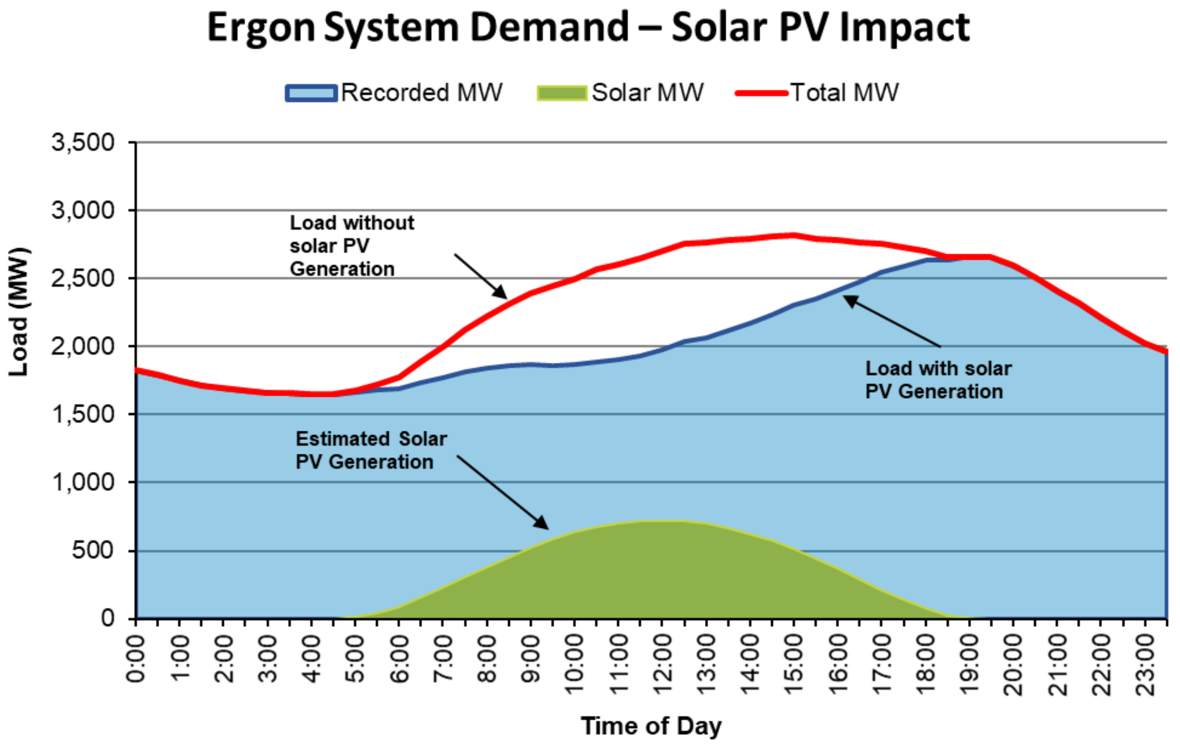
The current forecasts are based on underlying assumptions:

- GSP measures the aggregate economic activities throughout the whole rather than parts of Queensland
- The new liquefied natural gas (LNG) plants in central Queensland are pushing up the state economy as a whole to a lesser extent as the construction phase has shifted to production export and has limited impact on economic growth in SEQ or many other regional areas
- While GSP directly affects business firms, its influence on ordinary households is limited because electricity is a necessary service for them. The majority of households, regardless of their income levels, will use more electricity in the peak period of a hot day (for air conditioning), but won’t use an unnecessary extra amount if temperatures are mild.

4.3 Solar PV

The figure below illustrates the impact that solar PV has on the Ergon system peak demand. Over the 2019/20 summer, the Ergon network peaked at 2,660 MW on 7:00 pm 16 December 2019. Without PV generation, it is estimated that the peak would have occurred at 3:00 pm and would have been 156 MW higher than the recorded 7:00 pm peak. As battery storage becomes more affordable and therefore more widely used, daily peaks may revert to mid-to-late afternoon, as less PV generation is exported in preference for re-charging storage batteries.

Figure 6: System Demand – Solar PV Impact, 16th December 2019



4.3.1 Electric Vehicles and Energy (battery) Storage

Mainstream uptake of electric vehicles (EVs) and Plug-in Hybrid electric vehicles (PHEVs) have the potential to increase energy and demand forecasts in the future. Similarly, customer interest in energy storage systems (batteries of various kinds) is increasing. The number of known energy storage systems in the Ergon Energy network is approximately 2,800 as of June 2020.

Ergon Energy's forecasting model is based on the peak day profile for residential, commercial and industrial customers, with the marginal impact of EV's and batteries and solar PV incorporated into that profile.

4.3.2 Temperature Sensitive Load

Temperature sensitive loads from electrical appliances like air conditioning and refrigeration, are major drivers of peak demand on the network. The most extreme loads seen on the network over a year are typically driven by a combination of hot (and usually humid) weather conditions during times of high industrial and commercial activity.

Given the vastness of the Ergon network, a number of weather stations are required to capture the variability of weather conditions. Weather data from the following stations has been sourced from the Bureau of Meteorology (BOM), based on their representativeness of the weather in key population regions, and the quality of their extended weather history:

- Cairns Aero (FN region)
- Townsville Aero (North QLD region)
- Mackay MO (Mackay region)
- Rockhampton Aero (Central region)
- Maryborough (Wide Bay region)
- Oakey (South West region)

The zone substation forecasting methodology also utilises weather data, with a process to identify the most relevant weather station to relate to a zone substation's load – further details of the substation forecasting process are detailed below.

4.4 Substation and Feeder Maximum Demand Forecasts

The forecasting process predicts where extra capacity is needed to meet growing demand, or new assets are required in developing areas. Ergon Energy reviews and updates its temperature-corrected system summer peak demand forecasts after each summer season and each new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks. For consistency, the system level peak demand forecast is reconciled with the bottom-up substation peak demand forecast after allowances for network losses and diversity of peak loads. This process accounts for drivers which only become significant at the higher points of aggregation (e.g. economic and demographic factors), while also enabling investment decisions to be based on local factors. Hence individual substation and feeder maximum demand forecasts are prepared to analyse and address limitations for prudent investment decisions.

The take-up of solar PV is continuing as electricity prices rise and the cost of solar PV falls, and the emerging influence of electric vehicles and battery storage systems is also incorporated at the system and substation levels of forecasting.

Balanced against this general customer trend, the forecasts produced post-summer 2019-20 have provided a range of demand growth rates. The forecasts are used to identify network limitations and then investigate the most cost-effective solution which may include increased capacity, load transfers or demand management alternatives.

While growth in demand continues to increase very slowly at a system level, there can be significant growth at a localised substation level. In the 2020-25 period, the percentage compound growth rates of substations were as follows:

- 70% have an average compound growth rate of between 0% and 2%
- 7% have an average compound growth rate of more than 2%.

The ten-year substation peak demand forecasts are prepared at the end of summer (and may also be updated post winter) to enable appropriate technical evaluation of network limitations for both existing and proposed substations. The forecasts are developed from historical peak demands, weather, photovoltaic installations, electric vehicles, battery storage systems, as well as economic and demographic data via the system demand forecasts. Independently produced forecasts for economic variables and photovoltaic installations, electric vehicles and battery storage systems uptake (by the SA2 level) are also sourced from Deloittes and the CSIRO respectively.

Output from solar PV is generally coincident with Commercial and Industrial (C&I) peak demands, and there has been a significant increase in PV for C&I premises over the last couple of years. While this will provide benefits for those parts of the network which peak during times of significant PV generation, there are many other areas of the network which peak later in the afternoon/evening, where the impact of PV generation on the peak may either be limited or non-existent.

4.4.1 Substation Forecasting Methodology

Ergon Energy employs a bottom-up approach reconciled to a top-down evaluation, to develop the ten-year zone substation peak demand forecasts using validated historical peak demands and expected load growth based on demographic and appliance information in small area grids. Ergon also incorporates feedback from the regional planning engineers to review, discuss and validate growth rates and temperature-corrected starting points for the new forecast.

Peak demand forecasts are produced for each zone substation for summer and winter seasons. The forecasts are calculated at the 10 PoE and 50 PoE levels and are projected forward for ten years from the most recently completed season.

Zone substation forecasts are based on a probabilistic approach using a multiple regression estimation methodology to produce a distribution for 10 PoE and 50 PoE values. Larger block loads are incorporated (after validation for size and timing by the planning engineers) along with growth rates (with care taken to avoid double counting block loads and growth) to produce a forecast of the future load at each zone substation for the following ten years for summer and winter.

The zone substation peak demand forecasts are then aggregated up to the ten-year bulk supply point and transmission connection point demand forecasts, which take into account diversity of individual zone substation peak demands (coincidence factors) and network losses. This aggregated zone substation forecast is then reconciled with the independent system demand forecast and calibrated as required.

This approach has the advantage of incorporating uncertainty relating to weather events into the forecasting methodology.

Specifically, the ten-year substation demand forecasts are prepared by:

- Validating uncompensated substation peak demands are determined for the most recent summer period
- Regressing minimum and maximum temperature at five BOM weather stations against substation daily maximum demand, with the best-fit relationship is used to determine the substation's probability of exceedance distribution
- Using demand variability to determine the 50 PoE and 10 PoE values if the substation's load does not demonstrate a significant temperature – demand relationship.
- Reviewing historical variations from forecast to identify modelling inaccuracies or project/load transfers, block load variations.
- Calculating starting values for apparent power (MVA), real power (MW) and reactive power (MVAr) for summer day, summer night, winter day, winter night.
- Analysing demographics, preparing customer load profiles, and checking against customer connections and changes in population growth across the different regions
- Incorporating the expected impact and growth in solar PV, battery storage, and plug-in EVs at the substation level
- Reviewing and validating new block loads and load transfers with the planning engineers before inclusion in the forecast
- Reviewing the timing and scope of proposed transmission connection projects
- Applying the growth rates, block loads, transfers and transmission projects to the starting values to determine the forecast demand for each of the ten years starting from a coincident demand basis
- Aggregating the zone substation forecast peak demands to their parent bulk supply and transmission connection points for the distribution system coincident time
- Reconciling the total aggregated zone substation demand with the independently produced system demand forecast, to ensure that economic and demographic factors only evident at the system level, can be incorporated into the zone substation forecasts.

An important part of the modelling process is the careful review of the accuracy of the previous substation peak demand forecasts to identify and resolve any systematic errors or biases in the forecasting approach. It should be noted that the substation forecast modelling tool can differentiate between approved and proposed projects in the process.

4.4.2 Transmission Feeder Forecasting Methodology

A simulation tool is used to model the 110 kV and 132 kV transmission network. The software was selected to align with tools used by Powerlink and the Australian Energy Market Operator (AEMO). Powerlink provides a base model on an annual basis. This base model is then refined to incorporate future network project components and is uploaded with peak forecast loads at each zone substation, bulk supply and connection point from Substation Investment Forecasting Tool (SIFT).

Twenty models are created using this simulation tool, with each model representing the forecast for a particular season in a particular year. The models have five years of summer day 50 PoE and 10 PoE data and five years of winter night 50 PoE and 10 PoE data.

4.4.3 Sub-transmission Feeder Forecasting Methodology

Forecasts for sub-transmission feeders are produced for a five-year window, which aligns with the capital works program. The forecasts identify the anticipated maximum loadings on each of the sub-transmission feeders in the network under a normal network configuration.

Modelling and simulation are used to produce forecasts for the sub-transmission feeders. The traditional forecasting approach of linear regression of the historical loads at substations is not applicable, since it does not accommodate the intra-day variation. The modelling approach enables identification of the loading at different times of day to equate to the line rating in that period. A software tool models the 33kV sub-transmission network. The simulation tool has built-in support for network development which provides a variable simulation timeline that allows the modelling of future load and projects into a single model.

Ergon Energy combines the substation maximum demand forecasts and the daily load profiles of each individual substation to produce a forecast half-hour load profile for the maximum demand day at that substation. This is produced for each substation in the network. A series of load flows are then performed for each half-hour period of the day using these loadings. The forecast feeder load for each period is the maximum current experienced by the feeder in any half-hour interval during that period.

4.4.4 Distribution Feeder Forecasting Methodology

Distribution feeder forecast analyses carry additional complexities compared to sub transmission forecasting. This is mainly due to the more intensive network dynamics, impact of block loads, variety of loading and voltage profiles, lower power factors, peak loads occurring at different times/dates and the presence of phase imbalance. Also, the relationship between demand and average temperature is more sensitive at the distribution feeder level.

Forecasting of 11 kV feeder loads is performed on a feeder-by-feeder basis. The forecast begins by establishing a feeder load starting point by undertaking bi-annual 50 PoE temperature-corrected load assessments (post-summer and post-winter). This involves the analysis of daily peak loads for day and night to identify the load expected at a 50 PoE temperature after first identifying and removing any temporary (abnormal) loads and transfers.

On the macro level, the forecasting drivers are similar to those related to substations, such as economic and population growth, consumer preferences, solar PV systems, battery storage systems, electric vehicles etc. Accordingly, a combination of trending of normalised historic load data and inputs including known future loads, economic growth, weather, local government development plans, etc. is used to arrive at load forecasts.

Using a statistical distribution, the 10 PoE load value is extrapolated by using 80% of the temperature sensitivity from the 50 PoE load assessment. The summer assessment covers the period of December-January-February, and the winter assessment from June-July-August. Growth rates are applied, and specific known block loads are added, and events associated with approved projects are also incorporated (such as load transfers and increased ratings) to develop the feeder forecast. In addition, the 10 PoE load forecast is used for determining voltage limitations.

In summary, the sources used to generate distribution feeder forecasts are as follows:

- The historic maximum demand values, in order to determine historical demand growths. These historical maximum demands have been extracted from feeder metering and/or Supervisory Control and Data Acquisition (SCADA) systems and filtered/normalised to remove any abnormal switching events on the feeder network. Where metering/SCADA system data are not available, maximum demands are estimated using After Diversity Maximum Demand (ADMD) estimates or calculations using the feeder consumption and appropriate load factors
- The Queensland Government Statistician's Office spatial population projections, combined with Ergon's customer number forecasts to determine customer growth rates
- The forecast for solar PV systems, battery storage and EV from EQL's scenario modelling DER forecast is used as one of the growth drivers at distribution feeder level
- The temperature data, used to model the impacts of weather on maximum demand, is supplied by WeatherZone, which sources its data from the Bureau of Meteorology. This is used to determine approximate 10 and 50 PoE load levels
- Further forecast information is obtained from discussions with current and future customers, local councils and government.

4.4.5 System Maximum Demand Forecast

Ergon Energy reviews and updates its ten-year 50 PoE and 10 PoE system summer peak demand forecasts after each summer season and each new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks. For consistency and robustness, the substation peak demand forecast ('bottom-up') is reconciled with the system level peak demand forecast ('top-down') after allowances for network losses and diversity of peak loads.

A new regional approach has been developed to provide the 'top-down' forecast. Each of six regions is modelled separately and the sum of each of these regional peak demands at network peak coincidence provides an econometric ten-year total system maximum demand forecast based on identified factors which affect the load for each regional level. Inputs for the maximum demand forecast for each region include:

- Economic growth through the GSP (source: Deloittes NIEIR)
- Temperature (source: BOM)
- Population (source: NIEIR and Deloitte)
- Solar PV generation (source: customer installation data)
- Load history (source: corporate SCADA/metering database)
- Electric Vehicles
- Batteries.

The 'bottom-up' forecast consists of a ten-year maximum demand forecast for all zone substations (also described as 'spatial forecasts') which are aggregated to a system total and reconciled to the econometrically-derived system maximum demand. These zone substation forecasts are also aggregated to produce forecasts for bulk supply substations and transmission connection points.

In recent years, there has been considerable volatility in Queensland economic conditions; weather patterns and customer behaviour which have all affected total system peak demand. The influence of Queensland's moderate economic growth has had a moderating impact on peak demand growth through most of the state, while weather patterns have moved from extreme drought in 2009, to flooding & heavy rains and extended hot conditions over the past several summers. Summer conditions in the last two years have produced new record high maximum demand figures.

To complete the scenario, customer reaction to recent electricity price increases has started to wane resulting in customer load above long-term average trends at the 50 PoE temperature conditions. The amount of solar PV generation that has been connected to the network over recent years has continued to grow although at a steadier rate. Customer behaviour drivers are now incorporated into models used for system demand forecasting. The forecasts are developed using ABS data, Queensland Government data, AEMO data, NIEIR, an independently produced Queensland air conditioning forecast, solar PV connection data and historical peak demand data.

4.4.6 System Demand Forecast Methodology

The system forecasts are obtained from modelling a temperature-corrected multivariate regression model incorporating forecasts for factors including economic activity, demand management, population numbers, solar PV installations, EV and storage battery sales. The process comprised of modelling so that the:

- 50% PoE level — was obtained from a maximum demand distribution such that 50% of the values are each side of this value
- 10% PoE level — was obtained from a maximum demand distribution such that 10% of the values exceed this
- Actual maximum coincident demand at the network level for historical years is extracted from the Ergon Energy System Demand data set from system daily maximum demand loads. Temperature correction for 90%, 50% and 10% PoE system maximum demand is made using the past 20 years of daily temperature from selected weather stations throughout the distribution network
- Weather normalised data is derived using the past 20 years of temperatures.

Forecasts at differing levels of probability have been made using the Probability of Exceedance (PoE) statistic. In practical planning terms for an electricity distribution network, planning for a 90 PoE level would leave the network far too vulnerable to under-capacity issues, so only the 10 PoE and 50 PoE values are significant.

4.4.7 System Maximum Demand Forecast Results

The system-wide 2019-20 peak was 2,660MW at 7.00pm on 16th December 2019, an amount of 36MW more than the previous year's peak (see Figure 7). The higher peak can be attributed somewhat to growth but more so to a hot summer across all Ergon regions at one time. The results were significantly higher than the temperature corrected 50 POE peak but still less than the 10 PoE peak for 2019-20.

With the global and domestic economy still remaining subdued, we are continuing to forecast that energy consumption and overall demand will remain steady. However, some areas are continuing to see localised growth. With investment in the resource industry stagnant and the LNG industry in production, growth is being driven from outside of the mining sector, from industries such as tourism and residential housing investment.

Figure 7: Trend in System-wide Peak Demand

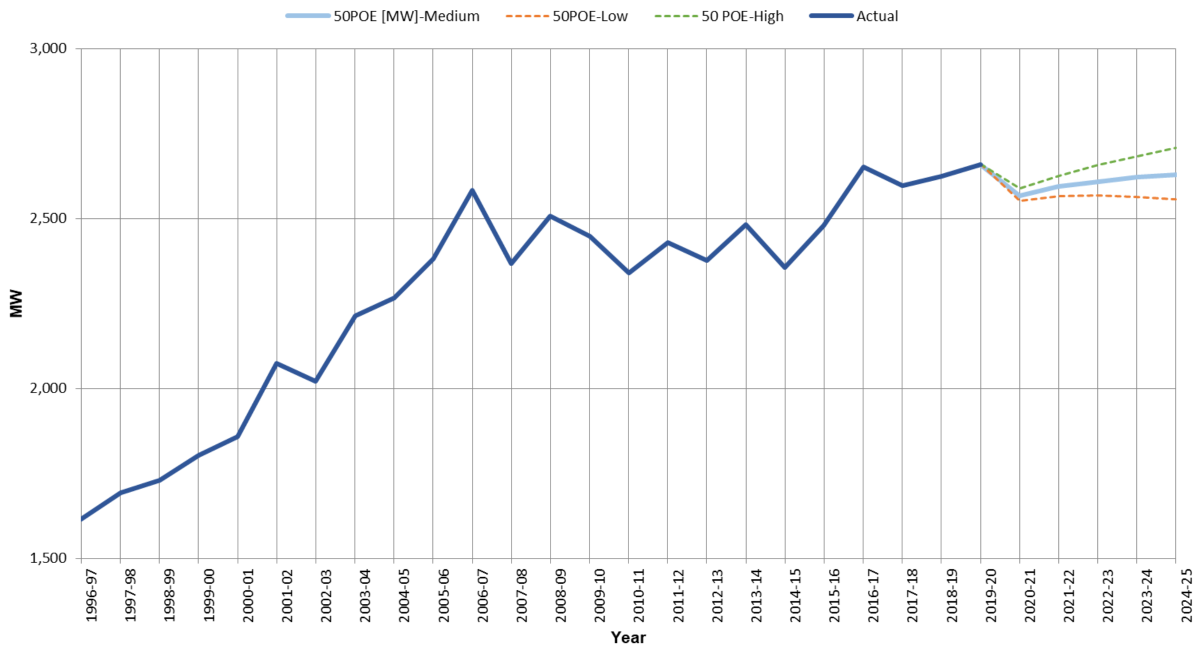


Table 2 summarises the historical actual demands and temperature-corrected 10 and 50 POE forecasts.

Table 2: Actual Maximum Demand Growth

Actual Maximum Demand Growth					
Demand	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Summer Actual (MW) [1]	2481	2637	2597	2623	2660
Growth (%)	0.7	0.3	0.6	0.8	1.0

1 Native Demand

Furthermore, Table 3 lists the maximum demand forecasts over the next five years for the 50PoE and 10PoE cases of peak demand with an average of 2,604 MW and a growth of 0.7% pa.

Table 3: Maximum Demand Forecast (MW)

Maximum Demand Forecast (MW)					
Forecast [1, 2]	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**
Summer (50% PoE)	2567	2594	2609	2621	2629
Growth (%)	1.3	1.0	0.6	0.5	0.3
Summer (10% PoE)	2783	2809	2824	2836	2844
Growth (%)	1.2	1.0	0.5	0.4	0.3

1 The five year demand forecast was developed using six weather station data as recommended by ACIL Allen
2 The demand forecasts include the impact of the forecast economic growth as assessed in August 2019.

The impact of solar PV generation, electric vehicles, and battery storage systems on peak demands is shown in the table below. As the Ergon regional peaks typically occur in the evenings (6.30pm to 8pm), the continued growth of solar PV will reduce loads during daylight hours but will not have any real effect on the evening peaks in future years. EV load has been included in the System Forecast baseline for this current year and for future forecast scenarios. EV charging is expected to occur from the early evening and extend into the middle of the night (off-peak), with the impact of EV charging on the system peak (afternoon period) will be small. It is assumed that battery storage will primarily be charged by solar PV and discharged over the late afternoon and early evening period between 4pm and 8pm with an initially small but growing impact on the system peak demand.

Table 4: Contribution of Solar PV, EV and Battery Storage Systems to Summer System Peak Demand

Contribution of Solar PV, EV and Battery Storage Systems to Summer System Peak Demand (MW)									
Impact Type	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Solar PV Capacity impact on System Peak Demand (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EV Load impact on System Peak Demand (MW)	<1	2	4	9	14	22	32	43	59
Battery Storage Systems Load impact on System Peak Demand (MW)	-5	-8	-13	-20	-30	-36	-42	-48	-54

Chapter 5

Network Planning Framework

5. Network Planning Framework

5.1 Background

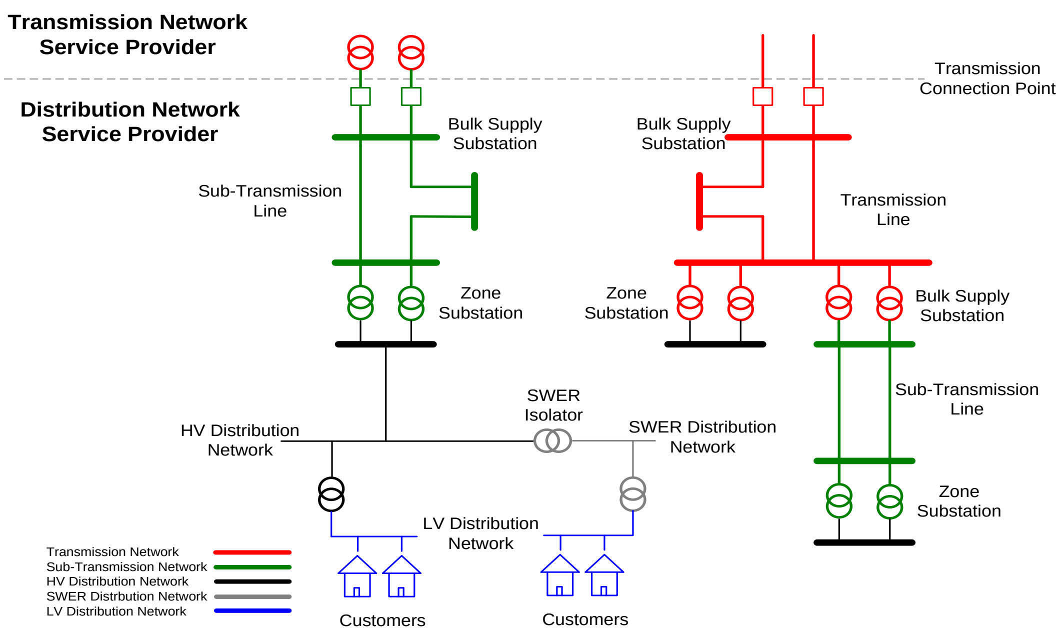
Network planning provides a balance between the customers' need for a safe, secure, reliable and high quality electricity supply with the customers' desire for a minimal service cost. A key part of the network planning process is to optimise the economic benefits of network augmentation and renewal facilitating "non-traditional" actions beyond the boundaries of the network, such as demand management, embedded generation solutions and other approaches.

The selection of the optimal network and business solution is achieved by:

- Determining and critically assessing key network limitations
- Developing and evaluating a broad range of network and non-network solutions
- Seeking to integrate and optimise outcomes using a variety of planning inputs
- Staging of project phases to ensure prudent expenditure.

This section outlines the network planning criteria, process, and framework that underpins our network planning approach. Figure 8 illustrates a traditional simplified DNSP network which typically consists of subtransmission, high voltage (HV) distribution, and low voltage (LV) networks, supplying customers at all voltage levels. It should be noted, as highlighted in other areas of this document, this traditional network topology is changing as we see greater numbers of embedded generators (and storage technology) at all voltage levels. This increased complexity and diversity at all levels within the network is both creating opportunity and challenge in the planning of the network.

Figure 8: Traditional Simplified DNSP Network



5.2 Planning Methodology

5.2.1 Strategic Planning

Ergon Energy's planning process involves the production of long-term strategic network development plans. These plans assess the electricity supply infrastructure requirements for defined areas based on the most probable forecast load growth projections. Scenario planning is used to obtain alternative development plans for a range of economic forecasts, population growths, and new technologies (such as solar PVs, EVs and battery energy storage systems). Demographic studies based on local government plans are carried out to help indicate the likely long-term demand for electricity across a development area. These include scenario modelling to test various outcomes, such as high or low customer response to demand management, tariff reform and energy efficiency initiatives.

The strategic planning process is an iterative and analytical process that provides an overall direction for the network development of a region. The purpose of strategic network development plans is to ensure the prudent management and investment for network infrastructure in both the short and long term, and to coordinate developments to address constraints and meet utilisation targets.

Strategic network development plans detail the results of the information and studies with an associated set of recommendations for proposed works. This includes:

- Details of all proposed works over the study period, including variations and dependence on different trigger factors
- Recommendations for easement and site acquisitions required in advance of any proposed works, including variations and dependence on trigger factors.

The long-term nature of strategic planning means that there is significant uncertainty around the estimations of load growth and location of load. The output of the strategic planning process gives direction to the short and medium-term recommendations, while allowing strategic site and easement acquisition and approvals to proceed. Specific outcomes of strategic network development plans may be used to identify areas where non-network solutions have potential to defer or avoid network augmentation. These are ongoing and reviewed as required.

5.2.2 Detailed Planning Studies

As the works identified within each strategic network development plan draw closer or where unforeseen customer initiated development changes occur, more detailed localised studies are performed. The shorter term detailed planning studies are conducted to identify all existing and anticipated network limitations within a five-year horizon. Ergon Energy is using area plans that encompass subtransmission, distribution, non-network and, where significant, asset renewal planning functions.

These planning studies are conducted at the subtransmission and distribution level to consolidate and assess any other factors that may have a material impact on the studied network. This usually includes an assessment of:

- Non-network alternatives
- Fault levels
- Voltage levels
- Security of supply requirements
- Quality of supply considerations
- Asset renewal
- Customer connections activity
- Local, state and federal government decisions and directions.

Options are considered for technical and economic feasibility to address the various issues with a final proposal progressed for approval.

5.3 Key Drivers of Augmentation

Network augmentation can be the result of customer activity, upstream augmentation works, network reconfiguration or major customer works that impact the shared network.

There are four general types of customer activity that can cause constraints in Ergon Energy's distribution system and prompt the need to invest:

- Organic growth that occurs when existing customers increase or change the profile of their electricity usage in a part of the network, or across the network. For example, the increase in air conditioner installations in the 1990's or the installation of solar systems in recent years
- Increases in the number of residential or small commercial customers in a part of the network
- Block loads connecting to a part of the network, such as new large commercial or industrial customers
- Changes/installation of medium to large scale embedded generators and/or storage technology.

Without network augmentation investment or non-network investment, customers' increased demand can result in load exceeding planning limits (including component capacity/ratings, voltage regulation limitations and protection limit encroachment) and/or the security criteria of the network.

Augmentation works within our network can also be driven by Powerlink, as the Transmission Network Service Provider (TNSP). Work on Powerlink's network may require compulsory activity within our network in order to ensure the transmission network integrity, and capacity can be delivered to the distribution network. Such activity could be the result of increased fault levels or plant rating limitations with these types of augmentation activities analysed and reviewed as part of the Joint Planning process conducted between Ergon Energy and Powerlink (or other DNSPs) as required by the NERs.

5.4 Network Planning Criteria

Network planning criteria guides how future network risk is to be managed or planned for and defines what conditions network augmentation or other related expenditure (such as demand management) should be undertaken.

There are two widely recognised methodologies for the development of planning criteria for power systems:

- Deterministic approaches (e.g. N-1, N-2, etc. redundancy)
- Probabilistic (risk-based) approaches.

Ergon Energy is required under Distribution Authority No. D01/99 to adhere to the probabilistic planning approach, where full consideration is given to network risk at each location, including operational capability, plant condition and network meshing with load transfers. Previously a deterministic approach applied, which required system remedy in the event of failure of one or two components.

The criteria give consideration to many factors including the capability of the existing network asset, the regulated supply standards (such as voltage, quality, reliability, etc.), the regulatory framework around investment decision making, the magnitude and type of load at risk, outage response capability and good electricity industry practice. Consideration is given to the complexity of the planning process versus the level of risk, allowing for simpler criteria to apply where lower risks exist and where the cost of potential investments is smaller.

While the probabilistic planning criteria are far more complex in application than deterministic, it increases the focus on customer service levels:

- **Customer Value Investment:** predominantly driven by the benefits gained from a reduction in the duration of unplanned outages i.e. Value of Customer Reliability (VCR), but also including (where applicable) other classes of market benefits
- **Mandatory Investment:** this includes the regulated standards for the quality of supply as per the NER, and the Minimum Service Standards (MSS) and Safety Net requirements in the Distribution Authority and any other regulatory obligations.

To avoid doubt, proposed investments that are <u>not</u> mandatory investments must have a positive Net Present Value (NPV) when all significant costs and benefits are accounted for, over a reasonable evaluation period (usually 20 years). While mandatory investments may not be NPV positive, however, different options and benefits are considered for each project with the most cost positive option being selected for progression. All investments are risk ranked and prioritised for consideration against Ergon Energy's budget and resource levels, with some network risks managed operationally.

5.4.1 Value of Customer Reliability

In December 2019, the AER published the results of an investigation into the value that NEM customers place upon reliability.

According to the AER Review, the VCR:

> *"… seek to reflect the value different types of customers place on reliable electricity under different conditions. As such, VCRs are useful inputs in regulatory and network investment decision-making to factor in competing tensions of reliability and affordability. Importantly, VCR is not a single number but a collection of values across residential and business customer types, which need to be selectively applied depending on the context in which they are being used"*

Components in the calculation of VCR include:

- Energy at Risk (EaR): the average amount of energy that would be unserved following a contingency event, having regard to levels of redundancy, alternative supply options, operational response and repair time
- Probability of the Contingency (PoC) occurring in a given year at a time when there is energy at risk
- Network losses between the measurement point and the customer
- Customer mix, by energy consumption across various customer sectors.

The first three factors are combined to calculate the 'annualised probability-weighted Unserved Energy (USE)' in MWh. The last factor, customer mix, is combined with the AER VCR tables to calculate the 'energy-weighted locational VCR' (in $/MWh). Finally, the two are multiplied to calculate the annual economic cost of unserved energy (VCR) associated with the given contingency (or contingencies). By also considering load growth and (for example) plant ageing, estimates of the annual VCR are calculated across the evaluation period (usually 60 years).

Changes in VCR associated with a particular project (or option) represent a benefit (if positive), or a cost (if otherwise) that is used as a benchmark to assess proposed solutions. To be comparable, proposed solutions are required to be expressed in terms of annualised costs or annuities. By balancing the VCR and the cost of supply, a more efficient service can be provided to our customers.

5.4.2 Safety Net

While the probabilistic customer economic value approach described above provides an effective mechanism for keeping costs low while managing most network risk; high-consequence-low-probability events could still cause significant disruption to supply with potential customer hardship and/or significant community or economic disruption.

The Safety Net requirements address this issue by providing a backstop set of 'security criteria' that set an upper limit to the customer consequence (in terms of unsupplied load) for a credible contingency event on our network. Ergon Energy is required to design, plan and operate its network to meet the restoration targets defined in Schedule 4 of Ergon Energy's Distribution Authority (shown in Table 5 below) *"…to the extent reasonably practicable".*

This acknowledges that regardless of level of preparation, there will always be combinations of circumstances where it is impossible to meet the restoration targets at the time of an event, though these should be rare. For example, if it is unsafe to work on a line due to ongoing storm activity. In addition, during the planning phase, where the risk of failing to meet the target timelines is identified as being of very low probability, investment to further mitigate the risk would generally not be recommended, as per industry best practice. This risk is also addressed with larger customers that enter into a negotiated connection contract with Ergon Energy, as the parties are able to agree upon the particular terms of the supply arrangement, including when and to what extent there may be restrictions on supply. Ergon Energy considers this approach strikes an appropriate balance in meeting the safety net targets while ensuring that investments in the network are prudent and efficient, and meets customer expectations of a secure, reliable and affordable supply.

Table 5: Service Safety Net Targets

Area	Targets for restoration of supply following an N-1 Event
Regional Centre[22]	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8000 customers) after 1 hour • Less than 15MVA (6000 customers) after 6 hours • Less than 5MVA (2000 customers) after 12 hours • Fully restored within 24 hours.
Rural Areas	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8000 customers) after 1 hour • Less 15MVA (6000 customers) after 8 hours • Less 5MVA (2000 customers) after 18 hours • Fully restored within 48 hours.

Efficient investments under the Safety Net provisions will provide mitigation for credible contingencies that could otherwise result in outages longer than the Safety Net targets.

Safety Net review of the network's subtransmission feeders with zone and bulk supply substations are performed annually where the planning team examine the network transfer capability, forecasts, substation asset ratings, bus section capability, network topology and protection schemes. Further work is undertaken to ensure items within the operational response plans are outworked; this may include asset spares, location of specialist machinery, access conditions and skills of crews. Ergon Energy annually reviews the inventory of mobile substations, skid substations and mobile generation and site suitability to apply injection if required to meet Safety Net compliance.

Ergon Energy continues to review the changing state of the network for Safety Net compliance as part of the normal network planning process, ensuring that care is taken to understand our customers' needs when considering the competing goals of service quality against cost of network.

[22] Regional Centre relates to larger centres with predominantly Urban feeders, whereas Rural Areas relates to areas that are not Regional Centres. Modelling and analysis are benchmarked against 50 PoE loads and based on credible contingencies.

5.4.3 Distribution Networks Planning Criteria

Distribution feeder ratings are determined by the standard conductor/cable used and installation conditions/stringing temperature. Consideration is also given to the impacts made by Electro-Magnetic Fields (EMF) as well as increasing load and customer counts on the reliability of distribution feeders.

Target Maximum Utilisation (TMU) is used as a trigger for potential application of non–network solutions or capacity improvements for the 11kV and 22kV network.

CBD and Critical Loads

In the regional areas for loads that require an N-2 supply, meshed networks are utilised. Mesh networks consist of multiple feeders from different bus sections of the same substation interconnected through common distribution substations. A mesh network can often lose a single component without losing supply - with the loss of any single feeder the remaining feeders must be capable of supplying the total load of the mesh.

In a balanced feeder mesh network, each feeder supplies an approximately equal amount of load and has the same rating, as the name describes. Any feeder in a balanced three feeder mesh should be loaded to no more than 67% utilisation under system normal conditions at 50 PoE. Any feeder in a balanced two feeder mesh should be loaded to no more than 50% utilisation under system normal conditions at 50 PoE.

Mesh networks are more common in the Brisbane dense central business district (CBD) areas where high reliability is critical and thus the loss of a single feeder should not affect supply.

Urban Feeders

What is referred to as an Urban feeder in the security criteria is essentially a radial feeder, with ties to adjacent radial feeders. A radial feeder with effective ties to three or more feeders should be loaded to no more than 75% utilisation under system normal conditions at 50 PoE.

On the loss of a feeder, closing the ties to other feeders allows supply to be restored to the affected feeder without overloading the tie feeders.

Values of TMU may need to be adjusted to ensure that there is adequate tie capacity to adjacent zone substations in accordance with the security standard. Each case needs to be considered separately.

It is recognised that tie capacity may not be available under all loading conditions because of voltage limitations.

Rural Feeders

For a point load that has no ties, or a rural radial feeder, the TMU will be capped at 0.90 at 50 PoE, unless the supply agreement specifically requires a different value.

5.4.4 Consideration of Distribution Losses

Distribution losses refer to the energy loss incurred in transporting energy across the distribution network. They are represented by the difference between energy purchased and energy sold. Ergon Energy includes all classes of market benefits (including network losses) in its analysis that it considers to be material for all projects, including those under the RIT-D and those projects where there is a material difference in losses between options.

5.5 Voltage Limits

5.5.1 Voltage Levels

Our distribution network consists of numerous different HV levels due to legacy network topologies, various specific customer or sub network requirements, or due to industry best practice for a network configuration. Table 6 below shows the system nominal voltage and the system maximum voltage for the main network voltages. The maximum voltage is generally the operating level that can be sustained without equipment damage.

Table 6: System Operating Voltages

System Nominal Voltage	System Maximum Voltage
132kV	145kV
110kV	123kV
66kV	72kV
33kV	36kV
22kV	24kV
11kV	12kV

5.5.2 Transmission and Subtransmission Voltage Limits

Target voltages on bulk supply substation busbars will be set in conjunction with Powerlink. Unless customers are supplied directly from the transmission or subtransmission networks, the acceptable voltage regulation on these networks will be set by the ability to meet target voltages on the distribution busbars at the downstream zone substations, considering upstream equipment limitations, under both peak and light load scenarios.

Where customers are supplied directly from these networks, supply voltages must meet the requirements shown in the previous section.

Where it can assist in meeting voltage limits, Line Drop Compensation (LDC) may be applied on zone substation transformers and line regulators to optimise the voltage regulation on the distribution network. In some instances, issues such as the distribution of load on individual feeders may mean that LDC is not a feasible solution.

5.5.3 Distribution Voltage Limits

Target voltages on zone substation busbars are set by Ergon Energy as relevant. These zone substation busbars are operated with either LDC, or with a fixed voltage reference or Automatic Voltage Regulator (AVR) set points. Downstream voltage regulators may also be set with LDC or with a standard set point.

For distribution systems, the network is operated to supply voltage at a customer's point of connection and considerations are also made to the variable impacts of the different LV network configurations on subsequent LV customers supply voltage.

Augmentation of the distribution network generally occurs when voltage limitations occur on the distribution network under system normal conditions.

Table 7 provides an indicative level of the maximum HV voltage drops in the distribution network, to ensure acceptable supply to LV customers. The drop defined is from the zone substation bus to the regulation zone extremity (which may or may not be the feeder extremity), for steady state conditions.

Table 7: Steady State Maximum Voltage Drop

Ergon Energy network targets	Maximum voltage drop – fixed voltage	Maximum voltage drop – with LDC
Urban	5.0%	8.0%
Short & Long Rural	6.4%	9.4%

5.5.4 Low Voltage (LV) Limits

Typically, LV network voltage is managed via the On Load Tap-Changer (OLTC) on the zone substation transformer, HV Voltage Regulators and a fixed buck (reduction) or boost (increase) available from the distribution transformer tap ratio to cater for additional network voltage rise/drop. In addition, LV Regulators (LVR) where installed enabling the LV network voltage to be managed in a similar way to the HV distribution and subtransmission networks, with an automatic response and voltage set point.

Augmentation of the LV network may occur when voltage limitations occur under system normal conditions and is occurring increasingly as a result of voltage rise due to solar PV compared to historical load based issues.

5.5.5 Fault Level Analysis Maximum Customer Voltage

The NER gives utilities the authority to specify the customer supply voltage range within the connection agreement for HV customers above 22kV. The NER requires Root Mean Square (RMS) phase voltages to remain between ±5% of the agreed target voltage (determined in consultation with AEMO); provided that at all times, the supply voltage remains between ±10% of the system nominal RMS phase to phase voltage except as a consequence of a contingency event.

In Queensland, for customers less than or equal to 22kV, the Queensland Electricity Regulation specifies steady-state (i.e. excluding transient events such as transformer energisation) supply voltage ranges for LV and HV customers. In 2017 the Queensland Electricity Regulation for LV changed from 415/240 volts +/- 6% to 400/230 volts +10%, -6%.

Table 8 below details the standard voltages and the maximum allowable variances for each voltage range from the relevant Queensland Electricity Regulation and the NER.

Table 8: Maximum Allowable Voltage

Nominal Voltage	Maximum Allowable Variance
<1,000V 230V Phase to Neutral 400V Phase to Phase	Nominal voltage +10% /- 6%
1,000V – 22,000V	Nominal voltage +/- 5% or as agreed
>22,000V	Nominal voltage +/- 10% or as agreed

The values in this table assume a 10 minute aggregated value and allow for 1% of values to be above this threshold, and 1% of values to be below this threshold.

5.6 Fault Level Analysis Methodology

Ergon Energy performs fault level analysis at all bulk supply point and zone substation higher voltage and lower voltage buses in our supply grid. Isolated generation sites are not considered in these studies.

Studies are based on anticipated network configurations for the present and future five years based on Ergon Energy and Powerlink Annual Planning Reports. Simulation studies are carried out for 3-phase, 2-phase to ground and 1-phase to ground faults.

The studies are based on two possible network configurations within each study year:

- Network Normal: all normally open bus ties on all buses are open
- Network Maximum: all normally open bus ties on all buses are closed.

The studies provide results for the sub-transient and synchronous fault levels for each network configuration:

- Sub-transient: a voltage factor of 1.1 is used to create a driving voltage of 1.1 p.u. behind sub-transient reactances
- Synchronous: a voltage factor of 1.0 is used to create a driving voltage of 1.0 p.u. behind synchronous reactances.

All fault level analysis results are stored in a spreadsheet which is then validated and analysed prior to publishing. Fault level studies are carried out based on the following assumptions:

- Major network connected generators are assumed to be in operation
- All transformers are fixed at nominal tap.

The fault levels are calculated in accordance with Australian Standard AS 3851. However, a voltage factor of 1.1 is used for all voltage levels when performing sub-transient analysis. In addition, a voltage factor of 1.0 is used for all voltage levels for synchronous fault level analysis.

5.6.1 Standard Fault Level Limits

Table 9 lists design fault level limits that apply to our network.

Table 9: Design Fault Level Limits

Network Type	Voltage (kV)	Existing Installation Current (kA)	New Installation Current (kA)
Sub-transmission	132/110	25 / 31.5	25 (3s)
Sub-transmission	66	25	25 (3s)
Sub-transmission	33	13.1	25 (3s)
Distribution	22	13.1	25 (3s)
Distribution	11	13.1	25 (3s)

While Table 9 presents design fault ratings, in some instances the values given for existing installations may not align with standard modern switchgear ratings. Site specific fault levels are considered in planning activities for network augmentations or non-network solutions.

It should be noted that if no fault time duration is specified in the table; then fault levels are quoted with a one second duration. A faster protection clearing time will be considered where appropriate. This can be further investigated when fault levels approach limits.

Where fault levels are forecast to exceed the allowable fault level limits, then fault level mitigation projects are initiated.

5.6.2 Fault Level Growth Factors

Fault levels on our network are affected by factors arising from within the network or externally, such as the TNSP’s network, generators and customer connections.

Fault level increases due to augmentation within the network are managed by planning policies in place to ensure that augmentation work will maintain short circuit fault levels within allowable limits.

Fault level increases due to external factors are monitored by annual fault level reporting, which estimate the prospective short circuit fault levels at each substation. The results are then compared to the maximum allowable short circuit fault level rating of the switchgear, plant and lines to identify if plant is operated within fault level ratings.

Ergon Energy obtains upstream fault level information from TNSP's annually. Changes throughout the year are communicated through joint planning activities as described in Section 5.10.1.

New connections of distributed generation and embedded generation which increase fault levels are assessed for each new connection to ensure limits are not infringed. Known embedded generators are added to simulation models so that the impacts of these generators on the system fault levels are determined.

5.7 Ratings Methodology

The evolution of large-scale renewable generation is challenging the philosophy of how network constraints are derived. Solar farms, for example, can push network assets to their thermal capacity daily, not seasonally. Step changes in utilisation are expected to become more prevalent in pockets of the network as more large-scale renewables are commissioned.

Plant ratings are determined using Ergon Energy's Plant Rating Guidelines which is based on the relevant Australian Standard.

5.7.1 Feeder Capacity and Ratings

To determine the feeder capacity for planning purposes the following methodology has been applied.

- Overhead lines – current carrying capacities are aligned to BOM Climate zones design ratings that are based on Joint Workings studies. The default overhead rating parameters used are listed in Section 5.7.2. Where the feeder backbone conductor decreases in size, the smaller conductor has been used in cases where there is minimal load upstream of the smaller conductor.
- Align the rating with the feeder load profile. While summer day is predominantly the rating restriction, low wind speeds in the morning and evening can cause network limitations.
- Loads caused by abnormal network configurations have been discounted when determining the peak demands.
- Where the existing conductor operating temperature is not known, a thermal rating of 50°C has been used. This is the typical overhead conductor thermal design temperature rating used in Ergon Energy regions.

5.7.2 Overhead Line Ratings

Overhead line ratings are based on environmental conditions, such as minimum wind speed and maximum ambient temperature, wind angle, conductor material properties, conductor emissivity and absorptivity, reflectance and solar radiation which are detailed further in this section. The wind speed, ambient temperature and wind angle have the most significant effect on the line rating.

Default parameter values used by Ergon Energy to calculate the overhead line ratings are shown in Table 10 and Table 11.

In design of run back schemes for renewable and other types of generation, a maximum threshold 100°C is applied to overhead lines to ensure that generators ramp back at a sufficient rate to maintain conductor temperatures below 100°C given the standard set of climate assumptions below.

Time of Day

In the context of static ratings, a day is split into day, evening, night/morning for both summer and winter as shown in Table 10. The shoulder seasonal months of April, May, September, October and November are generally rated with summer parameters.

Table 10: Time of Day Definition

Description	Abbreviation	Indicative time
Summer Day	SD	Dec-Mar, 9am to 5pm
Summer Evening	SE	Dec-Mar, 5pm to 10pm
Summer Night/Morning	SN/M	Dec-Mar, 10pm to 9am
Winter Day	WD	Jun-Aug, 9am to 5pm
Winter Evening	WE	Jun-Aug, 5pm to 10pm
Winter Night/Morning	WN/M	Jun-Aug, 10pm to 9am

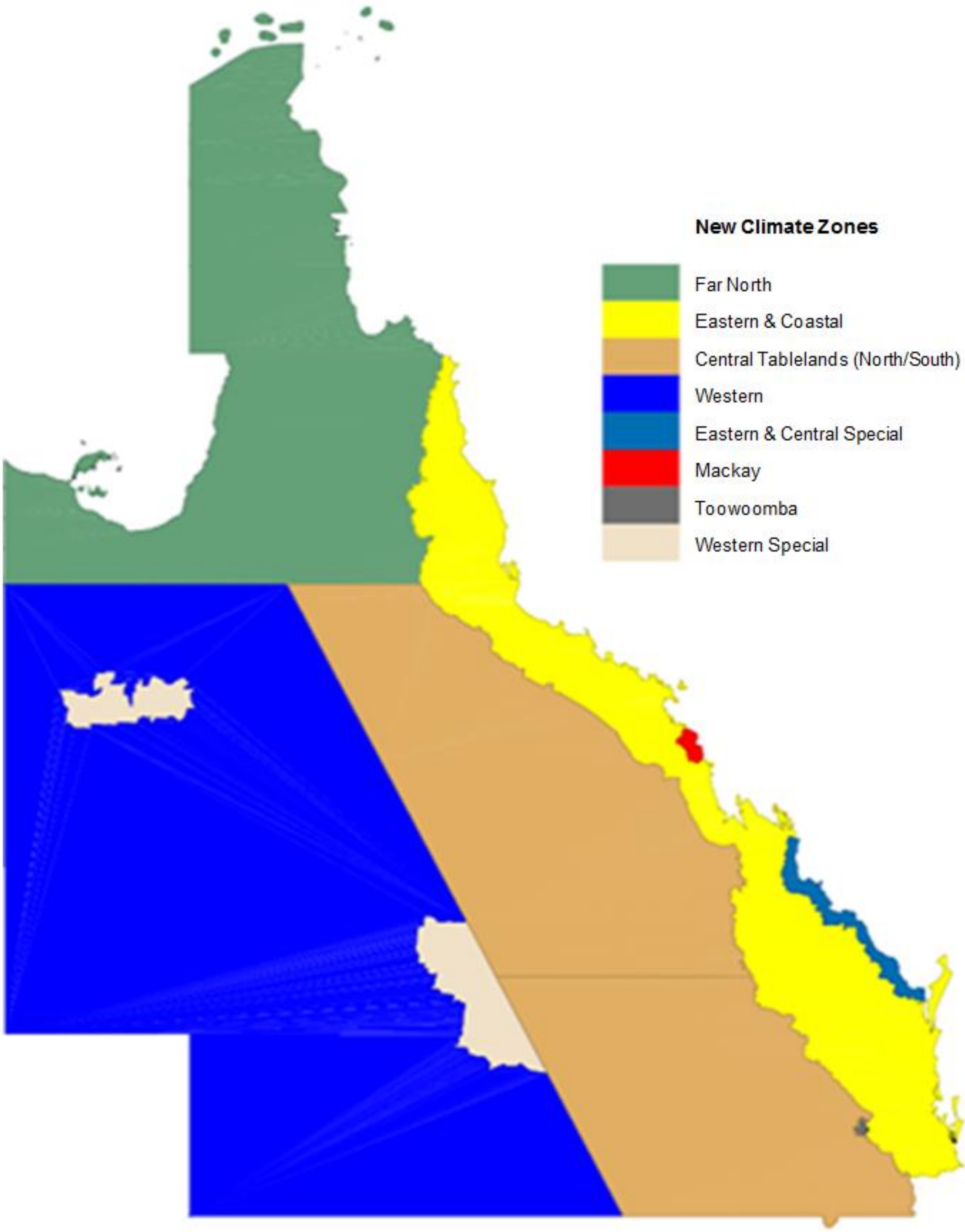
Climate Zones

The climate study produced the overhead line rating weather parameters for the state shown in Table 11. These nine climate zones are shown in Figure 9.

Table 11: Climate Zone Parameters

Region	SD		SE		SN/M		WD		WE		WN/M	
	Wind (m/s)	Ambient (°C)	Wind (m/s)	Ambient (°C)	Wind (m/s)	Ambient (°C)	Wind (m/s)	Ambient (°C)	Wind (m/s)	Ambient (°C)	Wind (m/s)	Ambient (°C)
Far North	0.8	38	0.4	34	0.2	30	1.4	32	0.7	28	0.3	24
Eastern & Coastal	1.3	35	0.8	31	0.3	27	1.2	28	0.5	23	0.3	23
Mackay	1.9	33	1.5	27	1.2	27	1.8	24	0.5	19	0.5	19
Eastern & Central Special	1.7	33	1.3	27	0.4	27	1.2	25	0.4	19	0.4	19
Toowoomba	1.8	33	1.8	27	1.8	21	1.8	19	1.5	14	1.3	11
Central Tablelands - North	1.3	37	0.7	34	0.2	29	0.8	30	0.4	26	0.2	20
Central Tablelands - South	1.3	37	0.7	34	0.2	29	0.8	25	0.4	22	0.2	15
Western	1.7	42	1.4	40	1.4	36	1.4	32	1.2	29	0.7	20
Western Special	1.5	41	0.8	37	0.3	32	1.1	32	0.4	28	0.3	20

Figure 9: Visualisation of Ergon Energy Climate Zones



5.7.3 Real Time Capacity Monitoring Ratings

Real time capacity monitoring in the network is applied to assess feeder constraints that rely on environmental parameters and thermal limits to determine their capacity. Measuring actual conditions using real time data, from field devices and weather stations, gives us greater flexibility in our load management response, which can be critical when responding to asset failure.

The results of real time capacity monitoring are used to compare to probabilistic ratings and confirm actual capacity in the network.

5.7.4 Transformer Ratings

Transformer ratings have been determined using Ergon Energy's Plant Rating Guidelines. The Normal Cyclic Capacity (NCC) rating determines the upper limit to which zone substation transformers should be loaded under normal cyclic operating conditions.

The NCC rating is dependent on the transformer condition, nameplate rating, applied loading profile, historical ambient temperatures and allowable loss of life. Transformer rate of ageing is limited to 'one day per day' loss of life when calculating the NCC rating.

There are individual cases where the rating applied is the nameplate rating because the transformer is in poor condition or because of generator connected loads.

Where generators are connecting to Ergon Energy's network resulting in power transformer reverse power flows up to nameplate, transformer ratings are limited to the base cooling mode of Oil Natural Air Natural (ONAN) for the purpose of the connection. Studies are being undertaken to assess the impact of accelerated aging under reverse power flows using the higher cooling modes.

5.8 Planning of Customer Connections

Customer Initiated Capital Works (CICW) are defined as works to service new or upgraded customer connections that are requested by Ergon customers. As a condition of our Distribution Authority, Ergon Energy must operate, maintain and protect its supply network in a manner that ensures the adequate, economic, reliable and safe connection and supply of electricity to our customers. It is also a condition that it allows, as far as technically and economically practicable, its customers to connect to its distribution network on fair and reasonable terms.[23]

Ergon Energy has a Connection Policy[24] that details the circumstances in which a customer must contribute towards the cost of its connection and how it is to be treated for regulatory purposes. This Policy came into effect on 1 July 2020.

[23] Ibid, s 43.

[24] Webpage: https://www.ergon.com.au/__data/assets/pdf_file/0009/270378/Connection-Policy-2020-2025.pdf

5.9 Major Customer Connections and Embedded Generators

Ergon Energy is committed to ensuring that, where technically viable, major customers are able to connect to the network. We have a clear Major Customer Connection (MCC) process available on our website[25] that aligns with the connection processes in Chapters 5 and 5A of the National Electricity Rules (NER). The process generally applies to proposed connections where the intended Authorised Demand (AD) or load, on our network exceeds 1,000kVA at a single site.

Ergon Energy has clear processes for the connection of Embedded Generation (EG) units, which apply to EG systems 30kVA and above. The processes may vary depending on the size of the generating unit and whether the system is exporting into our network. These processes are also listed on our website.[26]

The connection of any Major Customer or EG systems will require a technical assessment. This assessment will consider the effect that the connection will have on existing planning and capacity limitations (including component capacity/ratings, voltage regulation limitations and protection limit encroachment, system stability and reliability, fault level impacts and the security criteria). This assessment is necessary to ensure that Ergon Energy continues to operate the network in a manner that delivers adequate, economic, reliable and safe connection and supply of electricity to its customers.

Further information on the Major Customer connection process is available on the Ergon Energy website.[27]

5.10 Joint Planning

5.10.1 Joint Planning Methodology

The joint planning process ensures that different network owners operating contiguous networks work cooperatively to facilitate the identification, review and efficient resolution of options to address emerging network limitations from a whole of distribution and transmission network perspective.

Ergon Energy conducts joint planning with distribution network service providers and transmission network service providers as required. Joint planning involves Essential Energy (a DNSP operating in New South Wales), Powerlink and Energex near Toowoomba and north of Gympie.

For joint planning purposes, the primary focus is to ensure that network capacities are not exceeded. These limits relate to:

- Thermal plant and line ratings under normal and contingency conditions
- Plant fault ratings during network faults
- Network voltage to remain within acceptable operating thresholds
- Replacement of ageing or unreliable assets, and
- Network stability to ensure consistency with relevant standards.

[25] Webpage: https://www.ergon.com.au/network/connections/major-business-connections
[26] Webpage: https://www.ergon.com.au/network/connections/major-business-connections/large-scale-solar
[27] Webpage: https://www.ergon.com.au/network/connections/major-business-connections

5.10.2 Role of Ergon Energy in Joint Planning

Joint planning often begins many years in advance of any investment decision to address a specific emerging network limitation. Timing is reviewed annually, with detailed planning and approval completed based on the forecasted need and the lead time to complete the project. In this process, there is a steady increase in the intensity of joint planning activities, which typically would lead to a regulatory investment test consultation (either RIT-T or RIT-D). Among other things, the scope and estimated cost of options (including anticipated and modelled projects) is provided in published regulatory investment test documents consistent with the NERs.

Through this process Ergon is tasked with:

- Ensuring that its network is operated with sufficient capability, and augmented if necessary, to provide network services to customers
- Conducting annual planning reviews with TNSPs and DNSPs whose networks are connected to Ergon Energy's network
- Developing recommendations to address emerging network limitations through joint planning with DNSPs, TNSPs and consultation with Registered Participants and interested parties as defined by the National Electricity Rules. Net present value analysis is conducted to ensure cost-effective, prudent solutions are developed. Solutions may include network upgrades or non-network options, such as local generation and demand side management initiatives
- Undertaking the role of the proponent for jointly planned distribution augmentations in Regional Queensland
- Advising Registered Participants and interested parties of emerging network limitations within the time required for action
- Ensuring that its network complies with technical and reliability standards contained in the NER and jurisdictional instruments.

5.11 Joint Planning Results

5.11.1 Joint Planning with TNSP

Table 12 presents the outcomes of Ergon Energy's joint planning investments undertaken with Powerlink as described in Section 5.11.2 and 5.11.3 in 2019-20.

Table 12: Ergon Energy - Powerlink Joint Planning Investments

Region	Brief Description	Est. Capital Cost*	Est. Timing	Lead NSP
Northern	**H11 Nebo** - 11kV works required to replace end of life Transformer RMU	$2.7M	Oct-23	Powerlink
Northern	**T38 Mackay** - CT replacements for revenue and check metering compliance.	$2.2M	Sep-21	Powerlink
Northern	**T157 Ingham South** - Ergon Energy work related to Powerlink's Transformer 1 and Transformer 2 replacement.	$1.0M	Oct-21	Powerlink
Northern	**T51 Cairns** - Ergon Energy work to address constrained cable capacity.	$2.0M	Feb-24	Ergon Energy
Northern	**T92 Dan Gleeson** - Ergon Energy work related to Powerlink's Secondary Systems Upgrade.	$1.0M	Dec-20	Powerlink
Northern	**H039 Woree Substation** – Secondary systems and cable termination.	$0.5M	Oct-22	Powerlink
Southern	**T035 Dysart** - Install two 66/22kV 20MVA transformers to supply the Dysart area distribution network once Powerlink remove the existing 2 x 70MVA 132/66/22kV.	$13.1M	Aug-21	Powerlink
Southern	**T032 Blackwater** - Ergon Energy to reinstate 22kV energy supply to Blackwater area distribution network once Powerlink replace 2 of 3 Transformers, 132/66/11kV with single 160MVA. Includes Ergon asset refurbishment works.	$4.4M	Jun-24	Powerlink
Southern	**Egans Hill** - Secondary Systems Replacement	$0.7M	Aug-21	Powerlink
Southern	**H015 Lilyvale** - Powerlink to replace Transformers 3 & 4, 132/66/11kV with 160MVA units.	$3.3M	Oct-22	Powerlink

* Ergon Energy component (including overheads), associated costings as of October 2020

^ Project scope reduced from previous year's DAPR submission

5.11.2 Joint Planning with other DNSP

There were no investments resulting from joint planning in 2019-20 with Essential Energy, Energex, mining sector service providers or generators in the North Queensland Western Region.

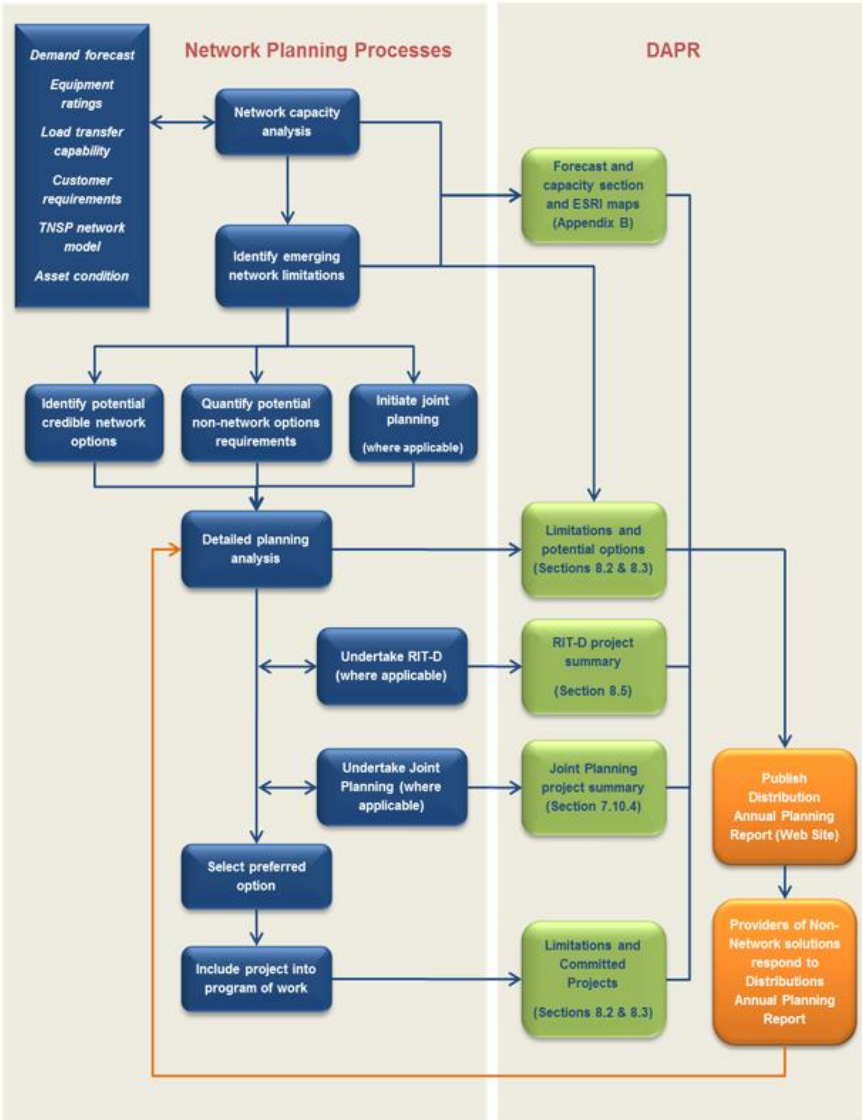
5.11.3 Further Information on Joint Planning

Further information on Joint Planning outcomes requiring a RIT-T led by Powerlink is available on the Powerlink website.[28] Alternatively, we welcome feedback or enquiries on any of the information presented in this DAPR via email.[29]

5.12 Network Planning – Assessing System Limitations

The methodology shown in Figure 10 is used in the preparation of the DAPR to report on subtransmission network and primary distribution feeder limitations and solutions, joint planning projects, and RIT-D projects.

Figure 10: System Limitations Assessing Process



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[28] Webpage: https://www.powerlink.com.au/planning-and-consultation
[29] Email: engagement@ergon.com.au

5.12.1 Joint Approach to Demand Forecasting

With the forecasting function of Ergon Energy and Energex merging work will continue developing common tools, techniques and processes to support the production of accurate and reliable forecasts. These forecasts include energy, peak demand, load customers, EV's, solar PV and other network parameters at various points within the electrical distribution, subtransmission and transmission network. Forecasts are developed with consideration of the impact of emerging technologies and demographic, economic and regulatory factors and community expectations. Forecast outcomes are then used for the determination of an optimised network capital program of work, determination of network capacity limitations, determination of contingency plans, determination of network pricing and Regulatory submissions.

5.12.2 Substation Analysis Methodology Assumptions

Bulk and zone substation analysis is a build-up of multiple pieces of data. Much of the analysis is specified in Section 5.2.2 and also takes into account Ergon Energy's Plant Rating Guidelines. Ergon Energy has a program of assessing plant rating capabilities within substations, with a focus on critical substation assets.

Further analysis is also conducted, as discussed in Section 5.4.2, around the Safety Net compliance of a substation. This analysis involves evaluation to determine whether efficient investments under the Safety Net provisions will provide mitigation for credible contingencies that could otherwise result in outages longer than the Safety Net targets.

These assessments, deterministic ratings and data collection provides the input data required for Ergon Energy's SIFT. The SIFT tool utilises the data from the forecast coupled with this rating data to provide an overview of a substation's limitation.

5.12.3 Subtransmission Feeder Analysis Methodology Assumptions

The subtransmission feeder methodology approach takes the substation maximum demand forecasts and the daily load profiles of each individual substation to produce a forecast half hour load profile for the maximum demand day at that substation. This is produced for each substation in the network and a series of load flows are then performed for each half hour period of the day using these loadings. The forecast feeder load for each period is the maximum current experienced by the feeder in any half hour interval during that period. These forecast load flows are then compared against the feeder ratings resulting from ratings methodology detailed in Section 5.7. The outcome of this methodology, as per the planning process discussed in Section 5.2, could be the creation of a project, data verification or load transfers. In these cases, these outcomes would be transferred to future forecasts and load flows.

5.12.4 Distribution Feeder Analysis Methodology Assumptions

Methodology and assumptions used for calculating the distribution feeder constraints are as follows:

- The previous maximum demands are determined from the historical metering/SCADA data for each feeder. These maximum demands are filtered to remove any temporary switching events
- The future forecast demands for each feeder are then calculated based on the historical and current customer growth rate and other localised factor
- The worst utilisation period (summer day, summer night, winter day or winter night) are calculated by dividing the period maximum demand by the period rating. This is the determining period which will trigger an exceedance
- The period rating is determined from the underground exit cable and first section of overhead line capacities only
- The maximum utilisation is forecast out two years. The year and season (i.e. summer or winter) is recorded where the maximum utilisation exceeded either (see Appendix E and Appendix F):
  - The three into four/75% nominal distribution feeder security criteria for urban planning area designated feeders (sufficient interties between feeders); or
  - The 90% criteria for rural planning area designated feeders (sparse or no interties between feeders)

  Note: the above criteria are only applied at a planning level, which in turn triggers further detailed analysis based on a number of factors. Not all breaches of these criteria will trigger augmentation.
- The amount of exceedance of the relevant planning utilisation level is calculated after the two forecast years (in MVA), and the amount of MW required to reduce the feeder below the required planning utilisation level is calculated (with an assumed power factor of 0.9).

We also analyse ‘downstream’ constraints using load flow analysis, however these studies are done on a case by case basis and are therefore not included in this methodology. Similarly, constraints on SWER and LV systems are also excluded.

Chapter 6

Network Limitations and Recommended Solutions

6. Network Limitations and Recommended Solutions

6.1 Network Limitations – Adequacy, Security and Asset Condition

There are no limitations identified on the transmission-distribution connection points with the TNSPs covering the forward planning period. Ergon Energy conducts joint planning with TNSPs as described in Section 5.10. Limitations affecting either network will be investigated jointly and follow the RIT-T or RIT D process to ensure prudent solutions are adopted.

Table 13 summarises the identified limitations across the Ergon Energy network for the DAPR period for which projects have been raised. Similarly, all files can also be downloaded directly from the Ergon Energy website.[30]

6.1.1 Bulk and Zone Substation Capacity Limitations

For each bulk and zone substation, a separate summary forecast of load, capacity and limitations has been produced for summer and winter based on the Customer Outcome Standard. These results are contained in Appendix E. Appendix D outlines the network limitations that have been identified through this process.

6.1.2 Transmission, Subtransmission and Distribution Feeder Capacity Limitations

For each transmission, subtransmission feeder and distribution feeder, a separate summary forecast of load, capacity and available load transfers for summer and winter has also been produced, and the results are also contained in Appendix E. Feeder limitations are identified using the simulation models and processes as described in section 4.4.2 and section 5.12.3. The outcome of this analysis would then potentially trigger the creation of new strategic projects which indirectly may or may not trigger an update of the forecast and re-run of the models.

For the distribution network, 59 feeders have been identified with constraints contributing to a load exceedance after two years. Further details for Ergon Energy's feeders can be found in Appendix D and Appendix E.

6.1.3 Asset Condition Limitations

Ergon has a range of project based planned asset retirements which will result in a system limitation. These retirements are based on the Asset Management Plans outlined in Section 2.4. These projects can be also found in Appendix D.

6.1.4 Fault Level Limitations

Ergon performs fault level analysis for it network assets. Where fault levels are forecast to exceed the allowable fault level limits, then fault level mitigation projects are initiated.

[30] Website: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report

Table 13: Summary of Substation and Feeder Limitations

Asset Type		Limitation Type		
		Capacity and Reliability	Asset Condition	Fault Level
Limitations with Proposed & Committed Solutions	Bulk Substation	0	1	0
	Zone Substation	4	21	0
	Sub-transmission Feeder	4	1	0
	Distribution Feeder	13	0	2

6.2 Summary of Emerging Network Limitations

Appendix D provides a summary of proposed committed work in the forward planning period and highlights the upcoming limitations for each bulk supply, zone substation, transmission feeder, subtransmission and distribution feeders. Potential credible solutions are provided for limitations with no committed works.

6.3 Network Asset Retirements and De-Ratings

Ergon Energy has a range of Project and Program based planned asset retirements which, if not addressed, will result in a system limitation. These retirements are based on the Asset Management Plans outlined in Section 2.4 Asset Management Overview. Some of these needs may be addressed by options that are yet to be determined and which could trigger the requirement to undertake a RIT-D assessment. A listing of planned projects is available from the link below and summarises ongoing planned Programs involving Distribution Line assets for the forward planning period i.e. until 2024/25.

6.4 Regulatory Investment Test Projects

6.4.1 Regulatory Investment Test Projects - In Progress

This section describes the RIT-Ds that were commenced in 2019-20 and includes several replacement driven projects that now require RIT-D assessment, as specified in the National Electricity Amendment published by the AER on 18th July 2017. Estimated total costs are provided in real 2019-20 dollars and are inclusive of overheads.

Table 14: Regulatory Test Investments - In Progress

Project Need, Credible Options and Conclusion	Preferred Option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Addressing Customer Demand Requirement in Western Grid/Barcaldine	$5.4M	Qtr 4 - 2023	Nil impact beyond regulated revenue.
Reliability and Capacity Reinforcement for the Cloncurry supply area	$7.9M	Qtr 4 - 2023	Nil impact beyond regulated revenue.
Reliable Provision of Electricity to the East Bundaberg area	$8.2M	Qtr 1 - 2024	Nil impact beyond regulated revenue.
Reliable Provision of Electricity to the Maryborough Supply area	$6.5M	Qtr 4 - 2025	Nil impact beyond regulated revenue.
Reliable Provision of Electricity to the Pialba (Hervey Bay) area	$8.7M	Qtr 3 - 2024	Nil impact beyond regulated revenue.
Pittsworth Regional Reinforcement	$6.9M	Qtr 3 - 2021	Nil impact beyond regulated revenue.
Reliable Provision of Electricity to Point Vernon (Hervey Bay) area	$15.8M	Qtr 2 - 2024	Nil impact beyond regulated revenue.

Note: All project costings in the table above are procured from publications from the Ergon Energy RiT-D website.

Further information on current augmentation and replacement RIT-D consultations is available in Appendix I or alternatively on the Ergon Energy RiT-D website.[31]

[31] Website: https://www.ergon.com.au/network/our-services/projects-and-maintenance/rit-d-projects

6.4.2 Regulatory Investment Test Projects - Completed

This section describes the RIT-Ds that were completed in 2019-20. Estimated costs are provided in real 2019-20 dollars and are inclusive of overheads.

Table 15: Regulatory Test Investments - Completed

Project	Preferred Option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Addressing reliability requirements in the Cannonvale network area	$23.6M	Qtr 4 - 2023	Nil impact beyond regulated revenue.
Addressing Reliability Requirement in the Cape River Network Area	$8.8M	Qtr 4 - 2024	Nil impact beyond regulated revenue.
Ensuring Reliability of Electricity Supply and Managing Network Asset Risks in the Douglas Shire Area	$27.2M	Qtr 1 - 2023	Nil impact beyond regulated revenue.
Addressing Reliability Requirements in the Garbutt Network area	$30.9M	Qtr 4 - 2023	Nil impact beyond regulated revenue.
Emerging Distribution Network Limitations in the Gracemere Area	$23.4M	Qtr 2 - 2022	Nil impact beyond regulated revenue.
Reliable Provision of Electricity to the Kilkivan Supply Area	$14.1M	Qtr 3 - 2023	Nil impact beyond regulated revenue.
Reliability and Capacity Reinforcement for the North Toowoomba Network	$9.5M	Qtr 2 - 2027	Nil impact beyond regulated revenue.
Addressing Reliability Requirements in the Planella Network area	$5.0M	Qtr 3 - 2023	Nil impact beyond regulated revenue.
Reliability of Electrical Supply and Network Asset Risk Management in the Wide Bay Burnett Area	$63M	Qtr 1 - 2024	Nil impact beyond regulated revenue.

Note: All project costings in the table above are procured from publications from the Ergon Energy RiT-D website.

Further information on current augmentation and replacement RIT-D consultations is available in Appendix I or alternatively on the Ergon Energy RiT-D website. [32]

[32] Website: https://www.ergon.com.au/network/our-services/projects-and-maintenance/rit-d-projects

6.4.3 Foreseeable RIT-D Projects

This section describes the augmentation and replacement driven projects for which a RIT-D assessment is expected to be initiated in the forward planning period for the next five years.

On 20th November 2018 the AER published a final determination of the 2018 cost threshold review. The AER's final determination for the distribution thresholds is that:

- The $5 million capital cost threshold referred to in NER clause 5.15.3(d)(1) be increased to $6 million. This is the cost threshold over which a RIT-D applies.

The revised cost thresholds will take effect on 1st January 2019.

The following table identifies those projects, addressing long term constraints, for which Ergon Energy has determined will potentially require a RIT-D assessment.

Table 16: Foreseeable RIT-D Projects to address long term constraints (>$6M)

Region	Driver	Projects	Expected Investment Test Commencement (Month-Year)	Expected Completion (Month-Year)
Northern	Asset Condition	Turkinje Reliable Provision of Electricity to the Atherton Tablelands supply area	Qtr 4 – 2020	Qtr 2 - 2029
Northern	Load Growth	Pleystowe Addressing Reliability in the Pleystowe Network Area	Qtr 4 – 2020	Qtr 1 - 2029
Southern	Asset Condition	Rockhampton South Reliable Provision of Electricity to the South Rockhampton supply area	Qtr 1 – 2021	Qtr 4 – 2025
Southern	Asset Condition	Biloela Reliable Provision of Electricity to the Biloela supply area	Qtr 1 – 2023	Qtr 1 - 2027
Southern	Asset Condition	Blackwater Reliable Provision of Electricity to the Blackwater supply area	TBA	Qtr 2 - 2024
Southern	Load Growth	Kingaroy Reliable Provision of Electricity to the Kingaroy supply area	TBA	Qtr 1 - 2024

Note: All project costings and milestones mentioned in the table above are procured from publications and financial reports as of October 2020.

6.4.4 Urgent and Unforeseen Projects

During the year, there have been no urgent or unforeseen investments by Ergon Energy that would trigger the RIT-D exclusion conditions for the application of regulatory investment testing.

6.5 Emerging Network Limitation Maps

This section covers the requirements outlined in the NER under Schedule 5.8 (n), which includes providing maps of the distribution network, and maps of forecasted emerging network limitations. The extent of information shown on maps, using graphical formats, has been prepared to balance adequate viewing resolution against the number or incidences of maps that must be reported. In addition to system-wide maps, limiting network maps are broken up into groupings by voltage. For confidentiality purposes, where third party connections are directly involved, the connecting network is not shown.

This information is provided to assist parties to identify elements of the network using geographical representation. Importantly, this does not show how the network is operated electrically. More importantly, this information should not be used beyond its intended purpose.

Following feedback from customers, interactive maps[35] are available on the Ergon Energy website.[36]

The maps provide an overview of the Ergon Energy network, including:

- Existing 132kV, 110kV, 66kV and 33kV feeders
- Existing bulk supply and zone substations
- Existing transmission connection points
- Existing 132kV, 110kV, 66kV and 33kV feeders with identified Safety Net / security standard limitations within the five-year forward planning period
- Existing bulk supply and zone substations with identified Safety Net / security standard limitations within the five-year forward planning period
- Existing distribution feeders or feeder meshes
- Existing distribution feeders or feeder meshes with forecast limitations within the next two years of the forward planning period
- Micro Embedded Generation Unit penetration percentage
- Planning regions.

[35] Website: https://www.ergon.com.au/daprmap2020

[36] Website: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report

Chapter 7

Demand Management Activities

7. Demand Management Activities

Demand Management (DM) is part of our suite of solutions for network management which may be used instead of or in conjunction with investments in network infrastructure, to ensure an optimised investment outcome.

7.1 What is Demand Management?

In the context of electricity networks DM is the act of modifying demand and/or electricity consumption, for the purpose reducing or delaying network expenditure (i.e. removing or delaying an underlying network constraint). This definition recognises that DM need not be specific to removing networks constraints only at times of peak demand. Rather that network support opportunities also include retirement or replacement of an aging asset; redundancy support during equipment failure; minimum demand and associated issues with voltage, system frequency and power quality management; managing diverse power flows and system security issues. In response to growing DER in the network, DM must evolve to include management of these customer assets to optimise end-to-end investment.

DM can also be particularly valuable when there is uncertainty in demand growth forecasts, as DM does not lock in long-term irreversible investment. In these situations, DM can provide considerable 'option value' and flexibility.

DM solutions are also known as non-network solutions as they provide an alternative to network-based solutions. In the Energex and Ergon Energy context, DM involves working with our customers and DM providers to modify demand and/or energy consumption to reduce operational costs or be an alternative to capital expenditure. The more capital expenditure that can be deferred or avoided, the greater the savings to our customers.

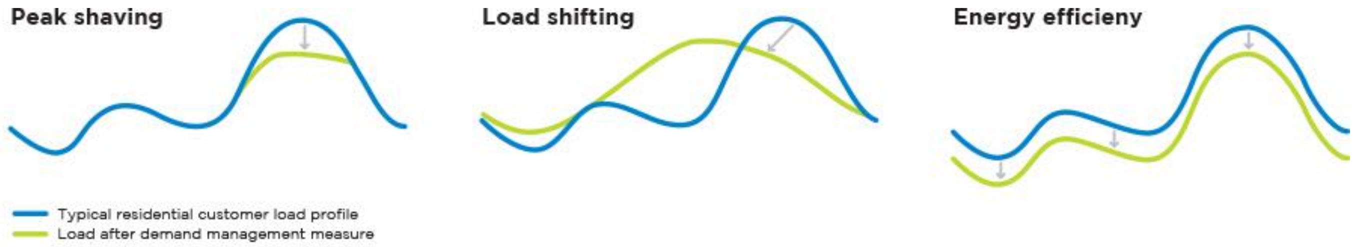
DM must be deployed to match the temporal (i.e. how often and what duration) and spatial (i.e. what level of the network and how many customers are affected) nature of the network constraint. As more DER is connected to our network, the temporal and spatial nature of network constraints will change. As such, our DM capability will need to adapt to suit these new and emerging network constraints.

There are three major DM approaches as outlined in the Table 17 and Figure 11.

Table 17: Demand Management Approaches

DM Approach	Description	Type of DM
Peak shaving	Reducing peak period (e.g. using onsite generation)	Demand response
Load shifting	Shifting demand to other time of the day when networks are less constrained (e.g. load control tariffs). Load shifting can be used to manage peak demand and minimum demand.	Demand Response
Energy efficiency	Use less electricity to perform the same task.	Energy efficiency

Figure 11: Demand Management Approaches



7.2 How is Demand Management Integrated into the Planning Process?

The planning process, as outlined in Chapter 5: Network Planning Framework and the following sections, includes the identification of network constraints and the assessment of DM solutions (refer to Figure 12 and Figure 13). When a network constraint is identified, a screen of non-network options is completed to determine if DM solutions offer credible options. Where a screening test finds that a non-network option may provide an efficient alternative solution (by partially or fully addressing the constraint), market engagement and investigation of possible DM solutions is initiated.

'In market' engagement activity depends upon forecast expenditure, size and timing of the constraint. Where total capital expenditure of the most expensive credible option is greater than $6 million, a RIT-D is undertaken (refer to Figure 13). For the list of projects that required a RIT-D assessment over the last year refer to Chapter 6: Network Limitations and Recommended Solutions and RIT-D consultation information available on the Ergon Energy website[37] forecast capital expenditure for the most credible option is less than $6 million, opportunities for credible non-network solutions are developed by gauging interest and ability of service providers and customers to participate. This can be done publishing network constraints (Target Areas) online using incentive maps or inviting proponents to respond to a Request for Proposal (RFP). Refer to section 7.4.2 and our Target Area maps[38] which provide online information on the network constraint and DM solution required for these areas.

Where a non-network solution is selected, a contract is established with the customer to provide permanent (energy efficiency) or point in time (when required) demand response. Measurement and verification are undertaken to determine the response achieved. The verified change in demand becomes an input into the forecast and the planning process.

[37] Website: https://www.ergon.com.au/network/our-services/projects-and-maintenance/rit-d-projects

[38] Website: https://www.ergon.com.au/network/manage-your-energy/incentives/search-incentives

Figure 12: Non-Network Assessment Process for expenditure >$6M (RIT-D)

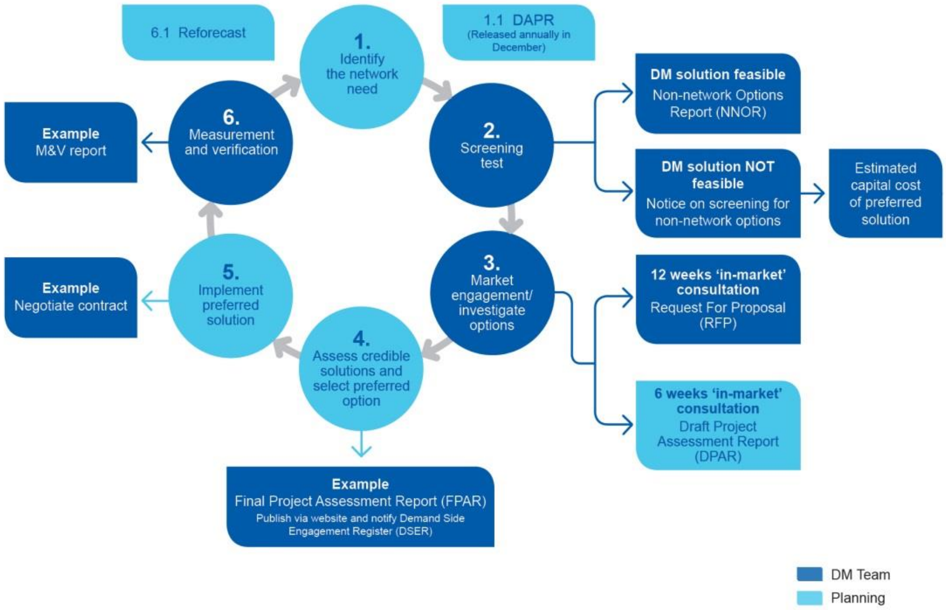
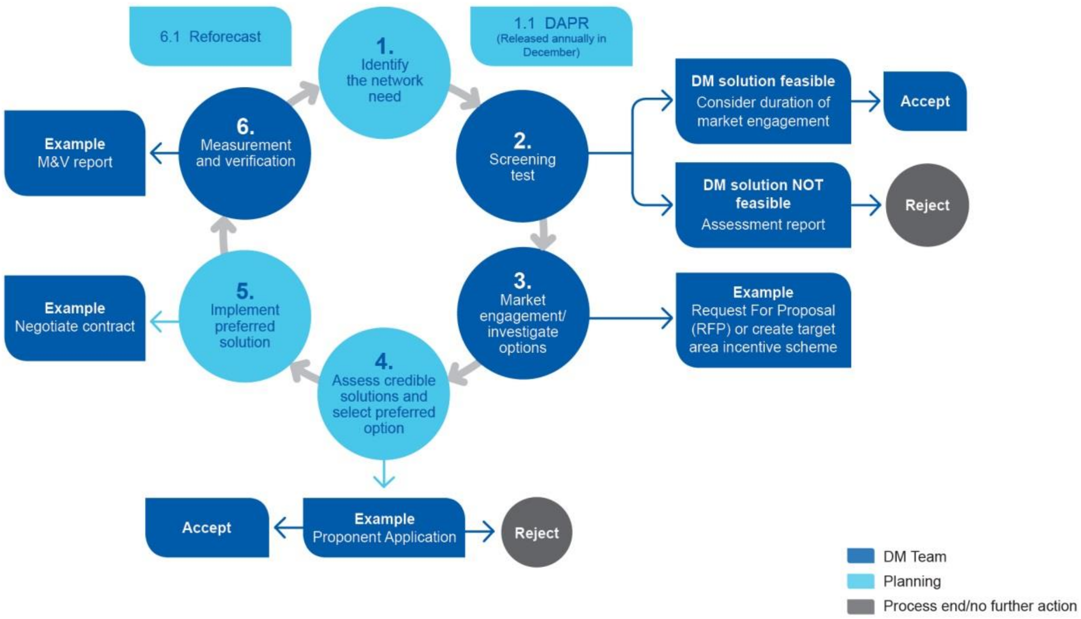


Figure 13: Non-Network Assessment Process for expenditure <$6M



7.3 Ergon Energy's Demand Side Engagement Strategy

The Ergon Energy Demand Side Engagement Strategy (DSES) communicates how Ergon Energy engages with customers and non-network providers on the supply of credible demand side solutions to address system constraints and lower costs for customers in the network distribution areas. The DSES remains our commitment to:

- Embed demand side engagement and non-network screening of network constraints into the distribution planning process
- Identify and transparently provide details of Ergon Energy's network constraints to customers and non-network service providers in consistent, simple and easy to understand terminology
- Identify and incentivise non-network solutions for broad based and targeted areas, engaging stakeholders and third party providers, as outlined in the Ergon Energy Demand Management Plan
- Provide adequate time, support and mechanisms for stakeholders to engage, respond and participate in non-network solutions, and
- Deliver and report non-network solutions that prevent, reduce or delay the need for network investment.

A copy of the DSES can be found on our website.[39]

7.4 What has the Ergon Energy DM Program delivered over the last year?

Four key initiatives were delivered by the DM Program in 2019-20:

- Broad based
- Targeted
- DM Development, and
- DM innovation.

7.4.1 Broad Based Demand Management

This initiative is available to residential and small business customers across the whole network. Demand reductions can occur across the whole network, rather than just in a local area with a network constraint. Broad based DM delivers direct control of loads during periods of extreme demand or emergency response. This capability is called up through our Summer Preparedness Plan (refer to Section 9.3.2) to minimise interruptions during summer season extreme weather conditions.

Incentives are provided to customers who enrol their PeakSmart air conditioners or connect their appliances to load control tariffs. Incentives are also given to industry partners who install PeakSmart enabled air conditioners. For more information on PeakSmart visit our website.[40]

[39] Website: https://www.ergon.com.au/__data/assets/pdf_file/0020/1005725/Demand-Side-Engagement-Strategy.pdf
[40] Website: https://www.ergon.com.au/network/manage-your-energy/reward-programs/peaksmart-air-conditioning

7.4.2 Targeted Demand Management

This initiative is available to customers and DM providers who can deliver DM solutions in specific areas of the network identified as having future network constraints (refer to Sections 6.2 and Appendix D Network Limitations and Mitigation Strategies). Market engagement is undertaken to seek DM solutions from customers and DM providers. Incentives are provided to customers or DM providers to provide DM solutions.

In 2019-20, 'in market' engagement for DM solutions continued in eight Target Areas across the region. Our Target Area maps[41] provide an online information on the network constraint and DM solution required for these areas. Verified customer and service provider DM solutions in these areas, which met technical, time and cost requirements, were incentivised to deliver demand reductions. In addition, seven embedded generation contracts were maintained to provide non-network solutions during the 2019-20 year.

7.4.3 Demand Management Development

This initiative drives continuous improvement of existing initiatives and enabling future DM capability. This included promoting DM through:

- Inputting and being involved in a range of market and industry consultations, forums and development of standards, and will continue to support the long-term development of demand management capabilities;
- Continuing to influence DM related standards and policies. One of the standards integral to the Ergon Energy DM is the suite of AS/NZS 4755 standards, which outline demand response capabilities for residential appliances. Work is close to completion with Standards Australia on a new standard AS 4755.2 which will cover "demand response systems" that do not require the individual physical elements defined in AS/NZS 4755.1. It is expected that this Standard will increase adoption of standardised demand response by appliance manufacturers, aggregators and networks. This will enable further innovation and software solutions for demand response of appliances
- Embarking on activities to transform the Fringe of Grid. This activity involves identification of high cost to serve network areas in Western Queensland and seeking non-traditional solutions, transition strategies and business models to enable customers' access to a safe, secure, affordable, reliable and efficient electricity supply;
- Supporting tariff reform by informing customers of associated DM opportunities. This will allow customers to make more efficient decisions about their energy investments and energy use, leading to better utilisation of the network; and
- Partnering with the agricultural industry groups and irrigation customers to trial the use of a small customer load control tariff. Given the success of the trial, three new network load control tariffs were developed, applying to both small and large customers, were approved for implementation from 1 July 2020.

[41] Website: https://www.ergon.com.au/network/manage-your-energy/incentives/search-incentives

7.4.4 Demand Management Innovation

The initiative supports future energy choices and DM capabilities that reduce long term network costs. A suite of innovative trials and projects to test and validate DM products and processes are funded via Demand Management Innovation Allowance Mechanism (DMIAM). These trials and projects are often started in response to emerging network challenges and opportunities (refer to Chapter 11).

A DMIAM annual report[42] is developed each year that summarises current and completed projects.

7.5 What will the Ergon Energy DM Program deliver over the next year?

Annually, Ergon Energy publishes a Demand Management Plan which includes our strategy for the next five years. Our strategy is to:

- Ensure efficient investment decision making
- Incentivise customer efficiency
- Active customer response enablers
- Manage two-way energy flows
- Transform supply at the fringe of grid
- Invest in innovation.

This plan explains our approach for delivering the Demand Management Program for Queensland and represents the initiatives and activities for the next financial year including the promotion of non-network solutions. A copy of our Demand Management Plan 2020-21[43] is available for review.

As part of our initiative to drive continuous improvement of existing initiatives and enabling future DM capability, the DM Program will support the uptake of new tariffs, as outlined in the 2020-25 Tariff Structure Statement.[44] A key action for 2020-21 will be the commencement of capacity tariff research.

Capacity tariffs will be explored and trials developed as part of a range of solutions to address the network challenges associated with the integration of large amounts of Distributed Energy Resources (DER) into the network. An example of a capacity tariff is one that has fixed charge, a capacity charge based on agreed use of the network, and a volume charge.

During this year, research and development of capacity tariff options will be undertaken, taking into account network requirements and customer impacts. Following appropriate stakeholder engagement and consultation, a field trial is expected to be designed to assess market response to capacity tariffs in Queensland, from both network and key stakeholders (i.e. Retailer and customer) perspective.

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[42] Website: https://www.ergon.com.au/network/manage-your-energy/managing-electricity-demand/demand-management-innovation-allowance

[43] Website: https://www.ergon.com.au/network/manage-your-energy/managing-electricity-demand/demand-management-plan

[44] Website: https://www.ergon.com.au/network/our-network/network-pricing-and-tariffs

Further information on our DM program and the promotion non-network options are detailed on our website.[45]

7.6 Key Issues Arising from Embedded Generation Applications

In several substation locations Ergon Energy is managing multiple enquiries seeking to connect large scale embedded generation in the same area of the network at a similar time. The complex network impacts are made more challenging by the speculative nature of these enquires. Further, we are obliged to keep customer information confidential which can result in issues around disclosure to customers with competing enquiries.

Network information and analysis provided to customers enquiring on the feasibility of an EG (Embedded Generation) project is based on the configuration of the network at the time of the response. However, the technical assessments and reports may need to be reviewed and recalculated once any one of the customers' projects becomes committed.

Ergon Energy's current approach is to work with generation proponents to manage this complex issue. We alert generation proponents to the risks and formally advise if another project has become committed and to encourage customers to seek a review of any technical assessments or reports already received in this instance.

Table 18: Embedded Generation Enquiries

Connection Enquiries	Numbers for 2019/20
Embedded Generator (EG) Connection Enquiries – Micro EG 30 kW or less	Not applicable
Embedded Generator Connection Enquiries >30 kW Low Voltage	No enquiries
Embedded Generator Connection Enquiries >30 kW High Voltage	59

Applications to Connect Received

In 2019/20 the number of applications to connect is shown in Table 19.

Table 19: Embedded Generation Applications

Connection Applications	Numbers for 2019/20
Embedded Generator Connection Applications – Micro EG 30 kW or less	20,867
Embedded Generator Connection Applications >30 kW Low Voltage	278
Embedded Generator Connection Applications >30 kW High Voltage	11

[45] Website: https://www.ergon.com.au/network/manage-your-energy/managing-electricity-demand

Average Time to Complete Connection

In 2019/20 the number of applications received and connected took an average time to complete as shown in Table 20.

Table 20: Embedded Generation Applications – Average Time to Complete (Business Days)

Connection Applications	Average time to complete 2019/20 (Business Days)
Embedded Generator Connection Applications – Micro EG 30 kW or less	37.9
Embedded Generator Connection Applications >30 kW Low Voltage	180
Embedded Generator Connection Applications >30 kW High Voltage	552*

*Includes negotiations with major customers involving complicated or large-scale design and protection studies as well as encompassing projects such as wind or solar farms.

Chapter 8

Asset Life-Cycle Management

8. Asset Life-Cycle Management

8.1 Approach

Ergon Energy has a legislated Duty to ensure all staff, the Queensland community and its customers are electrically safe. This Duty extends to eliminating safety risks based on “so far as is reasonably practical” principle. If elimination of safety risk is not practical, our responsibility is to mitigate risks based on the same principle.

Ergon Energy’s approach to asset life-cycle management, including asset inspection, maintenance, refurbishment and renewal, integrates several key objectives, including

1. Achieving its legislated safety Duty
2. Delivering customer services and network performances to meet the required standards and
3. Maintaining an efficient and sustainable cost structure.

Policies are used to provide corporate direction and guidance, and plans are prepared to provide a safe, reliable distribution network that delivers a quality of supply to customers consistent with legislative compliance requirements and optimum asset life. These policies and plans cover equipment installed in substations, the various components of overhead powerlines, underground cables and other distribution equipment.

The policies and plans define inspection and maintenance requirements, and refurbishment and renewal strategies for each type of network asset. Asset life optimisation takes into consideration maintenance and replacement costs, equipment degradation and failure modes, as well as safety, customer, environmental, operational and economic consequences.

All assets have the potential to fail in service. Ergon Energy’s approach to managing the risk of asset failures is consistent with regulatory requirements including the Electricity Act 1994 (Qld), Electrical Safety Regulation 2002 and the Electricity Safety Code of Practice 2010 – Works and good asset management practice. We distinguish between the expenditure for:

- Inspection and preventative maintenance works, where each asset is periodically assessed for condition, and essential maintenance is performed to ensure each asset continues to perform its intended function and service throughout its expected life
- Proactive refurbishment and replacement, where the objective is to renew assets just before they fail in service by predicting assets’ end-of-life based on condition and risk, and
- Run-to-failure refurbishment and replacement, which includes replacing assets that have failed in service.

A proactive approach is undertaken typically for high-cost, discrete assets, such as substation plant, where Ergon Energy records plant information history and condition data. This information is used to adjust maintenance plans and schedules, initiate life extension works if possible, and predict the remaining economic life of each asset. Proactive replacement or refurbishment is then scheduled as near to the predicted end of economic life as practical. This approach is considered the most prudent and efficient approach to achieve all required safety, quality, reliability and environmental performance outcomes, having regard for the whole-of-life equipment cost. The consequence of failure impacts the priority for replacement of the asset in the overall works program.

Low-cost assets, where it is not economic to collect and analyse trends in condition data, are operated to near-run-to-failure with minimal or no intervention. These assets are managed through an inspection regime, which is also required under legislation. The objective of this regime is to identify and replace assets that are very likely to fail before their next scheduled inspection. In addition, asset class collective failure performance is assessed and analysed regularly, with adverse trends and increasing risk issues becoming drivers for targeted maintenance, refurbishment or replacement programs.

Actual asset failures are addressed by a number of approaches depending on the nature of the equipment, identified failure modes and assessed risk. The approaches include on-condition component replacement, bulk replacement to mitigate similar circumstances, risk based refurbishment/replacement and run to failure strategies.

All inspection, maintenance, refurbishment and renewal work programs are monitored, individually and collectively, to ensure the intended works are performed in a timely, safe and cost effective fashion. These outcomes feed back into asset strategies to support prudent and targeted continuous improvement in life cycle performance overall.

8.2 Preventative Works

Ergon Energy manages safety and service compliance requirements via various preventative inspection and minor maintenance programs. These are collectively described below.

8.2.1 Asset Inspections and Condition Based Maintenance

Ergon Energy generally employs condition and risk-based asset inspection, maintenance, refurbishment and replacement strategies in line with its asset management policies and strategies. End-of-economic-life replacement and life-extension refurbishment decisions are informed by risk assessments considering safety, history, performance, cost, and other business delivery factors.

All equipment is inspected at scheduled intervals to detect physical indications of degradation exceeding thresholds that are predictive of a near-future failure. Typical examples of inspection and condition monitoring activities include:

- Analysis of power transformer oil to monitor for trace gases produced by internal faults
- Inspection of customer service lines
- Assessing the extent of decay in wood power poles to determine residual strength
- Inspection of timber cross-arms to detect visible signs of degradation, and
- Electrical testing of circuit breakers.

In particular, Ergon Energy has a well-established asset inspection program to meet regulatory requirements. All assets are inspected in rolling period inspection programs.

Remedial actions identified during inspections are managed using a risk assessed priority code approach. Pole assets, for example, employ a Priority 1 (P1) coding which requires rectification within thirty (30) days and Priority 2 (P2) unserviceable poles require rectification within six months. This ensures the required actions are completed within the recommended regulatory standards.

Consistent with the principles of ISO 55000 Asset Management, Ergon Energy is building its capability with an ongoing investment into technologies that deliver improvement in risk outcomes and efficiency. These efforts include utilising Lidar data from the aerial asset and vegetation monitoring management technology. This aircraft-based laser and imaging capture system provides spatial mapping of the entire overhead line network. The data captured is processed to enable identification and measurement of the network and surrounding objects such as buildings, terrain and vegetation. The system creates a virtual version of the real world to allow the fast and accurate inspection and assessment of the physical network and the surrounding environment, particularly vegetation. The integration of this information into our decision framework and works planning processes is increasingly delivering productivity and efficiency improvements, not only with vegetation management but with other network analytics such as clearance to ground analysis, clearance to structure analysis, pole movement and leaning poles analysis with other innovative identification systems being developed.

8.2.2 Asset Condition Management

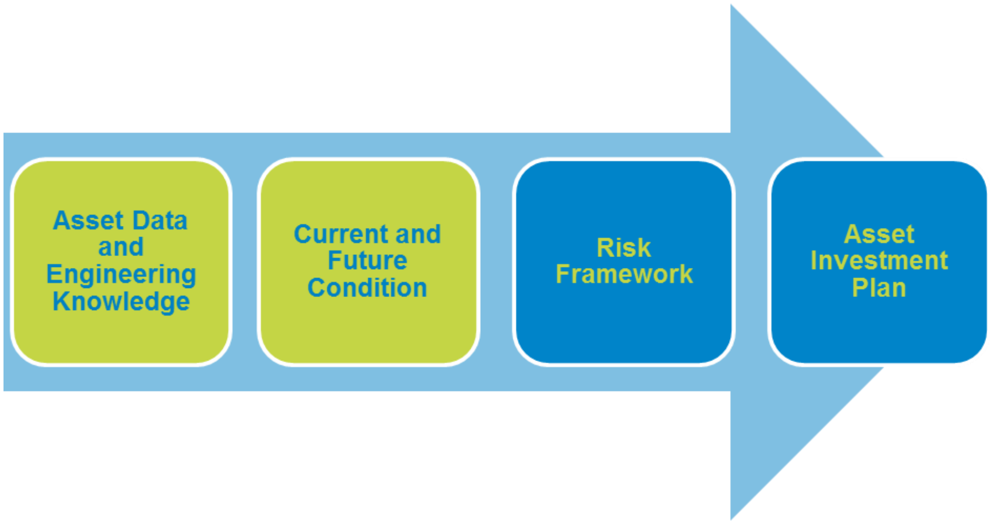
The processes for inspection and routine maintenance of Ergon Energy's assets are well established and constantly reviewed. Ergon Energy uses its asset management system to record and analyse asset condition data collected as a part of these programs. Formal risk assessments are conducted for all asset classes, identifying failure modes and consequences, as well as suitable mitigation measures. The results of these programs are regularly monitored, with inspection, maintenance, refurbishment and renewal strategies evolving accordingly. These strategies in turn are used to inform forecast expenditure.

Ergon Energy employs EA Technology's Condition Based Risk Management (CBRM) modelling methodology for high value assets where the effort required to develop, maintain and collect the information required to support the models is justified. This methodology combines current asset condition information, engineering knowledge and practical experience to predict future asset condition, performance and residual life of assets. The CBRM system supports targeted and prioritised replacement strategies. This technique is currently used for Substation Power Transformers, Circuit Breakers and Instrument Transformers as well as Underground Cables of 33kV and above.

The outputs from CBRM, Health Indices, are used in conjunction with an engineering assessment to form the basis of the application of the risk based methodology. The risk based methodology allows Ergon Energy to rank projects based on their consequence of failure in addition to their probability of failure. The development of the asset investment plan and specific projects are based on the risk score in conjunction with the engineering assessment and optimised to derive the asset investment program.

Figure 14 below provides a summary of the process for delivering network asset investment planning condition based risk management.

Figure 14: Process to Create Asset Investment Plan



Ergon Energy manages the replacement of assets identified for retirement through a combination of specific projects and more general programs.

Projects are undertaken where limitations are identified that are specific to a substation or feeder. Limitations of this nature are considered in conjunction with other network limitations including augmentation and connections to identify opportunities to optimise the scope of the project to address multiple issues and minimise cost. Project planning is undertaken in accordance with the Regulatory Investment Test for Distribution (RIT-D) which considers the ongoing need for the asset to meet network requirements as well alternative solutions to replacement and the impact on system losses where material. Assets without an ongoing need are retired at economic end of life and are not considered for replacement.

Programs of replacement are undertaken when the scope of works to address the identified limitations is recurring across multiple locations and does not require consideration under the RIT-D.

The following sections provide a summary of the replacement methodologies for the various asset classes in the Ergon Energy network.

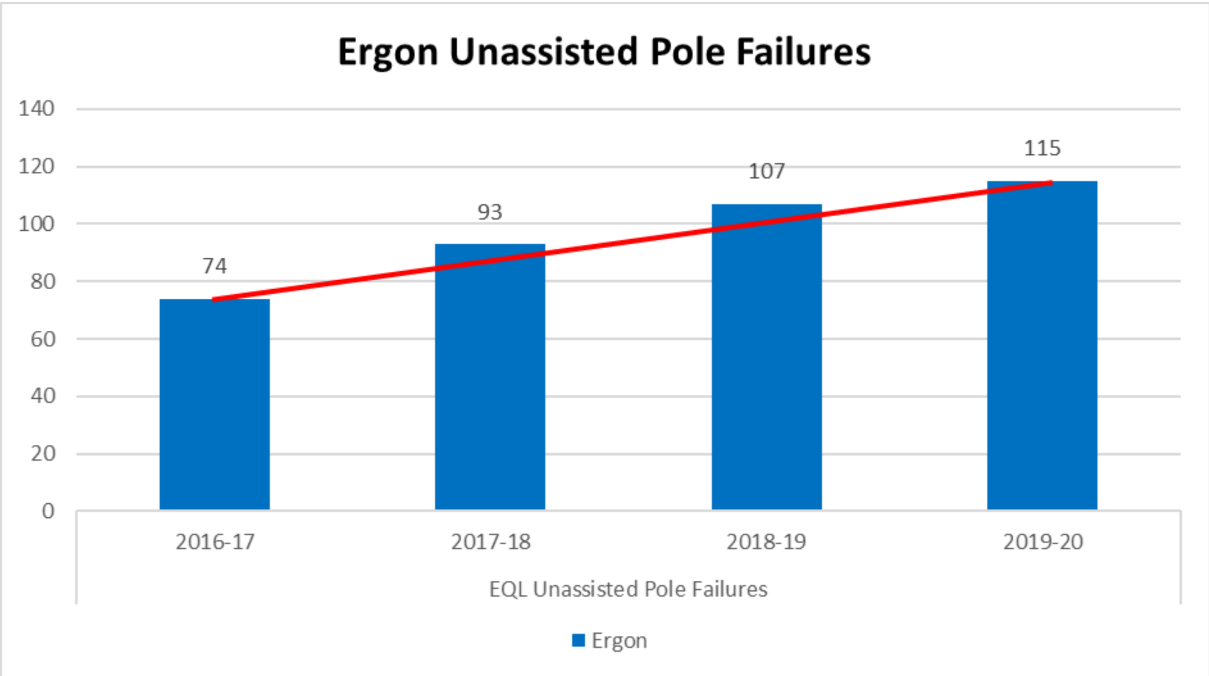
8.3 Line Assets and Distribution Equipment

8.3.1 Pole and Tower Refurbishment and Replacement

Poles and towers are inspected periodically as required by Queensland legislation. Poles require very little maintenance except for removal of vegetation and termite and bacteria barrier treatments, normally carried out during the inspection process. The majority of pole replacement is driven by well-established inspection programs used to identify severe structural strength degradation. Structural strength is determined in accordance with AS 7000.

The chart below shows this trend over the last 4 years.

Figure 15: Ergon Unassisted Pole Failures



Of concern, this has resulted in unassisted pole failure rates for the Ergon Energy network are falling below the industry Code of Practice threshold of 99.99% since late 2019.

Accordingly, to maintain the safety of the network and manage the pole age profile, the combined nailing and replacement volume is forecast to be around 20,000 poles per annum going forward.

A small volume of poles is also replaced when undertaking reconductoring programs as an efficient means of work delivery. Poles replaced under reconductoring programs will be either identified as approaching end of life based on asset criteria or as a result of mechanical design requirements to support the new conductor.

Targeted pole replacement programs make up the smaller remainder of the forecast. This program is estimated based on a combination of criteria that identify assets approaching end of life and that present a high risk in the event of in-service failure. The criteria used are a combination of pole type, age, location, previous strength assessment and/or the period the pole has been nailed. Risk is largely determined by the location with priority being given to replacement in high risk areas such as the vicinity of schools and public amenities.

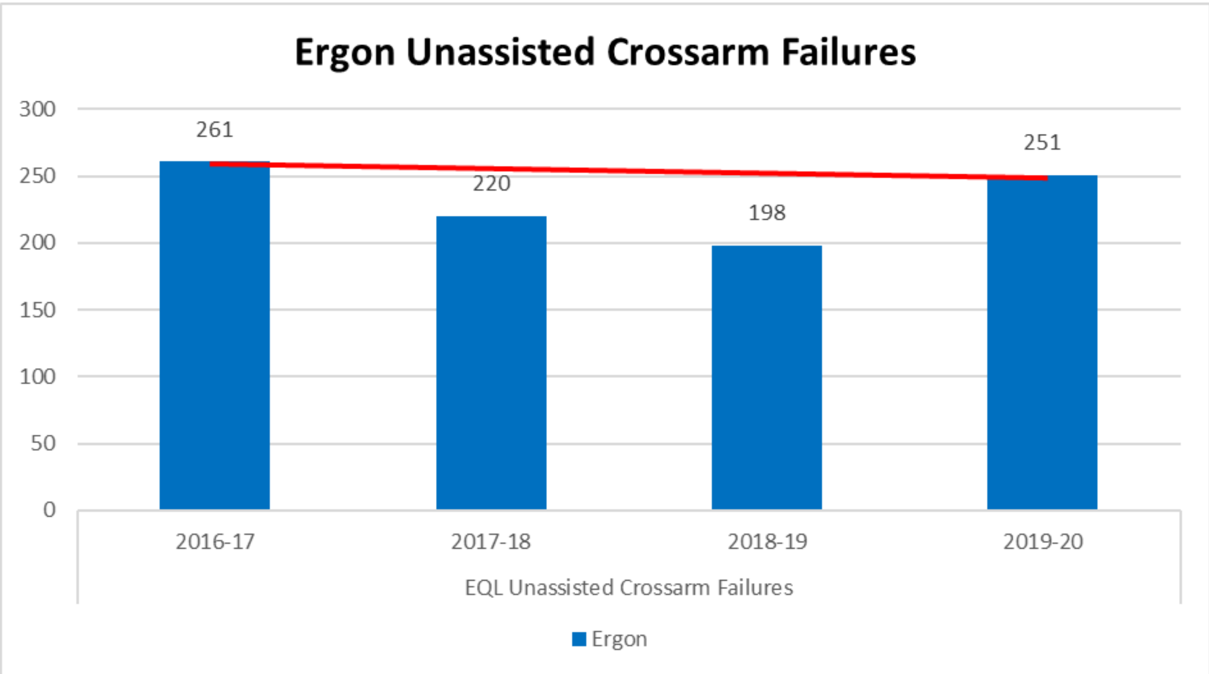
Pole nailing is a mid-life refurbishment method intended to restore ground line structural strength lost due to below-ground bacterial degradation and is applied based upon inspection outcomes. To date, pole nailing achieves an average of 15 years additional asset life. Historical nailing volumes have been used to forecast future staking volumes.

8.3.2 Pole Top Structures Replacement

Pole top structures condition and failure consequence risks (safety, customer reliability, environmental and business) are regularly assessed through asset inspection and defect identification processes. Specific pole top structure replacements are managed as part of the defect replacement programs. Historical volumes have been used to forecast replacement volumes. The defect identification process is subject to continuous process improvement. The unassisted crossarm failure rate has risen again last year. Thus, the overall volume of pole top structure replacement is forecast to increase as a consequence of this and additional crossarm replacement associated with pole and conductor replacement (refer adjacent sections).

The chart below shows the net Ergon Energy Unassisted Crossarm Failure Rate over the last 4 years.

Figure 16: Ergon Unassisted Crossarm Failures



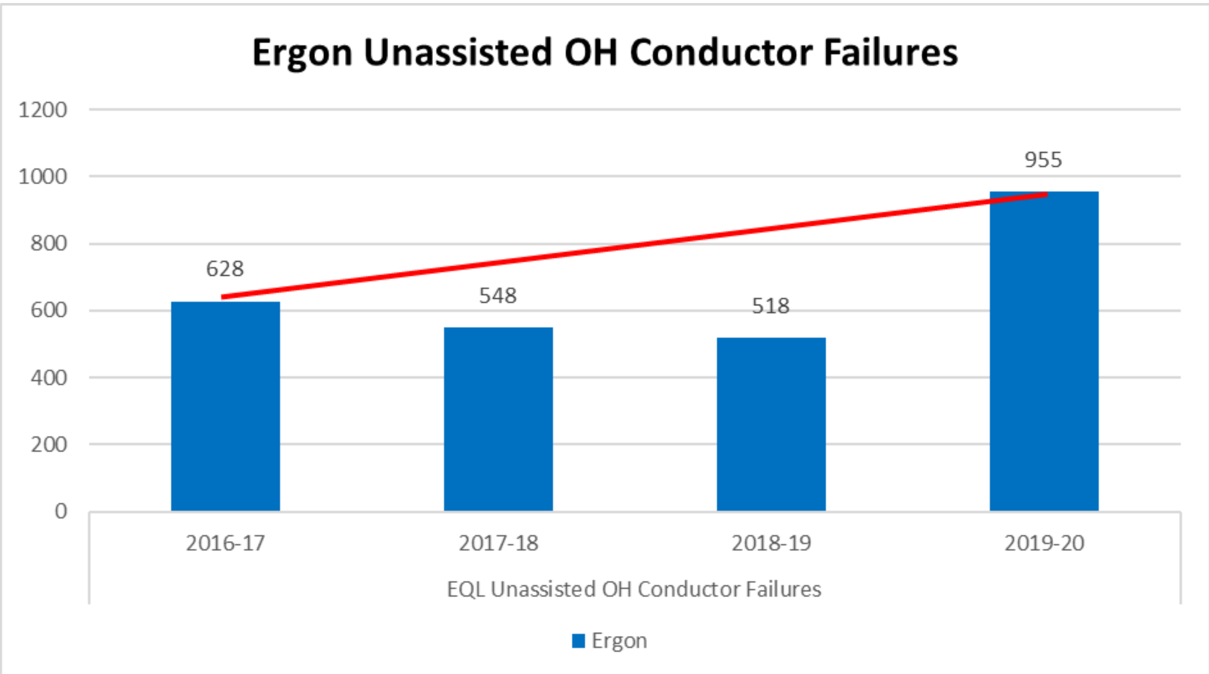
8.3.3 Overhead Conductor Replacement

Overhead conductor condition is difficult to assess in-situ as current visual inspection methods can only identify surface defects. Conductor age, type, construction, environment and in-service performance history are used as proxies for condition. Using this approach, at risk conductor is identified then field assessed by subject matter experts during project scoping to validate the corporate data and assess the asset in service. The number of splices/joints identified in each span is used as an indicator of in-service condition.

3/12 galvanised steel (SC/GZ) and small diameter hard drawn bare copper (HDBC) conductor have been identified and confirmed as prone to failure due to corrosion and mechanical fatigue caused by reduced stranding and cross-sectional area. These populations contribute significantly to the in-service failures and defects observed on the Ergon network. Refer to the Asset Management Plan for a comprehensive breakdown of the installed population, current levels of service and current and emerging technical issues.

Due to the geographically dispersed nature of the network, populations of conductor are subject to different operating environments and failure modes. Targeted programs are therefore aimed at known problematic conductor types and initially focused on those installed in populated, coastal regions where the likelihood of in service asset failure is considered greater. Remaining aged populations are managed through routine inspection programs with ongoing monitoring of conductor failure rates and performance metrics. The chart below shows the unassisted conductor failure trend over the last 4 years.

Figure 17: Ergon Unassisted OH Conductor Failures



More recently, the rolling 12 month number unassisted overhead conductor failures for Ergon Energy's network increased from 518 in June 2019 to 955 in June 2020. In response the overhead conductor replacement program is being accelerated resulting in a higher annual forecast volume during the current regulatory period. Because the network and in particular the conductor is ageing, this trend is only expected to increase over the longer term.

The prioritised scope of HV and LV distribution overhead conductor reconductoring based on known failures and risks includes:

- All remaining hard drawn bare copper 7/0.064" imperial and smaller*
- All coastal hard drawn bare copper <7/0.104" imperial aged 70+
- Coastal galvanised steel 3/12 imperial conductor aged 55+
- Coastal ACSR imperial conductor aged 70+
- Coastal Aluminium imperial conductor aged 70+

*Note: The replacement rate has been set so all small copper will be replaced during the current 5 year regulatory period

8.3.4 Underground Cable Replacement

Ergon Energy employs Condition Based Risk Management (CBRM) to forecast the retirement of underground cables greater than or equal to 33kV. Asset condition and failure consequence risks (safety, customer reliability, environmental and business) are regularly assessed for each cable within this population. This begins with a "Health Index" (HI) developed to represent asset condition. A higher HI value represents a more degraded asset, with corresponding higher likelihood of failure. In turn, this reflects as a higher likelihood of inability to achieve the basic customer energy delivery service. Ergon Energy considers assets for replacement when HI reaches 7.5. Ergon Energy risk framework is applied to forecast and target the assets for replacement going forward.

In general, distribution and low voltage cables are replaced upon identified defect or ultimate failure.

Underground cable assets are inspected periodically, as required by Queensland legislation. At transmission and sub-transmission voltages, routine maintenance monitors the electrical condition of the cable over sheaths and sheath voltage limiters, the performance of pressure feeds, the accuracy and condition of pressure gauges and alarm systems and the physical condition of the above ground structures and terminations. At distribution voltages, periodic inspections check the external condition of distribution cable systems including link pillars, link boxes and service pillars to ensure equipment remains in an acceptable condition.

8.3.5 Customer Service Line Replacement

Service replacement programs include works as part of an ongoing strategy to ensure compliance with statutory regulations relating to condition assessment of customer services. Public shocks are required to be reported to the Electrical Safety Office and are monitored against corporate performance targets. This asset class, particularly within the coastal regions of Ergon Energy, has underperformed against these metrics. As well as defect based replacement, a proactive, planned replacement program has been initiated to arrest the annual number of reported shocks due to end of life overhead service assets to meet expected service levels and comply with regulatory requirements. The proactive program is focussed on the removal of unsupported supply end taps along with the problematic neutral screened and colour coded service types, based on condition and historical performance, targeted on coastal communities where the majority of shocks are being reported.

8.3.6 Distribution Transformer Replacement

Distribution transformers are inspected periodically as required by Queensland legislation. Distribution transformers require very little maintenance except for removal of vegetation and animal detritus. They are reactively replaced, due to either electrical failure or poor condition as assessed by ground based inspection. It is generally considered uneconomical to refurbish distribution transformers, and they are routinely scrapped once removed. Replacement is with modern equivalent units.

8.3.7 Distribution Switches (including RMUs) Replacement

These assets are inspected periodically as required by Queensland legislation. All assets require basic cleaning maintenance such as removal of vegetation and animal detritus. HV switches require some mechanical maintenance, mostly related to moving parts. Oil filled RMUs require some maintenance related to cleaning of oil sludge. SF6 gas filled switches and RMUs require little other maintenance.

LV and HV switches, fuse and fuse carrier assets and RMUs are replaced reactively, either on electrical failure or poor condition as assessed by ground based inspection. Problematic asset types are proactively replaced by targeted programs.

Some refurbishment of components outside of sealed gas chambers is undertaken where economical to do so on in-service assets. It is generally considered uneconomical to refurbish LV and HV switches, fuse carriers and RMUs once removed, and they are routinely scrapped. Replacement is with modern equivalent units.

8.4 Substation Primary Plant

8.4.1 Overview

It has been assessed that previous asset management practices employed resulted in insufficient renewal being undertaken for substation assets. Accordingly, increased replacement of power transformers, protection relays and some associated assets is planned over the coming years as discussed in the individual sections below.

8.4.2 Power Transformer Replacement and Refurbishment

Asset condition and failure consequence risks (safety, customer reliability, environmental and business) are regularly assessed for each individual transformer. This begins with a "Health Index" (HI) developed to represent asset condition. A higher HI value represents a more degraded asset, with corresponding higher likelihood of failure. In turn, this reflects as a higher likelihood of inability to achieve the basic customer energy delivery service. Ergon Energy considers assets as potential candidates for replacement when HI reaches 7.5. The asset management plan documents the basis of the condition analysis and derivation of health index. Ergon Energy employs CBRM modelling to identify the poorest condition assets. The oldest substation transformers in the population that have exceeded their technical life are also considered as potential candidates for replacement to avoid an unsustainable build-up of very aged assets. Currently 55 of the 724 (7.6%) of the Ergon Energy power transformer fleet are over their 60 year expected service life.

Replacement of potential candidate assets is subsequently considered based on network requirements and in alignment with other network drivers such as augmentation and customer requested works to ensure the final option to address the identified limitation is the most cost effective from a whole-of-network perspective. The Ergon Energy risk framework is applied to prioritise asset replacement at a program level within financial and resource constraints.

8.4.3 Circuit Breaker, Reclosers, Switchboard Replacement and Refurbishment

Reclosers are a low cost item of plant used on lines in the distribution network where they are generally replaced on failure. Reclosers are also used in smaller substations as a low-cost circuit breaker alternative where they are managed similarly to circuit breakers.

Line reclosers are visually inspected periodically, as required by Queensland legislation. No other condition assessment is employed. Once physical indicators (e.g. severe corrosion, excessive oil leakage or loss of gas) develop that establish the recloser is at physical end of life, it is replaced.

Many line reclosers fail in service. Because of the volumes and labour costs involved, it has proven to be uneconomical to refurbish retired reclosers, and they are routinely scrapped. Replacement is with modern equivalent units.

Modern reclosers require very little maintenance except for periodic battery replacement and removal of vegetation and animal detritus.

Substation circuit breakers condition and failure consequence risks (safety, customer reliability, environmental and business) are regularly assessed for each individual substation asset. This begins with a "Health Index" (HI) developed to represent asset condition. A higher HI value represents a more degraded asset, with corresponding higher likelihood of failure. In turn, this reflects as a higher likelihood of inability to achieve the basic customer energy delivery service. Ergon Energy considers assets as potential candidates for replacement when HI reaches 7.5. The Asset Management Plan for Circuit Breakers and Reclosers documents the basis of the condition analysis and derivation of HI, using CBRM modelling to identify the poorest condition assets. The Ergon Energy risk framework is applied to prioritise asset replacement at a program level within financial and resource constraints.

8.4.4 Instrument Transformer Replacement and Refurbishment

Instrument transformer's condition and failure consequence risks (safety, customer reliability, environmental and business) are regularly assessed for each individual substation asset. A more degraded asset has a corresponding higher likelihood of failure. This has adverse implications for network protection as well as staff and public safety. In turn, this reflects as a higher likelihood of inability to achieve the basic customer service delivery and a safe network for the Queensland community. Ergon Energy considers assets for replacement based on assessed end of technical life, condition and risk. The Ergon Energy risk framework is applied to prioritise asset replacement at a program level within financial and resource constraints.

Currently 846 of 4,763 (18%) of the Ergon Energy instrument transformer fleet are over their 45 year expected service life. Where practical, timing of replacement is coordinated with other necessary works occurring in the substation to promote works efficiencies.

8.5 Substation Secondary Systems

8.5.1 Protection Relay Replacement Program

Protection relays are condition monitored and older models require regular maintenance. Protection relays react to power system faults and automatically initiate supply de-energisation. Failure consequences are predominantly damage to plant and safety impacts, including loss of ability to respond to power system faults and heightened safety risks due to continued energisation of failed assets. Duplication and redundancy are typically employed to reduce these safety risks, although some older sites retain designs where backup protection does not completely compensate for initial protection asset failure. This results in around 53,000km (45%) of network having inadequate backup protection.

Currently 1,500 of the approximately 6,000 (25%) of the Ergon Energy protection relay fleet are over their expected service life. There are an additional 520 relays that are considered problematic / obsolete types. It is also known that 23 substations with 83 distribution feeders with overhead wires have been identified as lacking SEF protection for the full feeder.

Due to the failure consequences, Ergon Energy has adopted a proactive replacement program targeting problematic and near end of life relays.

Wherever possible, replacement of obsolete protection schemes is undertaken with other capital work such as primary plant replacement or augmentation for efficiency reasons. In circumstances where this is not possible, standalone projects for replacement of the obsolete protection schemes are undertaken.

8.5.2 Substation DC Supply Systems

Outcome of a battery failure inside a substation can lead to high safety consequence such as serious injury to Ergon Energy personnel and reliability risk consequences such as complete loss of control and protection at a substation, maintaining the operation reliability of substation DC services is paramount.

Batteries are inspected and tested annually. As the batteries degrade with use and time, component elements are replaced upon failure, while complete battery banks and chargers are replaced on age.

8.6 Other Programs

8.6.1 Vegetation Management

Vegetation encroaching within minimum clearances of overhead powerlines presents safety risks for the public, Ergon employees and contract workers. Vegetation in the proximity of overhead powerlines is also a major cause of network outages during storms and high winds.

Ergon Energy's comprehensive vegetation management program minimises hazards and provides the required network reliability. To manage this risk we employ the following strategies:

- Cyclic programs, to treat vegetation on all overhead line routes. The cycle times are managed based on species, growth rates and local conditions; and
- Reactive spot activities to address localised instances where vegetation is found to be within clearance requirements and is unable to be kept clear until the next cycle or has been reported for action by customers.

8.6.2 Overhead Network Clearance

Ergon Energy has an obligation to meet the minimum clearance standards specified under the Electrical Safety Act (2002) (Qld) and associated regulations. The Fugro RoamesTM LiDAR technology has allowed the recent identification of conductor span clearance issues for all conductor types except service lines. All high priority clearance defects from the previous survey were completed before 30 June 2020 with all other defects scheduled for completion by 2022.

The next LiDAR overhead network clearance survey will commence in mid-2021 on a three- year cycle. During this cycle, an algorithm to compensate the effect of temperature on conductor sag will be trialled and applied to ensure compliance at 35ºC ambient temperature.

The Lidar technology has identified point in time clearance issues but has not been integrated with span loading and design information. Ergon Energy intends to combine such information to further identify other conductor clearance issues that are impacted by network loading. This work is scheduled to occur once the Lidar identified works has been completed.

8.7 Derating

In some circumstances, asset condition can be managed through reducing the available capacity of the asset (derating) in order to reduce the potential for failure or extend the life; for example reducing the normal cyclic rating of a power transformer due to moisture content. The reduction of available capacity may have an impact on the ability of the network to supply the forecast load either in system normal or contingency configurations and therefore result in a network limitation. Limitations of this nature are managed in alignment to augmentation processes.

Chapter 9

Network Reliability

9. Network Reliability

9.1 Reliability Measures and Standards

This section describes Ergon Energy's reliability measures and standards. The planning criteria, already discussed, when combined with reliability targets, underpins prudent capital investment and operating costs to deliver the appropriate level of service to customers.

Ergon Energy uses the industry recognised reliability indices, System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), to report and assess the reliability performance of its supply network.

9.1.1 Minimum Service Standards (MSS)

The MSS define the reliability performance levels required of our network, including both planned and unplanned outages, and drive us to maintain the reliability performance levels where the MSS limits have been met. The MSS limits for both SAIDI and SAIFI are applied separately for each defined distribution feeder category – Urban, Short Rural and Long Rural.

The reliability limits are prescribed in Ergon Energy's Distribution Authority, No. D01/99, October 2019. Ergon Energy is required to use all reasonable endeavours to ensure that it does not exceed the SAIDI and SAIFI limits set out in the Distribution Authority for the relevant financial year. Circumstances beyond the distribution entity's control are generally excluded from the calculation of SAIDI and SAIFI metrics.

Under Ergon Energy's Distribution Authority, exceedance of the same MSS limit in three consecutive financial years is considered a 'systemic failure' and constitutes a breach. Continuing on from 2015-20 regulatory control period, the MSS limits for the 2020-25 period in Schedule 3 of the Distribution Authority remain flat up to 2025.

9.1.2 Reliability Performance in 2019-20

The normalised results in Table 21 highlight favourable performance against the MSS for four of six of Ergon Energy's network performance measures in 2019-20.

Table 21: Performance Compared to MSS

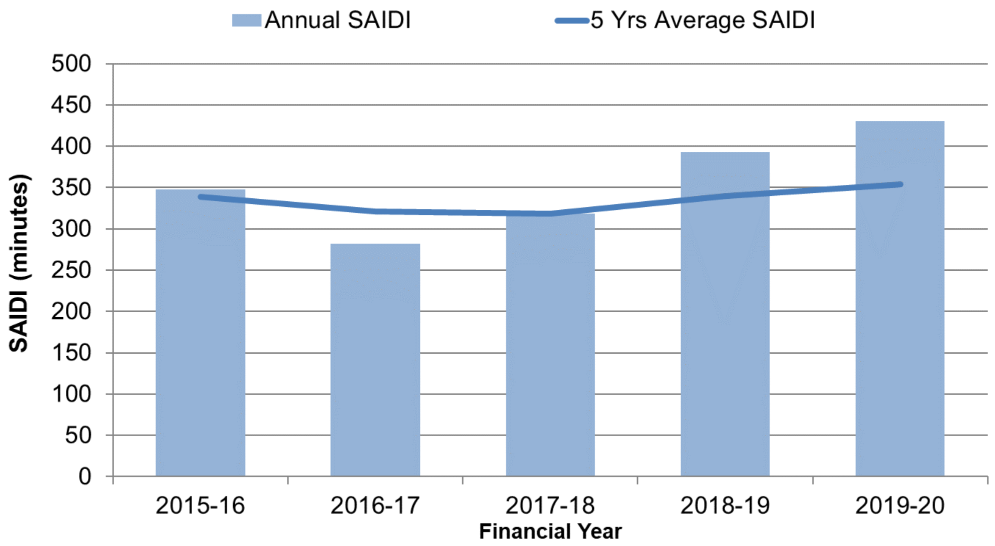
Normalised Reliability Performance		2018-19 Actual	2019-20 Actual	2015-20[46] MSS
SAIDI (mins)	Urban	147.72	224.94	149
	Short Rural	409.69	422.88	424
	Long Rural	1017.99	1056.01	964
SAIFI	Urban	1.297	1.798	1.98
	Short Rural	3.141	3.160	3.95
	Long Rural	5.863	6.458	7.40

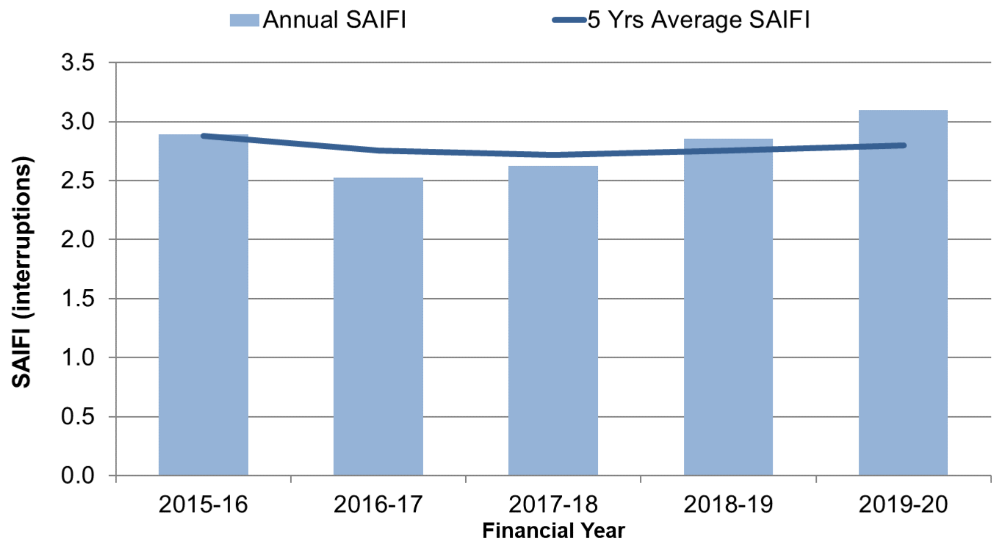
[46] Ergon Energy's MSS is 'flat-lined' for the current regulatory control period 2015-20.

In 2019-20, Ergon Energy reliability of supply was favourable to the Distribution Authority's MSS limits for four performance measures with both Urban and Long Rural SAIDI unfavourable to the MSS Limits. Ergon Energy's Urban and Long Rural networks reliability were influenced by a significant increase in the duration and frequency of planned supply interruptions required to accommodate high priority defect remediation and repairs across regional Queensland. Additionally, the Long Rural network was also highly influenced by high voltage conductor failures, with a significant proportion occurring during severe weather.

Figure 18 depicts the five-year rolling average reliability performance for both SAIDI and SAIFI at whole of regulated network level with the performance for the most recent years adversely impacted by the planned performance results.

Figure 18: MSS Network SAIDI and SAIFI Performance Five-year Average Trend





9.1.3 Reliability Compliance Processes

Ergon Energy has set its internal targets broken down between planned and unplanned targets, and by supply regions, with planned outage provisions for safety related repairs, maintenance, refurbishment and customer and the corporate initiated works, along with other forms of planned outages. The internal targets are primarily set based on average historical performance and are also seasonalised across the years to make greater allowance for unplanned outages during the storm season, between November and March.

9.1.4 Reliability Corrective Actions

Ergon Energy puts significant focus on its operational practices to improve the response time to unplanned outages and the management of planned outages that have direct impact on overall SAIDI, especially for our Long Rural network for which meeting the MSS SAIDI limit remains a challenge. As part of our reasonable endeavours to meet MSS limits for any feeder category we have continued with proactive deployment of mobile generators on selected high contributing feeders, bundling of planned works (where reasonably practical) and expedited return to service of failed assets with high reliability impact and network risks.

Ergon Energy continues to utilise advanced tools and other resources available to the Operations Control Centres to assist field operations with a more effective dispatch and coordination of response crews. During fault restoration, the network is sectionalised (where possible) to restore customers progressively. Weather forecasting services are being used to predict storm activity and prepare additional resources to respond to faults.

As one of its regulatory obligations under the Distribution Authority, Ergon Energy also continues to deliver its Worst Performing Feeder improvement program. While, this program is not targeted towards improving the average system level reliability, it continues to address the reliability issues faced by a smaller cluster of customers supplied by the poorly performing feeders or a section of these feeders.

In addition to the reliability improvement specific works, Ergon Energy continued to focus on the reliability outcomes from its asset maintenance, asset replacement and works planning. The asset maintenance and replacement strategies will either continue to have positive influence on reliability performance for this regulatory control period or provide additional benefits on reliability performance in the next regulatory control period.

9.2 Service Target Performance Incentive Scheme

The AER's Service Target Performance Incentive Scheme (STPIS) provides a financial incentive for our organisation to maintain and improve our service performance for our customers. The scheme rewards or penalises a DNSP, in the form of an increment or reduction on Annual Revenue Requirement, for its network performance relative to a series of predetermined service targets. The applicable revenue change is applied in the third year from the regulatory year when the performance outcomes are measured.

The scheme encompasses reliability of supply performance and customer service parameters. The reliability of supply parameters includes unplanned SAIDI and SAIFI applied separately for each feeder category (Urban, Short Rural and Long Rural). The incentive rates for the reliability of supply performance parameters of the STPIS are primarily based on the value that customers place on supply reliability (the VCR), energy consumption forecast by feeder type and the regulatory funding model.

The customer service performance target applies to our service area as a whole and is measured through a target percentage of calls being answered within agreed time frames. Service performance targets for all the parameters were determined at the beginning of the regulatory control period.

The AER requests the reporting of annual performance against the STPIS parameters applicable to Ergon Energy under its Distribution Determination, via a Regulatory Information Notice (RIN).

Ergon Energy's 2019-20 Performance RIN's response included completed templates (and relevant processes, assumptions and methodologies) relating to reliability performance reporting under the STPIS. More information on Ergon Energy's and Energex's recent RIN submissions can be found on the AER's website.[47]

[47] Website: https://www.aer.gov.au/networks-pipelines/network-performance

9.2.1 STPIS Results

The normalised results in Table 22 highlight a favourable year end performance against STPIS for five of six network performance measures in 2019-20. As this table presents average duration and the frequency of unplanned supply interruptions, lower numbers indicate stronger results and less interruption to our customers' electricity supply.

Table 22: Performance Compared to STPIS

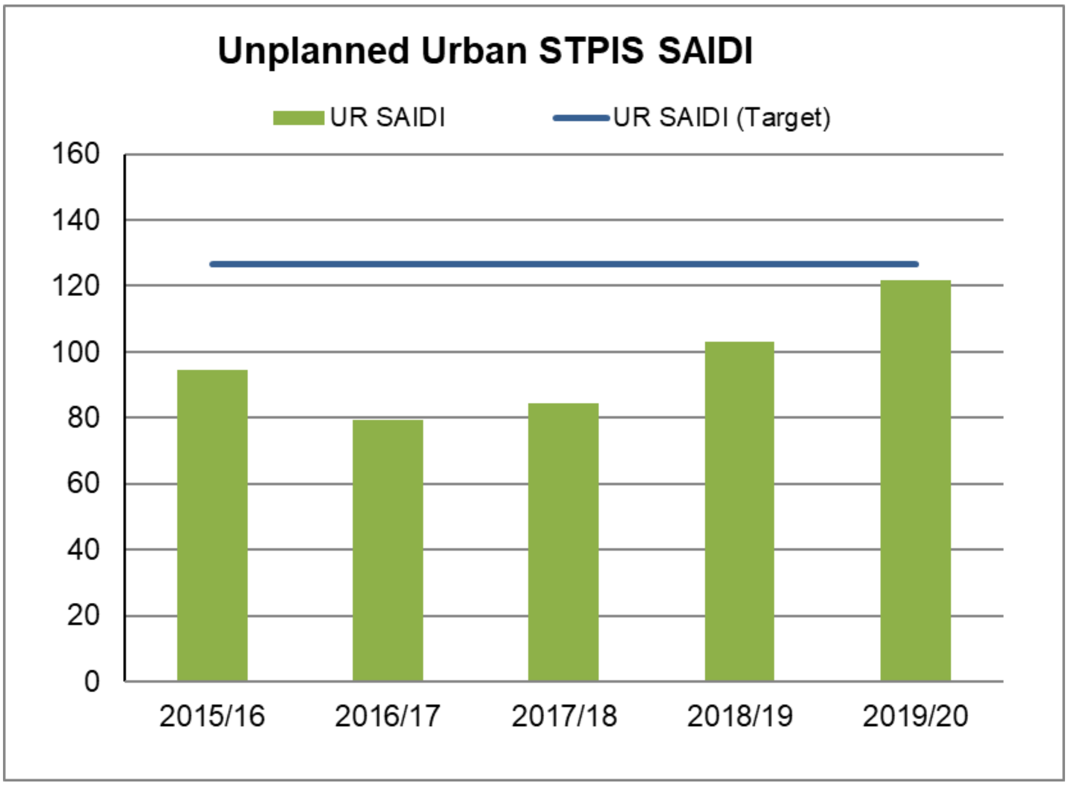
Normalised Reliability Performance		2018-19 Actual	2019-20 Actual	2015-20[48] STPIS
Unplanned SAIDI (mins)	Urban	103.08	121.82	126.73
	Short Rural	287.65	261.15	317.06
	Long Rural	722.98	752.08	742.47
Unplanned SAIFI	Urban	1.075	1.360	1.503
	Short Rural	2.568	2.477	3.019
	Long Rural	4.455	5.205	5.348

In 2019-20, Ergon Energy's reliability of supply outperformed the unplanned performance targets under the AER's STPIS for five of six measures, while Long Rural SAIDI was unfavourable to the STPIS Target. Ergon Energy's Long Rural network's reliability was influenced by a significant increase in the duration and frequency of high voltage conductor failures, with a significant proportion occurring during severe weather. Our overall reliability unplanned performance has improved since the inception of STPIS in 2010 with both the duration and frequency of overall unplanned outages reducing by 16.6% and 14.3% respectively.

Figure 19 to Figure 21 depict the STPIS targets and results for the 2015-20 period. The actuals are the normalised values (i.e. exclusions are applied as per Clause 3.3 of the STPIS).

[48] Ergon Energy's STPIS is 'flat-lined' for the current regulatory control period 2015-20.

Figure 19: STPIS Targets and Results for Unplanned Urban 2015-20 Period



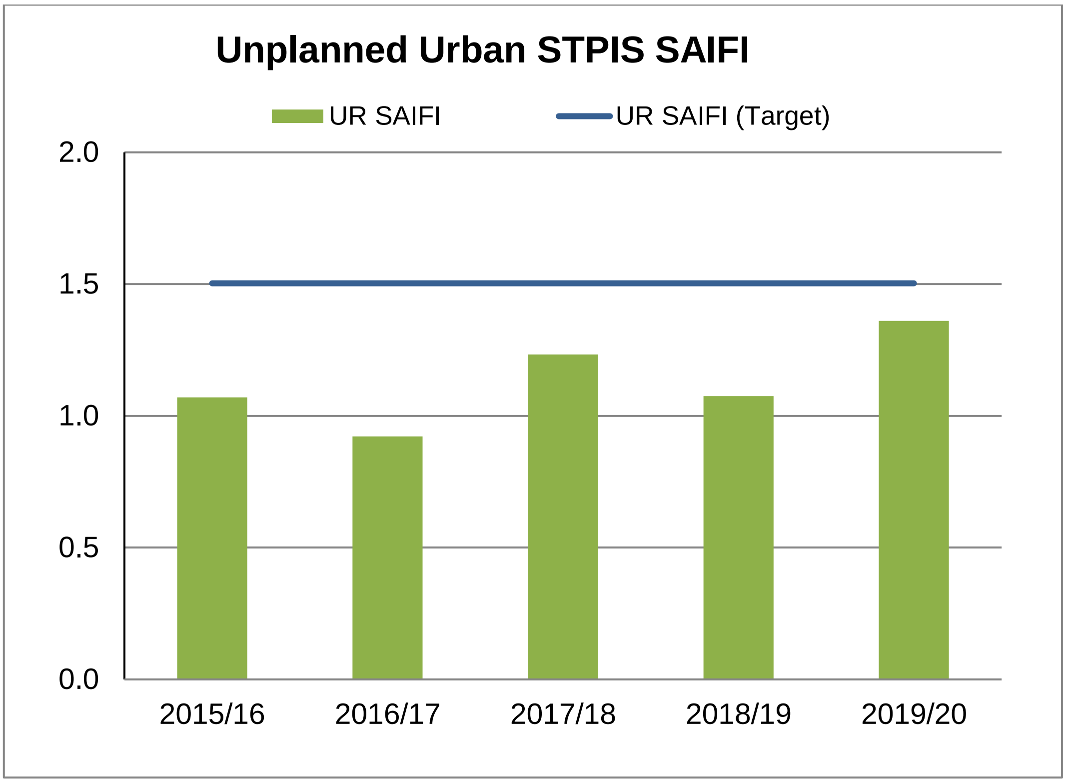
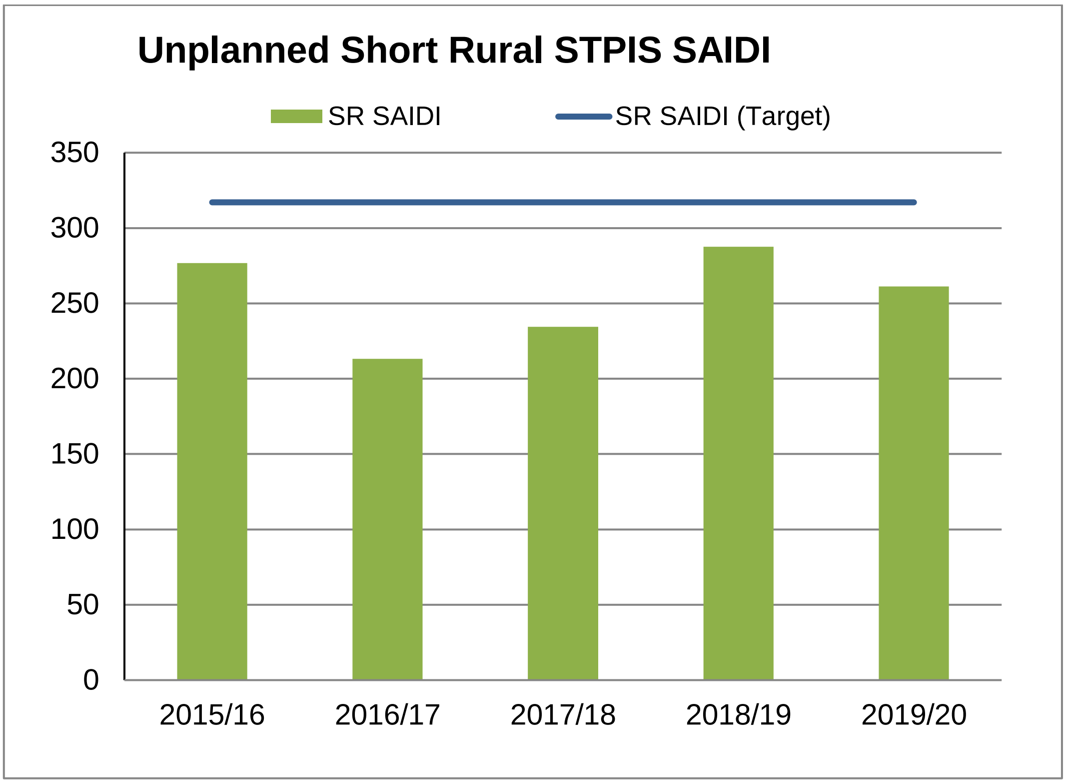


Figure 20: STPIS Targets and Results for Short Rural 2015-20 Period



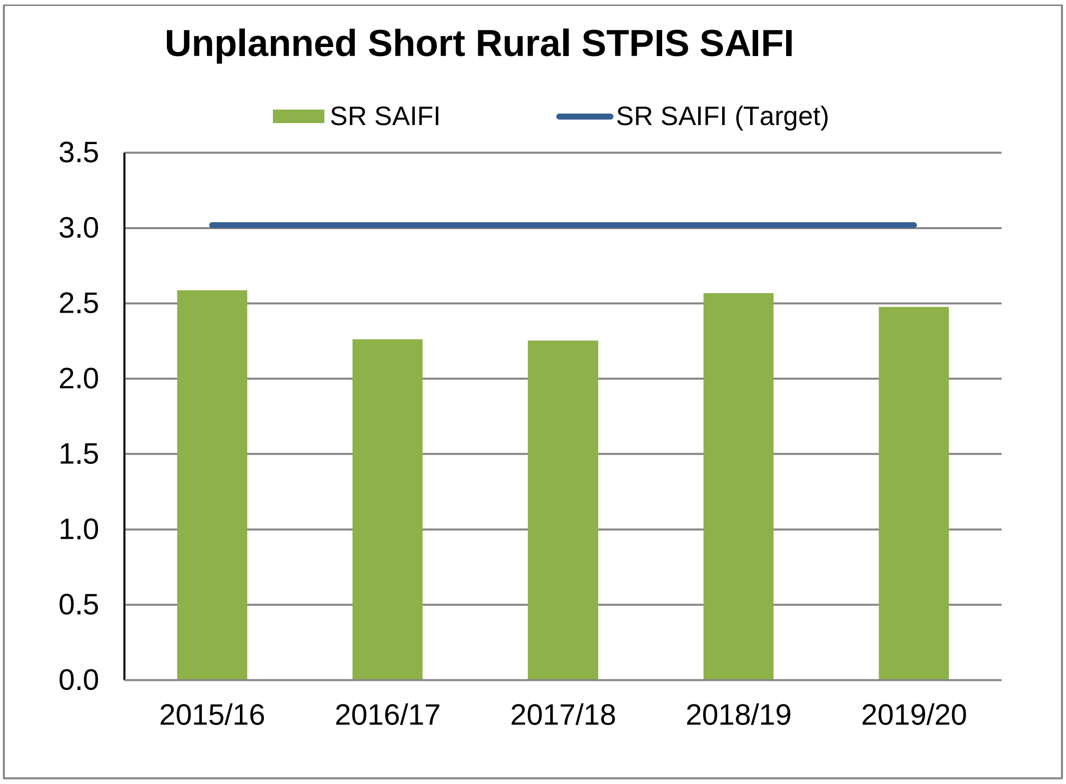
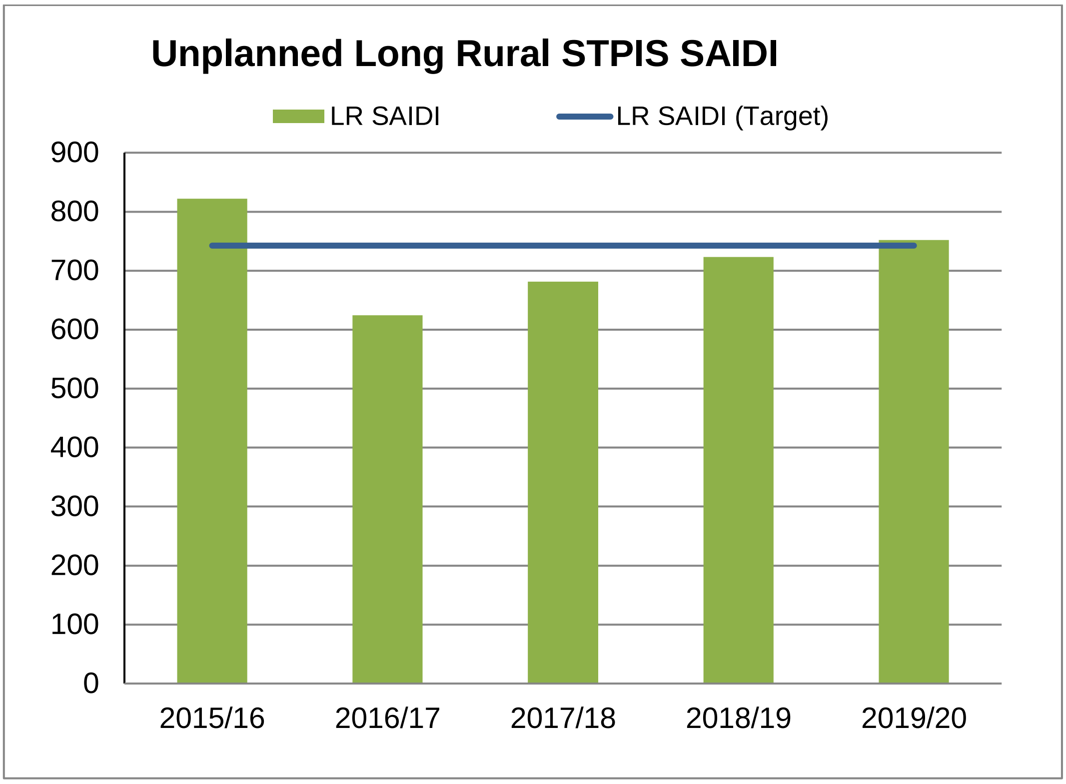
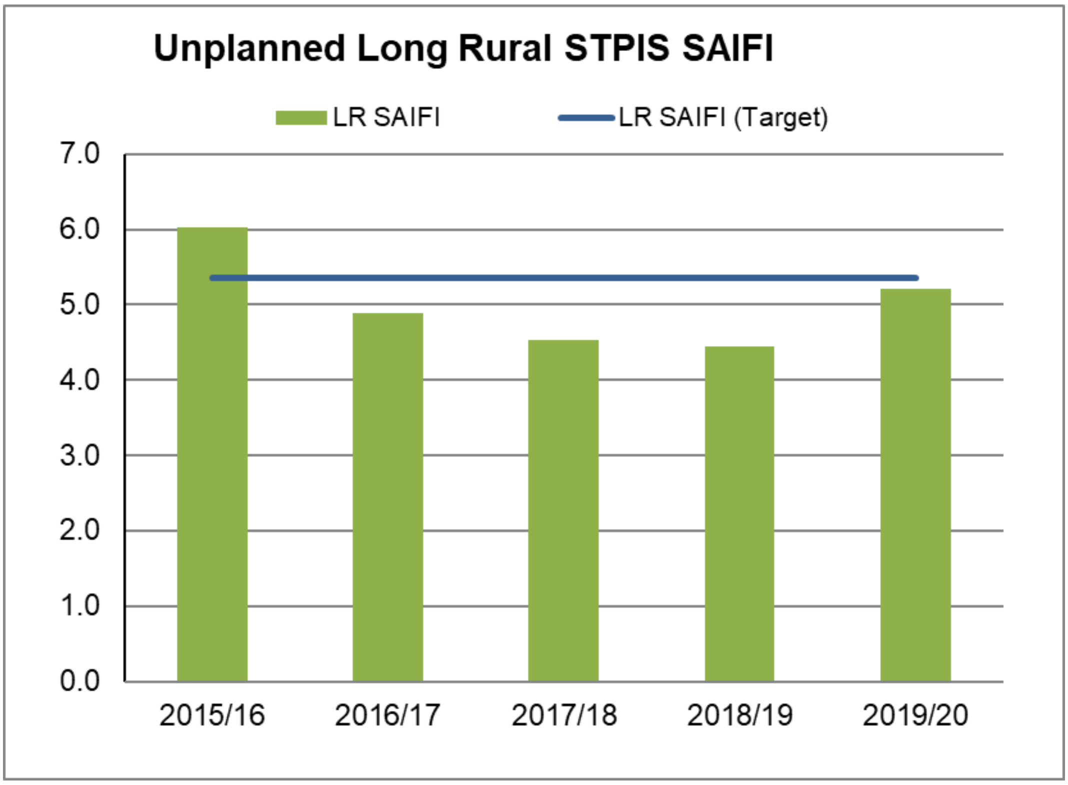


Figure 21: STPIS Targets and Results for Long Rural 2015-20 Period





9.3 High Impact Weather Events

9.3.1 Emergency Response

Ergon Energy is conscious that its responses to emergency events, particularly those driven by weather, are delivered in an environment of continually increasing need and expectation, both from customers and community stakeholders. More than ever, our response must consider the increasing customer dependency on electricity as technology and appliances become more sophisticated and economic activity becomes more reliant on e-commerce.

Ergon Energy's response priorities in order of importance are:

- Ensuring personal safety - both public and Ergon Energy employees
- Protecting equipment and infrastructure from damage
- Efficient supply restoration - including meeting communication requirements of customers and emergency service agencies.

As further commitment to these priorities and the communities we serve, Ergon Energy has established a dedicated team to lead Emergency Planning and Response on behalf of the distribution network. This team will focus on key priorities to further optimise our response capability being; emergency planning, preparation, resilience and response.

Disaster and Emergency Exercises

To better enable our network to cope with emergency events, a number of preparation exercises will be conducted throughout the year in preparation for the bushfire and summer storm season. Participation in these exercises involves key staff across Ergon Energy to confirm and enhance their knowledge of the approach to an emergency response. Ergon Energy also participates in external disaster exercises and works closely with the State Disaster Coordination Centre as well as local disaster management groups to provide advice on the power network and Ergon Energy response as well as further enhance our interoperability with emergency services, government agencies to ensure readiness.

Damage Assessment

The damage assessment process has been significantly enhanced through greater utilisation of technology including the use of mobile devices incorporating geospatial and asset data capture capability. The combined process produces more accurate and timely field data for the planning, restoration and recovery, which supports improved response times and savings to Ergon Energy and the local economy.

Forecasting/Modelling/Tracking

We are improving our use of predictive modelling of weather events and their associated impacts through the utilisation of spatial systems. These applications are overlaid on our assets and draw from multiple data sources to enable Ergon Energy to make strategic and operational decisions for improved planning and response to events.

Post Event Reviews and Actions

Our response capability is constantly tested by a range of severe weather events across the state, and each event is unique in terms of scale and impact. During the 2019-20 season Ergon Energy experienced three significant bushfire across the network. Comprehensive post implementation reviews are conducted to identify further opportunities to enhance our processes, plans, technology, people development and overall response capability. These types of reviews are critical as part of continually meeting stakeholder expectations and reducing the negative impact of large scale disasters on the Queensland community.

9.3.2 Summer Preparedness

Summer Preparations for the 2020-21 Storm Season

The specific activities being undertaken to prepare the network for the 2020-21 bushfire and summer storm season, and generally improve reliability, include:

- Network maintenance and other reliability improvement programs including vegetation management, asset inspection and defect remediation, feeder patrols, bushfire mitigation program, aerial inspections, network monitoring and control capability and flood risk mitigation
- Network capacity and security improvement programs including; planning for security of supply, plant emergency rating information, strategic spare components, temporary load support and demand management
- Securing generation assets including:
  - Strategic mobilisation of ‘Pegasus’ HV mobile injection units that work in conjunction with generation equipment
  - Generation sharing agreements with Energex
  - Generation hire arrangements with private suppliers
  - Working closely with local disaster management groups and councils to identify critical infrastructure priorities and generation requirements.

Ergon Energy continues to utilise LiDAR technology to acquire 3D representations of network assets which are displayed in a geo-spatial visualisation application to assist with vegetation management and asset maintenance. With this capability Ergon Energy has already carried out LiDAR inspection of the entire network each year. This information identifies defects and is contributing to reduced maintenance and planning costs, and increased safety and reliability of supply for our customers and communities.

The data captured is processed to enable measurement of the network and surrounding objects such as buildings, terrain and vegetation.

In addition to these specific activities, much of Ergon Energy’s annual program of work to develop, maintain and operate the network is aimed at providing a resilient network in preparation for the summer storm season.

Resources

Ergon Energy has a diverse range of skilled resources engaged both internally and externally. In the lead up to summer, substantial resources are available including:

- A field workforce of approximately 2,800 employees and contractors (including design, construction, maintenance, inspection and vegetation workers). This capability is deployed as necessary for any event that occurs through the bushfire and summer storm season
- Leave rosters are managed to ensure adequate availability of field resources for an emergency response throughout the season
- Additional resource support from Ergon Energy Network and interstate DNSPs.

Customer and Community Engagement

Ergon Energy keeps its customers informed and engaged through:

- The Customer Contact Centre
- Community awareness and education campaigns
- Direct media and community engagement forums
- Website, social media and other online communications.

9.3.3 Bushfire Management

Ergon reviews and updates a Bushfire Risk Management Plan annually. The Plan is published in August each year and contains a list of programs and specific initiatives to reduce bushfire risks. Ergon has on-going programs to replace aged conductors, install conductor spacers, install gas insulated switches in lieu of air-break switches, replacement of sub optimal pole top constructions and utilises sparkless fuses in high bushfire risk areas. It also reports and investigates suspected asset related bushfires.

9.4 Guaranteed Service Levels

Section 2.3 of the EDNC[49] specifies a range of Guaranteed Service Levels (GSLs) that DNSPs must provide to their *small customers*. The GSLs are notified by the Queensland Competition Authority (QCA) through the code. Where we do not meet these GSLs we pay a financial rebate to the customer.

GSLs are applied by the type of feeder supplying a customer with limits appropriate to the type of GSL as outlined below in Table 23. Some specific exemptions to these requirements can apply. For example, we do not need to pay a GSL for an interruption to a small customer's premises within a region affected by a natural disaster (as defined in the EDNC).

Table 23: Guaranteed Service Levels

EDNC	GSL	Urban feeder	Short rural feeder	Long rural / isolated feeder
Clause 2.3.3	**Wrongful disconnections** (Wrongfully disconnect a small customer)	Applies to all feeders equally		
Clause 2.3.4	**Connections** (Connection not provided)	On business day agreed with customer. Applies to all feeders equally		
Clause 2.3.5	**Reconnections** (Reconnection not provided within the required time)	If requested before 12.00pm -same business day. Otherwise next business day	Next business day	Within 10 business days
Clause 2.3.6	**Hot Water Supply** (Failure to attend the customer's premises within the time required concerning loss of hot water supply)	Within one business day	Within one business day	By business day agreed with customer
Clause 2.3.7	**Appointments** (Failure to attend specific appointments on time)	On business day agreed with customer. Applies to all feeders equally		
Clause 2.3.8	**Planned Interruptions** (Notice of a planned interruption to supply not given)	4 business days as defined in Division 6 of the NERR under Rule 90 (1). Applies to all feeders equally		
Clause 2.3.9(a)(i)	**Reliability – Interruption Duration** (If an outage lasts longer than...)	18 hours	18 hours	24 hours
Clause 2.3.9(a)(ii)	**Reliability – Interruption Frequency** (A customer experiences equal or more interruptions in a financial year)	13	21	21

[49] Webpage: https://www.ergon.com.au/network/our-network/electricity-distribution-network-code

9.4.1 GSL Payment

The EDNC requires that a DNSP use its best endeavours to automatically remit a GSL payment to an eligible customer. Customers receive the payment for most GSLs within one month of confirmation, however, in the case of Interruption Frequency GSL the payments will be paid to the currently known customer once the requisite number of interruptions has occurred. Table 24 shows the number of claims processed to date and paid in 2019-20.

Table 24: Number of Claims Processed to Date and Paid in 2019-20

GSL	Number Paid	Amount Paid
Wrongful Disconnection	36	$5,112
Connection of Supply	7	$1,311
Customer Reconnection	28	$2,620
Hot Water Supply	0	$0
Appointments	96	$5,472
Planned Interruptions	885	$28,349
Duration of Interruption	4,839	$551,550
Frequency of Interruption	20	$2,280
TOTAL	**5,911**	**$596,694**

9.5 Worst Performing Distribution Feeders

In accordance with Clause 11 of the Distribution Authority No. D01/99, Ergon Energy continues to monitor the worst performing feeders on its distribution network and report on their performance. Under the authority, Ergon Energy is also required to implement a program to improve the performance outcomes for the customers served by the worst performing distribution feeders.

In October 2019 the worst performing distribution feeder improvement program criteria set out in Clause 11.2(c) of the Distribution Authority No. D01/99 were amended and are outlined below:

Clause 11. Improvement Programs

(c) The worst performing feeder improvement program will apply to any distribution feeder that meets the following criteria:

> *(i) The distribution feeder is in the worst 5% of the network's distribution HV (high voltage) feeders, based on its three-year average SAIDI/SAIFI performance; and*
>
> *(ii) The distribution HV feeder's SAIDI/SAIFI outcome is 200% or more of the MSS SAIDI/SAIFI limit applicable to that category of feeder.*

The list of our worst performing distribution feeders, as defined by Clause 11.2(c) of the Distribution Authority No. D01/99 up to June 2020, has been provided in Appendix G. Ergon Energy's worst performing distribution feeder assessment for 2019-20 is summarised below:

- 7% of Ergon Energy's distribution feeders meet the worst performing feeder improvement program criteria at June 2020 (87 distribution feeders in total – 9 Urban, 47 Short Rural and 31 Long Rural)
- The 87 distribution feeders meeting the worst performing feeder improvement program criteria supply 1.31% of the Ergon Energy's total number of customers
- 34 of the distribution feeders have carried over from the list from the 2018-19 reporting period.

Table 25 below shows the comparative average, minimum and maximum 3-year average SAIDI/SAIFI for the reported worst performing distribution feeder across the feeder categories for 2019-20.

Table 25: 2019-20 Worst Performing Feeder List – Current Performance (2019-20)

	3 Year Average Feeder SAIDI (mins)			3 Year Average Feeder SAIFI (int.)		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Urban	2,357.97	4,844.51	7,346.15	9.30	11.02	13.00
Short Rural	1,962.93	3,544.16	11,310.55	9.32	12.03	18.22
Long Rural	1,955.65	3,797.16	9,220.41	14.94	16.62	18.29

Review of Worst Performing Distribution Feeders

- 78% of the 50 worst performing feeders identified in 2018-19 saw an improvement in their annual SAIDI as of June 2020. Two of those feeders now have significantly improved annual SAIDI, and are now favourable to the June 2020 MSS limits
- During 2019-20, Ergon Energy completed detailed engineering reviews of 8 of the 50 worst performing feeders that were identified based on their three years' average SAIDI performance up to 2018-19. This included 2 Urban, 5 Short Rural and 1 Long Rural feeders. Three of these feeders did not present any opportunities for capital investment to improve reliability with all of the feeders showing significant performance improvement as of June 2020
- The worst performing distribution feeder reviews included detailed analysis of different type of outages (planned and unplanned) and outage triggers and contributing causes. The contributions from different segments of the electricity supply chain (subtransmission, distribution, SWER etc.) were also analysed to understand the drivers of the poor performance and to identify the reliability improvement opportunities for the reviewed feeders
- The contribution from the subtransmission network outages to the worst performing distribution feeders, especially for the Urban and Short Rural feeders, is proportionally high (more than 50% in most of the cases). Adverse weather conditions have also been the key contributor to the worst performing distribution feeder performance
- A small number of the worst performing feeders were found to have high average SAIDI due to one-off, low-probability events, often triggered by storm conditions. Most of the time, these feeders did not show need/prospect for capital investment and as such are being monitored for any potential deterioration in their future performance.

Network asset solutions that could be applied at subtransmission network level are usually very high cost options and such investment cannot be considered prudent to improve reliability for a small cluster of customers or a feeder/feeder section with very low customer density.

Consistent with 2015-20 regulatory term, Ergon Energy only sought limited capex for the worst performing feeder improvement program from the AER for the 2020-25 regulatory control period. This supports our customers' preference for lower electricity prices rather than improved network reliability. We are ensuring that the investment in the worst performing feeder improvement program is prudently spread across different feeders/regions.

The reliability improvement solutions identified from the worst performing distribution feeder reviews conducted in the 2015-20 regulatory control period have mainly included low to moderate capital investment options and we expect this to continue in this regulatory period. However, with the inclusion of SAIFI in the new worst performing feeder improvement program criteria, there could be need for network solutions to address the asset failure rates which may require slightly higher cost investments when compared to only managing outage duration to improve SAIDI.

The low cost, quick win solutions on WPFs mainly include protection setting changes, installation of Line Fault Indicators with communication and Fuse Savers. The moderate investment options include installation of new Automatic Circuit Reclosers, Sectionalisers, Remote Controlled Gas Switches and also relocation and/or replacement of switching devices. The identified solutions are currently being implemented. Ergon Energy will continue reviews of its worst performing distribution feeders during 2020-21.

The overall approach for the worst performing feeder performance improvement includes the following in order of preference and affordability:

1. Improved network operation by:
    - investigating to determine predominant outage cause
    - implementing reliability or operational improvements identified through the investigation of any unforeseen major incidents
    - improving fault-finding procedures with improved staff-resource availability, training and line access
    - improving availability of information to field staff to assist fault-finding, which could include communications, data management and availability of accurate maps and equipment
    - planning for known contingency risks until permanent solutions are available
2. Prioritisation of preventive-corrective maintenance by:
    - scheduling asset inspection and defect management to poorly performing assets early in the cycle
    - scheduling worst performing distribution feeders first on the vegetation management cycle
    - undertaking wildlife mitigation (e.g. birds, snakes, possums, frogs) in the vicinity of worst performing distribution feeders
3. Augmentation and refurbishment through capex by:
    - refurbishing or replacing ageing assets (for both powerlines and substations).

9.6 Safety Net Target Performance

Ergon Energy's Distribution Authority (D01/99) describes the performance reporting obligations against service Safety Net targets.

Supply interruption events over 2019-20 have been reviewed in detail to identify any instances where the actual restoration performance may not have achieved the service Safety Net targets set out in Schedule 4 of the Distribution Authority (as described in Section 5.4.2).

In 2019-20, there were no events exceeding the service Safety Net targets.

Chapter 10

Power Quality

10. Power Quality

The quality of network power affects both customer experience and the efficiency and stability of the network. This section covers two related but distinct areas which are Quality of Supply (QoS) and Power Quality (PQ). QoS is a measure of the customer-initiated requests for Ergon Energy to investigate perceived issues with their quality of the supply. PQ is the compliance of measured system wide network conditions with defined parameter limits.

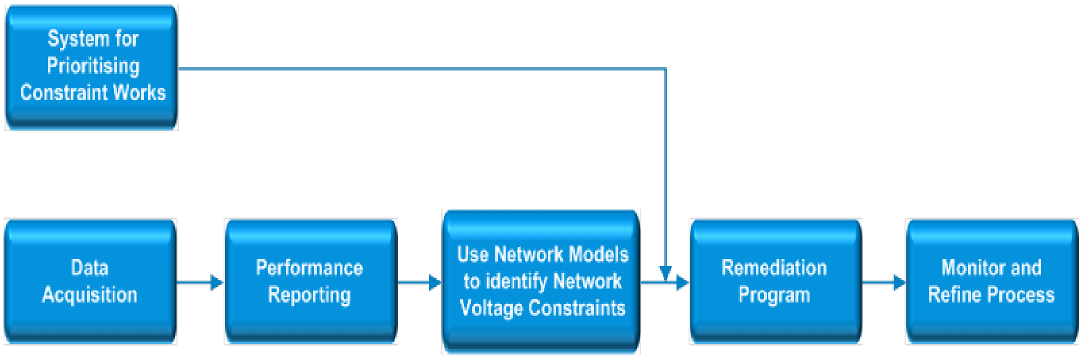
10.1 Quality of Supply Process

Ergon Energy responds to customer QoS enquiries / complaints by carrying out an investigation which may include the installation of temporary monitoring equipment on the network and at customers' premises and this data is used in conjunction with existing network monitors to analysis and determine what remediating is necessary.

Due to the complexity of the network and the large number of sites involved, the management of quality of supply presents many challenges. To address these challenges, a proactive and systematic approach shown in Figure 22 is adopted. This involves:

- Establishing suitable data acquisition (monitoring) and reporting systems to identify problem areas
- Establishing objective measures and supporting systems for prioritising remedial works
- Developing network models down to the LV that allow problem areas to be predicted
- Implementing and tracking improvements from remediation programs
- Measuring results to refine the network model and remediation options.

Figure 22: Systematic Approach to Voltage Management

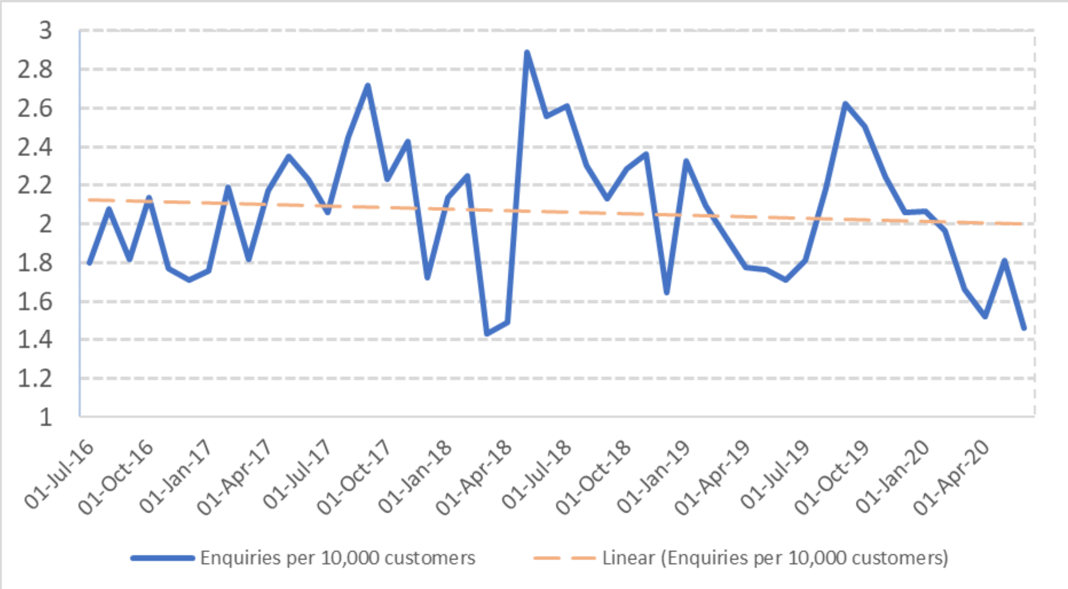


Ergon Energy has developed a series of reports from the PQ Data Warehouse to identify and prioritise power quality issues. These reports enable the large volume of power quality time series data captured from the monitoring devices to be more easily analysed with possible drivers such as equipment failure and network topology as possible causes. Ergon Energy takes a pro-active approach to identify possible sites where PQ and QoS issues may exist. Sites that exceed limits are prioritised and emailed to PQ staff daily for action. PQ staff then work with customer service and Operations staff to rectify issues before the issue is seen or impacts customers equipment and/or safety.

10.2 Customer Experience

The QoS experienced by customers is measured by the number of QoS enquires lodged by customers. QoS enquiries occur when a customer contacts Ergon Energy with a concern that their supply may not be meeting the standards. Figure 23 shows that the number of enquiries on a normalised basis per 10,000 customers per month. On average, there has been a slight decrease over the last 3 years.

Figure 23: Quality of Supply Enquiries per 10,000 customers



QoS enquires are selected from categories on initial contact as follows: low voltage, voltage dips, voltage swell, voltage spike, solar PV, TV or radio interference, motor start problems, and noise from appliances. Figure 24 shows a breakdown of the enquiries received by the reported symptoms over the last 12 months, with the largest identifiable category, at 47%, related to solar PV issues. Many of these are associated with customer installations where solar PV inverters could not export without raising voltages above statutory limits (although inverters are designed to disconnect when voltage rises excessively, regular occurrences of this reduce the level of electricity exported and can often cause voltage fluctuations and customer complaints). The comparison to the previous five years is shown in Figure 25.

Figure 24: Quality of Supply Enquiries by Category 2019-20

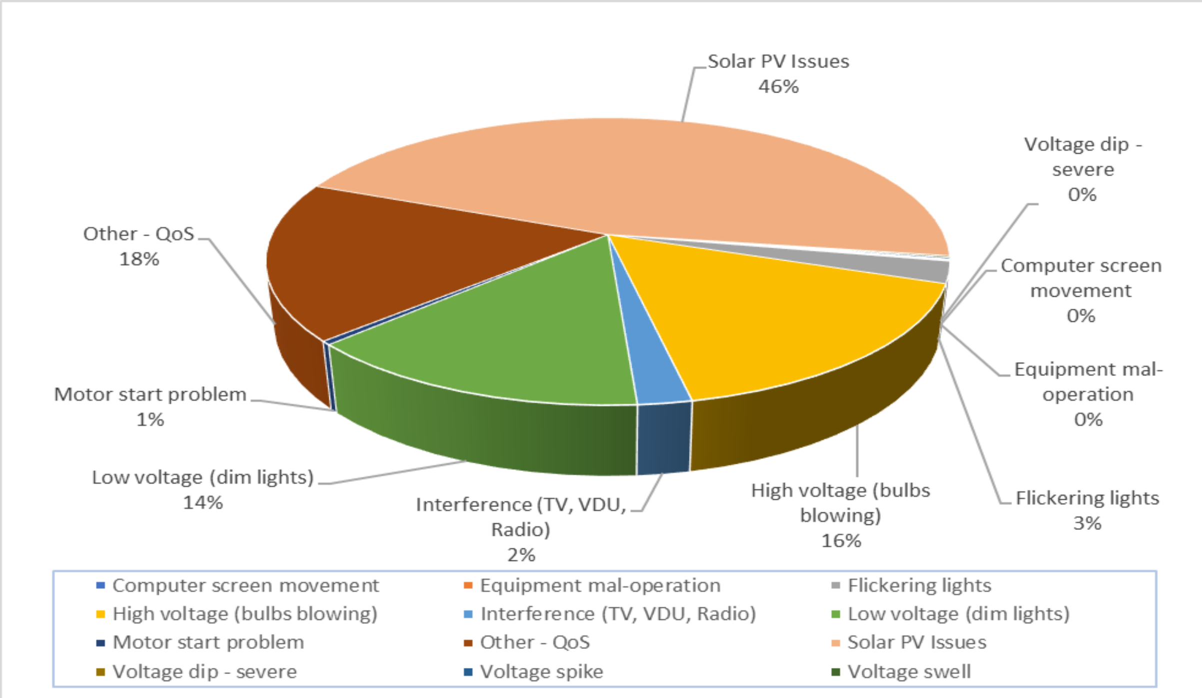
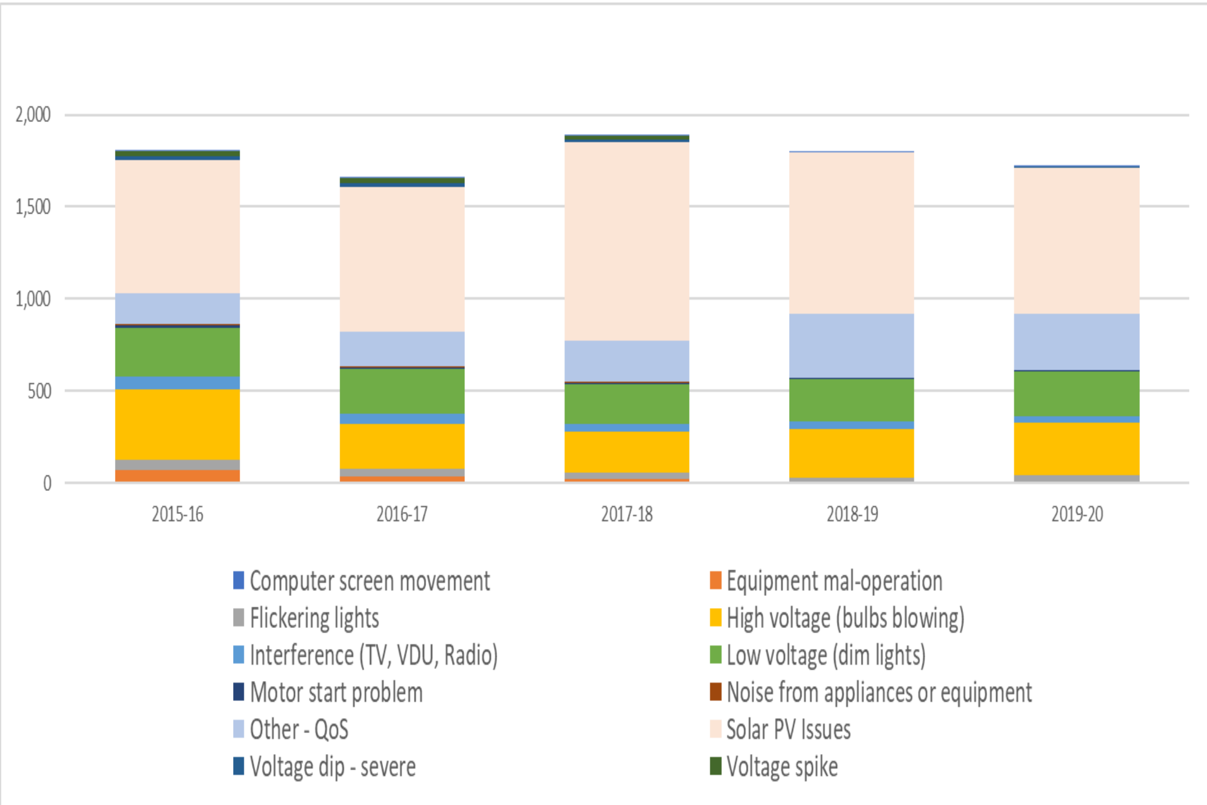


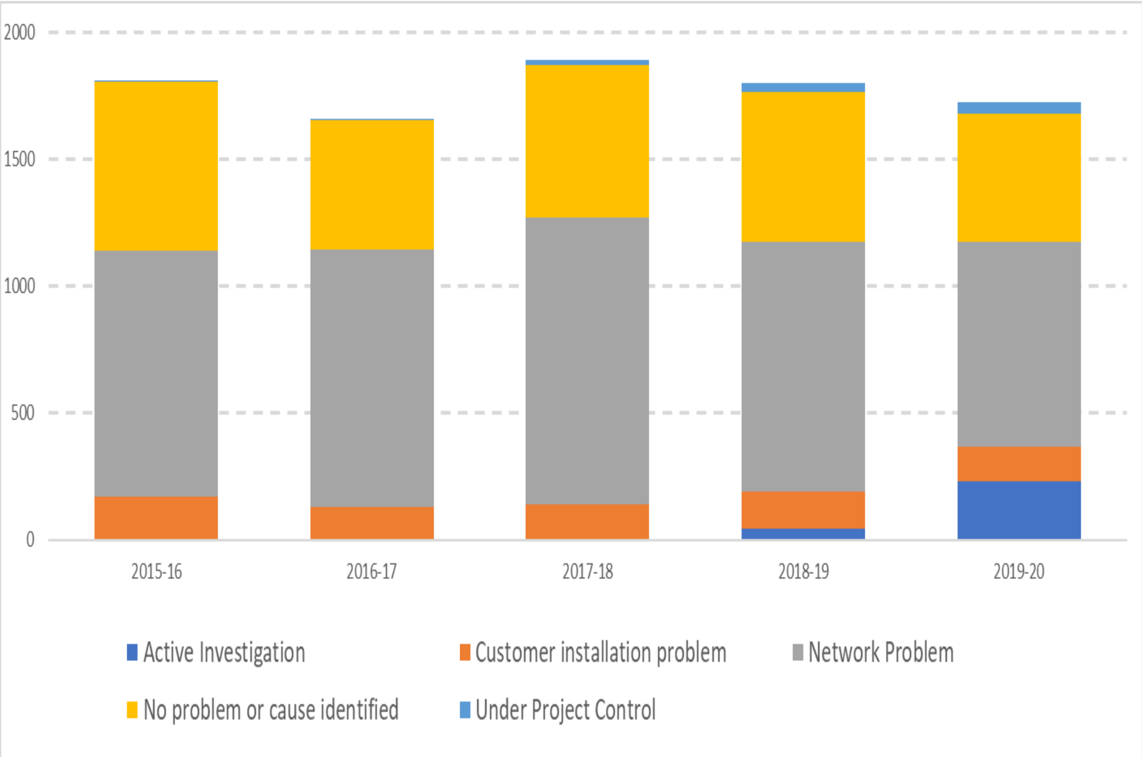
Figure 25: Quality of Supply Enquiries by Year



The number of QoS enquiries received in 2019-20 decreased by 4.38% when compared to the previous year from 1,801 to 1,722 enquires. The ongoing connection of solar PV systems has continued to be the leading cause for customers to make a QoS enquiry.

The causes at close out for QoS enquires is shown in Figure 26. The data shows that 47% of the enquires to date were due to a network issue, there was no fault found for 29% and the fault was on the customers side of the connection for 7.7% of the total enquiries. There are however, 233 (13.5%) enquires considered open and/or under investigation.

Figure 26: Quality of Supply Enquiries by Type at Close Out



10.3 Power Quality Supply Standards, Code Standards and Guidelines

The Queensland Electricity Regulation and Schedule 5.1 of the NER lists a range of network performance requirements to be achieved by DNSPs. Ergon Energy's planning policies takes these performance requirements into consideration when reviewing network developments. The tighter of the limits is applied where there is an overlap between regulations and the NER.

In October 2017 the Queensland Electricity Regulation has amended to change the low voltage (LV) from 415/240 volts +/-6% to 400/230V +10%/-6% to harmonise with Australian Standard 61000.3.100 and a majority of other Australian states.

Some of the relevant requirements under the Regulations/Rules are listed below and further defined in Table 26, Table 27, Table 28 and Table 29, namely:

- **Magnitude of Power Frequency Voltage** - During credible contingency events, supply voltages should not rise above its normal voltage by more than the time dependent limits defined in Figure S5.1a.1 of the Rules
- **Voltage Fluctuations** - A NSP must maintain voltage fluctuation (flicker) levels in accordance with the limits defined in Figure 1 of Australian Standard AS 2279.4:1991. Although a superseded standard, it is specifically referenced under a Derogation of the Rules (S9.37.12) applicable to Queensland
- **Voltage Harmonic Distortion** - A DNSP must use reasonable endeavours to design and operate its network to ensure that the effective harmonic distortion at any point in the network is less than the compatibility levels defined in Table 1 of Australian Standard AS/NZS 61000.3.6:2001
- **Voltage Unbalance** - A NSP has a responsibility to ensure that the average voltage unbalance measured at a connection point does not vary more often than once per hour by more than the amount set out in Table S5.1a.1 of the NER.

Table 26: Allowable Variations from the Relevant Standard Nominal Voltages

Voltage Levels	Electricity Regulations	NER
Low voltage (less than 1kV)	+10 / -6%1	±10%
Medium voltage (1kV to 22kV)	±5%1	±10%
High voltage (22kV to 132kV)	As Agreed	±10%
[1] Limit is only applicable at customer's terminals.		

Table 27: Allowable Planning Voltage Fluctuation (Flicker) Limits

Voltage Levels	Electricity Regulations	NER
Low voltage (less than 1kV)	Not Specified	Pst = 1.0, Plt =0.8 (ΔV/V – 5%)
Medium voltage (11kV) and 33kV)	Not Specified	Pst= 0.9, Plt=0.8, (ΔV/V – 4%)
High voltage (110kV, 132kV)	Not Specified	Pst= 0.8, Plt=0.6, (ΔV/V – 3%)

Table 28: Allowable Planning Voltage Total Harmonic Distortion Limits

Voltage Levels	Electricity Regulations	NER
Low voltage (less than 1kV)	Not Specified	7.3%
Medium voltage (11kV to 33kV)	Not Specified	6.6%
Medium voltage (66kV)	Not Specified	4.4%
High voltage (132kV)	Not Specified	3%

Table 29: Allowable Voltage Unbalance Limits

Voltage Levels	Electricity Regulations	NER
Low voltage (less than 1kV)	Not Specified	2.5%
Medium voltage (1kV to 33kV)	Not Specified	2.0%
High voltage (66kV to 132kV)	Not Specified	1.0%

Where there is need to clarify requirements; the relevant Australian and International Electro-Technical Commission (IEC) Standards are used to confirm compliance of our network for PQ. Ergon Energy Network also has the Standard for Network Performance, which provides key reference values for the PQ parameters.

The Power Quality Planning Guideline, Harmonic Allocation Guideline and the Standard for Transmission and Distribution and Planning are joint working documents with Energex that describe the planning requirements including with respect to power quality. These guidelines apply to all supply and distribution planning activities associated with the network.

10.4 Power Quality Performance in 2019-20

10.4.1 Power Quality Performance Monitoring

Processes for PQ monitoring have been developed from the requirements of the Queensland Electricity Regulations and the NER Rules.

Ergon Energy started to install network monitors in 2009 and currently has in excess of 2,560 PQ monitors on distribution transformers throughout the network that monitor and record the network PQ performance. These monitors are remotely monitored and provide an insight into power quality performance at the junction of the Medium Voltage (MV) and LV networks. Monitors currently cover more than 930 feeders or roughly 78% of the feeders in the network.

Each of these monitors contributes to give an indication of the state of the network for PQ parameters. The monitor data is downloaded four times daily, recorded, accessed and presented based on 10 minute averages. The data is usually available the following day. PQ reports are presented in various ways to identify potential network issues that may need urgent investigation and resolutions. All PQ monitors are installed on the terminals of the distribution transformers and therefore there maybe differences at the end of the LV feeder due to high load during the evening and rise in voltage during the day depending on the amount of solar along the feeder.

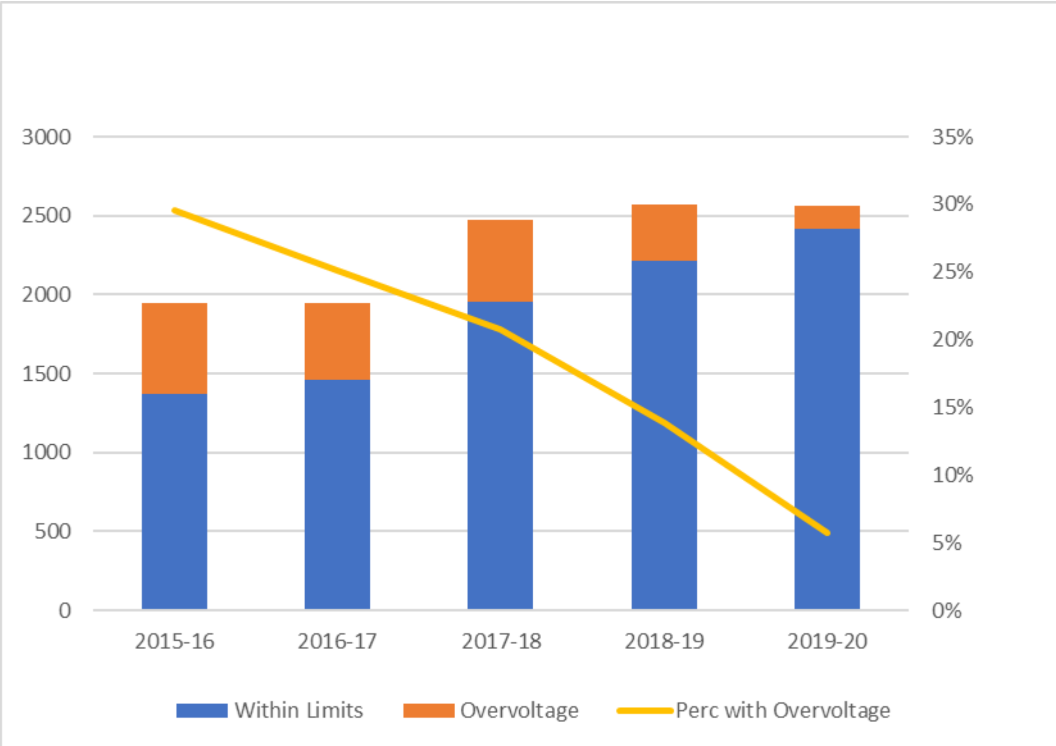
10.4.2 Steady State Voltage Regulation – Overvoltage

The number of monitored sites that reported overvoltage outside of regulatory limits of 253V was 6% for 2019-20. This means 6% of sites recorded an exceedance of the upper limit for more than 1% of the time based on 10 minute averages. This is a notable improvement from the 18-19 year when there were 13.87% of sites with overvoltage. Figure 27 shows the number of monitored sites that have recorded over-voltage conditions for the last five years and percentage of overvoltage sites for each year. This is the seventh consecutive year that improvement has occurred to reduce the number of sites with overvoltage issues.

Ergon Energy has continued to improve the network voltage performance by constantly working to review network data and modelling and make the necessary changes to ensure the network is meeting all PQ parameters. The impact of the roll out of 230 volts is now being seen throughout the network. The take-up of solar PV is continuing throughout regional Queensland and as a result the requirement to monitor power quality is an increasing necessity.

All PQ monitor sites are at the terminals of the distribution transformers and Ergon Energy recognises the need to have monitors at the end of long LV runs where a high percentage of customers have solar systems. Sites that only have a monitor at the transformer terminals may find the voltage not within limits at the further end of the LV network under load conditions. Improvements will continue to be achieved during 2020-25 regulatory control period, by implementation of the Customer Quality of Supply strategy. Further analysis of monitored transformers is continuing as more sites are fitted with monitors.

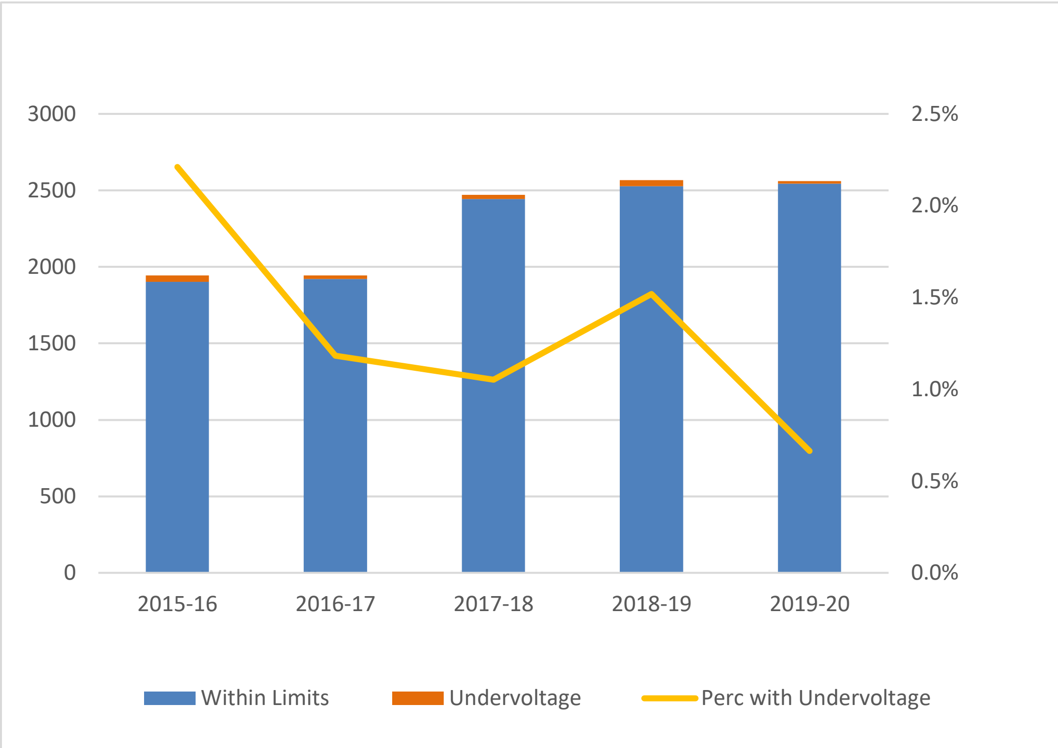
Figure 27: Overvoltage sites



10.4.3 Steady State Voltage Regulation – Undervoltage

The change to 230V sees the lower limit for low voltage move to 216.2V. The number of monitored sites recording under-voltage issues outside of the regulatory limit of 216.2V was 0.7% for 2019-20. This means 0.7% of monitored sites recorded an exceedance of the lower limit for more than 1% of the time based on 10 minute averages. Figure 28 shows the number of monitored sites that have recorded under-voltage conditions for the last five years. There has been a decrease in the number of sites experiencing under voltage issues.

Figure 28: Undervoltage Sites

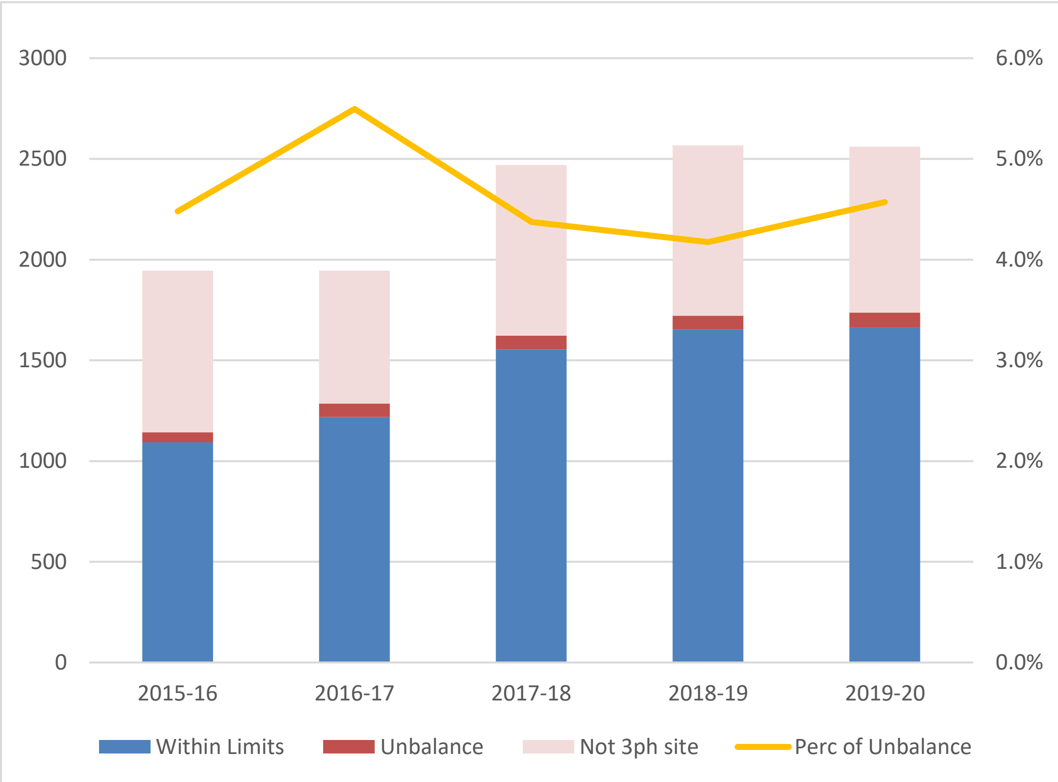


10.4.4 Voltage Unbalance

Data from the monitored 3-phase sites shows that 4.6% of these sites were outside of the required unbalance standard of 2.5% during 2019-20. Figure 29 shows the number of sites that have recorded unbalanced conditions for the past five years.

Typically, unbalance is seen on the rural feeders where there are SWER networks and a large number of single phase customers in the associated downstream feeder, which impacts on the overall balance of the three phase feeder. Due to predominantly radial nature and high number of single phase transformers, Ergon Energy's distribution network has a high number of monitors on single phase transformers. Monitored sites that are not three phase, are also shown as part of the five year trend shown in Figure 29.

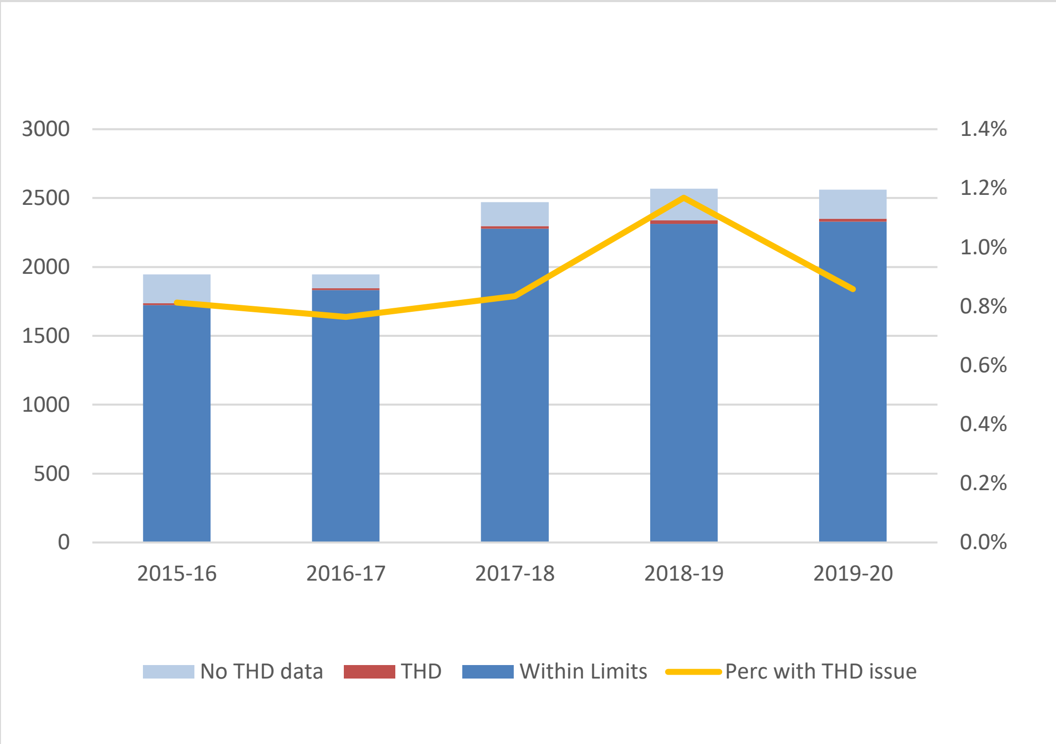
Figure 29: Voltage Unbalance Sites



10.4.5 Harmonics Distortion

Harmonics are a measure of the impurity of the voltage and are recorded as Total Harmonic Distortion (THD) representing all harmonics levels from the second to the fiftieth harmonic. Not all monitored sites are capable of measuring harmonic with 211 of the 2,561 sites (8.2%) not capable of harmonic reporting. There were 0.86% of sites recording harmonics that exceeded the regulatory limits of 8.6% during 2019-20. This figure will be at the upper limit as when some faults occur with voltage and unbalance it impacts on harmonics recorded values. Figure 30 shows the percentage of sites that exceed THD limits.

Figure 30: Total Harmonic Distortion (THD) Sites



Typical sources of harmonic distortion include electronic equipment incorporating switch mode power supplies, modern air conditioners with variable speed drive inverters and solar PV inverters. The data indicates that customer equipment is largely conforming to the Australian Standards for harmonics emissions, but continual vigilance is required to ensure harmonic levels remain within the required limits.

10.5 Power Quality Ongoing Challenges and Corrective Actions

During 2019-20 Ergon Energy continued to focus its voltage management strategy on all voltage levels of the network however a high percentage were associated with the LV customers. In 2019, Energy Queensland finalised the Customer Quality of Supply Strategy which covers the Power Quality strategy for Ergon Energy and Energex. It covers the changing network connections and configurations, increasing customer peak demands, the high penetration of solar PV and its continued growth, the battery energy storage systems and the impact of Electric Vehicles (EVs).

10.5.1 Medium/High Voltage Network

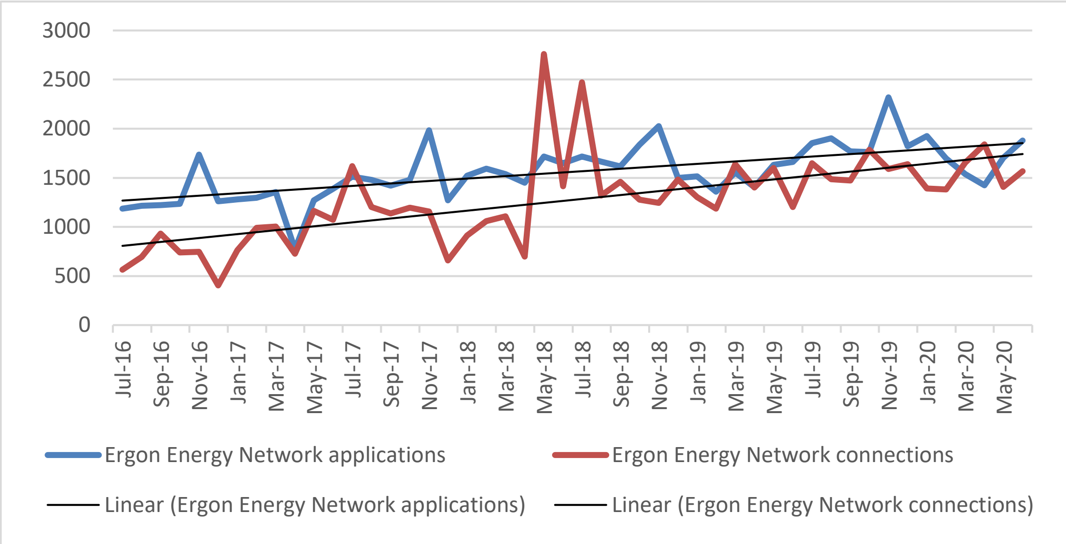
Ergon Energy has a high number of large industrial customers and large embedded generators (solar farms, bio-fuels) that have equipment that can impact the power quality parameters such voltage and harmonics. Many of these customers are on dedicated feeders and it is not possible to monitor all these customers' feeders. Ergon Energy has installed PQ analysers on a number of these feeders at zone substations and will continue to install additional analysers to build a profile of the power quality parameters for the type of industry and ensure customer connections remain compliant for the PQ parameters as part of the connection agreement.

10.5.2 Low Voltage Network

The high penetration of solar PV systems on the LV networks has highlighted some of the limitations in the network. The main issues have been in balancing the solar PV systems during the day and peak loads during non-daylight periods on the LV network. This continues to require on going work to ensure the PQ parameters are maintained within limits and to ensure neutral currents are limited. The Customer Quality of Supply Strategy for 2020-25 has identified the need for further monitoring of the LV network.

Figure 31 shows that the number of solar applications and connections has continued to increase each year for the past 4 years. The continued increase of solar connections shows that continual vigilance and expenditure will be required throughout the network to ensure it remains compliant with relevant PQ standards. The Customer Quality of Supply Strategy has identified that to the high percentage of LV customers with solar systems it will require continual work in balancing customers connections on the LV network to minimise neutral current and negative load in the MV network.

Figure 31: Solar PV Applications and Connections



As part of its Opex program, Ergon Energy will carry out targeted transformer tap adjustment programs and rebalancing programs to address voltage issues in areas with solar PV penetration exceeding 50%. This is supported by data showing significant numbers of distribution transformer tap settings on non-optimal settings and unbalance of voltages at distribution transformer LV terminals.

10.5.3 Planned Actions for 2020-25 Regulatory Period

Ergon Energy will continue to have a focus on voltage management for low and medium voltage network issues identified through PQ data analysis. This will be further supported by determining suitable methods to monitor and rectify the network to ensure compliance continues. Typical rectification of voltage and PQ issues could include the installation of Statcoms, switched capacitor, Low Voltage Regulator (LVR) and On Load Tap Changers (OLTC).

Chapter 11

Emerging Network Challenges and Opportunities

11. Emerging Network Challenges and Opportunities

Ergon Energy faces a number of specific network challenges and opportunities as it seeks to balance customer service and cost. These include the continuing issues related to the growing penetrations of solar PV, battery energy storage systems and electric vehicles, climate change, as well as land and easement acquisition.

11.1 Solar PV

11.1.1 Solar PV Emerging Issues and Statistics

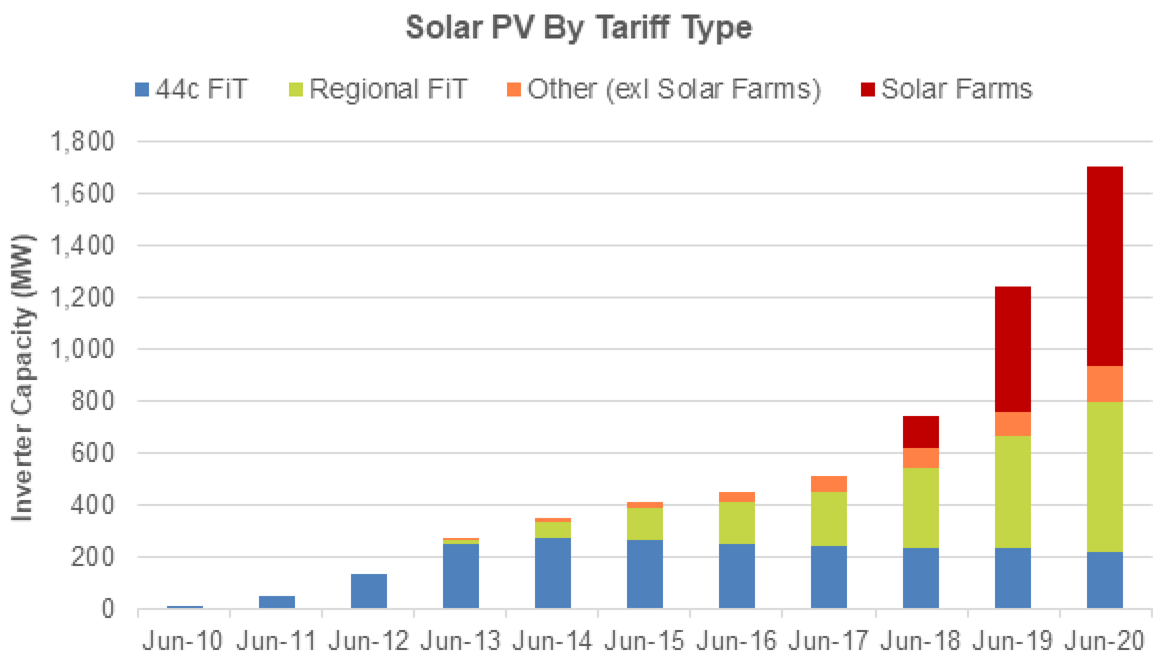
Queensland has the highest penetration of solar PV systems on detached houses (36%) not only in Australia,[50] but compared with any country. In our network, 30% of detached houses have a solar PV system connected, with an average inverter capacity of around 4.6 kW. The rapid uptake of solar PV has changed the way power travels through the network, from a purely one-way to bi-directional energy flow. The impact is greatest in the LV network and creates a number of system design and operation challenges. Due to the PV penetration level and the nature of its network, Ergon Energy is on the leading edge of the Australian distribution industry in responding to these issues. It is deploying a range of projects and initiatives to ensure safe operation of the network, a secure and high-quality supply, and economically viable solutions for customers both with and without solar PV.

The growth rate in solar PV connection volumes trended upwards in 2019/20. An average of around 1,600 new systems with a combined capacity of around 39 MW, and average capacity of 24.8 kW (including solar farms), were connected per month. Ergon Energy now has a total of 179,030 PV systems connected (at June 2020) with an installed capacity of 1,708 MW, the majority of which are installed on residential rooftops.

Figure 32 shows the increase in installed solar PV capacity, including small- and medium-scale PV systems and solar farms. Over the past 12 months, the volume of connections increased by around 12%, and the PV capacity increased by around 38%. Of the 468 MW of PV capacity added, around 289 MW, or almost two-thirds of the capacity, was comprised of solar farms. The growth in the number of small- and medium-scale PV systems is leading to a large number of distribution transformers with high solar PV penetration, and almost 20% of MV distribution feeders have experienced reverse power flows during the middle of the day.

[50] Australian PV Institute, "Mapping Australian Photovoltaic Installations". Accessed 07/08/20, Website: https://pv-map.apvi.org.au/animation

Figure 32: Grid-Connected Solar PV System Capacity by Tariff as at June 2020



Another significant network issue resulting from increased solar PV connections is voltage rise on LV networks. Voltage rises when demand is light, solar PV reduces network demand further, and solar PV inverters export to the grid. At some points in the network, the voltage is raised to the limits of statutory requirements, at which point solar inverters are programmed to trip.

Ergon Energy had approximately 780 QoS enquiries in 2019-20 related to solar PV, predominantly resulting from high voltages. This volume was 9% down from the previous year. As the number of solar PV systems increases, managing the voltage within statutory limits becomes more challenging. We have undertaken, or are undertaking, a range of initiatives to minimise the impact of solar PV on the network and reduce the cost to resolve constraints, including the transition to a 230V network standard, tariff review, trialling new technologies such as LV Statcom and energy storage trials. We have also worked with a diverse group of industry partners through the Solar Enablement Initiative and Expanded Network Visibility Initiative with the aim of applying advanced modelling techniques to enhance our network modelling capability and improve its hosting capacity. Implementing a 230V network standard is allowing more voltage variation, allowing many existing solar PV systems to operate more effectively and allowing more customers to connect solar PV systems and export to the grid.

From a customer perspective Ergon Energy continues to streamline the application process and reduce network risks by enabling minimal- and partial-export connections. Minimal-export generating units essentially don't permit export of generated electricity to the distribution network. Applications for export-limited inverters remain in the minority as the increase in September 2017 to the capacity limit under the Queensland Government's regional Feed-in-Tariff (Regional FiT) from 5 kW to 30 kW has made exporting more attractive for some customers. Ergon Energy and Energex have jointly released an updated LV connection standard and draft HV connection standard covering solar PV systems, as discussed in Section 11.2.2.

11.1.2 Impacts of Solar PV on Load Profiles

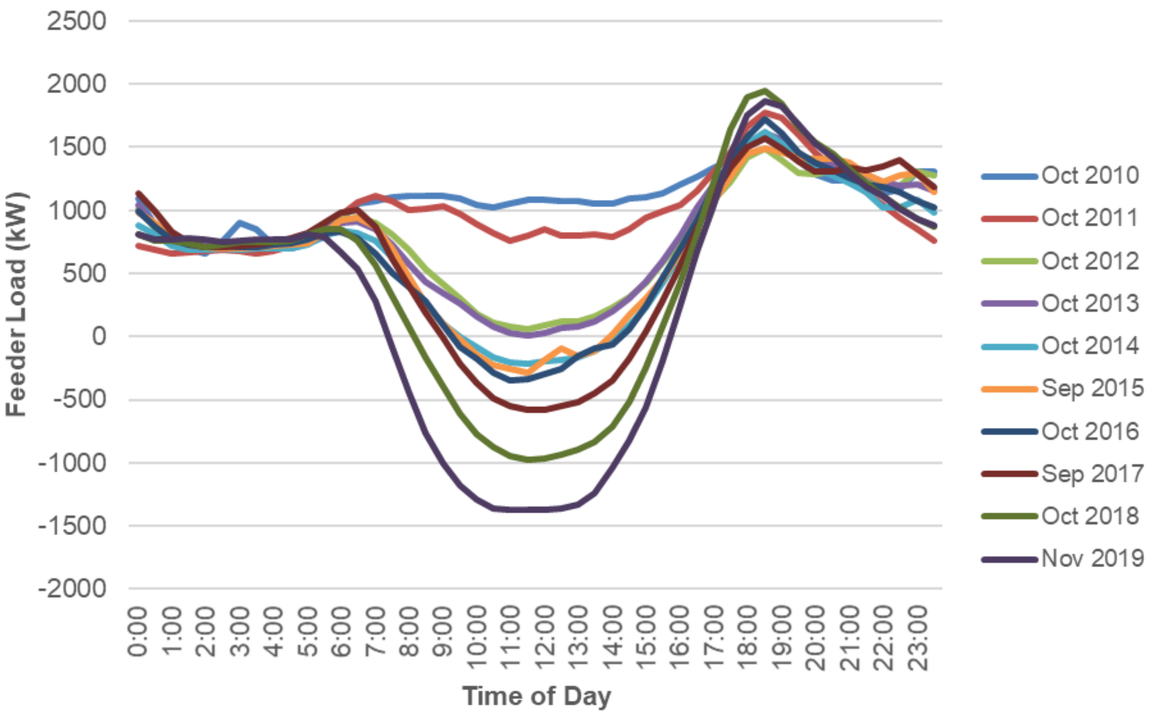
Solar PV is impacting load profiles, asset utilisation, load forecasting and load volatility.

Traditionally, the total aggregated demand of our network peaks is between mid-afternoon and early evening during summer, generally on the hottest days of the year. The impact of solar on the shape of our network load profile is evident in peak load statistics. While the 2019-20 demand peak was recorded at 7.00pm in the evening, the actual peak in consumption would have occurred at 3.00pm if not for PV generation. However, on that day in December 2019, solar generation was meeting more than 23% of the total Queensland network demand at midday, and nearly 15% at 3.00pm when the peak would have occurred. While this changed the shape of the network demand during the day, the evening peak remained unaffected, as PV systems were not generating at this time.

The change in load pattern as the penetration of solar PV systems on a feeder has increased is illustrated in Figure 33. This figure shows the daily load pattern on a residential feeder in Burrum Heads (near Hervey Bay) for the lowest spring midday demand day over nine consecutive years. The daytime generation of solar has increased to the point that the feeder back-feeds significantly through to the zone substation.

The summer peak demand for the feeder is still occurring at approximately the same time of night in 2019 as it did in 2010. While the night summer peak demand has been growing slowly over the years, the midday demand in spring has reduced by over 2MW. This increase in daily variance makes it more challenging to keep the network voltage within statutory limits and can also result in decreased asset life of some equipment as voltage regulation devices operate more frequently.

Figure 33: Burrum Heads Feeder Profile: Annual Changes Observed for Spring 2010-19



The increase in EG on our feeders makes it more challenging to identify underlying load growth, as additional daytime load can be offset by local generation. Variation to energy use patterns or growth in load only becomes fully apparent when an unexpected event causes the solar PV systems to stop generating.

On occasions where solar PV generation is not available, such as during an afternoon thunderstorm, the full customer load is supplied from the network, which can result in large and rapid variations in energy flows.

In this instance the demand on the feeder was extremely volatile; low during the day with consumers generating and also consuming energy, then rapidly peaking when the storm clouds rolled in. The solar PV generation fell away completely for a short time while the customer load reduction was delayed. The net result was a peak demand event in the early afternoon that was higher than the feeder's usual evening peak.

As networks are designed for supplying the maximum demand required by our customers, increasing penetrations of intermittent embedded generating units will significantly increase the complexity of planning and operating networks, could result in excessive voltage drops, overloading of components, protection operation issues and loss of supply if not appropriately managed.

The following figures show the uptake of solar PV across the Ergon Energy network based on zone substation supply areas. Figure 32 indicates the total number of customers in each zone substation who have solar PV installed, and Figure 33 indicates the total installed capacity in the same areas. The five zone substation areas with the highest numbers have been highlighted on each map.

Figure 34: Number of customers with Solar PV by Zone Substation

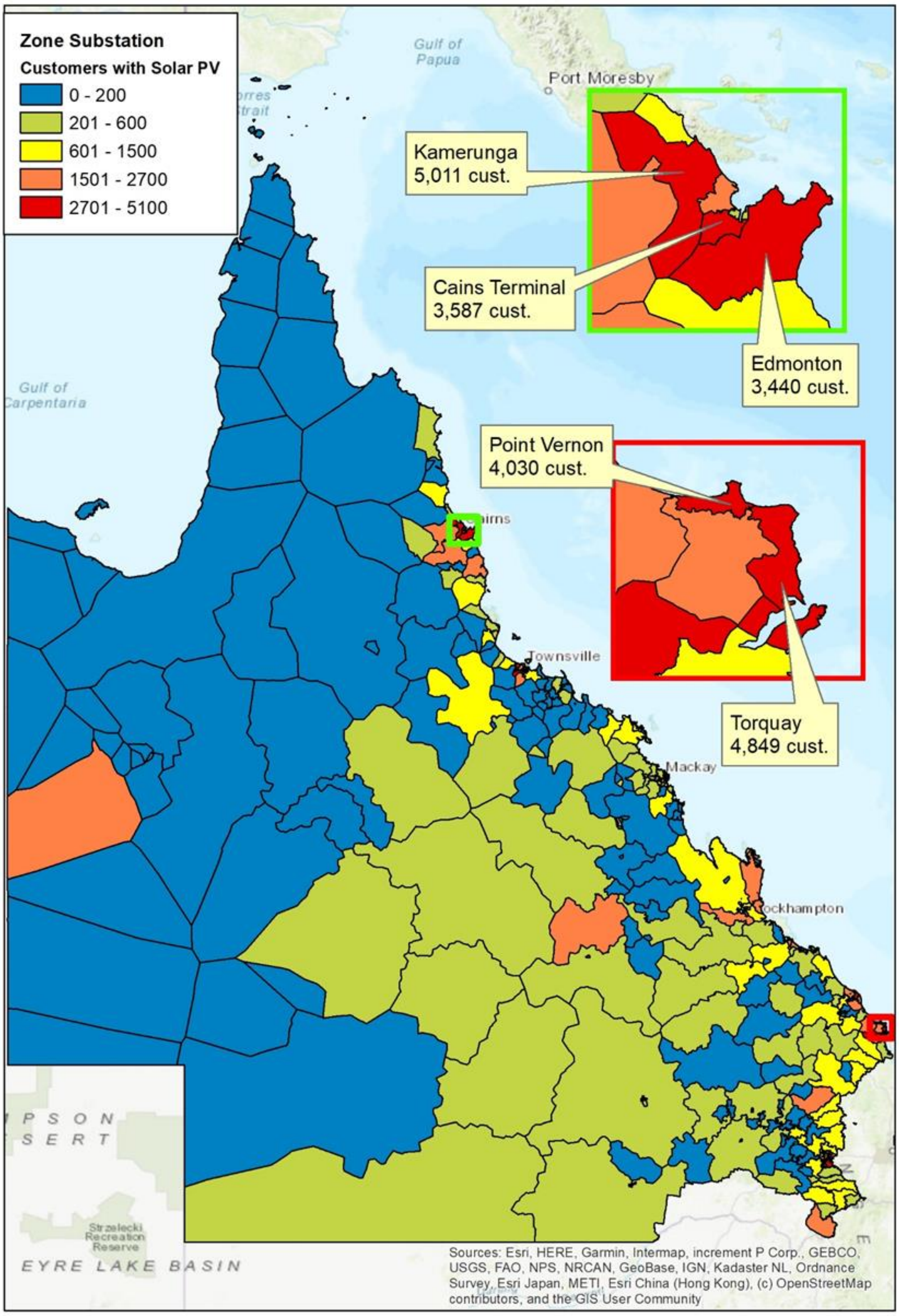
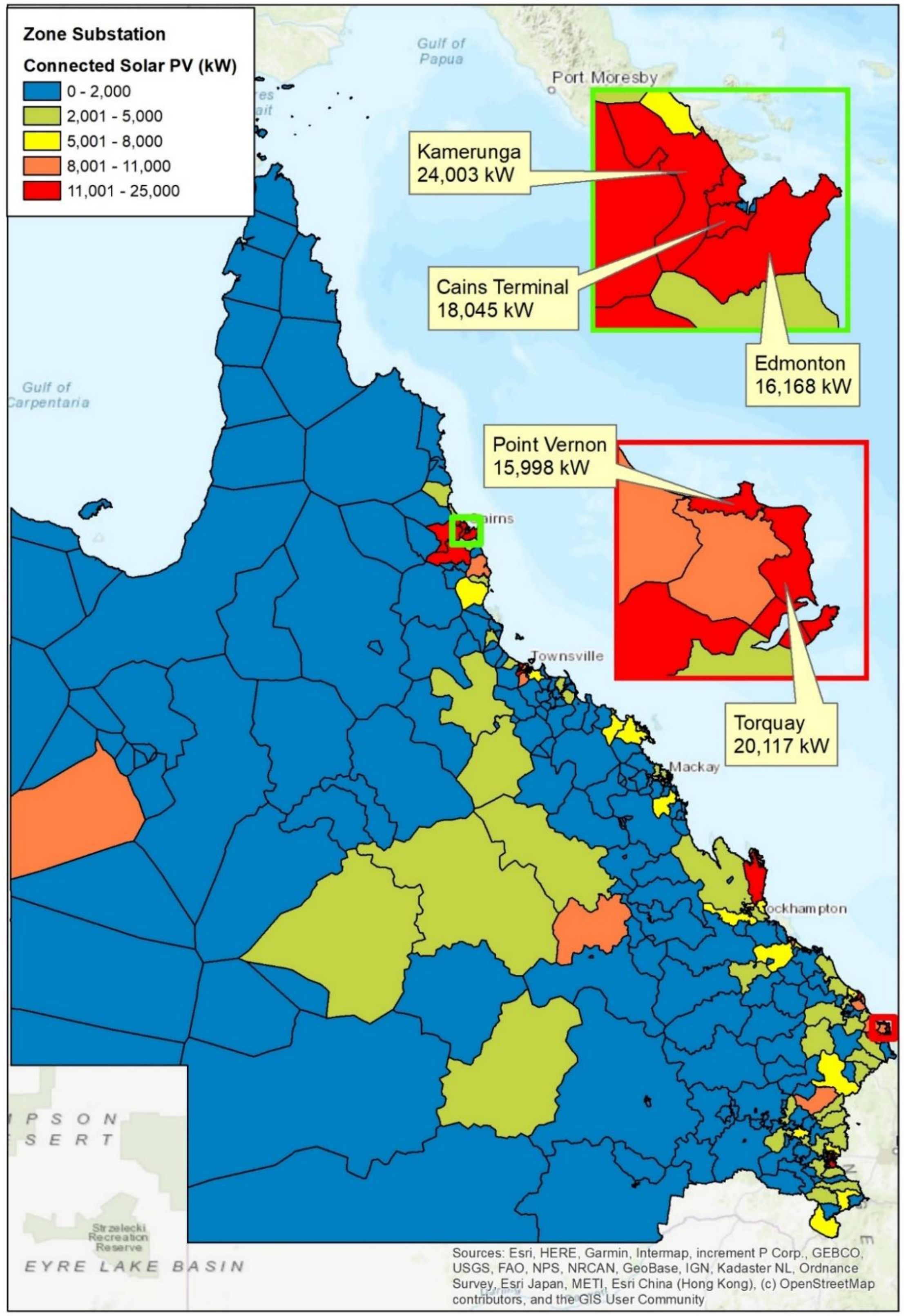


Figure 35: Installed Capacity of Solar PV by Zone Substation



11.1.3 Solar PV Remediation Options

A range of traditional, new technology and non-network solutions as shown in Table 30 are used to address network limitations associated with increasing PV penetrations at the LV, MV and zone substation levels. The most cost-effective solution and the PV penetration at which it is required will be site specific and overtime several solutions may be implemented to maximise PV hosting capacity.

Table 30: Remediation Options for Increasing Penetrations of Solar PV

	Network Solutions	Non-network Solutions
Increasing S V Penetration	1. Change transformer tap	I. Update zone substation AFLC schedules
	2. Phase balance PV & load	**Coordinated via LV DERMS**
	3. Upgrade distribution transformer capacity	
	4. Install additional distribution transformer &. reconfigure LV area	II. Implement Dynamic Operating Envelopes on new DER
	5. Re-conductor LV mains	
	6. MV upgrade where multiple LV networks impacted	III. Procure non-network load/generation shifting service from the market
	7. New technology (LV Regulator, Statcom, Voltage Regulating Distribution Transformer)	

11.2 Strategic Response

11.2.1 Future Grid Roadmap

While there are a number of scenarios that could eventuate beyond 2025, it is certain that the immediate period (to 2025) and ultimately at least the next two decades will see significantly higher levels of intermittent and controllable Distributed Energy Resources (DER), new and increasingly active energy service providers, and an increased emphasis on the role of distribution networks on the overall system and market operation. Drawing from work such as the Energy Networks Australia and CSIRO Electricity Network Transformation Roadmap[51] (ENTR) and looking globally at other progressive markets – such as the UK, Germany, California, New York, and New Zealand – it is apparent that the network business model will need to further evolve to become the operator of an intelligent grid platform.

[51] Website: https://www.energynetworks.com.au/projects/electricity-network-transformation-roadmap/

In response Ergon Energy has developed a Future Grid Roadmap[52] to provide a guiding holistic pathway for transforming the network business to have the capability necessary to achieve the following:

- Support affordability while maintaining security and reliability of the energy system
- Ensure optimal customer outcomes and value across short, medium and long-term horizons – both for those with and without their own DER
- Support customer choice through the provision of technology neutrality and reducing barriers to access the distribution network
- Ensure the adaptability of the distribution system to new technologies
- Promoting information transparency and price signals that enable efficient investment and operational decisions.

As an immediate priority, the roadmap also outlines the no-regret investments necessary to ensure efficient management and operation of the distribution network during the immediate period, while allowing a smooth transition to the future network business role.

11.2.2 Improving Standards for Increased DER Connections

In order to ensure that Ergon Energy continues to develop collaborative and mutually beneficial stakeholder relationships we have continued to engage with the solar PV and battery industries to evolve distributed energy resource (DER) connection standards.

In November 2019, Ergon Energy introduced improvements to its small IES standard that allowed customers to start generating electricity from their solar or batteries as soon as they have been commissioned, where modern metering is already installed.

In February 2020, the small Inverter Energy Systems (IES) and LV standards were updated to align with the National DER Connection Guidelines from Energy Networks Australia (ENA). Using the guidelines improves transparency and consistency in standards requirements between distribution networks in Australia. As more distribution networks make the move towards using the guidelines, Ergon Energy will seek to work with other jurisdictions to create greater alignment to improve outcomes for customers, industry and networks.

As part of the work to deliver standards to the connection guidelines, Ergon worked collaboratively with other distributors to develop nationally supported uniform power quality response mode settings (volt-var, volt-watt) which enable the management of higher penetrations of DER. These settings have been included in our standards, taking advantage of advanced inverter technology to provide positive customer outcomes.

In July 2020 the small IES and LV standards were updated to align with Ergon's new Connection Policy. The Connection Policy delivered new aligned Model Standing Offer connections between Energex and Ergon Energy. The assessment criteria were reviewed for alignment and with modern engineering principles to deliver increased hosting capacity for DER exports.

[52] Webpage: https://www.talkingenergy.com.au/40930/documents/98191

Ergon Energy has also delivered an update to its joint HV connection standard for DER aligning with the National DER Connection Guidelines with Energex which:

- Introduces clear DER communication requirements along with cyber security to ensure safe, reliable management of a distributed grid, and
- Introduces various measures to help network security and resilience by adopting best practice requirements.

11.3 Electric Vehicles

The charging of Plug-in Hybrid Electric Vehicles (PHEVs) and Battery Electric Vehicles (BEVs) creates a new class of electrical load that could have significant impacts on the low voltage electricity network and upstream aspects of the electricity supply chain. EVs are already popular overseas, so while still forming an emerging industry in Australia, their numbers are expected to grow dramatically in Queensland as their purchase costs decrease, availability increases and more charging infrastructure is deployed.

The growth in EV numbers also presents us opportunities to collaborate with relevant stakeholders to create customer access to optimal private and public charging solutions based on the affordability and convenience priorities of EV owners. If EV owners increasingly charge their vehicles outside network peak demand periods, this will enhance network utilisation, reduce customer charging costs and deliver many other significant benefits to our business and society. As the proportion of renewable energy entering the grid, and the uptake of solar PV systems, increase, the greenhouse gas emissions intensity of electricity reduces, creating an increasing environmental advantage for EVs over petrol- or diesel-fuelled vehicles.

In the 12 months to 30 June 2020, the volume of plug-in EVs registered in Queensland increased by 80% to more than 3,400 vehicles. However, EVs still only account for 0.12% of all registered cars in Queensland, and 1.0% of cars sales over the previous 12 months. Battery storage capacity of currently available PHEVs and BEVs is in the range of 12 kWh (e.g. Mitsubishi Outlander PHEV) to 100 kWh (e.g. Tesla Model S [BEV]). A 120 kW Tesla Supercharger is capable of charging the Model S battery from 20% to 80% capacity in around 30 minutes. Ultra-fast charging stations are rated up to 350 kW.

Ergon Energy aims to lower relevant barriers to EV ownership and better understand and capitalise on EV charging. To help achieve this, we have developed a Network Electric Vehicles Tactical Plan, a summarised version of which is available on our website.[53] The tactical plan outlines the key actions our network business will take over the next one to two years to prepare for EVs.

As the proportion of renewable energy entering the grid, and the uptake of solar PV systems increase, the greenhouse gas emissions intensity of electricity reduces, creating an increasing environmental advantage for EVs over petrol- or diesel-fuelled vehicles.

[53] Website: https://www.ergon.com.au/network/manage-your-energy/smarter-energy/electric-vehicles-ev/our-ev-plan
Associated document: https://www.ergon.com.au/__data/assets/pdf_file/0006/854565/Network-EV-Tactical-Plan-Overview-FINAL.pdf

11.4 Battery Energy Storage Systems

Ergon Energy continues to monitor developments in the residential and commercial Battery Energy Storage Systems (BESS) market. We have built on our previous trials and extended the testing of BESS to a real-world environment in customers' premises. The trials and tests we have performed in this area have enabled us to continue to engage with the energy storage market on standards, safety and connection requirements. We recognise the potential for BESS to provide network benefits (peak demand and/or power quality issues) and customer benefits. However, we also recognise the barriers to effectively utilising this developing resource.

The number of customer battery installations continues to grow modestly, with around 2,900 BESS now connected to the Ergon network. The average capacity of a home battery storage system is around 10kWh. The largest battery connected to our network currently is rated at 8MWh, or 8,000kWh, with a maximum output of 4,000kW.

BESS for network use continue to be developed, particular focusing on the potential for energy storage in grid support and microgrid applications. Since the completion of the deployment of our Grid Utility Support Systems (GUSS) comprising energy storage in SWER networks, we have been focussing on further development of the use of energy storage for fringe of grid, microgrids and isolated networks areas.

We have developed battery monitoring systems for our BESS that are supporting existing infrastructure such as communications facilities to improve our asset management functions for these resources.

We have engaged the market for the first tier of Stand-Alone Power Systems (SAPS) to investigate renewable generation and energy storage solutions as an alternative to Fringe-of-Grid assets where customer-beneficial and cost-effective outcomes can be achieved.

11.5 Land and Easement Acquisition Timeframes

In order to ensure we can operate within the land and easement acquisition timeframes and meet community expectations for engagement, Ergon Energy needs to secure land in strategic areas before urban expansion has occurred and demand has increased. It can take many years to finalise land acquisition, therefore the need to commence these activities early in the process is vital.

The land and easement acquisition process must be completed well ahead of finalisation of design and construction of new infrastructure. It is managed in conjunction with proactive community engagement activities to ensure community expectations are balanced with the technical requirements, environmental outcomes, and the time and cost constraints of the project.

Strategic land acquisition is based on current forecasting. We are however, in a challenging environment with the potential risk of project scope changes as new technologies or non-network alternatives become available. Changes to project scope of this nature, may result in land or easement stranding if the changes are significant by the time the solution is required. During this time, there may also be changes to state planning policies, statutory compliance requirements and changes to legislation that may affect the project scope and delivery.

Despite the changes in demand and a reduction in the capital works program, the need to identify future network constraint areas or areas flagged for future urban or commercial development will need to continue.

11.6 Impact of Climate Change on the Network

A changing climate is leading to changes in the frequency and intensity of extreme weather and climate events including extreme temperatures, greater variations in wet and dry weather patterns (e.g. flooding, drought), bush fires, tropical cyclones, storms and storm surges as well as changing oceans and sea levels. This suggests that there may be the likelihood of inundation or other damage to exposed and low lying Energy Queensland assets creating reliability problems as well as associated maintenance and asset replacement expenditures.

Ergon, as part of EQL, acknowledges and aligns with the Queensland State Government Pathways to a climate resilient Queensland, Queensland Climate Adaption Strategy 2017-2030 and now has a Low Carbon Future Statement and an Environmental Sustainability and Cultural Heritage Policy.

Ergon Energy proposes to address the impacts of climate change by the following measures:

- Keeping abreast of changes in planning guidelines and construction standards
- Keeping abreast of new storm surges and flood layers produced by councils and other agencies
- Undertaking surveillance and flood planning studies on network assets which are likely to be impacted by significant weather events, storm surges and flooding
- Undertaking network adaptions that assist in mitigating the risk of bushfire.

11.7 Large-scale Renewables Projects

Ergon Energy is currently managing more than 110 enquiries, from preliminary to final commissioning stages, totalling more than 3GW of renewable energy investment. To date, more than 1.2GW of large-scale renewable generating systems is connected to the Ergon Energy network, in addition to more than 1.9GW of renewable energy generating systems connected to Powerlink's transmission network in regional Queensland.[54] Our support for these projects has the potential to provide a major economic benefit for regional Queensland as we move towards a renewable energy future. Ergon Energy continues to address the challenge of connecting large-scale generation to the distribution network including system strength assessment, determining the effect on assets, rule changes, and divergence in the national electricity rules as they are applied to TNSPs and DNSPs.

[54] Website Source: 2020 Powerlink TAPR - https://www.powerlink.com.au/reports/transmission-annual-planning-report-2020

Chapter 12

Information Technology and Communication Systems

12. Information Technology and Communication Systems

12.1 Information Communication and Technology Investment 2019-20

This section summarises the material investments Ergon Energy has made in the 2019-20 financial year, relating to ICT systems.

The key investment priority during the year was to progress programs within the Digital Enterprise Building Blocks (DEBBs) portfolio, with key milestones achieved in the following areas:

- Desktop Transformation Program
- Human Resource Employee Central Platform
- Financial and Procurement Services
- Health Safety and Environment
- Governance Risk and Compliance, and
- Enterprise Content Management.

In addition to this there were a number of operational investments commenced or completed to ensure the ongoing stability of Energy Queensland's suite of digital capability and infrastructure.

Table 31 provides an initiative level summary of ICT investment undertaken in 2019-20. These include projects which commenced prior to this year and investments not completed by 30th June 2020. Further information on the scope of each initiative is included below.

Table 31: ICT Investments 2019-20

Description	2019-20 Actual Cost $M
Corporate Services	$34.08
Network Asset Management	$24.56
Network Operations	$10.00
Enterprise Services	$4.34
Customer, Market and Metering	$1.46
Infrastructure, Security and Devices	$13.30
Minor Applications Change and Compliance	$6.74
Total	**$94.48**

Note: Actuals (as of 30 June) include ICT Managed Capex Program of work specific investment for Ergon Energy Corporation Limited only (i.e. does not include ICT investment funded through other portfolios already identified in other sections of this report).

Information Technology and Communication Systems

Corporate Services

Commencement of the planning and procurement phase for the replacement of Ergon Energy's Enterprise Resource Planning (ERP) and Enterprise Asset Management (EAM) systems began in 2016-17 and continued throughout the regulatory period. Ergon Energy's core ERP/EAM system reached both technical and financial obsolescence in mid-2015. Renewal of the ERP systems with contemporary systems has enabled Ergon Energy to consolidate satellite applications. The initiatives encompass procurement, people, culture, safety, finance and planning, corporate services and works and asset management footprints. The program has been delivered through Energy Queensland Digital Enterprise Building Block Initiatives program. The sub programs delivered within this initiative encompass the following:

People, Culture and Safety

- Replacement of systems and processes that support the core Human Resource, Payroll and Health, Safety and Environment (HSE) functionality. The new tools support core HR and Payroll, Performance, Recruitment, Training, Workforce Planning and HSE functions
  - Solutions are helping to integrate data across core processes, standardise reporting and analysis and ensure key processes may be performed from the internal network and from mobile devices.

Procurement and Finance Systems

- Replacement of systems and processes that support procurement with a single unified Energy Queensland solution, including managing, sourcing, contract and supplier management, and buying processes
- Integrated processes and systems, both internally and externally, improving collaboration with stakeholders and suppliers
- An advanced source-to-settle solution with the ability to acquire goods and services from the community with simplicity, governance and affordability.
- Enable common processes and standardised analysis and reporting to provide oversight and insights into organisational performance. This includes end-to-end purchasing; maintenance work execution (non-network); time capture and reporting; financial accounting and reporting; solution accessibility through internal network and mobile devices.

Network Asset Management

The Asset and Works Management (AWM) project is part of the Digital Enterprise Building Blocks and implementing a single system and process that supports the distribution business for Ergon Energy. The new tools will support lifecycle and financial management for assets through all stages of the asset lifecycle.

The Geographic Information System (GIS) Portal provides the capability to view all network data, maps and applications in a single environment and replaces legacy disparate solutions. This investment has resulted in improved visualisation and data harmonisation and is an important step as we progress a fully unified GIS solution for Energy Queensland in the coming period.

Network Operations

Ergon Energy's Operation Control systems use ageing technology to manage the distribution of Electricity for Ergon Energy customers. During this period planning has been occurring to deliver a consolidated, proven and modernised platform with consistent business processes for Energy Queensland. This will allow our teams to support each other seamlessly and maximise business continuity in times of significant events.

Additional investment this period has resulted the development of an enhanced and consistent set of outage maps now available on Ergon Energy's website. This will be further enhanced through the above mentioned Unified DMS initiative with real-time visibility and improved monitoring and response times for Ergon Energy crews when electricity outages occur.

Type 6 Meter Reading devices are used by Ergon Energy crews to collect customer data from meters in the field. During this period a project has completed the replacement of end-of-life equipment with contemporary devices (iPhones) ensuring the continuity of network billing.

Enterprise Services

The Desktop Transformation program was initiated to improve technology to deal with evolving business needs, a distributed workforce, changing ways of working and an increasingly complex cyber security environment. Investment in this program has provided Ergon Energy users with the ability to securely connect and consume digital services and information via contemporary software solutions such as Microsoft Office, SharePoint and other collaboration tools, on current operating environments and devices. The implementation successfully completed in June 2020.

Customer Market and Metering

Ergon Energy's Distribution Customer and Market Operations business continues to function in a period of internal change and regulatory reforms. Substantial regulatory reforms such as National Energy Customer Framework (NECF) and more recently the introduction of the Power of Choice is driving consumer flexibility and choices in the way consumer's use and purchase electricity. Industry impacts such as solar, battery storage, intelligent networks and electric vehicles are also driving customer choice.

Investment against this initiative in 2019-20 was focused on providing customers with contemporary communication channels, workflow automation and alignment (across all area of the state) to meet customer requirements and exploit opportunities to streamline process. These outcomes were delivered through completion of the Business Improvement and Automate Systems, and Distribution Customer Transformation projects.

Investment has been committed to upgrading and optimising the Service Interactions portal to improve the customer experience for Electrical Contractors through making the portal device centric across multiple platforms.

Infrastructure, Security and Devices

The renewal of Ergon Energy's ICT infrastructure assets is delivered in accordance with Ergon Energy's ICT Infrastructure Asset Renewal Guidelines. ICT infrastructure and technology software asset performance degrade due to age and technical obsolescence. To sustain capability an ongoing program is required to replace these assets. Assets covered by the program include; PC fleet (desktops, laptops), Windows server equipment, Unix server equipment, corporate data network equipment, Ergon Energy property works infrastructure, server storage infrastructure renewal and growth, asset renewal of ICT peripheral equipment including printers and mobile phones. The program also includes infrastructure software renewal of ICT technologies such as Exchange Email, integration technologies and database environments.

The modernisation of the corporate network fully enabling wireless access capability for all users at all Ergon Energy sites continued during 2019-20 extending to all regional Queensland sites including depots and substations that have historically not had wireless capability. Phase 1 and 2 have completed and Phase 3 to address requirements at Energy Queensland data centres is being planned.

Minor Applications Change and Compliance

This includes minor improvements and updates across the ICT systems footprint including; work force automation, market systems, knowledge management systems, and customer service systems which support Ergon Energy's business operations. Investments in this area across 2019-20 included maintaining the security of the network and supporting working from home arrangements imposed by COVID-19 and ensuring compliance to regulatory imposed tariff reform changes.

Changes to systems to manage new rules coming into effect during this period include Fatigue Management Solutions, Apprentice Training Certification Tools and preparation for the introduction of an Online Payment Portal. These initiatives enhance the safety, security and wellbeing of both Ergon Energy customers and employees.

12.2 Forward ICT Program

As Ergon Energy looks toward the future, ICT systems and capability must be maintained for sustainability, cybersecurity, compliance and operational safety. Planned technology replacements will also be leveraged to enable the company's planned productivity improvement.

In the coming period, Ergon Energy will focus on ICT as an enabler of business performance consistent with the following ICT strategic themes:

- Maintain systems for sustainability, cybersecurity, remote working requirements and operational safety
- Leverage ICT replacements for digital transformation, enabling Ergon Energy's productivity improvement targets
- Maintain efficient ICT performance in a rapidly changing technology environment
- Leverage innovative technologies for efficiency and customer service.

In the new regulatory control period, commencing from 2020/21, the focus of the ICT Program for Ergon Energy will be the continuation of Energy Queensland's digital transformation through the consolidation and rationalisation of legacy applications with consistent best-practice business technologies and processes. Planned investment during this time has been grouped within a set of seven roadmap segments including:

- Customer and Market Systems
- Asset and Works Management
- Distribution Network Operations
- Corporate Systems
- Cybersecurity, Productivity and ICT Support
- ICT Devices and Infrastructure
- Minor Change and Compliance.

A high level summary of potential ICT investment for the Distribution Business for the forward ICT Program is shown in Table 32. Emerging priorities and new technologies will result in ongoing prioritisation and may require adjustments dependent on the determination received. Forecasts have been grouped by initiative names as included in the ICT Plan for 2020-2025.

Table 32: ICT Investment Forecast 2020-21 to 2024-25

Initiative	2020-21 $M	2021-22 $M	2022-23 $M	2023-24 $M	2024-25 $M
Asset and Works Management	$34.87	$20.61	$5.28	$4.32	$0.47
Distribution Network Operations	$13.37	$10.92	$2.25	-	-
Customer and Market Systems	$8.75	$10.27	$6.01	$5.19	$6.93
Corporate Systems	$2.45	$0.73	$2.12	$2.80	$8.01
ICT Management Systems, Productivity and Cybersecurity	$2.95	$2.92	$0.76	$3.28	$3.29
Infrastructure Program	$7.15	$8.07	$8.38	$9.12	$9.09
Minor Applications Change	$3.57	$3.68	$3.79	$3.91	$4.02
Grand Total	**$73.11**	**$57.21**	**$28.58**	**$28.63**	**$31.81**

Note: Forecasts (as of 30 June) include ICT Managed Capex Investment for Ergon Energy Corporation Limited only (i.e. does not include ICT investment funded through other portfolios already identified in other sections of this report). Forecasts are represented as $ Nominal values.

12.3 Metering

Ergon is currently separating load control from metering, as it relates to network operation and network management. Ergon 's plans will require that third-party metering providers retain the Ergon load control assets installed in customer switchboards to maintain Ergon's considerable load control facilities.

Ergon will seek to maximise the remaining value in existing meter stocks, by leveraging existing metering capabilities wherever possible. For example, the current suite of interval capable electronic meters may be reprogramed to support market offerings such as Time-of-Use (ToU) tariffs or other similar time-based pricing structures.

Ergon will also continue to operate a Meter Asset Management Plan (MAMP) in a prudent and efficient manner to enable enhanced benefits and cost savings to customers.

Ergon will continue to develop and implement consistent work practices and supporting standards, such as the Queensland Electrical Connection Manual (QECM) and Queensland Electrical Metering Manual (QEMM), to ensure these align with the rollout of smart-ready meters in a contestable marketplace.

12.3.1 Revenue Metering Investments in 2019/20

There were minimal revenue metering investments in 2019/20 due to Power of Choice legislation that prevents Ergon from installing any new meters in NEM connected areas. Non NEM Revenue Meter Capital expenditure for 2019/2020 was less than $50,000

12.3.2 Revenue Metering Investments from 2020/21 to 2024/25

The future investment in revenue metering by Ergon will be minimal and will mainly be focused on network devices, and ongoing forecast Non NEM Revenue Meter Capital expenditure for is anticipated to be less than $50,000 per annum.

12.4 Operational and Future Technology

Ergon Energy is responsible for optimising the reliability, security and utilisation performance of the regulated electricity assets to ensure that both regulatory and corporate performance outcomes are achieved in a manner that is safe to the workplace and the public. Traditional distribution networks are facing a number of challenges brought about by customer energy choices and the introduction of new technologies such as grid energy storage, private battery storage, solar PV, voltage regulation solutions and a multitude of specialised monitoring tools and devices. Ergon Energy recognises that these technologies play a key role in improving the utilisation, reliability, security and performance of our regulated electricity assets.

12.4.1 Telecommunications

Ergon Energy's telecommunication strategy comprises of four major goals:

(i) To ensure that the existing telecommunication infrastructure continues to operate at a performance level required to support the operation of an electricity distribution network.

(ii) To introduce new functionality and technology that supports operational improvement within the organisation, enabling the business to implement new initiatives in the area of network demand management to minimise the impact on the environment.

(iii) To increase the telecommunications network's capacity to accommodate the demand for connectivity ensuring operation and management of the electricity distribution network.

(iv) To invest prudently in new infrastructure and the use of commercial services to provide the most cost effective outcome for Ergon Energy's customers. Further, to minimise duplicate investment through establishing and using telecommunication infrastructure common to other government organisations.

The delivery of the following major categories of work will support the achievement of Ergon Energy's telecommunications strategy:

1. Field Mobile Networks – These networks provide field workforce primary mission critical voice communications to support a safe and efficient work environment
    - Over the last seven years, from Toowoomba to the North of Cairns, the legacy VHF two-way mobile network has been progressively replaced by a P25 based network. This area typically has the highest density of network and staff within Ergon distribution areas. P25 provides a secure digital two-way network and achieves the required quality, availability and reliability to support the field mobile radio networks strategy. The final P25 projects required to complete the planned replacement of the east coast VHF two-way mobile network are currently in delivery. These projects will be completed progressively completed over the next year
    - Provision of a platform to achieve the field mobile radio network strategy in western Queensland areas needed a different approach to P25 due to the vast areas involved and a typical lower density of network and staff. A commercial product called SATPTT that has been recently adopted by other Queensland Government agencies operating in rural and remote areas and is to be used to provide the required functionality. The work is largely completed, a final integration is required to complete the project.

2. Communications Site Infrastructure Program - this program replaces site support infrastructure such as power supplies, diesel generators and air conditioning to ensure that services remain in operation. This is an ongoing business as usual aged replacement program that is based on a condition assessment of equipment’s capacity to provide satisfactory service and performance to meet the requirements for the distribution network. Accelerated battery replacements are anticipated over the next three years due to the asset categories’ age profile and higher than forecast battery cell failure rates
3. Communications Network Assets Program - these invest in the renewal of aged and unsupported active telecommunications equipment, based on a condition assessment of equipment’s capacity to provide satisfactory service and performance to meet the requirements for the distribution network. Projects progressed over 2019-20 include Network Management Systems and legacy voice related aged replacements. Significant projects that have been approved for implementation over the next five years include Time Division Multiplexing (TDM) related projects. These projects will:
    - Extend the life of the existing TDM network
    - Confirm a Tele-protection solution for carriage over an IP/MPLS network
    - Replacement of a Legacy Telco service management system.

   Aged replacement projects will cover the following technologies:
    - Ethernet related asset classes
    - Microwave Radios assets
    - Operational Support Systems servers
    - Additional Legacy Voice related asset classes.
4. Network Capacity and Coverage - The purpose of the program is to increase the capacity and resiliency of the communication network through increasing the communication coverage across the State. This program differs from the age replacement programs as the primary purpose is to augment the communications network. This program represents the only augmentation driven projects for the telecommunications network.

12.4.2 Operational Systems

Ergon Energy classifies Operational Technology (OT) as the systems, applications, and intelligent devices and their data that can directly or indirectly monitor, control or protect the power network.

Our OT strategies therefore include:

- managing the technology environment independent of the underlying telecommunications environment, so that they can develop independently without impacting upon each other
- separating the collection, storage and governance of data functions from the users of the data so that users can focus on using and interpreting the data
- centrally managing support and maintenance of intelligent electronic devices
- developing greater security and resilience as part of the overall design, given the increased exposure to cyber and physical security threats.

Our forward program remains focused on the systems and infrastructure required to collect, manage and control data for asset management purposes, as well as to provide for remote monitoring and operation of the power network. Our ongoing mandate is to ensure a standards-based approach to all future and current operational systems and devices the network, including the interactions between them.

The current systems within the OT scope are detailed below.

12.4.3 Supervisory Control and Data Acquisition

Currently there is a dedicated substation control system across a large portion of the network, with 97% of customers connected to substations with Supervisory Control and Data Acquisition (SCADA) capability. This includes approximately 75% of the zone substations and the majority of pole top devices. These are managed centrally through the Operational Control Centres (OCC) in Rockhampton and Townsville. The SCADA system is the largest OT system deployed in Ergon Energy. Its primary focus is the operation and control of the HV network.

Work to select a common RTU for Energy Queensland as the new standard platform has been substantially completed. A suitable solution for one of the ten core building block elements is still being resolved.
Work to establish the new standards to enable deployment of the new platform and to change support systems to allow the new equipment to suitably integrate into the current environment continued.

The work to support transition from the current master station to the Unified Distribution Management System (UDMS) is ongoing.

12.4.4 Totem

The SCADA system is critical to the operation of the network, designed for high availability and careful consideration is given as to what is connected to the system. Historically only data points that are immediately useful to OCC operations are connected, reducing system size, cost and complexity. In recognition of this, Ergon Energy actively makes use of ‘Totem’ — an IoT (Internet of Things) platform for the collection and processing of data beyond the scope of the SCADA system. Totem continues to help Ergon Energy minimise expenditure associated with broader network data collection.

12.4.5 Isolated Systems

Ergon Energy has a number of stand-alone power stations supplying communities isolated from the main grid, in western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait islands, and Palm Island.

We are investing in the secure integration and interconnection of these sites for centralised operation and control within our primary OT environment.

The first of these isolated systems has been integrated into the central operational control system, with further projects underway to provide improved control of these systems at other sites.

12.4.6 Advanced Power Quality Infrastructure

Ergon Energy's advanced power quality data collection and analysis tools are hosted and supported within the OT environment, enabling our PQ (Power Quality) engineers to focus on serving our customers rather than the underlying technology.

12.4.7 Operational Security

Ergon Energy recognises the importance of cyber security for the power network and its users and continues to invest in the security standard of all operational systems. It is continuing to refine its operational security to mitigate current and future threats. Ergon Energy will be renewing aging security and support infrastructure in its Operational Technology Environment.

12.4.8 Configuration Management System

Ergon Energy is setting down the foundations to enable the smarter network of the future. As a key part of these preparations, the Communications Network Operations Centre (CNOC) has begun accepting operational alarms from select devices in the field, with a view to expand to similar intelligent assets in the future. This increased capability is the first step in an extension of the centres normal activities that traditionally focuses on our communications infrastructure only.

In line with this capability, Ergon Energy has invested in a device Configuration Management System (CMS) to centralise and standardise configuration management of intelligent devices deployed on the power network. The CMS is currently used to manage protection devices, with more device classes expected to be added in the future.

12.4.9 Operator Telephony Console Replacement

Ergon Energy's existing operator telephony console is end of support and will be upgraded to the latest platform of the encumbent vendor (Zetron).

12.4.10 Intelligent Grid Enablement

Over the next five years Ergon Energy plans to invest in the development of a smarter network for the future. The growth of DER in distribution networks, at both residential and commercial scales, requires Ergon Energy to consider new approaches for maximising DER hosting capacity.

In order to deliver sustainable outcomes for the network and choice for the customer, Ergon Energy plans on the delivering the following major capabilities:

- State Estimation – Following on from a number of successful pilot programs, Ergon Energy is investing further in capabilities to improve visibility on our Medium Voltage (MV) and Low Voltage (LV) networks without substantial investment in field sensing equipment. This in turn will allow more precise real time calculation of network constraints and hosting capacity of customer owned renewable energy systems and to provide better accuracy in our general network planning.
- Low Voltage Distributed Energy Management System (LVDERMS) - Given the wide range of functions, applications and solutions in this space, Energy Queensland intends to take an incremental approach to ensure any deployments are closely aligned with a business use case and tangible customer benefit, such as increased export capabilities or improved quality of supply. We are working closely with several industry partners and working groups to ensure alignment with other Australian distributors and Standards under development. As per our submission to the Australian Energy Regulator (AER) the immediate focus is on higher volume, low criticality connections (less than 1.5MVA) for residential and commercial connected DER on our low voltage network. In the longer term these will be merged to incorporate lower volume, high criticality connections (greater than 1.5 MVA) that have a material impact on grid stability and operations. For both categories the focus is on developing and implementing scalable building blocks, including the update of network connection standards to incorporate emerging DER communication protocols such as IEEE 2030.5 to allow secure communication with customers, third parties and market operators.
- The Real Time Data Hub – This platform aims to utilise concepts from IT centric systems and apply them to OT based devices and systems to handle large quantities of data in real time and make it available in a consistent format and interface to end users and initiatives. This will be a key enabler of the state estimation initiative indicated above.

12.4.11 Common Operational Technology Environment (OTE)

This project is building a common telecommunications and operational technology environment that will host both Energex and Ergon Energy operational technology solutions. The project will allow the deployment of a common Distribution Management System (DMS) and common operator console solutions for Energex and Ergon Energy reducing costs.

12.4.12 LV Network Safety Monitoring Program

Safety by design is fundamental to Egon Energy network strategy, providing safe and reliable electricity residents and businesses across regional Queensland and is at the core of Ergon Energy's corporate values. Neutral integrity failures on the Low Voltage (LV) network are a significant cause of customer safety incidents. Ergon Energy is committed to customer safety imperatives and considers that the detection of neutral integrity failures is critical to mitigating customer safety risks. Ergon Energy is investing in developing a smart network monitoring device with neutral integrity monitoring capability which will be installed under a trial on selected customer premises throughout Queensland. The scope provides for gathering of field data, through purpose-built sensors or through smart meters, derivation of information from the field data, and detection and raising of alerts for neutral integrity failures in the Ergon Energy network or in customer installations. The pilot program provides a foundation to enabling further investment by Ergon Energy over the 2020-2025 regulatory control period in equipment, systems and processes to detect neutral integrity failures through increased LV visibility. The data leveraged from this platform will feed into various applications including the LV Management System of the Intelligent Grid Enablement program. Currently a pilot is being deployed and then the wider program will commence in 2022. In 2019-20, Ergon (in a joint project with Energex) successfully proved the technology concept through a small-scale deployment and prepared the program deployment building blocks for a large-scale trial.

12.4.13 Investments in 2019-20

Table 33 summarises Ergon Energy's Information Technology and Communication systems investments for 2019-20.

Table 33: Information Technology and Communication Systems Investments 2019-20

Description	Direct Cost ($M, 2019-20)
Telecommunications Network	
Field Mobile Networks	$8.0
Communications Site Infrastructure Program	$0.4
Communications Network Assets Program	$3.6
Network Capacity and Coverage	$1.59
Operational Systems	
Operator telephony console replacement	$1.7
Common OTE	$0.6
LV Network Monitoring program	$4.4
Total	**$20.3**

Note: All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.

12.4.14 Planned Investments for 2020-21 to 2024-25

Table 34 summarises Ergon Energy's OT and associated Telecommunication planned investments for 2020-21 to 2024-25.[55]

Table 34: Operational Technology Planned Investments 2020-21 to 2024-25

Description	Direct Cost ($M)
Telecoms Network	
Field Mobile Networks	$6.0
Communications Site Infrastructure Program	$11.9
Communications Network Assets Program	$31.8
Network Capacity and Coverage	$11.7
Operational Systems	
SCADA and Automation Refurbishment / Replacement	$3.5
OT Refurbishment / Replacement	$2.9
Intelligent Grid Enablement	$6.6
Secure Data Zone	$0.6
Control Room Productivity	$0.6
OT Security enhancements	$3.5
OT Meter Management	$0.1
OT Environment enhancements	$0.9
CMS Expansion	$0.6
Totem Expansion	$2.0
LV Network Safety Monitoring Program (pilot and rollout)	$60.7
Total	**$ 143.4**

Note: All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.

[55] Expenditure is provisional only and will be dependent on internal prioritisation of competing expenditure.

Appendix A

Terms and Definitions

Appendix A. Terms and Definitions

Term/Acronym	Definition
10 PoE Forecast	Peak load forecast with 10% probability of being exceeded in any year (i.e. a forecast likely to be exceeded only once every 10 years), based on normal expected growth rates and temperature corrected starting loads. 10 PoE forecast load is not to exceed NCC for system normal (network intact) in all cases excepting distribution substations network element category.
50 PoE Forecast	Peak load forecast with 50% probability of being exceeded in any year (i.e. an upper range forecast likely to be exceeded only once every two years), based on normal expected growth rates and temperature corrected starting loads.
ABS	Australian Bureau of Statistics
AC / ac	Alternating Current
ACR	Automatic Circuit Recloser: an Integrated fault break switch and control system (including protection trip and reclose) suitable for pole mounting.
ACS	Alternative Control Services: a distribution service provided by Ergon Energy that the AER has classified as an Alternative Control Service under the NER. Includes fee based services, quoted services, Public Lighting Services and Default Metering Services.
ADMD	After Diversity Maximum Demand
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFLC	Audio Frequency Load Control: a method of switching loads by modulating audio frequency signals transmitted over the powerline.
AIDM	Asset Inspection and Defect Management
AVR	Automatic Voltage Regulator
BAU	Business As Usual
BESS	Battery Energy Storage Systems
BOM	Bureau of Meteorology
BSS	Bulk Supply Substation is a substation that converts energy from transmission voltages to subtransmission voltages. Note: A Bulk Supply Substation is not a Transmission Connection Point if Ergon Energy owns the incoming 'transmission voltage' feeder. Refer to definition of 'TCP' and 'Transmission Network' below for further explanation.
B2B	Business to business
CA	Capricornia Region
CAC	Connection Asset Customers
CAIDI	Customer Average Interruption Duration Index: a network reliability performance index, indicating the interruption duration that each customer experiences on average (minutes) per interruption.
Capacitor bank (Shunt Capacitor)	An assembly at one location of capacitors and all necessary accessories, such as switching equipment, protective equipment and controls, required for a complete operating installation.
CAPEX / capex	Capital Expenditure
CBRM	Condition-Based Risk Management
CESS	Capital Expenditure Sharing Scheme
C&I	Commercial and Industrial – Customer classification

Term/Acronym	Definition
Circuit Breaker (CB)	A mechanical switch device capable of making, carrying and breaking currents under normal circuit conditions as well as making, carrying for a specified time and breaking currents under specified abnormal conditions, such as those of short circuit.
CIS	Customer Information System
CMS	Configuration Management System
CNOC	Communications Network Operations Centre
Committed Investment	For the purposes of this document a committed investment has received project approval and financial release of funds by the authorised investment governance authority. In accordance with the Ergon Energy Investment Approval Gated Methodology this correlates with project approval and full funding release for an appropriate Gate 3 business case.
CONNEX	Customer Initiated Capital Works
Constraint	A condition whereby a limit, that has been pre-set to a declared criterion, is exceeded. For the purposes of this document a constraint is deemed to be a condition that exceeds the planning and security criteria for each asset class, as determined by Ergon Energy. It should be noted that identification of an asset as 'constrained' does not necessarily imply that the integrity or capability threshold of the asset has been compromised.
Contingency Event	As defined by the NER, 'an event affecting the power system which AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units or transmission elements'
CPI	Consumer Price Index
CP	Corporate Plan
CPSS	Community Powerline Safety Strategy
CT	Current Transformer: a device typically used in protection and metering systems to measure current in primary conductors.
Customer Minutes	Customer Minutes: a measure of the number of customers interrupted multiplied by the duration of a power outage or outages, incorporating any staged restoration.
Cyclic Load	Power load that occurs in such a way that periods of overloads are followed by periods of light load. A piece of equipment may be cyclically loaded and the life expectancy not reduced if the accelerated rate of deterioration of the insulation during heavily loaded periods is counterbalanced by the decelerated rate of deterioration during the light loaded periods.
CymCap	Software by CYME International T&D for calculation of ampacity and temperature rise calculations for power cable installations
DA	Ergon Energy's Distribution Authority DO1/99 (DA)
DAE	Deloitte Access Economics
DAPR	Ergon Energy's Distribution Annual Planning Report
DC / dc	Direct Current
DEBB	Digital Enterprise Building Blocks
Demand Side Management (DSM)	Demand Side Management: the design and implementation of programs designed to influence customer use of electricity in ways that will produce a desired change in system load shape.
DEE	Dangerous Electrical Event
DER	Distributed Energy Resources

Term/Acronym	Definition
DF	Distribution Feeder
DFD	Distribution Feeder Database
DLC	Direct Load Control
DM	Demand Management. Alternate term is Non-Network Alternatives
DMIA	Demand Management Innovation Allowance
DMS	Distribution Management System
DMIS	Demand Management Incentive Scheme
DNAP	Distribution Network Augmentation Plans
DNCR	Distribution Network Capability Report
DNRME	Queensland Department of Natural Resources, Mines and Energy
DNSP	Distribution Network Service Provider
DR	Demand Reduction
DRIM	Demand Reduction Incentive Map, where customer demand reduction incentives, reflective of the value of capital deferral and network security risk, will be provided to the market
Dropout Fuse	A fuse in which the fuse carrier drops into a position to provide an isolating distance after the fuse has operated.
DT	Distribution Transformer
DTS	Distributive Temperature Sensor
DUOS	Distribution Use Of System
EAM	Enterprise Asset Management
EaR	Energy at Risk
EBSS	Efficiency Benefit Sharing Scheme
EDNC	Electricity Distribution Network Code (replaced the EIC on 1st July 2015)
EDO Fuse	Expulsion Drop-Out (EDO) disconnector fuse units
EECL, Ergon Energy	Ergon Energy Corporation Limited
EMF	Electro Magnetic Field
EQL	Energy Queensland Limited
EG	Embedded generating units >30kVA in size.
EQL	Energy Queensland Limited
ERP	Enterprise resource planning: business management software, typically a suite of integrated applications, that a company can use to collect, store, manage and interpret data from many business activities.
ESRI	Environmental Systems Research Institute
EV	Electric Vehicle

Term/Acronym	Definition
Fault	1. A defect in any equipment in the system. 2. In an electric power system, a fault is any abnormal electric current. For example, a short circuit is a fault in which current bypasses the normal load. An open-circuit fault occurs if a circuit is interrupted by some failure. In three-phase systems, a fault may involve one or more phases and ground, or may occur only between phases. In a ‘ground fault’ or ‘earth fault’, charge flows into the earth.
Feeder Utilisation	Percentage of feeder rating utilised under network maximum demand conditions with thermal rating of the feeder measured at the time and season of maximum demand.
FFA	Field Force Automation
FiT	Feed-in-tariff
FN	Far North region of Queensland
FPAR	Final Project Assessment Report
GIS	Geographic Information System: a system that lets users visualize, question, analyse, interpret, and understand data to reveal relationships, patterns, and trends.
GOC	Government Owned Corporation
GSL	Guaranteed Service Level
GSP	Gross State Product: sourced from the ABS website
GUSS	Grid Utility Support System: an energy storage system developed by Ergon Energy and optimised for Single Wire Earth Return (SWER) systems. The main functions of GUSS are: Peak Load and Voltage support of the SWER. It provides a solution to relieve both capacity and voltage constraints as an alternative to traditional poles, wires & transformer upgrades.
High Voltage (HV)	(1.) For distribution networks in Australia, HV normally refers to 11,000 V or higher. (2.) For the purpose of the *Electrical Safety Act 2002* (Qld), HV is defined as voltage above 1000V AC or 1500V DC. (3.) HV and LV may also be used to distinguish between the higher voltage side of a transformer and the lower voltage side of a transformer.
HSE	Health, Safety and Environment
ICC	Individually Calculated Customers
ICT	Information and Communications Technology
IoT	Internet of Things
IPS	Intelligent Process Solutions
IT	Isolation Transformer (SWER)
Joint Workings	Collaboration between Ergon Energy and Energex to jointly work on key initiatives to reduce customer cost and provide a consistent customer experience throughout the State.
KPI	Key Performance Indicators
KRA	Key Result Areas
LAR	Load at Risk
LARc	Load at Risk under Contingency Conditions
LDC	Line Drop Compensation
LED	Light-emitting Diode. Is a semiconductor device that emits visible light when an electric current pass through it
LiDAR	Light Detection And Ranging. A remote sensing technology that measures distance by illuminating a target with a laser and analysing the reflected light.

Term/Acronym	Definition
Load Factor	The ratio of the average demand to the peak demand. This gives an indication of the ‘flatness’ of load profile.
Load Forecast	Forecast loads for a minimum of 10 years based on validated starting loads, forecast growth rates, identified load transfers and block loads.
Long Rural Feeder (LR)	A feeder which is not a CBD, urban or isolated feeder with a total route length greater than 200km.
Low Voltage (LV)	1. For distribution networks in Australia, LV is nominally 240/415V AC. or 230/400V AC at 50Hz. 2. For the purpose of the electrical safety act, LV is defined as voltage above 32V AC or 120V DC (ripple free) and not exceeding 1,000V AC. or 1,500V DC. respectively. 3. HV and LV may also be used to distinguish between the higher voltage side of a transformer and the lower voltage side of a transformer.
LVR	Low Voltage Regulator
MAB	Metering Asset Base
MARS	Meter Asset Register and Services.
MAMP	Metering Asset Management Plan
Maximum Demand (MD)	The maximum electrical load over a set period of time. The figure may be for use with tariff calculations or load surveys and the units may be in; kVA, kW or amps.
MCC	Major Customer Connection
MD	Maximum or Peak Demand
MDI	Maximum Demand Indicator
MED	Major Event Day
MEGU	Micro embedded generating units which are between 0 to 30kVA in size as defined in AS4777, which includes inverter energy systems such as solar PV generators
MK	Mackay region
MSS	Minimum Service Standards
MV	Medium Voltage
MVA	Mega Volt Amp
MVAr	Mega Volt Amps (reactive)
MVARu	Mega Volt Amps (reactive uncompensated)
MW	Megawatt – nameplate capacity
N/A	Not available as yet or Not applicable to the requirement
N-1	The conditions under which all (or a certain percentage) of the electricity load will continue to be supplied under conditions whereby a critical system element is out of service. ‘N’ is all elements in service, ‘N-1’ is with one element (normally one with the highest capacity) out of service. Also known as a credible contingency.
NAPM	Network Asset Preventative Maintenance
NCC	Normal Cyclic Capacity
NECF	National Energy Customer Framework is a set of national laws, rules and regulations governing the sale and supply of energy (electricity and reticulated natural gas) to consumers. Refer to https://www.dews.qld.gov.au for more information.
NEL	National Electricity Law

Term/Acronym	Definition
NEM	National Electricity Market
NEO	National Energy Objectives (AEMC)
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
Network Limitations	A network limitation can be defined as a situation when the HV network is unable to supply electricity to the customer in accordance with the following supply standards.
NGER	National Greenhouse and Energy Reporting Act 2007 (Cth)
NIEIR	National Institute of Economic and Industry Research
NIM	Net Interstate Migration (NIM)
NNA	Non-Network Alternatives. An alternate term is Demand Management
NODW	Network Operations Data Warehouse
NOM	Net Overseas Migration
NOMAD	A 10MVA mobile substation developed by Ergon Energy for planned work and emergency response.
Net Present Value (NPV)	A calculation that compares the amount invested today to the present value of the future cash receipts from the investment. In other words, the amount invested is compared to the future cash amounts after they are discounted by a specified rate of return.
NQ	North Queensland region
NTC	Network Tariff Code
NVD	Neutral Voltage Displacement
OC/EF	Over Current and Earth Fault
OCC	Operational Control Centres
OH	Overhead
OHEW	Overhead Earth Wires
OLTC	On Load Tap-Changer: A device for changing a transformer’s tapping ratio suitable for operation while the transformer is energised or on load. Generally, it consists of a diverter switch with a transition impedance and a tap selector which can be with or without a change-over selector, the whole being operated by the driving mechanism. In some forms of tap-changers, the functions of the diverter switch and the tap selector are combined in a selector switch.
ONAN	Oil Natural Air Natural
OPEX / opex	Operating Expenditure
OT	Operational Technology (OT) is the information communications technology (ICT) systems, applications, and intelligent power network devices and their data that can directly, or indirectly, monitor, control or protect the power network.
PHEV	Plug-in Hybrid Electric Vehicle
Power factor (pf)	The ratio of ‘real’ power (W) to total power (VA)

Term/Acronym	Definition
Power of Choice / PoC	Power of Choice was a milestone report from the Australian Energy Market Commission, commissioned by Australia's Federal, State and Territory energy ministers to help identify ways to help consumers better manage their electricity use and costs. This report has impacted the way in which DNSPs: work on embedded networks, provide metering, interact with the market and provide customer education.
PoE	Probability of Exceedance
PoW	Program of Work
Powerlink	Queensland Electricity Transmission Corporation Limited
PQ	Power Quality
Primary Distribution System	Refers to the 11kV and 22kV and in some instances 33kV electricity supply network.
p.u.	Per unit. A per-unit system is the expression of system quantities as fractions of a defined base unit quantity.
PV	PV stands for photovoltaic which is a technical term for solar power generation.
QCA	Queensland Competition Authority
QGSO	Queensland Government Statistician's Office
QHES	Queensland Household Energy Survey
QoS	Quality of Supply
RAB	Regulated Asset Base
Recloser	A fault-make and break device which monitors the line current and automatically trips for a fault condition. It is fitted with auto reclosing capability.
Regional FiT	The regional FiT rate is set by the Queensland Competition Authority each year and is paid by the electricity retailer. All eligible customers connecting an eligible solar PV system to an approved network receive the regional FiT.
RFI	Request For Information
RIN	Regulatory Information Notice. The AER issues RINs under Division 4 of Part 3 of the National Electricity (Queensland) Law (NEL) to EECL for information collection purposes.
RIT-D	The RIT-D or Regulatory Investment Test for Distribution is a cost-benefit test that electricity distribution network businesses must apply when assessing the economic efficiency of different investment options
RMS	Root Mean Square
RTD	Resistive Temperature Device
RTU	Remote Termination Unit. This is a key part of the Supervisory Control and Data Acquisition (SCADA) system used in substations.
SAC Large	Standard Asset Customer - Large
SAIDI	System Average Interruption Duration Index – Network reliability performance index, indicating the total minutes, on average, that customers are without electricity during the relevant period (minutes).
SAIFI	System Average Interruption Frequency Index – Network reliability performance index, indicating the average number of occasions each customer is interrupted during the relevant period (interruptions).
SCADA	Supervisory Control and Data Acquisition

Term/Acronym	Definition
SCAR	Substation condition assessment report
SCI	Statement of Corporate Intent
SCS	Standard Control Services: are core distribution services associated with the access and supply of electricity to customers. They include network services (e.g. construction, maintenance and repair of the network) and some connection services (e.g. small customer connections). We recover our costs in providing Standard Control Services through network tariffs billed to retailers.
SEQ	South East Queensland
SIFT	Substation Investment Forecast Tool, used to produce the demand forecasts.
SKID	Refers to Ergon Energy's 33/11kV and/or 66/11kV skid mounted substations located across the network. The units were developed for longer term emergency/contingency response, and longer term maintenance works at substations without N-1 capacity or sufficient Safety Net contingency.
SMDB	Statistical Metering Database
SNAP	Subtransmission Network Augmentation Plan
SSI	Sag Severity Index - a value given to a voltage sag based on contours of the CBEMA curve. As voltage sags increase in depth and duration so does the sag severity index reflecting the increasing disturbance of sags as this occurs. SSI is based on the University of Wollongong's methodology.
Statcom or Static Synchronous Compensator	A shunt device, which uses force-commutated power electronics, to control power flow and improve transient stability on electrical power networks. In addition, static synchronous compensators are installed in select points in the power system to perform the following: Voltage support and control Voltage fluctuation and flicker mitigation Unsymmetrical load balancing Power factor correction Active harmonics cancellation Improve transient stability of the power system
STPIS	Service Target Performance Incentive Scheme, as documented under *Electricity Distribution Network Service Providers Service Target Performance Incentive Scheme (AER, Nov 2009)* with targets set through the AER's Distribution Determination process.
Substation (S/S or SS)	An assemblage of equipment at one location, including any necessary housing, for the conversion or transformation of electric energy and connection between two or more feeders.
Subtransmission	An intermediate voltage used for connections between transmission connections points / bulk supply substations and zone substations. It is also used to connect between zone substations. Typically, subtransmission voltages are 33kV and above. (Note however that 33kV is also used for distribution in some parts of the Ergon Energy network.)
Surge Arrester / Surge Diverter	A device designed to protect electrical apparatus from high transient voltage.
SVC	Static Var Compensator
SVR	Step Voltage Regulator
SW	South Western region of Queensland

Term/Acronym	Definition
SWER	Single Wire Earth Return. Distribution to customers using a single wire conductor with the greater mass of Earth as the return path. Used extensively to supply remote rural areas
Switchgear	The combination of electrical disconnects, fuses and/or circuit breakers used to isolate electrical equipment. The use of switchgear is both to de-energize equipment to allow work to be done and to clear faults downstream
TAN	Trade Ally Network. A registry of local, state and national businesses that can assist customers in exploring energy efficiency and demand management opportunities and cashback incentive payment claims.
Transmission Connection Point (TCP)	Transmission Connection Point: A point at which connection is made between a transmission network and the Ergon Energy network. Otherwise known as a transmission-distribution connection point.
TDM	Time Division Multiplexing
TF, TX	Transformer
THD	Total Harmonic Distortion
THDI	Total Harmonic Distortion Index – THDI is the maximum of the three (one for each phase) 95th percentile THD levels at a site. THDI is expressed as a percentage of the reference voltage.
TMU	Target Maximum Utilisation
TNI	Transmission Node Identity
TNSP	Transmission Network Service Provider
Transmission Network	Generally, the electricity supply network operating at or above a nominal voltage of 110kV. However, as Ergon Energy owns some HV assets that might otherwise be owned and operated by a TNSP, clause 9.32.1(b) of the NER provides a permanent derogation in relation to the definition of 'transmission network' in Queensland to allow Ergon Energy to own and operate these assets as a DNSP. Hence Ergon Energy does not own or operate a transmission network.
UG	Underground
UoSA	Use of System Agreement
UR	Urban
V	Volts
VA	Volt Amps - unit of the vector magnitude of electrical power
VAR	Volt Amps Reactive - unit of the reactive component of electrical power
VCR	Value of Customer Reliability – an economic measure of unsupplied energy to customers
Voltage Regulation	The level of variation in the voltage that occurs at a site
Voltage Regulator (VR)	A device that controls voltages in the power networks
Voltage Sag	A temporary reduction of the voltage at a point in the electrical system below 90% of the nominal. The description of voltage sags can be by retained voltage and duration. Voltage sags may last from half a cycle to one minute.
Voltage Unbalance	A condition in poly-phase systems in which the RMS values of line-to-line voltages (fundamental component) or the phase angles between them are not all equal.
VT	Voltage Transformer: a device typically used in protection and metering systems to measure voltage in primary conductors.
W	Watts - unit of the 'real' component of electrical power

Term/Acronym	Definition
WB	Wide Bay region of Queensland
WPF	Worst Performing Feeder – has meaning in the Ergon Energy Distribution Authority
Zone Substation (ZS) or (ZSS)	A substation that converts energy from transmission or subtransmission voltages to distribution voltages.

Appendix B

NER and DA Cross-Reference

Appendix B. NER and DA Cross-Reference

Table 35: NER Cross Reference

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(a) information regarding the DNSP and its network including:		
(1)	a description of its network;	**1.2** Network Overview **2.2** Ergon Energy's Electricity Distribution Network **11** Emerging Network Challenges and Opportunities **Appendix C** Network Security Standards
(2)	a description of its operating environment;	**1.2** Network Overview **2.2** Ergon Energy's Electricity Distribution Network **2.3** Network Operating Environment **3** Community and Customer Engagement **9.1** Reliability Measures and Standards **9.2** Service Target Performance Incentive Scheme **9.3** High Impact Weather Events **10.3** Power Quality Supply Standards, Code Standards and Guidelines **11** Emerging Network Challenges and Opportunities
(3)	the number and types of its distribution assets;	**2.2** Ergon Energy's Electricity Distribution Network
(4)	methodologies used in preparing the Distribution Annual Planning Report, including methodologies used to identify system limitations and any assumptions applied; and	**5.2** Planning Methodology **5.4** Network Planning Criteria **5.5** Voltage Limits **5.6** Fault Level Analysis Methodology **5.7** Ratings Methodology **5.12** Network Planning – Assessing System Limitations **Appendix E** Substation Forecast and Capacity Tables **Appendix F** Feeder Forecast and Capacity Tables
(5)	analysis and explanation of any aspects of forecasts and information provided in the Distribution Annual Planning Report that have changed significantly from previous forecasts and information provided in the preceding year;	**1.5** Changes from 2019 DAPR
(b) forecasts for the forward planning period, including at least:		
(1)	a description of the forecasting methodology used, sources of input information, and the assumptions applied;	**4** Strategic Forecasting

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(2)	load forecasts (i) at the transmission-distribution connection points; (ii) for subtransmission lines; and (iii) for zone substations, including, where applicable, for each item specified above: (iv) total capacity; (v) firm delivery capacity for summer periods and winter periods; (vi) peak load (summer or winter and an estimate of the number of hours per year that 95% of peak load is expected to be reached); (vii) power factor at time of peak load; (viii) load transfer capacities; and (ix) generation capacity of known embedded generating units;	**6.1** Network Limitations – Adequacy, Security and Asset Condition **6.5** Emerging Network Limitation Maps **Appendix E** Substation Forecast and Capacity Tables **Appendix F** Feeder Forecast and Capacity Tables
(3)	forecasts of future transmission-distribution connection points (and any associated connection assets), subtransmission lines and zone substations, including for each future transmission-distribution connection point and zone substation: (i) location; (ii) future loading level; and (iii) proposed commissioning time (estimate of month and year);	**6.1** Network Limitations – Adequacy, Security and Asset Condition **6.5** Emerging Network Limitation Maps **Appendix E** Substation Forecast and Capacity Tables
(4)	forecasts of the Distribution Network Service Provider's performance against any reliability targets in a service *target performance incentive scheme*; and	**9.2** Service Target Performance Incentive Scheme

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(5)	a description of any factors that may have a material impact on its network, including factors affecting; (i) fault levels; (ii) voltage levels; (iii) other power system security requirements; (iv) the quality of supply to other Network Users (where relevant); and (v) ageing and potentially unreliable assets;	**2.2** Ergon Energy's Electricity Distribution Network **5** Network Planning Framework **6** Network Limitations and Recommended Solutions **7.2** How is Demand Management Integrated into the Planning Process? **7.4** What has the Ergon Energy DM Program delivered over the last year? **8** Asset Life-Cycle Management **9.1.4** Reliability Corrective Actions **9.3** High Impact Weather Events **10** Power Quality **11** Emerging Network Challenges and Opportunities
(b1)	for all *network* asset retirements, and for all *network* asset de-ratings that would result in a system limitation, that are planned over the forward planning period, the following information in sufficient detail relative to the size or significance of the asset: 1) a description of the *network* asset, including location; 2) the reasons, including methodologies and assumptions used by the *Distribution Network Service Provider*, for deciding that it is necessary or prudent for the *network* asset to be retired or de-rated, taking into account factors such as the condition of the *network* asset; 3) the date from which the *Distribution Network Service Provider* proposes that the *network* asset will be retired or de-rated; and 4) if the date to retire or de-rate the *network* asset has changed since the previous *Distribution Annual Planning Report*, an explanation of why this has occurred;	**6.3** Network Asset Retirements and De-Ratings

<table>
<tr><th colspan="2">National Electricity Rules Version 116
Chapter 5: Network Connection, Planning and Regulation
Schedule 5.8 Distribution Annual Planning Report
For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:</th><th>Report Section</th></tr>
<tr><td>(b2)</td><td>for the purposes of subparagraph (b1), where two or more network assets are:
1) of the same type;
2) to be retired or de-rated across more than one location;
3) to be retired or de-rated in the same calendar year; and
4) each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination),
those assets can be reported together by setting out in the Distribution Annual Planning Report:
5) a description of the network assets, including a summarised description of their locations;
6) the reasons, including methodologies and assumptions used by the Distribution Network Service Provider, for deciding that it is necessary or prudent for the network assets to be retired or de-rated, taking into account factors such as the condition of the network assets;
7) the date from which the Distribution Network Service Provider proposes that the network assets will be retired or de-rated; and
8) if the calendar year to retire or de-rate the network assets has changed since the previous Distribution Annual Planning Report, an explanation of why this has occurred;</td><td>6.3 Network Asset Retirements and De-Ratings</td></tr>
<tr><td colspan="3">(c) information on system limitations for subtransmission lines and zone substations, including at least:</td></tr>
<tr><td>(1)</td><td>estimates of the location and timing (month(s) and year) of the system limitation;</td><td rowspan="4">6.1 Network Limitations – Adequacy, Security and Asset Condition
6.5 Emerging Network Limitation Maps
Appendix E Substation Forecast and Capacity Tables
Appendix F Feeder Forecast and Capacity Tables</td></tr>
<tr><td>(2)</td><td>analysis of any potential for load transfer capacity between supply points that may decrease the impact of the system limitation or defer the requirement for investment;</td></tr>
<tr><td>(3)</td><td>impact of the system Limitation if any, on the capacity at transmission-distribution connection points;</td></tr>
<tr><td>(4)</td><td>a brief discussion of the types of potential solutions that may address the system limitation in the forward planning period, if a solution is required; and</td></tr>
</table>

National Electricity Rules Version 116 **Chapter 5: Network Connection, Planning and Regulation** **Schedule 5.8 Distribution Annual Planning Report** **For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:**	**Report Section**
(5) where an estimated reduction in forecast load would defer a forecast system limitation for a period of at least 12 months, include: (i) an estimate of the month and year in which a system limitation is forecast to occur as required under subparagraph (1); (ii) the relevant connection points at which the estimated reduction in forecast load may occur; and (iii) the estimated reduction in forecast load in MW or improvements in power factor needed to defer the forecast system limitation;	
(d) for any primary distribution feeders for which a Distribution Network Service Provider has prepared forecasts of maximum demands under clause 5.13.1(d)(1)(iii) and which are currently experiencing an overload, or are forecast to experience an overload in the next two years the Distribution Network Service Provider must set out:	
(1) the location of the primary distribution feeder;	**6.1** Network Limitations – Adequacy, Security and Asset Condition **6.5** Emerging Network Limitation Maps **Appendix F** Feeder Forecast and Capacity Tables
(2) the extent to which load exceeds, or is forecast to exceed, 100% (or lower utilisation factor, as appropriate) of the normal cyclic rating under normal conditions (in summer periods or winter periods);	
(3) the types of potential solutions that may address the overload or forecast overload; and	
(4) where an estimated reduction in forecast load would defer a forecast overload for a period of 12 months, include: (i) estimate of the month and year in which the overload is forecast to occur; (ii) a summary of the location of relevant connection points at which the estimated reduction in forecast load would defer the overload; (iii) the estimated reduction in forecast load in MW needed to defer the forecast system limitation;	
(e) a high-level summary of each RIT-D project for which the regulatory investment test for distribution has been completed in the preceding year or is in progress, including:	
(1) if the regulatory investment test for distribution is in progress, the current stage in the process;	**6.4** Regulatory Investment Test Projects
(2) a brief description of the identified need;	

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(3)	a list of the credible options assessed or being assessed (to the extent reasonably practicable);	
(4)	if the regulatory investment test for distribution has been completed a brief description of the conclusion, including: (i) the net economic benefit of each credible option; (ii) the estimated capital cost of the preferred option; and (iii) the estimated construction timetable and commissioning date (where relevant) of the preferred option; and	
(5)	any impacts on Network Users, including any potential material impacts on connection charges and distribution use of system charges that have been estimated;	
(f) for each identified system limitation which a Distribution Network Service Provider has determined will require a regulatory investment test for distribution, provide an estimate of the month and year when the test is expected to commence;		**6.4.3** Foreseeable RIT-D Projects
(g) a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address an urgent and unforeseen network issue as described in clause 5.17.3(a)(1), including:		
(1)	a brief description of the investment, including its purpose, its location, the estimated capital cost of the investment and an estimate of the date (month and year) the investment is expected to become operational;	**6.4.4** Urgent and Unforeseen Projects
(2)	a brief description of the alternative options considered by the Distribution Network Service Provider in deciding on the preferred investment, including an explanation of the ranking of these options to the committed project. Alternative options could include, but are not limited to, generation options, demand side options, and options involving other distribution or transmission networks;	
(h) the results of any joint planning undertaken with a Transmission Network Service Provider in the preceding year, including:		

<table>
<tr><th colspan="2">National Electricity Rules Version 116

Chapter 5: Network Connection, Planning and Regulation

Schedule 5.8 Distribution Annual Planning Report

For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:</th><th>Report Section</th></tr>
<tr><td>(1)</td><td>a summary of the process and methodology used by the Distribution Network Service Provider and relevant Transmission Network Service Providers to undertake joint planning;</td><td rowspan="3">5.10 Joint Planning
5.11 Joint Planning Results</td></tr>
<tr><td>(2)</td><td>a brief description of any investments that have been planned through this process, including the estimated capital costs of the investment and an estimate of the timing (month and year) of the investment; and</td></tr>
<tr><td>(3)</td><td>where additional information on the investments may be obtained;</td></tr>
<tr><td colspan="3">(i) the results of any joint planning undertaken with other Distribution Network Service Providers in the preceding year, including:</td></tr>
<tr><td>(1)</td><td>a summary of the process and methodology used by the Distribution Network Service Providers to undertake joint planning;</td><td rowspan="3">5.10 Joint Planning
5.11 Joint Planning Results</td></tr>
<tr><td>(2)</td><td>a brief description of any investments that have been planned through this process, including the estimated capital cost of the investment and an estimate of the timing (month and year) of the investment; and</td></tr>
<tr><td>(3)</td><td>where additional information on the investments may be obtained;</td></tr>
<tr><td colspan="3">(j) information on the performance of the Distribution Network Service Provider’s network, including:</td></tr>
<tr><td>(1)</td><td>a summary description of reliability measures and standards in applicable regulatory instruments;</td><td rowspan="5">9 Network Reliability
10 Power Quality</td></tr>
<tr><td>(2)</td><td>a summary description of the quality of supply standards that apply, including the relevant codes, standards and guidelines;</td></tr>
<tr><td>(3)</td><td>a summary description of the performance of the distribution network against the measures and standards described under subparagraphs (1) and (2) for the preceding year;</td></tr>
<tr><td>(4)</td><td>where the measures and standards described under subparagraphs (1) and (2) were not met in the preceding year, information on the corrective action taken or planned;</td></tr>
<tr><td>(5)</td><td>a summary description of the Distribution Network Service Provider's processes to ensure compliance with the measures and standards described under subparagraphs (1) and (2); and</td></tr>
</table>

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(6)	an outline of the information contained in the Distribution Network Service Provider's most recent submission to the AER under the service target performance incentive scheme;	**9.2** Service Target Performance Incentive Scheme
(k) information on the Distribution Network Service Provider's asset management approach, including:		
(1)	a summary of any asset management strategy employed by the Distribution Network Service Provider;	**2.4** Asset Management Overview **8** Asset Life-Cycle Management
(1A)	an explanation of how the Distribution Network Service Provider takes into account the cost of distribution losses when developing and implementing its asset management and investment strategy;	**5.4.4** Consideration of Distribution Losses
(2)	a summary of any issues that may impact on the system limitations identified in the Distribution Annual Planning Report that has been identified through carrying out asset management; and	**2.4** Asset Management Overview **6.3** Network Asset Retirements and De-Ratings**8** Asset Life-Cycle Management
(3)	information about where further information on the asset management strategy and methodology adopted by the Distribution Network Service Provider may be obtained;	**2.5.3** Further Information
(l) information on the Distribution Network Service Provider's demand management activities, including:		
(1)	a qualitative summary of: (i) non-network options that have been considered in the past year, including generation from embedded generating units; (ii) key issues arising from applications to connect embedded generating units received in the past year; (iii) actions taken to promote non-network proposals in the preceding year, including generation from embedded generating units; (iv) the Distribution Network Service Provider's plans for demand management and generation from embedded generating units over the forward planning period;	**7** Demand Management Activities
(2)	a quantitative summary of the following:	**7.6** Key Issues Arising from Embedded Generation

National Electricity Rules Version 116 **Chapter 5: Network Connection, Planning and Regulation** **Schedule 5.8 Distribution Annual Planning Report** **For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:**		**Report Section**
	(i) connection enquiries received (under clause 5.3A.5); (ii) applications to connect received (under clause 5.3 A.9); and (iii) the average time taken to complete applications to connect;	Applications
(m) information on the Distribution Network Service Provider's investments in information technology and communication systems which occurred in the preceding year, and planned investments in information technology and communication systems related to management of network assets in the forward planning period; and		**12** Information Technology and Communication Systems
(n) a regional development plan consisting of a map of the Distribution Network Service Provider's network as a whole, or maps by regions, in accordance with the Distribution Network Service Provider's planning methodology or as required under any regulatory obligation or requirement, identifying:		
(1)	subtransmission lines, zone substations and transmission-distribution connection points; and	**6.5** Emerging Network Limitation Maps
(2)	any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders	

Table 36: DA Cross Reference

Distribution Authority No. D01/99 **DAPR reporting obligations:**		**Report Section**
10.2 Safety Net Targets:		
(b)	From 1 July 2014 onwards, the distribution entity will, as part of its Distribution Annual Planning Report, monitor and report on the measures taken to achieve its Safety Net targets.	**5.4.2** Safety Net
(c)	From 1 July 2015 onwards, the distribution entity will, as part of its Distribution Annual Planning Report, monitor and report on its performance against its Safety Net targets.	**9.6** Safety Net Target Performance
11.2 Improvement Programs requirements:		

Distribution Authority No. D01/99 DAPR reporting obligations:		Report Section
(a)	From 1 July 2014 onwards, the distribution entity will, as part of its Distribution Annual Planning Report, monitor and report on the reliability of the distribution entity's worst performing distribution feeders;	**9.5** Worst Performing Feeders **Appendix G** Worst Performing Distribution Feeders
14.3 Periodic Reports and Plans:		
	From 1 July 2014 onwards, the distribution entity must report in its Distribution Annual Planning Report on the implementation of its Distribution Network Planning approach under clause 8 Distribution Network Planning.	
	Clause 8: Distribution Network Planning 8.1 Subject to clauses 9 Minimum Service Standards, 10 Safety Net and 11 Improvement Programs of this authority and any other regulatory requirements, 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.	**5.4** Network Planning Criteria **9** Network Reliability **Appendix G** Worst Performing Distribution Feeders

Appendix C

Network Security Standards

Appendix C. Network Security Standards

Under the Distribution Authority, Ergon Energy is obligated to promulgate customer value, which provides customer safety net targets approved under the provisions in the *Electricity Act 1994*. These targets applied from 1st July 2014 and form the basis for the Distribution Annual Planning Report and the AER regulatory determination covering the period 2015-20. Safety Net requirements address the network operation issues and the customer impacts arising from high-consequence-low-probability network events and are only applicable to credible contingency (N-1) events.

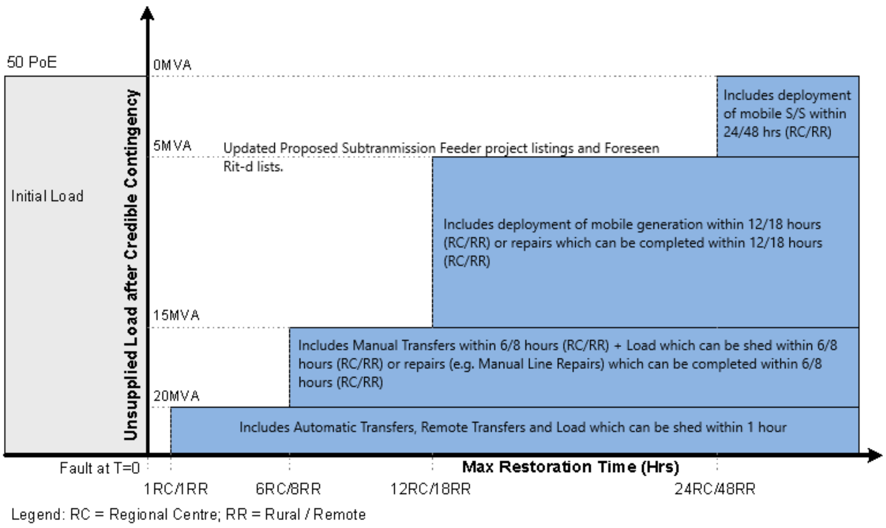
Customer value can be leveraged by combining Minimum Service Standard (MSS) provisions, Worst Performing Feeder programs, concurrent maintenance plans, network operating strategies, contingency plans, and safety net targets. This underpins prudent capital and operating costs and delivers value to the customer. To this end, Ergon Energy's strategic planning practices have adopted the safety net targets.

The Safety Net criteria allow Ergon Energy to make use of available network transfers and zone substation and bulk supply capabilities and are inherent in the assessment of security standard compliance. Where these assessments indicate that the network is not able to meet the required security standards, the resulting system limitation are addressed to ensure customer service expectations are achieved. A range of actions to defer or avoid investments such as non-network solutions, automated, remote and manual load transfer schemes and the deployment of a mobile substation and/or mobile generation increase utilisation of network assets are also considered to comply with Safety Net criteria. Specific security requirements of large customer connections that are stipulated under the relevant connection agreement are treated separate to the Safety Net criteria.

The safety net targets contained in the Ergon Energy's Distribution Authority and applied in the Ergon Energy's strategic network planning are shown in Table 37.

Table 37: Ergon Energy Safety Net Targets

Area	Targets for restoration of supply following an N-1 Event
Regional Centre[56]	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8,000 customers) after 1 hour; • Less than 15MVA (6,000 customers) after 6 hours; • Less than 5MVA (2,000 customers) after 12 hours; and • Fully restored within 24 hours.
Rural Areas	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8,000 customers) after 1 hour; • Less 15MVA (6,000 customers) after 8 hours; • Less 5MVA (2,000 customers) after 18 hours; and • Fully restored within 48 hours.



Unsupplied load after credible contingency and maximum restoration time

In compliance with the Distribution Authority, Regional Centre applies to non-CBD urban areas predominantly supplying actual maximum demand per total feeder route length of greater than 0.3MVA per km. Rural Areas then apply to non-CBD and non-urban areas. All analysis is based on 50% Probability of Exceedance (PoE) loads.

The economic merits of exceeding safety net targets will be derived by customer reliability value assessment. A key input to calculating the economic value customers place on reliability is Value of Customer Reliability (VCR). The economic customer value based approach will be utilised to optimise the timing of individual projects and to assist in prioritising significant projects addressing Safety Net issues.

In a limited number of cases, a higher level of network security will be considered in the interest of public safety or significant economic or community impact.

[56] Regional Centre relates to larger centres with predominantly Urban feeders, whereas Rural Areas relates to areas that are not Regional Centres. Modelling and analysis are benchmarked against 50 PoE loads, based on credible contingencies.

Appendix D

Network Limitations and Mitigation Strategies

Appendix D. Network Limitations and Mitigation Strategies

This section provides details concerning asset limitations and presents committed solutions or potential options for each limitation.

In comparison to the 2019 DAPR, some projects addressing network limitations would have either completed the regulatory process, have entered construction or been commissioned. However, some projects identified in the 2019 DAPR have been deferred beyond the forward planning period due to declining growth in demand forecasts. Furthermore, some projects have been re-assessed and subsequently cancelled. This section provides updated information for the forward planning period.

Details of asset limitations and their associated potential solutions are contained in the Distribution System Limitation Templates prepared in accordance with Australian Energy Regulator's (AER) in the following hyperlinks:

- Substation-Limitations-and-Committed-Solutions
- Substation-Limitations-and-Proposed-Solutions
- Transmission-and-Subtransmission-Feeder-Limitations-and-Proposed-Solutions
- Transmission-and-Subtransmission-Feeder-Limitations-and-Committed-Solutions
- Distribution-Feeder-Limitations-and-Committed-Solutions
- Asset-Replacement-Projects

Further details can be obtained from the Ergon Energy website.[57]

GIS based mapping including forecasts and limitations are available via an ESRI GIS Portal.[58]

[57] Website: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report

[58] Website: https://www.ergon.com.au/daprmap2020

Appendix E

Substation Forecast and Capacity Tables

E:1 Transmission Connection Point Load Forecast

E:2 Substation Capacity and Load Forecasts

E:3 Forecasts for Future Substations and TCPs

Appendix E. Substation Forecast and Capacity Tables

The following subsections contain Substation Forecast and Capacity Tables as well as Transmission Connection Point (TCP) details in the Ergon Energy network.

Further details can be obtained from the Ergon Energy website.[59]

GIS based mapping including forecasts and limitations are available via an ESRI GIS Portal.[60]

E:1 Transmission Connection Point Load Forecast

The detailed load forecasts for TCPs are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link. (Note that TCPs where Ergon Energy owns the power transformers are categorised in this document as bulk supply substations and are included in Appendix E:2 Substation Capacity and Load Forecasts).

Forecast	Link to Microsoft Excel compatible file and ESRI GIS Portal
TCPs (where Ergon Energy does not own the power transformers)	Transmission-Connection-Point-Forecasts-2020.xlsx https://www.ergon.com.au/__data/assets/excel_doc/0005/1082255/Transmission-Connection-Point-Forecasts-2020.xlsx

Contents

The tables contained in this spreadsheet include the following information for 50 PoE and 10 PoE loads in Summer and Winter:

- Ergon Energy region;
- TNI: NEM-Transmission Node Identity
- TCP Name : Name of the Transmission Connection Point
- Forecast Peak Load (MW)
- Forecast Peak Load (MVARu) (VARu = Volt Amps Reactive Uncompensated, i.e. with stated compensation not active)
- Forecast Compensation (MVAR)

Note: The forecast loads are given exclusive of any connected embedded generation.

[59] Website: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report

[60] Website: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report/maps/qld/dapr-map-2020

Exclusions

Forecast capacity is not provided in this spreadsheet. In the majority of cases, the capacity at the TCP is controlled by the TNSP, and hence reported by them. In the relatively few cases where the Ergon Energy asset boundary at the TCP is inclusive of power transformers, the substation capacity will appear in the zone or bulk supply substation forecast tables in Appendix E:2 Substation Capacity and Load Forecasts and E:3 Forecasts for Future Substations and TCPs.

Embedded generation

Table 38 presents embedded generation connected to the load side of TCPs where Ergon Energy does not own the power transformers. All other embedded generation appears in the substation capacity and load forecasts below in Appendix E:2 Substation Capacity and Load Forecasts.

Table 38: Embedded Generation Connected to Load Side of TCP

Region	Connection Point	Nameplate Rating (MW)
Northern	South Johnstone Mill 22/11kV Substation, 22kV	17.3
Northern	Gordonvale 22kV Switching Station, 22kV	13
Northern	T048 Tully 132/22kV Substation, Tully Mill 22kV Feeder	19.8
Northern	T055 Turkinje 132/66kV Substation, Dimbulah 66kV Feeder	24
Northern	Kidston 132/6.6kV Substation, 132kV	50
Northern	Pioneer Mill 66kV Switching Station	67.8
Northern	Townsville Power Station 66kV Switchyard	82
Northern	Ingham 66/11kV Substation, Victoria Mill 66kV Feeder	24
Northern	Collinsville 33kV Substation	42.5
Northern	T38 Mackay 33kV	30
Northern	T141 Pioneer Valley to GLEL Glenella 66kV Feeder	38
Northern	T34 Moranbah 11kV	12
Northern	T34 Moranbah 66kV	100
Southern	H015 Lilyvale 66kV	63
Southern	Barcaldine Substation 132kV	37
Southern	T83 Roma 132kV	2x45
Southern	Emerald Solar Park - Lilyvale & Blackwater 66kV	72

E:2 Substation Capacity and Load Forecasts

The detailed capacity and load forecasts for bulk supply and zone substations where Ergon Energy owns the power transformers are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link. Where limitations are identified in this table, further explanation is given in Section 6.1.

Forecast	Link to Microsoft Excel compatible file and ESRI GIS Portal
Bulk supply and zone substations:	Substation-Forecasts-2020.xlsx
	https://www.ergon.com.au/__data/assets/excel_doc/0020/1082252/Substation-Forecasts-2020.xlsx

Contents

The tables include the following information:

- Region
- Substation name
- Capacity of commissioned Embedded Generation (with Connection Agreements)
- Forecast over the next five years for:
    - Normal Cyclic Capacity - the total capacity with network components and equipment intact
    - Emergency Cyclic Capacity – the long term firm delivery capacity under single contingency conditions
    - Maximum demand (MVA) (50% PoE and 10% PoE)
    - Hours above 95% of maximum demand
    - Expected power factor at peak load
    - Summer and Winter firm capacity
    - The load in MVA which can be transferred to other supply sources (automatically and manually)
    - Whether required security is achieved.

Exclusions

- Where transfers or generation are not required to meet Safety Net, available transfer capacity has not been assessed and therefore is not included in the reports.
- Bulk supply substations owned by Powerlink or other NSPs connected to the Ergon Energy network.
- Bulk supply substations dedicated to major customers at which the security criteria are a function of the particular customer connection agreement.
- Bulk supply substations that are shared sites where Ergon Energy does not own the bulk supply power transformers.
- Zone substations owned by Powerlink which provide a connection point at 11kV or 22kV to the

Ergon Energy network.

- Zone substations dedicated to major customers at which the security criteria are a function of the particular customer connection agreement.
- Minor zone substations (Maximum demand <0.5MVA) which are regarded as 'defacto' distribution transformers.
- De-rating factors such as transformer cables and bus ratings are not considered in these forecasts. Substation capacity is based on transformer ratings only.

E:3 Forecasts for Future Substations and TCPs

Table 39 and Table 40 set out the forecast capacity for the forward planning period for approved future substations and transmission connection points.

Table 39: Forecasts for Future Substations

Region	Future Substation	Location	Proposed Commissioning Time	Future Loading Level
Northern	Cape River East – New Substation	North Queensland North-West Region	Qtr 4 2024	Available in 2020
Southern	Gracemere 66/11kV - New Substation	Rockhampton Region	Qtr 2 2022	Refer Appendix E:2 Substation Capacity and Load Forecasts
Southern	Kleinton 33/11kV – New Substation	Toowoomba Region	Qtr 3 2024	Available in 2020

Note: Milestones as of October 2020 internal reports and are subject to change.

Table 40: Forecasts for Future Transmission Connection Points

Region	Future Transmission Connection Point	Location	Proposed Commissioning Time	Future Loading Level
-	Nil approved	-	-	-

Appendix F

Feeder Forecast and Capacity Tables

F:1 Subtransmission Feeder Capacity and Load Forecast

F:2 Forecasts for Future Subtransmission Lines

F:3 Distribution Feeder Limitations Forecast

Appendix F. Feeder Forecast and Capacity Tables

The following subsections contain Feeder Forecast and Capacity Tables for subtransmission and distribution feeders in the Ergon Energy network.

Further details can be obtained from the Ergon Energy website.[61]

GIS based mapping including forecasts and limitations are available via an ESRI GIS Portal.[62]

F:1 Subtransmission Feeder Capacity and Load Forecast

Subtransmission line capacity and load forecasts for both summer and winter are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link:

Forecast	Link to Microsoft Excel compatible file and ESRI GIS Portal
Subtransmission feeder (10 POE & 50 POE)	Subtransmission-Feeder-Forecast-10PoE-2020.xlsx
	https://www.ergon.com.au/__data/assets/excel_doc/0003/1082253/Subtransmission-Feeder-Forecast-10PoE-2020.xlsx
	Subtransmission-Feeder-Forecast-50PoE-2020.xlsx
	https://www.ergon.com.au/__data/assets/excel_doc/0004/1082254/Subtransmission-Feeder-Forecast-50PoE-2020.xlsx

Information is presented for both current and future forecasts for the relevant network asset.

The subtransmission line tables include the following information:

- Ergon Energy region
- Ergon Energy ECORP code
- Ergon Energy operational code
- Subtransmission feeder name and description
- 10 POE & 50 POE forecasts
- % of Rated Amps
- Loading (Amps)
- Power Factor
- Rating (Amps)
- Summer and Winter capacity and load forecasts for five years
- SD = Summer Day (9am to 5pm)
- SE = Summer Evening (5pm to 10pm)
- SN/M = Summer Night/Morning (10pm to 9am)

61 Website: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report

62 Website: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report/maps/qld/dapr-map-2020

Note:

- Summer - December to March
- All other months are classed as summer - March, April, May, September, October, and November.

F:2 Forecasts for Future Subtransmission Lines

Table 41 sets out the forecast capacity for the forward planning period for approved future subtransmission lines.

Table 41: Forecasts for Future Subtransmission Lines

Region	Future Subtransmission Line	Location	Proposed Commissioning Time	Future Loading Level
Southern	Egans Hill – Gracemere - New 66kV OH Line Construction	Rockhampton Region	Qtr 2 2022	Refer **Appendix F:1** (refer to Gracemere substation forecast)
Southern	Reinforce Burnett Heads - New 66kV OH Line Construction	Bundaberg Region	Qtr 1 2024	Available in 2021
Southern	Nikenbah to Point Vernon – New 66kV Line Construction	Maryborough Region	Qtr 2 2022	Available in 2021

F:3 Distribution Feeder Limitations Forecast

Primary distribution feeders which are currently overloaded or forecast to experience an overload in the next two years are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link:

Forecast	Link to Microsoft Excel compatible file and ESRI GIS Portal
Distribution feeder limitations	Distribution-Feeder-Limitations-and-Committed-Solutions-2020.xlsx
	https://www.ergon.com.au/__data/assets/excel_doc/0006/867417/Distribution-Feeder-Limitations-and-Committed-Solutions-2020.xlsx

Appendix F. Feeder Forecast and Capacity Tables

Contents of Table:

The distribution feeder limitation tables include the following information:

- Ergon Energy region
- Distribution feeder name, ID and location
- Load exceedance after two years (MVA)
- Forecast season that exceedance occurs (Summer / Winter)
- Forecast year that exceedance occurs
- Forecast month/s that exceedance occurs
- Load reduction needed to defer the exceedance by 12 months (MW).

Note: Assumed power factor of 0.9.

Connection Points for Load Reduction:

In all cases, the connection point to apply load reduction would be downstream of the substation exit feeder cable and/or first section of line.

Possible Solutions:

Refer to Section 6.1 Network Limitations – Adequacy, Security and Asset Condition for a list of possible solutions.

Exclusions:

Dedicated customer connection assets are excluded from the analysis.

Appendix G

Worst Performing Distribution Feeders

Appendix G. Worst Performing Distribution Feeders

Table 42: Worst Performing Distribution Feeders

Feeder Asset ID	SAIDI & SAIFI Performance	Feeder Length (km)	Customer Number	Feeder Category	2019-20 MSS SAIDI Limit	3 Year Average SAIDI	2019-20 MSS SAIFI Limit	3 Year Average SAIFI	Improvement Program Criteria Met
10020674	Reviewed 2014-15	885.1	68	LR	964	9229	7.40	18.33	SAIDI and SAIFI Performance
10020675	Reviewed 2016-17	77	391	SR	424	769	3.95	9.61	SAIFI Performance
10020848	Reviewed 2019-20	75.8	103	SR	424	2450	3.95	7.00	SAIDI Performance
10020857	Pending Review	90.7	212	SR	424	1250	3.95	11.16	SAIFI Performance
10131875	Pending Review	11.4	11	SR	424	3441	3.95	7.67	SAIDI Performance
20001962	Pending Review	74.8	311	SR	424	1575	3.95	11.16	SAIFI Performance
20002143	Pending Review	8.3	2	SR	424	3724	3.95	3.33	SAIDI Performance
20002149	Pending Review	13.4	2	SR	424	4533	3.95	4.50	SAIDI Performance
20003547	Pending Review	0.3	1	UR	149	5296	1.98	13.00	SAIDI and SAIFI Performance
20003550	Reviewed 2014-15	50.8	346	SR	424	3398	3.95	9.64	SAIDI and SAIFI Performance
20003866	Pending Review	582.1	83	LR	964	2373	7.40	3.60	SAIDI Performance
20003983	Reviewed 2016-17	138.9	75	SR	424	2929	3.95	9.36	SAIDI and SAIFI Performance
20004937	Pending Review	778.1	325	LR	964	2802	7.40	7.00	SAIDI Performance
20005039	Pending Review	15.1	2	SR	424	7635	3.95	17.17	SAIDI and SAIFI Performance
20005787	Reviewed 2015-16	72.2	46	SR	424	4893	3.95	12.35	SAIDI and SAIFI Performance
20006350	Reviewed 2018-19	130.2	246	SR	424	2819	3.95	11.02	SAIDI and SAIFI Performance
20006383	Reviewed 2014-15	504.5	186	LR	964	4182	7.40	10.44	SAIDI Performance
20006478	Pending Review	32	54	SR	424	1453	3.95	9.50	SAIFI Performance
20006518	Reviewed 2015-16	140.4	179	SR	424	1541	3.95	9.99	SAIFI Performance
20006599	Pending Review	1.1	1	SR	424	1030	3.95	15.00	SAIFI Performance
20007373	Reviewed 2019-20	2.9	46	UR	149	1276	1.98	9.41	SAIFI Performance
20007634	Reviewed 2015-16	1296.7	296	LR	964	2551	7.40	7.21	SAIDI Performance
20007736	Reviewed 2019-20	466.1	87	LR	964	4585	7.40	11.10	SAIDI Performance

Appendix G. Worst Performing Distribution Feeders

Feeder Asset ID	SAIDI & SAIFI Performance	Feeder Length (km)	Customer Number	Feeder Category	2019-20 MSS SAIDI Limit	3 Year Average SAIDI	2019-20 MSS SAIFI Limit	3 Year Average SAIFI	Improvement Program Criteria Met
20008686	Reviewed 2015-16	299.9	49	LR	964	3022	7.40	12.37	SAIDI Performance
20008745	Reviewed 2016-17	397.8	35	LR	964	5363	7.40	14.82	SAIDI and SAIFI Performance
20008784	Reviewed 2017-18	329.5	33	LR	964	8371	7.40	14.02	SAIDI Performance
20008837	Reviewed 2017-18	264.1	28	LR	964	5190	7.40	14.22	SAIDI Performance
20009089	Pending Review	3.7	1	UR	149	4790	1.98	7.00	SAIDI Performance
20009483	Pending Review	0	1	SR	424	2166	3.95	2.67	SAIDI Performance
20010437	Pending Review	11.8	6	SR	424	2912	3.95	4.44	SAIDI Performance
20010444	Reviewed 2015-16	59.3	44	SR	424	3801	3.95	14.07	SAIDI and SAIFI Performance
20010480	Reviewed 2015-16	95.6	107	SR	424	3762	3.95	13.82	SAIDI and SAIFI Performance
20010573	Reviewed 2018-19	81.9	23	SR	424	2111	3.95	13.03	SAIDI and SAIFI Performance
20010596	Pending Review	97.5	40	SR	424	1621	3.95	10.34	SAIFI Performance
20010627	Pending Review	1.7	1	SR	424	859	3.95	11.33	SAIFI Performance
20011122	Pending Review	0	2	SR	424	811	3.95	14.67	SAIFI Performance
20011126	Pending Review	406.2	39	LR	964	2578	7.40	9.61	SAIDI Performance
20011420	Pending Review	146	47	SR	424	1430	3.95	17.47	SAIFI Performance
20011458	Pending Review	4.9	4	SR	424	1108	3.95	15.08	SAIFI Performance
20011464	Pending Review	29.8	102	SR	424	1951	3.95	18.22	SAIDI and SAIFI Performance
20011824	Reviewed 2016-17	224.4	31	LR	964	5453	7.40	12.54	SAIDI Performance
20013260	Pending Review	14.1	5	SR	424	2525	3.95	15.33	SAIDI and SAIFI Performance
20013575	Pending Review	2.8	5	SR	424	1094	3.95	15.47	SAIFI Performance
20020666	Reviewed 2018-19	305.6	32	LR	964	3790	7.40	8.73	SAIDI Performance
25267897	Pending Review	224.1	43	LR	964	3513	7.40	9.00	SAIDI Performance
25267901	Reviewed 2016-17	412.7	42	LR	964	4917	7.40	8.67	SAIDI Performance
25268404	Reviewed 2014-15	2.7	158	UR	149	1001	1.98	9.31	SAIFI Performance
25268407	Reviewed 2016-17	18.7	136	SR	424	1468	3.95	11.63	SAIFI Performance

Appendix G. Worst Performing Distribution Feeders

Feeder Asset ID	SAIDI & SAIFI Performance	Feeder Length (km)	Customer Number	Feeder Category	2019-20 MSS SAIDI Limit	3 Year Average SAIDI	2019-20 MSS SAIFI Limit	3 Year Average SAIFI	Improvement Program Criteria Met
25268413	Reviewed 2016-17	936.8	129	LR	964	3442	7.40	12.82	SAIDI Performance
25272934	Reviewed 2015-16	89.7	21	SR	424	2028	3.95	4.62	SAIDI Performance
25272938	Reviewed 2017-18	383.6	65	LR	964	1956	7.40	5.39	SAIDI Performance
25273274	Reviewed 2016-17	134.4	21	SR	424	4117	3.95	6.44	SAIDI Performance
25273297	Reviewed 2016-17	295.8	60	LR	964	3643	7.40	7.93	SAIDI Performance
25276003	Reviewed 2016-17	320.8	49	LR	964	3116	7.40	8.84	SAIDI Performance
25280567	Pending Review	0	1	UR	149	4520	1.98	4.33	SAIDI Performance
30053752	Pending Review	201.3	739	LR	964	1975	7.40	8.89	SAIDI Performance
30053764	Pending Review	1.1	1	UR	149	7346	1.98	4.00	SAIDI Performance
30053773	Reviewed 2017-18	94.6	270	SR	424	1144	3.95	9.13	SAIFI Performance
30053777	Reviewed 2016-17	116.5	285	SR	424	2227	3.95	9.37	SAIDI and SAIFI Performance
30053848	Pending Review	61.6	275	SR	424	1139	3.95	9.51	SAIFI Performance
30053867	Reviewed 2017-18	98	201	SR	424	3197	3.95	9.69	SAIDI and SAIFI Performance
30053868	Pending Review	7	15	SR	424	4611	3.95	9.81	SAIDI and SAIFI Performance
30053875	Pending Review	1.7	1	UR	149	5465	1.98	12.00	SAIDI and SAIFI Performance
40001032	Reviewed 2016-17	140.8	33	SR	424	3204	3.95	13.47	SAIDI and SAIFI Performance
40001033	Reviewed 2017-18	396.1	97	LR	964	6008	7.40	12.95	SAIDI Performance
40001041	Pending Review	214.4	72	LR	964	3510	7.40	7.32	SAIDI Performance
40001052	Pending Review	242.6	50	LR	964	4893	7.40	11.40	SAIDI Performance
40001057	Pending Review	0.2	1	UR	149	4124	1.98	6.33	SAIDI Performance
40001071	Pending Review	0.2	1	UR	149	2358	1.98	5.00	SAIDI Performance
40001116	Pending Review	1071.9	995	LR	964	2318	7.40	7.61	SAIDI Performance
40001206	Reviewed 2017-18	29.6	70	SR	424	1968	3.95	5.20	SAIDI Performance
40200482	Reviewed 2014-15	46.9	30	SR	424	1593	3.95	9.66	SAIFI Performance
40200483	Pending Review	287.2	88	LR	964	2565	7.40	13.06	SAIDI Performance

Appendix G. Worst Performing Distribution Feeders

Feeder Asset ID	SAIDI & SAIFI Performance	Feeder Length (km)	Customer Number	Feeder Category	2019-20 MSS SAIDI Limit	3 Year Average SAIDI	2019-20 MSS SAIFI Limit	3 Year Average SAIFI	Improvement Program Criteria Met
40223076	Pending Review	699.1	287	LR	964	2228	7.40	6.20	SAIDI Performance
50000011	Reviewed 2016-17	184.6	88	SR	424	2339	3.95	10.88	SAIDI and SAIFI Performance
50000040	Pending Review	250.9	349	LR	964	1990	7.40	9.49	SAIDI Performance
50000160	Pending Review	279.6	282	LR	964	2181	7.40	14.44	SAIDI Performance
50000161	Reviewed 2017-18	77.4	91	SR	424	1503	3.95	11.20	SAIFI Performance
60026644	Reviewed 2017-18	2551.5	318	LR	964	2119	7.40	7.96	SAIDI Performance
60026696	Pending Review	884.7	181	LR	964	2002	7.40	8.09	SAIDI Performance
60026741	Reviewed 2016-17	118.4	127	SR	424	1228	3.95	10.58	SAIFI Performance
60026787	Pending Review	1078.7	153	LR	964	2858	7.40	6.62	SAIDI Performance
60306801	Pending Review	75.8	7	SR	424	4981	3.95	2.29	SAIDI Performance
82563751	Pending Review	7.3	1	SR	424	2593	3.95	4.67	SAIDI Performance
82651966	Pending Review	7	4	SR	424	2090	3.95	4.17	SAIDI Performance
84706956	Pending Review	30.1	4	SR	424	2829	3.95	11.00	SAIDI and SAIFI Performance
85351479	Pending Review	0	1	SR	424	3081	3.95	3.33	SAIDI Performance

Appendix H

Network Description and Maps

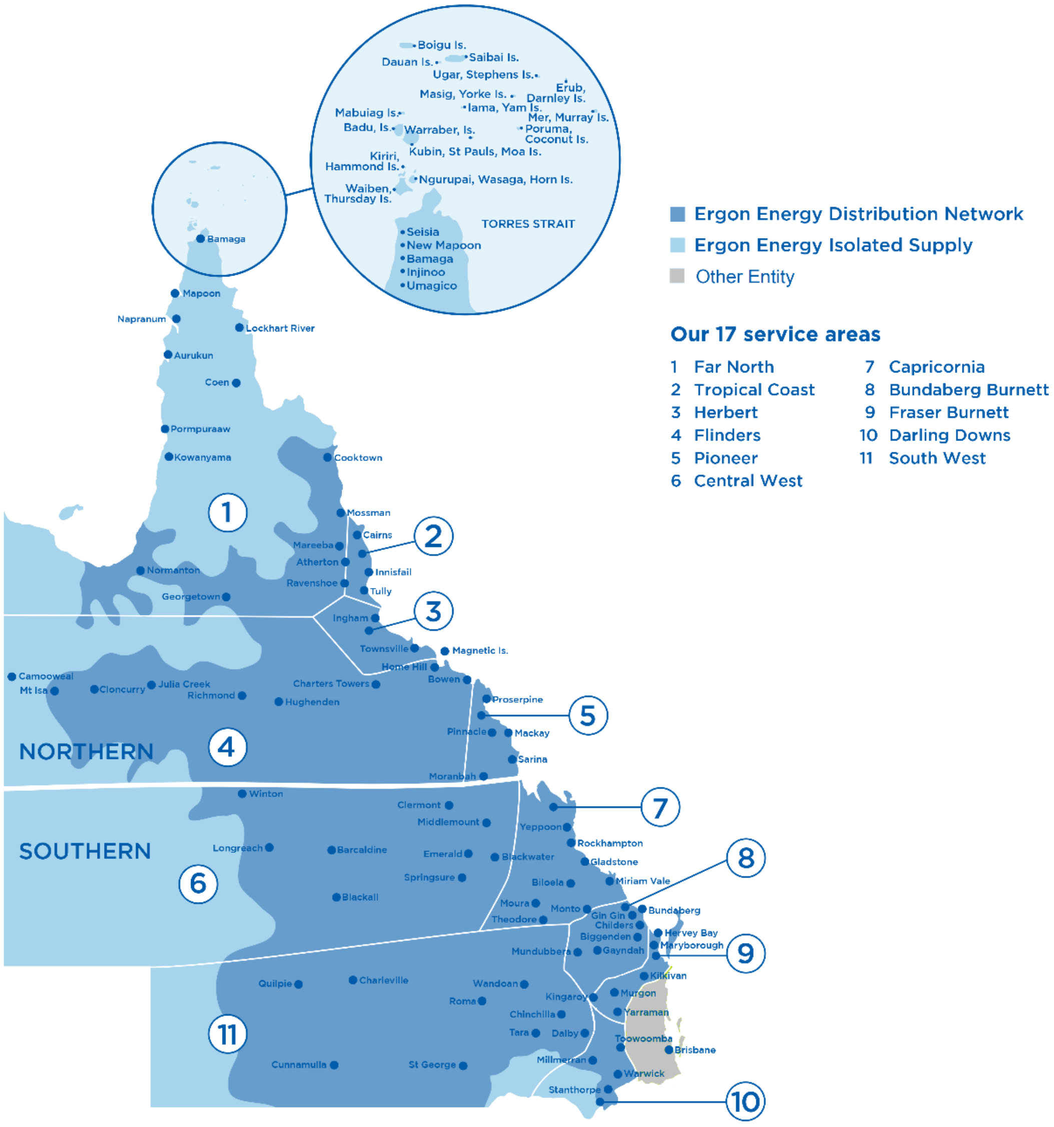
Appendix H. Network Description and Maps

H:1 Planning Regions Overview

As Energy Queensland moves into its current structure, new boundaries and terminology are being adopted for grouping field areas to support efficient service delivery. There are three geographic regions in the Distribution business unit - Northern, Southern and South East.

Ergon Energy has grouped the network broadly into two new planning areas: Northern and Southern as shown in Figure 36 below.

Figure 36: Ergon Energy Network Planning Areas



Within the Northern and Southern regions there are now eleven distinct planning regions within these areas, as shown in Table 43. The following sections provide a description of the planning regions and the hubs they envelop.

Table 43: Ergon Energy Network Planning Regions

	Planning Regions	
	Northern	**Southern**
Sub Regions	Far North	Central West
	Tropical Coast	Capricornia
	Herbert	Bundaberg Burnett
	Flinders	South West
	Pioneer	Fraser Burnett
		Daring Downs

H:2 Network GIS Online Maps

Network maps covering the entire Ergon Energy area are provided in GIS format in an ESRI GIS Portal.[63]

The map also shows the forecast emerging network limitations. The limitations include: subtransmission lines, zone substations and primary distribution feeders that are forecast to have constraints.

H:3 Northern Region

The Northern Region commences at St Lawrence on the east coast, extending west to the Northern Territory border and north to the northern most island in Torres Strait, Boigu Island. The region consists of five major areas – Far North, Tropical Coast, Herbert, Flinders and Pioneer.

The Far North and Tropical Coast areas, with Cairns as the major centre, are tropical environments with high annual rainfall and exposure to summer electrical storms and cyclones. A substantial part of the wet tropics is also World Heritage Listed, requiring special consideration with regard to the operation and maintenance of any electrical infrastructure.

The Herbert (with Townsville as the major centre) and parts of the Flinders areas are also tropical environments with exposure to summer electrical storms and cyclones. These two areas extend from Bowen in the south to Ingham in the north and west to the Northern Territory border.

The Pioneer region is a sub-tropical environment with exposure to summer electrical storms and cyclones and consists of two main geographic areas (Mackay and Bowen Basin) with regard to

[63] Webpage: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report/maps/qld/dapr-map-2020

electrical infrastructure.

The Northern Region includes many small regional towns with the following listing identifying some of the larger communities in the area, as per Table 44.

Table 44: Queensland Northern Regions

Sub Regions	Regional Communities
Far North	Cooktown, Mossman, Port Douglas, Mareeba, Atherton, Malanda, Millaa, Mt Molloy, Dimbulah, Chillagoe, Ravenshoe, Georgetown, Normanton, Croydon and Karumba
Tropical Coast	Cairns, Gordonvale, Babinda, Innisfail, Tully, Mission Beach and Cardwell
Herbert	Townsville, Ingham, Magnetic Island
Flinders	Ayr, Clare, Home Hill, Giru, Gumlu, Bowen, Collinsville, Charters Towers, Julia Creek, Hughenden, Winton, Richmond, Mount Isa, Cloncurry
Pioneer	Mackay, Carmila, Proserpine, Airlie Beach, Laguna Quays, Hayman, Hamilton, Daydream, South Molle, Long Islands, Moranbah, Glenden Nebo, Sarina, Pleystowe, Eungella, Eton and Rosella

Far North

The Far North area is centred on the major rural towns of Mareeba and Atherton and includes the smaller rural communities of Malanda, Millaa, Mt Molloy, Dimbulah and Chillagoe. In addition, the coastal communities of Mossman, Port Douglas and Cooktown are supplied from the Far North network. The area is served from the one 132/66kV connection point, T55 Turkinje substation (located near Mareeba). The Far North system consists of a 66kV subtransmission network, a dual circuit 132kV transmission line from Turkinje to the Craiglie 132/22kV zone substation near Port Douglas, and a single circuit 132kV line to the Lakeland 132/66/22kV substation that supplies the Cooktown area.

In addition, the Far North western system takes in the Georgetown, Normanton, Croydon, and Karumba communities in the Gulf of Carpentaria. The area is served from the H13 Ross connection point in Townsville where a 132kV single circuit line owned by Ergon Energy to supply this area originates.

Tropical Coast

The Tropical Coast area covers the city of Cairns and environs, as well as the townships of Tully, Innisfail, Cardwell and Mission Beach along the coastal strip. The area is served by 132/22kV connection points which are supplied from the Powerlink 132kV network. In addition the Cairns City and Cairns North 132/22kV zone substations are supplied via Ergon Energy owned 132kV dual circuit lines connected to Powerlink's Woree 275/132kV connection point.

Herbert

The Herbert area covers the city of Townsville and environs, as well as the townships and surrounding rural areas north to and including Ingham. The area is served by five 132/66kV connection points (one in Ingham and four in Townsville), and one 132/11kV connection point, which are supplied from the Powerlink 132kV network. Ergon Energy takes supply at the 66kV side of Powerlink's 132/66kV transformers for five of these connection points, and at the 132kV terminals of the 132/11kV transformers at the Alan Sherriff 132/11kV connection point. Where Ergon Energy takes supply from Powerlink at the four connection points in Townsville a meshed 66kV network is formed that provides supply to fifteen 66/11kV zone substations.

Flinders

This area basically covers Burdekin/Bowen, Midwestern and Western areas of the North Queensland region.

South of Townsville is the coastal strip centred around the major rural towns of Ayr and Home Hill in the Burdekin, and the coastal community of Bowen. It also includes the mining township of Collinsville and its surrounding rural loads. The Burdekin area is served from the connection point at T193 Clare South, located near the Clare township, the Bowen area including the township of Merinda is served from the T181 Bowen North connection point, located near the Merinda township and two 66kV feeders emanating from the T039 Proserpine 132/66kV connection point which is located in the Ergon Energy Mackay region. Collinsville is supplied at 33kV from an Ergon Energy 33kV switching station connected to the T220 Collinsville North connection point.

The mid-western system of the Flinders area extends from Charters Towers west to Julia Creek and takes in the towns of Hughenden, Winton and Richmond. All these towns are connected at 66kV. Ergon Energy's Millchester 132/66kV substation is located on the outskirts of Charters Towers and is supplied by an Ergon Energy owned single circuit 132kV transmission line from Powerlink's Ross substation in Townsville. Limited capacity is also available via 66kV lines from Stuart substation (Townsville) and T193 Clare South substation to Charters Towers substation. The area west of Charters Towers is supplied by two 66kV feeders, one from Charters Towers substation and one from Millchester substation, to Hughenden substation. Each of these 250km long feeders goes through a 66kV voltage regulator at Cape River substation, which is about 100km from Charters Towers.

The Flinders western area comprises the Mount Isa and Cloncurry regions, and also the non-regulated network supplying the Carpentaria Minerals Province mining loads. This network is isolated from the coastal network, which interconnects eastern Australia, and operates outside of the NEM. Our network here is supplied at 132kV from the Mica Creek Power Station and Diamantina Power Station in Mount Isa. The Duchess Road substation, which services the Mount Isa load, is supplied by two 132kV feeders from Mica Creek B Yard. Ergon Energy's Mica Creek 132/220kV C Yard supplies the Carpentaria Minerals Province mining loads and the Chumvale 220/66kV substation by two 220kV feeders. Chumvale substation provides 66kV supply to two 66/11kV substations that serve the township of Cloncurry.

Pioneer

The Pioneer region is a sub-tropical environment with exposure to summer electrical storms and cyclones and consists of two main geographic areas (Mackay and Bowen Basin) with regard to electrical infrastructure.

The Mackay area centred on the provincial city of Mackay and extends from the small rural community of Carmila in the south, to the rural township of Proserpine and surrounding area in the north including the tourist destinations of Airlie Beach and Laguna Quays. The coastal strip supply area also provides supply to the Hayman, Hamilton, Daydream, South Molle and Long Islands of the Whitsunday group. The area is served by the two 132/33kV connection points of Alligator Creek and Mackay and two 132/66kV connection points of Pioneer Valley and Proserpine, all of which are supplied from Powerlink's 132kV network. Ergon Energy takes supply at the connection points at the 33kV or 66kV sides of Powerlink's transformers.

The Bowen Basin area is centred about the mining towns of Moranbah, Glenden and Nebo and includes around 16 major coal mines. The mines are either supplied from substations connected to the 66kV supply system from the Moranbah 132/66kV connection point, the 66kV supply system from the Kemmis 132/66kV connection point or from substations connected to the Powerlink 132kV network.

H:4 Southern Region

The Southern Region commences near Stanthorpe in the South East Queensland and extends west to the South Australia and Northern Territory boarder. The Northern extremity of the region includes areas of Rockhampton, Middlemount, Clearmont and Longreach. The area includes the Sub Regions of Central West, Capricornia, Bundaberg Burnett, South west, Fraser Burnett and the Darling Downs.

The Southern Region includes many small regional towns with the following listing identifying some of the larger communities in the area, as per Table 45.

Table 45: Queensland Southern Regions

Sub Regions	Regional Communities
Central West	Longreach, Barcaldine, Blackall, Springsure, Emerald, Blackwater, Clermont, Middlemount, Dysart, Boulia, Bedourie, Birdsville, Windorah
Capricornia	Yeppoon, Rockhampton, Gladstone, Miriam Vale, Moura, Biloela, Monto, Theodore, Anges Waters, Seventeen Seventy, Taroom
Bundaberg Burnett	Bundaberg, Gin, Childers, Mundubbera, Biggenden, Gayndah, Proston, Eidsvold, Mt Perry, Bargara, Moore Park, Woodgate
South West	Quilpie, Charleville, Cunnamulla, Roma, St George, Wandoan, Chinchilla, Tara , Dalby, Miles, Dirranbandi, Mitchell, Augathella, Thargomindah
Fraser Burnett	Murgon, Kingaroy, Yarraman, Kilkivan, Maryborough, Hervey Bay, Nanango, Yarraman, Blackbutt, Wondai, Howard, Burrum Heads
Darling Downs	Toowoomba, Millmerran, Warwick, Stanthorpe, Pittsworth, Oakey, Crows Nest, Cecil Plains

Central West

The Central West area takes in the major rural and mining communities of Emerald, Blackwater, Barcaldine, Clermont and Dysart, along with their surrounding areas. The area also extends west to supply the communities of Barcaldine, Longreach and Blackall and further west to the west to the Queensland/Northern Territory/South Australia state border. This area is supplied from the Powerlink connection points of T032 Blackwater, H15 Lilyvale and T035 Dysart, and also Ergon Energy's T076 Barcaldine. Ergon Energy also takes supply at lower voltages at Blackwater (66kV and 11kV) and Dysart (22kV). The Central West systems include extensive SWER networks.

Capricornia

The Capricornia area incorporates the provincial city of Rockhampton and the surrounding coastal area including Yeppoon and Emu Park, as well as Biloela and Gladstone areas. The Rockhampton area takes supply from Powerlink 132/66kV connection points at T23 Rockhampton, T127 Egans Hill and T061 Pandoin. Ergon Energy takes supply at the connection points at the 66kV sides of the Powerlink 132/66kV transformers.

The Gladstone area is supplied from T019 Gladstone South, H067 Calliope River, T199 Yarwun bulk connection points, and Ergon Energy's Boat Creek and Gladstone North 132/66kV substations. Biloela, Moura and surrounding areas are supplied from the T026 Biloela and T027 Moura 132/66kV bulk connection points. South of the Gladstone area, Ergon Energy has the T166 Granite Creek 132/66kV substation which then supplies Ergon Energy's 66/22kV Agnes Water zone substation. Ergon Energy takes supply from Powerlink at 132kV for Boat Creek and Gladstone North substations, 66kV and 11kV at Gladstone South, 66kV and 11kV at Biloela, 66kV and 22kV at Moura and 132kV at Gin to supply Granite Creek. Supply from Biloela also extends into the North Burnett to supply Ergon Energy's Monto substation.

Bundaberg Burnett

The local Bundaberg area is centred about the provincial city of Bundaberg and also takes in the smaller rural communities of Givelda, Bullyard, South Kolan, Wallaville, Gooburrum, Meadowvale as well as the coastal communities of Bargara and Burnett Heads. Bundaberg is supplied from Powerlink Gin and Teebar Creek 275/132kV substations. Voltage is transformed from 132kV to 66kV at Ergon Energy's T20 Bundaberg supply point. Two main 66kV rings exist; the first connects the Bundaberg and South Kolan substations, and the other connects the Bundaberg, South Bundaberg, East Bundaberg, Bundaberg Central and West Bundaberg substations. Ergon's Isis 132/66kV substation supplies Childers, as well as parts of the North Burnett including Degilbo, Munduberra, Gayndah and Eisvold.

South West

Ergon Energy's Roma 132/6/33kV substation is supplied via an Ergon Energy owned double circuit 132kV line from Powerlink's Columboola 132kV switchyard. A 132/66kV transformer at Roma substation supplies 66kV feeders to St George substation and Charleville substation (from which 66kV feeders to Cunnamulla and Quilpie emanate). The distribution supply network from these systems also extends through to Thargomindah, Dirranbandi and Augathella.

Ergon Energy's Dalby East substation which services the Dalby region is supplied via two Ergon Energy owned single circuit 110kV transmission lines from Powerlink's Tangkam 110kV switching station. Chinchilla substation is supplied by Powerlink owned double circuit 132kV line from either Powerlink's Tarong switchyard or Powerlink's 275/132kV Columboola substation. The Columboola 132/33kV substation connects the Condamine power station into the Chinchilla-Roma 132kV lines and provides 33kV supply to the surrounding region including Miles 33/11kV zone substation. A number of 33kV feeders emanate from Dalby, Chinchilla, Miles and Columboola substations to supply the 33/11kV and 33/22kV zone substations (and several customer owned 33/0.433kV substations) in the area.

Numerous 19.1kV and 12.7kV SWER systems existing in the South West Area

Fraser Burnett

Ergon Energy's Kingaroy substation is supplied via Powerlink's H18 Tarong 275/132/66kV substation. 66kV feeders emanate from Kingaroy Substation to supply rural communities of Nanango, Yarraman and Kumbia as well as Sunwater and Stanwell pumping sites. A 66kV line connects the Kingaroy substation with the Murgon zone substation that is supplied from the Kilkivan 132/66kV substation. This line is operated normally open at the Kingaroy substation.

Ergon Energy's Maryborough 132/66kV substation is supplied from Ergon Energy's Aramara Switching station which connects via two 132kV feeders into Powerlink's Tee Bar Creek 275/132kV substation. Maryborough 132/66kV substation supplies Maryborough, Hervey Bay, and rural communities of Owanyilla, Gootchie, Woolooga and Howard to the south west, and the Hervey Bay coastal area. The area is presently served by nine zone substations which are supplied from the Maryborough 132/66kV substation. Ergon Energy's Kilkivan 132/66kV substation is supplied via dual circuit 132kV feeder from Powerlink's 275/132kV Woolooga site. Kilkivan 132/66kV substation supplies Kilkivan, Goomeri, Murgon, Wondai and Proston. A 66kV ring exists connecting the Kilkivan Town and Murgon substations. From Murgon a 66kV line also connects with the Kingaroy substation but is operated normally open at Kingaroy.

Darling Downs

To supply the Toowoomba, Warwick and Stanthorpe areas, Ergon Energy takes supply at 110kV from Powerlink owned 110kV feeder bays at the Middle Ridge 330/275/110kV connection point. 110kV feeders supply Ergon Energy's South Toowoomba, Torrington, Yarranlea, Warwick, and Stanthorpe 110kV bulk supply substations, and the Kearneys Spring and Toowoomba Central 110/11kV zone substations.

The T189 Oakey 110/33kV bulk supply substation, the 110kV lines and 110kV bus are owned by Powerlink with Ergon Energy owning the 110/33kV transformers. A number of 33/11kV zone substations are then supplied from the 110kV bulk supply substations mentioned above.

In addition, Ergon Energy takes supply at 33kV from the Energex owned Postmans Ridge substation. From Postmans Ridge substation two Ergon Energy owned 33kV lines supply a number of Toowoomba Regional Council water pumping stations as well as Ergon Energy's Crows Nest zone substation. Another 33kV feeder bay at Postmans Ridge substation provides a 33kV contingency supply to the North Street zone substation in Toowoomba.

Appendix I

RIT-D Projects

I:1 RIT-D – In Progress

I:2 RIT-D - Completed

Appendix I. RIT-D Projects

I:1 RIT-D – In Progress

This section describes the RIT-Ds that were commenced in 2019-20 and includes several replacement driven projects that now require RIT-D assessment, as specified in the National Electricity Amendment published by the AER on 18th July 2017. Estimated costs are provided within the associated RIT-D report found on the Ergon Energy website.[64]

Table 46: Regulatory Test Investments - In Progress

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Addressing Customer Demand Requirement in Western Grid/Barcaldine	$5.4M	Oct 2023	*Nil impact beyond regulated revenue.*
Project need: Barcaldine 132/66/22kV bulk supply substation (T072 BARC) has identified assets that are recommended for replacement. These assets are forecast to reach retirement based on a combination of Condition Based Risk Management (CBRM) modelling and known issues with problematic plant, which are required to be replaced or decommissioned to manage the safety and network risks associated with unplanned failure. The assessment identified that primary and secondary plant require replacement, including one 132/66/11kV 20MVA power transformer (T1), one 66/22kV 8/10MVA power transformer (T5), two 66kV circuit breakers, one set of three 66kV current transformers, five porcelain surge arrester sets, and one protection relay. Failure of the primary and secondary plant is a risk to network security which may lead to a breach of legislated Safety Net requirements, and significant long term outages to major customers. The purpose of this project is to address the risk to safety and network security posed by poor condition and problematic assets.			
Credible Options: 1) The preferred network option is to replace assets at T072 BARC substation that have been identified.			
Conclusion: The internal investigations undertaken on the feasibility of the non-network solutions revealed that it is unlikely to find a complete non-network solution or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Barcaldine bulk supply area to address the identified need. The preferred network option is to replace the assets in poor condition.			
Status: Ergon Energy is preparing a Final Project Assessment Report.			

[64] Website: https://www.ergon.com.au/network/our-services/projects-and-maintenance/rit-d-projects

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Reliability and Capacity Reinforcement for the Cloncurry supply area	$7.9M	Dec 2023	*Nil impact beyond regulated revenue.*

Project need:

Cloncurry 66/11kV Substation (CLON) and North Cloncurry 66/11kV Substation (NOCL) are normally supplied from Chumvale 220/66kV Substation (CHUM) via a single circuit 66kV sub-transmission feeder. Chumvale Substation is supplied by a single circuit 220kV feeder from the Mica Creek 'C' Substation (MICC) at Mt Isa. There is also a single circuit 66kV sub-transmission feeder from Mount Isa's Duchess Road 132/11/66kV Substation (DURO) to a normally open isolation point (designated DR-CC-1), which is located outside Chumvale Substation.

Approximately 184 spans on the Duchess Road to Cloncurry 66kV feeder have been identified as having insufficient ground clearance to meet minimum statutory requirements at the 50°C designed operating temperature. As such, the thermal rating of the feeder is no longer adequate to supply Cloncurry under peak load conditions and Ergon Energy would not comply with the Safety Net requirements based on credible contingencies benchmarked against 50% POE load in the present configuration.

For the failure of the 220/66kV transformer at Chumvale Substation, resulting in the loss of supply to Cloncurry and North Cloncurry Substations, full restoration of supply would be greater than 48 hours due to the distance of this area from the required mobile generation assets and the complex logistics involved in the deployment of these generation assets. As such, supply restoration is not Safety Net compliant for this scenario.

Condition data also indicates that the 66kV voltage transformers and 11/66kV step-up transformer (T4) at Duchess Road Substation which supplies the DR-CC-1 66kV feeder are reaching end of life; and there are three sets of ABB Duoroll isolators on the 66kV bus at Duchess Road Substation which are inoperable and recommended for retirement.

Ergon Energy proposes to meet the identified need by uprating the Duchess Road to Cloncurry 66kV feeder through inter-poling the spans with insufficient ground clearance and replacing the 66/11kV step-up transformer and undertaking 66kV asset refurbishment at Duchess Road Substation.

Credible Options:

1) Uprate the DR-CC-1 66kV Feeder and Replace 66kV assets at Duchess Road substation
2) Install a second 220/66kV transformer at Chumvale substation
3) Install 2.5MVA of permanent stand-by generation assets at Cloncurry

Conclusion:

The preferred internal network option at this stage is to uprate the DR-CC-1 66kV feeder to 9.5MVA by inter-poling spans, replace the existing 66/11kV step-up transformer and refurbish the 66kV bus at Duchess Road Substation.

Status:

Ergon Energy has published a non-network options report to external parties to identify potential non-network options that address the identified needs of the project, a release of Draft Project Assessment Report is being prepared.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Reliable Provision of Electricity to the East Bundaberg area	$8.2M	Mar 2024	*Nil impact beyond regulated revenue.*

Project need:

A condition assessment of East Bundaberg Zone Substation (EABU) has identified assets that are recommended for replacement. These assets are forecast to reach retirement based on a combination of Condition Based Risk Management (CBRM) modelling and known issues with problematic plant, which are required to be replaced or decommissioned to manage the safety and network risks associated with unplanned failure. The assessment identified that several major items of substation plant require replacement. These include the 66/11kV power transformers and 66kV circuit breakers. Failure of the primary and secondary plant is a risk to network security which may lead to a breach of legislated Safety Net requirements. Catastrophic failure of plant or structures also presents a safety risk to the general public as well as to our own staff. The purpose of this project is to address the risk to safety and network security posed by poor condition and problematic assets.

Credible Options:

1) Replace assets at East Bundaberg Substation identified as poor condition. These include the 66/11kV power transformers and 66kV circuit breakers.

Conclusion:

The internal investigations undertaken on the feasibility of the non-network solutions revealed that it is unlikely to find a complete non-network solution or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the East Bundaberg area to address the identified need.

The preferred network option is to replace assets at East Bundaberg Substation that have been identified as being in poor condition..

Status:

Ergon Energy is proceeding to publish a Final Project Assessment Report.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Reliable Provision of Electricity to the Maryborough Supply area	$6.5M	Nov 2025	*Nil impact beyond regulated revenue.*

Project need:

Maryborough 132/66kV substation (MARYSS) T59 is a Bulk Supply Point which supplies approximately 50,000 customers and 125MVA of peak load through connected Zone Substations. The 75MW Susan River Solar Farm is also connected to the 66kV network through a dedicated substation. MARYSS is located west of Maryborough and supplies the majority of the Fraser Coast Local Government Area, including the major regional centres of Maryborough and Hervey Bay as well as several smaller towns.

The purpose of this project is to address poor condition assets, compliance Safety Net provisions of the Distribution Authority, and compliance with performance standards as set out in the National Electricity Rules.

Credible Options:

1) Replace assets deemed to be in poor condition including 132kV & 66kV circuit breakers, CTs and VTs and protection relays associated with the 66kV bus and Kilkivan and Pialba Feeders.

Conclusion:

The internal investigations undertaken on the feasibility of the non-network solutions revealed that it is unlikely to find a complete non-network solution or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Maryborough area to address the identified need.

The preferred network option is to replace assets in poor condition, install bus couplers to address Safety Net and upgrade protection to meet NER Network Performance requirements.

Status:

Ergon Energy is proceeding to publish a Final Project Assessment Report.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Reliable Provision of Electricity to the Pialba (Hervey Bay) area	$8.7M	Mar 2025	*Nil impact beyond regulated revenue.*

Project need:

A condition assessment of Pialba Substation has identified assets that are recommended for replacement. These assets are forecast to reach retirement based on a combination of Condition Based Risk Management (CBRM) modelling and known issues with problematic plant, which are required to be replaced or decommissioned to manage the safety and network risks associated with unplanned failure.

This assessment identified that primary and secondary plant including the 66kV circuit breakers, the 11kV switchboard, and most protection relays require replacement. An assessment of the civil structures on site also identified the control building, several plant support structures and the 66kV galvanised water pipe bus require replacement due to being defective beyond repair.

Failure of the primary and secondary plant is a risk to network security which may lead to a breach of legislated Safety Net requirements. As the substation site is located nearby to a busy intersection and several residential developments, catastrophic failure of plant or structures also presents a safety risk to the general public as well as to our own staff.

The purpose of this project is to address the risk to safety and network security posed by poor condition and problematic assets.

Credible Options:

1) Replace assets deemed to be in poor condition including 66kV circuit breakers, 11kV switchboard and majority of protection relays CTs and VTs, protection relays and various civil works.

Conclusion:

The internal investigations undertaken on the feasibility of the non-network solutions revealed that it is unlikely to find a complete non-network solution or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Hervey Bay area to address the identified need.

The preferred network option is to replace the assets in poor condition.

Status:

Ergon Energy is proceeding to publish a Final Project Assessment Report.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Pittsworth Regional Reinforcement	$6.9M	Jan 2023	*Nil impact beyond regulated revenue.*

Project need:

Broxburn 33/11kV substation (BROX) has two 5MVA 33/11kV transformers supplying the township of Pittsworth and surrounding rural areas including some relatively significant chicken farm loads. Peak demand was 10.46MVA in February 2018 which exceeded the substation nameplate capacity and is expected to exceed the emergency cyclic capacity by 2022.

The two transformers at BROX were manufactured in the 1960s (58 years old) and the Condition Based Risk Management (CBRM) methodology calculates the end of life of the transformers at 2025 and 2029 respectively. Neither transformer has bunding or oil containment systems posing an environmental risk for aged transformers in poor condition. Adding to this, the transformers are of an unusually narrow configuration. This is problematic because if a failure occurs, they cannot be replaced with any Ergon Energy standard transformers or contingency spares due to lack of clearance to the bus. There are also a large number of high voltage switches that are nearing end of life, and the transformer protection scheme does not meet the current protection standard1 of Ergon Energy.

Based on load forecasts, the substation is expected to exceed its emergency cyclic capacity with both transformers in service by 2022. Without addressing these emerging constraints proactively, during peak load times this will result in forced load shedding.

A significant number of primary plant within BROX is at the end of life as determined by the CBRM methodology. If this aged equipment is not replaced before the nominated end of life, there will be an increased likelihood of plant failure. As well as presenting safety risks, the unplanned, sporadic and uncontrolled nature of such failures increases the costs of rectification. The proposed investment under this project addresses these limitations in an economic, efficient and safe manner.

Credible Options:

1) 10MVA skid at BROX (internal option) This will require the installation of two 10MVA skids at BROX, and a 10MVA skid at Yarranlea South 33/11kV substation (YASO) in stages to align with the demand and replacement date of aged assets.
2) 2x10MVA skid at BROX (internal option) This will require the installation of two 10MVA skids at BROX simultaneously by 2021, and a 10MVA skid at YASO by 2028.
3) Battery Energy Storage System (external submission provider) This proposes the installation of a 10MW BESS for peak lopping by 2021, a 10MVA skid at YASO by 2028, and a 10MVA skid at BROX by 2029.

Conclusion:

Ergon Energy's preferred solution is to introduce 10MVA skid at BROX. This option will achieve the reliable and safe supply of electricity in the Pittsworth area.

Status:

Ergon Energy published a Draft Project Assessment report (DPAR) on 7 April 2020 where the technical and financial analysis of the internal options were provided. Written submissions to the DPAR were invited.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Reliable Provision of Electricity to Point Vernon (Hervey Bay) area	$15.8M	April 2024	*Nil impact beyond regulated revenue.*

Project need:

A review of Safety Net compliance at Point Vernon 66/11kV Zone Substation (POVE) has identified that a credible failure would result in total loss of supply to the substation which is unable to be restored within Safety Net timeframes. Credible failures include the loss of the 66kV bus or bus section at Pialba, pole failure on the 66kV Point Vernon feeder (M023), or loss of the Point Vernon substation 66kV circuit breaker or bus section.

As a condition of its Distribution Authority (DA) Ergon Energy must ensure, to the extent reasonably practicable, that it achieves the Safety Net restoration targets as specified in the DA. The purpose of the Safety Net is to seek to effectively mitigate the risk of low probability high consequence network outages to avoid unexpected customer hardship and/or significant community or economic disruption.

The purpose of this project is to address compliance with the Safety Net provisions of the Distribution Authority.

Credible Options:

1) Extension of a new 66kV feeder to Point Vernon from the existing 66kV network and install necessary equipment to energise the feeder

Conclusion:

The internal investigations undertaken on the feasibility of the non-network solutions revealed that it is unlikely to find a complete non-network solution or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Hervey Bay area to address the identified need.

The preferred network option is to extend a new 66kV feeder to POVE to address Safety Net requirements.

Status:

Ergon Energy is preparing to publish a Draft Project Assessment Report.

I:2 RIT-D – Completed

This section describes the RIT-Ds that were completed in 2019-20. Estimated costs are provided within the associated RIT-D report found on the Ergon Energy website.[65]

Table 47: Regulatory Test Investments – Completed

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Addressing Reliability Requirements in the Cannonvale Network area	$23.6M	Dec 2024	*Nil impact beyond regulated revenue.*

Project need:

From Cannonvale Substation (CANN) which is the main substation in the area, the radial 66kV network supplying the other three substations has a load of approximately 16.4MVA. The radial supply arrangement to the area and the existing manual 66kV switching arrangement at Cannonvale has resulted in less than ideal power supply reliability due to frequent outages. A credible fault on this network would mean that supply would not be restored within the requirements of the Safety Net security criteria, with this situation worsening as load increases.

The CANN-01 66kV feeder cable entering the switchyard at CANN failed in 2017. It is probable that other failures in cables of the same type and age will occur over the next few years as all cables in and out of CANN are of similar type and vintage as the failed CANN-01 entry cable. Any restoration of such a failure is likely to result in extended outage durations to customers and island resorts. Additionally, the transformer 66kV circuit breakers at Cannonvale are planned for condition-based replacement due to safety concerns in the event of a potential failure.

The combination of these drivers has prompted a coordinated plan to review and reinforce the 66kV supply arrangement to meet security criteria obligations, address aged asset issues, improve supply reliability to customers and provide capacity for future growth and development.

Credible Options:

1) Cannonvale Substation 66kV Switchyard Upgrade & Duplication / Replacement of 66kV Cables.
2) New Dedicated 66kV Feeder from Proserpine to Proserpine Mill & Duplication / Replacement of 66kV Cables.
3) Construct 66kV switchyard at future Riordanvale Substation site & duplication / replacement of 66kV cables.

Conclusion:

Ergon Energy's preferred solution to address the identified need is applying Cannonvale Substation 66kV Switchyard Upgrade & Duplication / Replacement of 66kV Cables.

Status:

The Final Project Assessment Report (FPAR) represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to take steps to progress the proposed preferred option to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements, as necessary.

[65] Websitehttps://www.ergon.com.au/network/our-services/projects-and-maintenance/rit-d-projects

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Addressing Reliability Requirement in the Cape River Network Area	$8.8M	Nov 2024	*Nil impact beyond regulated revenue.*

Project need:

Cape River 66/11kV Substation (CARI) is an integral node in the North Queensland mid-west 66kV sub transmission network which supplies 4,102 customers (directly and indirectly) and two major renewable generation projects in the Hughenden area. CARI was built in the mid-1960s and a significant portion of the primary plant is now at or approaching the assessed end of life based on age and condition. CARI consists of four 66kV feeder bays, a 66kV voltage regulator, a 66/11kV 1MVA power transformer and two outdoor 11kV feeder bays.

Based on a Condition Based Risk Management analysis of the effect of current condition and ageing on the expected life of the asset, the following have been deemed to reach retirement age:

- The 66/11kV 1MVA transformer (YOM 1954) is 65 years old and is poor condition.
- The C152 (CT-CR-1 Fdr) and D152 (CR-HU-1 Fdr) 66kV circuit breakers are of ABB

HLC type. These are part of a REPEX replacement program due to a known potentially explosive failure mode. The roller contacts on ABB HLC circuit breakers of the same make and model at other sites in the network have failed. The hazard exists if there is insufficient contact pressure between the moving contact and the roller contact frame if one or more of the roller contacts is / are missing with the circuit breaker in the closed position. This may lead to arcing across this point resulting in generation of gas bubbles and an increase in internal pressure within the circuit breaker with the pressure causing eventual failure of the circuit breaker.

- There are approximately ten 66kV timber pole isolator structures and a number of other timber pole support structures for the 66kV overhead bus. The condition of the poles is not known, however site photos show that a number of the timber poles at this site are supported by pole nails.
- Additionally, asbestos has been identified in the internal walls, ceiling, soffit and external walls of the control building at CARI. Ergon Energy has a strategy to remove all asbestos containing materials from our assets, to minimise staff and contractor exposure to respirable asbestos fibres.

The deteriorated condition of the assets at Cape River Substation poses significant safety risks to staff working in proximity to these assets and reliability of supply risks to customers supplied from Cape River Substation.

The identified need for investment is to remediate the safety and reliability risks currently associated with the aged assets at Cape River Substation in order to maintain a safe, reliable supply of electricity to customers in the Cape River region.

Credible Options:

1) Rebuild of Cape River Substation within the new Cape River East site and decommissioning the existing Cape River Substation.
2) Replacement of the aged assets at Cape River Substation

Conclusion:

Ergon Energy's preferred network option is to install a 33/11kV transformer, 66kV feeder bays, 11kV feeder bays and associated protection and control equipment at the adjacent Cape River East Substation and decommissioning the existing Cape River Substation.

Status:

The Final Project Assessment Report (FPAR) represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to take steps to progress the proposed preferred option to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements, as necessary

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Ensuring Reliability of Electricity Supply and Managing Network Asset Risks in the Douglas Shire Area	$27.2M	Nov - 2024	*Nil impact beyond regulated revenue.*

Project need:

The Mossman 66/22kV Substation was constructed in 1964 and supplies some 3250 customers from the local 22kV distribution network in the Douglas Shire Council area from Mossman and north to the Daintree. Key customers supplied from the distribution network include the hospital, emergency services, aged care and retirement village, sugar mill, water and sewerage treatment plants, schools, communication sites, tourism facilities, resorts and businesses.

The Mossman Substation is supplied by two aged 66kV timber pole lines from Powerlink's Turkinje 132/66kV Substation via Mossman 1 (MOSS 1) and Mossman 2 (MOSS 2) feeders constructed in 1975 and 1958 respectively. The Mossman Substation comprises of two incoming 66kV overhead feeders which supply the two outdoor 66kV bus sections, four Circuit Breaker (CB) bays and isolators. Two 1963 vintage 10MVA 66/22kV transformers supply, an outdoor 22kV yard supply comprising two 22kV bus sections, seven 22kV CBs, and thirteen isolators. Secondary systems, communication and protection equipment is housed in the substation control building. The four Mossman 22kV feeders share intra-feeder ties and an inter-feeder tie with the adjacent 132/22kV Craiglie Substation 22kV distribution network which supplies approximately 4280 customers.

A substation condition assessment has highlighted the aged assets, reliability, safety and environmental risks at the Mossman Substation. The Mossman 66kV feeders which also supply the Mount Molloy Substation in the Northern Atherton Tableland area experience reliability issues and high maintenance costs reflecting late 1950s' design standards, assets reaching the end of service life (e.g. 35km of 1958 vintage 7/0.104 HDBCC 66kV conductor) and exposure to adverse operating conditions (i.e. termites, bushfires, lightning activity, wet tropic rainforests and cyclones). Ergon Energy has determined that network investment is essential in the Douglas Shire area for it to reliably and safely continue to provide electricity services and manage end of life asset risks. The primary drivers of this investment are reliability of the Mossman Substation and 66kV feeders, managing the 66kV and 22kV asset condition and safety concerns.

Ergon Energy's preferred internal solution is to convert Mossman to a 132/22kV Substation supplied from a 132kV tee-off a switched feeder at Yalkula and retire MOSS 1 and MOSS 2 66kV feeders back to Mount Molloy.

Credible Options:

1) Transition Mossman Substation from 66/22kV to 132/22kV and extend the Yalkula 132kV bus.
2) Staged Replacement of the 66kV Line and Aged Mossman Substation Plant as Required.
3) Full Retirement/Recovery of Mossman 66/22kV Substation, Upgrade Craiglie Substation to Supply Mossman 22kV Distribution Area.

Conclusion:

Ergon Energy's preferred solution to address the identified need as a Transition Mossman Substation from 66/22kV to 132/22kV and extend the Yalkula 132kV bus.

Status:

The Final Project Assessment Report (FPAR) represents the final stage of the consultation process in relation to the application of the RIT-D. Ergon Energy intends to take steps to progress the proposed preferred option to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements, as necessary.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Addressing Reliability Requirements in the Garbutt Network area	$30.9M	Nov - 23	*Nil impact beyond regulated revenue.*

Project need:

Garbutt 132/66/11kV (T046) Substation (GARB) is a Powerlink Queensland (PLQ) / Ergon Energy (EE) shared site located in Townsville. GARB Substation was established in 1958 and progressively developed since to be a critical node within the Townsville sub transmission (66kV) network. GARB links two transmission feeders to seven zone substations (inclusive) and supplies 48,500 customers and 86MVA of load (directly and indirectly).

There is minimal forecast load growth at the substation however many assets are approaching or at the end of service life. Most notably the structures that support the 66kV air insulated busbar and bay equipment have been assessed to have insufficient structural integrity to safely provide support for the equipment. Some equipment and the majority of structures are 40-60 years old.

The deteriorated condition of the assets at Garbutt Substation poses significant safety risks to staff working in proximity to these assets and reliability of supply risks to customers supplied from Garbutt Substation. The identified need for investment is to remediate the safety and reliability risks currently associated with the aged assets at Garbutt Substation in order to maintain a safe, reliable supply of electricity to customers in the Townsville region.

Credible Options:

1) Replacement of the aged 66kV assets at Garbutt Substation with 66kV Gas Insulated Switchgear (GIS)
2) Replacement of the aged 66kV assets at Garbutt Substation with 66kV Air Insulated Switchgear (AIS).

Conclusion:

Ergon Energy's preferred solution to address the identified need is the Replacement of the aged 66kV assets at Garbutt Substation with 66kV Gas Insulated Switchgear (GIS) located within the existing Garbutt Substation boundary

Status:

The Final Project Assessment Report (FPAR) represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to take steps to progress the proposed preferred option to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements, as necessary.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Emerging Distribution Network Limitations in the Gracemere area	$23.4M	Apr 2022	*Nil impact beyond regulated revenue.*

Project need:

Ergon Energy has identified increasing risks to reliable supply in the electricity distribution network supplying the Gracemere area in Central Queensland.

Malchi Zone Substation load is approaching constraint due to the consistent strong growth in the region. Continuing growth and demand will risk security of supply to customers.

Credible Options:

1) 1x20MVA 66/11kV Substation at Gracemere Site (Preferred option)
2) 1x10MVA 66/11kV Compact Substation at Gracemere Site
3) 1x10MVA 66/11kV Compact Substation on Gavial-Gracemere Road

Conclusion:

From the technical and financial analysis presented above, Ergon Energy found that neither the externally proposed and internally identified alternative options represent feasible options, either alone or in any combination with a network option.

Ergon Energy intends to proceed with Option 1, construction of a 1x20MVA 66/11kV substation at the Gracemere Zone Substation site

Status:

Ergon Energy has prepared a Final Report.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Reliable Provision of Electricity to the Kilkivan Supply Area	$14.1M	Sep 2023	*Nil impact beyond regulated revenue.*

Project need:

Kilkivan Substation (KILK) is an integral node within the South Burnett sub transmission (66kV) network linking to six zone substations. There is minimal forecast load growth at the substation however many assets are approaching or at the end of service life, with some equipment greater than 55 years old. The nearby Kilkivan Town 66/11kV zone substation (KITO) was constructed in the 1950s and has a number of assets in very poor condition, approaching or at the end of service life. The continued operation of these aging assets at KILK and KITO is expensive and uneconomical, and poses a significant challenge in maintaining a reliable supply to the distribution area.

The key drivers requiring Ergon Energy to make further investments in the KILK and KITO supply areas are the reliability of assets that are at the end of their life, environmental risk and compliance with safety and current standards.

Credible Options:

1) Full substation rebuild of Kilkivan Substation (KILK) on the area adjacent to the existing substation site

Conclusion:

Based on the demand management options considered above, it is deemed that sufficient demand management measures could not be feasibly implemented to technically and economically defer the network investment required at KILK or KITO substations, particularly as the key investment driver is the safe and reliable supply of electricity to consumers through an asset base which is at its end of life. The aged asset replacement will address issues with security and reliability customer service standards, environmental risk, safety and substation design standards compliance.

If deemed that de-loading KITO transformers could significantly extend their life, a change to Ergon Energy's hot water LC strategy without further customer engagement could cost effectively help de-load or alleviate some issues caused by reverse power flows. Beyond these few points it is unlikely there are any financial benefits from seeking expressions of interest from the market for a Non Network Alternative to replacing KILK and decommissioning KITO.

Status:

This Final Project Assessment Report represents the final stage of the consultation process in relation to the application of the RIT-D. Ergon Energy intends to commence with the preferred network option which is a full substation rebuild of Kilkivan Substation on the area adjacent to the existing substation site..

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Reliable Provision of Electricity to the Bundaberg Burnett area	$63M	Feb 2024	*Nil impact beyond regulated revenue.*

Project need:

Ergon Energy Corporation Limited (Ergon Energy) is responsible (under its Distribution Authority (DA)) for electricity supply to the Wide Bay - Burnett area in Queensland.

The existing 66kV M028 feeder forms part of the 66kV subtransmission network supplying the 66/11kV zone substations Degilbo (DEGI), Gayndah (GAYN), Mundubbera Town (MUTO) and Eidsvold (EIDS) as well as the Mount Rawdon gold mine (MORW). Feeder M028 is 92km long, 66 years old and has reached its end of life based on the condition of the 7/.104 HDBC conductor and wooden poles. Due to the poor condition of the poles and the conductor, and the fact that there is no overhead earth wire for lightning protection, the feeder has extremely poor reliability. Feeder M028 has four times the subtransmission feeder average number of outages and has become a safety risk to power workers and the public. The Isis – Gayndah 66kV ring which is normally run closed, is voltage constrained during present peak loading, and is limited by the thermal rating of the M028 feeder during the contingency loss of the other half of the ring (M049 feeder).

- The first objective of the proposed investment is to maintain a safe and sustainable energy supply to customers by reducing the significant safety and environmental risks associated with the aged M028 feeder to as low as reasonably practicable (ALARP).
- The second objective is to ensure that there is sufficient capacity in the network to meet existing customer demand and also to enable customers to connect new loads in the future.
- The third objective is to provide a secure and reliable energy supply to customers by ensuring that the network meets Ergon Energy's statutory network security and reliability performance standards.

Credible Options:

1) Replace the aged M028 feeder with a new 66kV single circuit wood pole feeder, strung with Iodine conductor and optical ground wire (OPGW), originating from the 132/66kV Isis Bulk Supply Point and connecting Degilbo and Gayndah zone substations by December 2023.
2) Replace the aged M028 feeder with a new 66kV single circuit concrete pole feeder, strung with Iodine conductor and optical ground wire (OPGW), originating from the 132/66kV Isis Bulk Supply Point and connecting Degilbo and Gayndah zone substations by December 2023.
3) Replace the aged M028 feeder with a new 66kV single circuit concrete pole feeder, strung with Neon conductor and optical ground wire (OPGW), originating from the 132/66kV Isis Bulk Supply Point and connecting Degilbo and Gayndah zone substations by December 2023.
4) Replace the aged M028 feeder with a new 66kV single circuit wood pole feeder, strung with Iodine conductor and optical ground wire (OPGW), originating from the 132/66kV Isis Bulk Supply Point and connecting Degilbo and Gayndah zone substations by December 2023. Install a 10MW / 20MWh BESS connecting to the 11kV bus at Gayndah zone substation.

Conclusion:

The preferred option is to replace M028 with a new 66kV single circuit concrete pole line strung with Neon conductor and OPGW.

Status:

This Final Project Assessment Report represents the final stage of the RIT-D process to address the identified need at in the Wide Bay - Burnett area. Ergon Energy is processing any potential queries disputing the publicised conclusions.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Reliability and Capacity Reinforcement for the North Toowoomba Network	$9.5M	2025-30 (Next regulatory Period)	*Nil impact beyond regulated revenue.*

Project need:

Predictions identify a doubling of population growth in Highfields in the next ten years potentially impacting upon load demand for both Highfields, Cawdor and Meringandan Substations. Operational plant within Highfields and Meringandan Substations are at or approaching end of life.

To enable a safe and sustainable energy supply to customers management of the asset lifecycle of these sites needs to be addressed.

Furthermore Ergon Energy needs to ensure that sufficient capacity in the network to meet existing and future customer demand and to avoid customer load shedding during peak demand, as well as secure and reliable energy supply to customers by addressing statutory network security and reliability performance standards.

Credible Options:

1) Build a 33/11kV 20MVA KLTN substation with modular building of 33kV & 11kV switchgear at site adjacent to MERN site in 2021; decommission HIGH in 2024; install a 2nd 33/11kV 20MVA substation at KLTN in 2034, decommission MERN outdoors substation
2) Build KLTN substation with 2 x 33/1 kV 20MVA transformers in 2021, decommission MERN substation
3) Install a 2nd 33/11kV 10MVA SKID at CAWD in 2021; decommission HIGH in 2024; install a 33/11kV 10MVA SKID at MERN in 2034
4) Install a 33/11kV 10MVA SKID at MERN in 2021; build 2 x 33/11kV 20MVA KLTN substation in 2034, decommission MERN in 2034

Conclusion:

Based on the DM options considered, it is deemed that sufficient demand management measures cannot be feasibly implemented to technically and economically defer the network investment required at Meringandan and Kleinton substations. Consequently, a Non-Network Options Report has not been prepared in accordance with rule 5.17.4(c) of the National Electricity Rules.

Status:

Ergon Energy has published a Notice of No Non-Network Options under clause 5.17.4(d) of the National Electricity Rules NER on 29/10/2019. Final Project Assessment Report (FPAR) has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(p) of the NER as the final step of this RIT-D process.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
Addressing Reliability Requirements in the Planella Network area	$5.0M	Jul 2023	*Nil impact beyond regulated revenue.*

Project need:

Planella (PLAN) 33/11kV Zone Substation is located in the suburb of Rural View on the northern beaches of Mackay, and the substation services the Mackay northern beaches suburbs of Shoal Point, Bucasia, Eimeo, Dolphin Heads, Blacks Beach and Rural View. This area is primarily a residential area, and the surrounding suburbs are highlighted in the Mackay Regional Council regional planning scheme strategic framework for growth over the next 15 years.

Planella Substation presently supplies 6,316 customers and has two 33/11kV OLTC transformers which have both an N-1 transformer cyclic and long-term emergency cyclic rating of 15.3MVA. The substation is presently supplied via a single circuit radial 33kV sub-transmission line which is teed off the line from Glenella (GLEL) 66/33/11kV Substation to North Mackay (NOMA) 33/11kV Substation just outside North Mackay Substation.

Planella does not have N-1 security and is reliant on the 33kV radial feeder between North Mackay and Planella. Currently a fault on this section of line will result in an outage for all Planella customers which combine for a peak load at risk of approximately 15.85MVA. Planella does not comply with the Safety Net requirements based on credible contingencies benchmarked against 50% PoE load in the present configuration.

Under most circumstances, the wood poles of the 33kV Planella tee – Planella sub-transmission line are accessible; however in the event of periods of heavy rainfall and/or king tides, sections of the line passing through mangrove wetlands become virtually inaccessible. For the loss of the incoming 33kV feeder, resulting from a pole failure or wires on ground in an inaccessible location, the customer outage duration would be greater than 12 hours hence supply restoration is not Safety Net compliant for this scenario.

The identified need for investment is to remediate the supply reliability risks currently associated with the single 33kV overhead timber pole feeder supplying Planella Substation in order to maintain a safe, reliable supply of electricity to customers in the supply area.

Credible Options:

1) Rebuild a 1.5km section of the existing 33kV feeder in the storm tide inundation flood zone using concrete pole construction, obtain easements & develop additional 11kV feeder ties.
2) Construct a new single circuit 33kV mixed overhead & underground feeder from Glenella to Planella.
3) Construct a new double circuit 66kV mixed overhead & underground feeder from Glenella to Planella and convert Planella Substation to 66/11kV.

Conclusion:

Ergon Energy's preferred solution to address the identified need is to Rebuild a 1.5km section of the existing 33kV feeder in the storm tide inundation flood zone using concrete pole construction, obtain easements & develop additional 11kV feeder ties.

Status:

The Final Project Assessment Report (FPAR) represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to take steps to progress the proposed preferred option to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements, as necessary

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