Distribution Annual Planning Report 2022

NETWORK

Version Control

Version	Date	Description
1.0	22/12/2022	Final for Publication
1.1	17/01/2023	Update to Section 11.8
1.2	28/04/2023	Update to hyperlink referencing
1.3	4/09/2023	Update Links to new website

Further Information

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

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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 document 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. The information contained in this report is subject to annual review. Ergon Energy is obligated to publish future editions by 31 December, in accordance with the National Electricity Rules.

All financials presented in the DAPR are correct at the time of writing (Dec 2022) and represent the existing organisational accounting treatment, which may be subject to change. Forecasted data is subject to ongoing variations. Energy Queensland is finalising the alignment of its Cost Allocation Methodology between Ergon Energy and Energex, potentially impacting the treatment of some Capital and Operational Project costs.

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

Contact Information

Further information on Ergon Energy's network management is available on our website.[2]

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Executive Summary

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

The DAPR provides the community and stakeholders with an insight into the key factors shaping our future investment plans, the current and forecasted electricity demand and performance trends. 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 varied impacts on the economy, we continued to provide reliable and secure supply to our customers. Ergon Energy's network reliability performance results were favourable for three of the six measures in the Distribution Authority. System Average Interruption Duration Index (SAIDI) for all three feeder categories (Urban, Short Rural and Long Rural) were unfavourable to the respective Minimum Service Standards (MSS). Planned outages associated with the increase in safety-driven works on ageing sections of the network have impacted the overall duration of supply interruptions across the network. EQL continues to implement its best endeavours to minimise the impact on our communities through our approach to the program's delivery.

The 2021-22 summer peak of 2,637MW, recorded between 6:30 and 7:00 pm on Thursday, 3 March 2022, was the lowest maximum demand Ergon Energy has experienced in the last five years. The uptake of solar Photovoltaic (PV) in the residential, commercial and industrial sectors has created the need to forecast minimum demand on Ergon Energy's network. The most recent minimum demand occurred on 20 August 2022 with a minimum of 862MW.

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. Information and Communications Technology (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, battery storage and Electric Vehicles (EVs), as well as the next generation of home and commercial energy management systems. 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) 2022 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 forward planning period 2022-23 to 2026-27 as a requirement under the National Electricity Rules (NER Rule 5.13 and Schedule 5.8) and in in compliance with Queensland's Electricity Distribution Network Code (clause 2.2) and Distribution Authority.

This report captures the results of planning activities including forecasts of emerging network limitations for the purposes of market consultations. Importantly, customer supply risks are assessed through ongoing planning activities, and in conjunction with market participants, appropriate future investments are scheduled to ensure risks are addressed in accordance with obligated service standards.

For readers seeking to learn more about planning outcomes since the 2021 DAPR, please refer to Sections 5.10: Joint Planning and 6.4: Regulatory Investment Test Projects, as well as Appendix C: Network Limitations and Mitigation Strategies for committed projects and proposed opportunities.

Ergon Energy understands that as cost of living pressures increase for many regional Queenslanders, prudent investment plans are required in order to maintain required performance targets whilst minimising operating and capital costs. In addition, Ergon Energy must continue to ensure the safety of the public and its employees by managing the risks associated with the electricity network.

1.2 Network Overview

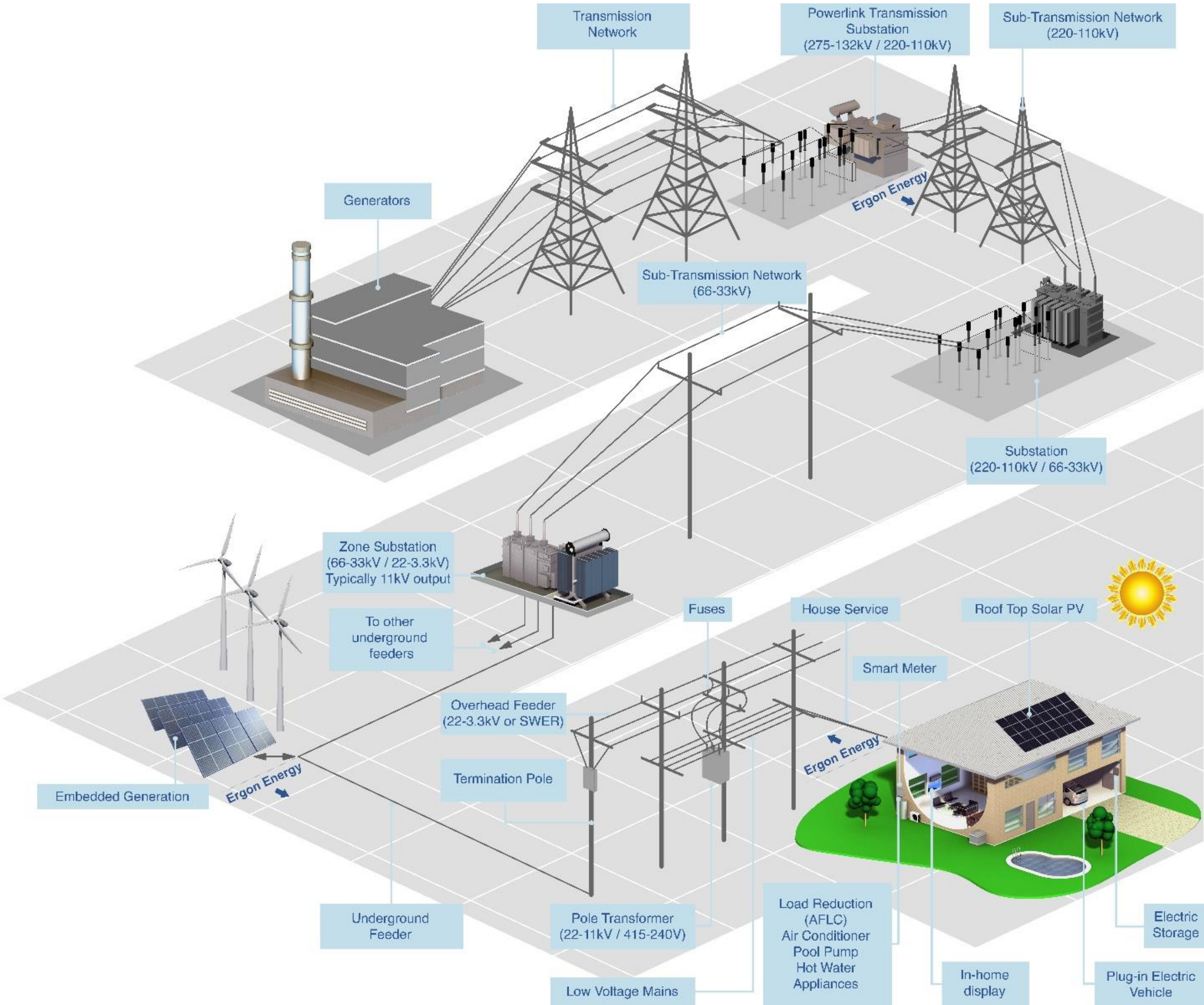
Electricity is a commodity that underpins our modern society, providing energy to domestic, commercial, industrial, agricultural and mining sectors, supporting lifestyle and prosperity of individuals as well as our state as a whole.

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.

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 sub-transmission 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 (LV) 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.

With the increase in Embedded Generation (EG) systems being connected to the network, including small and large scale solar Photovoltaic (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 is periodically in reverse, creating both challenges and opportunities for the 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:

- Sub-transmission lines at 220, 132, 110, 66 and majority of 33kV 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 33 (minority), 22, 19.1, 12.7, 11, 6.6 and 3.3kV.

1.3 Peak Demand

The capacity of a network is the amount of electricity it can supply to every customer at any point in time. 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 one of the critical factors in the planning 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 and sub-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, dependent 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 2021-22 was recorded at 2,637MW on Thursday, 3 March 2022 between 6:30 and 7:00 pm.

1.4 Minimum Demand

Historically, Strategic Load 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 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 transformers’ tap or ‘buck’ range is restricted
- **Zone Substation level** – Cyclic issues due to reverse flow may reduce the life of zone substation transformers
- **Feeder level** – Stability of individual feeders are potentially impacted 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 Energy’s 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 Energy 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.

Considering the Ergon Energy network as a whole, between 2013 and 2018 the annual minimum demand typically occurred early morning during summer at values around 1,100MW. However, the sizeable scale and rapid growth of solar PV installations is changing the shape of the load profile – which is creating new annual minimums in the daytime during the shoulder seasons. As a result, there is now expected to be a trend decline in minimums, with the latest minimum demand decreased to 862MW on August 2022.

This trend indicates that future system minimum demands will be expected to occur during the day and not in the evening.

1.5 Changes from Previous Year's 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 2022 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 2021 DAPR:

- Review and update of Ergon Energy's demand side management policy, strategy and initiatives
- There were six projects approved with credible options having an estimated cost greater than $6 million having completed the Regulatory Investment Test for Distribution (RIT-D) process for Distribution with a further three more projects in-progress. RIT-D project information is presented in Section 6.4: Regulatory Investment Test Projects
- Update to Chapter 3: Community and Customer Engagement, with alignment towards customer interactions and engagement activities. Our engagement activities ensure we are meeting the unique and diverse needs of our communities and customers by continuously investing in talking and listening to our customers and other stakeholders about their expectations, concerns and suggestions
- The title for Chapter 11 has been changed from 'Emerging Network Challenges and Opportunities' to 'Network Challenges and Opportunities', catering for the incorporation of new technologies
- Introduced new items by National Electricity Rules (NER) including:
    - Section 9.7: Emergency Frequency Control Schemes and Protection Systems, has been included
    - Appendix D and Appendix E include Distributed Energy Resources (DER) forecasts for both substation and feeders respectively.
- Sub-transmission Feeder Contingent (N-1) Load-Only 50 PoE Forecast, has been created using 50PoE temperature corrected forecast with a coincidence at 6pm and network model placed in an N-1 contingent state
- Worst Performing Distribution Feeders - although commonly reported, this item has been given a dedicated section - Appendix F, for its reference material
- DAPR Maps – is presented with a sub-transmission feeder 10PoE forecast. A similar 50PoE forecast with contingent N-1 criteria (as mentioned above) is available as supporting information.

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 website[5] for further information and the opportunity to submit commentary or queries.

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

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

Chapter 2

Corporate Profile

2. Corporate Profile

2.1 Corporate Overview

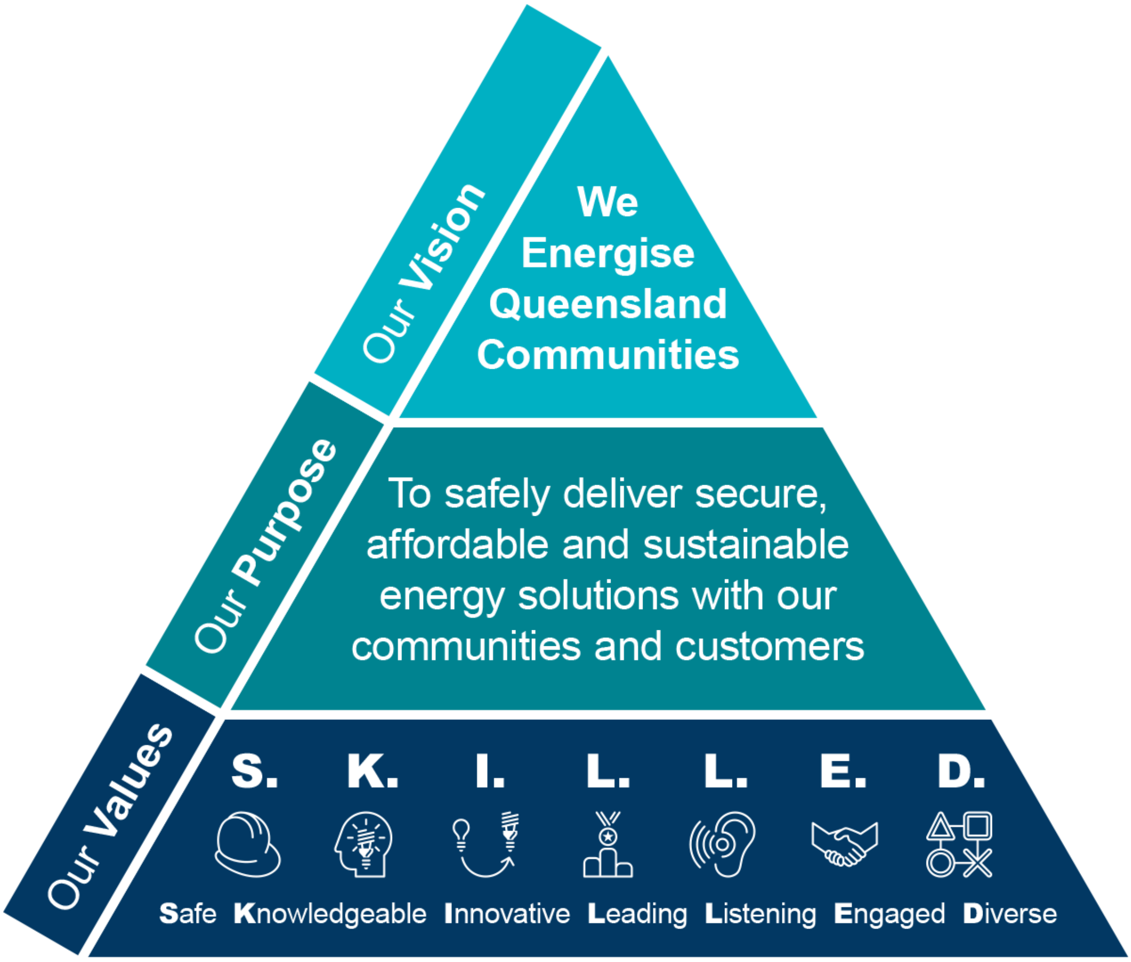
Ergon Energy (Ergon Energy Corporation Limited) is a subsidiary of Energy Queensland Limited, the Queensland government owned corporation formed through a merger in June 2016.

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 over 750,000 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 $16.6b.

The bulk of the electricity distributed enters Ergon Energy'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 (DER), 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 kilometer
- 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, 6.6kV, SWER and Low Voltage (LV) with peaks ranging between 68kW and 4.2MW. These isolated systems supply 39 communities (approximately 21,000 customers[6]) isolated from the main grid and are located in western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait islands and Palm Island.

[6] Customer head-count as quoted from the 'Isolated Network Strategy 2030'. Websource: https://www.ergon.com.au/__data/assets/pdf_file/0017/1021517/Isolated-Networks-Strategy-2030.pdf

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	22
Bulk Supply Substations	37
Zone Substations[7] (ZS)	262
Distribution Transformers	97,570
Power Poles	1,046,303
Overhead Powerlines - Sub-transmission[8]	15,045km
- High Voltage Distribution	112,131km
- Low Voltage Distribution	17,576km
Underground Power Cable	9,425km
Number of Feeders - Sub-transmission feeders[8]	440
- Distribution feeders[9]	1,221
- Other Feeders[10]	789
Network Customers	
Customers on Urban Network	239,253
Customers on Short Rural Network	443,086
Customers on Long Rural Network	84,275
Total Customers[11]	774,804
Isolated Network Customers[12]	8,190

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

[7] Includes zone substation in regulated and non-regulated zones. This count disregards joint owned zone substations or sites dedicated to single customers

[8] Includes transmission feeders

[9] Includes island feeders

[10] Includes SWER feeders

[11] Regulated network customers, as of 30th June 2022, EB RIN T3.4

[12] Customer connection count

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 kilometers 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: High Impact Weather Events.

2.3.2 Shareholder and Government Expectations

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

This supports the Queensland Government's target of 50% renewable energy by 2030, and net zero emissions by 2050.

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 from investigating 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 continued, supported by the lookup and live[13] online application that allows member of the community to pinpoint our overhead powerlines and powerpole locations.

The 'app' was built by geospatially overlying powerlines onto imagery, enabling others in the community to effectively plan activities 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 Management System (EQL HSE MS) 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 management system. The management system is currently accredited to:

- ISO 14001:2015 Environment Management System
- ISO 45001:2018 Occupational Health and Safety Management System

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

The management system 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, 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.

Our internal EQL HSE IMS Hazard Control Manual addresses these HCs which are in-turn subject to third party HSE IMS Surveillance audits as well as an annual Electrical Entity audit conducted by the Electrical Safety Office (ESO).

2.3.5 Environmental Commitments

Ergon Energy is committed to reduce the environmental and cultural heritage impact of our operations as outlined in the Energy Queensland's Environmental Sustainability & Cultural Heritage Policy.[14] We will safely deliver secure, affordable and sustainable energy solutions for our customer and communities through reducing our carbon emissions, supporting increased connection of renewable, implementation of our First Nations Reconciliation Action Plan and create energy security for our communities in times of natural disasters.

The Ergon Energy electricity network traverses diverse environmental and culturally significant areas including coastal, rural and urban landscapes. The ISO 14001 (Environment) certified Energy Queensland Integrated Management Systems (IMS) provides an effective operational framework to plan, implement, monitor and improve our services with balanced consideration of the risks and opportunities to our environment, cultural heritage and communities. We implement and support robust systems and processes founded in legislative compliance, set and transparently report on objectives and targets to continually improve environmental and cultural heritage outcomes.

The Energy Queensland Low Carbon Future Statement[15] outlines our support of Queensland's transition to a low carbon future, the management of our greenhouse gas emissions and the implementation of plans to build greater resilience to mitigate the potential risks of a changing climate.

[14] Websource: https://www.energyq.com.au/__data/assets/pdf_file/0004/836113/P058-Environmental-Sustainability-and-Cultural-Heritage-Policy.pdf

[15] Websource: https://www.energyq.com.au/__data/assets/pdf_file/0007/836107/Low-Carbon-Future-Statement-Policy-P056-687228.pdf

2.3.6 Legislative Compliance

Prior to the establishment of Energy Queensland, Ergon Energy was a Queensland Government Owned Corporation (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 Energy and Public Works (DEPW)), 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* (Qld), are the:

- Treasurer and Minister for Trade and Investment
- 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 2019, 2020 and 2021
- Aboriginal Cultural Heritage Act 2003 (Qld) and Torres Strait Islander Cultural Heritage Act 2003 (Qld)
- Work Health and Safety Act 2011 (Qld)
- 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.[16]

2.4 Asset Management Overview

Management of Ergon Energy's current and future assets is core business for Ergon Energy. 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.

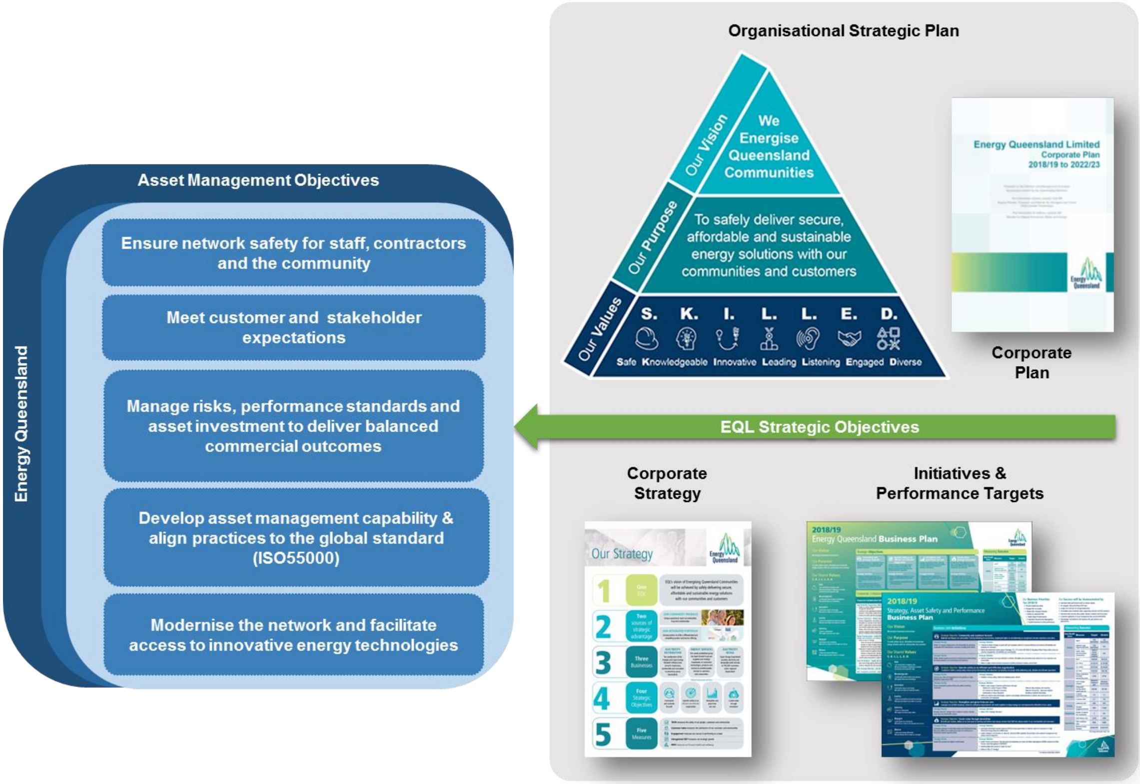
This policy together with the Strategic Asset Management Plan (SAMP), are the primary documents in the asset management documentation hierarchy and influence subordinate asset management strategies, plans, standards and processes.

[16] Website: www.aer.gov.au

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



2.4.4 Investment Process

2.4.4.1 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. **Grid Investment Plan** - 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 PoW scorecard is prepared monthly, and key metrics are included in the PoW Delivery Index, which is a corporate Key Performance Indicator (KPI) that, with monthly performance reporting for key projects, informs the Executive and Board. Quarterly PoW 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.

2.4.5 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
- 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 PoW on a priority basis to deliver appropriate network-wide risk mitigation. Energex/Ergon Energy Network optimises its PoW 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.

2.4.6 Further Information

Further information on our network management is available on the Ergon Energy website.[17]

[17] Websitehttps://www.ergon.com.au/network/our-network

Chapter 3

Community and Customer Engagement

3. Community and Customer Engagement

3.1 Overview

To ensure we are meeting the unique and diverse needs of our communities and customers we engage regularly with our customers and other stakeholders on their thoughts, needs, expectations, and concerns.

With our industry undergoing a period of rapid transformation, an open dialogue is critical for 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 for creating real long-term value for our customers, our business, and Queensland.

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

This year's engagements built on earlier extensive engagement around the network businesses' network investment plans and our Regulatory Determination for 2020-25, and our network tariff reform program, as well as focusing on the economic, social, environmental and governance topics relevant to our business that matter most to our different stakeholders.

This chapter provides an overview of our 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 on our publication website[18] including our Annual Report and Energy Charter Disclosure Report. In addition, the 2020 and Beyond Community and Customer Engagement Report[19] is also published with our Regulatory Determination.

3.2 Our Engagement Program

3.2.1 Customer and Community Council and Other Forums

This year saw the renewal of the Energy Queensland Customer Council, now renamed the Customer and Community Council. The Council's new charter and broader membership have been to ensure not only our customers, but the wider community voice is captured in our engagements. To better support these representatives in engaging with the business, we introduced remuneration for the group's members to assist in capacity building and supporting their ability to engage.

We also established a Tariff Reform Working Group (TRWG), made up of industry and stakeholder representatives, with the aim of co-designing potential new network tariffs to be trialled with residential customers in 2022-23. The customer insights from this will inform our future reforms for Ergon Energy Network's and Energex's next respective Tariff Structure Statements.

Network tariff reform is a complex topic that requires a balance between the needs of customers, the business and the Australian Energy Regulator, so it is vital that we bring our customers on the network tariff reform journey. Both the Customer and Community Council and TRWG are now bringing a broad cross section of voices to the table.

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[18] Website: https://www.energyq.com.au/publications

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

We also continue to support forums for major customers, local government and the agricultural sector 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,[20] of which we are a signatory, 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 also remains critical to delivering for our customers.

Our industry engagement also includes participation, with industry memberships, in state-wide forums and operational engagement 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 Queensland. Each area has a locally based manager who build relationships with our local community stakeholders and understand the areas unique concerns.

To support local stakeholder engagement, we also host Board stakeholder events regionally to ensure we keep in touch with our communities' expectations. While this remains challenging with the ongoing impact of COVID-19, they are considered to 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,[21] as an effective tool to interact with targeted stakeholders, as well as a channel to reach a wider audience across Queensland as we engage on key energy topics and issues.

It has been especially useful this year in consulting with industry stakeholders on enabling dynamic customer connection for Distributed Energy Resources (DER) and for engaging community stakeholders interested in our Local Network Battery Plan, which is seeing utility-scale, network-connected batteries installed across regional Queensland to support the state's continual uptake of renewable energy.

3.2.5 Our Customer Research Program

This year, we embedded two new corporate measures; Customer Satisfaction (CSAT) and a Net Trust Score (NTS), to put customers at the centre of our decision-making. These new metrics are based on tracking research around our customer experience and social license or reputation that enables us to benchmark our brands against other businesses and help us raise the bar.

To target service improvements, we also continued to survey the customer experience following our key service interactions for each customer group, from the large businesses to our residential customers. Overall trends for satisfaction for each service, as well as specific feedback, from these surveys are used across the Group.

[20] Websource: https://www.theenergycharter.com.au/

[21] Website: https://www.talkingenergy.com.au

Our third tracking survey is the Queensland Household Energy Survey.[22] Funded by Energex and Ergon Energy Network in conjunction with Powerlink Queensland, this survey tracks customer perceptions and overall attitudes to electricity prices and power supply reliability, as well as energy use and energy efficiency behaviours, and interest in emerging energy-related technologies.

These were also supported by a program of additional market research activities used to explore specific topics more deeply, for example qualitative customer journey mapping to obtain insights into the customer experience around the purchase and charging behaviours of Electric Vehicle (EV) owners, and a customer survey with flood affected customers to obtain insights in to their experience of interacting with the network business as part of our disaster response to the February/March 2022 floods in Southern Queensland.

Additionally, we have also undertaken a second comprehensive materiality assessment of our Environmental, Social and Governance issues to better identify and prioritise the topics that matter most to our stakeholders. This review, which included stakeholder interviews, was important to maintaining a deep understanding of the contribution we can best make to sustainability, considering our rapidly changing operating environment, and the evolving priorities of stakeholders and issues important to the business.

This year's research builds on the in-depth research undertaken,[23] 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.

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 economic environment continues to bring 'energy inclusion and customer vulnerability' and 'economic resilience 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. Our highest performing 'trust driver' in our NTS research *'Is strongly focused on safety'*, followed by *'They are a local employer'*.

[22] Website: https://www.talkingenergy.com.au/qhes

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

Our community's health concerns around the COVID-19 pandemic, especially in our First Nations communities, continues to have implications for our operational response.

3.3.2 More Affordable Electricity Pricing

Electricity affordability remains a concern for many of our customers, both from a cost of living and a business competitiveness perspective.

We track price and affordability perceptions in our annual Queensland Household Energy Survey.[24]

Despite a number of years of tariff relief, the current volatility in the wholesale energy markets, and the associated rise in electricity prices, is leading to concerns about value and the disruption across the industry.

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

41%*

Have high concern about their ability to pay their household electricity bill.

*Queensland Household Energy Survey 2022. Question: How concerned are you about your ongoing ability to pay your electricity bill? Scale 0-10: High concern 7-10. Note: last year's report included Moderate and High results: 6-10.

Network Tariffs

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

In the 2022 Queensland Household Energy Survey,[25] 53% of customers indicated their willingness to change how they use electricity to manage both peak and minimum demand if they had a better understanding of what the personal benefits would be, with 40% indicating interest in time of use electricity pricing where they would pay less during the day and more during the evening when peak demand is an issue.

53%*

are willing to change how they use electricity with a better understanding of the personal benefits.

*Queensland Household Energy Survey 2022. Question: Which of the following would encourage you to make changes to how you use electricity to help manage peak and minimum demand? Top answer selected: Knowing what the benefits are for me personally.

While informed stakeholders recognise that network tariff reform is needed to respond to the changes in the market and to deliver sustainable charges for the future, more engagement is required to further advance reforms for future years with customer tariff trials commencing in late 2022 to obtain insights into customer understanding and impacts of proposed new network and retail tariff options.

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 remains 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.

[24] Website: https://www.talkingenergy.com.au/qhes

[25] Websource: https://qhes.com.au/wp-content/uploads/2022/08/2022-QHES-Report.pdf

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 as 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. Customers' feedback on the natural disaster events we responded to continues to show we respond well when these events occur and that our contribution is important to communities in getting them back up and running quickly.

More than 180,000 customers lost power during the major floods and associated severe storms that occurred in Brisbane and across southern Queensland in early 2022. At its peak more than 57,000 customers were without electricity supply at any one time. In response, Energex and Ergon Energy Network field crews and support teams were mobilised and worked tirelessly to safely restore network supply to all customers who could be safely reconnected.

61%*

have a positive sense of security around their electricity supply.

*Queensland Household Energy Survey 2022. Question: Please indicate on the scale below how much you agree with the following statements regarding Queensland's energy transmission and distribution providers (i.e. Powerlink, Ergon Energy and Energex). Answer: These energy suppliers give me a sense of security about my electricity supply. Scale 0-10; Agree 7-10

Despite the ongoing impact of natural disasters across the network, 61% of participants in the 2022 Queensland Household Energy Survey indicated they have a positive sense of security around their electricity supply.

The second phase of the Thriving Communities Partnership Queensland Chapter's Disaster Planning and Recovery Collaborative Research Project,[26] which has built on the national virtual roundtable in late 2020, strengthened our understanding of the relationship between the experiences of individuals, first responders and front-line service providers. The research 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. This has advanced collaborative opportunities for positive change.

Reliability

General perceptions of Queensland's energy supply have continued to improve, with most customers agreeing that they have a reliable supply of energy.

Growing year-on-year, 74% of survey participants agreed they were provided with a 'reliable energy supply'. Sentiment that price and reliability are well balanced has also continued to increase in the 2022 Queensland Household Energy Survey.

Power outages have immediate customer and broader economic impacts. The quality of supply is also important to some customers. Some, however, especially those in the more rural and remote areas of our network, consider they are poorly serviced.

74%*

are satisfied with power supply reliability. This improved, despite ongoing supply challenges.

*Queensland Household Energy Survey 2022. Question: These energy suppliers provide my household with a reliable energy supply. Scale 0-10; Agree 7-10. Note: last year's report included results for Agree: 8-10.

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

Customer Experience

This year we implemented our new corporate Customer Satisfaction (CSAT) metric approach, which involves surveying customers quarterly via an independent panel asking how satisfied they are with the services receive by the business. The new corporate CSAT metric measures customer satisfaction across all our brands with an indexed score provided for Energy Queensland. This year our CSAT recorded a score of 72.2/100, above our target (69/100) and stretch target (70/100). Importantly, the key CSAT drivers tracked indicate that as mentioned previously in this report our customers are generally satisfied that we '*provides a reliable power supply'* and in our ability to *'deliver work in a timely manner'* our top scoring key drivers, but that we have further progress to make in our drive to be *'customer focused'* and *'understand my [our customers'] needs'*.

As our interactions and research indicates, expectations around the customer experience are generally increasing, especially around handling their enquiries in a timely manner and in regard to information and notifications on issues such as power outages. Many see outage updates and restoration times as important as preventing the initial outage, a fact highlighted through the 2022 Queensland Household Energy Survey results, where 62% of respondents indicated they were satisfied with the time taken to restore electricity to their home after an outage, but only 38% satisfied with the communications around the outage.

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 number of households indicating their intention to consider installing solar energy continues to rise year on year, with many also now indicating interest in home battery storage systems. In the 2022 Queensland Household Energy Survey, 15% of respondents indicated their intention to purchase battery storage within the next three years with a further 36% indicating a desire to do so within the next 3-10 years. These intentions could see around 150,000 home battery systems in use by 2030.

In the survey, over a third (34%) of participants were aware of the concept behind community batteries.

The growth in solar is changing the shape of load profiles across the day, and throughout the year, 'hollowing out' the load during the middle of the day. This has significant implications for the grid with the potential to impact system stability, and reverse power flows and voltages issues.

In the 2022 Queensland Household Energy Survey, we found just under half (49%) of our customers are potentially aware of the need to manage minimum demand on the electricity network, rising to 61% amongst those who have solar PV.[27]

With Electric Vehicles (EV) potentially being a significant load on the network in the coming years, the 2022 Queensland Household Energy Survey also continued to track perceptions on EVs.[12]

26%*

intend to purchase new or additional solar energy for their home within the next three years.

*Queensland Household Energy Survey 2022. Question: Do you intend to purchase additional or replacement solar panels for your home within the next 3 years? / Do you intend to purchase solar panels for your home within the next 3 years?

49%*

are aware of the need to manage minimum demand on the electricity network.

*Queensland Household Energy Survey 2022. Question: Due to the high take up of rooftop solar PV systems, this creates high export of electricity to the grid and households using less electricity from the grid between 9am and 3pm than other times of the day. This is known as minimum demand. Are you aware of the need for electricity distributors to manage minimum demand on the grid?

[27] Website: https://www.talkingenergy.com.au/qhes

Consideration of EVs has significantly increased, with 71% of survey participants that are considering purchasing a new vehicle in the next three years willing to consider an EV, up from 54% in 2020. Price and charging ability are the main barriers for many, with 59% indicating they are still too expensive and 43% highlighting concerns over lack of public charging stations.

71%*

of those considering purchasing a motor vehicle would consider an EV, versus 54% in 2020.

*Queensland Household Energy Survey 2022. Question: to those considering purchasing a motor vehicle in the next 3 years, would you consider purchasing a plug-in electric car or plug-in hybrid car in the next 3 years?

The majority of the EV owners who participated in the survey indicated their willingness to personally manage their EV charging time to avoid peak electricity demand on the network (63%), with just over half (53%) also indicating they were open to the concept of a third party, such as their electricity network provider, managing their charging to address electricity demand.

From earlier research we know our customers expect us to be able to facilitate and accommodate integration of renewables, battery storage and Electric Vehicles (EVs) into the network, without creating risks to network security, supply quality or performance.

Despite the challenges of managing solar on the network and keeping voltages within statutory limits, across our networks we are continuing to see a decrease in the number of 'quality of supply' enquiries lodged by customers. However, the largest proportion of these continue to be concerns relating to solar PV related issues as listed in Chapter 10: Power Quality.

Collaboration

Our customers, communities and other stakeholders, expect us to keep them informed in a timely manner and engage with them transparently and meaningfully on a regular basis.

87%*

said it was important we modernise our electricity networks to continue to enable customers to take up new technologies.

*Future Energy Survey. Question: How important is it that we modernise our electricity networks to continue to enable customers to take up new technologies? ' Don't know' excluded.

Findings from research into our business customers' experience during power outages showed that while customers were highly supportive of the networks' need to conduct work relating to reliability, there were opportunities to support customers in preparing contingency plans and improve communications.

Across our industry's peak bodies and other stakeholders there is a strong desire to engage and work with us to realise the benefits from today and tomorrow's emerging technologies, and a recognition of the valuable role the network provides in the energy transformation.

This remains vital, with only 44% nationally in the Energy Consumers Australia's Sentiment Survey June 2022[28] confident the market is working in their long term interests. In the context of this, in our own research, we are gaining more of an understanding around trust – 'working to make electricity more affordable' and 'to do the right thing'.

Information and awareness will remain 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.

[28] Website: https://ecss.energyconsumersaustralia.com.au/sentiment-survey-june-2022/key-indicators-national-sentiment-june-2022/

Our demand management program continues to be 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 Management Plan, [29] which seeks utilise 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.

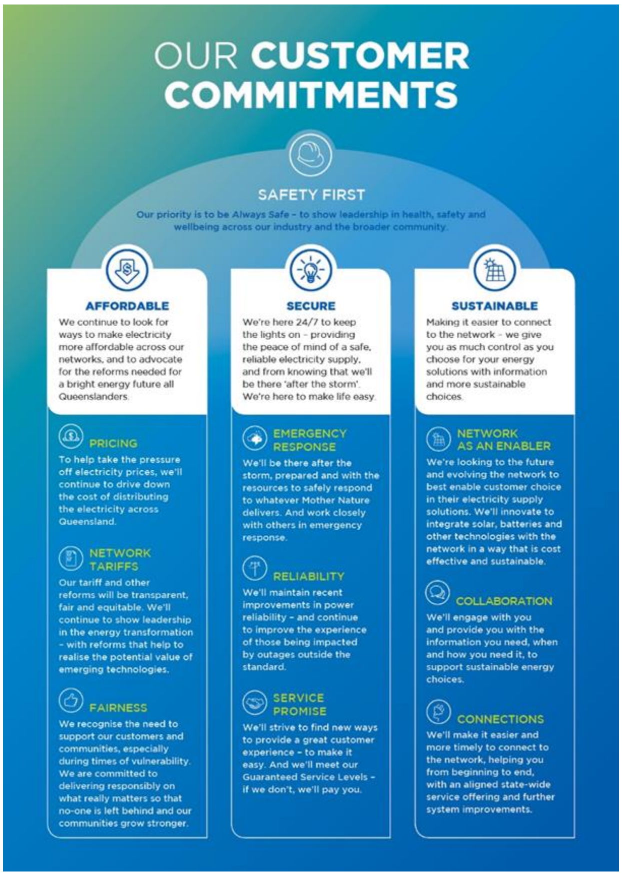
Connections

Reasonable, clear timeframes and costs for connections are critical to Queensland's economic development. Customers are seeking a simplification of our connection process, shorter time frames, and for continued equitable support of embedded generator connections. There continues to be support for our efforts to align our service offering across Queensland.

3.4 Our Customer Commitments

As part of our planning process for our Regulatory Determination, we responded to the community and customer insights we heard at the time with a set of commitments for 2020 to 2025. Our Customer Commitments, provided by Figure 6 below, continue to prioritise our investment plans, including the strategies and specific investments reflected in this report.

Figure 6: Our Customer Commitments



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

Chapter 4

Network Forecasting

4. Network Forecasting

Forecasting is a critical element of Ergon Energy's network planning and is essential to the planning and development of the electricity supply network. Due to the growth in peak demand and the expansion of the network into new areas, both locally and regionally, forecasting is a key driver for investment decisions leading to augmentation of the network.

Ergon Energy has adopted a detailed and mathematically rigorous approach to forecasting peak demand, electricity delivered (energy), DER generation and customer numbers with methods used described in the following sections. Audits on the Ergon Energy forecasting models are regularly undertaken by external forecasting specialists with suggested improvements to forecasting methodologies continually being made.

Ten-year energy forecasts are prepared at a system level, at customer category levels and for certain individual network tariffs. Energy forecasts are used to determine annual network losses and to establish network tariff prices, and are developed using the latest economic, electricity consumption and technology trend data. Key assumptions used in the development of these forecasts are documented and updated regularly.

Electrical demand and DER forecasts are not only undertaken at the system level but are also calculated for all zone substations and feeders for a period of 10 years. Growth in peak demand and DER integration is not uniform across the state of Queensland, therefore electrical demand and generation forecasts are used to identify emerging local network limitations and network risks needing to be addressed by either supply side or customer-based solutions. Electrical demand forecasts therefore guide the timing and scope for capital expenditure (to expand or enhance the network), the timing required for demand reduction strategies to be established, and for risk management plans to be put in place.

A Strategic Forecasting Annual Report will also be available in detailing further discussion on the methodology and assumptions applied in the peak demand forecasts and including:

- Minimum demand forecasts
- Energy purchases and energy sales forecasts
- Customer number forecasts
- Distributed Energy Resources forecasts (solar PV, Electric Vehicles (EVs) and energy storage systems)
- Economic and demographic forecasts and commentary relating to population growth, GSP and the Queensland economic outlook.

4.1 Forecasting Assumptions

There are several factors which influence the forecasts assumptions used in the development of the peak demand and DER forecasts. These are discussed in the following sections.

4.1.1 Economic Growth

The level of economic activity is a major influence on many aspects of our industry. While the impact of economic growth is felt most directly at the individual household and business level, it is not possible to build a model which takes every one of these into account. As such, higher level measures of economic activity are used where measures of current activity and forecasts are available. Gross State Product (GSP) projections are a key driver to many of our forecasting models.

The Queensland Treasury released its 2022/23 State Budget in late June 2022. The COVID-19 pandemic had hit the state economy hard in the 2019/20 financial year, which resulted the Gross State Product (GSP) falling by 0.6%. However, the aggregate economic activity recovered 2.0% in the 2020/21 year, contributed by the substantial income support and stimulus provided across all levels of government, including the substantial relaxation of restrictions and vaccine rollout. As a result, the Queensland economy and its local labour market have outperformed the rest of the nation over the same period. Despite the Omicron outbreaks in the earlier period of 2022, coupled with the floods around Feb/Mar 2022, which was estimated to be around $1 billion, or ¼ percentage point of GSP, the Queensland's domestic economic activity, according to Queensland Treasury, still rose in the March-22 quarter, and was 7.8% higher than its pre-pandemic level.

Although Queensland recently experienced subdued overseas migration growth, the state has attracted interstate migrants to Queensland during the pandemic, which helped support overall population growth and activity. It is anticipated that the 2022/23 budget will help further enhance employment opportunities across Queenslander, foster private sector investment and growth, and deliver record levels of infrastructure investment. This includes a $59.1 billion infrastructure investment program over the next 4 years to 2025/26 to enhance the state's productive capacity. The Budget also provides $6.8 billion in concessions (including subsidies, discounts and rebates) to individuals and families to ease cost of living pressures and reduce costs for business. Queensland Treasury predicts the state economy will grow by 3.0% in 2021/22 (slightly below the 3¼ % when the 2021/22 budget update was released) before slowing to 2¾ % over the years to 2025/26. Meanwhile, the labour market continues to remain robust. After falling to 4½ % in 2021/22, the state's unemployment rate is forecast to sit low across the years to 2025/26, between 4 and 4¼ %, as sustained employment growth and a pick-up in wages growth keep the participation rate elevated.

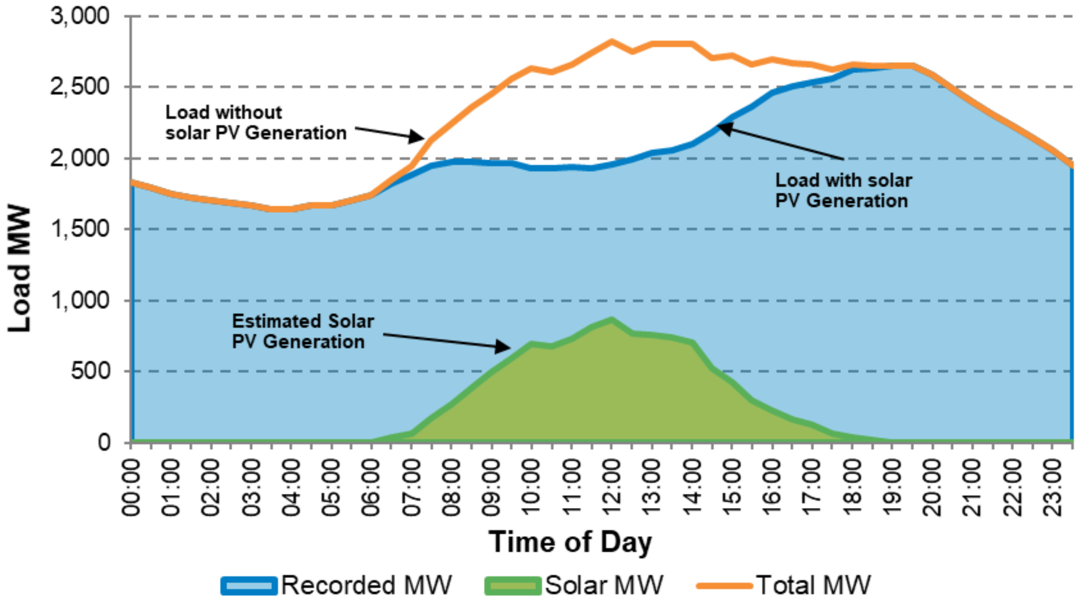
4.1.2 Solar PV

Solar PV has a significant load impact on our network, typically affecting the energy forecast outlook. The impact of solar PV is based on profiles which have been constructed to predict generation (and export) for rooftop systems for all forecast scenarios. In 2022, Energy Queensland had engaged ENEA Consulting to provide a Distributed Energy Resource (DER, which include solar PV, Electric Vehicles and Energy Storage Systems) forecast for both Energex and Ergon Energy networks respectively.

A 0.5% per-annum degradation factor was used for solar PV systems. Small systems are designed to generate energy for the home with excess energy exported. Commercial-scale installations are larger and may or may not export to the grid. Utility-scale solar farms are designed to export.

The 2021-22 Ergon Energy's summer system peak of 2,637MW occurred between 6:30 and 7:00 pm on the 3 March 2022 and it was estimated without PV generation, the peak would have occurred at 12:00 pm and would have been 174MW higher. As battery storage becomes more affordable and therefore widely used, daily peaks may revert to mid-to-late afternoons, as less PV generation is exported in preference for re-charging storage batteries, refer to Figure 7.

Figure 7: System Demand – Solar PV Impact, 3 March 2022



4.1.3 Electric Vehicles and Energy (battery) Storage

Mainstream uptake of Electric Vehicles (EVs) and Plug-in Hybrid Electric Vehicles (PHEVs) will increase energy and demand forecasts over the forecast horizon. The uptake rate of EVs and PHEVs has historically not been high due to a combination of factors including the high initial cost and low availability of various vehicle types. However, it is anticipated that EV is likely to have a significant increase through time with as more various vehicle types are on offer in the market, and the EV cost creeping closer to price parity with its Internal Combustible Engine (ICE) counterpart. Therefore, the impact factored into the System Demand forecast has been relatively small in the earlier years of the forecast but increases over time with the growing population of vehicles. Nonetheless, it is expected that a major part of the uptake of EV will be in South East Queensland (SEQ).

Customer interest in energy storage systems (batteries of various kinds) continues to increase. The number of known energy storage systems in the Ergon Energy network is approximately 4,100 as of June 2022. Over the next five to ten years energy storage will continue to grow with:

- Falling prices as battery storage production increases in scale
- New technology (safer, higher energy densities, larger capacities), and
- Package-deals of solar PV and battery storage systems promoted by major retailers and solar PV installers.

Ergon Energy's forecasting model is based on an average typical hot summer day demand profile for residential, and business customers. These assumptions are refined over time as more customers adopt EV and storage systems, and their usage data becomes available. The impact of energy storage on the customer's energy consumption profile is 'behind the meter' which means that it cannot be directly measured.

Historically, there has also been little high-quality data surrounding the number and size of batteries being installed, all of which makes forecasting the larger scale impact over time more difficult.

4.1.4 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 (although the scale of solar PV generation now creates other possibilities for extreme loads due to cloud cover). At the system level, the modelling process has continued to be refined over the years, with population replacing air-conditioning as a variable used in the equation as it is better able to represent the impact of broader range of electrical appliances during the extreme conditions.

Given the vastness of the Ergon Energy network, a number of weather stations are required to capture the variability of weather conditions across the network. The process also requires a long history of quality weather data – eliminating many candidate stations. 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:

Table 2: Listing of Weather Station locations for temperature correction

Weather Stations used in the substation temperature correction process			
Applethorpe	Gatton	Mackay	Rolleston
Ayr	Gayndah Airport	Mackay Airport	Roma
Blackall	Georgetown	Mareeba	St George
Bundaberg	Gympie	Maryborough	St Lawrence
Cairns	Hamilton Island	Miles	Thargomindah Airport
Charleville	Hervey Bay	Mount Isa	Toowoomba
Clermont Airport	Hughenden	Normanton	Townsville
Cloncurry	Julia Creek	Oakey	Warwick
Cooktown	Kingaroy	Proserpine	Winton Airport
Dalby	Longreach	Richmond	
Emerald	Low Isles	Rockhampton	

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.

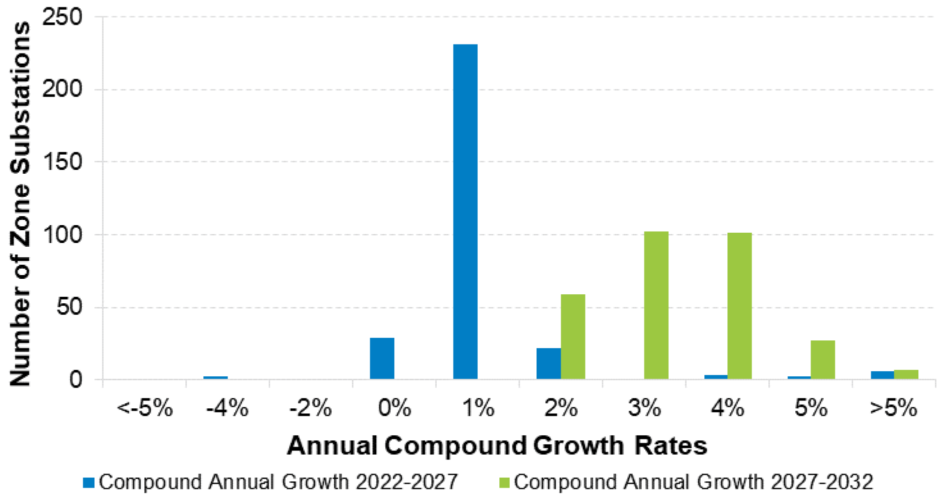
4.2 Zone Substation and Feeder Maximum Demand Forecasts

The forecasting process provides the ability to predict 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 bottom-up substation peak demand forecast is reconciled with the system level 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 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 (EVs) and battery storage systems has been incorporated at the system and substation levels of forecasting.

The forecasts are used to identify network limitations and to investigate the most cost-effective solutions which may include increased capacity, load transfers or Demand Management alternatives. The main impact we are starting to see on growth rates is Electric Vehicle charging load which is evident on the distribution of growth rates for zone substations is shown in Figure 8.

Figure 8: Zone Substation Growth Distribution 2022-2032



While growth in demand is around 2% at a system level over a 10-year horizon, there can be significant variations in growth at a localised substation level.

In the 2022-27 period, the percentage compound growth rates of substations were as follows:

- 11% have an average compound growth rate at or below 0%
- 85% have an average compound growth rate between 0% and 2%
- 2% have an average compound growth rate between 2% and 5%
- 2% have an average compound growth rate of more than 5%.

Ergon Energy has incorporated demand management initiatives into the summer and winter substation forecasts. The initiatives include broad application of air conditioning control, pool pump control and hot water control capability. Demand management is also being targeted at substations with capacity limitations in an effort to defer capital expenditure. The approach used is to target commercial and industrial customers with incentives to reduce peak demand. The resulting reductions are captured in the Substation Investment Forecasting Tool (SIFT) and in the ten-year peak demand forecasts.

These forecasts underpin the detailed analysis provided in Appendix D and Appendix E of the DAPR.

The ten-year substation peak demand forecasts are prepared at the end of summer and are produced within SIFT. To enable appropriate technical evaluation of network limitations, these forecasts are completed for both existing and proposed substations. The forecasts are developed using data from internal sources as well as the ABS, AEMO and the Queensland Government. Economic and demographic influences are incorporated via the system demand forecasts. Independently produced forecasts for economic variables and photovoltaic installations, Electric Vehicles (EVs) and battery storage systems uptake are also sourced from Deloitte's and the ENEA Consulting respectively.

Output from solar PV is generally coincident with Commercial and Industrial (C&I) peak demand. Although the scale is small compared to residential solar PV, increasing penetration at C&I premises will provide benefits through reduced substation and feeder peak demands. There is also an impact by solar PV on feeders that have a mixed load of C&I and residential connections. Feeders that are predominantly residential exhibit load profiles that are 'hollowed out' in the afternoons, which generally results in the reduction of the peak demand that would have occurred without solar PV generation to offset it. The remaining shoulder of the modified afternoon peak demand then becomes the de facto peak demand for the day, which occurs in the early evening when solar generation has fallen.

4.2.1 Zone 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. Validated historical peak demands and expected load growth based on demographic and Distributed Energy Resource (DER – solar PV generation, Electric Vehicles, and un-aggregated battery energy storage capacity) are used as data inputs into the forecasting model. The planning team provides local insights where relevant, as well as project, block load and load transfer information.

The peak demand forecasts are produced for:

- 50 Probability of Exceedance (PoE) and 10 PoE levels (i.e. Probability of Exceedance – 50 year average season and 10 year extreme season levels)
- Each zone substation
- Summer and winter, and
- Base, Low and High scenarios.

Zone substation forecasts are based on a probabilistic approach using a multiple regression estimation methodology. This approach has the advantage of incorporating a range of variability into the predictions.

A Monte Carlo simulation using BOM daily minimum and maximum temperature history is used to calculate the 10 PoE and 50 PoE maximum demands for each zone substation. Growth rates are then calculated using a separate model for summer and winter. Growth rates, load transfers and new major customer loads are then incorporated into the future load at each zone substation.

The zone substation forecasts are successively aggregated up to the bulk supply, and transmission connection points, to create forecasts at those levels – after taking diversity and losses into account. This aggregated forecast is then reconciled with the independent system demand forecast and adjusted as required.

The process sequence used to develop the ten-year substation demand forecast is briefly described as follows:

- Validated uncompensated substation peak demands are determined for the most recent summer and winter seasons
- These loads are then associated with minimum and maximum temperatures at the relevant weather stations, to calculate the substation's temperature demand relationship
- Many industrial substations tend not to have much temperature sensitivity, as their load can vary due to a range of other factors. As a result, these 50 PoE and 10 PoE values tend to be based on sets of business rules chosen to reflect these expected load variations
- Previous substation peak demand forecasts are reviewed against temperature-adjusted results as part of a process looking for the causes behind individual variations
- Starting values for apparent power (MVA), real power (MW) and reactive power (MVAr) are calculated for the key benchmarks of "summer day", "summer night", "winter day", and "winter night"
- The predicted impact of solar PV, battery storage, and Battery Electric Vehicles and Plug-In Hybrid Electric Vehicles is incorporated into year-on-year peak demand growth rates
- The size and timing of block loads, transfers and projects are reviewed and validated with Grid Planning and Network Management asset managers before inclusion in the forecast
- The different elements of the forecast – growth rates, block loads, transfers are combined and applied to the starting values to produce a 10-year demand forecast
- The substation peak demand forecasts are reviewed extensively and compared with previous forecasts, with a focus on the relative error between recorded demand and the forecast for the most recent season. If necessary, adjustments are made to incorporate late information or factors not able to be included in the forecasting model

- Zone substation forecast peak demands are aggregated up to bulk supply substation, and transmission connection point levels (after allowing for coincidence and losses) to produce forecasts at those network levels
- The zone substation forecast is “reconciled” against the system peak demand forecast to ensure that factors only clear at the distribution level (e.g., expected economic growth), are incorporated at the zone substation level. This is done by calibrating relevant zone substations forecasts for the time of co-incident peak, which flows through to an adjustment of the zone substation’s local peak.

Zone substation forecasts are based upon a number of inputs, including:

- Network topology (source: corporate equipment registers)
- Load history (source: corporate SCADA/metering database)
- Known future developments (new major customers, network augmentation, etc.) (source: Major Customer Group database)
- Customer categorisation (SIFT)
- Temperature-corrected start values (calculated by the FLARE forecasting model)
- Forecast growth rates for organic growth (calculated by the FLARE forecasting model), and
- System maximum demand forecasts.

The impact of Embedded Generation (EG) on the Ergon Energy forecasted peak and minimum demand are estimated for each zone substation using the solar PV and Battery Energy Storage Systems uptake forecast and their corresponding demand load profiles. This is based on the medium Distributed Energy Resource (DER) uptake scenario for solar PV and battery storage systems forecast, sourced by ENEA Consulting for all zone substations. The forecasted EG for each zone substation is disaggregated from the systems level forecast based on the historical DER penetration rates across each individual zone substation in the forecast. The demand load profiles for solar PV are then estimated by modelling the historical relation between available solar PV inverter capacity and the measured solar irradiance hourly profiles based on a typical peak demand and minimum demand day.

Electric vehicles (EV) are not considered as part of the embedded generating unit category as the Vehicle to Grid (V2G) technology is considered to be at its infant stage, and the DER forecast suggests that EV would have an impact on the network from a peak demand perspective rather than generation. The forecast use of distribution services (export) by embedded generating units are estimated from each zone substation’s load profile forecast. The uptake of solar PV systems is pushing the middle of the day load towards zero and causing reverse power flow in some parts of the network. This reverse power flow has been utilised to represent the zone substation export caused by the EG. The EG export for each zone substation is forecasted on both peak and minimum demand events using the medium DER uptake scenario forecast and demand profiles.

4.2.2 Transmission Feeder Forecasting Methodology

A simulation tool is used to model the 110kV and 132kV 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. Two network loading scenarios have been considered: native load and load with DER and generation integration. For the load scenario peak forecast loads at each bulk supply, zone substation and connection point are loaded into the model from SIFT. For the DER scenario, the DER forecast is determined and integrated into the SIFT loading and large generating systems are enabled.

Twenty models for each scenario 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.

4.2.3 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.

There are two network load scenarios that have been considered, native load and loading with DER and generation integration. The native load scenario provides indication of areas of the network may require augmentation due to load, impacts of phenomenon like solar masking being considered. The DER and generation integration scenario highlight areas of the network that have high penetration of generation and capacity constraints or areas where capacity for EG remains.

4.2.4 Distribution Feeder Forecasting Methodology

Distribution feeder forecast analyses carry additional complexities in comparison to sub-transmission feeder forecasting. This is mainly due to the 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 distribution feeder loads are performed bi-annually on a feeder-by-feeder basis. The summer assessment covers the period of November to March, and the winter assessment from June to August. The key forecasting drivers are like those related to substations, such as population and distributed energy resources growth.

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

- The historic maximum demand values, in order to determine load starting point by undertaking bi-annual 50 PoE and 10 PoE temperature-corrected load assessment. 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 loads and 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 weather data, used to model the impacts of weather on maximum demand, is supplied by Weather Zone, which sources its data from the Bureau of Meteorology. This is used to determine approximate 10 and 50 PoE load levels
- Customer growth on feeders is estimated by using the Queensland Government Statistician's Office spatial population projections, combined with Ergon Energy's customer number forecasts by residential and business customer segments
- The EQL's scenario-based forecast for distributed energy resources that includes solar PV capacity, battery storage capacity and Electric Vehicle (EV) uptake is used as one of the growth drivers at distribution feeder level. The average per-unit day load profile per customer segment for each DER technology is estimated to calculate the DER impact on maximum day load profile forecast for each feeder

- After applying the growth rates from customer and DER forecast, 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.

Similar to the zone substation forecasting methodology under Section 4.2.1: Zone Substation Forecasting Methodology, the demand of EG on the Ergon Energy forecasted peak and minimum demand are also modelled for each distribution feeder. The medium DER uptake scenario was used for solar PV and Battery Energy Storage Systems along with their corresponding demand load profiles. EVs are not considered as part of the embedded generating unit category as described in Section 4.2.1.

The forecasted EG for each distribution feeder substation is disaggregated from the systems level forecast based on the historical DER penetration rates across each individual feeder. The demand load profiles for solar PV are then estimated by modelling the historical relation between available solar PV inverter capacity and the measured solar irradiance hourly profiles based on a typical peak demand and minimum demand day.

The forecast use of distribution services (export) by embedded generating units are estimated from each feeder distribution load profile forecast. The uptake of solar PV systems is pushing the middle of the day load towards zero and causing reverse power flow in some parts of the network. This reverse power flow has been utilised to represent the distribution feeder export caused by the EG. The EG export for each distribution feeder is forecasted on both peak and minimum demand events using the medium DER uptake scenario forecast and demand profiles.

4.3 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 half hourly trace is modelled separately with a semi parametric model and the sum of each of these regional peak demands at network peak coincidence provides a distribution of max demand for each of the ten-years future total system maximum demand. 50 PoE and 10 PoE maximum demand are then calculated for each year for their respective distribution.

Inputs for the maximum demand forecast for each region include:

- Economic growth through the GSP and Population[30]
- Weather variables[31] (e.g. temperature, rainfall, Global Horizontal Irradiance - GHI)
- Load history
- Solar PV generation, Electric Vehicles and Energy Storage.[32]

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. For further details regarding the zone substation forecasting methodology please refer to Section 4.2.1.

[30] Source: Queensland Government Statistician's Office and Deloitte

[31] Source: Bureau of Meteorology (BOM)

[32] Source: ENEA Consulting

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 the peak demand growth through most of the state. At the same time, weather patterns have moved from extreme drought in 2009, to flooding and heavy rain in recent years, to extended hot conditions over the past several summer periods. Summer conditions produced new record highs a couple of years ago, but now Covid and La Nina have combined to produce a peak demand well below trend.

Customer sensitivity to electricity prices has decreased as the amount of solar PV generation connected to the network continues to grow. Customer behaviour drivers are now incorporated into models used for system demand forecasting. The forecasts are developed using ABS data, external consultant DER data, Queensland Government data, AEMO data, solar PV connection data, and historical peak demand data.

4.3.1 System Demand Forecast Methodology

Naturally, there is a level of uncertainty in predicting future values. To accommodate the uncertainty, forecasting 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 considered relevant for planning purposes.

The methodology used to develop the system demand forecast is comprised of:

- Actual half-hourly recorded demand at the legacy regions for historical years is extracted from the Ergon Energy demand data
- Historic PV generation is then added back to the load traces
- System forecasts are obtained from modelling a temperature-corrected semi parametric model using economic, demand management and population variables
- Simulation of future PV generation as well as other DER components are added in to predict future demand
- 50 PoE level — this best estimate level is obtained from a maximum demand distribution such that 50% of the values are on each side of this value, and
- 10 PoE level — this highest level is obtained from a maximum demand distribution such that 10% of the values exceed this.

The nature of the system maximum demand methodology and the resulting forecast is such that it is considered the most accurate and reliable indicator of future demand in the network.

The system-wide 2021-22 peak was 2,637MW between 6:30 and 7:00 pm on 3 March 2022, an increase from previous year's peak as listed in Figure 9.

Figure 9: Trend in System-wide Peak Demand

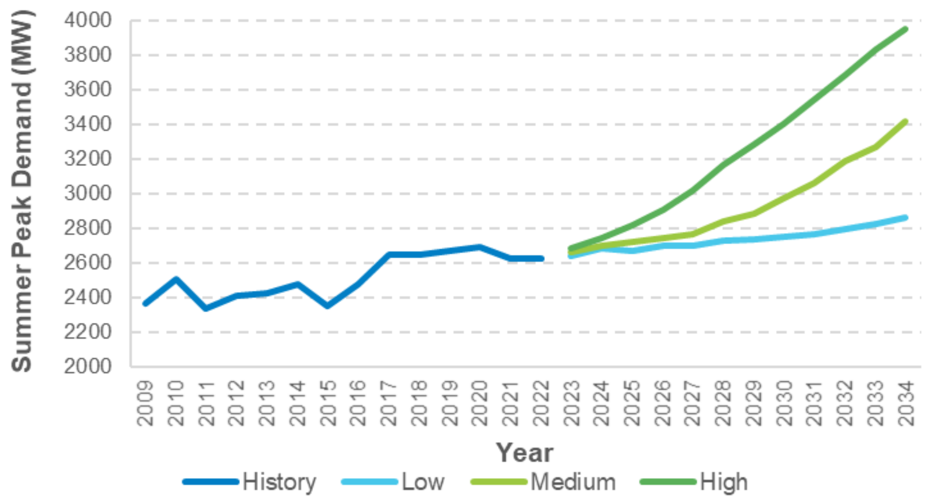


Table 3 summarises the historical actual demands.

Table 3: Actual Maximum Demand Change

Actual Maximum Demand Growth					
Demand	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**
Summer Actual (MW) [1]	2,597	2,623	2,660	2,587	2,637
Annual (%) Change	-2.0	1.0	1.4	-2.7	2.0

[1] Native Demand

Furthermore, Table 4 lists the maximum demand forecasts over the next five years for the 50 PoE and 10 PoE cases.

Table 4: Maximum Demand Forecast

Maximum Demand Forecast (MW)					
Forecast [1, 2]	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**2026-27**
Summer (50% PoE)	2,666	2,700	2,723	2,747	2,770
Growth (%)	-	1.3	0.9	0.9	0.8
Summer (10% PoE)	3,070	3,107	3,147	3,154	3,195
Growth (%)	-	1.2	1.3	0.2	1.3

[1] The summer actual demand has been adjusted to take account of EG operating at the time of system peak demand.

[2] The demand forecasts include the impact of the forecast economic growth as assessed in March 2022.

The forecast of general solar PV generation at the time of summer peak demand for regional Queensland is expected to be insignificant in the forecast horizon. Solar PV will continue to grow steadily with retailers providing options for customers to either bundle solar PV with battery storage or to purchase individual options. The forecast Ergon Energy system peak demands are expected to occur outside of the solar PV generation times, as a result 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. Conversely, the increase in uptake of Electric Vehicles (EVs) would impose a more significant impact to Ergon Energy's peak demand from 2028 and onwards.

Chapter 5

Network Planning Framework

5. Network Planning Framework

5.1 Background

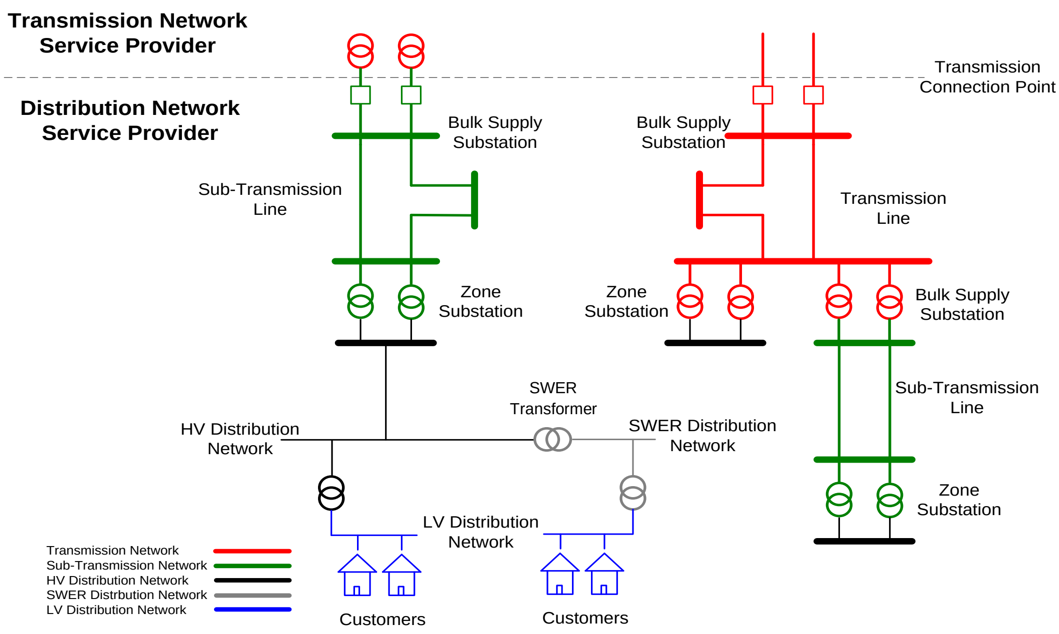
Ergon Energy's Network planning framework aims to provide a balance between the customers' need for a safe, secure, reliable and high quality electricity supply with the customers' desire for a minimal service cost. A key part of the network planning process is to optimise the economic benefits of network augmentation and renewal facilitating "non-traditional" options beyond the boundaries of the network, such as demand management, Embedded Generation (EG) solutions and other approaches. Addressing of network limitations and risks is at the core of the planning framework to ensure the solutions are optimal to meet current and future requirements.

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 10 illustrates a traditional simplified DNSP network which typically consists of sub-transmission, 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 are creating both opportunities and challenges in the planning of the electricity supply network.

Figure 10: 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 develop alternative network 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 procedure 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 of network infrastructure for both the short and long term as well as to coordinate developments addressing constraints and meet utilisation targets.

Strategic network development plans detail the results of the long term strategic forecasting and network 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 ultimate load growth (i.e. a worst case scenario) and exact location of load. The output of the strategic planning process gives direction to the medium and long-term recommendations, while allowing strategic site and easement acquisition as well as approvals to proceed. Specific outcomes of strategic network development plans are explored to identify areas where non-network solutions have potential to defer or avoid network augmentation. These works are ongoing and reviewed as required.

5.2.2 Detailed Planning Studies

In order to address the forecast network limitations and ensure ongoing safe and reliable operation of the network, network augmentation and replacement project options for a specific site/network are identified in the detailed planning proposals. As requirement dates for recommended works within each strategic network development plan draw closer or where unforeseen customer initiated development changes occur, more detailed localised network planning 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 sub-transmission, distribution, non-network and where significant, asset renewal planning functions.

These planning studies are conducted at the sub-transmission 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 and network reliability considerations
- Asset renewal
- Customer connections activity
- Local, state and federal government decisions and directions.

The planning process for a network segment involves the following major steps in a typical routine planning cycle:

- Identify network risks/limitations in the system
- Validate load forecasts
- Evaluate the capability of the existing system
- Formulate network options to address these risks/limitations and identify any feasible non-network solutions from prospective proponents
- Compare options on the basis of technical and economic considerations
- Select a preferred development option
- Undertake regulatory public consultations for projects as required, and carry out detailed evaluation upon receipt of any alternative solutions from the registered participants/ proponents
- Initiate action to implement the preferred scheme through formal project approvals.

Project planning and approvals are currently carried out in accordance with the RIT-D requirements applicable for the projects having credible options valued at more than $6 million.

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 changes in customer requirements, load growth, aged assets, 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:

1. 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
2. Increases in the number of residential or small commercial customers in a part of the network
3. Block loads connecting to a part of the network, such as new large commercial or industrial customers
4. Changes/installation of medium to large scale embedded generators and/or storage technology.

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

Augmentation works within our network can also be driven by Powerlink, as the Transmission Network Service Provider (TNSP). Work on Powerlink’s network may also 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. These types of augmentation activities are analysed and reviewed as part of the Joint Planning process conducted between Ergon Energy and Powerlink (or other DNSPs) as required by the NER.

Demand Forecast

Accurate demand forecasting is essential to the planning and development of the electricity supply network. Ergon Energy has adopted a detailed and mathematically rigorous approach to forecasting of electricity demand, and customer numbers. These methods are described in detail in Chapter 4: Network Forecasting. Ergon Energy also undertakes regular audits and reviews by external forecasting specialists on its forecasting models. Demand forecasts are not only undertaken at the system level but are also calculated for all substations and feeders for the forward planning period. These forecasts are used to identify emerging network limitations and risks that need to be addressed by either network or non-network based solutions. These forecasts are then used as an input to determine the timing and scope of capital expenditure, or the timing required for demand reduction strategies to be established, or risk management plans to be put in place.

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.)
- Probabilistic (risk-based) approaches.

Ergon Energy is required under Distribution Authority No. D01/99 to adhere to the deterministic planning approach, where full consideration is given to network risk at each location, including operational capability, plant condition and network meshing with load transfers.

This criteria gives 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 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 as week as any other regulatory obligations.

For increased confidence on the network investments, proposed investments that are not mandatory 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 consistently considered for each project with the most cost positive option 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 of VCR calculation 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 metering 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's 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

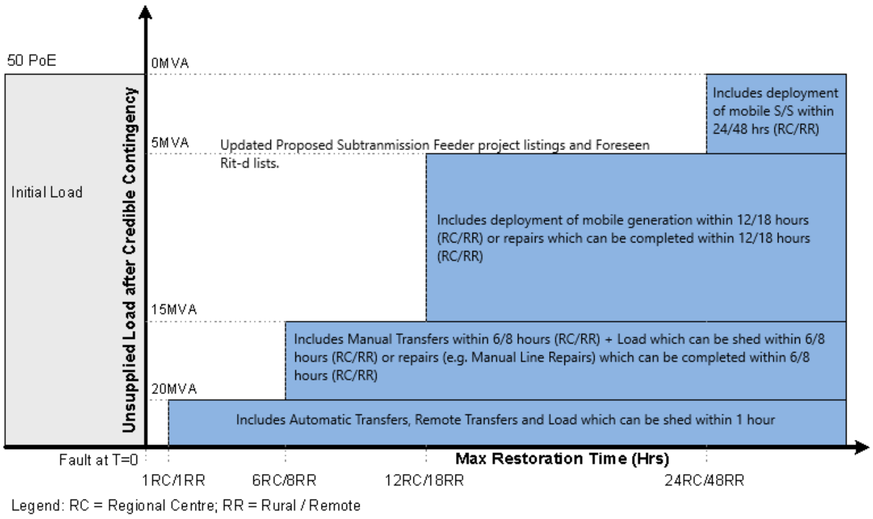
While the VCR approach described above, provides an effective mechanism for keeping costs low while managing most network risk; high-consequence-low-probability events could still cause significant disruption to supply with potential customer hardship and/or significant community or economic disruption.

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 statement 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 adverse weather conditions, though these should be rare. 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[33]	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 • 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 • Fully restored within 48 hours.



Unsupplied load after credible contingency and maximum restoration time

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 sub-transmission 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 the cost of network.

33 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.

5.4.3 Risk Quantification and CECV

Ergon Energy has also incorporated risk quantification methodology into its planning analysis. This framework provides a way to monetise items such as safety, environmental or bushfire risks.

In June 2022 the AER published their final determination of the Cost of Export Curtailment Value (CECV). This methodology provides a mechanism to monetise the value reducing DER generation export due to network limitations and where appropriate help to provide justification for network augmentation.

5.4.4 Distribution Network Planning Criteria

Distribution feeder ratings are determined by the standard conductor/cable utilised 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 both the 11kV and 22kV network.

CBD and Critical Loads

In the regional areas for loads that require full supply redundancy to manage contingencies, 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

In relation to Safety Net, an Urban feeder 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 90% at 50 PoE, unless the supply agreement specifically requires a different value.

5.4.5 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 Rating 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 as opposed to 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 a consolidated EQL Plant Rating Manual which is based on the relevant Australian Standard.

An alignment of the plant rating philosophies between Energex and Ergon Energy was completed to form the EQL Plant Rating Manual. The process involved a review of the environmental climate conditions and operational time blocks for overhead static line ratings. As a result of the review, changes have been made to the Ergon Energy operational time blocks as shown in Table 6 and Table 7. The most significant change is to the time blocks, for example day was previously from 9am to 5pm, and is now 6am to 6pm.

5.5.1 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 EQL climate zones with appropriate design ratings. The default overhead rating parameters used are listed in Section 5.5.2: Overhead Line Ratings. 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
- Alignment of 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 peak demands
- Where the existing conductor operating temperature is not known, a thermal rating of 50°C has been used. This is the typical legacy overhead conductor thermal design temperature rating used in Ergon Energy regions.

5.5.2 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; as well as 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 6 and Table 7. In design of curtailment 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 in the following standard set of climate assumptions.

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 6. The shoulder seasonal months of April, May, September, October and November are generally rated with summer parameters.

Table 6: Time of Day Definition

Description	Abbreviation	Indicative time
Summer Day	SD	Dec-Mar, 6am to 6pm
Summer Evening	SE	Dec-Mar, 6pm to 10pm
Summer Night/Morning	SN/M	Dec-Mar, 10pm to 6am
Winter Day	WD	Jun-Aug, 6am to 6pm
Winter Evening	WE	Jun-Aug, 6pm to 10pm
Winter Night/Morning	WN/M	Jun-Aug, 10pm to 6am

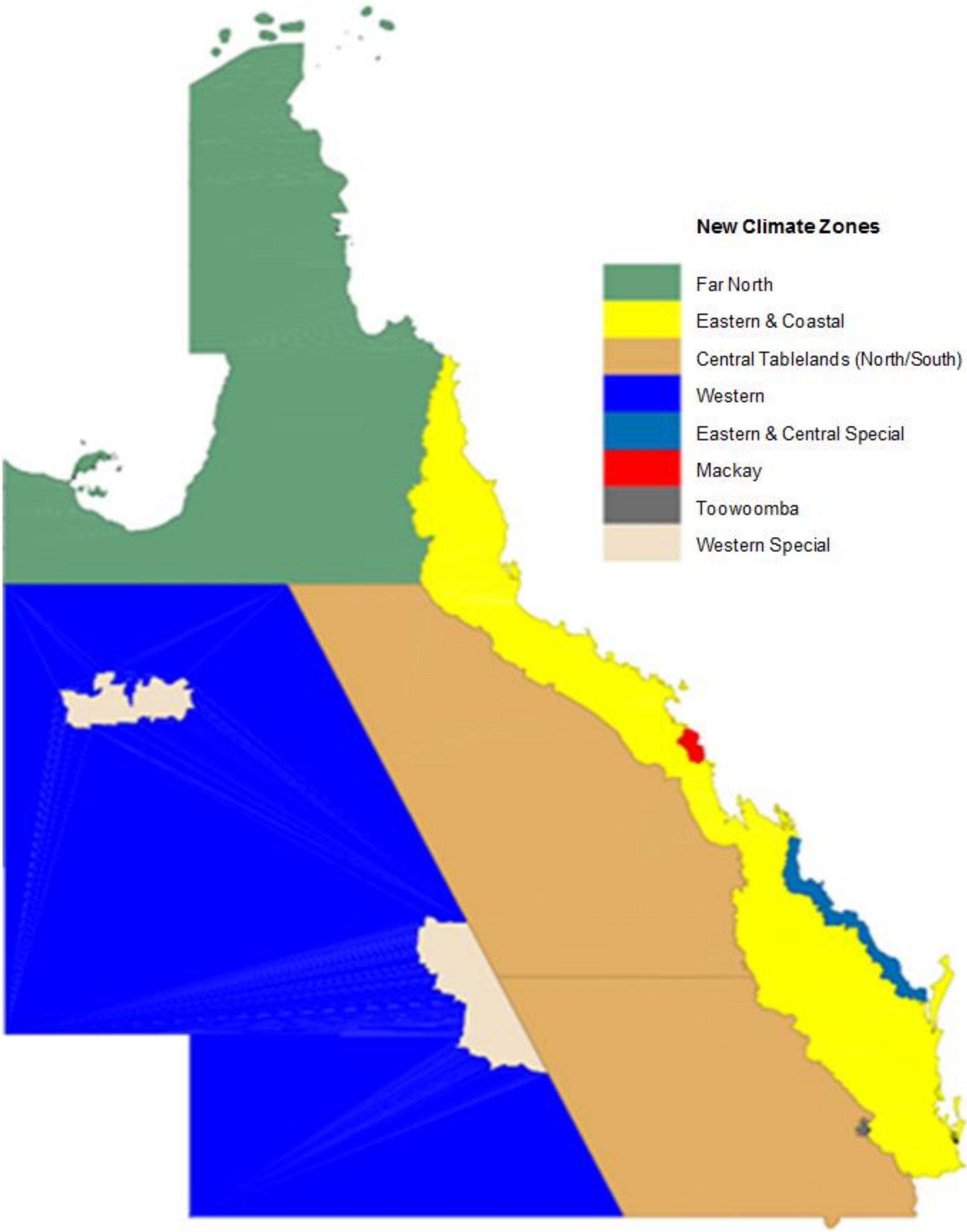
Climate Zones

The weather parameters for the state shown in Table 7. These nine climate zones are shown in Figure 11.

Table 7: 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 11: EQL Climate Zones



5.5.3 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 offer greater flexibility for our load management response, which can be critical when resolving asset failures in a timely manner.

Results of real time capacity monitoring are also utilised to compare to probabilistic ratings and confirm actual capacity in the network.

5.5.4 Transformer, Switchgear & Cable Ratings

Transformer ratings have been determined using EQL's Plant Rating Manual. 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 where the transformer is in poor condition or due to generator connected loads.

For generators connected to Ergon Energy's network result in reverse power flows up to nameplate value, transformer ratings are limited to the base cooling mode of Oil Natural Air Natural (ONAN) for the purpose of the connection. Ageing studies conducted as part of the connection process may apply further restrictions.

HV switchgears are rated in accordance with AS 62271. The default rating is the manufacturers' nameplate rating of the switchgear.

Underground cables are rated in accordance with IEC 60853 and IEC 60287 supported by EQL environmental assumptions.

5.6 Voltage Limits

5.6.1 Voltage Levels

Ergon Energy's distribution network consists of numerous different HV levels due to legacy network topologies, various specific customer or sub network requirements, or driven by industry best practice for a network configuration. Table 8 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 8: System Operating Voltages

System Nominal Voltage (kV)	System Maximum Voltage (kV)
132	145
110	121
66	72
33	36
22	24
11	12

5.6.2 Sub-transmission Voltage Limits

Target voltages for bulk supply substation busbars are set in conjunction with Powerlink. Unless customers are supplied directly from the transmission or sub-transmission networks, the acceptable voltage regulation on these networks is determined by their ability to meet target voltages for distribution busbars of downstream zone substations with consideration of 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.

5.6.3 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; a fixed voltage reference or Automatic Voltage Regulator (AVR) set points. Downstream voltage regulators may also be set with LDC or a standard set point.

For distribution systems, the network is operated at supply voltage standard at a customer's point of connection with considerations made to regarding 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 with 10 PoE forecast loads, or under N-1 conditions with 50 PoE forecast loads.

Table 9 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 9: Steady State Maximum Voltage Drop

Ergon Energy Network Targets	Maximum Voltage Drop – no LDC	Maximum Voltage Drop – with LDC
Urban & Short Rural	4%	7%
Long Rural	5%	8%
SWER	8%	11%

5.6.4 Low Voltage Limits

Typically, Low Voltage (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, Low Voltage Regulators (LVR) where installed, enable the LV network voltage to be managed in a similar way to the HV distribution and sub-transmission networks, with an automatic response and voltage set point.

Augmentation of the LV network may be required where rebalancing of customer loads and solar connections or resetting the distribution transformer taps is not sufficient to ensure voltages are within statutory limits. In this case, it is required to reduce the voltage drop through the transformer and LV circuits typically by uprating or installing a new transformer and reconfiguring the LV network. LVRs and Statcoms might also provide an additional reinforcement option.

5.6.4.1 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.

Table 10 below details the standard voltages and the maximum allowable variances for each voltage range from the relevant Queensland Electricity Regulation and the NER.

Table 10: 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.

5.7 Fault Level Analysis Methodology

Ergon Energy performs fault level analysis at all bulk supply point and zone substation High Voltage (HV) and Low Voltage (LV) buses in our network. Isolated generation sites are not considered in these studies.

These studies are undertaken using Ergon Energy's sub-transmission network model which has been developed and prepared using the PowerFactory network modelling software program. A transmission network model has been provided by Powerlink and merged with the sub-transmission model at all of Ergon Energy's respective transmission connection points.

Short circuit simulation studies are carried out for 3-phase, 2-phase to ground and 1-phase to ground faults in accordance with IEC 60909 Short-circuit currents in three-phase A.C. systems. Studies are performed to obtain both maximum and minimum fault levels for specific network configurations.

All short circuit simulation results are stored in a database which is then validated and analysed prior to publishing. For meshed networks, additional analysis is carried out to identify the fault current contribution of individual circuits, hence identifying the magnitude of current which a breaker is subjected to under a fault condition. Equipment having a rated short circuit withstand below the observed fault level are then identified.

5.7.1 Maximum Fault Level Analysis

The maximum fault level studies are based on two possible network configurations:

- **System Normal:** where all network elements remain as per their normal state
- **System Maximum:** where all normally open switches are closed within the boundary of a substation to produce the maximum fault level result for that substation.

The network sources used to obtain maximum fault levels for both the system normal and system maximum network configuration are based on Powerlink's maximum generation dispatch scenarios for fault level analysis purposes.

Based on the IEC 60909 standard, the maximum fault level analysis studies are carried out based on the following assumptions:

- A voltage factor of 1.1 is used to create a driving voltage of 1.1 p.u.
- Major network connected generators are assumed to be in operation
- All transformers are fixed at nominal tap
- Conductor temperature of 20°C.

5.7.2 Minimum Fault Level Analysis

The minimum fault level studies are based on two possible network configurations:

- **System Normal:** where all network elements remain as per their normal state
- **System N-1:** where a single item of plant is removed from service to produce the minimum fault level result for that substation.

The network sources used to obtain minimum fault levels for both the system normal and system N-1 network configuration are based on Powerlink's minimum generation dispatch scenarios for fault level analysis and system strength assessment purposes.

Based on the IEC 60909 standard, the minimum fault level analysis studies are carried out based on the following assumptions:

- A voltage factor of 1.0 is used to create a driving voltage of 1.0 p.u.
- All network connected generation within the Ergon Energy network are assumed to be offline (**except** generators in the Mt Isa area)
- All transformers are fixed at nominal tap
- Conductor temperature is referred to the maximum operating temperature.

5.7.3 Standard Fault Level Limits

Table 11 lists design fault level limits that apply to our network.

Table 11: Design Fault Level Limits

Network Type	Voltage (kV)	Existing Installation Current (kA)	New Installation Current (kA)
Sub-transmission	132/110	25 / 31.5	40 (1s)
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 11 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, fault level mitigation projects are initiated.

5.7.4 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 to ensure that augmentation work 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. These results are compared to the maximum allowable short circuit fault level rating of the switchgear, plant and lines to identify whether these assets have operated within appropriate 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: Joint Planning Methodology.

New connections of distributed generation and EG, which increase fault levels, are assessed for each new connection to ensure limits are not infringed. Known embedded generators are added to simulation models to determine their potential impacts on the system fault levels.

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 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.[34]

Ergon Energy has a Connection Policy[35] 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.

5.9 Customer Connections and Embedded Generators

Ergon Energy is committed to ensuring that, where technically viable, major customers are able to connect to the network. A Major Customer Connection (MCC) process is available on our website[36] which 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 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.[37]

The connection of any Major Customer and/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.

[34] Ibid, s 43.

[35] Websource: https://www.ergon.com.au/__data/assets/pdf_file/0018/1009053/Connection-Policy-2020-2025.pdf

[36] Website: https://www.ergon.com.au/network/our-services/connections/major-business-connections

[37] Website:https://www.ergon.com.au/network/our-services/connections/major-business-connections/large-generation-and-batteries

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
- Network stability to ensure consistency with relevant standards.

5.10.2 Joint Planning and Joint Implementation Register

A register has been set up to capture all information relating to limitation identification, planning, consultation and subsequent project implementation between Ergon Energy and external parties. This ensures joint activities are tracked throughout the lifetime of a project, from the time a limitation is identified to final commissioning of the chosen solution. The register is shared with the respective TNSP or DNSP and is updated regularly.

5.10.3 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 Energy 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.

5.10.4 Joint Planning with TNSP

Table 12 presents the outcomes of Ergon Energy's joint planning investments undertaken with Powerlink as described in Sections 5.10.4: Joint Planning with TNSP and 5.10.6: Further Information on Joint Planning in 2021-22.

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	$2.3M	Apr-25	Powerlink
Northern	**T51 Cairns** - Ergon Energy work to address constrained cable capacity.	$1.9M	Aug-24	Ergon Energy
Northern	**T053 Cairns** – Upgrade TR1 and Circuit Breakers	$0.6M		Powerlink
Northern	**New Meringa Substation**	N/A	2032	Ergon Energy
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 Energy asset refurbishment works.	$5.7M	Jun-24	Powerlink
Southern	**H015 Lilyvale** - Powerlink to replace Transformers 3 & 4, 132/66/11kV with 160MVA units.	$1.3M	Dec-24	Powerlink

* Ergon Energy component (including overheads), associated costings as of October 2022

^ Project scope reduced from previous year's DAPR submission

5.10.5 Joint Planning with other DNSP

There were no investments resulting from joint planning in 2021-22 with Essential Energy, Energex, mining sector service providers or generators in the North Queensland Western Region.

5.10.6 Further Information on Joint Planning

Further information on Joint Planning outcomes requiring a RIT-T led by Powerlink is available on the Powerlink website.[38] Alternatively, Ergon Energy welcomes feedback or enquiries on any of the information presented in this DAPR via email.[39]

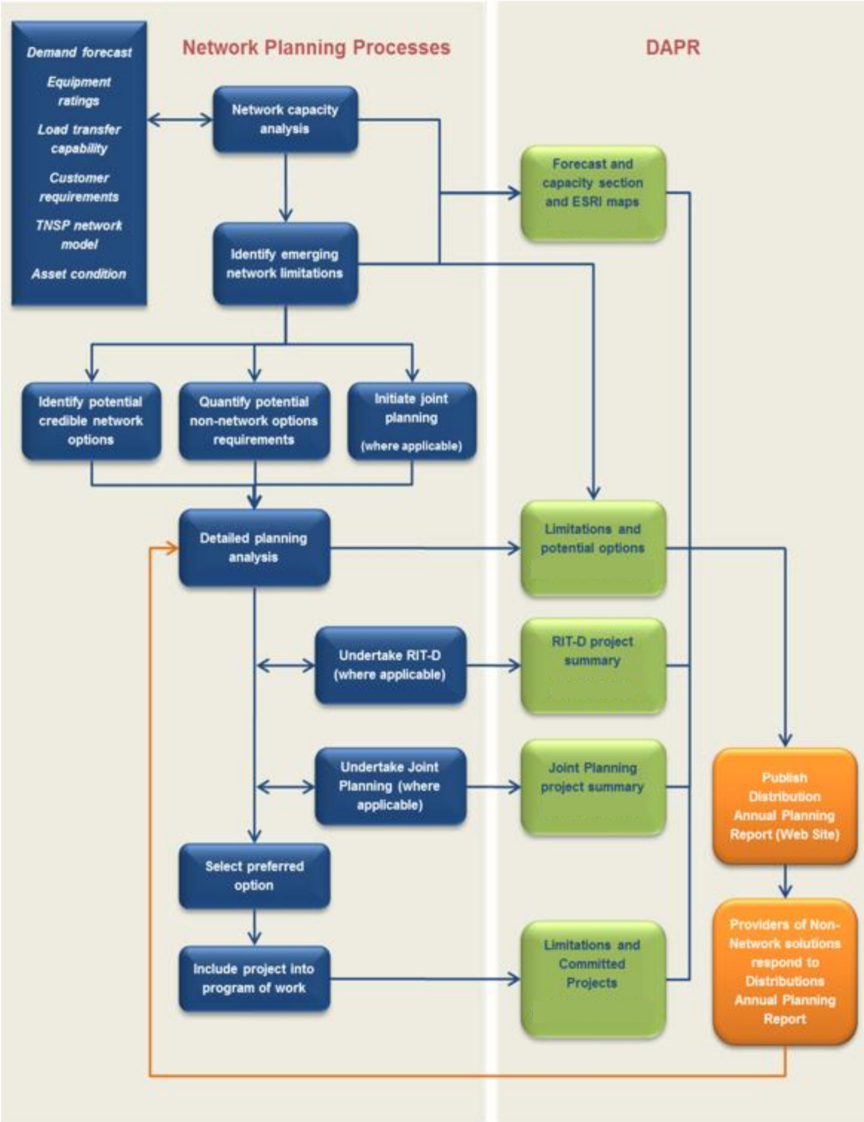
5.11 Network Planning – Assessing System Limitations

The methodology shown in Figure 12 is used in the preparation of the DAPR to report on sub-transmission network and primary distribution feeder limitations and solutions, joint planning projects and RIT-D projects.

[38] Website: https://www.powerlink.com.au/planning-and-consultation

[39] Email: engagement@ergon.com.au

Figure 12: System Limitations Assessing Process



Following the assessment of emerging network limitations, network and non-network options are considered for addressing the prevailing network limitations. These recommendations then become candidate projects for inclusion in the Ergon Energy's Program of Work (PoW) and are allocated with a risk score based on the Ergon Energy's network risk-based assessment framework for prioritisation purposes.

The PoW also undergoes ongoing assessment to determine if targeted area demand management activities can defer or remove the need for particular projects or groups of projects. Remaining projects form the organisation's PoW for the next five years. Detailed planning is also done for each PoW project to complete a RIT-D consultation if required, and obtain project approvals for acquisitions, construction and implementation

5.11.1 Bulk and Zone 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: Detailed Planning Studies and also takes into account Ergon Energy's Plant Rating Guidelines. Ergon Energy has processes in place to assess plant rating capabilities within substations, with a focus on critical assets.

Further analysis is also conducted, as discussed in Section 5.4.2: Safety Net, 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.

5.11.2 Sub-transmission Feeder Analysis Methodology Assumptions

The sub-transmission 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 5.5: Rating Methodology. The outcome of this methodology, as per the planning process discussed in Section 5.2: Planning Methodology, 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.

5.11.3 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 (refer to Appendix D and Appendix E). The year and season (i.e. summer or winter) is recorded where the maximum utilisation exceeded either:
- The three into four (i.e. 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 apparent power - MVA), and the amount of real power (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

Overview of 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 5.10.4: Joint Planning with TNSP. 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.[40]

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. These results are contained in Appendix D. Appendix C outlines the network limitations that have been identified through this process.

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 Joint Planning. 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.

6.1.2 Transmission, Sub-transmission and Distribution Feeder Capacity Limitations

For each transmission, sub-transmission 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 D. Feeder limitations are identified using the simulation models and processes as described in Sections 4.2.2: Transmission Feeder Forecasting Methodology and 5.11.1: Bulk and Zone Substation Analysis Methodology Assumptions. 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, 73 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 C and Appendix D.

6.1.3 Asset Condition Limitations

Ergon Energy 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: Asset Management Overview. These projects can be also found in Appendix C.

6.1.4 Fault Level Limitations

Ergon Energy 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.

6.1.5 Embedded Generating Unit Capacity Limitations

For each distribution feeder, Ergon Energy produce a forecast of the capacity of embedded generating units and a forecast of the minimum demand. Feeder limitations are identified using the simulation models. There are currently no limitations identified on Ergon Energy's distribution feeders over the forward planning period as a result of embedded generating unit capacity.

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

6.2 Summary of Emerging Network Limitations

Appendix C 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, sub-transmission and distribution feeders. Potential credible solutions are provided for limitations with no committed works.

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.

Table 13: Summary of Substation and Feeder Limitations

Asset Type		Limitation Type			
		Capacity and Reliability	Asset Condition	Fault Level	Embedded Generating Unit Capacity
Limitations with Proposed & Committed Solutions	Bulk Substation	1	2	-	-
	Zone Substation	2	14	-	-
	Sub-transmission Feeder	3	0	-	-
	Distribution Feeder	73	0	3	-

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 2025-26.

6.4 Regulatory Investment Test Projects

6.4.1 Regulatory Investment Test Projects - In Progress and Completed

As per the National Electricity Rules clause 5.17.3 and detailed further in Section 2.2 of the RIT-D Application Guidelines (December 2018), a RIT-D proponent is not required to apply the RIT-D for projects where the estimated capital cost of the most expensive potential credible option is less than the RIT-D cost threshold (as varied in accordance with a 'RIT-D cost threshold' determination). The RIT-D cost threshold is $6 million.

The following approved projects shown in Table 14 have credible options greater than the RIT-D cost threshold of $6 million. As such, the Final Project Assessment Reports for these projects are published in the Ergon Energy website[41] under Current Consultations.

Table 14: Regulatory Test Investments - In Progress and Completed

Project Name	RIT-D Forecast/Actual Completion
Kingaroy	Qtr 4 2022
Biloela	Qtr 1 2022
Barcaldine, Longreach, Blackall	Qtr 2 2022
Turkinje	Qtr 1 2023
Rocky South	Qtr 2 2022
Rocky Glenmore	Qtr 2 2022

Further information on current augmentation and replacement RIT-D consultations is available in on the Ergon Energy RiT-D website.

6.4.2 Foreseeable RIT-D Projects

The forward Ergon Energy Program of Work (PoW) includes projects (having credible network options costing more than $6 million) that have the potential to become RIT-D projects. A summary list of such projects that have been identified to address emerging network limitations in the forward planning period is shown in Table 15.

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

Table 15: Foreseeable RIT-D Projects to address long term constraints (>$6M)

Project Name	Expected Investment Test Commencement (Month-Year)
North Street Asset Replacement	Qtr 1 2023
Cranbrook Asset Replacement	Qtr 1 2023
Sarina Transformer and switchboard replacement	Qtr 2 2023
Walkers Substation Refurbishment	Qtr 3 2023
Pandoin – Keppel 66kV Feeder Establishment	Qtr 4 2023
Mount Garnett	Qtr 3 2023

6.4.3 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[42] are available on the Ergon Energy website.

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.

[42] Website: https://www.ergon.com.au/daprmap2022

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 of 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. It can also provide solutions in response to the 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. With rapidly 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 investments. 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.

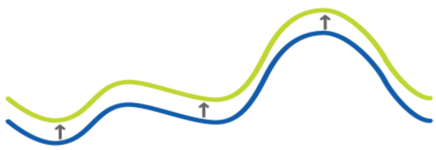
DM must be deployed to match the temporal (i.e. frequency and duration) and spatial (i.e. what level of the network and how many customers are affected) nature of the network constraint. As more DER is connected to our network, the temporal and spatial nature of network constraints will change. As such,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

There are different approaches to DM (as listed in Figure 13):

- Demand Response (DR), including peak shaving, load shifting, valley filling, and flexible load and generation, which is used when required
- Energy efficiency, which results in permanent reduction of demand
- Strategic load growth, which results in permanent increase of demand, beyond 'valley filling'.

These approaches are implemented by customers or DM providers in exchange for financial incentives or as required by a connection standard.

Figure 13: Demand Management Approaches

Description	
Demand Response (DR): Temporary modification of load or generation as required (e.g. in response to signal from network or price signal). There are different types of DR used for wholesale, emergency, network and ancillary services.	
Peak shaving – reducing demand during peak period (e.g. using onsite generation or battery storage). PeakSmart air conditioning is an example of emergency DR aimed at 'peak shaving'.	
Load shifting – shifting demand outside of peak demand periods. Load control tariffs are an example of network DR aimed at 'load shifting'. They can also be used for emergency DR. **Valley filling** – shifting demand into periods of low demand. Time of Use (TOU) tariffs and load control tariffs are examples of network and wholesale DR aimed at 'valley filling'.	
Flexible load and generation – modifying load and generation according to DR signals, published technical constraint envelopes and energy market prices (e.g. batteries could be charged during times of low demand). The Dynamic Customer Connection consultation [43], Dynamic Operating Envelopes (DOE), Vehicle to Grid (V2G) trials and AEMO's recent Wholesale Demand Response Mechanism consultation[44] are potential future examples of wholesale and/or network DR platforms, strategies and approach.	
Energy Efficiency: Permanent reduction of demand, at peak times and non-peak times.	
Energy efficiency – using less electricity to perform the same task.	
Strategic flexible load growth: permanent increase of demand (where network capacity allows), beyond 'valley filling'.	
Strategic flexible load growth – encouraging new loads (where network capacity allows), beyond valley filling. For example, growth in EVs and other modes of electric transport and electrification of industrial processes.	
Typical residential customer load profile Load or generation after demand management Typical solar generation	

For more detailed information concerning our DM plans including strategy, customers and challenges please refer to our [Demand Management Plan (April 2022)](https://www.ergon.com.au/__data/assets/pdf_file/0010/1006669/Demand-Management-Plan-2022-23.pdf)[45] document.

[43] Website: https://www.talkingenergy.com.au/dynamicder
[44] Website: https://aemo.com.au/en/initiatives/trials-and-initiatives/wholesale-demand-response-mechanism
[45] Websource: https://www.ergon.com.au/__data/assets/pdf_file/0010/1006669/Demand-Management-Plan-2022-23.pdf

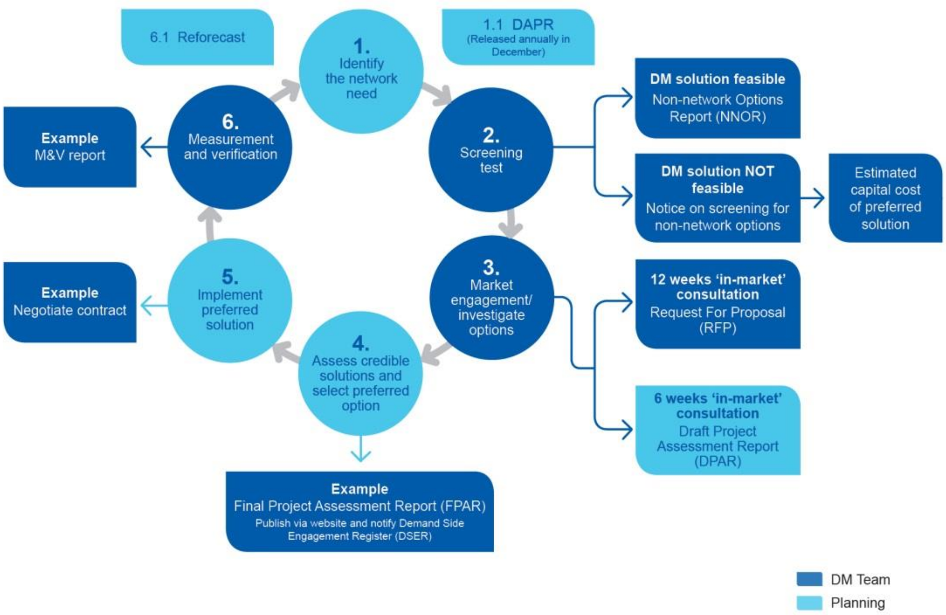
7.2 How Demand Management Integrates into the Planning Process

The planning process, as outlined in Chapter 5: Network Planning Framework and the following sections, include the identification of network constraints and the assessment of DM solutions (refer to Figure 14 and Figure 15). 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 15). For a 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.[46] Where 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 is achieved by inviting proponents to respond to a Request for Proposal (RFP).

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. Figure 14 and Figure 15 present the process of non-network solution assessment process for project expenditures larger and smaller than $6M respectively.[47]

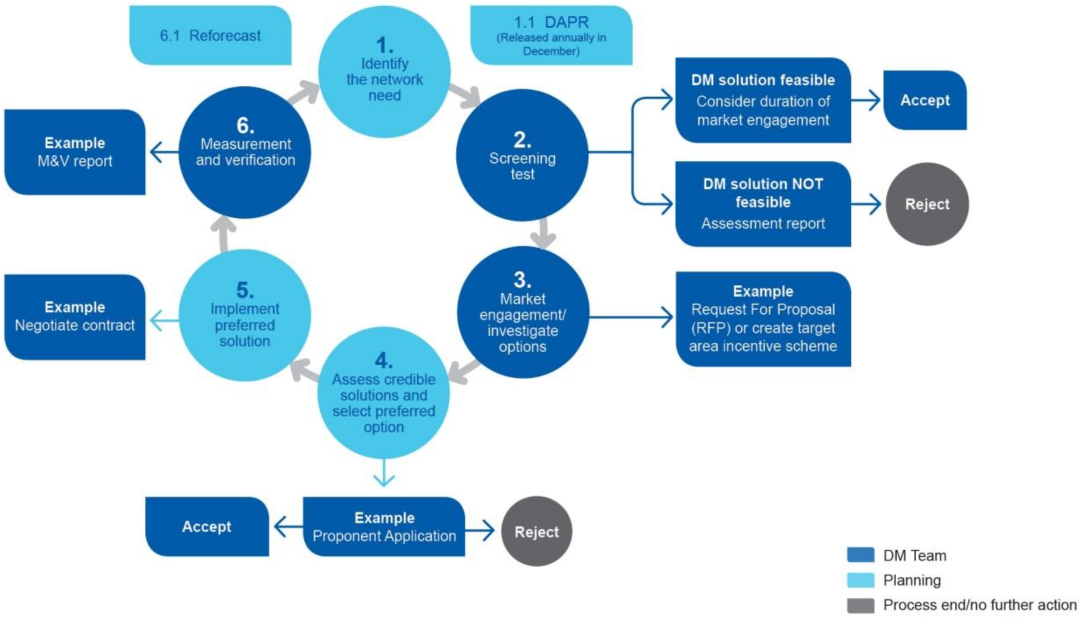
Figure 14: Non-Network Assessment Process for expenditure >$6M (RIT-D)



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

[47] Websource: https://www.ergon.com.au/__data/assets/pdf_file/0020/1005725/Demand-Side-Engagement-Strategy.pdf

Figure 15: 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 solution providers with respect to the supply of credible demand side solutions while addressing system constraints and lowering costs for customers in the network distribution areas. The DSES retains 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
- 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.[48]

[48] Websource: https://www.ergon.com.au/__data/assets/pdf_file/0020/1005725/Demand-Side-Engagement-Strategy.pdf

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

Four key initiatives were delivered by the DM Program in 2021-22:

- Broad Based
- Targeted
- DM Development
- 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 Emergency Management Plan (refer to Section 9.3.1: Summer Preparedness) to minimise interruptions during summer season extreme weather conditions.

Incentives are provided to customers who enrol their PeakSmart air conditioners. Incentives are also given to industry partners who install PeakSmart enabled air conditioners. For more information on PeakSmart visit our website.[49]

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: Summary of Emerging Network Limitations and Appendix C: Network Limitations and Mitigation Strategies). Market engagement is undertaken to seek DM solutions from customers and DM providers. Incentives are offered to customers or DM providers to deliver DM solutions.

In 2021-22, 'in market' engagement for DM solutions continued via a number of Regulatory Investment Test consultations and Distribution Feeder Target Areas across the region. 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, Ergon Energy is managing six Network Support Agreements to provide non-network solutions during the 2021-22 year. Early market engagements were released seeking Request for Proposals (RFP) for 20 distribution feeder limitations in the region.

7.4.3 Demand Management Development

This initiative drives continuous improvement of existing initiatives and enabling future DM capability by:

- Contributing and engaging in a range of market and industry consultations and forums with DM providers, manufacturers, large retailers and aggregators
- Influencing DM related standards and regulations, including the suite of AS/NZS 4755 standards, which outline demand response capabilities for residential appliances. The new AS 4755.2 currently being finalised, is expected to increase adoption of standardised demand response by appliance manufacturers, aggregators and networks, enabling further innovation and software solutions for demand response of appliances
- Embarking on activities to transform the Fringe of Grid. This activity involves modelling to assist in the identification of high cost to serve network areas for Fringe of Grid customers and considers where non-traditional solutions (e.g. standalone power systems) might be suitable and beneficial
- Supporting network tariff reform by leading the development of proposed tariff trials in partnership with two electricity retailers to commence in the first quarter of 2023

[49] Webpage: https://www.ergon.com.au/network/manage-your-energy/cashback-rewards-program/peaksmart-air-conditioning/peaksmart-air-conditioning-rewards

- Coordinating the development of an emergency backstop mechanism, to implement the required system, documentation and process changes to enable the Connection Standards to reflect the backstop requirements (refer to Section 11.9: Minimum System Load – Emergency Backstop Mechanism)
- Working with Electric Vehicle (EV) stakeholders to get greater understanding potential impacts associated with EVs charging on the network and educating and informing the market.

7.4.4 Demand Management Innovation

This initiative supports future energy choices and DM capabilities by reducing 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: Emerging Network Challenges and Opportunities).

A DMIAM annual report[50] is developed each year that summarises current and completed projects.

7.5 Ergon Energy DM Program delivery 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 2022-23[51] is available online.

While striving to meet our long term strategy, our DM portfolio will continue to evolve in response to system and local network needs and as innovations are implemented. Some of the key focus areas of action for 2022-23 will be to undertake a vehicle to grid functionality trial; a capacity tariff trial, in partnership with a Retailer(s); increase network DER hosting capacity through improved network visibility and dynamic operating envelopes; and trialling batteries with customers in remote areas.

Further information on our DM program and the promotion non-network options are detailed on our website.[52]

In the forward planning period, those areas for which we will be seeking non-network solutions will be published via our Regulatory Test Consultation pages[53] on our website.

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 (EG) in the same network area at similar times. These complex network impacts are made more challenging by the speculative nature of these enquires. Furthermore, Ergon Energy is obliged to keep customer information confidential which can result in issues around disclosure to other customers with competing enquiries.

Network information and analysis provided to customers enquiring on the feasibility of an EG project is based

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

[51] Websource: https://www.ergon.com.au/__data/assets/pdf_file/0010/1006669/Demand-Management-Plan-2022-23.pdf

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

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

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 to cater for evolving network changes.

Ergon Energy's current approach is to work with generation proponents to manage this complex issue. Generation proponents are alerted to the risks and formally advised should an alternate project becomes committed. In these instances, customers are encouraged to seek a review of any technical assessments or reports already received to help ascertain their impact.

7.6.1 Connection Enquiries Received

Ergon Energy has established processes which apply to connection enquiries and applications for embedded generators. These processes comply with the requirements of the National Electricity Rules. In 2021-22 the number of connection enquiries received is shown in Table 16. For micro EG 30kW or less (mainly solar PV), there is no connection enquiry phase i.e. all connection requests are processed as applications.

Table 16: Embedded Generation Enquiries

Connection Enquiries	Numbers for 2021-22
Embedded Generator (EG) Connection Enquiries – Micro EG 30kW or less	Not applicable
Embedded Generator Connection Enquiries >30kW Low Voltage	266
Embedded Generator Connection Enquiries >30kW High Voltage	29

7.6.2 Applications to Connect Received

In 2021-22 the number of applications to connect is shown in Table 17.

Table 17: Embedded Generation Applications

Connection Applications	Numbers for 2021-22
Embedded Generator Connection Applications – Micro EG 30kW or less	19,185
Embedded Generator Connection Applications >30kW Low Voltage	116
Embedded Generator Connection Applications >30kW High Voltage	10

7.6.3 Average Time to Complete Connection

In 2021-22 the number of applications received and connected took an average time to complete as shown in Table 18.

Table 18: Embedded Generation Applications – Average Time to Complete (Business Days)

Connection Applications	Average time to complete 2021-22 (Business Days)
Embedded Generator Connection Applications – Micro EG 30kW or less	24
Embedded Generator Connection Applications >30kW Low Voltage	97
Embedded Generator Connection Applications >30kW High Voltage	196

*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 practicable*" 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:

- Achieving its legislated safety duty
- Delivering customer services and network performances to meet the required standards
- Maintaining an efficient and sustainable cost structure.

Policies are used to provide corporate direction and guidance, as well as plans 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, as well as 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, plus
- 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 discussed in Section 2.4: Asset Management Overview. 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 are 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
- Inspection of cable pits
- 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

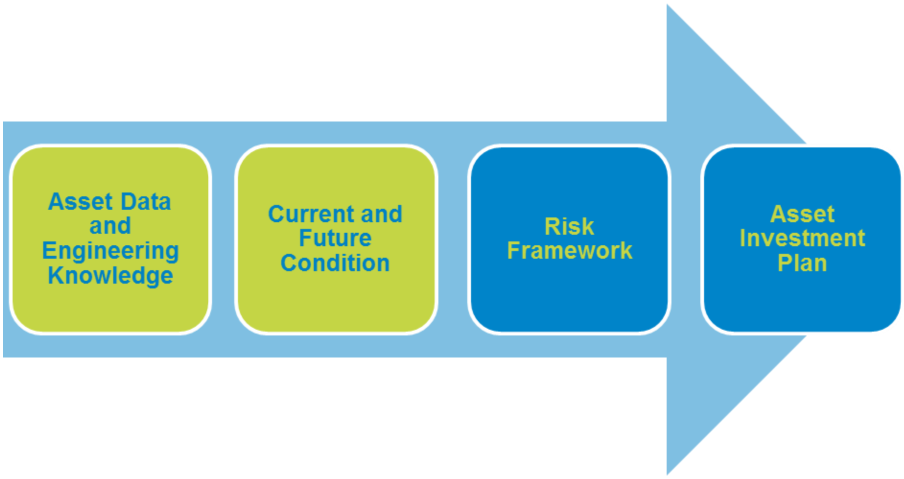
The processes for inspection and routine maintenance of Ergon Energy's assets are well established and constantly reviewed. Ergon Energy uses its asset management system to record and analyse asset condition data collected as a part of these programs. Formal risk assessments are conducted for all asset 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 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 Wood Poles, Overhead Conductors and 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 16 below provides a summary of the process for delivering network asset investment planning condition based risk management.

Figure 16: 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.

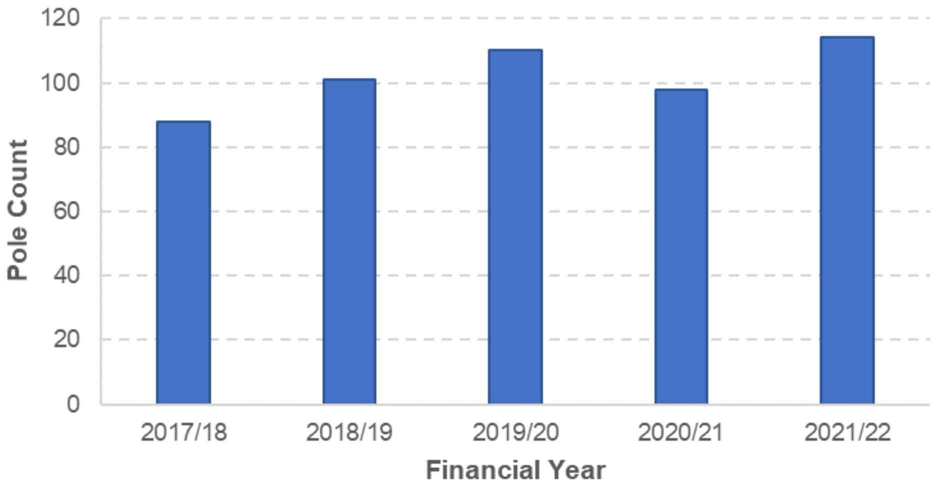
A small volume of poles is also replaced when undertaking reconductoring programs as an efficient means of work delivery. Poles replaced under reconductoring programs will be either identified as approaching end of life based on asset criteria or as a result of mechanical design requirements to support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

Ergon Energy has been addressing a concern, that unassisted pole failure rates are falling below the industry Code of Practice threshold of 99.99% since late 2019. Figure 17 below shows the unassisted pole failure trend over the past 5 years:

Figure 17: Unassisted Pole Failures



To address this issue, changes were made to the pole serviceability algorithms which has resulted in a significant increase to the number of pole replacements.

Ergon Energy has also been utilising a Condition Based Risk Management model for its wood pole assets to better understand future replacement volumes, associated risk and support the decisions around managing this asset class going forward.

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 overall volume of pole top structure replacement is forecast to increase associated with pole and conductor replacement (refer adjacent Sections 8.3.1: Pole and Tower Refurbishment and Replacement and 8.3.3 Overhead Conductor Replacement).

8.3.3 Overhead Conductor Replacement

Overhead conductor condition is difficult to assess in-situ as current visual inspection methods 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) conductors have both 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 Energy 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 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 high HI value represents a more degraded asset, with corresponding high likelihood of failure. In turn, this reflects as a high 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 (LV) 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.

Cable pits are underground access chambers used during underground cable installation, housing cable joints and splitting/routing cables. These concrete cable pits are subject environmental conditions that corrode cable supports and concrete steel reinforcement. Cable joints are also subject to water ingress and heat/overloading deterioration, which may result in an over pressurisation of the chamber causing the pit lid to dislodge.

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 the condition assessment of customer services. Compromised or broken neutral connections can lead to a dangerous rise in potential on the installations earthing system and metallic parts, which can compromise a person's safety. Public shocks are required to be reported to the Electrical Safety Office (ESO) and are monitored against corporate performance targets. This asset class is narrowly performing at an acceptable level against these metrics due to ongoing proactive replacement programs. Ergon Energy has also initiated online monitoring of service integrity using in house LV safety monitors and access to smart meter data where applicable. Table 19 lists the number of Neutral Failures over the previous three years.

Table 19: Number of Ergon Energy's Neutral Failures by Financial Year

Type of Fault	2019-20	2020-21	2021-22
Neutral Faults	181	154	182

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. Replacements are generally undertaken with a modern equivalent unit.

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 for 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. Replacements are generally undertaken with a modern equivalent unit.

8.4 Substation Primary Plant

8.4.1 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 high HI value represents a degraded asset, with corresponding high likelihood of failure. In turn, this reflects as a high likelihood or inability to achieve 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 the 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 exceptionally aged assets.

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.

8.4.2 Circuit Breaker, Reclosers, Switchboard Replacement and Refurbishment

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 high HI value represents a degraded asset, with corresponding high likelihood of failure. In turn, this reflects as a high likelihood or 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.

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. Replacements are generally undertaken with a modern equivalent unit.

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

8.4.3 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. The more degraded an asset becomes; the corresponding higher likelihood of failure is realised. This has adverse implications for network protection as well as staff and public safety. In turn, this reflects as a high likelihood of inability to achieve 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.

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 a large proportion of network having inadequate backup protection.

Currently 25% of the Ergon Energy protection relay fleet are over their expected service life. Approximately one third of these relays that are considered problematic/obsolete types. It is also known that a small number of substations have been identified as lacking SEF (Sensitive Earth Fault) protection.

Due to the potential consequences of relay failure, 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 a 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 Energy 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 maintains a comprehensive vegetation management program to minimise the community and field staff safety hazards and provide 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, as well as
- 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 allows the identification of conductor span clearance issues for all conductor types except service lines.

The Lidar technology has identified point in time clearance issues but has not, as yet 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.

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 operational 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, results 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. Our network planning and security criteria, when combined with reliability targets, underpin 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 defines the reliability performance levels required of our network, including both planned and unplanned outages, which guides us to improve reliability performance levels. 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 (DA) 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 DA, exceedance of the same MSS limit in three consecutive financial years is considered a 'systemic failure' and constitutes a breach. The MSS limits for the regulatory control period in Schedule 2 of the DA remain flat up to 2025.

9.1.2 Reliability Performance in 2021-22

The normalised results in Table 20 highlight favourable performance against the MSS for three of six of Ergon Energy's network performance measures in 2021-22.

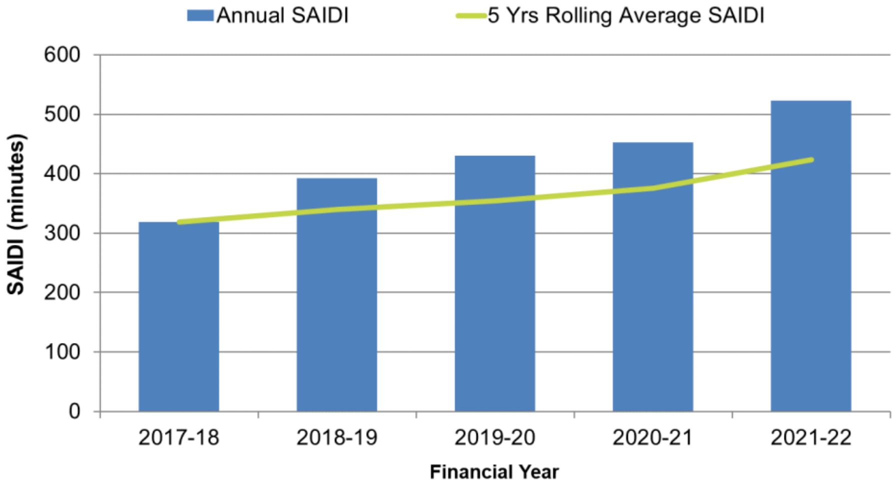
Table 20: Annual Normalised Reliability Performance Compared to MSS Limits

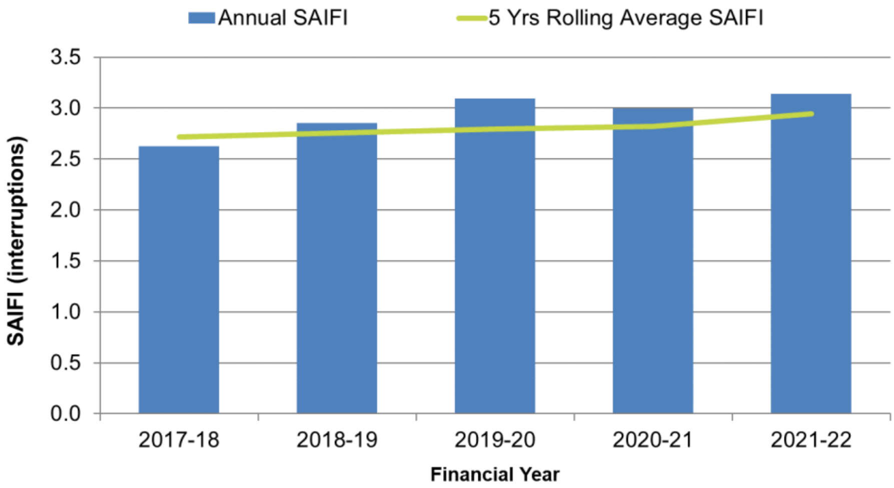
	Feeder Category	2020-21 Actual	2021-22 Actual	2021-25* MSS Limits
SAIDI (mins)	Urban	236.29	243.54	149
	Short Rural	460.65	522.75	424
	Long Rural	1048.29	1343.58	964
SAIFI	Urban	1.624	1.684	1.98
	Short Rural	3.196	3.304	3.95
	Long Rural	5.978	6.539	7.40

* A single MSS Limit is set for each feeder category for each Regulatory Control Period

In 2021-22, Ergon Energy reliability of supply was favourable to the DA's MSS limits for the SAIFI performance measures for all three Urban, Short Rural, and Long Rural networks. SAIDI for the three feeder categories were unfavourable to the MSS limits due to increased safety driven Program of Works (PoW) since 2018. Additionally, the Long Rural network was also highly influenced by High Voltage (HV) asset failures (e.g. cross-arm and pole 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: Annual Network SAIDI and SAIFI Performance with Five-year Rolling Average Trend





9.1.3 Reliability Compliance Processes

Ergon Energy has set its internal performance targets broken down between planned and unplanned targets. Planned outage targets provide provision for safety related programs and repairs, maintenance, refurbishment, customer connections and the corporate initiated works. 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. There is, however, no capex allocated specifically to achieve these internal targets. The internal targets are used as the reference for tracking performance during a year and to put necessary operational measures in place where required and feasible.

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. Long Rural feeders start at 200kms in length and traverse rugged country, for which finding the fault and repairing within a reasonable time is challenging. Hence, meeting the MSS SAIDI limit remains a challenge for this feeder category. 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 DA, Ergon Energy also continues to deliver its Worst Performing Feeder improvement program, detailed in Section 9.5: Worst Performing Distribution Feeders. 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 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 2021-22 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 recent RIN submissions can be found on the AER's website.[54]

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

9.2.1 STPIS Results

The normalised results in Table 21 highlight a favourable year end performance against the STPIS targets, for two of six of Ergon Energy's network performance measures in 2021-22. 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 21: Normalised Reliability Performance Compared to STPIS Targets

	Feeder Category	2020-21 Actual	2021-22 Actual	2021-25* STPIS Targets
Unplanned SAIDI (mins)	Urban	113.25	130.08	117.04
	Short Rural	265.85	305.16	280.80
	Long Rural	706.59	907.28	773.05
Unplanned SAIFI	Urban	1.114	1.242	1.195
	Short Rural	2.398	2.477	2.527
	Long Rural	4.547	4.825	5.078

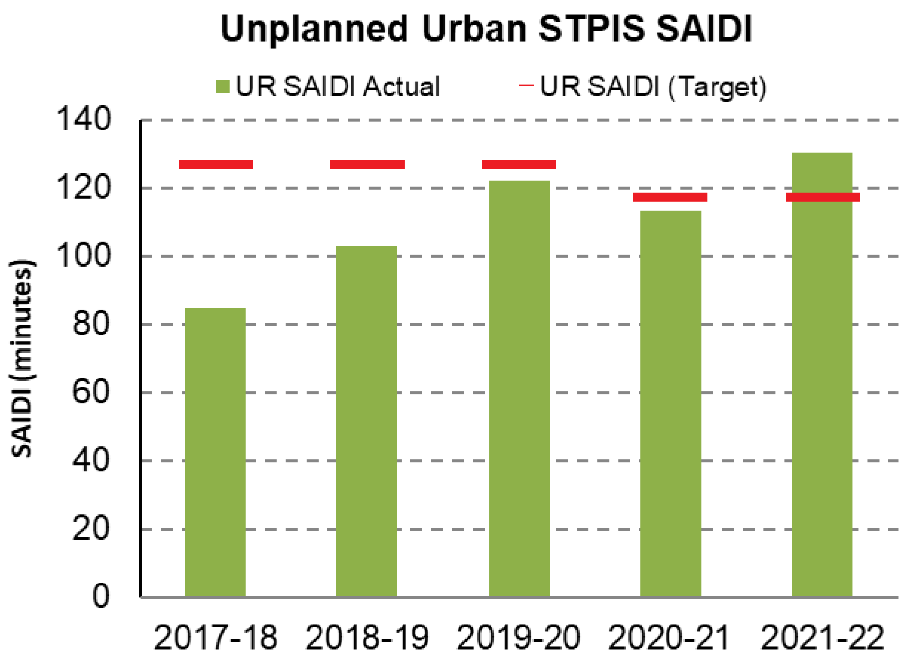
*A single STPIS Limit is set for each feeder category for each Regulatory Control Period

In 2021-22, Ergon Energy reliability of supply was favourable to the Short Rural and Long Rural SAIFI measures for STPIS. Urban SAIDI and SAIFI were unfavourable to the STPIS target primarily due to an increase in emergency maintenance. Short Rural SAIDI was unfavourable to the STPIS target primarily due to an increase in high voltage conductor failures. Long Rural SAIDI was unfavourable to the STPIS target primarily due to an increase in high voltage asset failures. Increases in Short Rural and Long Rural SAIDI in 2021-22 coincided with an increase in outages occurring during wet and storm conditions.

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 3.3% and 17.4% respectively.

Figure 19 to Figure 21 depict the STPIS targets and results for the 2017-22 period. The actuals are the normalised values (i.e. exclusions are applied as per Clause 3.3 of the STPIS).

Figure 19: STPIS Targets and Results for Unplanned Urban



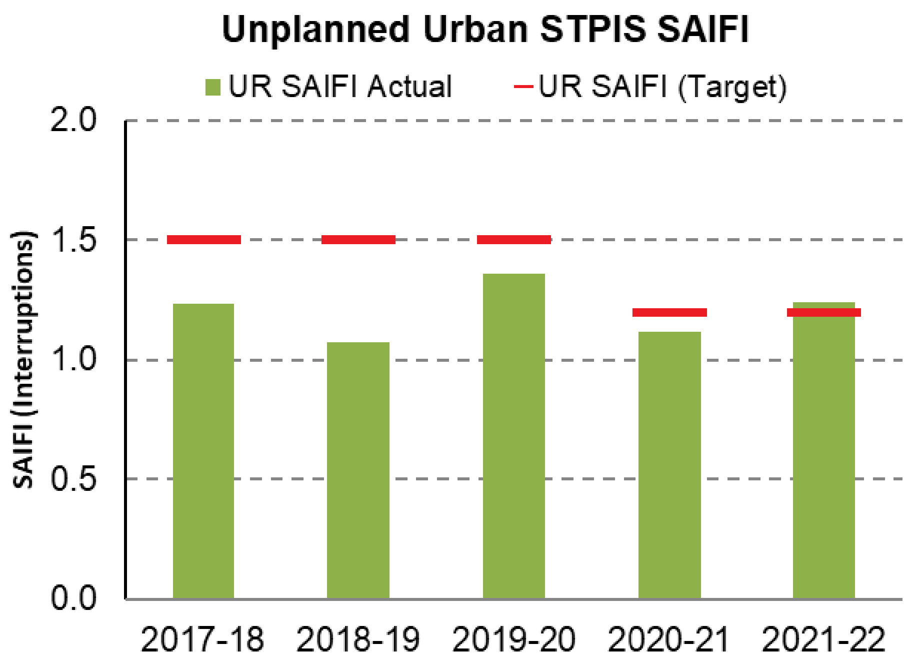


Figure 20: STPIS Targets and Results for Short Rural

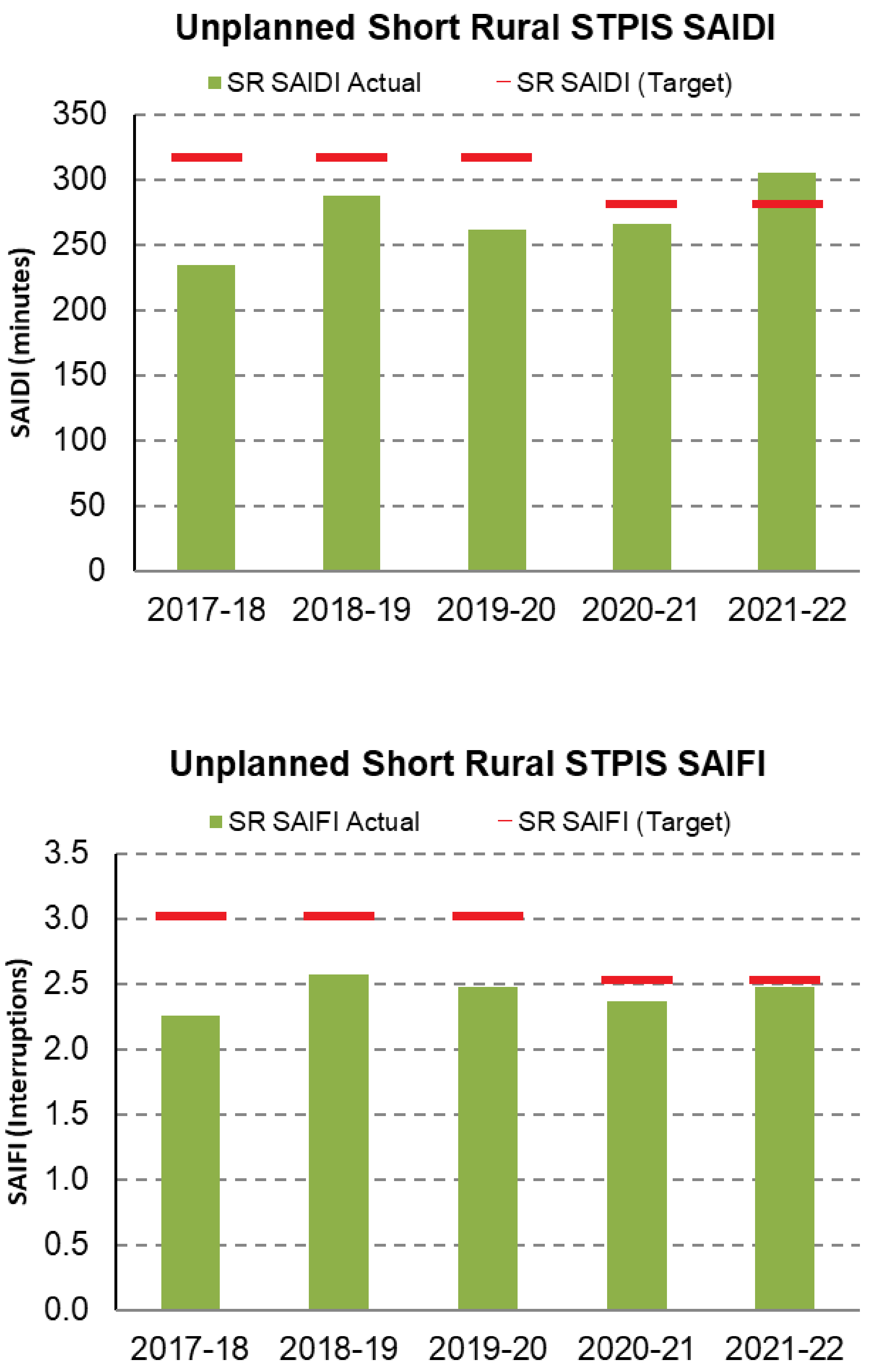
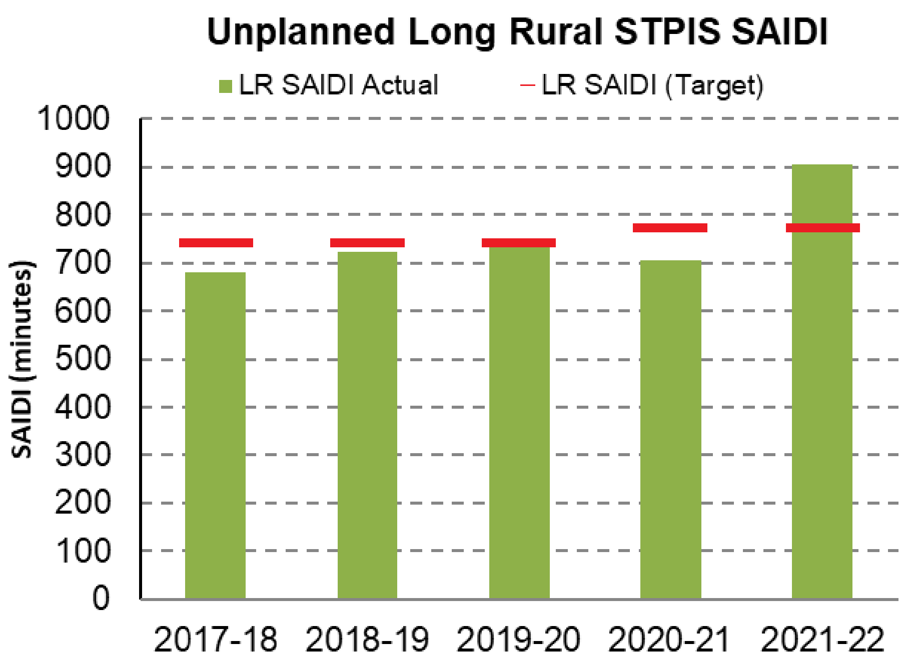
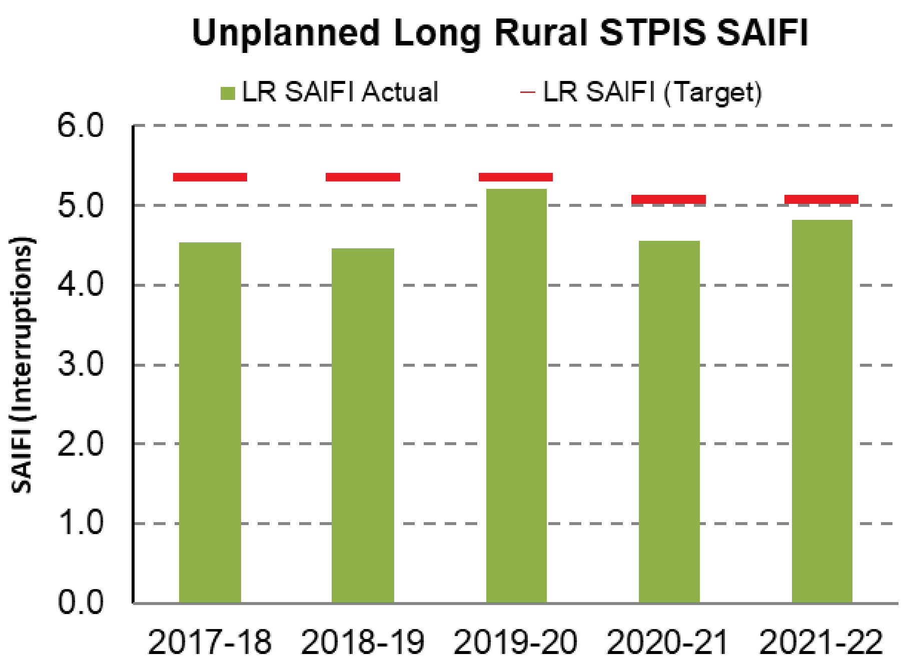


Figure 21: STPIS Targets and Results for Long Rural





9.3 High Impact Weather Events

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.

Ergon Energy plans for the occurrence of extreme weather events and has developed the following plans which are also available at our website:[55]

- Natural Hazards Management Plan (expansion of the previous Summer Preparedness Plan)
- Bushfire Risk Management Plan.

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, response and recovery.

Ergon Energy regularly conducts detailed reviews of all escalated response events to ensure it confirms the effectiveness of processes and identifies opportunities to improve the safe and timely restoration for the community.

To better enable our network to cope with emergency events, a number of preparation exercises are carried out throughout the year in preparation for the summer storm season, bushfire and floods as outlined in detailed in the sub-sections below.

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.

9.3.1 Summer Preparedness

Ergon Energy conducts annual preparations prior to each summer storm season to provide its customers in North Queensland with a reliable network that minimises interruptions during extreme weather conditions. Where disruptions occur, we plan to keep the community fully informed and respond as quickly as possible to restore supply safely. Preparations include the review of response programs and processes, resourcing and ongoing network related capital and operating works prior to summer to achieve a secure and reliable network. Comprehensive post implementation reviews are also 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.

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

Key activities undertaken in preparation for severe weather events include but is not limited to:

- Construction of new equipment to a standard that provides increased resilience and reduces the impact severe weather events have on the continuity of supply to our customer
- Maintain a significant mobile generation and mobile substation fleet that supports the restoration of supply following severe weather events
- Ensure an appropriate inventory of critical spare equipment is on hand at strategic locations to support rebuild and restoration efforts
- Routine inspection and maintenance of vegetation in proximity to overhead powerlines that may contribute to failures of the asset and the creation of a safety risk to the community
- Routine maintenance and inspection of substation equipment, overhead powerlines and poles, inspection of waterway crossings and a range of other network assets
- Prior to the annual storm season critical overhead powerlines are aerially inspected for any potential conditional defects that may contribute to the risk of failure
- Interagency relationships and cooperation are maintained through representation and collaboration with both the State and Local Disaster Management Committees/Centres across the state
- Formalise relationships with other Distribution Entities in support of response and recovery efforts during and post severe weather events through a Memorandum of Understanding
- Implementation of a highly trained expert Emergency Management Team that provide central coordination and management of the response and recovery following a severe weather event
- Training in the preparation of formal restoration plans that provides prioritised focus on restoring services to critical community infrastructure such as hospitals, aged care facilities, evacuation centres, shopping centres, fuel stations, sewerage and water treatment plants, major traffic intersections, etc.
- Community Engagement in preparation for and during the post event recovery is a strong focus and is provided through a combination of our customer contact centres, social and mainstream media platforms and our community outreach teams that are deployed into the affected communities.

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 carries out LiDAR inspection of the entire network each year. This information identifies defects and is contributing to reduced maintenance and planning costs, with increased safety and reliability of supply for our customers and communities. The data captured is processed to enable measurement of the network and clearances to surrounding objects such as buildings, terrain and vegetation.

In addition to these specific activities, much of Ergon Energy’s annual Program of Work (PoW) 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 Energex and interstate DNSPs.

9.3.2 Bushfire Management

Ergon Energy reviews and updates the Bushfire Management Plan annually. The plan is published in August each year and contains a list of programs and specific initiatives to reduce bushfire risks impacted by the network. Ergon Energy has on-going asset replacement and improvement in high bushfire risk areas. Ergon Energy also reports and investigates suspected asset related bushfires.

Key activities undertaken in preparation for bushfire events include but is not limited to:

- Mapping through our Geospatial Information System (GIS) to identify the network equipment installed in bushfire hazard areas
- Engaging a dedicated weather service provider to provide specialist weather advice on forecast weather patterns including heatwaves, storms and lightning levels which is overlayed with Sentinel satellite fire detection information and network asset locational information to inform event management team
- Maintain a significant mobile generation and mobile substation fleet that supports the restoration of supply following significant network damage resulting from bushfire events
- Implementing a vegetation management strategy to reduce fuel load in proximity to powerline poles and the potential for vegetation contact with overhead powerlines
- Routine maintenance and inspection of overhead powerlines and poles and a range of other network assets. This program extends to privately owned powerline assets where they make connection to the utility assets
- Interagency relationships and cooperation are maintained through representation and collaboration with both the State and Local Disaster and Bushfire Management Committees across the state
- Exploration of bushfire risk modelling by industry recognised academic experts to improve the identification and management of the ignition and consequential damage risk to assets
- Conservative operational work practice during periods of heightened bushfire danger including but not limited to:
    - Limited offroad use of motor vehicles and machinery that may trigger an ignition event from the high operating temperatures of exhaust systems
    - Special consideration when using equipment such as generators, chainsaws, brush cutters, metal cutting or welding to determine fire start risk and the appropriate controls to reduce that ignition risk.
- Capital investment to reduce the likelihood of fire starts from electrical assets and to reduce the risk of network asset damage from external fires. Examples of the range of initiatives undertaken include but is not limited to:
    - Line refurbishment programs– such as replacement of aged (or corroded) conductor, installation of insulated/covered conductors
    - Lines defect remediation – repair and remediation of defects identified through asset inspection, such as cross-arms, insulators tie wires etc.
    - Programs for condemned pole replacement
    - Customer Service line replacement programs
    - The transition to a range of updated equipment standards as new equipment is installed
    - Trialling and development of a range of fire resilient pole materials/technologies (such as composite fibre) along with the ongoing use of concrete and steel rebutted poles in bushfire prone areas
    - Ongoing research and development and trials of fire-resistant coatings such as fireproof paint and fireproof wraps for wood poles in fire prone areas

- Ongoing research into advanced protection systems that limit the potential for network equipment failures resulting in a bushfire ignition.

9.3.3 Flood Resilience

Our flood 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 2021-22 season Ergon Energy experienced two significant weather events across the network resulting in flooding in the Fraser Burnett region. Key activities undertaken by Ergon Energy in preparation for flooding events include but is not limited to:

- Mapping through our Geospatial Information System to identify the network equipment installed in flood prone areas
- Modernisation of flood modelling through Geospatial Information Systems as a step toward a dynamic risk assessment and agile response approach
- Engaging a dedicated weather service provider to provide specialist weather advice on forecast weather patterns likely to cause flooding
- Interagency relationships and cooperation are maintained through representation and collaboration with Disaster Management Committees across the state
- Standardisation of ground mounted equipment such as switches, distribution substations and pillars enable efficient replacement when inundation causes irreparable damage
- Memoranda of Understanding with other agencies including local councils along with weather service providers like the Bureau of Meteorology providing information on river and creek levels along with historical inundation contouring to inform local flood management plans
- Development and annual version review of local flood management plans identify the electrical equipment and customer installations at risk of inundation and allow proactive precautionary isolation of electrical supply to manage inundation risk
- Capital investment to increase resilience and reduce the inundation risk to electrical assets are made through an annual program of work that include but is not limited to:
  - Relocation of ground mount equipment in flood prone areas
  - Installation of additional switching points on the network to reduce the impact of preventative isolation on the continuity of supply to customers
  - Providing additional drainage in large substations where groundwater presents an increased risk to electrical equipment
  - Developing flood barricades for large substations where overland water presents a risk of inundation within the control buildings.
- Standardisation of the post flood asset condition assessment and maintenance repair activities on inundated equipment to expediate the return to service where repair is possible
- Construction new equipment is to a higher standard to increase resilience and reduce the impact floods events have on the continuity of supply to our customers
- Maintain a significant mobile generation and mobile substation fleet that supports the restoration of supply following severe weather events
- Ensure an appropriate inventory of critical spare equipment is on hand at strategic locations to support rebuild and restoration efforts
- Standardisation of installed equipment that supports an efficient retrofit replacement for assets irreparably damaged as a result of inundation.

9.4 Guaranteed Service Levels

Section 2.3 of the Electricity Distribution Network Code (EDNC)[56] 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 22. 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 22: 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 2.3.7	**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

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

9.4.1 Automated 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 23 shows the number of claims processed to date and paid in 2020-21.

Table 23: Number of Claims Processed to Date and Paid in 2020-21

GSL	Number Paid	Amount Paid
Wrongful disconnections	23	$3,565
Connection not provided by the agreed date	5	$992
Reconnection not provided within the required time	25	$3,224
Failure to attend appointments on time	76	$4,712
Notice of a planned interruption to supply not given	644	$23,224
Interruption duration GSL	6,050	$750,200
Interruption frequency GSL	0	$0
TOTAL	**11,955**	**$1,619,940**

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 distribution 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***
>
> *11.2 (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 2022, has been provided in supporting documentation.[57] Ergon Energy's worst performing distribution feeder assessment for 2021-22 is summarised below:

- 7% of Ergon Energy's distribution feeders meet the worst performing feeder improvement program criteria as of June 2022 (95 distribution feeders in total – 6 Urban, 61 Short Rural and 28 Long Rural)
- The 95 distribution feeders meeting the worst performing feeder improvement program criteria supply 1.6% of the Ergon Energy's total number of customers
- 68 of the distribution feeders have carried over from the list from the 2020-21 reporting period.

Table 24 below shows the comparative three-year average SAIDI/SAIFI for the total of planned and unplanned outages for the reported worst performing distribution feeders across the feeder categories for 2021-22. Additional information on this subject can be found in Appendix F: Worst Performing Distribution Feeders.

Table 24: 2021-22 Worst Performing Distribution Feeder List – Current Performance (2021-22)

Feeder	3 Year Average Feeder SAIDI (mins)	3 Year Average Feeder SAIFI (int.)
Category	Average	Average
Urban	2,725	9.44
Short Rural	3,790	9.34
Long Rural	3,570	10.69

9.5.1 Details of Worst Performing Distribution Feeders from 2021-22

Urban feeders:

- The Urban worst performing distribution feeder list consists of six feeders. From the total of six feeders, two met only the worst performing distribution feeder SAIDI criteria, two met only the SAIFI criteria and two met both the SAIDI and SAIFI criteria.

Short Rural feeders:

- The Short Rural worst performing distribution feeder list consists of 61 feeders. From the total of 61 feeders, 22 met only the worst performing distribution feeder SAIDI criteria, 26 met only the SAIFI criteria and 13 met both the SAIDI and SAIFI criteria.

Long Rural feeders:

- The Long Rural worst performing distribution feeder list consists of 28 feeders. From the total of 28 feeders 27 met only the worst performing distribution feeder SAIDI criteria and one met both the SAIDI and SAIFI criteria.

9.5.2 Review of Worst Performing Distribution Feeders from 2020-21

- 67% of the 85 worst performing feeders identified in 2020-21 saw an improvement in their annual SAIDI as of June 2022. Five of those feeders are now favourable to the June 2022 MSS SAIDI limits
- 67% of the 85 worst performing feeders identified in 2020-21 saw an improvement in their annual SAIFI as of June 2022. 16 of those feeders are now favourable to the June 2022 MSS SAIFI limits.

[57] Web source: https://www.ergon.com.au/__data/assets/excel_doc/0019/1081711/Worst-Performing-Distribution-Feeders-2022.xlsx

During the 2021-22 period Ergon Energy completed detailed engineering reviews for six worst performing distribution feeders. The feeder reviews included detailed analysis of different type of outages (planned and unplanned) and outage triggers and contributing factors. The contributions from different segments of the electricity supply chain (sub-transmission, 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. Six feeder reliability improvement projects have been raised following the feeder reviews.

9.5.3 Worst Performing Feeder Improvement Program

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.

The low capital investment options 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. Ergon Energy will continue reviews of its worst performing distribution feeders during 2022-23.

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 training and availability, 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
    - Optimising management of planned works.
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) such as pole guards, conductor configuration and spacing, and line markers for worst performing distribution feeders.
3. Augmentation and refurbishment through capex by:
    - Refurbishing or replacing conditioned assets (for both powerlines and substations).

9.6 Safety Net Target Performance

In accordance with Clause 10 of the Distribution Authority No. D01/99, Ergon Energy will ensure, to the extent reasonably practicable, that we achieve safety net compliance and continue to monitor unplanned outages on our sub transmission network and report on our performance against Safety Net Targets.

As per Clause 10.1, the purpose of the service 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.

There were no events exceeding the service Safety Net targets in the 2021-22 period, where the customer safety targets were breached.

9.7 Emergency Frequency Control Schemes and Protection Systems

Ergon Energy has been transitioning from centralised under frequency schemes to discrete under frequency schemes for several years. Decentralisation is expected to continue as protection relays are replaced by devices having under frequency capability.

Ergon Energy has a portion of:

- Distribution feeders (11 and 22kV) with dedicated Under Frequency Load Shedding (UFLS) installed
- Sub-transmission schemes (66 and 110kV)
- Schemes at 33kV covering both distribution and sub-transmission feeders.

Devices installed on distribution feeders have remote control and can be enabled and disabled via SCADA. Remote enablement/disablement can be configured to operate automatically, however this control is limited at high speed due to the power flow supervision being remote to the substation. Future installations are expected to have power supervision in the decentralised under frequency relay to ensure that power supervision can operate at high speed.

UFLS protection schemes are the only wide area protection or control scheme that are expected to have capability of leading to cascading outages or major supply disruptions.

Chapter 10

Power Quality

10.1 Quality of Supply Process

10.2 Customer Experience

10.3 Power Quality Supply Standards, Code Standards and Guidelines

10.4 Power Quality Performance 2021-22

10.5 Power Quality Ongoing Challenges and Corrective Actions

10. Power Quality

The quality of network power affects both the customer experience, and the efficiency and stability of the network. This section covers two related but distinct areas, 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 the quality of their supply. PQ is the measure of compliance of measured system wide network conditions with defined parameter limits.

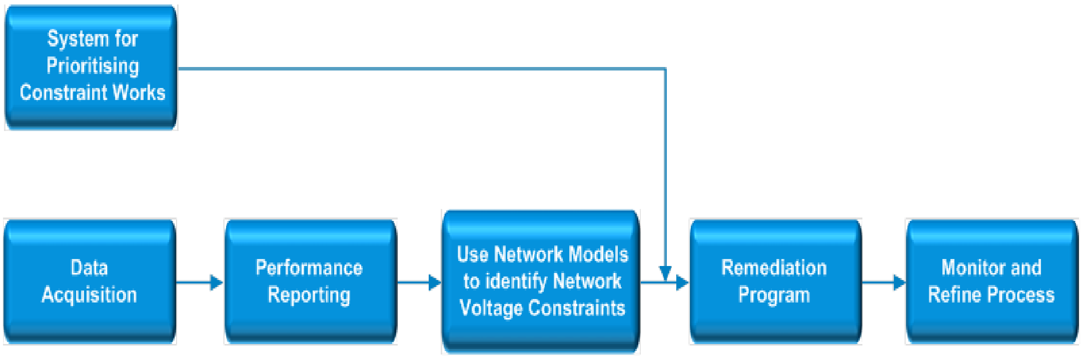
10.1 Quality of Supply Process

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

Due to the complexity of the network and the large number of sites involved, the management of specific quality of supply issues, 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



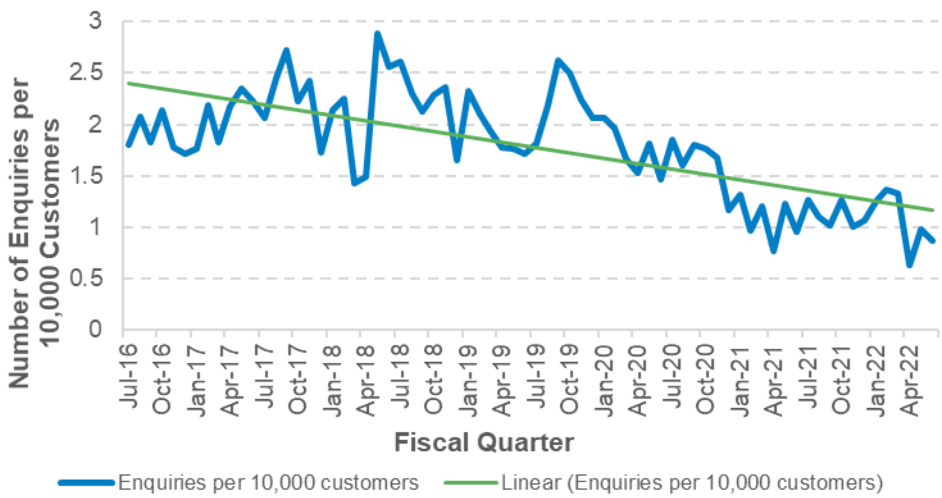
Ergon Energy has developed a series of semi-automated reports from the PQ Data Warehouse to identify and prioritise resolution of power quality issues. These reports enable the large volume of power quality time series data captured from the monitoring devices to be more easily analysed, with non-compliances highlighted from possible causes, such as equipment failure and network topology. 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 Subject Matter Experts (SMEs) daily for action. PQ SMEs then work with customer service and Operations teams to rectify issues before they impact customers equipment and/or safety.

10.2 Customer Experience

The QoS experienced by customers is measured by the number of QoS enquiries 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. There has been a continued decrease over the last 5 years with Quality of Supply enquiries.

Figure 23: Quality of Supply Enquiries per 10,000 Customers per Month



QoS enquiries are selected from categories on initial contact by the customer 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 39%, 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). An 8% decrease in solar PV enquires has been complemented by a 10% increase in low voltage enquiries. The comparison to the previous five years is shown in Figure 24.

Figure 24: Quality of Supply Enquiries by Category 2021-22

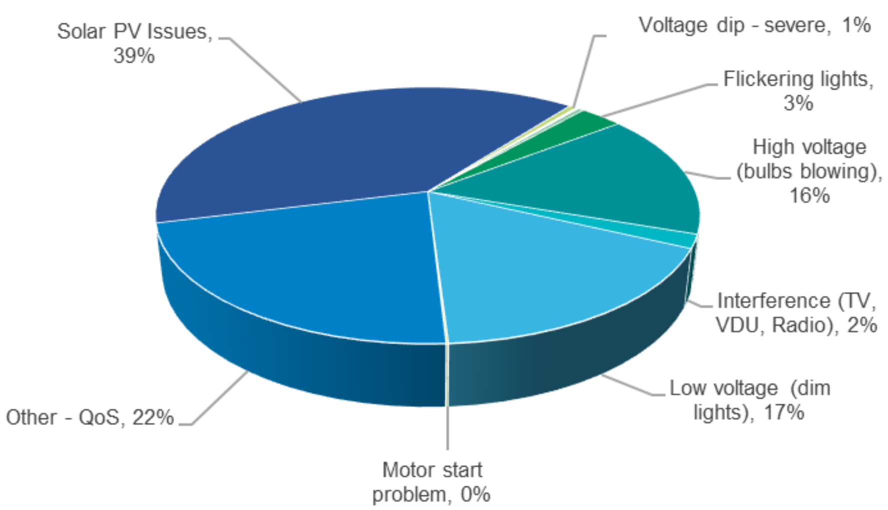
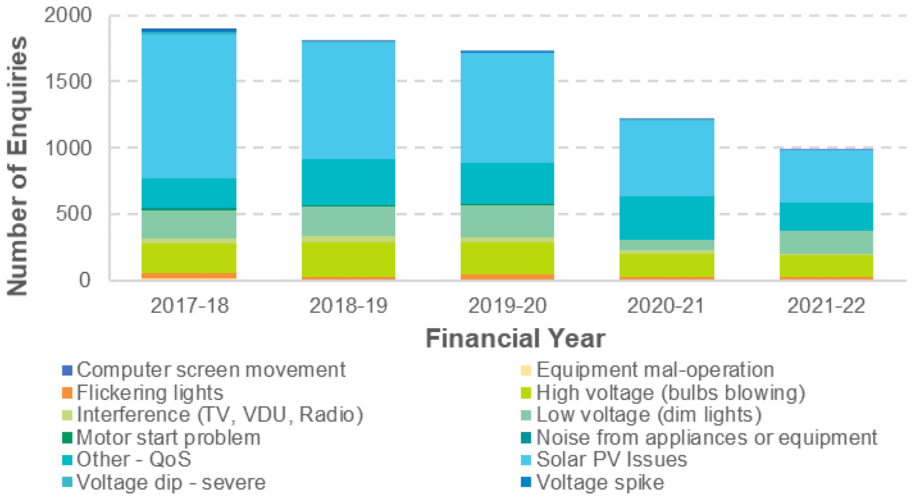


Figure 25: Quality of Supply Enquiries by Category by Year

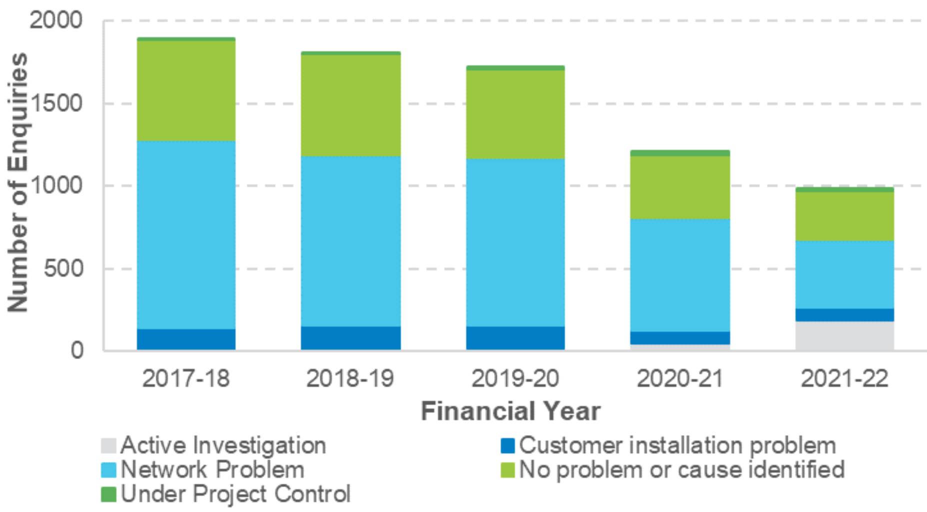


The number of QoS enquiries received in 2021-22 decreased by 18.5% when compared to the previous year from 1,213 to 987 enquiries. The ongoing connection of solar PV systems has continued to be the leading cause for customers to make a QoS enquiry.

The causes at enquiry close out for QoS enquiries is shown in Figure 26. The data shows that 41.5% of the enquiries to date were due to a network issue, no fault found 30.1% and the fault was on the customers side of the connection, 7.7%. High Voltage (HV), Low Voltage (LV) and Solar Enquiries make up majority of the customer enquiries. Network solutions range from low cost solutions of balancing the LV Network and changing the tap position on the transformer, to more costly solutions of upgrading the customers service conductors and upgrading the LV network conductors to accommodate the extra solar generation can occur.

Some LV networks are reaching greater than 70% penetration of solar PV, calculated against the distribution transformer capacity.

Figure 26: Quality of Supply Enquiries by Cause 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 was amended to change the Low Voltage (LV) requirements from 415/240 volts +/-6% to 400/230V +10%/-6% to harmonise with Australian Standard 61000.3.100 and align with majority of other Australian states.

Some of the relevant requirements under the Regulations/Rules are listed below and further defined in Table 25 to Table 28, 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 25: 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%

Table 26: 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 to 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 27: 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 28: 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 Network Performance Standard, Harmonic Allocation Guideline and the Standard for Transmission and Distribution Planning are joint working documents with Energex that describe the planning requirements including power quality. These guidelines apply to all supply and distribution planning activities associated with the network.

10.4 Power Quality Performance 2021-22

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.

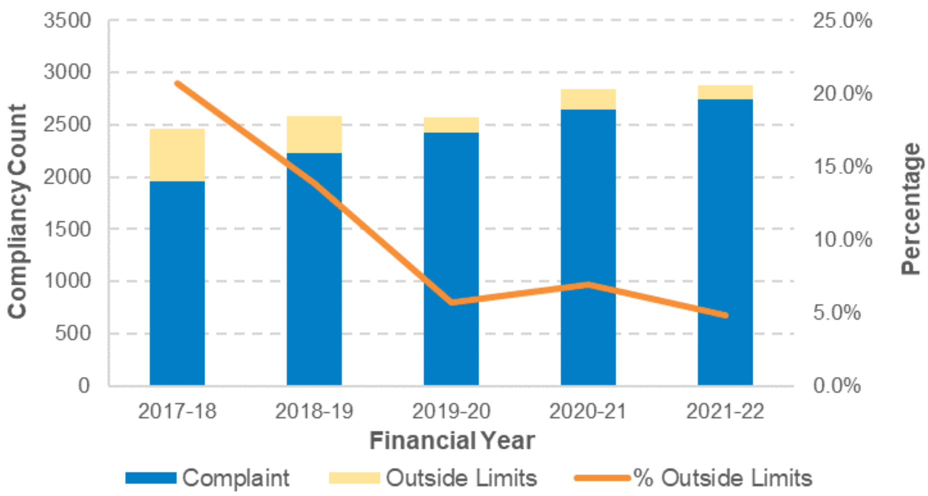
Ergon Energy started to install network monitors in 2009 and currently has in excess of 3050 PQ monitors on distribution transformers throughout the network that monitor and record the network PQ performance. These monitors are remotely monitored and provide an insight into power quality performance at the junction of the Medium Voltage (MV) and LV networks. Each of these monitors contributes to provide 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 resolution. 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 4.83% for 2021-22. This means 4.83% of sites recorded an exceedance of the upper limit for more than 1% of the time based on 10 minute averages. This is a slight improvement from the 2021-22 year when there were 5.4% of sites with overvoltage recorded. 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. 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. This is evident with the positive impact of the roll out of 230 volts 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 currently at the terminals of the distribution transformers, that is the start of the LV runs. Due to the diversity of the customers loads and solar along the LV distribution network, some monitors may show the voltages are within limits at the Distribution transformer, while the voltages at the end of the LV run during peak load during the summer evenings maybe below limits. The same occurs for peak solar generation periods and low load periods, the voltages maybe above standard limits. Ergon Energy recognises that further PQ monitoring is required at the end LV runs. 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.

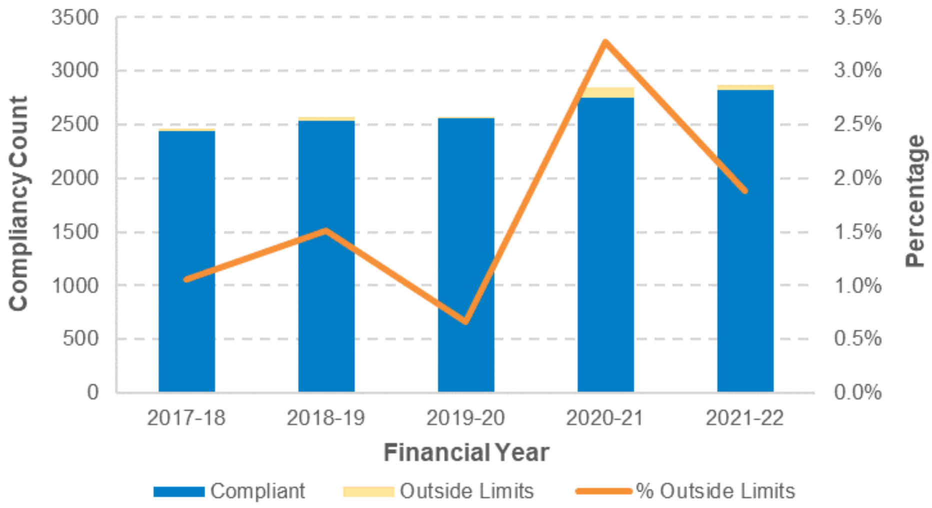
Figure 27: Number of Monitored Sites Reporting Overvoltage



10.4.3 Steady State Voltage Regulation – Undervoltage

The 230V standard sees the lower limit for Low Voltage (LV) move to 216.2V. The number of monitored sites recording undervoltage issues outside of the regulatory limit of 216.2V was 1.88% for 2021-22. This means 1.88% 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 undervoltage conditions for the last five years. There has been a decrease in the number of sites experiencing under voltage issues.

Figure 28: Number of Monitored Sites Reporting Undervoltage

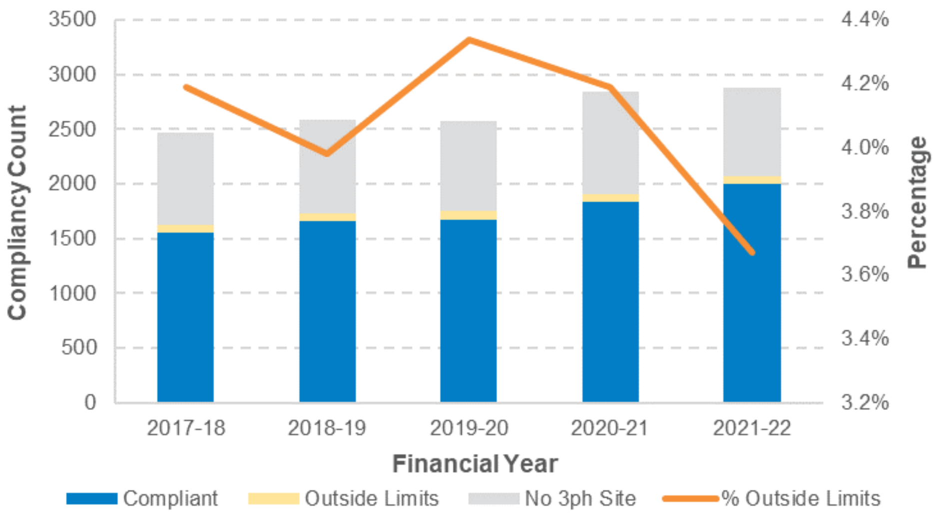


10.4.4 Voltage Unbalance

Data from the monitored 3-phase sites shows that 3.67% of these sites were outside of the required unbalance standard for LV of 2.5% during 2021-22. Figure 29 shows the number of sites that have recorded unbalanced conditions for the past five years.

Typically, unbalance is seen on the 3 phase sections of rural feeders where there are SWER networks and a large number of single phase customers in the associated downstream feeder. Due to predominantly radial nature of Ergon Energy's network and the high number of single phase transformers, Ergon Energy has a higher number of PQ 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.

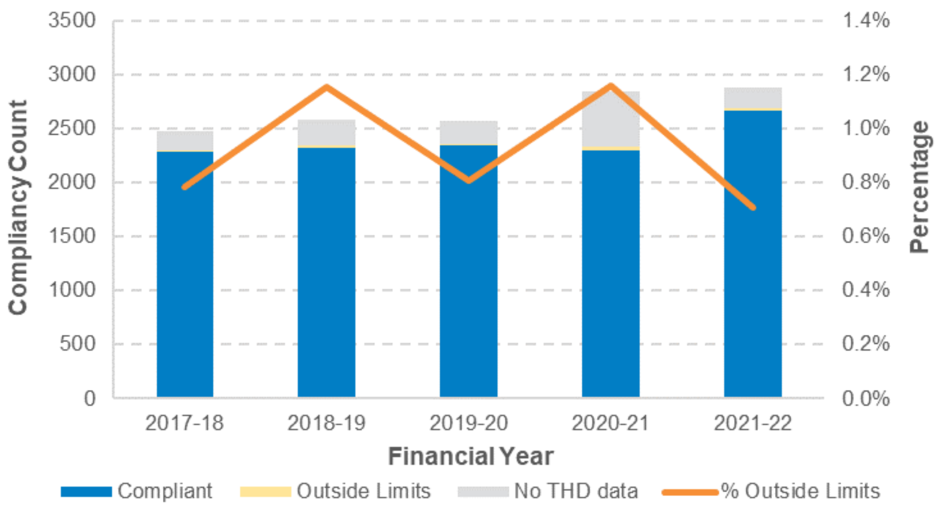
Figure 29: Number of Monitored Sites Reporting Voltage Unbalance



10.4.5 Harmonics Distortion

Harmonics are a measure of the impurity of the voltage and are recorded as Total Harmonic Distortion (THD) representing the summation all harmonics levels from the second to the fiftieth harmonic. Not all monitored sites are capable of measuring harmonic with 195 of the 2,878 sites (6.7%) not capable of harmonic reporting. There were 0.71% of sites recording harmonics that exceeded the regulatory limits of 8.0% during 2021-22. 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, VSD (Variable Speed Drives) controlled pumps, 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 2021-22 Ergon Energy continued to focus its voltage management strategy on all voltage levels of the network. Ergon Energy has voltage management challenges at bulk supply points and sub-transmission networks from the increase connection of large scale solar farms, and further challenges in the LV and lesser extent the MV networks due to the increase in residential solar systems. In 2019, Energy Queensland finalised the Customer Quality of Supply Strategy which covers the Power Quality strategy for Ergon Energy and Energex.

10.5.1 Medium/High Voltage Network

Ergon Energy has a high number of large industrial customers and large embedded generators (solar farms, biofuels) 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 PQ parameters as part of the connection agreement.

10.5.2 Low Voltage Network

The high penetration of solar PV systems on the Low Voltage (LV) networks has highlighted some 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 ongoing work to ensure 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, continual work balancing customer connections on the LV network to minimise neutral current, and negative load in the MV network. The full impact of solar PV is discussed in Chapter 11: Emerging Network Challenges and Opportunities.

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 and/or Low Voltage Regulator (LVR).

Chapter 11

Network Challenges and Opportunities

11. 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 (EVs), climate change, as well as land and easement acquisition.

11.1 Solar PV

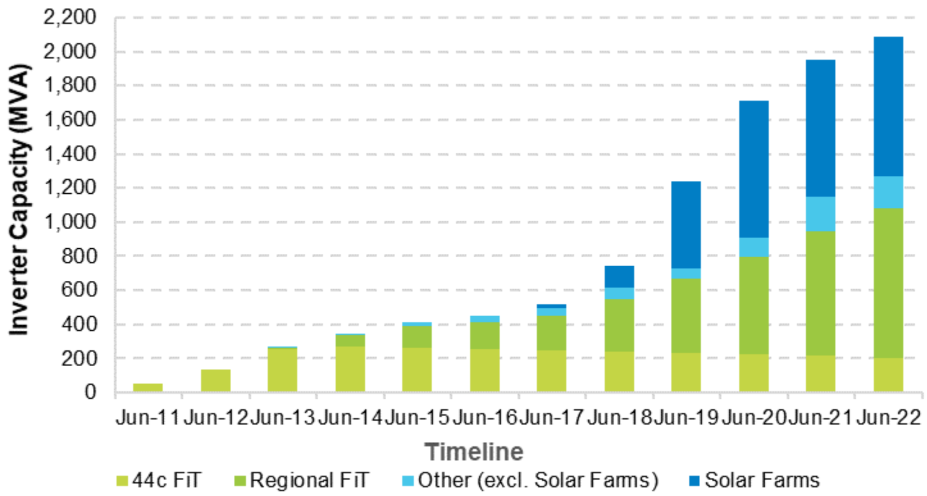
11.1.1 Solar PV Emerging Issues and Statistics

In Ergon Energy's network, 33% of detached houses have a solar PV system connected, with an average inverter capacity of around 4.8kVA. 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 continues to deploy 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 monthly volumes of solar PV connections trended downwards over 2021-22. Each month on average, around 1,400 new systems with a combined inverter capacity of around 15MVA, and average capacity of 10.2kVA, were connected. Ergon Energy now has a total of 216,159 PV systems connected at June 2022 with an installed capacity of 2,089MVA, with around 93% of systems installed on residential rooftops.

Figure 31 shows the increase in installed solar PV capacity, including small-, medium- and large-scale PV systems. Over the past 12 months, the volume of connections decreased by around 12% compared with the volume in the previous 12 months, and the PV capacity decreased by around 50%. The 119MVA of PV capacity added did not include any solar farms. The ongoing 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 over the year around 27% of zone substations experienced reverse power flows during the middle of at least one day.

Figure 31: Grid-Connected Solar PV System Capacity by Tariff as at June 2021



Another significant network issue resulting from increased solar PV connections is voltage rise and unbalance on LV networks. Voltage typically rises notably when solar PV generation and export is high.

Ergon Energy had approximately 390 QoS enquiries in 2021-22 related to solar PV, predominantly resulting from high voltages. Pleasingly, this volume was 32% down from the previous year, which was 37% down on the volume of the year before. These results reinforce the value of initiatives we have undertaken, or are undertaking, to minimise the impact of increasing volumes 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 and data analysis to enhance our visibility of network power flows and support the hosting of additional solar PV 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.

11.1.2 Impacts of Solar PV on Load Profiles

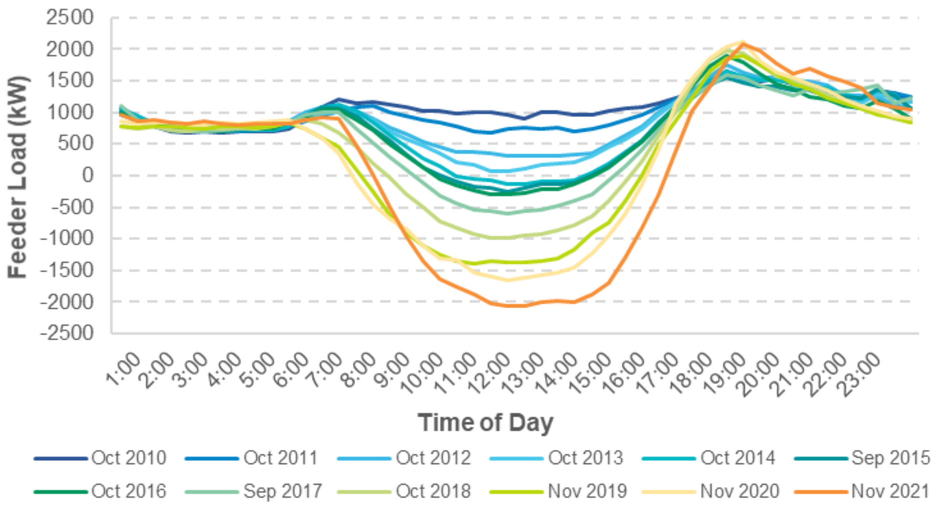
Solar PV is impacting load profiles, asset utilisation, load forecasting and load volatility.

Traditionally, the total aggregated demand of our network peaks 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. The system demand peak is now recorded in the evening, so the timing of the peak is not directly affected by PV generation, as PV systems are not generating at this time.

The change in load pattern as the penetration of solar PV systems on a feeder increases as illustrated in Figure 32. 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 12 consecutive years. The daytime generation of solar has increased to the point that the feeder back-feeds significantly through to the zone substation.

The spring peak demand for the feeder is still occurring at approximately the same time of night (slightly later) in 2021 as it did in 2010. While the night-time peak demand has been growing slowly over the years, the midday demand in spring has reduced by around 3MW. 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 32: Burrum Heads Feeder Profile: Annual Changes Observed for Spring 2010-21



The increase in Embedded Generation (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 electricity 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 must be supplied from the network, which can result in large and rapid variations in energy flows.

In such instances, the demand on the feeder is extremely volatile; low during the day with consumers generating and also consuming energy, then rapidly peaking when the storm clouds roll in. The solar PV generation can fall away completely for a short time, yet the customer load reduction can be delayed as air conditioners continue to run. The net result is a peak demand event in the early afternoon that can be 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, and 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 33 indicates the total installed capacity on each zone substation that has solar PV installed and Figure 34 indicates the proportion of customers with PV in the same areas. The five zone substation areas with the highest numbers have been highlighted on each map.

Figure 33: Installed Capacity of Solar PV by Zone Substation

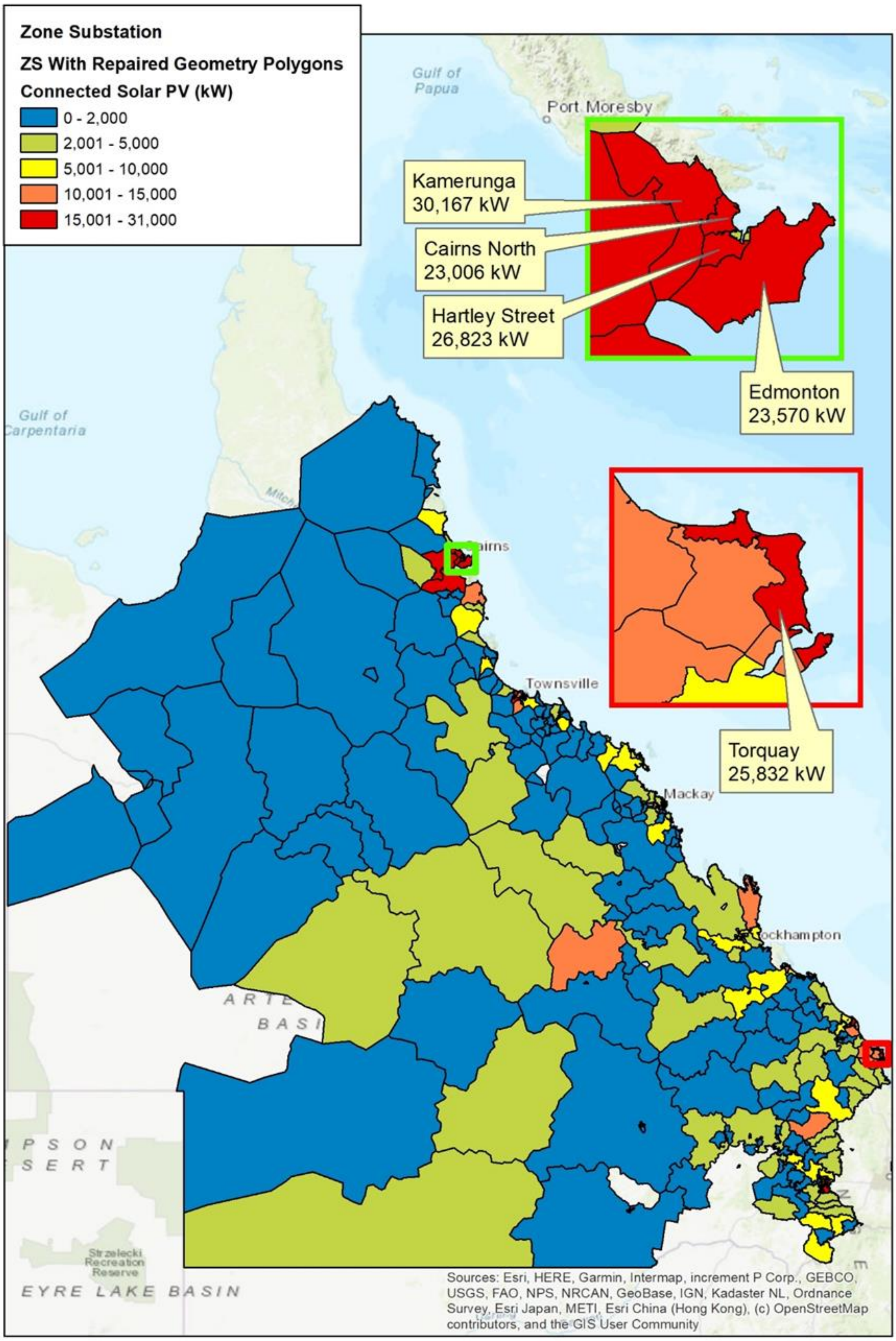
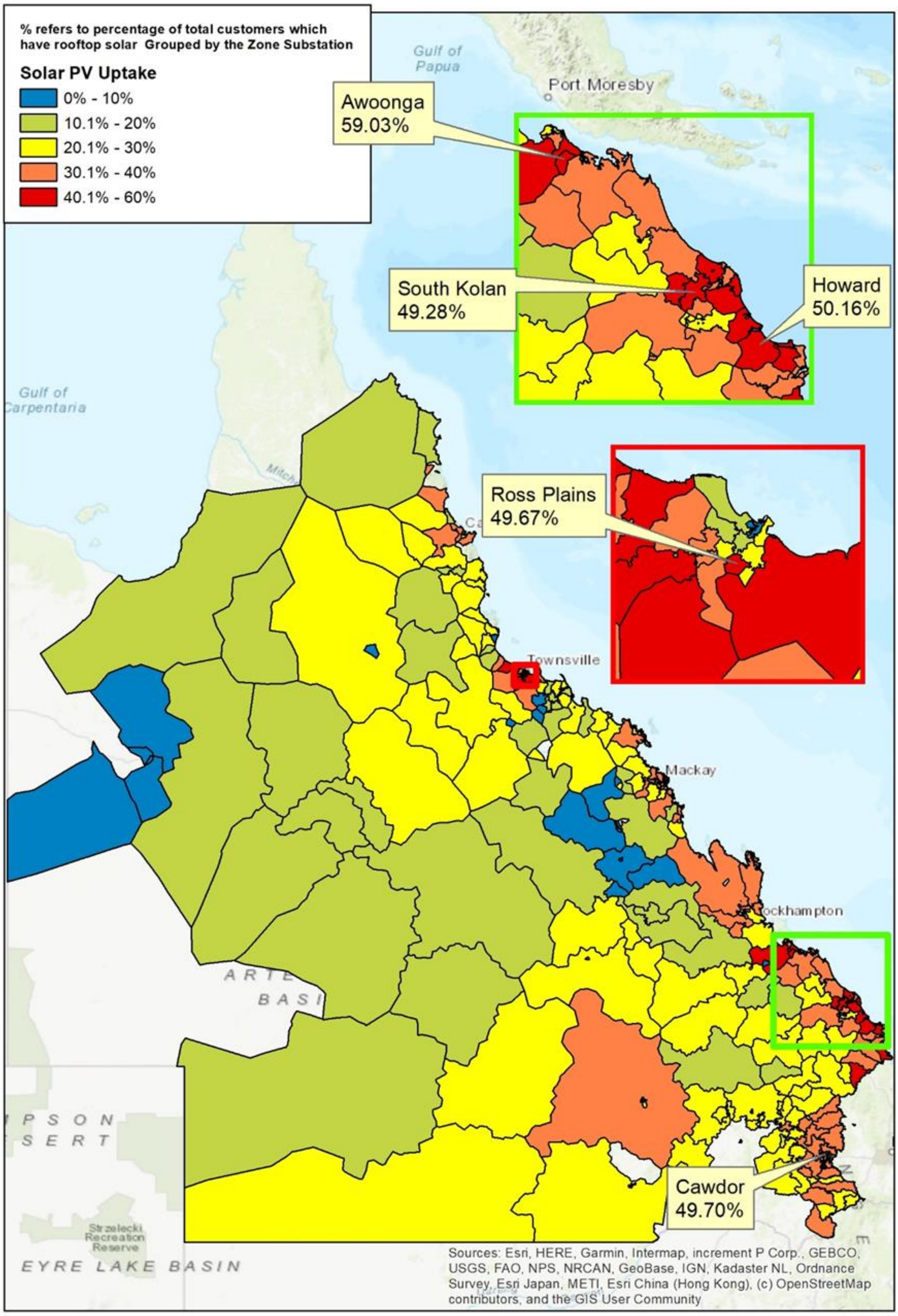


Figure 34: Solar PV uptake by Zone Substation



11.1.3 Solar PV Remediation Options

A range of traditional, new technology and non-network solutions as shown in Table 29 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 level at which it is required will be site specific and overtime several solutions may be implemented to maximise PV hosting capacity.

Table 29: Remediation Options for Increasing Penetrations of Solar PV

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

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[58] (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.

In response Ergon Energy has developed a Future Grid Roadmap[59] 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.

[58] Website: https://www.energynetworks.com.au/projects/electricity-network-transformation-roadmap/
[59] Website: https://www.talkingenergy.com.au/40930/documents/98191

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.

11.3 Electric Vehicles

The charging of Plug-in Hybrid Electric Vehicles (PHEVs) and Battery Electric Vehicles (BEVs) together, termed EVs, creates a new class of electrical load that could have significant impacts on the Low Voltage (LV) 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 likely 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 both private and commercial 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 other stakeholders. As the proportion of electricity entering the grid from renewable energy, and the uptake of solar PV systems, increase, the greenhouse gas emissions intensity of electricity generation and distribution reduces, creating an increasing environmental advantage for EVs over petrol- or diesel-fuelled vehicles.

In the 12 months to 30 June 2022, the volume of EVs registered in Queensland increased by 86% to more than 11,700 vehicles. Around 10% of those EVs are in regional Queensland, although passenger EVs still only account for 0.4% of all registered cars in Queensland, 3.5% of cars sold over the previous 12 months were EVs, up from 1.6% in the previous year. There is no evidence yet that EV charging is having any detrimental impact on the network. As EV volumes inevitably increase, and potentially rapidly, network challenges will emerge; however, so will opportunities to manage EV charging to deliver benefits to the network, the entire electricity supply chain, EV owners and all electricity users.

Ergon Energy aims to play its part in enabling EV ownership and better understand and capitalise on EV charging. To help achieve this, we have developed a Network Electric Vehicles Tactical Plan, which is available on our website.[60] The tactical plan outlines the key actions our network business will take over the next one to two years to prepare for EVs. Three tactics are now defined as complete. In the next version of the tactical plan to be released in late 2022, completed tactics will be replaced with new tactics, and other tactics updated and reiterated.

11.4 Battery Energy Storage Systems

The adoption rate of battery energy storage systems (BESS) is still modest, with only around 2% of solar PV owners on our network having invested in a BESS. However, our 2022 Queensland Household Energy Survey results indicate that 13% of regional Queensland respondents who have heard of battery storage intend to install a system within the next three years.

Ergon Energy continues to monitor influencing factors and technologies in the residential and commercial BESS market to evolve our relevant 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 BESS installations connected to the Ergon Energy network was around 4,000 at June 2022. 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 export capacity of 4,000kW.

[60] 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/0010/1104022/Our-Network-Electric-Vehicles-Tactial-Plan-Overview.pdf

Experience from the testing of BESS available on the market suggests that there is opportunity for increased sophistication in the systems operation that would increase the potential value that the systems provide to the network and customer. Improved market signals would be required to stimulate these improvements.

Building on our deployment of our Grid Utility Support Systems comprising energy storage in SWER networks, we are developing energy storage solutions for fringe-of-grid, microgrids and isolated networks areas.

Taking our trials of BESS to the next level in 2021-22, we rolled out five 4MW/ 8MWh BESS across the Ergon Energy network. These systems in Toowoomba, Hervey Bay, Bundaberg, Townsville and Cairns have been deployed in areas of high solar PV penetration to absorb some of the excess PV generation and feed it back into the grid during peak demand periods. This stabilises the grid and supports the adoption of more solar PV systems. The deployment of 12 more sites has been approved and site selection is under way.

11.5 Stand Alone Power Systems

In alignment with our Future Grid Roadmap we have initiated a project 'Transforming Supply for our Fringe of Grid Customers'. The project is focused on rural and remote customers at our fringe of grid.

Ergon Energy is working with Queensland Government, customers, communities and other stakeholders to develop transition strategies and business models that ensure our customers continue to have access to safe, secure, affordable, reliable and efficient energy supply solutions.

Ergon Energy Network has approximately 65,000 kilometers of Single Wire Earth Return (SWER) lines, one of the largest SWER networks in the world supplying 4 per cent of Ergon Energy Network's customers. The majority of the SWER network was installed in the 1970's and 1980's and is located in western Queensland where it is sparsely populated.

Providing cost-effective and reliable electricity supply in remote locations is challenging and as the network comes to the end of its life, alternative future supply options are being investigated. Stand Alone Power Systems is one of our initiatives focused on different supply models for our fringe-of-grid customers.

The Stand Alone Power Systems (SAPS) typically include renewable generation (predominately solar PV), battery storage with back-up diesel generation. Advances in battery management systems and reductions in the cost of battery technologies are enabling SAPS to become increasingly economically viable compared to traditional network supply, by poles and wires, in remote locations.

These technologies can improve individual customer experiences, particularly for remote customers who are supplied electricity over long distances, whilst providing the opportunity to lower the cost of providing energy services in the future. The current regulatory framework does not allow distributors to disconnect customers from the grid and supply them by SAPS and we continue to advocate and work with regulatory bodies to deliver community and customer focused energy supply solutions. We are trialling network support SAPS as an alternative to network supply for individual customers supplied by long SWER lines and exploring the long-term opportunities SAPS may provide for our customers.

11.6 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.

11.7 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 Ergon Energy network assets creating reliability problems as well as associated maintenance and asset replacement expenditures.

Ergon Energy, 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 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
- Assessing the ability of our network to withstand increasing weather events and the impact on customer reliability.

11.8 Large-scale Renewable Energy Projects

Ergon Energy is currently managing more than 100 enquiries, from preliminary to final commissioning stages, for large-scale (>1500kW) renewable energy generating systems, totalling almost 6GW of renewable energy investment. To date, almost 1.1GW of large-scale renewable generating systems is connected to the Ergon Energy network, in addition to more than 1.8GW of renewable energy generating systems connected to Powerlink's transmission network in regional Queensland as found in the Powerlink TAPR.[61] 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.

[61] Website: https://www.powerlink.com.au/reports/transmission-annual-planning-report-2022

11.9 Minimum System Load – Emergency Backstop Mechanism

The overall demand for electricity from the grid is falling, particularly in the middle of the day when large amounts of electricity is being generated from solar systems and exported back into the electricity grid. This is creating a challenge referred to as 'minimum system load'. The grid can handle large amounts of solar and there are a range of actions that network operators implement to ensure our system stays safe and secure. As Queensland is connected to the national electricity grid, changes in the balance between supply and demand can be managed across the network by the Australian Energy Market Operator (AEMO), Powerlink Queensland, Energex and Ergon Energy Network. However, modelling by AEMO has found that if the connection between Queensland and the national electricity grid is interrupted when there are very low levels of demand and high levels of solar output, there is a risk that some parts of the electricity network in Queensland could experience blackouts. To reduce this risk and allow more solar to be safely connected to the network, a new emergency measure has been established that can be used as a last resort, after all other actions have been taken, to keep our power supply secure. This emergency measure is referred to as the 'emergency backstop mechanism'.

From 6 February 2023, all new and some replacement inverter energy systems (like rooftop solar PV), with aggregated capacity of 10kVA and above, will need to have a generation signalling device (GSD) fitted that will enable the inverter to receive a signal to switch off. The signal is sent to the GSD from Ergon Energy Network and Energex's powerline signalling system, known as Audio Frequency Load Control (AFLC). For larger sites with multiple inverters, including embedded networks, installers have the option of using a GSD on each inverter or installing a single GSD connected to a Demand Response Controller. Some exclusions apply to the requirement to install a GSD – including inverter energy systems where the inverter is solely supplied by a battery, and any inverter energy systems installed at a location that is not serviced by the AFLC system.

The emergency backstop mechanism will be instigated by Ergon Energy Network and Energex under the direction of AEMO in alignment with the Distribution Authorities set out by the Department of Energy and Public Works, to help maintain a safe and secure network. This will only occur in response to specific network emergency conditions, such as when the main electricity connection between Queensland and the National Electricity Market (NEM) is offline at the same time there are high levels of PV generation being exported back into the grid. It cannot be operated under any other circumstances, and it will only be instigated after various other mechanisms available to the network operators have been implemented.

More information on emergency backstop mechanism is available in our website [62]

[62] Website: https://www.ergon.com.au/network/our-services/connections/residential-and-commercial-connections/solar-connections-and-other-technologies/emergency-backstop-mechanism

Chapter 12

Information Technology and Communication Systems

12. Information Technology and Communication Systems

12.1 Information Communication and Technology

Information Communication and Technology Investment 2021-22

This section summarises the material investments Ergon Energy has made in the 2021-22 financial year, relating to ICT systems.

Energy Queensland recognises ICT as a key enabler of efficient business operation, customer services and safety management and aligns its digital strategy to provide technology solutions which are secure, sustainable, and affordable. This is being achieved by prioritising the consolidation of digital solutions across the organisation. The key focus for the year was delivery of scope consistent with the AER Plan approved for the five-year period that began on 1 July 2020. The key focus areas for this year have been:

- Enterprise Asset Management solution transformation
- Upgrade of the Network's Distribution and Outage Management systems
- Asset Inspection and Monitoring Tools replacement
- Planning for the replacement of the Customer and Market Systems suite of solutions, and
- Protecting the security of the digital network through improving Cyber Security maturity.

In addition to the core delivery program, 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 30 provides an initiative level summary of Ergon Energy's ICT investment undertaken in 2021-22. These include projects which commenced prior to this year and investments not completed by 30 June 2022. Further information on the scope of each initiative is included below.

Table 30: ICT Investments 2021-22

Description	2021-22 Actual Cost $M
Asset and Works Management	$33.79
Distribution Network Operations	$16.14
Customer and Market Systems	$4.91
Corporate Systems	$31.52
ICT Management Systems, Productivity and Cybersecurity	$3.90
Infrastructure Program	$8.42
Minor Applications Change and Compliance	$2.87
Total	**$101.55**

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).

Asset and Works Management

The Asset and Works Management (AWM) stream is considered one of Energy Queensland's Digital Enterprise Building Block (DEBBs) being delivered as part of an overarching program. Two key initiatives were progressed during 2020-21.

AWM is delivering integrated functionality to help Ergon Energy manage its asset investment portfolio and integrated Program of Work (PoW). This includes maintenance planning, scheduling, and delivery of all types of work in the field critical to the reliability and safety of the electricity network. The first release has provided the ability for EQL Fleet teams to own and manage their fleet data and refine information within the maintenance plans and strategies. The focus for 2021-22 has been further developing the solution for roll out across all areas and field crews.

The Geographic Information System (GIS) is a key element of the asset management process. Between the Enterprise Asset Management (EAM) and the GIS, the core data for each asset within the physical and electrical network models are mastered, while supporting the major asset lifecycle processes of design, build and commissioning. Ergon Energy's existing system is end of life, significantly customised and no longer adaptable to business change. The replacement of this solution with a sustainable, best practice solution occurred in 2021-22, resulting in productivity improvements and network capital efficiency.

Distribution Network Operations

The Network Operation Control systems provide the technology to better connect our people, technology and data to manage the distribution of electricity for customers. Planning that occurred in the previous period has been leveraged to deliver a consolidated, proven, and modernised platform with consistent business processes for Energy Queensland. This will allow teams to support each other seamlessly and maximise business continuity in times of significant events anywhere in Queensland and represents a significant transformation from the out-dated, manual processes previously in place. Development of the new capability for Control Centres was undertaken during 2021-22 and roll out across Ergon Energy's regional offices and depots is scheduled to complete early in 2022-23.

Customer and Market Systems

Customer and Market Systems include the digital applications, tools and data stores to support Ergon Energy's market compliance, customer and stakeholder management functions in areas including contact centre services, customer information management, meter data management and retailer invoices and remittance management and are critical systems in supporting Ergon Energy with fulfilling its market obligations.

Existing systems are ageing, not keeping up with technology advances and cyber threats and in some cases no longer supported by vendors. Planning for the replacement of the suite of Customer and Market Systems completed during 2021-22 resulting in approval to commence the implementation phase.

Corporate Systems

Ergon Energy's core Enterprise Resource Planning (ERP) system reached both technical and financial obsolescence in mid-2015. Renewal of the ERP systems with contemporary systems commenced late in the previous regulatory period and is being finalised in the current period.

The People, Culture and Safety program has implemented a modern technology platform to replace people process related IT system including core human resource function in addition to recruitment, training, and talent management solutions.

The Procurement stream has established a new platform to enable consistent effective procurement processes and strategic contract management.

Ergon Energy's document and records management system is being replaced by leveraging the foundation capability delivered by the new ERP system. This is building a contemporary, consolidated solution for Energy Queensland and is delivering improved shared services productivity through best practice processes and ensures ongoing compliance with regulatory and legislative requirements as specified in the Public Records Act.

ICT Management Systems, Productivity and Cybersecurity

Energy Queensland operates in one of the most-commonly targeted sectors for cyber-attacks. As these threats continue to evolve, reaching into industrial control systems and supply chains, it requires even greater efforts to manage risk. EQL has some specific cyber risk factors relating to the convergence of Information Technology and Operations Technology, and the strategic importance of Critical Infrastructure. During FY21-22, a revised Cyber Security Strategy and a new Information Security Policy was developed, which focuses on getting our foundations right and building for the future beyond 2025. The Cyber Uplift Program (CUP) is ensuring EQL is safeguarding its information, and therefore its customers, against cyber security threats; maturing and strengthening our cyber security posture; developing a cyber security knowledgeable workforce; and building our cyber security maturity in line with industry good practice.

Infrastructure Program

The renewal of Ergon Energy's ICT infrastructure assets is delivered in accordance with Energy Queensland's ICT Infrastructure Asset Renewal Guidelines. Digital infrastructure and technology software asset performance degrades due to age and technical obsolescence. To sustain capability an ongoing program is required to replace these assets. Assets covered by the program include: Digital Fleet (desktops, laptops, mobile devices and video conferencing equipment); corporate data network equipment; server storage infrastructure renewal and growth. The program also includes infrastructure software renewal of ICT technologies such as Exchange Email, integration technologies and database environments.

Energy Queensland's 2030 Digital Strategy identified the need for a digital response to disruptions through disintermediation, distributed energy, digital technology, and public policy agendas. This mandates the ability to respond quickly to changes and readiness to engage with emerging technology while maintaining safety, supporting positive customer experiences, providing excellent value for money to the Queensland community and protecting EQL data and systems while managing risk. A critical enabler for 2030 ambition has been the transition from a predominantly on premise ICT infrastructure to robust, secure, well managed, flexible, and efficient hybrid cloud infrastructure. An initiative was undertaken during 2021-22 to establish Cloud Broker capability.

Minor Applications Change and Compliance

Investments to address safety and compliance during 2021-22 included changes to the Customer and Market Systems to ensure compliance to regulatory imposed settlement rule changes and annual tariff reform changes.

12.2 Forward ICT Program

As Ergon Energy looks toward the future, it will continue to ensure digital systems and capabilities are maintained for sustainability, cybersecurity, compliance, and operational safety. Continuing the inflight technology replacements and planning for additional improvement will also be leveraged to enable the company's planned productivity improvement.

Energy Queensland continues to be committed to the transformation program currently inflight, which is planned to be delivered across multiple years due to the scale and complexity involved in replacing several major systems in parallel. This approach has been agreed to realise efficiencies by reducing multiple integration activities that would have otherwise been required.

A high-level summary of potential ICT investment for Ergon Energy's Distribution Business for the forward ICT Program is shown in Table 31. Emerging priorities and new technologies will result in ongoing prioritisation and may require adjustments to the current plan. Forecasts have been grouped by initiative names as included in the ICT Plan for 2020-25.

Table 31: ICT Investment Forecast 2022-23 to 2026-27

Initiative	2022-23 $M	2023-24 $M	2024-25 $M	2025-26 $M	2026-27 $M
Asset and Works Management	$51.84	$17.75	$6.75	$8.50	$3.50
Distribution Network Operations	$19.12	$3.38	$3.50	$5.25	$15.00
Customer and Market Systems	$10.90	$6.82	-	-	-
Corporate Systems	$21.29	$5.86	$6.46	$3.50	$3.50
ICT Management Systems, Productivity and Cybersecurity	$6.57	$3.50	$4.50	$3.50	$3.50
Infrastructure Program	$7.51	$9.91	$12.15	$6.00	-
Minor Applications Change	$1.78	$1.25	$2.75	$1.25	$1.25
Grand Total	**$119.01**	**$48.47**	**$36.11**	**$28.00**	**$26.75**

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. Forecasts for 2025-26 and 2026-27 are estimates and likely to change.

12.3 Metering

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

Ergon Energy 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 Energy 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 Energy 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 2021-22

There were minimal revenue metering investments in 2021-22 due to Power of Choice legislation that prevents Ergon Energy from installing any new meters in NEM connected areas. Non-NEM Revenue Meter Capital expenditure for 2021-22 was less than $50,000.

12.3.2 Revenue Metering Investments from 2022-23 to 2026-27

The future investment in revenue metering by Ergon Energy 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 a range of directions for the company:

- Transition away from obsolete Telecommunications technologies and equipment
- Ensure Obsolete technologies remain viable while still in service
- Improve management of supporting infrastructure
- Enable Regulated growth and reduce cost of Regulated services by aligning opportunities with un-regulated growth
- Improve Monitoring the Telecommunications Environment
- Cross stream initiatives
- Improve asset management of Telecommunications environment
- Re-organise responsibilities between divisions / groups and department to embrace automation, adoption of new technologies and digital enablement.

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

i. 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 Energy 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 are now practically complete
- 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
- Integration between the P25 Network, the SATPTT system and the controller voice console solution is currently underway to improve safety for workers by providing making the process of contacting the control centre operatives consistent between the platforms.

ii. 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 two years due to the asset categories' age profile and higher than forecast battery cell failure rates.

iii. 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 2021-22 include Network Management Systems and legacy voice related aged replacements and the 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.

iv. 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 by the following:

Supervisory Control and Data Acquisition

Work to support transition from the current master station to the Unified Distribution Management System (UDMS) is ongoing. 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 replacement RTU for the in house developed unit that will be common across Energy Queensland has been completed. Work is underway changing support systems to allow the new equipment to suitably integrate into the current environment. Work to enable standardised integration of substation battery systems and customer Distributed Energy Resources (DER), in a manner enabling Dynamic Operating Envelopes (DOE) has been progressing. As well as enabling the initial substation battery systems, this is an enabler for DERMS (see Intelligent Grid Enablement section below) with the first systems scheduled for commissioning in Q1 2022.

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.

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.

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 is continuing to renew aging security and support infrastructure in its Operational Technology Environment and migrating to a common security philosophy and implementation with Energex. Additional threats were identified during the period and a range of mitigation activities is occurring.

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.

Operator Telephony Console Replacement

Ergon Energy's existing operator telephony console was at the end of support and has been upgraded to the latest platform of the encumbent vendor (Zetron).

Intelligent Grid Enablement

Ergon Energy is investing in the development of a smarter network for the future. The growth of Distributed Energy Resources (DER) in distribution networks, both at residential and commercial levels, requires Ergon Energy to consider new approaches for maximising DER hosting capacity.

In order to deliver sustainable outcomes for the network and choice for customers, Ergon Energy has begun delivery of the following major intelligent grid capabilities:

- SEP2 (IEEE 2030.5) Utility Server - Implementation of a suitable and common communication standard between the DNSP and DER/aggregators to communicate constraints and opportunities is a critical building block in enabling 'active' connections for all customers. This work is a result of our stakeholder consultation on dynamic connection agreements.[63] External access to this server is now available for third parties
- The Telemetry Hub is an internal collection of systems that integrate, store, process and visualise the diverse and increasing streams of telemetered data from the electrical network and provide this information in a common format for consumption by multiple end use cases. 2021/22 saw the successful delivery of an internal user portal and production event streaming platform in co-operation with our Digital division
- Distribution System State Estimation (DSSE) - A process for estimating the most probable electrical state of a network without the need for measurement data at every point. DSSE provides complete network visibility at any point in time using available data and can dramatically reduce the capital and operation cost of deploying physical monitors to the network. The DSSE and corresponding integrations were productionised in 2021/22, delivering near real time and historic state estimation to demonstration feeders
- Capacity Constraint Optimiser (CCO) - A constraint engine which determines the active network performance and limits, applies allocation rules and passes subsequent constraint envelopes via an orchestration system to deliver the best outcome. Used in combination with the DSSE, the CCO delivered an optimised operating envelope to sites and was formed the basis of the network winning the 2021 ENA Innovation Award[64]
- Distributed Energy Resources Management System (DERMS) – Similar to the existing Distribution Management System (DMS), the DERMS platform is being developed as a dedicated head end system to interact with and manage all sizes of DER and existing Audio Frequency Load Control (AFLC) infrastructure. It is envisioned to run with a high degree of autonomy with manual intervention by exception. In 2021/22 both a Request For Information (RFI) and Request For Tender (RFT) procurement exercises were run to establish a suitable technology partner for the network, with contract award forecast for mid-2022/23 financial year
- Network model sharing by Common Information Model (CIM) – The as-built/as-operated model or 'digital twin' of the electricity network forms a critical foundation to many digitally enabling initiatives and as such, Ergon Energy is investing in standardising it's availability to new and existing systems. A trial was run in 2021/23 with a demonstration feeder exported from GIS systems into the common format and successfully re-imported into downstream systems. Productionalisation is planned for 2022/23 via a dedicated Digital project.

[63] Web source: https://www.talkingenergy.com.au/dynamicconnections
Additional Source: Consultation Paper on Enabling Dynamic Customer Connections for DER
https://www.talkingenergy.com.au/64816/widgets/321357/documents/190166
[64] Web source: https://www.energynetworks.com.au/events/2021-energy-network-industry-awards/

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.

LV Network Safety Monitoring Program

Safety by design is fundamental to Egon Energy's network strategy, providing safe and reliable electricity to 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 deploying a smart network monitoring device with neutral integrity monitoring capability which will be installed under a dedicated safety program on selected customer premises throughout Queensland. The scope provides for gathering of field data, through purpose-built sensors and/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 and/or in customer installations. The 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.

12.4.3 Investments in 2021-22

Table 32 summarises Ergon Energy's Information Technology and Communication systems investments for 2021-22.

Table 32: Information Technology and Communication Systems Investments 2021-22

Description	Direct Cost ($M)
Telecommunications Network	
Field Mobile Networks	$1.37
Communications Site Infrastructure Program	$1.97
Communications Network Assets Program	$8.20
Network Capacity and Coverage	$1.45
Operational Systems	
Operator telephony console replacement	$1.80
Common OTE	$0.10
OT Security projects	$1.89
SCADA and Automation Enhancement	$0.17
LV Network Safety Monitoring program	$0.10
Intelligent Grid Enablement	$2.42
Total	**$19.47**

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 Energy and Energex, potentially impacting the treatment of some Capital and Operational Project costs.

12.4.4 Planned Investments for 2022-23 to 2026-27

Table 33 summarises Ergon Energy's OT and associated Telecommunication planned investments for 2022-23 to 2025-27.[65]

Table 33: Operational Technology Planned Investments

Description	Direct Cost ($M planned)
Telecoms Network	
Field Mobile Networks	$4.62
Communications Site Infrastructure Program	$16.58
Communications Network Assets Program	$38.60
Network Capacity and Coverage	$31.51
Operational Systems	
Common OTE	$3.07
OT Security projects	$2.92
SCADA and Automation Enhancement	$9.38
LV Network Safety Monitoring Program	$40.8
Intelligent Grid Enablement	$13.60
Total	**$ 161.08**

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 Energy and Energex, potentially impacting the treatment of some Capital and Operational Project costs.

[65] 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
BEV	Battery Electric Vehicles
BOM	Bureau of Meteorology
BSS	Bulk Supply Substation is a substation that converts energy from transmission voltages to sub-transmission 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 its 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.
DA	Ergon Energy's Distribution Authority DO1/99 (DA)
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
DEPW	Department of Energy and Public Works
DER	Distributed Energy Resources
DF	Distribution Feeder
DFD	Distribution Feeder Database
DLC	Direct Load Control
DM	Demand Management. Alternate term is Non-Network Alternatives

Term/Acronym	Definition
DMIA	Demand Management Innovation Allowance
DMS	Distribution Management System
DMIS	Demand Management Incentive Scheme
DNAP	Distribution Network Augmentation Plans
DNCR	Distribution Network Capability Report
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
EG	Embedded generating units >30kVA in size.
EMF	Electro Magnetic Field
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
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

Term/Acronym	Definition
GSL	Guaranteed Service Level
GSP	Gross State Product: sourced from the ABS website
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.
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
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

Term/Acronym	Definition
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
MOU	Memorandum of Understanding
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
NEL	National Electricity Law
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 supply standards.
NNA	Non-Network Alternatives. An alternate term is Demand Management
NODW	Network Operations Data Warehouse
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

Term/Acronym	Definition
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)
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

Term/Acronym	Definition
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
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
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.
Sub-transmission	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, sub-transmission 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.

Term/Acronym	Definition
SVC	Static Var Compensator
SVR	Step Voltage Regulator
SW	South Western region of Queensland
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
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.
UFLS	Under Frequency Load Shedding
UG	Underground
UR	Urban
V	Volts
V2G	Vehicle to Grid
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
WB	Wide Bay region of Queensland

Term/Acronym	Definition
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 sub-transmission voltages to distribution voltages.

Appendix B

NER and DA Cross-Reference

Appendix B. NER and DA Cross-Reference

Table 34: NER Cross Reference

National Electricity Rules Version 181 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 **5.4.2** Safety Net **11** Emerging Network Challenges and Opportunities
(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** Rating Methodology **5.6** Voltage Limits **5.7** Fault Level Analysis Methodology **5.11** Network Planning – Assessing System Limitations **Appendix D** Substation Forecast and Capacity Tables **Appendix E** 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 Previous Year's 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** Network Forecasting
(2)	load forecasts (i) at the transmission-distribution connection points; (ii) for sub-transmission lines; and (iii) for zone substations,	**6.1** Network Limitations – Adequacy, Security and Asset Condition **6.5** Emerging Network Limitation Maps **Appendix D** Substation Forecast and Capacity Tables **Appendix E** Feeder Forecast and Capacity Tables

National Electricity Rules Version 181 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
	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;	
(2A)	forecast use of distribution services by embedded generating units: (i) at the transmission-distribution connection points; (ii) for sub-transmission lines; and (iii) for zone substations,	**4.2.3** Sub-transmission Feeder Forecasting Methodology **4.2.4** Distribution Feeder Forecasting Methodology **6.1** Network Limitations – Adequacy, Security and Asset Condition **6.1.5** Embedded Generating Unit Capacity Limitations **6.2** Summary of Emerging Network Limitations **Appendix E:** Feeder Forecast and Capacity Tables
	including, where applicable, for each item specified above: (iv) total capacity to accept supply from embedded generating units; (v) firm delivery capacity for each period during the year; (vi) peak supply into the distribution network from embedded generating units (at any time during the year) and an estimate of the number of hours per year that 95% of the peak is expected to be reached; and (vii) power factor at time of peak supply into the distribution network	
(3)	forecasts of future transmission-distribution connection points (and any associated connection assets), sub-transmission lines and zone substations, including for each future transmission-distribution (i) location; (ii) future loading level; and (iii) proposed commissioning time(estimate of month and yar);	**6.1** Network Limitations – Adequacy, Security and Asset Condition **6.5** Emerging Network Limitation Maps **Appendix D** 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 181 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 Demand Management Integrates 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 **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

National Electricity Rules Version 181 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
(b2)	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;	**6.3** Network Asset Retirements and De-Ratings
(c) information on system limitations for subtransmission lines and zone substations, including at least:		
(1)	estimates of the location and timing (month(s) and year) of the system limitation;	**6.1** Network Limitations – Adequacy, Security and Asset Condition **6.5** Emerging Network Limitation Maps **Appendix D** Substation Forecast and Capacity Tables **Appendix E** Feeder Forecast and Capacity Tables
(2)	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;	
(3)	impact of the system limitation if any, on the capacity at transmission-distribution connection points;	
(4)	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	

National Electricity Rules Version 181 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 E** 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;	
(d1) for any primary distribution feeders for which a Distribution Network Service Provider has prepared forecasts of demand for distribution services by embedded generating units under clause 5.13.1(d1)(3) and which are currently experiencing a system limitation, or are forecast to experience a system limitation 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 E** Feeder Forecast and Capacity Tables
(2)	the extent to which demand for distribution services by embedded generating units exceeds, or is forecast to exceed, 100% (or lower utilisation factor, as appropriate) of the normal capacity to provide those distribution services under normal conditions;	

National Electricity Rules Version 181 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)	the types of potential solutions that may address the system limitation or forecast system limitation;	
(4)	where an estimated reduction in demand for distribution services by embedded generating units would defer a forecast system limitation for a period of 12 months, include: (i) an estimate of the month and year in which the system limitation (ii) a summary of the location of relevant connection points at which the estimated reduction in demand for distribution services by embedded generating units would defer the system limitation; and (iii) the estimated reduction in demand for distribution services by embedded generating units 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;	
(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;		**6.4.2** 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:		

National Electricity Rules Version 181 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
(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;	**6.4.3** 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:		
(1)	a summary of the process and methodology used by the Distribution Network Service Provider and relevant Transmission Network Service Providers to undertake joint planning;	**5.10** Joint Planning
(2)	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	
(3)	where additional information on the investments may be obtained;	
(i) the results of any joint planning undertaken with other Distribution Network Service Providers in the preceding year, including:		
(1)	a summary of the process and methodology used by the Distribution Network Service Providers to undertake joint planning;	**5.10** Joint Planning
(2)	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	
(3)	where additional information on the investments may be obtained;	
(j) information on the performance of the Distribution Network Service Provider's network, including:		
(1)	a summary description of reliability measures and standards in applicable regulatory instruments;	**9** Network Reliability **10** Power Quality
(2)	a summary description of the quality of supply standards that apply, including the relevant codes, standards and guidelines;	

National Electricity Rules Version 181 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 summary description of the performance of the distribution network against the measures and standards described under subparagraphs (1) and (2) for the preceding year;	
(4)	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;	
(5)	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	
(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;	**5.4.5** 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;	**2.4.6** Further Information
(l) information on the Distribution Network Service Provider's demand management activities, including:		

National Electricity Rules Version 181 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
(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: (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;	**7.6** Key Issues Arising from Embedded Generation Applications
(3)	a quantitative summary of: (i) enquiries under clause 5A.D.2 in relation to the connection of micro embedded generators or non-registered embedded generators; and (ii) applications for a connection service under clause 5A.D.3 in relation to the connection of micro embedded generators or nonregistered embedded generators;	**7.6** Key Issues Arising from Embedded Generation 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	

National Electricity Rules Version 181 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
(o) the analysis of the known and potential interactions between:		
(1)	any emergency frequency control schemes, or emergency controls in place under clause S5.1.8, on its network; and	**6.5** Emerging Network Limitation Maps **9.7** Emergency Frequency Control Schemes and Protection Systems
(2)	protection systems or control systems of plant connected to its network (including consideration of whether the settings of those systems are fit for purpose for the future operation of its network),	
undertaken under clause 5.13.1(d)(6), including a description of proposed actions to be undertaken to address any adverse interactions		

Table 35: 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:		
(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 Distribution Feeders **Appendix F** Worst Performing Distribution Feeders **Supporting Document:** "Worst-Performing-Distribution-Feeders-2022.xlsx"
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.	

Appendix B. NER and DA Cross-Reference

Distribution Authority No. D01/99 DAPR reporting obligations:	Report Section
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 F** Worst Performing Distribution Feeders **Supporting Document:** "Worst-Performing-Distribution-Feeders-2022.xlsx"

Appendix C

Network Limitations and Mitigation Strategies

Appendix C. 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 2021 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 previous 2021 DAPR have been deferred beyond the forward planning period due to declining growth in demand forecasts. Furthermore, some projects have been since - 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-2022.xlsx[66]
- Substation-Limitations-and-Proposed-Solutions-2022.xlsx[67]
- Transmission-and-Subtransmission-Feeder-Limitations-and-Proposed-Solutions-2022.xlsx[68]
- Transmission-and-Subtransmission-Feeder-Limitations-and-Committed-Solutions-2022.xlsx[69]

Further details can be obtained from the Ergon Energy website.[70]

GIS based mapping including forecasts and limitations are available via the Ergon Energy's latest DAPR Map.[71]

[66] Websource: https://www.ergon.com.au/__data/assets/excel_doc/0006/1081707/Substation-Limitations-and-Committed-Solutions-2022.xlsx

[67] Websource: https://www.ergon.com.au/__data/assets/excel_doc/0011/1081676/Substation-Limitations-and-Proposed-Solutions-2022.xlsx

[68] Websource: https://www.ergon.com.au/__data/assets/excel_doc/0010/1081675/Transmission-and-Subtransmission-Feeder-Limitations-and-Proposed-Solutions-2022.xlsx

[69] Websource: https://www.ergon.com.au/__data/assets/excel_doc/0007/1081663/Transmission-and-Subtransmission-Feeder-Limitations-and-Committed-Solutions-2022.xlsx

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

[71] Website: https://www.ergon.com.au/daprmap2022

Appendix D

Substation Forecast and Capacity Tables

Appendix D. 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.[72]

GIS based mapping including forecasts and limitations are available via Ergon Energy's latest DAPR Map.[73]

D:1 Transmission Connection Point Load Forecast

The detailed load forecasts for TCPs are presented on Ergon Energy's DAPR Map site and in Microsoft Excel™ format via the following link below. (Note that TCPs where Ergon Energy owns the power transformers are categorised in this document as bulk supply substations and are included in Appendix D:2 Substation Capacity and Load Forecasts).

Forecast	Link to Microsoft Excel compatible file
TCPs (where Ergon Energy does not own the power transformers)	Transmission-Connection-Point-Forecasts-2022.xlsx[74]

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 (EG).

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 D:2 Substation Capacity and Load Forecasts and D:3 Forecasts for Future Substations and TCPs.

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

[73] Website: https://www.ergon.com.au/daprmap2022

[74] Website: https://www.ergon.com.au/__data/assets/excel_doc/0007/1081636/Transmission-Connection-Point-Forecasts-2022.xlsx

Embedded generation

Table 36 presents Embedded Generation (EG) connected to the load side of TCPs where Ergon Energy does not own the power transformers. All other EG appears in the substation capacity and load forecasts below in Appendix D:2 Substation Capacity and Load Forecasts.

Table 36: 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
Southern	Yarranlea North 110kV Switching Station	103
Southern	Gin – Bundaberg 110kV	78
Southern	Drillham Switching Station	180.6
Southern	Middlemount 66kV	26

D: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 Ergon Energy's DAPR Map site and in Microsoft ExcelTM format via the following link. Where limitations are identified in this table, further explanation is given in Section 6.1: Network Limitations – Adequacy, Security and Asset Condition.

Forecast	Link to Microsoft Excel compatible file
Bulk supply and zone substations:	Substation-Forecasts-2022.xlsx[75]

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)
- DER impacts including Capacity for Embedded Generation (MVA) and Firm Capacity for Embedded Generation (MVA)
- 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.

[75] Website: https://www.ergon.com.au/__data/assets/excel_doc/0009/1081629/Substation-Forecasts-2022.xlsx

D:3 Forecasts for Future Substations and TCPs

Table 37 and Table 38 set out the forecast capacity for the forward planning period for approved future substations and transmission connection points.

Table 37: Forecasts for Future Substations

Region	Future Substation	Location	Proposed Commissioning Time	Future Loading Level
Southern	Gracemere 66/11kV - New Substation	Rockhampton Region	Qtr 1 2023	Available in 2023
Southern	Kleinton 33/11kV – New Substation	Toowoomba Region	Qtr 3 2024	Available in 2023

Note: Milestones as of November 2022 internal reports and are subject to change.

Table 38: Forecasts for Future Transmission Connection Points

Region	Future Transmission Connection Point	Location	Proposed Commissioning Time	Future Loading Level
-	Nil approved	-	-	-

Appendix E

Feeder Forecast and Capacity Tables

Appendix E. Feeder Forecast and Capacity Tables

The following subsections contain Feeder Forecast and Capacity Tables for sub-transmission and distribution feeders in the Ergon Energy network.

Further details can be obtained from the Ergon Energy website.[76]

GIS based mapping including forecasts and limitations are available via Ergon Energy's DAPR Map.[77]

E:1 Sub-transmission Feeder Capacity and Load Forecasts

Sub-transmission line capacity and load forecasts for both summer and winter are presented on Ergon Energy's DAPR Map site and in Microsoft Excel™ format via the following link:

Forecast	Link to Microsoft Excel compatible file
Sub-transmission feeder (10 PoE & 50 PoE)	Subtransmission-Feeder-Forecast-10PoE-2022.xlsx[78]
	Subtransmission-Feeder-Forecast-50PoE-Contingent-N-1-2022.xlsx[79]

Information is presented for both current and future forecasts for the relevant network asset.

The sub-transmission line tables include the following information:

- Ergon Energy region
- Ergon Energy ECORP code
- Ergon Energy operational code
- Sub-transmission 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)

Note:

- Summer - December to March
- All other months are classed as summer - March, April, May, September, October, and November.

[76] Website: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report
[77] Website: https://www.ergon.com.au/daprmap2022
[78] Website: https://www.ergon.com.au/__data/assets/excel_doc/0020/1081631/Subtransmission-Feeder-Forecast-10PoE-2022.xlsx
[79] Website: https://www.ergon.com.au/__data/assets/excel_doc/0003/1081632/Subtransmission-Feeder-Forecast-50PoE-Contingent-N-1-2022.xlsx

E:2 Sub-transmission Feeder Minimum Demand with DER Forecast

Sub-transmission feeders which are constrained based on substation minimum demand forecasts over the next five years:

Forecast	Link to Microsoft Excel compatible file
Sub-transmission feeder limitations	Subtransmission-Feeder-Forecast-Min-Demand-DER-2022.xlsx[80]

Contents of Table:

The distribution feeder limitation tables include the following information:

- Ergon Energy region
- Sub-transmission feeder name, identification and location
- Loading (measured in Amps, MVA, MW), power factor, conductor constraint (voltage), line rating (Amps) and utilisation (%)
- Five year forecast grainularised into summer day, summer evening and summer night-morning.

Limitations:

- Each Feeder reports the most constrained element, not the highest loaded element
- Runback schemes or dispatch constraints are not modelled. The results represent unconstrained generation
- Some generator voltage control schemes are not modelled. Reported voltages may be outside of normal specification
- 12pm loading was chosen to capture peak generation with minimum load in the majority of locations. In some locations the highest % loading of feeder elements occurs at times of day other than 12pm.

Exclusions:

Distribution feeders and single supplied customers. In addition, feeders supplying Charleville, Quilpie and Cunnamulla substations have been excluded from this report due to modelling limitations with the SVC for voltage control.

[80] Website: https://www.ergon.com.au/__data/assets/excel_doc/0005/1081634/Subtransmission-Feeder-Forecast-Min-Demand-DER-2022.xlsx

E:3 Sub-transmission Feeder Contingent (N-1) Minimum Demand with DER Forecast

This workbook provides a forecast of Sub-transmission Capacity constraints based on EQLs substation minimum demand forecasts with the network placed in an N-1 contingent state (i.e. the loading on the remaining network with any single feeder out of service):

Forecast	Link to Microsoft Excel compatible file
Sub-transmission feeder limitations	Subtransmission-Feeder-Forecast-Min-Demand-DER-Contingent-N-1-2022.xlsx[81]

Contents of Table:

The distribution feeder limitation tables include the following information:

- Ergon Energy region
- Sub-transmission feeder name, identification and location
- Loading (measured in Amps), power factor, conductor constraint (voltage), line rating (Amps) and utilisation (%)
- Five year forecast.

Limitations:

- Automatic or manual tripping and/or restoration schemes are not modelled.
- Runback schemes or dispatch constraints are not modelled. The results represent unconstrained generation
- Some generator voltage control schemes are not modelled. Reported voltages may be outside of normal specification
- Contingency scenarios may not have a direct network relationship with the feeder. For example, contingencies resulting in changes to general network voltages may result in marginally higher % loading in unrelated feeder elements
- 12pm loading was chosen to capture peak generation with minimum load in the majority of locations. In some locations the highest % loading of feeder elements occurs at times of day other than 12pm.

Exclusions:

Distribution feeders and single supplied customers. In addition, feeders supplying Charleville, Quilpie and Cunnamulla substations have been excluded from this report due to modelling limitations with the SVC for voltage control.

[81] Website: https://www.ergon.com.au/__data/assets/excel_doc/0006/1081635/Subtransmission-Feeder-Forecast-Min-Demand-DER-Contingent-N-1-2022.xlsx

E:4 Forecasts for Future Sub-transmission Lines

Table 39 sets out the forecast capacity for the forward planning period for approved future sub-transmission lines.

Table 39: Forecasts for Future Sub-transmission Lines

Region	Future Sub-transmission Line	Location	Proposed Commissioning Time	Future Loading Level
Southern	Egans Hill – Gracemere - New 66kV OH Line Construction	Rockhampton Region	Qtr 1 2022	Available in 2023
Southern	Reinforce Burnett Heads - New 66kV OH Line Construction	Bundaberg Region	Qtr 3 2027	Available in 2023
Southern	Boyne Residential-Boyne Residential Switching – Establish new 66kV Feeder	Maryborough Region	Qtr 3 2024	Available in 2023

E:5 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 Ergon Energy's DAPR Map site and in Microsoft Excel™ format via the following link:

Forecast	Link to Microsoft Excel compatible file
Distribution feeder limitations	Distribution-Feeder-Limitations-and-Committed-Solutions-2022.xlsx[82]

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 Appendix C: Network Limitations and Mitigation Strategies for a list of possible solutions.

Exclusions:

Dedicated customer connection assets are excluded from the analysis.

[82] Website: https://www.ergon.com.au/__data/assets/excel_doc/0008/1081628/Distribution-Feeder-Limitations-and-Committed-Solutions-2022.xlsx

E:6 Distribution Feeder DER Forecast

Distribution feeders which are constrained based on substation minimum demand forecasts over the next five years.

Forecast	Link to Microsoft Excel compatible file
Distribution feeder DER Forecast	Distribution-Feeder-DER-Forecast-2022.xlsx[83]

Contents of Table:

The distribution feeder limitation tables include the following information:

- Ergon Energy region
- Distribution feeder name, ID and location
- 5 year Power Forecast (MW)

Exclusions:

- Feeders dedicated to single customer connections
- Unmetered feeders
- Unsupplied or out of service feeders

[83] Website: https://www.ergon.com.au/__data/assets/excel_doc/0007/1081627/Distribution-Feeder-DER-Forecast-2022.xlsx

Appendix F

Worst Performing Distribution Feeders

Appendix F. Worst Performing Distribution Feeders

The Worst Performing Distribution Feeders includes details of MSS SAIDI and SAIFI limits as well as the associated three year average for 2021/22. This is available in spreadsheet format via the following hyperlink:

- Worst-Performing-Distribution-Feeders-2022.xlsx[84]

Further details can be obtained from the Ergon Energy website.[85]

[84] Websource: https://www.ergon.com.au/__data/assets/excel_doc/0019/1081711/Worst-Performing-Distribution-Feeders-2022.xlsx

[85] Website: https://www.ergon.com.au/network/network-management

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